UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit A: Department, Order No. 202-25-14 (Dec. 30, 2025)

Department of Energy
Washington, DC 20585

Order No. 202-25-14

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists within the Western Electricity Coordinating Council (WECC) Northwest assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

Craig Station (Craig) is an electric generating facility in Craig, Colorado. Craig is operated by the Tri-State Generation and Transmission Association (Tri-State). Craig consists of three coal-fired generation units, Unit 1 (446.4 MW), Unit 2 (446.4 MW), and Unit 3 (534.8 MW), with a combined name plate capacity of 1427.6 MW.[3] Unit 1 and Unit 2 are co-owned by Tri-State, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy (co-owners).[4] Unit 3 is wholly owned by Tri-State. Unit 1 and Unit 2 began operations in 1980 and 1979 respectively. Unit 3 began operations in 1984. Unit 1 is slated to cease operations in December 2025. Unit 2 and Unit 3 are slated to retire in 2028.[5]

EMERGENCY SITUATION

In its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that in the WECC Northwest assessment area, which includes Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming, "[e]nergy variability is greater in the Northwest than other WECC regions due to the large share of wind and hydro in the portfolio." The LTRA notes that:

> [f]ive [gigawatts] of baseload resource retirements are anticipated between 2024 and 2028. The energy needs are to be replaced by solar, wind, and [battery energy storage systems], further increasing variability in the portfolio. Given the retiring of baseload resources, supply chain issues preventing the construction of [battery energy storage systems] resources are a concern as they assist in meeting demand

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] U.S. Energy Information Administration, Form EIA-860, Schedule 3: Generator Data (2024), https://www.eia.gov/electricity/data/eia860/.
[4] Platte River Power Authority, Craig Units 1 & 2 (Yampa Project), https://prpa.org/generation/yampa-project/.
[5] As a coal-fired facility, it would be difficult for the Craig Unit 1 to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Tri-State and co-owners were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

during shoulder periods where solar availability is dropping but loads remain high.[6]

The 2024 WECC Western Assessment of Resource Adequacy notes that peak demand in WECC's Northwest-Central subregion, which includes Colorado, is "forecast to grow by 8.5% over the next decade, from 33 GW in 2025 to 36 GW in 2034."[7] Meanwhile, WECC notes that most planned retirements are "baseload generation, such as coal, natural gas, and nuclear."[8]

Since 2019, 571.3 MW of coal-fired generating capacity across six units at three locations have retired in Colorado,[9] leading to a decline in the share of coal-generated electricity from 45% to 28%.[10] Looking forward, by 2029, about 3,700 megawatts of coal-fired generating capacity in Colorado is scheduled to retire according to the Energy Information Administration (EIA),[11] accounting for all but one coal-fired power plant in Colorado. In that same time frame, 675.6 MW of natural gas-fired generating capacity in Colorado will retire as well.[12] In 2025, intermittent wind accounted for over 5,300 MW of Colorado's electricity generating capacity.[13]

Executive orders issued by President Donald J. Trump on January 20, 2025 and April 8, 2025 underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, "Declaring a National Energy Emergency," in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[14] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[15] In a subsequent Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion

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[6] *NERC 2024 Long-Term Reliability* Assessment, at 130 (Dec. 2024, corrected Jul. 11, 2025), https://www.nerc.com/globalassets/ourwork/assessments/2024-ltra_corrected_july_2025.pdf.
[7] Western Electricity Coordinating Council, *Western Assessment of Resource Adequacy 2024: Peak Demand by Subregion*, at 2, https://www.wecc.org/sites/default/files/documents/products/2024/WARA%202024%20Peak%20Demand%20by%20Subregion.pdf.
[8] Western Electricity Coordinating Council, *Western Assessment of Resource Adequacy*, https://feature.wecc.org/wara/.
[9] *Id.*
[10] U.S. Energy Information Administration, *Electricity Data Browser, Net Generation for All Sectors Annually from 2019-2024, State: Colorado, (last accessed Dec. 30, 2025),* https://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vtvp&geo=0000000000g&sec=g&freq=A&start=2019&end=2024&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0.
[11] U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of November 2025, Plant State: Colorado, Technology: Conventional Steam Coal* (Nov. 2025), https://www.eia.gov/electricity/data/eia860m/.
[12] U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of November 2025, Plant State: Colorado, Technology: Natural Gas Fired Combustion Turbine and Natural Gas Stream Turbine* (Nov. 2025), https://www.eia.gov/electricity/data/eia860m/.
[13] U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of November 2025, Plant State: Colorado, Technology: Onshore Wind Turbine* (Nov. 2025), https://www.eia.gov/electricity/data/eia860m/.
[14] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.
[15] *Id.*

of artificial intelligence data centers and increase in domestic manufacturing."[16]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[17]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[18] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Craig Unit 1 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes, and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety.

I have made the determination that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Craig Unit 1 shall be made available for operation until March 30, 2026.

Based on my determination of an emergency set forth above, I hereby order:

A. From December 30, 2025, Tri-State and the co-owners, shall take all measures necessary to ensure that Craig Unit 1 is available to operate at the direction of either Western Area Power Administration (WAPA)—Rocky Mountain Region Western Area Colorado Missouri (WACM) in its role as Balancing Authority or the Southwest Power Pool (SPP) West in its role as the Reliability Coordinator, as applicable.[19] Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry

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[16] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

[17] U.S. Department of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (Jul. 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[18] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

[19] U.S. Energy Information Administration, Form EIA-860, Schedule 3: Plant Data (2024), https://www.eia.gov/electricity/data/eia860/.

practices.

B. To minimize adverse environmental impacts, this Order limits operation of Craig Unit 1 to the times and within the parameters established in paragraph A. Tri-State shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Craig Unit 1 has operated in compliance with this Order.

C. All operations of Craig Unit 1 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By January 20, 2026, Tri-State, in coordination with the co-owners, is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Craig Unit 1 consistent with this Order. Tri-State and the co-owners shall also provide such additional information regarding the environmental and operational impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. Tri-state and the co-owners are directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for Craig Unit 1 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Craig Unit 1 shall not be considered a capacity resource.

H. This Order shall be effective from 11:59 PM Eastern Standard Time (EST) on December 30, 2025, and shall expire at 11:59 PM Eastern Daylight Time (EDT) on March 30, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. at 7:08PM EST on this 30th day of December 2025.

Chris Wright

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**

Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Colorado Public Utilities Commission

Chairman Eric Blank
Commissioner Megan Gilman
Commissioner Tom Plant

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Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
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Exhibit B: Declaration of Josh Korth (Oct. 22, 2026)

UNITED STATES OF AMERICA

BEFORE THE

UNITED STATES DEPARTMENT OF ENERGY

ORDER NO. 202-26-49

DECLARATION OF JOSHUA KORTH

I, Joshua Korth, declare under penalty of perjury pursuant to 28 U.S.C. § 1746, that the following is true and correct to the best of my knowledge:

1. I am a resident of the State of Colorado. I am over the age of 18 and have personal knowledge of all the facts stated herein, except to those matters stated upon information and belief; as to those matters, I believe them to be true. If called as a witness, I could and would testify competently to the matters set forth below.

2. As the supervisor of the State Implementation Plan ("SIP") Technical Development Unit within the Air Pollution Control Division of the Colorado Department of Public Health and Environment ("Air Division"), I submit this declaration in support of the State of Colorado's Request for Rehearing ("Request") of the Department of Energy's ("Department") Order No. 202-26-49 ("Renewed Order") issued on September 25, 2026, regarding a coal-fired generating unit ("Craig Unit 1") at the Craig Station facility in Craig, Colorado.

Personal Background and Qualifications

3. I have been employed at the Air Division since 2019.

4. I received a Bachelor's Degree in Chemistry from Luther College in Decorah, Iowa in 2001.

5. I have been involved in environmental work, specifically air quality, within the electric utility industry during my entire professional career.

a. From 2001 to 2008, I was employed by Teledyne Monitor Labs, Inc., as a regulatory specialist. In that role I developed certification and quality assurance testing reports for clients who purchased and installed continuous emissions monitoring systems to meet local, State, and federal regulatory requirements.

b. From 2008 to 2011, I was employed by Environmental Systems Corporation as a senior air quality specialist. In that role, I assisted clients with interpreting Title V operating permits and consulted on the design of data acquisitions systems to collect and report air quality data for State and federal regulatory requirements.

c. From 2011 to 2019, I was employed by Public Service Company of Colorado ("Public Service") as an environmental analyst. In that role, I was responsible for documenting ongoing compliance with State and federal air quality requirements, developing air permit applications, and participating in rulemaking activities that could impact the utility sector.

6. The Air Division is charged with implementing the Federal Clean Air Act and the Colorado Air Pollution Prevention and Control Act. In my current role at the Air Division, I am responsible for leading teams that provide technical analysis and support for the development of SIPs required by the federal Clean Air Act and of Colorado air quality regulations.

7. The teams I lead collaborate with the Colorado Energy Office on the development of programs to achieve Colorado's greenhouse gas ("GHG") reduction goals. My teams also collaborate with, and testify before, the Colorado Public Utilities Commission ("CoPUC") related to emissions calculations and tracking as well as other air quality questions involving electric utilities.

8. The retirement of Craig Unit 1 by December 31, 2025 is required by Colorado's air quality regulations and the Federally approved Round 1 Regional Haze SIP, and aligns with many of Colorado's priorities and emissions reduction goals and obligations. Craig Unit 1's retirement was a carefully planned action toward emissions reductions in furtherance of compliance with federal law and achieving the State's goals. The Renewed Order unjustly and improperly interferes with this planning.

Department of Energy Renewed Order

9. I am familiar with the Renewed Order regarding Craig Unit 1.

10. The Air Division has the knowledge and expertise to advise on ways to best meet any actual electric emergency in Colorado while minimizing conflicts with environmental laws, specifically with environmental air quality laws. However, the Department did not attempt to consult with the Air Division to discuss any component of the Renewed Order, including to identify mechanisms to address the claimed

emergency while minimizing environmental impact or conflicts with local, State, or federal environmental laws or regulations.

11. It is my understanding that Craig Unit 1 was not in operation at the time of issuance of the initial Order No. 202-25-14 ("Original Order"). The Air Division had been advised by the operator of an outage that occurred on December 19, 2025 due to a mechanical failure of a valve resulting in the unit going off-line. The Air Division had been further advised by the operator that repairs and maintenance were needed to Craig Unit 1 in order to bring the unit back online pursuant to the Original Order. As of the date of this Declaration, I understand that those repairs and maintenance have been completed to comply with the Original Order.

12. It is also my understanding that, during the duration of the Original Order, Craig Unit 1 was not called upon by either Western Area Power Administration ("WAPA") or Southwest Power Pool ("SPP") to operate and accordingly did not operate.

13. I also understand that, during the duration of Order No. 202-26-21 ("Second Order"), SPP called a Resource Advisory on April 7, 2026, and called up Craig Unit 1 to operate for about two weeks during the advisory.

14. The Air Division has also been advised that, during the duration of Order No. 202-26-31 ("Third Order") SPP called up Craig Unit 1 twice to operate for several days in July.

15. It is my understanding that during these three time periods, Craig Unit 1 operated mostly at minimum capacity.

16. According to my knowledge, as of the date of this declaration, Craig Unit 1 has not been called up by SPP to operate or operated other than during those time periods.

17. Forcing Craig Unit 1 to continue to be made available and/or operate will negatively impact air quality in Colorado for a few reasons, including:

a. Craig Unit 1's startup and continued operation will result in harm to the environment, and the health and wellbeing of Coloradans through the emission of additional and unnecessary air pollution;

b. Craig Unit 1's startup and continued operation will violate State regulations, federal air quality plans, and the unit's federally enforceable operating permit; and

c. Craig Unit 1's startup and continued operation may harm Colorado's ability to comply with the federal Clean Air Act and meet statutory statewide GHG reduction targets.

I. Craig Unit 1 is a significant source of air pollution.

18. Craig Unit 1 is a significant source of particulate matter ("PM"), nitrogen oxides ("NOx"), sulfur oxides ("SOx"), carbon monoxide ("CO"), hazardous air pollutants ("HAPs"), and GHG emissions.

19. The relevant regulations and permits for Craig Unit 1 specify a "potential to emit[,]" as that term is defined by applicable laws of: 1,891 tons per year ("tpy") of PM; 435 tpy of PM10; 22,695 tpy of SO_2; 13,239 tpy of NOx; 60 tpy of volatile organic compounds ("VOC"); and 498 tpy of CO.[1]

[1] Exhibit LL (Division, *Technical Review Document for Operating Permit 96OPMF155* (Jan. 2005)).

20. In April 2025, the operator reported emissions of numerous air pollutants from Craig Unit 1 for calendar year 2024 including: 86 tons of PM10; 49 tons of PM2.5; 335 tons of SOx; 2,176.6 tons of NOx; and 239 tons of CO. Craig Unit 1 also emitted non-criteria pollutants, including 2,391 pounds ("lbs") of cyanide and 7,204 lbs of manganese.[2] In January, 2026, the operator reported emissions of mercury for calendar year 2025 of 9.59 lbs.[3]

21. In July 2026, as part of its federal quarterly emissions reporting of SO2, CO2, and NOx, for the Acid Rain Program, the operator reported emissions of these pollutants that would not have occurred had Craig Unit 1 retired as planned by December 31, 2025. For the second quarter, running from April 1 through June 30, 2026, and covering the short time period Craig Unit 1 was called on in April, Craig Unit 1 emitted the following: 14.923 short tons of SO2, 82,890.96 short tons of CO2, and 85.538 short tons of NOx.[4]

22. The December 31, 2025 scheduled retirement of Craig Unit 1 would have resulted in significant emissions reductions, reducing emissions by the amounts and types of air pollutants described above as well as others identified in Craig Unit 1's 2025 updated Air Pollution Emission Notice ("APEN").

23. Craig Unit 1's startup and continued operation may also result in excess emissions. In the past, Craig Station has experienced numerous malfunctions that resulted in at least brief periods of emissions above permitted levels. If Craig Unit 1 continues to operate, more malfunctions may occur, which would result in even

[2] *See* Exhibit MM (Tri-State, General APEN- Form APCD-200 (Apr. 21, 2025)).
[3] Exhibit DDD (Letter from Jerome H. Sturhahn, Senior Vice President of Tri-State, to Shannon McMillian, Compliance and Enforcement Program Manager, CDPHE (Jan. 26, 2026)), at 4.
[4] *Craig Unit 1 Q2 Acid Rain Emissions Reporting* (2026).

greater emissions beyond the additional emissions generated from Craig Unit 1 not retiring as planned.

24. If Craig Unit 1 continues to operate beyond its planned retirement date, it will continue to cause the emission of, and directly emit, air pollution in Colorado, which will further harm the environment, public health and welfare, as well as Colorado's ability to comply with other federal and State environmental laws.

II. Craig Unit 1's continued operation will harm the environment, and health and wellbeing of Coloradans.

25. Pollutants like PM, SOx, GHG, NOx, CO, and VOC harm the environment through their contribution to climate change and general pollution of the ambient air, which can cause visibility impairment, harms to public health, sensitive ecosystems and wildlife, heat waves, drought, severe wildfires, and flooding in Colorado and beyond.

26. The pollution from Craig Unit 1 contributes to climate change, which is already having dire effects on the State of Colorado, its people, and its natural resources. In recent years, the people of Colorado have suffered dramatic impacts from extreme heat, drought, wildfires, and flooding.

27. Emissions of criteria air pollutants such as PM10, PM2.5, CO, NOx, VOC, and SOx emitted by Craig Unit 1 may reduce visibility, harm wildlife, and contribute to public health impacts.[5] Exposure to these pollutants may also increase risk of heart

[5] *See* Colorado Department of Public Health and Environment ("CDPHE"), *Regional Haze in Colorado* (2026); 42 U.S.C. § 7409; *see also* 40 C.F.R. § 50.

attacks, lung disease, respiratory problems, headaches, dizziness, and premature death.[6]

III. Craig Unit 1's continued operation will violate State and federal air quality regulations and its permit, and may hinder Colorado's ability to comply with other environmental laws.

28. While the Renewed Order requires Craig Unit 1 to comply with applicable environmental requirements "to the maximum extent feasible while operating consistent with the emergency conditions[,]"[7] this direction is vague and unclear. The Renewed Order's requirement in paragraph B to "minimize adverse environmental impacts [] [by] limit[ing] operation [] to the times and within the parameters [established] in paragraph A"[8] of the Renewed Order, is similarly vague and unclear. The Air Division cannot ascertain what the Department has determined are appropriate operating conditions to ensure conflicts with environmental laws and environmental impacts are minimized. Further, Craig Unit 1's continued operation will make cost-effective compliance with many State and federal air quality regulations infeasible.

29. Colorado and its sources of air pollution are required by certain State and federal regulations to reduce the amount of pollution emitted through measures such as emission limits and controls and operational adjustments. Sometimes, in lieu of incurring the costs required to reduce emissions, operators will choose to retire older, high-emitting units like Craig Unit 1.

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[6] *See* CDPHE, *Regional Haze in Colorado* (2026).
[7] Exhibit WWW, Renewed Order, ¶ C.
[8] *Id.*, ¶ B.

30. Craig Unit 1's continued operation will violate Air Quality Control Commission ("Air Commission") Regulation Number 23, Colorado's federally approved Regional Haze SIP, and its Title V Permit. Craig Unit 1's startup and continued availability and operation may further hinder the State's ability to comply with federal Clean Air Act requirements of both the National Ambient Air Quality Standards ("NAAQS") program and the Regional Haze program, as well as its ability to meet pollution reduction targets set out in State law.

31. *First*, Colorado's Air Commission adopted Craig Unit 1's retirement date of December 31, 2025 into Regulation Number 23.[9] This provision of Regulation Number 23 is federally enforceable because it has been approved by EPA into Colorado's SIP.[10]

32. *Second*, EPA has adopted rules that require states to reduce emissions of visibility impairing pollutants that negatively impact Class I areas. Class I areas are areas designated as such to maintain natural conditions free from the adverse effects of air pollution because these areas may be home to sensitive ecosystems or species that could be harmed by even small increases in pollutants.[11] Under the visibility program requirements, states must conduct detailed and expensive analyses, and based on the results of those analyses, impose federally enforceable controls and emission limits upon the largest and most impactful sources of haze pollutants. Colorado developed its Regional Haze SIP to fulfill these requirements. Colorado's

[9] 5 Colo. Code Reg. § 1001-27.
[10] Approval and Promulgation of Air Quality Implementation Plans; Colorado; Regional Haze State Implementation Plan, 83 Fed. Reg. 31332 (July 5, 2018); EPA, *EPA Approved Statues and Regulations in the Colorado SIP* (Jan. 6, 2026).
[11] CDPHE, *Regional Haze in Colorado* (2026).

Regional Haze SIP includes requirements for certain sources of air pollution to install pollution control technologies or take other actions to reduce emissions of NOx, SOx, and PM, as well as monitoring and reporting requirements for tracking visibility impairment and emissions reductions over time.[12] The Department did no analysis to assess the impact of its Renewed Order on Colorado's compliance with the federal Clean Air Act visibility program.

33. *Third*, major sources of air pollution are required to apply for and obtain a Title V operating permit, which is a federally enforceable permit containing conditions for operation, management, reporting, and recordkeeping. Craig Unit 1 is a major source of air pollution on its own. The Air Division issued the Craig Station a renewed Title V Operating Permit on July 1, 2021.[13] This Title V Permit includes emissions limits, operational requirements, reporting obligations, and other requirements to ensure the safe and environmentally sound operation of Craig Unit 1. Specifically, Condition 1.10. of Craig Unit 1's Title V operating permit requires the Unit to close on or before December 31, 2025. This date was agreed upon by the operator and the State to avoid the need for additional controls or conversion of the source to another fuel type as part of the Round 1 Regional Haze SIP and was later incorporated into the operating permit. Both the SIP and the Title V permit have been reviewed and approved by the EPA.

[12] Exhibit NN (Division, *Colorado Visibility and Regional Haze SIP for the Twelve Mandatory Class I Federal Areas in Colorado* (Dec. 15, 2016)).
[13] Exhibit KK (Division, *Operating Permit No. 96OPMF155* (July 1, 2021)).

34. *Fourth*, the federal Clean Air Act requires states to achieve attainment with NAAQS. Two of the criteria pollutants for which such standards are adopted include ozone and oxides of nitrogen. Oxides of nitrogen are also ozone precursor pollutants. Craig Unit 1 is a significant emitter of NOx. The Air Division is not aware of any analysis the Department did to assess the impacts of the continued availability or operation of Unit 1 upon Colorado's ability to comply with and achieve the federal Clean Air Act's NAAQS attainment program. And the lack of detail and clarity in the Renewed Order as to when and how Craig Unit 1 will operate if and when called upon prevents the Air Division from doing its own analysis.

35. *Finally*, the Colorado Legislature adopted statewide GHG pollution reduction goals to achieve a 26% reduction by 2025; 50% reduction by 2030; 65% reduction by 2035; 70% reduction by 2040; 95% by 2045; and net-zero by 2050 as compared to 2005 levels.[14] Craig Unit 1's planned retirement date of December 31, 2025 is a part of the State's larger plan to reduce GHG emissions to meet these statutory statewide targets. The Renewed Order, to the extent it requires Craig Unit 1 to startup and/or operate, will impede Colorado's ability to meet its statewide GHG reduction goals. The Air Division was not consulted by the Department in any analysis to assess Craig Unit 1's continued availability and operation upon these GHG reduction goals.

[14] § 25-7-102(2)(g), Colo. Rev. Stat.

IV. Craig Unit 1's continued operation will result in more pollution and will incur more costs.

36. The December 31, 2025 retirement of Craig Unit 1 is an important part of the overall pollution reduction strategy in Colorado. Colorado's air quality agencies have worked with air pollution sources for decades to carefully plan efficient and reasonable emissions reductions to help the environment, public health and welfare, and to ensure a just transition for air pollution sources. The continued operation of Craig Unit 1 will not only disrupt this planning, but will also harm the environment, public health and welfare, and violate numerous federal and State air quality regulations. The Department did not consult with the Air Division as to whether and how Craig Unit 1 could be operated consistently with State or federal environmental requirements.

37. If Craig Unit 1 continues to be available and operate it should be required to comply with the maintenance, operational, and monitoring requirements of its Title V permit, which will result in additional costs to the operator outside of what was expected from a December 31, 2025 retirement date. The Department did not consult with the Air Division as to whether and how Craig Unit 1 could be operated consistent with the Title V permit.

38. It is unclear to the Air Division if there are adequate supplies of coal onsite to continue to operate Craig Unit 1 along with the other units at the facility. If there are inadequate supplies, the source of additional supplies of coal that will be used to continue to operate Craig Unit 1 is not known by the Division. Not all coal has the same emissions profile when combusted. Thus, the use of a different source of coal to continue to operate the units at the Craig Station may have an even greater

impact on air quality and public health than the use of existing supplies. The Department did not consult with the Air Division as to the quantification of these impacts or methods to minimize or mitigate them.

39. Further, the Air Division does not regulate and track all of the emissions associated with the transport of coal to the Craig Station. If additional coal must be delivered to the facility to support the continued operation of the coal units, this will result in additional emissions of air pollution from the mining, loading, transport, and unloading of the fuel that would not have otherwise occurred if Craig Unit 1 was retired as planned. Thus, without details in the Renewed Order, and an understanding of the actions that the operator will be required to undertake to comply with the Renewed Order, the Air Division cannot quantify the emissions impact from the acquisition and transport of any additional coal to the Craig Station resulting from the Renewed Order. The Department did not consult with the Air Division as to the quantification of these impacts or methods to minimize or mitigate them.

40. The Renewed Order's delay of the retirement of Craig Unit 1 will have negative regulatory, environmental, and health and welfare impacts on the State of Colorado.

I declare under penalty of perjury that, to the best of my knowledge, the foregoing is true and correct.

Executed this 22 day of October, 2026.

Joshua Korth Digitally signed by Joshua Korth
Date: 2026.10.22 09:37:39 -06'00'

Joshua Korth

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	)	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit C: Declaration of Erin O'Neil (Oct. 21, 2026)

UNITED STATES OF AMERICA

BEFORE THE

UNITED STATES DEPARTMENT OF ENERGY

ORDER NO. 202-26-49

DECLARATION OF ERIN O'NEILL

I, Erin O'Neill, declare under penalty of perjury pursuant to 28 U.S.C. § 1746, that the following is true and correct to the best of my knowledge:

1. I am a resident of the State of Colorado. I am over the age of 18 and have personal knowledge of all the facts stated herein, except to those matters stated upon information and belief; as to those matters, I believe them to be true. If called as a witness, I could and would testify competently to the matters set forth below.

2. As Deputy Director of the Colorado Public Utilities Commission ("CoPUC"), I submit this declaration in support of the State of Colorado's Request for Rehearing ("Request") of the Department of Energy's ("Department") Order No. 202-26-49 ("Renewed Order") issued on September 25, 2026, regarding a coal-fired generating unit ("Craig Unit 1") at the Craig Station facility in Craig, Colorado.

Personal Background and Qualifications

3. I have served as the Deputy Director of the CoPUC since 2023.

4. I have a Bachelor of Science degree in Mechanical Engineering from Cornell University and a Master of Science in Technology and Policy from the Massachusetts Institute of Technology.

5. I have been employed in the Fixed Utilities Section of the CoPUC since 2016. My current position is Deputy Director where I am responsible for the management of the CoPUC's staff of litigation experts including professional engineers, economists, and accounting and financial experts. My duties also include providing technical economic and policy advice and testimony to the CoPUC. Prior to joining the CoPUC, I worked as an economic consultant in the energy and environmental industry for nearly 20 years. From 2005 through 2016 I worked as an independent consultant. From 1996 to 2005 I was a Senior Consultant for the NorthBridge Group, an economic and strategic consulting firm serving the electricity and gas industries. I have extensive experience in electricity price forecasting, resource planning, and risk management.

6. Under Article XXV of the Colorado State Constitution and Title 40 of the Colorado Revised Statutes ("Colo. Rev. Stat."), the CoPUC is the State regulatory agency with jurisdiction to regulate rates and charges for the sale of electric energy to consumers within the State, and to generally supervise and regulate public utilities in Colorado. This regulation includes the adjudication of Electric Resource Plans ("ERPs") filed by Colorado's investor-owned electric utilities and wholesale electric cooperatives.

7. As Deputy Director of Fixed Utilities, I routinely provide the CoPUC with expert witness testimony and direct the development and submission of expert witness testimony of the CoPUC's litigation staff. The CoPUC's staff provide testimony on electric resource planning covering topics, including load forecast, reserve margin requirements, effective load carrying capacity, reliability metrics, unit performance

characteristics, extreme weather and other sensitivity analyses, and transmission modeling. In addition to providing expert testimony on resource planning, I and my staff provide the CoPUC with expert witness testimony in applications for certificates of public convenience and necessity ("CPCNs") for generation and transmission resources, distribution infrastructure planning, renewable energy portfolio standard plans, retail customer program offerings, and other proceedings.

Department of Energy Order

8. I am familiar with the Renewed Order regarding the Craig Unit 1 coal-fired power plant.

9. The Craig Station is a three-unit, 1,285 megawatt ("MW") coal-fired electric generating facility located near Craig, Colorado. Craig Units 1 and 2 are owned by Tri-State Generation and Transmission Association, Inc. ("Tri-State"), Platte River Power Authority, PacifiCorp, Salt River Project, and Public Service Company of Colorado ("Public Service") (collectively "Craig Unit 1 Owners"); Craig Unit 3 is 100% owned by Tri-State.[1] The nameplate capacity for Craig Unit 1 is 427 MW, for Craig Unit 2 is 410 MW, and for Craig Unit 3 is 448 MW.[2] Tri-State is the operating agent for all three units.[3]

10. "In 2016, Tri-State announced an agreement to retire Craig Unit 1 by December 31, 2025 as part of revisions to the Colorado [R]egional [H]aze State Implementation Plan [("SIP")]."[4] In 2020, Tri-State announced its Responsible Energy

[1] Exhibit F (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Attachment BN-2 (Tri-State, *2020 IRP/ERP*, Public (Dec. 1, 2020)) ("2020 ERP")), at 182.
[2] *See id.*
[3] *See id.*
[4] *See id.*

Plan, which included the announced retirements of Craig Unit 2 by September 30, 2028, and Craig Unit 3 by December 31, 2030.[5] More recently, the CoPUC approved a January 1, 2028 retirement date for Craig Unit 3.[6] Craig Unit 1's approved retirement has been incorporated into extensive resource adequacy planning processes throughout the last decade.

11. This declaration addresses the CoPUC's resource planning process and recent CoPUC resource planning proceedings.

I. The CoPUC's Resource Planning Processes

12. For decades, Colorado has implemented robust and successful electric resource planning processes. These have been a model for the competitive acquisition of generating resources, assessing reliability and determining that there will be sufficient electricity to meet expected load, including planning for plant retirements. These processes consider resource adequacy and reliability, while ensuring that Colorado rates remain economic and balance a multitude of federal, State and local interests.[7]

13. As part of Colorado's overall energy planning framework, each investor-owned retail electric utility and wholesale electric generation and transmission cooperative is required to submit to the CoPUC an application for approval of an ERP.[8]

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[5] *See id.* at 23; Exhibit G (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Attachment BN-1 (Tri-State, *Responsible Energy Plan* (Jan. 2020))), at 3.
[6] Exhibit AA (CoPUC, Decision No. R24-0602, issued on August 22, 2024, in Proceeding No. 23A-0585E), ¶ 60.
[7] FERC Order No. 872 supports the use of competitive solicitations as a means to foster competition in the procurement of generation and to encourage the development of Qualifying Facilities under the Public Utility Regulatory Policies Act of 1978. *Implementation Issues Under the Public Utility Regulatory Policies Act of 1978 (Order No. 872), 172 F.E.R.C. ¶ 61,041, ¶ 416 (2020).*
[8] § 40-2-125.5, Colo. Rev. Stat.; 4 Colo. Code Regs. § 723-3-3603(a) (2025).

The utility must conduct a periodic examination of its energy sales and demand forecasts as compared to its existing resources to ensure that sufficient generation will be available to meet customer needs, ensure reliability, and satisfy any applicable emission reduction requirements. ERPs must contain electric demand and energy forecasts, evaluation of existing resources, an assessment of planning reserve margins and contingency plans for the acquisition of additional resources. Each ERP proceeding thoroughly considers resource adequacy and reliability at multiple stages.

14. Through Colorado's resource planning process, utilities thoroughly consider and review inputs to resource adequacy analyses to arrive at a target planning reserve margin. Colorado's regulated electric utilities have historically planned for a 0.1 days per year loss of load expectation ("LOLE") standard, meaning that the system should be expected to have insufficient resources to serve load on no more than one day every 10 years.[9] Using this LOLE and the resulting planning reserve margin required to maintain this LOLE, the utilities propose additional generation amounts for the planning period. Following extensive stakeholder input and vetting through cross examination and consideration by the CoPUC, the utilities conduct a competitive all-source solicitation for these additional resources. The additional generation must be able to cost-effectively meet system needs, including availability or dispatchability at certain hours of the day.

[9] *See* CoPUC, Hrg. Ex. 109, Direct Testimony and Attachments of Zachary Ming, Rev. 1, filed on May 30, 2025, in Proceeding No. 24A-0422E; CoPUC, Hrg. Ex. 109, Direct Testimony and Attachments of Zachary Ming, Rev. 1, ZM-1(Energy Environmental Economics, *2024 Public Service Company of Colorado Resource Adequacy Study* (Aug. 2024)), filed on May 30, 2025, in Proceeding No. 24A-0422E; CoPUC, Hrg. Ex. 115, Direct Testimony and Attachments of Kevin D. Carden, filed on March 31, 2025, in Proceeding No. 21A-0141E, at 8-10.

15. In each ERP, the utility must identify a resource acquisition period, provide the forecast loads and resources balance through that period, and provide forecasting, modeling, and analytical data to support the proposed acquisition period and level of resource acquisition. The resource acquisition period is proposed by the utility and approved by the Commission to address periods of anticipated capacity shortfall with sufficient lead time to procure or build cost-effective projects to address the identified need. When the utility industry has undergone large transitions or has faced a geopolitical or regulatory climate that injects significant uncertainty into resource planning, the CoPUC has approved ERPs with shorter resource acquisition periods that still allow for the lead-time needed to build resources. In such situations, relying on shorter and medium-term forecasts and modeling can provide more certainty that Colorado customers will not pay for unnecessary generation acquired in response to inaccurate load projections produced by speculative long-term modeling.

16. In addition, Colorado's resource planning process allows for the filing of interim ERPs to fill generation needs not identified or fully satisfied by ERPs completed on the regular cadence, including in case of project failures of selected ERP resources.[10] And outside of the ERP processes, the CoPUC may approve the construction of generating resources by granting CPCNs for specific resources proposed by the utility.[11] The Colorado public utility statutes and the CoPUC's procedural rules also allow for the modification of prior CoPUC decisions, and waiver

[10] 4 Colo. Code Regs. §§ 723-3-3603(a), -3605(a)(II) (2025).
[11] 4 Colo. Code Regs. § 723-3-3102 (2025).

or variance requests.[12] These interim ERP processes, CPCN proceedings, and procedural options allow electric utilities and the State to quickly respond to changes in load or available resources.

17. The Colorado resource planning process addresses medium and long-term resource needs through a careful, robust, and competitive process to ensure cost effective system reliability. And the process allows utilities to flexibly respond to new situations through mechanisms such as interim resource plans, CPCNs, and the designation of back-up projects in case of project failures. The CoPUC has significant experience with the energy planning of Colorado's utilities and with Colorado's energy policies. The CoPUC also has access to a range of data, insights, and assessments regarding the needs and capabilities of Colorado's electric grid. To my knowledge, the Department did not attempt to consult with the CoPUC regarding any aspect of the Renewed Order.

II. Tri-State's Colorado Resource Planning Requirements

18. The CoPUC has examined Tri-State's resource planning for over a decade.[13] For many years, Tri-State submitted resource planning reports to the CoPUC. In 2019, the Colorado General Assembly required the CoPUC to promulgate new ERP rules addressing applications for approval of ERPs filed by Tri-State, Colorado's single wholesale electric cooperative.[14] These rules were adopted by the CoPUC in March 2020.[15]

[12] § 40-6-112, Colo. Rev. Stat.; 4 Colo. Code Regs. § 723-1-1003 (2025).
[13] *See* CoPUC, Decision No. C11-0721, issued on July 5, 2011, in Proceeding No. 10M-879E.
[14] § 40-2-134, Colo. Rev. Stat.
[15] CoPUC, Decision No. C20-0155, issued on March 10, 2020, in Proceeding No. 19R-0408E.

19. Under the CoPUC's ERP rules, Tri-State was required to file an ERP in 2020, and it must file an ERP every four years beginning June 1, 2023.[16] In addition to the required four-year cycle, Tri-State may file interim plans or requests for CPCNs.[17]

20. Colorado ERP proceedings contain two phases. In Phase I, the CoPUC reviews and may approve, or approve with modifications, the utility's plan to acquire new utility resources. In Phase I of the ERP process, the CoPUC assesses the energy and capacity needs of the utility, determines an indicative resource acquisition plan based on generic pricing and characteristics for available generation types, and establishes the analytical evaluation framework for ultimate project selection. Following Phase I, the utility conducts a competitive, all-source solicitation and receives bids for resources. Using these bids and resource planning modeling software, the utility prepares portfolios of resources that differ based on modeling inputs and assumptions, which fulfill different economic and policy goals such as least cost, high labor scoring, geographic diversity of resources, deeper emissions reductions, and balanced utility and developer ownership. In Phase II, a final cost-effective resource portfolio is determined. Phase II ERP modeling may also include the evaluation of significant market uncertainties, most often load growth and natural gas prices.

21. Tri-State initiates Phase I of an ERP proceeding by filing its ERP application. Among many other required components, each ERP application must include: a proposed resource acquisition period; an annual electric demand and

[16] 4 Colo. Code Regs. §§ 723-3-3605(a)(I), -(II) (2025).
[17] 4 Colo. Code Regs. §§ 723-3-3102, -3605(a)(II) (2025).

energy forecast; assessments of existing generation and transmission resources; an assessment of planning reserve margins; an assessment of the need for additional resources based on the forecasts, existing resources, planning reserve margins, estimation of the effective load carrying capacity by resource type, and other factors; a proposed Request for Proposal and model contracts to be used to solicit resource bids, and bid evaluation criteria Tri-State will use in ranking bids received.[18]

22. Electric energy and demand forecasts must be completed for each year within the planning period, and must be fully explained and documented with data, assumptions, methodologies, and models.[19] The forecasts must include, among other components, the electric demand placed on the utility's system for each hour of the day for peak-day, average-day, and representative off-peak days for each calendar month.[20] Tri-State must develop and justify a range of forecasts of coincident summer and winter peak demand and energy sales that its system may reasonably be required to serve during the planning period, including base case, high, and low forecast scenarios.[21]

23. Each ERP application must justify planning reserve margins for the base case, high, and low forecast scenarios, to include risks associated with the development of generation, losses of generation capacity, losses of transmission capability, risks due to known or reasonably expected changes in environmental

[18] 4 Colo. Code Regs. §§ 723-3-3605(a)(IV), -(f), -(g)(II)(G)(ii) (2025).
[19] 4 Colo. Code Regs. § 723-3-3605(b) (2025).
[20] *Id.*
[21] *Id.*

regulatory requirements, and other risks.[22] Tri-State must also describe and justify the means by which it assesses system reliability.[23]

24. The application must also include an assessment of the costs and benefits of early retirements of utility-owned resources, an assessment of the costs and benefits of the integration of intermittent resources on the utility's system, and contingency plans for the acquisition of additional resources if actual circumstances deviate from the most likely estimate of future resource needs or the acquisition of replacement resources if expected resources are not developed in accordance with the approved ERP.[24]

25. After an adjudication on the ERP application, involving discovery, rounds of written testimony and associated documents resulting in records with page counts totaling in the tens of thousands or hundreds of thousands, robust stakeholder engagement, public comment hearings, a live evidentiary hearing with cross-examination by parties and the CoPUC, negotiated settlements and stipulations, and any necessary briefing, the CoPUC must issue a Phase I decision. This includes determinations on the need for additional resources, planning reserve margin, methodology for determining resource effective load carrying capacity by resources type and geography, the documents and analytical methodology to be used in a competitive resource solicitation, and bid evaluation criteria. The Phase I decision also defines the specific alternative portfolios Tri-State must model in Phase II after bids are received,[25] for example a least-cost portfolio or a reduced load portfolio and

[22] 4 Colo. Code Regs. § 723-3-3605(e) (2025).
[23] *Id.*
[24] 4 Colo. Code Regs. §§ 723-3-3605(a), -(e)(III) (2025).
[25] 4 Colo. Code Regs. § 723-3-3605(g)(III)(B) (2025).

the sensitivity analyses to be conducted (e.g., high load growth or high natural gas prices).

26. Phase II of the ERP proceeding begins after the issuance of the Phase I decision. Tri-State will conduct its competitive, all-source solicitation, receive competitive bids and utility-owned proposals, and file an ERP Implementation Report. In the ERP Implementation Report, Tri-State must present the resource portfolios required by the Phase I decision, with associated cost and other information, and must identify its preferred, cost-effective resource plan (*i.e.*, its preferred resource portfolio).[26]

27. After an opportunity for party comments on the ERP Implementation Report, an opportunity for Tri-State to respond to such comments, and any other necessary procedures, the CoPUC issues its Phase II decision establishing the final cost-effective resource plan.[27] In making this decision the CoPUC considers various statutory factors, including whether the resource plan meets the energy policy goals of Colorado, such as giving full consideration to cost-effective resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.[28]

28. Following the Phase II decision, Tri-State then proceeds to implement the approved resource portfolio. Additionally, Tri-State must file annual progress reports with the CoPUC on its efforts under the approved plan and on emerging resource needs, including an updated forecast, an updated evaluation of planning

[26] 4 Colo. Code Regs. § 723-3-3605(h) (2025).
[27] *Id.*
[28] *Id.*; § 40-2-134, Colo. Rev. Stat.

reserve margins and contingency plans, and an updated assessment of additional resource needs.[29]

III. Relevant CoPUC Resource Planning Proceedings

29. Since the announcement in 2016 that Craig Unit 1 would retire by December 31, 2025, the CoPUC has considered multiple electric resource planning reports and ERPs that include the unit's retirement as an assumption in the modeling of resource needs. None of these proceedings resulted in a CoPUC determination that the retirement of Craig Unit 1 would result in reliability issues.[30]

30. Tri-State's 2015 Integrated Resource Plan ("IRP")/ERP was filed on October 30, 2015 in accordance with CoPUC rules requiring reports on resource planning.[31] While this pre-dates the Craig Unit 1 retirement announcement in 2016, Tri-State's 2015 IRP/ERP addresses resource planning methods that remained relevant until Tri-State's subsequent 2020 ERP application filing.

31. In its 2015 IRP/ERP, Tri-State presented its planning for the resource acquisition period 2016-2021, and a planning period 2016-2035. Tri-State reported that under the base load scenario with full planning reserves, it did not expect a capacity shortage within the resource acquisition period, and that it projected it

[29] 4 Colo. Code Regs. § 723-3-3618 (2025).
[30] *See* CoPUC, Decision No. R22-0191, issued on March 28, 2022, in Proceeding No. 20A-0528E; CoPUC, Decision No. C23-0437, issued on June 30, 2023, in Proceeding No. 20A-0528E; Exhibit AA; Exhibit E (CoPUC, Decision No. C25-0612, issued on August 26, 2025, in Proceeding No. 23A-0585E); CoPUC, Decision No. C22-0459, issued August 3, 2022, in Proceeding No. 21A-0141E; CoPUC, Decision No. C24-0052, issued on January 23, 2024, in Proceeding No. 21A-0141E; CoPUC, Decision No. C25-0747, issued on November 6, 2025, in Proceeding No. 24A-0442E.
[31] CoPUC, Tri-State, IRP/ERP ("Tri-State 2015 IRP/ERP"), filed on October 30, 2015, in Proceeding No. 15M-0852E. Tri-State explained its 2015 IRP/ERP was developed to meet the Integrated Resource Planning requirements of the Western Area Power Administration and the ERP requirements of the CoPUC. Tri-State 2015 IRP/ERP, at 5.

would not need additional generation resources until 2023.[32] As part of its support for this statement, Tri-State presented an assessment of planning reserve margins. It explained that, at the time, it used a fixed 15% minimum planning reserve margin and that this 15% level had been the industry standard for years.[33]

32. Tri-State's 2015 IRP/ERP also catalogued its various methods for responding to unexpected capacity shortages, including employing small diesel generation and relying on its membership in utility reserve sharing groups or reciprocal outage assistance arrangements with other utilities.[34] For any longer-term resource adequacy shortcomings, Tri-State explained that it reevaluates its future load/resource balance at a minimum one-year interval to identify and appropriately resolve resource adequacy issues.[35] It explained it would be well positioned to respond to longer-term contingencies through pursuing additional demand-side resources, power purchase agreements, or capacity self-build.[36]

33. Tri-State first incorporated the retirement of Craig Unit 1 by December 31, 2025 in the scenario modeling for its 2017 Annual Progress Report.[37] After updating its resource planning model inputs to include changes to its generation portfolio, including the retirement of Craig Unit 1, Tri-State reported that new

[32] *See id.* at 107, 132.
[33] *See id.* at 107.
[34] *See id.* at 108.
[35] *See id.*
[36] *See id.* at 107-108.
[37] CoPUC, ERP Annual Progress Report, Revised, filed on June 2, 2017, in Proceeding No. 15M-0852E.

generating capacity would not be needed until 2025.[38] Subsequent annual progress reports moved this date to 2026 and then 2027.[39]

34. Tri-State's 2020 ERP application, which was subject to CoPUC review and approval under new statutory provisions, was intended "to describe Tri-State's need for additional electric resources, and ultimately identify a cost-effective resource portfolio to reliably meet such need[,]" and "to respond to what Tri-State's Utility Members and their member-customers have been asking for – a transition to a cleaner power supply, reduced GHG emissions, and an opportunity to realize the potential benefits of lower cost electricity."[40] Tri-State also emphasized that its resource planning process "is intended to generate a plan to meet forecast energy and demand obligations with existing resources, new resources, and/or market purchases, while respecting environmental and transmission constraints, complying with applicable federal and State legislative and regulatory obligations, and doing so in the most economical and reliable manner."[41]

35. Tri-State presented a 10-year resource acquisition period (2021-2030) and a 20-year resource planning period (2021-2040). In its assessment of resource needs, Tri-State assumed the retirement of Craig Unit 1 by December 31, 2025, the retirement of Craig Unit 2 by September 30, 2028, and Craig Unit 3 by December 31,

[38] *See id.* at 16.
[39] CoPUC, ERP for Annual Progress Report, filed on October 31, 2018, in Proceeding No. 15M-0852E, at 17; CoPUC, ERP Annual Progress Report, filed on December 10, 2019, in Proceeding No. 15M-0852E, at 22.
[40] Exhibit JJ (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E), at 35:1-15.
[41] CoPUC, Hrg. Ex. 102, Direct Testimony and Attachments of Lisa K. Tiffin, filed on December 1, 2020, in Proceeding No. 20A-0528E, at 7:15-20.

2029.[42] Tri-State identified a need for new generation in 2029 to provide replacement capacity support for the announced retirement of Craig Unit 3, but did not identify any other resource needs given its expected generation portfolio and load forecast.[43]

36. To identify its need for additional resources, Tri-State developed a range of long-term load forecasts, including base case, low load, and high load scenarios.[44] Tri-State used a 15% planning reserve margin, and supported the adequacy of the planning reserve margin and the viability of expansion plans under different load scenarios using a probabilistic Loss of Load Probability ("LOLP") study.[45] The study used the target "LOLP of less than [one] day in 10 years[,] which corresponds to a LOLP of less than 0.0274 percent on an annual hour basis."[46] The study analyzed "two forecast years, 2025 and 2030, under four capacity expansion [("CE")] plans" using varying load forecasts and capacity addition assumptions.[47] For two of these CE scenarios, the study found the target would be exceeded in 2030, while the other plans met the target in both years.[48] The study found that additional energy storage capability would be able to compensate for these exceedances so that all scenarios met the LOLP target.[49] Tri-State explained that its ERP scenarios followed this methodology and included standalone batteries as selected by the models in the base case and alternative scenarios evaluated in its ERP, including in its

[42] Exhibit F, at 31.
[43] Exhibit JJ, at 37:15-19.
[44] CoPUC, Hrg. Ex. 102, Direct Testimony and Attachments of Lisa K. Tiffin, filed on December 1, 2020, in Proceeding No. 20A-0528E, at 21:1-11.
[45] *See id.* at 41:10-42:7; Exhibit F, at 2348-2356.
[46] *See id.* at 2355.
[47] *See id.* at 2351.
[48] *See id.* at 2351.
[49] *See id.* at 2351 (finding the addition of "two (2) and three (3) 100 MW 4-hour batteries with 400 MWh of energy storage capability. . . . to the Base CE and MARS CE plans, respectively[,]" resulted in both plans meeting the LOLP target).

preferred plan.[50] Tri-State also explained that "[a]ll scenarios to some extent utilize transmission interconnection capacity made available by thermal retirements. All plans show considerable resource additions in [western Colorado] due to the transmission capacity that will become available through the retirement of the Craig facility."[51]

37. Tri-State also addressed its contingency plans for how electric generation and customer demand will actually show up during the resource acquisition period, explaining it has various options including purchasing short-term capacity through resource solicitations, initiation of negotiations with replacement bidder(s), and acceleration of project in-service dates.[52]

38. After modelling an additional six variations of its initial preferred plan through a stakeholder process and at the direction of the CoPUC, with each variation assuming the retirement of Craig Unit 1 by December 31, 2025, Tri-State arrived at its Revised Preferred Plan.[53] "[T]he Revised Preferred Plan would add approximately 2 GW of new renewable generation and 250 MW of new battery storage by 2030," and a new gas-fired resource in 2030, alongside the retirement of certain coal units by 2030.[54] Tri-State explained the Revised Preferred Plan was "the responsible and economic resource plan because it reflects the known financial, operational, and

[50] *See id.* at 30.
[51] *See id.* at 135.
[52] *See id.* at 30.
[53] CoPUC, Hrg. Ex. 109, Second Supplemental Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 2, filed on September 28, 2021, in Proceeding No. 20A-0528E, Fourth Corrected Attachment LKT-3 (Tri-State, 2020 IRP/ERP (Sept. 28, 2021, filed on Nov. 10, 2021)), at 99.
[54] CoPUC, Hrg. Ex. 109, Second Supplemental Direct Testimony and Attachments of Lisa K. Tiffin, filed on September 28, 2021, in Proceeding No. 20A-0528E, at 12:15-13:16.

contractual conditions of our system, while maintaining a focus on reliability and affordability for our Members."[55]

39. In its Phase I decision, the CoPUC approved Tri-State's 2020 ERP application and specifically the modelling inputs and assumptions in Tri-State's Revised Preferred Plan with limited modifications contained in a settlement agreement.[56] The CoPUC also directed that after Tri-State receives resource bids, it models at least four Phase II resource portfolios in addition to the base Revised Preferred Plan, each with a sensitivity for extreme weather and high gas price.[57]

40. In its 2020 ERP Phase II Implementation Report, Tri-State reported on the results of its competitive resource solicitation and presented five resource portfolios. In its comparative portfolio analysis, Tri-State explained that it performed a reliability metric check on each portfolio, including that the portfolio would meet: a planning reserve margin minimum of 15%, the loss of load hours target of less than one day in 10 years, and an expected unserved energy target of less than 0.5 Gigawatt hours ("GWh") annually.[58]

41. Tri-State's Phase II preferred cost-effective resource portfolio continued to be the Revised Preferred Plan portfolio, which it selected as a result of the portfolio's "overall performance across the reliability, environmental, and financial categories analyzed" and which it supported as reflective of "its Members' strategic directives to ensure reliable, affordable, and responsible service."[59] It

[55] *See id.* at 13:1-9.
[56] CoPUC, Decision No. R22-0191, issued on March 28, 2022, in Proceeding No. 20A-0528E.
[57] *Id.*, ¶¶ 49-50.
[58] CoPUC, 150-Day Report, Public, filed on February 13, 2023, in Proceeding No. 20A-0528E, at 17.
[59] *See id.* at 5.

explained that the portfolio resulted in planning reserve margins ranging from 17% in 2022 to 29% in 2030, with zero loss of load hours and zero annual expected unserved energy during that period.[60] Tri-State also explained that in the period from 2025-2029 when Craig Units 1 and 2 retire, "it continues to be capacity-long and maintains a sufficient mix of both dispatchable and intermittent resources to meet load needs."[61] In its Phase II decision, the CoPUC approved Tri-State's selection of the Revised Preferred Plan portfolio as the cost-effective resource plan.[62] Tri-State later confirmed that it "is capacity-long and the 2026 resources identified in the 2020 ERP Phase II are not necessary for meeting resource adequacy or reliability requirements."[63]

42. Tri-State's next ERP was filed in 2023. Tri-State explained that through its 2023 ERP, "Tri-State will ensure reliability and resource adequacy, maintain affordability for Members, and meet compliance obligations, including those related to environmental responsibility."[64] Tri-State presented a 6-year resource acquisition period (2026-2031) and a 20-year resource planning period (2024-2043). In its assessment of resource needs, Tri-State assumed the retirement of Craig Unit 1 by December 31, 2025, the retirement of Craig Unit 2 by September 30, 2028, and Craig Unit 3 by January 1, 2028.[65] Tri-State explained it "selected an acquisition period of

[60] *See id.* at 28.
[61] *See id.*
[62] CoPUC, Decision No. C23-0437, issued on June 30, 2023, in Proceeding No. 20A-0528E, ¶ 47.
[63] CoPUC, Notice of Failed Bids, Public, filed on July 24, 2023, in Proceeding No. 20A-0528E, ¶ 12.
[64] Exhibit W (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E), at 11:22-12:4.
[65] Exhibit X (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1 (Tri-State, *2023 ERP Phase I*, Rev. 2 (Apr. 22, 2024))), at 19, 21, 32, 44, 55, 66.

six years through 2031 to ensure that, as fossil resource retirements in Colorado occur through the end of the decade, sufficient resources would be in place to continue to meet resource adequacy and reliability requirements."[66]

43. To identify its need for additional resources, Tri-State developed a range of long-term load forecasts, including base case, low load, and high load scenarios.[67] Tri-State increased its planning reserve margin to 22%, transitioning to a 30.5% reserve margin in 2028 after the retirement of Craig Station. This approach "was developed through a Strategic Energy Risk Valuation Model [("SERVM"), which Tri-State described as] a system-reliability planning and production cost model designed to analyze the capabilities of an electric system during a variety of conditions under thousands of different scenarios[,] . . . . able to identify potential risks to system reliability across the entire year, not just at system peak."[68] As part of this modeling, Effective Load Carrying Capabilities ("ELCCs") were determined for each resource type to model each resource's capacity potential for the specifics of Tri-State's system, rather than simply relying on the nameplate capacity adjusted for the availability factor.[69] Such ELCC calculations incorporate the coincidence of resource generation with system peak demand accounting for specific geographic location and the proximity of other existing renewable resources. The model used the target LOLE of 0.1 days/year, which is equivalent to an expectation of one day of loss

[66] *See id.* at 6.
[67] Exhibit CC (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1-Attachment F (*Electric Energy and Demand Forecast*, Public)), at 7-9.
[68] Exhibit X, at 14.
[69] Exhibit OO (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1 – Attachment G-1 (Astrape Consulting, *Reserve Margin and Effective Load Carrying Capability (ELCC) Study*, Public (Aug. 2, 2023))), at 8.

of load every 10 years.[70] The use of ELCC calculations is a conservative view of accredited capacity because it takes into account the intermittency of each resource type, the specific geographic location of each resource, and the proximity of other resources of a like type and corresponding reduction in dependable capacity such proximity creates. Tri-State explained that the planning reserve margin calculation also "discounts the capacity of conventional resources by their Equivalent Forced Outage Rate and several of Tri-State's thermal resources have relatively high and increasing forced outage rates."[71]

44. Tri-State modeled five scenarios for Phase I of its 2023 ERP, and for each scenario, sensitivity analyses were performed on each scenario's expansion plan to re-dispatch the plans under extreme weather events and high gas price conditions.[72] "Level 1" reliability metric checks were performed on each scenario to ensure it would meet: a planning reserve margin minimum of 22%, transitioning to 30.5% in 2028, the loss of load hours target of less than one day in 10 years, and an expected unserved energy target of less than 0.4 GWh annually.[73] Additional "Level 2" reliability checks were performed on each scenario's extreme weather event sensitivity result.[74] Tri-State explained that each scenario was able to meet the Level 1 and Level 2 reliability metrics during the resource acquisition period.[75]

[70] *See id.* at 8.
[71] Exhibit DD (CoPUC, Hrg. Ex. 103, Direct Testimony and Attachments of Brian L. Thompson, Rev. 1, filed on May 24, 2024, in Proceeding No. 23A-0585E), at 15:2-4.
[72] Exhibit X, at 15.
[73] *See id.* at 17.
[74] *See id.* at 18.
[75] *See id.* at 90.

45. In its Phase I decision on Tri-State's 2023 ERP, the CoPUC approved Tri-State's 2023 ERP application, including Tri-State's evaluation of need during the resource acquisition period and the retirement date of January 1, 2028 for Craig Unit 3.[76] The CoPUC also directed that after Tri-State receives resource bids, it model various portfolios including Tri-State's preferred scenario, each with a sensitivity for extreme weather.[77]

46. In its 2023 ERP Phase II Implementation Report, Tri-State reported on the results of its competitive resource solicitation and presented six resource portfolios.[78] The analysis of each portfolio includes in its assumptions the retirement of Craig Unit 1 by December 31, 2025, Craig Unit 2 by September 30, 2028, and Craig Unit 3 by January 1, 2028.[79] Tri-State also created three back-up bid pools.[80]

47. Tri-State's Phase II preferred cost-effective resource portfolio was the New ERA Gas Flexibility Shafer Replacement ("FLEXSR") portfolio, which it selected as a result of the portfolio's "overall performance across the reliability, environmental, and financial categories analyzed" and which it supported as reflective of "its Members' strategic directives to ensure reliable, affordable, and responsible service."[81] The FLEXSR portfolio, "which was the least-cost portfolio, would add 700 MW of wind and solar, 650 MW of storage, and 307 MW of gas between 2026-2031[;]" replace turbines at an existing gas-powered combined cycle generating facility; and

[76] Exhibit AA, ¶¶ 50, 60.
[77] *See id.* ¶¶ 29, 50.
[78] Exhibit J (CoPUC, 120 Day ERP Implementation Report, Public, filed on April 11, 2025, in Proceeding No. 23A-0585E).
[79] *See id.* at 21, 32, 43, 54, 64, and 75.
[80] *See id.* at 7.
[81] *See id.* at 6.

retire two coal plants within the resource acquisition period.[82] This portfolio also assumes the previously announced retirement dates of Craig Unit 1 and Craig Unit 2 and the newly approved retirement of Craig Unit 3 by January 1, 2028.[83] The 307 MW gas facility will interconnect at the Craig transmission substation and has a commercial operation date of 2029.

48. Tri-State explained that it performed a reliability metric check on each portfolio using the same Level 1 and Level 2 reliability metrics applied to Phase I scenarios, and that each portfolio satisfied the metrics.[84] It explained that the FLEXSR portfolio resulted in planning reserve margins ranging from 24% in 2025 to 34% in 2031, with zero loss of load hours and zero annual expected unserved energy during that period.[85] Tri-State explained that it remains in a capacity-long position until 2030, but that resource acquisitions are required during the 2023 ERP resource acquisition period to ensure new resources are available in 2030.[86]

49. In its Phase II decision, the CoPUC approved Tri-State's selection of the FLEXSR portfolio as the cost-effective resource plan.[87] The CoPUC also found "Craig Unit 1 is not required for reliability or resource adequacy purposes based on the record in this ERP. Every portfolio that Tri-State modeled assumes Craig Unit 1 retires at the end of 2025 and does not provide any energy or capacity after 2025. At the

[82] *See id.*
[83] *See id.* at 54.
[84] *See id.* at 95.
[85] *See id.* at 62.
[86] *See id.* at 7.
[87] Exhibit E, ¶ 90.

same time, Tri-State convincingly concludes that every portfolio meets all reliability metrics and is reliable."[88]

50. On December 1, 2025, Tri-State filed its annual ERP progress report. It reports that it "has 500 MW of preferred portfolio storage resources under contract, 200 MW of preferred portfolio wind resources under contract, and is continuing contracting efforts for other preferred portfolio resources, including evaluation of back-up bids as needed."[89] Tri-State stated that with an updated load forecast, utilized in Phase II of the 2023 ERP and Phase II preferred resources, it does not forecast a capacity shortfall to occur until 2035.[90]

51. On March 17, 2026, and on June 30, 2026, Tri-State provided further updates on its ERP resource acquisitions. [91] It reported it has executed contracts for 200 MW of wind generation, 100 MW of solar generation, and 550 MW of battery storage.[92] Tri-State reports it is delaying pursuit of back-ups for certain bids, including a bid for 307 MW of gas-fired generation, until it attains further certainty regarding federal funding through the United States Department of Agriculture's Empowering Rural America program.[93]

[88] *See id.* ¶ 116.
[89] Exhibit Z (CoPUC, Tri-State, *2025 Annual Progress Report*, filed on December 1, 2025, in Proceeding No. 23A-0585E), at 10-11.
[90] *See id.* at 8.
[91] See Exhibit EEE (CoPUC, Tri-State, *Notice Regarding Phase II Developments,* filed on March 17, 2026, in Proceeding No. 23A-0585E)); Exhibit ZZZ (CoPUC, Tri-State, *Phase II Status Update*, filed on June 30, 2026, in Proceeding No. 23A-0585E).
[92] Exhibit EEE (CoPUC, Tri-State, *Notice Regarding Phase II Developments,* filed on March 17, 2026, in Proceeding No. 23A-0585E)), at 2.
[93] Exhibit EEE, at 3.

52. Additionally, in its 2026 Electric Resource Adequacy Report, filed on March 17, 2026, Tri-State provided its expected loads and resources for years 2026 through 2035.[94] Tri-State shows that it expects excess resources for all years.[95]

Conclusion

53. The CoPUC has been implementing careful and robust electric resource planning for decades. Colorado's process has developed over time to incorporate a competitive all-source solicitation to ensure cost-effective electricity supply. Colorado's quantitative modeling requirements allow different kinds of resources to be considered together to develop the energy supply system in a holistic manner. Colorado does not pre-maturely pick a winning technology or bid but rather allows the marketplace to develop and offer bids that can work within the system to reliably deliver cost-effective power.

54. The CoPUC's process incorporates a conservative approach to reliability by utilizing stringent loss of load metrics and incorporating and re-evaluating the system reserve margin as needed over time and depending on the resource mix of the system. Reliability is further considered through the robust calculation of ELCCs that incorporate geographic location and the potential saturation of other nearby renewable resources so that the ERP modeling accurately incorporates a portfolio view of accredited reliable capacity. In addition, Colorado considers and evaluates multiple future perspectives by modeling sensitivities such as extreme weather, high load growth, and high natural gas prices. This additional quantitative modeling serves

[94] Exhibit VV (CoPUC, Tri-State, Notice of 2026 Resource Adequacy Annual Report, filed on March 17, 2026, in Proceeding No. 26M-0028E).
[95] *Id.* at 3.

to stress test planning portfolio results to ensure reliable service. Colorado has a long history of robust resource planning, successfully partnering with utilities and a diverse set of stakeholders to develop cost-effective and reliable electric supply.

55. By delaying the retirement of this aging coal-fired unit, the Department is conflating dispatchability with reliability and undermining a decade of careful and collaborative planning. The end result is Colorado electric customers being forced to support an unreliable resource and the Craig Unit 1 Owners dedicating resources to maintain a coal plant that is less reliable and more costly than other generation resources.

I declare under penalty of perjury that, to the best of my knowledge, the foregoing is true and correct.

Executed this _21st____ day of _October_____, 2026.

Erin O'Neill - DORA

Erin O'Neill

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit D: Department, Order No. 202-26-49 (October 14, 2026)

UNITED STATES OF AMERICA

BEFORE THE

UNITED STATES DEPARTMENT OF ENERGY

ORDER NO. 202-26-49

DECLARATION OF JOSEPH PEREIRA

I, Joseph Pereira, declare under penalty of perjury pursuant to 28 U.S.C. § 1746, that the following is true and correct to the best of my knowledge:

1. I am a resident of the State of Colorado. I am over the age of 18 and have personal knowledge of all the facts stated herein, except to those matters stated upon information and belief; as to those matters, I believe them to be true. If called as a witness, I could and would testify competently to the matters set forth below.

2. As Director of the Colorado Office of the Utility Consumer Advocate ("UCA"), I submit this declaration in support of the State of Colorado's Request for Rehearing ("Request") of the Department of Energy's ("Department") September 27, 2026 Order No. 202-26-49 ("Renewed Order") regarding a coal-fired generating unit ("Craig Unit 1") at the Craig Station facility in Craig, Colorado.

Personal Background and Qualifications

3. I have served as the Director of the UCA since March 2026. Prior to that I served as Deputy Director of the office beginning in 2019.

4. I received my Bachelor's Degree in Public Policy from Metropolitan State University and conducted graduate work at the Center for Energy and Environmental

Policy at the University of Delaware. I also received training in regulatory studies at the Institute of Public Utilities at Michigan State University.

5. Prior to my work at UCA, I served as Regulatory Director at the Citizens Utility Board of Minnesota, advocating for consumers in utility resource acquisition, resource planning, distribution system planning, vehicle electrification, performance-based ratemaking, and other topics. I also served as the Director of Low-Income and Residential Energy Services at the Colorado Energy Office, where I oversaw policy, programs and regulatory activities related to residential and low-income utility customers.

6. As UCA Director, I am responsible for managing the office's statutory mandate to represent the public interest and, to the extent consistent with the public interest, the specific interests of residential, agricultural, and small business utility consumers by appearing in State and federal proceedings which may have an impact on utility rates.[1]

7. In evaluating the public interest, the UCA gives due consideration to Colorado's grid reliability, statutory decarbonization goals, a just transition for the State's coal communities and workers, environmental justice, and the short- and long-term effect of the proceeding upon various classes of consumers.[2]

[1] § 40-6.5-104(1), Colo. Rev. Stat.; § 40-6.5-106(2)–(2.5), Colo. Rev. Stat.
[2] § 40-6.5-104(2), Colo. Rev. Stat.

8. UCA takes an active role in ensuring that Colorado's State energy policy is implemented in a way that furthers the public interest. UCA's advocacy at the State level regularly provides a consumer-focused perspective on costs, reliability, and keeping utilities on track to meet the State's climate goals. UCA intervened and advocated for the public interest in Tri-State Generation and Transmission Association, Inc.'s ("Tri-State") most recent Electric Resource Plan ("ERP").[3]

Department of Energy Renewed Order

9. I am familiar with and have fully reviewed the Department's Renewed Order regarding Craig Unit 1.

10. The Renewed Order's directions that: 1) the co-owners of Craig Unit 1 shall take all measures necessary to ensure it is available to operate to meet the emergency; and 2) Southwest Power Pool ("SPP") take every step to employ economic dispatch of Craig Unit 1 during hours necessary to meet the emergency, run counter to the public interest in Colorado. The Initial Order No. 202-25-14 ("Original Order"), Second Order No. 202-26-21 ("Second Order"), and Third Order No. 202-26-31 have increased—and the Renewed Order is likely to continue increasing—costs for Colorado's rural electric cooperative customers, and they inject uncertainty into Colorado's established long-term electric resource planning process. From a reliability perspective, continued operation of Craig Unit 1 is not necessary and not in the public interest. From a consumer cost perspective, continued operation of Craig Unit 1 is not in the public interest.

[3] CoPUC, Proceeding No. 23A-0585E.

Consumer Costs

11. Craig Unit 1's retirement, justified primarily by economics, has been anticipated by Tri-State, PacifiCorp, Platte River Power Authority, Salt River Project, and Public Service Company of Colorado ("Public Service") (together, "Craig Unit 1 Owners"), and the State of Colorado since 2016.[4] All of the electric resource planning performed since then by the Craig Unit 1 Owners and the other public utilities in Colorado has assumed Craig Unit 1 would cease operations at the end of 2025. For Tri-State specifically, the Colorado Public Utilities Commission ("CoPUC") found in August 2025 that "Craig Unit 1 is not required for reliability or resource adequacy purposes based on the record of [Tri-State's most recent] ERP."[5]

12. The Renewed Order fails to recognize that utility consumers have already paid—and are currently paying—for the approved plans and investments that the Craig Unit 1 Owners have determined are necessary to safely retire Craig Unit 1 while maintaining adequate reliability. Because of the Renewed Order, consumers who have been paying for Craig Unit 1's replacement generation will also be forced to pay for expensive, excess generation that was not requested by the Craig Unit 1 Owners and is not necessary.

13. Craig Unit 1's high costs can be attributed to its high fuel cost and low efficiency. Economic justification for Craig Unit 1's retirement is supported by a recent analysis performed by Grid Strategies.[6] According to that study, it is likely to

[4] Tri-State, *Craig Station owners, regulators and environmental groups reach agreement on proposed revisions to Colorado regional haze plan* (Sept. 1, 2016).
[5] Exhibit E (CoPUC, Decision No. C25-0612, issued on August 26, 2025, in Proceeding No. 23A-0585E), ¶ 116.
[6] Grid Strategies, *The Economic Cost of a DOE Mandate for the Craig Unit 1 Coal-Burning Generator to Continue Operating* (Dec. 2025).

cost approximately $20 million in fuel, operations, and maintenance costs to continue operating Craig Unit 1 for the 90-day effective period of the Renewed Order. The study estimates that on an annual basis, Craig Unit 1 will cost approximately $85 million to operate. This estimate does not account for deferred maintenance which is required to keep Craig Unit 1 available to operate, undertaken when Tri-State believed the plant would retire at the end of 2025; it also does not account for additional expenditures that may now be necessary for a plant that began operating in 1980 and is likely nearing the end of its operational life.

14. In response to the Original Order issued by the Department on December 30, 2025, Tri-State said that "retaining [Craig] Unit 1 will likely require additional investments in operations, repairs, maintenance and, potentially, fuel supply, all factors increasing costs."[7]

15. As illustrated by the analysis performed by Grid Strategies, operating Craig Unit 1 is likely to cost more in the future than it did in the past. This is due to increasing operations and maintenance costs, repair costs for the mechanical failure, and other additional investments that will be necessary to extend the life of Craig Unit 1.

16. As the operator of Craig Unit 1, Tri-State will incur higher costs to serve its member utility cooperatives. Some of these costs have already been—and will continue to be—passed on to rural electrical cooperative consumers. According to Tri-

[7] Exhibit QQ (*Tri-State,* U.S. DOE orders Tri-State to keep Craig Generating Station unit operating for next 90 days (Dec. 31, 2025)), at 2.

State's Chief Executive Officer Duane Highley at the time the Original Order was issued:

> As a not-for-profit cooperative, our membership will bear the costs of compliance with this order unless we can identify a method to share costs with those in the region. There is not a clear path for doing so, but we will continue to evaluate our options.[8]

17. Based on my experience and familiarity with Colorado's ERP process and UCA's participation in the State's orderly retirement of coal-fired electricity generating stations, I can conclude that the Renewed Order is not in the public interest for the State of Colorado because it has imposed unnecessary costs on rural electricity consumers and it is likely to continue to raise rates for a substantial portion of Colorado's electricity consumers.

I declare under penalty of perjury that, to the best of my knowledge, the foregoing is true and correct.

Executed this 14 day of October, 2026.

Joseph M. Pereira

Joseph Pereira

[8] *Id.*, at 3.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit E: CoPUC, Decision No. C25-0612, issued on August 26, 2025,
in Proceeding No. 23A-0585E.

Decision No. C25-0612

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 23A-0585E

IN THE MATTER OF THE APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2023 ELECTRIC RESOURCE PLAN.

PHASE II COMMISSION DECISION APPROVING COST-EFFECTIVE RESOURCE PLAN, GRANTING MOTION TO WAIVE CERTAIN CPCN FILING REQUIREMENTS, AND DENYING MOTION TO ENFORCE SETTLEMENT, STRIKE COMMENTS, AND REQUIRE NEW MODELING

Issued Date: August 26, 2025
Adopted Date: August 1, 2025

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I. BY THE COMMISSION

A. Statement

1. On April 11, 2025, Tri-State Generation and Transmission Association, Inc. (Tri-State) filed its Electric Resource Plan ("ERP") Implementation Report in Phase II of this ERP proceeding in accordance with the Commission's ERP Rules set forth in 4 *Code of Colorado Regulations* 723-3-3600 *et seq.,* and specifically Rule 3605. The ERP Implementation Report

summarizes the bid evaluation and selection resulting from Tri-State's competitive solicitations for new utility resources pursuant to the Commission's Phase I decision in this same ERP proceeding.

2. By this Phase II Decision, we establish Tri-State's Preferred Portfolio (also called Portfolio 4 or FLEXSR) as a cost-effective resource plan. The plan includes the acquisition of 400 MW of wind generation, 200 MW of solar generation, 650 MW of storage, and 307 MW of gas-fired generation between 2026 and 2031. Phase II of Tri-State's ERP also entails the replacement of the gas turbines at Tri-State's J.M. Shafer plant ("Shafer") to improve its capacity contributions. Importantly, the Preferred Portfolio maintains the previously announced retirements of certain coal-fired generation facilities at Tri-State's Craig and Springerville plants. Based on the record in this Proceeding and all required considerations, including those in §§ 40-2-123, 40-2-124, 40-2-129, and 40-2-134, C.R.S., and as set forth in Rule 3605, we conclude that the Preferred Portfolio includes clean energy resources that can be acquired at a reasonable cost and rate impact and with appropriate consideration to: Best Value Employment Metrics ("BVEM"); issues of energy security, economic prosperity, and environmental protection; and the energy policy goals of the State of Colorado.

3. We also grant the Motion for Partial Waiver of Rules 3102 and 3103 in Connection with a Gas Resource Addition and Craig Station Retirement ("CPCN Motion") filed by Tri-State on April 15, 2025.

4. We further deny the Motion to Enforce Settlement Agreement, Strike Comments, and Require New Modeling ("CC/WRA Motion") filed jointly by the National Resources Defense Council and Sierra Club (together the "Conservation Coalition") and Western Resource Advocates ("WRA") on June 18, 2025, consistent with the discussion below.

B. Discussion

1. Electric Resource Planning for Tri-State

5. This Proceeding addresses the second ERP application filed by Tri-State since the enactment of Senate Bill ("SB") 19-236. That statute directed the Commission to promulgate ERP rules for wholesale electric cooperatives such as Tri-State, considering whether such cooperatives serve a multistate operational jurisdiction, have a not-for-profit ownership structure, and have a resource plan that meets the energy policy goals of the State.[1]

6. The Commission promulgated Rule 3605 in Proceeding No. 19R-0408E in accordance with SB 19-236.[2] Under that rule, in Phase I of an ERP, the wholesale electric cooperative assesses the need for additional resources given its energy and demand forecasts, existing resources, planning reserve margins, and other factors, including statewide goals to reduce greenhouse gas ("GHG") emissions. The wholesale electric cooperative is directed to set forth a plan for acquiring resources either through a competitive process or an alternative method of resource acquisition, and to provide bid policies, requests for proposals (RFPs), model contracts, and criteria for bid evaluation, as necessary. Phase II begins after the Commission issues its Phase I decision.

7. Pursuant to Rule 3605(h)(II), the Commission must consider certain public interest and statutory criteria in its Phase II decision approving, conditioning, modifying, or rejecting the wholesale electric cooperative's preferred cost-effective resource plan. That is, pursuant to §§ 40-2-123 and 40-2-124, C.R.S., the Commission considers renewable energy resources, energy efficient technologies, and resources that affect employment and long-term economic viability of

[1] *See* § 40-2-134, C.R.S.
[2] Proceeding No. 19R-0408E, Decision No. C20-0155, issued March 10, 2020.

Colorado communities. The Commission further considers resources that, among other characteristics, provide beneficial contributions to energy security, economic prosperity, environmental protection, and insulation from fuel price increases. Additionally, the Commission determines whether the wholesale electric cooperative has provided sufficient BVEM information in accordance with § 40-2-129, C.R.S.; certified compliance with the objective standards for the review of such metrics based on the Phase I decision; and whether the utility has agreed to use a project labor agreement for the construction or expansion of a generating facility. The wholesale electric cooperative must request BVEM information from bidders through its RFP process, including information on training programs, employment of Colorado workers, and long-term career opportunities.

8. With respect to the establishment of a cost-effective resource plan in Phase II, the Commission also considers the net present value of revenue requirements ("NPVRR") for the potential resource portfolios to be established as the cost-effective resource plan, with and without the application of the social cost of carbon dioxide emissions pursuant to § 40-3.2-106(3), C.R.S. Ultimately, in accordance with § 40-2-134, C.R.S., the Commission determines whether the final cost-effective resource plan meets Colorado's energy policy goals.

2. Phase I Procedural Background

9. On December 1, 2023, Tri-State filed its 2023 ERP in this Proceeding, initiating Phase I.

10. A full procedural history of Phase I is set forth in Decision No. R24-0602 ("Phase I Decision").

11. By Decision No. R24-0080-I, issued by Administrative Law Judge ("ALJ") Aviv Segev, the Commission established the parties to this proceeding: Tri-State; Trial Staff of

the Colorado Public Utilities Commission ("Staff"); the Colorado Office of the Utility Consumer Advocate ("UCA"); the Colorado Energy Office ("CEO"); the City of Craig and Moffat County; Poudre Valley Rural Electric Association, Inc.; Highline Electric Association; K.C. Electric Association ("KC Electric"); San Isabel Electric Association, Inc. ("San Isabel"); Southeast Colorado Power Association; and Y-W Electric Association, Inc.; Big Horn Rural Electric Company, Carbon Power & Light, Inc., High West Energy Inc., Wheatland Rural Electric Association, Wyrulec Company, Inc., Niobrara Electric Association, High Plains Power, Inc., and Garland Light & Power Co. (collectively "Wyoming Cooperatives"); Colorado Solar and Storage Association ("COSSA") and Solar Energy Industries Association (collectively "COSSA/SEIA"); the Conservation Coalition; Colorado Independent Energy Association ("CIEA"); Southwest Energy Efficiency Project; Interwest Energy Alliance; and WRA.

12. The Phase I Decision, also rendered by ALJ Segev, approved a comprehensive and unopposed Settlement Agreement that resolved all contested issues in Phase I. The ALJ's recommended decision became the Phase I decision of the Commission on September 11, 2024, without modification.

13. The Settlement Agreement approved by the Phase I Decision contemplates three concurrent solicitations (RFPs) for Phase II, each meeting certain specifications: a Dispatchable RFP; a Standalone Storage RFP, and a Renewable RFP. The Settling Parties agreed that the Commission should approve a Phase II portfolio from among a set of defined portfolios to be modeled by Tri-State pursuant to the terms of the Settlement Agreement.[3] These portfolios include: Tri-State's Preferred Portfolio; the Preferred Portfolio with specific modifications; an "unconstrained portfolio that allows all resources to be selected by the model;" an additional

[3] Phase I Decision, Att. A, Unopposed Comprehensive Settlement Agreement, ¶ 4.2, pp. 5-9.

portfolio of Tri-State's choosing; and a "Contingent No New Gas Portfolio" if the other portfolios modeled select new gas-fired resources.[4] Notably, a provision in the Settlement Agreement requires Tri-State to solicit bids for a gas plant within Moffat County.[5] The Settlement Agreement also includes a provision that Tri-State will apply a $1/MWh price improvement over the life of the proposed project or contract in the evaluation and modeling of bids located in Moffat County.[6] The Settlement Agreement further sets out additional filing requirements for the Implementation Report to be filed in Phase II ("ERP Implementation Report") and spells out Tri-State's commitments related to processes and actions in its next ERP to be filed in 2027.

14. Tri-State issued the three RFPs on September 13, 2024, commencing Phase II. Tri-State received 145 individual eligible bid proposals as reported in its "45-Day Report" filed on December 12, 2024.

C. Tri-State's ERP Implementation Report

15. Rule 3605(h)(I) lays out the minimum requirements for the report that is filed by the wholesale electric cooperative in Phase II. Tri-State must present cost-effective resource plans in accordance with the Commission's Phase I decision and shall identify its preferred cost-effective resource plan. The report must: (1) apply the cost of carbon dioxide emissions to all existing and new utility resources in its modeling of the costs and benefits of all resource plans as required by the Commission's decision in Phase I; (2) present a calculation of the NPVRR for each portfolio required by the Commission's decision in Phase I and the NPVRR for each existing and new utility resource included in the portfolio, as well as the total cost of carbon dioxide emissions of the total portfolio, calculated using the cost of carbon set forth in the Commission's decision in Phase I and

[4] Phase I Decision, Att. A, Unopposed Comprehensive Settlement Agreement, ¶ 4.3, pp. 9-11.
[5] Phase I Decision, Att. A, Unopposed Comprehensive Settlement Agreement, ¶ 4.2.6.1, p. 7.
[6] Phase I Decision, Att. A, Unopposed Comprehensive Settlement Agreement, ¶ 5.4.1, pp. 24-25.

calculated without using the cost of carbon dioxide emissions; (3) present, for each portfolio, the net present value calculation of the total cost of carbon dioxide emissions calculated by multiplying the total emissions of that portfolio by the cost of carbon dioxide; and (4) provide the Commission with the BVEM information provided by bidders.

16. The ERP Implementation Report that Tri-State filed on April 11, 2025, addresses the requirements in Rule 3605(h)(I) and the requirements in the Settlement Agreement for six modeled portfolios of 52 bids advanced to Phase II modeling. Tri-State also summarizes the factors the Commission must consider in rendering its Phase II pursuant to pursuant to Rule 3605(h)(II) with respect to each of the six modeled portfolios.

17. The six modeled portfolios include:

Portfolio 1. New ERA Expanded (NEE)
Portfolio 2. New ERA Limited Gas (NELG)
Portfolio 3. New ERA Gas Flexibility (FLEX)
Portfolio 4. FLEX Shafer Replacement (FLEXSR) "Preferred Portfolio"
Portfolio 5. No New Gas (NNG)
Portfolio 6. No New Gas Shafer Replacement (NNGSR)

18. Tri-State used EnCompass resource planning software to complete capacity expansion and portfolio optimization analyses. The Resource Acquisition Period ("RAP") for Phase II is 2026 through 2031.

19. Tri-State explains in the ERP Implementation Report that its Preferred Portfolio, Portfolio 4, was selected for its overall performance across the established reliability, environmental, and financial categories as analyzed and described in the Report. Tri-State asserts that the portfolio meets both "Level 1" and "Level 2" Reliability Metrics. Tri-State clarifies that its Preferred Portfolio also meets Colorado emissions reduction targets for GHGs, the Colorado

Renewable Energy Standard, and the New Mexico Renewable Portfolio Standard. Tri-State further claims that it is the least-cost portfolio from the perspective of the rates its members will pay.

20. As stated above, the Preferred Portfolio comprises 1,350 MW of wind, solar, and storage resources. The Preferred Portfolio also maintains the retirement of coal capacity at Craig and Springerville by March 2031. Craig 1 is scheduled for retirement on December 31, 2025; Craig 2 is scheduled for retirement on September 30, 2028; and Craig 3 is scheduled for retirement on January 1, 2028; and Springerville 3 is scheduled for retirement on March 1, 2031.[7] The 307 MW gas combustion turbine included in the Preferred Portfolio will be located in Moffat County will have up to a 30 percent hydrogen blend capability and a planned operation date of 2029. The Preferred Portfolio further reflects Tri-State's plan to replace and upgrade the gas turbines at Shafer. According to Tri-State, the upgraded turbine replacements would require less maintenance expenses in the early four years, increase the capacity from 272 MW to 281 MW, and improve the heat rate at the plant.

21. Notably, the ERP Implementation Report presents Portfolio 6 (or "No New Gas/Shafer Replacement" or "NNGSR"), which replaces the 307 MW gas turbine project in the Preferred Portfolio with an additional 550 MW storage. Both the Preferred Portfolio and Portfolio 6 include the same 400 MW of wind, 200 MW of solar, and 650 MW of battery storage. Both portfolios also reflect the turbine replacements at Shafer.

22. In terms of environmental factors, Tri-State explains that the Phase II modeling indicates all six portfolios can achieve the Colorado GHG reduction targets in 2025, 2026, 2027,

[7] Tri-State ERP Implementation Report, Tables 7, 28, 49, 70, 91, and 112, pp. 21, 32, 43, 54, 64, 75, respectively.

and 2030. Tri-State concludes that the forecasted emissions reductions in 2030 meet the minimum statutory requirement and do not vary substantially across the six portfolios.

23. In the comparative financial analysis presented in the ERP Implementation Report, Tri-State states that the Preferred Portfolio is shown to have a lower cost (*i.e.*, the lowest NPVRR) without consideration of the social cost of emissions (or a cost that is $88 million less than Portfolio 6 or 0.5 percent). However, Portfolio 6 has a lower cost with social cost of emissions (by $329M, or 1.1 percent).

24. Tri-State explains that the Preferred Portfolio requires the least amount of resource additions with less transmission capital expenditures. Tri-State also raises concerns about the potential risk in overreliance on 4-hour batteries suggested by the resource additions in Portfolio 6. Tri-State admits that it has not yet deployed any batteries on its system. Tri-State also expects storage technologies, including longer duration storage options, to make advancements in the coming years.

25. Tri-State further states in the ERP Implementation Report that it remains in a capacity-long position until 2030. However, Tri-State explains that resource acquisitions are required through this Phase II for ensuring ongoing resource adequacy and reliability as the coal units at Craig and Springerville are retired in 2028 and 2031 and to maintain progress toward emission reductions for Colorado statutory compliance as well as for New ERA funding eligibility.[8] Tri-State explains that waiting to procure resources needed for 2030 until the 2027 ERP would not be prudent given that its Phase II process may not conclude until late 2028 or early 2029.

[8] Pursuant to the terms of the Settlement Agreement approved by the Phase I Decision, Tri-State filed a notice in this Proceeding on October 25, 2024, three days before the Phase II bid deadline, stating that Tri-State has been awarded New ERA funding from the U.S. Department of Agriculture and that the New ERA grants and loans support a clean energy transition for rural communities to achieve significant GHG reductions.

26. In terms of curtailments, Tri-State explains that none of the six portfolios result in wind curtailment costs for purchased power agreements ("PPAs"). However, significant solar curtailment costs are expected for all portfolios due to the integration of large amounts of intermittent resources into the system within a short time span. Tri-State succinctly states: "More intermittent resources leads to more curtailment, but storage additions mitigate curtailments."[9]

27. With respect to reliability, Tri-State explains that each of the six portfolios met Level 1 and 2 Reliability Metrics but that the Preferred Portfolio "achieves reliability in the most cost-effective manner."[10] Anticipating the potential interest in Portfolio 6 due to the terms of the Settlement Agreement, Tri-State states that the retirement of dispatchable coal resources cannot be affordably or reliably replaced solely with semi-dispatchable resources. The new resources, including the dispatchable gas plant in Moffat County, will provide jobs and tax base that support community vitality across many areas of Tri-State's system.

28. For transmission costing purposes, Tri-State explains that it completed interconnection optimization for the Preferred Portfolio and Portfolio 6. According to Tri-State, optimizing the Preferred Portfolio enabled the avoidance of an estimated $370 million in transmission capital expenditures during the RAP. Likewise, optimizing Portfolio 6 enabled the estimated avoidance of approximately $317 million in transmission capital expenditures during the RAP.

29. Tri-State also conducted Encompass modeling to identify three back-up bid pools. Tri-State explains that it will, to the extent necessary, utilize these backup bid pools to replace

[9] Tri-State ERP Implementation Report, p. 94.
[10] Tri-State ERP Implementation Report, p. 95.

Preferred Portfolio bids that fail. If a Preferred Portfolio bid cannot move forward, Tri-State aims to replace it with a similarly sized, similar technology type project, if possible, subject to limitations and economics. Tri-State states that upon any bid failure(s), it would utilize bids from the relevant back-up bid pool, along with the remaining viable Preferred Portfolio bids, and run a dispatch at that time to ensure continued adherence to the same affordability, reliability, and responsibility metrics and principles each Phase II portfolio was measured against. Tri-State will also: notify the Commission of any bid failures; identify steps taken to remediate the failed project, where feasible; and identify the back-up bid, or combination of backup bids, selected from the pools.

30. Finally, with respect to BVEM, Tri-State explains that Rule 3605(h)(I)(A)(iii) requires it to provide to the Commission certain BVEM information provided by bidders." The BVEM information provided by bidders whose bids were advanced to modeling is specifically provided in Attachment F-1 to the ERP Implementation Report. Tri-State explains that BVEM is a non-price factor ("NPF") analyzed by Tri-State as an element of bids' community stewardship.[11]

31. Tri-State requests that the Commission find its Preferred Portfolio to be a cost-effective resource plan and approve it through this Phase II decision. Tri-State concludes that its ERP Implementation Report provides extensive detail on the multiple portfolios modeled and "builds a clear record that supports approval of Tri-State's preferred portfolio."[12] Tri-State requests the Commission approve Tri-State's Preferred Portfolio as the final cost-effective resource plan for Phase II of the 2023 ERP, pursuant to Rule 3605(h)(II).

[11] Tri-State ERP Implementation Report, p. 13.
[12] Tri-State ERP Implementation Report, p. 95.

D. Independent Evaluator Report

32. In its Phase I application filing, Tri-State committed to using an Independent Evaluator ("IE") "to add further assurance of consistency and fairness in its bid evaluation process for both Build Transfer and PPA agreements."[13]

33. On April 15, 2025, 1898 & Co.—the IE retained by Tri-State— filed its Phase II report. The IE states that it was responsible for confirming that: all assumptions used in the RFP were reasonable; there is no discernable bias for or against any respondent or permitted technology; all respondents have access to the same information at the same time; and all bids are evaluated using the same assumptions and criteria.[14]

34. The IE concludes that Tri-State's RFP process was conducted fairly without bias towards or against any acceptable technology or respondent. The IE further concludes that the established protocols were adhered to and that it is unaware of any improper contact between Tri-State and any bidder.

35. The IE states that it was actively engaged throughout the RFP process: reviewing all RFP documents as the process commenced; reviewing all bids submitted and the communications between Tri-State and bidders; and holding frequent meetings with Tri-State throughout the engagement. The IE states that "all assumptions used in the EnCompass modeling were reasonable, and that the overall scoring process was conducted fairly without bias towards or against any acceptable technology or respondent."[15]

[13] Hr. Ex. 101, Tiffen Direct, p. 41.
[14] IE Report, p. 1.
[15] IR Report, p. 5.

E. APCD ERP Verification Report

36. On May 12, 2025, the Air Pollution Control Division ("APCD") of the Colorado Department of Public Health and Environment filed a Verification Report. The APCD report indicates that House Bill 21-1266, codified, in part, at § 25-7-105, C.R.S., requires Tri-State to submit an ERP to the Commission that achieves at least an 80 percent reduction in GHG emissions associated with the Tri-State's sales to customers within Colorado by 2030, when compared to a 2005 baseline. The APCD report also states, as part of House Bill 21-1266, the APCD is required to provide verification of the GHG emissions reductions projected in the ERP.

37. APCD concludes that the emission reductions for the Preferred Portfolio are 80 percent below baseline levels. APCD explains that the modeling data provided by Tri-State was used to cross-check entries in the calculation of emissions in accordance with APCD's Verification Workbook and associated guidance.

F. Phase II Party Comments

1. Staff

38. Staff asserts that it: "does not oppose approval of Tri-State's Preferred Portfolio (Portfolio 4) but also does not oppose approval of the No New Gas version of the Preferred Portfolio (Portfolio 6)."[16] However, Staff notes that the "transmission optimization" was only applied to the Preferred Portfolio and Portfolio 6, which "makes it impossible to directly compare those portfolios to the others."[17] Staff states that the additional transmission analysis revealed significant network upgrade costs that could be avoided by modifying the modeling assumptions and, for the Preferred Portfolio, making manual changes to a subset of the selected resources.

[16] Staff Comments, p. 23.
[17] Staff Comments, p. 4.

Staff highlights that such information was not used to re-optimize the four other portfolios. Staff thus requests clarification from Tri-State on certain aspects of the transmission optimization analysis.

39. Staff also states that Tri-State's proposal to replace the gas turbines at Shafer was not examined in Phase I, and, since the Preferred Portfolio and Portfolio 6 cannot be compared to other portfolios, it is not possible to determine the cost and benefits of the Shafer turbine replacements. Staff hence asks that Tri-State provide a better process for evaluation of any similar projects in future ERPs.[18]

2. UCA

40. UCA supports Tri-State's Preferred Portfolio because it has the lowest PVRR and because it provides gas-fired capacity in Western Colorado.[19]

41. UCA notes, however, that Tri-State's proposal to replace the turbines at Shafer were not disclosed in Phase I. UCA also raises questions about the capacity factors for new gas units because they appear inconsistent with the reported heat rates of the plants.[20] And while UCA generally supports the inclusion of transmission costs that relate to bids, which appears in Appendix G of the ERP Implementation Report, it offers the following suggestions related to transmission.[21] First, UCA states that wind and solar can share transmission as both reach their peak outputs at different times of the day. While some additional curtailment might result from this sharing, this could easily be included in the evaluation of projects. Additionally, wind and solar can share transmission with firm resources firming the capacity. Second, Tri-State only includes its transmission analysis for Portfolios 4 and 6, and the lack of transmission analysis for

[18] Staff Comments, p. 4.
[19] UCA Comments, p. 1.
[20] UCA Comments, pp. 4-6.
[21] UCA Comments, p. 6.

the other portfolios could pose difficulties because not all transmission costs will have been similarly applied.

3. CEO

42. CEO requests the Commission approve Tri-State's Preferred Portfolio.[22]

43. CEO argues the Preferred Portfolio aligns with clean energy and GHG emissions reduction policy requirements and goals.[23] CEO notes that although the Preferred Portfolio includes a new gas 307 MW facility and replacement of the Shafer turbines, the turbines are being proposed as both gas- and hydrogen-capable, which presents the opportunity to transition to even lower GHG emitting resources over the long term.[24]

44. CEO also contends Tri-State's Preferred Portfolio supports Just Transition efforts in Moffat County, consistent with what Tri-State, City of Craig, and Moffat County endorsed in the Phase I Settlement Agreement. CEO states: "Co-locating gas resources in Moffat County could provide additional support to the City of Craig and Moffat County and cost-saving opportunities for Tri-State's Members."[25]

45. CEO also suggests Tri-State should use the acquisition of 650 MW of storage to gain familiarity with the technology, reduce curtailments of renewable energy resources, and minimize the use of gas and coal resources.[26]

4. Moffat County and City of Craig

46. Moffatt County and City of Craig "fully support" Tri-State's Preferred Portfolio and note that the two resources proposed for Moffat County—the new gas plant and a 200 MW

[22] CEO Comments, p. 13.
[23] CEO Comments, pp. 7-8.
[24] CEO Comments, p. 8.
[25] CEO Comments, pp. 10-12.
[26] CEO Comments, p. 12.

storage asset—"have the potential to provide significant tax revenues for the local community and taxing districts… while also providing multiple employment opportunities for Northwest Colorado residents, including Craig Station, Hayden Station, and coal mine workers."[27] These parties also included letters of support from the Associated Governments of Northwest Colorado and the Craig Rural Fire Protection District.

5. San Isabel and KC Electric

47. San Isabel Electric Association and KC Electric Association each filed comments in the form of a standard letter submitted by non-party cooperatives members of Tri-State. They support the Preferred Portfolio, stating: "This portfolio identifies bid selections that result in a plan that meets both industry-standard and heightened extreme weather reliability metrics and state GHG and renewable requirements at a lower cost than the alternative portfolios."

6. Wyoming Cooperatives

48. The Wyoming Cooperatives state that they worked in coordination with Tri-State to help create the Level I and Level II reliability metrics but they remain concerned about the cost it will take to meet those metrics given Colorado's environmental policies.[28] They also state that while Tri-State's Preferred Portfolio is the lowest cost modeled plan, it still comes with a projected NPVRR of $16.4 billion dollars that will be recovered from Tri-State's member cooperatives. They explain that "it was imperative that Tri-State receive funding under the New ERA Program to help mitigate rate impacts during the clean energy transition."[29] They add, however, that "even with the addition of billions of dollars of New ERA funding projected to be in place, Tri-State's

[27] Moffat County and City of Craig Comments, pp. 3-4.
[28] Wyoming Cooperatives Comments, pp. 1-2.
[29] Wyoming Cooperatives Comments, p. 2.

rate payers are facing SUBSTANTIAL wholesale rate increase projections over the next 10 years, and double digit increases from 2026 - 2028 to implement the Preferred Portfolio."[30]

7. Conservation Coalition

49. The Conservation Coalition objects to Commission approval of Tri-State's Preferred Portfolio and instead supports Portfolio 6. The Conservation Coalition urges Tri-State to reconsider its decision and select Portfolio 6 as its preferred plan, and, if Tri-State does not make that change, it asks the Commission to approve Portfolio 6 instead of the Portfolio 4.

50. For instance, Conservation Coalition argues that Portfolio 6 has the lowest capital costs for generation and transmission during and the lowest PVRR when including the social cost of emissions. In addition, without the social cost of emissions, Tri-State's Preferred Portfolio only has 0.5 percent advantage over Portfolio 6 during periods of "highly uncertain cost estimates in the 2030s and 2040s." [31] Conservation Coalition goes on to argue that Portfolio 6 would save hundreds of millions of dollars in capital costs for generation and transmission during the RAP relative to the Preferred Portfolio.[32] Conservation Coalition adds that Portfolio 6 has lower risks than the Preferred Portfolio, such as a lower risk of overbuilding capacity and lower risks associated with making future off-system sales. [33]

51. Conservation Coalition further notes that the Preferred Portfolio would emit 4.2 million tons more carbon dioxide emissions relative to alternative portfolios such as Portfolio 6. Conservation Coalition argues Tri-State should not pass up the opportunity to select Portfolio 6 to accomplish 4 million tons of additional carbon dioxide emissions reductions in the

[30] Wyoming Cooperatives Comments, p. 2.
[31] Conservation Coalition Comments, p. 2.
[32] Conservation Coalition Comments, p. 7.
[33] Conservation Coalition Comments, pp. 10-13.

2030s and 2040s for little to no incremental cost.[34] Conservation Coalition also argues that Colorado law already requires Tri-State to eliminate its carbon dioxide emissions by 2050 and it is virtually certain that Colorado will adopt interim carbon dioxide emissions reduction requirements for the years before 2050.[35]

52. With respect to reliability, Conservation Coalition argues that both the Preferred Portfolio and Portfolio 6 meet the Level 1 and 2 Reliability Metrics "with both having no unserved energy or zero loss of load probability; and both have nearly identical reserve margins. Thus, reliability is not a basis for rejecting Portfolio 6, as the portfolio meets all of the same reliability metrics as Portfolio 4."[36] Conservation Coalition likewise states, to the extent that Tri-State is concerned that it may need a new gas plant to come online in 2031, Tri-State has better options than bringing a plant online in 2029 that it does not need for capacity purposes in 2029 or 2030.[37]

53. Conservation Coalition further challenges Tri-State's concerns about a potential "overreliance" on storage. Conservation Coalition states: "Because Portfolio 6 would add battery projects over a 5-year period, it would enable Tri-State to gain experience with the earlier projects before adding the later projects. Tri-State offers no explanation as to why the experience it gains in 2026 and 2027 with the early battery projects would not allow it gain the knowledge it needs to then operate additional battery projects in 2028–2030." [38]

54. Conservation Coalition also notes that the Preferred Portfolio and Portfolio 6 have the same local economic benefits because the Phase I settlement guarantees significant community

[34] Conservation Coalition Comments, p. 13.
[35] Conservation Coalition Comments, p. 3.
[36] Conservation Coalition Comments, p. 3.
[37] Conservation Coalition Comments, p. 11.
[38] Conservation Coalition Comments, p. 18.

assistance payments by Tri-State regardless of which portfolio the Commission approves here in Phase II. Specifically, under any portfolio, Tri-State will pay $22 million to an economic development fund administered by Moffat County and the City of Craig, as well as payments for lost tax revenue to Moffat County and the City of Craig totaling $48 million from 2028 through 2038.[39]

55. Conservation Coalition further suggests there are serious questions of accuracy of Tri-State's Phase II modeling. Conservation Coalition states: "Tri-State has taken at face value the bidder specifications that the heat rate of the new gas plant would be significantly lower (*i.e.*, more efficient) than any publicly available heat rates for comparable combustion turbines… Rather than verify these questionable assumptions or seek contractual guarantees that the bidder will actually achieve these unusually low heat rates, Tri-State simply plugged these values into the model and returned results that are as unusual as the heat rates: having a peaking gas plant run at a 40% capacity factor for multiple years. For these reasons, the Commission should view Tri-State's economic modeling of the new proposed gas plant with deep skepticism."[40] Conservation Coalition also argues that the quantity of off-system sales from the new gas plant that Tri-State assumes is so large that changing that assumption would alter the relative economic ranking of the portfolios.[41] More generally, Conservation Coalition raises concerns surrounding the Encompass model, stating that the model is "not completing on its own" but is rather "stopping" due to exceeding maximum run-time limits (with every single portfolio and simulation step).[42]

[39] Conservation Coalition Comments, p. 20.
[40] Conservation Coalition Comments, p. 2.
[41] Conservation Coalition Comments, p. 11.
[42] Conservation Coalition Comments, p. 22.

8. WRA

56. WRA raises many of the same arguments as Conservation Coalition, objecting to the approval of Tri-State's Preferred Portfolio and supporting Portfolio 6 instead. WRA similarly asks that the Commission direct Tri-State to pursue Portfolio 6 instead of its Preferred Portfolio.[43]

57. WRA claims, for example, that Portfolio 6 has the lowest capital costs over the planning period, the lowest renewable curtailment costs, and the lowest PVRR when accounting for social cost of emissions, the last of which "accounts for the real-world costs of the emissions associated with utility resource acquisitions."[44] WRA also stresses that Portfolio 6 has the least curtailment across all of the presented portfolios.[45] Furthermore, WRA echoes the position of Conservation Coalition, stating that in selecting a cost-effective plan, the Commission should consider the real risk that new gas-fired generation resources may become stranded assets. WRA argues that deferring or avoiding the acquisition of new natural gas units can help to reduce customer stranded cost risk, lower emissions and costs, and allow for consideration of new clean, dispatchable technology bids in future solicitations.[46]

58. In terms of Level 1 Reliability Metrics, WRA notes the ERP Implementation Report indicates that Portfolio 6 is associated with zero loss of load hours and zero expected unserved energy during the modeling period. Further, the planning reserve margin for Portfolio 6 exceeds Tri-State's requirements as established in Phase I. According to WRA, Portfolio 6 outperforms the Preferred Portfolio according to Level 2 Reliability Metrics, because the Preferred Portfolio is

[43] WRA Comments, p. 5.
[44] WRA Comments, p. 7.
[45] WRA Comments, p. 11.
[46] WRA Comments, p. 13.

associated with one loss of load event under the extreme weather event analysis, whereas Portfolio 6 experienced no loss of load.[47]

59. WRA also asks the Commission to recognize that all of the portfolios presented in the ERP Implementation Report, including the Portfolio 6, are accompanied by the Just Transition commitments established in Phase I of this proceeding (*i.e.*, $70 million in payments, with $22 million paid over first four years into an economic development fund and $48 million paid over 11 years as property tax backstop payments, as well as a transfer of water rights).[48]

60. Turning to emission reductions, WRA asks that Tri-State provide, via its response comments, a quantitative and qualitative explanation for its projected system-wide and Colorado GHG emissions as well as Colorado GHG emissions through the entire planning period (ending in 2043), and a description of why the Company did not assess whether it was prudent to replace the Shafer turbines during Phase I.[49] For instance, WRA notes that the portfolios presented in the ERP Implementation Report only achieve an expected 80 percent emission reduction by 2030, as required by statute, but no further. According to WRA, this result contrasts with the Phase I modeling that indicated additional emission reductions were possible.[50] And with regard to Tri-State's modeling of Shafer, WRA states: "Tri-State's unilateral decision to construct the portfolios in this manner reflects a concerning lack of transparency in the Company's resource planning efforts. During Phase I, Tri-State did not indicate that it was considering replacement or repair of Shafer."[51] More generally, WRA asks the Commission to require Tri-State to present all Phase II portfolios on an analytically equivalent basis going forward.[52]

[47] WRA Comments, pp. 8-9.
[48] WRA Comments, pp. 13-14.
[49] WRA Comments, p. 4 and pp. 14-18.
[50] WRA Comments, Figures WRA-4 and 5, p. 15.
[51] WRA Comments, p. 20.
[52] WRA Comments, p. 21.

9. CIEA

61. CIEA primarily focuses on Tri-State's bid scoring process for this Phase II and concludes that its proposed reforms "are necessary to ensure a competitive and cost-effective resource acquisition process that serves the public interest."[53]

62. For example, CIEA contends that Tri-State was required to provide additional information on NPFs related to bid resources pursuant to Decision No. C23-0437, which required "[a]t minimum, [the 45-day report in Tri-State's next ERP] should include information on the number of bids that failed each screen, and the specific criteria within each screen that caused bids to fail… and assess whether any adjustments are advisable for future solicitations."[54] According to CIEA, Tri-State's 45-Day Report provided some of this information, but not in a meaningful way that was responsive to the Commission's concern. CIEA goes on to explain that neither the 45-Day Report nor the ERP Implementation Report provided sufficient detail as to the bids that failed each individual NPF screen and that both reports failed to explain why individual bids were eliminated by its NPF evaluation which, apparently, eliminated the majority of the bid pool prior to computer modeling.[55] CIEA also faults Tri-State for not including a discussion of how project characteristics aligned with its color-coding process, which went from three colors to five colors, in either its Report, the IE Report, or the 45-Day Report.

63. CIEA states that NPF screening data should be released in a disaggregated form prior to Tri-State's next RFP so that bidders better understand how Tri-State evaluates bids across NPF criteria.[56] CIEA suggests that this information, if released would also become public under Rule 3605(h)(III).

[53] CIEA Comments, p. 10.
[54] CIEA Comments, pp. 3-4, citing Proceeding No. 20A-0528E, Decision No. C23-0437, p. 25.
[55] CIEA Comments, pp. 5-7.
[56] CIEA Comments, p. 8.

10. COSSA

64. In its comments, COSSA asks Tri-State to explain the impacts of the launch of SPP RTO West on its interconnection process, specifically for projects that are a part of the Phase II portfolios. COSSA further requests that Tri-State provide any other relevant details about how the process for projects requesting interconnection on the Tri-State system that are not a part of this ERP will change under SPP RTO West.[57]

G. Phase II Public Comments

65. Several dozens of members of the retail cooperatives served by Tri-State filed individual comments objecting to the acquisition of new gas-fired resources while otherwise supporting Tri-State's plans to acquire renewables and storage. A petition filed by over 200 cooperative members was also submitted again favoring the acquisition of renewables and storage but objecting to the new gas plant.[58]

66. In addition, certain local government officials in Colorado communities served by Tri-State—including county commissioners, elected town officials, and local government employees—filed comments expressing support for the adoption of Portfolio 6, stating that it "maximizes clean energy acquisition and limits investment in new gas infrastructure for the sake of energy affordability and community resilience to climate change."[59]

67. The Craig Rural Fire Protection District filed comments in support of Tri-State's Preferred Portfolio.[60]

[57] COSSA Comments, p. 2.
[58] Tri-State 2023 ERP Petition (Against NG).
[59] Comments 33 Local Government Reps.
[60] Comments Craig Rural Fire Protection District.

68. The Mayor of Ridgeway, San Miguel County, and San Miguel Power Association support the development of geo-thermal resources. [61]

H. Tri-State's Response to Party Comments

69. Tri-State defends the selection of its Preferred Portfolio in its responsive comments filed on June 10, 2025. Tri-State states that its projected costs are $88 million lower when compared to the next-closest alternative, which addresses a critical economic need for Tri-State's members. Additionally, Tri-State maintains that the Preferred Portfolio supports Colorado employment, provides stable tax revenue for Moffat County, and achieves APCD-verified emission reductions consistent with state requirements.[62]

70. With respect to the advocacy of Conservation Coalition and WRA to require Portfolio 6 over the Preferred Portfolio, Tri-State emphasizes that dispatchable combustion turbine capacity bids and semi-dispatchable battery capacity are not "identical." For example, Tri-State explains that it did not reject Portfolio 6 simply because of the potential overreliance on batteries.[63] Tri-State claims that Portfolio 6 does not offer the resources needed in the Western part of the state for spinning reserves and without a reliable resource to fill that gap, the stability of the system could be compromised, leading to increased operational risks and higher overall costs. Tri-State further argues the current low Effective Load Carrying Capability ("ELCC") of 45 percent for 4-hour batteries after the addition of 400 MW of storage indicates a substantial risk given its more limited contributions to system reliability during times of peak demand. Tri-State adds: "In contrast, long-duration batteries could potentially address this risk if those technologies further advance, offering a higher ELCC and therefore greater assurance of their

[61] Comments Ridgeway Mayor, San Miguel County Geothermal Support, San Miguel Power Association - Geothermal.
[62] Tri-State Response Comments, p. 6
[63] Tri-State Response Comments, p. 14.

contribution to reliability, and if their costs also decrease. However, it is important to recognize that, at present, gas plants provide a far more dependable solution, with an ELCC of 95 percent."[64]

71. Tri-State further argues its Preferred Portfolio includes robust, dispatchable generation resources that support grid reliability, especially during peak demand periods or when renewable sources are insufficient. Tri-State stresses that: "Although battery integration is important for a balanced energy strategy, the immediate needs of the Western Colorado system, particularly in the transition away from coal, require the inclusion of reliable dispatchable resources like gas plants to ensure overall system reliability."[65] More generally, with respect to reliability metrics, Tri-State explains that although they are critical, they "do not assess the benefits of a balanced energy strategy, including factors such as the value of reserves for system balancing."[66] Tri-State goes on to argue that, considering the minimal amount of Expected Unserved Energy ("EUE") shown in the Preferred Portfolio, and the portfolio's sufficient unused thermal capacity, it is difficult to draw a definitive conclusion that Portfolio 6 is more reliable.[67]

72. Tri-State generally agrees with Conservation Coalition's calculation of projected planning reserve margins during the RAP, acknowledging that the reserve margin will increase in 2029 and 2030 and then decrease rapidly in 2031 when the Springerville unit comes offline. Tri-State explains, however, that the timing of the resource additions in the portfolios presented in the ERP Implementation Report is not driven by the optimization of reserve margins but instead reflects resource acquisitions intended to ensure sufficient capacity is online by the time the Springerville unit is retired.[68] In other words, Tri-State argues there was no modeling assumption

[64] Tri-State Response Comments, p. 16.
[65] Tri-State Response Comments, p. 15.
[66] Tri-State Response Comments, p. 15.
[67] Tri-State Response Comments, p. 16.
[68] Tri-State Response Comments, p. 16.

around excess capacity. Rather, shifts in capacity seen in all portfolios are due to the timing of contracted sales coming offline and resource capacity coming online based on the modeled Commercial Operation Dates provided by bidders.

73. Turning to WRA's criticisms of Tri-State's portfolio selection through the lens of emissions, Tri-State objects to WRA's characterization of the projected emission reductions as "stalled." Tri-State states that it remains on track to meet all applicable emissions reductions requirements.[69] Tri-State also addresses the factors contributing to differences in expected emission reductions between Phase I and Phase II.[70]

74. Tri-State further explains that it has taken a conservative approach in modeling the economics of a new gas unit in the ERP Phase II modeling by limiting the depreciable life to 20 years.[71] In comparison, a recent generation plant depreciation study calculated a life span of 46-54 years for Tri-State's existing combustion turbine plants based on a database of over 9,000 U.S. power plants.

75. With respect to Conservation Coalition's contention that the heat rate for the selected gas-fired plant in the Preferred Portfolio appears to be lower than the specifications for comparable gas turbines, Tri-State admits that it used the heat rate as supplied by the bidder to conduct its Phase II modeling.[72] Nevertheless, Tri-States argues that the selection of the gas plant within the Preferred Portfolio is driven primarily by the need for dispatchable capacity and that, even if the heat rate for the plant is increased, the potential result will only be a reduction in the annual capacity factor of the plant but the model would likely still select that same resource.[73]

[69] Tri-State Response Comments, p. 20.
[70] Tri-State Response Comments, pp. 20-21.
[71] Tri-State Response Comments, p. 37.
[72] Tri-State Response Comments, p. 24.
[73] Tri-State Response Comments, p. 24.

Tri-State further explains that regardless of the heat rate guaranteed under the contract for the associated bid, it is committed to operating its system in a manner to achieve the Colorado emission reduction targets.

76. Tri-State goes on to argue that Conservation Coalition's and WRA's preference for Portfolio 6 due to lower risks of overbuilding is "counterintuitive," because Portfolio 6 results in building 1,900 MWs compared to 1,657 MWs.[74] Additionally, Tri-State argues that Portfolio 6 relies significantly on 4-hour duration battery energy storage, which increases risk by decreasing resource diversity, increasing supply chain issues around storage resources, and thereby increasing the likelihood of failed bids requiring additional considerations of back-up bids. Tri-State also faults the selection of Portfolio 6 instead of the Preferred Portfolio, because Tri-State argues that it needs to gain more operational experience with batteries before significantly increasing its reliance on the storage inherent in Portfolio 6.[75]

77. With respect to CIEA's concern regarding the number of bids that were eliminated in Phase II, Tri-State notes that a higher proportion of bids were advanced to modeling here than in the previous 2020 ERP.[76] Tri-State also clarifies that all bid screens, for purposes of determining bids advanced to modeling, were completed prior to the submission of the 45-Day Report and there were no "additional" NPF screens prior to computer modeling as CIEA suggested. Tri-State also explains that its 45-Day Report fully complied with Decision No. C23-0437, the Phase II decision in Tri-State's first ERP, which required Tri-State to work with interested stakeholders to attempt to arrive at mutually agreeable and practical level of information that can be provided.

[74] Tri-State Response Comments, p. 15.
[75] Tri-State Response Comments, p. 24.
[76] Tri-State Response Comments, p. 8.

78. With respect to CIEA's suggestion that the Commission require Tri-State to provide to individual bidders the "color" of the NPF analysis in which each area of their bid was categorized and the reasons for that categorization, Tri-State argues it has already provided detailed information on how it conducts its NPF analysis in Phase I testimony, the Bid Policy, the RFPs, the 45-Day Report, and the ERP Implementation Report.[77]

79. Tri-State further argues that disclosure of NPF information is unnecessary because, as stated above, Tri-State has already expressed its willingness to meet individually with bidders to discuss how their projects were evaluated.[78] Tri-State has also committed to including a numeric framework for its NPF analysis and to providing a scoring sheet as part of its direct filing in Phase I of its 2027 ERP, as provided in the 2023 Phase I Settlement Agreement.

I. Tri-State's CPCN Motion

80. On April 15, 2025, Tri-State filed the CPCN Motion. Tri-State requests that the Commission waive the requirement to file separate applications for Certificates of Public Convenience and Necessity ("CPCN") for two categories of actions: (1) the potential construction of a gas-fired generation resource that may be selected in Phase II; and (2) the retirement of the units at Craig. The Motion asserts that both issues are, or will, be fully addressed within this Proceeding and that duplicative filings would be inefficient and unnecessary.[79]

81. Tri-State notes that because it is not rate-regulated by the Commission, cost recovery considerations central to CPCN applications for investor-owned utilities are inapplicable here.[80] Accordingly, the primary regulatory objectives typically served by CPCN applications,

[77] Tri-State Response Comments, p. 11.
[78] Tri-State Response Comments, p. 13.
[79] CPCN Motion, pp. 11 and 16.
[80] CPCN Motion, p. 17.

such as prudence reviews, cost allocation, and rate impact analysis, are not applicable.[81] The Motion emphasizes that the Commission's oversight in this proceeding is grounded in ensuring that Tri-State's resource planning complies with the public interest and applicable law, which will be satisfied through the ERP process itself.

82. Tri-State also requests that the Commission waive subsections (b), (e), and (f) of Rule 3102 to the extent those provisions would otherwise require the resubmission of information, such as detailed project specifications and BVEM information, that will already be addressed in the Phase II filings in this Proceeding.[82] In support, Tri-State highlights the overlap between the requirements in Rule 3102(f) and those found in Rule 3605(h)(II)(C), which governs the treatment of BVEM information in Phase II bid evaluation.[83]

J. Motion to Enforce Settlement, Strike Comments, and Require New Modeling

1. Conservation Coalition's and WRA's Joint Motion

83. On June 18, 2025, Conservation Coalition and WRA ("Joint Movants") jointly filed the CC/WRA Motion. The Joint Movants allege that Tri-State violated terms of the Phase I Settlement Agreement, particularly in the assessment within Tri-State's response comments of the reliability attributes of the resource portfolios presented in the ERP Implementation Report.

84. The CC/WRA Motion asserts that: "The Commission cannot approve Tri-State's preferred portfolio when Tri-State itself acknowledges that its modeling of the preferred portfolio rests on an incorrect value for a key input."[84] They suggest that the Commission take two actions: (1) strike, and give no weight to, Tri-State's statements on pages 12–13 of its response comments stating that a portfolio is reliable only if it includes a new gas plant in western Colorado; and

[81] CPCN Motion, pp. 1, 9, 11, and 17.
[82] CPCN Motion, p. 12.
[83] CPCN Motion, p. 15.
[84] CC/WRA Motion, p.3.

(2) either require Tri-State to re-run the modeling of the Preferred Portfolio with the correct inputs for the gas plant and provide a summary of changes to the results for the portfolio including resource build decisions, system cost, emissions, and utilization of the new gas plant, or refuse to approve any portfolio that includes the gas plant, which was modeled with an incorrect input.

2. Tri-State's Response

85. Tri-State filed a response objecting to the relief sought in the CC/WRA Motion. Tri-State argues that the motion is an improper attempt to reply to Tri-State's response comments, a procedural step not contemplated in the Commission's ERP Rules. Tri-State further argues that, because time is of the essence for the Commission to issue its Phase II decision, granting certain of the relief sought in the CC/WRA motion, such as additional modeling, will prolong the process and "could expose Tri-State and its Members to higher prices or lost opportunities as developers adjust to tariffs or new legislation, and could delay resources being included in a Resource Solicitation Cluster ("RSC") for interconnection study... on the basis of speculative concerns that are unlikely to result in material changes to the record currently before the Commission."[85] Tri-State asserts that it complied with § 4.8.2 of the Settlement Agreement by ensuring that all portfolios were modeled to meet Level I and II reliability metrics. Tri-State further contends that: "Nothing in the Settlement Agreement or the Commission's rules supports excising Tri-State's statements simply because the Conservation Parties disagree with them."[86] Tri-State argues that: "Running the model again might change the projected net present value of Portfolio 4 or its emissions by a modest amount, but it would not likely lead to a different portfolio being superior. On the other hand, the harm of delay is tangible: potential higher costs to Tri-State's Members and

[85] Tri-State Response CC/WRA Motion, p. 3.
[86] Tri-State Response CC/WRA Motion, p. 7.

potential failure to meet planned in-service dates if procurement and interconnection is stalled. The public interest favors moving forward with a decision based on the best available information now, rather than perfection of information later."[87]

3. COSSA/SEIA Response

86. COSSA/SEIA do not take a position on the request to strike Tri-State's Phase II comments, but they oppose any re-modeling of the Preferred Portfolio 4, citing the urgent need to approve clean energy resources while current federal tax incentives are still available. They likewise warn that re-modeling would introduce delays that could result in lost funding opportunities.

87. COSSA/SEIA go on to emphasize that any delay in approving Tri-State's resource acquisitions could threaten the feasibility and affordability of its clean energy transition, especially given the time-sensitive nature of the New ERA grants. They also argue that Tri-State's Phase II process must be evaluated considering this broader policy context and pressing financial deadlines, even if the process was potentially imperfect.

88. COSSA/SEIA urges the Commission to immediately approve all renewable energy projects common to both the Preferred Portfolio and Portfolio 6 in the event that the Commission grants the CC/WRA Motion. They explain that this approach would allow Tri-State to move forward with acquiring those projects while the modeling dispute is resolved. They also propose that if the Commission finds the record inadequate to support the Preferred Portfolio, Portfolio 6 should be approved as a fallback, recognizing that this path, too, carries litigation and delay risks.

[87] Tri-State Response to CC/WRA Motion, p. 22.

89. Finally, COSSA/SEIA requests that the Commission require Tri-State to provide regular updates on its PPA negotiations, modeled on reporting requirements from Proceeding No. 21A-0141E. They suggest monthly updates showing project status, executed contracts, and any fallback bids being considered, to help ensure timely acquisition and minimize risk.

K. Discussion, Findings, and Conclusions

1. Cost Effective Resource Plan

90. We approve Tri-State's selection of the Preferred Portfolio as the cost-effective resource plan even though there are elements of Portfolio 4, we do not prefer when compared to Portfolio 6. The Commission's role in Phase II of this ERP is to ensure that Tri-State respects the stakeholders in this process, considers and responds to their requests, and presents a preferred plan that is reasonably supported by the evidence in the record. The Commission should not substitute its judgement for Tri-State's when the selection of its preferred plan could be deemed reasonable and an alternative could also be deemed reasonable based on the same record. The corollary to that orientation is that Tri-State takes responsibility for the risks it and its cooperative members assume by pursuing its preferred plan.

91. We are persuaded that the Preferred Portfolio is an economic selection based on the presentation Tri-State makes in the ERP Implementation Report. This is a nuanced conclusion, however, because the Phase II record is not as "clear" as Tri-State concludes in its ERP Implementation Report. While the Preferred Portfolio is shown by Tri-State's modeling to potentially be cheaper than Portfolio 6 by some financial measures, it is also shown to be more expensive when applying the social cost of carbon and could be more expensive when considering the cost risks in possible future scenarios for curtailments or emission reduction requirements

beyond 2030. Nevertheless, based on the record, we can reasonably conclude that, in terms of economics, the Preferred Portfolio and Portfolio 6 are likely equivalent.

92. The siting of the natural gas plant in Moffat County will help to bring development and tax base to the community in the face of the retirement of the units at Craig. We further acknowledge that the project is supported by a broad range of parties including the local communities. The City of Craig and Moffat County have filed support for the gas plant citing concerns about ongoing tax revenue.

93. We highlight the level of renewables in both the Preferred Plan and Portfolio 6, and, consistent with the parties' comments and Tri-State's response, we encourage Tri-State to secure those projects expeditiously. Critically, the record also shows that both the Preferred Portfolio and Portfolio 6 comply with Colorado's emission reduction targets.

94. We also highlight Tri-State's commitment to acquiring more than 650 MW of battery storage, which most of the parties' support and we conclude is reasonable. While we can understand Tri-State's interest in resource diversity through the inclusion of the gas plant in Moffat County, primarily because Tri-State persuades us that there are ancillary benefits from the operation of the proposed plant in Western Colorado, we are not convinced that a legitimate barrier to acquiring the additional storage in Portfolio 6 is Tri-State's lack of experience with operating such resources. Tri-State currently has so little experience with storage of such scale such that it is unclear whether there is any meaningful difference between the two portfolios in the development of storage over time, the point raised by the Conservation Coalition and WRA.

95. Notwithstanding our approval of the Preferred Plan, the record also reveals serious modeling challenges that have fostered doubts among certain parties. As discussed below, we intend to address those challenges, and other needed improvements to Tri-State's implementation

of ERPs, before Tri-State files its next ERP to achieve a clearer record on prudent economic planning in the future. We further reiterate the financial risks highlighted by certain parties in their comments on Tri-State's ERP Implementation Report and assume that Tri-State's board and cooperative members are aware of these risks as they relate to preferred Tri-State's resource selection.

96. We also remain concerned about Tri-State's policies that prevent its member cooperatives from investing themselves directly in energy storage to reduce their demand charges. Considering the positive demonstration of the role battery storage can service on its system, Tri-State would also benefit from changing its policy to allow their member cooperatives to manage their costs through additional strategic investments in energy storage, to lower system peaks, thereby lowering costs and reducing fuel price risk for its membership.

97. In sum, we find that Tri-State has adequately considered statutory requirements for §§ 40-2-123, 40-2-124, and 40-2-134, C.R.S., set forth in Rule 3605, including environmental and social factors and insulation from fuel price increases through the focused competitive bid process and the selection of a renewable resource. The Preferred Portfolio supports the energy policy goals of Colorado in putting Tri-State on the path to achieve 80 percent reduction of GHG emissions by 2030.

2. Best Value Employment Metrics

98. Rule 3605(h)(II)(C) states that the Commission's Phase II decision shall determine, in accordance with § 40-2-129, C.R.S., whether the utility has obtained and provided BVEM information and has taken certain other steps. BVEM information includes the availability of training programs such as apprenticeships; the employment of in-state instead of out-of-state labor; long-term career opportunities; and industry-standard wages, health care, and pension benefits.

As in is previous ERP, Tri-State's bid evaluation process applied BVEM information as a qualitative NPF within Community Stewardship.[88]

99. No comments were filed suggesting deficiencies in the BVEM data that was provided by bidders.

100. Upon review of the materials and the bid process, particularly Attachment F to the ERP Implementation Report, we find that Tri-State has complied with Rule 3605(h)(II)(C), and in accordance with § 40-2-129, C.R.S., Tri-State has provided the requisite BVEM information and has demonstrated objective standards for how it evaluated BVEM as between bids.

3. Motion for CPCN Waivers

101. No responses to Tri-State's CPCN Motion were filed. Tri-State's CPCN Motion is therefore deemed to be unopposed.[89]

102. On May 22, 2025, through Decision No. R25-0393-I ("Interim Decision"), ALJ Segev granted the CPCN Motion. Regarding the retirement of the units at Craig, the Interim Decision concludes that good cause exists to waive the requirements of Rule 3103(a). The ALJ states that the Commission approved the retirement of Craig unit 1 in its Phase I decision, concluding that it is consistent with the public interest and supported by the Settlement. The ALJ states that no further public convenience and necessity determination is required under Rule 3103, as the record in this proceeding has already fully addressed the timing, justification, and implications of the retirement. Accordingly, "A separate CPCN application would serve no additional regulatory purpose and would unnecessarily duplicate prior findings."[90]

[88] Tri-State ERP Implementation Report, pp. 9 and 13.
[89] CPCN Motion, p. 2.
[90] Interim Decision, ¶ 26, p. 10.

103. By this Decision, we uphold the ALJ's findings and conclusions with respect to the retirement of the units at Craig. We therefore incorporate the findings entered in the Interim Decision with respect to the units at Craig. No separate CPCN filing is necessary to support the retirement of the units at Craig.

104. Regarding the gas plant in Moffat County within the Preferred Plan, the Interim Decision finds that because the Phase II ERP process will include a robust evaluation of the need, alternatives, costs, timelines, and employment metrics associated with the resource addition, rendering a separate CPCN proceeding would be duplicative and inefficient. The Interim Decision states: "a CPCN application may be waived when the proposed facility is subject to thorough evaluation and public review in a Commission approved ERP." [91] The Interim Decision also concludes that no prudence or cost-recovery determinations are implicated due to Tri-State's exempt status under § 40-9.5-103, C.R.S.

105. We also agree with the ALJ on this point and incorporate the findings entered in the Interim Decision with respect to the new gas plant. No separate CPCN filing is necessary to support the construction and operation of the facility by Tri-State.

4. Phase II Motion of Conservation Coalition and WRA

106. We deny the requests in the CC/WRA Motion for additional modeling and reject the suggestion that the Commission refrain from approving any portfolio that includes the gas plant included in the Preferred Plan because we instead conclude that the record in this Proceeding supports the adoption of Tri-State's Preferred Portfolio as a cost-effective resource plan.

107. Turning to the request to strike certain portions of Tri-State's responsive comments, we acknowledge the importance of ensuring that all parties adhere to the commitments in a

[91] Interim Decision, ¶ 24, p. 9.

Settlement Agreement. However, in this Phase II, the record reflects that Tri-State applied Level 1 and Level 2 reliability metrics to all six portfolios presented in the ERP Implementation Report, and that all of them passed those screens. No party disputes that point. The Settlement Agreement also provides that the parties in Phase II, including Tri-State, retain the right to take any position on the modeling. Notably, the Settlement Agreement does not constrain what those arguments can be, so long as the portfolios presented in the ERP Implementation Report meet the agreed reliability thresholds.

108. Here, the Joint Movants express concern that Tri-State's responsive comments create an impression that only the Preferred Portfolio is "reliable." However, it is necessary to distinguish between modeling and compliance with the Settlement Agreement and the advocacy of any party. The Settlement Agreement required uniform modeling which Tri-State provided. The Settlement Agreement did not bind parties to silence on the issues of operational judgment or grid conditions in Phase 2.

109. We conclude that there is no evidence of the type of misrepresentations that would warrant the striking of portions of Tri-State's responsive comments in Phase II or evidence that Tri-state failed to comply with the framework of the Settlement Agreement approved in Phase I. Selectively excluding portions of one party's advocacy, particularly when the Settlement Agreement explicitly preserves the right of any party to present such positions, would raise concerns about fairness and consistency.

110. Accordingly, we deny the request to strike any of Tri-State's responsive comments and thus also deny the final element of the CC/WRA Motion. While we share COSSA/SEIA's interest in Tri-State pursuing the renewable and storage projects in the Preferred Plan expeditiously, we deny their request that the Commission require Tri-State to provide regular

updates on its PPA negotiations. As explained above, it is incumbent upon Tri-State to implement its Preferred Plan to the benefit of its cooperative members.

5. Future Proceeding Prior to 2027 ERP

111. In Tri-State's last ERP proceeding, the Phase II decision addressed several requirements for Tri-State's next ERP.[92] The Phase I Settlement Agreement approved in this Proceeding also includes several provisions related to Tri-State's next ERP to be filed in 2027.[93]

112. In this Proceeding, CIEA, Staff, and others direct some or all of their comments on needed improvements to Tri-State's ERP practices, including improvements to modeling, disclosures and assessments of resource actions such as the replacement of the turbines at Shafer, and bid screening. As discussed above, the modeling challenges in this Phase II have raised concerns among certain parties and have complicated the establishment of a cost-effective resource plan. All these issues merit further consideration prior to Tri-State's next ERP.

113. However, we are also mindful of Tri-State's request for a Phase II Decision as soon as possible. Tri-State argues in its response to party comments that time is of the essence with respect to acquisition of any of the resources described in the ERP Implementation Report.[94] Tri-State points to the present volatility of the global market for renewable-energy equipment and recent U.S. tax and trade actions have introduced material pricing risks that Tri-State hopes to mitigate by promptly executing bid agreements.

114. In the interest of issuing this Phase II Decision as quickly as possible and due to the press of business before the Commission currently, we decline to render findings and directives related to the Tri-State's next ERP. Instead, because the next ERP will not be filed until late 2027,

[92] Decision No. C23-0437, issued June 30, 2023, Proceeding No. 20A-0528E.
[93] Phase I Settlement Agreement, pp. 15, 18, 19-20, 24-25.
[94] Tri-State Response Comments, pp. 4-5.

we conclude that it would be more efficient and appropriate to take up these issues in a separate future proceeding.

6. Craig Units Not Needed for Reliability

115. In their comments on the ERP Implementation Report, Conservation Coalition urges the Commission to make a factual finding in this Proceeding that Craig Unit 1 is not needed for reliability purposes after December 31, 2025. They argue that the Commission should make this finding because it is fully supported by the record and because the federal Department of Energy has threatened use of Section 202(c) of the Federal Power Act to force coal units to operate beyond their announced retirement dates.

116. We agree with Conservation Coalition Conservation Coalition that Craig Unit 1 is not required for reliability or resource adequacy purposes based on the record in this ERP. Every portfolio that Tri-State modeled assumes that Craig Unit 1 retires at the end of 2025 and does not provide any energy or capacity after 2025. At the same time, Tri-State convincingly concludes that every portfolio meets all reliability metrics and is reliable.

7. Waiver of Rule 3605(h)(II)(A)

117. By its own motion, the Commission waives Rule 3605(h)(II)(A), which requires the Commission to issue a written decision on Phase II within 90 days after the receipt of the wholesale electric cooperative's report. Additional time has been needed in this Proceeding given the Commission's significant caseload at this time and the unanticipated complexity of the Phase II decision caused in large part by the modeling challenges discussed above.

II. ORDER

A. The Commission Orders That:

1. The Commission approves as a cost-effective resource plan the Preferred Portfolio presented by Tri-State Generation and Transmission Association ("Tri-State") in its 2023 Electric Resource Plan Phase II Implementation Report filed on April 11, 2025, in accordance with the Electric Resource Planning Rules set forth at 4 *Code of Colorado Regulations* 723-3-3600 *et seq*., and consistent with the discussion above.

2. The Motion for Partial Waiver of Rules 3102 and 3103 in Connection with a Gas Resource Addition and Craig Station Retirement filed by Tri-State on April 15, 2025, is granted, consistent with the discussion above.

3. The Motion to Enforce Settlement Agreement, Strike Comments, and Require New Modeling filed jointly by the National Resources Defense Council, Sierra Club, and Western Resource Advocated on June 18, 2025, is denied, consistent with the discussion above.

4. Rule 723-3-3605(h)(II)(A) is waived, consistent with the discussion above.

5. The 20-day period provided for in § 40-6-114, C.R.S., within which to file an Application for Rehearing, Reargument, or Reconsideration, begins on the first day following the effective date of this Decision.

6. This Decision is effective upon its Issued Date.

B. ADOPTED IN COMMISSIONERS' DELIBERATIONS MEETING August 1, 2025.

(S E A L)

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

ATTEST: A TRUE COPY

TOM PLANT

Commissioners

Rebecca E. White,
Director

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit F: CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Attachment BN-2
(Tri-State, *2020 IRP/ERP,* Public (Dec. 1, 2020)



TRI-STATE
Generation and Transmission Association, Inc.

A Touchstone Energy® Cooperative



Colorado PUC E-Filings System

2020 Integrated Resource Plan/Electric Resource Plan

Volume I

December 1, 2020

Submitted to:

Western Area Power Administration
Colorado Public Utilities Commission

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1 Compliance Tables

Table 1: Comparison Reference for Rule 3605

Rule	Vol	Section	Subsection	Attachment(s)
3605(a)(I)	II	3. Assessment of Resources		
3605(a)(II)				
3605(a)(III)	I	12. Confidential & Highly Confidential Information	Highly Confidential	
3605(a)(IV)(A)	I	5. Landscape	Resource Acquisition Period	
3605(a)(IV)(B)	II	1. Electric Energy and Demand Forecast		Attachment Vol II 1-1 Tri-State Load Forecasts by State & Member
3605(a)(IV)(C)	II	3. Assessment of Resources		Attachment Vol II 5-4 Report on Review of Existing Resources; Attachment Vol II 5-5 Benchmarking Study
3605(a)(IV)(D)	II	4. Transmission System & Planning	Transmission Planning	
3605(a)(IV)(E)	I	5. Landscape	Planning Reserve Margin; Contingency Plan	
3605(a)(IV)(F)	I	6. Assessment of Resource Needs		
3605(a)(IV)(G)	I	8. Base Case & Alternative Scenario Results		
3605(a)(IV)(G)	II	3. Assessment of Resources	Overview of Thermal Resources	
3605(a)(IV)(G)	II	5. Phase I Modeling Details	Generic Resource Cost, Performance & Emissions Data	
3605(a)(IV)(G)	II	6. Scenario Results Data	Emissions & Water Usage Data	Attachment Vol II 6-1 Annual Emissions & Water Usage
3605(a)(IV)(H)	I	8. Base Case & Alternative Scenario Results		
3605(a)(IV)(H)	II	5. Phase I Modeling Details	Social Cost of Carbon	
3605(a)(IV)(I)	I	8. Base Case & Alternative Scenario Results		
3605(a)(IV)(I)	II	3. Assessment of Resources	Overview of Thermal Resources	
3605(a)(IV)(I)	II	5. Phase I Modeling Details	Generic Resource Cost, Performance & Emissions Data	

Rule	Vol	Section	Subsection	Attachment(s)
3605(a)(IV)(I)	II	6. Scenario Results Data	Emissions & Water Usage Data	Attachment Vol II 6-1 Annual Emissions & Water Usage
3605(a)(IV)(J)	II	7. Phase II RFP		Attachment Vol II 7-1 Phase II All Source RFP
3605(a)(IV)(K)	I	12. Confidential & Highly Confidential Information	Confidential; Highly Confidential	
3605(a)(IV)(L)	I	8. Base Case & Alternative Scenario Results		
3605(a)(IV)(M)	I	9. Base Case & Alternative Scenario Comparison	Present Value Revenue Requirement	
3605(a)(IV)(N)	II	5. Phase I Modeling Details	Assessment of Costs & Benefits of Integration Intermittent Resources	
3605(a)(IV)(O	II	5. Phase I Modeling Details	Third Party Studies	Attachment Vol II 5-1 through 5-7
3605(a)(IV)(P)	II	5. Phase I Modeling Details	Modeling Assumptions & Analytical Methodology	
3605(a)(IV)(Q)	I	11. Resource Acquisition Plan –Action Plan	ERP Implementation Report Plan	
3605(b)	II	1. Electric Energy and Demand Forecast		Attachment Vol II 1-1 Tri-State Load Forecasts by State & Member
3605(c)(I)	II	3. Assessment of Resources	Overview of Thermal Resources; Overview of Purchases; Forced Outage Assistance Agreements; Scheduling Agent Agreements	Attachment Vol II 5-4 Report on Review of Existing Resources
3605(c)(II)	II	3. Assessment of Resources	Benchmarking	Attachment Vol II 5-5 Benchmarking Study
3605(c)(III)	II	3. Assessment of Resources	Overview of Ancillary Services	
3605(d)i	II	4. Transmission System & Planning		Attachment Vol II 4-1 Tri-State Transmission Facility Ratings Report
3605(d)ii	II	4. Transmission System & Planning		
3605(d)iii	II	4. Transmission System & Planning		Attachment Vol II 4-3 Tri-State Transmission Project Information

Rule	Vol	Section	Subsection	Attachment(s)
3605(d)IV	I	11. Resource Acquisition Period – Action Plan	Phase II Competitive Bidding Process & Criteria	
3605(d)V	I	11. Resource Acquisition Period – Action Plan	Action Plan Items	
3605(e)	I	5. Landscape	Planning Reserve Margin; Contingency Plan	Attachment Vol II 5-2 B&V Loss of Load Probability Study; Attachment Vol II 5-3 B&V Modified Effective Load Carrying Capability Study
3605(f)(I)	I	8. Base Case & Alternative Scenario Results		
3605(f)(II)(A)	I	6. Assessment of Resource Needs	Renewable Portfolio/Energy Standards	
3605(f)(II)(A)	I	8. Base Case & Alternative Scenario Results		
3605(f)(II)(A)	II	6. Scenario Results Data	RES/RPS Data	Attachment Vol II 6-2 RES/RPS
3605(f)(II)(B)	I	8. Base Case & Alternative Scenario Results		
3605(f)(II)(C)	I	6. Assessment of Resource Needs	GHG and CO_2 Regulation	
3605(f)(II)(C)	I	8. Base Case & Alternative Scenario Results		
3605(f)(II)(C)	II	5. Phase I Modeling Details	GHG & CO_2 Reduction Methodology used in Scenarios	
3605(f)(I)(III)				
3605(g)(I)				
3605(g)(II)	I	11. Resource Acquisition Period – Action Plan	Phase II Competitive Bidding Process & Criteria	
3605(g)(II)	II	7. Phase II RFP		Attachment Vol II 7-1 Phase II All Source RFP

Table 2: Compliance Reference for WAPA 10 CFR part 905

Rule	Vol	Section	Subsection	Attachment(s)
905.11(a) Full range of alternate resources	II	5. Phase I Modeling Details	Generic Resource Cost, Performance and Emissions Data	
905.11(a) Adequate and reliable service	I	5. Landscape	Planning Reserve Margin; Contingency Plan	
905.11(a) Adequate and reliable service	I	9. Base Case & Alternative Scenario Comparison	Comparison of Planning Reserve Margins	
905.11(a) Adequate and reliable service	II	5. Phase I Modeling Details	Summary of 3rd Party Studies	Attachment Vol II 5-2 B&V Loss of Load Probability Study
905.11(a) Diversity, Reliability, Dispatchability, Other risk factors	I	9. Base Case & Alternative Scenario Comparison	Diversity, Dispatchability, & Reliability Comparison	
905.11(a) Energy savings achieved through energy efficiency	I	6. Assessment of Resource Needs	Demand Side Management & Energy Efficiency	
905.11(a) Energy savings achieved through energy efficiency	II	5. Phase I Modeling Details	Modeling Assumptions & Analytical Methodology	Attachment Vol II 5-1 Demand Side Management & Energy Efficiency Potential Study
905.11(a) Treat demand and supply resources on a consistent and integrated basis	II	5. Phase I Modeling Details	Model Description; Modeling Assumptions & Analytical Methodology	
905.11(b) Consider electrical energy resource needs	I	6. Assessment of Resource Needs		
905.11(b)(1) Conduct an assessment and comparison of available existing and future supply and demand-side	I	7. Alternative Scenario Analysis; 8. Base case & Alternative Scenario		

Rule	Vol	Section	Subsection	Attachment(s)
resource options based on its size, type, resource needs, geographic location and competitive situation.		Results; 9. Base Case & Alternative Scenario Comparison		
905.11(b)(1)(iv) Reasonable analysis of the options	I	9. Base Case & Alternative Scenario Comparison		
905.11(b)(2) Include an action plan	I	11. Resource Acquisition Period – Action Plan	Action Plan Items	
905.11(b)(2)(i) List the time period that the action plan covers	I	11. Resource Acquisition Period – Action Plan	Action Plan Items	
905.11(b)(2)(ii)(a-c): Include an action plan summary	I	11. Resource Acquisition Period – Action Plan	Action Plan Items	
905.11(b)(3) Minimize adverse environmental effects of new resource acquisitions	I	9. Base Case & Alternative Scenario Comparison; 10. Summary of Preferred Plan		
905.11(b)(3) Include a qualitative analysis of environmental effects in a summary format	I	10. Summary of Preferred Plan		
905.11(b)(4) Provide ample opportunity for full public participation	I	4. High Level 2020 Resource Plan Process	Public Input Process	
905.11(b)(4) Brief description of public involvement activities	I	4. High Level 2020 Resource Plan Process	Public Input Process	
905.11(b)(4)(i) Contain an approval resolution by the appropriate governing body	I	2. Executive Summary	Tri-State Board Approval	Attachment Vol 1 2-1 Tri-State Board Resolution

Rule	Vol	Section	Subsection	Attachment(s)
905.11(b)(5) Contain a statement that the customer conducted load forecasting, including specific data	II	1. Electric Energy and Demand Forecast		Attachment Vol II 1-1 Tri-State Load Forecast by State & Member
905.11(b)(6) Measurement strategies for IRP's objectives	I	9. Base Case & Alternative Scenario Comparison		
905.11(b)(6) Identify a baseline from which the customer will measure the benefits of IRP implementation	I	8. Base Case & Alternative Scenario Results	Base Case	

Table 3: Compliance Reference for November 12, 2020 Commission Guidance[1]

Item	Vol	Section	Subsection	Attachment(s)
Rework Benchmarking to reflect Staff group ranking methodology.	II	3. Assessment of Existing Resources	Benchmarking	Attachment Vol II 5-5 B&V Benchmarking Study[2]
Provide a full presentation of ancillary services.	II	3. Assessment of Existing Resources	Overview of Merchant Ancillary Services	
Provide 5 years of historical data on all input parameters as available.	II	3. Assessment of Existing Resources	Overview of Thermal Resources	
Provide 5 years of historical data on energy and demand charges for power purchases.	II	3. Assessment of Existing Resources	Overview of Purchases	
Alter model values to historic levels or provide justification for any deviations from historical data.	II	3. Assessment of Existing Resources	Overview of Thermal Resources	
Justify coal cost projections; conduct a market to market analysis, or both.	II	3. Assessment of Existing Resources	Overview of Thermal Resources	
Provide 5 years of historical data on capital expenses and justification of forecasts.	II	3. Assessment of Existing Resources	Overview of Thermal Resources	
Develop a record on potential pollution control related capital expenses.	N/A	N/A	N/A	Testimony of Mr. Berger
Provide additional information of the nature of its capital balances and related depreciation, amortization and impairment treatment of its	II	3. Assessment of Existing Resources	Overview of Thermal Resources	

[1] In order to provide an accurate and complete ERP filing to the Commission by December 1, 2020, Tri-State froze this report as of November 23, 2020 at 12:00pm. As of that point in time, a Commission Order related to final guidance in Proceeding No. 20M-0218E had not yet been published. Tri-State made best efforts throughout this report to meet Commission guidance as interpreted from the November 12, 2020 Commission weekly meeting.

[2] The B&V Benchmarking Study as filed on August 3, 2020 is submitted with this filing. Upon receipt of the Commission Order related to final guidance in Proceeding No. 20M-0218E, Tri-State will reengage B&V to modify the Benchmarking Study to match Commission expectations and will provide the revised study as soon as reasonably possible.

Item	Vol	Section	Subsection	Attachment(s)
assets. Identify any costs that can be avoided by early retirement.				
Identify debt obligations by plant.	II	3. Assessment of Existing Resources	Overview of Thermal Resources	
Provide a description of the source of all unit performance parameters used in its modeling.	II	3. Assessment of Existing Resources	Overview of Thermal Resources	
Provide 5 years of actual historical data for each parameter in B&V Review of Existing Resources,	II	3. Assessment of Existing Resources	Overview of Thermal Resources	
Provide a robust and supported explanation of any discrepancies between its model values and actual historic unit level performance.	II	3. Assessment of Existing Resources	Overview of Thermal Resources	
Apply Social Cost of Carbon to all resources (in or out of state)	I	7. Alternative Scenario Analysis		
Apply Social Cost of Carbon to all resources (in or out of state)	I	8. Base Case & Alternative Scenario Results		
Apply Social Cost of Carbon to all resources (in or out of state)	II	5. Phase I Modeling Details	Social Cost of Carbon	
Use the interagency working group Social Cost of Carbon; convert to short tons; escalate to 2020 using appropriate CPI	II	5. Phase I Modeling Details	Social Cost of Carbon	
Use a 3% discount rate for Social Cost of Carbon.	II	5. Phase I Modeling Details	Financial Analysis Process	
Use a 3% discount rate for Social Cost of Carbon.	I	9. Base Case & Alternative Scenario Comparison	Present Value Member Revenue Requirement Comparison	
Address whether same or similar approach for integrating transmission planning as identified in joint transmission proposal related to CO20-0661-1 is feasible for Tri-State.	II	4. Transmission System & Planning	Response to C20-0661-I Related to Transmission Impacts on the ERP Process	

2 Executive Summary

Introduction

Pursuant to Colorado Public Utilities Commission (Commission) Decision No. C20-0304, in Proceeding No. 19R-0408E and Rule 3605 (a)(I) of the Commission's Rules regulating Electric Utilities, Tri-State Generation and Transmission Association, Inc. (Tri-State) presents its Integrated Resource Plan/Electric Resource Plan ("Resource Plan"). This Resource Plan is also developed to meet the Integrated Resource Planning requirements of the Western Area Power Administration (WAPA) as described in the Energy Planning and Management Program (10 CFR part 905).

This Resource Plan also covers the following WAPA preference allocation recipients:

Pueblo of Laguna, Pueblo of Zuni, Ramah Navajo Chapter, Canoncito Band of Navajos, Ute Mountain Ute Tribe, Wind River Reservation, Nambe Pueblo, Pueblo of Jemez, Pueblo of Pojoaque, Pueblo of San Ildefonso, Pueblo of San Juan, Pueblo of Santa Clara, Pueblo of Zia, Southern Ute Indian Tribe, Mescalero Apache Tribe, Alamo Navajo Chapter, Colorado, the City of Truth or Consequences, New Mexico and Schriever Air Force Base.

Tri-State is a wholesale cooperative electric generation and transmission association consisting of 42 Utility Member Systems located across Colorado, Nebraska, New Mexico and Wyoming. As directed by Colorado Decision CO 10-0101, Tri-State has previously filed Resource Plans in the state of Colorado in 2010 and 2015 as well as Annual Progress Reports (APR). With the passage of Senate Bill 19-236 in Colorado in May 2019, Tri-State as a wholesale generation and transmission electric cooperative operating in the state of Colorado became subject to resource planning regulation by the Commission. Rules guiding this process are per C20-0304 and were finalized in late April 2020, with an effective date of July 15, 2020. As directed by Commission Decision No. C20-0304, Tri-State filed a June 1, 2020 informational filing which was an Assessment of Existing Resources per 3605(c). On August 3, 2020, Tri-State revised the filing to include additional information and in order to be responsive to motions filed by interveners. While participating in an extensive discovery process related to these filings, Tri-State gathered necessary data, developed and analyzed scenarios and prepared this Resource Plan to be filed by December 1, 2020 as required. As required by the Commission, this Resource Plan is inclusive of Tri-State's Assessment of Resources as filed on August 3, 2020 along with an itemized list of updates. Tri-State also included additional information to address comments related to Proceeding No. 20M-0218E as well as Commission guidance as interpreted from the November 12, 2020 Commission's weekly meeting . This assessment can be found in Volume II Section 3 Assessment of Resources of this report.

Resource Need

Tri-State has selected a 20-year period from 2021 through 2040 for its Resource Planning Period (RPP). Per rule 3605(a)(IV)(A) Tri-State has set the Resource Acquisition Period (RAP) for this Resource Plan as 2021 through 2030.

Tri-State's system-wide base load forecast for the RAP shows an average annual load growth rate of ~1.6%. The system load forecast was developed using a bottom up approach based on historical Utility Member System load data, separated into nine classes and applying relevant statistical models by class.

Utility Member System forecasts were combined to arrive at regional forecasts that were used for production cost modeling and the Tri-State system-wide forecast. Many factors can potentially influence Tri-State's load forecast and projected growth. These factors include potential Utility Member System exits, potential transition of some Utility Member Systems from all requirements contracts to partial requirements contracts, increased levels of member distributed generation, long-term impacts of COVID, long-term impacts of environmental regulations on the oil and gas industries and beneficial electrification. To account for potential deviation in load growth Tri-State develops a low and high load forecast. These forecasts are described in more detail in Volume II Section 1 Electric Energy and Demand Forecast of this report.

In early 2020, Tri-State announced the Responsible Energy Plan (REP), which includes among other initiatives, the announced retirements of Escalante Generating Station in 2020 and the retirement of all three units comprising the Craig Generating Station by 2030, as well as the addition of 1 GW of renewables by 2024. These are key Tri-State actions to supply affordable, responsible, reliable energy to Tri-State Utility Member Systems.

For this Resource Planning process, Tri-State included these announced retirements in its base assumptions. Tri-State also reviewed emerging technologies and updated its generic resource dataset to reflect proven technologies, including various types of wind, solar and gas resources, as well as energy storage. Four-hour Lithium-Ion (Li-Ion) batteries of varying sizes were used in the generic resource data set. Tri-State projected that battery prices would decline by approximately 6% per year over the RAP, compared to current pricing. Renewable generation pricing is projected to rise slightly by the mid-2020s due to the scheduled expiration of tax credits, and then is forecast to decline gradually over the RPP as a result of projected technological improvements.

As illustrated in Figure 1, Tri-State forecasts a capacity need in 2029 based on planned retirements, existing owned resources and supply contracts, and the base load forecast.

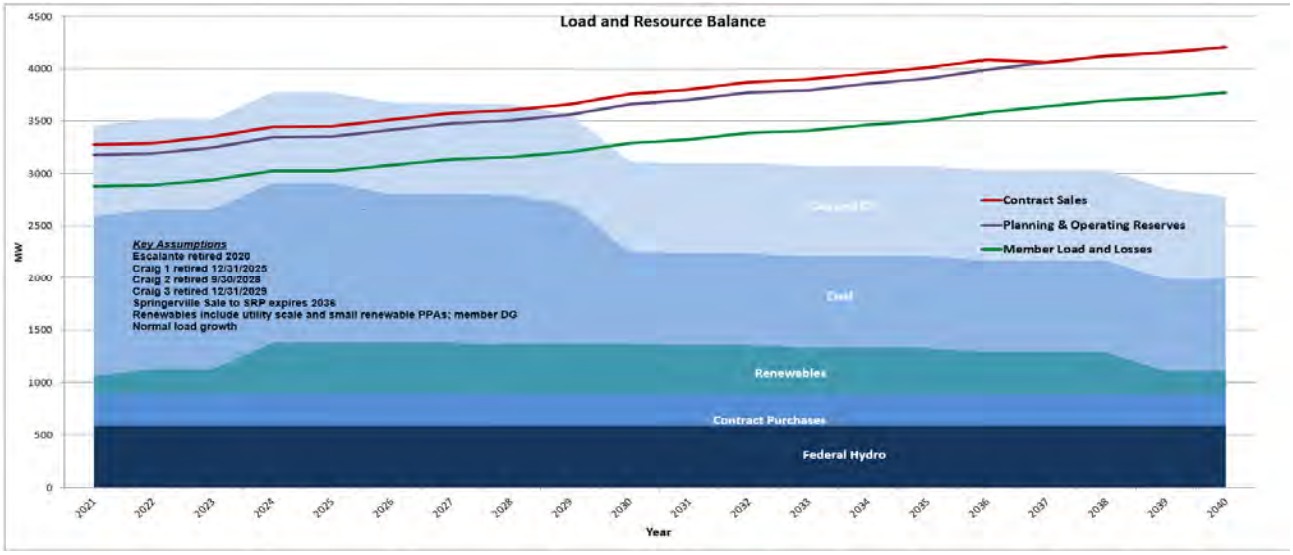

Figure 1: Tri-State Load and Resource Balance (Projected)

Industry & Regulatory Factors

Key external factors influencing this Resource Plan include potential new environmental regulation, the regional development of organized markets and state targets for Greenhouse Gases (GHG)/Carbon Dioxide ($CO_{2)}$ reductions. Tri-State is scheduled to begin operation with the California Independent System Operator's (CAISO) Western Energy Imbalance Market (WEIM) with its load and resources located in Public Service New Mexico's Balancing Authority (PNM-BA) in April 2021. Tri-State is also scheduled to begin operation in Southwest Power Pool's (SPP) Western Energy Imbalance Service (WEIS) in February 2021 for its Colorado, Wyoming and Western Nebraska loads and resources located in the Western Area Power Authority Balancing Authority (WAPA-BA). Tri-State developed modeling treatment for the intra hour effects of imbalance markets as described in Volume II Section 5 Phase I Modeling Details of this report. Tri-State also made adjustments to market depth in models beginning in 2025 to represent a forecast of the development of a "day-2" Regional Transmission Organization (RTO) organized market. Differences between imbalance markets and "day-2" organized markets are explained in more detail in Section 6 Assessment of Resource Needs under the Imbalance Markets, Regional Transmission Organizations and Independent System Operators subsection of this report.

Colorado GHG/CO_2 reduction targets are a key factor that heavily influence scenarios in this Resource Plan. Tri-State's alternative scenarios evaluated reductions in CO_2 emissions based on forecast and historic wholesale electricity sales in the state of Colorado and through the application of a Social Cost of Carbon (SCoC) across Tri-State's system. Details can be found in Section 7 Alternative Scenario Analysis of this report.

Preferred Resource Plan

In assessing the Base Case and Alternative Scenarios, Tri-State has selected the 80% Carbon Reduction (CR) V4 scenario as its preferred plan. Primary reasons for this selection include:

- Generation locations and technology diversity, as illustrated in Figure 2, are sufficient to fully utilize interconnection capability made available from announced retirements.
- Forecast additional thermal retirements projected to occur after the RAP and in addition to announced retirements during the RAP, allow a manageable transition to zero carbon resources while maintaining reliability and affordable rates.
- Transmission system network upgrade costs are minimized during the RAP compared to the base case.
- The PVRR for the RPP is ~$400M higher than the Base Case while achieving the state of Colorado GHG/CO_2 reduction target of 80% GHG/CO_2 reduction by 2030 from a 2005 baseline.
- Overall emissions and water usage are significantly reduced by 2030 from current levels and are significantly lower than in the Base Case.
- The scenario uses a glide path from 2025 to 2030, as illustrated in Figure 3, for CO_2 reduction goals in the state of Colorado to achieve meaningful reductions in the near term.

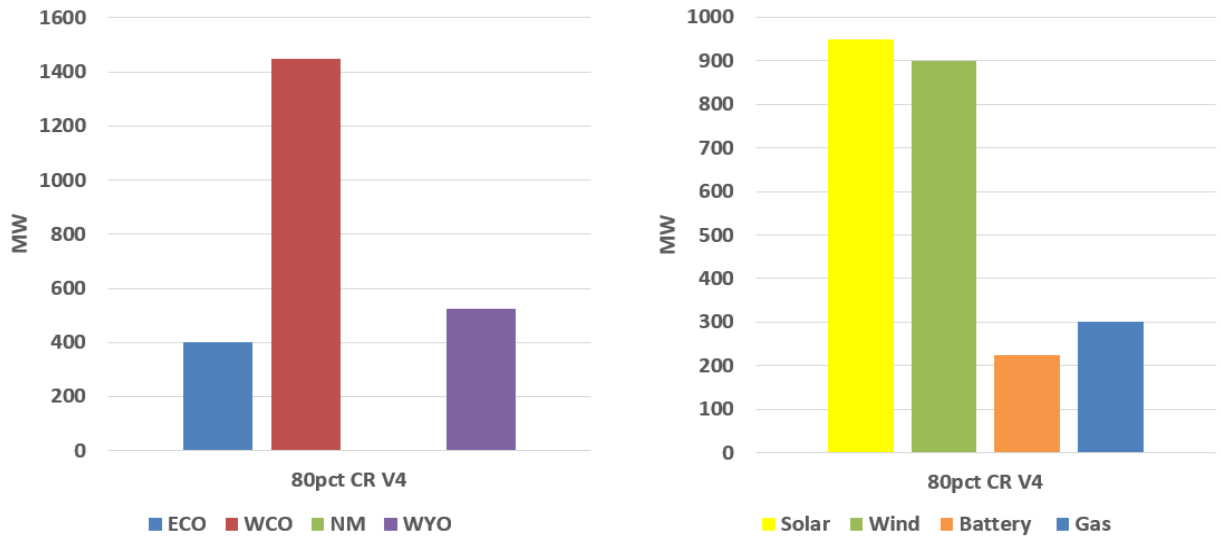

Figure 2: Preferred Plan Resource Additions over the RAP by Geographic Location and Technology

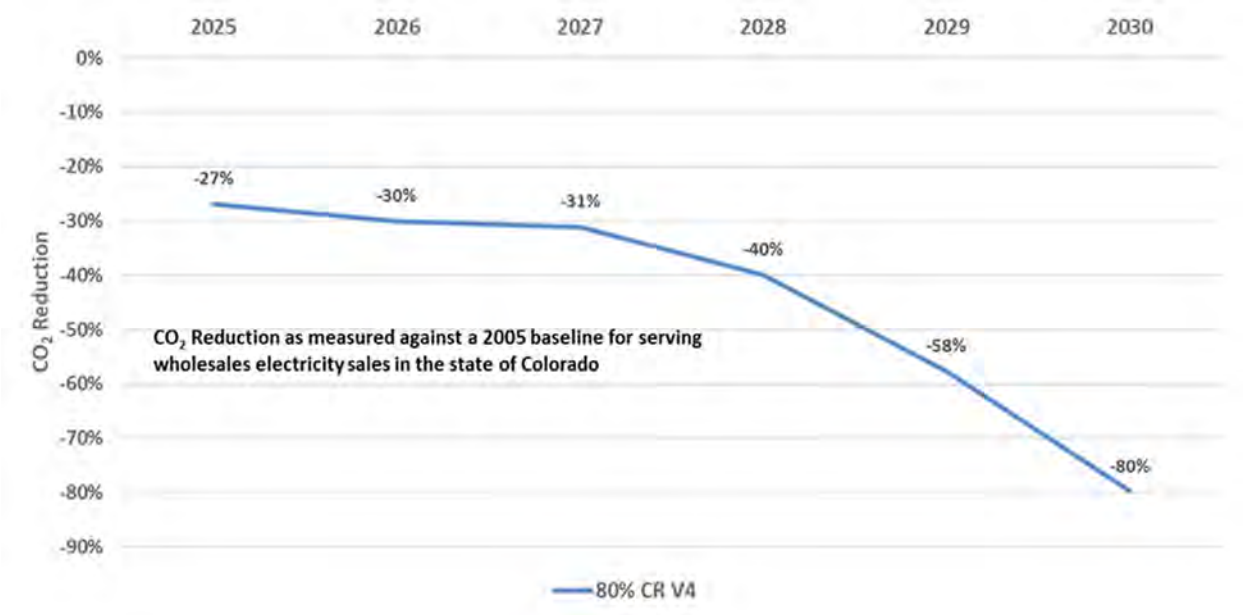

Figure 3: Preferred Plan Glide Path to CO_2 Reduction in Colorado

Action Plan

RAP – Phase II:

Tri-State's base case scenario indicates a capacity need in 2029. In order to meet near term emissions reductions additional renewable resources are forecast for deployment in the preferred plan during the RAP. Table 4 identifies resources by location, nameplate capacity, technology and year, as determined in the preferred plan

Table 4: Preferred Plan Resources during RAP

Location	Capacity (MW)	Technology	Year
East Colorado	100	Wind	2025
Wyoming	100	Wind	2025
West Colorado	200	Solar	2026
Wyoming	100	Wind	2026
West Colorado	100	Solar	2027
West Colorado	200	Solar	2028
Wyoming	100	Wind	2028
West Colorado	200	Standalone Battery	2029
West Colorado	200	Solar	2029
East Colorado	100	Wind	2029
Wyoming	100	Wind	2029
Wyoming	25	Standalone Battery	2030
West Colorado	300	Natural Gas - Combined Cycle	2030
West Colorado	250	Solar	2030
East Colorado	200	Wind	2030
Wyoming	100	Wind	2030

Given the uncertainty related to Tri-State's Utility Member System load in the near term, Tri-State anticipates that its initial Phase II process will focus on resource needs by 2025, as indicated by the shading in Table 4. We anticipate that resources needed for the period from 2026 to 2030 will be addressed in the June 1, 2023 ERP or subsequent ERPs.

By 2023, we will have better information regarding potential load reductions that could reduce capacity needs after 2025. In addition, while the RAP extends from 2021 to 2030, Tri-State is reluctant to engage in activities to add conventional thermal resources (300 MW natural gas combined cycle in 2030) without allowing time for emerging technologies that provide equally reliable capacity, but with lower emissions, to become competitive.

Utility Member System Programs:

Tri-State plans to use the following studies as guides to work with Utility Member Systems to develop relevant programs that may be beneficial to Tri-State and its membership.

- Attachment Vol II 5-1 Demand Side Management & Energy Efficiency Potential Study
- Attachment Vol II 5-7 Beneficial Electrification Potential Study

Retirement Requirements & Impacts:

With the announced retirement dates of Springerville Unit 1 and Springerville Unit 2, Tri-State plans to engage in discussions with Salt River Project (SRP), the owner of Springerville Unit 4, as well as other parties necessary to determine the impacts on Springerville Unit 3 (SPV3) for future resource planning.

While the preferred plan indicates a retirement of Laramie River Station (LRS) Unit 3 by 2033, we note that there is no agreement in place that would be required to implement this retirement with the co-owners of the Missouri Basin Power Project. Modeling performed under the preferred plan showed that the continued operation of both (LRS) Unit 2 and Unit 3 at levels needed to satisfy and maintain an 80% CO_2 reduction in Colorado would not be economic, which is why the preferred plan reflects a retirement of LRS Unit 3.

Modeling Improvements:

Tri-State plans to modify its current modeling software or replace if necessary, in order to improve modeling items prior to the June 1, 2023 ERP. Key items slated for modeling improvement include but are not limited to: the ability to handle emission reductions on a state-by-state basis in a robust manner, the ability to model sub-hourly effects, more robust modeling of intermittent resources, streamlined management of transmission capex impacts, and improved treatment of intermittent resource curtailments.

3 Introduction & Background

Purpose of Filing

The purpose of this Resource Plan is to meet the requirements of Proceeding No. 19R-0408E and Rule 3605 (a)(i) of the Commission's Rules regulating Electric Utilities and to meet the Integrated Resource Planning requirements of the Western Area Power Administration (WAPA) as described in its Energy Planning and Management Program (10 CFR part 905).

Tri-State's approach to developing a Resource Plan takes into consideration internal and external factors. Internal factors include being responsive to Utility Member System needs for affordable, responsible power while maintaining a reliable system. For purposes of this Resource Plan, Tri-State also focuses on the potential impacts to Tri-State's resource planning process due to Utility Member System interest in items such as wholesale electric service contract buyouts, transitioning from all requirements contracts to partial requirements contracts, and the increased deployment of distributed generation. These impacts will be discussed further in the Utility Member Sales Forecast subsection found in Volume II Section 1 Electric Energy and Demand Forecast of this report. External factors include requirements driven by legislation in any state within Tri-State's footprint. Recent legislative actions impacting this Resource Plan include CO_2 and GHG reduction requirements in Colorado and updates to the Renewable Portfolio Standard requirements in New Mexico. These impacts are discussed in more detail in Section 6 Assessment of Resource Needs of this report. While developing its Resource Plan, Tri-State must monitor

internal and external factors and ensure that the Resource Plan meets Utility Member System needs while adhering to applicable laws and regulations across a diverse footprint.

Additionally, Tri-State faces unique challenges given its diverse footprint, which include participation in joint owned generating units and wholesale electric market environments. While Tri-State's system crosses multiple states, Tri-State is only regulated for purposes of resource planning in the state of Colorado. Tri-State must meet individual state regulatory and legislative requirements while developing system-wide solutions. Tri-State has several resources that are jointly owned, which increases the difficulty and complexity of possible resource retirement decisions. Tri-State also faces resource planning challenges associated with the evolving nature of energy imbalance markets, and the possible future deployment of full "day-2" RTO markets, layered upon operations spanning multiple balancing authorities, utilizing extensive third-party transmission rights associated with long term network and point-to-point agreements. To illustrate, Tri-State's load in the PacifiCorp (PAC) BA has been part of the WEIM operated by CAISO since 2014. Tri-State is scheduled to enter the WEIS market operated by SPP in February 2021 with load and resources physically located or pseudo-tied into the WAPA-BA and is scheduled to join the WEIM in April 2021 with load and resources physically located or pseudo-tied into the PNM-BA. These challenges are discussed further throughout this report.

Finally, one key input to the Resource Plan is the Responsible Energy Plan (REP) as announced by Tri-State in January 2020. The following REP items influence Tri-State resource planning in general, and the preferred plan.

- Eliminating 100% of Tri-State emissions from coal in New Mexico by the end of 2030
- Eliminating 100% of Tri-State emissions from coal in Colorado by the end of 2030
- Achieving a 90% reduction in CO_2 emissions across the generation facilities Tri-State owns or operates in Colorado
- Achieving a 70% reduction in CO_2 emissions associated with Colorado wholesale electric sales
- Adding 1 GW of renewable resources by 2024
- Increasing Utility Member System contract flexibility and options to deliver more local renewable generation
- Promoting participation in a RTO
- Extending the benefits of a clean grid

Tri-State's base case and alternative scenarios in the Resource Plan include the retirement of coal in New Mexico (Escalante Generating Station in November 2020), and the retirement of coal resources in Colorado as identified in the REP, which includes the retirement of all three units comprising the Craig Generating Station[3] by 2030. Tri-State's expansion plan portfolios in all alternative scenarios exceed the REP goal of a 70% reduction in CO_2 emissions associated with Colorado wholesale electric sales.

The 1 GW of renewable resources by 2024 as identified in the REP includes resources obtained through RFP processes conducted in 2018 and 2019. These now under contract resources include Crossing Trails, Spanish Peaks, Niyol, Coyote Gulch, Dolores Canyon, Axial Basin, Escalante, and Spanish Peaks II. More

[3] The retirement of the Craig Generating Station is subject to a regulatory approval process with the Commission.

information on these resources is available in Volume II Section 3 Assessment of Existing Resources under the subsection of Overview of Purchases.

Tri-State has a long-standing Board policy allowing for member-distributed generation, which allows members to meet a portion of their energy needs with local renewable generation. Member distributed generation is included in the modeling in this Resource Plan, and more information on this modeling is located in Volume II section 5 Phase I Modeling Details.

Additionally, Tri-State's Board has approved a partial requirements contract option for Utility Member Systems. The methodology for the buy down payment to transition from an all requirements contract to a partial requirements contract is currently moving through the necessary Federal Energy Regulatory Commission (FERC) process. In 2021, Tri-State will conduct an Open Season process with its Utility Member Systems who are interested in this option. While the Low Load forecast used into two alternative scenarios is somewhat representative of potential load declines, partial requirements was not specifically modeled in this Resource Plan. Tri-State expects to have specific partial requirements driven contract changes impacting load forecasts available for its June 1, 2023 ERP process.

Tri-State is actively promoting the need for an RTO in the western interconnection to reliably interconnect more renewable resources while keeping power affordable. While full modeling for an organized market is not undertaken in the scenario analysis of this Resource Plan, starting in 2025 a market depth adjustment is made in order to simulate greater market accessibility. Further detail on modeling setup is available in Volume II Section 5 Phase 1 Modeling Details.

Tri-State engaged Mesa Point Energy to conduct a beneficial electrification potential study for Tri-State's system. This study is included as Attachment Vol II 5-7 Beneficial Electrification Potential Study. Due to the timing of the completion of this study (October 2020), this information was not included in an alternative scenario. Tri-State does expect to include beneficial electrification potential relevant to Tri-State's Utility Member System in its June 1, 2023 ERP filing.

This assessment of load and resource requirements leading to a Resource Plan is intended to meet Tri-State's obligation to provide reliable, affordable and responsible power to its Utility Member Systems and to develop options to meet resource needs in an evolving industry.

Contents and Organization of the 2020 Resource Plan

This Resource Plan is organized into two volumes with relevant sections identified as follows:

Volume I:

- Executive Summary
- Introduction and Background
- 2020 Resource Planning Process
- Landscape
    - System Energy Mix
    - External Market Dynamics
    - RPP & RAP
    - Planning Reserve Margin and Contingency Plan

  - Environmental Regulation
- Assessment of Resource Needs
- Alternative Scenario Analysis, Results and Comparison
- Preferred Plan
- Action Plan & Phase II Requirements
- Confidential and Highly Confidential Information

Volume II Technical Appendix:

- Energy and Demand Load Forecasts
- Commodity Pricing
- Assessment of Resources
- Transmission Overview
- Phase I Modeling Details
- Attachments of third party studies, scenario detail and RFP related items

4 2020 Resource Planning Process

Data and System Preparation

Tri-State's process for developing the Resource Plan includes data verification, third party reviews and related updates, development of assumptions, and scenario analysis. Regular updates of financial and energy data occur throughout the year and are used for short-term and long-term analyses and forecasting processes. Tri-State freezes base assumptions at the beginning of any scenario evaluation process, such as an ERP, to maintain the ability to reasonably compare among scenarios. Tri-State's software systems for this analysis include Hitachi ABB E7 Capacity Expansion (CE), Hitachi ABB E7 Portfolio Optimization (PO), Hyperion, and Utilities International Planner (UIPlanner). These systems, as well as their use in the resource planning process, are discussed in Volume II Section 5 Phase I Modeling Details of this report.

Tri-State engaged three outside consultants to assist in preparing material for this Resource Plan. Black & Veatch (B&V) supported review of key data including commodity pricing and unit characteristics and costs for existing and expansion plan resources. Additionally, B&V performed a Loss of Load Probability (LOLP) Study and a modified Effective Load Carrying Capability (ELCC) study. Ascend Analytics (Ascend) provided ramping analysis and a stochastic review of Tri-State's renewable resource hourly profiles. CDG Engineering provided technical system support. Various results from consultants' work products are included and incorporated into this report, and studies or results in their entirety can be found as Attachments to Volume II 5-1 to 5-7.

Upon completion of data setup and verification, scenario analyses was conducted to develop forecasts of capacity and resource needs to maintain planning reserve margins, support affordable supply to Utility Member Systems, and provide for compliance with applicable environmental regulations. The base case

and alternative scenario analysis results are discussed beginning in Section 7 Alternative Scenario Analysis of this report.

Scenario Analysis Overview

Tri-State analyzed various scenarios for this Resource Plan, by first modeling an expansion plan in CE, then running an hourly dispatch for the 20-year planning period in PO, followed by incorporation of the this dispatch and expansion plan information into Hyperion and finally transitioning Hyperion data into UIPlanner to develop a forecast of companywide expenses and revenue requirements. Transmission capital expenditures were also determined for each scenario and passed to UIPlanner. Final analysis of all scenario data in UIPlanner led to the development of a Present Value Revenue Requirement (PVRR) for each scenario. Details of these processes are discussed further in Volume II Section 5 Phase I Modeling Details of this report. Figure 4 illustrates the sequential steps of this process and the associated primary software systems:

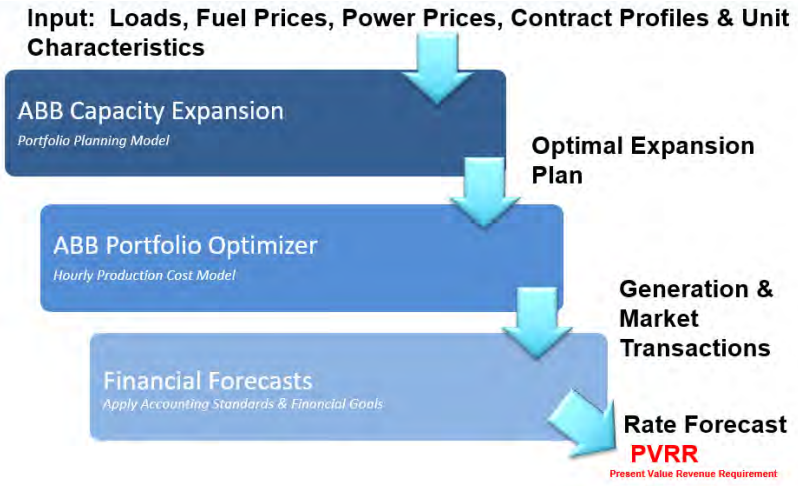

Figure 4: Scenario Modeling Flowchart

Stakeholder Outreach

Per 10 CFR part 905.11(b)(4) related to WAPA's Integrated Resource Plan (IRP) requirement, Tri-State has historically held public workshops to engage the public in the IRP process. However, due to COVID19 and related concerns for public welfare, Tri-Stated posted on its website in May 2020 that such meeting(s) would be postponed. In late July Tri-State determined that establishing a communication route for the WAPA IRP with the public that did not involve face-to-face contact would be necessary due to the continued COVID19 threat. At that time, Tri-State posted on its website in the Stakeholder Outreach and in Resource Planning pages that Tri-State was actively working on the IRP and would take comments from the public via its resourceplanning@tristategt.org email address. Additionally, Tri-State posted that it would post any such comments in the same section of the Tri-State website along with responses. Tri-State used this communication protocol to solicit concerns and input from the public as part of its WAPA IRP public process. Tri-State did not receive any comments or input through this process. Additionally, as part of the Colorado Electric Resource Plan (ERP) process under Proceeding 20M-0218E, Tri-State engaged in an extensive and far-reaching discovery processes from late July 2020 through late September 2020

with various parties. This discovery process resulted from Tri-State's June 1, 2020 informational filing, which was an Assessment of Resources per Rule 3605(c). A comment period related to this proceeding occurred in late September and early October. Tri-State's response included plans to address specific items identified as items of concerns in its December 1, 2020 Resource Plan filing. Comments from participating parties as well as Tri-State's response to those comments are available on the Commission's website.

Summary and Update of 2015 Colorado ERP

Tri-State's Action Plan from the 2015 ERP included several elements and was updated via APRs, the most recent of which was filed in December 2019. An update to the elements of this Action Plan is summarized below:

Affordable Clean Energy Rule and State Plans Review and Evaluation:

Since the 2015 ERP filing, the U.S. Environmental Protection Agency (EPA) repealed the Clean Power Plan. On July 8, 2019, the EPA finalized the Affordable Clean Energy (ACE) rule. State plans implementing the ACE rule will be due in July 2022, with initial compliance to be achieved by designated facilities no later than 24 months after State plan submittal, except if a State determines a longer period is appropriate and includes legally enforceable increments of progress. Colorado is expected to take initial steps in 2021 to implement the ACE rule. The legality of the ACE rule has been argued before the District of Columbia Court of Appeals.

Generation Planning and Development:

Since the 2015 ERP filing, Tri-State has both expanded its renewable resource portfolio and announced coal retirements. An additional 51 MW of capacity in the Missouri Basin Power Project was also acquired, which includes LRS generation rights, water rights and critical TOT 3 transmission. Tri-State past and announced retirements of coal-fired generation are as follows:

- San Juan 3 (40 MW share) retired in 2017
- Nucla Generating Station retired in 2019 (ahead of 2022 regional haze requirement)
- Escalante Generating Station retired November 2020
- Craig 1 to be retired by 12/31/2025
- Craig 2 to be retired by 9/30/2028
- Craig 3 to be retired by 12/31/2029

Renewable resource additions since 2015 are addressed in the Expansion of Renewable Portfolio subsection below. Tri-State is also moving forward with plans to participate in both the WEIM and the WEIS with expected market entry dates in 2021. It is anticipated that Tri-State load and resources located in the PNM BA and PSCO BA (in 2022) will participate in the WEIM, and load and resources located in WAPA will participate in the WEIS market.

Transmission Planning and Development:

Tri-State provides wholesale electric transmission service and makes wholesale sales of electric energy to 42 Utility Members in four states (using facilities located across five states), including the approximately 5,665 miles of high-voltage transmission lines over which Tri-State has ownership or capacity interests, as

well as the approximately 409 substations and switchyards that Tri-State owns or has a major equipment ownership interest. Tri-State's interstate transmission facilities are interconnected with those of other utilities, including WAPA, Nebraska Public Power District (NPPD), Black Hills Colorado Electric, Inc. (BHCE), PAC, PSCO, Platte River Power Authority (PRPA), Colorado Springs Utilities (CSU), Basin Electric Power Cooperative (BEPC), Tucson Electric Power (TEP), PNM, and Deseret Generation & Transmission Cooperative. The majority of Tri-State's transmission facilities operate as part of the Western Interconnection. A small portion of Tri-State's facilities supports its load centers in the Eastern Interconnection and is under the functional control of SPP.

Delivery to Tri-State Utility Member Systems also requires that Tri-State contract for transmission service from multiple third parties including PSCO, PNM, WAPA, PAC, PRPA, BHCE and others.

Tri-State continues to support regional transmission study efforts, primarily through its participation at WestConnect and the Colorado Coordinated Planning Group. Tri-State is continuing to make transmission investments to serve growing loads, increase reliability, ensure system stability, and support additional generation interconnections.

Expansion of Renewable Energy Portfolio:

Renewable energy has always been an important part of Tri-State's resource portfolio through purchases of Federal hydropower from the Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP). The CRSP and LAP hydro contracts provide approximately 580 MW of firm capacity, and are contracted to Tri-State through 2054 and 2057 respectively. Since 2010 Tri-State has significantly increased the amount of renewable generation in its supply portfolio, via power purchase agreements (PPAs) with the addition of approximately 27 MW of small hydro, 85 MW of solar and 367 MW of wind currently operating and providing energy to Tri-State under long term purchase contracts.

In 2018, Tri-State issued a Request for Proposal (RFP) for renewables resources that resulted in a competitive bidding process and PPAs for the output of the following facilities:

- 104 MW Crossing Trails Wind (COD expected late 2020 or early 2021)
- 100 MW Spanish Peaks I Solar (COD expected 2023)

In 2019, Tri-State issued another RFP that resulted in a competitive bidding process and PPAs for the output of the following facilities:

- 200 MW Niyol Wind (expected 2021)
- 200 MW Escalante Solar (expected 2023)
- 145 MW Axial Basin Solar (expected 2023)
- 120 MW Coyote Gulch Solar (expected 2023)
- 110 MW Dolores Canyon Solar (expected 2023)
- 40 MW Spanish Peaks II Solar (expected 2023)

In addition, Tri-State Utility Member Systems' local renewable and distributed generation projects that are operating or under development has grown to 131 MW.

Tri-State has over 2,000 MW of renewable generating capacity in its resource portfolio, including CRSP and LAP hydropower, existing renewable resources and additional contracted renewable resources scheduled to be on line by 2024. Tri-State continues to engage in efforts to reduce CO_2, monitor impacts to reliability and look for opportunities to increase its renewable portfolio.

Refinement and Development of new EE and DR Products & Services:

An ongoing part of Tri-State's Action Plan, Tri-State has continued to implement Energy Efficiency (EE) programs and continues to evaluate Demand Response (DR) programs. Options that have been evaluated include residential/small commercial, irrigation, large commercial and industrial programs. These offerings are annually evaluated and refined based on industry trends, effectiveness and member feedback. For demand response, the Tri-State Utility Member System rate design, effective January 1, 2016, contains a peak demand signal, which allows member systems to control or shift their peak load, and provides a strong economic incentive to do so. This has resulted in Utility Member Systems establishing successful programs around irrigation, commercial and industrial, and residential technology load control and peak load management. Tri-State's program offerings were recently expanded to include incentives for beneficial electrification, including an on-going heat pump and heat pump water heater incentive, electric vehicle (EV) charging infrastructure incentives, and non-road EV incentives. The EE program has led to cumulative energy savings of over 212 GWh in 2019. Additionally, Tri-State completed a Demand Side Management (DSM) and Energy Efficiency Potential study with an outside consultant to further evaluate the achievable potential and cost savings for use in this resource planning process. The final study can be found in Attachment Vol II 5-1 Demand Side Management and Energy Efficiency Potential Study. An additional study for Beneficial Electrification (BE) Potential was commissioned and can be found in Attachment Vol II 5-7 Beneficial Electrification Study.

Research & Development (R&D) Programs and Projects:

Tri-State keeps informed of research, development and advanced technology initiatives through its membership in Electric Power Research Institute (EPRI) and through its participation in the National Rural Electric Cooperative Association (NRECA) Cooperative Research Network (CRN).

Some examples of Tri-State's past or present involvement in R&D projects include:

- Use of unmanned aerial vehicles to improve transmission, distribution, and generation maintenance.
- Dynamic load shaping to integrate renewable energy more cost-effectively.
- Beneficial Electrification to reduce emissions, increase energy efficiency, and improve customer's lives and businesses.
- Decarbonized hydrogen/ammonia production for season scale energy storage, grid balancing, and de-carbonization of energy uses that are hard to electrify.
- Energy storage to reduce the cost of integrating renewable energy and as an alternative to transmission and distribution upgrades.
- Incorporating DERs into resource planning to account for the effects of rooftop solar and electric vehicles on load and peak forecasting.

5 Landscape

System Energy Mix

Figure 5 shows a representation of Tri-State's 2019 Resource mix. The capacity values are based on summer nameplate ratings of Tri-State's owned, leased and long-term contracted resources. The energy values are based on gross sales to both Utility Member Systems and nonmember sales, including transmission losses. The 2019 portion of JM Shafer sold to PSCo under a tolling agreement is included in both the energy and capacity representations. Renewable energy includes WAPA hydro, existing and contracted utility scale renewables, member distributed generation and the percentage of the Basin contracts for which Renewable Energy Credits (RECs) were received from BEPC (~25% of Basin West and Electrically East contract energy).

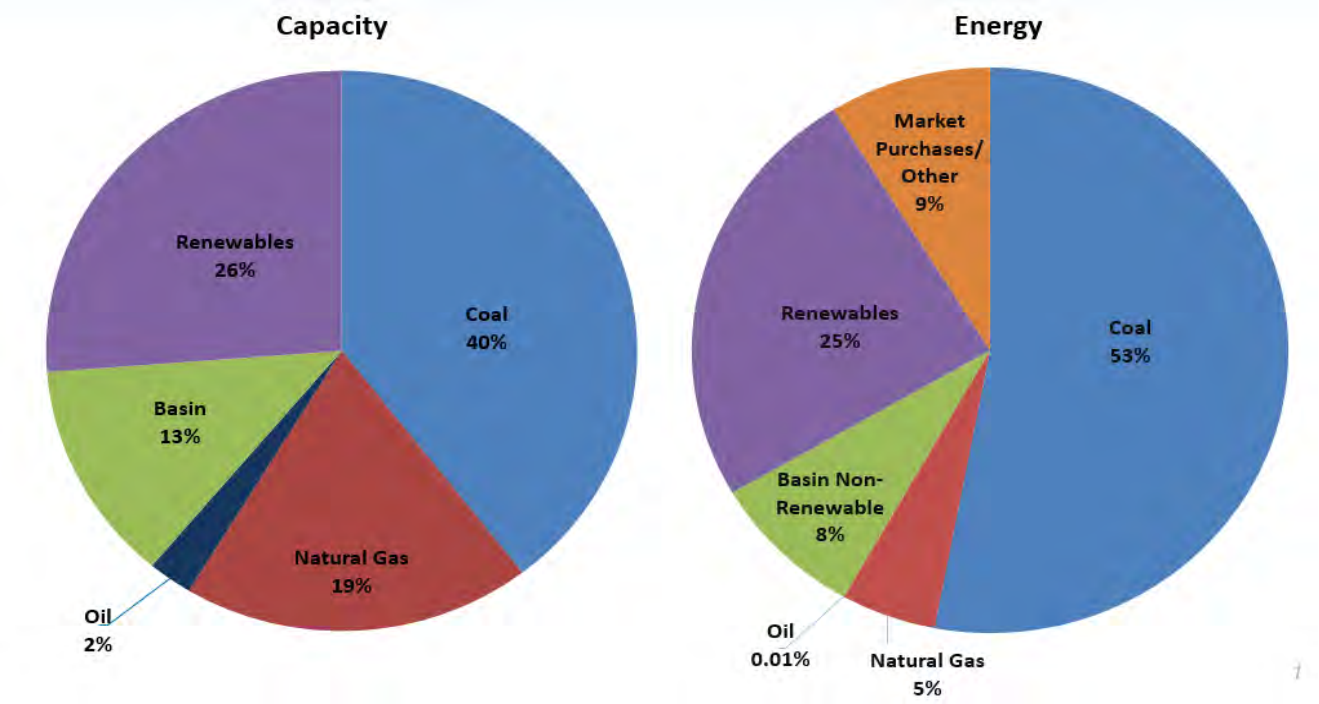

Figure 5: Tri-State 2019 Total System Resource Mix

Figure 6 shows a representation of Tri-State's forecast 2030 Resource Mix based on the preferred plan (80pct CR V4). Capacity values are based on summer nameplate ratings of owned, leased, long-term contracted resources and expansion plan resources. Energy values are based on forecast gross sales to both Utility Member Systems and nonmember sales as well as charging load for energy storage including transmission losses. Renewable energy forecasts includes WAPA hydro, existing and expansion plan utility scale renewables, member distributed generation and the percentage of the Basin contracts for which RECs are forecast to be received.

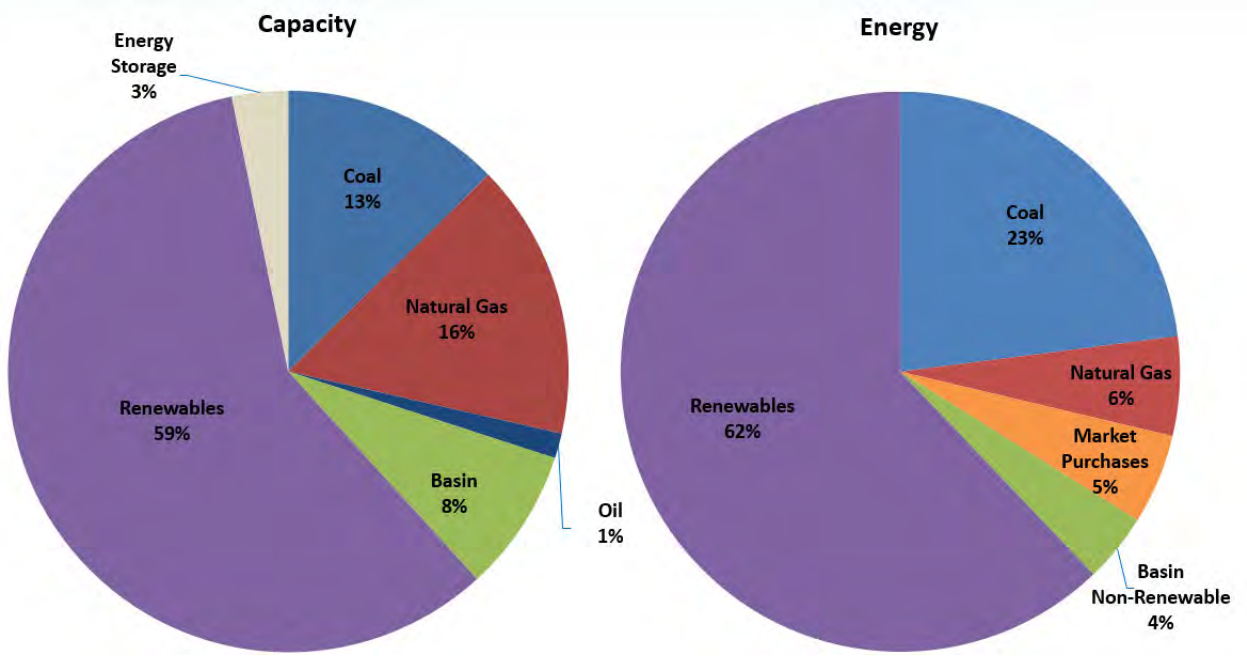

Figure 6: Tri-State Projected 2030 Resource Mix – Preferred Plan

Tri-State's preferred plan increases renewable generation on a capacity and energy basis from ~25% of system mix in 2019 to ~60% of system mix in 2030. This occurs along with a significant reduction in the capacity and energy contribution of coal fired generation. Coal capacity is forecast to decrease from ~40% in 2019 to ~13% in 2030, based on capacity and from ~53% in 2019 to ~23% in 2030 based on energy. Gas is forecast to remain reasonably constant on an energy basis from 2019 to 2030 and is forecast to be slightly reduced on a capacity basis. Along with the addition of energy storage by 2030, gas provides a reliability backstop for the integration of intermittent renewable resources.

Energy Market Dynamics and External Factors

Changing wholesale electricity market environments and external factors were considered in the development of this Resource Plan. The following factors are significant:

- Fuel Pricing
- Organized Market Development Timelines
- Possible Future Environmental Regulations
- Shift to Renewables & Increased Deployment of Distributed Energy Resources (DER)

Fuel pricing has an impact on the development of the load forecast as described below, and influences the selection of resources in the expansion plan to meet system capacity and energy needs, and the dispatch order of resources. In some instances, electricity that Tri-State Utility Member Systems offers to retail customers competes with propane, natural gas and fuel oil as an energy source. Historical price data for these alternative energy sources is obtained annually from the Department of Energy's (DOE) Energy Information Administration (EIA) State Energy Data System, Petroleum Marketing Monthly and Annual Energy Outlook. This data is used in the evaluation of the potential competition for purposes of load forecasting. Separately Tri-State's expansion planning and hourly dispatch models are populated with coal and natural gas forward price curves to forecast resource dispatch costs as they compare to other resources and forward wholesale electricity market power pricing.

Tri-State is currently planning entry, as a market participant, into the WEIM and WEIS in 2021. Entry into the WEIM is planned for Tri-State's load and resources located in the PNM-BA in April 2021. Additionally, Tri-State has a small portion of load that has been in the WEIM in PAC's BA since PAC's entry in 2014. PSCo has announced its intent to enter WEIM in 2022. Tri-State's load in the PSCo BA will enter the WEIM at that time and relevant resource participation remains under evaluation. Separately, Tri-State is planning to enter the WEIS market as a market participant in February 2021 for those load and resources located within the WAPA-BA.

In 2019, New Mexico passed legislation increasing the Renewable Portfolio Standard (RPS) percentages in New Mexico to 40% by 2025 and 50% by 2030. In Colorado, SB 19-236 and HB 19-1261 were also passed, addressing GHG and CO_2 reduction targets for all sectors including electricity sales. Specific rules addressing these emission targets are under development by the Colorado Air Quality Control Commission (AQCC). With uncertainty around final rules, Tri-State made reasonable efforts to meet and verify emission reductions based on known proposed methodologies. Both higher RPS standards and emission reduction targets impact the resource planning process in regards to resource mix. The latter has an impact both on the type of supply resources Tri-State can consider as well as the potential impact to forecast load as some of Tri-State's Utility Member Systems have load driven by industries that will also be impacted by GHG/CO_2 emission regulations.

As Utility Member Systems and their customers continue to deploy more DERs, the long-term potential effect on Tri-State's load forecast and overall Resource Plan continues to be evaluated.

The treatment of these evolving market environments and external factors are described in more detail in Section 6 Assessment of Resource Needs of this report.

Resource Planning Period

Tri-State's resource planning process uses a 20-year planning period. Tri-State selected a 20-year planning period from 2021 through 2040. For resource planning purposes Tri-State believes that this planning period appropriately maintains a focus on nearer term impacts, and properly addresses forecasts for commodity pricing, load growth rates and emerging technologies. The selection of a 20-year planning period allows the opportunity to evaluate and respond to changes in markets, technology, load and environmental and regulatory impacts over time.

Resource Acquisition Period

The RAP represents the timeframe during which detailed implementation plans are outlined. As required by Rule 3605(a)(IV)(A), the RAP must encompass the years through 2030, representing an initial 10-year RAP. The 10-year RAP provides sufficient time to allow for selection and implementation of various demand-side and supply-side actions, as well as supporting activities including permitting, RFPs, contract negotiations, and transmission interconnection. This will also provide adequate time to complete competitive market assessments of resource expansion opportunities. By not extending the RAP beyond the 10-year period, risks due to uncertainties with the bidding process, load forecasts, and commodity and labor prices are reduced.

While the Resource Acquisition Period spans from 2021 through 2030, Tri-State's next Colorado ERP filing defined by rule 3605(a)(II) is due by June 1, 2023 and every four years thereafter. Due to the timing of the next ERP, as well as the substantial uncertainty related to Tri-State's load forecast Tri-State generally would prefer to delay irreversible resource decisions as long as possible, particularly related to capital intensive options. The next 12 to 24 months will be particularly informative in regards to Tri-State's projected system load. Additionally, Tri-State would prefer to allow additional time for technology to advance non-CO_2 emitting dispatchable options that will potentially be more cost-competitive with thermal resources in the future.

Planning Reserve Margin

Tri-State has historically used a fixed 15 percent minimum planning reserve margin in its planning process. This minimum level of desired planning reserve margin is calculated as 15 percent of net load. Net load is calculated as firm load, minus firm purchases, plus firm sales. Firm purchases include Tri-States' WAPA hydro power and BEPC Western Interconnection[4], which together provide approximately 850 MW of firm capacity during peak load periods. After subtracting the capacity of firm purchases from firm load, the reserve requirement is reduced by approximately 130 MW. Tri-State's operating reserve requirements, which are inclusive of contingency reserve obligations in the Southwest Reserve Sharing Group (SRSG), and via sub-entity agreements with PSCO and WAPA who are members of the Northwest Power Pool, are

[4] Basin Electrically East contract is a full requirements contract served by BEPC and the contract and associated load are excluded from the planning reserve margin calculation.

included as part of the planning reserve margin. A 15 percent minimum planning reserve margin is a conservative measure and is comparable to industry standards. Tri-State uses the minimum planning reserve margin in the base case and all alternative scenarios.

In 2020, Tri-State engaged B&V to conduct a probabilistic LOLP study to analyze the adequacy of the current planning reserve margin and the viability of expansion plans under different scenarios including a base case, a CO_2 reduction scenario and two versions of low load scenarios. This analysis began in late spring 2020 in order to provide Tri-State input into the ERP base case and alternative scenarios. One key takeaway from the study is the value of dispatchable or semi-dispatchable resources when integrating renewables in relation to avoiding unserved energy. In the LOLP study B&V used 4-hour Lithium ion (Li-ion) batteries as needed to satisfy planning reserve margins. Tri-State's ERP scenarios follow this methodology and include standalone batteries as selected by the models in the base case and alternative scenarios evaluated in this Resource Plan. The conclusion of this B&V study is that the current planning reserve margin is adequate to continue to provide reliable service to Tri-State's Utility Member Systems. The results of the study can be found in Attachment Vol II 5-2 B&V Loss of Load Probability study.

Contingency Plan

Tri-State recognizes the need to be flexible in regards to changing demands. Forecast electric generation and customer demand will not actualize exactly as planned, and transmission or generation projects could be unexpectedly delayed for many reasons. This section attempts to identify contingencies that could occur during the RAP and to develop alternatives to address them.

Potential Contingency Events:

- Failed contract negotiations with selected bidders or proposal withdrawal
- Project development delays or cancellation
- Transmission development delays
- Higher than anticipated electric demand
- Extended outages of transmission or generation facilities

Contingency Plan options available to Tri-State include:

- Purchase of short-term capacity via an RFP process to cover anticipated shortfalls.
- Initiation of negotiations with replacement bidder(s)
- Issuance of additional RFPs
- Acceleration of the in-service dates of projects

Depending on the need and severity of the contingency, any combination of the options listed above could be implemented. In the event Tri-State forecasts a near-term capacity shortage, the appropriate course of action would depend upon several factors including magnitude of shortage, timing and length of shortage, market conditions, and projects currently in progress.

Environmental Regulation

Regional Haze Rule and Retirement of Coal-Fired Electric Generating Units:

The Regional Haze Rule establishes requirements for states to periodically create State Implementation Plans ("SIPs") to protect visibility in national parks and wilderness areas throughout the United States, with a visibility goal of returning to natural visibility conditions by 2064. The Regional Haze Rule could require additional controls for particulate matter, SO2 and NOx emissions from any source with such emissions, including certain utility sources. The Regional Haze Rule requires that states revise their SIPs every ten years.

Under the existing, approved Colorado SIP, Tri-State committed to NOx emissions rates that resulted in the installation of selective catalytic reduction on Craig Station Unit 2 and the owners of Craig Station Unit 1 will retire Craig Station Unit 1 by December 31, 2025.

The APCD is now developing its second SIPs, which are due to the EPA by July 2021. The AQCC on November 20, 2020 took preliminary final action to adopt a regional haze regulation and SIP that, if finally approved, would incorporate the voluntarily announced retirement of Craig Station Unit 2 no later than September 30, 2028 and would require accelerated retirement of Craig Station Unit 3 no later than December 31, 2028. The AQCC anticipates taking final action in December 2020.

See Mr. Berger's testimony for more detail on environmental regulations applicable to Tri-State.

6 Assessment of Resource Needs

Resource Capacity & Energy

Traditional utility resource planning requires that a comparison of demand forecasts, existing generation, and purchase and sale commitments be developed in order to forecast the need for additional resources to maintain appropriate reserve margins.

The assumptions for the load and resource balance are as follows:

- Total obligations are defined as firm load, losses, firm contract sales, operating reserves, and planning reserves.
    - 2020 long term load forecast data
- All existing purchase and sales contracts are assumed to expire on their terms, with the exception of distributed generation under Tri-State Board Policy 115 and Board Policy 119, which are continued through the entire planning period.
- Craig 1 station will be retired by 12/31/2025.
- Craig 2 station will be retired 9/30/2028.
- Craig 3 station will be retired 12/31/2029.
- No spot purchases or sales are included.

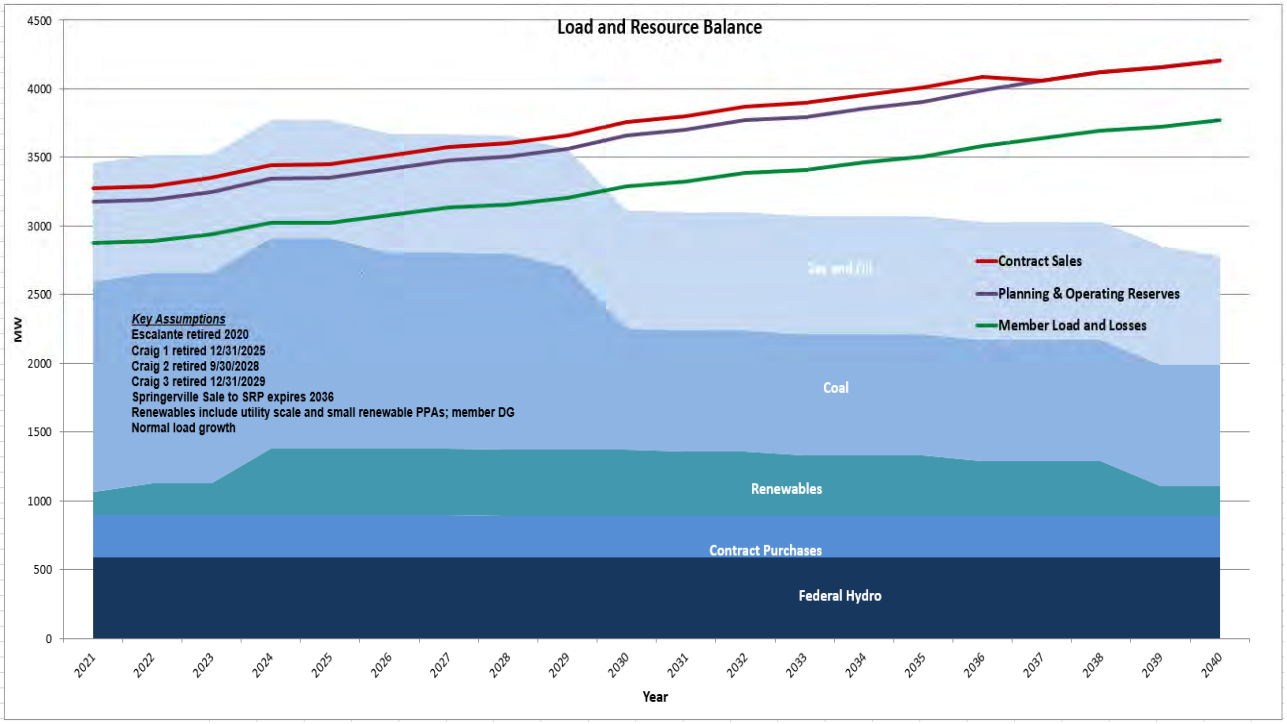

Figure 7: Tri-State Load and Resource Balance (Projected)

The above graph indicates a capacity resource need in 2029, which is later than the 2019 APR assessment. It is important to note that other factors may drive the need for additional generation beyond the scope of the above standard assessment. The scenarios described in Section 7 Alternative Scenario Analysis of this report are designed to demonstrate the potential impact that various load growth and legislative and environmentally driven conditions have on resource planning. In the evaluation of each scenario, the overall environmental impact and costs are considered in addition to resource diversity, dispatchability and reliability.

The capacity credit for existing and expansion plan resources is determined by technology. Capacity credit for dispatchable resources or semi-dispatchable resources is 100% of the summer rating. The contribution of renewables to system peak is based on B&V's modified ELCC Study as identified in Attachment Vol II 5-3 B&V Modified Effective Load Carrying Capability Study. This study takes into account the impact of additional renewables to the timing of the system peak. For example, as more solar is added to the system, the peak is pushed further into evening hours where solar is not capable of fully contributing to the peak, thus resulting in a decline in capacity credit. Final capacity credit values by technology are shown in Table 5.

Table 5: Modeled Capacity Credits by Technology

Resource Technology	**Capacity Credit** *(% of Nameplate)*
Thermal – Existing and Generic Resources	100%
Standalone Batteries	100%
Existing Solar (Commercial & Under Contract)	35%
Existing Wind (Commercial & Under Contract) & Wind Generic Resources	30%
Solar Generic Resources	15%
Solar + 25 MW Battery Generic Resources	15% Solar; 100% for Battery
Wind + 25 MW Battery Generic Resources	30% for Wind; 100% for Battery

Renewable Portfolio/Energy Standards

Overview:

The purpose of this analysis is to document Tri-State's forecasted compliance with the Colorado Renewable Energy Standard (RES) and the New Mexico Renewable Portfolio Standard (RPS), as well as any future compliance obligations for specific amounts of renewable and carbon free energy resources that may be enacted on the state or federal level affecting Tri-State or its member systems. Currently only Colorado and New Mexico have regulations requiring renewable, recycled or carbon neutral energy sources.

Compliance Obligations:

A RES/RPS requires a utility to generate, or cause to be generated, electricity from certain eligible renewable energy resources, at a percentage of retail electricity sales or as a percentage of energy provided to members. The definition of a renewable energy resource varies slightly depending on the state, but generally includes solar, wind, biomass, geothermal and small hydro resources. The Colorado statute also allows the application of recycled energy or waste heat energy and greenhouse gas neutral resources to count toward the total compliance requirement. The combination of these resources, together with renewable energy, is termed eligible energy.

The Colorado General Assembly left the RES unchanged in 2019, and the focus has shifted to GHG/CO_2 reduction requirements for which rules are still to be promulgated. It remains uncertain how this legislation applies to Tri-State. For the RES, Tri-State, as a Qualifying Wholesale Utility (QWU) under Colorado statute must meet a 20% Renewable Energy Standard (RES) by 2020. The Colorado RES also imposes a requirement on Tri-State's Utility Member Systems, as Qualifying Retail Utilities (QRU) under Colorado statute, increasing renewable energy at various levels until reaching 10% in 2020. The 20% Tri-State obligation may include Utility Member System-located renewable projects used towards satisfaction of the 10% requirement on cooperative electric associations by 2020.

In New Mexico, SB 489, also known as the Energy Transition Act, was signed into law in 2019. It leaves in place the RPS requirement through 2024 and increases renewable requirements starting in 2025. Tri-State Utility Member Systems are still required to meet a 5% RPS by 2015, which then escalates 1% per year to 10% in 2020 through 2024. The RPS requirement then rises to 40% for 2025 through 2029 and to 50%

beginning in 2030 through 2049. In 2050, the legislation sets a target of serving all retail sales with 100% zero carbon resources, composed of at least 80% renewable energy. This target is conditioned upon compliance solutions being technically feasible, and not having negative impacts to reliability or affordability. Another significant change to the NM RPS is that for co-ops, "hydropower facilities supplying no greater than the amount of energy from hydropower facilities that were part of an energy supply portfolio prior to July 1, 2007" (§ 62-15-37) can now be applied toward compliance. This category of renewable energy for Tri-State's New Mexico Utility Member Systems is essentially the CRSP allocation from the Western Area Power Administration's SLCA/IP projects that are assigned to New Mexico.

The current Colorado RES and New Mexico RPS requirements by year through 2020 are shown in Table 6.

Table 6: RES/RPS Requirements in Colorado and New Mexico

	Colorado		New Mexico
Year	**Co-ops**	**Tri-State**	**Co-ops**
2008-2010	1%		
2011-2014	3%		
2015	6%		5%
2016	6%		6%
2017	6%		7%
2018	6%		8%
2019	6%		9%
2020 – 2024	10%	20%	10%
2025-2029	10%	20%	40%
2030-2050	10%	20%	50%
2050 - beyond	10%	20%	80%

The Colorado RES includes a distributed generation (DG) requirement applicable to cooperative electric associations in an amount of 1% of total retail electricity sales starting in 2020. For cooperative electric associations with fewer than ten thousand (10,000) meters, the DG requirement is three quarters of 1% or 0.0075.

Only renewable energy resources count toward the DG requirement and of this requirement, one-half must come from wholesale DG and the other half from retail DG. Wholesale DG is defined as a renewable energy resource with a nameplate rating of ≤ 30 MW. Retail DG is defined as a renewable energy resource that is located on the customer's side of the utility meter and supplies no more than 120% percent of the average annual consumption. The most common example of retail DG is rooftop solar. Colorado statute allows subscription-based renewable energy facilities (ex., community solar) ≤ 5 MW to count towards meeting retail DG requirements. Cooperative electric associations may subtract industrial retail sales from total retail sales in calculating its retail DG requirement.

Compliance Reporting

Tri-State and its Utility Member Systems must submit a written report to the state utility regulatory bodies each spring documenting its compliance with state RES/RPS requirements for the preceding calendar year.

Tri-State documents its own as well as its Utility Member Systems' compliance with the Colorado RES and the New Mexico RPS through the retirement of Renewable Energy Certificates (REC). A REC represents the environmental attributes from one (1) megawatt-hour (MWh) of electricity generated from a renewable energy source. Both Colorado and New Mexico statutes provided for the use of multipliers depending on the technology and location of the project, whereby one MWh of energy could result in more than one REC being produced. All multipliers have been phased out since the RPS requirements were first developed; however many of the projects Tri-State uses for compliance achieved commercial operation before the expiration of the multipliers, and continue to benefit from grandfathered REC multipliers.

Most RECs used for state compliance are registered with the Western Renewable Energy Generation Information System (WREGIS) or in some cases, (BEPC non-hydro RECs) with the Midwest Renewable Energy Tracking System (M-RETS). RECs which are not used for compliance, sold or otherwise transferred in the year in which the associated renewable energy was generated may be carried forward for up to 5 years in Colorado and 4 years in New Mexico.

Tri-State's Compliance Analysis Methodology

Compliance with the Colorado RES and the New Mexico RPS is based on actual retail sales, although it should be noted that not all energy provided by Tri-State to its members translates into retail sales. This is due to system losses and members' own sales for resale. In order to forecast retail sales and determine projected RES and RPS compliance, the year-over-year growth rates for Colorado and New Mexico sales are calculated from the long-term financial forecast (LTFF) provided by the Load Forecasting Group and are applied to the actual retail sales values reported in previous years' Compliance Reports. Then using the RPS requirement levels shown in Table 6, the required number of RECs (corresponding to GWhs) by year to achieve RPS/RES compliance is calculated for Colorado and New Mexico.

Beginning in 2020, Tri-State's Colorado RES compliance obligation as a Qualified Wholesale Utility will be based on the amount of energy Tri-State provides to its Colorado Utility Member Systems. Therefore, the most current long-term load forecast for the energy Tri-State expects to provide its Colorado Utility Member Systems (excluding member generation) is used together with Table 6 to calculate the Colorado compliance obligation.

For both load and resources, forecast values are replaced with actual values at the beginning of each year for the preceding year. The forecasts for existing large utility scale projects, WAPA hydro and small hydro projects assume a continuation of past performance; although solar generation forecasts reflect a 0.5% degradation factor. In addition, any new projects with Tri-State Board approved PPAs are included using the forecasts provided by the developer. Forecasts reflect projected energy through the term of the PPAs.

The actual and forecast requirements are plotted graphically against the actual and forecast supply of RECs to depict Tri-State's compliance progress.

Results

The chart in Figure 8 is a graphical representation of Tri-State and its Utility Member Systems' progress towards meeting Colorado and New Mexico compliance obligations through 2040 on a yearly basis. Based on current progress, Tri-State and its member systems are exceeding the RES and RPS requirements.

The chart does not reflect banking effects of RECs that are provided for in each of the Colorado and New Mexico renewable energy statutes. During years when Tri-State and its Utility Member Systems are exceeding compliance levels, these entities may bank their unused RECs and apply them toward future years' obligations. Additionally, the figure represents only Tri-State's current renewable resource portfolio and respective PPA durations, without the inclusion of additional resources or expansion plan scenarios. It also does not reflect REC sales, or Tri-State-owned WAPA RECs not applicable toward compliance or Basin REC allocations from previous years (ex., in addition to the current year allocations, WAPA and BASIN may provide additional RECs with a prior year's vintage that it or other members/customers cannot use).

Considering the actual and forecast data in Figure 8 below and those factors not reflected in the chart, Tri-State remains confident in its ability to meet both its own and its Utility Member Systems' compliance obligations over the long term.

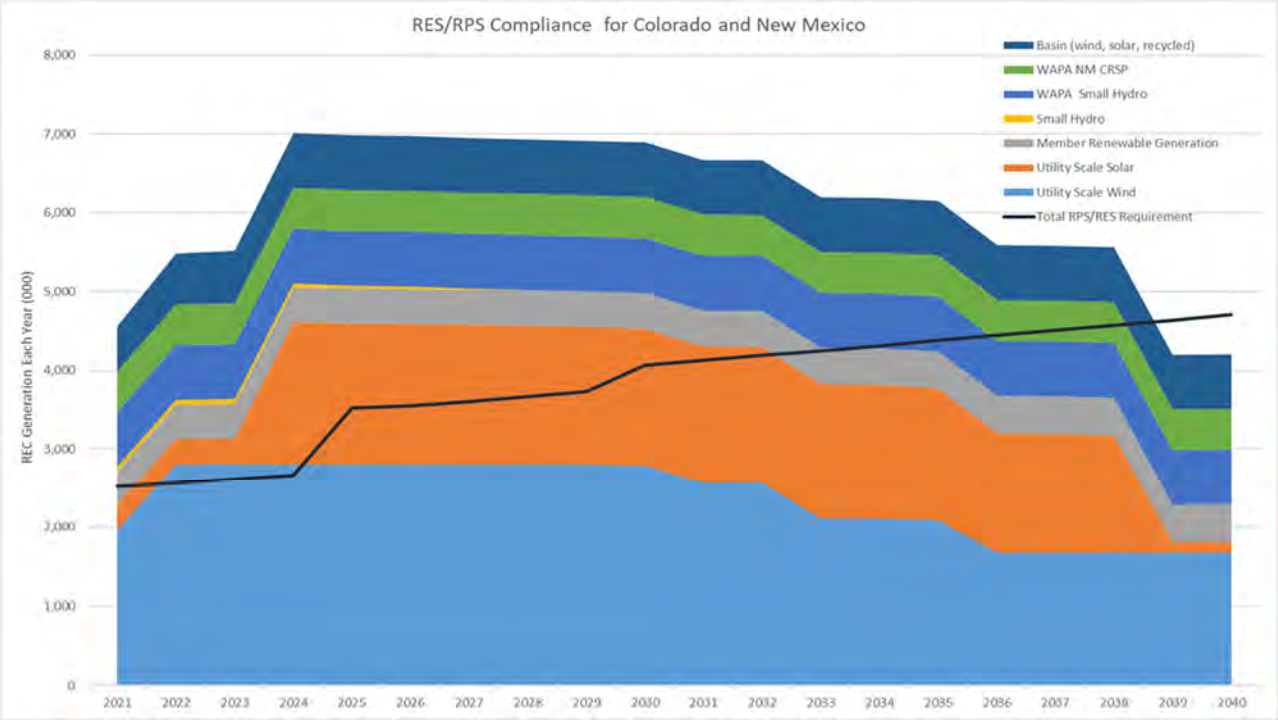

Figure 8: RES/RPS Compliance for Colorado and New Mexico

Demand Side Management and Energy Efficiency

As stated in Tri-State's 2019 APR, an important and ongoing part of Tri-State's Action Plan is the on-going implementation of Demand Side Management (DSM) measures. Options that have been evaluated include programs related to residential, small commercial, irrigation, large commercial and industrial programs. These offerings are continually refined based on effectiveness and Utility Member System feedback. As a generation and transmission provider, Tri-State does not have retail load and is reliant upon Utility Member System participation in DSM program implementations.

Demand Response:

Tri-State's current A-40 rate design provides Tri-State's Utility Member Systems an incentive to control load during Tri-State's defined peak period. Tri-State's A-40 rate consists of energy, generation demand and transmission demand rates. Some Tri-State Utility Member Systems successfully use active load control methods during Tri-State's defined peak period to reduce their monthly demand usage and related demand charges. Tri-State provides tools such as a real time load graph to help inform our members on when it may be optimal for them to control. Demand Response programs that have been developed at the Utility Member System level include:

- Irrigation Demand Response
- Commercial and Industrial Peak Load Management
- Water Heater and Air Conditioning Demand Response

Energy Efficiency:

Tri-State's electric energy efficiency program has been in place since 1985, and many of our current measures have been a strong part of our offerings for the past several years. However, with naturally evolving markets and consumer interest, these programs are continually monitored and discussed with our member system staff to ensure that they are creating value for their consumers. As we conduct our resource planning efforts, Tri-State is evaluating energy efficiency programs and offerings in order to achieve value and energy savings for our members and their consumers. Considerations in our program design include the diverse and small distribution coop staff, and historical and current membership feedback on program needs and focus. Current offerings include, but are not limited to, the following:

- Residential and commercial heating and cooling, including air source and ground source heat pumps and energy star air conditioners
- Residential LED lighting as a post-purchase rebate; Tri-State is evaluating alternative implementation pathways for this measure for the future.
- Commercial retrofit and new construction LED lighting, including refrigerated case doors, occupancy sensors, and other efficient LED lighting measures
- Heat pump water heaters
- Low-income weatherization
- Premium efficiency electric motors and variable speed drives
- Energy Star appliances

Pilot projects are available to all Utility Member Systems and can lead to DSM products.

In addition to these incentives, Tri-State offers a multitude of other programs to promote energy efficiency and the sharing of information around such programs. These include:

- R&D projects, such as the cold climate heat pump and irrigation efficiency projects done in partnership with the Electric Power Research Institute (EPRI) and our Utility Member Systems.
- Rebates on member system staff education, such as energy audit training.

- Working partnerships with external stakeholders such as state energy offices, efficiency groups, and others to promote their available programs to our membership and collaboration strengthening the market availability for energy efficient measures and contractors.
- Consumer education material on EE measures, including newsletter pieces, blog posts, educational webinars, social media pieces and others.

Table 7: 2019 Year-End Cumulative Energy Efficiency Results

Category	Typical Measures	kW Savings	kWh Savings
Agricultural	Irrigation Motors Variable Speed Drive Retrofits	13,446	22,513,016
C&I HVAC	Air Source and Ground Source Heat Pumps	4,858	5,312,892
C&I Lighting	LED Lighting Street & Parking Lot Lighting Refrigerated Case Doors	37,055	133,388,834
C&I Motors	Variable Speed Drive Retrofits	4,207	8,577,080
Residential HVAC	Air Conditioners Air Source and Ground Source Heat Pumps	83,924	56,681,586
Residential - Other	LED Lamps, Energy Star Appliances Electric Water Heaters Low Income Weatherization	52,531	26,080,067
Total		**196,020**	**252,553,476**

Energy Efficiency Historical Results:

- 2016 - $2,078,582
- 2017 - $2,349,835
- 2018 - $3,338,435
- 2019 - $3,327,027
- 2020 Budget - $6,697,353

Additionally, in late 2019, Tri-State initiated a DSM & EE Potential study through an outside consultant with the goal of receiving updated information in regards to achievable potential and cost savings in the areas of energy efficiency, demand response, and distributed energy resources for use in Tri-State's 2020 ERP process. Tri-State intends to leverage this study along with Utility Member Systems' input to evolve and expand products and service offerings in a manner beneficial to Tri-State and its member systems. Key findings from this study include:

- Identifies significant cost effective opportunities for energy and demand savings for energy efficiency programs.

- Identifies limited opportunities for DR programs; long-term operation is key for cost effectiveness.
- Distributed Energy Resource (DER) programs are not cost effective except for larger systems in specific regions.

The complete study is included as Attachment Vol II 5-1 Demand Side Management & Energy Efficiency Potential Study.

GHG & CO_2 Regulation

Tri-State continually evaluates current and proposed legislation while identifying appropriate strategies for its resource portfolio. The following legislation passed in 2019 by the state of Colorado significantly affects Tri-State's assessment of existing and future resources and is incorporated into this resource planning process:

- Colorado HB 19-1261 GHG statewide reduction goals and targets
- Colorado SB 19-096 GHG reporting
- Colorado SB 19-236 Clean Energy Plan and CO_2 Reduction

Tri-State has actively participated in Colorado AQCC working groups and sessions related to this legislation. Through this process, Tri-State has gathered insight and information from related regulations and guidance document processes and forms to create a GHG/CO_2 reduction spreadsheet to apply to each scenario that uses Colorado AQCC methodologies and expected calculations while trying to reflect Tri-State's unique position as a utility serving load in multiple states on a wholesale basis only. Some key components of Tri-State approach to addressing these emission reductions include:

- Addressing CO_2 reduction in relation to all wholesale electricity sales in Colorado whether to Tri-State's Utility Member Systems or non-members.
- Removing Tri-State Utility Member Systems in Colorado who have exited Tri-State (baseline and forecast).
- Addressing GHG reduction at a retail level based on retail sales of Tri-State Utility Member Systems.
- Incorporating all emissions produced by Tri-State owned generation located in Colorado.
- Applying emissions to out of state resources or purchases that are forecast to serve Colorado load or sales.

Tri-State's methodology for CO_2 and GHG emission reductions is based on a mass based comparison of 2030 forecast emissions to a 2005 emissions baseline. Some scenarios include a glide path to CO_2 reduction beginning in 2025. Details of the GHG/ CO_2 calculations can be found in Volume II Section 5 Phase I Modeling Details of this report and results can be found in Section 8 Base Case and Alternative Scenario Results of this report.

Beneficial Electrification

In addition to energy efficiency and demand response, Tri-State has identified Beneficial Electrification (BE) as a key goal in its on-going action plan. Tri-State has long standing electrification programs such as incentives for air source and ground source heat pumps, electric outdoor power equipment such as lawn mowers, and has established several electric vehicle programs, including funding to assist members in expanding public charging infrastructure.

In early 2020, Tri-State commissioned a BE potential study to evaluate measures and their potential to be impactful in Tri-State's service area. The primary objective of this study is to assess the technical, beneficial, and achievable electrification potential from a variety of measures over the planning horizon. This study was designed to measure achievable potential, not program potential, and is intended to assist Tri-State in developing future ERPs. The achievable potential focuses on what *could be*, but does not account for limitations that could come from program portfolio structure or organization limitations.

The study evaluated measures in the residential, irrigation, commercial, and industrial sectors. Measures must meet one of the following criteria without adversely impacting the other three:

- Saves the member-consumer money
- Reduces emissions
- Improves quality of life
- Fosters grid resiliency

The complete study can be found in Attachment Vol II 5-7 Tri-State Beneficial Electrification Potential Study. Key findings from this study include:

- Technologies assessed include electric building heating measures, electric vehicles and non-road electric vehicles, cooking measures, and electric equipment such as lawn and garden equipment.
- The achievable-moderate scenario would result in approximately 2.5 GWh of load growth in year 1, rising to 653 GWh of cumulative growth through the planning study.
- BE provides for emissions reductions.
- The irrigation sector carries significant potential from electrification of motors currently powered by natural gas, propane, or diesel.
- The commercial sector includes a large portion of potential emissions reductions from off-road EV measures such as electric forklifts.
- The top 7 most impactful measures are:
    - Small, light duty battery electric vehicles
    - Irrigation pump motors
    - Heat pump water heaters
    - Electric forklifts (class V and IV)
    - Air source heat pumps
    - Electric buses
- Customer adoption will be a hurdle to overall beneficial electrification uptake.

Due to the timing of the completion of this study, along with the additional necessary work to establish programs and implement the potential, the BE load growth is not included in any alternative scenario.

Tri-State expects to have a clearer picture of an overall BE program and related Utility Member System customer acceptance for use in preparation for the June 1, 2023 Colorado ERP filing.

Imbalance Markets, Regional Transmission Organizations and Independent System Operators (ISO)

Tri-State has the following current and expected activity in relation to imbalance markets:

- Tri-State's load located in PAC has been in the CAISO WEIM since 2014.
- Tri-State's load and resources in WAPA-BA will enter SPP's WEIS in February 2021 or such date as the Western Markets Executive Committee determines.
- Tri-State's load and resources in PNM will enter CAISO WEIM in April 2021.
- PSCo has announced entry into CAISO WEIM in 2022. Tri-State's load in PSCo will move into the WEIM at that time and prior to PSCo's entry date Tri-State will assess whether to participate in the WEIM with resources in PSCo.

To represent this market entry in the Resource Plan Tri-State modeled two imbalance markets, WEIS and WEIM, in addition to existing modeled markets of Craig, Ault, LRS, and Four Corners. The WEIS and WEIM are tied to the Colorado East power curve and Palo Verde power curve, respectively as described in Volume II Section 2 Commodity Pricing of this report. After entry into the market, Tri-State will begin to use appropriate locational marginal pricing as it becomes available to improve forward curve predictors for these markets and will adjust market depths to reflect imbalance activity. The WEIS and WEIM markets are modeled from their entry dates in 2021 through 2024, at which time Tri-State takes these markets to zero in the model and expands the depths of Craig, Ault, LRS, and Four Corners markets to reflect potential formation of an RTO across Tri-State's system footprint in which Tri-State can fully participate.

Expected benefits of the WEIM and WEIS include:

- accessibility to a wider market for Tri-State resources,
- lower power purchase prices,
- potential for development of a "day-2" market, and
- additional ability to integrate renewables.

Tri-State believes entry into imbalance markets will improve reliability and help to reduce the cost of serving Utility Member System load. Additionally, the formation of a full RTO or ISO will further increase the ability to integrate renewables, while maintaining reliability and reducing costs as both day ahead and real time functions related to unit commitment and economic dispatch of both energy and ancillary services will be under the umbrella of one market operator over an extended footprint.

7 Alternative Scenario Analysis

Overview

Tri-State uses scenario analysis for resource planning. The process is designed to measure the effect of changes to key assumptions and the impact of sensitivities on key inputs. For the 2020 IRP/ERP process, Tri-State established a base case using inputs known as of June 2020. This case does not include changes

from normal assumptions or any regulatory impacts. The purpose of the base case is for use as a standard against which other scenarios can be measured. Each alternative scenario is analyzed for financial, reliability and environmental impact. Financial impacts include transmission capital expenditures, resource build costs, and resulting PVRR for the RPP. Reliability impacts include dispatchability, diversity and reliability assessment. Environmental impacts include system-wide emissions rates and water usage for hourly dispatch, as well as required GHG/CO_2 reduction in the state of Colorado. Compliance with RES in Colorado and RPS in New Mexico is also assessed for each scenario.

Tri-State used base inputs as well as scenario-specific assumptions, and employed an iterative process to reach an optimal expansion plan for a given study. The expansion plan was then analyzed for transmission capital expenses, run through the production cost hourly dispatch model, and analyzed in financial forecasting software to arrive at a final PVRR.

In the Section 9 Base Case & Alternative Scenario Comparison of this report, comparisons of PVRR, GHG/CO_2 reduction in Colorado, transmission capital expense, SCoC, and emissions and water usage can be found. A qualitative comparison of reliability impacts is also included. Scenarios are given rankings for diversity, dispatchability and reliability with scores ranging from one to three, where one is lowest and three is highest.

- High diversity is determined by having variability in fuel supply and location in resource mix.
- High dispatchability is determined as the operational ease of increasing or curtailing the resource mix, as well as financial impact.
- High reliability is determined as a resource mix with strong ability to support the grid and flexibility in providing ancillary services.

Alternative Scenario Process

Method for Developing Alternative Scenarios:

The CE model optimized alternative scenario expansion plans by selecting the plan with the lowest costs while adhering to various constraints. Some constraints include 1) minimum levels of planning / operating reserve margins, 2) limits on CO_2 and nitrous oxides (NO_x) emissions to specified levels, and 3) limits on new resources in a given location, so as not to exceed transmission link capacities.

For scenarios with a CO_2 emission constraint applied, CE was unable to completely model the constraint. CE accounts for CO_2 emissions associated with thermal units located within Colorado. However, for thermal generation located outside of Colorado serving loads both in Colorado and in other states, the CO_2 emissions cannot be included in the CE constraint. Therefore, the resulting CE expansions plans did not fully meet the targeted emission limits. In order to meet the carbon emission targets, the CE expansion plans for each scenario were modified outside of CE through additional analysis. Adjustments included adding more renewable resources and/or changing the installation dates of resources identified in the expansion plan. Some considerations for making adjustments were locating resources to minimize transmission network upgrades, the feasibility of wind or solar in any given transmission area, maximizing the use of transmission made available through resource retirements, ensuring the minimum reserve requirement is met and balancing the mix of technologies.

Scenarios:

In an effort to develop alternative plans, Tri-State first developed the base case. As previously stated, the base case serves as a standard against which other scenarios can be measured. The base excludes GHG/CO_2 reductions in Colorado. It was developed using the following main inputs:

- Load forecast – 2020 annual long term forecast
- Electric price forecast – May 2020 spring reset long term forecast
- Gas price curves - May 2020 spring reset long term forecast
- Coal price forecast – 2020 forecast
- Announced coal unit retirements
- A set of generic resources as listed in Volume II Section 5 Phase I Plan Modeling Details of this report.

Note that in all scenarios, 2021 preliminary budget data was used as it represented the best available data on Tri-State's expected 2021 budget. These resource planning processes will not drive a change in the 2021 budget.

For a more complete summary of the remaining inputs, see Volume II Section 5 Phase I Plan Modeling Details under the Modeling Assumptions subsection in this report.

Two primary metrics against which alternative plans were evaluated were PVRR and reduction in GHG/CO_2 emissions in the state of Colorado. Each alternative scenario was required to meet minimum reserve requirements, serve Utility Member System loads, and not exceed the capacities of the transmission links serving the various modeling regions.

Tri-State developed the following alternative scenarios:

- 80pct CR Version 1
- 80pct CR Version 2
- 80pct CR Version 3
- 80pct CR Version 4
- Low Load 80pct CR Version 1
- Low load 80pct CR Version 2
- Social Cost of Carbon (SCC)

The 80pct CR Version 1 scenario was developed by calculating an emissions constraint of 20% of the Colorado 2005 Baseline emissions. The resulting mass-based emissions quantity was then applied as a restriction within the expansion plan and dispatch models to the extent technically feasible for the year 2030. This resulted in CO_2 emissions being reduced in 2030 by 80% from 2005 levels, in regards to emissions from wholesale electricity sales in Colorado. Additionally, this scenario includes a glide path beginning in 2025 for further reducing emissions annually until arriving at the requirement of 80% reduction in CO_2 emissions in Colorado for 2030 relative to the 2005 Colorado Baseline. This scenario also included forced aggressive level EE and low level DR in Colorado.

The 80pct CR Version 2 scenario is similar to the 80pct CR Version 1 scenario but with the removal of generic DR& EE resources as supply-side options. The scenario was analyzed to see how the PVRR and overall costs would be impacted by the removal of aggressive energy efficiency in Eastern Colorado and Western Colorado, which were present in Version 1.

The 80pct CR Version 3 scenario is similar to the 80pct CR Version 2 scenario but includes an additional wind resource to improve CO_2 reduction and enhance reliability.

The 80pct CR Version 4 scenario is similar to the 80pct CR Version 2 scenario but includes an additional solar resource to improve carbon reduction and enhance reliability.

The Low Load 80pct CR Version 1 uses the low load forecast. The load forecast used is the lower end of a 90% prediction interval estimated for the expected load. This scenario also achieves an 80% reduction in CO_2 emissions related to emissions from wholesale electricity sales in Colorado in 2030, using the year 2005 as a baseline.

The Low Load 80pct CR Version 2 is similar to the Low Load 80pct CR Version 1 but with the removal of generic DR & EE resources as supply-side options.

The SCC scenario uses the technical support document under *Executive Order 12866 – Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis,* to determine the social cost of carbon. Values were converted from metric to short tons and escalated from 2007 to 2020 dollars. Tri-State used revised values for real and nominal prices per PUC Staff's comments[5] in Proceeding No. 20M–0218E and as interpreted from guidance in Commission's November 12, 2020 weekly meeting. The social cost of carbon per ton for each existing and generic resource was calculated by multiplying in each year the social cost of carbon per short ton (in real dollars) times the CO_2 emission rate of each resource. Social Cost of Carbon was applied to both in state and out of state resources. This value was added to the variable operating & maintenance (VOM) cost for each resource in each year of the RPP. Only the CE expansion plan model used these escalated VOMs. Market purchases are not used in expansion planning. SCC was not applied to the Basin contracts, as the expansion plan tool is not set up to evaluate retiring contracts.

The nominal social cost of carbon for the final dispatch of the SCC scenario including existing and generic resources, market purchases, energy imbalance purchases and the Basin contracts were passed to UIPlanner for calculation of the PVRR. The social cost of carbon specific to each resource for each year in both real and nominal dollars can be found in Volume II Section 5 Phase I Modeling Details under the subsection of Social Cost of Carbon of this report.

8 Base Case & Alternative Scenario Results

This section identifies key data assumptions and results related to expansion plan, capacity factors of thermal resources, annual emissions by owned or contracted resource, CO_2 reduction in Colorado by 2030 from a 2005 Colorado Baseline and social cost of carbon.

[5] See Volume II Section 5 Phase I Modeling Details under subsection of Social Cost of Carbon for values used.

Tri-State transmission areas that represent modeling regions are as follows:

- Eastern Colorado (ECO)
- Western Colorado (WCO)
- Wyoming (WYO)
- New Mexico (NM)
- Nebraska (NE)
- Springerville (SPV)
- Mt Elbert
- Wyoming Green

Load, resources and markets are assigned to these transmission areas. More detail on these transmission areas can be found in Volume II Section 5 Phase I Modeling Details under the subsection of CE and PO of this report.

Base Case

Base Case assumptions are as listed in Volume II Section 5 Phase I Plan Modeling Details under the subsection of Modeling Assumptions of this report.

Assumptions Unique to this Case:

- No additional assumptions unique to this case.

Results:

Table 8: Expansion Plan (Base Case)

Location	MW	Technology	Year
East Colorado	400	Solar	2029
East Colorado	100	Solar	2030
New Mexico	100	Wind	2030
New Mexico	200	Natural Gas - Combustion Turbine	2030
West Colorado	200	Natural Gas - Combustion Turbine	2030
West Colorado	300	Natural Gas - Combined Cycle	2030
East Colorado	200	Wind	2031
East Colorado	100	Wind	2032
East Colorado	300	Wind	2033
East Colorado	100	Wind	2034
West Colorado	100	Stand Alone Battery	2036
West Colorado	200	Solar	2038
East Colorado	100	Stand Alone Battery	2039
West Colorado	200	Solar	2039
Wyoming	300	Wind	2039
East Colorado	100	Stand Alone Battery	2040
New Mexico	100	Stand Alone Battery	2040
West Colorado	300	Solar	2040

Location	MW	Technology	Year
Wyoming	200	Wind	2040

Note: No DSM or EE generic resources were chosen as part of this scenario.

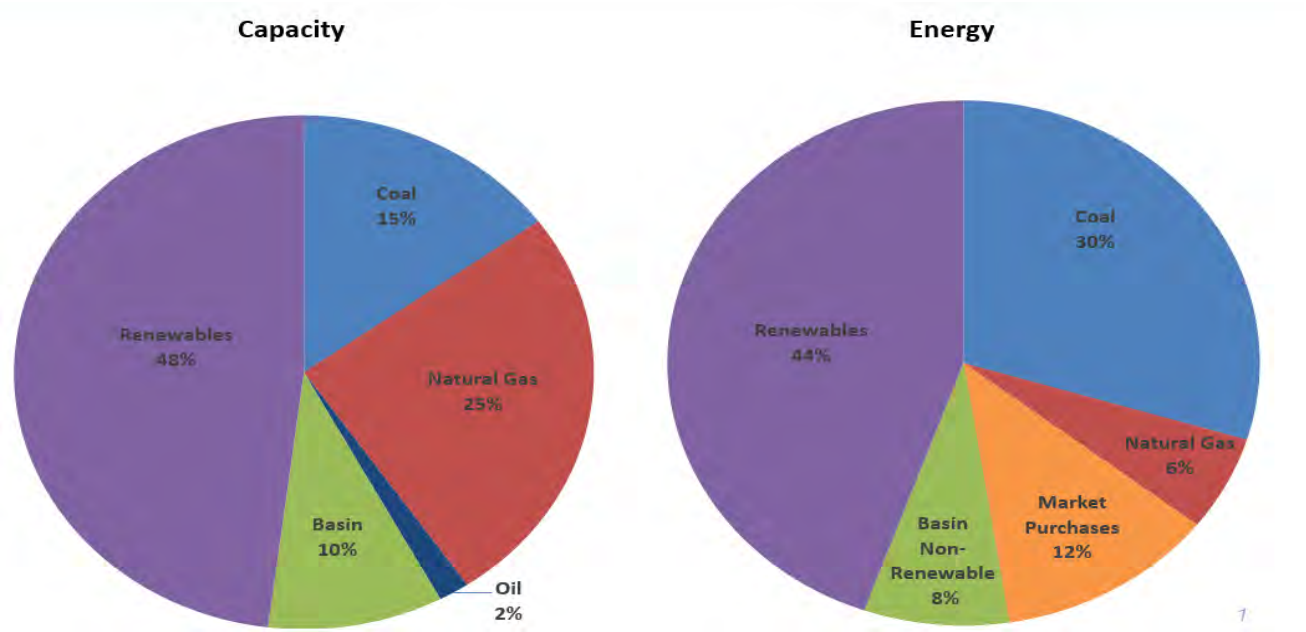

Figure 9: Projected Tri-State System Resource Mix 2030 (Base Case)

Table 9: Projected Annual Capacity Factors for Thermal Resources (Base Case)

Resource	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	77%	75%	77%	77%	73%	0%	0%	0%	0%	0%
Craig 2	94%	92%	79%	87%	84%	89%	93%	70%	0%	0%
Craig 3	81%	89%	83%	78%	80%	91%	83%	94%	89%	0%
LRS 2	96%	79%	95%	88%	82%	94%	94%	83%	93%	93%
LRS 3	81%	85%	93%	72%	94%	92%	82%	93%	82%	93%
SPV3	54%	46%	52%	49%	53%	62%	67%	65%	70%	75%
JM Shafer	19%	14%	16%	14%	32%	26%	23%	21%	15%	19%
Rifle	0%	0%	0%	0%	2%	5%	4%	3%	0%	4%
Limon	0%	0%	0%	0%	2%	4%	3%	1%	0%	0%
Knutson	0%	0%	0%	0%	2%	4%	3%	1%	0%	0%
Pyramid	2%	5%	2%	1%	6%	7%	7%	8%	6%	5%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
200MW CT NM	0%	0%	0%	0%	0%	0%	0%	0%	0%	9%
200MW CT WCO	0%	0%	0%	0%	0%	0%	0%	0%	0%	12%
300MW CC WCO	0%	0%	0%	0%	0%	0%	0%	0%	0%	13%

Table 10: Environmental Impact - System Wide (Base Case)

Year	CO_2 *(tons)*[6]	SO_2 *(tons)*	NO_x *(tons)*	Hg *(tons)*	PM *(tons)*	Water *(gallons)*	RES CO*	RPS NM
2021	13,575,649	6413	10,820	0.2473	449	6,063,231,450	*C*	*C*
2022	13,112,030	6377	10,697	0.2521	440	5,866,523,011	*C*	*C*
2023	13,465,748	6612	11,054	0.2542	465	6,081,369,710	*C*	*C*
2024	12,418,246	5999	10,129	0.2325	409	5,645,835,819	*C*	*C*
2025	13,311,462	6450	10,861	0.2455	474	6,089,406,874	*C*	*C*
2026	13,503,812	6843	10,799	0.2646	487	6,259,139,589	*C*	*C*
2027	13,328,387	6526	10,238	0.2476	456	6,078,848,688	*C*	*C*
2028	13,458,489	6840	10,629	0.2648	470	6,146,381,311	*C*	*C*
2029	12,695,812	6595	10,149	0.2526	431	5,759,577,146	*C*	*C*
2030	10,741,321	4578	6,802	0.1124	370	4,454,365,320	*C*	*C*
2031	10,364,206	4336	6,491	0.1048	362	4,214,761,807	*C*	*C*
2032	10,531,882	4424	6,632	0.1079	358	4,412,138,345	*C*	*C*
2033	10,578,004	4562	6,816	0.1115	374	4,480,370,331	*C*	*C*
2034	10,228,549	4365	6,493	0.1047	360	4,288,332,918	*C*	*C*
2035	10,579,417	4411	6,671	0.1071	363	4,454,780,697	*C*	*C*
2036	10,817,841	4545	6,819	0.1109	376	4,464,021,434	*C*	*C*
2037	10,697,018	4334	6,594	0.1047	374	4,258,808,429	*C*	*C*
2038	10,621,067	4299	6,622	0.1046	367	4,348,735,743	*C*	*C*
2039	10,701,330	4508	6,829	0.1103	380	4,418,473,131	*C*	*C*
2040	10,332,855	4452	6,559	0.1058	360	4,258,987,351	*C*	*C*
Total	235,063,123	107,467	168,703	3.446	8,125	102,044,089,106		
per MWh**	*1,197*	*0.55*	*0.86*	*0.00002*	*0.04*	*260*		

*C = compliant; N = noncompliant; Sulfur Dioxide (SO_2), Mercury (Hg), Particulate Matter (PM)
**Pounds per MWh of Member Load for emissions; Gallons per MWh of Member Load for water

Table 11: Social Cost of Carbon Nominal Dollars – System Wide (Base Case)

Year	Annual Social Cost of Carbon

[6] All tons are in short tons. CO_2, SO_2 and NO_x are per net MWh; HG and PM are per gross MWh.

2021	$644,979,092
2022	$650,487,802
2023	$697,256,412
2024	$670,833,641
2025	$749,701,519
2026	$792,673,740
2027	$815,030,848
2028	$856,901,966
2029	$824,466,048
2030	$726,005,894
2031	$728,810,985
2032	$770,301,855
2033	$804,245,666
2034	$808,259,972
2035	$868,464,333
2036	$922,220,916
2037	$946,793,068
2038	$975,757,409
2039	$1,020,050,781
2040	$1,021,609,331
Total	**$16,294,851,278**

Table 12: GHG/CO_2 Emissions for Serving Wholesale Electricity Sales in Colorado Projected in 2030 from a 2005 Baseline (Base Case)

2030	Fuel Type	Energy (MWh)	Emission Rate (tons/MWh)	Carbon Emissions (Tons)
CO Sales to Members		13,660,989		
CO Sales to Members inc Transmission Losses (5%)		14,344,038		
COMarket Sales (including 5% markup for transmission losses)		271,700		
Standalone battery load (90% efficiency) charging & Mt Elbert net		0		
Craig 1 & 2	Coal - Retired		1.17	0
Craig 3	Coal - Retired		1.05	0
LRS Imports	Coal	3,423,670	1.15	3,945,779
Nucla	Coal - Retired		1.30	0
Rifle	Gas	29,362	0.60	17,617
Knutson 1&2	Gas	0	0.75	0
Limon 1 & 2	Gas	121	0.75	91
Burlington 1 & 2	Oil	0	1.12	0
Shafer	Gas	463,143	0.49	226,940
CRSP East & West (CO)	Federal Hydro	929,700	0.00	0
LAP (CO)	Federal Hydro	717,301	0.00	0
Small Power Producers	Small Hydro	710	0.00	0
Basin AU PPA	egrid RMPA	876,385	0.64	560,886
Expansion Plan Wind PPAs (CO & WY)	Wind	0	0.00	0
Expansion Plan Gas (CO) combined cycle	Gas	353,145	0.40	141,258
Expansion Plan Gas (CO) Aeroderivative, RICE, CT	Gas	363,599	0.75	272,699
Expansion Plan Solar (CO)	Solar	1,263,895	0.00	0
Energy Imbalance (PSCO and prorate of WAPA)	egrid RMPA	133,131	0.64	85,204
CO Market Purchases	egrid RMPA	1,658,231	0.64	1,061,268
Kit Carson	Wind	165,656	0	0
Carousel	Wind	653,199	0	0
Colorado Highlands	Wind	361,418	0	0
Crossing Trails	Wind	408,330	0	0
Spanish Peaks	Solar	244,985	0	0
San Isabel	Solar	67,207	0	0
Twin Buttes	Solar	307,745	0	0
Niyol	Wind	890,207	0	0
Coyote Gulch	Solar	279,776	0	0
Dolores Canyon	Solar	250,291	0	0
Axial	Solar	315,286	0	0
Basin Electrically East	Egrid MROW	103,000	0.62	63,860
Policy 115 - CO only	Mix	356,246	0	0
			Carbon Tons	6,375,603
			GHG tons	6,407,189
Mass Based Carbon Reduction for Electricity Sales	-31%			
Mass Based GHG Reduction For Electricity sales	-31%			

Table 13: GHG/CO_2 Emissions for Serving Utility Member System Retail Sales in Colorado in 2030 from a 2005 Baseline (Base Case)

		Option 1	Option 2
	MWh	Carbon Emissions Based on How served	Carbon Emissions based on Percentage of Sales
Retail Load (Member load reduced for distribution & transm	13,114,549	3,799,652	5,720,761
Carbon Rate (Tons/MWh)		0.29	0.44
GHG Emission		3818383.83	5,748,964
Carbon Reduction for retail sales		-38%	-8%
GHG Reduction for retail sales		-38%	-9%
Resources Expected to Exclusively Serve Load			
Rifle	29,362	17,617	
CRSP East & West (CO)	929,700	0	
LAP (CO)	717,301	0	
Small Power Producers	710	0	
Basin AU PPA	876,385	560,886	
Expansion Plan Wind PPAs (CO & WY)	0	0	
Expansion Plan Solar (CO)	1,263,895	0	
Kit Carson	165,656	0	
Carousel	653,199	0	
Colorado Highlands	361,418	0	
Crossing Trails	408,330	0	
Spanish Peaks	244,985	0	
San Isabel	67,207	0	
Twin Buttes	307,745	0	
Niyol	890,207	0	
Coyote Gulch	279,776	0	
Dolores Canyon	250,291	0	
Axial	315,286	0	
Policy 115 - CO only	356,246	0	
Total	8,117,699	578,504	
Net After transmission losses	7,711,814	549,578	
Balance	5,402,735	3,250,074	

Table 14: Financial (Nominal Dollars) & Reliability Impact

Impact Item	Value
Present Value Member Revenue Requirement (Millions)	$20,878
Expansion Plan Capex + IDC : Generation (Millions)	$1,249
Expansion Plan Capex + IDC : Transmission (Millions)	$1,624
Diversity	2
Dispatchability	3
Reliability	3

Transmission Impact

Beyond normal interconnection transmission expenses, significant additional network upgrades for size in this plan (Costs are in 2020 dollars) were incurred as follows:

- ~$400M in Eastern Colorado in 2029
- ~$400M in New Mexico in 2030
- ~$300M in Eastern Colorado in 2031
- ~$300M in Eastern Colorado in 2039

Detailed transmission expenses related to generic resources are shown in the following table.

Table 15: Transmission Interconnection & Network Upgrade Expenses (2020 Real Dollars) (Base Case)

Year	**Size** *(MW)*	**Type**	**Interconnection Cost** *($M)*	**Network Upgrade at POI Cost** *($M)*	**Network Upgrade for Size** *($M)*
Eastern Colorado (ECO) Transmission Area					
2029	100	Solar	0	5.89	0
2029	100	Solar	0	2.6	419.56
2029	100	Solar	0	2.6	0
2029	100	Solar	0	2.6	0
2030	100	Solar	0	2.6	0
2031	100	Wind	0	12.98	334.39
2031	100	Wind	0	5.2	0
2032	100	Wind	0	2.6	0
2033	100	Wind	0	5.2	0
2033	100	Wind	0	2.6	0
2033	100	Wind	0	5.2	0
2034	100	Wind	0	2.6	0
2039	100	Battery	2.19	5.2	283.39
2040	100	Battery	2.19	2.6	0
Western Colorado (WCO) Transmission Area					
2030	200	CT	1.63	0.5	0
2030	300	CC	1.63	0.5	0
2036	100	Battery	2.19	0.5	0
2038	100	Solar	0	3.7	0

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2038	100	Solar	0	1.85	0
2039	100	Solar	0	3.7	0
2039	100	Solar	0	1.85	0
2040	100	Solar	0	2.6	0
2040	100	Solar	0	2.6	0
2040	100	Solar	0	2.6	0
Wyoming (WYO) Transmission Area					
2039	100	Wind	0	11.43	0
2039	100	Wind	0	2.6	0
2039	100	Wind	0	2.6	22.04
2040	100	Wind	0	2.6	0
2040	100	Wind	0	11.43	0
New Mexico (NM) Transmission Area)					
2030	200	CT	2.19	2.6	0
2030	100	Wind	0	1.85	385.34
2040	100	Battery	2.19	2.6	13.4

80pct CR Version 1

Assumptions Unique to this Scenario:

Modeling assumptions are per Volume II Section 5 Phase I Plan Modeling Details under the subsection of Modeling Assumptions of this report with the following exceptions:

Table 16: Unique Assumptions (80pct CR V1)

Assumption Item	Description
Additional Retirements	Allowed – coal retirements after 2025; SPV3 not allowed to retire until after end of Salt River Project (SRP) contract (first year 2037)
Thermal Resource Status: **Econ** - Model can choose to turn resource on and off but resource has a 168 hour on line min. **Must Run** - Model can choose what level to run the resource at but resource cannot go lower than min.	**Must Run 2021 - 2024 :** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV 3 **Econ 2025 - 2040:** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV 3 **Econ 2021 - 2040:** Burlington 1, Burlington 2, Knutson 1&2, Limon 1&2, Pyramid 1-4, Rifle, and Shafer
Build Limits	• Max Study – ECO 2000 • Max Study – NM 400 • Max Study – Storage 1200 • Max Study – Thermal 300

Assumption Item	Description
	• Max Study – WY 650 • Max Annual – Renewable 1000
DSM & EE Level	Aggressive EE and Low DR forced for ECO and WCO
CO_2 Reduction	80% CO_2 in 2030 from 2005 baseline in relation to electricity sales in Colorado; Glide path from 2025 to 2030
Mt. Elbert	Off
Transmission Links	See Table 17 for detail
Market Depths	See Tables 18 & 19 for detail

Table 17: Applied Transmission Link Capacity (80pct CR V1)

Link Name	From Transmission Area	To Transmission Area	Forward Capacity *(MW)*	Backward Capacity *(MW)*	Dates
LK-E_CO>NM	WACM_Eastern_Colorado	New Mexico	124	0	2021 - 2040
LK-LAP>E_CO	Mt_ Elbert	WACM_Eastern_Colorado	107	139	2021 - 2040
LK-SPRV>NM	Springerville	New Mexico	317	0	2021 - 2035
LK-SPRV>NM	Springerville	New Mexico	359	0	2036
LK-SPRV>NM	Springerville	New Mexico	417	0	2037 - 2040
LK-W_CO>E_CO	West_Colorado	WACM_Eastern_Colorado	457	150	2021 - 2040
LK-W_CO>NM	West_Colorado	New Mexico	0	170	2021 - 2024
LK-W_CO>NM	West_Colorado	New Mexico	50	170	2025 - 2026
LK-W_CO>NM	West_Colorado	New Mexico	50	100	2027
LK-W_CO>NM	West_Colorado	New Mexico	50	50	2028 - 2040
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	400	400	2021
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	550	400	2022 - 2025
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	450	400	2026
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	350	400	2027
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	250	400	2028
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	150	400	2029
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	50	400	2030 -2040
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	0	0	2021 - 2024
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	600	0	2025 - 2040

Table 18: Market Sales Hourly Capacity (80pct CR V1)

Dates	MS-4 Corner-N_NM *(MW)*	MS-WEIM *(MW)*
Jan 2021 - Mar 2021	20-OFF / 75-ON	0
Apr 2021 - 2024	0-OFF / 20-ON	25-OFF / 60-ON
2025-2040	150	0

Dates	MS-Ault-E_CO *(MW)*	MS-Craig-NW_CO *(MW)*	MS-LRS-WY *(MW)*	MS-WEIS *(MW)*
Jan 2021	0-OFF / 50-ON	15-OFF / 100-ON	0	0
Feb 2021 - 2024	0-OFF / 25-ON	0-OFF / 25-ON	0	25-OFF / 125-ON
2025-2029	150	50	200	0
2030-2040	50	50	200	0

Table 19: Market Purchases Hourly Capacity (80pct CR V1)

Dates	MP-4 Corner-N_NM *(MW)*	MP-WEIM *(MW)*
Jan 2021 - Mar 2021	100	0
Apr 2021 - 2024	85	15
2025-2034	200	0
2035-2040	400	0

Dates	MP-Ault-E_CO *(MW)*	MP-Craig-NW_CO *(MW)*	MP-LRS-WY *(MW)*	MP-WEIS *(MW)*
Jan 2021	200	125	75	0
Feb 2021 - 2024	150	100	75	75
2025-2034	200	200	200	0
2035-2040	400	400	400	0

Results:

Table 20: Expansion Plan (80pct CR V1)

Location	MW[7]	Technology	Year
East Colorado	See Profile	Aggressive - Energy Efficiency	2022
West Colorado	See Profile	Aggressive - Energy Efficiency	2022
East Colorado	See Profile	Low – Demand Response	2022
West Colorado	See Profile	Low – Demand Response	2022
East Colorado	100	Wind	2025
Wyoming	100	Wind	2025
West Colorado	200	Solar	2026
Wyoming	100	Wind	2026
West Colorado	100	Standalone Battery	2027
West Colorado	100	Solar	2027
West Colorado	200	Solar	2028
Wyoming	100	Wind	2028
West Colorado	100	Standalone Battery	2029
West Colorado	200	Solar	2029
Wyoming	100	Wind	2029
Wyoming	25	Standalone Battery	2030
West Colorado	300	Natural Gas – Combined Cycle	2030
West Colorado	200	Solar	2030
East Colorado	200	Wind	2030
Wyoming	100	Wind	2030
East Colorado	100	Wind	2032
Wyoming	100	Wind	2033
East Colorado	100	Wind	2033
Wyoming	100	Wind	2034
East Colorado	100	Wind	2034
West Colorado	100	Solar	2035
East Colorado	100	Wind	2035
New Mexico	100	Standalone Battery	2036
East Colorado	100	Wind	2036
Wyoming	25	Standalone Battery	2037
East Colorado	100	Standalone Battery	2037
West Colorado	100	Standalone Battery	2037
East Colorado	100	Wind	2037
New Mexico	200	Wind	2037
West Colorado	300	Solar	2038
New Mexico	100	Wind	2038
East Colorado	100	Standalone Battery	2039

[7] See Volume II Section 5 Phase I Modeling Details under the subsection of Modeling Assumptions & Methodology>DSM & EE of this report for profile information.

Location	MW[7]	Technology	Year
East Colorado	400	Solar	2039
East Colorado	100	Standalone Battery	2040
West Colorado	25	Standalone Battery	2040

Table 21: Proposed Retirements (80pct CR V1)

Location	MW	Technology	Year
LRS 3	231	Coal	2033
SPV3	417	Coal	2038

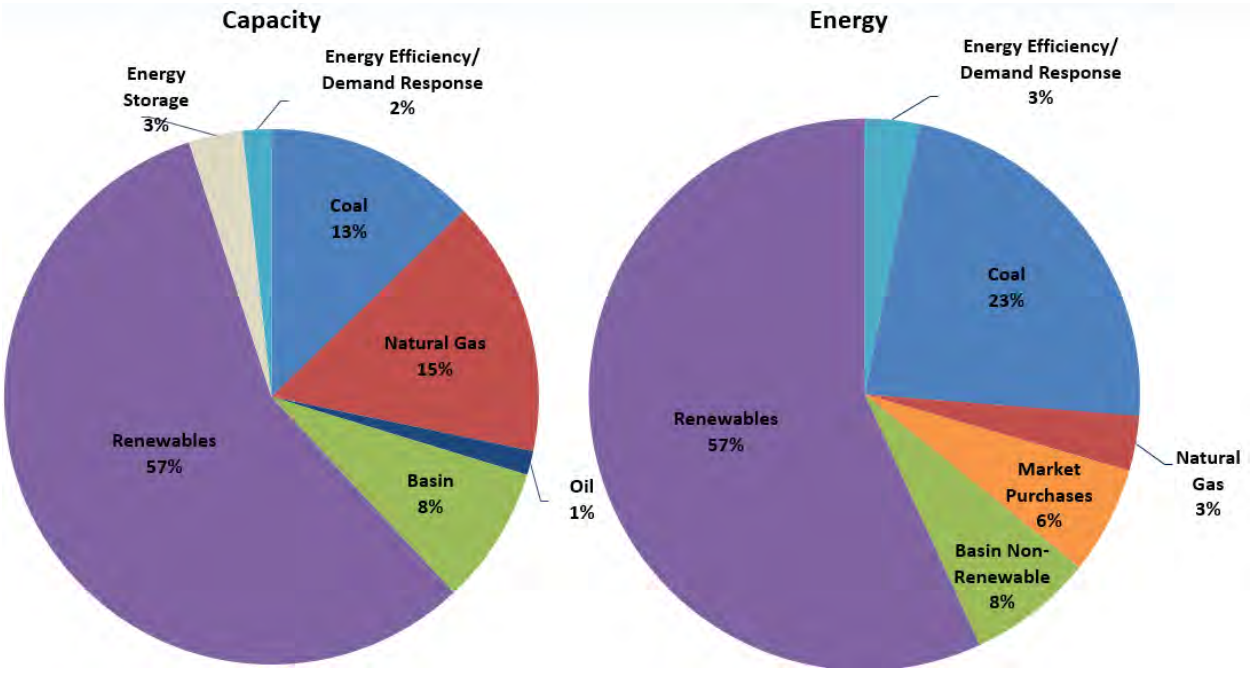

Figure 10: Projected System Capacity and Energy Mix (80pct CR V1)

Table 22: Projected Annual Capacity Factors for Thermal Reources (80pct CR V1)

Resource	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	75%	85%	82%	83%	68%	0%	0%	0%	0%	0%
Craig 2	86%	91%	78%	87%	76%	85%	87%	37%	0%	0%
Craig 3	73%	87%	79%	79%	70%	87%	78%	67%	19%	0%
LRS 2	93%	74%	94%	78%	82%	92%	93%	82%	91%	85%
LRS 3	80%	80%	92%	66%	93%	90%	81%	91%	81%	81%
SPV3	48%	46%	50%	48%	43%	45%	52%	51%	59%	56%
JM Shafer	21%	13%	15%	13%	31%	22%	15%	11%	6%	1%
Rifle	0%	0%	0%	0%	1%	1%	0%	0%	5%	0%
Limon	0%	0%	0%	0%	4%	3%	0%	0%	0%	0%

Resource	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Knutson	0%	0%	0%	0%	3%	3%	0%	0%	0%	0%
Pyramid	0%	5%	2%	1%	8%	6%	5%	5%	5%	4%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
300MW CC WCO	0%	0%	0%	0%	0%	0%	0%	0%	0%	26%

Table 23: Environmental Impact – System Wide (80pct CR V1)

Year	CO_2 *(tons)*[8]	SO_2 *(tons)*	NO_x *(tons)*	Hg *(tons)*	PM *(tons)*	Water *(gallons)*	RES CO*	RPS NM
2021	13,248,122	6056	10,257	0.2305	429	5,726,854,057	*C*	*C*
2022	12,940,848	6188	10,482	0.2448	424	5,743,726,155	*C*	*C*
2023	13,306,681	6480	10,886	0.2471	457	5,968,245,238	*C*	*C*
2024	12,121,536	5776	9,812	0.2257	387	5,473,733,881	*C*	*C*
2025	12,483,909	5993	10,165	0.2238	450	5,613,203,615	*C*	*C*
2026	12,437,232	6412	10,180	0.2499	456	5,718,226,436	*C*	*C*
2027	12,137,777	6137	9,604	0.2337	421	5,532,345,140	*C*	*C*
2028	11,141,134	5835	8,918	0.2124	399	5,052,210,969	*C*	*C*
2029	9,596,311	4577	6,770	0.1316	323	4,113,955,503	*C*	*C*
2030	8,605,190	3995	5,913	0.0972	309	3,785,176,551	*C*	*C*
2031	8,562,944	3946	5,819	0.0948	310	3,703,433,543	*C*	*C*
2032	8,673,832	3971	5,889	0.0961	304	3,831,399,175	*C*	*C*
2033	7,583,638	2890	4,418	0.0652	181	3,327,906,815	*C*	*C*
2034	6,984,456	2540	3,896	0.0545	153	3,022,665,802	*C*	*C*
2035	7,307,532	2703	4,129	0.0594	161	3,182,198,961	*C*	*C*
2036	7,389,922	2721	4,093	0.0594	159	3,200,812,876	*C*	*C*
2037	6,627,845	2427	3,707	0.0520	141	2,828,444,813	*C*	*C*
2038	5,001,214	1659	3,092	0.0365	117	1,836,504,994	*C*	*C*
2039	4,835,095	1574	3,001	0.0347	113	1,716,243,528	*C*	*C*
2040	5,053,335	1618	2,997	0.0340	110	1,694,937,299	*C*	*C*
Total	186,038,552	83,497	134,028	2.683	5,804	81,072,225,351		
per MWh**	*947*	*0.43*	*0.68*	*0.00001*	*0.03*	*206*		

*C = compliant; N = noncompliant

**Pounds per MWh of Member Load for emissions; Gallons per MWh of Member Load for water

[8] All tons are in short tons. CO_2, SO_2 and NO_x are per net MWh; HG and PM are per gross MWh.

Table 24: Social Cost of Carbon Nominal Dollars – System Wide (80pct CR V1)

Year	Annual Social Cost of Carbon
2021	$629,418,285
2022	$641,995,465
2023	$689,019,949
2024	$654,805,398
2025	$703,093,750
2026	$730,065,535
2027	$742,225,046
2028	$709,356,028
2029	$623,184,442
2030	$581,624,779
2031	$602,146,210
2032	$634,404,075
2033	$576,583,984
2034	$551,911,706
2035	$599,875,322
2036	$629,990,844
2037	$586,630,517
2038	$459,461,507
2039	$460,881,226
2040	$499,623,184
Total	**$12,306,297,253**

Table 25: GHG/CO_2 Emissions for Serving Wholesale Electricity Sales in Colorado Projected in 2030 from a 2005 Baseline (80pct CR V1)

2030	Fuel Type	Energy (MWh)	Emission Rate (tons/MWh)	Carbon Emissions (Tons)
CO Sales to Members		13,660,989		
CO Sales to Members inc Transmission Losses (5%)		14,344,038		
COMarket Sales (including 5% markup for transmission losses)		683,100		
Standalone battery load (90% efficiency) charging & Mt Elbert net		42,476		
Craig 1 & 2	Coal - Retired		1.17	0
Craig 3	Coal - Retired		1.05	0
LRS Imports	Coal	71,268	1.15	82,136
Nucla	Coal - Retired		1.30	0
Rifle	Gas	813	0.60	488
Knutson 1&2	Gas	0	0.75	0
Limon 1 & 2	Gas	0	0.75	0
Burlington 1 & 2	Oil	0	1.12	0
Shafer	Gas	27,244	0.49	13,350
CRSP East & West (CO)	Federal Hydro	929,860	0.00	0
LAP (CO)	Federal Hydro	717,302	0.00	0
Small Power Producers	Small Hydro	710	0.00	0
Basin AU PPA	egrid RMPA	876,385	0.64	560,886
Expansion Plan Wind PPAs (CO & WY)	Wind	3,049,679	0.00	0
Expansion Plan Gas (CO) combined cycle	Gas	679,058	0.40	271,623
Expansion Plan Gas (CO) Aeroderivative, RICE, CT	Gas	0	0.60	0
Expansion Plan Solar (CO)	Solar	2,275,011	0.00	0
Energy Imbalance (PSCO and prorate of WAPA)	egrid RMPA	133,131	0.64	85,204
CO Market Purchases	egrid RMPA	1,112,498	0.64	711,998
Kit Carson	Wind	165,656	0	0
Carousel	Wind	653,199	0	0
Colorado Highlands	Wind	361,418	0	0
Crossing Trails	Wind	408,330	0	0
Spanish Peaks	Solar	244,985	0	0
San Isabel	Solar	67,207	0	0
Twin Buttes	Solar	307,745	0	0
Niyol	Wind	890,207	0	0
Coyote Gulch	Solar	279,776	0	0
Dolores Canyon	Solar	250,291	0	0
Axial	Solar	315,286	0	0
DSM/EE	Load Reduction	750,658	0	0
Basin Electrically East	egrid MROW	103,000	0.62	63,860
Policy 115 - CO only	Mix	356,467	0	0
			Carbon Tons	1,789,546
			GHG tons	1,792,630
Mass Based Carbon Reduction for Electricity Sales	-81%			
Mass Based GHG Reduction For electricity sales	-81%			

Table 26: GHG/CO_2 Emissions for Serving Utility Member System Retail Sales in Colorado in 2030 from a 2005 Baseline (80pct CR V1)

		Option 1	Option 2
	MWh	Carbon Emissions Based on How served	Carbon Emissions based on Percentage of Sales
Retail Load (Member load reduced for distribution & transm	13,251,159	1,486,853	1,573,601
Carbon Rate (Tons/MWh)		0.11	0.12
GHG Emission		1489411.15	1,576,308
Carbon Reduction for retail sales		-76%	-75%
GHG Reduction for retail sales		-76%	-75%
Resources Expected to Exclusively Serve Load			
Rifle	813	488	
CRSP East & West (CO)	929,860	0	
LAP (CO)	717,302	0	
Small Power Producers	710	0	
Basin AU PPA	876,385	560,886	
Expansion Plan Wind PPAs (CO & WY)	3,049,679	0	
Expansion Plan Solar (CO)	2,275,011	0	
Kit Carson	165,656	0	
Carousel	653,199	0	
Colorado Highlands	361,418	0	
Crossing Trails	408,330	0	
Spanish Peaks	244,985	0	
San Isabel	67,207	0	
Twin Buttes	307,745	0	
Niyol	890,207	0	
Coyote Gulch	279,776	0	
Dolores Canyon	250,291	0	
Axial	315,286	0	
Basin Electrically East	103,000	63,860	
Policy 115 - CO only	356,467	0	
Total	12,253,327	625,234	
Net After transmission losses	11,640,661	593,972	
Balance	1,610,499	892,881	

Table 27: Financial (Nominal Dollars) & Reliability Impact (80pct CR V1)

Impact Item	Value
Present Value Member Revenue Requirement (Millions)	$21,406
Expansion Plan Capex + IDC : Generation (Millions)	$1,263
Expansion Plan Capex + IDC : Transmission (Millions)	$2,406
Diversity	3
Dispatchability	2
Reliability	2

Transmission Impact

Beyond normal interconnection transmission expenses, significant additional network upgrades for size in this plan (Costs are in 2020 dollars) were incurred as follows:

- ~$400M in Eastern Colorado in 2030
- ~$150M in Western Colorado in 2030
- ~$300M in Eastern Colorado in 2034
- ~$400M in New Mexico in 2037
- ~$300M in Eastern Colorado in 2040

Detailed transmission expenses related to generic resources are shown in the following table.

Table 28: Transmission Interconnection & Network Upgrade Expenses(2020 Real Dollars) (80pct CR V1)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2025	100	Wind	0	5.89	0
2030	100	Wind	0	2.6	419.56
2030	100	Wind	0	2.6	0
2032	100	Wind	0	2.6	0
2033	100	Wind	0	2.6	0
2034	100	Wind	0	12.98	334.39
2035	100	Wind	0	5.2	0
2036	100	Wind	0	1.85	0
2037	100	Wind	0	2.6	0
2037	100	Battery	2.19	5.2	0
2039	100	Battery	2.19	2.6	0
2039	100	Solar	0	1.85	0
2039	100	Solar	0	5.2	0
2039	100	Solar	0	2.6	0
2039	100	Solar	0	1.85	0
2040	100	Battery	2.19	5.2	283.39

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Western Colorado (WCO) Transmission Area					
2026	100	Solar	0	3.7	0
2026	100	Solar	0	1.85	0
2027	100	Battery	1.63	0.5	0
2027	100	Solar	0	3.7	0
2028	100	Solar	0	1.85	0
2028	100	Solar	0	2.6	0
2029	100	Solar	0	2.6	0
2029	100	Solar	0	2.6	0
2029	100	Battery	1.63	0.5	0
2030	100	Solar	0	11.43	0
2030	100	Solar	0	2.6	0
2030	300	CC	2.19	0.5	167.67
2035	100	Solar	0	2.6	0
2037	100	Battery	2.19	2.6	0
2038	100	Solar	0	1.03	0
2038	100	Solar	0	1.03	0
2038	100	Solar	0	12.98	0
2040	25	Battery	2.19	2.6	0
Wyoming (WYO) Transmission Area					
2025	100	Wind	0	11.43	0
2026	100	Wind	0	2.6	0
2028	100	Wind	0	2.6	22.04
2029	100	Wind	0	2.6	0
2030	100	Wind	0	11.43	0
2030	25	Battery	2.19	2.6	0
2033	100	Wind	0	2.6	0
2034	100	Wind	0	2.6	0
2037	25	Battery	2.19	0.5	0
New Mexico (NM) Transmission Area)					
2036	100	Battery	2.19	2.6	0
2037	100	Wind	0	1.85	385.34
2037	100	Wind	0	1.85	0
2038	100	Wind	0	1.85	0

80pct CR Version 2

Assumptions Unique to this Scenario:

Modeling assumptions are per Volume II Section 5 Phase I Plan Modeling Details under the subsection of Modeling Assumptions of this report with the following exceptions:

Table 29: Unique Assumptions (80pct CR V2)

Assumption Item	Description
Additional Retirements	Allowed – coal retirements after 2025; SPV3 not allowed to retire until after end of SRP contract (first year 2037)
Thermal Resource Status: **Econ** - Model can choose to turn resource on and off but resource has a 168 hour on line min. **Must Run** - Model can choose what level to run the resource at but resource cannot go lower than min.	**Must Run 2021 - 2024 :** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV **Econ 2025 - 2040:** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV **Econ 2021 - 2040:** Burlington 1, Burlington 2, Knutson1&2, Limon 1&2, Pyramid 1-4, Rifle, and Shafer
Build Limits	• Max Study – ECO 2000 • Max Study – NM 400 • Max Study – Storage 1200 • Max Study – Thermal 300 • Max Study – WYO 650 • Max Annual – Renewable 1000
DSM & EE Level	Existing DSM EE only
CO_2 Reduction	80% CO_2 reduction in 2030 from 2005 baseline in relation to electricity sales in Colorado; Glide path from 2025 to 2030
Mt Elbert	Off
Transmission Links	See Table 30 for details
Market Depth	See Tables 31 & 32 for details

Table 30: Applied Transmission Link Capacities (80pct CR Version 2)

Link Name	From Transmission Area	To Transmission Area	Forward Capacity *(MW)*	Backward Capacity *(MW)*	Dates
LK-E_CO>NM	WACM_Eastern_Colorado	New Mexico	124	0	2021 - 2040
LK-LAP>E_CO	Mt_ Elbert	WACM_Eastern_Colorado	107	139	2021 - 2040
LK-SPRV>NM	Springerville	New Mexico	317	0	2021 - 2035
LK-SPRV>NM	Springerville	New Mexico	359	0	2036
LK-SPRV>NM	Springerville	New Mexico	417	0	2037 - 2040
LK-W_CO>E_CO	West_Colorado	WACM_Eastern_Colorado	457	150	2021 - 2040
LK-W_CO>NM	West_Colorado	New Mexico	0	170	2021 - 2024
LK-W_CO>NM	West_Colorado	New Mexico	50	170	2025 - 2026
LK-W_CO>NM	West_Colorado	New Mexico	50	100	2027
LK-W_CO>NM	West_Colorado	New Mexico	50	50	2028 - 2040
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	400	400	2021
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	550	400	2022 - 2025
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	450	400	2026
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	350	400	2027
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	250	400	2028
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	150	400	2029
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	50	400	2030 - 2040
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	0	0	2021 - 2024
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	600	0	2025 - 2040

Table 31: Market Sales Hourly Capacity (80pct CR Version V2)

Dates	MS-4 Corner-N_NM *(MW)*	MS-WEIM *(MW)*
Jan 2021 - Mar 2021	20-OFF / 75-ON	0
Apr 2021 - 2024	0-OFF / 20-ON	25-OFF / 60-ON
2025-2040	150	0

Dates	MS-Ault-E_CO *(MW)*	MS-Craig-NW_CO *(MW)*	MS-LRS-WY *(MW)*	MS-WEIS *(MW)*
Jan 2021	0-OFF / 50-ON	15-OFF / 100-ON	0	0
Feb 2021 - 2024	0-OFF / 25-ON	0-OFF / 25-ON	0	25-OFF / 125-ON
2025-2029	150	50	200	0
2030-2040	50	50	200	0

Table 32: Market Purchases Hourly Capacity (80pct CR Version 2)

Dates	MP-4 Corner-N_NM *(MW)*	MP-WEIM *(MW)*
Jan 2021 - Mar 2021	100	0
Apr 2021 - 2024	85	15
2025-2034	200	0
2035-2040	400	0

Dates	MP-Ault-E_CO *(MW)*	MP-Craig-NW_CO *(MW)*	MP-LRS-WY *(MW)*	MP-WEIS *(MW)*
Jan 2021	200	125	75	0
Feb 2021 - 2024	150	100	75	75
2025-2034	200	200	200	0
2035-2040	400	400	400	0

Results:

Table 33: Expansion Plan (80pct CR V2)

Location	MW	Technology	Year
East Colorado	100	Wind	2025
Wyoming	100	Wind	2025
West Colorado	200	Solar	2026
Wyoming	100	Wind	2026
West Colorado	100	Solar	2027
West Colorado	200	Solar	2028
Wyoming	100	Wind	2028
West Colorado	200	Standalone Battery	2029
West Colorado	200	Solar	2029
East Colorado	100	Wind	2029
Wyoming	100	Wind	2029
Wyoming	25	Standalone Battery	2030
West Colorado	300	Natural Gas - Combined Cycle	2030
West Colorado	200	Solar	2030
East Colorado	200	Wind	2030
Wyoming	100	Wind	2030
East Colorado	100	Wind	2032
East Colorado	100	Wind	2033
Wyoming	100	Wind	2033
East Colorado	100	Wind	2034
Wyoming	100	Wind	2034

Location	MW	Technology	Year
West Colorado	100	Solar	2035
East Colorado	100	Wind	2035
New Mexico	100	Standalone Battery	2036
East Colorado	100	Wind	2036
East Colorado	100	Standalone Battery	2037
West Colorado	100	Standalone Battery	2037
Wyoming	25	Standalone Battery	2037
East Colorado	100	Wind	2037
New Mexico	200	Wind	2037
West Colorado	300	Solar	2038
New Mexico	100	Wind	2038
East Colorado	100	Standalone Battery	2039
East Colorado	400	Solar	2039
East Colorado	100	Standalone Battery	2040
West Colorado	25	Standalone Battery	2040

Table 34: Proposed Retirements (80pct CR V2)

Location	MW	Technology	Year
LRS 3	231	Coal	2033
SPV3	417	Coal	2038

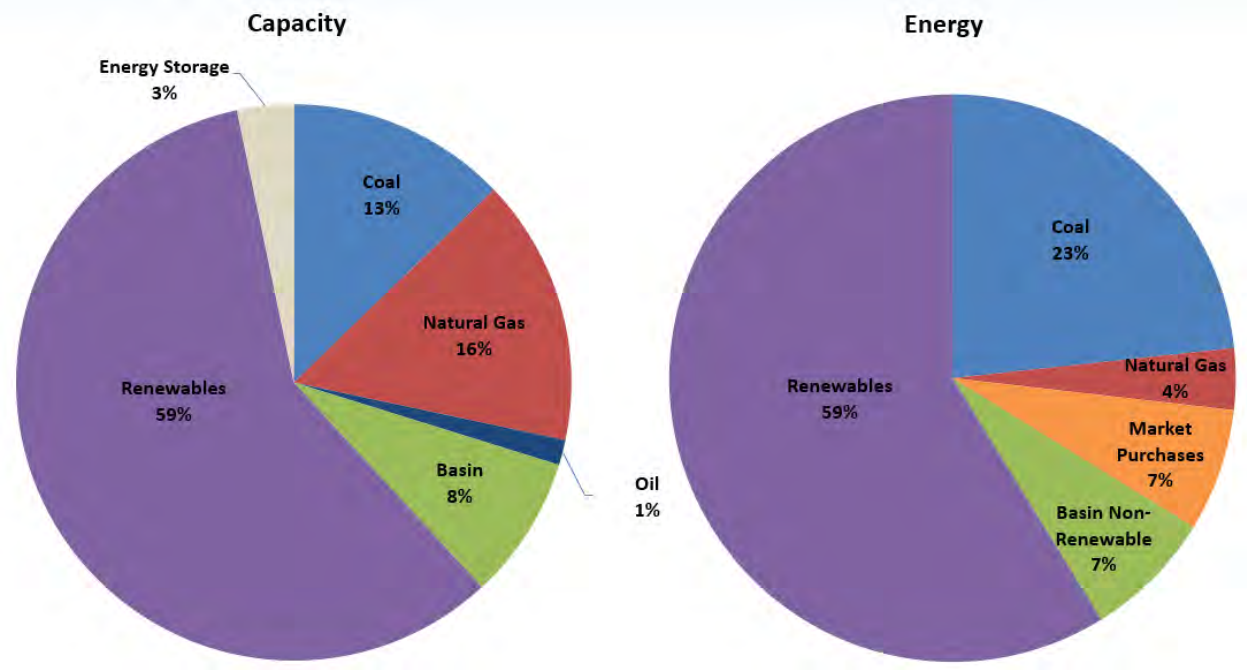

Figure 11: Projected System Capacity and Energy Mix (80pct CR V2)

Table 35: Projected Annual Capacity Factors (80pct CR V2)

Resource	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	75%	85%	83%	84%	68%	0%	0%	0%	0%	0%
Craig 2	86%	91%	78%	88%	76%	85%	86%	44%	0%	0%
Craig 3	73%	88%	80%	80%	69%	88%	77%	65%	18%	0%
LRS 2	93%	73%	94%	79%	82%	93%	93%	82%	92%	85%
LRS 3	80%	80%	93%	66%	93%	91%	81%	91%	81%	82%
SPV3	48%	46%	51%	48%	45%	49%	52%	53%	62%	57%
JM Shafer	21%	14%	16%	14%	32%	23%	19%	12%	6%	1%
Rifle	0%	0%	0%	0%	2%	2%	1%	0%	8%	0%
Limon	0%	0%	0%	0%	4%	4%	1%	0%	0%	0%
Knutson	0%	0%	0%	0%	3%	4%	1%	0%	0%	0%
Pyramid	0%	5%	2%	1%	8%	6%	6%	6%	5%	4%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
300MW CC WCO	0%	0%	0%	0%	0%	0%	0%	0%	0%	28%

Table 36: Environmental Impact – System Wide (80pct CR V2)

Year	CO_2 *(tons)*[9]	SO_2 *(tons)*	NO_x *(tons)*	Hg *(tons)*	PM *(tons)*	Water *(gallons)*	RES CO*	RPS NM
2021	13,248,122	6056	10,257	0.2305	429	5,726,854,057	*C*	*C*
2022	12,984,474	6197	10,508	0.2457	425	5,759,294,460	*C*	*C*
2023	13,409,879	6515	10,964	0.2492	460	6,012,037,957	*C*	*C*
2024	12,268,619	5836	9,936	0.2287	392	5,539,999,761	*C*	*C*
2025	12,588,836	6005	10,167	0.2231	452	5,654,821,299	*C*	*C*
2026	12,677,176	6508	10,319	0.2531	463	5,838,902,658	*C*	*C*
2027	12,216,747	6120	9,618	0.2324	425	5,556,389,500	*C*	*C*
2028	11,303,247	5824	8,906	0.2101	402	5,092,449,011	*C*	*C*
2029	9,791,318	4630	6,848	0.1324	329	4,212,956,177	*C*	*C*
2030	8,749,703	4017	5,967	0.0978	313	3,824,718,238	*C*	*C*
2031	8,679,065	3938	5,859	0.0949	314	3,701,224,831	*C*	*C*
2032	8,947,358	4035	6,003	0.0977	312	3,926,922,913	*C*	*C*
2033	7,775,321	2881	4,462	0.0652	186	3,340,671,623	*C*	*C*
2034	7,238,511	2556	3,955	0.0549	157	3,065,107,428	*C*	*C*
2035	7,640,839	2738	4,186	0.0605	164	3,225,897,233	*C*	*C*
2036	7,748,707	2751	4,112	0.0598	160	3,247,031,866	*C*	*C*
2037	7,200,745	2538	3,839	0.0545	148	2,982,362,473	*C*	*C*
2038	5,414,627	1692	3,176	0.0377	122	1,882,342,021	*C*	*C*
2039	5,288,539	1607	3,096	0.0360	118	1,757,938,157	*C*	*C*
2040	5,552,251	1643	3,074	0.0349	115	1,732,012,501	*C*	*C*
Total	190,724,082	84,087	135,252	2.699	5,884	82,079,934,163		

[9] All tons are in short tons. CO2, SO2 and NOx are per net MWh; HG and PM are per gross MWh.

Year	CO_2 *(tons)*[9]	SO_2 *(tons)*	NO_x *(tons)*	Hg *(tons)*	PM *(tons)*	Water *(gallons)*	RES CO*	RPS NM
per MWh**	*971*	*0.43*	*0.69*	*0.00001*	*0.03*	*209*		

*C = compliant; N = noncompliant
**Pounds per MWh of Member Load for emissions; Gallons per MWh of Member Load for water

Table 37: Social Cost of Carbon Nominal Dollars - System Wide (80pct CR V2)

Year	Annual Social Cost of Carbon
2021	$629,418,285
2022	$644,159,756
2023	$694,363,556
2024	$662,750,812
2025	$709,003,249
2026	$744,150,231
2027	$747,054,076
2028	$719,677,747
2029	$635,848,166
2030	$591,392,410
2031	$610,311,817
2032	$654,409,754
2033	$591,157,628
2034	$571,987,104
2035	$627,236,443
2036	$660,577,286
2037	$637,337,962
2038	$497,441,767
2039	$504,103,527
2040	$548,951,023
Total	**$12,681,332,597**

Table 38: GHG/CO_2 Emissions for Serving Wholesale Electricity Sales in Colorado Projected in 2030 from a 2005 Baseline (80pct CR V2)

2030	Fuel Type	Energy (MWh)	Emission Rate (tons/MWh)	Carbon Emissions (Tons)
CO Sales to Members		13,660,989		
CO Sales to Members inc Transmission Losses (5%)		14,344,038		
COMarket Sales (including 5% markup for transmission losses)		606,743		
Standalone battery load (90% efficiency) charging & Mt Elbert net		44,862		
Craig 1 & 2	Coal - Retired		1.17	0
Craig 3	Coal - Retired		1.05	0
LRS Imports	Coal	12,090	1.15	13,934
Nucla	Coal - Retired		1.30	0
Rifle	Gas	488	0.60	293
Knutson 1&2	Gas	0	0.75	0
Limon 1 & 2	Gas	0	0.75	0
Burlington 1 & 2	Oil	0	1.12	0
Shafer	Gas	28,656	0.49	14,041
CRSP East & West (CO)	Federal Hydro	929,860	0.00	0
LAP (CO)	Federal Hydro	900,034	0.00	0
Small Power Producers	Small Hydro	710	0.00	0
Basin AU PPA	egrid RMPA	876,385	0.64	560,886
Expansion Plan Wind PPAs (CO & WY)	Wind	3,436,970	0.00	0
Expansion Plan Gas (CO) combined cycle	Gas	733,674	0.40	293,470
Expansion Plan Gas (CO) Aeroderivative, RICE, CT	Gas	0	0.60	0
Expansion Plan Solar (CO)	Solar	2,275,011	0.00	0
Energy Imbalance (PSCO and prorate of WAPA)	egrid RMPA	133,131	0.64	85,204
CO Market Purchases	egrid RMPA	1,265,067	0.64	809,643
Kit Carson	Wind	165,656	0	0
Carousel	Wind	653,199	0	0
Colorado Highlands	Wind	361,418	0	0
Crossing Trails	Wind	408,330	0	0
Spanish Peaks	Solar	244,985	0	0
San Isabel	Solar	67,207	0	0
Twin Buttes	Solar	307,745	0	0
Niyol	Wind	890,207	0	0
Coyote Gulch	Solar	279,776	0	0
Dolores Canyon	Solar	250,291	0	0
Axial	Solar	315,286	0	0
DSM/EE	Load Reduction		0	0
Basin Electrically East	egrid MROW	103,000	0.62	63,860
Policy 115 - CO only	Mix	356,467	0	0
			Carbon Tons	1,841,331
			GHG tons	1,844,017
Mass Based Carbon Reduction for Electricity Sales	-80%			
Mass Based GHG Reduction For electricity sales	-80%			

Table 39: GHG/CO_2 Emissions for Serving Utility Member System Retail Sales in Colorado in 2030 from a 2005 Baseline (80pct CR V2)

		Option 1	Option 2
	MWh	Carbon Emissions Based on How served	Carbon Emissions based on Percentage of Sales
Retail Load (Member load reduced for distribution & transm	13,251,159	1,188,856	1,627,124
Carbon Rate (Tons/MWh)		0.09	0.12
GHG Emission		1190587.93	1,629,494
Carbon Reduction for retail sales		-81%	-74%
GHG Reduction for retail sales		-81%	-74%
Resources Expected to Exclusively Serve Load			
Rifle	488	293	
CRSP East & West (CO)	929,860	0	
LAP (CO)	900,034	0	
Small Power Producers	710	0	
Basin AU PPA	876,385	560,886	
Expansion Plan Wind PPAs (CO & WY)	3,436,970	0	
Expansion Plan Solar (CO)	2,275,011	0	
Kit Carson	165,656	0	
Carousel	653,199	0	
Colorado Highlands	361,418	0	
Crossing Trails	408,330	0	
Spanish Peaks	244,985	0	
San Isabel	67,207	0	
Twin Buttes	307,745	0	
Niyol	890,207	0	
Coyote Gulch	279,776	0	
Dolores Canyon	250,291	0	
Axial	315,286	0	
Basin Electrically East	103,000	63,860	
Policy 115 - CO only	356,467	0	
Total	12,823,025	625,039	
Net After transmission losses	12,181,874	593,787	
Balance	1,069,285	595,069	

Table 40: Financial (Nominal Dollars) & Reliability Impact

Impact Item	Value
Present Value Member Revenue Requirement (Millions)	$21,283
Expansion Plan Capex + IDC : Generation (Millions)	$1,257
Expansion Plan Capex + IDC : Transmission (Millions)	$2,373
Diversity	3
Dispatchability	2
Reliability	2

Transmission Impact

Beyond normal interconnection transmission expenses, significant additional network upgrades for size in this plan (Costs are in 2020 dollars) were incurred as follows:

- ~$400M in Eastern Colorado in 2029
- ~$150M in Western Colorado in 2030
- ~$300M in Eastern Colorado in 2032
- ~$400M in New Mexico in 2037
- ~$300M in Eastern Colorado in 2039

Detailed transmission expenses related to generic resources are shown in the following table.

Table 41: Transmission Interconnection & Network Upgrade Expenses (2020 Real Dollars) (80pct CR V2)

Year	**Size** *(MW)*	**Type**	**Interconnection Cost** *($M)*	**Network Upgrade at POI Cost** *($M)*	**Network Upgrade for Size** *($M)*
Eastern Colorado (ECO) Transmission Area					
2025	100	Wind	0	5.89	0
2029	100	Wind	0	2.6	419.56
2030	100	Wind	0	2.6	0
2030	100	Wind	0	2.6	0
2032	100	Wind	0	12.98	334.39
2033	100	Wind	0	2.6	0
2034	100	Wind	0	5.2	0
2035	100	Wind	0	2.6	0
2036	100	Wind	0	1.85	0
2037	100	Wind	0	5.2	0
2037	100	Battery	2.19	2.6	0
2039	100	Battery	2.19	5.2	0
2039	100	Solar	0	1.85	0
2039	100	Solar	0	2.6	0
2039	100	Solar	0	5.2	283.39
2039	100	Solar	0	1.85	0

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2040	100	Battery	2.19	2.6	0
Western Colorado (WCO) Transmission Area					
2026	100	Solar	0	3.7	0
2026	100	Solar	0	1.85	0
2027	100	Solar	0	3.7	0
2028	100	Solar	0	1.85	0
2028	100	Solar	0	2.6	0
2029	100	Solar	0	2.6	0
2029	100	Solar	0	2.6	0
2027	100	Battery	1.63	0.5	0
2029	100	Battery	1.63	0.5	0
2030	100	Solar	0	11.43	0
2030	100	Solar	0	2.6	0
2030	300	CC	2.19	0.5	167.67
2035	100	Solar	0	2.6	0
2037	100	Battery	2.19	2.6	0
2038	100	Solar	0	1.03	0
2038	100	Solar	0	1.03	0
2038	100	Solar	0	12.98	0
2040	25	Battery	2.19	2.6	0
Wyoming (WYO) Transmission Area					
2025	100	Wind	0	11.43	0
2026	100	Wind	0	2.6	0
2028	100	Wind	0	2.6	22.04
2029	100	Wind	0	2.6	0
2030	100	Wind	0	11.43	0
2030	25	Battery	2.19	2.6	0
2033	100	Wind	0	2.6	0
2034	100	Wind	0	2.6	0
2037	25	Battery	2.19	0.5	0
New Mexico (NM) Transmission Area)					
2036	100	Battery	2.19	2.6	0
2037	100	Wind	0	1.85	385.34
2037	100	Wind	0	1.85	0
2038	100	Wind	0	1.85	0

80pct CR Version 3

Assumptions Unique to this Scenario:

Modeling assumptions are per Volume II Section 5 Phase I Plan Modeling Details under the subsection of Modeling Assumptions of this report with the following exceptions:

Table 42: Unique Assumptions (80pct CR V3)

Assumption Item	Description
Additional Retirements	Allowed – coal retirements after 2025; SPV3 not allowed to retire until after end of SRP contract (first year 2037)
Thermal Resource Status: **Econ** - Model can choose to turn resource on and off but resource has a 168 hour on line min. **Must Run** - Model can choose what level to run the resource at but resource cannot go lower than min.	**Must Run 2021 - 2024 :** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV **Econ 2025 - 2040:** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV **Econ 2021 - 2040:** Burlington 1, Burlington 2, Knutson 1&2, Limon 1&2, Pyramid 1-4, Rifle, and Shafer
Build Limits	• Max Study – ECO 2000 • Max Study – NM 400 • Max Study – Storage 1200 • Max Study – Thermal 300 • Max Study – WY 650 • Max Annual – Renewable 1000
DSM & EE Level	Existing DSM EE only
CO_2 Reduction	80% CO_2 reduction in 2030 from 2005 baseline in relation to electricity sales in Colorado; Glide path from 2025 to 2030
Mt. Elbert	Off
Transmission Links	See Table 43 for detail
Market Depth	See Tables 44 & 45 for detail

Table 43: Applied Transmission Link Capacities (80pct CR Version 3)

Link Name	From Transmission Area	To Transmission Area	Forward Capacity *(MW)*	Backward Capacity *(MW)*	Dates
LK-E_CO>NM	WACM_Eastern_Colorado	New Mexico	124	0	2021 - 2040
LK-LAP>E_CO	Mt_ Elbert	WACM_Eastern_Colorado	107	139	2021 - 2040
LK-SPRV>NM	Springerville	New Mexico	317	0	2021 - 2035
LK-SPRV>NM	Springerville	New Mexico	359	0	2036
LK-SPRV>NM	Springerville	New Mexico	417	0	2037 - 2040
LK-W_CO>E_CO	West_Colorado	WACM_Eastern_Colorado	457	150	2021 - 2040
LK-W_CO>NM	West_Colorado	New Mexico	0	170	2021 - 2024
LK-W_CO>NM	West_Colorado	New Mexico	50	170	2025 - 2026
LK-W_CO>NM	West_Colorado	New Mexico	50	100	2027
LK-W_CO>NM	West_Colorado	New Mexico	50	50	2028 - 2040
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	400	400	2021
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	550	400	2022 - 2025
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	450	400	2026
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	350	400	2027
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	250	400	2028
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	150	400	2029
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	50	400	2030 - 2040
LK-WYGreen--	Wyoming Green	WACM_Eastern_Colorado	0	0	2021 - 2024
LK-WYGreen--	Wyoming Green	WACM_Eastern_Colorado	600	0	2025 - 2040

Table 44: Market Sales Hourly Capacity (80pct CR Version 3)

Dates	MS-4 Corner-N_NM *(MW)*	MS-WEIM *(MW)*
Jan 2021 - Mar 2021	20-OFF / 75-ON	0
Apr 2021 - 2024	0-OFF / 20-ON	25-OFF / 60-ON
2025-2040	150	0

Dates	MS-Ault-E_CO *(MW)*	MS-Craig-NW_CO *(MW)*	MS-LRS-WY *(MW)*	MS-WEIS *(MW)*
Jan 2021	0-OFF / 50-ON	15-OFF / 100-ON	0	0
Feb 2021 - 2024	0-OFF / 25-ON	0-OFF / 25-ON	0	25-OFF / 125-ON
2025-2029	150	50	200	0
2030-2040	50	50	200	0

Table 45: Market Purchases Hourly Capacity (80pct CR Version 3)

Dates	MP-4 Corner-N_NM *(MW)*	MP-WEIM *(MW)*
Jan 2021 - Mar 2021	100	0
Apr 2021 - 2024	85	15
2025-2034	200	0
2035-2040	400	0

Dates	MP-Ault-E_CO *(MW)*	MP-Craig-NW_CO *(MW)*	MP-LRS-WY *(MW)*	MP-WEIS *(MW)*
Jan 2021	200	125	75	0
Feb 2021 - 2024	150	100	75	75
2025-2034	200	200	200	0
2035-2040	400	400	400	0

Results:

Table 46: Expansion Plan (80pct CR V3)

Location	MW	Technology	Year
East Colorado	100	Wind	2025
Wyoming	100	Wind	2025
West Colorado	200	Solar	2026
Wyoming	100	Wind	2026
West Colorado	100	Solar	2027
West Colorado	200	Solar	2028
Wyoming	100	Wind	2028
West Colorado	200	Standalone Battery	2029
West Colorado	200	Solar	2029
East Colorado	100	Wind	2029
Wyoming	100	Wind	2029
Wyoming	25	Standalone Battery	2030
West Colorado	300	Natural Gas - Combined Cycle	2030
West Colorado	200	Solar	2030
East Colorado	300	Wind	2030
Wyoming	100	Wind	2030
East Colorado	100	Wind	2033
Wyoming	100	Wind	2033
East Colorado	100	Wind	2034
Wyoming	100	Wind	2034
West Colorado	100	Solar	2035
East Colorado	100	Wind	2035

Location	MW	Technology	Year
New Mexico	100	Standalone Battery	2036
East Colorado	100	Wind	2036
East Colorado	100	Standalone Battery	2037
West Colorado	100	Standalone Battery	2037
Wyoming	25	Standalone Battery	2037
East Colorado	100	Wind	2037
New Mexico	200	Wind	2037
West Colorado	300	Solar	2038
New Mexico	100	Wind	2038
East Colorado	100	Standalone Battery	2039
East Colorado	400	Solar	2039
East Colorado	100	Standalone Battery	2040
West Colorado	25	Standalone Battery	2040

Table 47: Proposed Retirements (80pct CR V3)

Location	MW	Technology	Year
LRS 3	231	Coal	2033
SPV3	417	Coal	2038

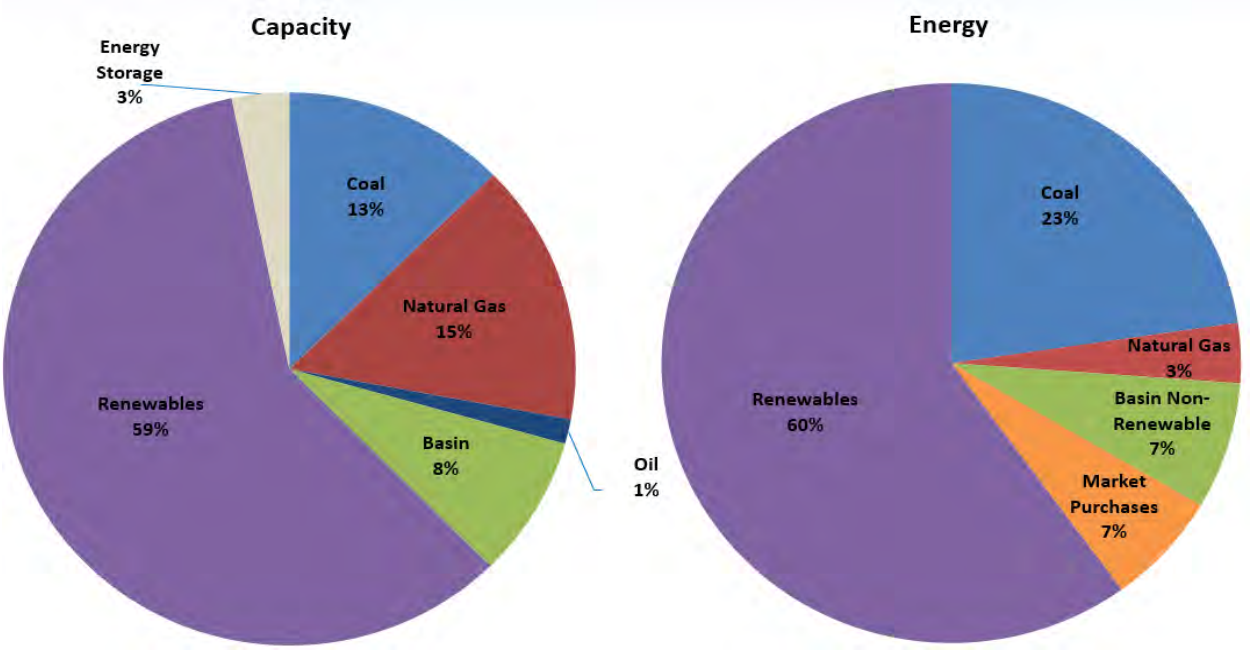

Figure 12: Projected System Capacity and Energy Mix (80pct CR V3)

Table 48: Projected Annual Capacity Factors (80pct CR V3)

Resource	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	75%	75%	76%	77%	62%	0%	0%	0%	0%	0%
Craig 2	86%	91%	79%	88%	77%	85%	86%	44%	0%	0%
Craig 3	73%	88%	81%	81%	70%	88%	77%	65%	18%	0%
LRS 2	93%	74%	94%	80%	82%	93%	93%	82%	92%	83%
LRS 3	80%	82%	92%	67%	93%	91%	81%	91%	81%	80%
SPV3	48%	46%	51%	48%	43%	49%	52%	53%	62%	57%
JM Shafer	21%	14%	16%	14%	32%	23%	19%	12%	6%	1%
Rifle	0%	0%	0%	0%	2%	2%	1%	0%	8%	0%
Limon	0%	0%	0%	0%	4%	4%	1%	0%	0%	0%
Knutson	0%	0%	0%	0%	4%	4%	1%	0%	0%	0%
Pyramid	0%	5%	2%	1%	8%	6%	6%	6%	5%	4%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
300MW CC WCO	0%	0%	0%	0%	0%	0%	0%	0%	0%	28%

Table 49: Environmental Impact - System Wide (80pct CR V3)

Year	CO_2 *(tons)*[10]	SO_2 *(tons)*	NO_x *(tons)*	Hg *(tons)*	PM *(tons)*	Water *(gallons)*	RES CO*	RPS NM
2021	13,248,122	6056	10,257	0.2305	429	5,726,854,057	*C*	*C*
2022	12,979,028	6247	10,486	0.2474	428	5,762,669,045	*C*	*C*
2023	13,393,204	6533	10,930	0.2505	460	6,005,107,457	*C*	*C*
2024	12,265,698	5868	9,924	0.2302	395	5,543,522,205	*C*	*C*
2025	12,508,020	5969	10,083	0.2224	450	5,593,737,378	*C*	*C*
2026	12,677,176	6508	10,319	0.2531	463	5,838,902,658	*C*	*C*
2027	12,216,747	6120	9,618	0.2324	425	5,556,389,500	*C*	*C*
2028	11,303,247	5824	8,906	0.2101	402	5,092,449,011	*C*	*C*
2029	9,791,318	4630	6,848	0.1324	329	4,212,956,177	*C*	*C*
2030	8,523,385	3947	5,853	0.0955	306	3,769,596,165	*C*	*C*
2031	8,542,638	3921	5,833	0.0941	312	3,735,005,592	*C*	*C*
2032	8,887,830	4035	6,003	0.0977	312	3,926,922,913	*C*	*C*
2033	7,714,484	2881	4,462	0.0652	186	3,340,671,623	*C*	*C*
2034	7,177,841	2556	3,955	0.0549	157	3,065,107,428	*C*	*C*
2035	7,592,733	2738	4,186	0.0605	164	3,225,897,233	*C*	*C*
2036	7,701,227	2751	4,112	0.0598	160	3,247,031,866	*C*	*C*
2037	7,151,550	2538	3,839	0.0545	148	2,982,362,473	*C*	*C*
2038	5,364,139	1692	3,176	0.0377	122	1,882,342,021	*C*	*C*
2039	5,239,415	1607	3,096	0.0360	118	1,757,938,157	*C*	*C*
2040	5,502,009	1643	3,074	0.0349	115	1,732,012,501	*C*	*C*

[10] All tons are in short tons. CO2, SO2 and NOx are per net MWh; HG and PM are per gross MWh.

Year	CO_2 *(tons)*[10]	SO_2 *(tons)*	NO_x *(tons)*	Hg *(tons)*	PM *(tons)*	Water *(gallons)*	RES CO*	RPS NM
Total	189,779,811	84,063	134,957	2.700	5,879	81,997,475,457		
per MWh **	966	0.43	0.69	0.00001	0.03	209		

*C = compliant; N = noncompliant

**Pounds per MWh of Member Load for emissions; Gallons per MWh of Member Load for water

Table 50: Social Cost of Carbon Nominal Dollars - Sytem Wide (80pct CR V3)

Year	Annual Social Cost of Carbon
2021	$629,418,285
2022	$643,889,557
2023	$693,500,123
2024	$662,592,985
2025	$704,451,699
2026	$744,150,231
2027	$747,054,076
2028	$719,677,747
2029	$635,848,166
2030	$576,095,568
2031	$600,718,318
2032	$650,055,906
2033	$586,532,220
2034	$567,192,958
2035	$623,287,453
2036	$656,529,612
2037	$632,983,704
2038	$492,803,489
2039	$499,421,024
2040	$543,983,650
Total	**$12,610,186,773**

Table 51: GHG/CO_2 Emissions for Serving Electricity Sales in Colorado Projected in 2030 from a 2005 Baseline (80pct CR V3)

2030	Fuel Type	Energy (MWh)	Emission Rate (tons/MWh)	Carbon Emissions (tons)
CO Sales to Members		13,660,989		
CO Sales to Members inc Transmission Losses (5%)		14,344,038		
COMarket Sales (including 5% markup for transmission losses)		671,284		
Standalone battery load (90% efficiency) charging & Mt Elbert net		38,516		
Craig 1 & 2	Coal - Retired		1.17	0
Craig 3	Coal - Retired		1.05	0
LRS Imports	Coal	0	1.15	0
Nucla	Coal - Retired		1.30	0
Rifle	Gas	1,041	0.60	624
Knutson 1&2	Gas	0	0.75	0
Limon 1 & 2	Gas	0	0.75	0
Burlington 1 & 2	Oil	0	1.12	0
Shafer	Gas	28,608	0.49	14,018
CRSP East & West (CO)	Federal Hydro	929,860	0.00	0
LAP (CO)	Federal Hydro	717,302	0.00	0
Small Power Producers	Small Hydro	710	0.00	0
Basin AU PPA	egrid RMPA	876,385	0.64	560,886
Expansion Plan Wind PPAs (CO & WY)	Wind	3,786,193	0.00	0
Expansion Plan Gas (CO) combined cycle	Gas	730,369	0.40	292,147
Expansion Plan Gas (CO) Aeroderivative, RICE, CT	Gas	0	0.60	0
Expansion Plan Solar (CO)	Solar	2,275,011	0.00	0
Energy Imbalance (PSCO and prorate of WAPA)	egrid RMPA	133,131	0.64	85,204
CO Market Purchases	egrid RMPA	1,171,662	0.64	749,864
Kit Carson	Wind	165,656	0	0
Carousel	Wind	653,199	0	0
Colorado Highlands	Wind	361,418	0	0
Crossing Trails	Wind	408,330	0	0
Spanish Peaks	Solar	244,985	0	0
San Isabel	Solar	67,207	0	0
Twin Buttes	Solar	307,745	0	0
Niyol	Wind	890,207	0	0
Coyote Gulch	Solar	279,776	0	0
Dolores Canyon	Solar	250,291	0	0
Axial	Solar	315,286	0	0
DSM/EE	Load Reduction		0	0
Basin Electrically East	egrid MROW	103,000	0.62	63,860
Policy 115 - CO only	Mix	356,467	0	0
			Carbon Tons	1,766,603
			GHG tons	1,769,132
Mass Based Carbon Reduction for Electricity Sales	-81%			
Mass Based GHG Reduction For electricity sales	-81%			

Table 52: GHG/CO_2 Emissions for Serving Utility Member System Retail Sales in Colorado in 2030 from a 2005 Baseline

		Option 1	Option 2
	MWh	Carbon Emissions Based on How served	Carbon Emissions based on Percentage of Sales
Retail Load (Member load reduced for distribution & transm	13,251,159	1,097,647	1,555,055
Carbon Rate (Tons/MWh)		0.08	0.12
GHG Emission		1099215.75	1,557,278
Carbon Reduction for retail sales		-82%	-75%
GHG Reduction for retail sales		-82%	-75%
Resources Expected to Exclusively Serve Load			
Rifle	1,041	624	
CRSP East & West (CO)	929,860	0	
LAP (CO)	717,302	0	
Small Power Producers	710	0	
Basin AU PPA	876,385	560,886	
Expansion Plan Wind PPAs (CO & WY)	3,786,193	0	
Expansion Plan Solar (CO)	2,275,011	0	
Kit Carson	165,656	0	
Carousel	653,199	0	
Colorado Highlands	361,418	0	
Crossing Trails	408,330	0	
Spanish Peaks	244,985	0	
San Isabel	67,207	0	
Twin Buttes	307,745	0	
Niyol	890,207	0	
Coyote Gulch	279,776	0	
Dolores Canyon	250,291	0	
Axial	315,286	0	
Basin Electrically East	103,000	63,860	
Policy 115 - CO only	356,467	0	
Total	12,990,069	625,371	
Net After transmission losses	12,340,566	594,102	
Balance	910,594	503,544	

Table 53: Financial (Nominal Dollars) & Reliability Impact

Impact Item	Value
Present Value Member Revenue Requirement (Millions)	$21,359
Expansion Plan Capex + IDC : Generation (Millions)	$1,257
Expansion Plan Capex + IDC : Transmission (Millions)	$2,356
Diversity	3
Dispatchability	2
Reliability	2

Transmission Impact

Beyond normal interconnection transmission expenses, significant additional network upgrades for size in this plan (Costs are in 2020 dollars) were incurred as follows:

- ~$400M in Eastern Colorado in 2029
- ~$150M in Western Colorado in 2030
- ~$300M in Eastern Colorado in 2030
- ~$400M in New Mexico in 2037
- ~$300M in Eastern Colorado in 2039

Detailed transmission expenses related to generic resources are shown in the following table.

Table 54: Transmission Interconnection & Network Upgrade Expenses (2020 Real Dollars) (80pct CR V3)

Year	**Size** *(MW)*	**Type**	**Interconnection Cost** *($M)*	**Network Upgrade at POI Cost** *($M)*	**Network Upgrade for Size** *($M)*
Eastern Colorado (ECO) Transmission Area					
2025	100	Wind	0	5.89	0
2029	100	Wind	0	2.6	419.56
2030	100	Wind	0	2.6	0
2030	100	Wind	0	2.6	0
2030	100	Wind	0	12.98	334.39
2033	100	Wind	0	2.6	0
2034	100	Wind	0	5.2	0
2035	100	Wind	0	2.6	0
2036	100	Wind	0	1.85	0
2037	100	Wind	0	5.2	0
2037	100	Battery	2.19	2.6	0
2039	100	Battery	2.19	5.2	0
2039	100	Solar	0	1.85	0
2039	100	Solar	0	2.6	0
2039	100	Solar	0	5.2	283.39
2039	100	Solar	0	1.85	0
2040	100	Battery	2.19	2.6	0

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Western Colorado (WCO) Transmission Area					
2026	100	Solar	0	3.7	0
2026	100	Solar	0	1.85	0
2027	100	Solar	0	3.7	0
2028	100	Solar	0	1.85	0
2028	100	Solar	0	2.6	0
2029	100	Solar	0	2.6	0
2029	100	Solar	0	2.6	0
2027	100	Battery	1.63	0.5	0
2029	100	Battery	1.63	0.5	0
2030	100	Solar	0	11.43	0
2030	100	Solar	0	2.6	0
2030	300	CC	2.19	0.5	167.67
2035	100	Solar	0	2.6	0
2037	100	Battery	2.19	2.6	0
2038	100	Solar	0	1.03	0
2038	100	Solar	0	1.03	0
2038	100	Solar	0	12.98	0
2040	25	Battery	2.19	2.6	0
Wyoming (WYO) Transmission Area					
2025	100	Wind	0	11.43	0
2026	100	Wind	0	2.6	0
2028	100	Wind	0	2.6	22.04
2029	100	Wind	0	2.6	0
2030	100	Wind	0	11.43	0
2030	25	Battery	2.19	2.6	0
2033	100	Wind	0	2.6	0
2034	100	Wind	0	2.6	0
2037	25	Battery	2.19	0.5	0
New Mexico (NM) Transmission Area)					
2036	100	Battery	2.19	2.6	0
2037	100	Wind	0	1.85	385.34
2037	100	Wind	0	1.85	0
2038	100	Wind	0	1.85	0

80pct CR Version 4

Assumptions Unique to this Scenario:

Modeling assumptions are per Volume II Section 5 Phase I Plan Modeling Details under the subsection of Modeling Assumptions of this report with the following exceptions:

Table 55: Unique Assumptions (80pct CR V4)

Assumption Item	Description
Additional Retirements	Allowed – coal retirements after 2025; SPV3 not allowed to retire until after end of SRP contract (first year 2037)
Thermal Resource Status: **Econ** - Model can choose to turn resource on and off but resource has a 168 hour on line min. **Must Run** - Model can choose what level to run the resource at but resource cannot go lower than min.	**Must Run 2021 - 2024 :** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV **Econ 2025 - 2040:** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV **Econ 2021 - 2040:** Burlington 1, Burlington 2, Knutson 1&2, Limon 1&2, Pyramid 1-4, Rifle, and Shafer
Build Limits	• Max Study – ECO 2000 • Max Study – NM 400 • Max Study – Storage 1200 • Max Study – Thermal 300 • Max Study – WY 650 • Max Annual – Renewable 1000
DSM & EE Level	Existing DSM EE only
CO_2 Reduction	80% CO_2 reduction in 2030 from 2005 baseline in relation to electricity sales in Colorado; Glide path from 2025 to 2030
Mt. Elbert	Off
Transmission Links	See Table 56 for details
Market Depths	See Tables 57 & 58 for details

Table 56: Applied Transmission Link Capacities (80pct CR V4)

Link Name	From Transmission Area	To Transmission Area	Forward Capacity *(MW)*	Backward Capacity *(MW)*	Dates
LK-E_CO>NM	WACM_Eastern_Colorado	New Mexico	124	0	2021 - 2040
LK-LAP>E_CO	Mt_ Elbert	WACM_Eastern_Colorado	107	139	2021 - 2040
LK-SPRV>NM	Springerville	New Mexico	317	0	2021 - 2035
LK-SPRV>NM	Springerville	New Mexico	359	0	2036
LK-SPRV>NM	Springerville	New Mexico	417	0	2037 - 2040
LK-W_CO>E_CO	West_Colorado	WACM_Eastern_Colorado	457	150	2021 - 2040
LK-W_CO>NM	West_Colorado	New Mexico	0	170	2021 - 2024
LK-W_CO>NM	West_Colorado	New Mexico	50	170	2025 - 2026
LK-W_CO>NM	West_Colorado	New Mexico	50	100	2027
LK-W_CO>NM	West_Colorado	New Mexico	50	50	2028 - 2040
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	400	400	2021
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	550	400	2022 - 2025
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	450	400	2026
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	350	400	2027
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	250	400	2028
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	150	400	2029
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	50	400	2030 - 2040
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	0	0	2021 - 2024
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	600	0	2025 - 2040

Table 57: Market Sales Hourly Capacity (80pct CR V4)

Dates	MS-4 Corner-N_NM *(MW)*	MS-WEIM *(MW)*
Jan 2021 - Mar 2021	20-OFF / 75-ON	0
Apr 2021 - 2024	0-OFF / 20-ON	25-OFF / 60-ON
2025-2040	150	0

Dates	MS-Ault-E_CO *(MW)*	MS-Craig-NW_CO *(MW)*	MS-LRS-WY *(MW)*	MS-WEIS *(MW)*
Jan 2021	0-OFF / 50-ON	15-OFF / 100-ON	0	0
Feb 2021 - 2024	0-OFF / 25-ON	0-OFF / 25-ON	0	25-OFF / 125-ON
2025-2029	150	50	200	0
2030-2040	50	50	200	0

Table 58: Market Purchases Hourly Capacity (80pct CR V4)

Dates	MP-4 Corner-N_NM *(MW)*	MP-WEIM *(MW)*
Jan 2021 - Mar 2021	100	0
Apr 2021 - 2024	85	15
2025-2034	200	0
2035-2040	400	0

Dates	MP-Ault-E_CO *(MW)*	MP-Craig-NW_CO *(MW)*	MP-LRS-WY *(MW)*	MP-WEIS *(MW)*
Jan 2021	200	125	75	0
Feb 2021 - 2024	150	100	75	75
2025-2034	200	200	200	0
2035-2040	400	400	400	0

Results:

Table 59: Expansion Plan (80pct CR V4)

Location	MW	Technology	Year
East Colorado	100	Wind	2025
Wyoming	100	Wind	2025
West Colorado	200	Solar	2026
Wyoming	100	Wind	2026
West Colorado	100	Solar	2027
West Colorado	200	Solar	2028
Wyoming	100	Wind	2028
West Colorado	200	Standalone Battery	2029
West Colorado	200	Solar	2029
East Colorado	100	Wind	2029
Wyoming	100	Wind	2029
Wyoming	25	Standalone Battery	2030
West Colorado	300	Natural Gas - Combined Cycle	2030
West Colorado	250	Solar	2030
East Colorado	200	Wind	2030
Wyoming	100	Wind	2030
East Colorado	100	Wind	2033
Wyoming	100	Wind	2033
East Colorado	100	Wind	2034
Wyoming	100	Wind	2034
West Colorado	100	Solar	2035
East Colorado	100	Wind	2035
New Mexico	100	Standalone Battery	2036
East Colorado	100	Wind	2036
East Colorado	100	Standalone Battery	2037

Location	MW	Technology	Year
West Colorado	100	Standalone Battery	2037
Wyoming	25	Standalone Battery	2037
East Colorado	100	Wind	2037
New Mexico	200	Wind	2037
West Colorado	300	Solar	2038
New Mexico	100	Wind	2038
East Colorado	100	Standalone Battery	2039
East Colorado	400	Solar	2039
East Colorado	100	Standalone Battery	2040
West Colorado	25	Standalone Battery	2040

Table 60: Proposed Retirements (80pct CR V4)

Location	MW	Technology	Year
LRS 3	231	Coal	2033
SPV3	417	Coal	2038

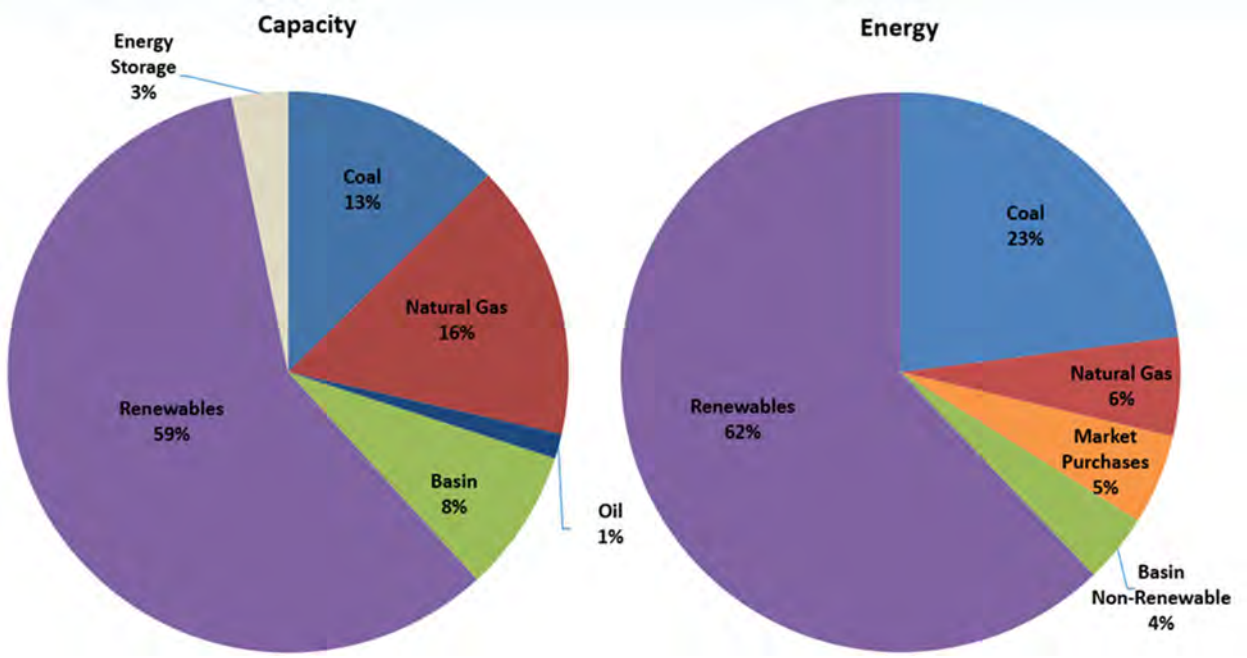

Figure 13: Projected System Capacity and Energy Mix (80pct CR V4)

Table 61: Projected Annual Capacity Factors (80pct CR V4)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	75%	75%	76%	77%	62%	0%	0%	0%	0%	0%
Craig 2	86%	91%	79%	88%	77%	85%	86%	44%	0%	0%
Craig 3	73%	88%	81%	81%	70%	88%	77%	65%	18%	0%
LRS 2	93%	74%	94%	80%	82%	93%	93%	82%	92%	85%
LRS 3	80%	82%	92%	67%	93%	91%	81%	91%	81%	82%
SPV3	48%	46%	51%	48%	43%	49%	52%	53%	62%	57%
JM Shafer	21%	14%	16%	14%	32%	23%	19%	12%	6%	6%
Rifle	0%	0%	0%	0%	2%	2%	1%	0%	8%	0%
Limon	0%	0%	0%	0%	4%	4%	1%	0%	0%	0%
Knutson	0%	0%	0%	0%	4%	4%	1%	0%	0%	0%
Pyramid	0%	5%	2%	1%	8%	6%	6%	6%	5%	3%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
300MW CC WCO	0%	0%	0%	0%	0%	0%	0%	0%	0%	44%

Table 62: Environmental Impact –System Wide (80pct CR V4)

Year	CO_2 *(tons[11])*	SO_2 *(tons)*	NO_x *(tons)*	Hg *(tons)*	PM *(tons)*	Water *(gallons)*	RES CO*	RPS NM
2021	13,248,122	6056	10,257	0.2305	429	5,726,854,057	*C*	*C*
2022	12,979,028	6247	10,486	0.2474	428	5,762,669,045	*C*	*C*
2023	13,393,204	6533	10,930	0.2505	460	6,005,107,457	*C*	*C*
2024	12,265,698	5868	9,924	0.2302	395	5,543,522,205	*C*	*C*
2025	12,508,020	5969	10,083	0.2224	450	5,593,737,378	*C*	*C*
2026	12,677,176	6508	10,319	0.2531	463	5,838,902,658	*C*	*C*
2027	12,216,747	6120	9,618	0.2324	425	5,556,389,500	*C*	*C*
2028	11,303,247	5824	8,906	0.2101	402	5,092,449,011	*C*	*C*
2029	9,791,318	4630	6,848	0.1324	329	4,212,956,177	*C*	*C*
2030	8,721,869	4008	6,146	0.0974	334	4,000,402,823	*C*	*C*
2031	8,635,907	3920	5,834	0.0944	313	3,684,306,893	*C*	*C*
2032	8,901,974	4016	5,979	0.0972	310	3,912,469,252	*C*	*C*
2033	7,726,018	2864	4,432	0.0648	184	3,313,847,970	*C*	*C*
2034	7,190,904	2540	3,940	0.0546	157	3,049,319,450	*C*	*C*
2035	7,621,654	2735	4,186	0.0604	164	3,223,841,371	*C*	*C*
2036	7,683,293	2726	4,108	0.0595	160	3,210,817,842	*C*	*C*
2037	7,025,629	2460	3,760	0.0528	145	2,881,023,549	*C*	*C*
2038	5,409,698	1693	3,183	0.0377	122	1,882,871,435	*C*	*C*
2039	5,261,336	1606	3,093	0.0360	118	1,759,877,993	*C*	*C*
2040	5,514,701	1641	3,068	0.0349	114	1,729,523,811	*C*	*C*
Total	190,075,543	83,964	135,098	2.699	5,901	81,980,889,875		

[11] All tons are in short tons. CO2, SO2 and NOx are per net MWh; HG and PM are per gross MWh.

Year	CO_2 *(tons[11])*	SO_2 *(tons)*	NO_x *(tons)*	Hg *(tons)*	PM *(tons)*	Water *(gallons)*	RES CO*	RPS NM
per MWh**	968	0.43	0.69	0.00001	0.03	209		

*C = compliant; N = noncompliant

**Pounds per MWh of Member Load for emissions; Gallons per MWh of Member Load for water

Table 63: Social Cost of Carbon Nominal Dollars – System Wide (80pct CR V4)

Year	Annual Social Cost of Carbon
2021	$629,418,285
2022	$643,889,557
2023	$693,500,123
2024	$662,592,985
2025	$704,451,699
2026	$744,150,231
2027	$747,054,076
2028	$719,677,747
2029	$635,848,166
2030	$589,511,102
2031	$607,276,988
2032	$651,090,393
2033	$587,409,167
2034	$568,225,210
2035	$625,661,540
2036	$655,000,760
2037	$621,838,465
2038	$496,988,999
2039	$501,510,544
2040	$545,238,447
Total	**$12,630,334,485**

Table 64: GHG/CO_2 Emissions for Serving Wholesale Electricity Sales in Colorado Projected in 2030 from a 2005 Baseline (80pct CR V4)

Carbon Emissions : Serving Wholesale sales in Colorado				
2030	**Fuel Type**	**Energy (MWh)**	**Emission Rate (tons/MWh)**	**Carbon Emissions (tons)**
CO Sales to Members		13,660,989		
CO Sales to Members inc Transmission Losses (5%)		14,344,038		
COMarket Sales (including 5% markup for transmission losses)		732,851		
Standalone battery load (90% efficiency) charging & Mt Elbert net		42,439		
Craig 1 & 2	Coal - Retired		1.17	0
Craig 3	Coal - Retired		1.05	0
LRS Imports	Coal	51,959	1.15	59,883
Nucla	Coal - Retired		1.30	0
Rifle	Gas	2,378	0.60	1,427
Knutson 1&2	Gas	0	0.75	0
Limon 1 & 2	Gas	0	0.75	0
Burlington 1 & 2	Oil	0	1.12	0
Shafer	Gas	140,637	0.49	68,912
CRSP East & West (CO)	Federal Hydro	929,860	0.00	0
LAP (CO)	Federal Hydro	717,302	0.00	0
Small Power Producers	Small Hydro	710	0.00	0
Basin AU PPA	egrid RMPA	876,385	0.64	560,886
Expansion Plan Wind PPAs (CO & WY)	Wind	3,436,970	0.00	0
Expansion Plan Gas (CO) combined cycle	Gas	1,163,236	0.40	465,294
Expansion Plan Gas (CO) Aeroderivative, RICE, CT	Gas	0	0.60	0
Expansion Plan Solar (CO)	Solar	2,401,401	0.00	0
Energy Imbalance (PSCO and prorate of WAPA)	egrid RMPA	133,131	0.64	85,204
CO Market Purchases	egrid RMPA	861,791	0.64	551,547
Kit Carson	Wind	165,656	0	0
Carousel	Wind	653,199	0	0
Colorado Highlands	Wind	361,418	0	0
Crossing Trails	Wind	408,330	0	0
Spanish Peaks	Solar	244,985	0	0
San Isabel	Solar	67,207	0	0
Twin Buttes	Solar	307,745	0	0
Niyol	Wind	890,207	0	0
Coyote Gulch	Solar	279,776	0	0
Dolores Canyon	Solar	250,291	0	0
Axial	Solar	315,286	0	0
DSM/EE	Load Reduction		0	0
Basin Electrically East	egrid MROW	103,000	0.62	63,860
Policy 115 - CO only	Mix	356,467	0	0
			Carbon Tons	1,857,014
			GHG tons	1,859,786
Mass Based Carbon Reduction for Electricity Sales	-80%			
Mass Based GHG Reduction For electricity sales	-80%			

Table 65: GHG/CO_2 Emissions for Serving Utility Member System Retail Sales in Colorado in 2030 from a 2005 Baseline (80pct CR V4)

		Option 1	Option 2
	MWh	Carbon Emissions Based on How served	Carbon Emissions based on Percentage of Sales
Retail Load (Member load reduced for distribution & transm	13,251,159	1,165,886	1,627,558
Carbon Rate (Tons/MWh)		0.09	0.12
GHG Emission		1167623.65	1,629,984
Carbon Reduction for retail sales		-81%	-74%
GHG Reduction for retail sales		-81%	-74%
Resources Expected to Exclusively Serve Load			
Rifle	2,378	1,427	
CRSP East & West (CO)	929,860	0	
LAP (CO)	717,302	0	
Small Power Producers	710	0	
Basin AU PPA	876,385	560,886	
Expansion Plan Wind PPAs (CO & WY)	3,436,970	0	
Expansion Plan Solar (CO)	2,401,401	0	
Kit Carson	165,656	0	
Carousel	653,199	0	
Colorado Highlands	361,418	0	
Crossing Trails	408,330	0	
Spanish Peaks	244,985	0	
San Isabel	67,207	0	
Twin Buttes	307,745	0	
Niyol	890,207	0	
Coyote Gulch	279,776	0	
Dolores Canyon	250,291	0	
Axial	315,286	0	
Basin Electrically East	103,000	63,860	
Policy 115 - CO only	356,467	0	
Total	12,768,573	626,173	
Net After transmission losses	12,130,144	594,865	
Balance	1,121,015	571,021	

Table 66: Financial (Nominal Dollars) & Reliability Impact

Impact Item	Value
Present Value Member Revenue Requirement (Millions)	$21,292
Expansion Plan Capex + IDC : Generation (Millions)	$1,257
Expansion Plan Capex + IDC : Transmission (Millions)	$2,380
Diversity	3
Dispatchability	2
Reliability	2

Transmission Impact

Beyond normal interconnection transmission expenses, significant additional network upgrades for size in this plan (Costs are in 2020 dollars) were incurred as follows:

- ~$400M in Eastern Colorado in 2029
- ~$150M in Western Colorado in 2030
- ~$300M in Eastern Colorado in 2032
- ~$400M in New Mexico in 2037
- ~$300M in Eastern Colorado in 2039

Detailed transmission expenses related to generic resources are shown in the following table.

Table 67: Transmission Interconnection & Network Upgrade Expenses (2020 Real Dollars) (80pct CR V4)

Year	**Size** *(MW)*	**Type**	**Interconnection Cost** *($M)*	**Network Upgrade at POI Cost** *($M)*	**Network Upgrade for Size** *($M)*
Eastern Colorado (ECO) Transmission Area					
2025	100	Wind	0	5.89	0
2029	100	Wind	0	2.6	419.56
2030	100	Wind	0	2.6	0
2030	100	Wind	0	2.6	0
2032	100	Wind	0	12.98	334.39
2033	100	Wind	0	2.6	0
2034	100	Wind	0	5.2	0
2035	100	Wind	0	2.6	0
2036	100	Wind	0	1.85	0
2037	100	Wind	0	5.2	0
2037	100	Battery	2.19	2.6	0
2039	100	Battery	2.19	5.2	0
2039	100	Solar	0	1.85	0
2039	100	Solar	0	2.6	0
2039	100	Solar	0	5.2	283.39
2039	100	Solar	0	1.85	0
2040	100	Battery	2.19	2.6	0

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Western Colorado (WCO) Transmission Area					
2026	100	Solar	0	3.7	0
2026	100	Solar	0	1.85	0
2027	100	Solar	0	3.7	0
2028	100	Solar	0	1.85	0
2028	100	Solar	0	2.6	0
2029	100	Solar	0	2.6	0
2029	100	Solar	0	2.6	0
2027	100	Battery	1.63	0.5	0
2029	100	Battery	1.63	0.5	0
2030	100	Solar	0	11.43	0
2030	100	Solar	0	2.6	0
2030	300	CC	2.19	0.5	167.67
2030	50	Solar	0	2.6	0
2035	100	Solar	0	2.6	0
2037	100	Battery	2.19	12.98	0
2038	100	Solar	0	1.03	0
2038	100	Solar	0	1.03	0
2038	100	Solar	0	5.2	0
2040	25	Battery	2.19	2.6	0
Wyoming (WYO) Transmission Area					
2025	100	Wind	0	11.43	0
2026	100	Wind	0	2.6	0
2028	100	Wind	0	2.6	22.04
2029	100	Wind	0	2.6	0
2030	100	Wind	0	11.43	0
2030	25	Battery	2.19	2.6	0
2033	100	Wind	0	2.6	0
2034	100	Wind	0	2.6	0
2037	25	Battery	2.19	0.5	0
New Mexico (NM) Transmission Area)					
2036	100	Battery	2.19	2.6	0
2037	100	Wind	0	1.85	385.34
2037	100	Wind	0	1.85	0
2038	100	Wind	0	1.85	0

Low Load 80pct CR Version 1

Assumptions Unique to this Scenario:

Modeling assumptions are per Volume II Section 5 Phase I Plan Modeling Details under the subsection of Modeling Assumptions of this report with the following exceptions:

Table 68: Unique Assumptions (Low Load 80pct CR V1)

Assumption Item	Description
Load Forecast	2020 Annual Load Forecast – LCL 90
Additional Retirements	Allowed – coal retirements in 2026; SPV3 not allowed to retire until after end of SRP contract (first year 2037)
Thermal Resource Status: **Econ** - Model can choose to turn resource on and off but resource has a 168 hour on line min. **Must Run** - Model can choose what level to run the resource at but resource cannot go lower than min.	**Must Run 2021 - 2024 :** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV **Econ 2025 - 2040:** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV **Econ 2021 - 2040:** Burlington 1, Burlington 2, Knutson 1&2, Limon 1&2, Pyramid 1-4, Rifle, and Shafer
Build Limits	• ECO 2021 to 2023 Annual Max: 0 • ECO 2024 to 2027 Annual Max: 100 • ECO 2028 to 2040 Annual Max: 10000 • Max Annual – Renewable: 1000 • Max Study – ECO: 2000 • Max Study – NM: 400 • Max Study – Storage: 1200 • Max Study – Thermal: 300 • Max Study – WY: 650
CO_2 Reduction	80% CO_2 reduction in 2030 from 2005 baseline in relation to electricity sales in Colorado; Glide path from 2025 to 2030
Transmission Links	See Table 69 for detail
Market Depths	See Table 70 & 71 for details

Transmission Links

Table 69: Applied Transmission Link Capacities (Low Load 80pct CR V1)

Link Name	From Transmission Area	To Transmission Area	Forward Capacity *(MW)*	Backward Capacity *(MW)*	Dates
LK-E_CO>NM	WACM_Eastern_Colorado	New Mexico	124	0	2021 - 2040
LK-LAP>E_CO	Mt_ Elbert	WACM_Eastern_Colorado	177	176	2021 - 2029
LK-LAP>E_CO	Mt_ Elbert	WACM_Eastern_Colorado	227	176	2030 - 2040
LK-SPRV>NM	Springerville	New Mexico	317	0	2021 - 2035
LK-SPRV>NM	Springerville	New Mexico	359	0	2036
LK-SPRV>NM	Springerville	New Mexico	417	0	2037
LK-W_CO>E_CO	West_Colorado	WACM_Eastern_Colorado	457	150	2021 - 2040
LK-W_CO>NM	West_Colorado	New Mexico	0	170	2021 - 2024
LK-W_CO>NM	West_Colorado	New Mexico	50	170	2025 - 2026
LK-W_CO>NM	West_Colorado	New Mexico	50	100	2027
LK-W_CO>NM	West_Colorado	New Mexico	50	50	2028 - 2040
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	400	400	2021
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	550	400	2022 - 2025
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	450	400	2026
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	350	400	2027
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	250	400	2028
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	220	400	2029
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	50	400	2030 - 2040
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	0	0	2021 - 2024
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	50	0	2025
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	150	0	2026
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	250	0	2027
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	350	0	2028
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	380	0	2029
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	600	0	2030 - 2040

Table 70: Market Sales Hourly Capacity (Low Load 80pct CR V1)

Dates	MS-4 Corner-N_NM *(MW)*	MS-WEIM *(MW)*
Jan 2021 - Mar 2021	20-OFF / 75-ON	0
Apr 2021 - 2024	0-OFF / 20-ON	25-OFF / 60-ON
2025-2040	150	0

Dates	MS-Ault-E_CO *(MW)*	MS-Craig-NW_CO *(MW)*	MS-LRS-WY *(MW)*	MS-WEIS *(MW)*
Jan 2021	0-OFF / 50-ON	15-OFF / 100-ON	0	0
Feb 2021 - 2024	0-OFF / 25-ON	0-OFF / 25-ON	0	25-OFF / 125-ON
2025-2029	150	50	200	0
2030-2040	50	50	200	0

Table 71: Market Purchases Hourly Capacity (Low Load 80pct CR V1)

Dates	MP-4 Corner-N_NM *(MW)*	MP-WEIM *(MW)*
Jan 2021 - Mar 2021	100	0
Apr 2021 - 2024	85	15
2025-2034	200	0
2035-2040	400	0

Dates	MP-Ault-E_CO *(MW)*	MP-Craig-NW_CO *(MW)*	MP-LRS-WY *(MW)*	MP-WEIS *(MW)*
Jan 2021	200	125	75	0
Feb 2021 - 2024	150	100	75	75
2025-2034	200	200	200	0
2035-2040	400	400	400	0

Results:

Table 72: Expansion Plan (Low Load 80pct CR V1)

Location	MW[12]	Technology	Year
West Colorado	See profile	Aggressive Energy Efficiency	2025
West Colorado	100	Solar	2026
West Colorado	100	Solar	2027
Wyoming	100	Wind	2027
Wyoming	100	Wind	2028
West Colorado	100	Standalone Battery	2029
West Colorado	100	Solar	2029
East Colorado	200	Wind	2029
West Colorado	100	Standalone Battery	2030
West Colorado	300	Natural Gas – Combined Cycle	2030
West Colorado	500	Solar	2030
East Colorado	100	Wind	2030
Wyoming	100	Wind	2030
Wyoming	25	Standalone Battery	2031
Wyoming	200	Wind	2031
Wyoming	100	Wind	2032
West Colorado	100	Solar	2033
Wyoming	100	Wind	2034
East Colorado	100	Wind	2035
East Colorado	100	Standalone Battery	2036
East Colorado	200	Wind	2036
New Mexico	100	Battery	2037
New Mexico	100	Wind	2037
East Colorado	100	Wind	2038
East Colorado	100	Standalone Battery	2039
New Mexico	100	Standalone Battery	2039
West Colorado	200	Solar	2039
East Colorado	50	Standalone Battery	2040
Wyoming	25	Standalone Battery	2040
New Mexico	100	Wind	2040

Table 73: Proposed Retirements (Low Load 80pct CR V1)

Location	MW	Technology	Year
LRS 3	231	Coal	2027
SPV3	417	Coal	2039

[12] See Volume II Section 5 Phase I Modeling Details under the subsection of Modeling Assumptions & Methodology>DSM & EE of this report for profile information.

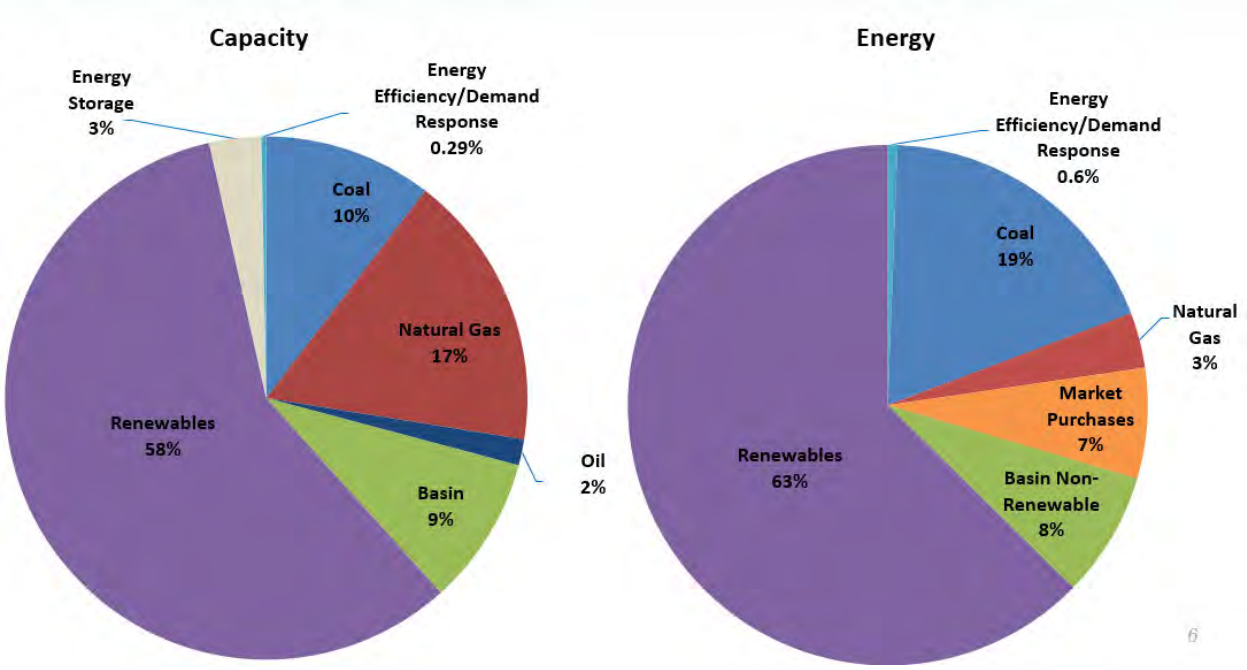

Figure 14: Projected System Capacity and Energy Mix (Low Load 80pct CR V1)

Table 74: Projected Annual Capacity Factors (Low Load 80pct CR V1)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	75%	79%	73%	71%	63%	0%	0%	0%	0%	0%
Craig 2	86%	86%	72%	78%	70%	85%	85%	40%	0%	0%
Craig 3	73%	76%	63%	61%	66%	85%	76%	66%	18%	0%
LRS 2	93%	74%	92%	78%	82%	92%	93%	84%	93%	88%
LRS 3	80%	75%	89%	62%	93%	90%	0%	0%	0%	0%
SPV3	48%	38%	43%	41%	32%	39%	52%	51%	57%	52%
JM Shafer	21%	6%	7%	4%	26%	19%	22%	13%	5%	2%
Rifle	0%	0%	0%	0%	0%	1%	0%	0%	2%	0%
Limon	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%
Knutson	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%
Pyramid	0%	1%	0%	0%	4%	4%	5%	5%	4%	3%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
300MW CC WCO	0%	0%	0%	0%	0%	0%	0%	0%	0%	23%

Table 75: Environmental Impact – System Wide (Low load 80pct CR V1)

Year	CO_2 *(tons[13])*	SO_2 *(tons)*	NO_x *(tons)*	Hg *(tons)*	PM *(tons)*	Water *(gallons)*	RES CO*	RPS NM
2021	13,248,122	6056	10,257	0.2305	429	5,726,854,057	*C*	*C*
2022	11,528,749	5574	9,507	0.2207	383	5,214,422,141	*C*	*C*
2023	11,643,176	5728	9,637	0.2143	411	5,316,878,666	*C*	*C*
2024	10,397,412	4982	8,479	0.1899	338	4,781,929,764	*C*	*C*
2025	11,438,864	5579	9,543	0.2124	424	5,202,302,115	*C*	*C*
2026	11,816,446	6137	9,864	0.2448	443	5,525,884,368	*C*	*C*
2027	9,997,041	4469	7,518	0.1891	270	4,678,925,102	*C*	*C*
2028	9,010,857	4031	6,627	0.1651	227	4,109,705,244	*C*	*C*
2029	7,425,906	2921	4,626	0.0888	163	3,172,306,802	*C*	*C*
2030	6,251,603	2331	3,807	0.0556	150	2,830,107,973	*C*	*C*
2031	5,875,778	2156	3,522	0.0497	138	2,657,620,281	*C*	*C*
2032	6,203,957	2371	3,828	0.0562	150	2,885,822,021	*C*	*C*
2033	6,341,186	2382	3,867	0.0566	153	2,912,561,758	*C*	*C*
2034	6,040,991	2218	3,605	0.0510	142	2,743,321,204	*C*	*C*
2035	6,425,910	2434	3,921	0.0576	155	2,975,816,027	*C*	*C*
2036	6,187,211	2364	3,819	0.0558	150	2,878,253,164	*C*	*C*
2037	5,747,902	2157	3,531	0.0502	138	2,633,939,407	*C*	*C*
2038	6,120,559	2360	3,804	0.0558	150	2,873,040,605	*C*	*C*
2039	4,592,993	1556	3,124	0.0396	121	1,816,343,814	*C*	*C*
2040	4,539,358	1486	2,962	0.0367	114	1,746,585,719	*C*	*C*
Total	160,834,022	69,290	115,849	2.320	4,651	72,682,620,234		
per MWh**	*975*	*0.42*	*0.70*	*0.00001*	*0.03*	*220*		

*C = compliant; N = noncompliant

**Pounds per MWh of Member Load for emissions; Gallons per MWh of Member Load for water

[13] All tons are in short tons. CO_2, SO_2 and NO_x are per net MWh; HG and PM are per gross MWh.

Table 76: Social Cost of Carbon Nominal Dollars – System Wide (Low Load 80pct CR V1)

Year	Annual Social Cost of Carbon
2021	$629,418,285
2022	$571,941,254
2023	$602,883,664
2024	$561,668,182
2025	$644,236,823
2026	$693,625,403
2027	$611,319,027
2028	$573,721,262
2029	$482,238,325
2030	$422,545,870
2031	$413,184,702
2032	$453,757,407
2033	$482,120,400
2034	$477,359,124
2035	$527,502,938
2036	$527,459,708
2037	$508,746,776
2038	$562,295,763
2039	$437,804,118
2040	$448,806,365
Total	**$10,632,635,396**

Table 77: GHG/CO_2 Emissions for Serving Wholesale Electricity Sales in Colorado Projected in 2030 from a 2005 Baseline (Low Load 80pct CR V1)

2030	Fuel Type	Energy (MWh)	Emission Rate (tons/MWh)	Carbon Emissions (tons)
CO Sales to Members		11,811,422		
CO Sales to Members inc Transmission Losses (5%)		12,401,993		
COMarket Sales (including 5% markup for transmission losses)		652,384		
Standalone battery load (90% efficiency) charging & Mt Elbert net		63,455		
Craig 1 & 2	Coal - Retired		1.17	0
Craig 3	Coal - Retired		1.05	0
LRS Imports	Coal	0	1.15	0
Nucla	Coal - Retired		1.30	0
Rifle	Gas	98	0.60	59
Knutson 1&2	Gas	0	0.75	0
Limon 1 & 2	Gas	0	0.75	0
Burlington 1 & 2	Oil	0	1.12	0
Shafer	Gas	36,293	0.49	17,784
CRSP East & West (CO)	Federal Hydro	929,860	0.00	0
LAP (CO)	Federal Hydro	717,302	0.00	0
Small Power Producers	Small Hydro	710	0.00	0
Basin AU PPA	egrid rmpa	876,385	0.64	560,886
Expansion Plan Wind PPAs (CO & WY)	Wind	2,252,982	0.00	0
Expansion Plan Gas (CO) combined cycle	Gas	601,811	0.40	240,724
Expansion Plan Gas (CO) Aeroderivative, RICE, CT	Gas	0	0.60	0
Expansion Plan Solar (CO)	Solar	2,022,232	0.00	0
Energy Imbalance (PSCO and prorate of WAPA)	egrid rmpa	133,131	0.64	85,204
CO Market Purchases	egrid rmpa	962,332	0.64	615,892
Kit Carson	Wind	165,656	0	0
Carousel	Wind	653,199	0	0
Colorado Highlands	Wind	361,418	0	0
Crossing Trails	Wind	408,330	0	0
Spanish Peaks	Solar	244,985	0	0
San Isabel	Solar	67,207	0	0
Twin Buttes	Solar	307,745	0	0
Niyol	Wind	890,207	0	0
Coyote Gulch	Solar	279,776	0	0
Dolores Canyon	Solar	250,291	0	0
Axial	Solar	315,286	0	0
DSM/EE	Load Reduction	117,720	0	0
Basin Electrically East	egrid MROW	103,000	0.62	63,860
Policy 115 - CO only	Mix	356,467	0	0
			Carbon Tons	1,584,409
			GHG tons	1,587,143
Mass Based Carbon Reduction for Electricity Sales	-83%			
Mass Based GHG Reduction For electricity sales	-83%			

Table 78: GHG/CO_2 Emissions for Serving Utility Member System Retail Sales in Colorado in 2030 from a 2005 Baseline (Low Load 80pct CR V1)

		Option 1	Option 2
	MWh	Carbon Emissions Based on How served	Carbon Emissions based on Percentage of Sales
Retail Load (Member load reduced for distribution & transm	11,338,965	978,823	1,369,553
Carbon Rate (Tons/MWh)		0.09	0.12
GHG Emission		980508.76	1,371,911
Carbon Reduction for retail sales		-84%	-78%
GHG Reduction for retail sales		-84%	-78%
Resources Expected to Exclusively Serve Load			
Rifle	98	59	
CRSP East & West (CO)	929,860	0	
LAP (CO)	717,302	0	
Small Power Producers	710	0	
Basin AU PPA	876,385	560,886	
Expansion Plan Wind PPAs (CO & WY)	2,252,982	0	
Expansion Plan Solar (CO)	2,022,232	0	
Kit Carson	165,656	0	
Carousel	653,199	0	
Colorado Highlands	361,418	0	
Crossing Trails	408,330	0	
Spanish Peaks	244,985	0	
San Isabel	67,207	0	
Twin Buttes	307,745	0	
Niyol	890,207	0	
Coyote Gulch	279,776	0	
Dolores Canyon	250,291	0	
Axial	315,286	0	
Basin Electrically East	103,000	63,860	
Policy 115 - CO only	356,467	0	
Total	11,203,136	624,805	
Net After transmission losses	10,642,979	593,565	
Balance	695,986	385,258	

Table 79: Financial (Nominal Dollars) & Reliability Impact

Impact Item	Value
Present Value Member Revenue Requirement (Millions)	$19,037
Expansion Plan Capex + IDC : Generation (Millions)	$1,191
Expansion Plan Capex + IDC : Transmission (Millions)	$1,946
Diversity	3
Dispatchability	2
Reliability	2

Transmission Impact

Beyond normal interconnection transmission expenses, significant additional network upgrades for size in this plan (Costs are in 2020 dollars) were incurred as follows:

- ~$400M in Eastern Colorado in 2029
- ~$150M in Western Colorado in 2033
- ~$300M in Eastern Colorado in 2036
- ~$400M in New Mexico in 2037

Detailed transmission expenses related to generic resources are shown in the following table.

Table 80 : Transmission Interconnection & Network Upgrade Expenses (2020 Real Dollars) (Low Load 80pct CR V1)

Year	**Size** *(MW)*	**Type**	**Interconnection Cost** *($M)*	**Network Upgrade at POI Cost** *($M)*	**Network Upgrade for Size** *($M)*
Eastern Colorado (ECO) Transmission Area					
2029	100	Wind	0	5.89	0
2029	100	Wind	0	2.6	419.56
2030	100	Wind	0	2.6	0
2035	100	Wind	0	2.6	0
2036	100	Wind	0	1.85	0
2036	100	Wind	0	2.6	334.39
2036	100	Battery	2.1	12.98	0
2038	100	Wind	0	5.2	0
2039	100	Battery	2.19	2.6	0
2040	25	Battery	1.63	1.85	0
2040	25	Battery	1.63	1.85	0
Western Colorado (WCO) Transmission Area					
2026	100	Solar	0	3.7	0
2027	100	Solar	0	1.85	0
2029	100	Solar	0	3.7	0
2029	100	Battery	1.63	0.5	0
2030	100	Solar	0	1.85	0
2030	100	Solar	0	2.6	0

Year	**Size** *(MW)*	**Type**	**Interconnection Cost** *($M)*	**Network Upgrade at POI Cost** *($M)*	**Network Upgrade for Size** *($M)*
2030	100	Solar	0	2.6	0
2030	100	Solar	0	2.6	0
2030	100	Solar	0	11.43	0
2030	100	Battery	1.63	0.5	0
2030	300	CC	2.19	0.5	0
2033	100	Solar	0	2.6	167.67
2039	100	Solar	0	2.6	0
2039	100	Solar	2.19	2.6	0
Wyoming (WYO) Transmission Area					
2027	100	Wind	0	11.43	0
2028	100	Wind	0	2.6	0
2030	100	Wind	0	2.6	0
2031	100	Wind	0	2.6	0
2031	100	Wind	0	11.43	0
2031	25	Battery	2.19	0.5	0
2032	100	Wind	0	2.6	0
2034	100	Wind	0	2.6	0
2040	25	Battery	2.19	0.5	0
New Mexico (NM) Transmission Area)					
2037	100	Battery	2.19	2.6	0
2037	100	Wind	0	1.85	385.34
2039	100	Battery	2.19	2.6	13.4
2040	100	Wind	0	1.85	0

Low Load 80pct CR Version 2

Assumptions Unique to this Scenario:

Modeling assumptions are per Volume II Section 5 Phase I Plan Modeling Details under the subsection of Modeling Assumptions of this report with the following exceptions:

Table 81: Unique Assumptions (Low Load 80pct CR V2)

Assumption Item	Description
Load Forecast	2020 Annual Load Forecast – LCL 90
Additional Retirements	Allowed – coal retirements in 2026; SPV3 not allowed to retire until after end of SRP contract (first year 2037)
Thermal Resource Status: **Econ** - Model can choose to turn resource on and off but resource has a 168 hour on line min. **Must Run** - Model can choose what level to run the resource at but resource cannot go lower than min.	**Must Run 2021 - 2024 :** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV **Econ 2025 - 2040:** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV **Econ 2021 - 2040:** Burlington 1, Burlington 2, Knutson 1&2, Limon 1&2, Pyramid 1-4, Rifle, and Shafer
Build Limits	• ECO 2021 to 2023 Annual Max: 0 • ECO 2024 to 2027 Annual Max: 100 • ECO 2028 to 2040 Annual Max: 10000 • Max Annual – Renewable: 1000 • Max Study – ECO: 2000 • Max Study – NM: 400 • Max Study – Storage: 1200 • Max Study – Thermal: 300 • Max Study – WY: 650
DSM & EE Level	Existing DSM/EE only
CO_2 Reduction	80% CO_2 reduction in 2030 from 2005 baseline in relation to electricity sales in Colorado; Glide path from 2025 to 2030
Transmission Links	See Table 82 for details
Market Depths	See Table 83 & 84 for details

Table 82: Applied Transmission Link Capacities (Low Load 80pct CR V2)

Link Name	From Transmission Area	To Transmission Area	Forward Capacity *(MW)*	Backward Capacity *(MW)*	Dates
LK-E_CO>NM	WACM_Eastern_Colorado	New Mexico	124	0	2021 - 2040
LK-LAP>E_CO	Mt_ Elbert	WACM_Eastern_Colorado	176	176	2021 - 2029
LK-LAP>E_CO	Mt_ Elbert	WACM_Eastern_Colorado	227	176	2030 - 2040
LK-SPRV>NM	Springerville	New Mexico	317	0	2021 - 2035
LK-SPRV>NM	Springerville	New Mexico	359	0	2036
LK-SPRV>NM	Springerville	New Mexico	417	0	2037
LK-W_CO>E_CO	West_Colorado	WACM_Eastern_Colorado	457	150	2021 - 2040
LK-W_CO>NM	West_Colorado	New Mexico	0	170	2021 - 2024
LK-W_CO>NM	West_Colorado	New Mexico	50	170	2025 - 2026
LK-W_CO>NM	West_Colorado	New Mexico	50	100	2027
LK-W_CO>NM	West_Colorado	New Mexico	50	50	2028 - 2040
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	400	400	2021
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	550	400	2022 - 2025
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	450	400	2026
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	350	400	2027
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	250	400	2028
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	220	400	2029
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	50	400	2030 - 2040
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	0	0	2021 - 2024
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	50	0	2025
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	150	0	2026
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	250	0	2027
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	350	0	2028
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	380	0	2029
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	600	0	2030 - 2040

Table 83: Market Sales Hourly Capacity (Low Load 80pct CR V2)

Dates	MS-4 Corner-N_NM *(MW)*	MS-WEIM *(MW)*
Jan 2021 - Mar 2021	20-OFF / 75-ON	0
Apr 2021 - 2024	0-OFF / 20-ON	25-OFF / 60-ON
2025-2040	150	0

Dates	MS-Ault-E_CO *(MW)*	MS-Craig-NW_CO *(MW)*	MS-LRS-WY *(MW)*	MS-WEIS *(MW)*
Jan 2021	0-OFF / 50-ON	15-OFF / 100-ON	0	0
Feb 2021 - 2024	0-OFF / 25-ON	0-OFF / 25-ON	0	25-OFF / 125-ON
2025-2029	150	50	200	0
2030-2040	50	50	200	0

Table 84: Market Purchases Hourly Capacity (Low Load 80pct CR V2)

Dates	MP-4 Corner-N_NM *(MW)*	MP-WEIM *(MW)*
Jan 2021 - Mar 2021	100	0
Apr 2021 - 2024	85	15
2025-2034	200	0
2035-2040	400	0

Dates	MP-Ault-E_CO *(MW)*	MP-Craig-NW_CO *(MW)*	MP-LRS-WY *(MW)*	MP-WEIS *(MW)*
Jan 2021	200	125	75	0
Feb 2021 - 2024	150	100	75	75
2025-2034	200	200	200	0
2035-2040	400	400	400	0

Results:

Table 85: Expansion Plan (Low Load 80pct CR V2)

Location	MW	Technology	Year
West Colorado	100	Solar	2026
West Colorado	100	Solar	2027
Wyoming	100	Wind	2027
Wyoming	100	Wind	2028
West Colorado	100	Solar	2029
East Colorado	200	Wind	2029
West Colorado	100	Standalone Battery	2030
West Colorado	300	Natural Gas - Combined Cycle	2030
West Colorado	500	Solar	2030
East Colorado	100	Wind	2030
Wyoming	100	Wind	2030
Wyoming	25	Standalone Battery	2031
Wyoming	200	Wind	2031
Wyoming	100	Wind	2032
West Colorado	100	Solar	2033
West Colorado	100	Standalone Battery	2034
Wyoming	100	Wind	2034
East Colorado	100	Wind	2035
East Colorado	100	Standalone Battery	2036
East Colorado	200	Wind	2036
New Mexico	100	Standalone Battery	2037
New Mexico	100	Wind	2037
East Colorado	100	Wind	2038
East Colorado	100	Standalone Battery	2039
New Mexico	100	Standalone Battery	2039
West Colorado	200	Solar	2039
East Colorado	50	Standalone Battery	2040
Wyoming	25	Standalone Battery	2040
New Mexico	100	Wind	2040

Table 86: Proposed Retirements (Low Load 80pct CR V2)

Location	MW	Technology	Year
LRS 3	231	Coal	2027
SPV3	417	Coal	2039

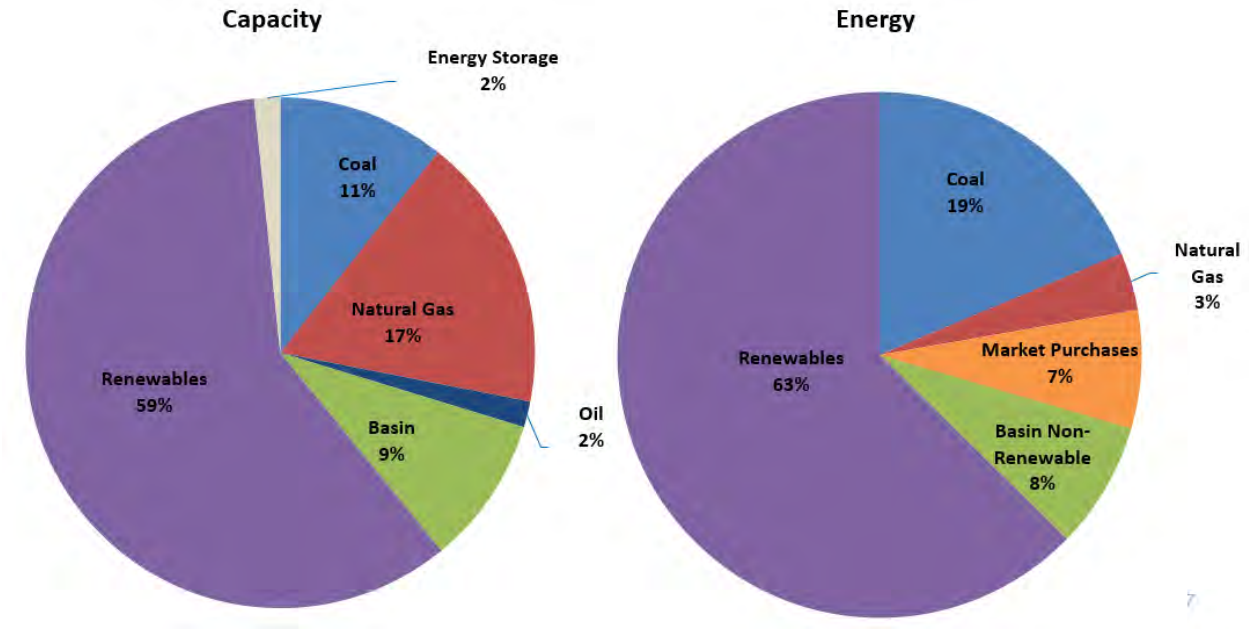

Figure 15: Projected System Capacity and Energy Mix (Low Load 80pct CR V2)

Table 87: Projected Annual Capacity Factors (Low Load 80pct CR V2)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	75%	79%	73%	71%	61%	0%	0%	0%	0%	0%
Craig 2	86%	86%	72%	78%	69%	85%	85%	40%	0%	0%
Craig 3	73%	76%	63%	61%	66%	85%	76%	66%	19%	0%
LRS 2	93%	74%	92%	78%	82%	92%	93%	84%	93%	87%
LRS 3	80%	75%	89%	62%	92%	89%	0%	0%	0%	0%
SPV3	48%	38%	43%	41%	33%	42%	52%	51%	57%	52%
JM Shafer	21%	6%	7%	4%	26%	20%	21%	13%	6%	2%
Rifle	0%	0%	0%	0%	0%	1%	0%	0%	4%	0%
Limon	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%
Knutson	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%
Pyramid	0%	1%	0%	0%	4%	4%	4%	5%	4%	3%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
300MW CC WCO	0%	0%	0%	0%	0%	0%	0%	0%	0%	23%

Table 88: Environmental Impact – System Wide (Low Load 80pct CR V2)

Year	CO_2 *(tons)*[14]	SO_2 *(tons)*	NO_x *(tons)*	Hg *(tons)*	PM *(tons)*	Water *(gallons)*	RES CO*	RPS NM
2021	13,772,442	6061	10,778	0.2305	486	6,212,774,902	*C*	*C*
2022	11,677,025	5575	9,655	0.2207	400	5,351,839,163	*C*	*C*
2023	11,756,302	5729	9,750	0.2143	423	5,421,719,931	*C*	*C*
2024	10,455,187	4982	8,537	0.1899	344	4,835,473,497	*C*	*C*
2025	11,659,972	5591	9,748	0.2129	447	5,418,219,347	*C*	*C*
2026	11,971,919	6179	9,945	0.2456	449	5,620,633,053	*C*	*C*
2027	10,009,492	4478	7,529	0.1897	270	4,681,453,646	*C*	*C*
2028	9,029,592	4033	6,629	0.1653	227	4,109,573,873	*C*	*C*
2029	7,488,990	2951	4,703	0.0909	167	3,217,480,869	*C*	*C*
2030	6,308,408	2332	3,814	0.0556	150	2,841,022,883	*C*	*C*
2031	5,934,993	2152	3,524	0.0495	139	2,660,199,189	*C*	*C*
2032	6,259,339	2363	3,833	0.0559	152	2,890,999,203	*C*	*C*
2033	6,487,689	2411	3,902	0.0571	155	2,957,106,895	*C*	*C*
2034	6,099,728	2219	3,609	0.0511	143	2,745,683,389	*C*	*C*
2035	6,624,580	2494	3,992	0.0590	159	3,053,690,095	*C*	*C*
2036	6,427,319	2435	3,891	0.0573	154	2,976,732,821	*C*	*C*
2037	5,852,185	2163	3,542	0.0503	139	2,644,867,071	*C*	*C*
2038	6,142,921	2326	3,774	0.0550	149	2,835,025,820	*C*	*C*
2039	4,734,087	1561	3,145	0.0398	123	1,828,353,105	*C*	*C*
2040	4,686,507	1488	2,970	0.0368	115	1,751,077,609	*C*	*C*
Total	163,378,677	69,524	117,270	2.327	4,788	74,053,926,362		
per MWh**	*990*	*0.42*	*0.71*	*0.00001*	*0.03*	*224*		

*C = compliant; N = noncompliant

**Pounds per MWh of Member Load for emissions; Gallons per MWh of Member Load for water

[14] All tons are in short tons. CO_2, SO_2 and NO_x are per net MWh; HG and PM are per gross MWh.

Table 89: Social Cost of Carbon Nominal Dollars – System Wide (Low Load 80pct CR V2)

Year	Annual Social Cost of Carbon
2021	$654,328,717
2022	$579,297,232
2023	$608,741,336
2024	$564,789,183
2025	$656,689,648
2026	$702,751,656
2027	$612,080,458
2028	$574,914,124
2029	$486,335,006
2030	$426,385,286
2031	$417,348,714
2032	$457,808,066
2033	$493,258,959
2034	$482,000,498
2035	$543,811,750
2036	$547,928,915
2037	$517,976,877
2038	$564,350,172
2039	$451,253,140
2040	$463,354,911
Total	**$10,805,404,649**

Table 90: GHG/CO_2 Emissions for Serving Wholesale Electricity Sales in Colorado Projected in 2030 from a 2005 Baseline (Low Load 80pct CR V2

2030	Fuel Type	Energy (MWh)	Emission Rate (tons/MWh)	Carbon Emissions (tons)
CO Sales to Members		11,811,422		
CO Sales to Members inc Transmission Losses (5%)		12,401,993		
COMarket Sales (including 5% markup for transmission losses)		708,810		
Standalone battery load (90% efficiency) charging & Mt Elbert net		49,040		
Craig 1 & 2	Coal - Retired		1.17	0
Craig 3	Coal - Retired		1.05	0
LRS Imports	Coal	106,727	1.15	123,003
Nucla	Coal - Retired		1.30	0
Rifle	wou	98	0.60	59
Knutson 1&2	Gas	0	0.75	0
Limon 1 & 2	Gas	0	0.75	0
Burlington 1 & 2	Oil	0	1.12	0
Shafer	Gas	48,697	0.49	23,862
CRSP East & West (CO)	Federal Hydro	929,860	0.00	0
LAP (CO)	Federal Hydro	717,302	0.00	0
Small Power Producers	Small Hydro	710	0.00	0
Basin AU PPA	egrid RMPA	876,385	0.64	560,886
Expansion Plan Wind PPAs (CO & WY)	Wind	2,294,556	0.00	0
Expansion Plan Gas (CO) combined cycle	Gas	612,152	0.40	244,861
Expansion Plan Gas (CO) Aeroderivative, RICE, CT	Gas	0	0.60	0
Expansion Plan Solar (CO)	Solar	2,022,232	0.00	0
Energy Imbalance (PSCO and prorate of WAPA)	egrid RMPA	133,131	0.64	85,204
CO Market Purchases	egrid RMPA	1,014,426	0.64	649,233
Kit Carson	Wind	165,656	0	0
Carousel	Wind	653,199	0	0
Colorado Highlands	Wind	361,418	0	0
Crossing Trails	Wind	408,330	0	0
Spanish Peaks	Solar	244,985	0	0
San Isabel	Solar	67,207	0	0
Twin Buttes	Solar	307,745	0	0
Niyol	Wind	890,207	0	0
Coyote Gulch	Solar	279,776	0	0
Dolores Canyon	Solar	250,291	0	0
Axial	Solar	315,286	0	0
DSM/EE	Load Reduction		0	0
Basin Electrically East	egrid MROW	103,000	0.62	63,860
Policy 115 - CO only	Mix	356,467	0	0
			Carbon Tons	1,750,967
			GHG tons	1,754,285
Mass Based Carbon Reduction for Electricity Sales	-81%			
Mass Based GHG Reduction For electricity sales	-81%			

Table 91: GHG/CO_2 Emission for Serving Utility Member System Retail Sales in Colorado in 2030 from a 2005 Baseline (Low Load 80pct CR V2)

		Option 1	Option 2
	MWh	Carbon Emissions Based on How served	Carbon Emissions based on Percentage of Sales
Retail Load (Member load reduced for distribution & transm	11,457,079	1,023,254	1,524,408
Carbon Rate (Tons/MWh)		0.09	0.13
GHG Emission		1025189.24	1,527,291
Carbon Reduction for retail sales		-83%	-76%
GHG Reduction for retail sales		-83%	-76%
Resources Expected to Exclusively Serve Load			
Rifle	98	59	
CRSP East & West (CO)	929,860	0	
LAP (CO)	717,302	0	
Small Power Producers	710	0	
Basin AU PPA	876,385	560,886	
Expansion Plan Wind PPAs (CO & WY)	2,294,556	0	
Expansion Plan Solar (CO)	2,022,232	0	
Kit Carson	165,656	0	
Carousel	653,199	0	
Colorado Highlands	361,418	0	
Crossing Trails	408,330	0	
Spanish Peaks	244,985	0	
San Isabel	67,207	0	
Twin Buttes	307,745	0	
Niyol	890,207	0	
Coyote Gulch	279,776	0	
Dolores Canyon	250,291	0	
Axial	315,286	0	
Basin Electrically East	103,000	63,860	
Policy 115 - CO only	356,467	0	
Total	11,244,710	624,805	
Net After transmission losses	10,682,474	593,565	
Balance	774,605	429,689	

Table 92: Financial (Nominal Dollars) & Reliability Impact

Impact Item	Value
Present Value Member Revenue Requirement (Millions)	$18,985
Expansion Plan Capex + IDC : Generation (Millions)	$1,185
Expansion Plan Capex + IDC : Transmission (Millions)	$1,951
Diversity	3
Dispatchability	2
Reliability	2

Transmission Impact

Beyond normal interconnection transmission expenses, significant additional network upgrades for size in this plan (Costs are in 2020 dollars) were incurred as follows:

- ~$400M in Eastern Colorado in 2029
- ~$150M in Western Colorado in 2034
- ~$300M in Eastern Colorado in 2036
- ~$400M in New Mexico in 2037

Detailed transmission expenses related to generic resources are shown in the following table.

Table 93: Transmission Interconnection & Network Upgrade Expenses (2020 Real Dollars) (Low Load 80pct CR Version 2)

Year	**Size** *(MW)*	**Type**	**Interconnection Cost** *($M)*	**Network Upgrade at POI Cost** *($M)*	**Network Upgrade for Size** *($M)*
Eastern Colorado (ECO) Transmission Area					
2029	100	Wind	0	5.89	0
2029	100	Wind	0	2.6	419.56
2030	100	Wind	0	2.6	0
2035	100	Wind	0	2.6	0
2036	100	Wind	0	1.85	0
2036	100	Wind	0	2.6	334.39
2036	100	Battery	2.1	12.98	0
2038	100	Wind	0	5.2	0
2039	100	Battery	2.19	2.6	0
2040	25	Battery	1.63	1.85	0
2040	25	Battery	1.63	1.85	0
Western Colorado (WCO) Transmission Area					
2026	100	Solar	0	3.7	0
2027	100	Solar	0	1.85	0
2029	100	Solar	0	3.7	0
2030	100	Solar	0	1.85	0

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2030	100	Solar	0	2.6	0
2030	100	Solar	0	2.6	0
2030	100	Solar	0	2.6	0
2030	100	Solar	0	11.43	0
2030	100	Battery	1.63	0.5	0
2030	300	CC	2.19	0.5	0
2033	100	Solar	0	2.6	0
2034	100	Battery	1.63	0.5	167.67
2039	100	Solar	0	2.6	0
2039	100	Solar	2.19	2.6	0
Wyoming (WYO) Transmission Area					
2027	100	Wind	0	11.43	0
2028	100	Wind	0	2.6	0
2030	100	Wind	0	2.6	0
2031	100	Wind	0	2.6	0
2031	100	Wind	0	11.43	0
2031	25	Battery	2.19	0.5	0
2032	100	Wind	0	2.6	0
2034	100	Wind	0	2.6	0
2040	25	Battery	2.19	0.5	0
New Mexico (NM) Transmission Area)					
2037	100	Battery	2.19	2.6	0
2037	100	Wind	0	1.85	385.34
2039	100	Battery	2.19	2.6	13.4
2040	100	Wind	0	1.85	0

Social Cost of Carbon

Assumptions Unique to this Scenario:

Modeling assumptions are per Volume II Section 5 Phase I Plan Modeling Details under the subsection of Modeling Assumptions of this report with the following exceptions:

Table 94: Unique Assumptions (Social Cost of Carbon)

Assumption Item	Description
Additional Retirements	Allowed – Coal and Gas retirements after 2025; SPV3 not allowed to retire until after end of SRP contract (first year 2037)
Social Cost of Carbon	Used Social Cost of Carbon adder for all thermal resources
Thermal Resource Status: **Econ** - Model can choose to turn resource on and off but resource has a 168 hour on line min. **Must Run** - Model can choose what level to run the resource at but resource cannot go lower than min.	**Must Run 2021 - 2040 :** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV **Econ 2021 - 2040:** Burlington 1, Burlington 2, Knutson 1&2, Limon 1&2, Pyramid 1-4, Rifle, and Shafer
Build Limits	• Max Study – Eco 2000 • Max Study – NM 400 • Max Study – Storage 1200 • Max Study – Thermal 1000 • Max Study - Wyo: 650 • Max Annual – Renewable 1000
EE & DR DSM Level	Aggressive EE and Low DR forced for ECO and WCO
CO_2 Reduction	RestrictedCO_2 levels on Colorado thermal resources
Transmission Links	See Table 95 for detail

Table 95: Applied Transmission Link Capacities (Social Cost of Carbon)

Link Name	From Transmission Area	To Transmission Area	Forward Capacity *(MW)*	Backward Capacity *(MW)*	Dates
LK-E_CO>NM	WACM_Eastern_Colorado	New Mexico	124	0	2021 - 2040
LK-LAP>E_CO	Mt_ Elbert	WACM_Eastern_Colorado	177	176	2021 - 2040
LK-LAP>WY	Mt_ Elbert	WACM_Wyoming	0	0	2021 - 2040
LK-SPRV>NM	Springerville	New Mexico	317	0	2021 - 2035
LK-SPRV>NM	Springerville	New Mexico	359	0	2036
LK-SPRV>NM	Springerville	New Mexico	417	0	2037 - 2040
LK-W_CO>E_CO	West_Colorado	WACM_Eastern_Colorado	457	150	2021 - 2040
LK-W_CO>NM	West_Colorado	New Mexico	0	170	2021 - 2024
LK-W_CO>NM	West_Colorado	New Mexico	50	170	2025 - 2029
LK-W_CO>NM	West_Colorado	New Mexico	50	50	2030 - 2040
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	400	400	2021
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	550	400	2022 - 2025
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	650	400	2026 - 2040

Results:

Table 96: Expansion Plan (Social Cost of Carbon)

Location	MW[15]	Technology	Year
East Colorado	See Profile	Aggressive - Energy Efficiency	2022
West Colorado	See Profile	Aggressive - Energy Efficiency	2022
East Colorado	See Profile	Low – Demand Response	2022
West Colorado	See Profile	Low – Demand Response	2022
Wyoming	200	Wind	2025
West Colorado	545	Natural Gas – Combined Cycle	2026
West Colorado	200	Solar	2026
Wyoming	500	Wind	2026
East Colorado	100	100 MW Wind + 25 MW Battery	2026
Wyoming	200	Wind	2027
West Colorado	125	Standalone Battery	2028
East Colorado	100	Solar	2028
West Colorado	100	Solar	2028
East Colorado	100	Wind	2028
New Mexico	100	Wind	2028
New Mexico	100	Standalone Battery	2029
West Colorado	100	Solar	2029
East Colorado	100	Standalone Battery	2030
West Colorado	300	Natural Gas – Combined Cycle	2030
West Colorado	100	Solar	2030

[15] See Volume II Section 5 Phase I Modeling Details under the subsection of Modeling Assumptions & Methodology>DSM & EE of this report for profile information.

Location	MW[15]	Technology	Year
East Colorado	200	Solar	2030
West Colorado	100	Solar	2031
Wyoming	100	Wind	2031
East Colorado	100	Standalone Battery	2032
West Colorado	200	Standalone Battery	2032
West Colorado	100	Solar	2032
East Colorado	200	Wind	2032
West Colorado	200	Solar	2033
East Colorado	100	Wind	2033
East Colorado	100	Wind	2035
East Colorado	100	Wind	2036
West Colorado	25	Standalone Battery	2037
East Colorado	175	Standalone Battery	2037
Wyoming	50	Standalone Battery	2037
East Colorado	300	Wind	2037
New Mexico	100	Wind	2037
West Colorado	200	Solar	2038
West Colorado	25	Standalone Battery	2039
West Colorado	300	Solar	2039
East Colorado	200	200 MW Wind + 50 MW Battery	2039

Table 97: Proposed Retirements (Social Cost of Carbon)

Location	MW	Technology	Year
LRS 2	230	Coal	2026
LRS 3	231	Coal	2026
Limon 1	70	Gas	2026
Rifle	81	Gas	2026
Craig 3	448	Coal	2026
Burlington 2	55	Oil	2028
Limon 2	70	Gas	2028
Shafer	272	Gas	2030
Burlington 1	55	Oil	2031
Knutson 2	70	Gas	2031
Pyramid 2	40	Gas	2031
SPV 3	417	Coal	2037

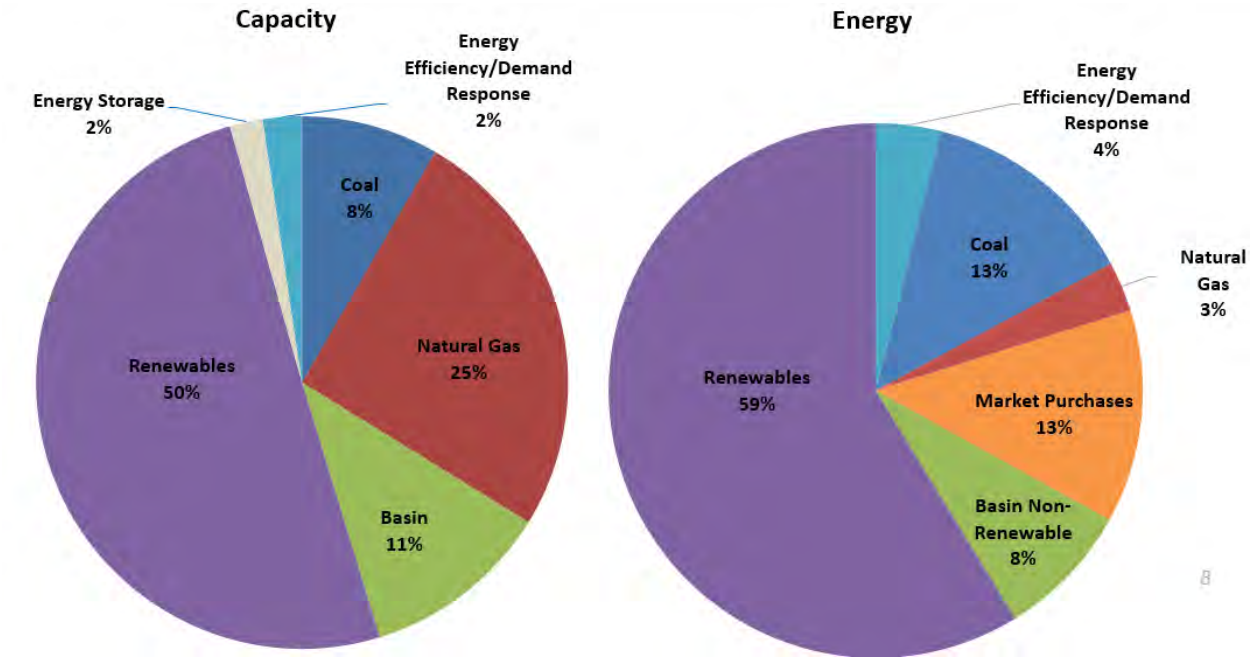

Figure 16: Projected System Capacity and Energy Mix (Social Cost of Carbon)

Table 98: Projected Annual Capacity Factors (Social Cost of Carbon)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	75%	75%	76%	76%	72%	0%	0%	0%	0%	0%
Craig 2	86%	92%	79%	88%	81%	89%	92%	68%	0%	0%
Craig 3	73%	89%	81%	80%	77%	0%	0%	0%	0%	0%
LRS 2	93%	76%	94%	80%	81%	0%	0%	0%	0%	0%
LRS 3	80%	83%	92%	67%	91%	0%	0%	0%	0%	0%
SPV3	48%	45%	50%	47%	50%	68%	70%	66%	73%	69%
JM Shafer	21%	13%	14%	12%	23%	35%	30%	24%	21%	0%
Rifle	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Limon	0%	0%	0%	0%	1%	5%	2%	0%	0%	0%
Knutson	0%	0%	0%	0%	1%	11%	4%	0%	0%	0%
Pyramid	0%	4%	2%	1%	3%	12%	11%	8%	7%	3%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
300MW CC WCO	0%	0%	0%	0%	0%	0%	0%	0%	0%	7%
545MW CC WCO	0%	0%	0%	0%	0%	6%	5%	4%	3%	8%

Table 99: Environmental Impacts –System Wide (Social Cost of Carbon)

Year	CO_2 (tons)[16]	SO_2 (tons)	NO_x (tons)	Hg (tons)	PM (tons)	Water (gallons)	RES CO*	RPS NM
2021	13,248,122	6056	10,257	0.2305	429	5,726,854,057	*C*	*C*
2022	12,991,001	6287	10,539	0.2490	431	5,776,661,343	*C*	*C*
2023	13,319,145	6518	10,884	0.2497	458	5,975,892,700	*C*	*C*
2024	12,166,643	5846	9,868	0.2288	392	5,503,236,276	*C*	*C*
2025	12,750,912	6255	10,442	0.2371	447	5,823,983,448	*C*	*C*
2026	6,908,114	1870	2,617	0.0275	123	2,791,679,589	*C*	*C*
2027	6,793,620	1899	2,567	0.0282	111	2,778,778,901	*C*	*C*
2028	6,144,670	1802	2,328	0.0254	90	2,514,938,704	*C*	*C*
2029	5,855,718	1803	2,186	0.0231	75	2,327,107,117	*C*	*C*
2030	5,670,966	1755	2,053	0.0221	59	2,211,328,045	*C*	*C*
2031	5,137,515	1598	1,855	0.0188	51	1,953,497,247	*C*	*C*
2032	5,419,677	1791	2,042	0.0227	58	2,213,570,810	*C*	*C*
2033	5,432,133	1790	2,022	0.0227	56	2,190,540,133	*C*	*C*
2034	5,340,999	1734	2,006	0.0215	57	2,144,928,469	*C*	*C*
2035	5,508,779	1817	2,126	0.0232	64	2,290,939,115	*C*	*C*
2036	5,418,447	1800	2,052	0.0228	59	2,216,417,034	*C*	*C*
2037	3,130,833	707	1,146	0.0000	24	848,869,064	*C*	*C*
2038	3,113,742	709	1,173	0.0000	26	871,207,757	*C*	*C*
2039	3,071,525	711	1,178	0.0000	26	876,782,122	*C*	*C*
2040	3,299,587	773	1,248	0.0000	28	898,694,707	*C*	*C*
Total	140,722,148	53,518	80,589	1.453	3,063	57,935,906,637		
*per MWh***	*717*	*0.27*	*0.41*	*0.00001*	*0.02*	*148*		

*C = compliant; N = noncompliant

**Pounds per MWh of Member Load for emissions; Gallons per MWh of Member Load for water

[16] All tons are in short tons. CO_2, SO_2 and NO_x are per net MWh; HG and PM are per gross MWh.

Table 100: Social Cost of Carbon Nominal Dollars – System Wide (Social Cost of Carbon)

Year	Annual Social Cost of Carbon
2021	$629,418,285
2022	$644,483,544
2023	$689,665,326
2024	$657,242,050
2025	$718,131,344
2026	$405,506,288
2027	$415,429,841
2028	$391,231,132
2029	$380,270,355
2030	$383,300,620
2031	$361,270,078
2032	$396,395,170
2033	$413,005,058
2034	$422,045,732
2035	$452,215,696
2036	$461,922,593
2037	$277,110,063
2038	$286,059,468
2039	$292,777,766
2040	$326,230,168
Total	**$9,003,710,579**

Table 101: GHG/CO_2 Emissions for Serving Wholesale Electricity Sales in Colorado Projected in 2030 from a 2005 Baseline (Social Cost of Carbon)

Carbon Emissions : Serving Wholesale sales in Colorado				
2030	**Fuel Type**	**Energy (MWh)**	**Emission Rate (tons/MWh)**	**Carbon Emissions (tons)**
CO Sales to Members		13,660,989		
CO Sales to Members inc Transmission Losses (5%)		14,344,038		
COMarket Sales (including 5% markup for transmission losses)		301,642		
Standalone battery load (90% efficiency) charging & Mt Elbert net		74,348		
Craig 1 & 2	Coal - Retired		1.17	0
Craig 3	Coal - Retired		1.05	0
LRS Imports - Retired	Coal	0	1.15	0
Nucla	Coal - Retired		1.30	0
Rifle	Gas	0	0.60	0
Knutson 1&2	Gas	1,863	0.75	1,397
Limon 1 & 2	Gas	0	0.75	0
Burlington 1 & 2	Oil	0	1.12	0
Shafer	Gas	0	0.49	0
CRSP East & West (CO)	Federal Hydro	929,860	0.00	0
LAP (CO)	Federal Hydro	717,302	0.00	0
Small Power Producers	Small Hydro	710	0.00	0
Basin AU PPA	egrid rmpa	876,385	0.64	560,886
Expansion Plan Wind PPAs (CO & WY)	Wind	2,600,896	0.00	0
Expansion Plan Gas (CO) combined cycle	Gas	544,694	0.40	217,878
Expansion Plan Gas (CO) Aeroderivative, RICE, CT	Gas	0	0.75	0
Expansion Plan Solar (CO)	Solar	2,022,232	0.00	0
Energy Imbalance (PSCO and prorate of WAPA)	egrid rmpa	133,131	0.64	85,204
CO Market Purchases	egrid rmpa	1,735,914	0.64	1,110,985
Kit Carson	Wind	165,656	0	0
Carousel	Wind	653,199	0	0
Colorado Highlands	Wind	361,418	0	0
Crossing Trails	Wind	408,330	0	0
Spanish Peaks	Solar	244,985	0	0
San Isabel	Solar	67,207	0	0
Twin Buttes	Solar	307,745	0	0
Niyol	Wind	890,207	0	0
Coyote Gulch	Solar	279,776	0	0
Dolores Canyon	Solar	250,291	0	0
Axial	Solar	315,286	0	0
DSM/EE	Load Reduction	753,474	0	0
Basin Electrically East	egrid MROW	103,000	0.62	63,860
Policy 115 - CO only	Mix	356,467	0	0
			Carbon Tons	2,040,211
			GHG tons	2,044,496
Mass Based Carbon Reduction for Electricity Sales	-78%			
Mass Based GHG Reduction For electricity sales	-78%			

Table 102: GHG/CO_2 Emission for Serving Utility Member System Retail Sales in Colorado in 2030 from a 2005 Baseline (Social Cost of Carbon)

GHG Emissions: Serving TS Utility Member System Retail Sales in Colorado			
		Option 1	Option 2
	MWh	Carbon Emissions Based on How served	Carbon Emissions based on Percentage of Sales
Retail Load (Member load reduced for distribution & Transn	13,114,549	1,848,150	1,826,917
Carbon Rate (Tons/MWh)		0.14	0.14
GHG Emission		1852023.56	1,830,746
Carbon Reduction for retail sales		-70%	-71%
GHG Reduction for retail sales		-70%	-71%
Resources Expected to Exclusively Serve Load			
Rifle	0	0	
CRSP East & West (CO)	929,860	0	
LAP (CO)	717,302	0	
Small Power Producers	710	0	
Basin AU PPA	876,385	560,886	
Expansion Plan Wind PPAs (CO & WY)	2,600,896	0	
Expansion Plan Solar (CO)	2,022,232	0	
Kit Carson	165,656	0	
Carousel	653,199	0	
Colorado Highlands	361,418	0	
Crossing Trails	408,330	0	
Spanish Peaks	244,985	0	
San Isabel	67,207	0	
Twin Buttes	307,745	0	
Niyol	890,207	0	
Coyote Gulch	279,776	0	
Dolores Canyon	250,291	0	
Axial	315,286	0	
Basin Electrically East	103,000	63,860	
Policy 115 - CO only	356,467	0	
Total	11,550,952	624,746	
Net After transmission losses	10,973,405	593,509	
Balance	2,141,145	1,254,641	

Table 103: Financial (Nominal Dollars) & Reliability Impact (Social Cost of Carbon)

Impact Item	SCC w SCoC	SCC w/o SCoC	SCC w SCoC (3% DR)	SCC w/o SCoC (3% DR)
Present Value Member Revenue Requirement (Millions)	$30,118	$22,715	$33,579	$25,445
Expansion Plan Capex + IDC : Generation (Millions)		$2,109		
Expansion Plan Capex + IDC : Transmission (Millions)		$2,328		
Diversity	3			
Dispatchability	2			
Reliability	2			

Transmission Impact

Beyond normal interconnection transmission expenses, significant additional network upgrades for size in this plan (Costs are in 2020 dollars) were incurred as follows:

- ~$400M in Eastern Colorado in 2028
- ~$400M in New Mexico in 2028
- ~$150M in Western Colorado in 2030
- ~$300M in Eastern Colorado in 2030
- ~$300M in Eastern Colorado in 2037

Detailed transmission expenses related to generic resources are shown in the following table.

Table 104: Transmission Interconnection & Network Upgrade Expenses (2020 Real Dollars) (Social Cost of Carbon)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2026	100	Wind+battery	0	5.89	0
2028	100	Solar	0	2.6	419.56
2028	100	Wind	0	2.6	0
2030	100	Solar	0	2.6	0
2030	100	Solar	0	2.6	334.39
2030	100	Battery	2.19	12.98	0
2032	100	Wind	0	5.2	0
2032	100	Wind	0	2.6	0
2032	100	Battery	2.19	5.2	0
2033	100	Wind	0	1.85	0
2035	100	Wind	0	2.6	0
2036	100	Wind	0	1.85	0
2037	100	Battery	2.19	5.2	0
2037	100	Wind	0	2.6	0

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2037	100	Wind	0	5.2	283.39
2037	100	Wind	0	2.6	0
2037	25	Battery	2.19	5.2	0
2037	25	Battery	2.19	2.6	0
2037	25	Battery	1.63	1.85	0
2039	100	Wind+battery	0	1.85	0
2039	100	Wind+battery	0	5.2	0
Western Colorado (WCO) Transmission Area					
2026	100	Solar	0	2.6	0
2026	100	Solar	0	3.7	0
2026	545	CC	2.19	0.5	0
2028	100	Battery	1.63	1.85	0
2028	25	Battery	1.63	0.5	0
2028	100	Solar	0	3.7	0
2029	100	Solar	0	1.85	0
2030	100	Solar	0	2.6	0
2030	300	CC	1.63	0.5	167.67
2031	100	Solar	0	2.6	0
2031	100	Battery	2.19	2.6	0
2031	100	Battery	2.19	2.6	0
2032	100	Solar	0	11.43	0
2033	100	Solar	0	12.98	0
2033	100	Solar	0	2.6	0
2037	25	Battery	2.19	2.6	2.01
2038	100	Solar	0	2.6	0
2038	100	Solar	0	1.03	33.6
2039	100	Solar	0	5.2	0
2039	100	Solar	0	2.6	0
2039	100	Solar	0	1.03	0
2039	25	Battery	2.19	2.6	0
Wyoming (WYO) Transmission Area					
2025	100	Wind	0	11.43	0
2025	100	Wind	0	2.6	0
2026	100	Wind	0	2.6	0
2026	100	Wind	0	2.6	0
2026	100	Wind	0	11.43	0
2026	100	Wind	0	2.6	0
2026	100	Wind	0	2.6	0

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2027	100	Wind	0	2.6	0
2027	100	Wind	0	11.43	0
2031	100	Wind	0	2.6	0
2037	25	Battery	2.19	0.5	0
2037	25	Battery	2.19	0.5	0
New Mexico (NM) Transmission Area)					
2028	100	Wind	0	1.85	385.34
2029	100	Battery	2.19	2.6	0
2037	100	Wind	0	1.85	0

9 Base Case & Alternative Scenario Comparison

Comparison of Key Inputs

Table 105: Key Inputs Applied for Alternative Scenario Modeling

Scenario Name	Base Case	80pct CR V1	80pct CR V2, V3 & V4	Low Load 80pct CR V1	Low Load 80pct CR V2	Social Cost of Carbon
Load Forecast	May 2020 - Base	May 2020 - Base	May 2020 - Base	May 2020 - Low	May 2020 - Low	May 2020 - Base
Electric Price Forecast	May 2020	May 2020	May 2020	May 2020	May 2020	May 2020
Gas Price Forecast	May 2020	May 2020	May 2020	May 2020	May 2020	May 2020
Coal Price Forecast	2020	2020	2020	2020	2020	2020
Coal Retirement	Announced	Announced & Allowed	Announced & Allowed	Announced & Allowed	Announced & Allowed	Announced & Allowed
Generic Resources for new Energy Efficiency & Demand Response	Additional Low or Aggressive EE and/or Low DR Allowed to be Selected but not Forced	Forced Aggressive EE & Low DR additional resources in CO	Existing DSM/EE only	Additional Low or Aggressive EE and/or Low DR Allowed to be Selected but not Forced	Existing DSM/EE only	Forced Aggressive EE & Low DR additional resources in CO
RPS Level	NM & CO Requirements	NM & CO Requirements	NM & CO Requirements	NM & CO Requirements	NM & CO Requirements	NM & CO Requirements
Carbon Reduction[17]	No Carbon Restriction	80%	80%	80%	80%	Restricted CO resources

[17] Amount of CO_2 reduction required from 2005 baseline in regards to serving wholesale electricity sales in Colorado.

Comparison by Location

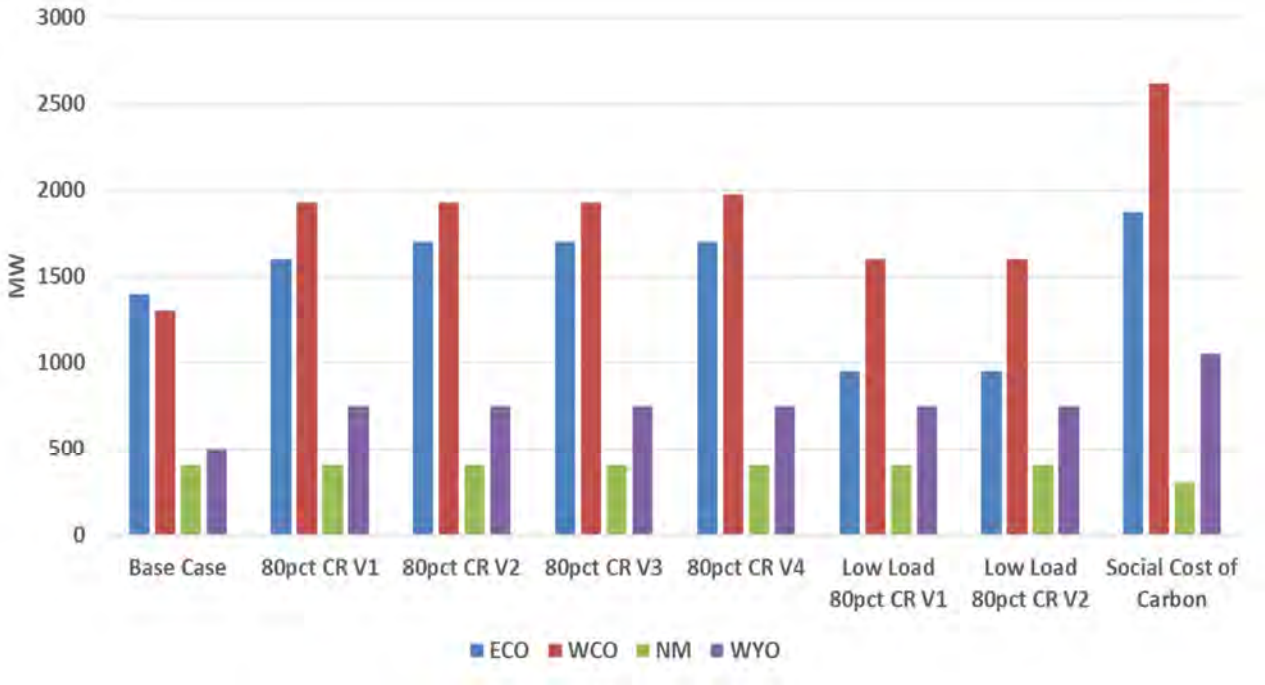

Figure 17: Resource Additions by Region for the RPP

Comparison by Technology

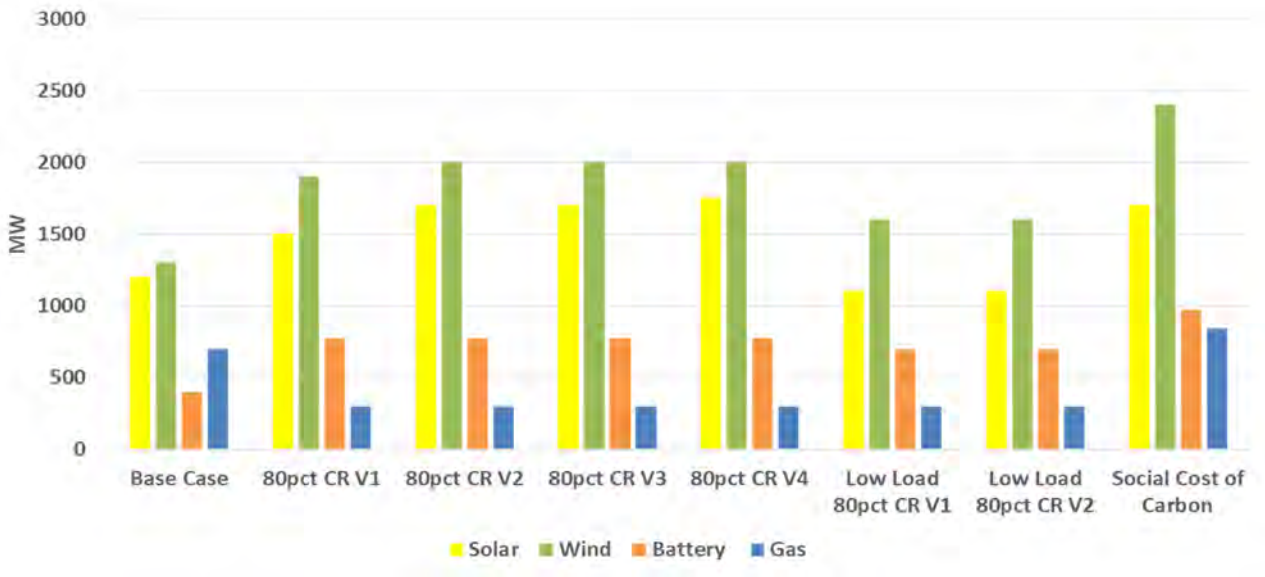

Figure 18: Resource Additions by Technology Type for the RPP

Comparison of Thermal Resource Retirements

All retirements show in first year offline.

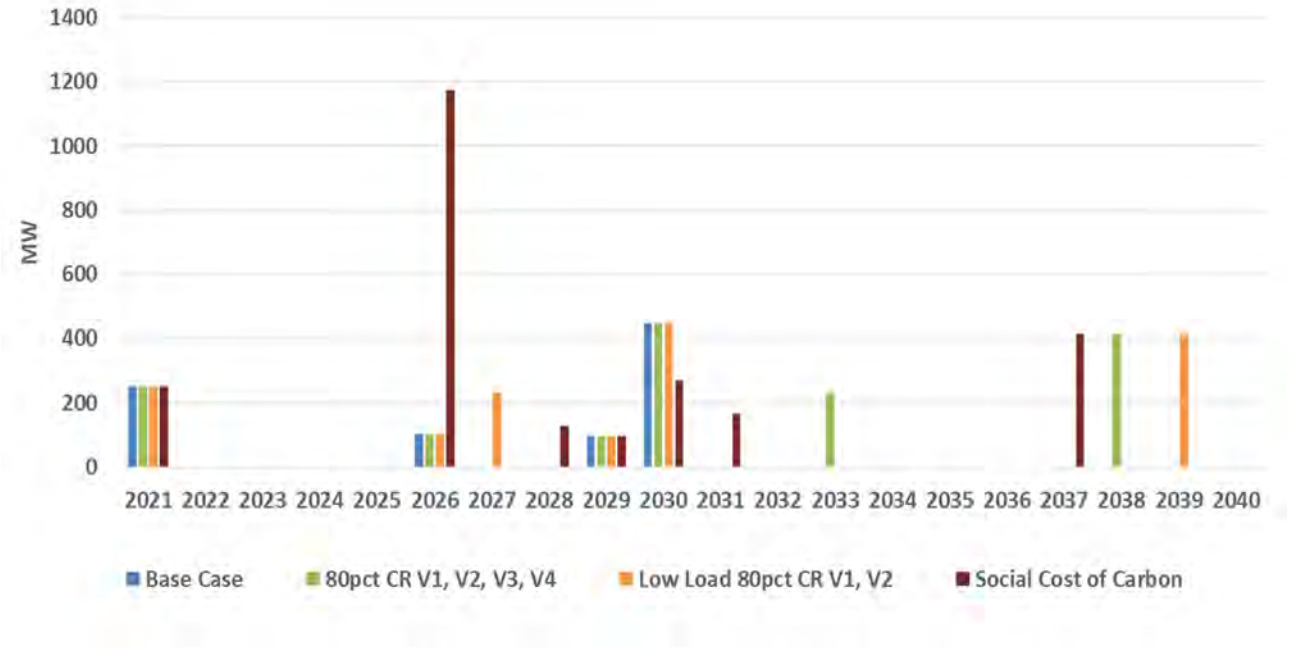

Figure 19: Thermal Retirement Comparison by Year

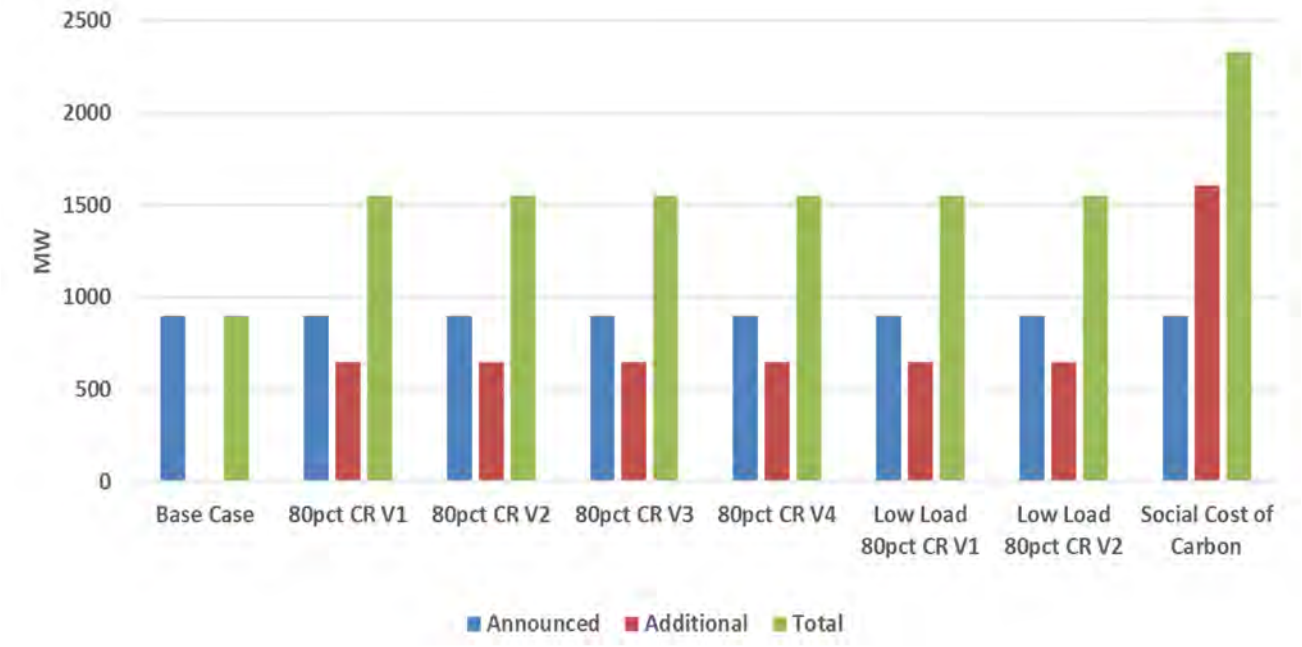

Figure 20: Thermal Retirement Comparison by Type for the RPP

Comparison of Planning Reserve Margins

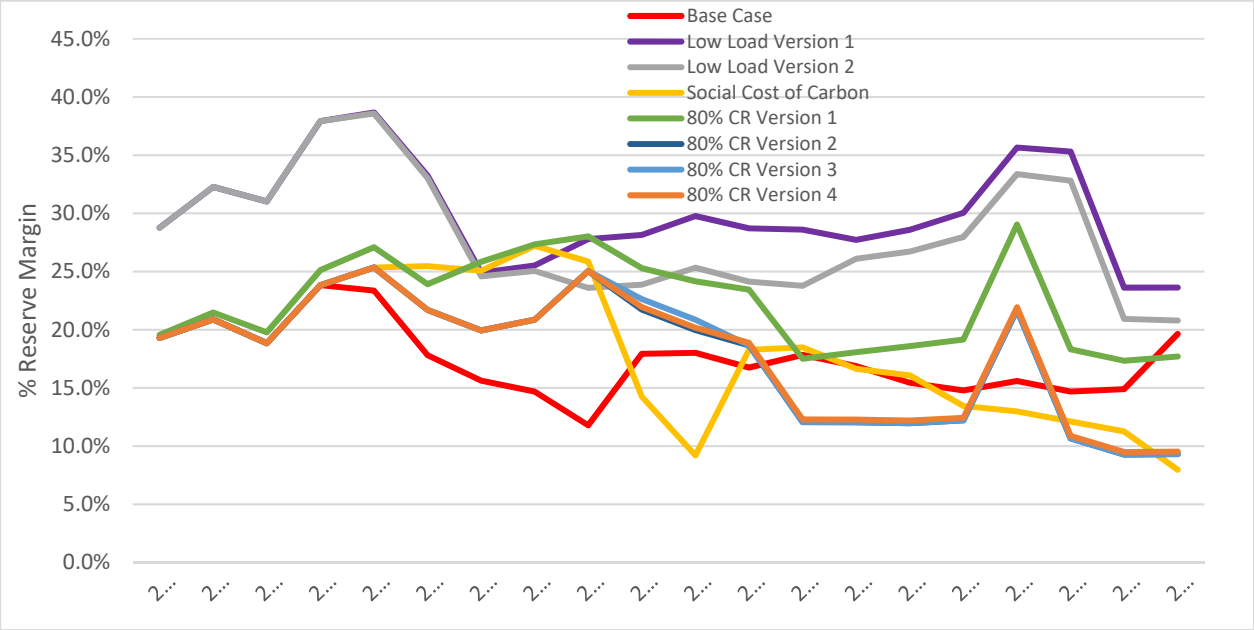

Figure 21: Comparison of Planning Reserve Margins

Social Cost of Carbon Comparison– System Wide (Nominal $)

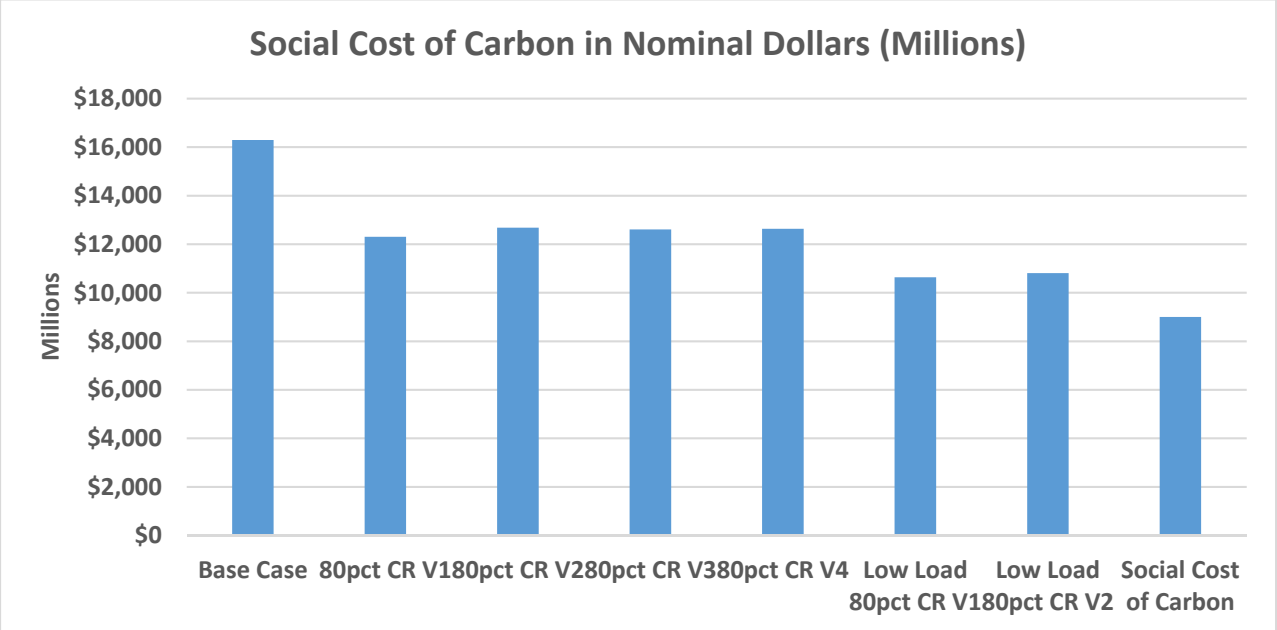

Figure 22: Comparison of Nominal Dollars for Social Cost of Carbon for the RPP

Comparison of CO2 Emissions & Reduction in Colorado in 2030

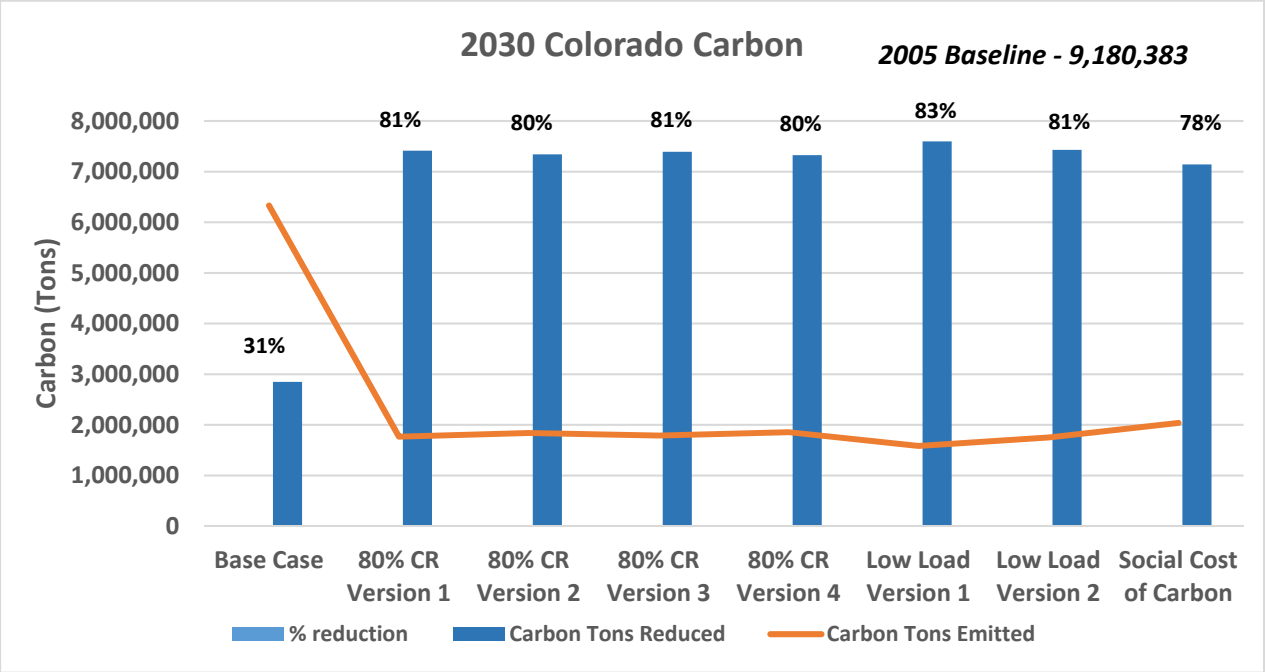

Figure 23: Comparison of Carbon Reduction in Colorado in 2030 (versus 2005 Baseline Levels)

Comparison of Significant Transmission Network Upgrades

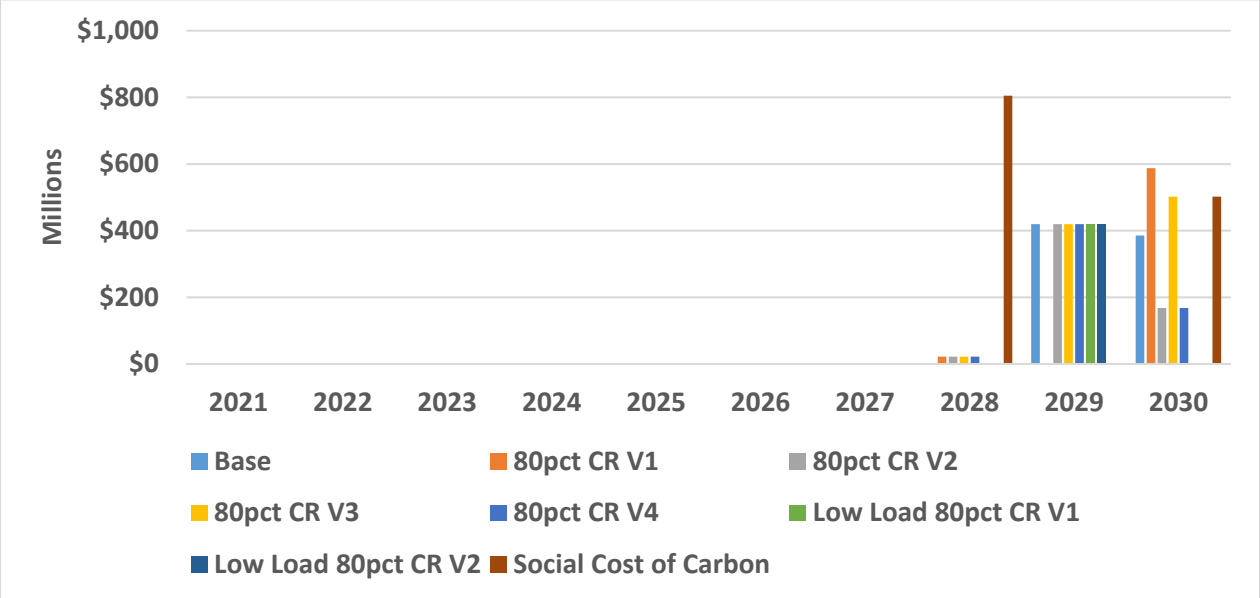

Figure 24 Significant Transmission Network Upgrades over RAP

Present Value Member Revenue Requirement Comparison (nominal dollars)[18]

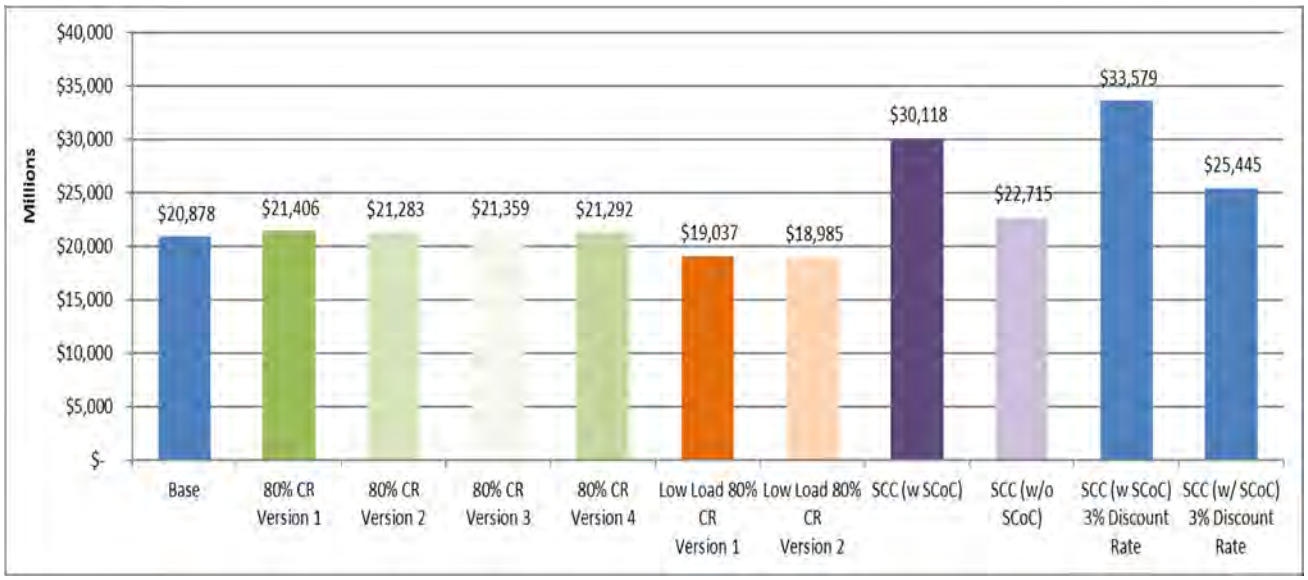

Figure 25: Comparison of Present Value Member Revenue Requirement over RPP

Expansion Plan Capex + IDC Comparison (nominal dollars)

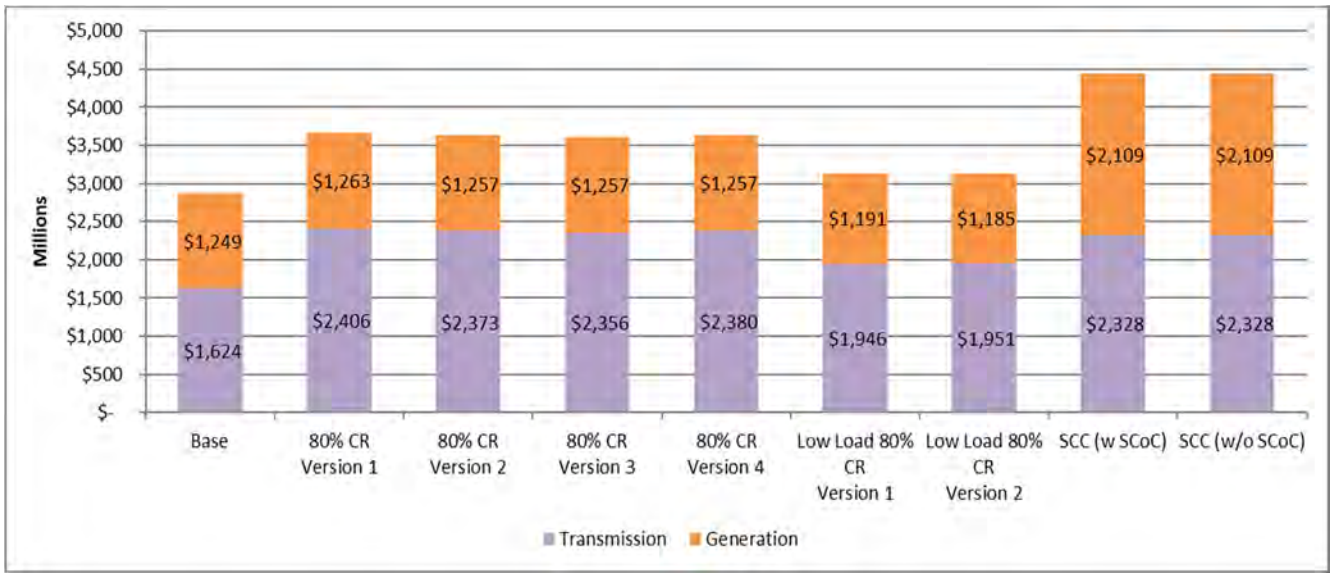

Figure 26: Comparison of Capital Expenditures and Interest During Construction over RPP

[18] A discount rate of 4.15% was used in calculating PVRR for all scenarios. An additional PVRR for the SCC scenario was calculated based on a 3% discount rate.

Emission & Water Usage Comparison System-Wide

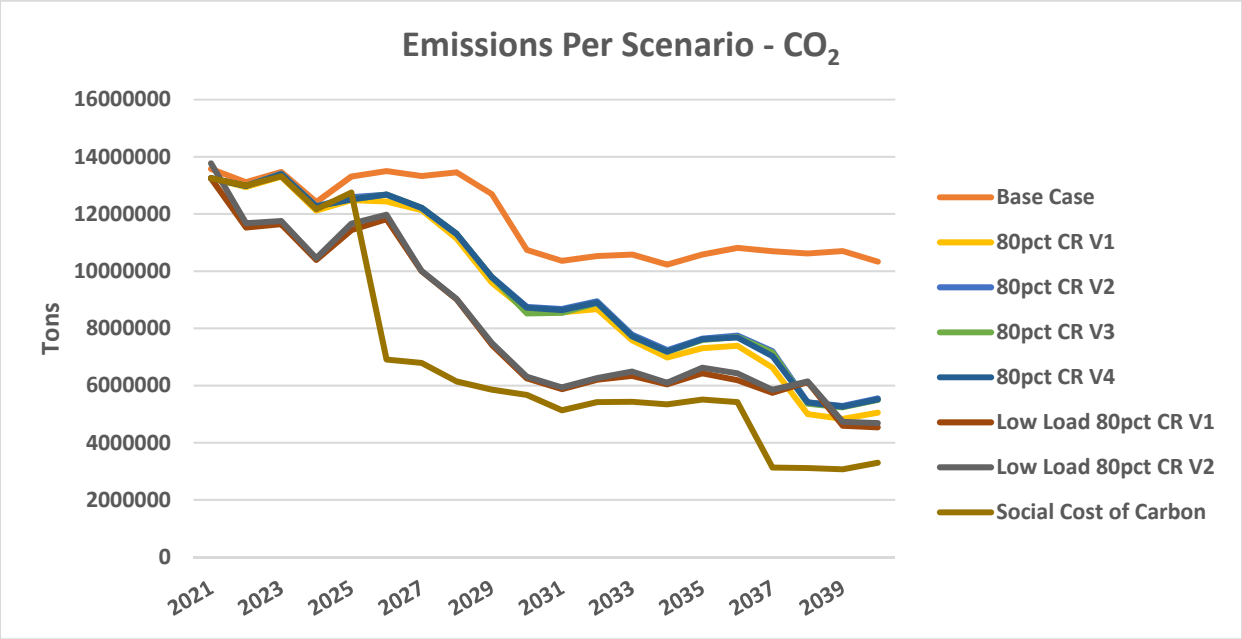

Figure 27: Comparison of CO_2 Emissions per Scenario

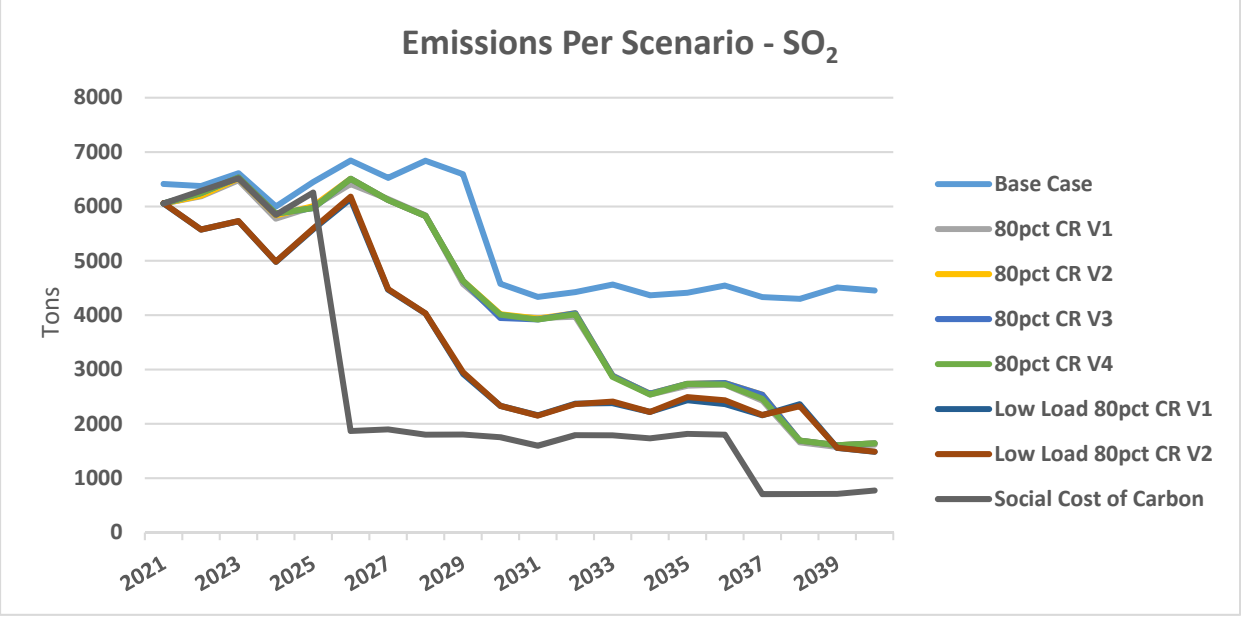

Figure 28: Comparison of SO_2 Emissions per Scenario

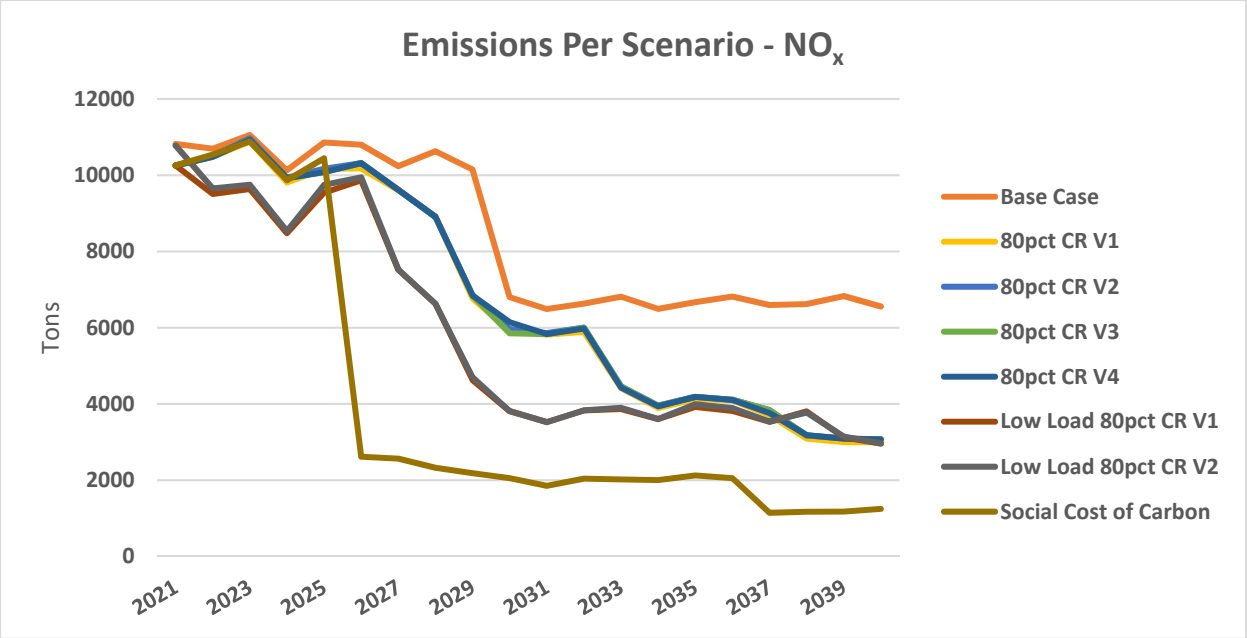

Figure 29: Comparison of NO_x Emissions per Scenario

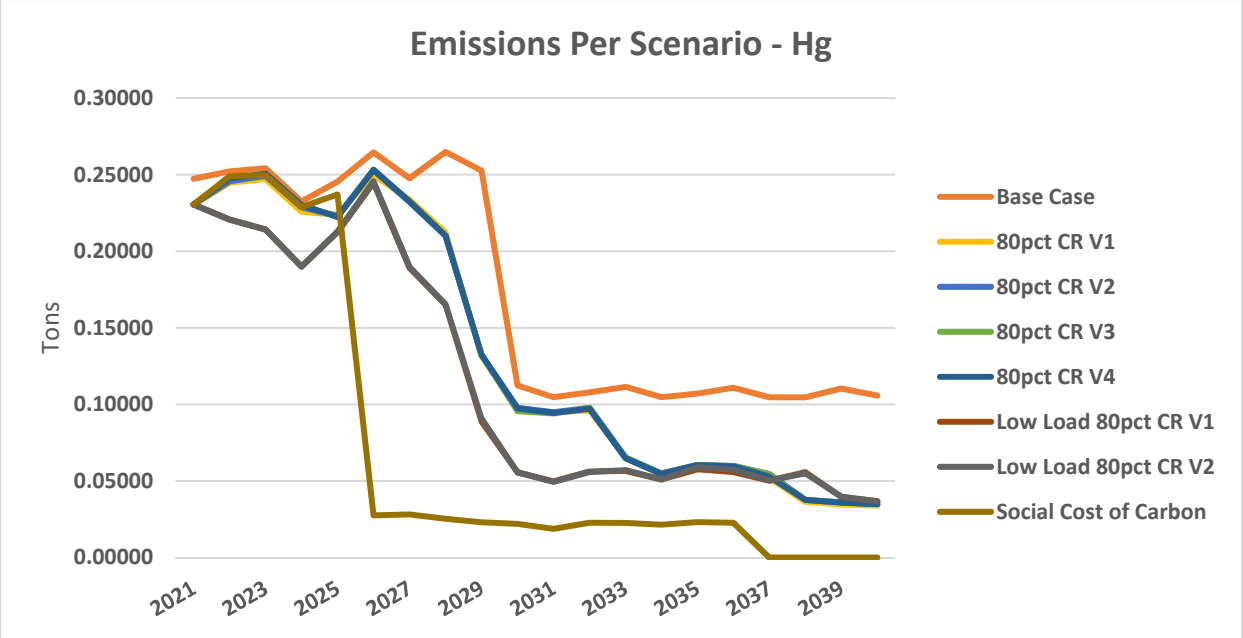

Figure 30: Comparison of Hg Emissions per Scenario

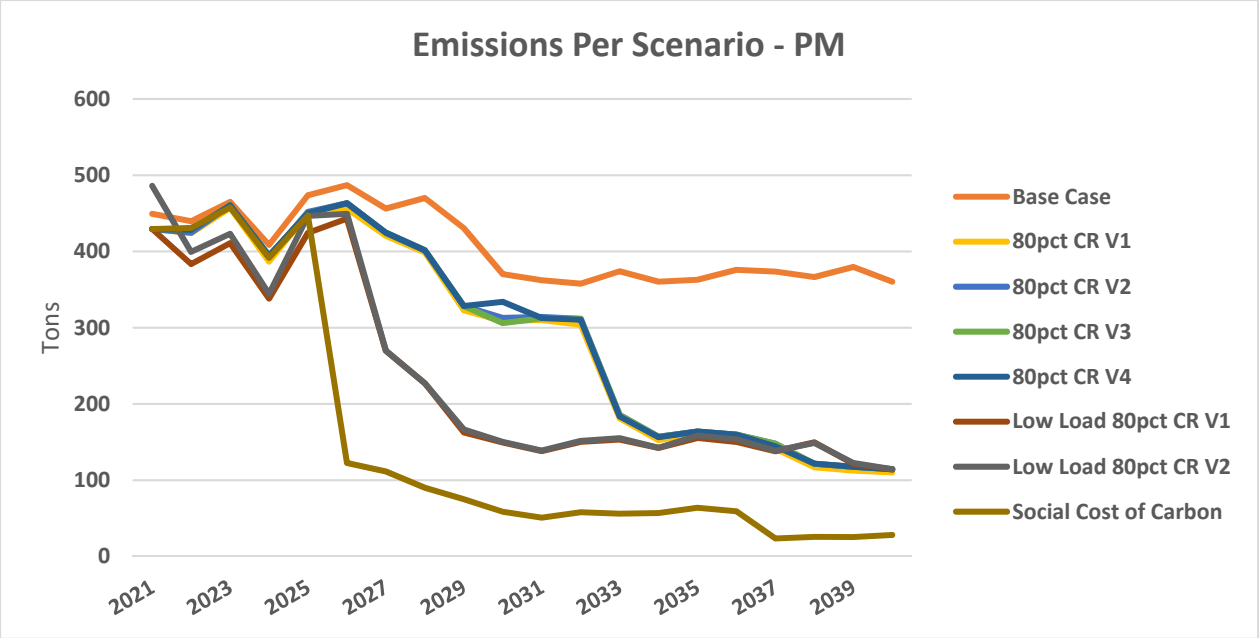

Figure 31: Comparison of PM Emissions per Scenario

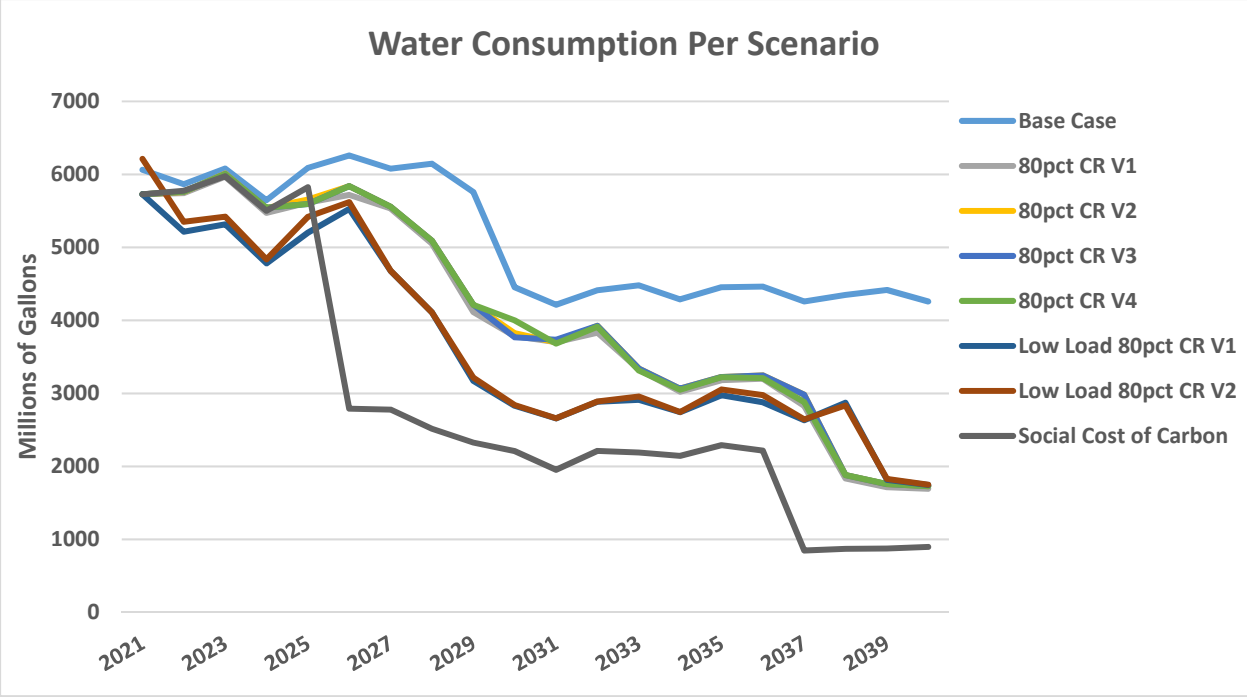

Figure 32: Comparison of Water Consumption per Scenario

RES/RPS Comparison

All scenarios fully meet Colorado RES and New Mexico RPS over the RAP. Data was checked both with contract energy profiles for existing and under contract, resources as stored in Hyperion for financial analysis and with the variable (intermittent) energy resource profiles as developed and used for dispatch in PO. Key drivers for meeting renewable energy or portfolio standards include retirement of thermal resources, significant planned addition of renewables and a focus on carbon reduction targets in the state of Colorado. See Attachment Vol II 6-2 RES/RPS for renewable standard evaluation of each scenario.

Diversity, Dispatchability, & Reliability Comparison

Tri-State applied a qualitative analysis to each scenario based on diversity, dispatchability and reliability defined as follows:

- Diversity is determined as having variability in fuel supply and location in resource mix.
- Dispatchability is determined as the operational ease of increasing or curtailing the resource mix as well as financial impact.
- Reliability is determined as a resource mix with strong ability to support the grid and flexibility in providing ancillary services

A score of 1 = Low, 2 = Medium and 3 = High.

Each alternative scenario scored high on diversity for both technology and location. All scenarios include varying levels of solar, wind, energy storage and gas resources and such resources are dispersed across the eastern Colorado, western Colorado, New Mexico and Wyoming regions within the model. The base case scores at a medium level on diversity due to a high quantity of thermal resources, both existing and generic. There are technical or economic feasibility limitations to the location of particular technologies within Tri-State's footprint. For instance, solar is technically feasible in western Colorado, but wind is not. Conversely, in Wyoming wind is more feasible than solar. The generic resource data set used for all scenarios reflected these feasibilities.

Dispatchability is highest in the base case as the expansion plan has a higher level of dispatchable resources allowing more ramping flexibility to handle the integration of intermittent resources. However, all GHG/CO_2 reductions scenarios have a reasonable level of dispatchability, as a significant portion of existing thermal resources, primarily gas, are retained in the plan along with the addition of a combined cycle gas resource and adequate amounts of energy storage. The SCC scenario retires significantly more thermal resources, but does add a larger quantity of expansion plan gas resources.

Reliability is the highest in the base case as the expansion plan includes a higher quantity of thermal resources, which historically have a greater capacity to support the grid in regards to reserves, regulation and voltage support. However, all GHG/CO_2 reduction scenarios have a reasonable level of retention of existing thermal resources along with addition of energy storage that will be used to help integrate renewables in a transitioning grid.

Table 106 illustrates the base case and scenario ranking in all three of these areas.

Table 106: Diversity, Dispatchability & Reliability Scoring

Scenario	Diversity	Dispatchability	Reliability	Total Score
Base	2	3	3	8
80% CR V1	3	2	2	7
80% CR V2	3	2	2	7
80% CR V3	3	2	2	7
80% CR V4	3	2	2	7
Low Load 80% Carbon Reduction V1	3	2	2	7
Low Load 80% Carbon Reduction V2	3	2	2	7
Social Cost of Carbon	3	2	2	7

Comparison Summary

The Base Case and seven alternative scenarios all share assumptions such as the same generic resource data set, commodity pricing, and announced coal retirements. Assumptions varied between scenarios in regards to DSM/EE, allowable thermal retirements, build limits by technology and location, transmission links and GHG/CO_2 reduction levels and/or costs.

All scenarios had a reasonable mix of solar, wind, energy storage and gas. The Base Case and SCC scenario had the most gas additions, but this is primarily due to a restriction on all other scenarios to meet GHG/CO_2 reduction goals in the state of Colorado. The SCC scenario also had significantly higher quantities of thermal resource retirements resulting in additional expansion plan gas resources. Energy Storage becomes increasingly more competitive across the RPP. Renewables begin and remain competitive throughout the RPP.

All scenarios to some extent utilize transmission interconnection capacity made available by thermal retirements. All plans show considerable resource additions in WCO due to the transmission capacity that will become available through the retirement of the Craig facility. Tri-State's primary transmission constraints resulting in a need for network upgrades occur in ECO. The ECO load area represents a significant portion of Tri-State's system load and most long-term load growth is focused in this area.

Retirement of existing thermal resources vary by scenario with SCC showing the highest volume of retirements. Announced retirement dates are included in all scenarios, and all scenarios except for the Base Case allow additional coal retirements starting in either 2025 or 2026. This timing limit allows for a reasonable timeframe for replacement decisions and acquisition of replacement resources. The SCC scenario also allows gas retirements.

Planning Reserve Margins (PRM) primarily run high between ~15% to ~25% during the RAP. Spikes are seen when thermal retirements occur and additional resources are brought on. The elevated PRM is due to the low energy cost of renewables coupled with lower capacity credits for renewables than their thermal counterparts as well as the semi-dispatchable nature of energy storage.

The Base Case shows GHG/CO_2 reduction of 31% in the state of Colorado as measured against a 2005 baseline. All other scenarios have GHG/CO_2 reductions in the state of Colorado as measured against a 2005 baseline of ~80%. System wide emissions and water usage are significantly reduced for all scenarios over the RAP. The calculated SCoC is the lowest in the SCC scenario but is also substantially reduced from

the base case in all 80% CR (base and low load) scenarios. The overall environmental impact of GHG/CO_2 reduction in all alternative scenarios is significant.

All scenarios easily meet Colorado and New Mexico RPS/RES requirements. This is driven by both the competitiveness of renewable resources as well as the GHG/CO_2 restrictions to meet state of Colorado goals.

As more thermal retirements result in fewer dispatchable resources on the bulk electric system. Tri-State has concerns about potential financial impacts driven by Balancing Authority alternative steps to continue to secure the reliability of the grid. While all of these scenarios have a reasonable diversity, dispatchability, and reliability mix from a planning perspective, it is critical for Tri-State to be aware of resource mix changes occurring in relation to the actions of other utilities in the Rocky Mountain and Southwest regions and to step into changes to resource mix in a responsible manner to ensure reliability and financial stability for Tri-State's Utility Member Systems. A representation of this regional impact can be seen in Figure 33.

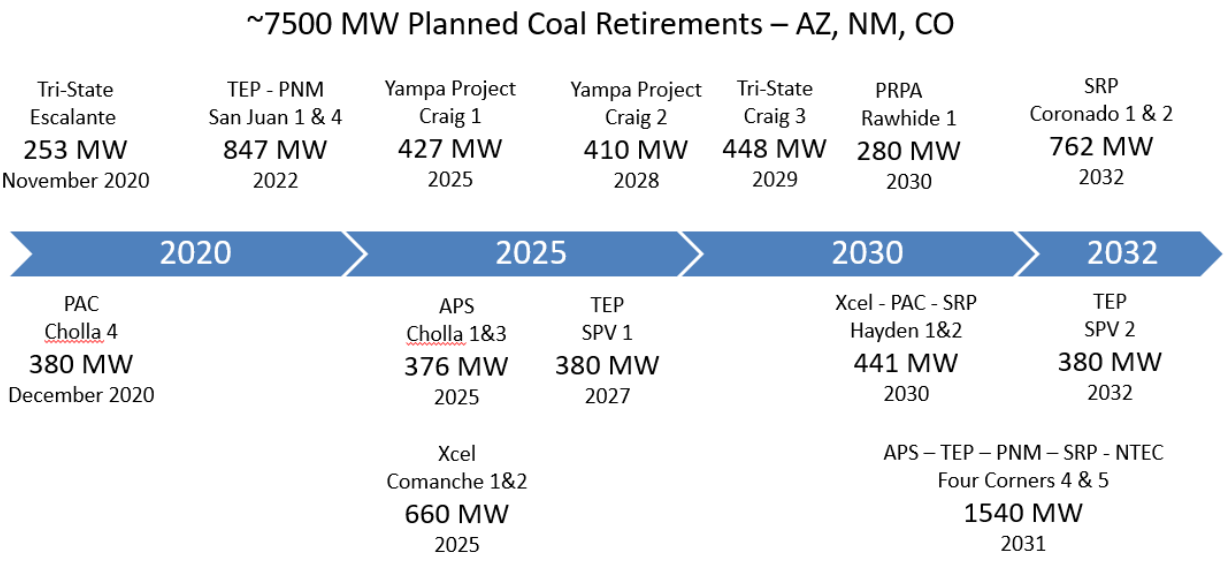

Figure 33: Planned Coal Retirements in Arizona, New Mexico and Colorado

10 Summary of Preferred Plan

In assessing the Base Case and Alternative Scenarios, Tri-State has selected the 80% CR V4 scenario as its preferred plan. Primary reasons for this selection include:

- Generation locations and technology diversity, as illustrated in Figure 34 are sufficient to fully utilize interconnection capability made available from announced retirements.
- Forecast additional thermal retirements projected to occur after the RAP as shown in Figure 35 and in addition to announced retirements during the RAP, allow a manageable transition to zero carbon resources while maintaining reliability and affordable rates.
- Transmission system network upgrade costs are minimized during the RAP compared to the base case.
- The PVRR for the RPP is ~$400M higher than the Base Case while achieving the state of Colorado GHG/CO_2 reduction target of 80% GHG/CO_2 reduction by 2030 from a 2005 baseline.
- Overall emissions and water usage are significantly reduced by 2030 from current levels and are significantly lower than in the Base Case.
- The scenario uses a glide path from 2025 to 2030, as illustrated in Figure 36, for carbon reduction goals in the state of Colorado to achieve meaningful reductions in the near term.

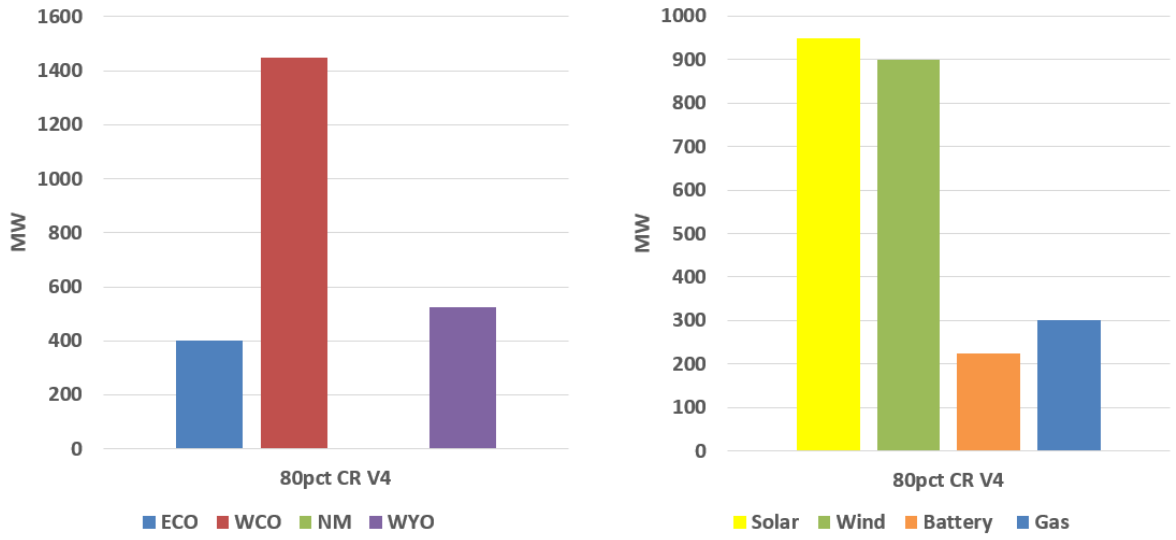

Figure 34: Preferred Plan Resource Additions over the RAP

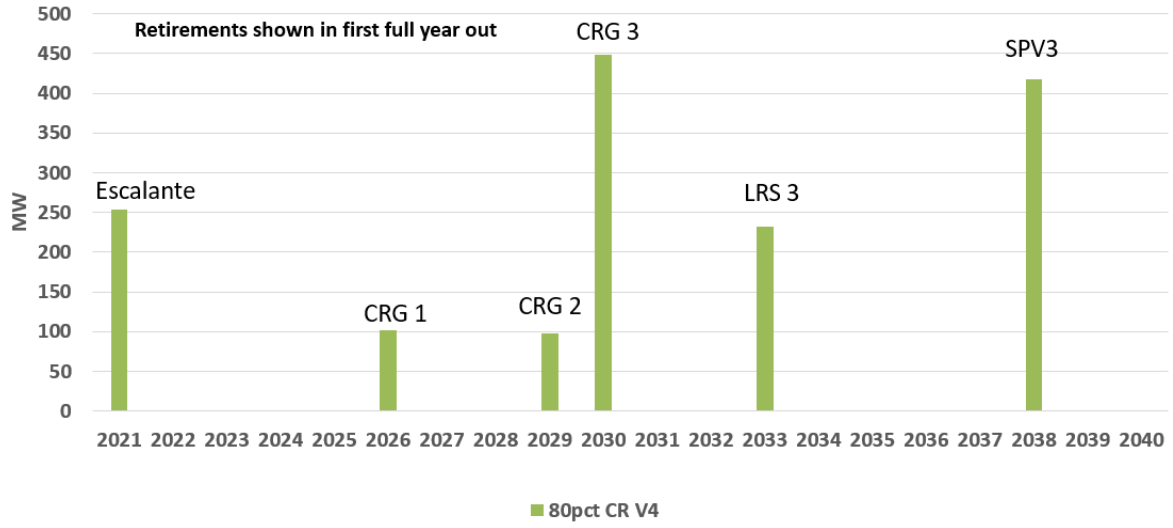

Figure 35: Preferred Plan Announced & Proposed Retirements

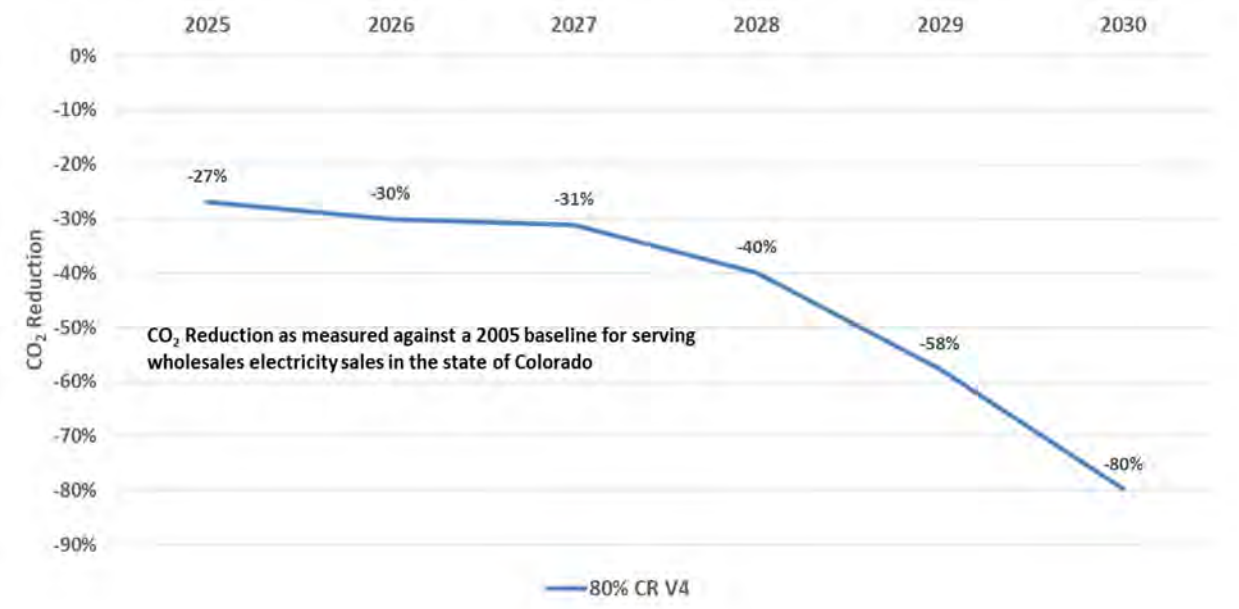

Figure 36: Glide Path to 80% CO_2 Reduction in 2030 from 2005 Base (Serving electricity sales in Colorado)

While this particular scenario does not include increases in DSM as an expansion plan resource, Tri-State is actively working on expanding DSM and EE programs to the extent Utility Member Systems are interested. As these programs are developed and expanded the resulting decrease to capacity needs in relevant years may affect future expansion plans. This scenario like all scenarios has a significant transmission capital expense component. As future resource plans are developed through the Commission ERP and WAPA IRP processes, Tri-State will continue to investigate ways to incorporate higher quantities of renewable resources while limiting transmission expense including the need for

network upgrades. DSM and EE as well as the expected move of some Utility Member Systems from all requirements contracts to partial requirements contracts driven by the desire to serve retail load with more distributed generation will help this effort and will continue to be explored in Tri-State's 2023 ERP.

This scenario retires thermal generation and replaces it primarily with renewables along with some energy storage and one 300 MW gas resource. The evolution of the grid away from thermal dispatchable resources to intermittent resources creates the potential for reliability and financial uncertainty, but the preferred plan takes a measured approach to minimize this risk.

11 Resource Acquisition Period - Action Plan

Action Plan Items

Tri-State's Action Plan covers the period of 2021 to 2030 (RAP). Items will be addressed as necessary between the Phase I final ruling and the next Colorado ERP filing, which is June 1, 2023. Tri-State will file annual updates to this Resource Plan and related Action Plan items with the Commission and WAPA.

Phase II Capacity Need:

Tri-State's base case scenario indicates a capacity need in 2029. In order to meet near term emissions reductions additional renewable resources are forecast for deployment in the preferred plan during the RAP. Table 107 identifies resources by location, nameplate capacity, technology and year, as determined in the preferred plan.

Table 107: Preferred Plan Resources during RAP

Location	Capacity (MW)	Technology	Year
East Colorado	100	Wind	2025
Wyoming	100	Wind	2025
West Colorado	200	Solar	2026
Wyoming	100	Wind	2026
West Colorado	100	Solar	2027
West Colorado	200	Solar	2028
Wyoming	100	Wind	2028
West Colorado	200	Standalone Battery	2029
West Colorado	200	Solar	2029
East Colorado	100	Wind	2029
Wyoming	100	Wind	2029
Wyoming	25	Standalone Battery	2030
West Colorado	300	Natural Gas - Combined Cycle	2030
West Colorado	250	Solar	2030
East Colorado	200	Wind	2030
Wyoming	100	Wind	2030

Given the uncertainty related to Tri-State load in the near term, Tri-State anticipates that its initial Phase II process will focus on resource needs by 2025, as indicated by the shading in Table 107. We anticipate that resources needed for the period from 2026 to 2030 will be addressed in the June 1, 2023 ERP or subsequent ERPs.

By 2023, we will have better information regarding potential load reductions that could reduce capacity needs after 2025. In addition, while the RAP extends from 2021 to 2030, Tri-State is reluctant to engage in activities to add conventional thermal resources (300 MW natural gas combined cycle in 2030) without allowing time for emerging technologies that provide equally reliable capacity, but with lower emissions, to become competitive.

Milestone – Tri-State intends to procure all resources in the preferred plan through 2025 as part of a competitive bidding process in Phase II. The start of Phase II will be dependent upon the timing of Phase I and the overall direction or the Commission. Tri-State plans to update progress on this item each year in its required IRP and ERP APR process.

Utility Member System Programs:

Tri-State plans to use the DSM EE Potential study produced by Mesa Point Energy and included as Attachment Vol II 5-1 Demand Side Management & Energy Efficiency Potential Study as a starting point from which to work with Utility Member Systems to establish additional DSM and EE programs over the RAP.

Tri-State plans to use the BE study produced by Mesa Point Energy and included as Attachment Vol II 5-7 Beneficial Electrification Potential Study as a guide from which to work with Utility Member Systems to establish BE programs over the RAP.

Milestone – Tri-State plans to update progress on this item each year in its required IRP and ERP APR process. Established programs with forecast growth will be utilized in the modeling for the June 1, 2023 IRP/ERP process.

Retirement Analysis:

With the announced retirement dates of Springerville Unit 1 and Springerville Unit 2, Tri-State plans to engage in discussions with SRP, the owner of Springerville Unit 4, as well as other parties necessary to determine the impacts on Springerville Unit 3 for future resource planning.

While the preferred plan indicates a retirement of LRS Unit 3 by 2033, we note that there is no agreement in place to that would be required to implement this retirement with the co-owners of the Missouri Basin Power Project. Modeling performed under the preferred plan showed that the continued operation of both LRS Unit 2 and Unit 3 at levels needed to satisfy and maintain an 80% CO_2 reduction in Colorado would not be economic, which is why the preferred plan reflects a retirement of LRS Unit 3.

Milestone – Tri-State plans to update progress on this item each year in its required IRP and ERP APR process. Tri-State will incorporate relevant changes in its modeling for the June 1, 2023 IRP/ERP process.

Model Improvements:

Tri-State plans to modify its current modeling software or replace if necessary, in order to improve modeling items prior to June 1, 2023 ERP. Key items slated for modeling improvement include but are not limited to: ability to handle emission reductions on a state-by-state basis in a robust manner, ability to model sub-hourly effects, more robust modeling of intermittent resources, streamlined management of transmission capex impacts, and improved treatment of intermittent resource curtailments.

Milestone – Tri-State plans to begin efforts for modeling software replacement or improvements in 2021 with completion in 2022 in time to begin the modeling for the Jun 1, 2023 IRP/ERP process.

Phase II Competitive Bidding Process & Criteria

A Request for Proposals (RFP) will be released soon after the issuance of the Commission's final Phase I decision approving and/or modifying Tri-State's ERP application. In support of this RFP, Tri-State has prepared competitive bidding documents organized as a single, all-source RFP seeking proposals for three different resource types. The RFP focuses on Power Purchase Agreements (PPA) as the likely transactional structure and does not contemplate any utility build or ownership options at this time.

The Phase I decision will define the scope of the RFP. As a result, this competitive bidding process description and RFP documents may be modified or supplemented as necessary to conform to the Commission's Phase I decision.

The RFP currently identifies three distinct categories of resources Tri-State will consider for resource additions.

1. Renewable Resources - All intermittent renewable and carbon-free resources without co-located storage whose pricing will be offered on an annual energy-only price. This includes, but is not limited to, wind and solar, hydroelectric, geothermal, biomass, and in Colorado, recycled energy or eligible coal-mine methane.

2. Semi-Dispatchable Resources - All stand-alone energy storage systems or resources coupled with storage systems that are limited in the amount of energy delivered during a particular cycle. This includes, but is not limited to, stand-alone battery systems, pumped hydro, compressed air energy storage systems as well as renewable resources with co-located thermal or battery storage.

3. Firm Capacity Resources - New or existing gas generation or any other resource that can be dispatched by Tri-State for a reasonable amount of time without any restriction on duration at the rated maximum capacity threshold. Renewable or carbon-free resources such as hydroelectric, biomass, and geothermal capable of this requirement may be bid into this resource type. Resources that include carbon capture technologies may be considered under this category as well.

RFP Documents

The RFP documents will be posted on the Tri-State website when the RFP is released. Any confidential or highly confidential information will be made available in accordance with a nondisclosure agreement as directed by Rule 3605(g)(II)(G)(iv) and which form is filed in an appendix to this ERP.

1. **RFP** – Announces the solicitation for resources. Provides a general description of Tri-State's system, outlines proposal submittal deadlines and other key dates in the evaluation schedule, identifies the required contents of a proposal, provides evaluation criteria, describes the resource types, contract terms, and minimum project size Tri-State is seeking. The RFP also includes contact information for submitting questions about the process.
2. **Model Contracts** - Developed for each of the resource type categories and that reflect Tri-State's expected PPA terms and conditions.
3. **Form Nondisclosure Agreement (NDA) -** Rule 3605(g)(II)(G)(iv) requires that bidders be provided with an NDA necessary for gaining access to confidential and highly confidential modeling inputs and assumptions filed in the Docket.
4. **Voluntary Consent Agreement** - Requests that entities proposing projects interconnecting with the Tri-State transmission system provide consent to allow the merchant function to communicate with the interconnection administrator (Tri-State Transmission function) regarding the project or projects submitted into the RFP.
5. **Bidder Response Forms** - These forms are in Microsoft Excel format with multiple tabs that request key data related to each proposal to allow Tri-State to evaluate each project and option offered.

Bid Fee

A non-refundable bid fee of $5,000 will be required. The bid fee is applicable to a single project location and single project technology. A bidder may propose up to three different combinations of pricing, contract term, size or commercial operation date options for a single project without having to submit an additional fee. Projects that are proposed with additional technology options (i.e., wind + solar or solar + battery storage) or different interconnection points will be considered different projects requiring an additional bid fee. Failure to submit the required bid fee will result in a proposal being disqualified from further evaluation.

RFP Release through Receipt of Bids

Pursuant to Rule 3605(g)(III)(D), the Phase I Decision will establish the deadline for the submittal of the ERP Implementation Report that will detail the cost-effective resource portfolios to be presented to the Commission. Given this deadline and the necessary time to fully evaluate the proposals submitted into the RFP and model various resource portfolios, the RFP will be issued to allow bidders approximately six weeks to submit their proposals to Tri-State.

Tri-State will send an email to all developers who have submitted proposals to past Tri-State RFPs to notify them when the RFP is released, as well as sending an email to developers or other entities that have contacted Tri-State since the last RFP and requested notification of future RFPs. Tri-State will announce the RFP release on its corporate website, as well as maintain a dedicated area on its website where the RFP, Commission Orders and other related documents will be posted.

Tri-State will ask bidders to submit a Notice of Intent to Bid (NOI) form (which will be located on the RFP website) within two weeks of the RFP being issued. This is not a mandatory step for bidders to participate in the RFP, but bidders will be encouraged to submit the NOI by the deadline.

Tri-State will answer questions from prospective bidders by posting and regularly updating a Q&A on the RFP website during the period after the RFP is released and before the proposal submittal deadline. This Q&A is intended to benefit all potential bidders and provide for efficient use of Tri-State staff time in providing answers to bidders that may have similar questions. In answering questions, care will be taken not to include identifying information about the bidder or project.

On or prior to the proposal due date, bidders will submit their proposals, bidder response forms, model contract comments, NDAs, and, if applicable, a voluntary form of consent electronically by email through the dedicated RFP email address, as well as ensure that a hard copy of the proposal has also been delivered. Bid fees are to be sent to Tri-State via check or wire transfer.

Upon receipt, Tri-State will ensure that proposals are complete. This includes having received both a hard and electronic copy of the proposals and associated documents, and the appropriate amount of bid fees. If any initial oversight or discrepancy is found, the bidder will be promptly notified and will be given the opportunity to immediately correct the issue.

Bid data will be imported and verified utilizing the bidder response forms. Each proposal and project option will be given the same attention and evaluated individually. The bid data will then be reviewed for completeness to identify any apparent bad data or misunderstandings. If any corrections or additional data are required, Tri-State will notify the bidder within 14 days of the receipt of the proposals.

Analysis of Bids

An initial economic analysis will be conducted where the Levelized Cost of Energy (LCoE) for each project option is calculated using the discount rate approved by the Commission in its Phase I decision. The LCoE will be calculated by determining the “all in” Net Present Value (NPV) of the average annual costs divided by the NPV of the average annual energy.

Projects will be categorized by technology within each resource type, commercial operation date, contract term, size, and location in order to ensure a meaningful comparison and analysis.

Projects will then be reviewed with respect to non-price factors. These will include the following:

- Best Value Employment Metrics
- Contribution to meeting GHG reduction goals of Colorado
- Location in a Tri-State utility member system service territory
- Financial viability of the bidder, including its parent or any other guarantor of services under the bidder's proposal

- Bidder's prior experience with project development
- Certainty of outside funding sources (i.e. tax credits or government subsidies)
- Compliance with all applicable local, state and federal laws, rules and orders
- Renewal and purchase options at the end of PPA
- Project retirement / decommissioning plan
- Legal, engineering and other costs required to implement the proposed project
- Forecasting capability

Tri-State may consider other factors that it deems to be relevant to its supply portfolio needs.

Following the initial analysis of projects on price and non-price factors, projects will then be evaluated with respect to transmission interconnection and network upgrade costs. Bidders are expected to clearly identify projected interconnection and transmission costs in their proposals as well as reflect these costs in the prices associated with each bid.

Following the analysis noted above, Tri-State may contact bidders with questions and requests for clarifying information, including a request to update or refresh pricing.

Short List, Modeling, Portfolio Analysis

Following the interconnection and transmission costs review, certain projects will be advanced to the Resource Planning Modeling group for development of resource portfolios utilizing a capacity expansion planning model, a production cost model, and financial models. The expansion planning and production cost modeling will take advantage of the detailed project data provided by bidders to better determine an overall system dispatch cost in the context of serving forecast load on the Tri-State system and the financial models will incorporate additional corporate data to determine the Net Present Value Revenue Requirement of each portfolio.

The modeling process will culminate in various resource portfolios, which together with a discussion of the non-price factors, will be included in an ERP Implementation Report to be filed as directed by the Phase I decision. The report will present various cost-effective portfolios comprised of projects bid into the RFP.

Project Agreement Negotiations and RFP Conclusion

Based on a final Commission Phase II Decision giving approval of a portfolio and potential back-up bids, Tri-State will complete its contract negotiations to implement the approved plan. Contingent on the final Phase II Decision, Tri-State may choose to commence contract negotiations after submitting its ERP Implementation Report.

Once agreement is reached on key terms, a contract will be signed if all terms are within the scope of the approval granted by the Commission and the Tri-State Board of Directors.

Once all contracts are finalized and the RFP has concluded, Tri-State will provide feedback to any bidder whose projects were not selected in the RFP process that has requested such feedback. This usually takes place on a phone call, but could occur in person or by email. Further, pursuant to 3605(h)(III) and (IV) Tri-

State will file a proposal to refile all confidential and highly confidential information related to the bids as well as post this information to the website.

ERP Implementation Report Plan

Tri-State proposes to include the following information in its Phase II ERP Implementation Report:

Proposed Resource Information

- Name of Bidder
- Project Name
- Location of Resource
- Resource Technology
- Nameplate Rating of Resource
- In-Service Year
- Contract Term
- Interconnection Point
- Interconnection Costs
- Levelized Cost of Energy
- Storage Capacity (if applicable)
- Storage Duration (if applicable)

Proposed Portfolio Information

- PVRR with and without SCoC
- Generation and Transmission CapEx
- Timing and location of network upgrades if applicable
- CO_2 reduction in Colorado in 2030 from a 2005 baseline
- SCoC totals by portfolios (Total emissions times SCoC)
- Planning Reserve Margin
- Emissions and Water Usage

12 Confidential and Highly Confidential Information

Confidential Information

Pursuant to Commission Rule 3605(a)(IV)(K), the following is a list of information included in this ERP Filing and which Tri-State has designated as confidential information:

- Scheduled Outage Plan (Maintenance)

Highly Confidential Information

Tri-State believes the following information requires extraordinary protection as highly confidential information:

- Fixed O&M expenses
- Variable O&M expenses
- Coal contract pricing and forward curve
- Unit specific capital balances, depreciation, amortization, impairment and decommissioning
- Contract/PPA energy rate, except in regards to Tri-State's LAP and CRSP hydropower purchase contracts with WAPA.
- Contract/PPA capacity rate, except in regards to Tri-State's LAP and CRSP hydropower purchase contracts with WAPA.
- Performance or operating output guarantees and any associated pricing adjustments included in Tri-State' Renewable PPAs
- Any information protected by a confidentiality clause in a PPA.
- Load forecast information at the Utility Member System level
- Renewable PPA and build transfer pricing for generic resources based on B&V proprietary model.

List of Acronyms

ACE	Affordable Clean Energy Rule
APR	Annual Progress Report
ARIMA	Auto Regressive Integrated Moving Average
BA	Balancing Authority
BE	Beneficial Electrification
BEPC	Basin Electric Power Cooperative
BHCE	Black Hills Colorado Electric, Inc.
BHCT	Black Hills Colorado Transmission
B&V	Black & Veatch
CAISO	California Independent System Operator
CE	Capacity Expansion
CO_2	Carbon dioxide
CR	CO_2 Reduction
CRN	Cooperative Research Network
CRSP	Colorado River Storage Project
CSU	Colorado Springs Utility
DER	Distributed Energy Resources
DG	Distributed Generation
DOE	Department of Energy
DR	Demand Response
DSM	Demand Side Management
ECO	Eastern Colorado
EE	Energy Efficiency
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
EPA	Environmental Protection Agency
ERPI	Electric Research Power Institute
ERP	Electric Resource Plan
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gases
Hg	Mercury
IRP	Integrated Resource Plan
ISO	Independent System Operator
LAP	Loveland Area Projects
LAPT	WAPA Rocky Mountain Region Loveland Area Projects
LCoE	Levelized Cost of Energy
LGIP	Large Generation Interconnection Process
LOLP	Loss of Load Probability
LRS	Laramie River Station

MBPP	Missouri Basin Power Project
MCP	Member Coincident Peak
M-RETS	Midwest Renewable Energy Tracking System
NERC	North American Reliability Corporation
NO_x	Nitrogen Oxides
NRECA	Nation Rural Electric Cooperative Association
NREL	National Renewable Energy Laboratory
OATT	Open Access Transmission Tariff
PAC	PacifiCorp
PM	Particulate Matter
POI	Point of Interconnection
PR	Partial Requirements
PPA	Power Purchase Agreement
PSCo	Public Service of Colorado
PNM	Public Service of New Mexico
PO	Portfolio Optimization
POD	Point of Delivery
PRPA	Platte River Power Authority
PVRR	Prevent Value Revenue Requirement
QRU	Qualifying Retail Utility
QWU	Qualifying Wholesale Utility
RAP	Resource Acquisition Period
REC	Renewable Energy Credit
REP	Responsible Energy Plan
RES	Renewable Energy Standard
RFP	Request for Proposal
RPP	Resource Planning Period
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SCC	Social Cost of Carbon (Scenario)
SCoC	Social Cost of Carbon
SIP	Regional Haze State Implementation Plan
SO_2	Sulfur Dioxide
SPP	Southwest Power Pool
SPV 3	Springerville Unit 3
SRP	Salt River Project
SRSG	Southwest Reserve Sharing Group
TA	Transmission Area
TEP	Tucson Electric Power
TP	Transmission Provider
WACM	Western Area Colorado Missouri
WAPA	Western Area Power Administration
WCO	Western Colorado

WEIM	Western Energy Imbalance Market
WEIS	Western Energy Imbalance Service
WMPA	Wyoming Municipal Power Agency
WREGIS	Western Renewable Energy General Information System

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TRI-STATE
Generation and Transmission Association, Inc.

A Touchstone Energy® Cooperative



2020 Integrated Resource Plan/Electric Resource Plan

Volume II Technical Appendix

December 1, 2020

Submitted to:

Western Area Power Administration
Colorado Public Utilities Commission

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1 Electric Energy and Demand Forecast

Description of Process 3605(b)(IV)

The base long-term load forecast is prepared with each of Tri-State's Utility Member Systems every year. Tri-State has a four state service territory, with 42 Utility Member Systems and each consists of up to nine retail classes in which a bottom-up forecast methodology is employed.

Inputs:

The primary source for historical retail data by each class of consumers is Rural Utilities Service (RUS) Form 7. Information on the number of accounts, energy use per account, total energy and the average price of electricity is collected monthly from each Member. In addition, data on large commercial accounts is gathered on RUS Form 345. Wholesale Utility Member System billing data is obtained from Tri-State monthly bills to Utility Member Systems.

Weather data from 20 weather stations within Tri-State's region is supplied through DTN Meteorlogix. Tri-State's database includes temperature, heating and cooling degree-days, and precipitation. Weather normalizations of this data are used in forecast models (defined as 10-year average values).

Tri-State obtains economic and demographic data for each Utility Member System from Woods & Poole Economics, Inc. (W&P). The vast majority of data from W&P originates with the Department of Commerce and Bureau of Economic Analysis (BEA). All projections of the economic and demographic data have been performed by W&P. Tri-State uses more than 20 measures of employment and income activity by sector from the W&P data.

The electricity that Tri-State Utility Member Systems provides to its retail customers often competes with propane, natural gas and fuel oil as an energy source. Historical price data for these alternative energy sources is obtained annually from the Department of Energy's (DOE) Energy Information Administration (EIA) State Energy Data System, Petroleum Marketing Monthly and Annual Energy Outlook. Tri-State based its price projections for each of these alternative fuels on information from the EIA.

The statistical models are estimated using annual historical data from 2000 through 2019.

Forecasting Process:

The nine retail classes include residential, seasonal, irrigation, small commercial, large commercial, public authorities, streetlights, resales to RUS, and resales to others. Each retail class, with the exception of large commercial, is broken into the number of customers and use-per-customer, which are then modeled separately and aggregated to arrive at forecast energy. By separating the demand forecast into the use-per-customer and customer components, Tri-State is able to better distinguish between the trends driving growth in the number of customers versus technology or weather impacts on customer-level usage.

Customer forecasts are generated using a combination of econometric techniques, time series regressions and simple trend analyses. Time Series processes typically utilize Auto Regressive Integrated Moving Average (ARIMA) modeling. Econometric models for customers consist of a multiple regression with explanatory variables including, but not limited to, population, employment and income.

Use-per-customer is also modeled using econometric models or simple trend analysis. Multiple regressions on use-per-customer typically consider weather, fuel prices and electric prices; however, in the event that there is not a good model fit, a five-year average is used. The residential use forecast is an exception and utilizes an end-use model when possible.

Additional detail on the forecast modeling by retail class can be found in Ms. Tiffin's direct testimony. Once the forecasts are completed for each Utility Member System, the final step is forecast aggregation to arrive at the Tri-State system forecast.

Demand Forecast:

The projected values of the Member Coincident Peak (MCP) demands are based upon an hourly load forecast. Hourly loads are generated for each calendar month by applying the projected purchased energy requirement to a corresponding normalized historical load duration curve. The resultant hourly loads are dispatched chronologically based upon known historical loads appearing in a typical month. Once individual members' hourly demand forecasts have been determined, they are summed to arrive at a total Tri-State hourly load forecast (using a bottom-up approach), allowing the coincident peak demand to be established.

The peak period used for billing is defined as the period between 12:00 (noon) and 10:00 PM, Monday through Saturday, except certain holidays. The Tri-State aggregate billing peak is the sum of the individual member coincident peaks from the hourly demand forecasts, which occur within the defined peak period. The Tri-State Coincident Peak for capacity planning is the highest hourly sum of Utility Member System hourly demand forecasts in July, as Tri-State is a summer peaking system.

Range of Forecasts 3605(b)(II):

Tri-State developed a range of forecasts including the base, low and high forecasts. To develop the low and high forecasts, Tri-State established prediction intervals to express uncertainty around the expected value forecast. The total variance includes both economic and weather related uncertainty. Intervals are generated for one standard deviation (68.27%) and 90%, meaning that the actual value should be within the given interval with a probability of 68.27% or 90% respectively. The lower limit of the 90% prediction interval was used as the Low Load forecast for Low Load scenarios. Many potential factors exist which could significantly reduce Tri-State's load, including:

- Potential Utility Member System buy-outs
- Transition of some Utility Member Systems from all to partial requirements wholesale electric service contracts
- Increased Utility Member System distributed generation
- Increased demand side management and energy efficiency
- Load reduction due to COVID impacts
- Load loss related to environmental and regulatory impacts to the oil and gas industries

The Low Load forecast represents the potential load reduction that could result from any combination or subset of these items. Figure 1 illustrates the deviation from the base load forecast for the Low load (TS LCL 90^{tH}) forecast as well as other potential load reductions such as Partial Requirements (PR), increased community solar subscription under Board Policy 119, increased distributed generation deployment under Board Policy 115, or the exit of a Utility Member System such as United Power. The figure indicates that the Low Load forecast is comparable during the early years of the RAP to the combination of low load drivers with the exception of a United Power Withdrawal (Total Drivers w/o UP out).

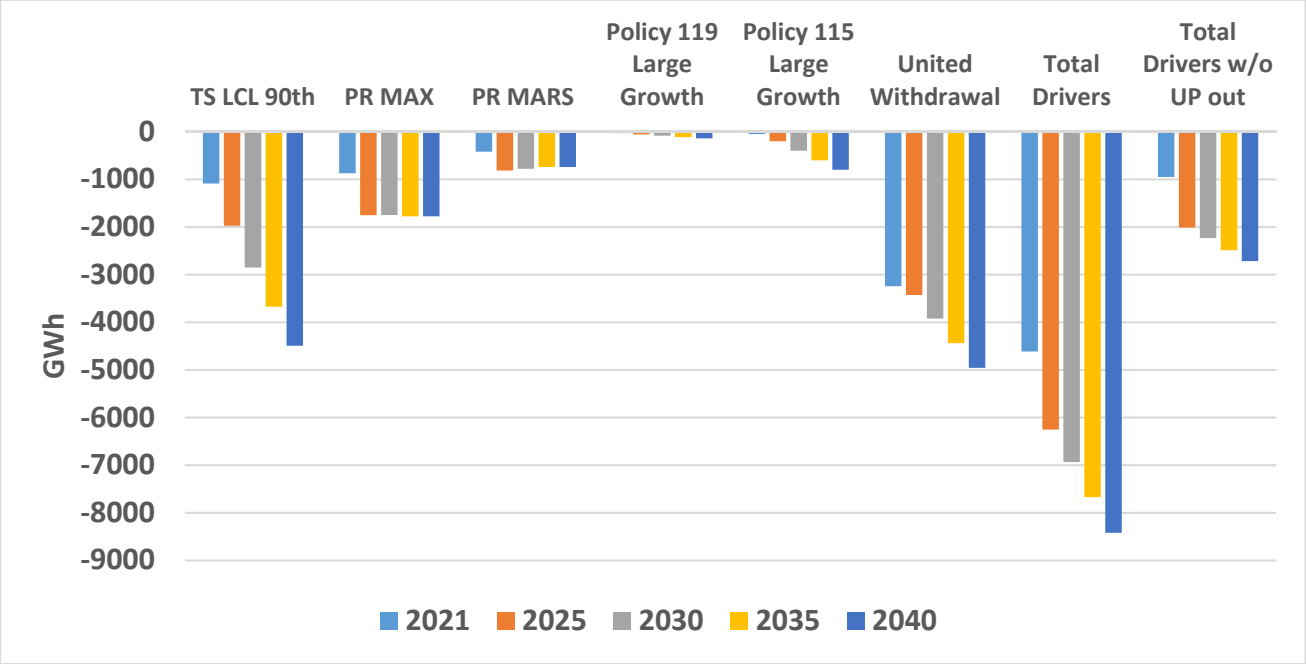

Figure 1: Comparison of Low Load Forecast to Potential Load Reductions - Energy

Tri-State did not conduct an alternative scenario for purposes of this Resource Plan in regards to UCL 90th (High) load forecast due to the number of potential risks that could result in significant reductions to Tri-State's system load. However, both the High Load forecast and Low Load forecast are presented in the following subsection, as well as in "Attachment Vol II 1-1 Tri-State Load Forecasts by Member and State".

Utility Member Sales Forecasts 3650(b)(I)(A)

The following graphs show Tri-State's load forecasts for the RPP for the Tri-State System. Tri-State's annual system energy average growth over the RPP is 1.55%, while summer coincident system demand has an annual average growth rate of 1.44%.

Where appropriate, data is presented for a range of forecasts, including Base, High and Low Load forecasts. Base, High and Low Load forecasts are marked with the following identifiers on all graphs:

- Base Load Forecast Scenario – PRS20 Expected Value
- High Load Forecast Scenario – UCL90_00
- Low Load Forecast Scenario – LCL90_00

Tri-State System Annual Energy Sales, Summer Peak & Winter Peak*:*

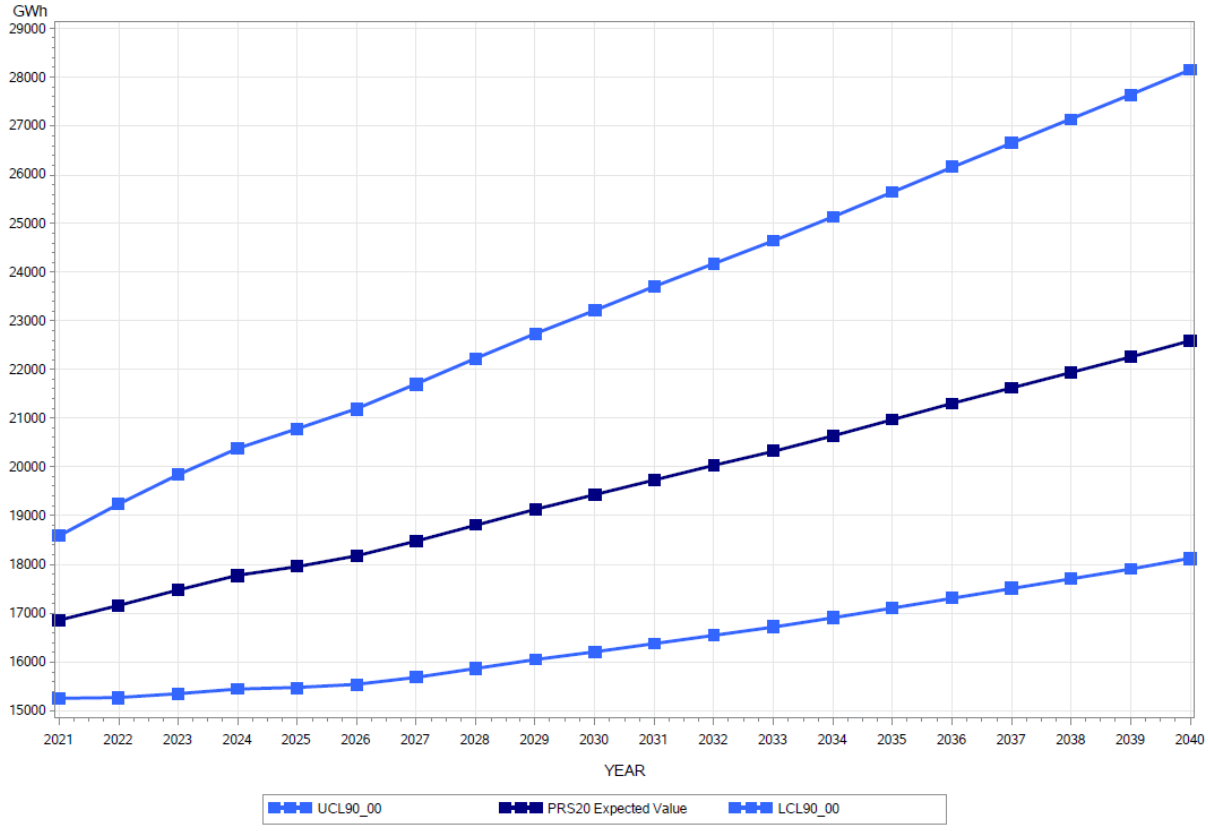

Figure 2: Tri-State System Annual Energy Sales to Utility Member Systems

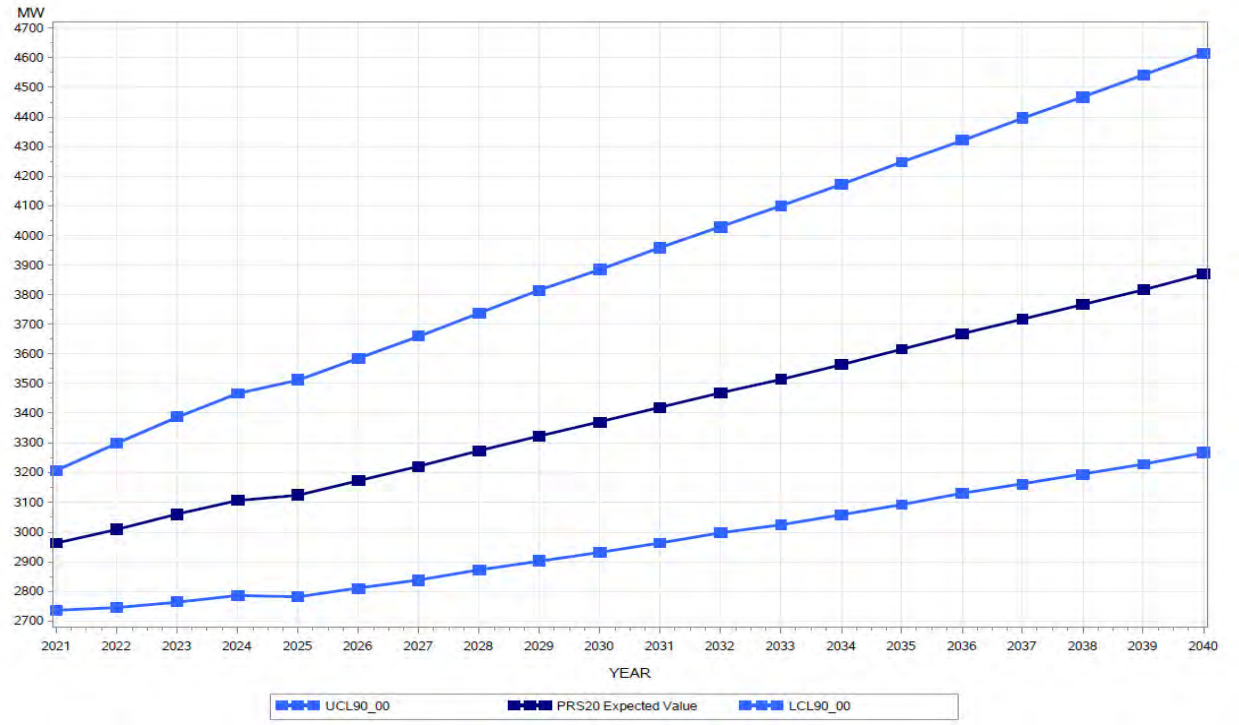

Figure 3: Tri-State System Annual Coincident Summer Peak

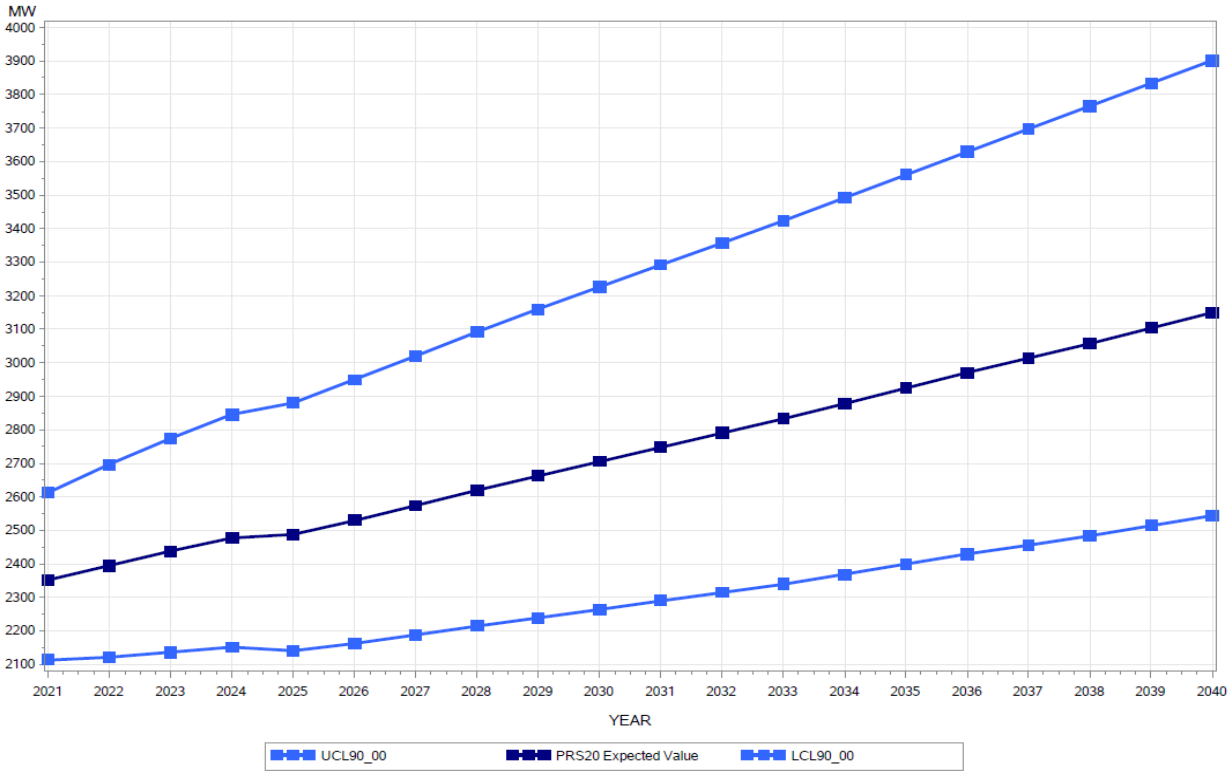

Figure 4: Tri-State System Annual Coincident Winter Peak

Tri-State's load forecasts for the RPP by State and Utility Member System are located in Attachment Volume II 1-1 Tri-State Load Forecasts by State and Member.

Table 1: Reference Guide for Attachment Vol II 1-1 State and Utility Member System Data

Rule	Item	Granularity	Page(s)
3605(b)(I)(A)	Annual Energy Sales	States	1-4
3605(b)(I)(A)	Annual Coincident Summer Peak	States	47-50
3605(b)(I)(A)	Annual Coincident Winter Peak	States	93-96
3605(b)(I)(A)	Annual Energy Sales	Utility Member System	5-46
3605(b)(I)(A)	Annual Coincident Summer Peak	Utility Member System	51-92
3605(b)(I)(A)	Annual Coincident Winter Peak	Utility Member System	97-138
3605(b)(I)(E)	Hourly Peak Day By Calendar Month	States	139-186
3605(b)(I)(E)	Hourly Off Peak Day by Calendar Month	States	691-738
3605(b)(I)(E)	Hourly Average Day by Calendar Month	States	1243-1290
3605(b)(I)(E)	Hourly Peak Day By Calendar Month	Utility Member System	187-690
3605(b)(I)(E)	Hourly Off Peak Day by Calendar Month	Utility Member System	739-1242
3605(b)(I)(E)	Hourly Average Day by Calendar Month	Utility Member System	1290-1794

Comparison of Load Forecasts (3605)(b)(III):

Comparison of 2015 ERP to 2020 ERP Load Forecast:

Tri-State has experienced changes in base load between the release of the 2015 ERP and the 2020 ERP. In 2015, Tri-State had 44 Utility Member Systems; however, 2020 reflects the departure of both Kit Carson and Delta Montrose Electric Association (DMEA). Another key difference is an improvement in the methodology used to forecast the large commercial class. Most individual large commercial and industrial accounts exhibit random walk behavior making it difficult to generate a forecast. The 2020 forecast combines the accounts and generates a forecast for energy using the growth exhibited in the previous 20 years resulting in a large commercial forecast for Tri-State system that better reflects historical patterns.

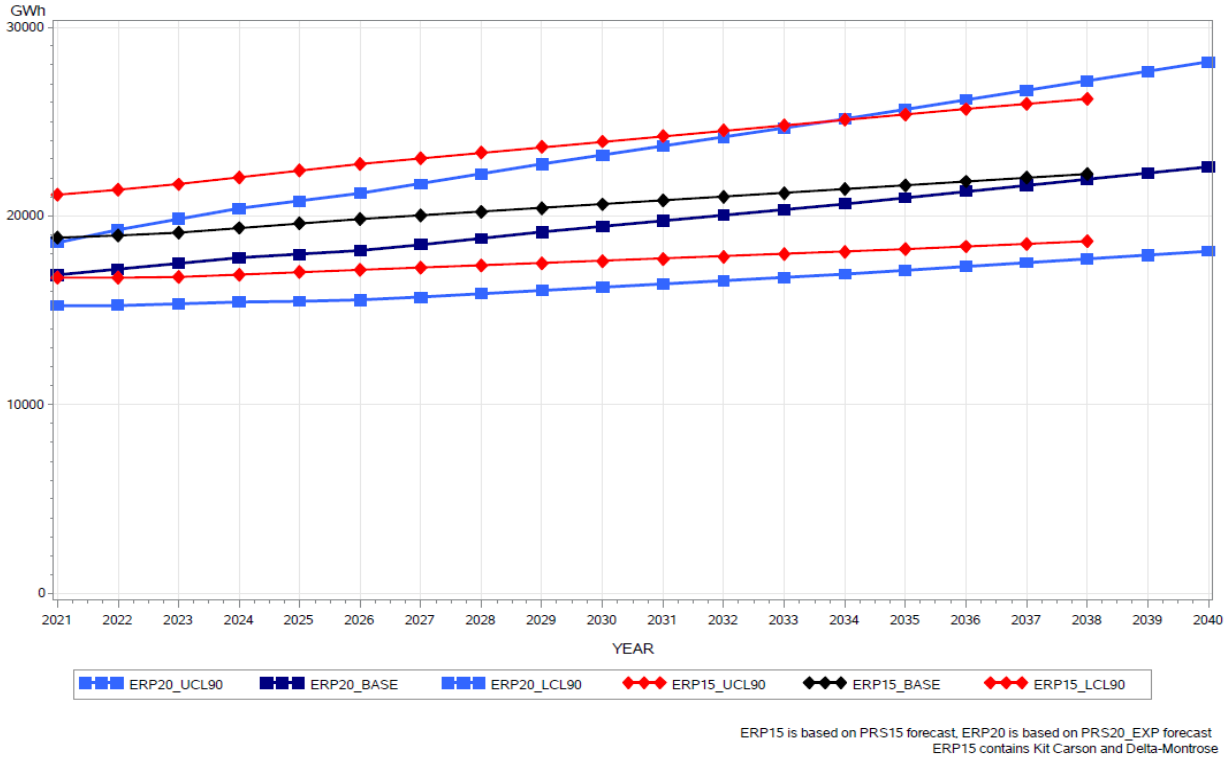

Figure 5: Tri-State System Annual Energy Sales to Utility Member Systems

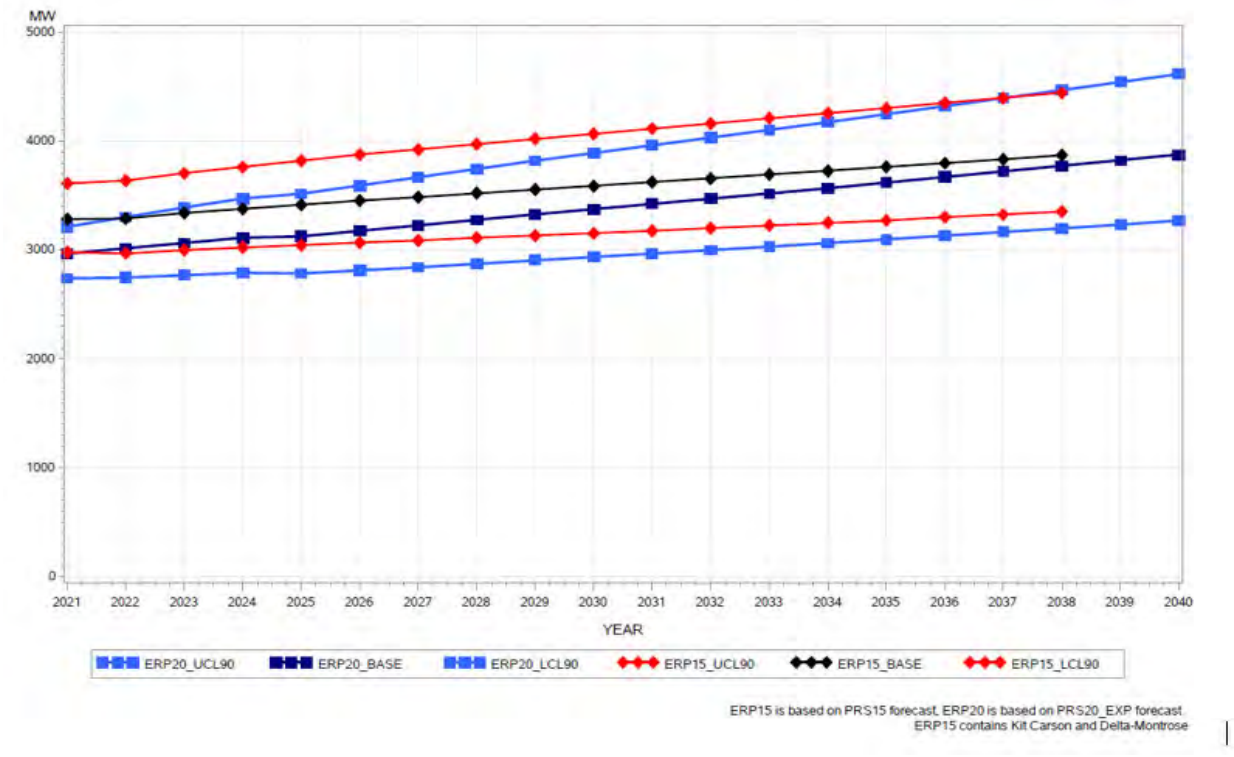

Figure 6: Tri-State System Annual Summer Coincident Peak

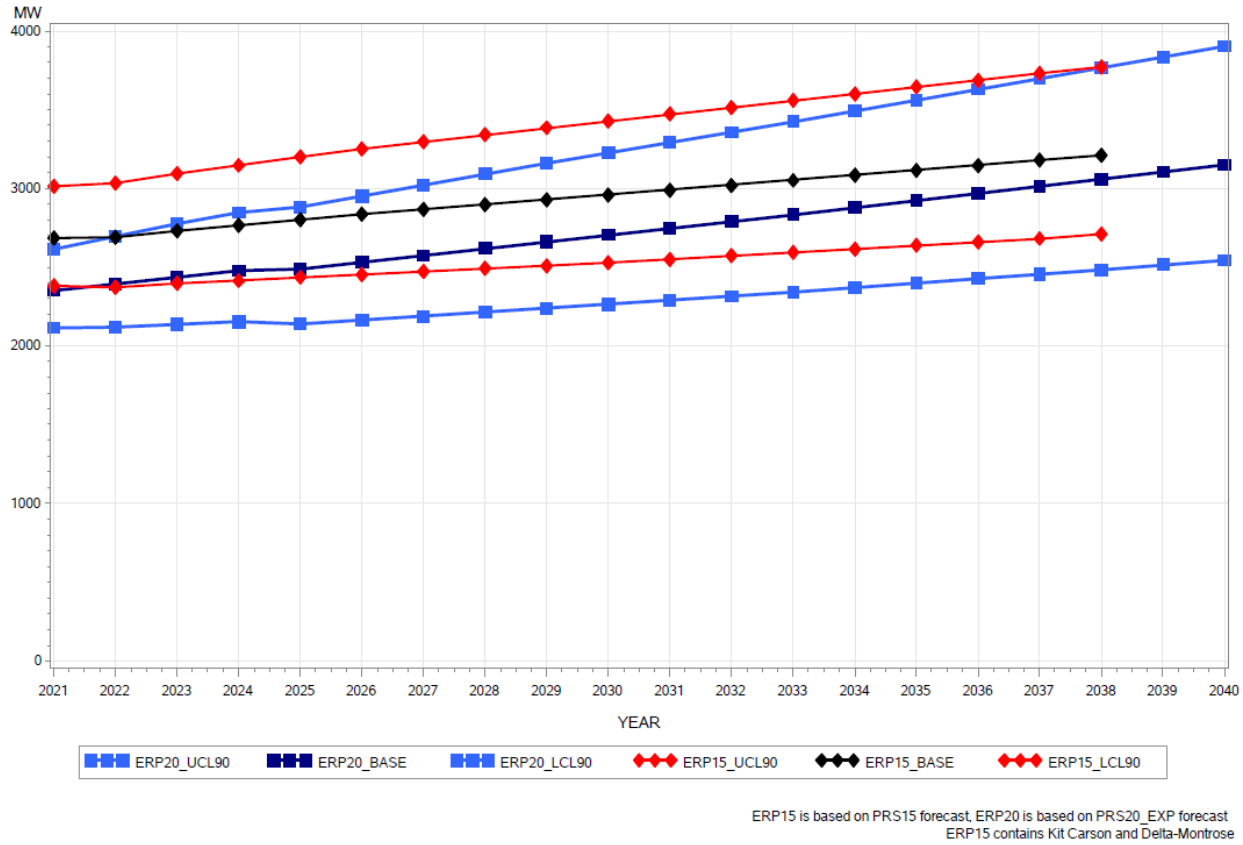

Figure 7: Tri-State System Annual Winter Coincident Peak

Comparison of Historical Forecasts & Actuals:

For the following tables Kit Carson is included in actuals and forecasts for 2015-2016 and DMEA is included in actuals and forecasts for 2015-2019. "PRS" and the corresponding year represents the forecast value.

Table 2: Tri-State System Annual Energy Sales to Utility Member Systems (Base) (GWh)

Obs	YEAR	ACTUAL	PRS15	PRS16_EXP	PRS17_EXP	PRS18_EXP	PRS19_EXP	PRS20_EXP
1	2015	15,941	16,316	.	.	.	.	.
2	2016	15,952	.	16,741	.	.	.	.
3	2017	16,159	.	.	16,181	.	.	.
4	2018	16,719	.	.	.	16,630	.	.
5	2019	16,752	.	.	.	.	17,080	.
6	2020	.	.	.	.	.	.	16,516
7	2021	.	.	.	.	.	.	16,857
8	2022	.	.	.	.	.	.	17,161
9	2023	.	.	.	.	.	.	17,476
10	2024	.	.	.	.	.	.	17,773
11	2025	.	.	.	.	.	.	17,958
12	2026	.	.	.	.	.	.	18,172
13	2027	.	.	.	.	.	.	18,479
14	2028	.	.	.	.	.	.	18,809
15	2029	.	.	.	.	.	.	19,131
16	2030	.	.	.	.	.	.	19,426
17	2031	.	.	.	.	.	.	19,733
18	2032	.	.	.	.	.	.	20,032
19	2033	.	.	.	.	.	.	20,326
20	2034	.	.	.	.	.	.	20,644
21	2035	.	.	.	.	.	.	20,974
22	2036	.	.	.	.	.	.	21,306
23	2037	.	.	.	.	.	.	21,624
24	2038	.	.	.	.	.	.	21,939
25	2039	.	.	.	.	.	.	22,262
26	2040	.	.	.	.	.	.	22,596

Table 3: Tri-State System Annual Energy Sales to Utility Member Systems (High Load) (GWh)

Obs	YEAR	ACTUAL	PRS15	PRS16_EXP	PRS17_EXP	PRS18_EXP	PRS19_EXP	PRS20_EXP
1	2015	15,941	17,121	.	.	.	.	.
2	2016	15,952	.	17,182	.	.	.	.
3	2017	16,159	.	.	16,939	.	.	.
4	2018	16,719	.	.	.	17,578	.	.
5	2019	16,752	.	.	.	.	17,857	.
6	2020	.	.	.	.	.	.	17,777
7	2021	.	.	.	.	.	.	18,596
8	2022	.	.	.	.	.	.	19,245
9	2023	.	.	.	.	.	.	19,844
10	2024	.	.	.	.	.	.	20,388
11	2025	.	.	.	.	.	.	20,780
12	2026	.	.	.	.	.	.	21,188
13	2027	.	.	.	.	.	.	21,696
14	2028	.	.	.	.	.	.	22,221
15	2029	.	.	.	.	.	.	22,733
16	2030	.	.	.	.	.	.	23,210
17	2031	.	.	.	.	.	.	23,698
18	2032	.	.	.	.	.	.	24,173
19	2033	.	.	.	.	.	.	24,641
20	2034	.	.	.	.	.	.	25,137
21	2035	.	.	.	.	.	.	25,645
22	2036	.	.	.	.	.	.	26,156
23	2037	.	.	.	.	.	.	26,650
24	2038	.	.	.	.	.	.	27,140
25	2039	.	.	.	.	.	.	27,640
26	2040	.	.	.	.	.	.	28,152

Table 4: Tri-State System Annual Energy Sales to Utility Member Systems (Low Load) (GWh)

Obs	YEAR	ACTUAL	PRS15	PRS16_EXP	PRS17_EXP	PRS18_EXP	PRS19_EXP	PRS20_EXP
1	2015	15,941	15,534	.	.	.	.	.
2	2016	15,952	.	15,721	.	.	.	.
3	2017	16,159	.	.	15,445	.	.	.
4	2018	16,719	.	.	.	15,426	.	.
5	2019	16,752	.	.	.	.	16,325	.
6	2020	.	.	.	.	.	.	15,324
7	2021	.	.	.	.	.	.	15,248
8	2022	.	.	.	.	.	.	15,263
9	2023	.	.	.	.	.	.	15,345
10	2024	.	.	.	.	.	.	15,443
11	2025	.	.	.	.	.	.	15,467
12	2026	.	.	.	.	.	.	15,532
13	2027	.	.	.	.	.	.	15,686
14	2028	.	.	.	.	.	.	15,866
15	2029	.	.	.	.	.	.	16,046
16	2030	.	.	.	.	.	.	16,207
17	2031	.	.	.	.	.	.	16,381
18	2032	.	.	.	.	.	.	16,553
19	2033	.	.	.	.	.	.	16,721
20	2034	.	.	.	.	.	.	16,911
21	2035	.	.	.	.	.	.	17,114
22	2036	.	.	.	.	.	.	17,319
23	2037	.	.	.	.	.	.	17,515
24	2038	.	.	.	.	.	.	17,708
25	2039	.	.	.	.	.	.	17,910
26	2040	.	.	.	.	.	.	18,121

Table 5: Tri-State System Annual Summer Coincident Peak (Base) (MW)

Obs	YEAR	ACTUAL	PRS15	PRS16_EXP	PRS17_EXP	PRS18_EXP	PRS19_EXP	PRS20_EXP
1	2015	2,627	2,857	.	.	.	.	.
2	2016	2,803	.	2,887	.	.	.	.
3	2017	2,850	.	.	2,786	.	.	.
4	2018	2,974	.	.	.	2,929	.	.
5	2019	3,010	.	.	.	.	2,993	.
6	2020	.	.	.	.	.	.	2,905
7	2021	.	.	.	.	.	.	2,963
8	2022	.	.	.	.	.	.	3,010
9	2023	.	.	.	.	.	.	3,060
10	2024	.	.	.	.	.	.	3,107
11	2025	.	.	.	.	.	.	3,125
12	2026	.	.	.	.	.	.	3,173
13	2027	.	.	.	.	.	.	3,221
14	2028	.	.	.	.	.	.	3,273
15	2029	.	.	.	.	.	.	3,324
16	2030	.	.	.	.	.	.	3,371
17	2031	.	.	.	.	.	.	3,420
18	2032	.	.	.	.	.	.	3,469
19	2033	.	.	.	.	.	.	3,515
20	2034	.	.	.	.	.	.	3,565
21	2035	.	.	.	.	.	.	3,617
22	2036	.	.	.	.	.	.	3,669
23	2037	.	.	.	.	.	.	3,718
24	2038	.	.	.	.	.	.	3,767
25	2039	.	.	.	.	.	.	3,818
26	2040	.	.	.	.	.	.	3,871

Table 6: Tri-State System Annual Summer Coincident Peak (High Load) (MW)

Obs	YEAR	ACTUAL	PRS15	PRS16_EXP	PRS17_EXP	PRS18_EXP	PRS19_EXP	PRS20_EXP
1	2015	2,627	2,975	.	.	.	.	.
2	2016	2,803	.	2,940	.	.	.	.
3	2017	2,850	.	.	2,895	.	.	.
4	2018	2,974	.	.	.	3,011	.	.
5	2019	3,010	.	.	.	.	3,106	.
6	2020	.	.	.	.	.	.	3,085
7	2021	.	.	.	.	.	.	3,208
8	2022	.	.	.	.	.	.	3,300
9	2023	.	.	.	.	.	.	3,388
10	2024	.	.	.	.	.	.	3,467
11	2025	.	.	.	.	.	.	3,513
12	2026	.	.	.	.	.	.	3,587
13	2027	.	.	.	.	.	.	3,661
14	2028	.	.	.	.	.	.	3,738
15	2029	.	.	.	.	.	.	3,815
16	2030	.	.	.	.	.	.	3,885
17	2031	.	.	.	.	.	.	3,959
18	2032	.	.	.	.	.	.	4,029
19	2033	.	.	.	.	.	.	4,099
20	2034	.	.	.	.	.	.	4,172
21	2035	.	.	.	.	.	.	4,248
22	2036	.	.	.	.	.	.	4,321
23	2037	.	.	.	.	.	.	4,396
24	2038	.	.	.	.	.	.	4,467
25	2039	.	.	.	.	.	.	4,541
26	2040	.	.	.	.	.	.	4,614

Table 7: Tri-State System Annual Summer Coincident Peak (Low Load) (MW)

Obs	YEAR	ACTUAL	PRS15	PRS16_EXP	PRS17_EXP	PRS18_EXP	PRS19_EXP	PRS20_EXP
1	2015	2,627	2,743	.	.	.	.	.
2	2016	2,803	.	2,731	.	.	.	.
3	2017	2,850	.	.	2,681	.	.	.
4	2018	2,974	.	.	.	2,705	.	.
5	2019	3,010	.	.	.	.	2,884	.
6	2020	.	.	.	.	.	.	2,735
7	2021	.	.	.	.	.	.	2,736
8	2022	.	.	.	.	.	.	2,745
9	2023	.	.	.	.	.	.	2,764
10	2024	.	.	.	.	.	.	2,786
11	2025	.	.	.	.	.	.	2,782
12	2026	.	.	.	.	.	.	2,811
13	2027	.	.	.	.	.	.	2,837
14	2028	.	.	.	.	.	.	2,872
15	2029	.	.	.	.	.	.	2,903
16	2030	.	.	.	.	.	.	2,932
17	2031	.	.	.	.	.	.	2,964
18	2032	.	.	.	.	.	.	2,997
19	2033	.	.	.	.	.	.	3,024
20	2034	.	.	.	.	.	.	3,058
21	2035	.	.	.	.	.	.	3,093
22	2036	.	.	.	.	.	.	3,130
23	2037	.	.	.	.	.	.	3,162
24	2038	.	.	.	.	.	.	3,195
25	2039	.	.	.	.	.	.	3,229
26	2040	.	.	.	.	.	.	3,268

Table 8: Tri-State System Annual Winter Coincident Peak (Base) (MW)

Obs	YEAR	ACTUAL	PRS15	PRS16_EXP	PRS17_EXP	PRS18_EXP	PRS19_EXP	PRS20_EXP
1	2015	2,261	2,346	.	.	.	.	.
2	2016	2,201	.	2,397	.	.	.	.
3	2017	2,191	.	.	2,282	.	.	.
4	2018	2,323	.	.	.	2,355	.	.
5	2019	2,288	.	.	.	.	2,393	.
6	2020	.	.	.	.	.	.	2,307
7	2021	.	.	.	.	.	.	2,352
8	2022	.	.	.	.	.	.	2,395
9	2023	.	.	.	.	.	.	2,438
10	2024	.	.	.	.	.	.	2,478
11	2025	.	.	.	.	.	.	2,487
12	2026	.	.	.	.	.	.	2,530
13	2027	.	.	.	.	.	.	2,574
14	2028	.	.	.	.	.	.	2,620
15	2029	.	.	.	.	.	.	2,663
16	2030	.	.	.	.	.	.	2,705
17	2031	.	.	.	.	.	.	2,749
18	2032	.	.	.	.	.	.	2,791
19	2033	.	.	.	.	.	.	2,833
20	2034	.	.	.	.	.	.	2,878
21	2035	.	.	.	.	.	.	2,925
22	2036	.	.	.	.	.	.	2,970
23	2037	.	.	.	.	.	.	3,014
24	2038	.	.	.	.	.	.	3,058
25	2039	.	.	.	.	.	.	3,104
26	2040	.	.	.	.	.	.	3,150

Table 9: Tri-State System Annual Winter Coincident Peak (High Load) (MW)

Obs	YEAR	ACTUAL	PRS15	PRS16_EXP	PRS17_EXP	PRS18_EXP	PRS19_EXP	PRS20_EXP
1	2015	2,261	2,485	.	.	.	.	.
2	2016	2,201	.	2,485	.	.	.	.
3	2017	2,191	.	.	2,410	.	.	.
4	2018	2,323	.	.	.	2,526	.	.
5	2019	2,288	.	.	.	.	2,523	.
6	2020	.	.	.	.	.	.	2,513
7	2021	.	.	.	.	.	.	2,613
8	2022	.	.	.	.	.	.	2,697
9	2023	.	.	.	.	.	.	2,775
10	2024	.	.	.	.	.	.	2,845
11	2025	.	.	.	.	.	.	2,881
12	2026	.	.	.	.	.	.	2,950
13	2027	.	.	.	.	.	.	3,020
14	2028	.	.	.	.	.	.	3,091
15	2029	.	.	.	.	.	.	3,160
16	2030	.	.	.	.	.	.	3,226
17	2031	.	.	.	.	.	.	3,292
18	2032	.	.	.	.	.	.	3,357
19	2033	.	.	.	.	.	.	3,424
20	2034	.	.	.	.	.	.	3,492
21	2035	.	.	.	.	.	.	3,561
22	2036	.	.	.	.	.	.	3,630
23	2037	.	.	.	.	.	.	3,698
24	2038	.	.	.	.	.	.	3,765
25	2039	.	.	.	.	.	.	3,834
26	2040	.	.	.	.	.	.	3,902

Table 10: Tri-State System Annual Winter Coincident Peak (Low Load) (MW)

Obs	YEAR	ACTUAL	PRS15	PRS16_EXP	PRS17_EXP	PRS18_EXP	PRS19_EXP	PRS20_EXP
1	2015	2,261	2,213	.	.	.	.	.
2	2016	2,201	.	2,236	.	.	.	.
3	2017	2,191	.	.	2,158	.	.	.
4	2018	2,323	.	.	.	2,189	.	.
5	2019	2,288	.	.	.	.	2,268	.
6	2020	.	.	.	.	.	.	2,115
7	2021	.	.	.	.	.	.	2,113
8	2022	.	.	.	.	.	.	2,121
9	2023	.	.	.	.	.	.	2,136
10	2024	.	.	.	.	.	.	2,152
11	2025	.	.	.	.	.	.	2,141
12	2026	.	.	.	.	.	.	2,163
13	2027	.	.	.	.	.	.	2,188
14	2028	.	.	.	.	.	.	2,215
15	2029	.	.	.	.	.	.	2,239
16	2030	.	.	.	.	.	.	2,263
17	2031	.	.	.	.	.	.	2,290
18	2032	.	.	.	.	.	.	2,316
19	2033	.	.	.	.	.	.	2,340
20	2034	.	.	.	.	.	.	2,368
21	2035	.	.	.	.	.	.	2,399
22	2036	.	.	.	.	.	.	2,429
23	2037	.	.	.	.	.	.	2,455
24	2038	.	.	.	.	.	.	2,483
25	2039	.	.	.	.	.	.	2,514
26	2040	.	.	.	.	.	.	2,544

Losses 3605(b)(I)(D):

Tri-State adds a 5% transmission loss factor to load across Tri-State's system in the Western Interconnection for modeling purposes. Tri-State load in the Western Interconnection is located in multiple BA and TP systems. The 5% transmission loss factor is meant to represent an average of expected transmission losses. Tri-State's load in the Eastern Interconnection is covered by a full requirements contract.

Energy and Capacity Sales to Other Utilities (3605)(b)(I)(B)

Annual contract energy and capacity sales to other utilities and counterparties are described below:

SRP Sale: SPV 3 Facility located in Arizona, 100MW (Maximum Capacity) ~375 GWh/year. Effective Date 10/20/2003; Contract Expires 8/31/2036.

PNM Unit Contingent Sale: 100MW unit contingent sale at SJ345. 100 MW (Maximum Capacity) ~876 GWh/year. Effective Date 06/01/2017; Contract Expires 05/31/2022. This is the sale side of a swap that reduces spinning reserve obligations.

WAPA Regulation Sale: Rate Schedule L-AS3 Partial Self Supply Utilizing Craig Station Unit 3: As the BA operator, WAPA provides Regulation and Frequency Response under Rate Schedule L-AS3. Tri-State currently purchases these services from WAPA. Historically, WAPA has provided this service by adjusting its Federal hydropower resources to balance load, generation, and interchange. This contract allows WAPA to diversify its availability of regulation and frequency response resources by utilizing 30MW of capacity of Craig Unit 3. Effective Date 07/01/2020. Contract Expires 10/01/2021. Either party may choose to discontinue service under this contract by providing sixty (60) days advance written notice to the other party.

Municipal Energy Agency of Nebraska (MEAN) Reserve Sale[1]: Tri-State provides operating reserves to Northwest Power Pool on behalf of MEAN under the terms of the MEAN sub-entity agreement. Effective Date 09/30/2020. Contract Expires 09/30/2021. Contract is evergreen unless terminated by either party via 180 day advanced written notice.

For all sales for purposes of resource planning, contract capacity at the time of peak is considered to be at maximum. This approach is based on conservative business practices. Dispatch energy is based on contract or forecast values.

Intra-utility Energy and Capacity Use (3605)(b)(I)(C)

Tri-State intra-utility loads consist of a number of service centers and the headquarters building. For these loads, Tri-State takes retail service from the local provider. Accordingly, Tri-State has no intra-utility loads that contribute to energy and capacity requirements for purposes of Tri-State resource planning.

[1] This sale was finalized after the start of the ERP process and was not included in the modeling.

2 Commodity Pricing

Electric Forward Curve

Tri-State models six markets to forecast purchase and sale activity across its Western Interconnection footprint, including four transaction points where trading activity currently occurs and two entities representing the real time energy imbalance markets of WEIS and WEIM:

- LRS – located in Wyoming
- AU – Ault in Eastern Colorado
- CRG – Craig in Western Colorado
- 4C – Four Corners in New Mexico
- WEIS – imbalance market in Colorado and Wyoming (WAPA BA)
- WEIM – imbalance market in New Mexico (PNM BA)

Tri-State employs a four-step approach to obtain its electric price forecast. First, a long-term Palo Verde price is derived from third-party data including Bloomberg energy future prices ("Market" prices) and Hitachi ABB & Wood Mackenzie forecasts ("Fundamental" prices). The Market prices are taken at the Palo Verde trading hub at a monthly temporal resolution for on-peak, off-peak, and composite periods. The Fundamental prices are determined from production cost modelling for the Palo Verde hub. For the near-term period (the first three years), Market prices are used, whereas in the long-term (years 11 to 20) Fundamental prices are used. For the mid-term (years four to ten), Market and Fundamental prices are blended to facilitate a smooth transition. Second, the blended Palo Verde prices are then used to derive regional (Colorado East, Colorado West, and New Mexico) prices using a basis adder[2]. Third, a system-wide price is then derived by taking a 30%, 30%, and 40% weighting of the Colorado East, Colorado West, and New Mexico regional prices, respectively creating a blended curve. Finally, Fundamental-based hourly scalars are used to calculate "8760" (all-hours) price streams for Palo Verde, Colorado East, Colorado West, New Mexico and Blended.

For modeling purposes, the 8760 price stream is applied as follows:

- Blended curve is applied to LRS, AU, CRG and NM markets
- Colorado East (COE) curve is applied to WEIS market
- Palo Verde (PV) curve is applied to WEIM market

Additionally, different multipliers are applied to the curves for purchase and sales as follow:

- Blended curve – purchases 95% and sales 85%
- COE curve – purchases 110% and sales 85%
- PV Curve – purchases 105% and sales 95%

The WEIS and WEIM markets are in effect in the model from 2021 to 2024. In 2025, Tri-State opens up market depth to reflect participation in a RTO for its entire footprint. At that point, only the four transaction point markets (LRS, AU, CRG and 4c) remain in use in the model. For more information on

[2] Basis adder is provided by Hitachi ABB.

market depths see Section 5 Phase 1 Modeling Details under the Modeling Assumptions subsection of this report.

Figure 8 represents the power forward curve data in real (2020) dollars for the RPP:

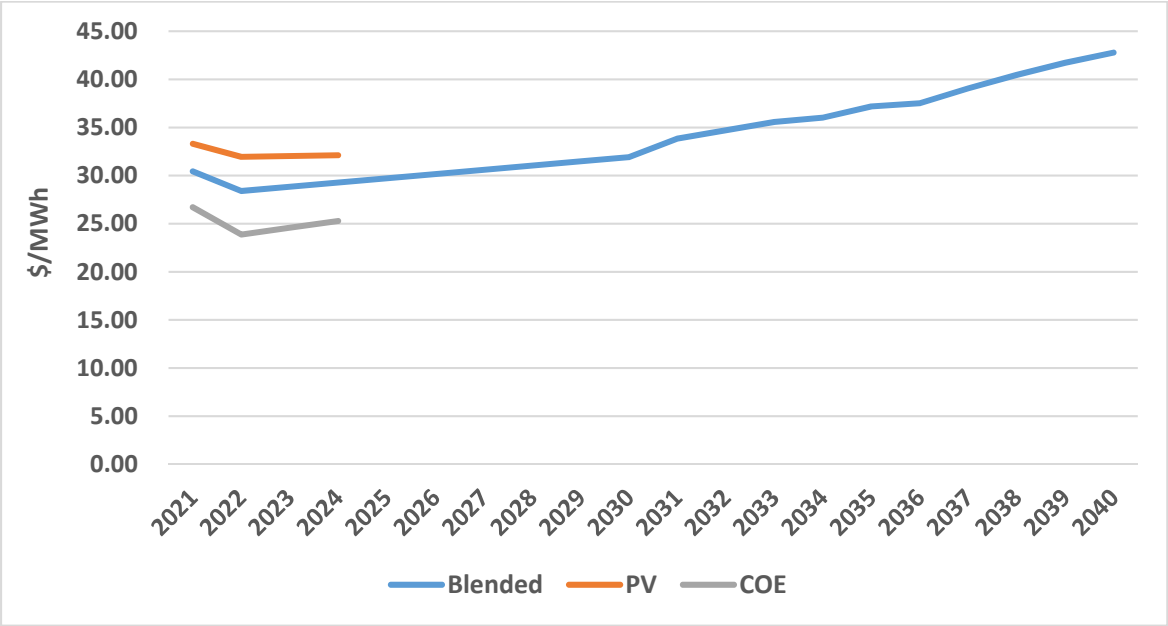

Figure 8: Electric Forward Curve

Gas Forward Curve

Tri-State uses a similar approach for gas forward pricing. First, prices are derived from a combination of third-party data including Bloomberg energy future prices ("Market" prices) and Hitachi ABB & Wood Mackenzie forecasts ("Fundamental" prices). The Market prices are taken at CIG hub and Waha hub at a monthly granularity. The Fundamental prices are derived from a production cost modelling approach for the Palo Verde hub. In the near-term (first five years) the Market prices are used, whereas in the long-term (years 11 to 20) the Fundamental prices are used. For the mid-term (years six to ten) the Market prices are blended with the Fundamental prices for a smooth transition. The monthly values are applied to all applicable days within the model.

For modeling purposes, the daily price stream is applied as follows:

- CIG curve is applied to JM Shafer, Rifle, Limon, Knutson and generic gas resources in Wyoming and Colorado.
- Waha curve is applied to Pyramid units and generic gas resources in New Mexico.

Figure 9 represents the gas forward curve in real (2020) dollars. Additional transport costs apply.

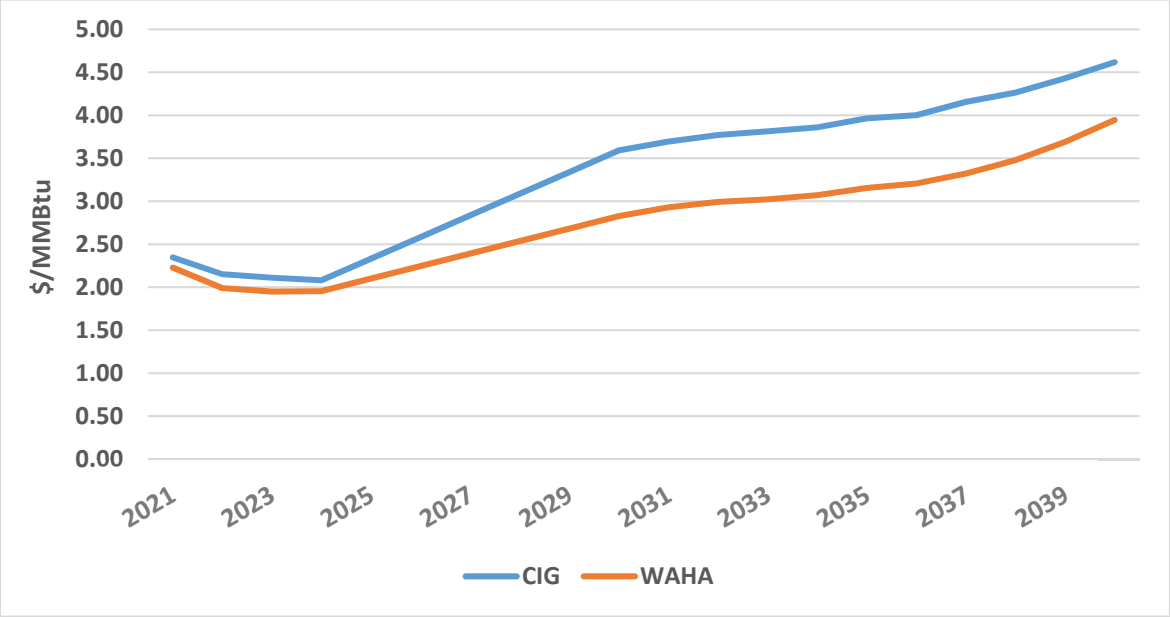

Figure 9: Gas Forward Curve

Table 11 summarizes the additional transport costs and forward curves associated with each gas generating unit:

Table 11: Transportation Costs & Fuel Forward Curve for Gas Resources

Existing Gas Plant	**Transport Adder** *($/MMBtu)*	**Forward Curve**
Limon	$0.31	CIG
Knutson	$0.31	CIG
Pyramid	$0.90	Waha
Rifle	$0.42	CIG
JM Shafer	$0.17	CIG
Generic Gas Resources – CO & WY	$0.31	CIG
Generic Gas Resources - NM	$0.70	Waha

Tri-State uses interruptible gas transport service except for a portion of service for JM Shafer. Tri-State has contractual rights to 14,697 Decatherm (Dth) of firm CIG transportation, (8,000 Dth from King to Lakin, 2,000 Dth from Lost Cabin to Lakin, and another 4,697 Dth from Beaver to Milton). For modeling purposes Tri-State assumes JM Shafer uses the firm transport at a sunk cost and then the additional potentially needed interruptible transport cost is considered and prorated. Therefore, JM Shafer has a lower transport adder than other units.

Coal Forward Curve

Tri-State forward coal prices change annually. Figure 10 shows the coal forward curve in real (2020) dollars. LRS and SPV3 values are all inclusive costs of fuel. CRG (Inc.) is the Craig coal cost as an incremental value. These values are used in CE and PO. Figure 11 shows the coal forward curve in nominal dollars, and all values are all inclusive costs of fuel. These values are used in the final PVRR analysis in UIPlanner.



Figure 10: Coal Forward Curve for CE & PO (2020 Dollars)

The Craig coal forward curve is based on the actual mine plan as forecast by Colowyo. The SPV 3 coal forward curve is based on an estimation of 2% annual escalation rate of the total delivered price (coal + freight). The LRS coal forward curve is provided by Basin and is an estimation of escalation occurring at the rate of 3% per year. Historical coal prices for these resources are located in Section 3 Assessment of Existing Resources.

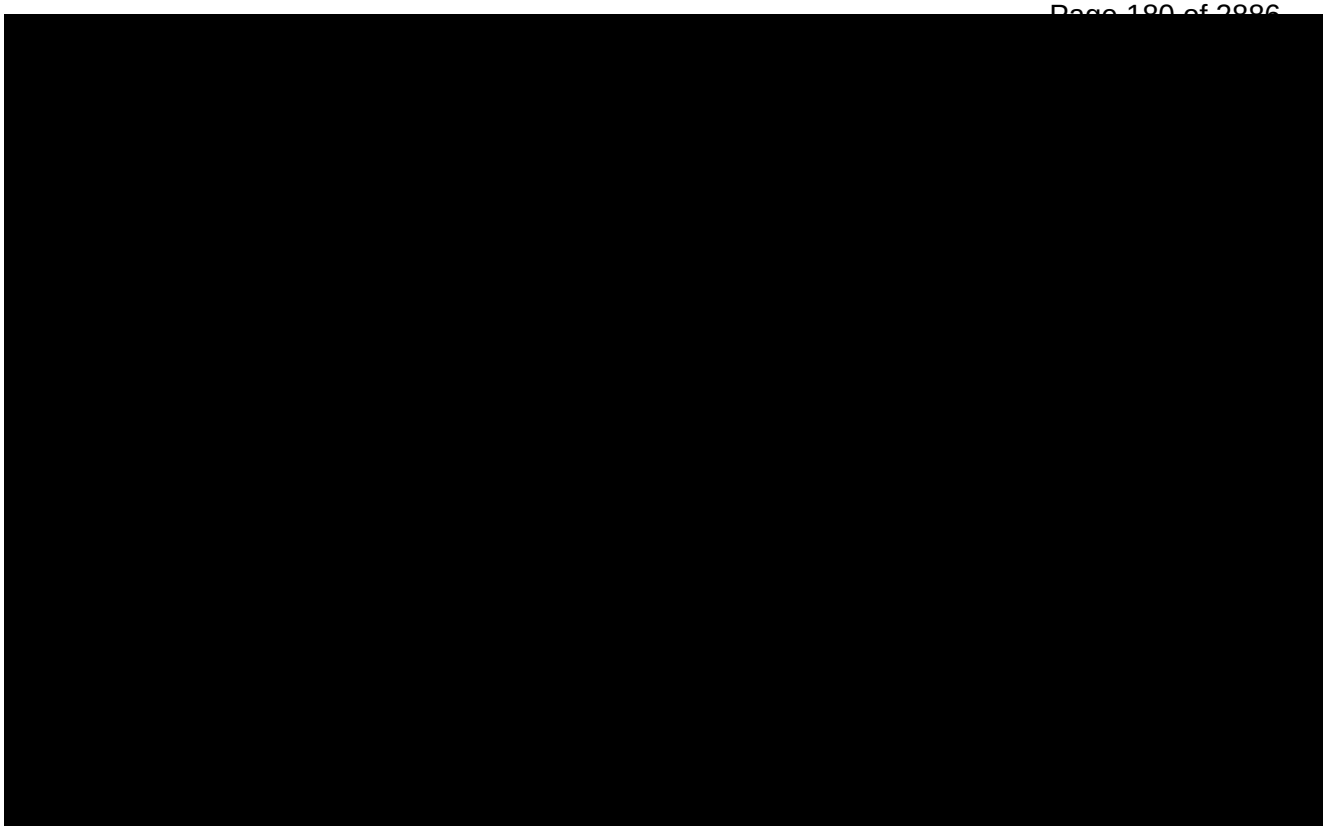

Figure 11: Coal Forward Curve for UIPlanner (Nominal dollars)

3 Assessment of Resources

Overview of Thermal Resources

The following is a description of Tri-State-owned and leased resources in terms of unit characteristics, emission rates and revenue requirements. The assessment excludes the following items, as Tri-State does not have any applicable resources in these categories:

- Thermal resources under contract (3605(c)(I)(A))
- Utility-owned energy storage resources (3605(c)(I)(A))
- Utility-owned thermal resources that are not in service at this time (3605(c)(I)(D))

The following assumptions and interpretations apply:

- The Springerville 3 minimum operating level was lowered from 251 MW to 109 MW in the fall of 2019 as a result of modifications to the coal mills and related logic. The modifications allow pulverizers to operate in a 4-burner operation per pulverizer vs the normal 6-burner operation. This allows velocity to be maintained through the mills at lower fuel throughput.
- NOx limits for Craig 1 are in place to comply with the Colorado State Implementation Plan related to the Regional Haze rule.
- Capacity credits values were updated. See Section 5 Phase I Modeling Details “Table 56: Capacity Credit Values”.

- Tri-State has transitioned to the use of random hourly profiles for renewable resources instead of average hourly profiles.
- Escalante is excluded, as it was retired November 2020.
- Craig units 1, 2, and 3 useful life dates are identified as their respective announced retirement date.
- Net Dependable Capacity for coal resources is the same MW value as Maximum Capacity. (3605(c)(I)(B))
- Net Dependable Capacity for gas resources varies by season and is identified by Summer and Winter Capacity MW values. Gas resources reach their maximum capacity level in the winter. (3605(c)(I)(B))
- Marginal heat rate is calculated as the average heat rate over the RAP, which is identified as 2021 to 2030, for a typical dispatch.
- Fuel cost can be derived from provided heat rates for each resource and forward fuel curves for each fuel type. Tri-State does not utilize a forward fuel curve for oil, as its oil units are used for reliability events rather than economic dispatch and planning.
- Emissions rates are based on 2018 actuals data as provided by Tri-State Environmental.
- For Revenue Requirements where Tri-State has partial ownership in a resource, costs represent Tri-State's prorata share.
- There are no planned significant new investment or maintenance expenses. O&M and Capex costs are representative of necessary maintenance and improvements to maintain reliability of the resources. (3605(c)(I)(E))
- Annual capital expenses[3] are an average of annual expenses over the RPP of 2021 to 2040 for the life of each resource as determined by useful life or planned retirement date.
- Operating and Maintenance costs (fixed and variable) are held constant over the planning period in planning and dispatch models (2020 dollars). UIPlanner (financial model) escalates costs for inflation.
- Costs associated with the use of emissions control systems are not separately forecast, but are instead included in overall operating and maintenance costs.
- Although not a unit level revenue requirement, SCoC is included in the revenue requirement tables for thermal resources as Tri-State is aware of the requirement to consider this value in its assessment of resources and resulting dispatches in relation to the ERP process. The SCoC is calculated as the resource CO_2 emission rate of each unit in tons per MWh times $46.60/ton SCoC for 2021. SCoC annual costs and calculated cost by resource can be found in Section 5 Phase I Modeling Details under the Social Cost of Carbon subsection of this report.

[3] Tri-State's Generation Engineering Department works with generating station engineering personnel as well as station management and corporate finance, to develop and recommend the annual capital budget request for generation. The engineering staff also develops a list of future capital expenditures needed to maintain availability and reliability of the generation stations along with maintaining regulatory and environmental compliance. These future capital expenditures make up the long-term capital forecast for Tri-State resources.

- Tri-State's gas fleet consists of intermediate and peaking units, which are designed for cycling; therefore, no cycling or integration costs are identified for those resources. (3605(c)(I)(J))
- Forecast values for model inputs are based on a combination of historical data and known or upcoming changes that will impact model input values.

Data Updates since August 3, 2030 Revision:

- Tri-States entitlement of LRS was re-rated at 461MW.
- Rifle minimum operating level was updated to 65MW.
- Craig 1, Craig 2, and Craig 3 VOMs were updated to $1.93, $1.78, & $2.45 respectively.
- Scheduled Outages for 2021 to 2030 updated from filing.
- Tri-State is using May 2020 versus March 2020 gas and power forwards curves
- Updated SCoC costs based on Commission Staff feedback

Coal-Fueled Generation Resources:

Craig Generating Station: Craig Station is a three-unit, 1,285 MW coal-fired electric generating facility located near Craig, Colorado. Tri-State owns a 24% interest in Craig Units 1 and 2 (Yampa Project)[4], which have nameplate ratings of 427 MW and 410 MW, respectively; a 100% interest in Craig Unit 3, which has a capacity of 448 MW; and a 49% interest in the common facilities, which serve all three units. Tri-State is the operating agent for all three units and is responsible for the daily management, administration and maintenance of the facility. The non-fuel costs associated with operating Craig units 1 and 2 are divided on a pro-rata basis among all the participants[5]. Tri-State's total share of Craig Station is 648 MW. In 2016, Tri-State announced an agreement with regulators and environmental groups to retire Craig Unit 1 by December 31, 2025 as part of revisions to the Colorado regional haze State Implementation Plan. Tri-State has also announced that Craig Units 2 and 3 will be retired by 2030.

Laramie River Generating Station: The Laramie River Station (LRS) is a three-unit, 1,700 MW coal-fired electric generating facility located near Wheatland, Wyoming. As a participant in the Missouri Basin Power Project[6], Tri-State has a 27.1% interest (461 MW) in LRS. For operational purposes, Tri-State receives energy only from LRS 2 and 3 due to their location in the Western Interconnection. LRS 1 is scheduled solely to the Eastern Interconnection, and Tri-State does not receive energy from this resource. LRS is operated by BEPC.

Springerville Unit 3: Springerville Unit 3 is a 417 MW coal-fired electric generating unit that is part of the four-unit generation station located near Springerville, Arizona. One hundred percent of Unit 3 is leased by Tri-State. Tucson Electric Power (TEP) is the plant operator for the Springerville Generating Station.

[4] Yampa Project includes Craig 1 and Craig 2 and related common facilities.
[5] Yampa Project participants include Tri-State, Platte River Power Authority, PacifiCorp, Salt River Project and Public Service Company of Colorado.
[6] The Missouri Basin Power Project is the Laramie River Electric Generating Station and Transmission System located in Wyoming. Its participants include Tri-State, BEPC, the Western Minnesota Municipal Power Agency (Missouri River Energy Services), the Lincoln Electric System, and the Wyoming Municipal Power Agency (WMPA).

Table 12: Unit Characteristics for Coal Resources

	Average Heat Rate *(btu/kWh)*	**Marginal Heat Rate** *(btu/kWh)*	**Quick Start Capable** *(Yes/No)*	**Minimum Operating Level** *(MW)*	**Useful Life**[7]
Craig 1	10,316	10,518	No	31	12/31/2025[8]
Craig 2	10,219	10,273	No	31	9/30/2028[9]
Craig 3	10,135	10,256	No	130	12/31/2029[10]
LRS 2	9,926	9,877	No	94	12/31/2041
LRS 3	10,286	10,205	No	94	12/31/2042
SPV3	9,945	10,174	No	109	12/31/2066

Table 13: Emission Rates and Water Usage for Coal Resources

	CO_2 *(lb/MWh)*	**SO_2** *(lb/MWh)*	**NOx** *(lb/MWh)*	**PM** *(lb/MWh)*	**HG** *(lb/MWh)*	**Water Usage** *(gal/MWh)*
Craig 1	2319	0.378	2.771	0.042	0.00001700	492
Craig 2	2350	0.345	0.672	0.047	0.00001400	492
Craig 3	2090	1.308	2.248	0.061	0.00007800	492
LRS 2	2203	1.101	2.331	0.095	0.00004110	528
LRS 3	2407	1.823	2.410	0.177	0.00004680	528
SPV3	2139	0.838	0.787	0.031	0.00001600	546

CO2, SO2, and NOx are lbs. per net MWh; PM and HG are lbs. per Gross MWh

Table 14: Revenue Requirements for Coal Resources (Real $)

	Fixed O&M[11] **Annual** *($000s)*	**Variable O&M** *($/MWh)*	**CapEx Costs Annual** *($000s)*	**Social Cost of Carbon** *($/MWh)*	**Integration & Cycling Costs** *($/MWh)*	**Fuel Curve**
Craig 1	[redacted]		~$800	$54.03	$0.129	CRG (Inc)
Craig 2			~$500	$54.76	$0.131	CRG (Inc)
Craig 3			~$3,000	$48.70	$0.124	CRG (Inc)
LRS 2			~$1,500	$51.33	$0.111	LRSG
LRS 3			~$1,500	$56.08	$0.108	LRSG
SPV3			~$6,500	$48.94	$0.138	SPV3

[7] Useful Life is determined by Tri-State's 2017 Generation Depreciation study unless otherwise identified.
[8] This date is the announced retirement date per the YAMPA participants
[9] This date is the announced retirement date per the YAMPA participants
[10] This date has been modified from 12/31/2044 per Tri-State's 2017 Generation Depreciation Study and reflects Tri-State's announcement to retire all of Craig station by 2030.
[11] Fixed O&M forecasts are arrived at on a resource specific basis by taking the VOM provided by TS generation engineering and multiply the value times recent historical annual generation and subtracting the production from total O&M expense for the same year. This value divided by total O&M of the historical year provides a percentage for fixed costs. The percentage is then applied to forecasted O&M to arrive at the fixed portion.

Tri-State forward coal prices change annually. Figure 10 in Section 2 Commodity Pricing of this report shows the Coal Forward Curve in real (2020) dollars as used in CE and PO for the ERP scenario modeling.

Gas & Oil-Fueled Generation Resources:

JM Shafer Generating Station: JM Shafer is a 272 MW natural gas-fueled, combined-cycle power plant located north of Fort Lupton, Colorado. The facility is wholly-owned by Tri-State subsidiary, Thermo Cogeneration Partnership, L.P., and operated by Tri-State.

Rifle Generating Station: Rifle Station is an 81 MW, natural gas-fueled combined-cycle power plant located near Rifle, Colorado. The facility is wholly-owned and operated by Tri-State.

Limon Generating Station: Limon Station is a two-unit, 140 MW, natural gas and oil-fired simple cycle combustion turbine facility located near Limon, Colorado. It is wholly-owned and operated by Tri-State.

Knutson Generating Station: Knutson Station is a two-unit, 140 MW, natural gas and oil-fired simple cycle combustion turbine facility located near Brighton, Colorado. It is wholly-owned and operated by Tri-State.

Pyramid Generating Station: Pyramid Station is a four-unit, 160 MW, natural gas and oil-fired simple cycle combustion turbine facility located near Lordsburg, New Mexico. It is wholly-owned and operated by Tri-State.

Burlington Generating Station: Burlington Station is a two-unit, 110 MW, oil-fired simple cycle combustion turbine facility located in Burlington, Colorado. It is wholly-owned and operated by Tri-State.

Table 15: Unit Characteristics for Gas Resources

	Summer Capacity *(MW)*	**Winter Capacity** *(MW)*	**Fuel Type**	**Average Heat Rate** *(btu/kWh)*	**Marginal Heat Rate** *(btu/kWh)*	**Quick Start Capable** *(Yes/No)*	**Minimum Operating Level** *(MW)*	**Useful Life**[12]
JM Shafer	272	272	NG	9,322	9,254	No	41	12/31/2047
Rifle	72	84	NG	10,321	9,676	No	65	12/31/2028
Limon	67	74	NG/FO	11,449	11,900	Yes	40	12/31/2048
Knutson	67	74	NG/FO	11,449	11,900	No	40	12/31/2048
Pyramid	40	40	NG/FO	9,742	9,909	Yes	25	12/31/2049
Burlington	48	60	FO	14,000	-[13]	Yes	25	12/31/2037

NG = Natural Gas; FO = Fuel Oil

[12] Useful Life is determined by Tri-State's 2017 Generation Depreciation study.
[13] Burlington did not dispatch over the RAP.

Table 16: Emission Rates and Water Usage for Gas Resources

	CO_2 *(lb/MWh)*	SO_2 *(lb/MWh)*	NOx *(lb/MWh)*	PM *(lb/MWh)*	HG *(lb/MWh)*	Water Usage *(gal/MWh)*
JM Shafer	981	0.008	0.747	0.080	n/a	348
Rifle	1206	0.001	2.611	0.239	n/a	1273
Limon	1495	0.008	0.378	0.062	n/a	57
Knutson	1502	0.009	0.341	0.124	n/a	21
Pyramid	1240	0.012	1.223	0.070	n/a	120
Burlington	2149	0.194	12.383	0.158	n/a	8.82

CO2, SO2, and NOx are lbs. per net MWh; PM is lbs. per Gross MWh

Table 17: Revenue Requirements for Gas Resources

	Fixed O&M Annual *($000s)*	Variable O&M *($/MWh)*	CapEx Costs Annual *($000s)*	Social Cost of Carbon *($/MWh)*	Fuel Curve
JM Shafer	[redacted]		~$1,500	$22.86	CIG
Rifle			~$200	$28.10	CIG
Limon			~$275	$34.83	CIG
Knutson			~$400	$35.00	CIG
Pyramid			~$300	$28.90	Waha
Burlington			~$450	$50.07	N/A

Tri-State forward gas prices change monthly. Figure 9 in Section 2 Commodity Pricing of this report shows the gas forward curve used in the ERP scenario modeling in real (2020) dollars. Additional transport costs apply.

Depreciation, Capital Balance, Amortization and Impairment:

Table 18 shows resource depreciation as of 4th Quarter 2019. Table 19 shows the capital balance, amortization and impairment of early retirements as identified in the preferred plan. It is important to note that Tri-State does not have project financing. Tri-State finances its assets as a portfolio; therefore, debt is not tied to specific units. In addition, annual fixed O&M and capital expenses are the only avoidable costs upon early retirement of a resource.

Table 18: Resource Depreciation as of 4th Quarter 2019

FACDESC	LAND_COST	FAS_COST	106_COST	CURRENT CAPITAL INVESTMENTS	TOTAL COST EXCLUDING LAND	DEPR_RESERVE	DEPRECIATION RATE	ESTIMATED ANNUAL DEPRECIATION
[redacted]								

Table 19: Capital Balance, Amortization and Impairment of Resources per Preferred Plan[14]

Facility Description	Additional Capital Expenditures 2020 to Retirement	Early Retirement Date	Impaired Amount at Retirement	Annual amortization Early Retirement Date to Original Accounting Date (includes amortization of	Decommissioning (Including dismantling, severance, community assistance)
[redacted]					

[14] The retirement of LRS 3 and SPV3 as identified in the preferred plan are subject to further study. Any retirement of an LRS facility will be determined by the MBPP participants.

Tri-State proactively works to reduce and eliminate capital expenses related to early retirement of resources as can be seen by the historical capital expense for the Nucla facility. Nucla was set to retire by December 31, 2022 as part of an agreement in 2016, which resulted in revisions to the Colorado Visibility and Regional Haze State Implementation Plan. Tri-State retired Nucla even earlier, in September 2019. Table 20 below shows that Nucla capital expenses were reduced to zero beginning in 2017.

Table 20: Nucla Historical Capital Expenses

	2015	2016	2017	2018	2019
NUCLA	$1,573,481	$1,334,631	$0	-	$0

Tri-State eliminated capital expenses for Nucla in the years leading up to the early retirement of the facility.

Projected Availability Factors:

For modeling purposes, availability factors are a result of modeled forced outage factors as well as planned outage hours. Tri-State assumes a 4% forced outage factor for all coal-fired generation. Historically, gas and oil resources are not assigned a forced outage factor due to their limited annual capacity factors. Tri-State updated its models to reflect recommended forced outage factors as provided by B&V in Attachment Vol II 5-4 B&V Report on Review of Existing Resources.

Any required Phase 1 modeling work will include forced outage factors by unit. These factors were developed using 5 years of historical data from MicroGADS (2015-2019). Table 21 shows the forced outage factors for each thermal unit for the 5-year historical period.

Table 21: Historical MicroGADS Forced Outage Factors for Tri-State Thermal Units

Resource	2015	2016	2017	2018	2019
Craig 1	4.85	1.59	2.11	5.53	1.21
Craig 2	2.31	1.19	7.03	0.27	2.18
Craig 3	6.71	6.42	5.35	45.24[15]	3.39
LRS 2	6.80	0.27	1.81	3.14	2.20
LRS 3	11.03	1.96	1.10	0.01	0.51
SPV3	2.11	15.08	15.88	7.77	9.09
Burlington 1	0.01	0.29	2.14	2.46	0.70
Burlington 2	1.98	0.00	0.10	0.67	0.32
Knutson 1	0.18	1.45	0.07	0.33	0.89
Knutson 2	0.10	1.71	0.05	0.21	0.66
Limon 1	0.02	2.16	0.11	1.71	0.29
Limon 2	0.31	0.88	1.15	0.45	0.57
Pyramid 1	0.01	0.53	0.15	0.27	0.35

[15] The Craig 3 steam turbine generator experienced a failure in 2018 resulting in a significant forced outage for repair. Due to the low probability of this type of event, Tri-State only considered 4 years of historical data to determine the forced outage factor for this thermal unit.

Resource	2015	2016	2017	2018	2019
Pyramid 2	0.02	0.42	0.30	2.76	0.07
Pyramid 3	0.16	0.78	0.02	0.26	0.97
Pyramid 4	0.01	0.46	0.04	0.26	2.41
Rifle[16]	0.00	5.17	2.64	2.01	1.43
JM Shafer	3.59	1.46	1.61	5.04	13.13

Table 22 provides the forced outage factors that will be used for any Phase 1 modeling for each thermal unit.

Table 22: Forced Outage Factors to be used in Phase 1 modeling

Unit	5-yr average (%)
Craig 1	3.06
Craig 2	2.60
Craig 3	5.47
LRS 2	2.84
LRS 3	2.92
SPV3	9.99
Burlington 1	1.12
Burlington 2	0.61
Knutson 1	0.58
Knutson 2	0.55
Limon 1	0.86
Limon 2	0.67
Pyramid 1	0.26
Pyramid 2	0.71
Pyramid 3	0.44
Pyramid 4	0.64
Rifle	2.25
JM Shafer	4.97

[16] For combined cycle plants (Rifle and JM Shafer), forced outage factors are reported for reach gas turbine and each steam turbine. The Plant-wide forced outage factor is determined as the average forced outage factor of all units comprising the entire plant.

Table 23: Applicable Scheduled Outage Plan over the RAP

	Craig 1	Craig 2	Craig 3	LRS 2	LRS 3	SPV3
Start Date	[redacted]					
Stop Date						
Start Date						
Stop Date						
Start Date						
Stop Date						
Start Date						
Stop Date						

Third Party Assessment:

In preparation for Tri-State's 2020 Resource Plan processes, Tri-State engaged B&V to assist Tri-State with this assessment of existing resources. The above data reflects the outcome of that assessment where applicable. Specific areas of recommended change were as follows:

Table 24: Summary of Third-Party Recommendations

B&V Recommendation	Conclusion
Increase Burlington Heat Rate	Adjustment made to heat rate curve
Change Availability Factor of Combined Cycle resources to 90%	Capacity factors are relatively low on Combined Cycle resources and remain so in CO_2 reduced cases, so Tri-State did not make this change at this time
Change Availability Factor of Combustion Turbine dual fuel resources to 96%	Capacity factors are relatively low on Combustion Turbine dual fuel resources and remain so in CO_2 reduced cases, so Tri-State did not make this change at this time
Change Availability Factor of Combustion Turbine oil resources to 98%	Capacity factors are relatively low on Combustion Turbine oil resources and remain so in CO_2 reduced cases, so Tri-State did not make this change at this time
Reduction in Rifle Fixed Costs	Rifle fixed costs are based on historical data. Tri-State will continue to monitor Rifle fixed costs and adjust as necessary.
Reduction to Burlington and Rifle NOx emission rate	Burlington and Rifle NOx emissions are based on historical data. There are conditions specific to these units that make their emissions rates higher than industry averages, so this will remain at the higher level for modeling purposes so as not to under represent potential emissions.
Increase to Rifle and JM Shafer SO_2 emission rates	Rifle and JM Shafer SO_2 emission rates are based on historical data. Tri-State will continue to monitor SO_2 for these units and update as needed.
Decrease of availability factor and related increase in equivalent forced outage factor for all gas units	JM Shafer and Rifle were modeled with the recommended 3% forced outage factor. Because capacity factors are relatively low on the remaining Combustion Turbine oil and

B&V Recommendation	Conclusion
	natural gas resources and remain so in CO_2 reduced cases, they were modeled at their winter and summer capacities.

The B&V evaluation of resources detail can be found in Attachment Vol II 5-4 B&V Report on Review of Existing Resources.

Resource Reference Data:

Table 25: Resource Characteristics Reference

Tri-State Resource Table										
State	Fuel	Name	Type	Unit Net Capacity (MW)	Modeled Capacity (MW)	Net Dependable Capacity (MW)	Year in Service/Contract Start	Estimated Retirement/End Date	Heat Rate	Availability Factor %*
--	Basin	East Basin_East Basin	Unspecified	317	317	317	Effective 1/16/1975	2050	N/A	N/A
--	Basin	West Basin_West Basin	Unspecified	268	268	268	Effective 1/16/1975	2050	N/A	N/A
AZ	Coal	Springerville 3	Steam Turbine	417	317	317	2006	2066	9,945	84.11
CO	Coal	Craig 1	Steam Turbine	427	102	102	1980	2025	10,316	91.93
CO	Coal	Craig 2	Steam Turbine	410	98	98	1979	2028	10,219	91.11
CO	Coal	Craig 3	Steam Turbine	448	448	448	1984	2029	10,135	82.34
WY	Coal	LRS 2	Steam Turbine	570	231	231	1981	2041	9,926	93.02
WY	Coal	LRS 3	Steam Turbine	570	230	230	1982	2042	10,286	93.57
CO	Oil	Burlington 1	Frame CT	55	55	48	1977	2037	14,000	97.92
CO	Oil	Burlington 2	Frame CT	55	55	48	1977	2037	14,000	98.73
CO	Gas/Oil	Knutson 1	Frame CT	70	70	67	2002	2048	11,449	96.78
CO	Gas/Oil	Knutson 2	Frame CT	70	70	67	2002	2048	11,449	95.99
CO	Gas/Oil	Limon 1	Frame CT	70	70	67	2003	2048	11,449	96.66
CO	Gas/Oil	Limon 2	Frame CT	70	70	67	2003	2048	11,449	92.96
CO	Gas	Rifle	Combined Cycle	81	81	72	1987	2028	10,321	90.77
CO	Gas	Shafer	Combined Cycle	272	272	272	1994	2047	9,322	88.06
NM	Gas/Oil	Pyramid 1	Aeroderivative CT	40	40	40	2003	2049	9,742	98.58
NM	Gas/Oil	Pyramid 2	Aeroderivative CT	40	40	40	2003	2049	9,742	98.62
NM	Gas/Oil	Pyramid 3	Aeroderivative CT	40	40	40	2003	2049	9,742	98.62
NM	Gas/Oil	Pyramid 4	Aeroderivative CT	40	40	40	2003	2049	9,742	98.53
--	Hydro	WAPA CRSP	Hydro	231	231	231	Effective 10/1/1989	2057	N/A	N/A
--	Hydro	WAPA LAP	Hydro	353	353	353	Effective 10/1/1989	2054	N/A	N/A
CO	Hydro	Small PPAs	Hydro PPA	22	22	22	various	various	N/A	N/A
CO	Solar	Axial	Tracking Array	145	145	51	2023	2038	N/A	N/A
CO	Solar	Coyote Gulch	Tracking Array	120	120	42	2023	2038	N/A	N/A
CO	Solar	Dolores	Tracking Array	110	110	39	2023	2038	N/A	N/A
CO	Solar	San Isabel	Tracking Array	30	30	11	2016	2041	N/A	N/A
CO	Solar	Spanish Peaks	Tracking Array	100	100	35	2023	2038	N/A	N/A
NM	Solar	Alta Luna	Tracking Array	25	25	9	2017	2042	N/A	N/A
NM	Solar	First Solar	Fixed	30	30	11	2010	2035	N/A	N/A
NM	Solar	SpanishPeaksTwo	Tracking Array	40	40	14	2023	2038	N/A	N/A
NM	Solar	TPE/Escalante	Tracking Array	200	200	70	2023	2040	N/A	N/A
CO	Wind	Carousel	Wind	150	150	45	2015	2041	N/A	N/A
CO	Wind	Colo Highlands	Wind	91	91	27	2012	2032	N/A	N/A
CO	Wind	Crossing Trails	Wind	104	104	31	2020	2035	N/A	N/A
CO	Wind	Kit Carson	Wind	51	51	16	2010	2030	N/A	N/A
CO	Wind	Niyol	Wind	200	200	60	2021	2041	N/A	N/A
CO	Wind	Twin Buttes	Wind	76	76	23	2017	2042	N/A	N/A

* Based on historical data 2015 -2019

Resource Historical Data:

Historical data for key modeling inputs are located in this subsection. Forecasts of modeling inputs are based on a combination of historical data and known present or upcoming changes that might impact forecasts. Explanations of deviations in historical data are included in this section.

Table 26 shows actual O&M expenses from 2015 to 2019 by resource or facility as available. Source of the data is Tri-State financials.

Table 26: Annual Historical O&M by Resource ($000s)[17]

Resource	2015	2016	2017	2018	2019
[redacted]					

Table 27 Annual Historical Capital Expenses by Resource ($)

Resource	2015	2016	2017	2018	2019
Craig 1&2	$15,292,219	$18,831,363	$14,207,660	$954,865	$733,093
Craig 3	$23,259,837	$13,183,323	$4,452,621	$1,031,365	$1,309,988
Burlington 1&2	$280,336	$17,504	$16,817	$479,627	$210,512
Limon 1&2	$66,250	$422,075	$746,182	$1,877,331	$387,852
Knutson 1&2	$23,427	$186,834	$331,991	$1,614,627	$164,062
Pyramid 1,2,3,&4	$397,258	$287,402	$11,604	$798,934	$133,503
Rifle	$193,100	$173,330	$109,516	$0	$0
JM Shafer	$26,070,218	$5,556,312	$1,810,132	$18,514,466	$10,295,315
LRS 2&3	$9,128,577	$7,341,987	$24,835,767	$28,798,723	$14,340,410
SPV3	$6,654,229	$7,873,305	$232,853	$4,230,232	$15,185,386
MISCELLANEOUS - OTHER	$16,606,825	$9,311,148	$5,573,490	$16,650,994	$5,874,228
TOTAL GENERATION	**$97,972,276**	**$63,184,583**	**$52,328,633**	**$74,951,164**	**$48,634,349**

[17] Note that until June 30, 2019, a portion of JM Shafer was under a tolling contract to PSCO, and therefore history of resource operation and resulting costs is not necessarily reflective of future use.

Capital expenditures fluctuate to reflect ongoing needs that have been determined by site personnel, guidelines by equipment manufacturers and regulations for environmental, safety and regulatory compliance. The timing of larger capital upgrades is planned with major maintenance work when feasible. Table 28 explains larger capital expenditures by facility in recent history.

Table 28: Explanation of Historical Capital Expenses

Facility	Explanation of Historical Capital Expenses
CRAIG 1&2	Primary capex driver in 2015 and 2017 were environmental upgrades. Primary capex drivers in 2016 were environmental upgrades and controls upgrades.
CRAIG 3	Primary capex drivers in 2015 were environmental upgrades, controls upgrades and water purchases. Primary capex driver in 2016 was the continuation of the environmental upgrades.
BURLINGTON 1&2	Primary capex driver in 2018 was replacing various protective relaying.
LIMON 1&2	Primary capex driver in 2018 upgrading/replacing the inlet silencers for both engines.
KNUTSON 1&2	Primary capex driver in 2018 upgrading/replacing the inlet silencers for both engines.
PYRAMID 1,2,3&4	Primary capex driver in 2018 replacing various protective relaying.
RIFLE	Tri-State has been actively trying to decrease capital expenses at Rifle other than what is necessary for compliance.
JM SHAFER	Primary capex drivers for 2015 and 2018 were water purchases and water infrastructure for operations. Primary capex drivers for 2019 were large maintenance projects including a complete engine overhaul/rebuild.
LRS 2&3	Primary capex drivers in 2017 and 2018 were environmental compliance projects. (Selective Catalytic Reduction and Selective Noncatalytic Reduction).
SPV3	Primary capex driver in 2019 was the superheater reheater pendant replacement.

Table 29: Annual Historical Fuel Price by Pipeline ($/MMBtu)

Hub	2015	2016	2017	2018	2019
CIG	$2.39	$2.25	$2.63	$2.58	$2.06
WAHA	$2.46	$2.33	$2.68	$2.01	$0.86

The average of the last 5 years (2015-2019) of CIG prices is $2.38/MMBtu while WAHA's 5 year average is $2.07/MMBtu. In Section 2 - Commodity Pricing - Gas Forward Curve Tri-State describes the methodology for developing its forward gas curves. The 1st five years (2021 – 2025) of forward curve pricing show CIG's average to be $2.20/MMBtu and WAHA is at $2.07/MMBtu. Following those years, the forecast shows gas prices increasing based upon blended midterm and fundamental pricing.

Table 30: Historical Coal Fuel Pricing by Resource ($/MMBtu)

Coal Source	2016	2017	2018	2019
CRG	[redacted]			
LRS				
SPV3				

Table 31 Annual Historical Heat Rate (btu/kWh)

Resource	2015	2016	2017	2018	2019
Craig 1&2	10153	10196	10165	10232	9370
Craig 3	10157	10219	10121	10472	9526
LRS 2 & 3	9345	9965	9080	9800	9082
SPV3	10115	10404	10211	9236	10700
Burlington 1&2	*	*	*	*	13444
Knutson 1&2	*	12803	12761	9070	12399
Limon 1&2	12860	12434	12525	12381	12048
Pyramid 1,2,3,&4	10415	10319	10444	10421	8163
Rifle	10272	9677	10135	*	9663
JM Shafer	8820	8368	8642	7840	8930

*** insufficient data**

Table 32: Annual Historical CO_2 Emissions Rate by Resource

Unit	CO_2 (lbs/net MWh)				
	2015	2016	2017	2018	2019
LRS 2	2350	2265	2225	2203	2379
LRS 3	2510	2530	2556	2407	2671
Craig 1	2282	2244	2299	2319	2395
Craig 2	2312	2252	2315	2350	2406
Craig 3	2110	2076	2084	2090	2171
Springerville 3	2250	2278	2160	2139	2392
Burlington 1	2174	2444	2452	2212	2248
Burlington 2	2145	2122	2261	2086	2259
Pyramid 1	1271	1203	1167	1240	1179
Pyramid 2	1196	1211	1252	1232	1203
Pyramid 3	1215	1372	1289	1250	1187
Pyramid 4	1275	1218	1237	1238	1206
Rifle	1197	1109	1195	1206	1154
Limon 1	1560	1525	1453	1498	1480
Limon 2	1528	1566	1546	1492	1479
Knutson 1	1469	1489	1479	1504	1481
Knutson 2	1507	1992	1533	1500	1517
JM Shafer	1050	986	981	981	944

Table 33: Annual Historical SO_2 Emissions Rate by Resource

Unit	SO_2 (lbs/net MWh)				
	2015	2016	2017	2018	2019
LRS 2	1.209	0.819	1.073	1.101	1.164
LRS 3	1.972	1.545	1.598	1.823	1.525
Craig 1	0.525	0.470	0.489	0.378	0.511
Craig 2	0.555	0.497	0.501	0.345	0.460
Craig 3	1.266	1.384	1.251	1.308	1.248
Springerville 3	0.708	0.816	0.932	0.838	0.810
Burlington 1	0.000	0.000	0.222	0.206	0.113
Burlington 2	0.000	0.000	0.174	0.182	0.113
Pyramid 1	0.017	0.011	0.011	0.013	0.006
Pyramid 2	0.014	0.020	0.027	0.017	0.006
Pyramid 3	0.011	0.063	0.024	0.012	0.006
Pyramid 4	0.011	0.012	0.015	0.006	0.006
Rifle	0.000	0.000	0.000	0.001	0.000
Limon 1	0.011	0.008	0.009	0.008	0.010
Limon 2	0.008	0.008	0.008	0.008	0.008
Knutson 1	0.008	0.007	0.009	0.009	0.008
Knutson 2	0.008	0.011	0.009	0.010	0.008
JM Shafer	0.005	0.005	0.005	0.008	0.005

Table 34: Annual Historical NOx Emissions Rate by Resource

Unit	NOx (lbs/net MWh)				
	2015	2016	2017	2018	2019
LRS 2	1.682	1.650	1.648	2.331	1.600
LRS 3	1.774	1.786	1.906	2.410	1.824
Craig 1	2.735	2.622	2.748	2.771	2.878
Craig 2	2.790	2.681	2.482	0.672	0.721
Craig 3	2.972	2.937	2.815	2.248	2.404
Springerville 3	0.827	0.817	0.900	0.787	0.963
Burlington 1	11.573	12.661	13.210	12.482	12.132
Burlington 2	11.657	11.502	12.123	12.283	12.193
Pyramid 1	1.358	1.087	1.208	1.253	1.189
Pyramid 2	1.306	1.190	1.122	1.169	1.218
Pyramid 3	1.176	1.287	1.299	1.253	1.178
Pyramid 4	1.607	1.186	1.127	1.218	1.157
Rifle	1.974	3.771	1.827	2.611	2.016
Limon 1	0.445	0.321	0.359	0.432	0.375
Limon 2	0.342	0.337	0.405	0.324	0.383
Knutson 1	0.368	0.349	0.363	0.345	0.341
Knutson 2	0.373	0.488	0.392	0.337	0.358
JM Shafer	0.773	0.735	0.749	0.747	0.703

Table 35: Annual Historical Hg Emissions Rate by Resource

Unit	Hg (lbs/gross MWh)				
	2015	2016	2017	2018	2019
LRS 2	0.0000053	0.0000064	0.0000061	0.0000411	0.0000086
LRS 3	0.0000042	0.0000091	0.0000097	0.0000468	0.0000111
Craig 1	0.0000014	0.0000017	0.0000030	0.0000170	0.0000044
Craig 2	0.0000027	0.0000036	0.0000025	0.0000140	0.0000036
Craig 3	0.0000089	0.0000092	0.0000091	0.0000780	0.0000070
Springerville 3	0.0000038	0.0000024	0.0000053	0.0000160	0.0000045
Burlington 1	N/A	N/A	N/A	N/A	N/A
Burlington 2	N/A	N/A	N/A	N/A	N/A
Pyramid 1	N/A	N/A	N/A	N/A	N/A
Pyramid 2	N/A	N/A	N/A	N/A	N/A
Pyramid 3	N/A	N/A	N/A	N/A	N/A
Pyramid 4	N/A	N/A	N/A	N/A	N/A
Rifle	N/A	N/A	N/A	N/A	N/A
Limon 1	N/A	N/A	N/A	N/A	N/A
Limon 2	N/A	N/A	N/A	N/A	N/A
Knutson 1	N/A	N/A	N/A	N/A	N/A
Knutson 2	N/A	N/A	N/A	N/A	N/A
JM Shafer	N/A	N/A	N/A	N/A	N/A

Table 36: Annual Historical PM Emissions Rate by Resource

Unit	PM (lbs/gross MWh)				
	2015	2016	2017	2018	2019
LRS 2	0.1410	0.0702	0.0544	0.0953	0.1052
LRS 3	0.1767	0.2115	0.0758	0.1770	0.1778
Craig 1	0.0845	0.0980	0.0649	0.0421	0.0379
Craig 2	0.0893	0.0552	0.0462	0.0469	0.0467
Craig 3	0.0522	0.0478	0.0399	0.0614	0.0124
Springerville 3	0.0378	0.0287	0.0748	0.0306	0.2478
Burlington 1	0.1601	0.1799	0.1803	0.1620	0.1654
Burlington 2	0.1580	0.1562	0.1653	0.1530	0.1663
Pyramid 1	0.0707	0.0661	0.0641	0.0710	0.0643
Pyramid 2	0.0666	0.0682	0.0709	0.0720	0.0658
Pyramid 3	0.0670	0.0835	0.0723	0.0720	0.0645
Pyramid 4	0.0699	0.0673	0.0686	0.0650	0.0660
Rifle	0.2829	0.1699	0.1881	0.2390	0.2370
Limon 1	0.0735	0.0598	0.0606	0.0616	0.0614
Limon 2	0.0604	0.0620	0.0618	0.0625	0.0593
Knutson 1	0.1170	0.1158	0.1142	0.1237	0.1156
Knutson 2	0.1221	0.1205	0.1186	0.1237	0.1174
J M Shafer	0.0570	0.0545	0.0551	0.0804	0.0514

Table 37: Annual Historical Water Usage Rate by Resource

Unit	Water Usage (gal/MWh)				
	2015	2016	2017	2018	2019
LRS 2	543	541	509	528	492
LRS 3	514	507	543	528	475
Craig 1	488	496	494	492	498
Craig 2	488	496	494	492	498
Craig 3	488	496	494	492	498
Springerville 3	555	571	584	546	625
Burlington 1	16	12	4	8.82	1
Burlington 2	16	12	4	8.82	1
Pyramid 1	107	129	132	120	93
Pyramid 2	107	129	132	120	93
Pyramid 3	107	129	132	120	93
Pyramid 4	107	129	132	120	93
Rifle	1350	1372	1951	1273	495
Limon 1	31	17	59	57	47
Limon 2	31	17	59	57	47
Knutson 1	46	10	32	21	18
Knutson 2	46	10	32	21	18
J M Shafer	255	472	451	348	460

Overview of Purchases

The following list provides summary information regarding current firm purchase power agreements in regards to capacity, energy and demand side resources. Tri-State does not have any wheeling or coordination agreements that provide capacity and energy.

Contract Purchases and Renewable PPAs differ from thermal resources in regards to applicable characteristics and costs. The format used below is intended to present the applicable data for these agreements as required in Rule 3605(c).

Summer capacities are representative of contract demand available to serve July peak.

Net Dependable Capacities (Capacity Credit) for renewable resources are identified in Section 5 Phase I Modeling Details under the Modeling Assumptions subsection of this report.

Contract Purchases:

Basin CROD Western Interconnection BEPC: Colorado & Wyoming: 268 MW summer capacity, ~1580 GWh/year[18]. Effective Date 1/16/1975; Restructured Date 10/1/2017; Contract Expires 12/31/2050.

- If either party wishes to terminate this agreement on its expiration date of 12/31/2050, notice must be given to the other party by January 1, 2045 in writing. Otherwise, this contract will remain in effect beyond its expiration date of 12/31/2050 until such time that either party gives to the other party not less than five years written notice of intent to terminate.

[18] Profile detail is shown in the Contract Profile Information subsection.

Basin Electrically East BEPC: All Requirements Purchase Contract for Electrically East Loads[19], Effective Date 1/16/1975; Restructured Date 10/1/2017; Contract Expires 12/31/2050.

- If either party wishes to terminate this agreement on its expiration date of 12/31/2050, notice must be given to the other party by January 1, 2045 in writing. Otherwise, this contract will remain in effect beyond its expiration date of 12/31/2050 until such time that either party gives to the other party not less than five years written notice of intent to terminate.

CRSP WAPA: 231 MW summer capacity ~1424 GWh/year. Seasonal Contract Rate of Delivery, specified monthly capacity and energy, and multiple delivery points apply to this contract. Effective Date 10/1/1989; Renewed Date 10/1/2017; Contract Expires 9/30/2057.

- Contracts TS-89-0005 and PL-89-0002 expire end of day, 9/30/2024. Contract TS-17-0128 is currently effective and commences delivery of Firm Electric Service beginning of day, 10/1/2024 through end of day 9/30/2057.

LAP WAPA: 353 MW summer capacity, ~900 GWh/year. Seasonal Contract Rate of Delivery, specified monthly capacity and energy, and multiple delivery points apply to this contract, Effective Date 10/1/1989; Contract Expiration 9/30/2054.

- Contract TS-89-0002 expires end of day, 9/30/2024. Contract TS-14-0238 is currently effective and commences delivery of Firm Electric Service beginning of day, 10/01/2024 through end of day, 9/30/2054.
- LAP contract includes rights to Mt. Elbert pump back storage 176 MW summer capacity with a 68% efficiency and prescribed generating and pumping hours. The Mt. Elbert contract capacity shares transmission with the LAP contract and the combination of usage cannot exceed the LAP contract max capacity in any hour.

Native American WAPA Allocations: Monthly (fixed schedule peaking) at 5 MW annually, ~28 GWh/year. Effective Date 10/1/2004; Expires 10/1/2024.

Central Valley Electric: ~1 MW capacity, ~5 GWh/year. Effective Date 12/05/1996; Contract Expires Evergreen

Public Service Company of New Mexico Unit Contingent Purchase: 100MW unit contingent purchase from PNM at SJ345. 100 MW (Maximum Capacity) ~876 GWh/year. Effective Date 06/01/2017; Contract Expires 05/31/2022. This is the purchase side of a swap that reduces spinning reserve obligations.

Additionally, Tri-State has several contracts under WSPP agreements that serve Utility Member system load associated with wind and solar facility station service for generators that are under contract and deliver energy to third party utilities but are located in a Tri-State Utility Member's service territory. These contracts are de minimis in nature (i.e., under 1 GWh in annual energy; 2 MW maximum demand).

- PRPA – Rawhide Solar Station Service (SS): Contract commenced 9/1/2016; contract expires 9/1/2021 – Expected to renew making the new contract expiration 9/1/2026
- PRPA – Prairie Solar SS: Contract commenced 5/1/2020; contract expires 5/1/2025

[19] Profile detail is shown in the Contract Profile Information subsection.

- PRPA – Roundhouse Wind SS: Contract commenced 6/3/2020; contract expires 6/1/2025
- CSU – Palmer Solar SS: Contract commenced 4/1/2020; contract expires 4/1/2025

Contract Profile Information:

Projected Basin Contract Energy & Demand

Basin CROD Western Interconnection contract energy profile is a set hourly profile identified by point of delivery. Stegall West 230KV Bus is located in Nebraska. AU 230KV and Story 230KV busses are located in Colorado. Figures 12 and 13 show the hourly profiles by point of delivery for each month:

POINT OF DELIVERY: STEGALL WEST 230KV BUS

Month\HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
JAN	73	71	72	71	74	75	84	92	91	88	86	85	82	81	79	80	86	94	97	95	94	90	85	75	2,000
FEB	73	72	72	72	74	81	85	91	90	89	88	86	83	82	81	81	85	89	97	96	94	91	85	74	2,011
MAR	69	67	68	68	72	76	83	82	82	81	80	77	75	75	74	74	75	79	84	84	84	80	74	69	1,832
APR	48	46	46	46	47	51	56	57	58	58	58	55	55	54	54	54	55	56	58	59	60	58	53	49	1,291
MAY	54	52	51	51	52	55	61	63	65	65	65	65	65	65	65	65	67	67	67	68	68	67	63	58	1,484
JUN	80	75	73	72	73	76	81	93	98	100	102	105	105	106	106	107	107	108	107	108	107	107	100	88	2,284
JUL	89	85	84	83	83	84	88	99	104	108	112	114	115	117	118	119	119	119	118	118	115	115	107	94	2,507
AUG	88	85	84	83	83	85	90	99	104	107	110	112	113	114	115	117	117	117	117	117	117	113	104	92	2,483
SEP	54	53	52	51	52	55	61	70	71	73	73	74	74	74	76	76	76	78	79	81	81	76	69	56	1,635
OCT	55	52	51	51	52	55	60	69	71	72	72	70	68	68	69	70	72	73	73	73	73	70	67	55	1,561
NOV	67	67	67	67	70	74	78	81	81	82	80	77	76	75	74	76	80	85	86	85	84	80	75	70	1,837
DEC	72	72	72	72	73	76	84	90	90	89	87	85	83	81	80	87	93	99	100	99	97	94	87	76	2,038

Amounts shown in MW, hours shown are Hour-Ending and in Mountain Standard Time

Figure 12: Basin CROD Western Interconnection Stegall West 230KV Bus Hourly Profile

POINT OF DELIVERY: AULT 230KV and STORY 230KV BUSSES

Month\HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
JAN	92	90	90	90	93	95	105	115	114	111	109	107	103	102	99	100	108	118	122	119	118	114	106	95	2,515
FEB	91	90	90	90	93	102	107	114	114	112	110	108	104	103	102	102	106	112	122	121	119	114	107	93	2,526
MAR	86	85	85	86	90	96	104	104	104	102	100	96	94	94	94	94	94	100	105	106	105	100	93	87	2,304
APR	60	58	57	57	59	64	70	72	72	72	72	70	69	68	67	67	69	71	72	73	75	73	66	61	1,614
MAY	67	65	64	64	65	70	76	80	81	82	82	82	82	82	82	82	85	85	85	85	85	84	80	72	1,867
JUN	100	95	92	92	92	96	102	118	123	126	130	131	132	133	133	135	136	136	136	136	136	134	126	110	2,880
JUL	111	107	106	104	104	106	110	123	130	135	140	143	145	146	148	149	149	149	148	148	145	144	135	117	3,142
AUG	110	107	106	104	105	107	111	124	129	135	137	140	142	143	145	146	146	146	146	146	146	146	140	130	115	3,106
SEP	68	66	64	64	65	69	76	88	90	91	92	93	93	93	95	95	96	98	98	102	102	95	85	70	2,048
OCT	68	65	64	64	65	69	76	86	89	90	90	88	85	85	86	88	90	92	92	92	91	88	84	69	1,956
NOV	84	83	83	83	87	93	98	102	102	102	100	97	95	93	93	96	99	106	108	106	104	100	94	87	2,295
DEC	90	90	89	89	91	96	105	113	113	111	108	106	103	102	100	108	117	123	125	124	122	118	109	95	2,547

Amounts shown in MW, hours shown are Hour-Ending and in Mountain Standard Time

Figure 13: Basin CROD Western Interconnection AU 230KV and STORY 230KV Busses Hourly Profile

Basin Electrically East contract has an energy and demand profile based on forecast Electrically East (Nebraska and Colorado) load, as this is a full requirements contract. The load served by this full requirements contract is located in the Eastern Interconnection primarily in the state of Nebraska with a small amount of Colorado load in the far northeastern portion of Colorado. On an average annual basis, ~15% of this purchase serves Colorado. The balance of this purchase serves load in Nebraska.

Hourly Profiles for the Basin Electrically East contract vary by season and are heavily impacted by irrigation. Figure 14 shows a typical hourly profile in a given day for the Irrigation and Non-Irrigation seasons. As shown by the orange line in the graph the hourly load during non-irrigation season barely exceeds 50 MW with a sharp morning peak, while the hourly load during irrigation season (yellow line) has a sustained daytime peak closer to ~280MW.

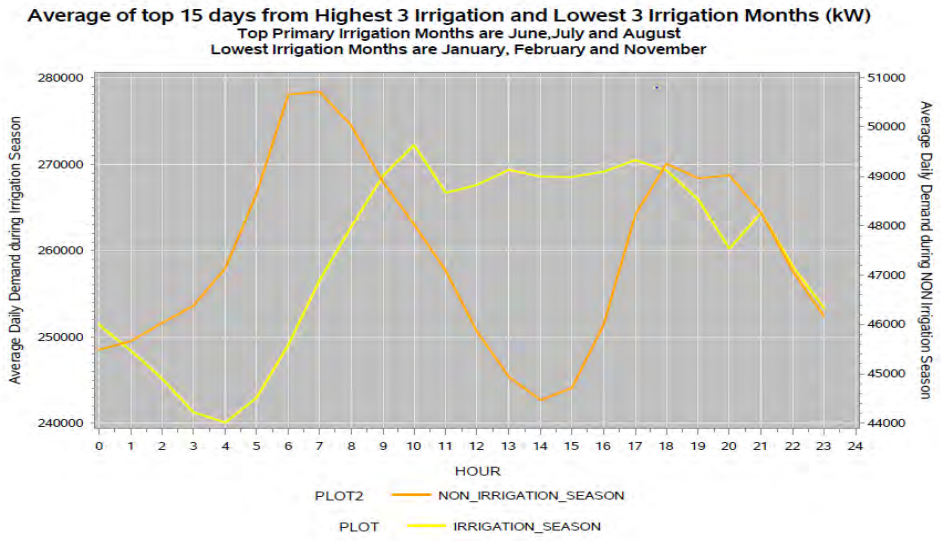

Figure 14: Basin Electrically East Irrigation and Non-Irrigation Seasons Demand Profiles

Below is a snapshot of historical energy and demand for the Basin Electrically East contract by month:

Table 38: Historical Energy and Demand for Basin Electrically East

Year	Data/UOM	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2018	Energy *(GWh)*	38	35	36	37	38	72	129	138	59	28	28	30
2018	Demand *(MW-Mo)*	76	76	62	64	88	191	335	269	126	55	49	53
2019	Energy *(GWh)*	29	29	27	23	35	45	137	117	60	24	29	29
2019	Demand *(MW-Mo)*	52	54	57	55	73	155	305	255	208	48	51	47

Below summarizes the annual projected energy and demand for each Basin contract.

Table 39: Annual Projected Energy for Basin Contracts

Energy *(GWh)*	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Basin CROD Western Interconnection[20]	1575	1575	1575	1580	1575	1575	1575	1580	1575	1575
Basin Electrically East [21]	664	683	686	689	692	694	698	701	704	707

Table 40: Annual Projected Demand for Basin Contracts

Annual Demand *(Sum of MW-Mo)*	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Basin CROD Western Interconnection	2458	2458	2458	2458	2458	2458	2458	2458	2458	2458
Basin Electrically East	1383	1553	1559	1566	1572	1579	1586	1594	1600	1608

Projected WAPA Contracts – LAP & CRSP Energy & Demand

LAP and CRSP contracts provide a set amount of energy delivered to each sub region by month. Additionally, an hourly minimum and maximum MW take is provided for each sub region by month. Tri-State is required to schedule on a two-day ahead basis the hydro in each sub region by "dispatching" the energy within the hourly minimum and maximum ranges.

Table 41 below summarizes the annual projected energy and demand for the WAPA CRSP and LAP contracts.

Table 41: Annual Projected Energy by Contract

Energy *(GWh)*	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
CRSP Total	1424	1424	1424	1424	1424	1424	1424	1424	1424	1424
Colorado Deliveries	930	930	930	930	930	930	930	930	930	930
New Mexico Deliveries	494	494	494	494	494	494	494	494	494	494
LAP Total	900	900	900	900	900	900	900	900	900	900
Colorado/Wyoming Deliveries	711	711	711	711	711	711	711	711	711	711
Nebraska Deliveries	189	189	189	189	189	189	189	189	189	189

[20] Energy is delivered to Colorado and Wyoming.
[21] ~15% of this purchase serves Colorado. Balance of purchase serves load in Nebraska. Energy and Demand data is per the 2020 annual load forecast.

Table 42: Annual Projected Demand by Contract

Annual Demand [22] *(Sum of MW-Mo)*	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
CRSP Total	4807	4807	4807	4807	4807	4807	4807	4807	4807	4807
Colorado Deliveries	3105	3105	3105	3105	3105	3105	3105	3105	3105	3105
New Mexico Deliveries	1702	1702	1702	1702	1702	1702	1702	1702	1702	1702
LAP Total	3823	3823	3823	3823	3823	3823	3823	3823	3823	3823
Colorado/Wyoming Deliveries	3029	3029	3029	3029	3029	3029	3029	3029	3029	3029
Nebraska Deliveries	794	794	794	794	794	794	794	794	794	794

Energy and Capacity Payments for Contract Purchases:

The following rates are averaged over the RAP:

Table 43: Average Energy and Demand Rates over the Resource Acquisition Period

Resource	**Energy Rate** *($/MWh)*	**Demand Rate** *($/KW-month)*
Basin CROD Western Interconnection		
Basin Electrically East		
CRSP	$12.19	$5.18
LAP	$15.72	$4.12
Native American WAPA Allocations		
Central Valley Electric		

Table 44: Historical Contract Pricing

Contracts	**Rate Type**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
WAPA LAP	Demand Rate ($/kW)	$5.43	$5.43	$4.79	$4.12	$4.12	$4.12
	Energy Rate ($/MWh)	$20.71	$20.71	$18.28	$15.72	$15.72	$15.72
WAPA CRSP	Demand Rate ($/kW)	$5.18	$5.18	$5.18	$5.18	$5.18	$5.18
	Energy Rate ($/MWh)	$12.19	$12.19	$12.19	$12.19	$12.19	$12.19
Basin Nebraska	Demand Rate ($/kW)						
	Energy Rate ($/MWh)						
Basin CO/WY	Demand Rate ($/kW)						
	Energy Rate ($/MWh)						
WAPA Native American Allocations	Average Energy Rate ($/MWh)						
WAPA Resource Balancing Purchase	Energy Rate ($/MWh)						
Central Valley Electric	Average Energy Rate ($/MWh)						
PNM UC	Energy Rate ($/MWh)						
PRPA - Rawhide Solar SS	Energy Rate ($/MWh)						
PRPA - Prairie Solar SS	Energy Rate ($/MWh)						
PRPA - Roundhouse Wind SS	Energy Rate ($/MWh)						
CSU - Palmer Solar SS	Energy Rate ($/MWh)						

[22] Representative of monthly billing demands per the contracts. Actual maximum available hourly capacity in any given month varies.
[23] Composite rate encompassing energy and demand components
[24] Composite rate encompassing energy and demand components

Renewable Power Purchase Agreements:

Cimarron (First Solar) Purchase: Facility located in northeastern New Mexico, 30 MW (Maximum Capacity), ~64 GWh/year. Effective Date 2/23/2009; COD 11/25/2010; Contract Expires 11/24/2035.

Kit Carson Wind Purchase: Facility located in eastern Colorado, 51 MW (Maximum Capacity), ~185 GWh/year. Effective Date 6/30/2009; COD 11/19/2010; Contract Expires 11/30/2030.

Colorado Highlands Wind Purchase: Facility located in northeastern Colorado, 94 MW (Maximum Capacity) 91 MW (Nameplate Capacity), ~369 GWh/year. Effective Date 2/28/2012; COD 12/6/2012; Contract Expires 12/31/2032.

Carousel Wind Purchase: Facility located in eastern Colorado, 150 MW (Maximum Capacity), ~665 GWh/year. Effective Date 12/27/2013; COD 07/07/2016; Contract Expires 7/31/2041.

San Isabel Solar Purchase: Facility located in southern Colorado, 30 MW (Maximum Capacity), ~77 GWh/year. Effective Date 8/19/2015; COD 12/5/2016; Contract Expires 12/31/2041.

Alta Luna Solar Purchase: Facility located in southern New Mexico, 25 MW (Maximum Capacity), ~77 GWh/year. Effective Date 9/24/2015; COD 1/12/2017; Contract Expires 01/31/2042.

Twin Buttes II Wind Purchase: Facility located in southeastern Colorado, 75 MW (Maximum Capacity), ~302 GWh/year. Effective Date 6/1/2015; COD 12/28/2017, Contract Expires 12/31/2042.

Spanish Peaks Solar Purchase: Facility located in southern Colorado, 100 MW (Maximum Capacity), ~267 GWh/year. Effective Date 12/12/2018; Expected COD 11/01/2023, Contract Expires 11/30/2038*.Crossing Trails Wind Purchase: Facility located in eastern Colorado, 104 MW (Maximum Capacity), ~439 GWh/year. Effective Date 2/5/2019; Expected COD 12/18/2020, Contract Expires 12/31/2035*.

Niyol Wind Purchase: Facility located in northeastern Colorado, 200 MW (Maximum Capacity), ~843 GWh/Year. Effective Date 12/18/2019; Expected COD 12/31/2021, Contract Expires 12/31/2041*.

Escalante Solar Purchase: Facility located in western New Mexico, 200 MW (Maximum Capacity), ~566 GWh/Year. Effective Date 12/10/2019; Expected COD 11/30/2023, Contract Expires 11/30/2040*.

Axial Basin Solar Purchase: Facility located in northwestern Colorado, 145 MW (Maximum Capacity), ~370 GWh/Year. Effective Date 12/10/2019; Expected COD 12/31/2023, Contract Expires 12/31/2038*.

Dolores Canyon Solar Purchase: Facility located in southwestern Colorado, 110 MW (Maximum Capacity), ~297 GWh/Year. Effective Date 12/10/2019; Expected COD 12/31/2023, Contract Expires 12/31/2038*.

Spanish Peaks II Solar Purchase: Facility located in southern Colorado, 40 MW (Maximum Capacity), ~107 GWh/Year. Effective Date 12/10/2019; Expected COD 12/31/2023, Contract Expires 12/31/2038*.

Coyote Gulch Solar Purchase: Facility located in southwestern Colorado, 120 MW (Maximum Capacity), ~331 GWh/Year. Effective Date 1/13/2020; Expected COD 12/31/2023, Contract Expires 12/31/2038*.

All solar power purchase agreements are assumed to have declining annual energy at approximately 0.5% per year to reflect solar panel degradation

*Contract expiration calculated from expected COD

Small Power Producers (Hydropower) Contracts:

Table 45: Summary of Small Power Producers (Hydro) Contracts

Facility Name (Maximum Capacity)	Effective Date	Expiration	Location
Boulder Hydro (5MW) & Other Facilities (1.27 MW)	6/1/2018	5/31/2028	Colorado
Denver Water/Williams Fork (3.5 MW)	1/1/2007	12/31/2026	Colorado
Mancos/Jackson Gulch (0.26 MW)	9/1/1995	2/8/2035	Colorado
Vallecito/Ptarmigan (5.6 MW)	6/25/2004	6/24/2024	Colorado
Garland Canal (2.9 MW)	12/10/2014	12/31/2024	Wyoming
Tri-County Water/Ridgway (8 MW)	8/22/2012	9/30/2023	Colorado

Energy Payments for Renewable Power Purchase Agreements:

The following rates are averaged over the RAP. Capacity rates are not applicable to our Renewable Power Purchase Agreements:

Table 46: Energy Prices for PPAs over the Resource Acquisition Period.

Resource	Energy Rate *($/MWh)*
Cimarron	[redacted]
Kit Carson	
Colorado Highlands	
Carousel	
San Isabel	
Alta Luna	
Twin Buttes II	
Spanish Peaks	
Crossing Trails	
Niyol	
Escalante	
Axial	
Dolores Canyon	
Spanish Peaks II	
Coyote Gulch	
Boulder Hydro & Other Facilities	
Denver Water/Williams Fork	
Mancos/Jackson Gulch	
Vallecito/Ptarmigan	
Garland Canal	
Tri-County Hydropower	

Table 47: Historical Renewable PPA Pricing ($/MWh)[25]

Renewables	2015	2016	2017	2018	2019	2020
Cimmaron						
Kit Carson						
Colorado Highlands						
Carousel						
San Isabel						
Alta Luna						
Twin Buttes						
Boulder Canyon Hydro						
Denver Water Board						
Garland Canal Hydro						
Mancos Water						
Vallectio						
Tri-County						

Contract Provisions – Modification of Capacity and Energy Purchased:

The above contract purchases and renewable purchase power agreements are a combination of must take energy or take or pay energy. Limited ability to modify capacity or energy purchased under these contracts exists. The few exceptions are listed below:

- Annually LAP contract capacity and energy is adjusted by WAPA per the contract formula. Additionally, WAPA can adjust capacity and energy due to changes in hydrology and river operations or the addition of new resources.
- At predetermined dates in the CRSP contract, WAPA will adjust capacity and energy as necessary up to the maximum 1% withdrawal limit for the resource pool. Additionally, WAPA can adjust capacity and energy due to changes in hydrology and river operations or the addition of new resources.
- All utility scale renewable projects have a right of first refusal option with regard to facility expansion and exercise of such option when made available could result in additional capacity and energy.
- All utility scale renewable projects allow for Tri-State to take excess energy produced over and above expected contract energy as defined by each contract
- The majority of Tri-State's utility scale renewable contracts have a provision to curtail energy production without penalty under certain conditions through an allowable curtailment option. The allowable curtailment amount varies by contract but does not exceed 1% of annual contract energy.

[25] Low pricing in 2015 for Carousel and 2017 for Twin Buttes is a result of test energy.

Note:

- The Basin CROD Western Interconnection contract does not expressly allow for the modification of capacity or energy amounts purchased. The contract exhibit identifies a set hourly energy profile that supplier will deliver and Tri-State will receive.
- The Basin Electrically East contract does not expressly allow for the modification of capacity or energy amounts purchased. The Basin Electrically East contract is a full requirements contract, and supplier is obligated to serve Tri-State Utility Member System load located in the Eastern Interconnection in its entirety at delivery points as identified in the contract including changes to Utility Member System load as a result of natural cycles of load growth or decline.

Emissions & RECs Associated with Contract Purchases and Renewable Purchase Power Agreements:

Tri-State receives Renewable Energy Credits (RECs) associated with its Renewable Purchase Power Agreements. Tri-State's renewable PPAs are non-CO_2 emitting resources.

The WAPA LAP contract energy is generally sourced from power generated at federal dams in the Pick-Sloan Missouri Basin Program – Western Division and the Frying pan-Arkansas Project, collectively Loveland Area Projects. The WAPA CRSP Contract energy is generally sourced from power generated by the Salt Lake Area Integrated Projects. WAPA purchases energy from other sources as needed to meet the marketing plan obligations of its federal electric service customers including the LAP and CRSP contracts with Tri-State. Primarily these deliveries are from hydro. Annually, Tri-State receives RECs for prior year deliveries, which are recorded in WREGIS. These contracts are considered non-CO_2 emitting resources.

The Basin CROD Western Interconnection contract and the Basin Electrically East contract do not specify a source within the contract. Basin has the sole ability to determine the source of the energy for these contracts on a daily and hourly basis. Both contracts do require the energy to be delivered to specific delivery points. Based on this, the energy provided by these contracts are "unspecified energy" as identified in the Colorado AQCC Regulation 22. In order to estimate emissions of these contracts for the purpose of this Resource Plan, Tri-State considered the following:

Basin CROD Western Interconnection Contract: while historically this contract has been primarily served by LRS, future supply of this contract is in no way limited to a source of LRS. Organized market development, changing environmental landscape in the Western Interconnection, changing market or business conditions for BEPC or other factors can potentially influence BEPC's choice for hourly sourcing of this contract energy.

Basin Electrically East: This load in its entirety is within the Southwest Power Pool (SPP) footprint and BEPC supplies this load through the SPP market process.

Actual CO_2 emission rates used for the Basin contracts are discussed further in Section 5 Phase I Modeling Details under the GHG & CO_2 Reduction Methodology subsection of this report.

Additionally, it is noted that Tri-State receives RECs related to both of the Basin contracts as a Class A member of BEPC under an associated board policy, Renewable Resource Obligations Policy. The allocation process is similar to Basin's capital credit allocation process for Class A members. Allocation of RECs is determined annually for prior year. Recent historical allocations have been equal to ~25% of energy delivered under the Basin Western Interconnection and Basin Electrically East contracts.

Utility Member System Distributed Generation:

Tri-State's wholesale power contract with each of its Utility Member systems and applicable Tri-State Board policies allow for and facilitate the development of local distributed generation projects in Tri-State Utility Members' service territories, including community solar projects. These renewable and distributed projects help to fulfill both Colorado and New Mexico RES/RPS requirements, as well as satisfy Utility Members' and consumers' interest in purchasing renewable power from locally-sited projects.

As of October 2020, over 60 renewable or distribution generation projects, totaling 131 MW of capacity and capable of producing ~370 GWh/year are operating or under development. Approximately 85% of Utility Member System distributed generation is located in Colorado, and on a capacity basis, approximately 80% of the distributed generation in Colorado and New Mexico is solar. It is expected that the number of these projects will continue to grow as pricing for renewable resources continues to be attractive and Utility Member Systems continue to show interest in supporting local renewable projects. These numbers are also expected to grow as a result of Tri-State's Board of Directors approving a new policy in 2019 that will facilitate the development of community solar projects throughout its Utility Member Systems' service territories.

These resources are neither owned by nor contracted to Tri-State, but instead serve Utility Member system load directly. Tri-State has not attempted to provide a detailed assessment of these generation projects.

Forced Outage Assistance Agreements

TEP Hazard Agreement[26]: Upon any full forced outage of Springerville Unit 2, Tri-State shall deliver 100 MW per hour to TEP. TEP will deliver 100 MW per hour for any full forced Springerville Unit 3 loss. Hazard supply is limited to 168 hours of delivery. Contract energy is optional. Expected Effective Date 12/01/2020; Contract Expires 03/31/2022. Contract is evergreen unless Parties submit notice of greater than 150 days or designated unit retires.

PRPA Hazard Agreement: Upon any full forced outage of Craig Unit 3, PRPA will deliver 100MW per hour to Tri-State. Upon any full forced outage of Rawhide Unit 1, Tri-State will deliver 100MWper hour to PRPA. Hazard supply is limited to 168 hours of delivery. Contract energy is must take. Effective Date 04/01/2014. Contract expires 03/31/2024. Contract can be terminated by either party on two years written notice.

[26] Replaces prior agreement.

Table 48: Forced Outage Assistance Agreements Historical Pricing

Average Energy Rate	2016	2017	2018	2019	2020
TEP Hazard Agreement					
PRPA Hazard Agreement					

Scheduling Agent Agreements

WMPA Contract: Tri-State acts as WMPA's scheduling agent for its WAPA Network Integrated Transmission Service Agreement, Federal hydropower, generation resources, sales of available energy, and purchases of replacement energy. Effective Date 09/26/2017; Commencement Date 10/01/2017; Contract Expires 6/30/2021.

- WMPA sells Tri-State ~125 GWh of excess energy/year in instances where WMPA's resources are in excess of its load requirements.
- Tri-State sells WMPA ~6 GWh of energy to serve WMPA's load/year when WMPA's resources are not sufficient to serve its load.
- Additionally, Tri-State provides WMPA's spinning and operating reserves in the amount of WMPA's Pro Rata Reserve Share as determined in accordance with the WMPA Sub-Entity Agreement with WAPA for participation in NWPP.

Overview of Merchant Transmission

Tri-State is a wholesale cooperative electric generation and transmission association consisting of 42 Utility Member systems located across four states, operating within multiple Balancing Authorities and served by multiple Transmission Providers. Additionally, Tri-State's load is dispersed in multiple states and in both the Eastern Interconnection grid and the Western Interconnection grid. Tri-State's load in the Eastern Interconnection, which primarily includes loads in Nebraska along with a small amount of northeastern Colorado load, is served by an all requirements contract with BEPC. Resources for serving Tri-State load in the Western Interconnection, which includes loads in Wyoming, Nebraska, Colorado and New Mexico, are a combination of company owned resources and PPAs.

Figure 15 below illustrates the geographic diversity of Tri-State's load and resources along with Tri-State Merchant[27] owned transmission capacity and related transmission constraints. In the Western Interconnection, Tri-State Merchant is a network transmission customer of the following Transmission Providers:

- Tri-State Generation & Transmission Association (Tri-State Transmission)
- PSCo
- PNM
- PRPA
- WAPA Rocky Mountain Region Loveland Area Projects (LAPT)
- BHCT

[27] Tri-State Merchant is the marketing arm of Tri-State Generation and Transmission Association that is responsible for planning and resource acquisitions in regards to energy, capacity and transmission necessary to serve Utility Member system load along with related dispatch, scheduling and settlements activity.

- PAC

Additionally, Tri-State Merchant is a Point-to-Point (PTP) transmission customer of many TPs in the Western Interconnection. Tri-State Merchant uses these network and PTP transmission rights within Western Electricity Coordinating Council (WECC) TOT[28] capacity limits and other system constraints to schedule power from resources to loads on a day ahead and hourly basis to serve Utility Member System loads. The "Tri-State owned capacity" arrows in Figure 15 represent Tri-State transmission rights between modeling regions.

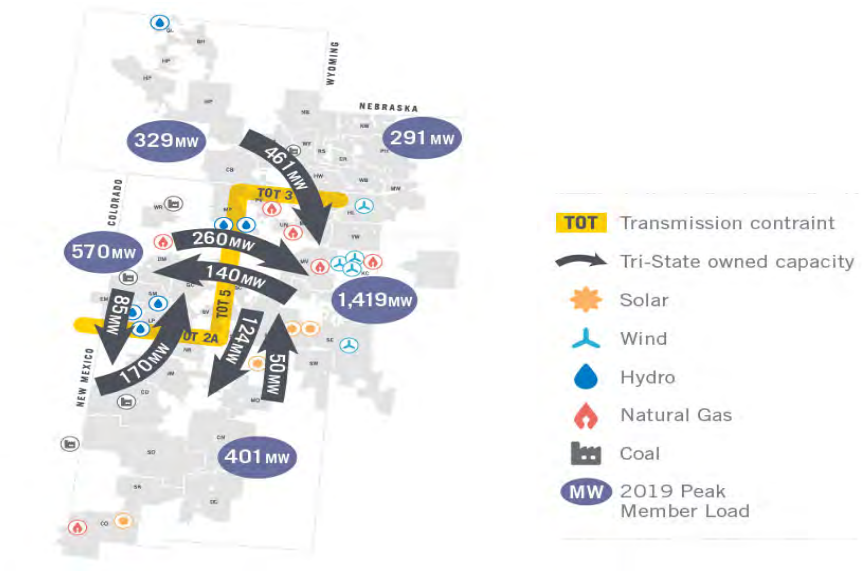

Figure 15: Tri-State System Major Transmission Paths

Table 49 represents Tri-State's major transmission reservations for moving power between regions across Tri-State's system. This is a reflection of the transmission modeling within the modeling systems for resource planning but does not represent a complete list of transmission rights including those within regions necessary to tag load in day-to-day operations.

Table 49: Tri-State's Major Transmission Network Paths

Transmission Capacity *(MW)*	**TOT**	**Path Flow Direction**	**TP/Type**	**Comments**
85	2a	NM to CO	TSGT Network	Path is often significantly reduced.
100	2a	NM to CO	CRCM PTP	
70	2a	CO to NM	TSGT Network	Path is often significantly reduced.
124	-	CO to NM	TSGT Network	Requires additional PTP leg to serve TS network load in PNM.

[28] A collection of transmission paths with a total operating limit that is often lower than the total of the underlying path reservations.

Transmission Capacity *(MW)*	**TOT**	**Path Flow Direction**	**TP/Type**	**Comments**
50	-	NM to CO	TSGT Network	Requires additional PTP leg to serve TS network load in PSCO.
461	3	WY to CO/CO to WY	TSGT MBPP[29]	Multiple reservation paths but total scheduled cannot exceed TOT limit.
260	5	West CO to East CO	TSGT Network	Additional PTP rights exist related to WAPA federal hydro contracts and other long-term firm PTP reservations.
140	5	East CO to West CO	TSGT Network	Additional 3rd party PTP transmission is available along this path at an additional cost.

In the Western Interconnection, Tri-State is required to deliver and tag power to sinks as configured in the North American Reliability Electric Corporation (NERC) webRegistry and as required by NERC Reliability Standards. Below is a breakdown of major load sinks:

- Nebraska West and Wyoming
  - 2 network sinks[30] in LAPT[31] TP – Western Area Colorado Missouri (WACM) BA and 1 ancillary[32] only sink in WACM BA
  - 3 network sinks in PAC TP and BA
- Colorado
  - 1 network sink in PSCO TP and BA and 3 ancillary only sinks in PSCO BA
  - 1 network sink in BHCT TP - PSCO BA
  - 1 network sink in LAPT TP and WACM BA
  - 3 ancillary only sinks in WACM BA
- New Mexico
  - 1 network sink in PNM TP and BA

There are specific Points of Delivery (POD) within each sink to which power can be delivered in order to supply Tri-State Utility Member System load. These PODs are similar to transaction points where purchases and sales occur. Tri-State may purchase power or move owned or contracted resources to these points, within applicable transmission rights, to serve load at the specific sinks.

WEIS/WEIM Transmission Impact:

[29] Transmission rights related to MBPP. However, use of this transmission is not limited to LRS.
[30] A network sink represents a subset of network delivery points with a third party TP where Tri-State has a network transmission integrated service agreement. Tri-State pays for network transmission on a prorata share basis each month based on load levels during the TP's peak.
[31] LAPT represents the transmission lines associated with the Loveland Area Projects federal hydropower
[32] An ancillary sink is a registered load within a Balancing Authority where only Tri-State Transmission is required to serve load.

Upon entry into energy imbalance markets in 2021, transmission and tagging for day ahead and real time activities will mostly remain as-is for load and resources located within WEIS and WEIM. However, the energy imbalance market will also introduce new intra-hour activity driven by the market operator. Intra-hour use of transmission by resources at the market operator's direction will be on a non-firm basis with no related tagging or charges.

RTO Transmission Impact:

Entry into an RTO consists of a common Open Access Transmission Tariff (OATT) and typically a market operator taking on BA responsibilities for the RTO footprint. The following are key changes related to or impacting transmission rights and usage in an RTO:

- One common OATT exists for the market and transmission billing is facilitated through the market operator.
- Congestion and losses are included as components of the Locational Marginal Price (LMP).
    - Resources are offered in at their location and awarded the LMP
    - Load is bid in at its location and pays the associated LMP
- Mitigation of congestion costs is handled through a financial congestion right that is to some extent correlated to transmission reservation rights.
- No tagging occurs within the market footprint; only imports, exports and wheel-thrus are tagged.

Overview of Merchant Ancillary Services

Tri-State meets its ancillary service requirements through Network Integration Transmission Service Agreements and Balancing Authority Ancillary Service Agreements. In the Western Interconnection, Tri-State receives ancillary services from PAC, PSCo, PNM and WAPA. As mentioned previously in this report, Tri-State's electrically east load is served via a full requirements contract with BEPC, which includes ancillary services.

Tri-State currently operates in bilateral energy and ancillary trading markets, and in 2021 will move additional load and resources into energy imbalance markets (WEIS and WEIM). Tri-State does not have load or resources in a full "day-2" organized market (an RTO or ISO) which would allow for both an energy and ancillary market.

Primary Ancillary Services:

The following is a list of primary ancillary services required via applicable TP OATTs and how Tri-State acquires these services, including applicability to any Tri-State resources:

Schedule 1 - Scheduling, System Control & Dispatch: Tri-State pays for this service monthly from appropriate TPs or BAs. Tri-State resources do not have any impact on or relation to this service.

Schedule 2 - Reactive Supply & Voltage Control: Tri-State pays for this service monthly from appropriate TPs or BAs. Tri-State's generating resources do not have any impact on or relation to this service. Tri-State does, however, have several applicable agreements with entities to partially self-supply reactive support via transmission system equipment in exchange for a reduced cost in service. Separately, Tri-

State generation resources are required via NERC Reliability Standards to follow reactive power instructions from Transmission Operators and operate in automatic voltage control mode.

Schedule 3 - Regulation and Frequency Response (includes load following capabilities): Tri-State pays for this service monthly from appropriate TPs or BAs. Applicable Tri-State-owned or contracted resources and Utility Member system distributed resources nameplate capacity are, at times, a factor in determining regulation cost, but Tri-State does not have any obligation to regulate for its own load or resources. Tri-State does, however, have generating resources that have the capability to operate in Automatic Generation Control (AGC) mode and thereby provide regulation as a service for a cost or partially self-supply regulation[33].

Tri-State generating resources that are AGC capable include:

- Craig 1,2,3
- LRS 2
- SPV 3
- JM Shafer
- Knutson 1,2
- Limon 1,2
- Pyramid 1,2,3,4
- Burlington 1,2

Schedule 4 - Energy Imbalance Service: Tri-State currently pays for this service monthly from appropriate TPs or BAs. Beginning in 2021, a significant portion of Tri-State's load and resources will be in two energy imbalance markets – the WEIS and WEIM. Upon entry, Tri-State will be able to participate with its resources located within the respective market's footprint. Financial settlements will occur with the appropriate Market Operator.

Schedule 5 - Operating Reserve Spinning Service: Tri-State self-provides spinning reserves through Southwest Reserve Sharing Group membership and via two sub-entity Reserve Sharing Group Agreements[34]. Tri-State generating resources typically online and capable of carrying spinning reserves include:

- Craig 1
- Craig 2
- Craig 3
- LRS2
- LRS3
- SPV 3
- JM Shafer

[33] See WAPA Regulation Contract for partial self-supply in Section 1 Electric Energy and Demand Forecast under the Energy and Capacity Sales to Other Utilities subsection for an example.

[34] The two sub entity Reserve Sharing Group Agreements are with PSCO and WAPA. PSCO and WAPA are participants of the Northwest Power Pool for reserve sharing as of the fall of 2019. Prior to that time PSCO, WAPA and Tri-State participated in the Rocky Mountain Reserve group for resources in these BAs.

Due to recent changes in operating standards in the Western Interconnection, operating reserves may be fully served via non-spinning supplemental service rather than the previous requirement that operating reserves must include of a minimum of 50% spinning reserves.

Schedule 6 - Operating Reserve Supplemental Service:

Tri-State self-supplies spinning reserves through Southwest Reserve Sharing Group member agreement and two sub-entity Reserve Sharing Group agreements. Tri-State's generating resources with quick start capability, which qualify for supplemental services, include:

- Burlington 1,2
- Limon 1,2
- Pyramid 1,2,3,4

Schedule 9 - Generator Imbalance Service: Tri-State currently receives and pays for this service monthly from appropriate TPs or BAs. Beginning in 2021, a portion of Tri-State's load and resources will be in two energy imbalance markets – the WEIS and the WEIM. Upon entry, Tri-State will be able to participate with its resources located within each respective market's footprint. Financial settlements will occur with the appropriate Market Operator.

Schedule 16 - Flex Reserve Service[35]: Tri-State currently takes and pays for this service monthly from appropriate TPs or BAs. This service is calculated based on proportional wind capacity contribution within the footprint as is used by the Balancing Authority to cover the costs of ramping requirements related to wind intermittency. There is no current option to self-supply.

Loss Supply Service: Tri-State either pays for this service monthly from appropriate TPs or BAs or provides physical loss requirement depending on specific contractual arrangements.

Self-Supply Discussion:

Tri-State has the ability to potentially self-supply all or a portion of the following ancillary services as allowed under TP OATTs and related contractual agreements:

- Reactive Supply and Voltage Control
- Regulation and Frequency Response
- Operating Reserves (Spinning or Supplemental)
- Loss Supply

With the transition of Tri-State's load and resources in the PNM-BA and WAPA-BA into WEIM and WEIS respectively Tri-State will also be able to offer in resources to meet intra-hour energy imbalance in these markets.

[35] Currently this ancillary service is only applicable to resources in PSCo.

Forecasting Ancillary Service Charges:

Table 50 provides a description of Tri-State's forecasting methodology for each ancillary service.

Table 50: Forecasting Methodology by Ancillary Service

Ancillary Service	Forecast Method
Scheduling, System Control & Dispatch	Current charges with adjustments for any known upcoming rate changes are used along with the appropriate forecast quantity (load or tags) to arrive at a forecast.
Reactive Supply & Voltage Control	Current charges with adjustments for any known upcoming rate changes are used along with the appropriate forecast quantity (load) to arrive at a forecast.
Regulation and Frequency Response	Current charges with adjustments for any known upcoming rate changes are used along with the appropriate forecast quantity (load, generation by type) to arrive at a forecast.
Energy Imbalance	Historical data is used to arrive at a forecast. The operational goal is always to minimize imbalance.
Operating Reserve Service (Spinning and Supplemental)	Tri-State models for self-supply of operating reserves on Pyramid and Burlington resources. Potential sales or purchases related to Reserve Sharing Group are forecast based on recent history. Contracts for specific sale of operating reserves as a service are forecast separately.
Generator Imbalance	Historical data is used to arrive at a forecast.
Flex Reserve Service	Financial forecast based on applicable resources and OATT rate. Included in Regulation forecast.
Loss Supply Service	Average of TP Provider's loss rate (5%) is applied to forecast load. Losses are included as load in the dispatch model.

Historical Ancillary Service Charges:

The following are average historical ancillary service charges from recent years as used to serve load across the Tri-State system in the Western Interconnection.

- Schedule 1 & 2 are recorded for accounting purposes with Network Transmission and Point-to-Point Transmission charges. The history detail for these charges is not readily available.
- Schedule 3 and Schedule 16 average annual regulation total charges for load and resources was $5 Million.
- Schedule 4 Energy Imbalance and Schedule 9 Generator Imbalance average annual purchase price was ~$25/MWh and the average annual sale price was ~$20/MWh.

- Schedule 5 & 6 Operating Reserves[36] average annual purchase price for receiving reserve activation assistance as part of a reserve sharing group or sub entity agreement was ~$40/MWh and average annual sale price was $80/MWh.

Current Ancillary Service Charges:

Table 51 shows current ancillary service rates for network and long-term firm PTP transmission.

[36] Reserve activation transactions occur upon the loss of a resource. The owner of the resource self-supplies replacement power to some extent and then purchases the additional assistance from reserve sharing counterparties.

Table 51 Ancillary Service Charges

ANCILLARY SERVICE CHARGES

Transmission Provider	Effective Date		Schedule 1	Schedule 2	Load Schedule 3	Non-VER Schedule 3	uncommitted VER - Wind Schedule 3	committed VER - Solar Schedule 3	Schedule 5	Schedule 6	Schedule 4	Schedule 9	Flex Reserves - Wind Schedule 16	Attachment R	Transmission Losses
BHTC															
	November 1, 2018	$/MW-month	$76.00	$61.00	$156.00	NA	NA	NA	$307.00	$288.00	See Note 1	See Note 1	NA	NA	1.94%
PAC	June 1, 2020														
		$/MW-hour							$151.00	$151.00					
		$/MW-month	$66.14	$45.83	$177.00	$150.00	$549.00	$469.00					NA	NA	4.45% (46kV +); 3.56% (34.5kV or less)
PNM	June 1, 2020				1.50%				1.50%	1.50%					
		$/MW-month	$30.00	$50.00	$129.00	NA	NA	NA	$140.40	$140.40			NA	See Note 7	2.67%
PSCO	January 1, 2020				1.27%	0.24%	2.07%	2.07%	3.50%	3.50%			12.05%		
		$/MW-month	$59.00	$302.00	$86.66	$16.38	$141.26	$141.26	$239.86	$67.27			$681.07	NA	2.20%-demand; 1.70%-energy
LAPT	October 1, 2020						148.00%	100.00%							
		$/MW-month	$21.14/schedule/day	$79.00	$205.00		$303.40	$205.00	See Note 2	See Note 2			NA	NA	4.50%
CRCM (LTFPTP)	October 1, 2020														
		$/MW-month	$21.14/schedule/day	$79.00	See Note 5	NA	NA	NA	See Note 5	See Note 5	See Note 6	See Note 6	NA	NA	4.50%
PRPA	June 1, 2020														
		$/MW-month	$0.00	$100.87	See Note 3	NA	NA	NA	See Note 4	See Note 4	See Note 3	See Note 5	NA	NA	1.94%
EPE - (Pre-OATT FPTP)	See Note 8	$/MW-month	$70.25	$44.00	See Note 6	NA	NA	NA	See Note 6	See Note 6	See Note 6	See Note 6	NA	NA	4.23%
TEP (LTFPFP)	September 11, 2020	$/MW-month	$41.00	$161.00	See Note 6	NA	NA	NA	See Note 6	See Note 6	See Note 6	See Note 6	NA	NA	3.44%
TSGT	October 1, 2020														
		$/MW-month	$332.00	$90.86	See Note 1	NA	NA	NA	See Note 1	See Note 1	See Note 1	See Note 1	NA	NA	3.378%

NOTES: Settlements
PAC - Schedule 5 & 6 are included in Regulation
PNM - Attachment R is Wheeling Expense
PSCO - Schedule 9 is included in Energy Imbalance
Schedule 16 is Regulation Expense
Schedule 1 & 2 are included as Wheeling Expense
Schedule 3 is Regulation and is Purchase Power Expense
Schedule 4 is Energy Imbalance and is PP Expense/NMS Revenue

Schedule 1 - Scheduling System control and dispatch services
Schedule 2 - Reactive Supply and Voltage Control service
Schedule 3 - Regulation and Frequency response service
Schedule 4 - Energy Imbalance Service
Schedule 5 - Operation Reserve (Spinning Reserve Service)
Schedule 6 - Operating Reserve (Supplemental Reserve Service)
Schedule 9 - Generator Imbalance Service
Schedule 16 - Flex Reserve Service

Note 1:	To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator
Note 2:	Pass Through (purchase price, energy activation, plus administrative fee)
Note 3:	TSGT's Network Load with PRPA - A/S 3 and 4 services supplied by WAPA
Note 4:	Platte River is not a balancing authority, and does not offer this service. Upon written request, Platte River will assist in arranging for the local balancing authority operator
Note 5:	Joint Dispatch Transmission Service ($0.00/MW-month)
Note 6:	A/S is not a required service for LTFPTP transmission service
Note 7:	Reliability Redispatch Costs and Methodology (details in PNM's OATT)
Note 8:	A/S Schedules 1 and 2 are not applicable with pre-OATT FPTP transmission service

Benchmarking

For the purposes of the Rule 3605(c)(II) Benchmarking requirement, Tri-State engaged Black & Veatch to perform an analysis of cost and performance of existing owned and contracted resources as compared to generic resources. The scope of this benchmarking analysis was limited to the following:

- Thermal and renewable utility scale resources that are:
  - Commercially operational, and
  - Located in the state of Colorado, or
  - Located outside of the state of Colorado but capable of serving Colorado load at any time.
- Basin Western Interconnection and Basin Electrically East contracts

Alta Luna and Cimarron renewable resources located in New Mexico are included in the benchmarking process but have never been scheduled to Colorado load.

Resources excluded from the benchmarking process include:

- Federal hydro contracts of LAP and CRSP as these long term, cost-based contracts for delivery of firm, renewable, quasi-dispatchable power with certain transmission and ancillary service benefits do not have a reasonable comparison within the generic resource pool.
- Other small contract purchases, small hydro power producer contracts

The full methodology, results and insights from the B&V benchmarking process are located in Attachment Vol II 5-5 B&V Benchmarking Study. This attachment was filed previously in the August 3, 2020 revised filing.

UPDATE: Tri-State is waiting for the Commission Order related to guidance in Proceeding No. 20M-0218E. Once this order is published, Tri-State will reengage B&V to revise this benchmarking study to meet Commission expectations. The revised study will be provided as soon as is reasonably possible.

The benchmarking process is informative to the overall resource planning process but does not take the place of scenario modeling required to arrive at least cost, reliable resources plans within transmission and environmental constraints.

Retirement Analysis

Tri-State allowed the expansion plan model to retire resources in the following scenarios:

- 80pct CR V1, V2, V3 and V4 – coal resources allowed to retire in 2025 except SPV3 which was allowed to retire after the end of the SRP sales contract (mid-year 2036)
  - Results: LRS 3 retires early 2030s; SPV3 retires late 2030s
- Low Load 80 pct CR V1 and V2 – coal resources allowed to retire in 2026 except SPV3 which was allowed to retire after the end of the SRP sales contract (mid-year 2036)
  - Results: LRS 3 retires late 2020s; SPV3 retires late 2030s
- Social Cost of Carbon – coal and gas resources allowed to retire in 2025 except SPV3 which was allowed to retire after the end of the SRP sales contract (mid-year 2036)

- Results: Craig 3, LRS 2 and LRS 3 retire in 2026; SPV3 retires in late 2030s; Various gas resources retired in late 2020s or early 2030s

In the 80pct CR V1, V2, V3 and V4 scenarios and Low Load CR V1, and V2 scenarios the expansion plan model chose to keep Craig 2 and 3 online until announced retirement dates. SPV3 was not allowed to retire prior to the end of the SRP contract associated with this resource in any scenario, because the current expansion plan model setup cannot appropriately consider the lost revenue of the SRP contract associated with SPV3 when making a retirement decision.

While the CE model is retiring LRS3 and SPV3 at varying times during the scenarios including in the preferred plan, Tri-State will need to work with the MBPP joint owners of Laramie River Station to determine the best retirement schedule for either LRS resource for all participants. In regards to SPV3 Tri-State will need to resolve the modeling issue mentioned above and work with other joint owners of common facilities at the Springerville station to arrive at the best retirement schedule for SPV3.

4 Transmission System & Planning

Overview – Transmission System

Tri-State owns (wholly or jointly) more than 5,500 miles of transmission lines in Colorado, Nebraska, New Mexico and Wyoming. Tri-State continues to support regional transmission study efforts. Tri-State continues to make transmission investments to serve growing loads, increase reliability, ensure system stability, and support additional generation development.

Transmission Planning

Tri-State transfer capability limitations on its transmission network are generally based on facility ratings. Tri-State's facility ratings equal the most limiting applicable Equipment Rating of the individual equipment associated with that facility. An overall transmission line rating factors in both the conductor rating and the associated terminal equipment ratings. Facility ratings commonly limit and affect the future siting of resources. See Attachment Vol II 4-1 Tri-State Facility Rating Report for additional detail.

The following Tri-State transmission projects have been identified in Tri-State's 10-year transmission plan filed pursuant to Rule 3627 included as Attachment Vol II 4-2 Tri-State 10-year Transmission Plan. Note, while these transmission projects were categorized as Planned in the filing, most are still in the developing stages. In Tri-State's experience, many of the planned transmission projects in the Rule 3627 report are ultimately modified or cancelled as the result of changing drivers and future needs.

- Burlington-Burlington (KCEA) 115kV Line Re-build
  - Tri-State will re-build the existing Burlington-Burlington KCEA line to increase the thermal rating of the line.
- Del Camino-Slater 115kV Line Uprate
  - This project will replace all the remaining spans of 397.5 ACSR conductor on the Del-Camino Slater line with 477 ACSR conductor.
- Falcon-Midway 115kV Line Uprate
  - This project involves raising, moving, or rebuilding structures along the Falcon-Midway 115kV line to increase the overall line rating to 145 MVA.

- Falcon-Paddock-Calhan 115kV Line
  - The current Falcon-Paddock-Calhan 69 kV transmission line will be rebuilt to create a 115 kV loop.
- Lost Canyon – Main Switch 115kV Line
  - This project will add a new 115kV line between Lost Canyon and Main Switch.
- Sisson Delivery Point Project
  - This project will add approximately 20 miles of new 115 kV transmission to radially serve the new Sisson substation radially north from the existing Keota substation.
- Vollmer Delivery Point Project
  - This project will tap the existing Jackson Fuller-Black Squirrel 115kV line and add approximately 2 miles of 115 kV transmission to serve the new Vollmer substation.
- Western Colorado Transmission Upgrade Project (re-build of Montrose-Nucla-Cahone 115kV line)
  - This project will rebuild the existing Montrose-Nucla-Cahone 115kV with 1272 ACSR conductor and be capable of future 230kV operation. Additionally, the line will be sectionalized at the new Maverick substation, rather than Nucla, which is located between Nucla and Norwood substations.

Project information for each transmission line or facility identified in 3605 (d)(II) can be found in Appendix E of the most recent Rule 3627 Report. See Attachment Vol II 4-3 Tri-State Transmission Project Information for a reduced copy of Appendix E showing the requested information for the identified projects.

Response to C20-0661-I Related to Transmission Impacts on the ERP Process

In the November 12, 2020 Commission weekly meeting the Commission gave guidance in regards to Proceeding No. 20M-0218E. Tri-State interpreted this guidance as the Commission requiring Tri-State to respond to the joint transmission proposal submitted by participants in Proceeding No. 19R-0096E. Tri-State first notes that it submitted comments in that proceeding pursuant to Decision No. C20-0661-I (the "Interim Decision") regarding the transmission-related rule proposals (the "Rule Proposals"). Tri-State's present position with respect to those proposals is the same as what it described in those earlier comments. Namely, while Tri-State agrees that some of the Rule Proposals have merit, there simply was not enough time remaining before Tri-State's ERP filing was due for Tri-State to incorporate any new requirements coming out of the 19R-0096E rulemaking process. Tri- State explains its position in more detail below, consistent with its earlier comments.

The rules governing this ERP filing were finalized in Proceeding No. 19R-0408E and became effective on July 15, 2020. These rules include Rule 3605(d), requiring Tri-State to submit an assessment of transmission resources, which will require Tri-State to provide extensive information regarding its current and planned transmission systems. This information includes Tri-State's transmission capabilities and future needs during the planning period for facilities of 115 kilovolts and above, the location and extent of transfer capability limitations on Tri-State's transmission network that may affect the future siting of resources, and a description of the transmission lines and facilities appearing in Tri-State's 2020 Rule 3627 Report that, as identified in that report, could reasonably be placed into service during the RAP. For each transmission line or facility that could reasonably be placed into service during the RAP, Tri-State must

include the following information detailing assumptions to be used for resource planning and bid evaluation purposes:

- length and location;
- estimated in-service date;
- injection capacity;
- estimated costs;
- terminal points; and
- voltage and megawatt rating.

In addition to providing this information, Tri-State must consider the transmission costs required by, or imposed on the system by, and the transmission benefits provided by a particular resource as part of the bid evaluation criteria. And it also must describe and shall estimate the cost of all new transmission facilities associated with any specific resources proposed for acquisition other than through a competitive acquisition process.

Tri-State has included this required information in Section 4 Transmission System & Planning and in other sections throughout this report as identified in the Transmission Summary subsection of Section 4.

The Rule Proposals in the Interim Decision would modify Commission Rules 3608, 3614, and 3615. These rules do not apply to Tri-State, nor should they be extended to do so. As was explained in Decision No. C20-0155 in Proceeding No. 19R-0408E, "given the structure and contents of Rule 3605 . . . the following ERP Rules being reviewed in Proceeding No. 19R-0096E are not intended to apply to Tri-State: . . . Existing/Proposed Rule 3608 Transmission Resources . . . Proposed Rule 3614. Phase I; and Proposed Rule 3615. Phase II." It would be contrary to this clear statement if the Rule Proposals in this proceeding were extended to modify the final rules adopted in Proceeding No. 19R-0408E.

Although Tri-State has not expressly incorporated any of the Rule Proposals into this ERP, it does agree in principle with some of the Initial Comments and Rule Proposals in the 19R-0096E proceeding. At a high level, Tri-State believes it will be important for the ERP process to account for transmission projects that are likely to come online during the resource acquisition period and recognizes that new transmission will be needed to meet Colorado's emissions-reduction goals. As such, Tri-State provides the following comments on some of the Rule Proposals or comments submitted in this proceeding.

Rule 3627 Information

Tri-State has no objection to the Commission taking administrative notice of the 2020 Rule 3627 filings in this ERP. While not all of the Rule 3627 information will be relevant to Tri-State's ERP, these filings nevertheless provide useful context regarding the transmission system and Tri-State believes they are appropriate to include in the ERP process. Indeed, under Rule 3605(d), Tri-State has already included information on those transmission resources in its Rule 3627 filing that could reasonably be placed into service during the resource acquisition period.

Planned Transmission Facilities

Tri-State agrees with the principle that transmission facilities under construction or for which a CPCN has been filed with the Commission at the time this ERP is being filed are in most cases facilities "that could

reasonably be placed into service during the resource acquisition period" under Rule 3605(d)(II). Tri-State has included such facilities in this ERP and intends to accept bids into these facilities as appropriate.

More generally, Tri-State notes that the RFP process for this ERP allows bidders to bid into developing transmission projects that are not yet in service, even where those facilities are not yet under construction and may be altered significantly or even cancelled. In general, this includes transmission projects that have been identified in Tri-State's 10-year transmission plan filed pursuant to Rule 3627.

While Tri-State intends to continue to accept such bids going forward, it urges the Commission to be cautious about adopting future rules that would encourage bids into projects that are still in the developing stages. In Tri-State's experience, many of the planned transmission projects in the Rule 3627 report are modified significantly or cancelled as the result of changing future needs. As an example, of the 16 new transmission line projects included in Tri-State's 3627 filings since 2014, only 2 have been constructed (the Burlington – Wray 230 kV line, and the Southwest Weld Expansion Project). This reflects the reality that Tri-State's long-term transmission planning reports are snapshots in time that rely heavily on forecasts of future drivers (oil and gas loads, for example) that change based on factors largely outside of Tri-State's control.

Tri-State further notes that it has network load that is served via other utilities' transmission systems and that it must coordinate with these utilities and conduct joint studies in some instances in order to accommodate new generation projects. This required coordination can add another layer of complexity and uncertainty with respect to some projects.

While bidders can bid into future, uncertain transmission projects, such bids are contingent on the continued need for the project. Where, as is often the case, the transmission project becomes unnecessary or dramatically changes, the economics of the bids relying on the project often become untenable.

Transmission Related Costs in Portfolios

Tri-State also agrees in principle with OCC that all transmission-related costs related to a particular generator bid should be included for purposes of bid evaluation.

Tri-State's ERP generally seeks to account for all such costs in order to ensure that it is securing the most cost effective generation for its Members. Tri-State notes that it is currently in the process of seeking FERC approval of certain reforms to its generator interconnection queue process that will allow it to better account for transmission costs associated with new generation through a cluster study process, rather than the sequential process it currently uses pursuant to the FERC Pro Forma Large Generator Interconnection Procedures.

Tri-State appreciates the Commission's consideration of these important transmission-related issues. Although the Commission should not adopt new requirements for Tri-State, Tri-State agrees with some of the Rule Proposals and comments in principle as discussed above. Tri-State recognizes the importance of these transmission-related items and is addressing some of them in this ERP filing.

Transmission Summary

In addition to the Transmission System & Planning section of this report transmission information related to Tri-State's system is available as follow:

- Volume I Section 8 Base case and Alternative Scenario Results contains specific transmission assumptions and transmission capital expenses by scenario.
- Volume I Section 11 Resource Acquisition Period – Action Plan contains transmission information related to the Phase II process.
- Volume II Section 3 Assessment of Resources contains a section on merchant transmission.
- Volume II Section 5 Phase 1 Modeling Details contains modeling constraints and assumptions related to transmission modeling.

5 Phase I Modeling Details

Model Description

Overview

Tri-State uses various industry standard software to perform resource planning including the following:

Table 52: Summary of Software Used in Tri-State Resource Planning

System	Purpose
SAS	Load forecasting by region for use in CE & PO and by member for use in Hyperion and UIPlanner.
Hitachi ABB Capacity Expansion (CE)	Develops expansion plans including resource acquisitions and retirements.
Hitachi ABB Portfolio Optimization (PO)	Hourly least cost dispatch within environmental and transmission constraints.
Transmission Siemens PSEE (PSEE)	Evaluates interconnection and network upgrade costs for new resources.
Hyperion	Receives load data from SAS and dispatch data from PO and incorporates this data along with capacity, energy, wheeling, transport and related expenses and revenues for transfer to UIPlanner.
Utilities International Planner (UIPlanner)	Financial model used to calculate PVRR for scenarios incorporating all expense and revenue data while adhering to Tri-State financial goals.

Tri-State's process for scenario analysis includes determining an expansion plan using CE, running an hourly dispatch for the 20-year planning period in PO, and gathering dispatch, plan and load data along with other capacity, energy and wheeling expenses and revenue in Hyperion. The CE plan for each scenario is sent to Tri-State's Transmission Planning group for an evaluation of transmission capital expenditures based on resource additions and retirements in each scenario. All analysis in CE, PO, Hyperion and Transmission are performed in real (2020) dollars without inflation. Final data is sent to UIPlanner for PVRR analysis for each scenario. UIPlanner inflates expense and revenues into nominal dollars.

The diagram below shows the succession through the primary software systems:

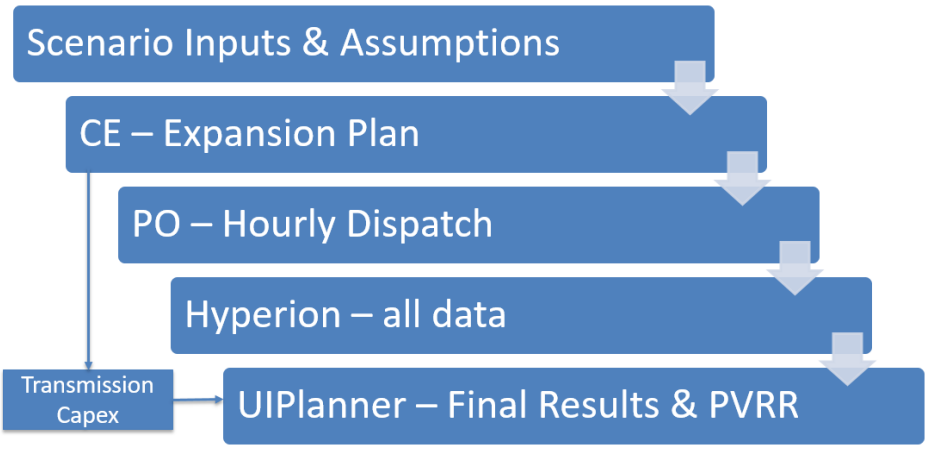

Figure 16: Scenario Modeling Process Overview

CE and PO

CE is a resource expansion planning model used to deliver an optimal expansion plan including timing, technology and size of potential resources. The plan respects a set planning reserve margin and adheres to transmission and emission constraints. For expansion planning, technologies are identified for use in the generic resource dataset. Emerging technologies are evaluated in regards to maturity and availability of reliable pricing and are included or excluded accordingly. Generic resources are set up as build, build transfers or power purchase agreements within the model. Characteristics and pricing of technologies included in the generic resource dataset can be found in the Section 5 Phase 1 Modeling Details under the Generic Resource Cost, Performance Emissions data subsection of this report.

CE uses a number of key inputs necessary for determining an ideal expansion plan from the perspective of cost, technology and timing within the planning horizon. Figure 17 lists inputs required for the system to define the expansion plan.

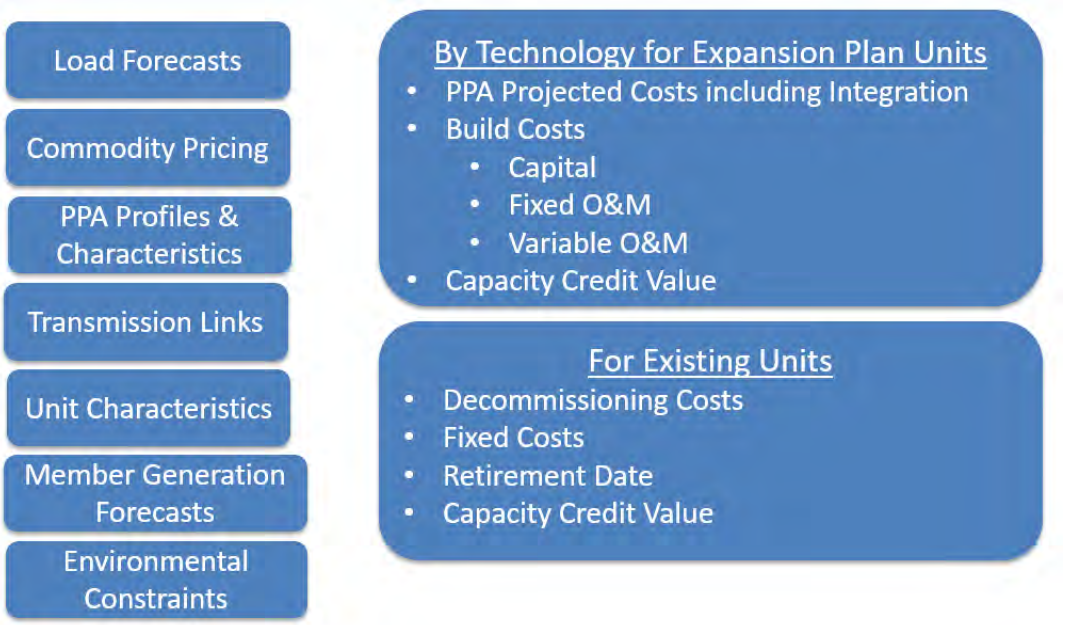

Figure 17: System Inputs for Expansion Plan Scenario Modeling

CE results include the size, timing, location, technology, and characteristics of each new unit.



Figure 18: Capacity Expansion (CE) Plan Results

The final expansion plan is then moved into the hourly dispatch model, PO.

PO is a production cost model used to determine a least-cost hourly dispatch plan based on unit operating characteristics, market prices, transmission constraints, regional load forecasts, and Power Purchase Agreements. Existing resources including any early retirements and generic resources additions identified in the expansion plan are modeled in PO for each scenario. Resources include thermals, renewables, energy storage, distributed generation, and demand-side-management, as

well as contracts with hourly and monthly energy limits. Final PO hourly output for the planning period is reviewed to ensure that all contract, environmental and dispatch limits are followed.

Dump Energy and Energy not Served:

As PO is modeling a dispatch over a 20-year period on an hourly basis, PO uses two methods to allow the model to complete within a reasonable timeframe. These methods are "dump energy" and "energy not served". "Dump energy" allows for an additional market outside of normal market depth limits where energy can be sold at an extremely low price. It is also a reasonable reference to potential curtailments in the plan driven by excess energy. "Energy not served" allows energy in a given hour that cannot be served by the existing and generic resources or existing market to be served at an extremely high market price. If the PO algorithm is having difficulty solving in a particular hour of the 20-year planning period with too much or too little energy, it can fall back on one of these methods to complete the overall dispatch. For each scenario, annual "dump energy" and "energy not served" are reviewed and kept within reasonable bounds. During the RAP, the threshold for "dump energy" is less than 25GWh in any given year, and the threshold for "energy not served" is less than .5GWh in any given year of a study.

Modeling Region/Transmission Area Setup:

PO and CE are setup with up to eight different Transmission Areas (TA) depending on the scenario. These are modeling regions that represent high-level operations of the Tri-State system footprint and allow for the modeling of known transmission limitations via links with set transmission capacity. TAs are not specific to any one TP. Load, resources and markets are assigned to these TAs for modeling purposes.

Table 53: Transmission Areas for CE and PO

TA	Geographical Location	BAs	Transmission Location
WACM_Eastern Colorado	Eastern Colorado	WACM, PSCo	East of TOT 5; South of TOT 3
WACM Wyoming	Wyoming & Nebraska West	WACM, PAC	North of TOT 3
WACM Wyoming Green[37]	Wyoming & Nebraska West	WACM	North of TOT 3
West_Colorado	Western Colorado	WACM	West of TOT 5
New Mexico	New Mexico	PNM	South of TOT 2
Springerville	Arizona	PNM[38]	PTP transmission to PNM
Mt. Elbert	Colorado	WACM	Shares LAP Hydro transmission
Nebraska	Nebraska East and Northeast Colorado	SPP	Eastern Interconnection

[37] This TA is used to allow TOT 3 transmission capacity to be assigned to renewable generic resources located in Wyoming while restricting the use of TOT 3 transmission capacity by thermal resources in the WACM Wyoming TA. The result is to allow more green power to flow from Wyoming to Colorado for CO_2 reduction.

[38] This resource transitioned to a pseudo-tie into PNM instead of WACM in 2020 due to planned entry into WEIM in 2021.

In the model, the Nebraska TA is setup so that load is met entirely by the Basin Electrically East purchase and no flow is allowed from Nebraska into any of the other TA's.

For the other TA's links are used to simulate transmission flow or the ability to flow from one TA to another. Maximum capacities are used to set the boundaries of the amount of energy that can flow from one TA to another. These link capacities are found in Section 5 Phase 1 Modeling Details under the Modeling Assumptions subsection of this report.

Transmission Capex Process

Planning level cost estimates for transmission facilities associated with generation expansion plan resources were developed by Tri-State's Transmission Planning department for the base case and each alternative scenario. For each resource in the expansion plan, a specific Point of Interconnection (POI) on Tri-State's transmission system was assumed within the given region (Eastern Colorado, Western Colorado, Wyoming, and New Mexico). These locations were chosen based on previous requests received as part of Tri-State's Large Generation Interconnection Process (LGIP) Queue, neighboring entities' LGIP studies, and/or locations known to be able to accommodate generation injection from coordinated planning efforts. Each unit was then assigned required upgrades at the POI, which typically consisted of a new switching station or additional breaker bays at an existing substation needed to tie in the generator.

For units assumed to be owned by Tri-State an additional interconnection facilities cost was assigned, which includes costs for generator tie line termination equipment and metering. These interconnection facilities costs were not included for generators assumed to be included in the expansion plan via a PPA as those costs would be borne by the generator owner, consistent with Tri-State's LGIP.

The bulk of the transmission costs are associated with additional Network Upgrades (beyond the POI facilities) that would be required to accommodate the aggregate levels of injection and maintain the reliability of the transmission system. These costs do not include costs for projects in Tri-State's 10-year transmission plan. Similarly, the expansion plan was only evaluated for transmission reliability impacts and transmission service for the additional resources was not in the scope of this analysis. The reliability impacts and necessary upgrades were identified by powerflow contingency analysis using Siemens' PSSE software and WECC approved powerflow models. In general, the costs were primarily associated with new transmission lines and/or transformers needed to mitigate thermal overloads associated with single contingencies.

To the extent possible, results from previous studies were leveraged to determine injection limits and identify Network Upgrades. Primarily, results from the Colorado Coordinated Planning Group's (CCPG) Lamar Front Range Task Force studies, Tri-State's LGIP System Impact Studies, and other internal Tri-State studies were utilized. Where needed, additional powerflow contingency analysis was performed by heavily dispatching the local existing resources consistent with LGIP study methodology. Due to the highly interconnected nature of Tri-State's transmission system, future changes made by other entities can greatly affect the results. As such, the provided cost estimates have a higher degree of uncertainty than is associated with typical planning level cost estimates. This is especially true for resources added beyond the ten-year horizon, as WECC does not build base cases beyond this

timeframe. Additionally, since it was assumed that a regional transmission organization (RTO) will be needed beyond the ten- year horizon, impacts to WECC Rated Paths were not considered.

Financial Analysis Process

Hyperion:

Data from the PO dispatch including the CE expansion plan resources and retirements along with hourly dispatch for resources, markets and contracts is loaded into Hyperion. Additionally, load forecasts and member distributed generation forecasts from SAS are loaded into Hyperion. Finally, manual forecast inputs including wheeling expense and revenue, ancillary service expense and revenue, capacity expense and revenue and fixed charges are entered into Hyperion. This data is compiled and sent to UIPlanner for final financial analysis.

UIPlanner:

Financial forecasting is completed within UIPlanner, resulting in a final value for PVRR for each scenario. UIPlanner is a financial forecasting model specifically designed for, and widely utilized in, the utility industry. Tri-State continuously maintains the functionality of the model, and on a periodic basis throughout the year, updates inputs and assumptions. Key rates used in ERP analysis include:

- Inflation rate of 1.7% in 2021 and 2022 and 2.0% 2023 to 2040
- Discount rate of 4.15%
- A discount rate of 3.00% per Commission guidance was also used for separate analysis of the SCC scenario

The model provides long-term financial forecast results such as Class A member rates, pro forma financial statements and financial ratios.

The expansion plan and hourly dispatch data from the CE and PO, along with the load forecast are extracted by Hyperion and files are prepared for import into UIPlanner. Transmission capital expenditures related to the expansion plan are prepared by Transmission Planning and imported into UI Planner. Along with Near-term operating and capital budgets and forecasts, UIPlanner forecasts capital expenditures, and operating and non-operating revenues and expenses. Financial assumptions and Board approved financial goals, including minimum equity to total capitalization ratios, debt service requirements, liquidity levels and net margins, are also input into UIPlanner. Given those parameters, UIPlanner solves for the minimum Class A revenue requirement to achieve those financial goals for each year of the study period. UIPlanner calculates the PVRR from the monthly revenue requirement over the study period.

For purposes of the base case and alternative scenarios, thermal retirements were handled as follows:

- Net book values impaired and amortized over original accounting life.
- Severance, community assistance and decommissioning cost estimates deferred and amortized over original accounting lives.
- Colowyo depletion accelerated to early retirement date.
- 50% of allocated G&A expense eliminated after an entity's retirement.

Modeling Constraints

As Tri-State progressed through its 2020 ERP process, some modeling issues were identified. The following identifies these issues, their impact to scenarios and plans for resolution.

Tri-State upgraded to its current version of CE and PO in early 2019. Despite robust functionality within the models themselves, some limitations were observed given new modeling requirements and workarounds were used to meet scenario requirements. These issues included the following items:

- The model does not allow a limit on emissions for transmission links. This created difficulties in limiting emissions within a particular state while considering imports. To work around this, Tri-State used an iterative process, which included placing emissions limits on resources where possible, manually checking emissions of final dispatch results and adjusting emission limits and re-running the dispatch as necessary to achieve appropriate emissions limits in a given state inclusive of imports.
- Tri-State's contractual share of Mt. Elbert, a pump storage resource associated with the LAP federal hydro contract, was modeled and functioning properly in initial scenarios. However, a software issue related to Mt. Elbert was encountered during successive scenario modeling which was unable to be resolved for a significant period of time. For impacted scenarios, Tri-State turned Mt. Elbert off and marked assumptions accordingly.
- Transmission capital expenditure analysis related to interconnection costs and network upgrade costs occur outside of CE and PO and typically occur after a CE plan for a given scenario is complete. It is difficult to incorporate into CE the cost of potential network upgrades. Tri-State works around this issue in the current model through the following methods:
    - Restricted early years of the model (prior to 2028) to allow limited generic resources from which the model could select. These restrictions were based on technology type and region depending upon available transmission interconnection and timing to accommodate network upgrades. For example, 200 MW of Wyoming and 100 MW of ECO interconnection capacity are available prior to 2028 without requiring additional significant network upgrades. Tri-State could not reasonably construct additional significant network upgrades in those regions prior to 2028. In such cases, priority for the interconnection capacity was given to renewable resources.
    - Applied a $600/KW transmission adder to the build cost of gas resources in eastern Colorado, where network upgrades are more likely to occur upon the addition of generic resources.
- DSM and EE were modeled as supply-side resources to compete with utility scale resources in CE and PO. While program costs were accounted for within CE, the lost member revenue from reduced load was not. This component of the analysis occurred in the financial models, Hyperion and UIPlanner.
- In scenarios where SPV3 was allowed to retire, the potential retirement date of the resource was limited to any time after the end of the related SRP contract (midyear 2036), as the model setup does not account for the impact of the revenue loss from the SRP contract.
- PO is an hourly least-cost dispatch tool and is unable to perform sub-hourly modeling in the current setup.

In 2021 Tri-State plans to revisit its current modeling setup, assess the current modeling tools, investigate other potential modeling tools and takes steps to close the above gaps from a system perspective without workarounds.

Modeling Assumptions

Table 54 identifies base modeling assumptions used in the 2020 ERP process.

Table 54: Modeling Assumptions used in 2020 ERP Base Case

Assumption Item	Description
Load Forecast	2020 Annual Long Term Forecast
Electric Price Forecast	May 2020 Spring Reset Long Term Forecast
Gas Price Forecast	May 2020 Spring Reset Long Term Forecast
Coal Price Forecast	May 2020
Announced Coal Retirements	• Escalante by 12/31/2020 • Craig 1 12/31/2025 • Craig 2 9/30/2028 • Craig 3 12/31/2029
Forced Outage Factors	• All Coal = 4% • Existing CC's = 3% • Existing CT's = 0% • Proposed CC's = 0% • Proposed CT's 0%
Thermal Resource Status: **Econ** - Model can turn resource on and off but resource has a 168-hour on-line minimum. **Must Run** - Model can choose the level at which resource is run but cannot dispatch lower than the resource minimum operating level.	• *Must Run 2021 - 2040*[39] : Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV • *Econ 2021 - 2040*: Burlington 1, Burlington 2, Knutson 1&2, Limon 1&2, Pyramid 1-4, Rifle, and JM Shafer
Build Limits – represents the capacity allowed to be built by Transmission Area/Modeling Region or technology.	• Max RPP – East Colorado 1200 MW • Max RPP – New Mexico 400 MW • Max RPP – Storage 400 MW • Max RPP – Thermal 300 MW • Max RPP – Wyoming 600 MW • Max Annual – Renewable 500 MW
Water limits	JM Shafer capacity factor limited to 47% due to current water contracts. Ability to purchase additional water exists.
Emission limits[40]	NOX Limits: • Craig 1 annual capacity factor limited to 80% or less

[39] Through 2040 or announced retirement data as applicable.

[40] A modeling error in 80pct CR V1 and 80pct CR V2 caused Craig 1 to run slightly above the allowed 80% capacity factor set by the Regional Haze agreement. Based on the correction in similar scenarios, the correction of the capacity factor to 80% results in movement of the dispatch generation to Craig 3 and Colorado gas resources. Tri-State did not rerun these two scenarios with this correction.

Assumption Item	Description
	• Pyramid annual capacity factor limited to 30%
EE & DR DSM Level	Low and Aggressive Energy Efficiency (EE) Allowed Low Demand Response (DR) allowed for all Regions.
RES/RPS Levels	Must meet or exceed current RES for Colorado and RPS for New Mexico.
CO_2 Reduction in Colorado	No forced CO_2 reductions or restrictions applied in base assumptions.
Contracts/Power Purchase Agreements	Allowed to expire on terms.
Mt Elbert	On and available to dispatch within contract parameters.
Member Distributed Generation	Treated as renewed upon contract expiration at a proxy price by technology: $25/MWh Wind, $44/MWh Solar, $55/MWh Biomass, hydro and other.
Transmission Links	See Table 55 for detail.
Capacity Credits	See Table 56 for detail.
Market Depths	See Table 57-58 for detail.

Transmission Constraints:

The following constraints were implemented from 2021 to 2027 in the model due to current interconnection limitations and time needed to accomplish significant network upgrades. It was assumed additional significant network upgrades are possible by 2028.

- From 2025 to 2027: New Mexico 0 MW, Wyoming 200 MW, Eastern Colorado 100 MW
- Until 2026 Western Colorado 0 MW interconnection, afterwards interconnection MW amount equal to Craig 1 capacity

Transmission Links:

Table 55: Transmission Links in Base Case

Link Name	From Transmission Area	To Transmission Area	Forward Capacity *(MW)*	Backward Capacity *(MW)*	Dates
LK-E_CO>NM	WACM_Eastern_Colorado	New Mexico	124	0	2021 - 2040
LK-LAP>E_CO	Mt_ Elbert	WACM_Eastern_Colorado	107	139	2021 - 2040
LK-SPRV>NM	Springerville	New Mexico	317	0	2021 - 2040
LK-W_CO>E_CO	West_Colorado	WACM_Eastern_Colorado	457	150	2021 - 2040

Link Name	From Transmission Area	To Transmission Area	Forward Capacity *(MW)*	Backward Capacity *(MW)*	Dates
LK-W_CO>NM	West_Colorado	New Mexico	0	170	2021 - 2024
LK-W_CO>NM	West_Colorado	New Mexico	50	170	2025 - 2040
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	400	400	2021
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	550	400	2022 - 2040

Capacity Credit Values:

For both solar and wind resources, an analysis was performed to determine an appropriate capacity credit value using a modified ELCC method[41]. In later years as more solar resources are added, the time of net system peak load is shifted to later in the day when the sun is setting (or has already set). Therefore, solar capacity credit is decreased. The capacity credit for wind is relatively consistent across all years of the various scenarios. Below are capacity credit values applied to base case scenario modeling.

Table 56: Capacity Credit Values

Resource Technology	Capacity Credit *(% of Nameplate)*
Thermal – existing and generic resources	100%
Standalone Batteries	100%
Existing Solar (Commercial & Under Contract)	35%
Existing Wind (Commercial & Under Contract) & Wind Generic Resources	30%
Solar Generic Resources	15%
Solar + 25 MW Battery Generic Resources	15% Solar; 100% for Battery
Wind + 25 MW Battery Generic Resources	30% for Wind; 100% for battery

Market Depths:

Tri-State has modeled several markets that represent typical locations of power transactions.

Sales Markets

- MS-4 Corner-N_NM – New Mexico
- MS-WEIM – New Mexico
- MS-Ault-E_CO – Eastern Colorado
- MS-Craig-NW_CO – Western Colorado
- MS-LRS-WY - Wyoming
- MS-WEIS - Eastern Colorado

[41] See Attachment Vol II 5-2 B&V Modified Effective Load Carrying Capability Study.

Purchase Markets

- MP-4 Corner-N_NM – New Mexico
- MP-WEIM – New Mexico
- MP-Ault-E_CO – Eastern Colorado
- MP-Craig-NW_CO – Western Colorado
- MP-LRS-WY - Wyoming
- MP-WEIS – Eastern Colorado

Tables 57 and 58 show the hourly market depths associated with each market for sales and purchases respectively, as applied to base case modeling. Market Depths are adjusted from base in alternative scenarios as necessary to accommodate for an evolving grid with higher quantities of intermittent resources and reducing levels of dispatchable resources. This is representative of the long-term need for an organized market to facilitate the addition of intermittent renewables. Changes to assumptions are identified in Volume I Section 8 Base Case and Alternative Scenario Results of this report.

Table 57: Market Sales (Hourly Capacity)

Dates	**MS-4 Corner-N_NM** *(MW)* [42]	**MS-WEIM** *(MW)*
Jan 2021 - Mar 2021	20-OFF / 75-ON	0
Apr 2021 - 2024	0-OFF / 20-ON	25-OFF / 60-ON
2025-2040	150	0

Dates	**MS-Ault-E_CO** *(MW)*	**MS-Craig-NW_CO** *(MW)*	**MS-LRS-WY** *(MW)*	**MS-WEIS** *(MW)*
Jan 2021	0-OFF / 50-ON	15-OFF / 100-ON	0	0
Feb 2021 - 2024	0-OFF / 25-ON	0-OFF / 25-ON	0	25-OFF / 125-ON
2025-2029	150	150	0	0
2030-2040	50	50	200	0

Table 58: Market Purchases (Hourly Capacity)

Dates	**MP-4 Corner-N_NM** *(MW)*	**MP-WEIM** *(MW)*
Jan 2021 - Mar 2021	100	0
Apr 2021 - 2024	85	15
2025-2040	200	0

[42] "OFF" and "ON" references off peak and on peak hours respectively.

Dates	MP-Ault-E_CO *(MW)*	MP-Craig-NW_CO *(MW)*	MP-LRS-WY *(MW)*	MP-WEIS *(MW)*
Jan 2021	200	125	75	0
Feb 2021 - 2024	150	100	75	75
2025-2040	200	200	200	0

Generic Resource Cost, Performance and Emissions Data

Cost and technology characteristics for generic resources including renewables, gas resources, and energy storage were verified by B&V. Below highlights key aspects of this review by resource type:

Thermal Resources: Working from Tri-State's original generic resource data set, which primarily consisted of gas resource cost and characteristics data from EPRI TAGWeb Version 3.52 software, B&V utilized in house subject matter experts to compare existing data for generic resources to B&V's independent check-estimates developed using a combination of past project estimates, Thermoflow's GTPRO/GTMASTER modeling software, and Original Equipment Manufacturer (OEM) online performance tools. Key data assessed included capital cost, net heat rate, ability to cycle and load follow, availability, emissions and operation and maintenance expense. Resulting recommended changes included additions or removal of existing gas generic resources in the data set as well as changes to underlying cost and performance data.

Renewable (including renewable plus batteries) Build Transfers: Tri-State was relying on National Renewable Energy Laboratories (NREL), EIA, EPRI and other industry resources to develop costs and characteristics for renewables modeled as build transfers. B&V in house subject matter experts reviewed capital expenses, O&M expenses and net capacity factors for build transfer renewables and provided recommendations.

Renewable (including renewable plus batteries) PPAs*:* B&V utilized its power project data for capital costs, O&M costs and expected production, and its in-house subject matter expertise to forecast PPA prices for generic renewable energy resources, including solar, solar + storage, wind, and wind + storage resources, within the Tri-State operating area. The renewable resources were assumed to have a 35-year life. Net energy output was calculated as follows:

Table 59: Renewable Resource Capacity and Energy Calculations

Resource Type	Net Capacity Factor *(%)*	Year 1 Net Energy Production *(MWh)*
Solar PV	30.0%	262,800
Solar PV + Storage	28.0%	245,192
Wind	43.0%	376,680
Wind + Storage	40.1%	351,442

Solar energy output was assumed to degrade at a rate of .32% per year.

The expiration of tax credits were taken into consideration, and prices were forecast by technology type and region.

Storage Builds: Tri-State was relying on NREL, EIA, EPRI and other industry resources to develop costs and characteristics for standalone energy storage, specifically Li-ion 4 hour batteries. B&V in house subject matter experts reviewed capital expenses, O&M expenses and efficiencies for energy storage builds and provided recommendations. Additionally, Tri-State utilized a proposed pumped storage project in New Mexico as the basis for pumped storage costs and characteristics.

Final costs and characteristics for generic resources as modeled in Tri-State's 2020 ERP process based on recommendations by B&V are as follows. All costs are in real (2020) dollars.

Table 60: Costs for Thermal Build Resources

Resource	Technology	Location[43]	Build Cost *($/kW)*	Fixed Cost *($ Annual)*	VOM *($/MWh)*	Startup Costs *($ per start)*
112_18x6RICE_eco	Recip Engine	Eastern CO	$1,881	$2,332,224	$7.42	$50
112_18x6RICE_nnm	Recip Engine	New Mexico	$1,281	$2,332,224	$7.42	$50
300_1x1_7FA05_eco	Combined Cycle	Eastern CO	$2,163	$4,000,000	$3.00	$500
300_1x1_7FA05_nnm	Combined Cycle	New Mexico	$1,563	$4,000,000	$3.00	$500
300_1x1_7FA05_swco	Combined Cycle	Western CO	$1,563	$4,000,000	$3.00	$500
300_1x1_7FA05_wyo	Combined Cycle	Wyoming	$1,563	$4,000,000	$3.00	$500
40_1x40LM6000_eco	Aeroderivative	Eastern CO	$2,247	$1,750,000	$5.94	$25
40_1x40LM6000_nnm	Aeroderivative	New Mexico	$1,647	$1,750,000	$5.94	$25
40_1x40LM6000_swco	Aeroderivative	Western CO	$1,647	$1,750,000	$5.94	$25
357_1x1_7HA01_nwco	Recip Engine	Western CO	$1,488	$4,603,200	$3.86	$600
46_9x5RICE_eco	Recip Engine	Eastern CO	$2,125	$1,024,398	$7.00	$50
46_9x5RICE_nnm	Recip Engine	New Mexico	$1,525	$1,024,398	$7.00	$50
46_9x5RICE_swco	Recip Engine	Western CO	$1,525	$1,024,398	$7.00	$50
545_1x1_7HA03_nwco	Combined Cycle	Western CO	$1,188	$5,899,500	$3.67	$600
81_2x40LM6000_eco	Aeroderivative	Eastern CO	$2,003	$2,250,000	$5.80	$50
81_2x40LM6000_wyo	Aeroderivative	Wyoming	$1,403	$2,250,000	$5.80	$50
93_1x100_LMS100_nnm	Aeroderivative	New Mexico	$1,525	$1,444,354	$5.00	$50
200_1x235_7FA05_eco	Combustion Turbine	Eastern CO	$1,271	$1,553,481	$1.00	$14,000
200_1x235_7FA05_nnm	Combustion Turbine	New Mexico	$671	$1,553,481	$1.00	$14,000
200_1x235_7FA05_swco	Combustion Turbine	Western CO	$671	$1,553,481	$1.00	$14,000

Table 61: Performance Characteristics for Thermal Build Resources

Resource	Rated Capacity *(MW)*	Average Heat Rate *(btu/kWh)*	Marginal Heat Rate *(btu/kWh)*	Minimum Operation *(MW)*	Ancillary Services
112_18x6RICE_eco	112	8250	8250	28	Reserves, Regulation
112_18x6RICE_nnm	112	8250	8250	28	Reserves, Regulation
300_1x1_7FA05_eco	300	6530	6530	150	Reserves, Regulation
300_1x1_7FA05_nnm	300	6530	6530	150	Reserves, Regulation
300_1x1_7FA05_swco	300	6530	6530	150	Reserves, Regulation
300_1x1_7FA05_wyo	300	6530	6530	150	Reserves, Regulation
40_1x40LM6000_eco	40	9300	9300	20	Reserves, Regulation

[43] Eastern Colorado Gas builds have a $600/KW adder for transmission network upgrade expense.

Resource	Rated Capacity *(MW)*	Average Heat Rate *(btu/kWh)*	Marginal Heat Rate *(btu/kWh)*	Minimum Operation *(MW)*	Ancillary Services
40_1x40LM6000_nnm	40	9300	9300	20	Reserves, Regulation
40_1x40LM6000_swco	40	9300	9300	20	Reserves, Regulation
357_1x1_7HA01_nwco	357	6280	6280	110	Reserves, Regulation
46_9x5RICE_eco	46	8400	8400	12	Reserves, Regulation
46_9x5RICE_nnm	46	8400	8400	12	Reserves, Regulation
46_9x5RICE_swco	46	8400	8400	12	Reserves, Regulation
545_1x1_7HA03_nwco	545	6170	6170	207	Reserves, Regulation
81_2x40LM6000_eco	81	9300	9300	40	Reserves, Regulation
81_2x40LM6000_wyo	81	9300	9300	40	Reserves, Regulation
93_1x100_LMS100_nnm	93	8900	8900	14	Reserves, Regulation
200_1x235_7FA05_eco	200	9800	9800	84	Reserves, Regulation
200_1x235_7FA05_nnm	200	9800	9800	84	Reserves, Regulation
200_1x235_7FA05_swco	200	9800	9800	84	Reserves, Regulation

Table 62: Emissions & Water Usage for Thermal Builds (pounds per MWh)

Resource	CO_2	SO_2	NOx	HG	PM	Water
112_18x6RICE_eco	949	0	0.15	N/A	0	0
112_18x6RICE_nnm	949	0	0.15	N/A	0	0
300_1x1_7FA05_eco	751	0.0078	0.747	N/A	0.0804	348
300_1x1_7FA05_nnm	751	0.0078	0.747	N/A	0.0804	348
300_1x1_7FA05_swco	751	0.0078	0.747	N/A	0.0804	348
300_1x1_7FA05_wyo	751	0.0078	0.747	N/A	0.0804	348
40_1x40LM6000_eco	1,070	0.012	1.223	N/A	0.07	120
40_1x40LM6000_nnm	1,070	0.012	1.223	N/A	0.07	120
40_1x40LM6000_swco	1,070	0.012	1.223	N/A	0.07	120
357_1x1_7HA01_nwco	722	0.0078	0.747	N/A	0.0804	348
46_9x5RICE_eco	966	0	0.15	N/A	0	0
46_9x5RICE_nnm	966	0	0.15	N/A	0	0
46_9x5RICE_swco	966	0	0.15	N/A	0	0
545_1x1_7HA03_nwco	710	0.0078	0.747	N/A	0.0804	348
81_2x40LM6000_eco	1,070	0.012	1.223	N/A	0.07	120
81_2x40LM6000_wyo	1,070	0.012	1.223	N/A	0.07	120
93_1x100_LMS100_nnm	1,127	0.008575	0.360	N/A	0.0929	57
200_1x235_7FA05_eco	1,127	0.008	0.378	N/A	0.0621	57
200_1x235_7FA05_nnm	1,127	0.008	0.378	N/A	0.0621	57
200_1x235_7FA05_swco	1,127	0.008	0.378	N/A	0.0621	57

Table 63: Costs for Solar and Wind Build-Transfers

Resource	Technology	Location	Build Cost in 2021 *($/kW)*[44]	Fixed Cost *(Annual $)*	VOM *($/MWh)*	Startup Costs *($ per start)*
PS-1x100PV_eco	Solar	Eastern Colorado	[redacted]		n/a	n/a
PS-1x100PV_nnm	Solar	New Mexico			n/a	n/a
PS-1x100PV_wco	Solar	Western Colorado			n/a	n/a
PS-1x100Wind_eco	Wind	Eastern Colorado			n/a	n/a
PS-1x100Wind_nnm	Wind	New Mexico			n/a	n/a
PS-1x100Wind_wyo	Wind	Wyoming			n/a	n/a

[redacted]

Table 64: Storage Costs

Resource	Technology	Location	Build Cost in 2021 *($/kW)*[45]	Fixed Cost *(Annual $)*	VOM *($/MWh)*	Startup Costs *($ per start)*
100MW Li-Ion Battery_eco	Li-ion Battery	Eastern Colorado	$1,270	$1,000,000	n/a	n/a
100MW Li-Ion Battery_wco	Li-ion Battery	New Mexico	$1,270	$1,000,000	n/a	n/a
100MW Li-Ion Battery_nnm	Li-ion Battery	Western Colorado	$1,270	$1,000,000	n/a	n/a
25MW Li-Ion Battery_eco	Li-ion Battery	Eastern Colorado	$1,359	$250,000	n/a	n/a
25MW Li-Ion Battery_nnm	Li-ion Battery	New Mexico	$1,359	$250,000	n/a	n/a
25MW Li-Ion Battery_wco	Li-ion Battery	Western Colorado	$1,359	$250,000	n/a	n/a
25MW Li-Ion Battery_wyo	Li-ion Battery	Wyoming	$1,359	$250,000	n/a	n/a
300 MW Pumped Storage	Pumped Storage	New Mexico	$2,200	$5,100,000	n/a	n/a

[44] For solar resources build costs decline over time at an average of ~4% per year during the RAP and remain steady thereafter. For wind resources build costs decline over time at an average of ~1.75% per year over the RPP.
[45] Battery build costs are projected to decline by 6% per year through the RAP.

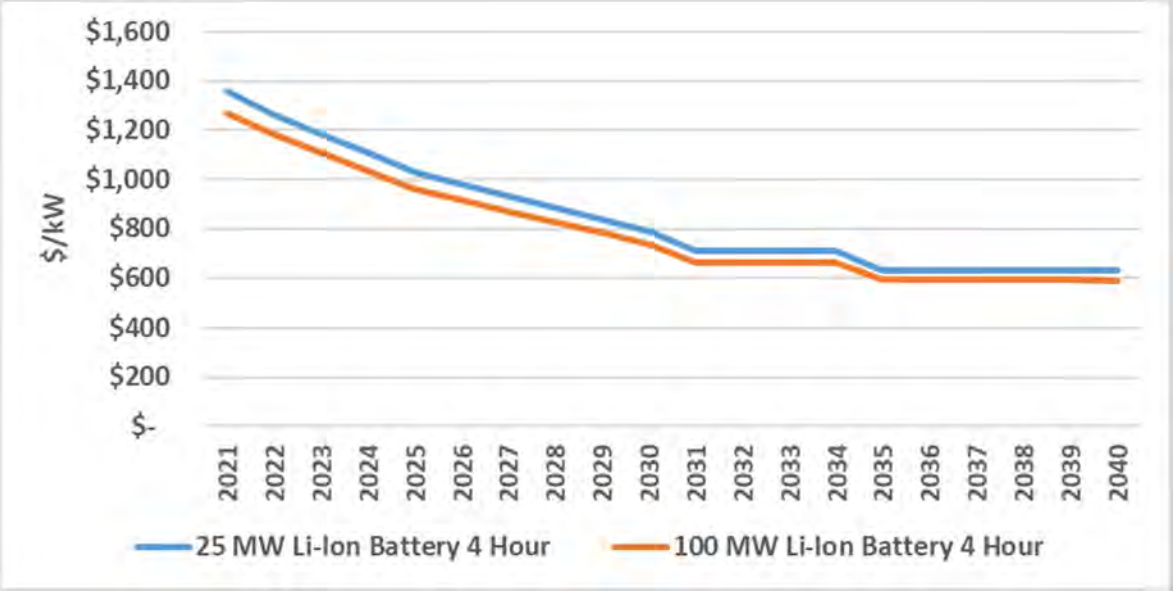

Figure 20: Li-Ion Battery Build Cost Curve

Table 65: Solar and Wind PPA Costs

Resource	Technology	Location	Capacity *(MW)*	Capacity Factor	Costs in 2021 *($/MWh)*
PS-1x100-PV_eco	Solar PV	Eastern Colorado	100	30%	
PS-1x100-PV_nnm	Solar PV	New Mexico	100	30%	
PS-1x100-PV_swco	Solar PV	Western	100	30%	
PS-1x50-PV_swco	Solar PV	Western	50	30%	
PS-1x100-PVBatt_eco	Solar PV + Battery	Eastern Colorado	100	28%	
PS-1x100-PVBatt_nnm	Solar PV + Battery	New Mexico	100	28%	
PS-1x100-PVBatt_swco	Solar PV + Battery	Western	100	28%	
PS-1x100-Wind_eco	Wind	Eastern Colorado	100	43%	
PS-1x100-Wind_nnm	Wind	New Mexico	100	43%	
PS-1x100-Wind_wyo	Wind	Wyoming	100	43%	
PS-1x100-WindBatt_eco	Wind + Battery	Eastern Colorado	100	40%	
PS-1x100-WindBatt_nnm	Wind + Battery	New Mexico	100	40%	
PS-1x100-WindBatt_wyo	Wind + Battery	Wyoming	100	40%	



Figure 21: Solar and Wind PPA Pricing



Figure 22: Solar + Battery and Wind + Battery PPA Pricing

Table 66: Performance Characteristics of Solar, Wind, and Storage Resources[46]

Resource	Rated Capacity *(MW)*	Average Heat Rate	Marginal Heat Rate	Minimum Operation
PS-1x100PV_eco	100	n/a	n/a	n/a
PS-1x100PV_nnm	100	n/a	n/a	n/a
PS-1x100PV_wco	100	n/a	n/a	n/a
PS-1x50PV_wco	50	n/a	n/a	n/a
PS-1x100-PVBatt_eco	100	n/a	n/a	n/a
PS-1x100-PVBatt_nnm	100	n/a	n/a	n/a
PS-1x100-PVBatt_wco	100	n/a	n/a	n/a
PS-1x100Wind_eco	100	n/a	n/a	n/a
PS-1x100Wind_nnm	100	n/a	n/a	n/a
PS-1x100Wind_wyo	100	n/a	n/a	n/a
PS-1x100WindBatt_eco	100	n/a	n/a	n/a
PS-1x100WindBatt_nnm	100	n/a	n/a	n/a
PS-1x100WindBatt_wyo	100	n/a	n/a	n/a
100MW Li-Ion Battery_eco	100	n/a	n/a	n/a
100MW Li-Ion Battery_wco	100	n/a	n/a	n/a
100MW Li-Ion Battery_nnm	100	n/a	n/a	n/a
25MW Li-Ion Battery_eco	25	n/a	n/a	n/a
25MW Li-Ion Battery_nnm	25	n/a	n/a	n/a
25MW Li-Ion Battery_wco	25	n/a	n/a	n/a
25MW Li-Ion Battery_wyo	25	n/a	n/a	n/a
300 MW Pumped Storage_NM	300	n/a	n/a	0

Table 67: Solar, Solar + Storage, Wind, & Wind + Storage Emissions & Water Usage (pounds per MWh)[47]

Resource	CO_2	SO_2	NOx	HG	PM	Water
PS-1x100PV_eco	0	0	0	0	0	0
PS-1x100PV_nnm	0	0	0	0	0	0
PS-1x100PV_wco	0	0	0	0	0	0
PS-1x50PV_wco	0	0	0	0	0	0
PS-1x100-PVBatt_eco	0	0	0	0	0	0
PS-1x100-PVBatt_nnm	0	0	0	0	0	0
PS-1x100-PVBatt_wco	0	0	0	0	0	0
PS-1x100Wind_eco	0	0	0	0	0	0
PS-1x100Wind_nnm	0	0	0	0	0	0
PS-1x100Wind_wyo	0	0	0	0	0	0
PS-1x100WindBatt_eco	0	0	0	0	0	0
PS-1x100WindBatt_nnm	0	0	0	0	0	0
PS-1x100WindBatt_wyo	0	0	0	0	0	0

[46] These resources were not modeled to provide ancillary services (i.e. regulation up, regulation down or contingency reserves).

[47] For wind plus battery and solar plus battery resources, the batteries are modeled as charged from the related renewable resource.

Table 68: Storage Emissions & Water Usage (pounds per MWh)[48]

Resource	CO_2	SO_2	NOx	HG	PM	Water
100MW Li-Ion Battery_eco	1280	0.40	0.70	-	-	-
100MW Li-Ion Battery_wco	1280	0.40	0.70	-	-	-
100MW Li-Ion Battery_nnm	1280	0.40	0.70	-	-	-
25MW Li-Ion Battery_eco	1280	0.40	0.70	-	-	-
25MW Li-Ion Battery_nnm	1280	0.40	0.70	-	-	-
25MW Li-Ion Battery_wco	1280	0.40	0.70	-	-	-
25MW Li-Ion Battery_wyo	1280	0.40	0.70	-	-	-
300 MW Pumped Storage	1280	0.40	0.70	-	-	-

Modeled life of resources are as follows:

- Wind, Solar, Wind plus battery, and Solar plus battery PPA – 20 years
- Wind and Solar Build transfer – 20 years
- Energy Storage Li-Ion Batteries – 15 years
- Energy Storage Pumped Storage Hydro – 30 years
- Gas Resources – 30 years

DSM & EE Generic Resources:

DSM & EE are modeled as supply side generic resources. This modeling is discussed in Section 5 Phase I Modeling Details under the Modeling Assumptions & Analytical Methodology subsection.

Consideration for Clean Energy and Energy Efficient Technologies

Tri-State includes clean energy and energy efficient technologies in its resource mix of available technologies for expansion planning. In regards to clean energy, available technologies included in expansion planning are solar, solar plus battery, wind and wind plus battery installations. Renewable resources are available in the generic resource dataset in each modeling region/TA in sufficient quantities to influence the environmental impact of the overall resource plan for a given scenario. Additionally, energy storage options in the form of stand-alone batteries as well as batteries coupled with solar and wind installations are made available in the generic resource data set to support the addition of renewable resources within the scenarios.

Tri-State also includes in the generic resource dataset for use in expansion planning demand side resource options including energy efficiency and demand response. These represent programs that Tri-State could develop with the consensus of and for use by Tri-State's Utility Member Systems. Forecast data for energy efficiency and demand response generic resource is based on the results of the 2020 DSM & EE Potential study, which can be found in Attachment Vol II 5-1 Demand Side Management & Energy Efficiency Potential Study. Forecast energy efficiency and demand response are selectable resources in scenarios

[48] Standalone batteries are modeled as charged from market purchases. Above rates, reflect expected market purchase emission rates based on egrid RMPA values for 2018 as available.

allowing the model to consider these resources on an economic basis. In select scenarios, the energy efficiency or demand response generic resources are forced. Further detail can be found in Volume I Section 8 Base Case and Alternative Scenario Results of this report.

Including renewable resources as well as demand side management and energy efficiency helps to continue to diversify Tri-State's fleet including increasing fuel diversity, which insulates the overall cost of power from technology specific fuel price increases. Diversity also incorporates different types of technology with varying generating patterns to more reliably serve Utility Member System load. Finally, diversity in resource planning by incorporating clean energy and energy efficient technologies into scenarios allows for a clear method of measuring environmental impact while respecting reliability.

Assessment of Costs and Benefits of Integration of Intermittent Resources

Tri-State 2020 ERP scenarios include the integration of significant quantities of intermittent renewable energy. The expansion plan for the base case alone, which does not include GHG/CO_2 restrictions as an assumption within the model, has ~2500 MW of wind and solar generic resources. Alternative scenarios with CO_2 restrictions related to the state of Colorado incorporate between ~2,700 MW and ~4,100 MW of wind and solar generic resources. Tri-State currently has ~467MW of commercially operational wind and solar across its system and an additional ~1000 MW under contract and expected to be commercially operational by 2024. As Tri-State looks to integrate a substantial amount of intermittent energy over the RPP, an assessment of the costs and benefits is necessary.

Costs related to integrating larger quantity of intermittent renewable resources include impacts to dispatchable resources, economic impacts, and the need to maintain reliability within an evolving grid. Currently, Tri-State uses thermal resources, coal and gas, to handle ramping needs to meet load requirements when renewable resources are not available. Coal resources that were primarily intended for base loading incur additional cycling costs of less than ~$0.15/MWh. This cost is due to the additional wear and tear on the resource, and specific cycling costs for Tri-State coal resources are identified in Section 3 Assessment of Resources under the subsection of Overview of Thermal Resources in this report. Gas resources are built to be flexible resources, and Tri-State has not determined a similar cycling cost impact to existing gas resources in Tri-State's fleet.

Related to this cycling requirement is the potential to curtail renewable resources in the event sufficient dispatchable generation is not available to move down in a low load, high renewable situation. Tri-State's current contracted and operational renewable resources are via PPAs, and specifically, the associated tax credit for wind resources can exacerbate the economic impact of curtailments. The addition of energy storage to accommodate power that would otherwise be curtailed is a potential solution. Tri-State's scenario modeling shows the need for energy storage to accommodate the integration of renewable resources. From a cost perspective, an expected decline in energy storage build costs over the next decade is necessary to allow this resource type to be a viable part of a renewable integration solution.

As dispatchable resources are retired and more renewables are brought onto the grid for economic and regulatory compliance reasons, the ability to have sufficient capacity to meet planning reserve margins and ramping requirements is critical. Related to this, Tri-State engaged Black & Veatch to perform a modified ELCC study based on the expected significant increase of renewable resources and decrease of dispatchable resources on Tri-State's system over the RPP. Details of the impact of the modified ELCC on

capacity credits for intermittent resources can be found in Volume I Section 6 Assessment of Resource Needs of this report. Overall, an evolving grid with less dispatchable resources and an increasing quantity of intermittent resources leads to a need for more ramping capabilities from existing and expansion plan resources. The movement of load and resources into an organized market where a larger set of resources can respond on a sub hourly basis to ramping needs is critical for successful integration of large quantities of intermittent renewable resources.

Benefits related to the integration of larger quantities of intermittent renewable resources include economic impacts, supply diversity and emissions reductions. Intermittent renewable generation projects represent a low cost option for meeting energy needs, and effective, large-scale integration of this resource is necessary to drive down the cost of serving Utility Member System load.

The low cost of renewables was a key driver behind Tri-State's recent RFPs, which resulted in the planned addition of 1 GW of renewables by 2024. Adding renewable resources also brings diversity to Tri-State's resource mix and allows for locating resources in areas where the addition of thermal resources is not a viable option. Another significant benefit of renewables is the resulting reduction in fleet emissions as renewable energy displaces thermal generation. Tri-State's Responsible Energy Plan, state-specific CO2 reduction goals, and Renewable Energy or Portfolio Standards are all intended to reduce the environmental impacts associated with electric power generation.

Modeling Assumptions & Analytical Methodology

Energy Storage

In the current CE and PO models, the value of energy storage is focused on its ability to assist with the integration of intermittent resources. This value includes the ability to smooth delivery of intermittent resources and avoidance of potentially costly renewable curtailments. Tri-State's western interconnection load and resources currently do not have access to full "day-2" organized markets with ancillary service markets, so the value of energy storage as a supplier of ancillary services such as regulation up and regulation down was not evaluated at this time.

Li-Ion Batteries:

Tri-State does not have any existing battery storage facilities, but Tri-State modeled generic Li-Ion battery storage facilities as resource options for expansion planning. The Li-Ion batteries were modeled with four hours of storage and either 100MW (ECO, CO, NM) or 25MW (ECO, WCO, NM, and WY) of capacity. Discharge capability of four hours of energy storage was modeled based on demonstrated projects and proposed projects previously evaluated. The batteries are allowed to have multiple cycles per day, but a 4% annual forced outage factor is applied. Batteries were modeled with a 90% efficiency. 100% of the capacity is assumed to be available to meet planning reserve requirements at the peak hour. Given that the generation expansion planning module can build multiple units of the same generic resource it can in theory build multiple four-hour resources to simulate an eight-hour or larger resource. The model is designed to dispatch the charge and discharge to most economically serve Utility Member System load. Specific cost and modeling data can be found in Section 5 Phase I Modeling Details under the Generic Resource Cost, Performance and Emissions Data subsection of this report.

Li-Ion Batteries combined with Solar and Wind:

Hybrid renewable-battery storage plants were modeled based on the existing 100MW wind and solar profiles paired with a 25MW/100MWh lithium-ion battery system. The hybrid facilities offer advantages in pricing due to the availability of Investment Tax Credits for hybrid solar facilities as well as efficiencies related to using a single inverter to reduce balance of plant construction costs. Discharge capability of four hours of energy storage was modeled based on demonstrated projects and proposed projects previously evaluated.

The hybrid facilities are modeled such that all of the power to charge the battery is produced from the associated renewable facility. For Solar-Battery hybrid facilities this resulted in new daily shapes created to maximize load peak shaving by moving energy into the 5 peak hours of the day. For Wind-Battery hybrid facilities the shape is developed to minimize ramping spikes and provide a consistent energy resource throughout the day. Specific cost and modeling data can be found in Section 5 Phase I Modeling Details under the Generic Resource Cost, Performance and Emissions Data subsection of this report.

Pumped Storage Hydro (Mt. Elbert):

The Mt. Elbert pumped storage hydro facility is part of Tri-State's portfolio, modeled within the eastern Colorado transmission area, as a part of its LAP hydro contract purchases. Tri-State does not operate Mt. Elbert, and Tri-State's share of the facility is limited to a daily schedule for pumping and generation and a seasonal amount of the energy and capacity. Per contractual limits, return energy is scheduled between Hour Ending (HE) 23 and HE7 and generation is scheduled between HE8 and HE22. Mt. Elbert is capable of storing up to 1380MWh in the summer season and can receive or generate a capacity of 176MW in a given hour. The "roundtrip" efficiency of the Mt. Elbert facility 68% in that 1.47MWh is required to add 1MWh of energy storage. The market is the source for charging/pump back energy. The total generation capacity of the Mt. Elbert pumped storage and LAP Hydro contract is limited by the capacity of the LAP Hydro contract. Within the limits of the contract and the capability of the facility Mt. Elbert is modeled to dispatch to reduce system costs.

Pumped Storage Generic Resource:

A generic pumped storage resource was modeled as an option for all scenarios. Because of the difficulty of development and siting a pumped storage facility, a single option in Northern New Mexico was identified and modeled. Tri-State's portion of the facility would be limited to 300MW of capacity and 2400MWh of energy or eight hours of storage at full capacity. The efficiency of the facility is assumed to be 80% or 1.25MWh of energy is required to add 1MWh of energy output. The market is the source for charging/pump back energy. The cost of the facility is modeled as $2,200/kW with a 30-year operating and book life. Due to the limited options for pump storage only one unit may be added in the study period and only in 2028 or later.

Renewables

Tri-State models existing, under contract and generic renewable resources as varying 8760 profiles. The methodology to arrive at these profiles utilizes historical generation for existing facilities as recorded by Tri-State's OSIsoft PI historian system. These actual monthly profiles are randomized to create new pseudo-random hourly profiles for the duration of the PPA contract. Up to five years of historical data

was used to develop the hourly profiles and, to the extent possible, the same dates were used across resources to maintain the same daily weather patterns and demonstrate the geographical diversity of the existing generation.

For generic renewable resources, a similar method was employed to develop hourly profiles. Tri-State uses similar existing resources that are most representative of future renewable resources in each geographical area to the extent possible. Western Colorado, eastern Colorado and Wyoming wind profiles for generic resources were developed from the Colorado Highlands wind facility. New Mexico generic resource solar profiles were developed from the Alta Luna solar facility, while the Colorado solar generic resource profiles were developed from the Spanish Peaks solar facility. Table 69 shows this setup and related capacity factors. Individual generation profiles were developed by randomizing the data. This mimics the geographic diversity of the generation. For hybrid wind-battery and solar-battery generic resources, the same renewable profiles were used and a 4 hour 25MW battery is used to maximize peak shaving for solar and limit high ramping hours for wind.

Table 69: Renewable Hourly Forecast Development

Renewable Options	Location(s)	Actual Generation Source	Storage Capacity	Capacity Factor
Tracking PV (PPA)	ECO, WCO	Spanish Peaks	N/A	28%
Tracking PV (Build Transfer)	ECO, WCO	Spanish Peaks	N/A	28%
Tracking PV (PPA)	NM	Alta Luna	N/A	32%
Tracking PV (Build Transfer)	NM	Alta Luna	N/A	32%
Tracking PV with Battery	ECO, WCO, NM	Alta Luna	25MW (4 Hour)	31%
Wind (PPA)	ECO, WCO, WY	Colorado Highlands	N/A	44%
Wind (Build Transfer)	ECO, WCO, WY	Colorado Highlands	N/A	44%
Wind with Battery	ECO, WCO, WY	Colorado Highlands	25MW (4 Hour)	40%

The annual outputs for new and existing generation were compared for reasonableness to the simulated forecast for each resource as created by Ascend Analytics. The complete results of the comparison can be found in Attachment Vol II 5-6 Ascend Analytics Renewables and Ramping Analysis.

Using the method described above for existing and under contract resources, annual energy for individual PPAs may be higher or lower than the forecasted contract energy amount due to the variability of the underlying technology, but the output is representative of previously recorded actual output. While this is to be expected, in the event that the total annual renewable energy was out of the range of contracted PPA energy, the Ascend hourly profiles were used in place of the outlier profiles to better align with the contract energy.

For financial modeling purposes actual contract energy for existing and contracted renewable PPAS is used in Hyperion and forwarded to UIPlanner for calculation of PVRR. The variance between Hyperion contract energy for existing and under contract renewables and the PO randomized 8760 profile annual totals are shown in Figure 23.

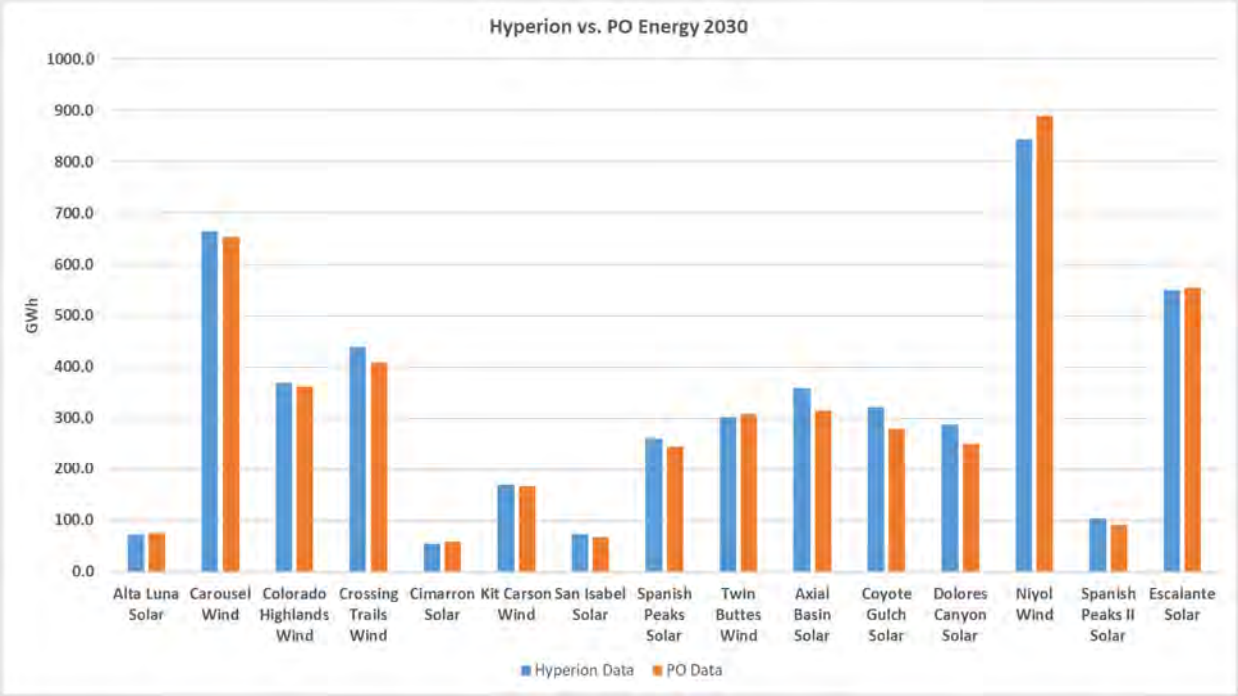

Figure 23: Hyperion versus PO Energy by PPA - Projected 2030

PO Dispatch data for renewables is used for determining GHG/CO_2 reduction.

DSM and EE

Tri-State's current demand side management and energy efficiency programs are described in Volume I Section 6 Assessment of Resource Needs under the subsection of Demand Side Management & Energy Efficiency.

In regards to potential expansion plan resources, Tri-State modeled in the generic resource dataset demand side resource options including energy efficiency and demand response by region.

Tri-State commissioned Mesa Point Energy to perform a DSM and EE potential study in 2019 that was completed in the spring of 2020. The study can be found as Attachment Vol II 5-1 Demand Side Management and Energy Efficiency Potential Study. This analysis was the basis for the modeled energy efficiency and demand response options in the generic resource dataset. The study was performed by load type (HVAC, Lighting, etc.), scenario (low achievable through max achievable), sector (Residential, Commercial, Industrial, Irrigation), and load region.

To model the resources, the individual load types, sectors, and load regions were consolidated to match the modeling regions/TAs used in CE and PO (New Mexico, West Colorado, East Colorado, Wyoming, and Nebraska). Tri-State modeled two levels of EE generic resources: Low Achievable and Aggressive Achievable and modeled one Low Achievable DR program level based on data from the study. For the EE generic resources costs were broken down to a must take $/MWh cost. For the DR generic resources, the associated study costs were represented as an annual fixed cost with a limited energy quantity representing the number of times that the demand response resource was called on as assumed by the DSM & EE Potential Study. It is important to note that the costs associated with DSM and EE are solely related to outgoing expenses related to funding the potential programs through incentives and promotion and does not include the opportunity cost associated with lost billing revenues.

Each EE or DR resource was eligible to be added during the years 2021, 2025, 2030, and 2035 with the same energy, capacity, and cost curves shifted to the start year. This was done to reduce the model size and complexity while allowing EE or DR resources to be introduced later in the study. For EE the model could select either Low or Aggressive Achievable generic resources within a region but not both. Modeled values can be found in Table 70 through Table 75.

Table 70: Energy (MWh) from Demand Response (Low Achievable)

Year	East Colorado	New Mexico	West Colorado	Wyoming
2021	131	43	35	37
2022	218	71	58	62
2023	355	115	95	100
2024	561	182	150	156
2025	850	276	228	235
2026	1,214	393	326	333
2027	1,608	520	432	438
2028	1,931	622	515	525
2029	2,148	689	569	583
2030	2,269	725	598	615
2031	2,331	742	610	630
2032	2,368	751	616	639
2033	2,395	756	620	645
2034	2,418	761	622	650
2035	2,438	765	624	655
2036	2,459	769	626	659
2037	2,480	772	628	663
2038	2,500	776	630	668
2039	2,527	782	634	673
2040	2,554	788	638	679

Table 71: Peak Capacity (MW) from Demand Response (Low Achievable)

Year	East Colorado	New Mexico	West Colorado	Wyoming
2021	2	1	1	1
2022	4	1	1	1
2023	6	2	2	2
2024	9	2	3	3
2025	14	4	5	4
2026	20	5	6	5
2027	26	7	9	7
2028	32	8	10	9
2029	35	9	11	10
2030	37	10	12	10
2031	38	10	12	10
2032	39	10	12	10
2033	39	10	12	11
2034	40	10	12	11
2035	40	10	13	11
2036	40	10	13	11
2037	41	10	13	11
2038	41	10	13	11
2039	41	10	13	11
2040	42	10	13	11

Table 72: Energy (MWh) from Energy Efficiency (Low Achievable)

Year	East Colorado	New Mexico	West Colorado	Wyoming
2021	12,370	7,756	6,093	4,112
2022	27,808	16,914	13,697	8,954
2023	44,834	27,154	22,083	13,978
2024	63,562	38,564	31,305	19,242
2025	84,189	51,077	41,466	24,963
2026	106,912	64,870	52,659	31,161
2027	131,971	80,056	65,002	37,896
2028	162,035	96,497	79,809	45,491
2029	192,962	113,373	95,040	53,327
2030	226,302	131,244	111,462	61,777
2031	261,647	150,039	128,872	70,670
2032	299,015	169,452	147,277	80,104
2033	338,278	189,315	166,616	90,006

Year	East Colorado	New Mexico	West Colorado	Wyoming
2034	379,575	210,071	186,954	100,501
2035	422,779	231,585	208,234	111,527
2036	454,261	242,111	223,740	117,453
2037	486,844	252,945	239,790	123,705
2038	519,974	263,812	256,107	129,965
2039	553,231	274,352	272,488	136,002
2040	586,909	285,037	289,075	142,135

Table 73: Capacity (MW) from Energy Efficiency (Low Achievable)

Year	East Colorado	New Mexico	West Colorado	Wyoming
2021	2	2	1	1
2022	5	4	3	2
2023	9	6	4	3
2024	12	8	6	4
2025	16	11	8	5
2026	21	14	10	6
2027	26	18	13	8
2028	32	21	16	9
2029	39	25	19	11
2030	47	30	23	12
2031	55	34	27	14
2032	63	38	31	16
2033	72	43	35	18
2034	81	48	40	20
2035	90	53	45	23
2036	98	56	48	24
2037	105	58	52	25
2038	113	61	56	27
2039	120	63	59	28
2040	128	65	63	29

Table 74: Energy (MWh) from Energy Efficiency (Aggressive Achievable)

Year	East Colorado	New Mexico	West Colorado	Wyoming
2021	25,522	15,370	12,571	8,315
2022	58,352	34,504	28,741	18,344
2023	95,548	56,809	47,062	29,153
2024	137,648	82,393	67,798	40,627
2025	185,432	110,975	91,334	53,413
2026	239,174	142,587	117,803	67,622
2027	298,593	176,974	147,068	83,279
2028	364,994	212,847	179,773	100,560
2029	432,758	248,988	213,149	118,296
2030	502,940	285,921	247,718	136,953
2031	574,208	323,291	282,817	155,938
2032	646,233	360,727	318,294	175,386
2033	718,589	397,729	353,932	194,926
2034	791,700	435,099	389,942	214,868
2035	865,590	472,673	426,336	235,066
2036	920,430	495,023	453,347	247,270
2037	976,073	517,830	480,753	259,546
2038	1,031,659	539,986	508,128	271,741
2039	1,086,722	560,923	535,251	283,423
2040	1,141,901	581,312	562,430	295,086

Table 75: Peak Capacity (MW) from Energy Efficiency (Aggressive Achievable)

Year	East Colorado	New Mexico	West Colorado	Wyoming
2021	5	3	2	2
2022	11	7	6	4
2023	19	12	9	6
2024	27	18	13	8
2025	36	25	18	11
2026	47	32	23	14
2027	59	40	29	17
2028	74	49	36	21
2029	88	58	44	25
2030	104	67	51	29
2031	120	76	59	33
2032	135	85	66	37
2033	151	94	75	41

Year	East Colorado	New Mexico	West Colorado	Wyoming
2034	168	103	83	45
2035	184	113	91	49
2036	196	118	97	52
2037	209	124	103	54
2038	221	129	109	57
2039	234	134	115	59
2040	245	138	121	61

Distributed Generation

Tri-State models member distributed generation projects, under Board Policy 115 and Board Policy 119, as resources in CE and PO. Energy forecasts of distributed generation projects are based on project history or history for similar technology types. Projects are associated with their appropriate region within the model. Hourly profiles are developed and used in PO dispatch. Projects are added to the model upon Tri-State Board and FERC approval. Additionally, a 2% annual expected growth forecast is included to represent potential future projects. In CE a capacity planning factor of 22% was applied to these resources. This percentile was derived from four years of hourly generation data during typical system peak hours in July and August and ranking them from smallest to largest. Then the generation level at the 15th percentile is selected as the estimated contribution to the system peak. This means that 85% of the time the capacity contribution will be equal to or greater than the estimate. Due to their size, these resources were not incorporated into the modified ELCC study.

GHG & $C0_2$ Reduction Methodology Used in Scenarios

The following is a description of the methodology for calculating Tri-State's CO_2 and GHG emissions baseline, calculating forecasted emissions and determining the resulting emission reductions.

GHG and CO_2 reductions are calculated on all wholesale electricity sales in the state of Colorado by Tri-State. Tri-State only sells electricity at the wholesale level. Wholesale electricity sales include sales to Tri-State's Utility Member Systems and non-member sales to counterparties (other utilities, marketers) at transaction points in Colorado. From a resource perspective, all resources in Colorado including owned thermal generators, renewable PPAs, long-term contracts with delivery points in Colorado, and forecast market purchases at Colorado transaction points are considered to supply wholesale electricity sales in Colorado. Also, Tri-State resources, thermal or renewable, located outside of Colorado that are forecast to be imported to serve wholesale Utility Member System load in Colorado are included in the total emissions calculation. GHG emissions include carbon equivalent (CO_2e) rates for CH_4, N_2O and SF_6.

GHG and CO_2 emissions are also calculated on retail load served in the state of Colorado by Tri-State's Utility Member Systems. To arrive at the forecast retail load the amount of wholesale electricity sales by Tri-State to Utility Member Systems in Colorado excluding transmission losses is reduced by representative distribution losses for a given year.

Calculation of Tri-State's 2005 Baseline of CO_2 & GHG Emission in the state of Colorado:

Colorado Electricity Sales are defined as all wholesale electricity sales including Tri-State sales to Utility Member Systems in Colorado and non-member sales from Colorado generation and/or sold at transaction points in CO. Delta Montrose Electric Association (DMEA) was a member of Tri-State in 2005 but withdrew as a member of Tri-State July 1, 2020. DMEA is included in the initial load calculation in order to arrive at total 2005 emissions, but related emissions for DMEA are then removed to arrive at the final 2005 baseload calculated emissions for Tri-State. Non-Member sales energy is based on Colorado non-member sales as identified in a Tri-State report from 2005, "All revenue by State.xls". All sales are marked up 6.1%, which is the transmission loss value identified in Tri-State's 2005 financial reports.

The following resources are considered to serve wholesale electricity sales in Colorado whether to Utility Member Systems or non-member sales:

- All thermal owned generation in Colorado
- LAP and CRSP hydro contract deliveries at transaction points in Colorado[49]
- Basin Western Interconnection at transaction points in Colorado [50]
- Small renewable contracts located in Colorado
- Any necessary balance required to meet wholesale electricity sales in Colorado was most likely imported from LRS 2 & LRS 3 with potential small contributions from Escalante Generating Station, San Juan 3, or the Pyramid facility.

CO_2 emission methodology and source for each 2005 resource are identified in Table 76:

Table 76: CO_2 Emission Rates – 2005

Resource	Emission Source	Emission Rate *(short tons/MWh)*
Craig 1 & 2[51]	Plant Rate (average of generator rates)	1.17
Craig 3	Generator Rate	1.05
Nucla	Generator Rate	1.30
Rifle	Generator Rate	0.95
Knutson 1 &2	Plant Rate (average of generator rates)	0.75
Limon 1 & 2	Plant Rate (average of generator rates)	0.75
Burlington 1 &2	Plant Rate (average of generator rates)	1.12
CRSP Colorado Deliveries	Federal Hydropower – No GHG/CO_2	0
LAP Colorado Deliveries	Federal Hydropower – No GHG/CO_2	0
Small Power Producers	Hydropower – – No GHG/CO_2	0
Basin Western Interconnect Colorado Deliveries	Plant Rate (average of LRS 2 & LRS 3 rates)	1.15
Market Purchases in Colorado	Based on average of Tri-State coal rates[52]	1.10
Imports from out of state	Plant Rate (average of generator rates)[53]	1.15

[49] Identified in 555XX Purch Pwr by State_2005.xls
[50] Identified in 555XX Purch Pwr by State_2005.xls
[51] Historical data is available as Yampa Project – Craig 1 & 2 combined
[52] No regional published rate available
[53] Average of LRS 2 & LRS 3 emission rates as LRS generation would have been the primary import source.

After determining the amount of wholesale electricity sales in Colorado and the necessary in and out of state resources that supplied those sales, emissions are calculated using rates from Table 76. Total emissions are then calculated. Next, the percentage of energy necessary to serve each of the following is calculated:

- DMEA load including losses
- Tri-State Utility Member Systems load in Colorado including losses (net of DMEA)
- Wholesale electricity sales to non-members including losses

The percentages of energy to supply Utility Member System sales including losses and wholesale electricity sales to non-members including losses are then summed and this percentage is applied to the total calculated emission. The result is Tri-State's 2005 CO_2 emissions baseline for wholesale electricity sales in Colorado, which is 9,180,383 short tons of CO_2 emissions.

GHG emissions for CH_4 and N_2O were calculated based on EPA CO_2e emission factors and fuel used for thermal generation. Additionally, SF_6 GHG emissions were provided by Tri-State's environmental department. Resulting 2005 GHG emissions baseline for wholesale electricity sales in Colorado is 9,257,365 CO_2e short tons of GHG emissions.

To determine CO_2 and GHG emissions in the state of Colorado in 2005 for Tri-State Utility Member System retail sales, Tri-State used Tri-State Utility Member System load net of DMEA and transmission losses and then further reduced the load amount by 7%[54] for distribution losses. Tri-State used two calculation options to arrive at emissions from Utility Member System retail load in Colorado:

Option 1 uses "known" resources serving Colorado load and itemizes the related MWh and emission associated with those resources. The balance of the energy required to serve Colorado Utility Member System retail load after netting the energy supplied from these resources is then given a CO_2 emission rate calculated from an average of Craig and LRS plant emissions and market purchase emissions. The CO_2 emissions from known resources and the calculated emissions for the balance energy are summed to arrive at total CO_2 emissions.

Option 2 calculates CO_2 emission by taking total 2005 CO_2 emissions (emissions caused by sales to Tri-State Utility Member Systems in Colorado including DMEA and non-member sales in Colorado) and multiplying this values times the quotient of Tri-State Utility Member System retail sales in Colorado divided by all Tri-State wholesale electricity sales in Colorado.

For both options the GHG adder (percentage), based on CH_4, N_2O and SF_6 CO_2e emissions divided by total CO_2e emissions, is applied to Utility Member System retail loadCO_2 emissions and used to arrive at total GHG emissions.

Based on option 1, Tri-State's 2005 baseline of CO_2 emissions to serve retail load in Colorado is 6,147,055 short tons. Tri-State's 2005 baseline of total GHG emissions to serve retail load in Colorado is 6,198,172 carbon equivalent short tons.

[54] Representative of average distribution losses at the Utility Member System level in 2005

Based on option 2, Tri-State's 2005 baseline of CO_2 emissions to serve retail load in Colorado is 6,244,171 short tons. Tri-State's 2005 baseline of total GHG emissions to serve retail load in Colorado is 6,296,096 carbon equivalent short tons.

Calculation of Tri-State's Forecasted CO_2 & GHG Emissions in the state of Colorado:

For forecast CO_2 and GHG emissions, the primary focus is emissions in 2030 and related reductions from the 2005 baselines. However, for some scenarios Tri-State calculated a glide path[55] beginning in 2025. Tri-State also monitored reduction levels in 2035 and 2040.

In general, the calculations for forecasted emissions are similar to the 2005 baseline method. Any differences are identified as follows:

- Transmission losses are calculated at 5% instead of 6.1% as this is more representative of current OATT loss factors.
- Distribution losses are calculated at 4%, as this is more representative of an average of Tri-State's Utility Member Systems' distributions losses today.
- Charging load that occurs, as a result of energy storage due to efficiency levels is included in the total load calculation. This includes batteries and pump back hydro serving Colorado wholesale electricity sales.
- In both 2005 and forecast emission calculations, gross load is used. Therefore, Utility Member System distributed generation forecast is used as a resource in serving electricity sales in Colorado for purposes of total emissions calculations.
- Basin Electrically East contract portion serving load in Colorado is pulled out as a separate line item due to Basin Electrically East now being served via an RTO (SPP).

CO_2 emission methodology and source for each forecasted resource are identified in Table 77:

Table 77: CO_2 Emission Rates - Forecasted

Resource	Emission Source	**CO_2 Emission Rate** *(short tons/MWh)*
Craig 1 & 2[56]	Plant Rate (average of generator rates)	1.17
Craig 3	Generator Rate	1.05
Rifle	Generator Rate	0.95
Knutson 1 &2	Plant Rate (average of generator rates)	0.75
Limon 1 & 2	Plant Rate (average of generator rates)	0.75
Burlington 1 &2	Plant Rate (average of generator rates)	1.12
JM Shafer	Generator Rate	0.49
CRSP Colorado Deliveries	Federal Hydropower – No GHG/CO_2 w RECs	0
LAP Colorado Deliveries	Federal Hydropower – No GHG/CO_2 w RECs	0
Small Power Producers	Hydro power – No GHG/CO_2 w RECs	0

[55] The glide path includes measured reductions in emissions beginning in 2025 and continually increasing to reach required emission reduction levels in 2030.
[56] Historical data is available as Yampa Project – Craig 1 & 2 combined.

Resource	Emission Source	CO_2 Emission Rate *(short tons/MWh)*
Basin Western Interconnect Colorado Deliveries	Published Regional rate – egrid RMPA[57]	0.64
Market Purchases in Colorado[58]	Published Regional rate – egrid RMPA	0.64
Kit Carson	Contract Rate - Wind w RECs	0
Carousel	Contract Rate - Wind w RECs	0
Colorado Highlands	Contract Rate - Wind w RECs	0
Crossing Trails	Contract Rate - Wind w RECs	0
Spanish Peaks	Contract Rate - Solar w RECs	0
San Isabel	Contract Rate - Solar w RECs	0
Twin Buttes	Contract Rate - Wind w RECs	0
Niyol	Contract Rate - Wind w RECs	0
Coyote Gulch	Contract Rate - Solar w RECs	0
Dolores Canyon	Contract Rate - Solar w RECs	0
Axial	Contract Rate - Solar w RECs	0
Basin Electrically East (Colorado portion)	Published Regional rate – Egrid MROW[59]	0.62
Colorado Member Generation	Renewables – No GHG w and w/o RECs	0
Imports from LRS 2&3	Plant Rate (average of generator rates)	1.15
Expansion Plan Wind	Contract Rate - Wind w RECs	0
Expansion Plan Solar	Contract Rate - Solar w RECs	0
Expansion Plan Combined Cycle	Generator Rate	0.4
Expansion Plan Combustion Turbine, RICE, Aeroderivative	Generator Rate	0.6

Basin Western Interconnection, Market Purchases in Colorado including energy imbalance and Basin Electrically East use the egrid published 2018 CO_2 emission rates for RMPA or MROW based on location. During the Colorado AQCC Clean Energy Plan Guidance process, discussion around forward emission rates for markets and contracts with unspecified sources included using region wide published numbers such as WECC and SPP. Additionally, the potential for using a trend line to 2030 was discussed. While Tri-State agrees that the market purchase and contracts with unspecified sources emission rates will likely decline between now and 2030, Tri-State has taken a conservative approach in its CO_2 reduction calculation by applying the 2018 emission rate. Also, it is important to note that there is a general movement towards organized markets in WECC, and it is likely that all of Tri-State's load and resources will be located within an RTO by 2030. In an RTO, load and resources are no longer connected in that a utility does not schedule their resource to their load, but instead bid load and offer resources into the market. At that point, the applicable RTO published emission rate may be the more suitable rate to apply to market purchases and contracts with unspecified sources.

[57] Rate is reflective of 2018 published egrid RMPA rate.
[58] Market purchases in Colorado includes energy imbalance forecast purchases.
[59] 2018 Egrid MROW rate

Calculations of total emissions are similar to 2005 method with the exception that there is no need to remove DMEA load as DMEA load is already removed from the load forecast.

CO_2 & GHG Reduction Calculations:

Following are the calculations for CO_2 reduction - forecasted vs 2005 baseline emission:

Colorado CO_2 Reduction:

- Colorado Wholesale Electricity Sales
  - 2005 CO Electricity Sales Baseline CO_2 emissions excluding DMEA minus forecasted 2030 CO Electricity Sales CO_2 emissions divided by 2005 CO Electricity Sales Baseline CO_2 emissions excluding DMEA
- Colorado Utility Member System Retail Sales
  - 2005 CO Member Retail Load Baseline CO_2 emissions excluding DMEA minus forecasted 2030 CO Member Retail Load CO_2 emissions divided by 2005 CO Member retail Load Baseline CO_2 emissions excluding DMEA

GHG Reduction:

- Calculate additional GHG emissions for CH_4, N_2O and SF_6 as CO_2e and add to CO_2 emissions for 2005 baseline and 2030 forecast. Use CO_2 reduction calculation method above to arrive at total GHG reduction

2005 Baseline:

Table 78: 2005 Baseline CO_2 & GHG emissions for Wholesale Electricity Sales in Colorado

Carbon Emission Mass base CO Generation - Electricity Sales in CO				
2005	**Fuel Type**	**Energy MWh**	**Carbon Emission Rate (tons/MWh)**	**Carbon Emissions**
CO Sales to Members		7,347,873		
CO Sales to Members inc Transmission Losses (6.1%)		7,796,093		
Craig 1 & 2	Coal	1,711,570	1.17	1,997,830
Craig 3	Coal	3,011,768	1.05	3,147,297
LRS Imports into CO	Coal	1,626,188	1.15	1,874,181
Nucla	Coal	736,962	1.30	958,051
Rifle	Gas	39,243	0.95	37,281
Knutson 1&2	Gas	22,843	0.75	17,132
Limon 1 & 2	Gas	23,027	0.75	17,270
Burlington 1 & 2	Oil	4,551	1.12	5,097
CRSP East & West (CO)	Federal Hydro	609,330	0.00	0
LAP (CO)	Federal Hydro	513,319	0.00	0
Small Power Producers	Small Hydro	40,396	0.00	0
Basin AU PPA	Coal	859,067	1.15	990,075
Wind PPAs	Wind	0	0.00	0
Gas PPAS	Gas	0	0.00	0
Solar PPAs	Solar	0	0.00	0
CO Market Purchases	Market	672,728	1.10	740,001
CO Market Sales (marked up 6.1% for trans losses)	Market	2,074,897		
	Check	7,796,093		9,784,215
	Check	9,870,990		0.99
Market Sales		2,074,897	21%	2,056,657
DMEA Load plus losses	574,163	609,187	6%	603,832
TS Load plus losses	6,773,710	7,186,906	73%	7,123,727
			Carbon Tons	9,180,383
			GHG Tons	9,257,364

Table 79: 2005 Baseline CO_2 & GHG Emissions for Tri-State Utility Member Systems' Retail Sales

2005 Baseline for TS Utility Member System Retail Sales			
		Option 1	**Option 2**
	MWh	**Carbon Emissions Based on How served**	**Carbon Emissions based on Percentage of Sales**
Retail Load (Member load reduced for distribution & transm	6,299,550	6,147,055	6,244,171
Carbon Rate (Tons/MWh)		0.98	0.99
GHG Emissions		6,198,172	6,296,096
Resources Known to Exclusively Serve Load			
Nucla	736,962	958,051	
Rifle	39,243	37,281	
Limon 1	5757	4317.75	
CRSP East & West (CO)	609,330	0	
LAP (CO)	513,319	0	
Small Power Producers	40,396	0	
Basin AU PPA	859,067	990,075	
Total	2,804,073	1,989,724	
Net After transmission losses	2,633,025	1,868,351	
DMEA Prorata Portion	8%	8%	
Serving Load net of DMEA	2,427,280	1,722,358	
Balance	3,872,270	4,278,704	

Social Cost of Carbon

In Table 80 column "PUC Staff Step 3" represents the values in real dollars for SCoC as applied to resource CO_2 emission rates for use in CE. Rates are applied to thermal resource CO_2 emission rates and added to VOM for use in CE modeling as shown in Table 81 and Table 82.

Table 80 Social Cost of Carbon Annual Values

2007	$/metric ton	$/short ton	Escalated $/short ton	PUC Staff Step 3 $/short ton (Real)	PUC Staff Step 4 $/short ton (Nominal)
2020	$42.00	$38.10	$46.00	$46.60	$46.58
2021	$42.00	$38.10	$46.00	$46.60	$47.51
2022	$43.00	$39.01	$47.10	$47.70	$49.61
2023	$44.00	$39.92	$48.19	$48.80	$51.78
2024	$45.00	$40.82	$49.29	$49.90	$54.02
2025	$46.00	$41.73	$50.38	$51.00	$56.32
2026	$47.00	$42.64	$51.48	$52.10	$58.70
2027	$48.00	$43.54	$52.57	$53.20	$61.15
2028	$49.00	$44.45	$53.67	$54.30	$63.67
2029	$49.00	$44.45	$53.67	$54.30	$64.94
2030	$50.00	$45.36	$54.76	$55.40	$67.59
2031	$51.00	$46.27	$55.86	$56.60	$70.32
2032	$52.00	$47.17	$56.95	$57.70	$73.14
2033	$53.00	$48.08	$58.05	$58.80	$76.03
2034	$54.00	$48.99	$59.14	$59.90	$79.02
2035	$55.00	$49.90	$60.24	$61.00	$82.09
2036	$56.00	$50.80	$61.33	$62.10	$85.25
2037	$57.00	$51.71	$62.43	$63.20	$88.51
2038	$58.00	$52.62	$63.52	$64.30	$91.87
2039	$59.00	$53.52	$64.62	$65.40	$95.32
2040	$60.00	$54.43	$65.71	$66.50	$98.87

Table 81 Social Cost of Carbon Values by Existing Resource (Real $)

	LRS 2	LRS 3	Craig 1	Craig 2	Craig 3	SPV3	Burlington 1	Burlington 2	Pyramid 1	Pyramid 2	Pyramid 3	Pyramid 4	Rifle	Limon 1	Limon 2	Knutson 1	Knutson 2	J. M. Shafer
Carbon Rate (Tons/MWh)	**1.1015**	**1.2035**	**1.1595**	**1.175**	**1.045**	**1.0695**	**1.106**	**1.043**	**0.62**	**0.616**	**0.625**	**0.619**	**0.603**	**0.749**	**0.746**	**0.752**	**0.75**	**0.4905**
2021	$51.33	$56.08	$54.03	$54.76	$48.70	$49.84	$51.54	$48.60	$28.89	$28.71	$29.13	$28.85	$28.10	$34.90	$34.76	$35.04	$34.95	$22.86
2022	$52.54	$57.41	$55.31	$56.05	$49.85	$51.02	$52.76	$49.75	$29.57	$29.38	$29.81	$29.53	$28.76	$35.73	$35.58	$35.87	$35.78	$23.40
2023	$53.75	$58.73	$56.58	$57.34	$51.00	$52.19	$53.97	$50.90	$30.26	$30.06	$30.50	$30.21	$29.43	$36.55	$36.40	$36.70	$36.60	$23.94
2024	$54.96	$60.05	$57.86	$58.63	$52.15	$53.37	$55.19	$52.05	$30.94	$30.74	$31.19	$30.89	$30.09	$37.38	$37.23	$37.52	$37.43	$24.48
2025	$56.18	$61.38	$59.13	$59.93	$53.30	$54.54	$56.41	$53.19	$31.62	$31.42	$31.88	$31.57	$30.75	$38.20	$38.05	$38.35	$38.25	$25.02
2026	$57.39	$62.70	$60.41	$61.22	$54.44	$55.72	$57.62	$54.34	$32.30	$32.09	$32.56	$32.25	$31.42	$39.02	$38.87	$39.18	$39.08	$25.56
2027	$58.60	$64.03	$61.69	$62.51	$55.59	$56.90	$58.84	$55.49	$32.98	$32.77	$33.25	$32.93	$32.08	$39.85	$39.69	$40.01	$39.90	$26.09
2028	$59.81	$65.35	$62.96	$63.80	$56.74	$58.07	$60.06	$56.63	$33.67	$33.45	$33.94	$33.61	$32.74	$40.67	$40.51	$40.83	$40.73	$26.63
2029	$59.81	$65.35	$62.96	$63.80	$56.74	$58.07	$60.06	$56.63	$33.67	$33.45	$33.94	$33.61	$32.74	$40.67	$40.51	$40.83	$40.73	$26.63
2030	$61.02	$66.67	$64.24	$65.10	$57.89	$59.25	$61.27	$57.78	$34.35	$34.13	$34.63	$34.29	$33.41	$41.49	$41.33	$41.66	$41.55	$27.17
2031	$62.34	$68.12	$65.63	$66.51	$59.15	$60.53	$62.60	$59.03	$35.09	$34.87	$35.38	$35.04	$34.13	$42.39	$42.22	$42.56	$42.45	$27.76
2032	$63.56	$69.44	$66.90	$67.80	$60.30	$61.71	$63.82	$60.18	$35.77	$35.54	$36.06	$35.72	$34.79	$43.22	$43.04	$43.39	$43.28	$28.30
2033	$64.77	$70.77	$68.18	$69.09	$61.45	$62.89	$65.03	$61.33	$36.46	$36.22	$36.75	$36.40	$35.46	$44.04	$43.86	$44.22	$44.10	$28.84
2034	$65.98	$72.09	$69.45	$70.38	$62.60	$64.06	$66.25	$62.48	$37.14	$36.90	$37.44	$37.08	$36.12	$44.87	$44.69	$45.04	$44.93	$29.38
2035	$67.19	$73.41	$70.73	$71.68	$63.75	$65.24	$67.47	$63.62	$37.82	$37.58	$38.13	$37.76	$36.78	$45.69	$45.51	$45.87	$45.75	$29.92
2036	$68.40	$74.74	$72.00	$72.97	$64.89	$66.42	$68.68	$64.77	$38.50	$38.25	$38.81	$38.44	$37.45	$46.51	$46.33	$46.70	$46.58	$30.46
2037	$69.61	$76.06	$73.28	$74.26	$66.04	$67.59	$69.90	$65.92	$39.18	$38.93	$39.50	$39.12	$38.11	$47.34	$47.15	$47.53	$47.40	$31.00
2038	$70.83	$77.39	$74.56	$75.55	$67.19	$68.77	$71.12	$67.06	$39.87	$39.61	$40.19	$39.80	$38.77	$48.16	$47.97	$48.35	$48.23	$31.54
2039	$72.04	$78.71	$75.83	$76.85	$68.34	$69.95	$72.33	$68.21	$40.55	$40.29	$40.88	$40.48	$39.44	$48.98	$48.79	$49.18	$49.05	$32.08
2040	$73.25	$80.03	$77.11	$78.14	$69.49	$71.12	$73.55	$69.36	$41.23	$40.96	$41.56	$41.16	$40.10	$49.81	$49.61	$50.01	$49.88	$32.62

Table 82: Social Cost of Carbon Values by Generic Resource (Real $)

	__BM 112_18x6RICE_CO2	__BM 200_1x235_7FA05_CO2	__BM 300_1x1_7FA05_CO2	__BM 357_1x1_7HA01_CO2	__BM 40_1x40LM6000_CO2	__BM 46_9x5RICE_CO2	__BM 545_1x1_7HA03_CO2	__BM 81_2x40LM6000_CO2	__BM 93_1x100_LMS100_CO2
Carbon Rate (Tons/MWh)	**0.6201**	**0.7475**	**0.3755**	**0.62**	**0.40**	**0.63**	**0.36**	**0.40**	**0.52**
2021	$28.90	$34.83	$17.50	$28.89	$18.55	$29.17	$16.54	$18.62	$24.43
2022	$29.58	$35.66	$17.91	$29.57	$18.99	$29.86	$16.93	$19.06	$25.00
2023	$30.26	$36.48	$18.32	$30.26	$19.42	$30.55	$17.32	$19.50	$25.58
2024	$30.94	$37.30	$18.74	$30.94	$19.86	$31.23	$17.71	$19.94	$26.16
2025	$31.63	$38.12	$19.15	$31.62	$20.30	$31.92	$18.11	$20.38	$26.73
2026	$32.31	$38.94	$19.56	$32.30	$20.74	$32.61	$18.50	$20.82	$27.31
2027	$32.99	$39.77	$19.98	$32.98	$21.18	$33.30	$18.89	$21.26	$27.89
2028	$33.67	$40.59	$20.39	$33.67	$21.61	$33.99	$19.28	$21.70	$28.46
2029	$33.67	$40.59	$20.39	$33.67	$21.61	$33.99	$19.28	$21.70	$28.46
2030	$34.35	$41.41	$20.80	$34.35	$22.05	$34.68	$19.67	$22.14	$29.04
2031	$35.10	$42.31	$21.25	$35.09	$22.53	$35.43	$20.09	$22.62	$29.67
2032	$35.78	$43.13	$21.67	$35.77	$22.97	$36.12	$20.48	$23.06	$30.24
2033	$36.46	$43.95	$22.08	$36.46	$23.40	$36.81	$20.87	$23.50	$30.82
2034	$37.14	$44.78	$22.49	$37.14	$23.84	$37.49	$21.26	$23.94	$31.40
2035	$37.83	$45.60	$22.91	$37.82	$24.28	$38.18	$21.66	$24.38	$31.97
2036	$38.51	$46.42	$23.32	$38.50	$24.72	$38.87	$22.05	$24.82	$32.55
2037	$39.19	$47.24	$23.73	$39.18	$25.16	$39.56	$22.44	$25.26	$33.13
2038	$39.87	$48.06	$24.14	$39.87	$25.59	$40.25	$22.83	$25.70	$33.70
2039	$40.55	$48.89	$24.56	$40.55	$26.03	$40.94	$23.22	$26.14	$34.28
2040	$41.24	$49.71	$24.97	$41.23	$26.47	$41.63	$23.61	$26.58	$34.86

In Table 80 column "PUC Staff Step 4" represents the values in nominal dollars for SCoC used in the calculation of PVRR for the SCC scenario. Resulting PVRR for the SCC scenario is identified in Volume I Section 9 Base Case and Alternative Scenario Comparison of this report. PVRR for this scenario is calculated both with and without the social cost of carbon with both Tri-State's discount rate of 4.15% and a discount rate of 3% per Commission guidance.

Additionally, this nominal value for SCoC for each year is applied to annual system CO_2 emissions for each scenario. Total system CO_2 emissions include emissions from energy imbalance, market purchases, thermal owned resources, and Basin contracts. Total SCoC for each scenario is identified in Volume I Section 8 Base Case and Alternative Scenario Results of this report.

Table 83 shows the Appendix 5 to Commission Staff comments from September 2020, which provided direction on values to use for SCoC and a comparison of Tri-State's original methodology.

Table 83 Extraction from PUC Staff Comments Appendix 5

Appendix 5 to Staff's Attachment 1:
Social Cost of Carbon Calculation and Implementation
Proceeding No. 20M-0218E
Page 3 of 6

Comparison of the Calculation of the Social Cost of Carbon for Modeling

Staff's Recommended Methodology:

Year	Step 1 Central Estimate (3% Average) ($2007/metric-ton)	Step 2 Central Estimate (3% Average) ($2007/short-ton)	Step 3 $2020/short-ton ($2007/short-ton)	Step 4 Inflation Factor	Step 4 Nominal $/Short-ton
2020	42	38	46.6	100%	46.58
2021	42	38	46.6	102%	47.51
2022	43	39	47.7	104%	49.61
2023	44	40	48.8	106%	51.78
2024	45	41	49.9	108%	54.02
2025	46	42	51.0	110%	56.32
2026	47	43	52.1	113%	58.70
2027	48	44	53.2	115%	61.15
2028	49	44	54.3	117%	63.67
2029	49	44	54.3	120%	64.94
2030	50	45	55.4	122%	67.59
2031	51	46	56.6	124%	70.32
2032	52	47	57.7	127%	73.14
2033	53	48	58.8	129%	76.03
2034	54	49	59.9	132%	79.02
2035	55	50	61.0	135%	82.09
2036	56	51	62.1	137%	85.25
2037	57	52	63.2	140%	88.51
2038	58	53	64.3	143%	91.87
2039	59	54	65.4	146%	95.32
2040	60	54	66.5	149%	98.87
2041	61	55	67.6	152%	102.53
2042	61	55	67.6	155%	104.58
2043	62	56	68.8	158%	108.42
2044	63	57	69.9	161%	112.37
2045	64	58	71.0	164%	116.44
2046	65	59	72.1	167%	120.63
2047	66	60	73.2	171%	124.93
2048	67	61	74.3	174%	129.36
2049	68	62	75.4	178%	133.92
2050	69	63	76.5	181%	138.60

Tri-State's Methodology

Year	Step 1 Central Estimate (3% Average) ($2007/metric-ton)	Step 2 Central Estimate (3% Average) ($2007/short-ton)	Step 3 Escalated ($2020/short-ton)
2020	42	38	46.0
2021	42	38	46.0
2022	43	39	47.1
2023	44	40	48.2
2024	45	41	49.3
2025	46	42	50.4
2026	47	43	51.5
2027	48	44	52.6
2028	49	44	53.7
2029	49	44	53.7
2030	50	45	54.8
2031	51	46	55.9
2032	52	47	57.0
2033	53	48	58.0
2034	54	49	59.1
2035	55	50	60.2
2036	56	51	61.3
2037	57	52	62.4
2038	58	53	63.5
2039	59	54	64.6
2040	60	54	65.7
2041	61	55	66.8
2042	61	55	66.8
2043	62	56	67.9
2044	63	57	69.0
2045	64	58	70.1
2046	65	59	71.2
2047	66	60	72.3
2048	67	61	73.4
2049	68	62	74.5
2050	69	63	75.6

Summary of Third Party Studies

The following third party studies were completed in support of Tri-State's 2020 ERP.

Table 84: Third Party Study Summaries

Third Party Study	Consultant	Attachment	Description
Demand Side Management/Energy Efficiency Potential Study	Mesa Point Energy	5-1	Evaluates Demand Side Management achievable potential in relation to energy efficiency and demand response across Tri-State's Utility Member Systems' territories.
Loss of Load Probability Study	Black & Veatch	5-2	Evaluates representative plans with varying load and CO_2 reduction statuses to determine the adequacy of the current planning reserve margin.
Modified Effective Load Carrying Capability Study	Black & Veatch	5-3	Determines reasonable capacity credits for wind and solar based on increasing renewable penetration levels.
Report on Assessment of Existing Resources	Black & Veatch	5-4	Assesses key costs and performance metrics of existing resources against industry standards.
Benchmarking Study	Black & Veatch	5-5	Compares existing resources to generic resources in regards to cost and performance.
Renewable & Ramping Analysis	Ascend Analytics	5-6	Assesses the reasonability of Tri-State's hourly renewable profiles for existing and generic resources and evaluates potential ramping needs related to integration of intermittent resources.
Beneficial Electrification Study	Mesa Point Energy	5-7	Evaluates the achievable potential to convert non-electrical load to electrical load within Tri-State's Utility Member System territories while reducing carbon emissions.

6 Scenario Results Data

Emissions & Water Usage Data

See Attachment Vol II 6-1 Annual Emissions and Water Usage for a detailed list of annual emissions and water usage data by resource for the base case and alternative scenarios.

RES/RPS Data

See Attachment Vol II 6-2 RES/RPS for a detailed annual list of RECs by resource for the base case and each alternative scenario. Renewable energy under PPAs are shown with contractual annual energy amounts from Hyperion as well as dispatched annual energy amounts from PO.

7 Phase II RFP

See Attachment Vol II 7-1 Phase II All-Source RFP.

See Attachment Vol II 7-2 Bidder Highly Confidential Non-Disclosure Agreement.

For model contracts, see the following attachments:

- Attachment Vol II 7-3 Dispatchable PPA
- Attachment Vol II 7-4 Semi-Dispatchable PPA
- Attachment Vol II 7-5 Renewable PPA

List of Acronyms

ACE	Affordable Clean Energy Rule
APR	Annual Progress Report
ARIMA	Auto Regressive Integrated Moving Average
BA	Balancing Authority
BE	Beneficial Electrification
BEPC	Basin Electric Power Cooperative
BHCE	Black Hills Colorado Electric, Inc.
BHCT	Black Hills Colorado Transmission
B&V	Black & Veatch
CAISO	California Independent System Operator
CE	Capacity Expansion
CO_2	Carbon dioxide
CR	CO_2 Reduction
CRN	Cooperative Research Network
CRSP	Colorado River Storage Project
CSU	Colorado Springs Utility
DER	Distributed Energy Resources
DG	Distributed Generation
DOE	Department of Energy
DR	Demand Response
DSM	Demand Side Management
ECO	Eastern Colorado
EE	Energy Efficiency
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
EPA	Environmental Protection Agency
ERPI	Electric Research Power Institute
ERP	Electric Resource Plan
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gases
Hg	Mercury
IRP	Integrated Resource Plan
ISO	Independent System Operator
LAP	Loveland Area Projects
LAPT	WAPA Rocky Mountain Region Loveland Area Projects
LCoE	Levelized Cost of Energy
LGIP	Large Generation Interconnection Process
LOLP	Loss of Load Probability
LRS	Laramie River Station

MBPP	Missouri Basin Power Project
MCP	Member Coincident Peak
M-RETS	Midwest Renewable Energy Tracking System
NERC	North American Reliability Corporation
NREL	National Renewable Energy Laboratories
NO_x	Nitrogen Oxides
NRECA	Nation Rural Electric Cooperative Association
OATT	Open Access Transmission Tariff
PAC	PacifiCorp
POI	Point of Interconnection
PM	Particulate Matter
PR	Partial Requirements
PPA	Power Purchase Agreement
PSCo	Public Service of Colorado
PNM	Public Service of New Mexico
PO	Portfolio Optimization
POD	Point of Delivery
PRPA	Platte River Power Authority
PVRR	Prevent Value Revenue Requirement
QRU	Qualifying Retail Utility
QWU	Qualifying Wholesale Utility
RAP	Resource Acquisition Period
REC	Renewable Energy Credit
REP	Responsible Energy Plan
RES	Renewable Energy Standard
RFP	Request for Proposal
RPP	Resource Planning Period
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SCC	Social Cost of Carbon (Scenario)
SCoC	Social Cost of Carbon
SIP	Regional Haze State Implementation Plan
SO_2	Sulfur Dioxide
SPP	Southwest Power Pool
SPV 3	Springerville Unit 3
SRP	Salt River Project
SRSG	Southwest Reserve Sharing Group
TA	Transmission Area
TEP	Tucson Electric Power
TP	Transmission Provider
WACM	Western Area Colorado Missouri
WAPA	Western Area Power Administration
WCO	Western Colorado

WEIM	Western Energy Imbalance Market
WEIS	Western Energy Imbalance Service
WMPA	Wyoming Municipal Power Agency
WREGIS	Western Renewable Energy General Information System

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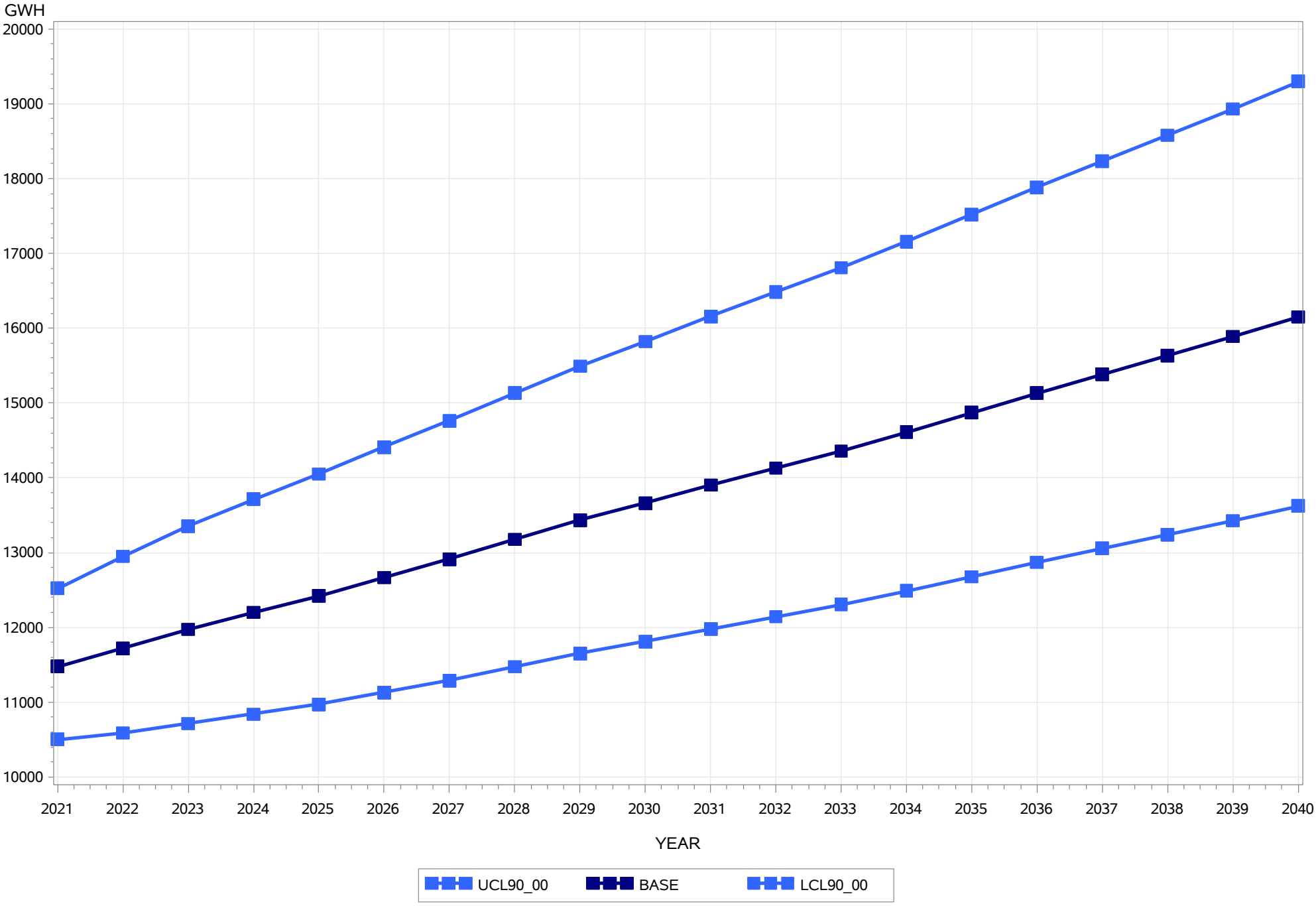
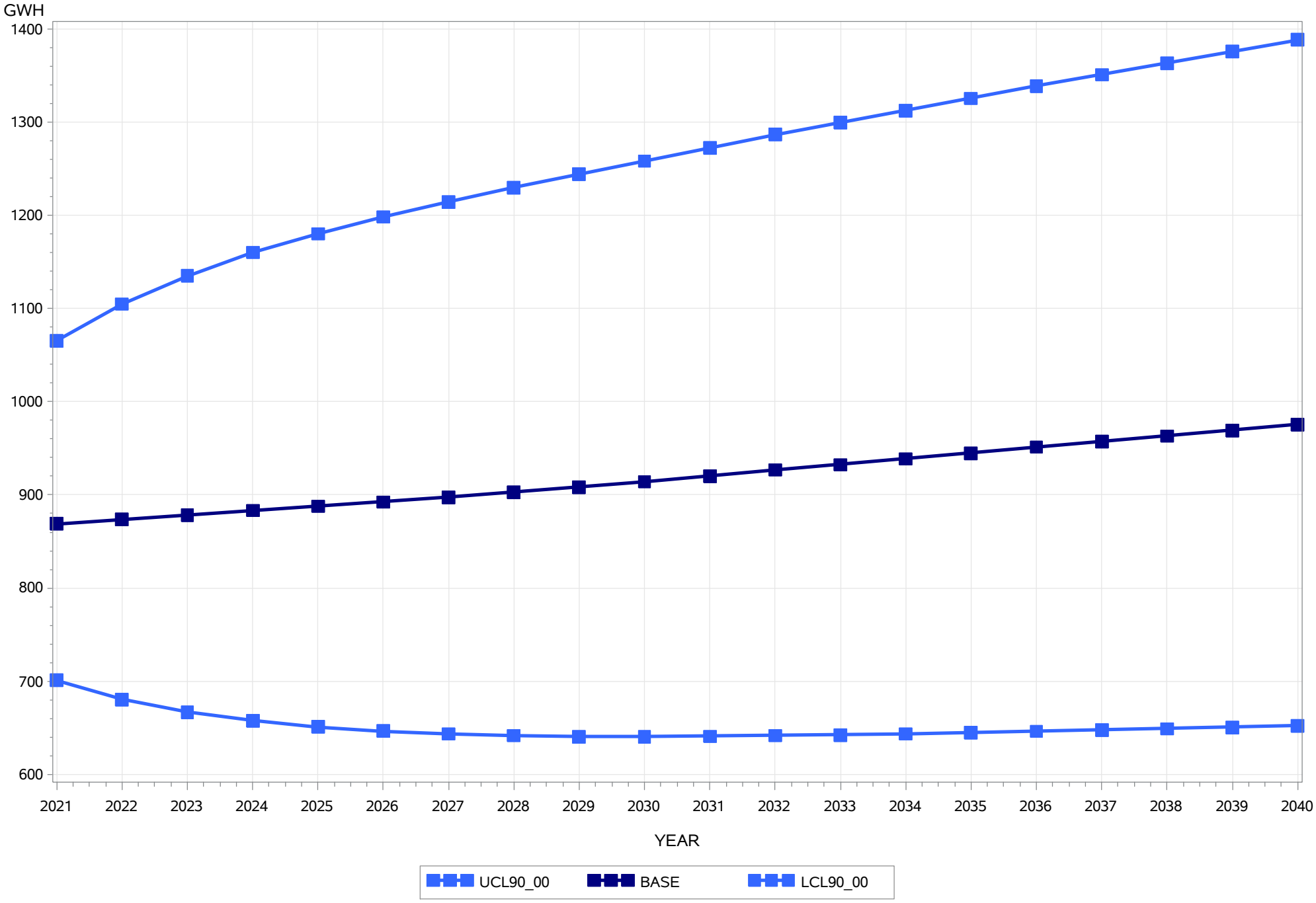
Attachment Vol II 1-1 Tri-State Load Forecasts by State & Member

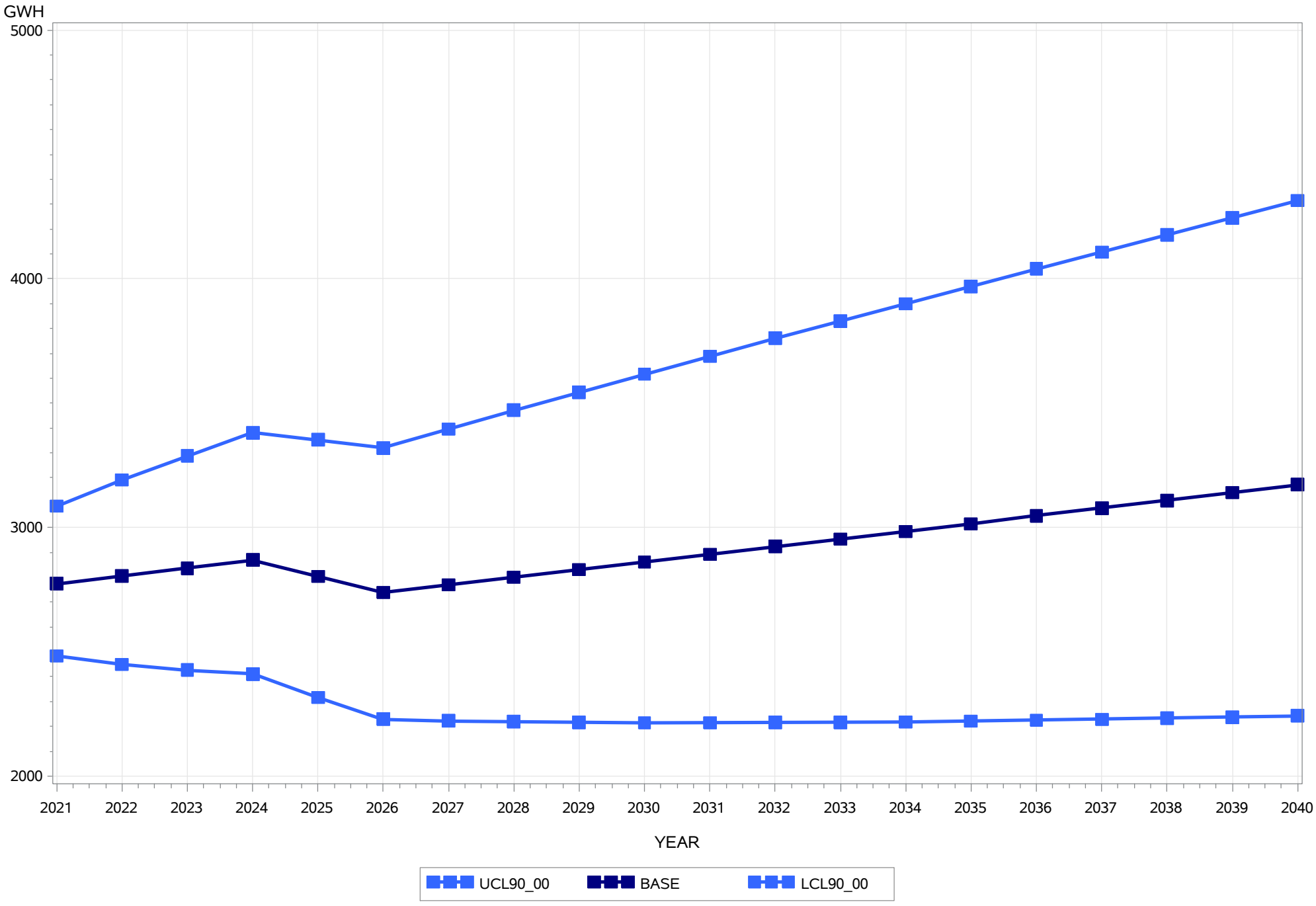
Total Annual Energy Sales
STATE OF COLORADO



Total Annual Energy Sales
STATE OF NEBRASKA



Total Annual Energy Sales
STATE OF NEW MEXICO



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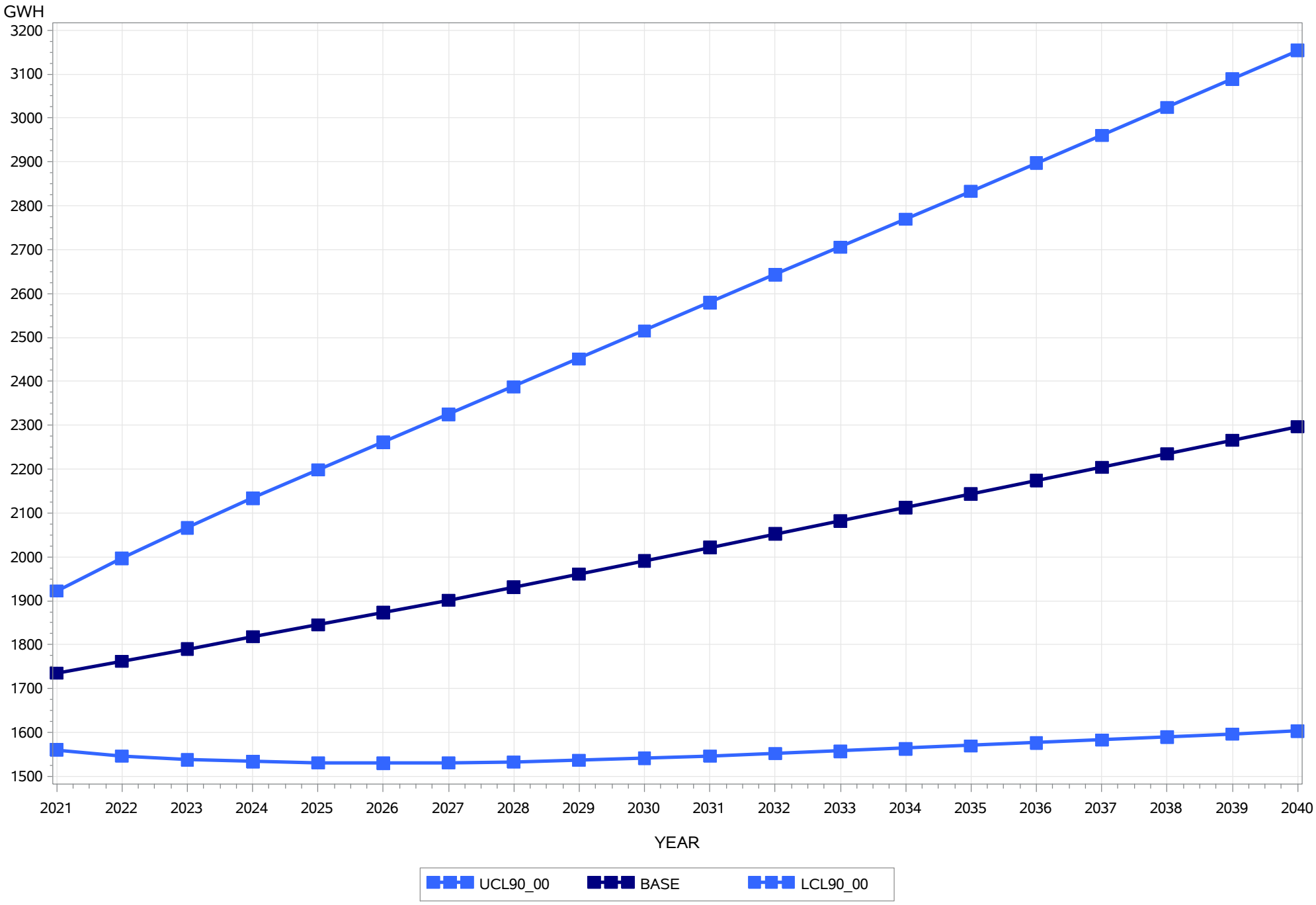
Total Annual Energy Sales
STATE OF WYOMING



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Total Annual Energy Sales
Big Horn Rural Electric Company

[redacted]

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Total Annual Energy Sales
Carbon Power and Light, Inc.

[redacted]

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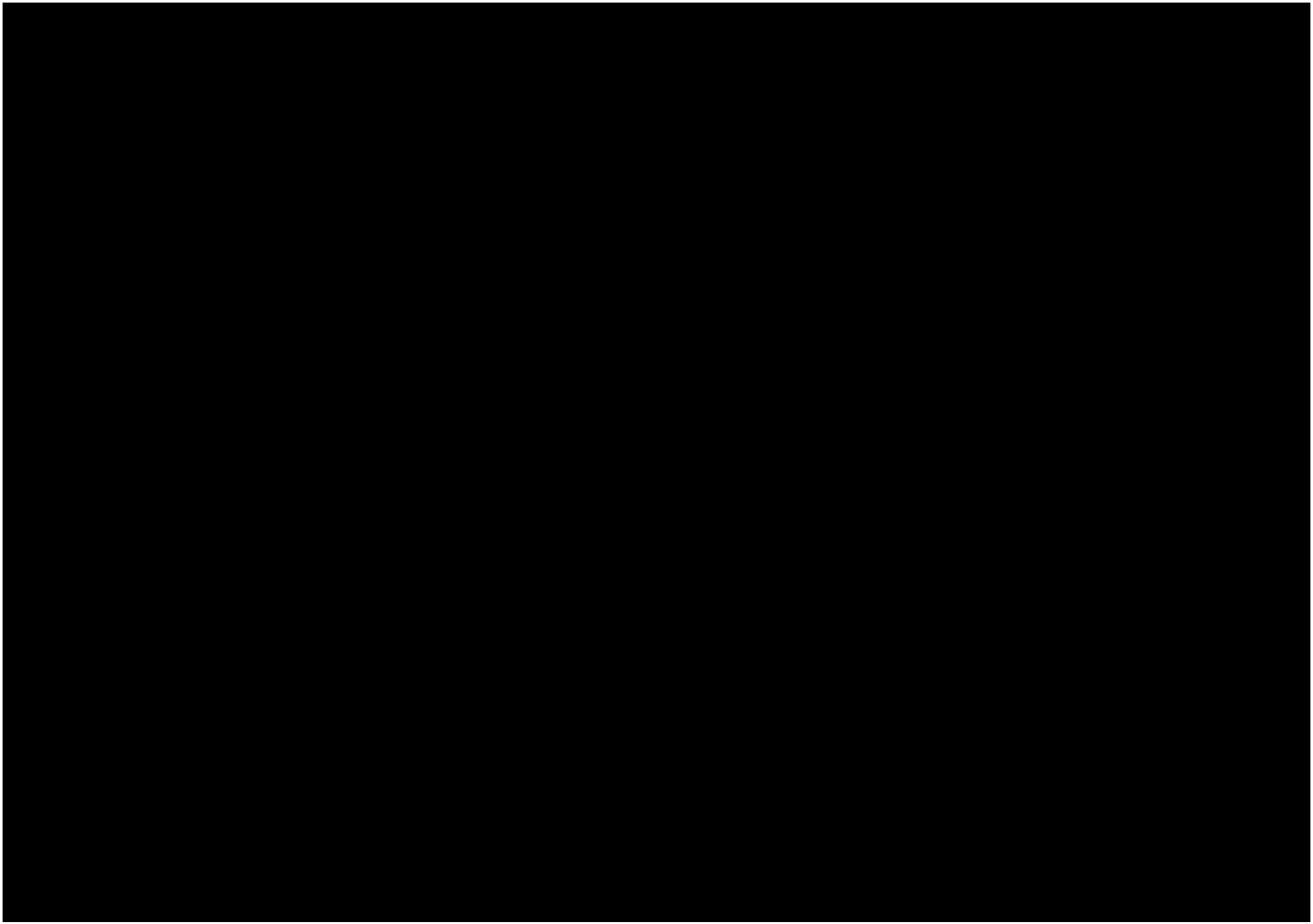
Total Annual Energy Sales

Continental Divide Electric Cooperative, Inc.



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Total Annual Energy Sales
Columbus Electric Cooperative, Inc.

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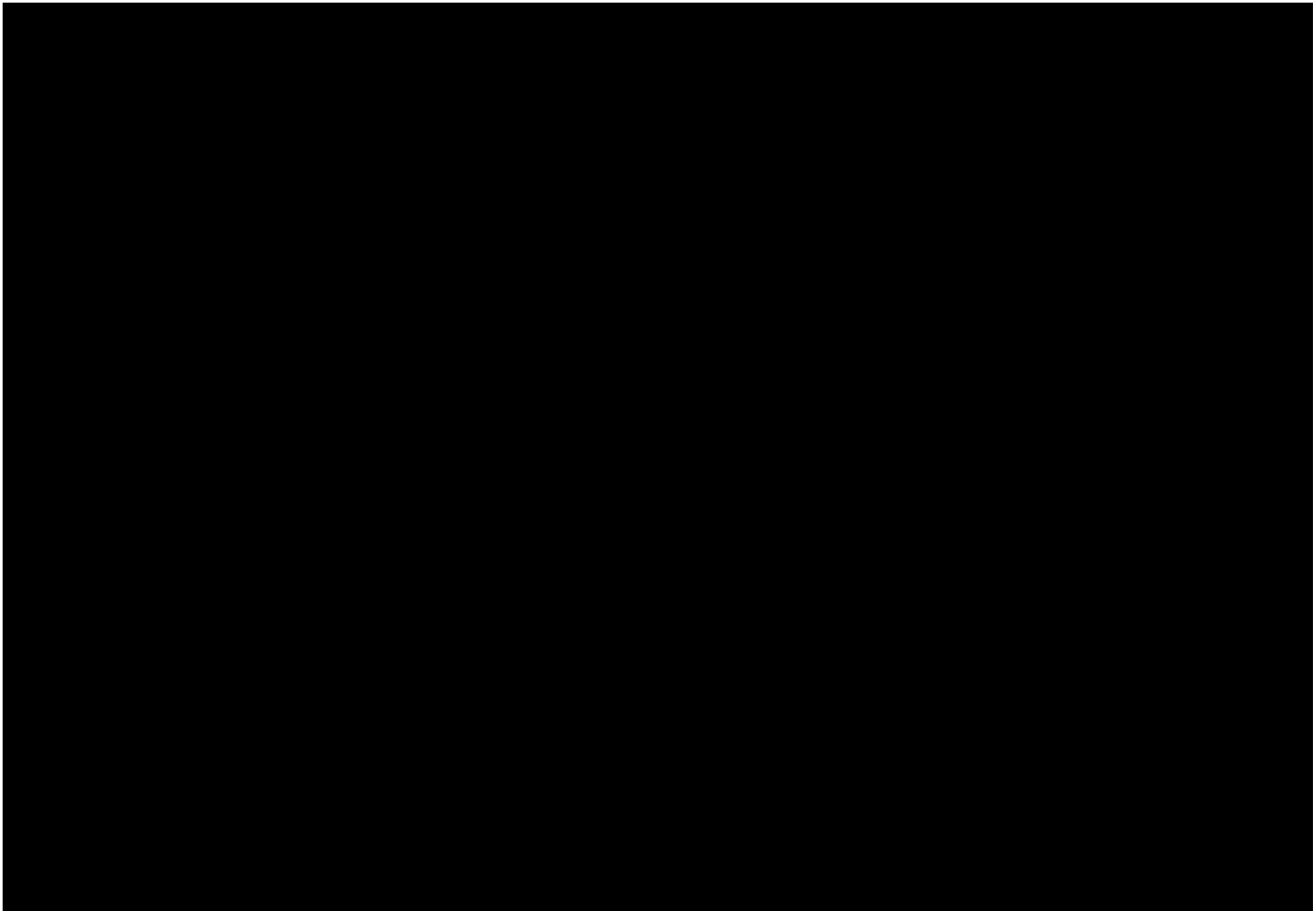
Total Annual Energy Sales

Central New Mexico Electric Cooperative, Inc.



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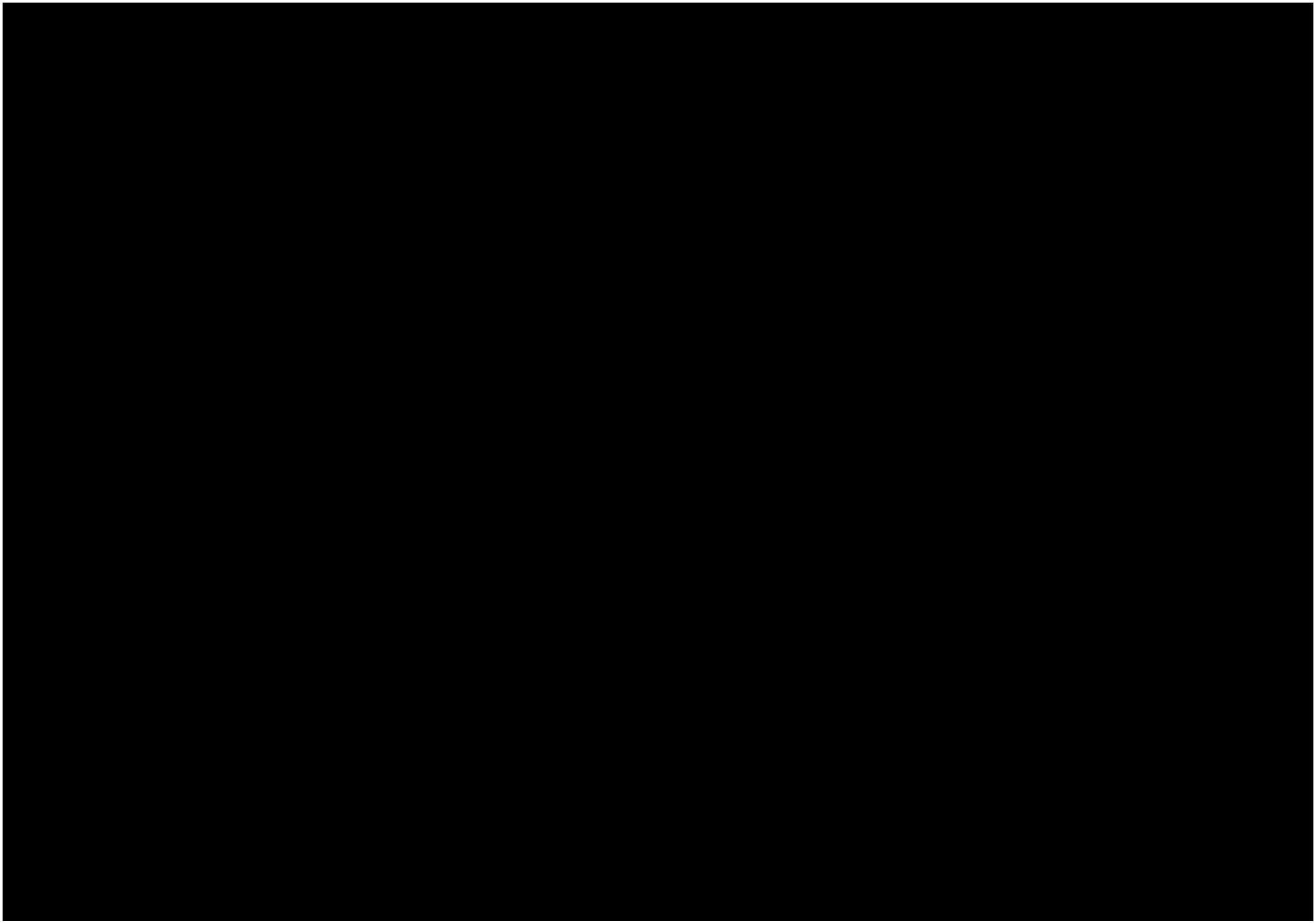
Chimney Rock Public Power District



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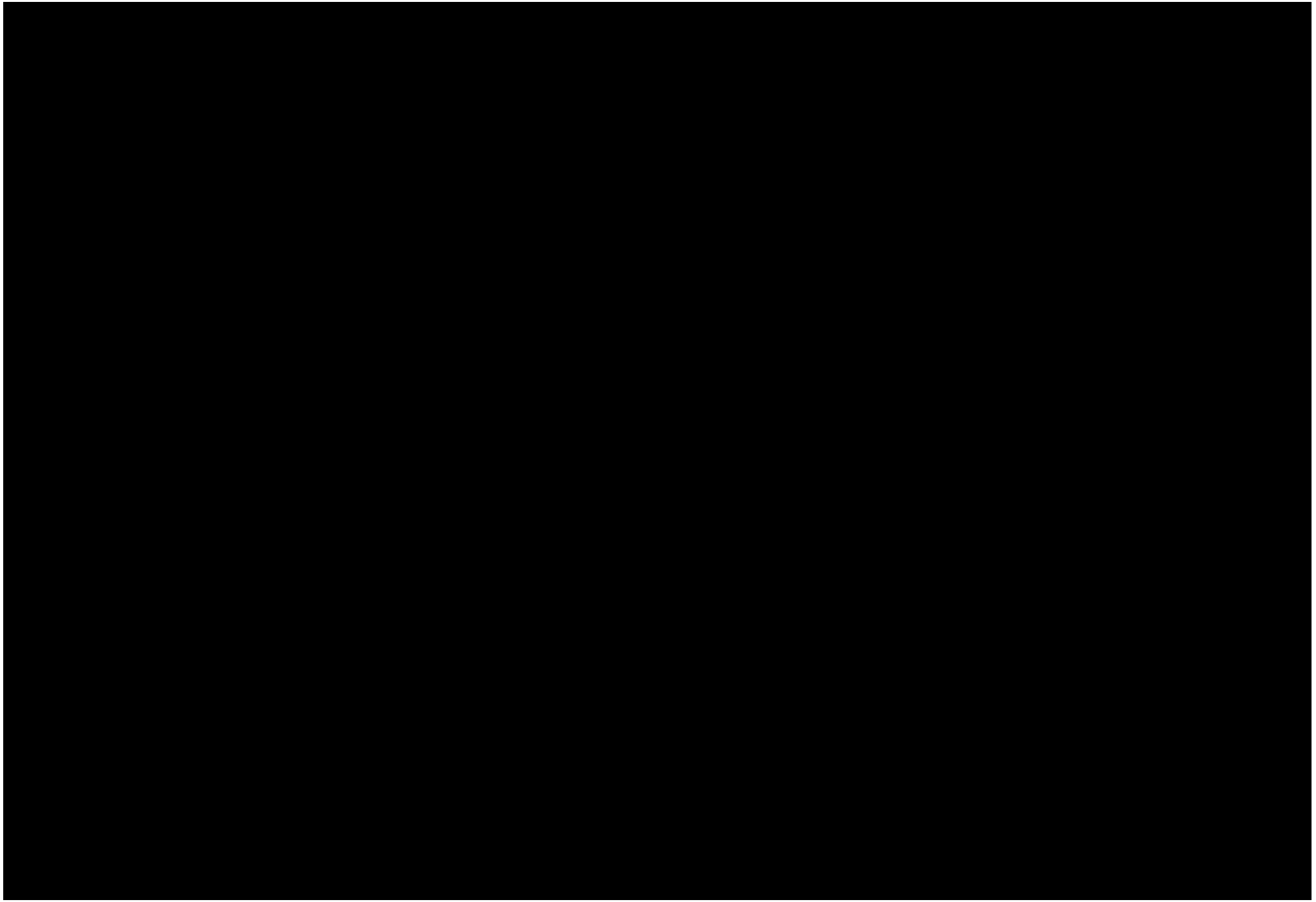
Empire Electric Association, Inc.



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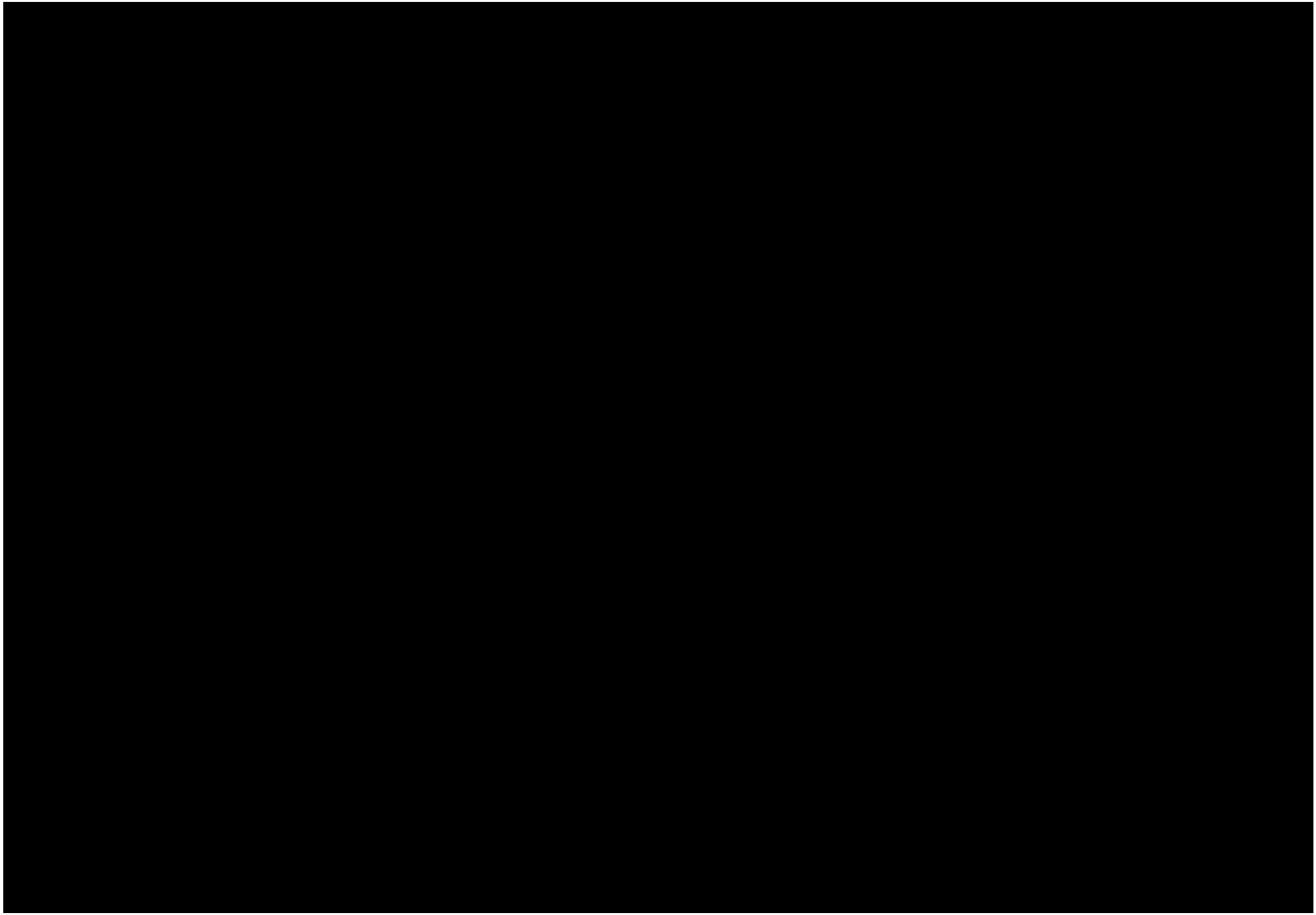
Total Annual Energy Sales
Garland Light and Power Company



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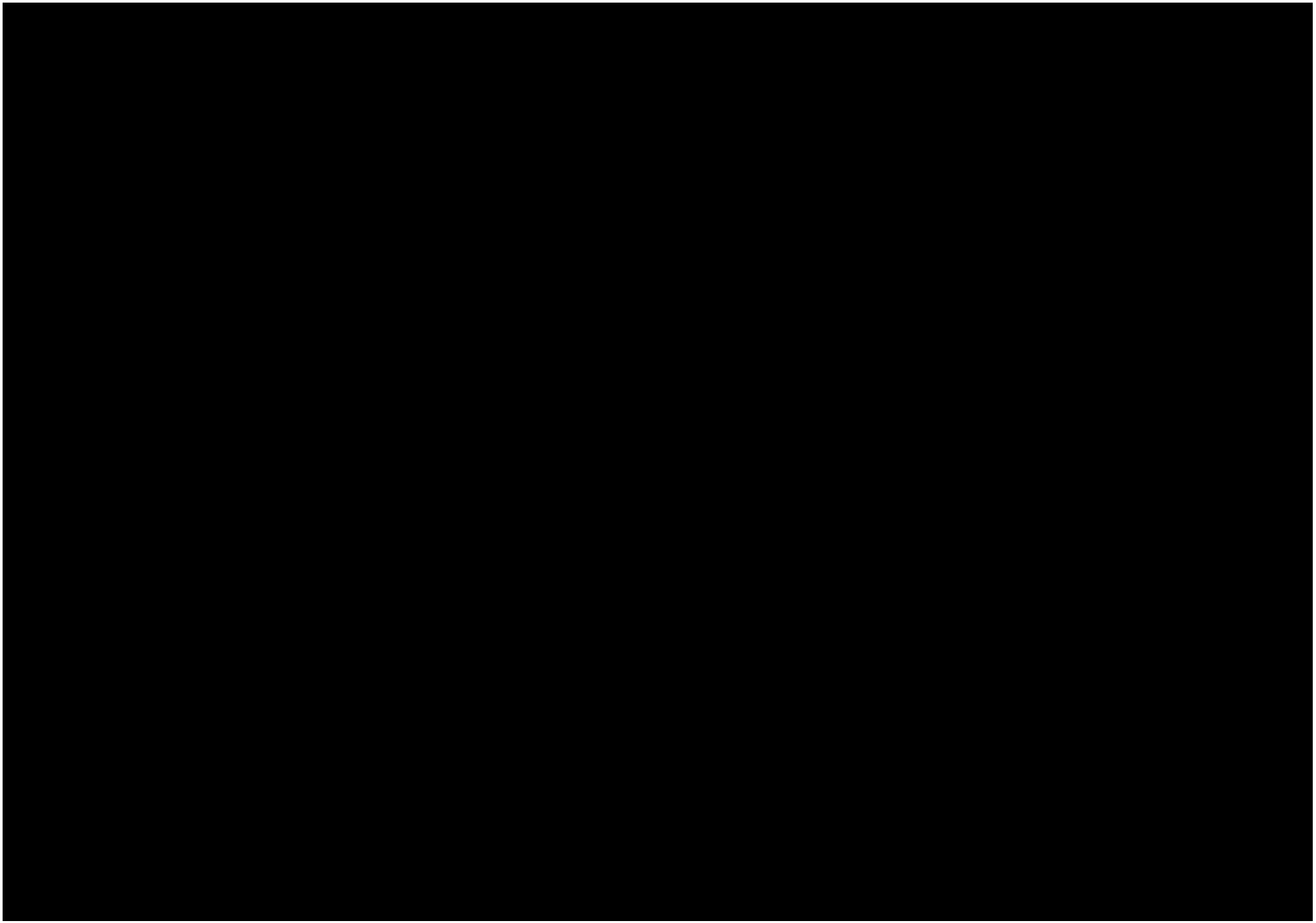
Highline Electric Association



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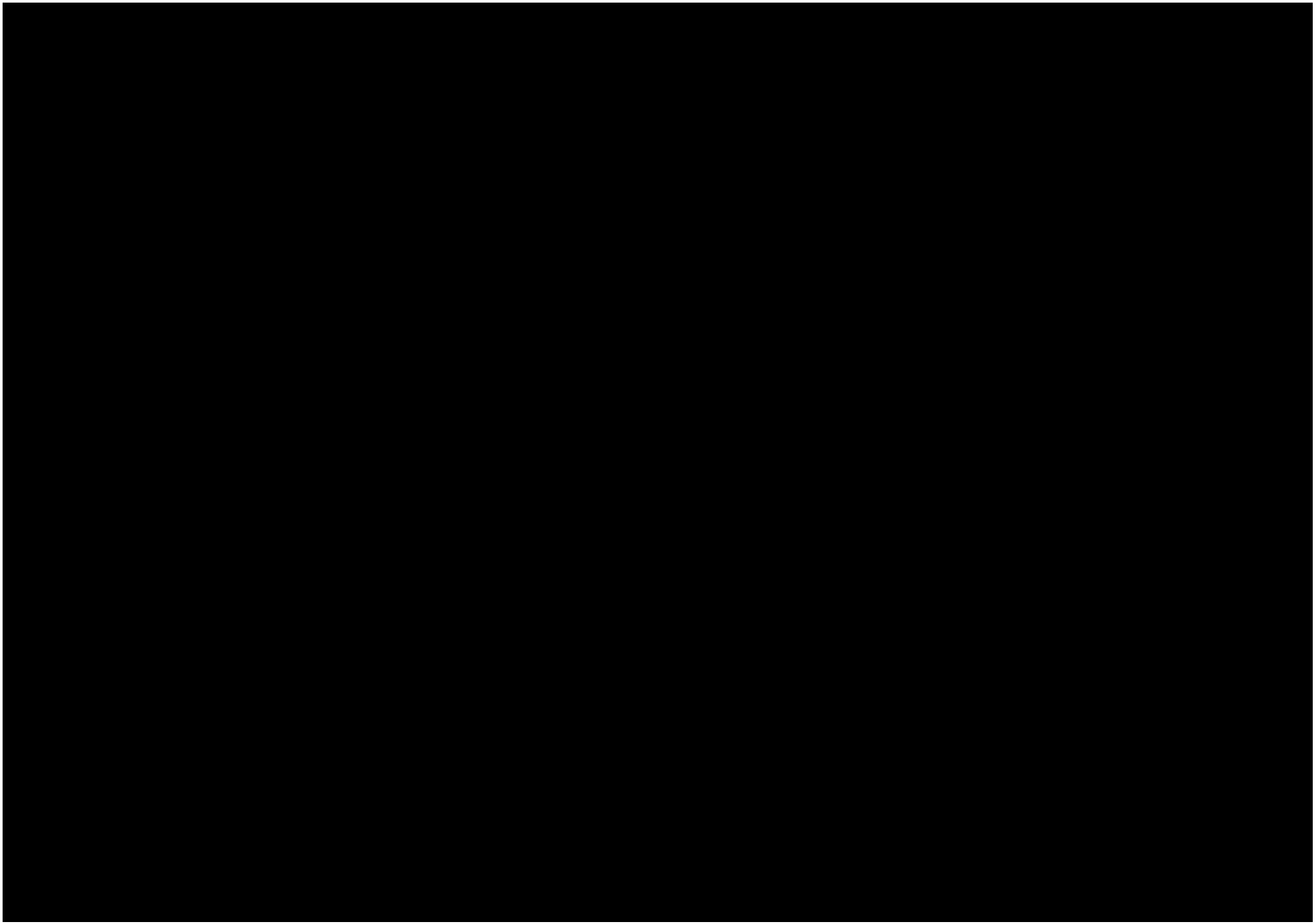

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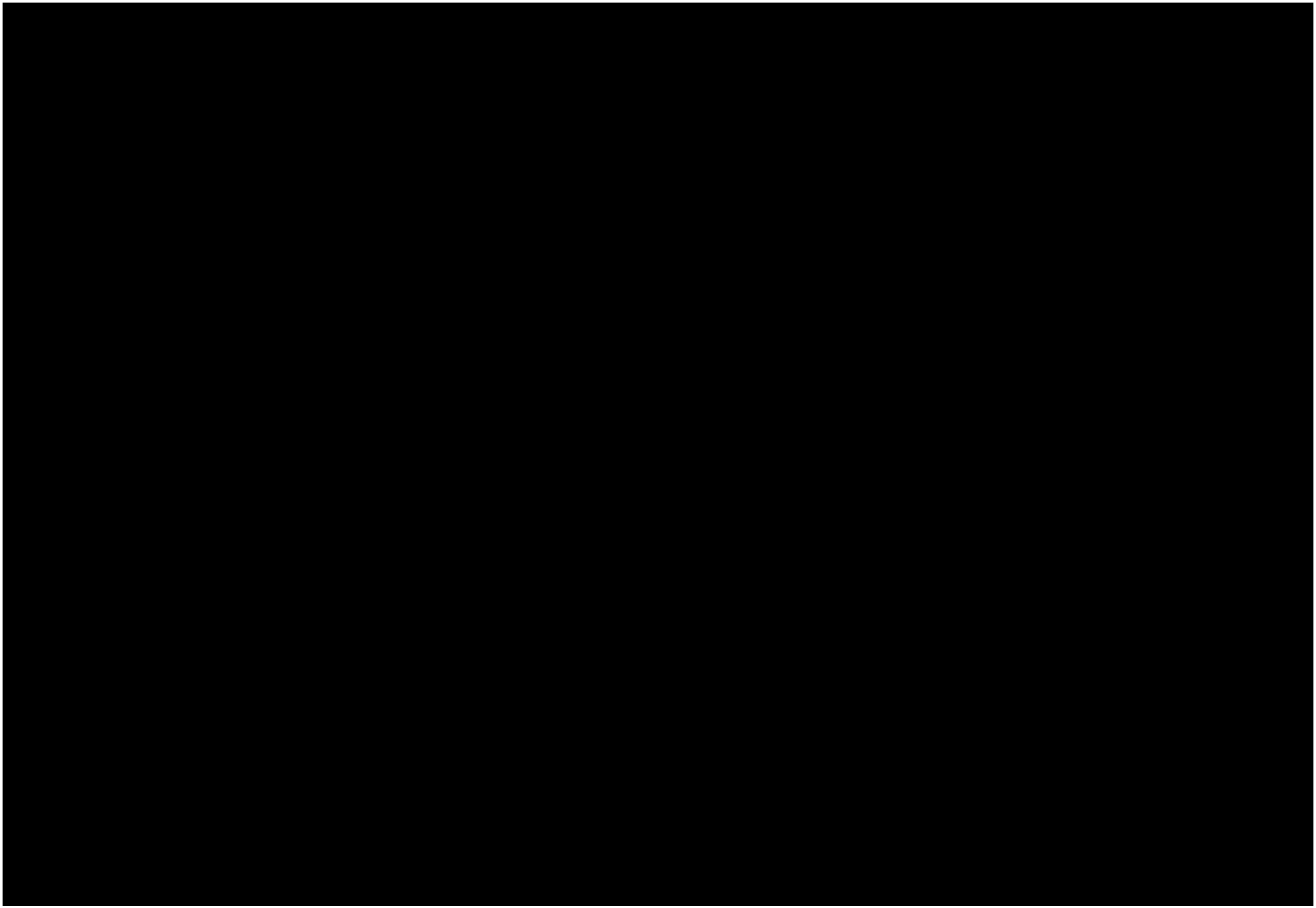
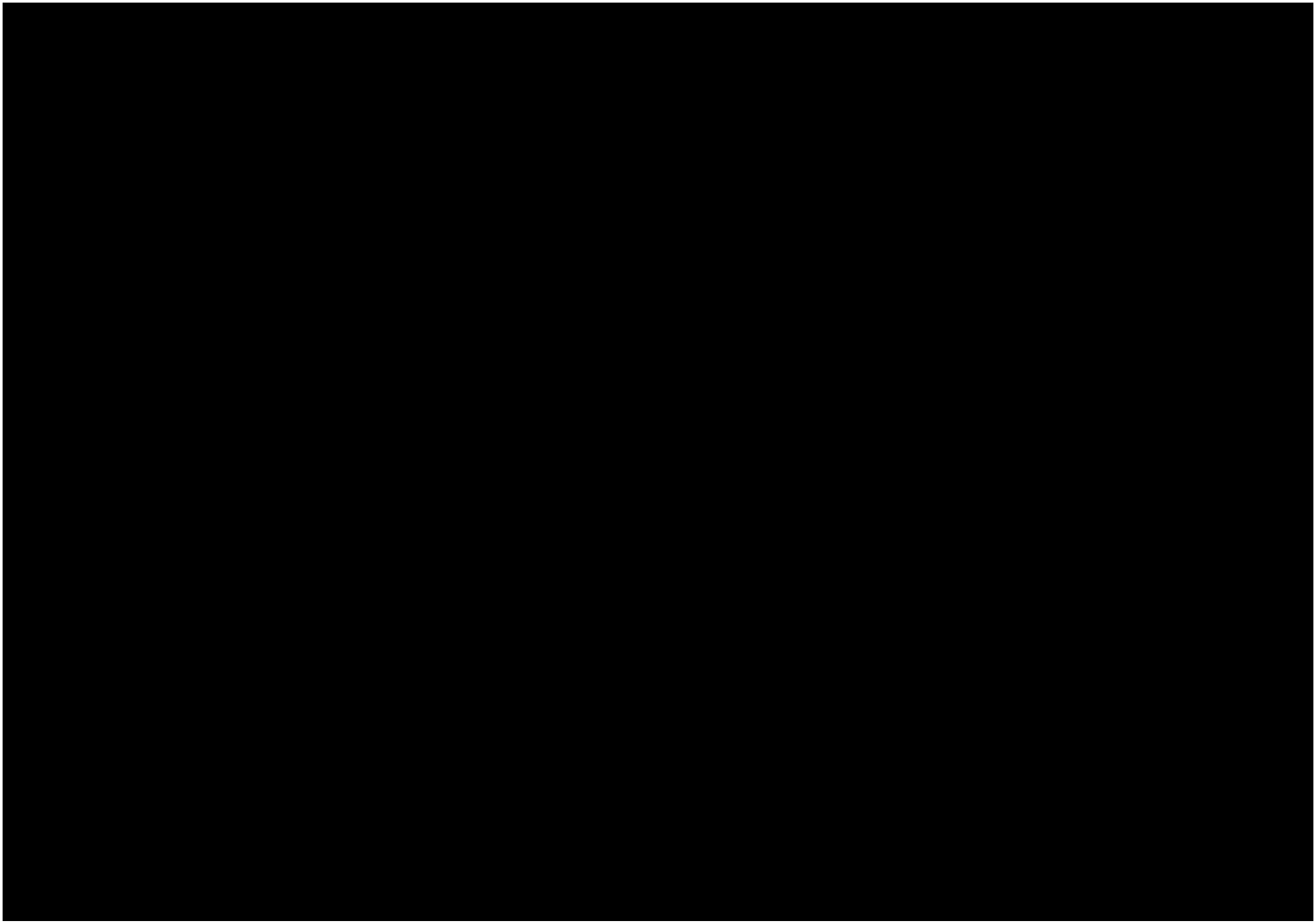


Total Annual Energy Sales
Jemez Mountains Electric Cooperative, Inc.



Total Annual Energy Sales
K.C. Electric Association, Inc.

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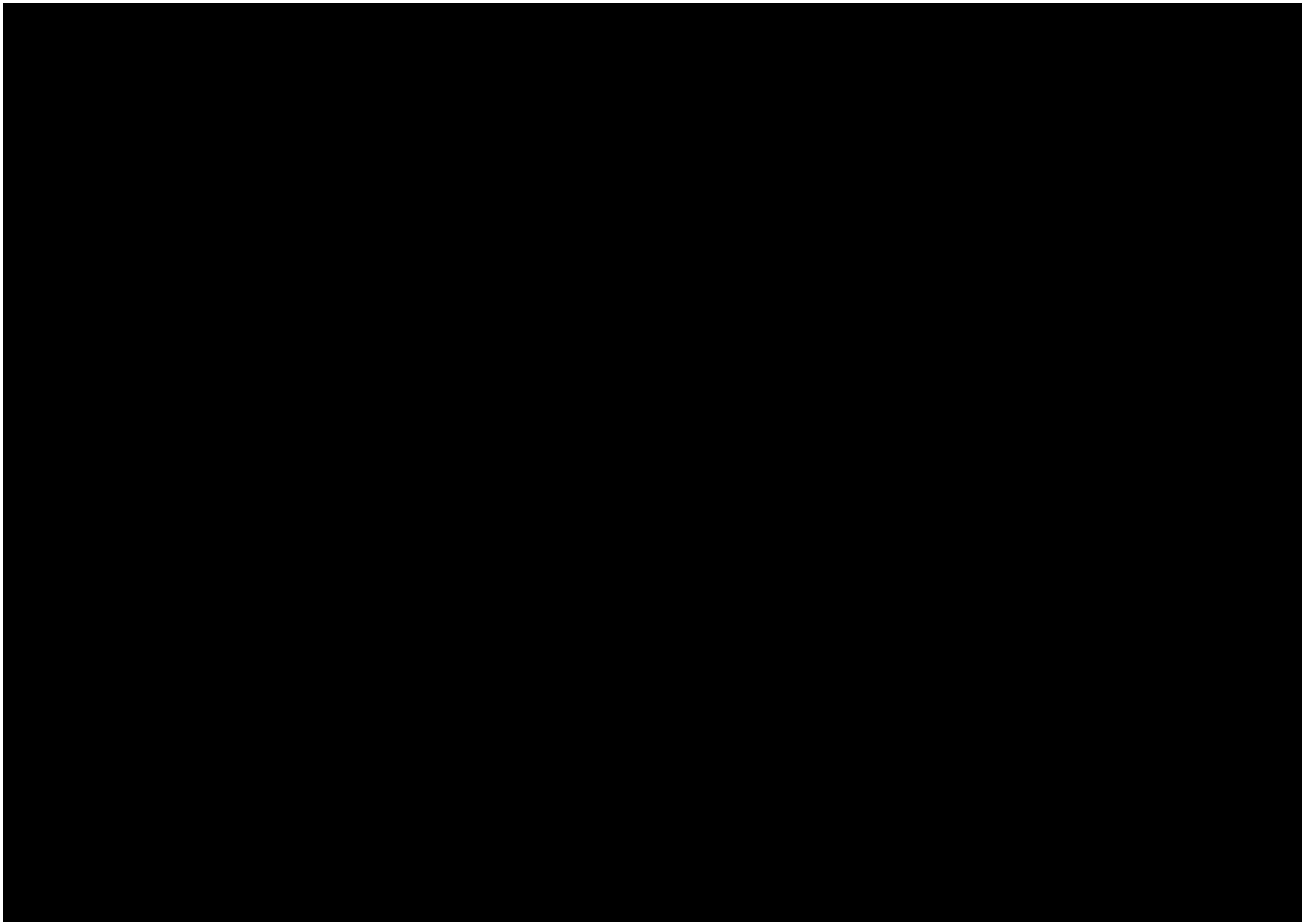
Total Annual Energy Sales
La Plata Electric Association, Inc.



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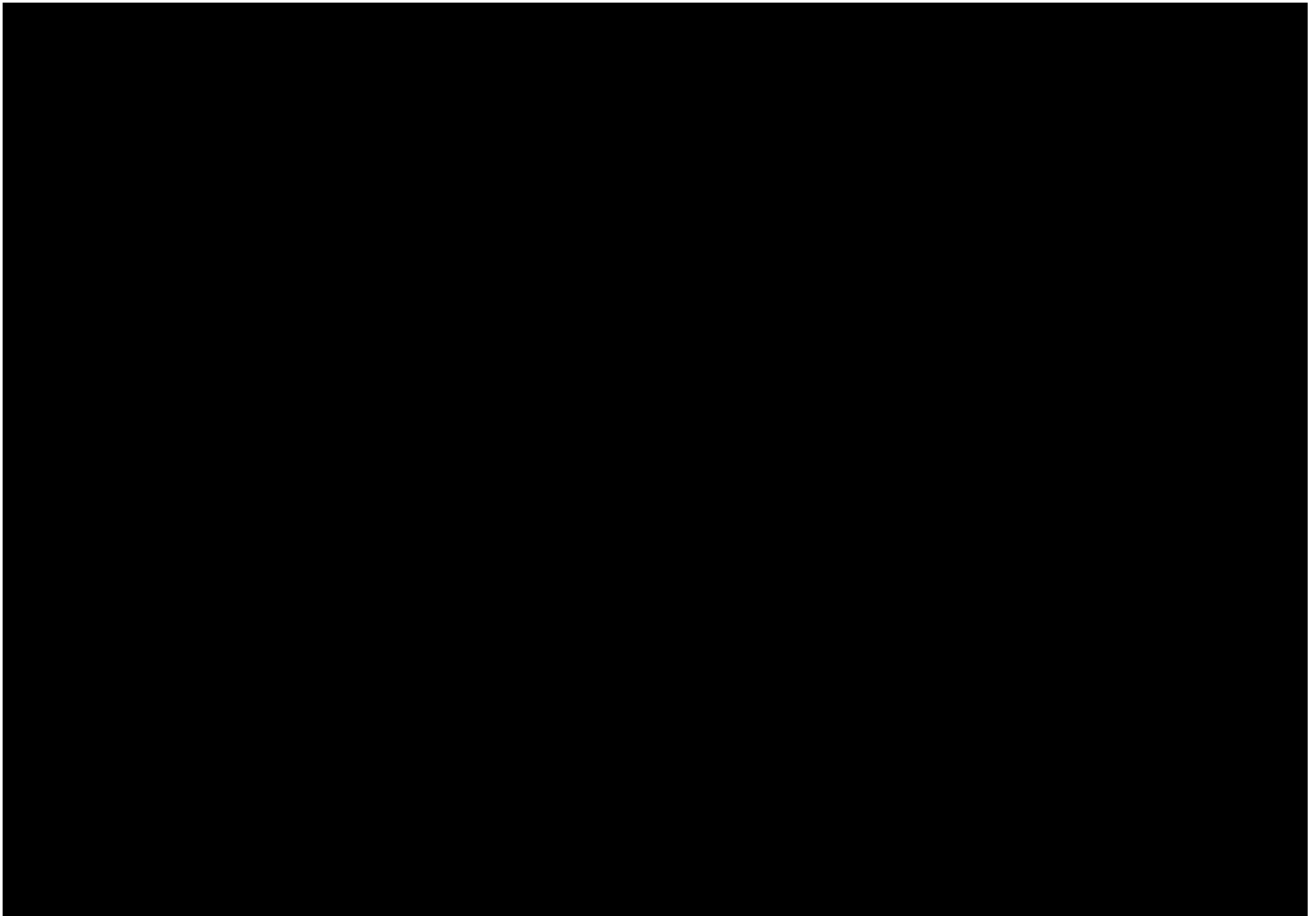
Morgan County Rural Electric Association



Total Annual Energy Sales
Mountain Parks Electric, Inc.

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Total Annual Energy Sales
Mora-San Miguel Electric Cooperative, Inc.

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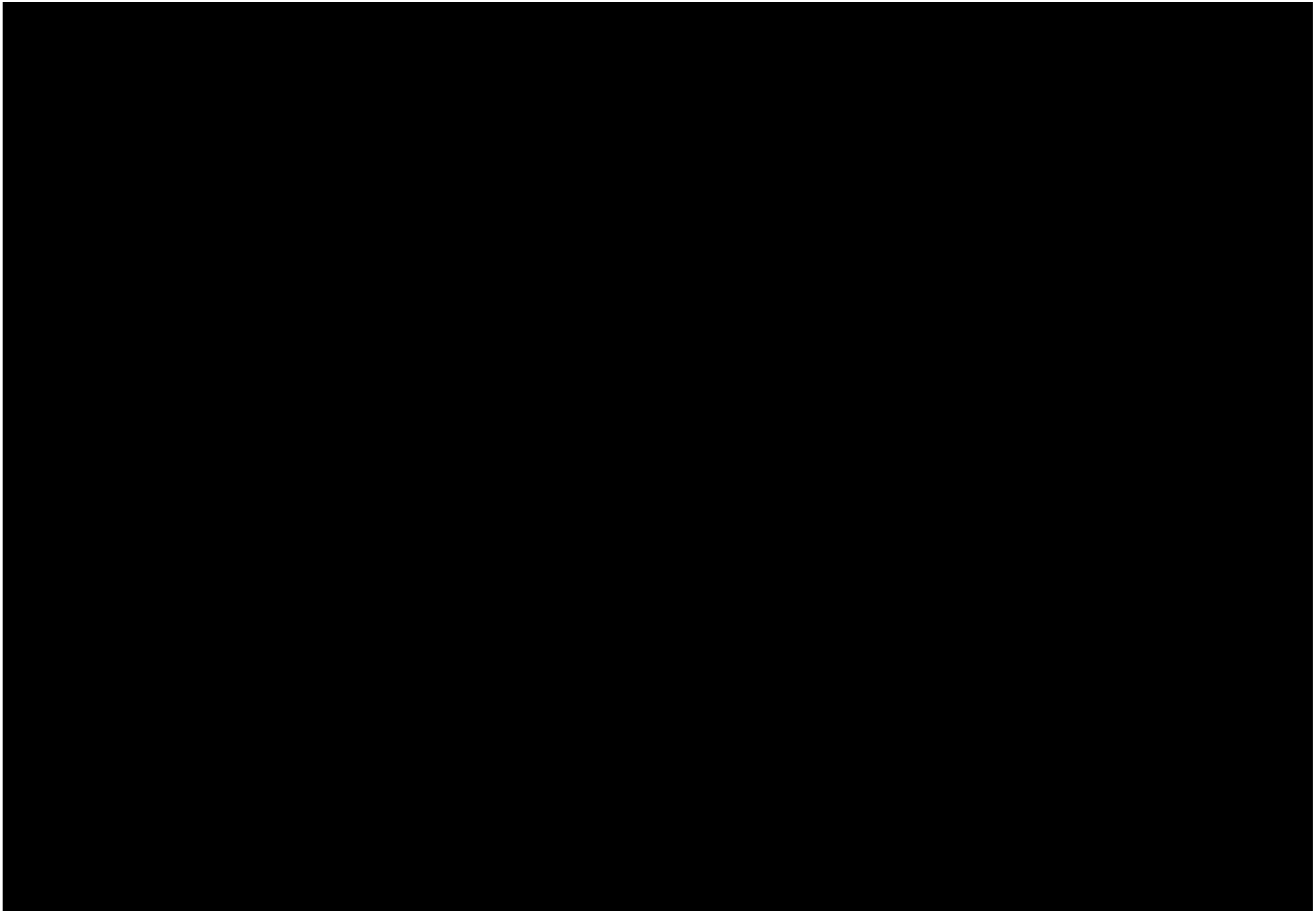
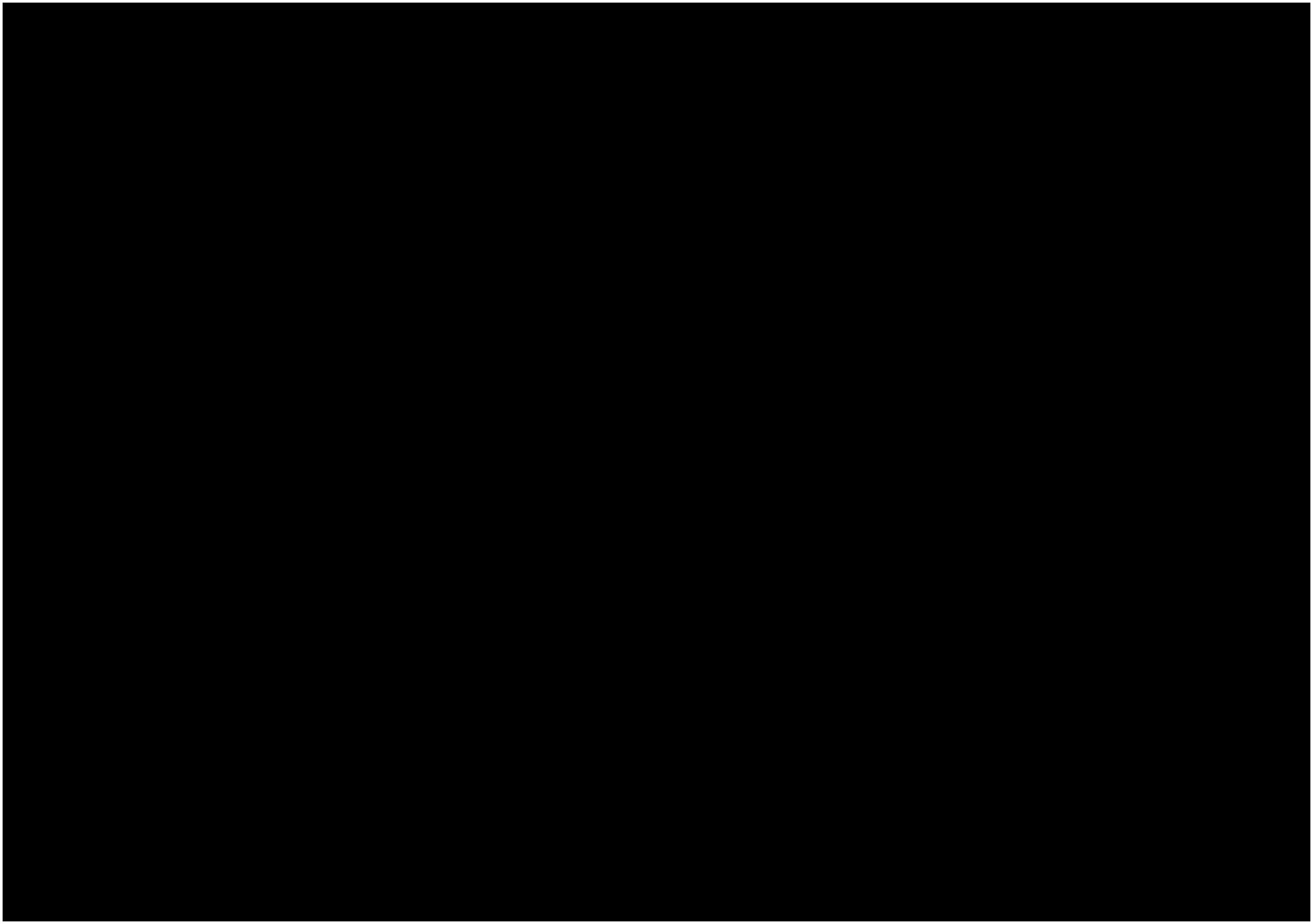
Total Annual Energy Sales
Mountain View Electric Association, Inc.



Total Annual Energy Sales
Midwest Electric Cooperative Corporation



Total Annual Energy Sales
Niobrara Electric Association, Inc.

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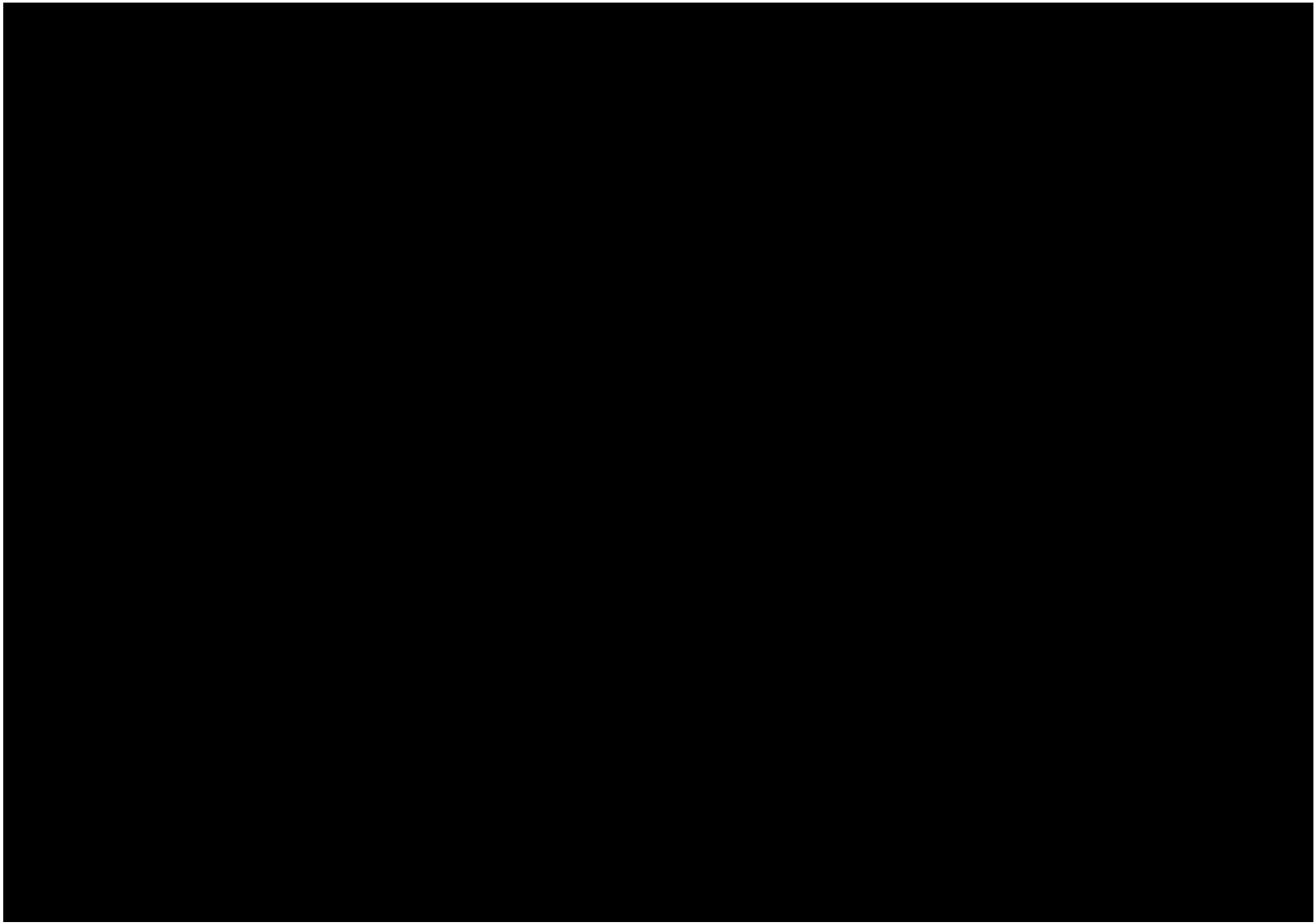
Total Annual Energy Sales
Northwest Rural Public Power District



Total Annual Energy Sales
Otero County Electric Cooperative, Inc.

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Total Annual Energy Sales
Panhandle Rural Electric Membership Association

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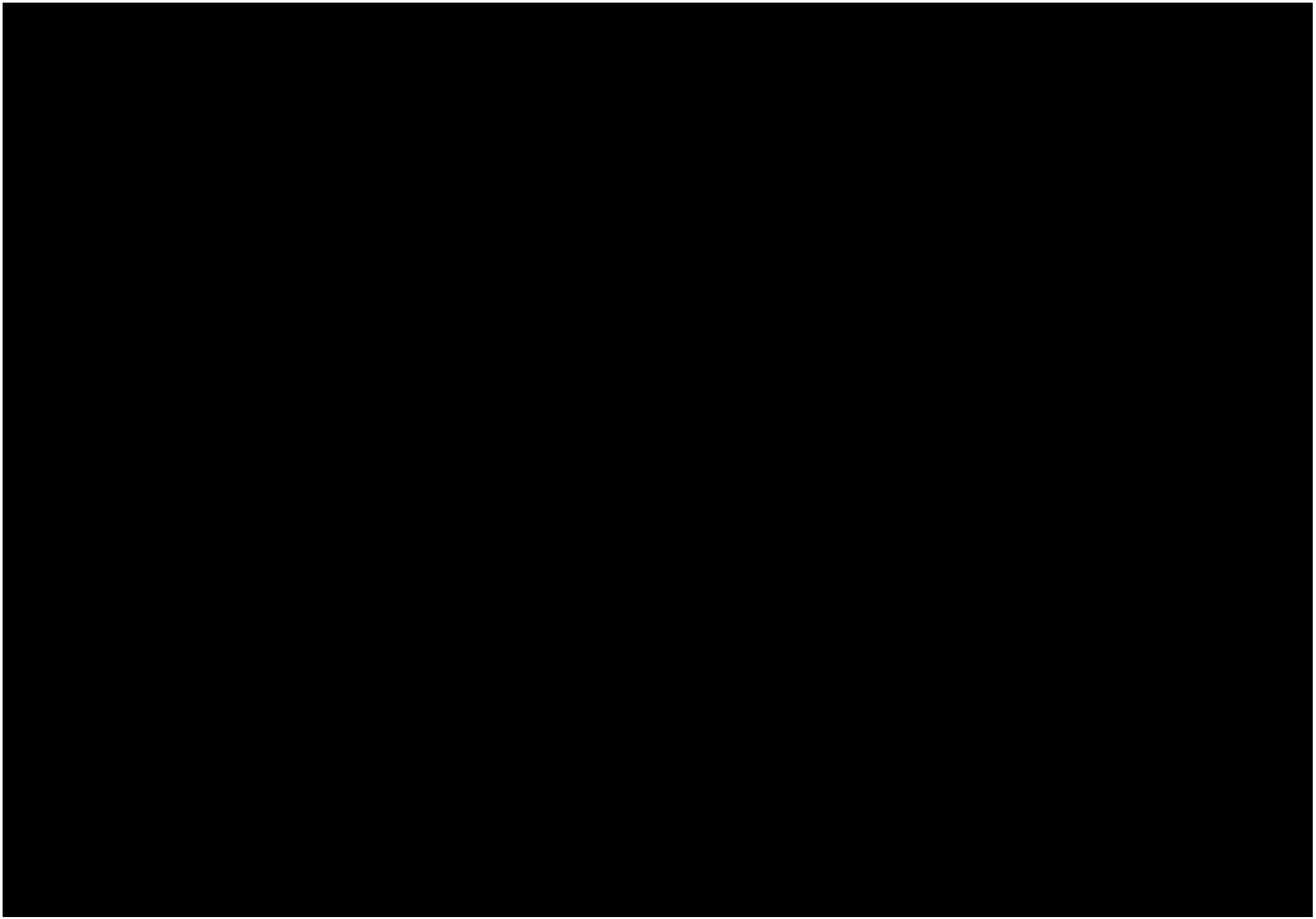
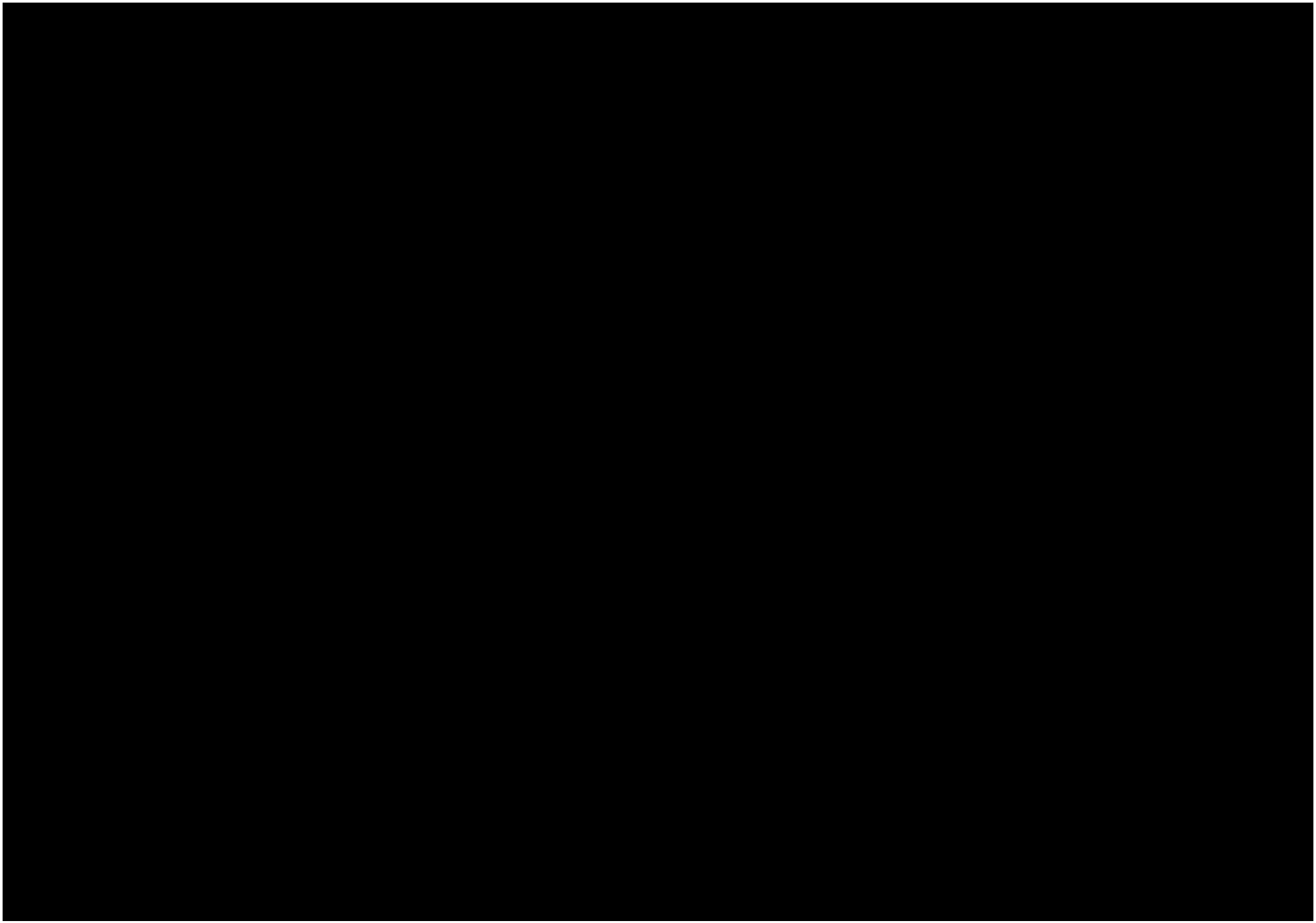
Total Annual Energy Sales
Poudre Valley Electric Association, Inc.



Total Annual Energy Sales
Northern Rio Arriba Electric Cooperative, Inc.



Total Annual Energy Sales
Roosevelt Public Power District

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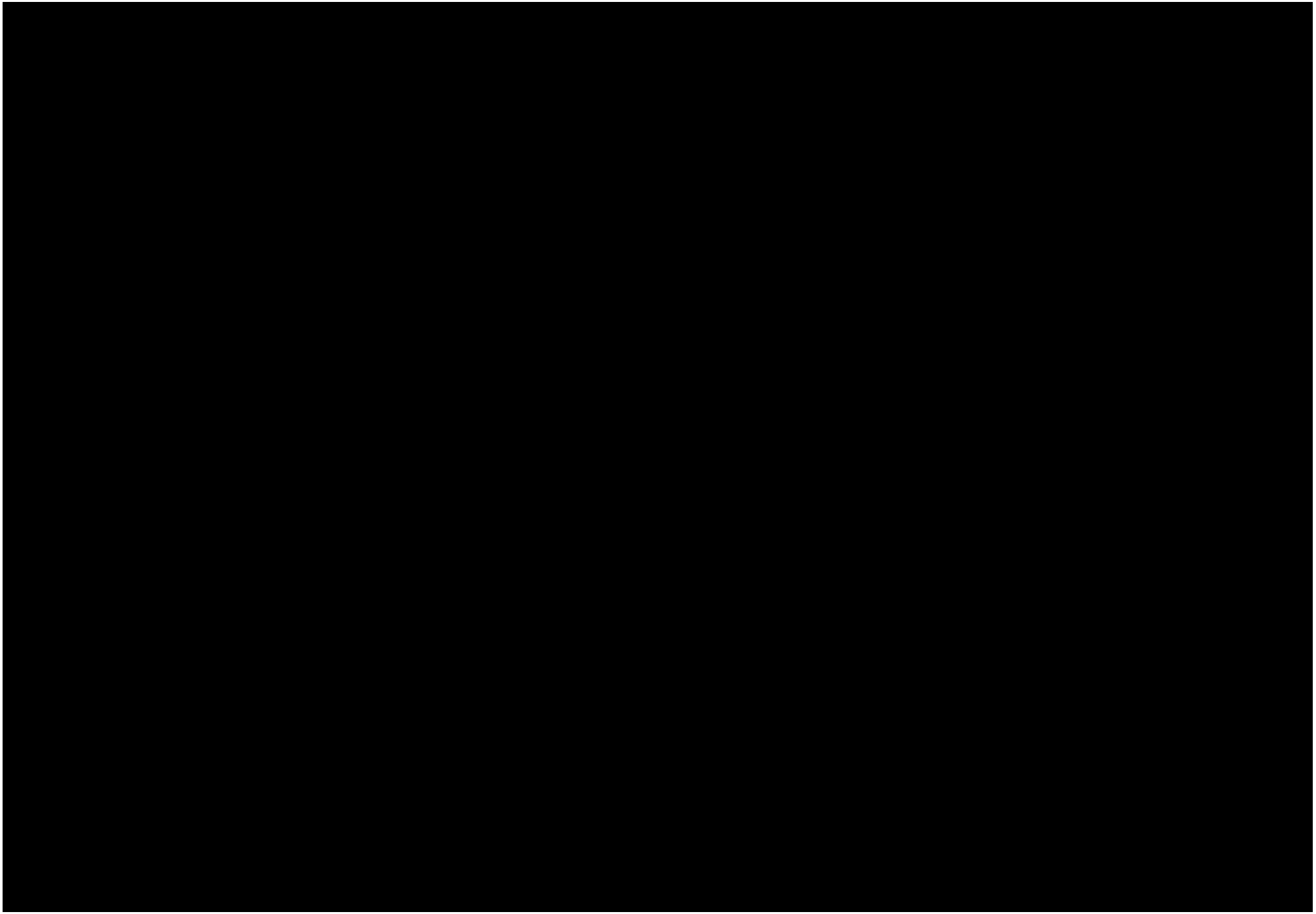
Total Annual Energy Sales
Sierra Electric Cooperative, Inc.



Total Annual Energy Sales
Sangre de Cristo Electric Association, Inc.

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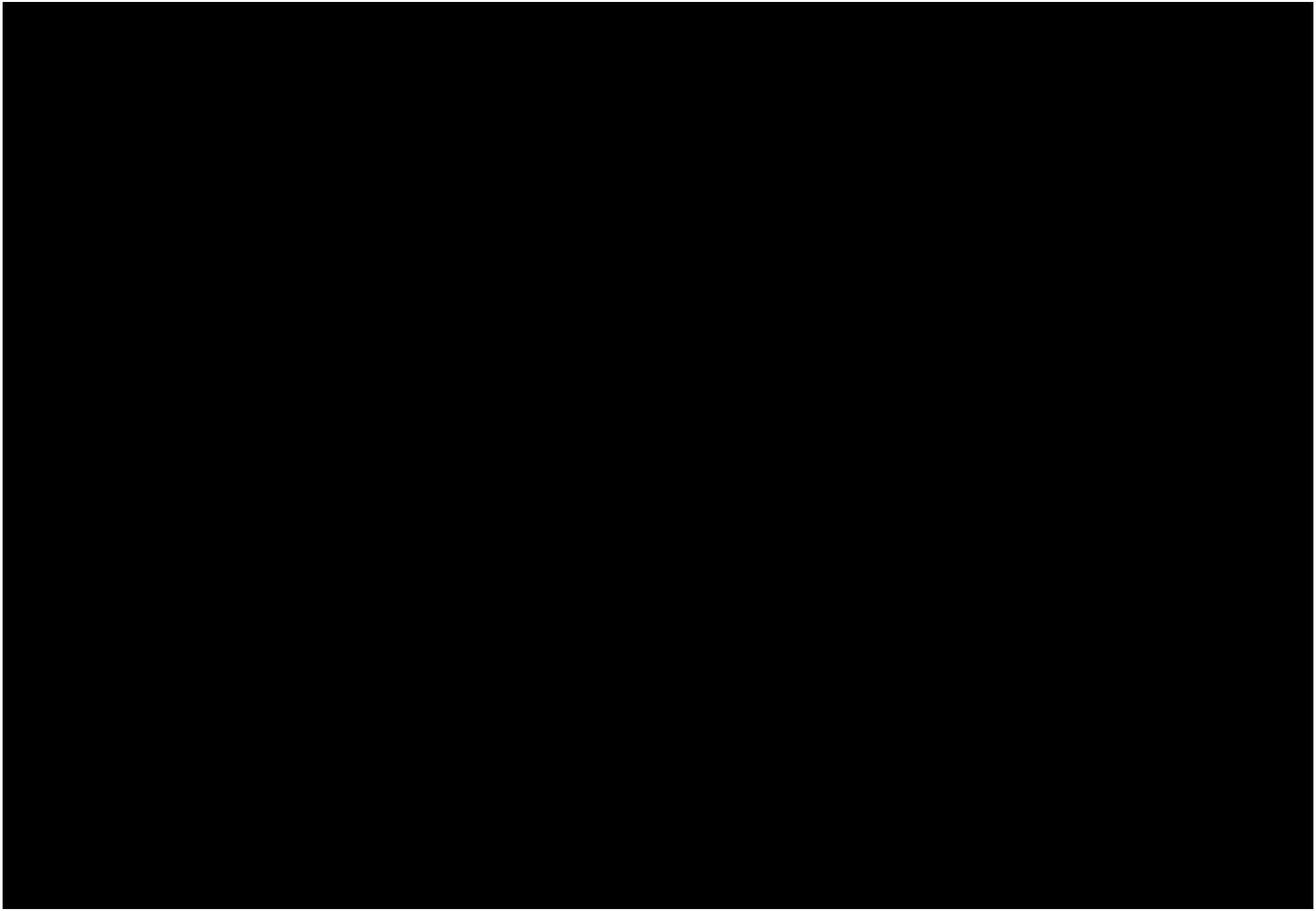
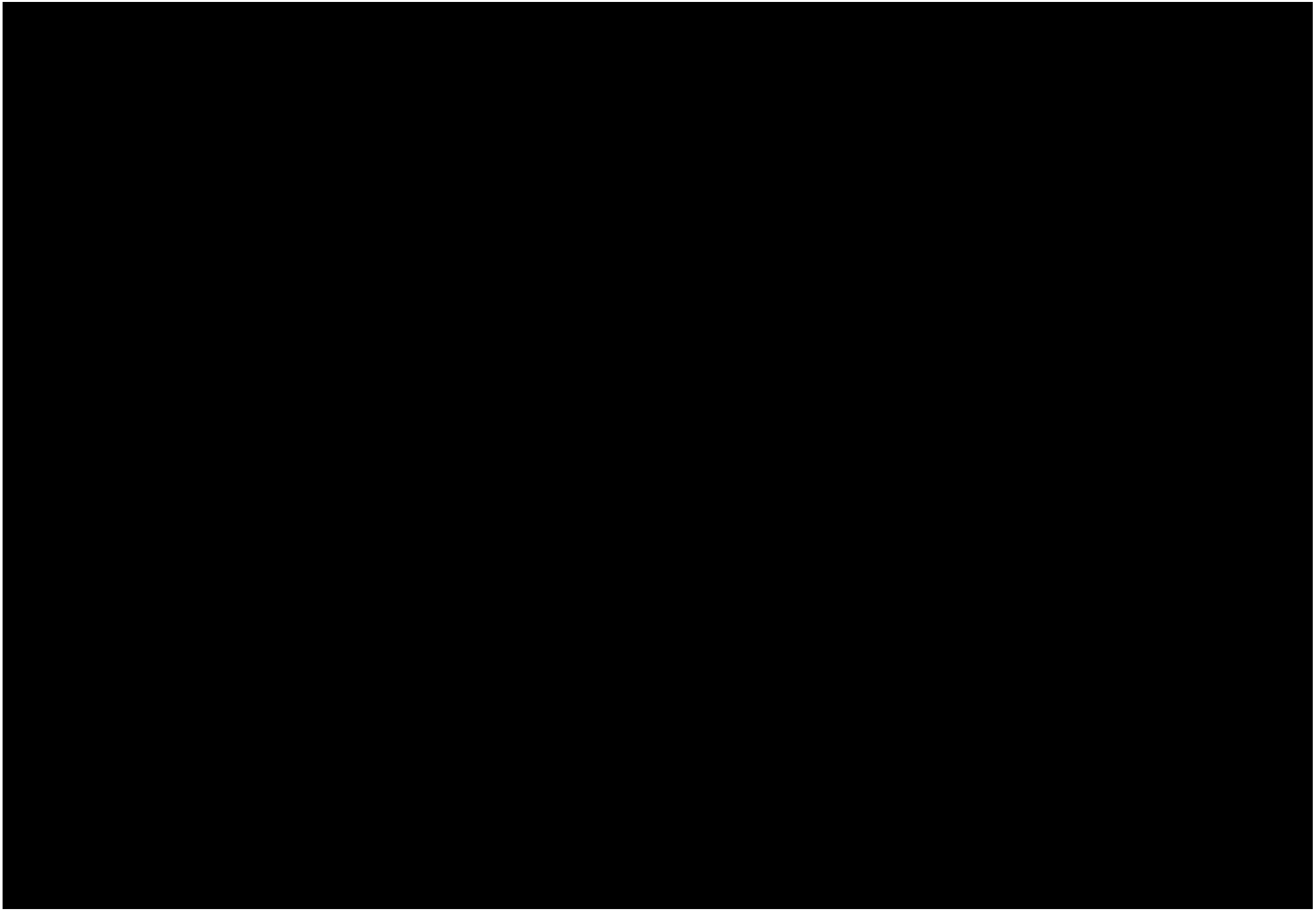
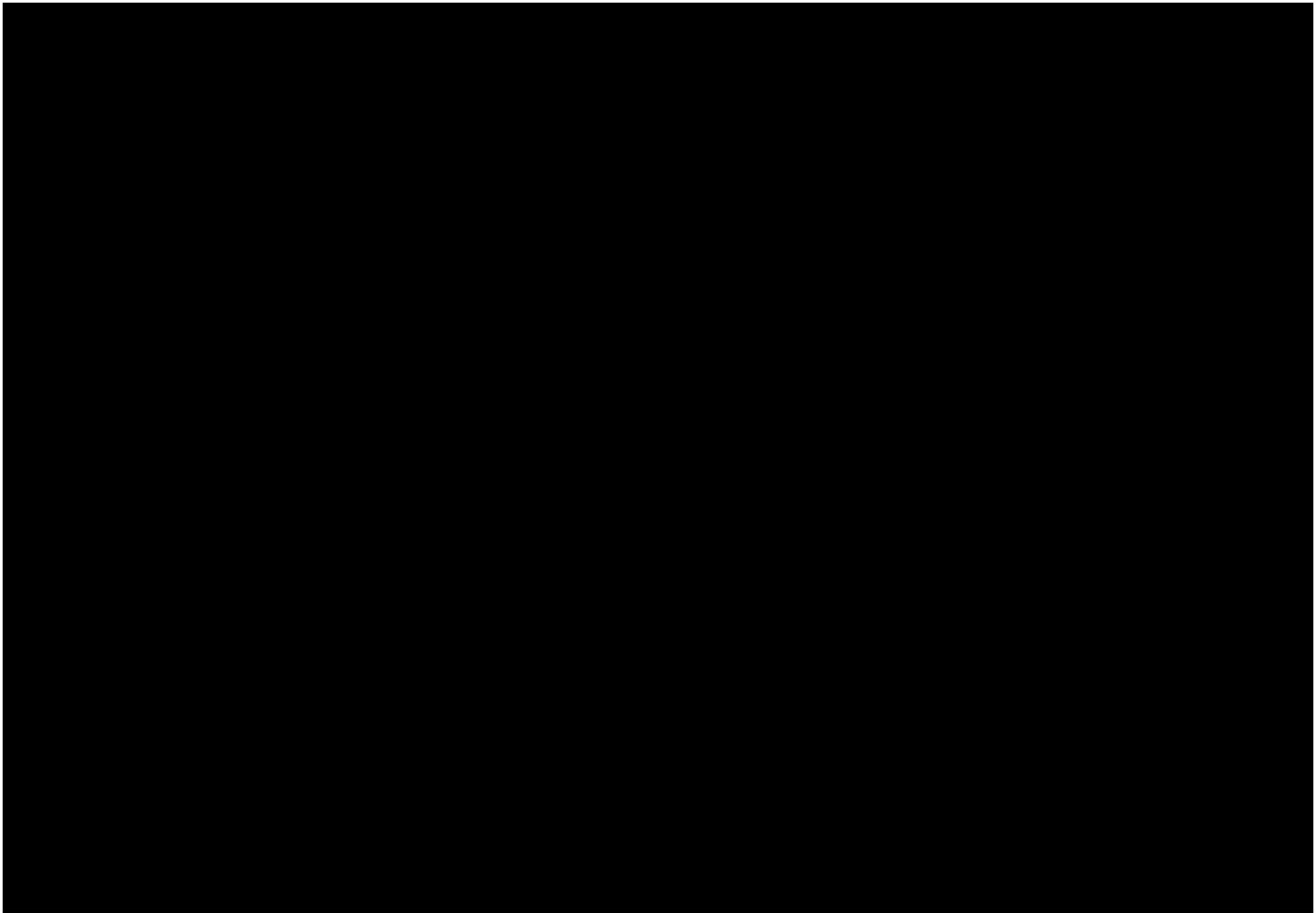
Total Annual Energy Sales
Southeast Colorado Power Association



Total Annual Energy Sales
San Isabel Electric Association, Inc.



Total Annual Energy Sales
San Luis Valley Rural Electric Cooperative, Inc.



Total Annual Energy Sales
San Miguel Power Association, Inc.

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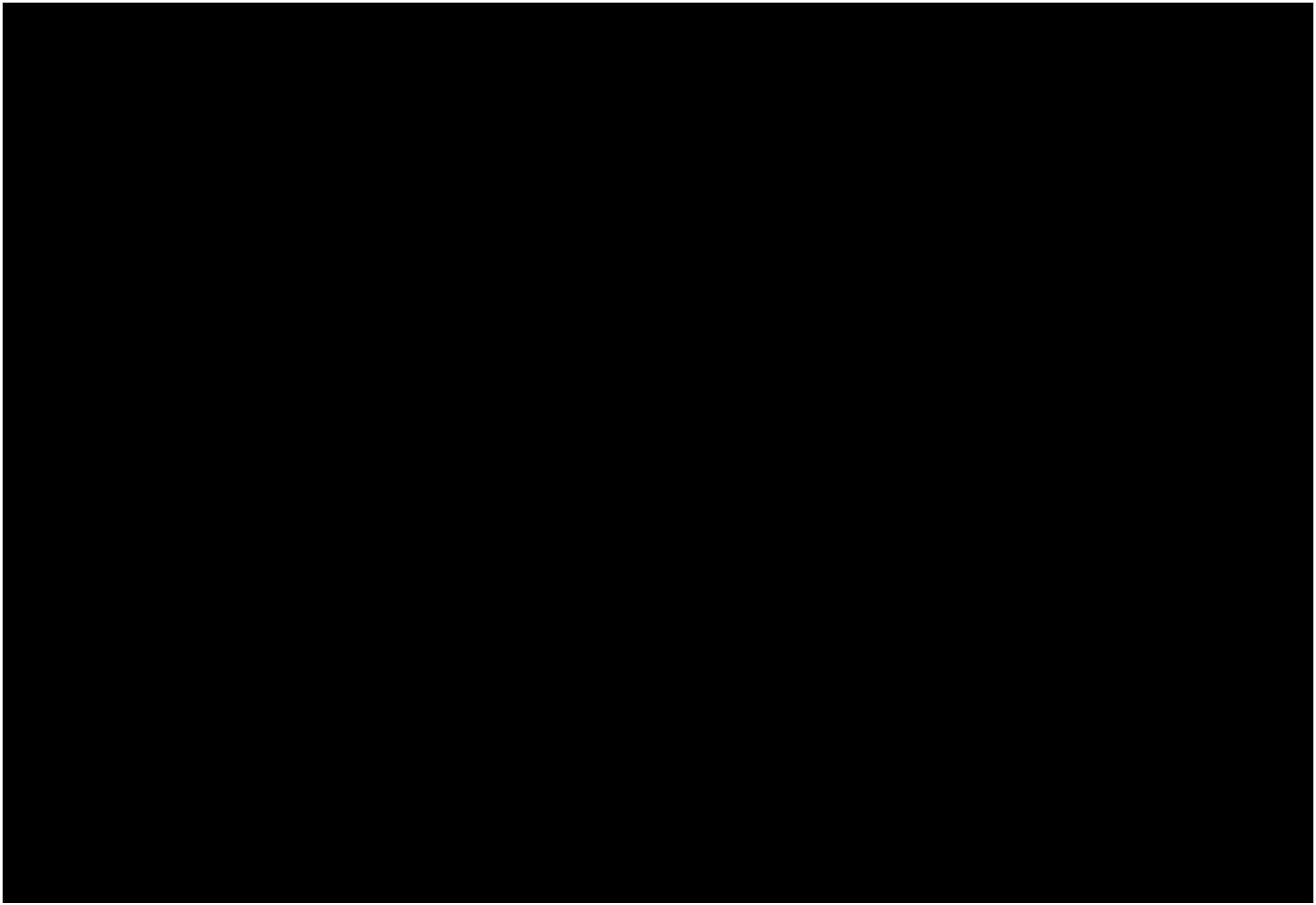
Total Annual Energy Sales
Socorro Electric Cooperative, Inc.



Total Annual Energy Sales
Springer Electric Cooperative, Inc.

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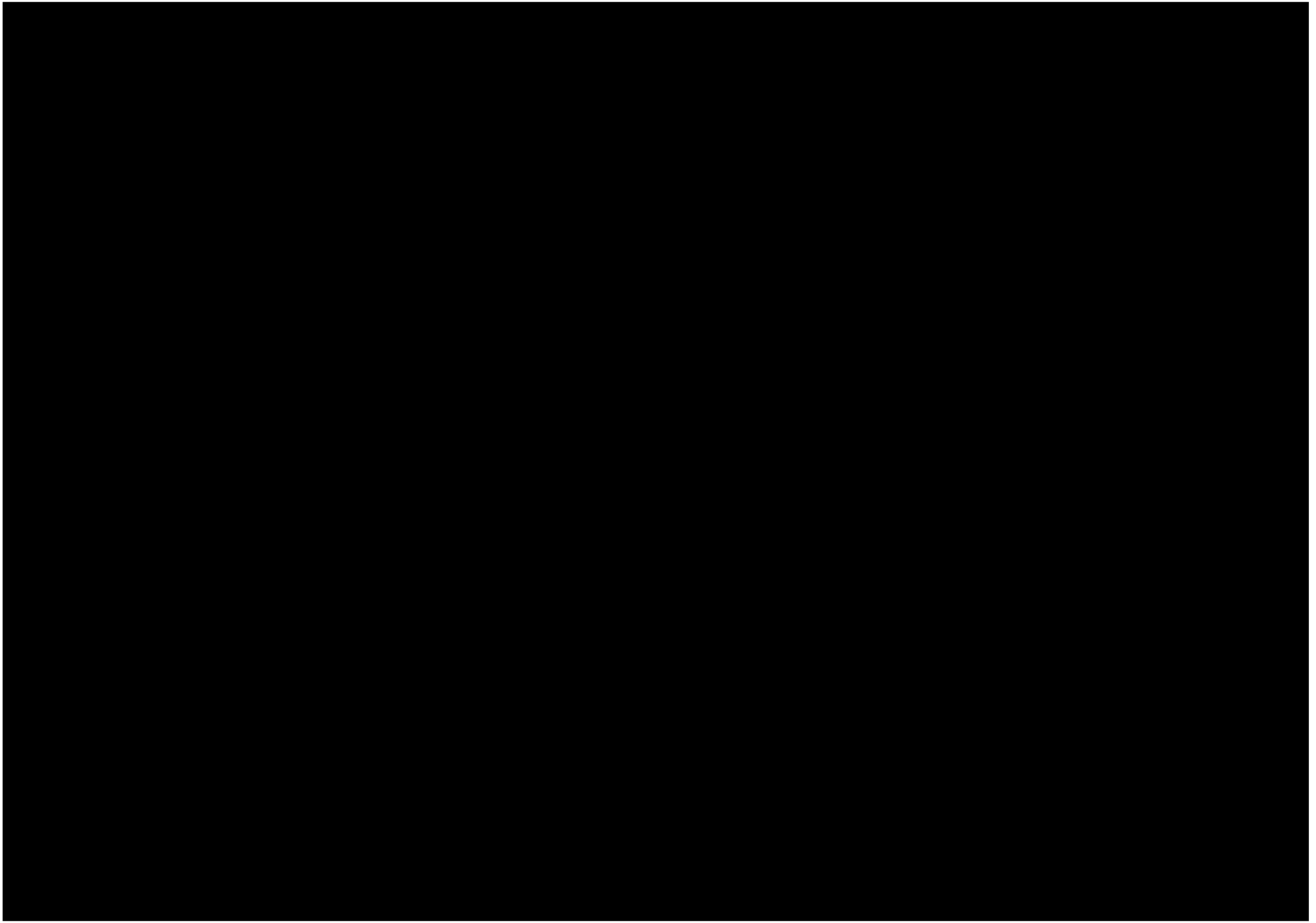
Total Annual Energy Sales
Southwestern Electric Cooperative, Inc.



Total Annual Energy Sales
United Power, Inc.

[redacted]

Total Annual Energy Sales
Wheat Belt Public Power District

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Total Annual Energy Sales
Wheatland Rural Electric Association, Inc.

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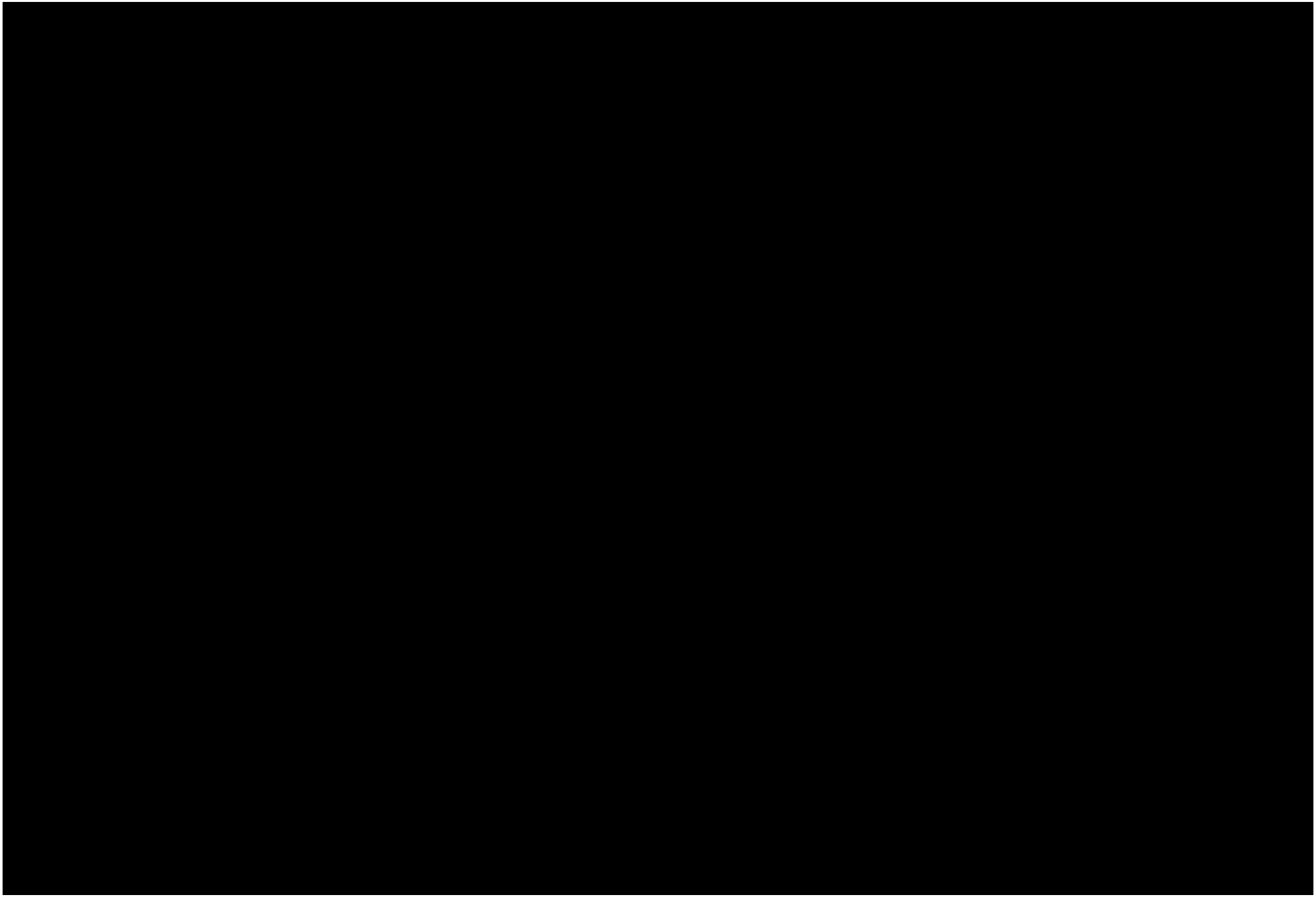
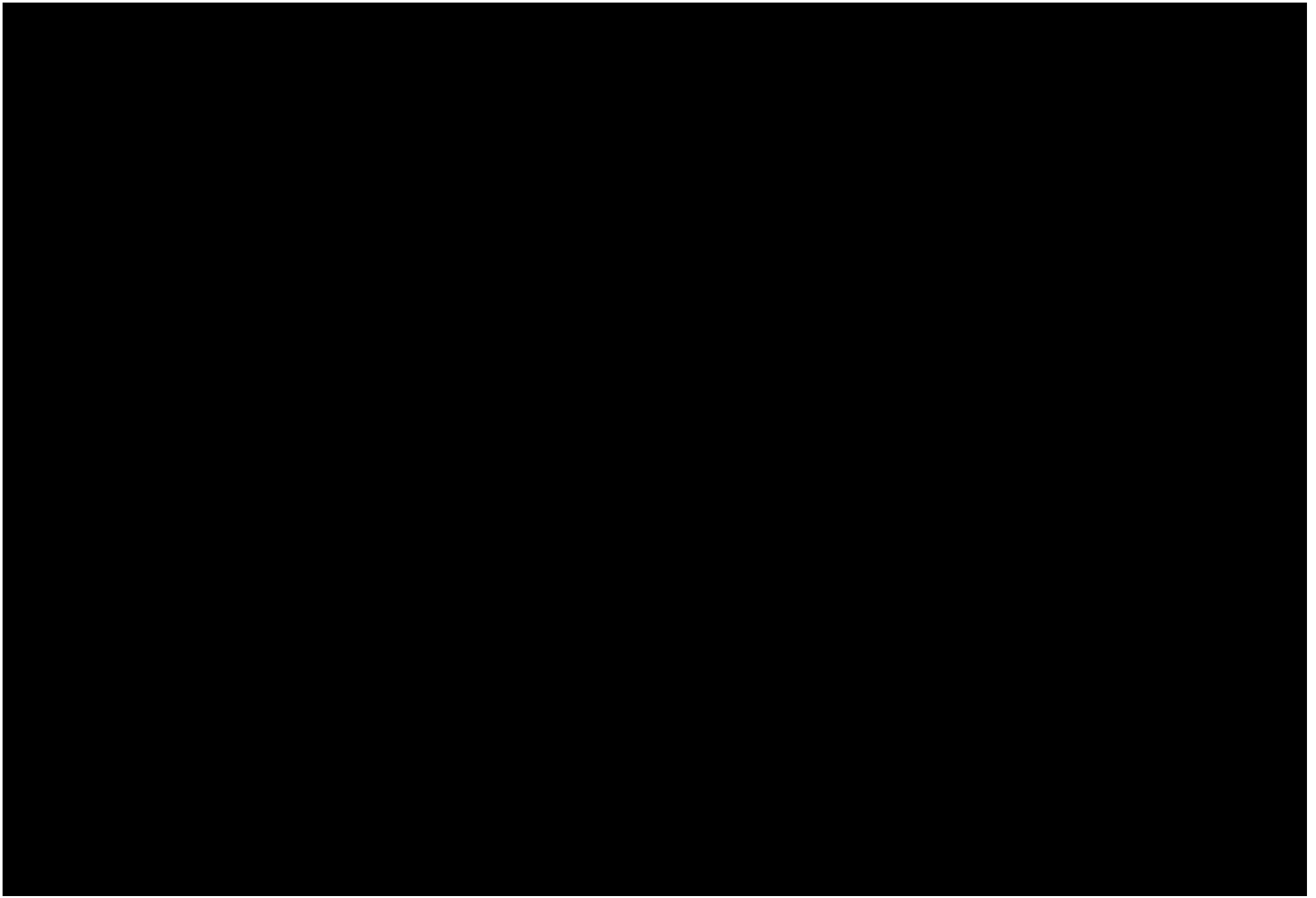
Total Annual Energy Sales
White River Electric Association, Inc.



Total Annual Energy Sales
Wyrulec Company



Total Annual Energy Sales
Y-W Electric Association, Inc.

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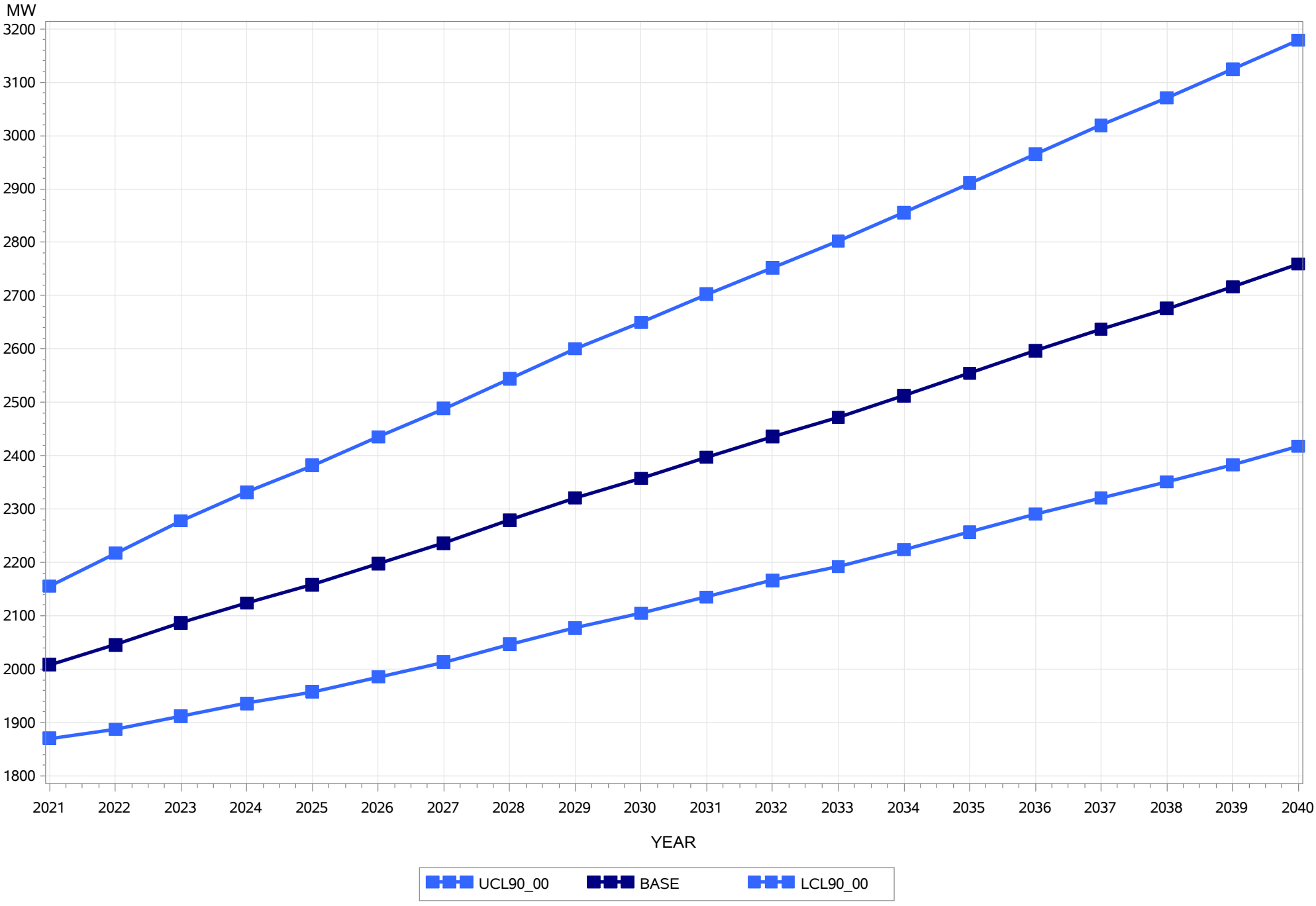
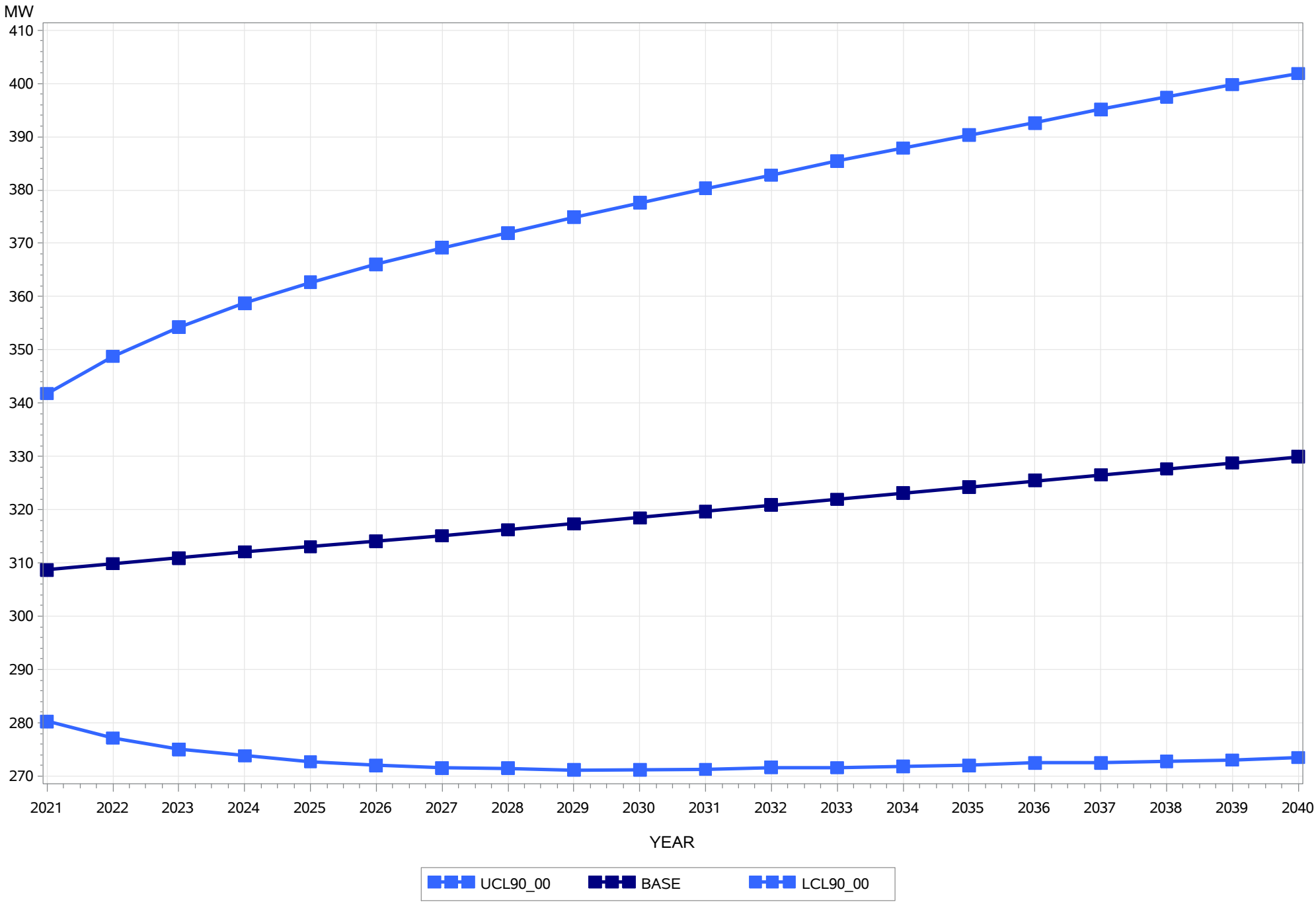
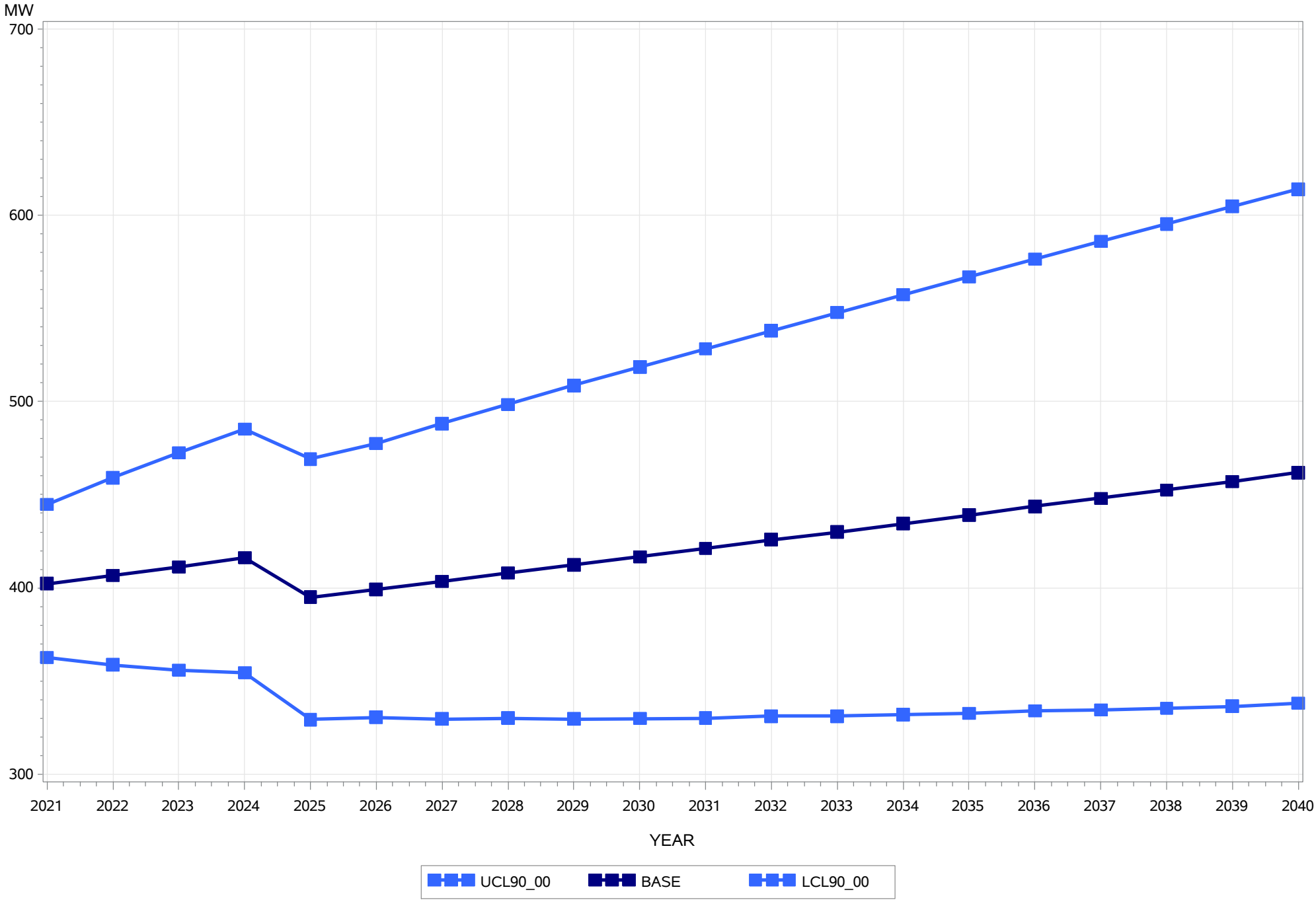
Annual Summer Coincident Peak
STATE OF COLORADO



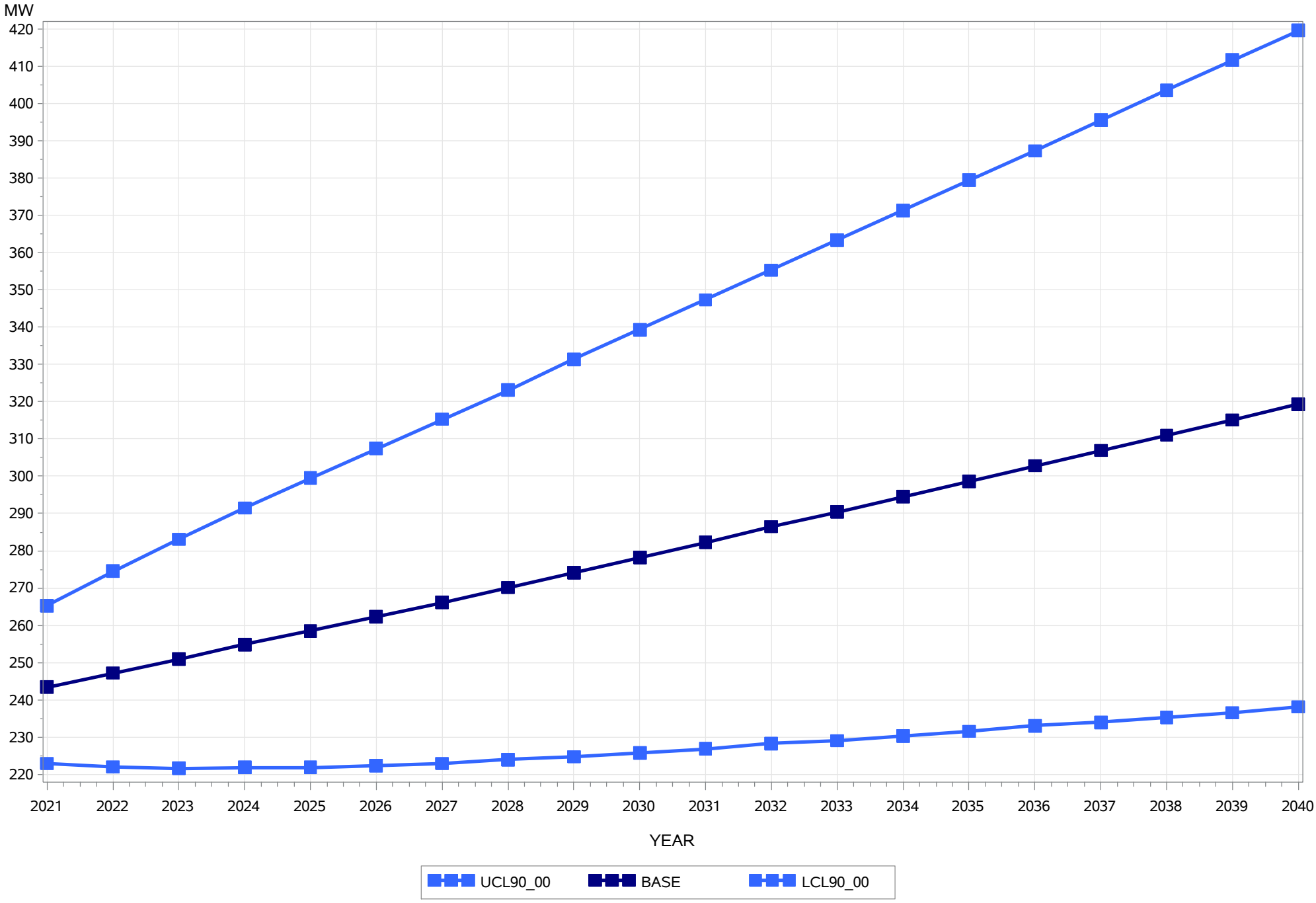
Annual Summer Coincident Peak
STATE OF NEBRASKA



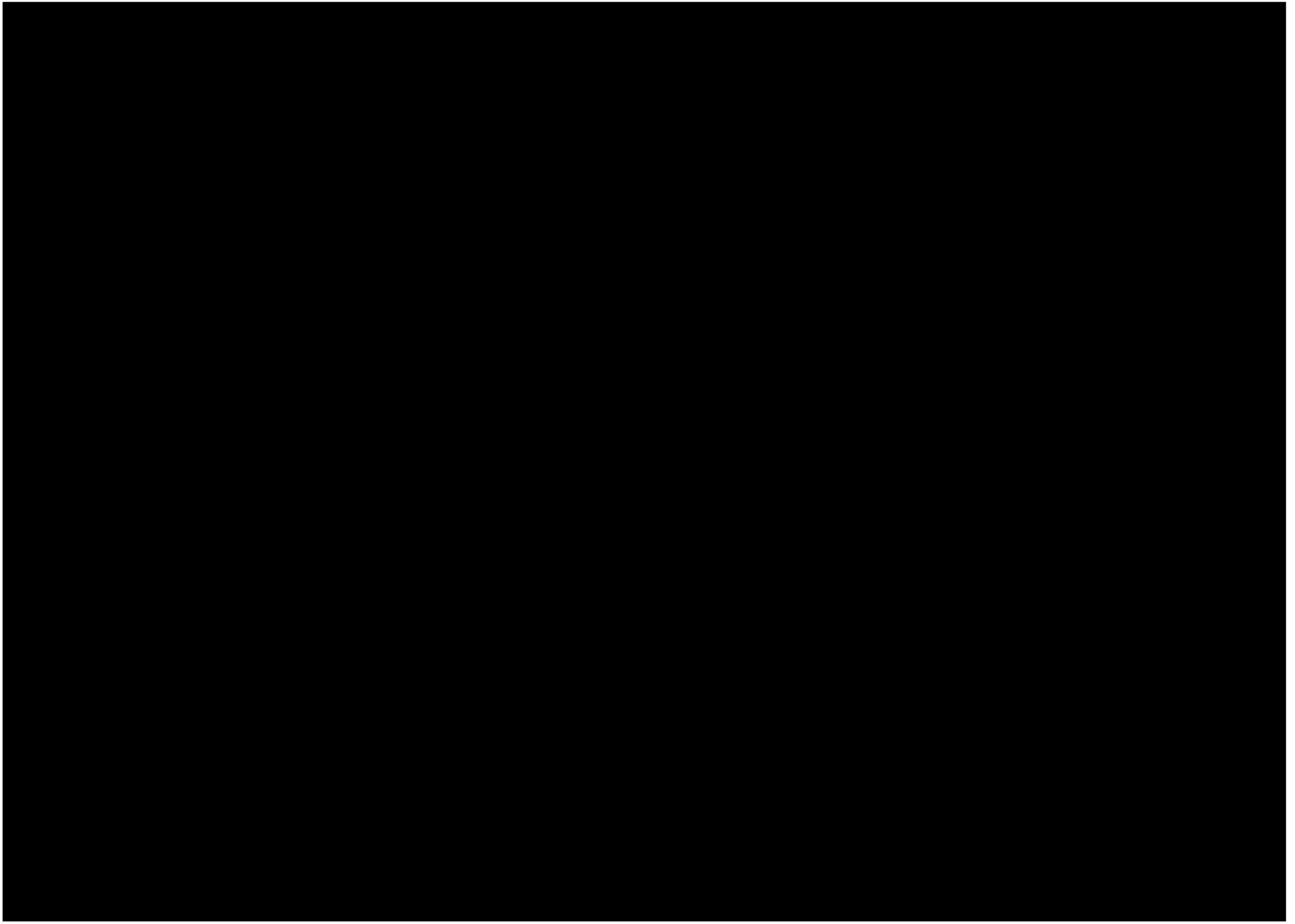
Annual Summer Coincident Peak
STATE OF NEW MEXICO



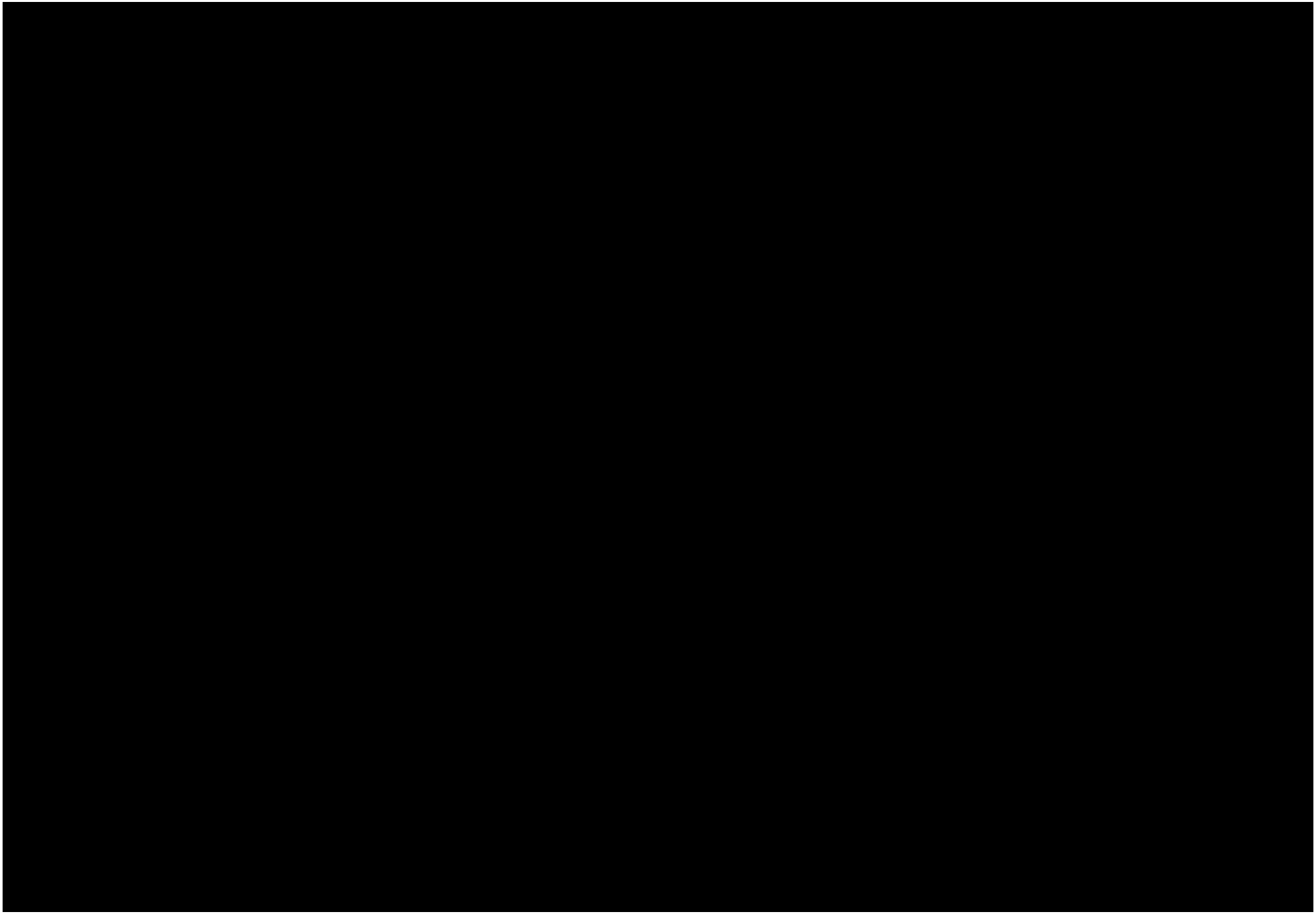
Annual Summer Coincident Peak
STATE OF WYOMING



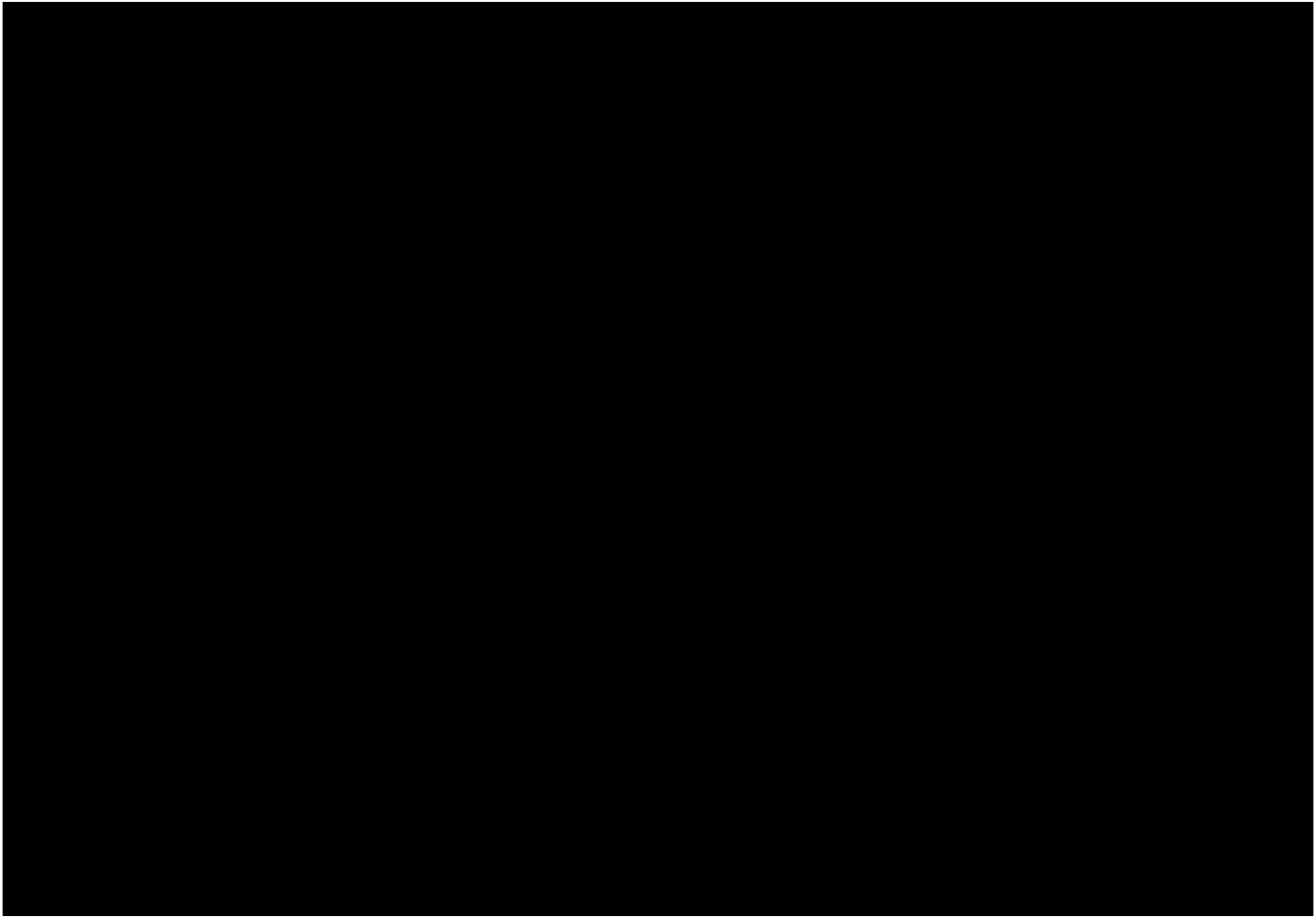
Annual Summer Coincident Peak
Big Horn Rural Electric Company



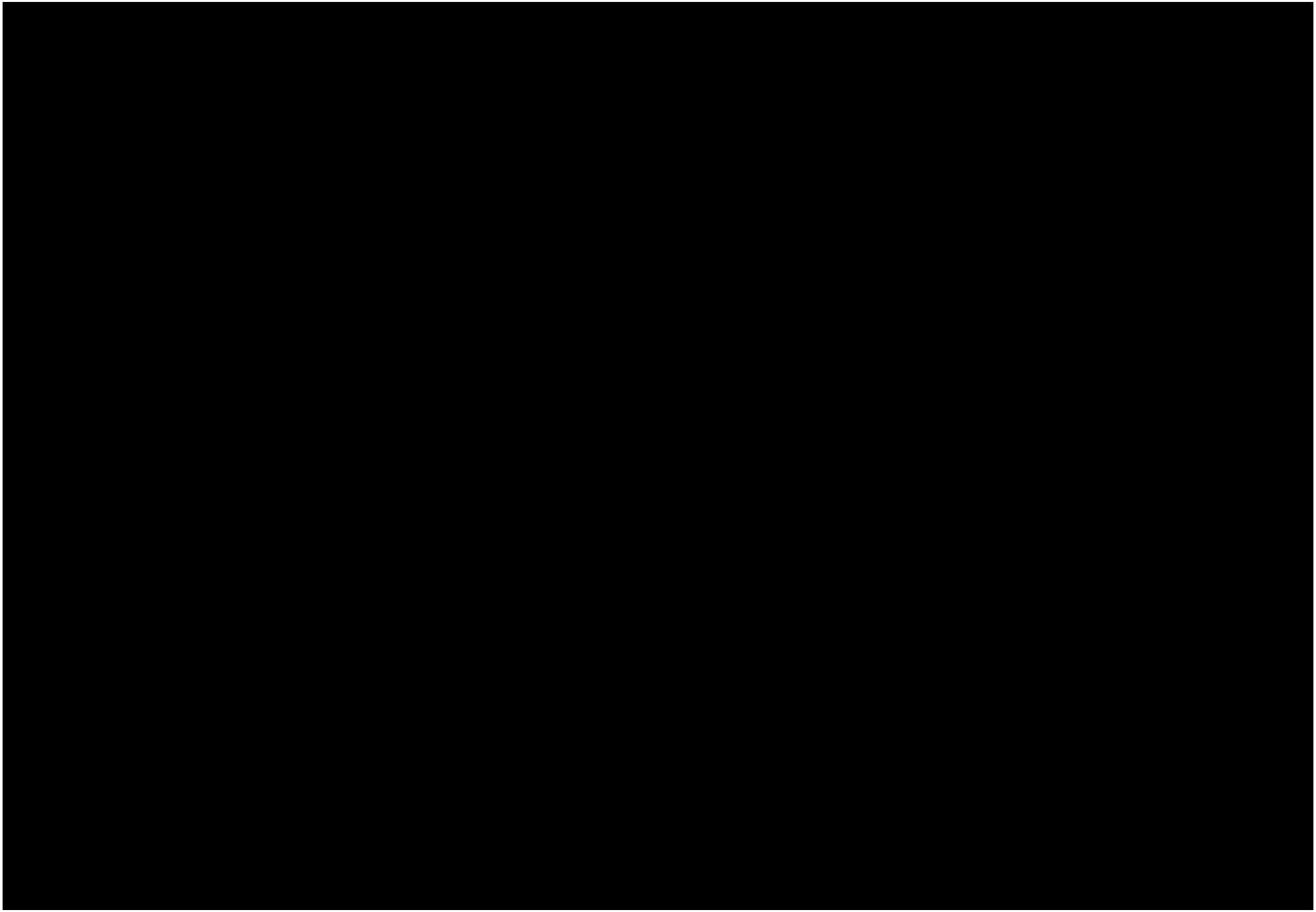
Annual Summer Coincident Peak
Carbon Power and Light, Inc.



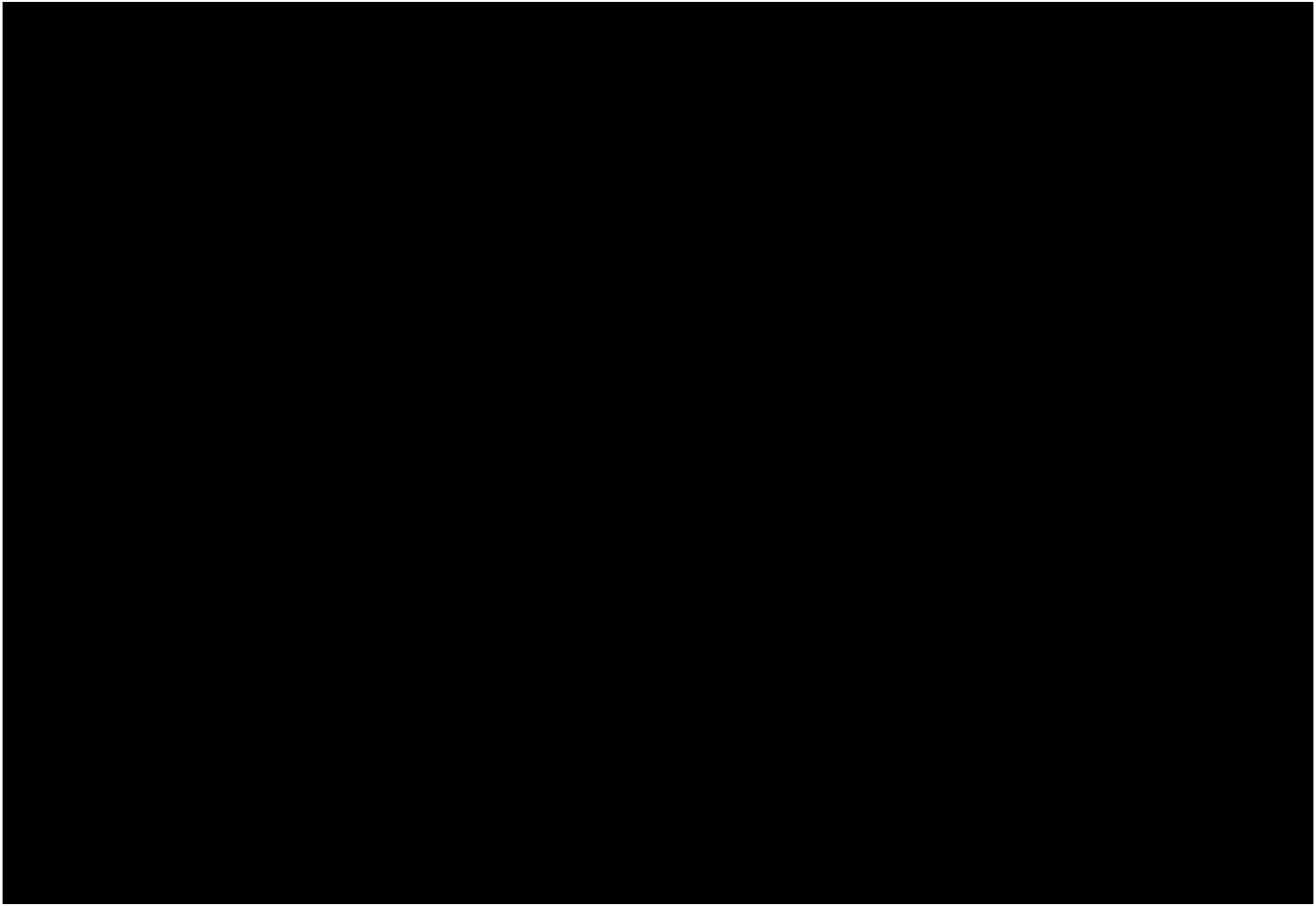
Annual Summer Coincident Peak
Continental Divide Electric Cooperative, Inc.



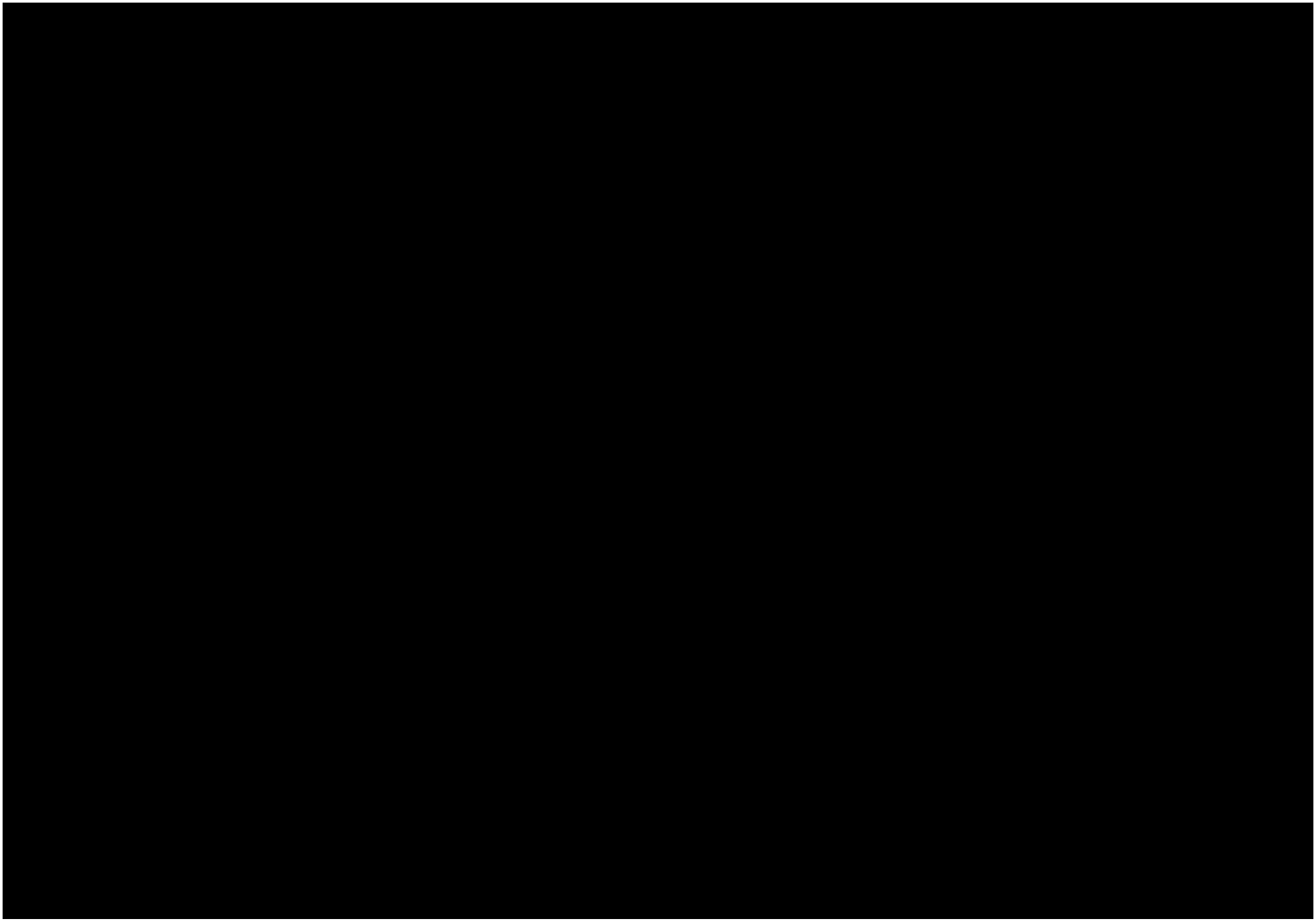
Annual Summer Coincident Peak
Columbus Electric Cooperative, Inc.



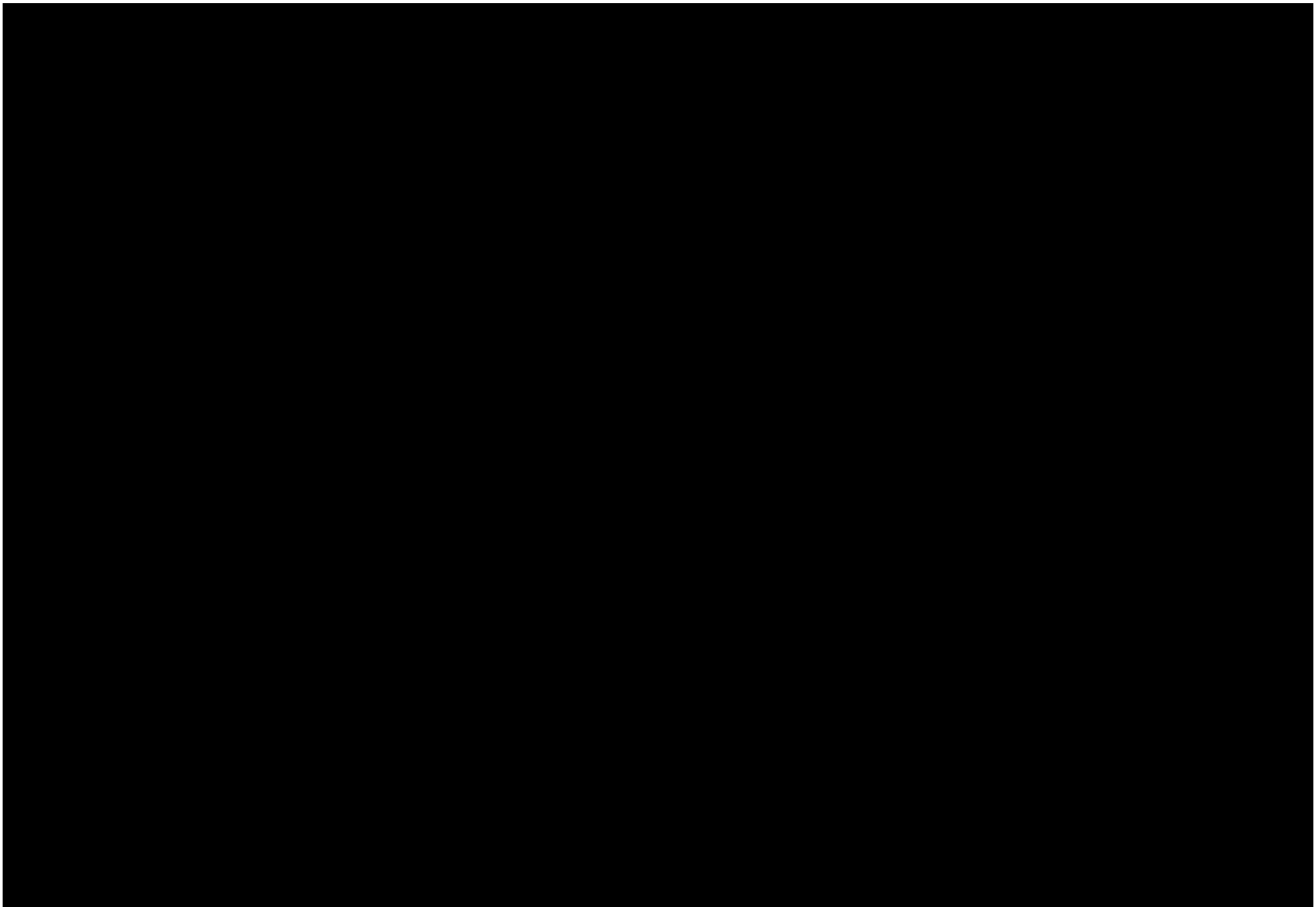
Annual Summer Coincident Peak
Central New Mexico Electric Cooperative, Inc.



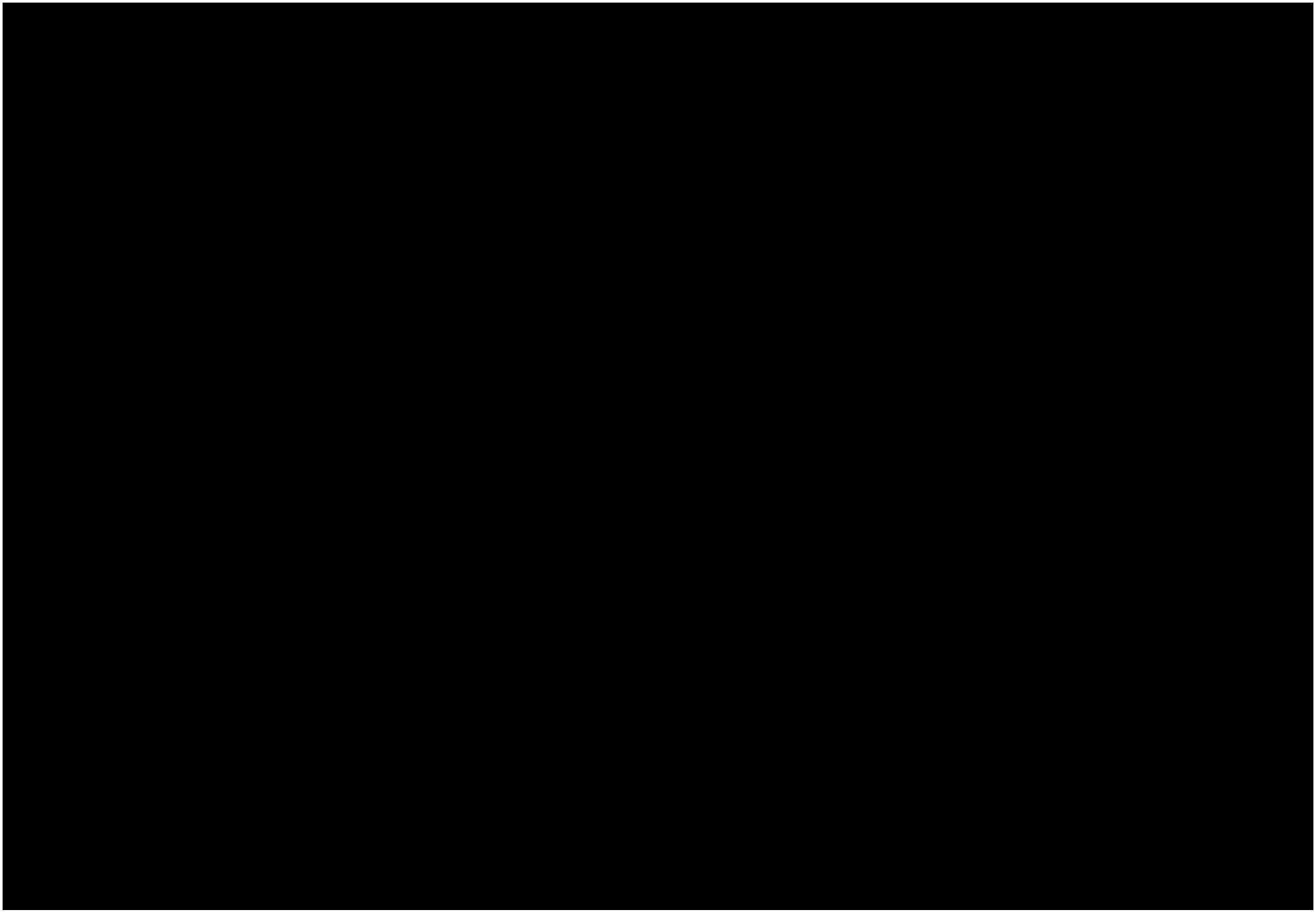
Annual Summer Coincident Peak
Chimney Rock Public Power District



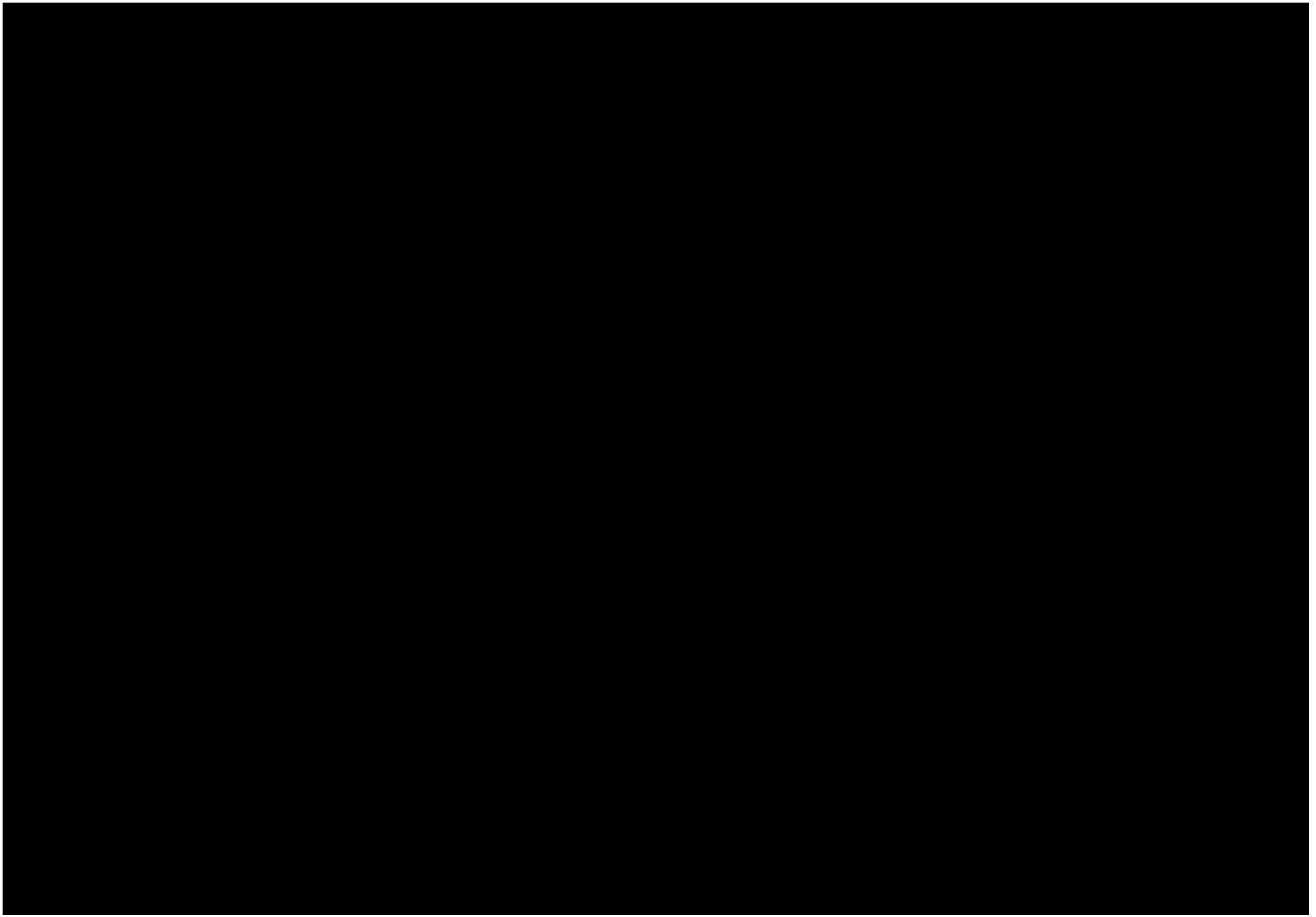
Annual Summer Coincident Peak
Empire Electric Association, Inc.



Annual Summer Coincident Peak
Gunnison County Electric Association, Inc.



Annual Summer Coincident Peak
Garland Light and Power Company



Annual Summer Coincident Peak
Highline Electric Association

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Annual Summer Coincident Peak

High Plains Power, Inc.

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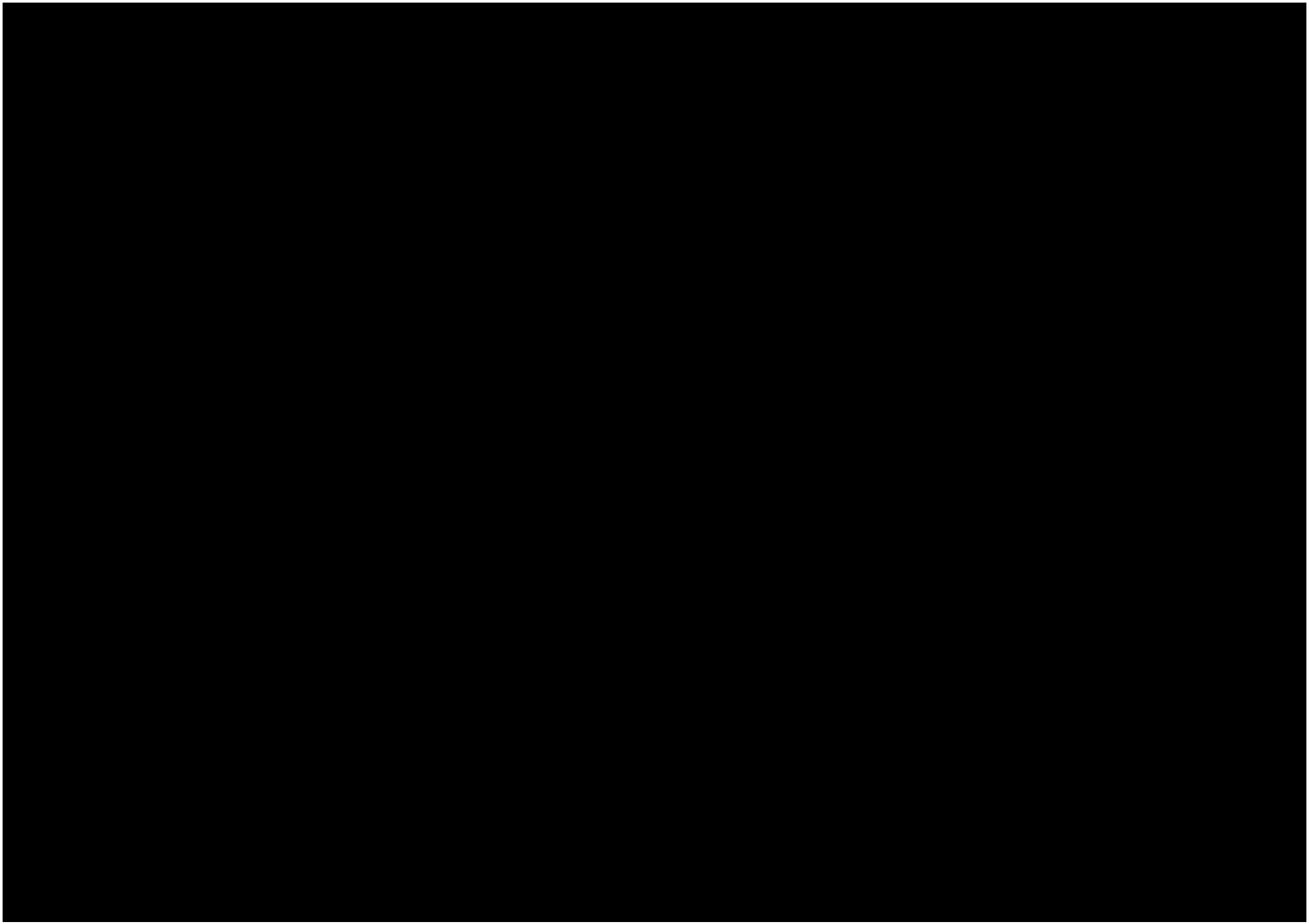
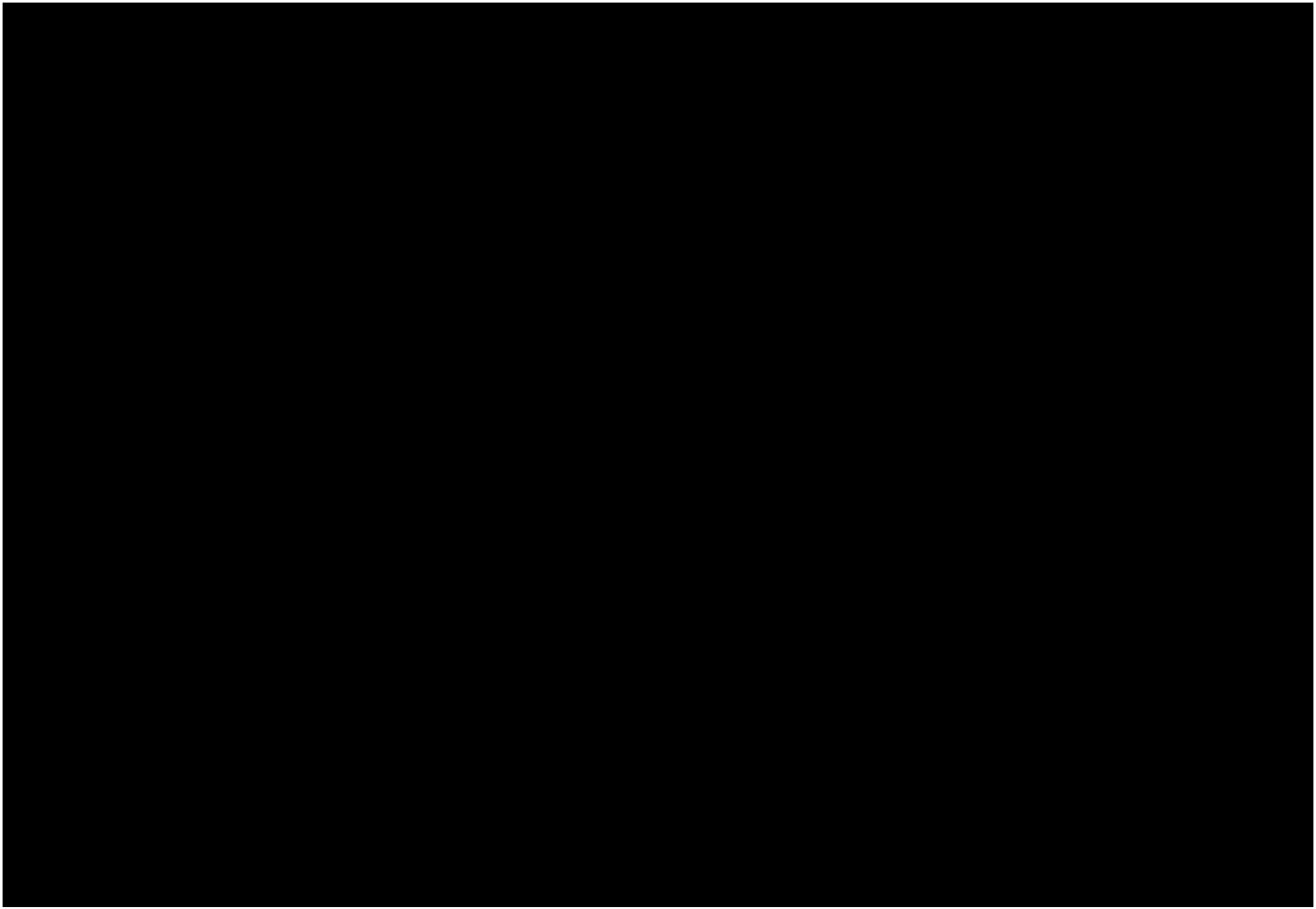
Annual Summer Coincident Peak
High West Energy, Inc.

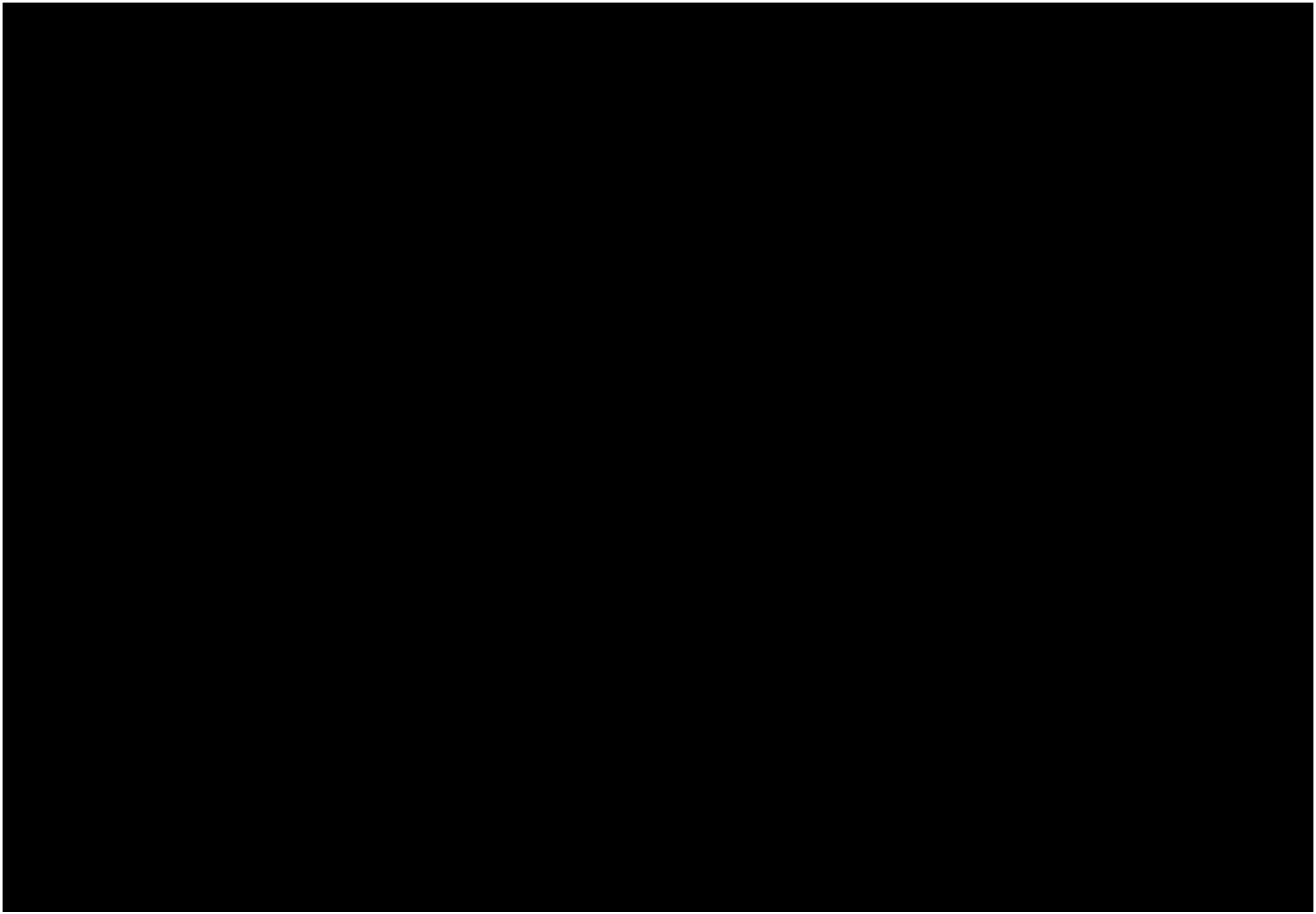


Annual Summer Coincident Peak

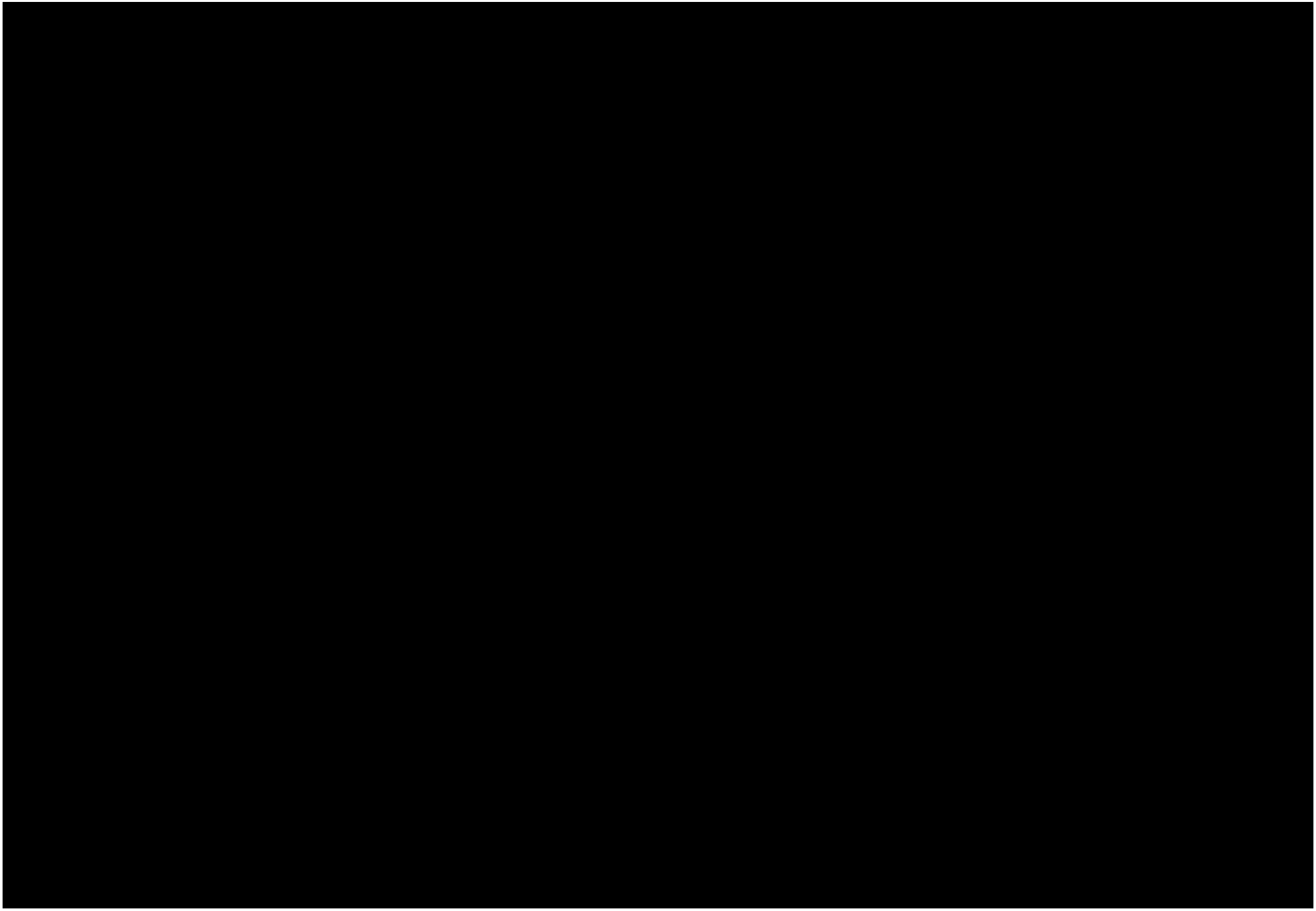
Jemez Mountains Electric Cooperative, Inc.



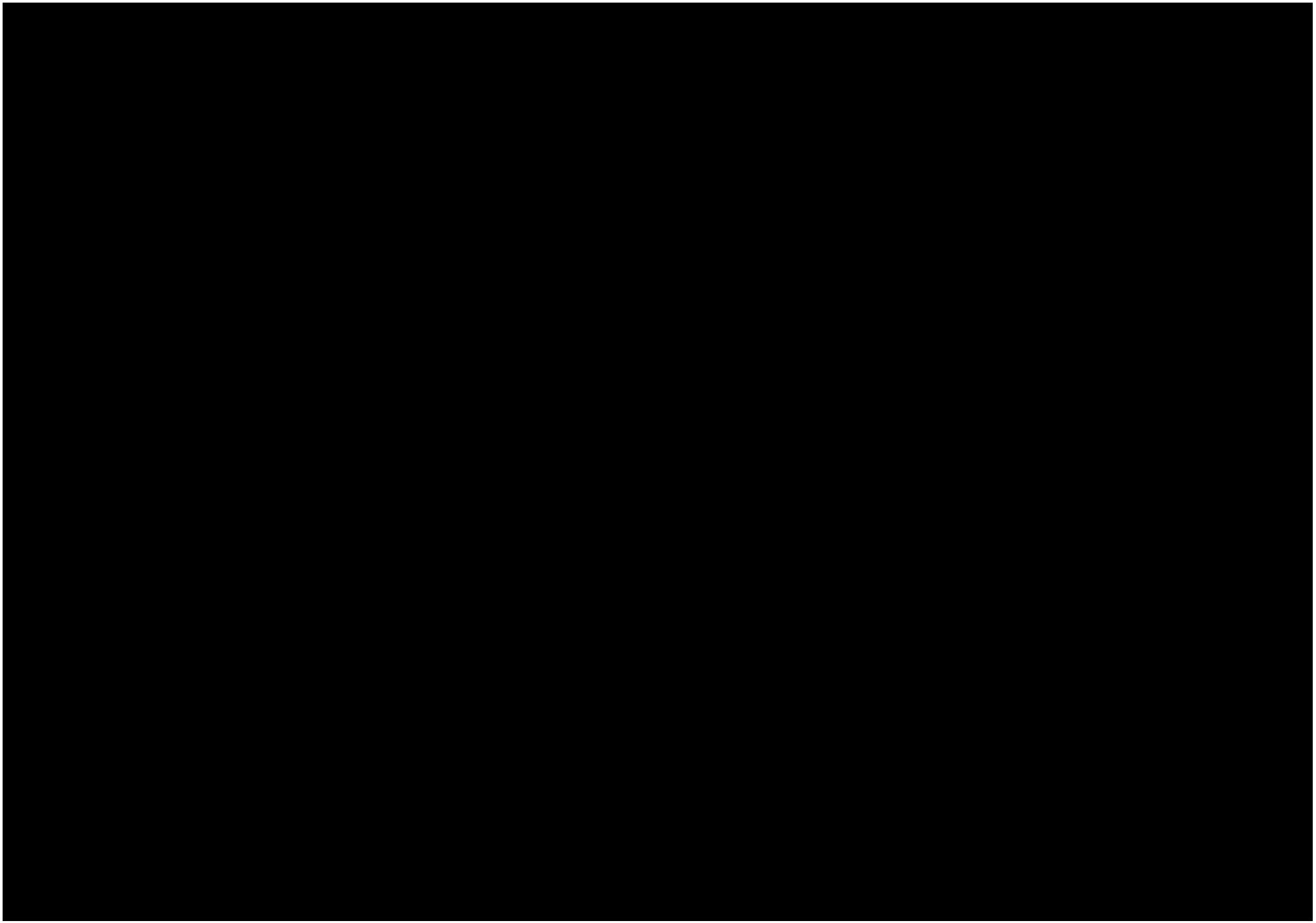
Annual Summer Coincident Peak
K.C. Electric Association, Inc.



Annual Summer Coincident Peak
La Plata Electric Association, Inc.

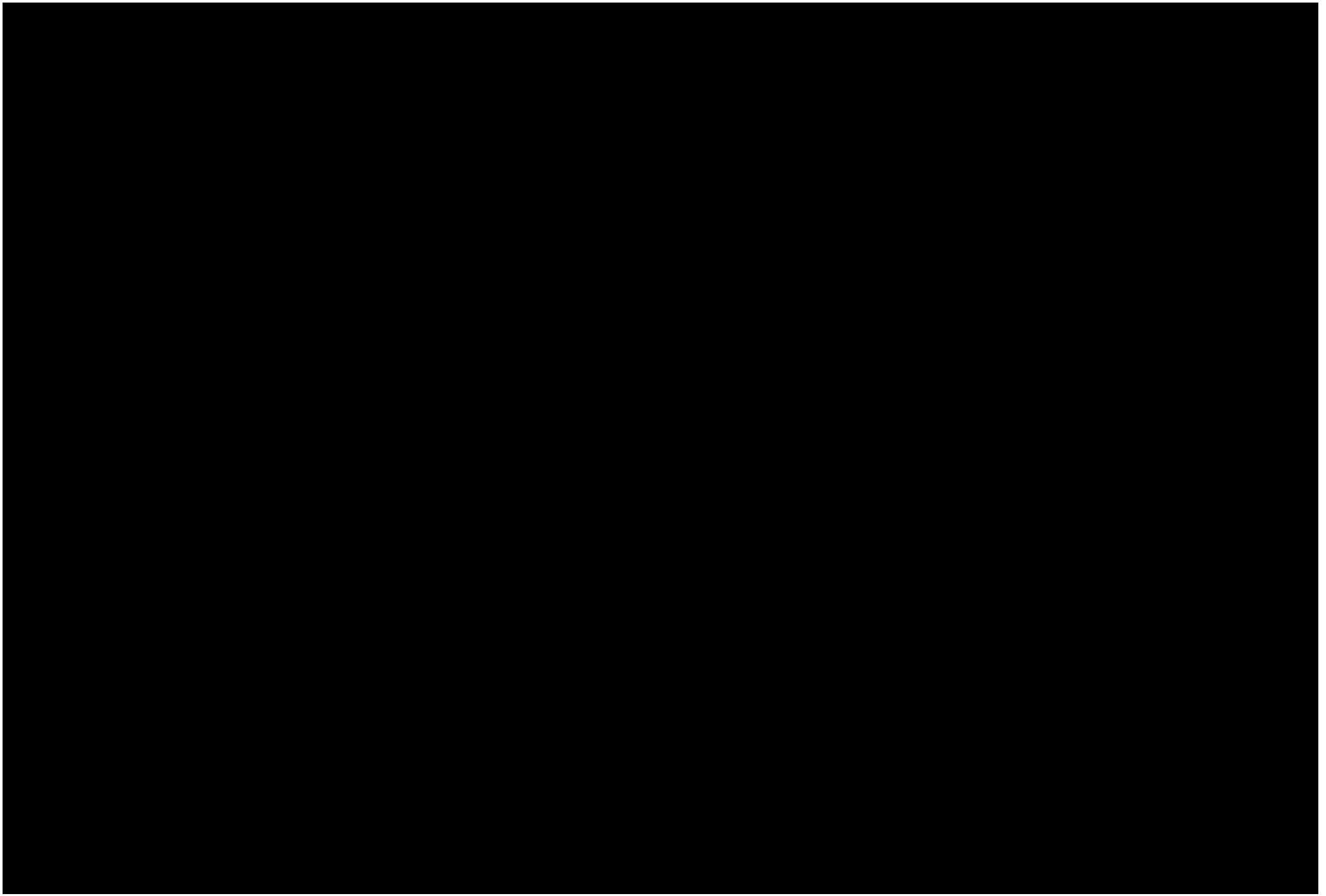


Annual Summer Coincident Peak
Morgan County Rural Electric Association

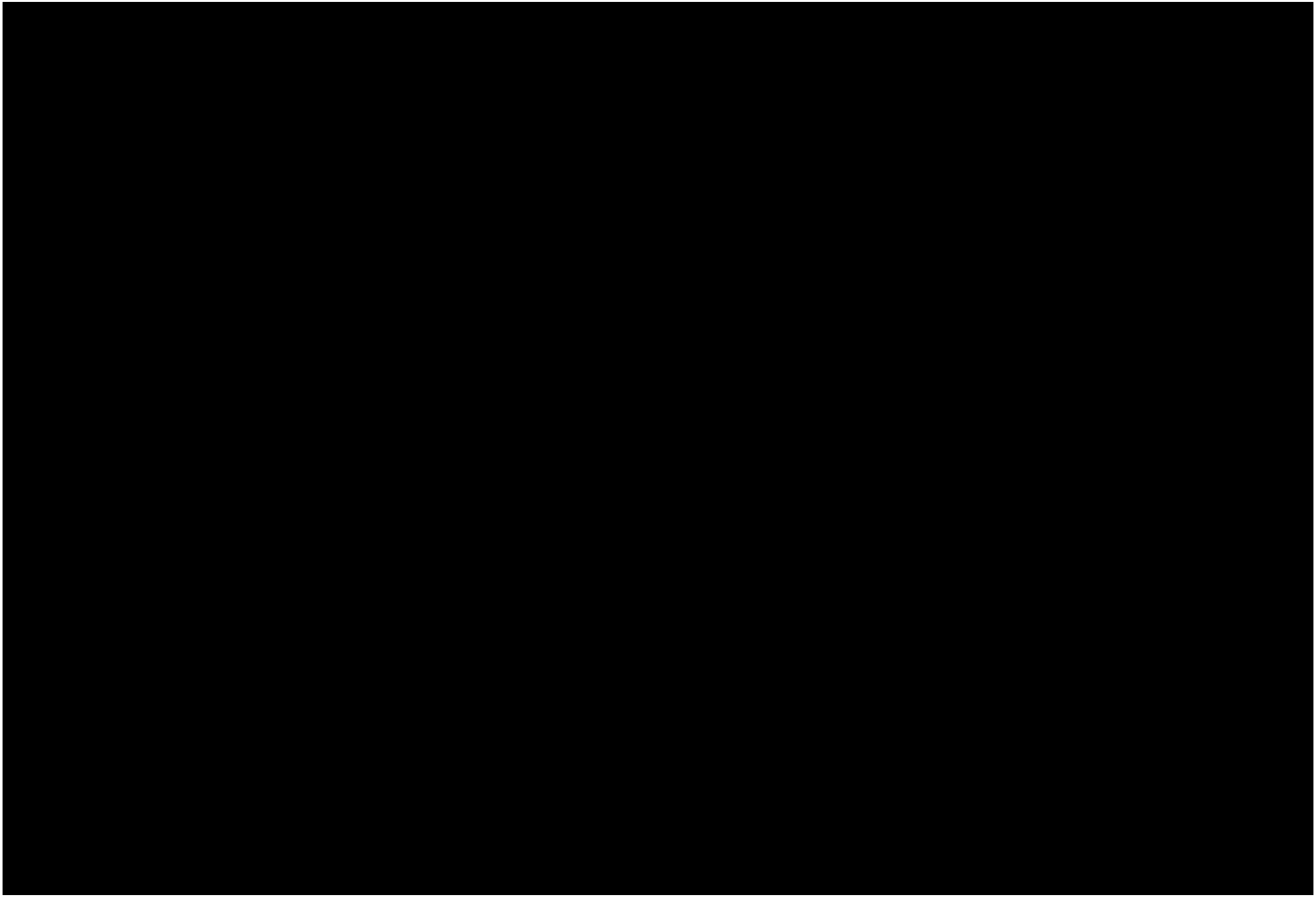


Annual Summer Coincident Peak

Mountain Parks Electric, Inc.



Annual Summer Coincident Peak
Mora-San Miguel Electric Cooperative, Inc.



Annual Summer Coincident Peak
Mountain View Electric Association, Inc.

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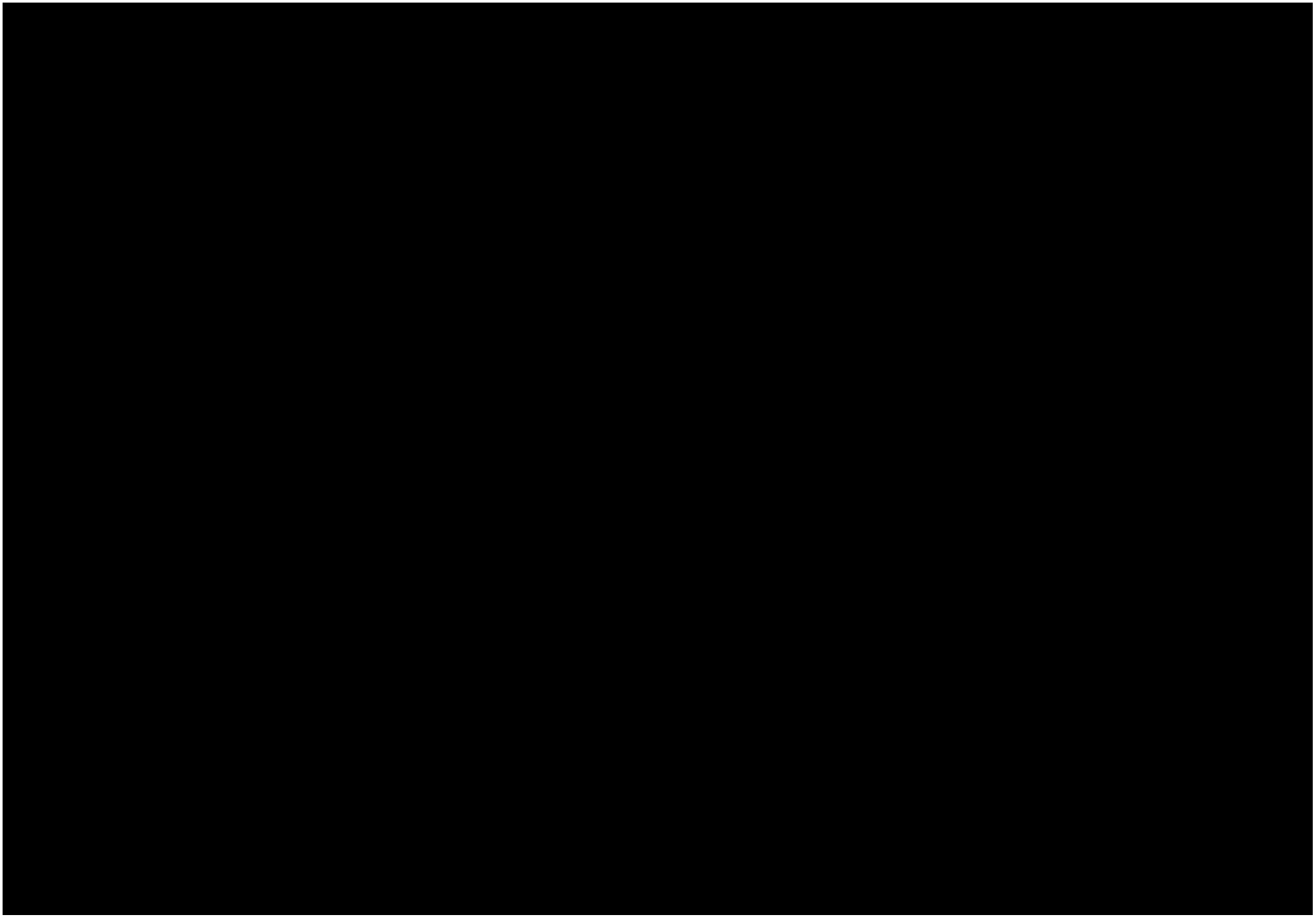
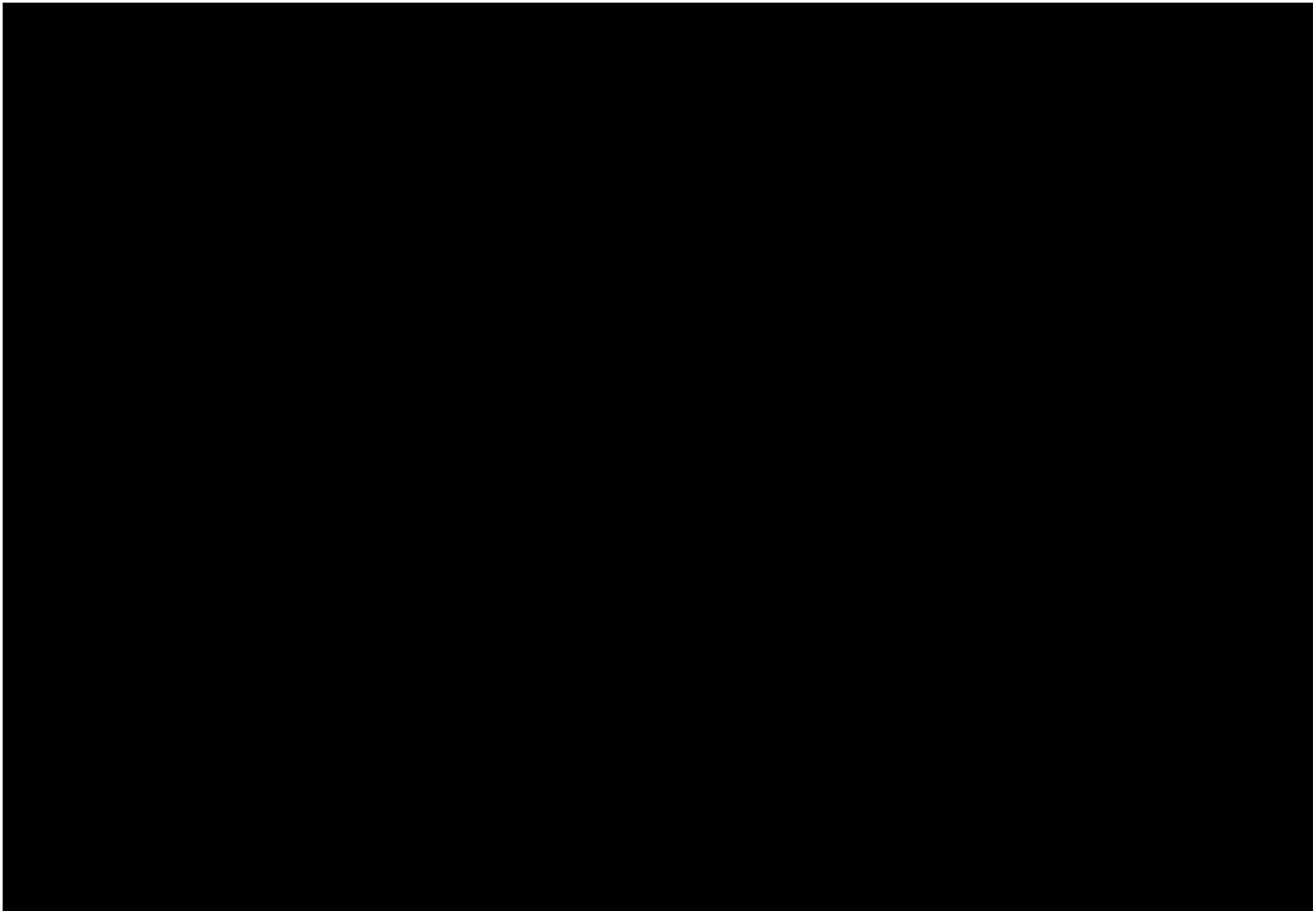
Annual Summer Coincident Peak
Midwest Electric Cooperative Corporation

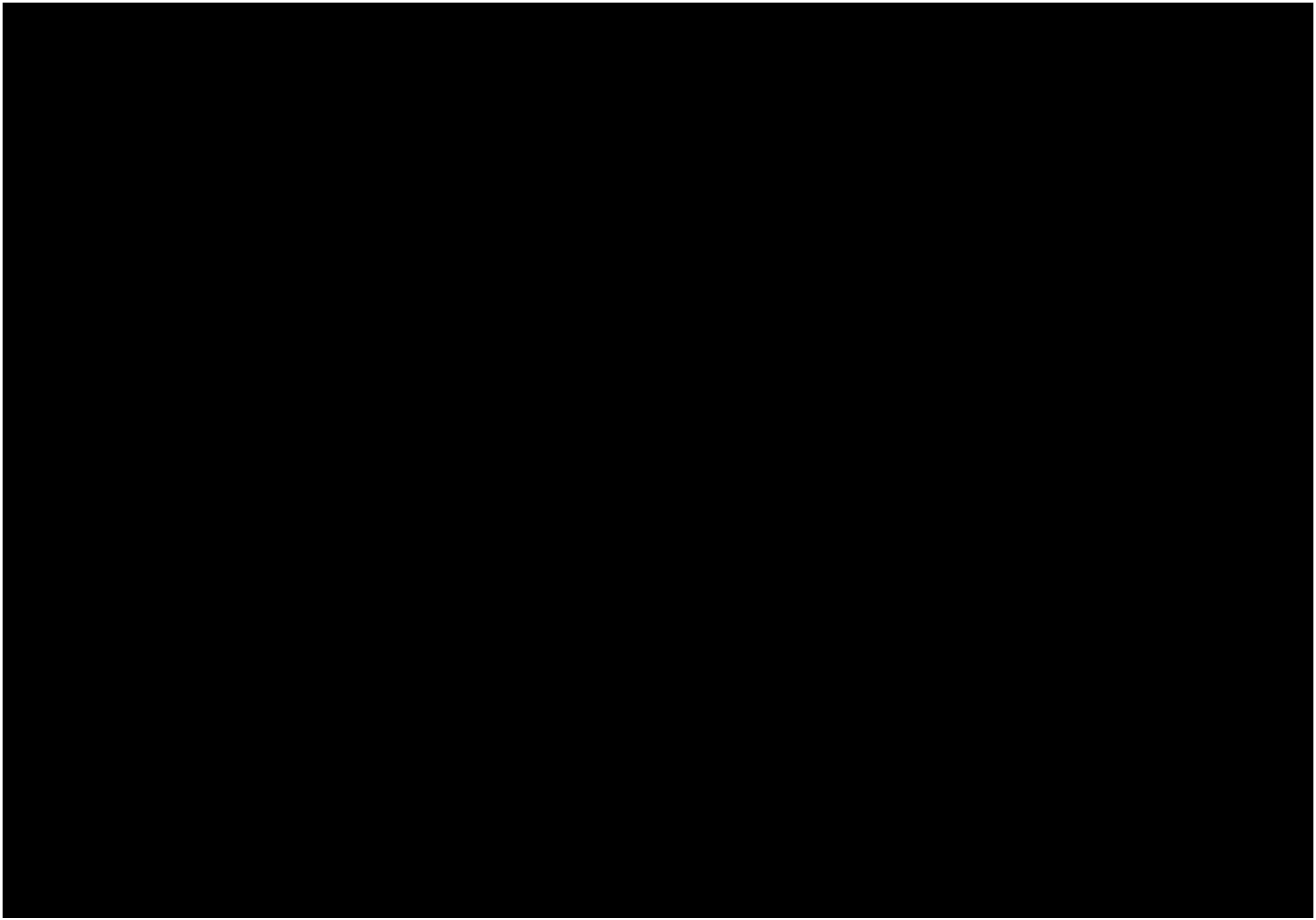


Annual Summer Coincident Peak

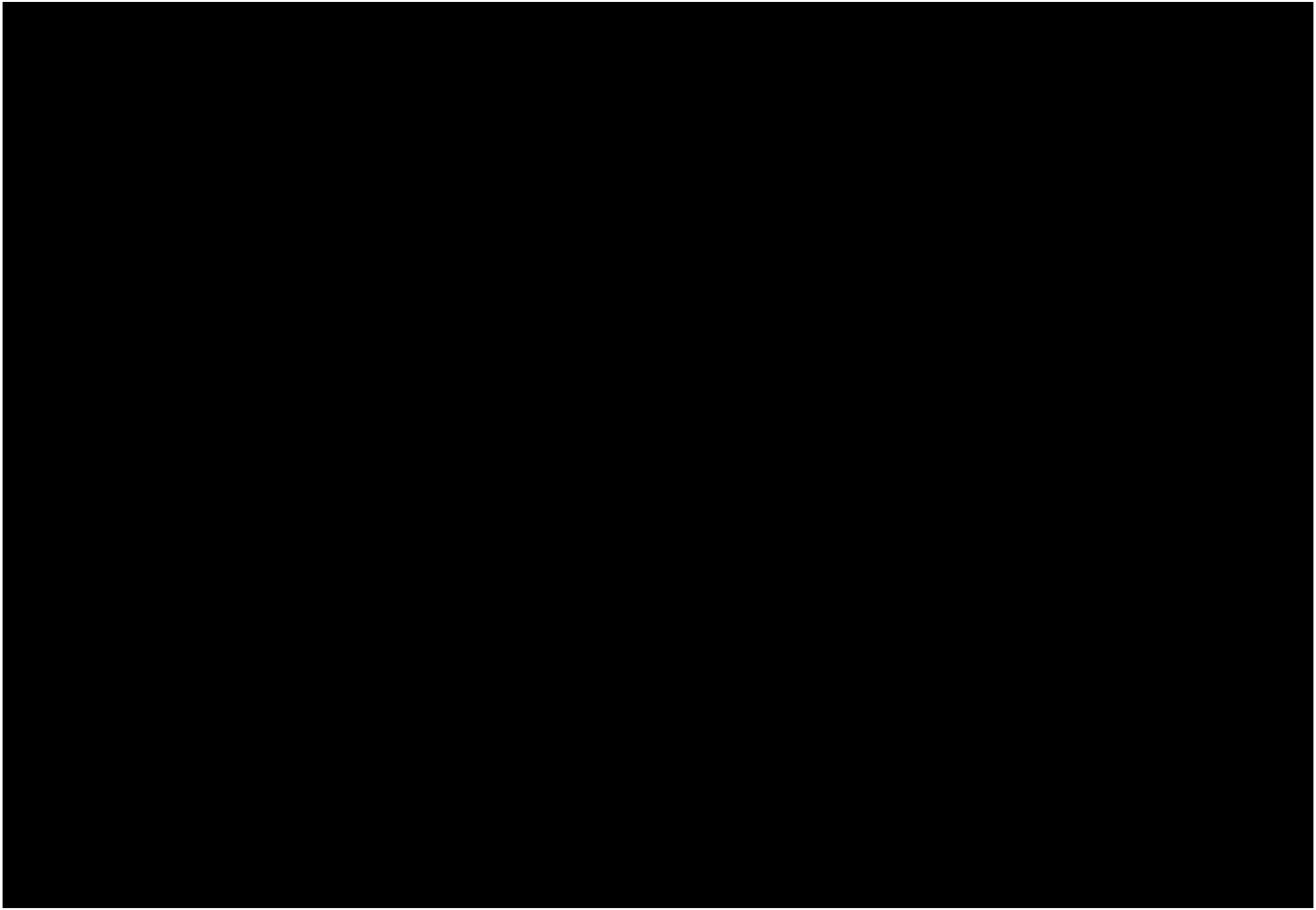
Niobrara Electric Association, Inc.



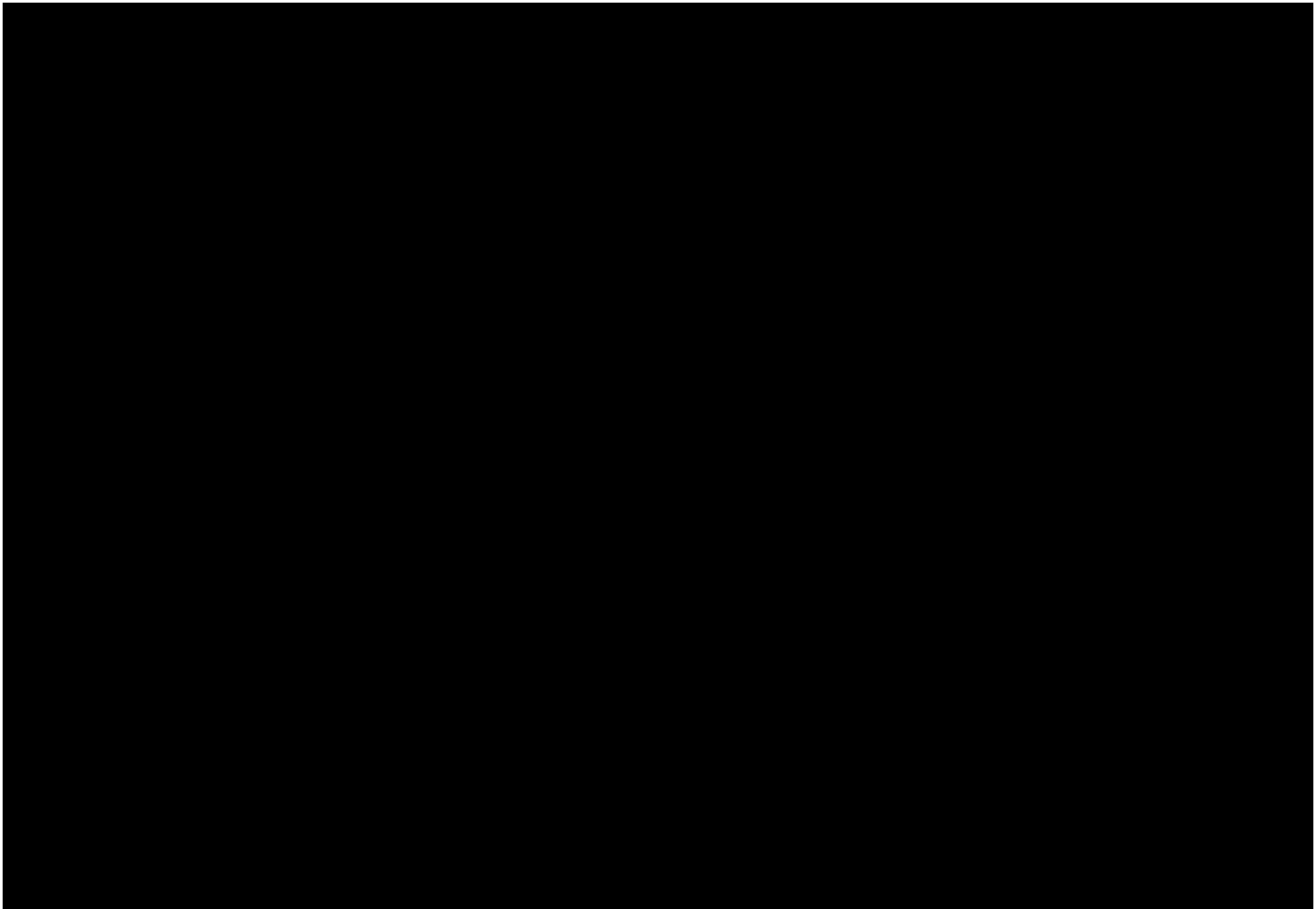
Annual Summer Coincident Peak
Northwest Rural Public Power District



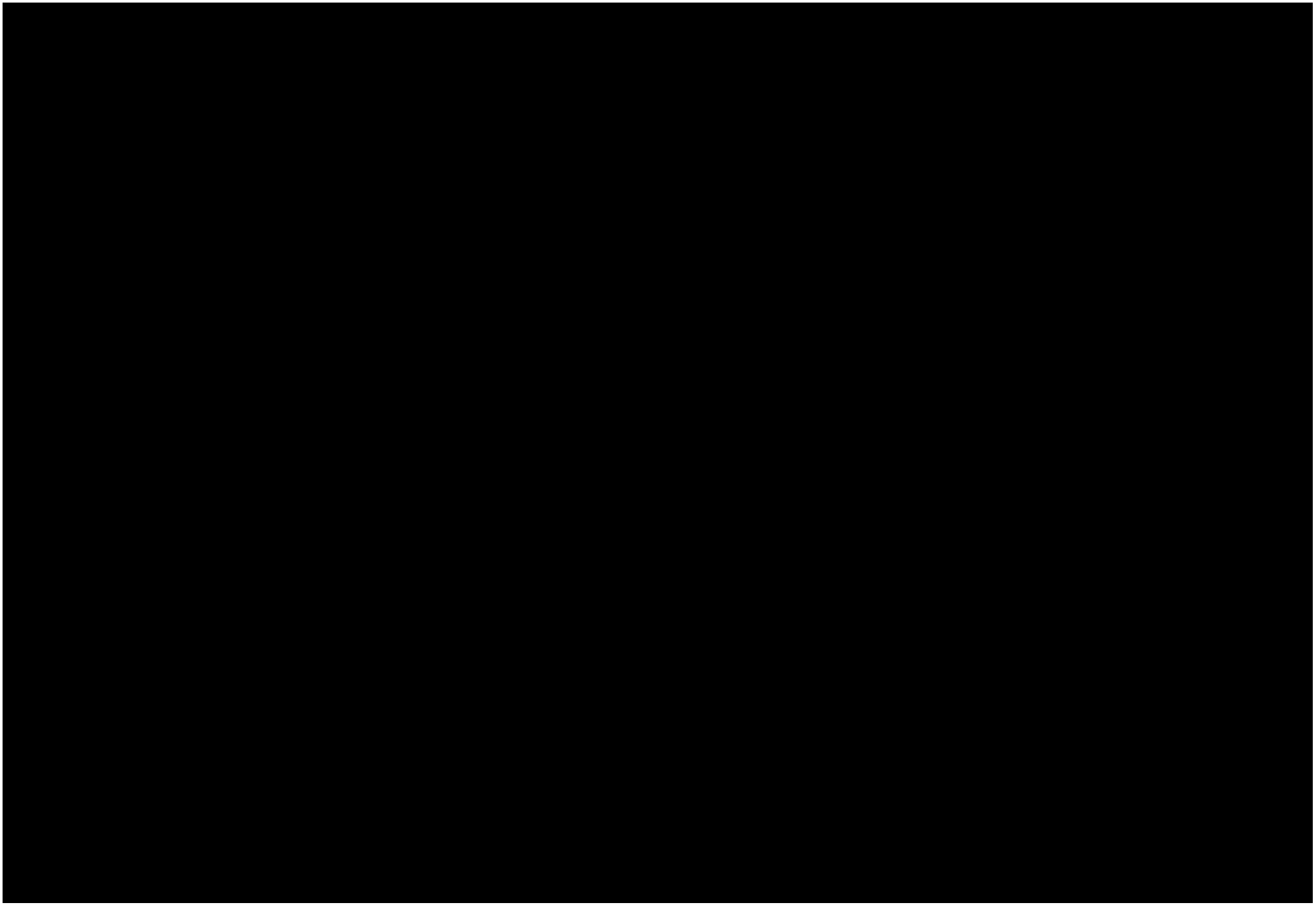
Annual Summer Coincident Peak
Otero County Electric Cooperative, Inc.



Annual Summer Coincident Peak
Panhandle Rural Electric Membership Association

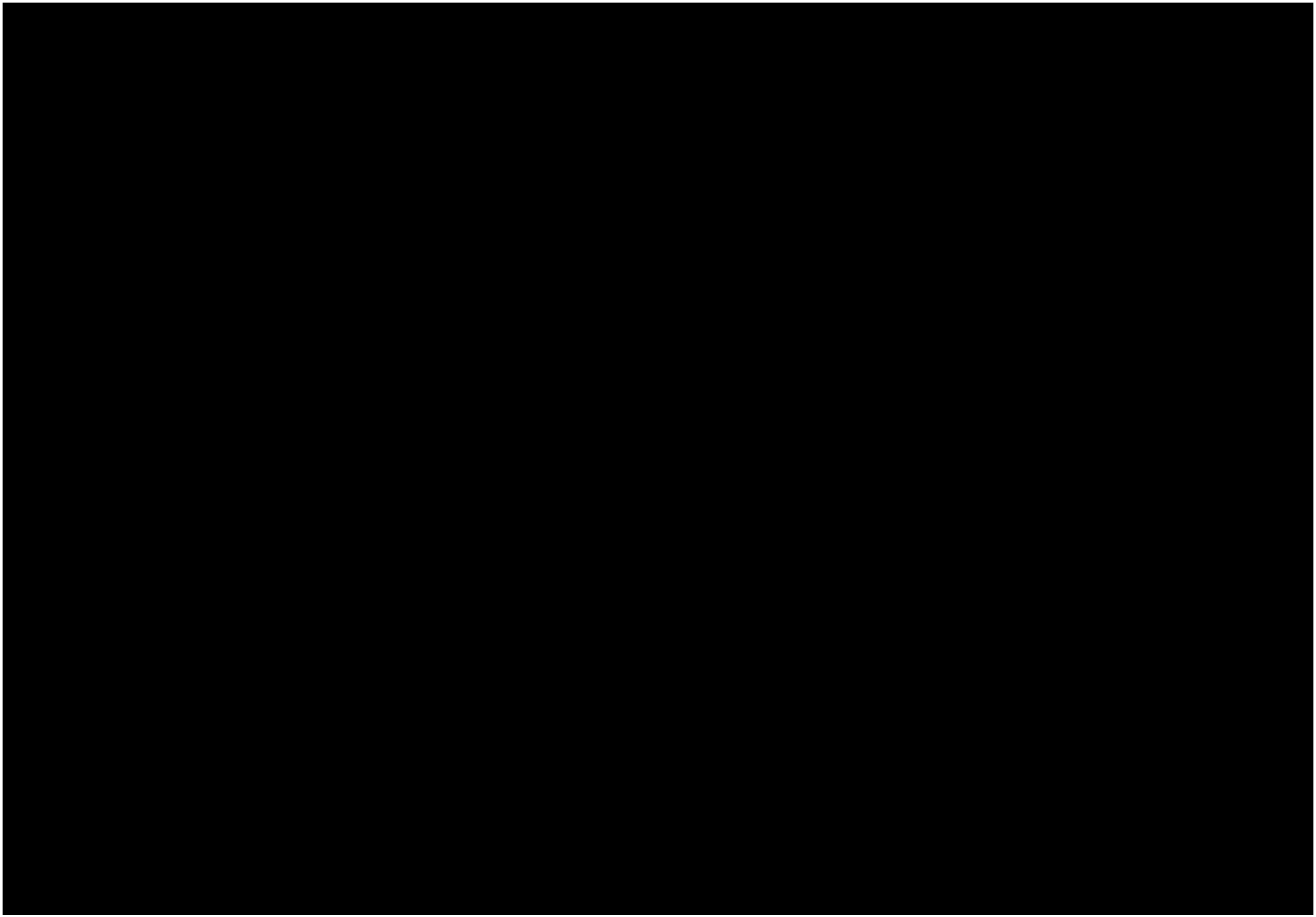


Annual Summer Coincident Peak
Poudre Valley Electric Association, Inc.

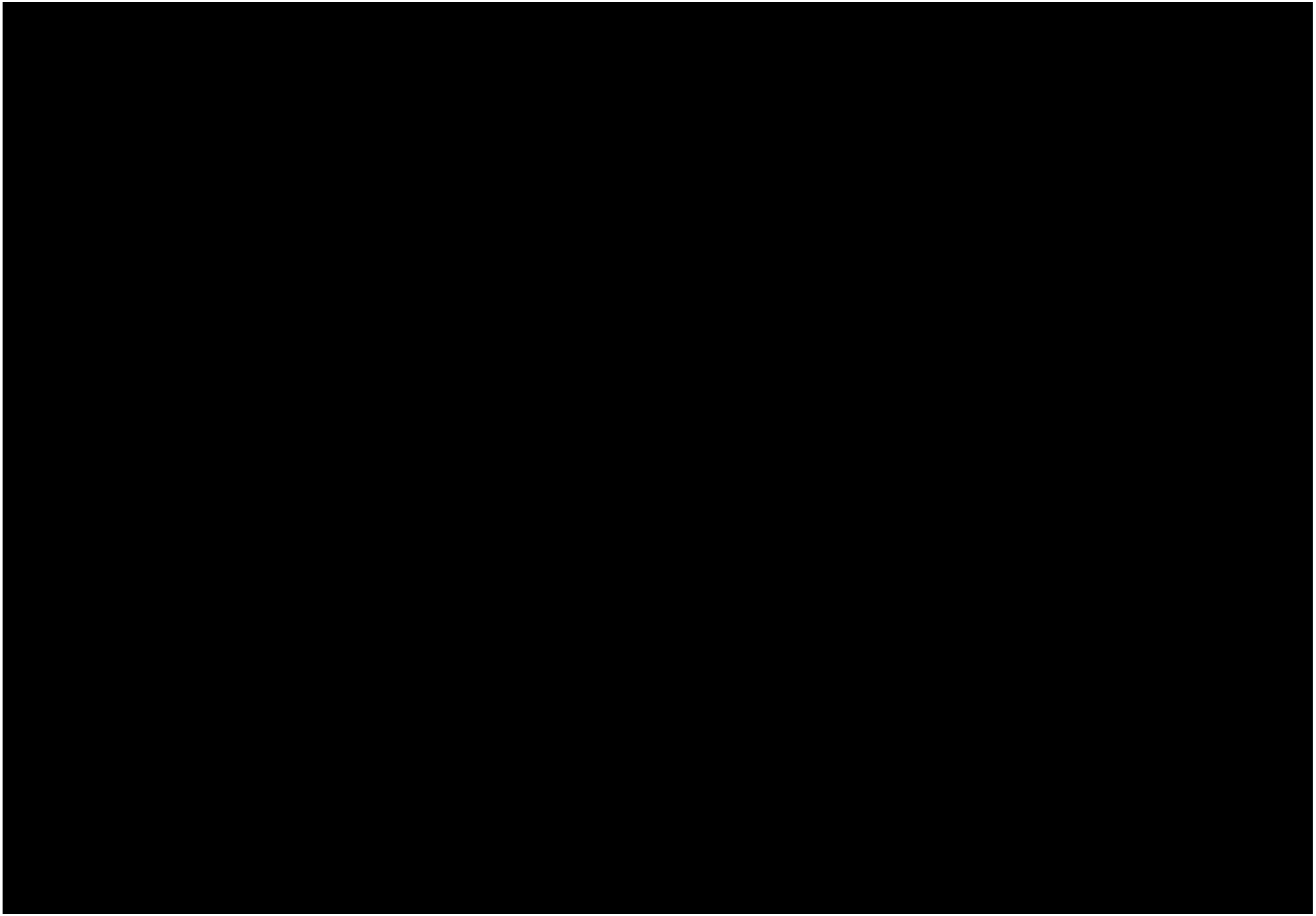


Annual Summer Coincident Peak

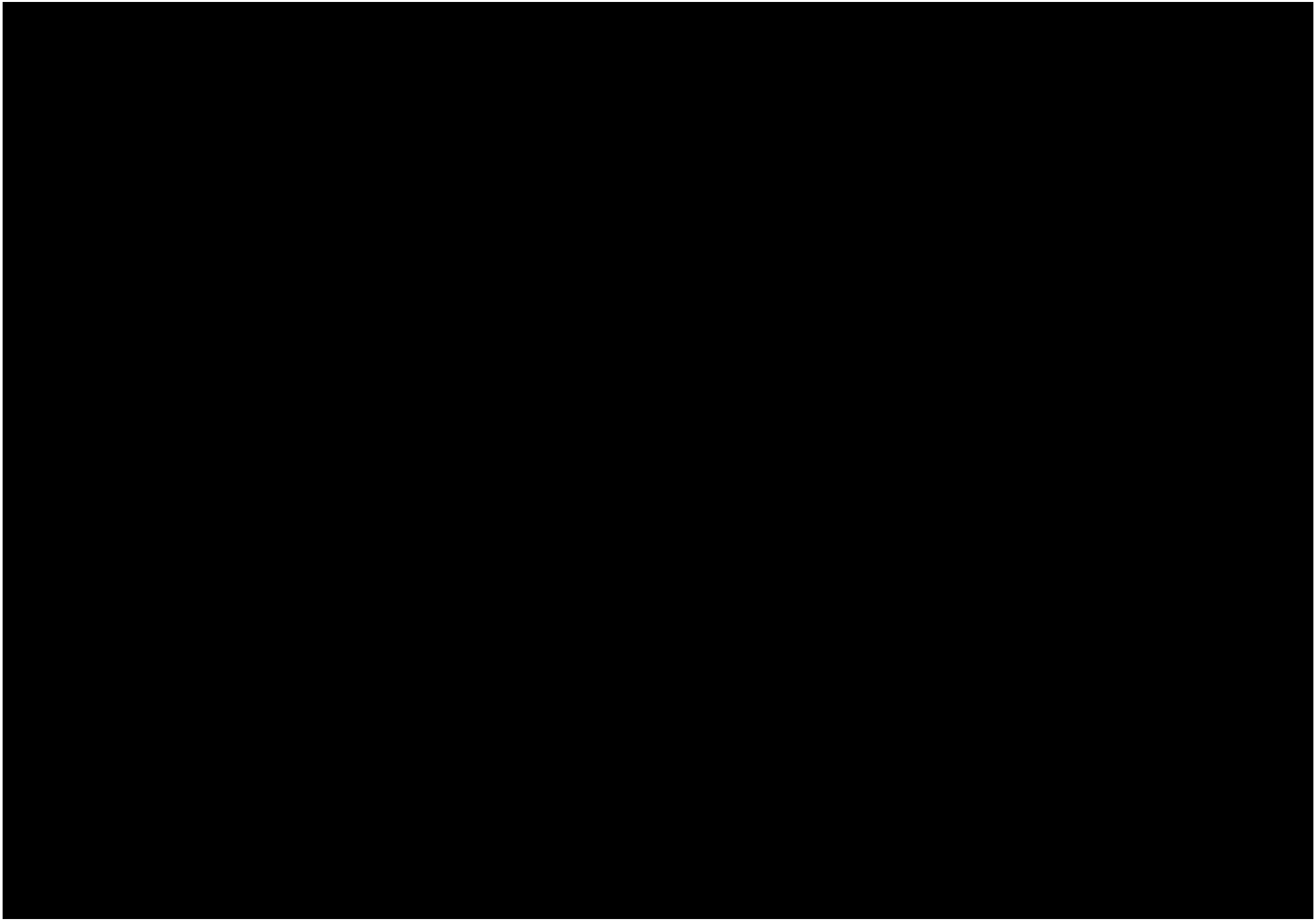
Northern Rio Arriba Electric Cooperative, Inc.



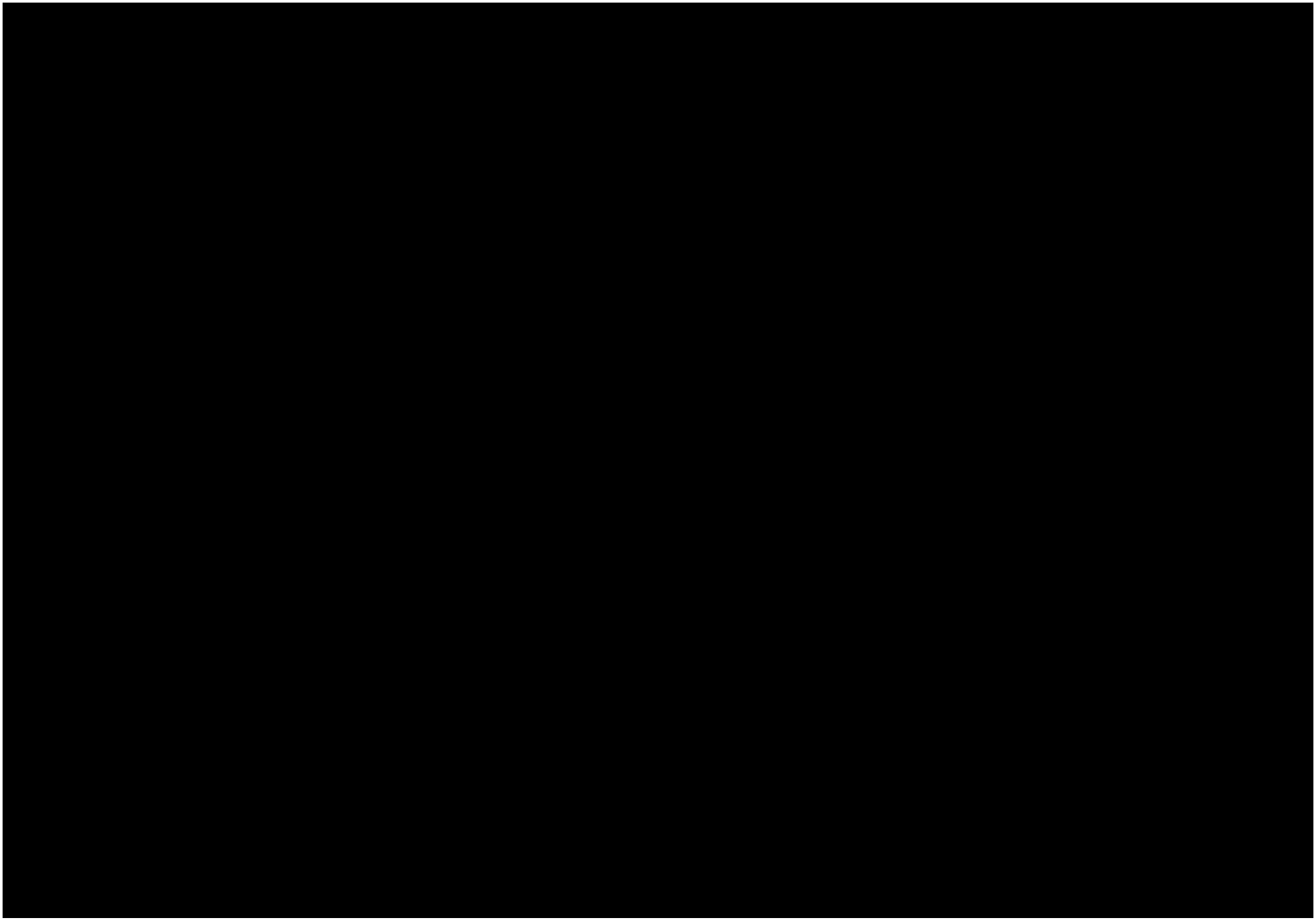
Annual Summer Coincident Peak
Roosevelt Public Power District



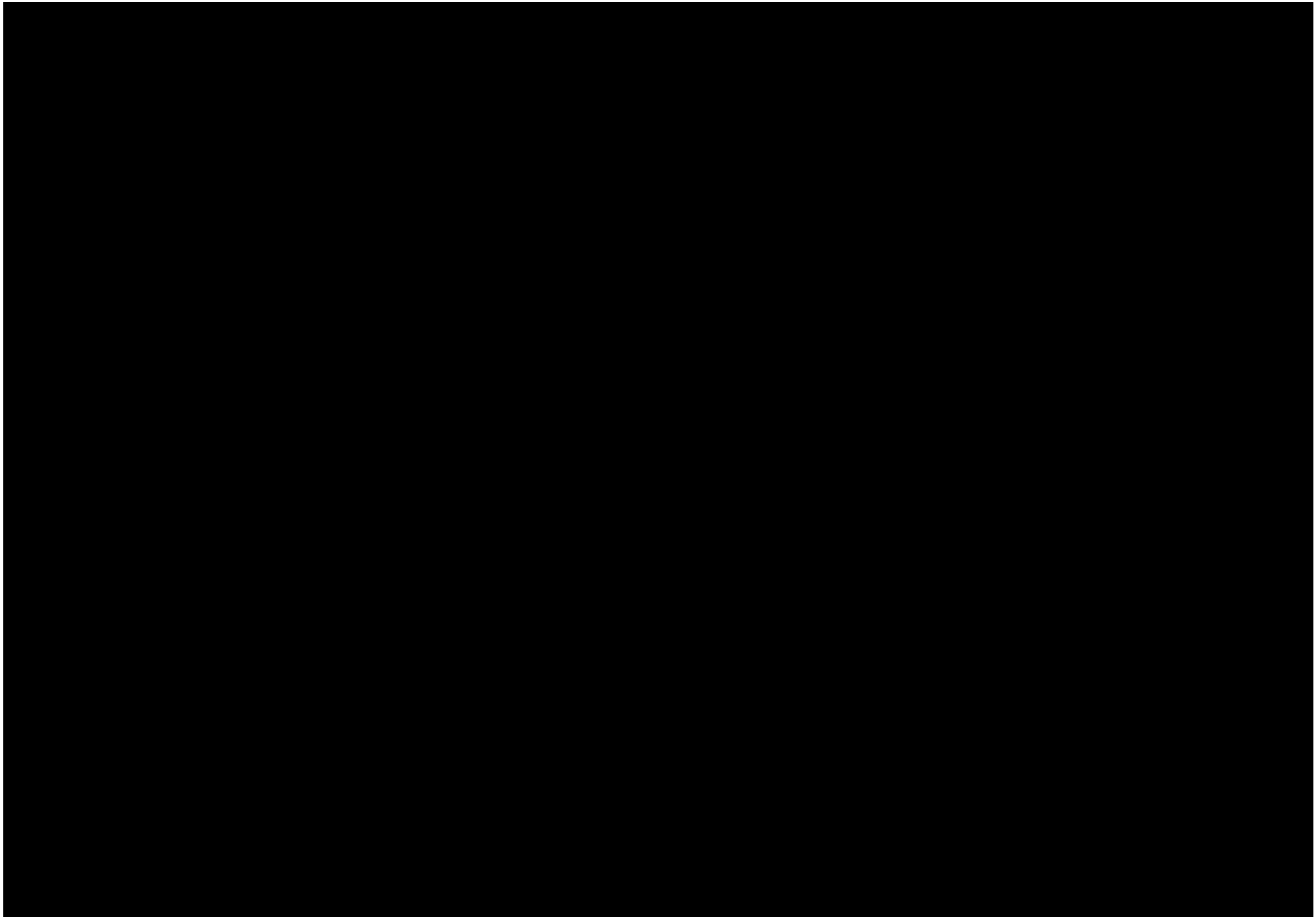
Annual Summer Coincident Peak
Sierra Electric Cooperative, Inc.



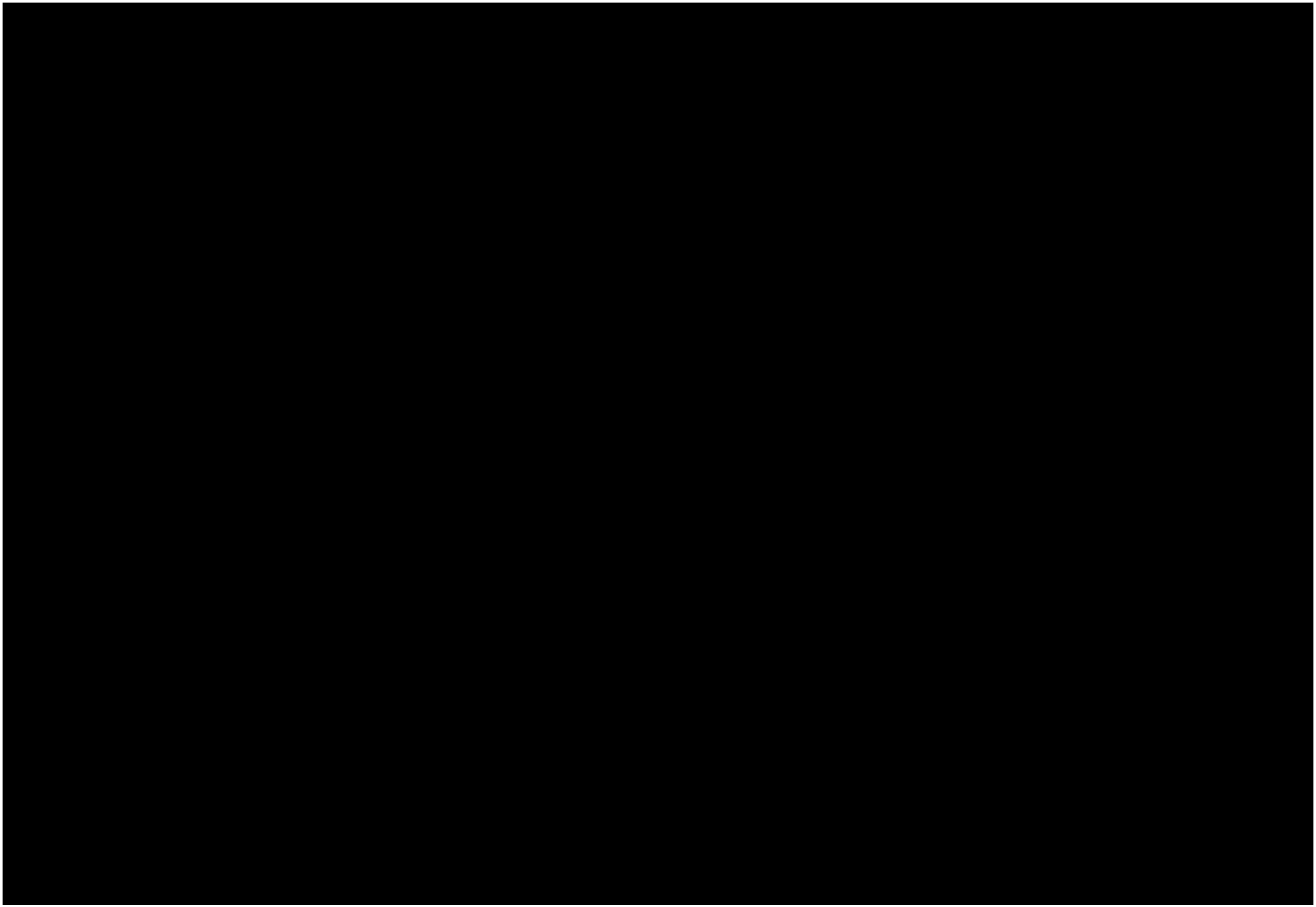
Annual Summer Coincident Peak
Sangre de Cristo Electric Association, Inc.



Annual Summer Coincident Peak
Southeast Colorado Power Association

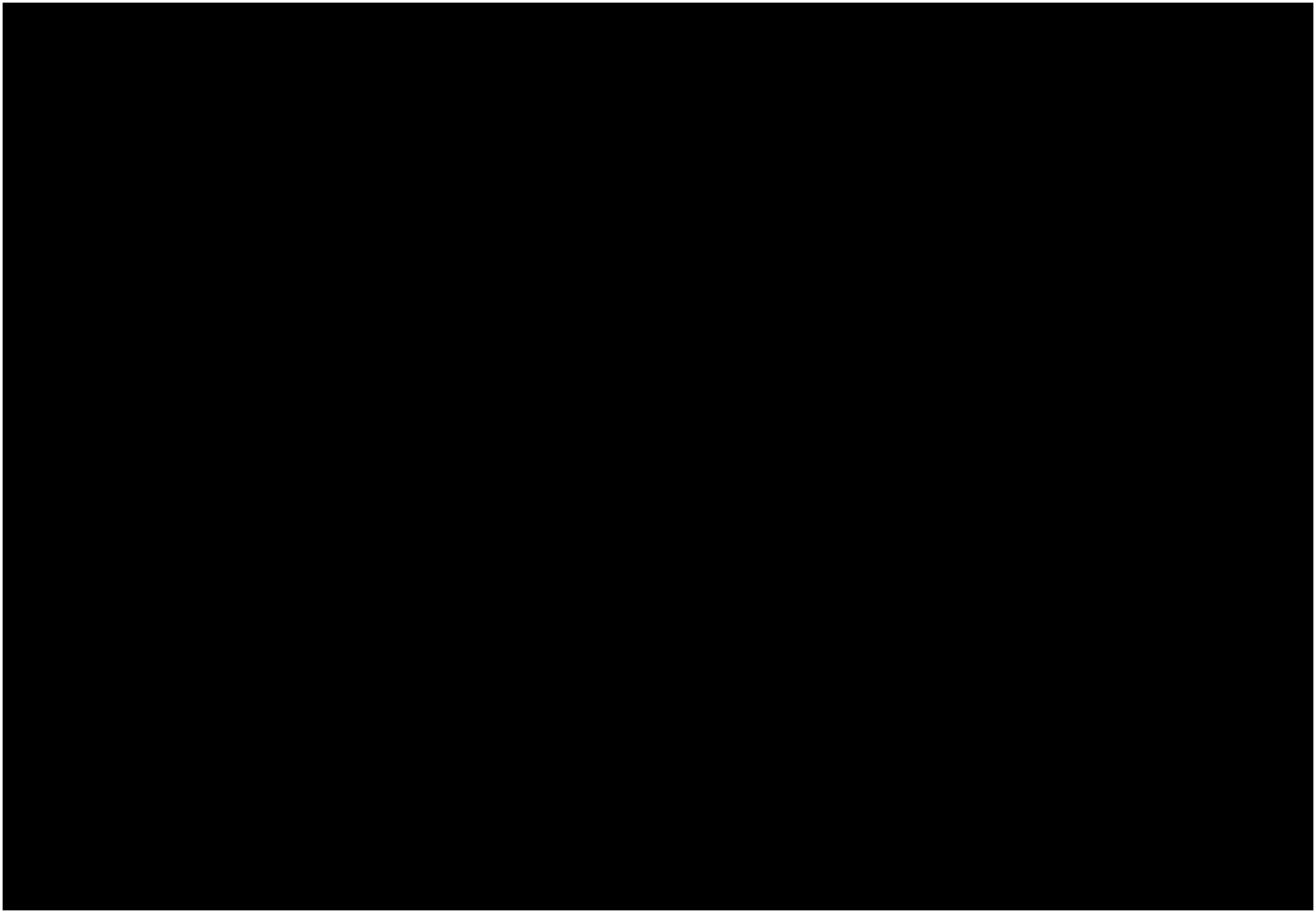


Annual Summer Coincident Peak
San Isabel Electric Association, Inc.



Annual Summer Coincident Peak

San Luis Valley Rural Electric Cooperative, Inc.

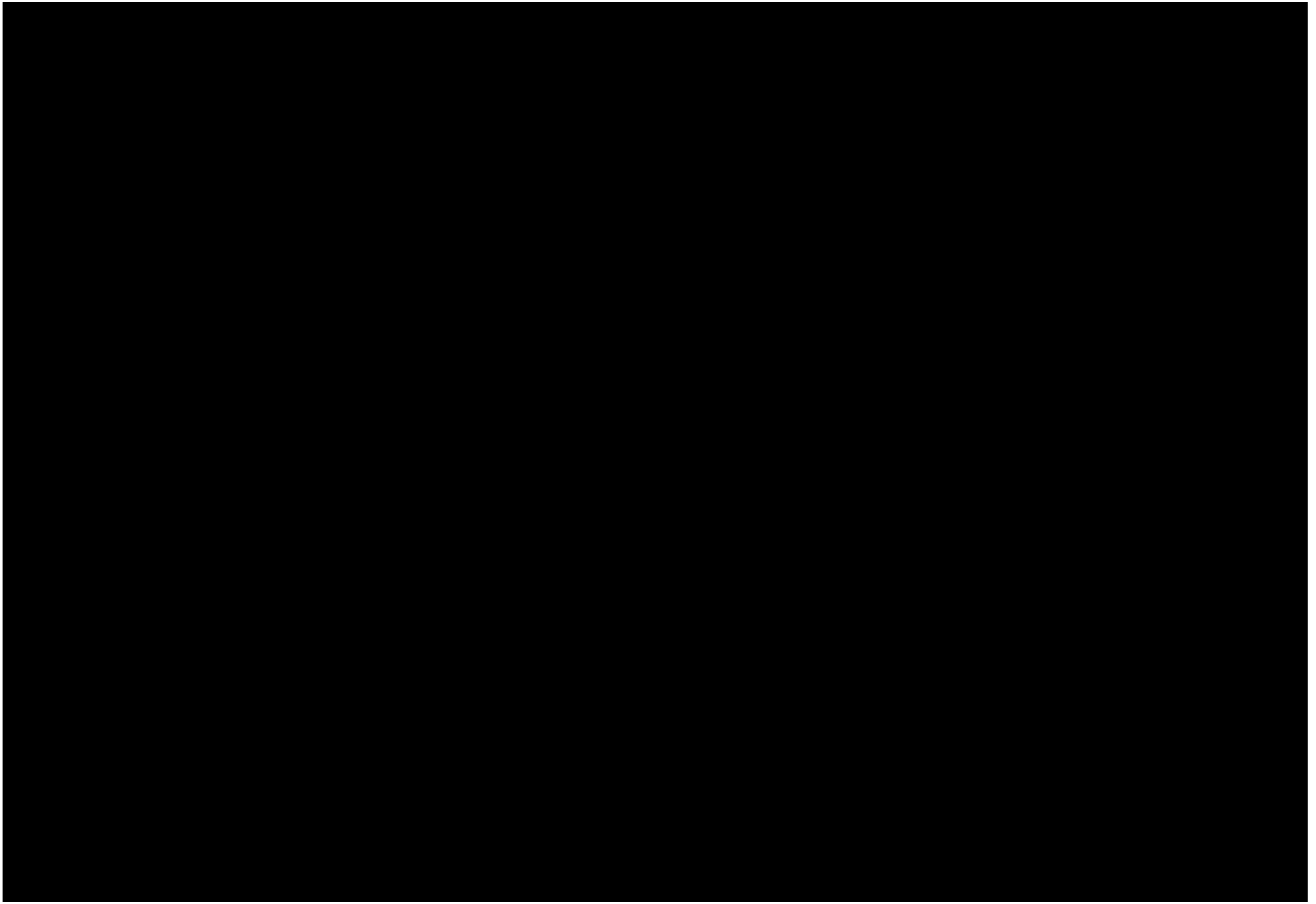


Annual Summer Coincident Peak

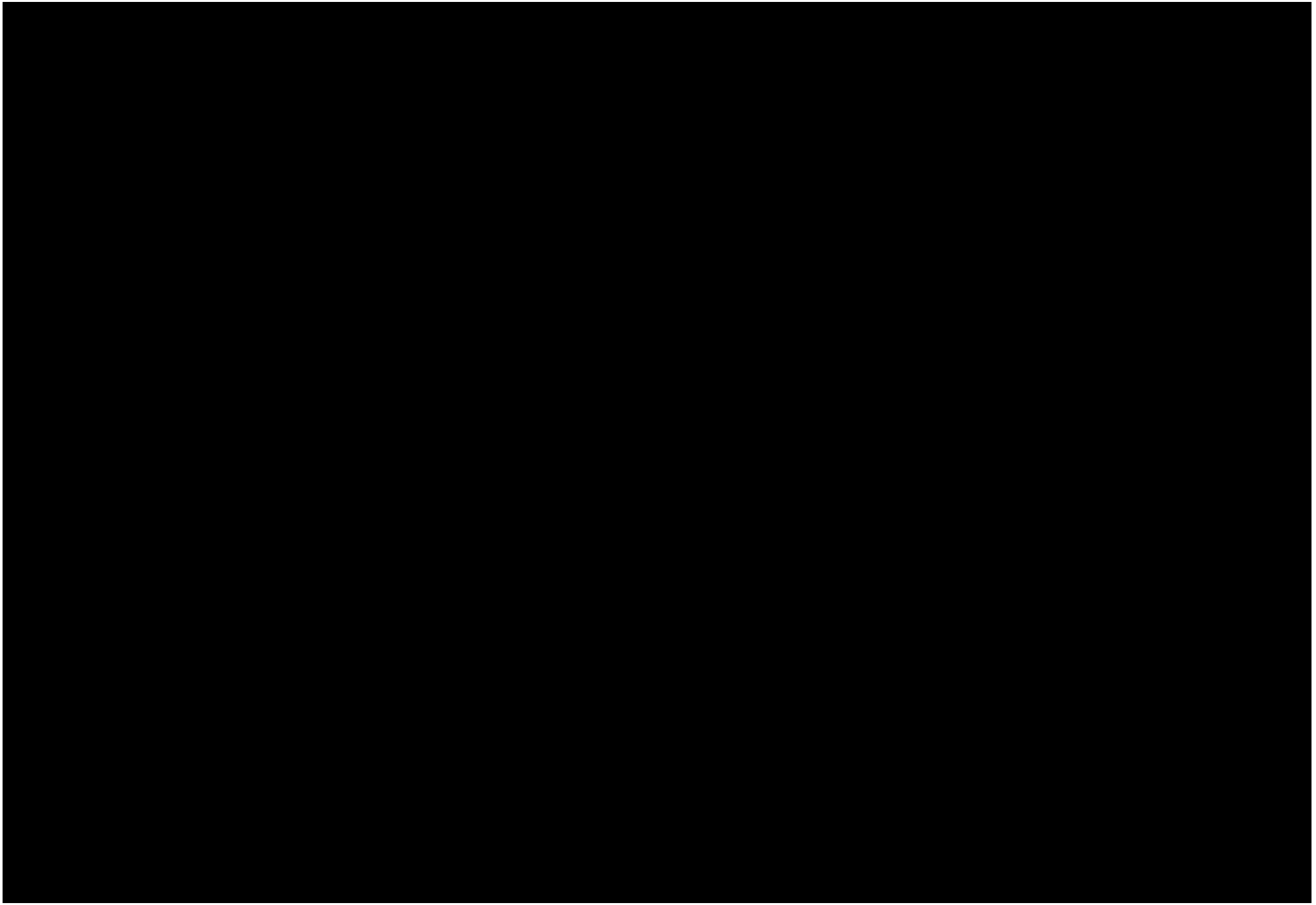
San Miguel Power Association, Inc.

[redacted]

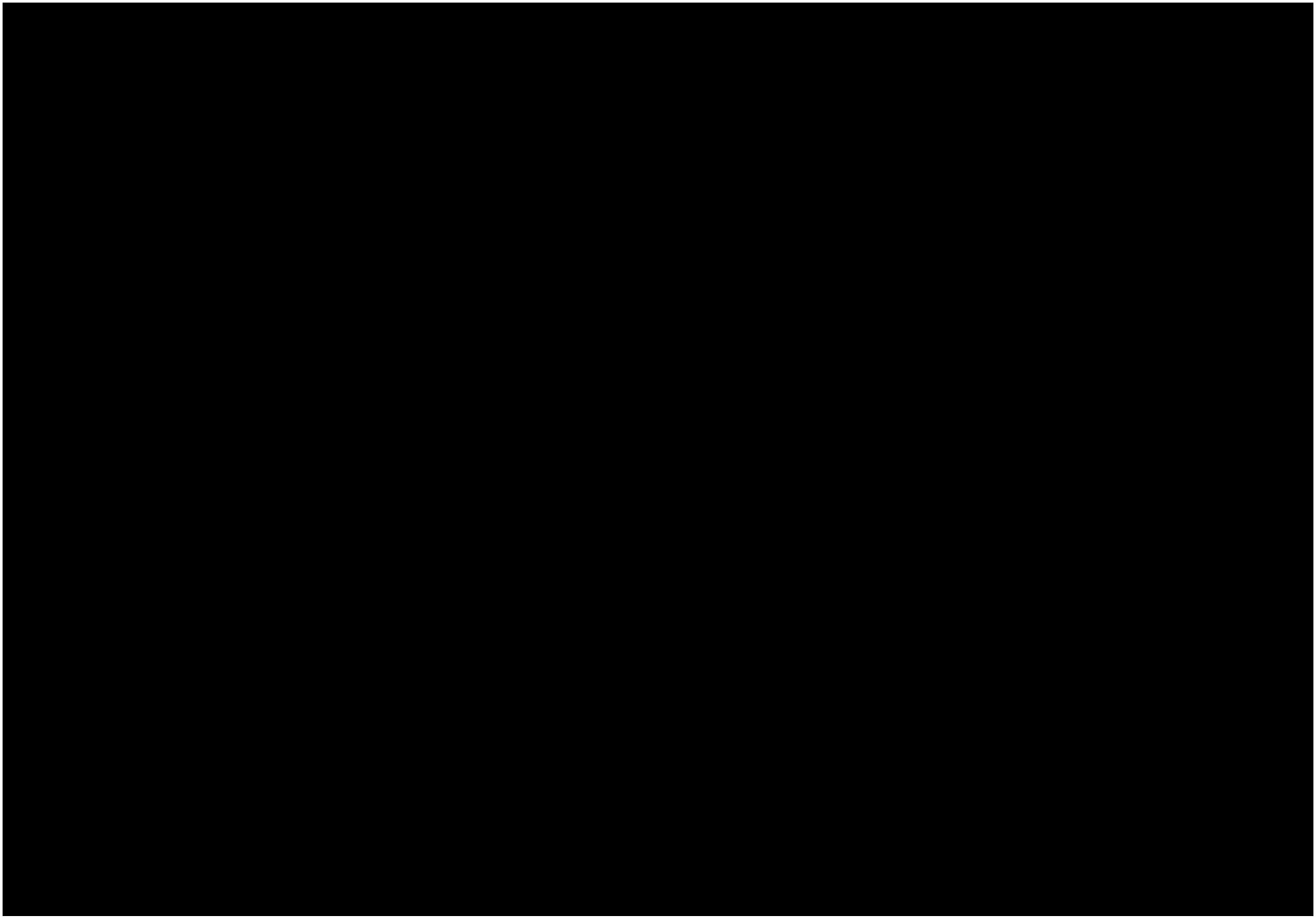
Annual Summer Coincident Peak
Socorro Electric Cooperative, Inc.



Annual Summer Coincident Peak
Springer Electric Cooperative, Inc.

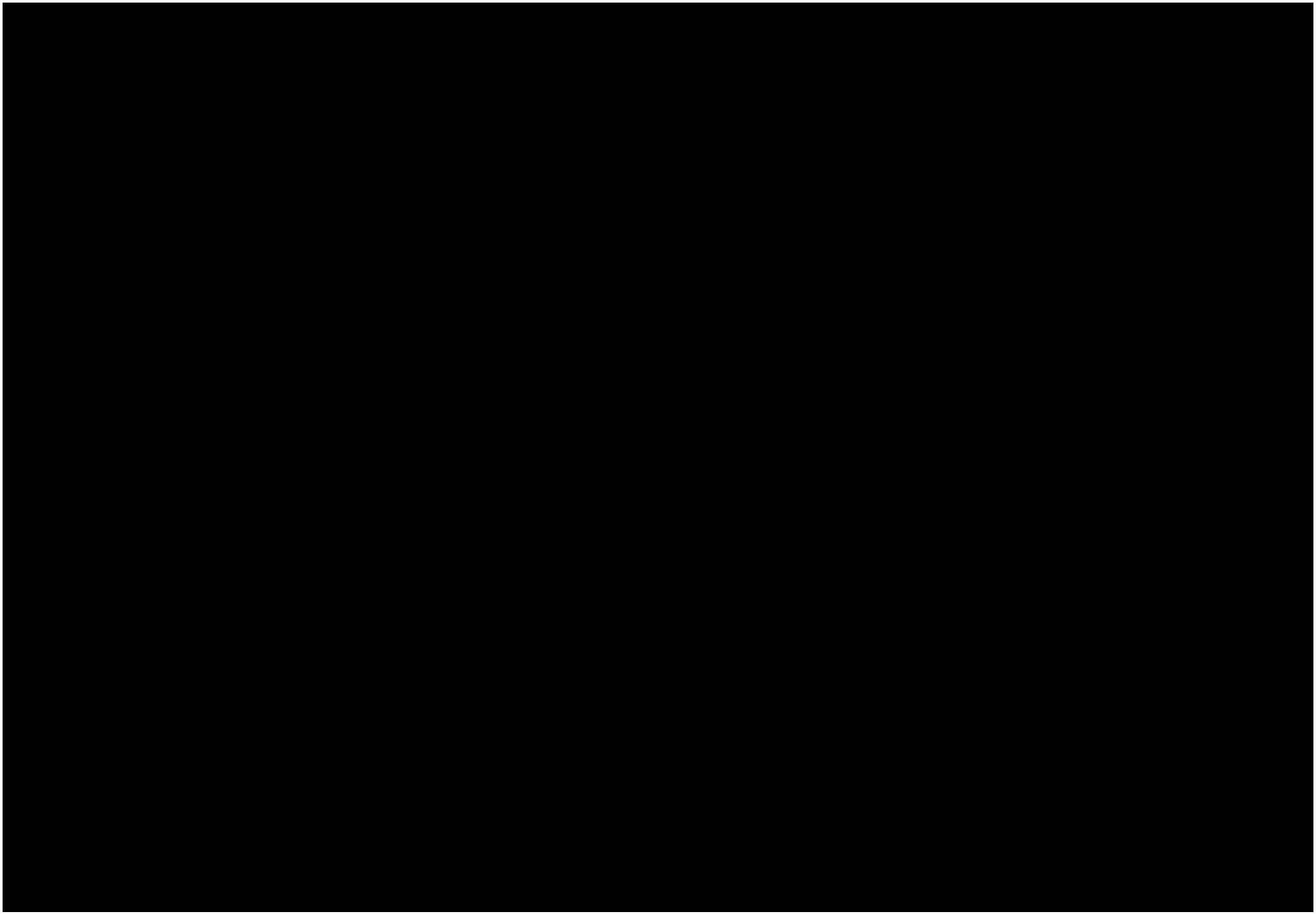


Annual Summer Coincident Peak
Southwestern Electric Cooperative, Inc.



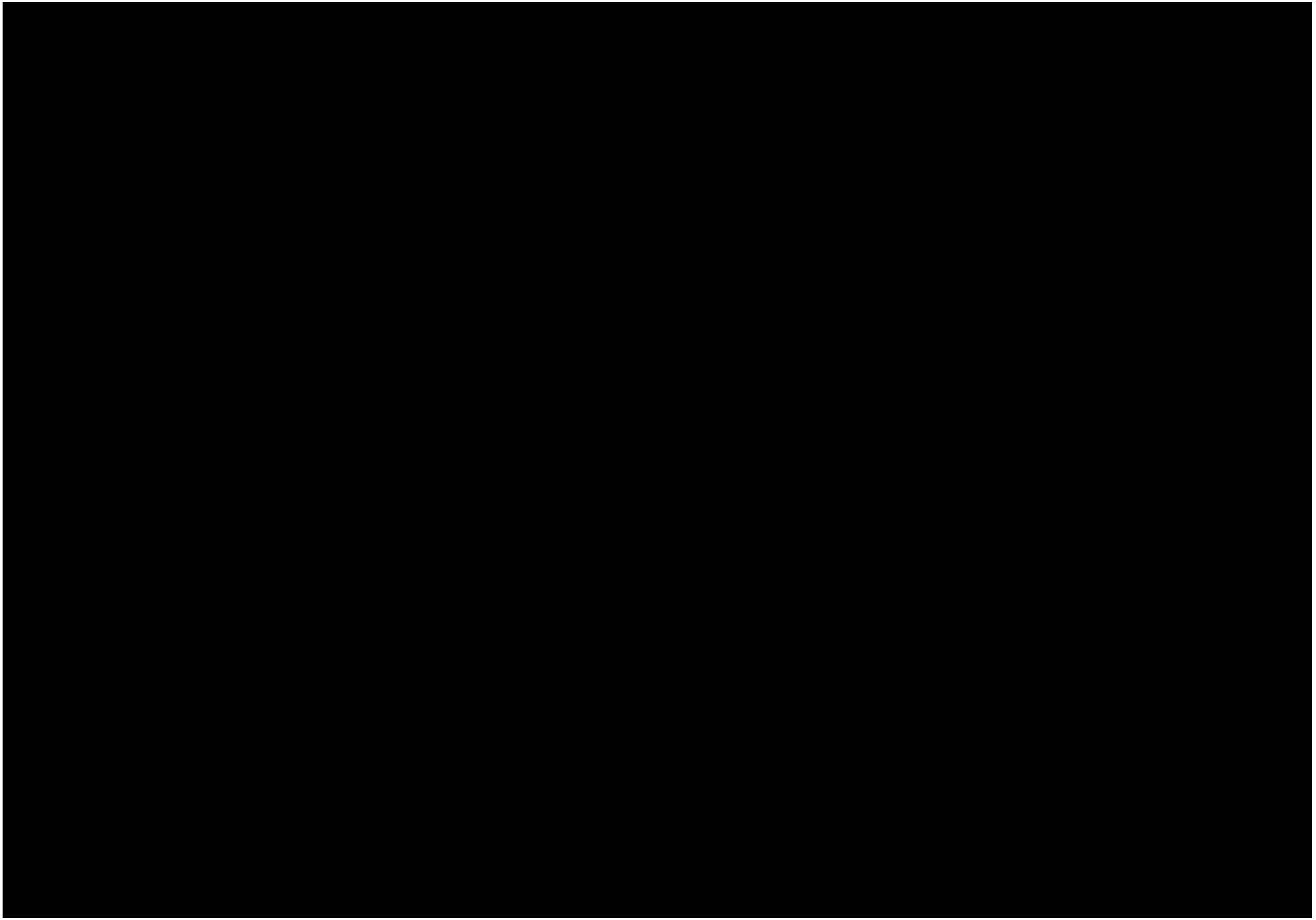
Annual Summer Coincident Peak

United Power, Inc.



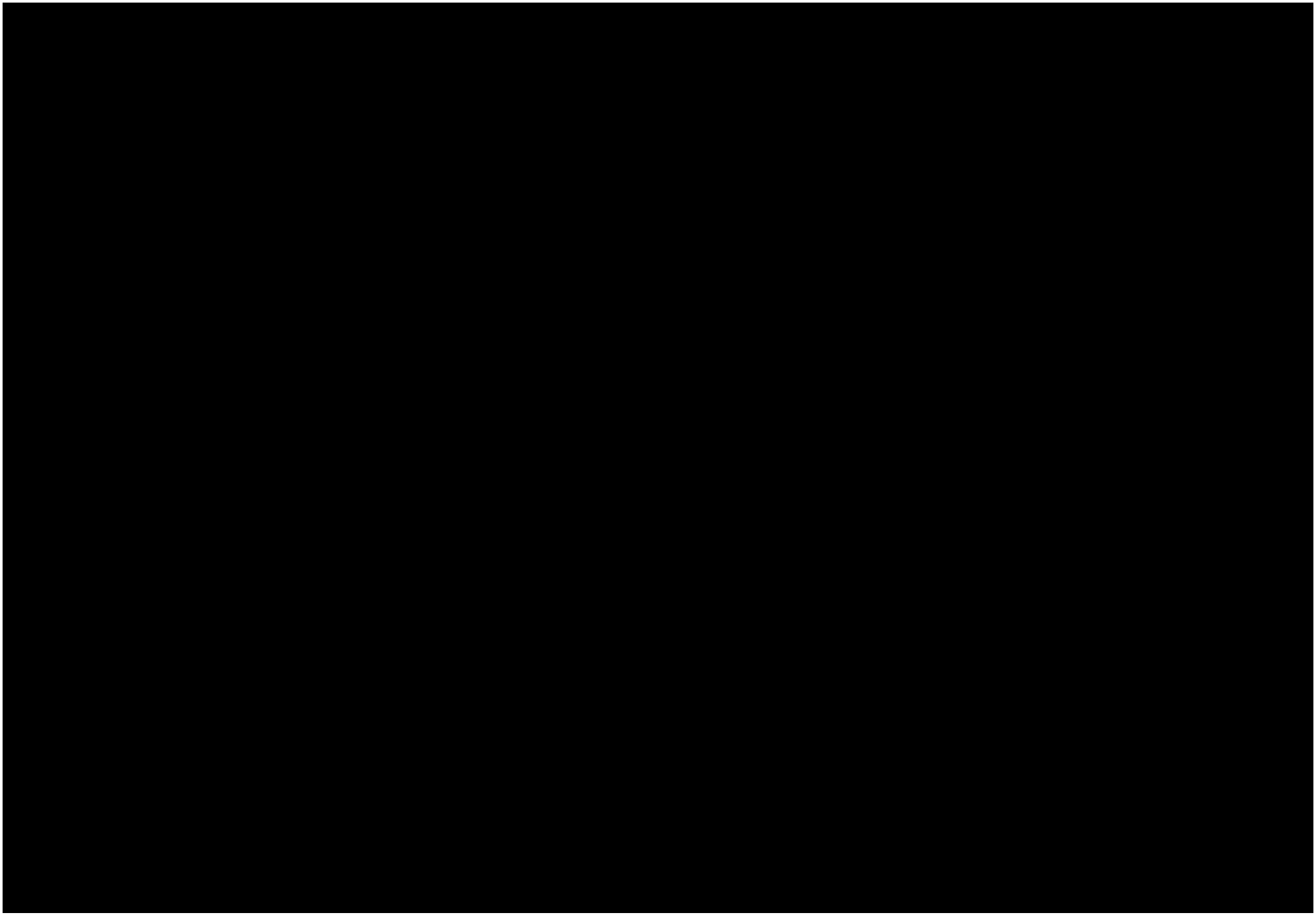
Annual Summer Coincident Peak

Wheat Belt Public Power District



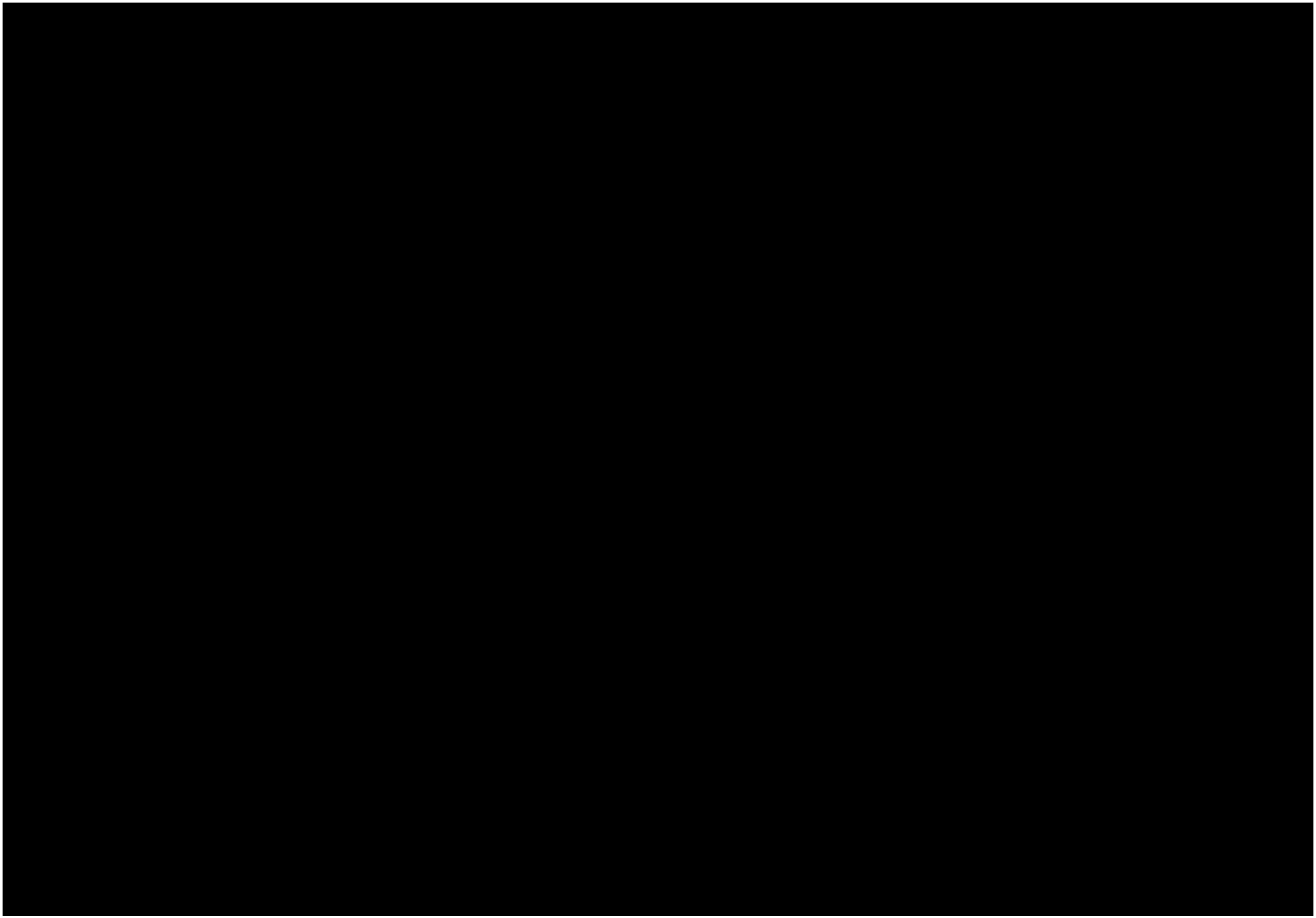
Annual Summer Coincident Peak

Wheatland Rural Electric Association, Inc.

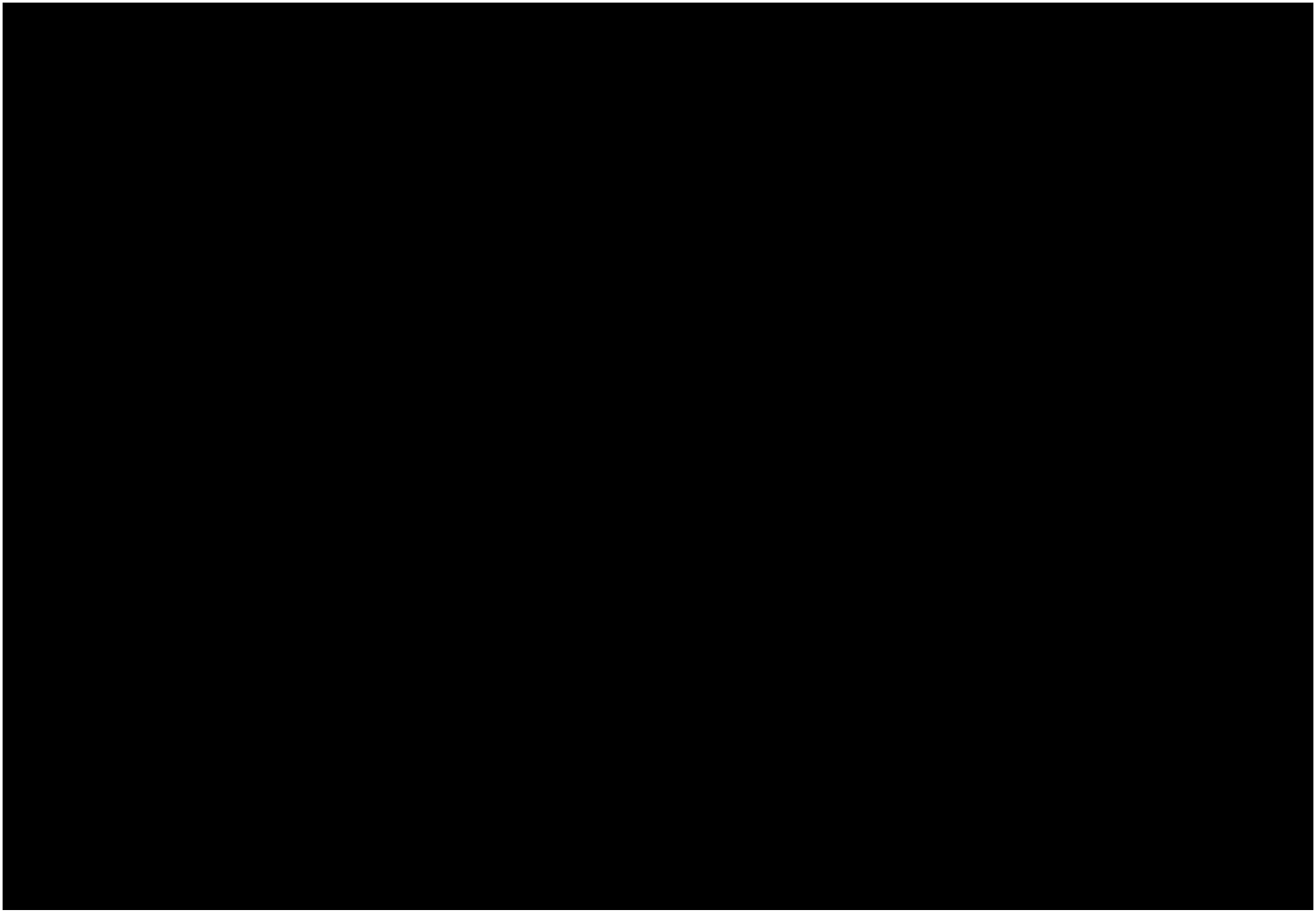


Annual Summer Coincident Peak

White River Electric Association, Inc.



Annual Summer Coincident Peak
Wyrulec Company



Annual Summer Coincident Peak
Y-W Electric Association, Inc.

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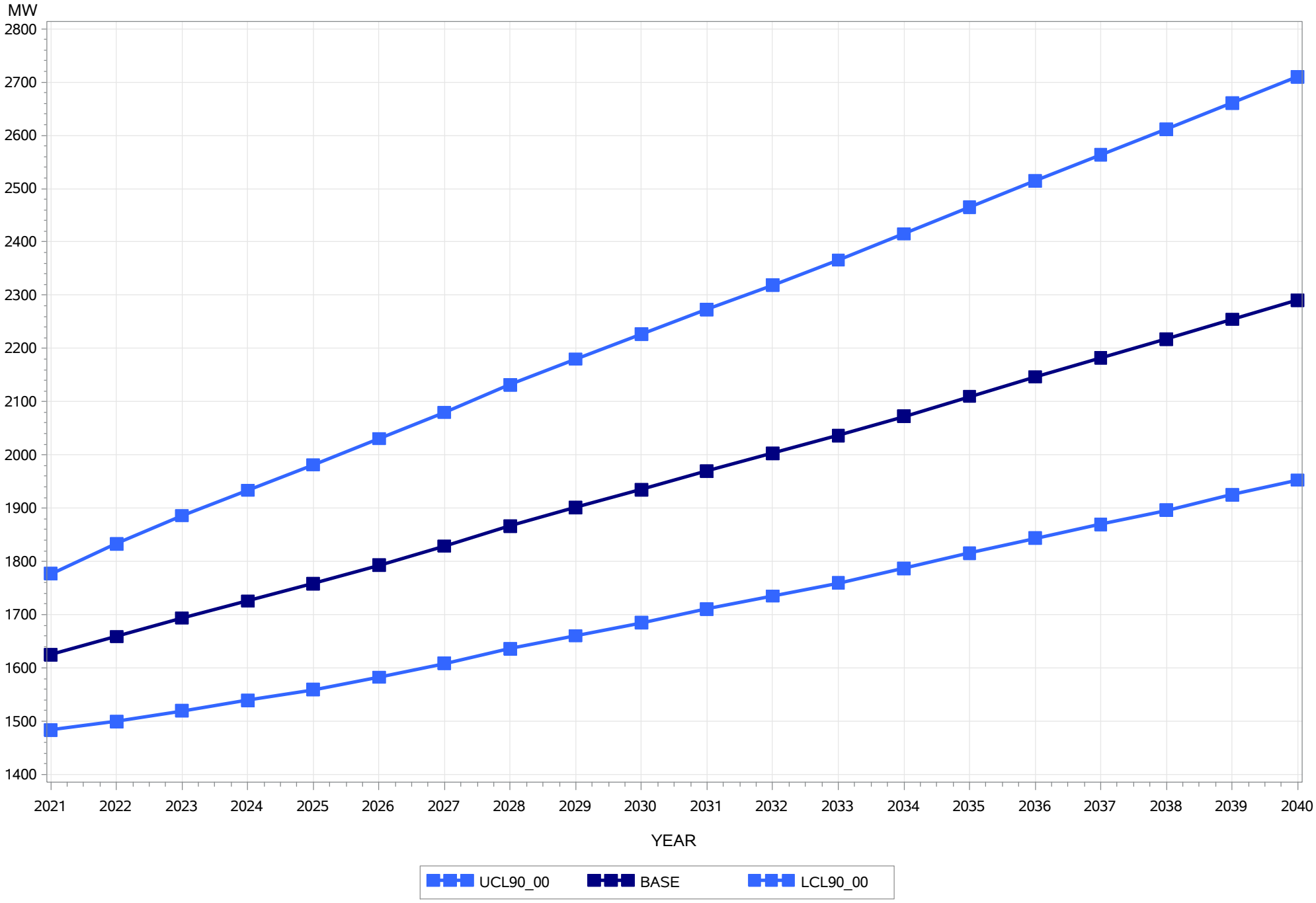
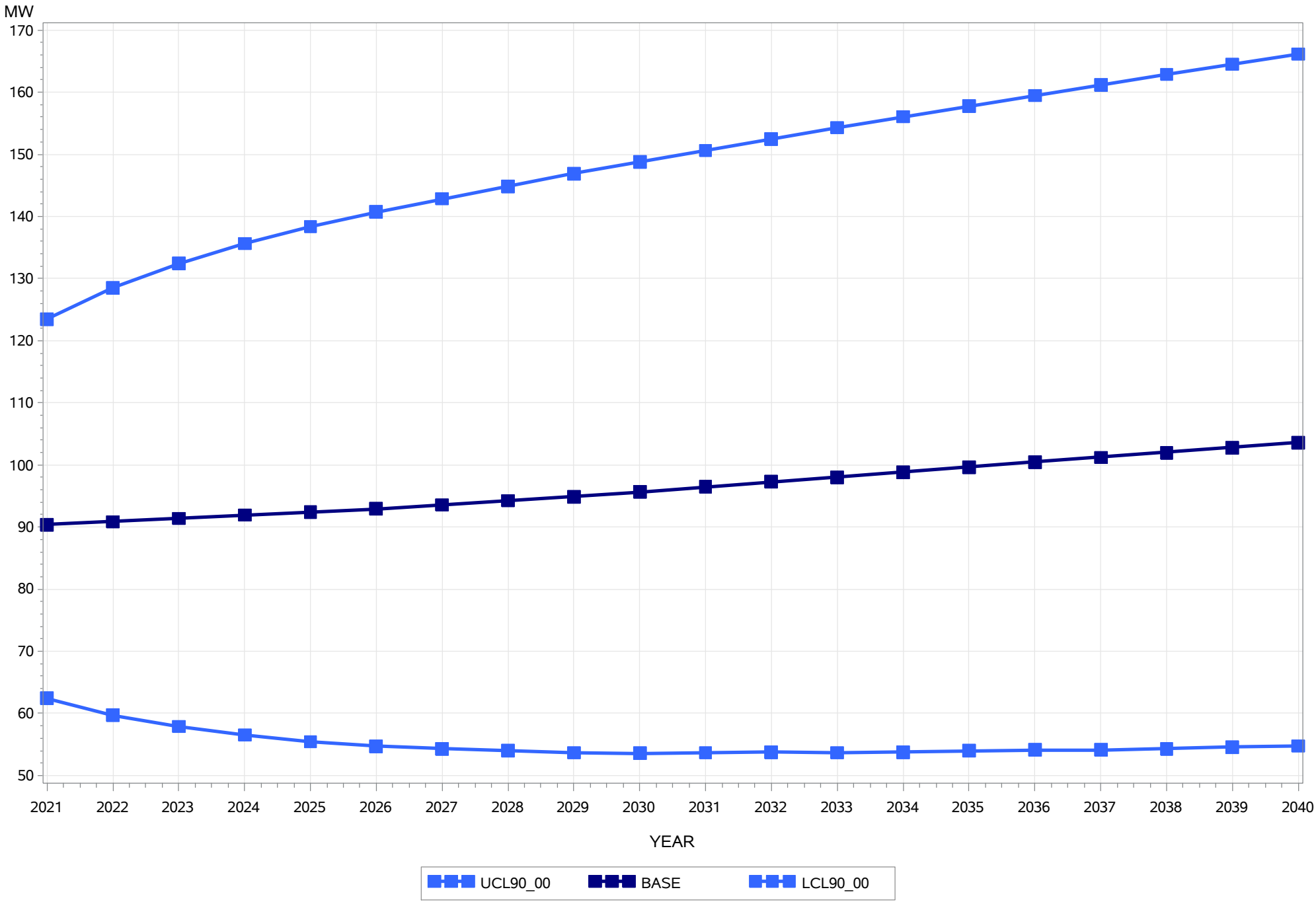
Annual Winter Coincident Peak
STATE OF COLORADO



Annual Winter Coincident Peak
STATE OF NEBRASKA



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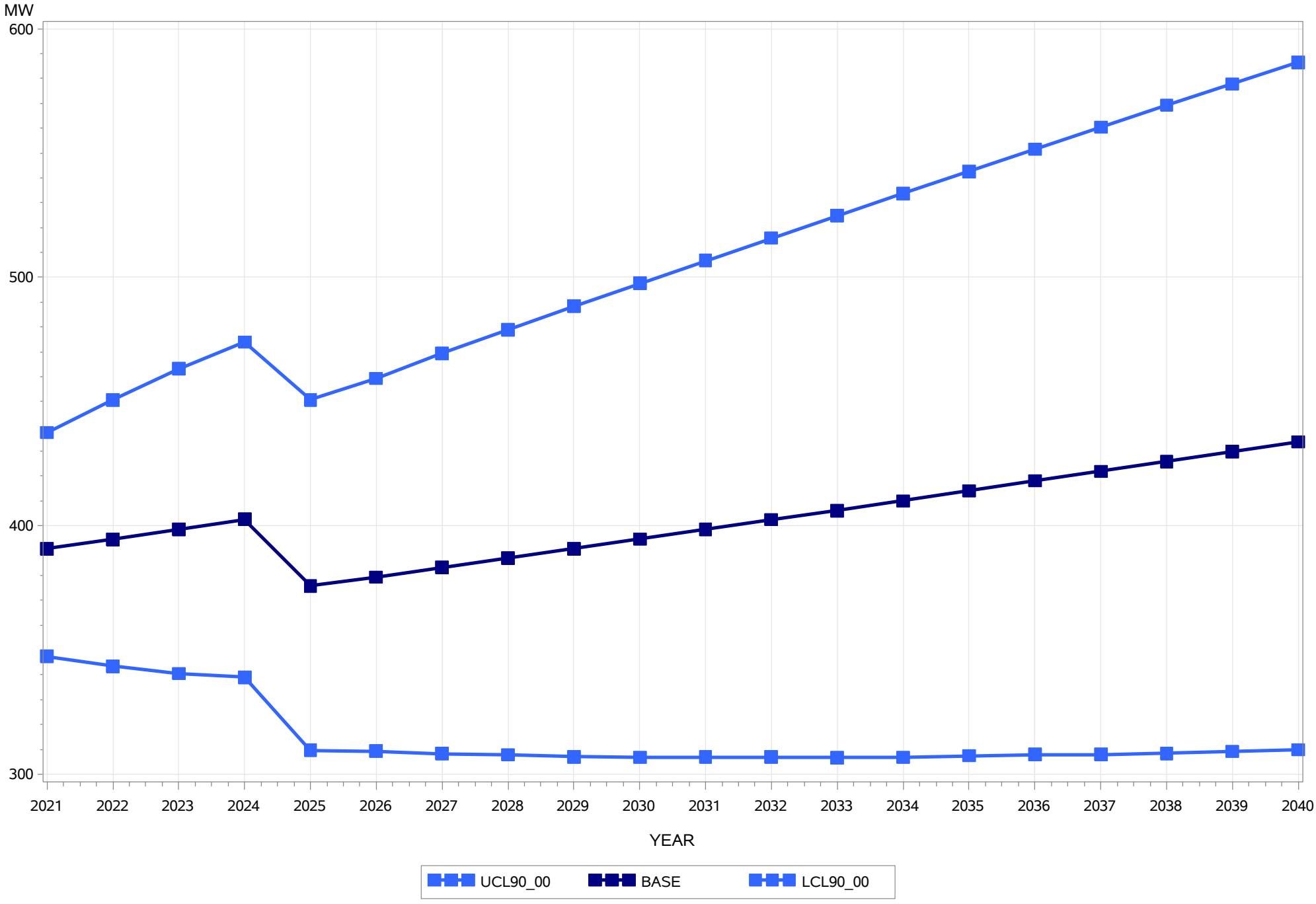
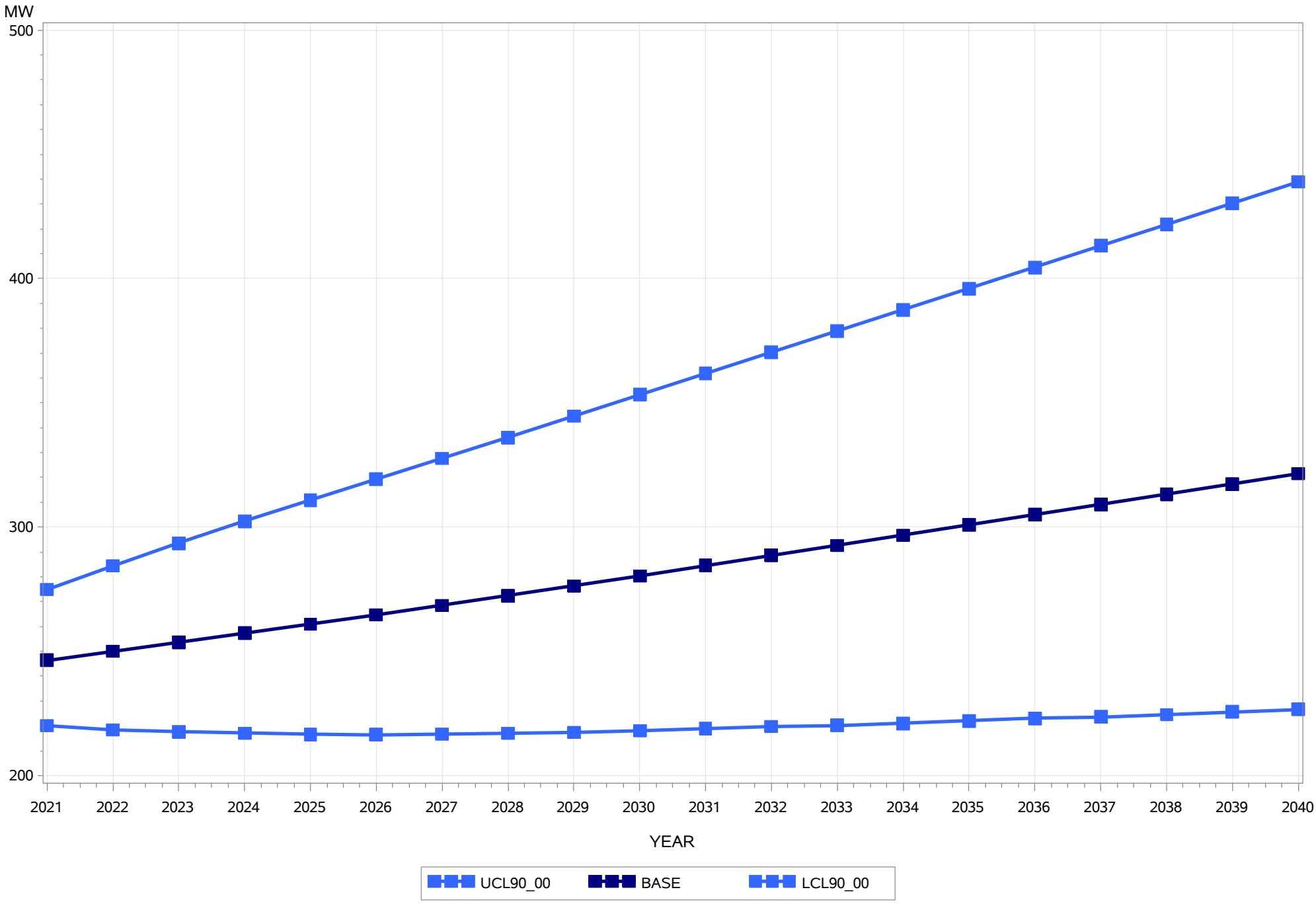
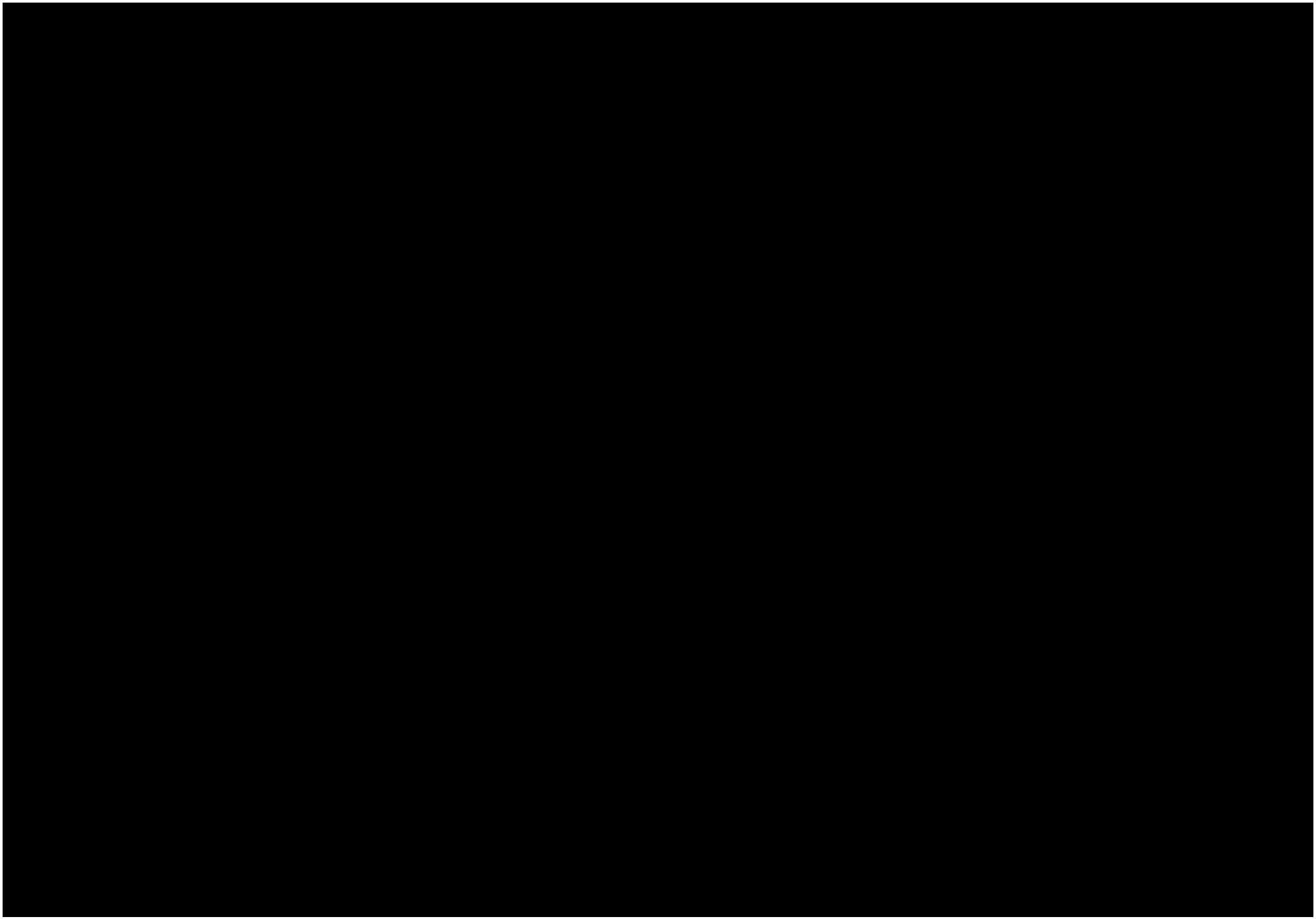
Annual Winter Coincident Peak
STATE OF NEW MEXICO



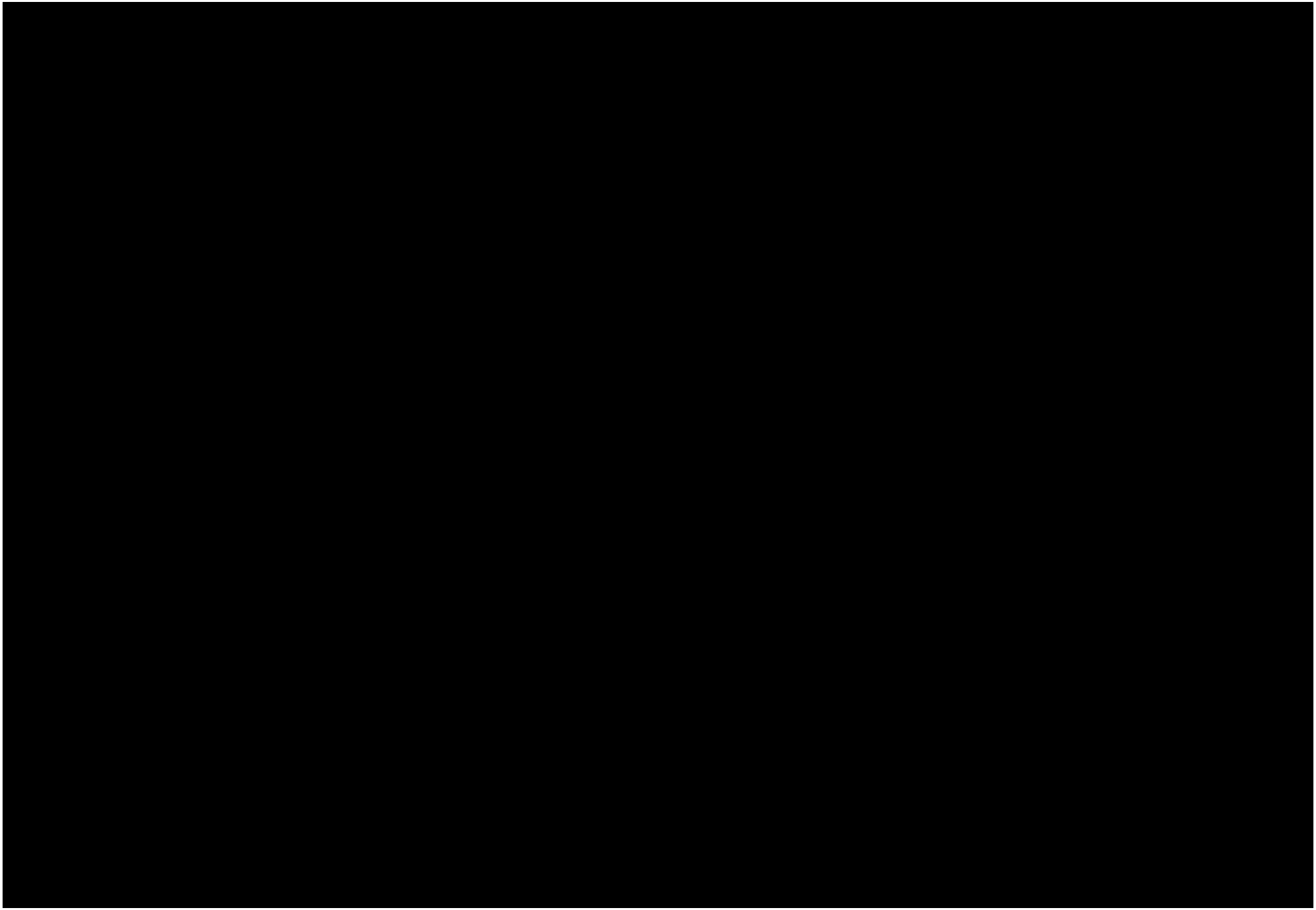
Annual Winter Coincident Peak
STATE OF WYOMING



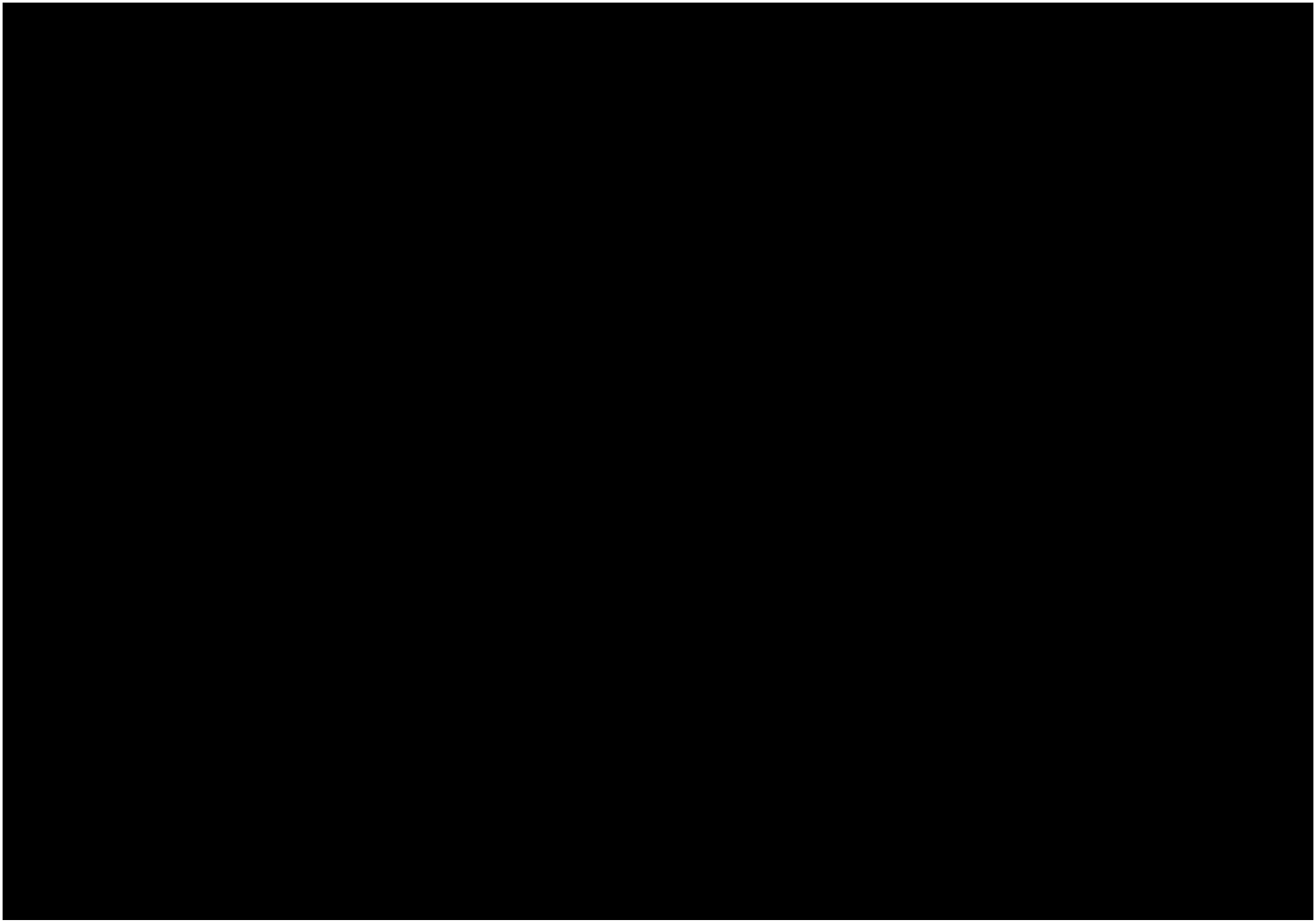
Annual Winter Coincident Peak
Big Horn Rural Electric Company



Annual Winter Coincident Peak
Carbon Power and Light, Inc.



Annual Winter Coincident Peak
Continental Divide Electric Cooperative, Inc.



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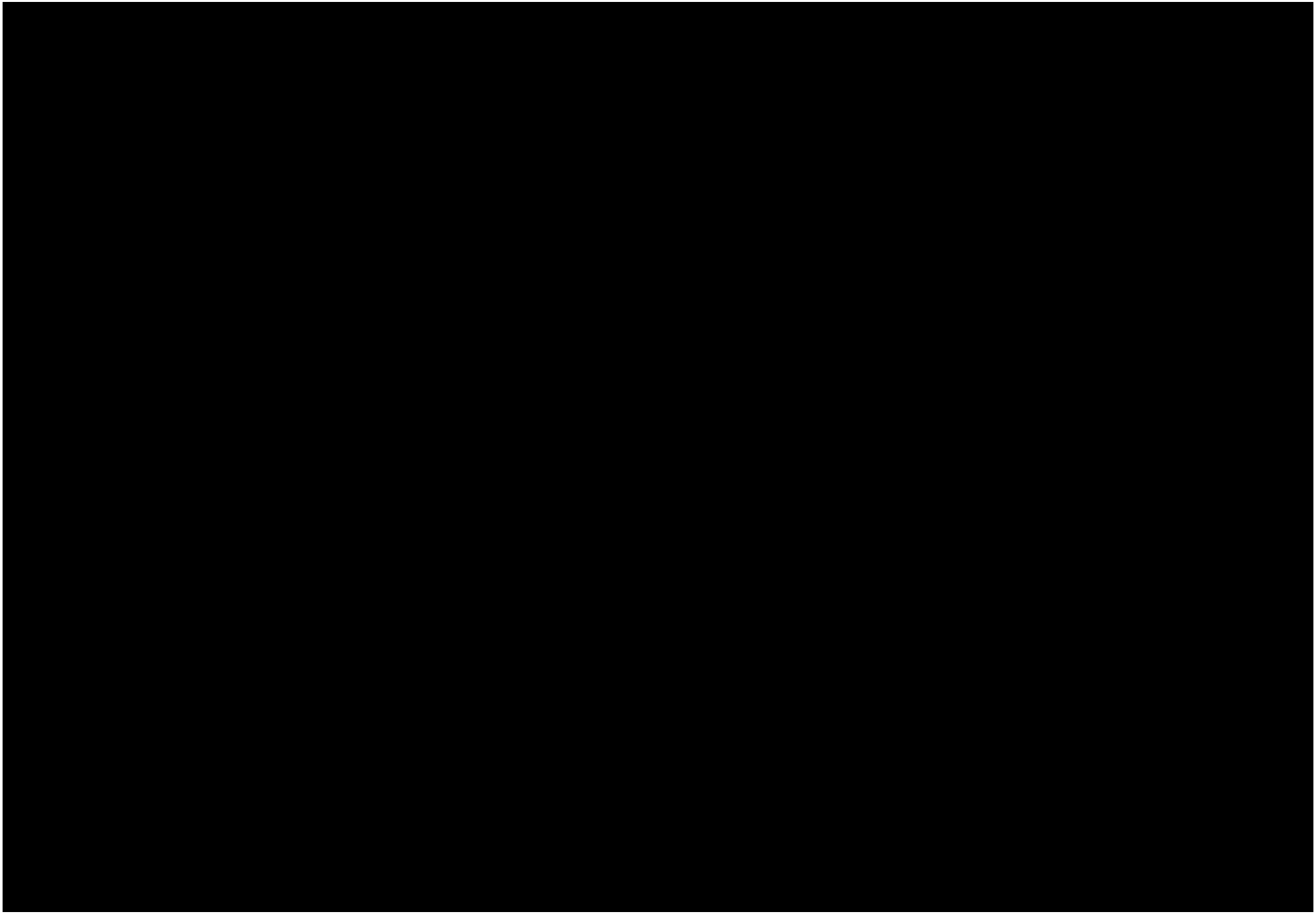
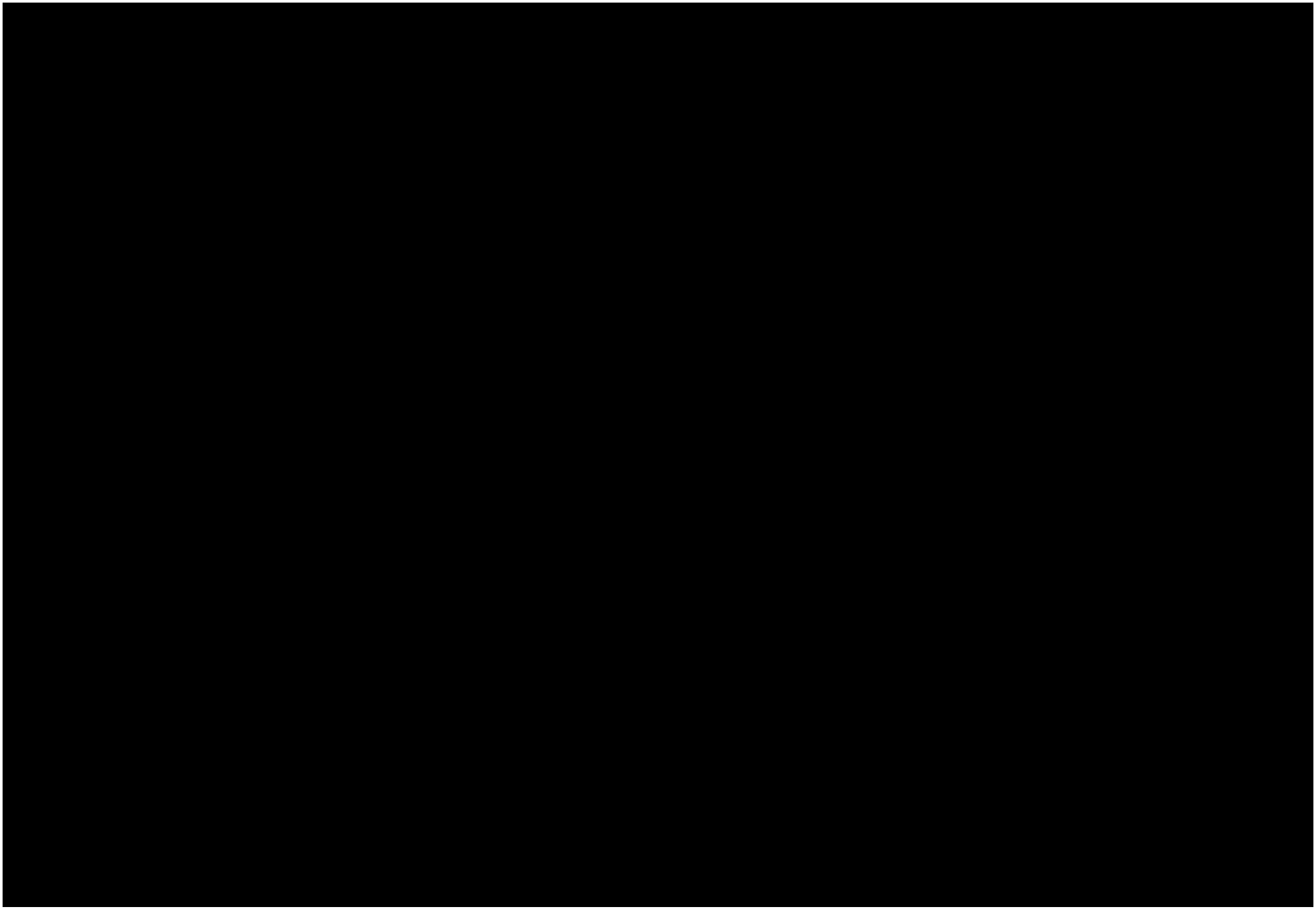
Annual Winter Coincident Peak

Columbus Electric Cooperative, Inc.

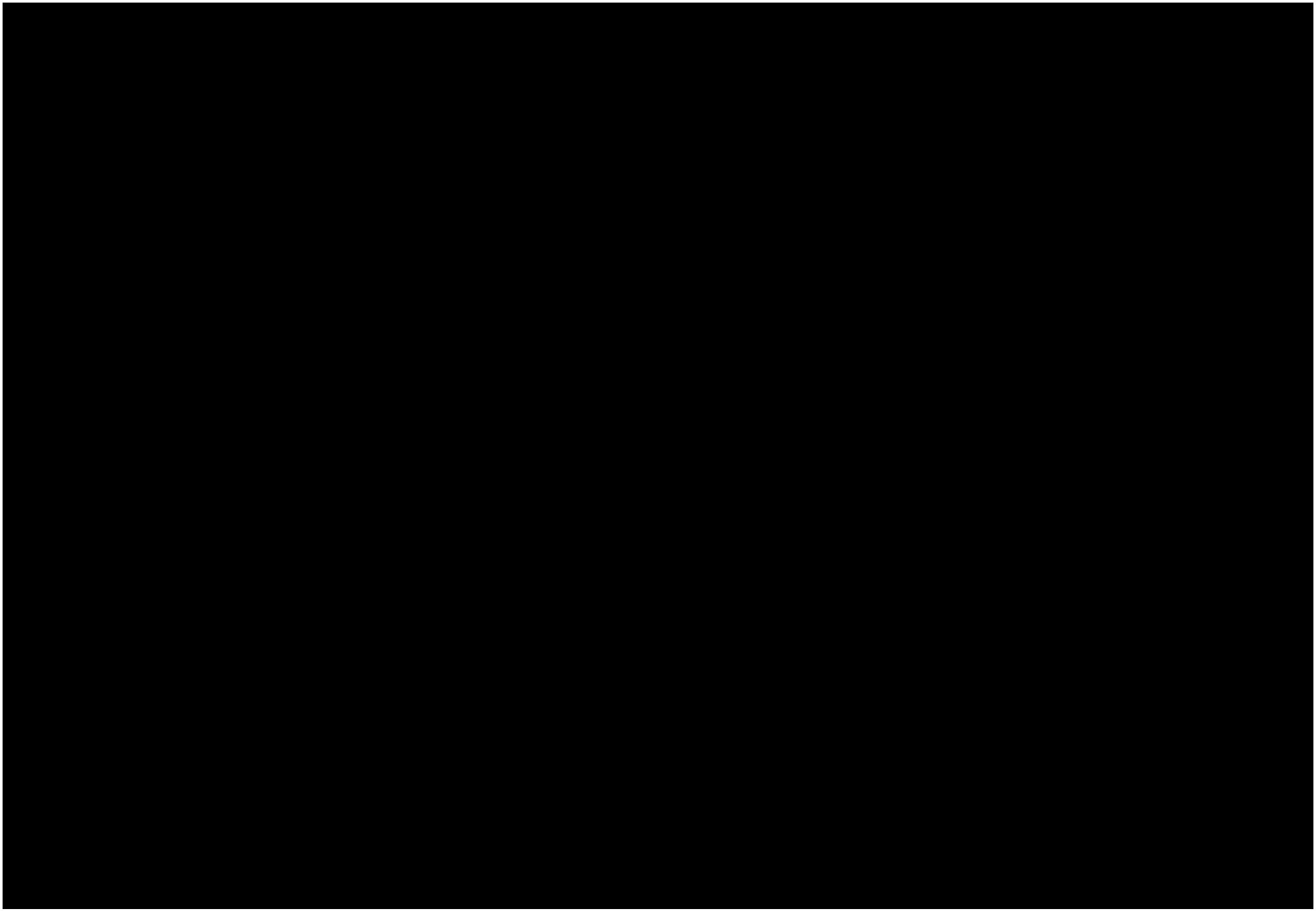


Annual Winter Coincident Peak

Central New Mexico Electric Cooperative, Inc.



Annual Winter Coincident Peak
Chimney Rock Public Power District



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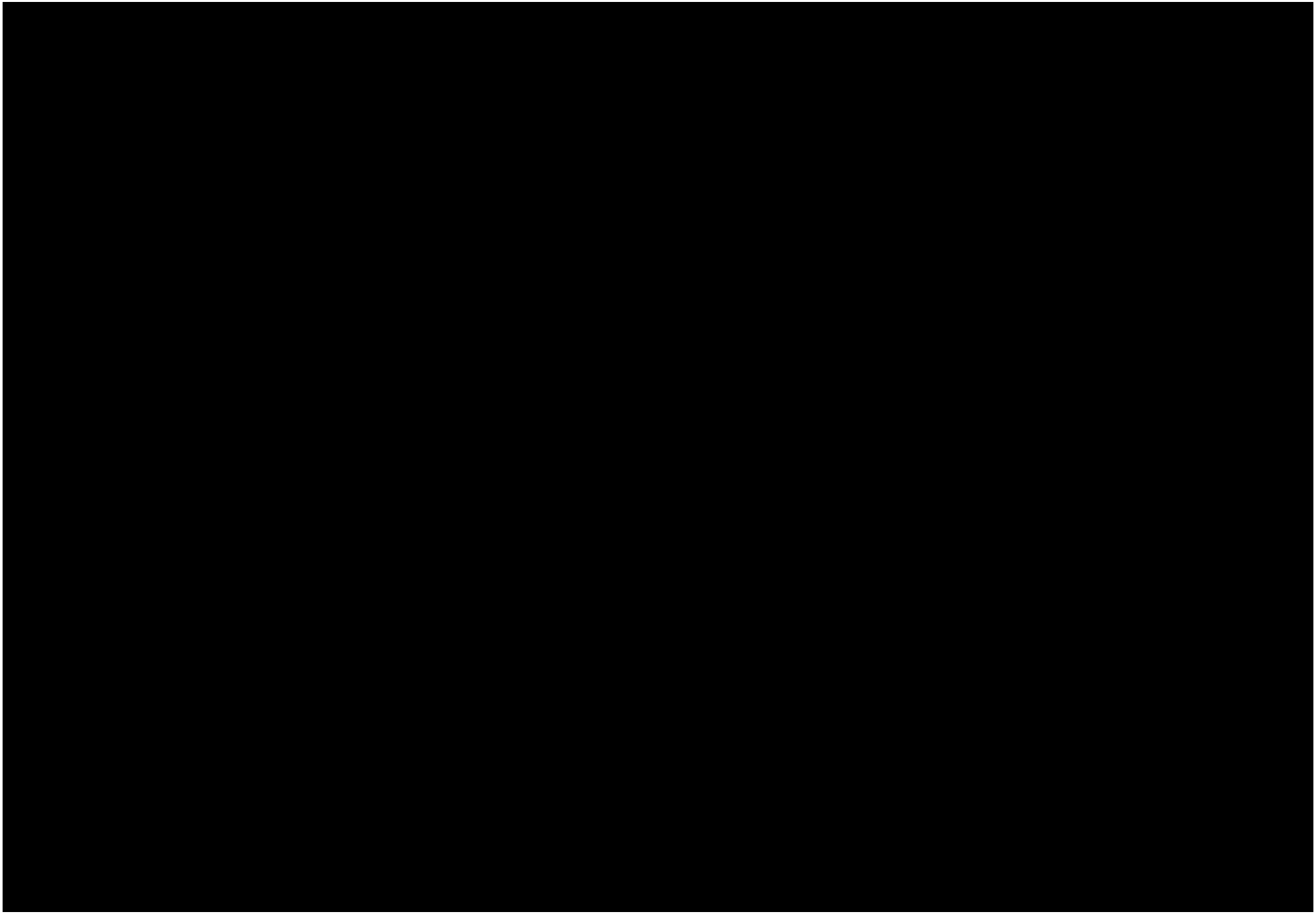
Annual Winter Coincident Peak

Empire Electric Association, Inc.



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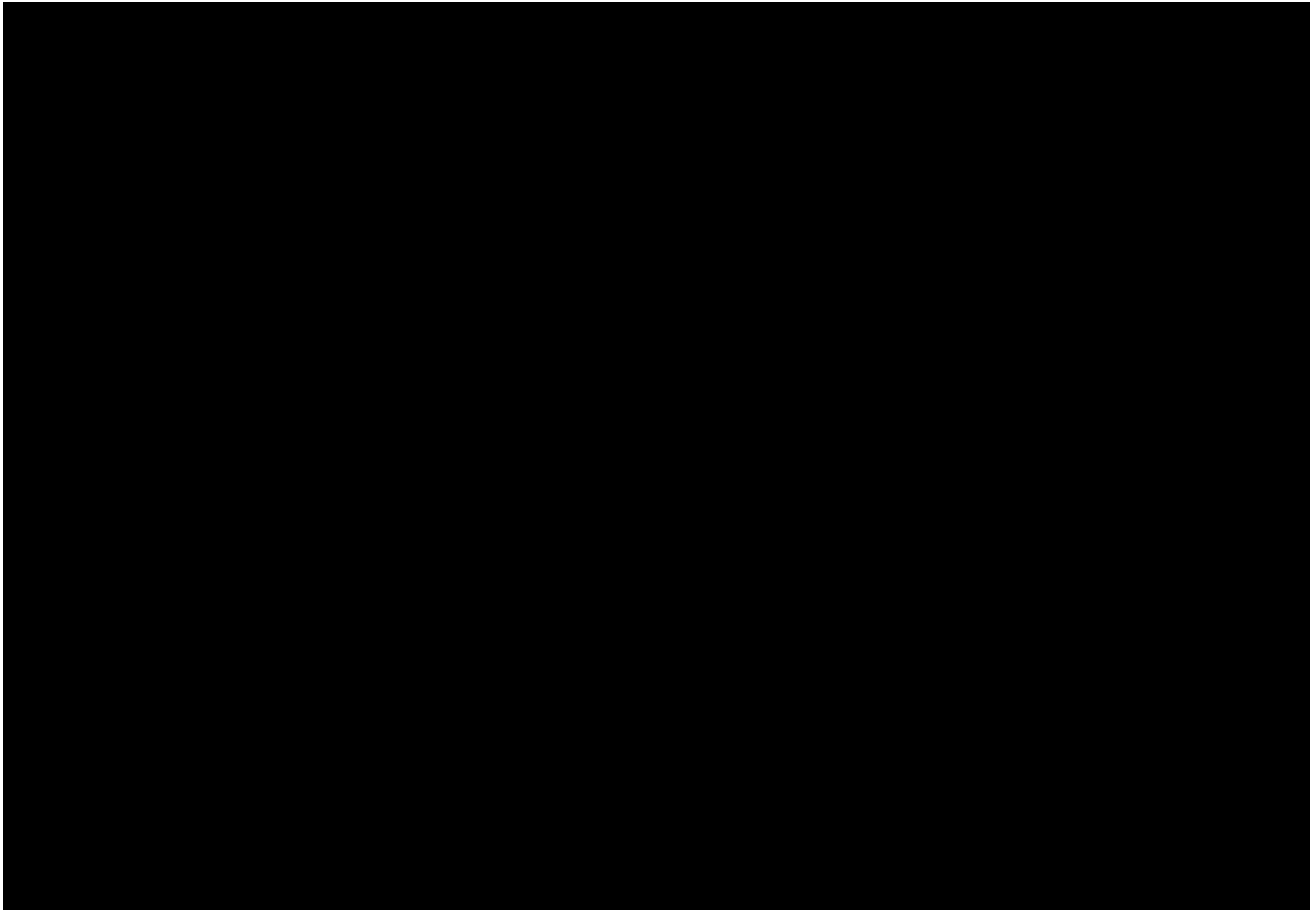
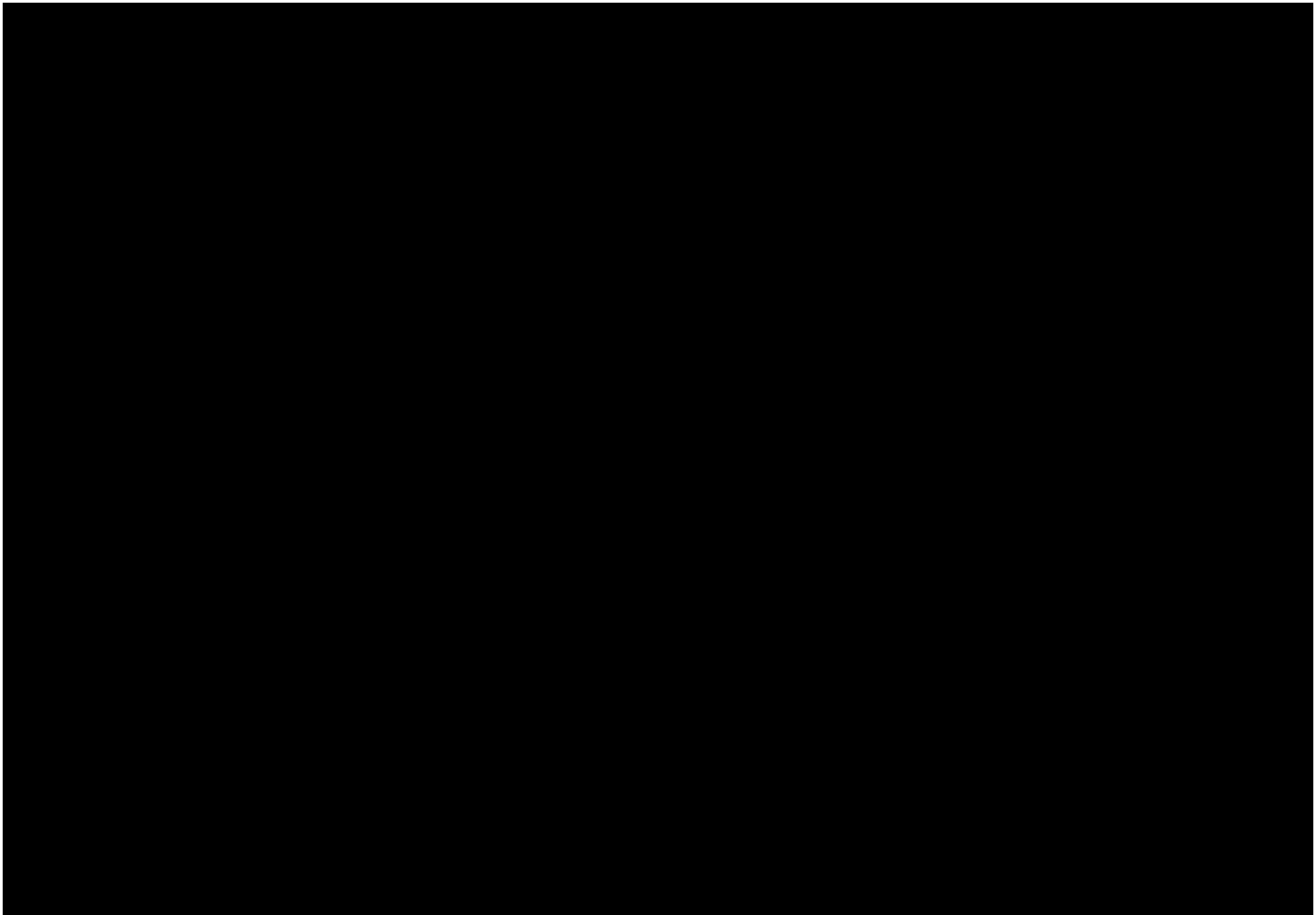
Annual Winter Coincident Peak

Gunnison County Electric Association, Inc.



Annual Winter Coincident Peak
Garland Light and Power Company



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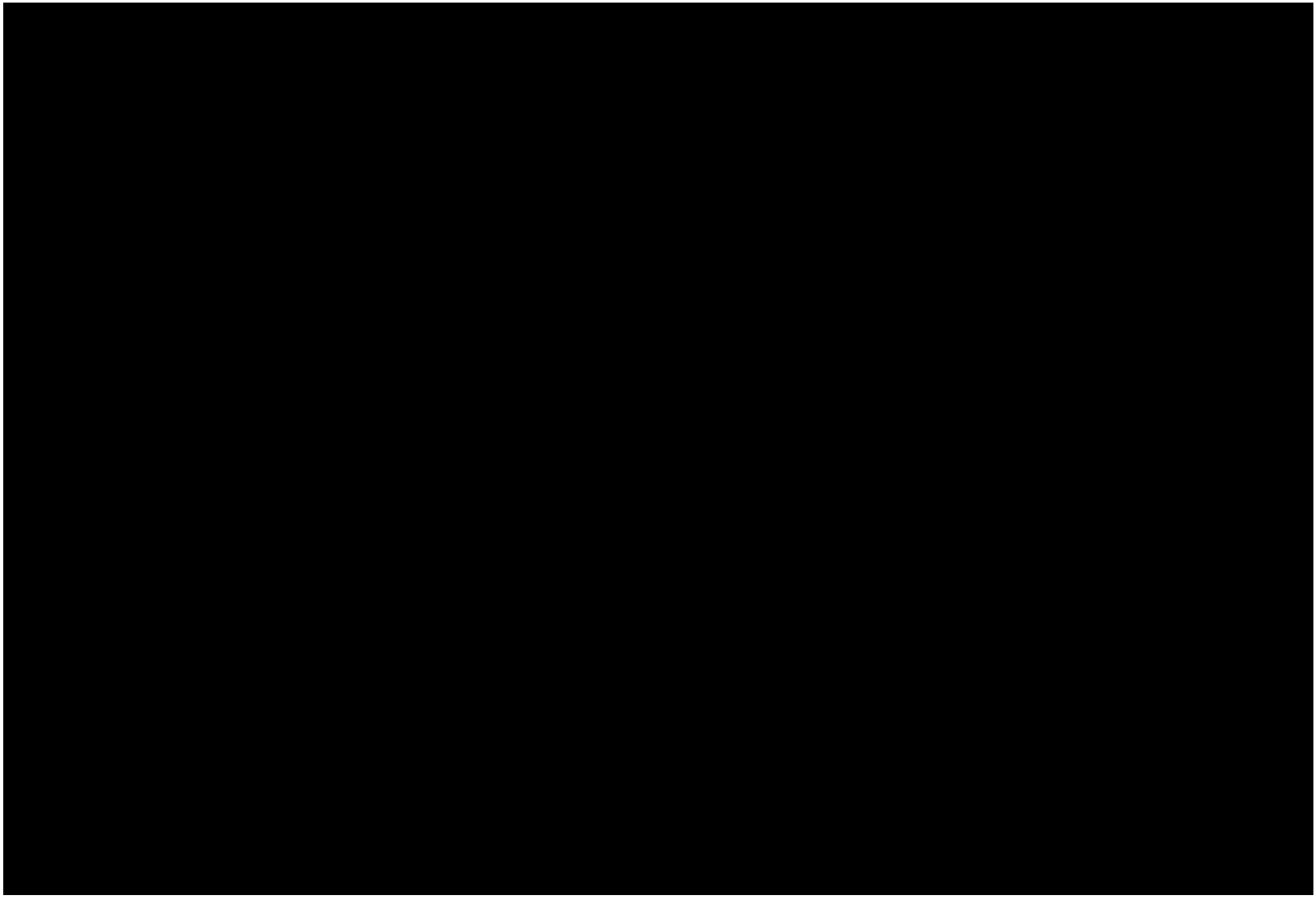
Annual Winter Coincident Peak

Highline Electric Association



Annual Winter Coincident Peak
High Plains Power, Inc.

[redacted]

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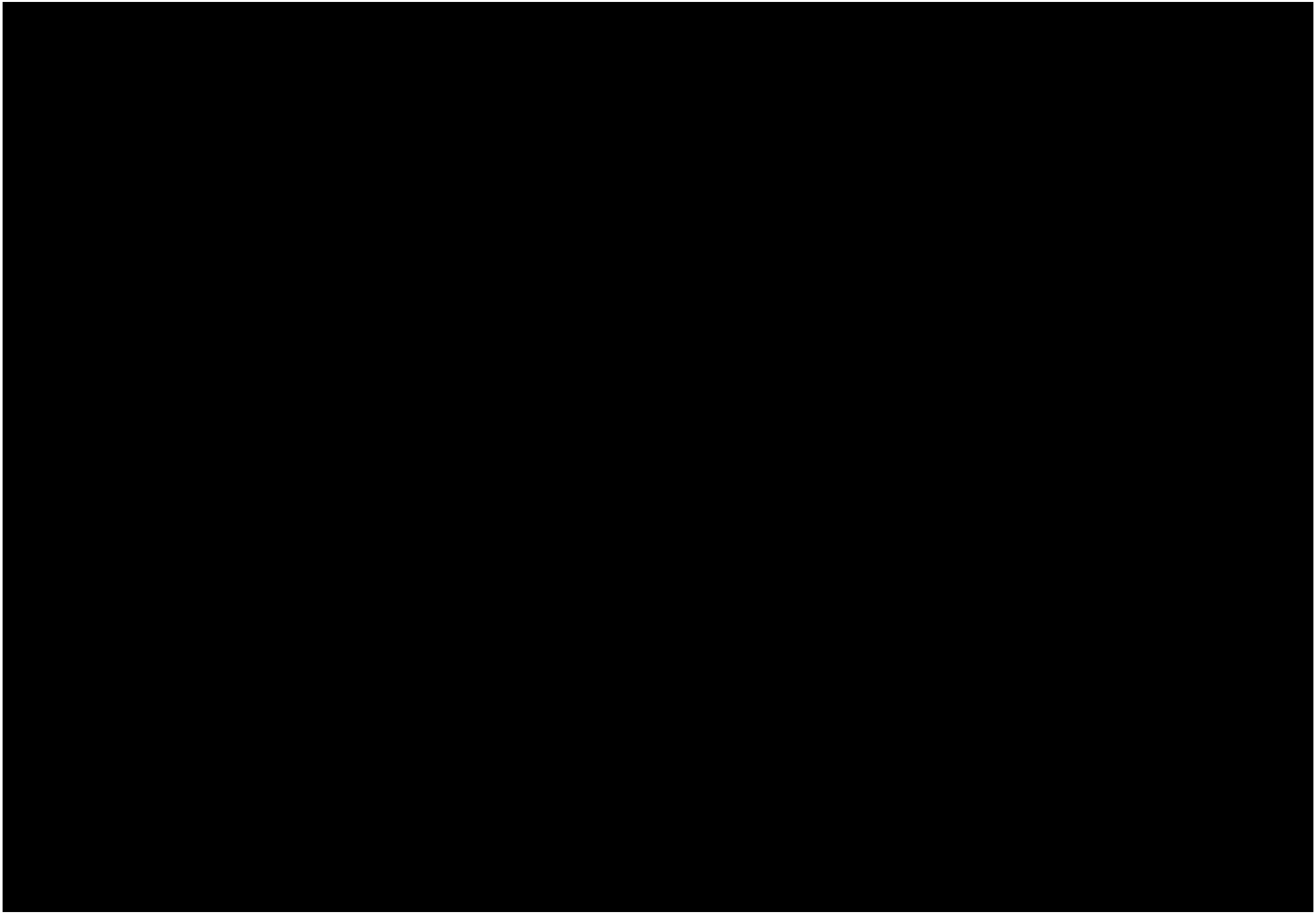
Annual Winter Coincident Peak

High West Energy, Inc.



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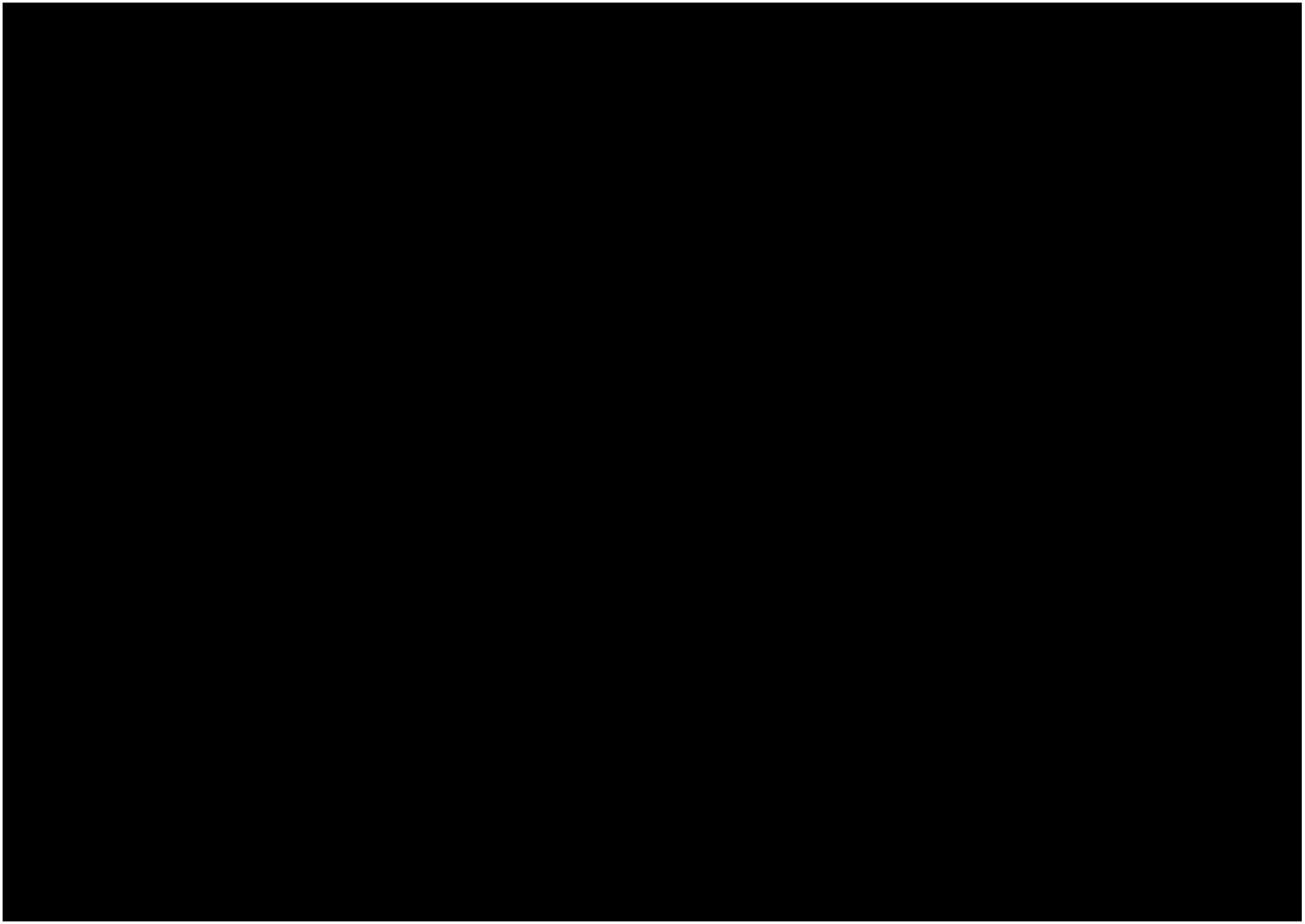
Annual Winter Coincident Peak

Jemez Mountains Electric Cooperative, Inc.



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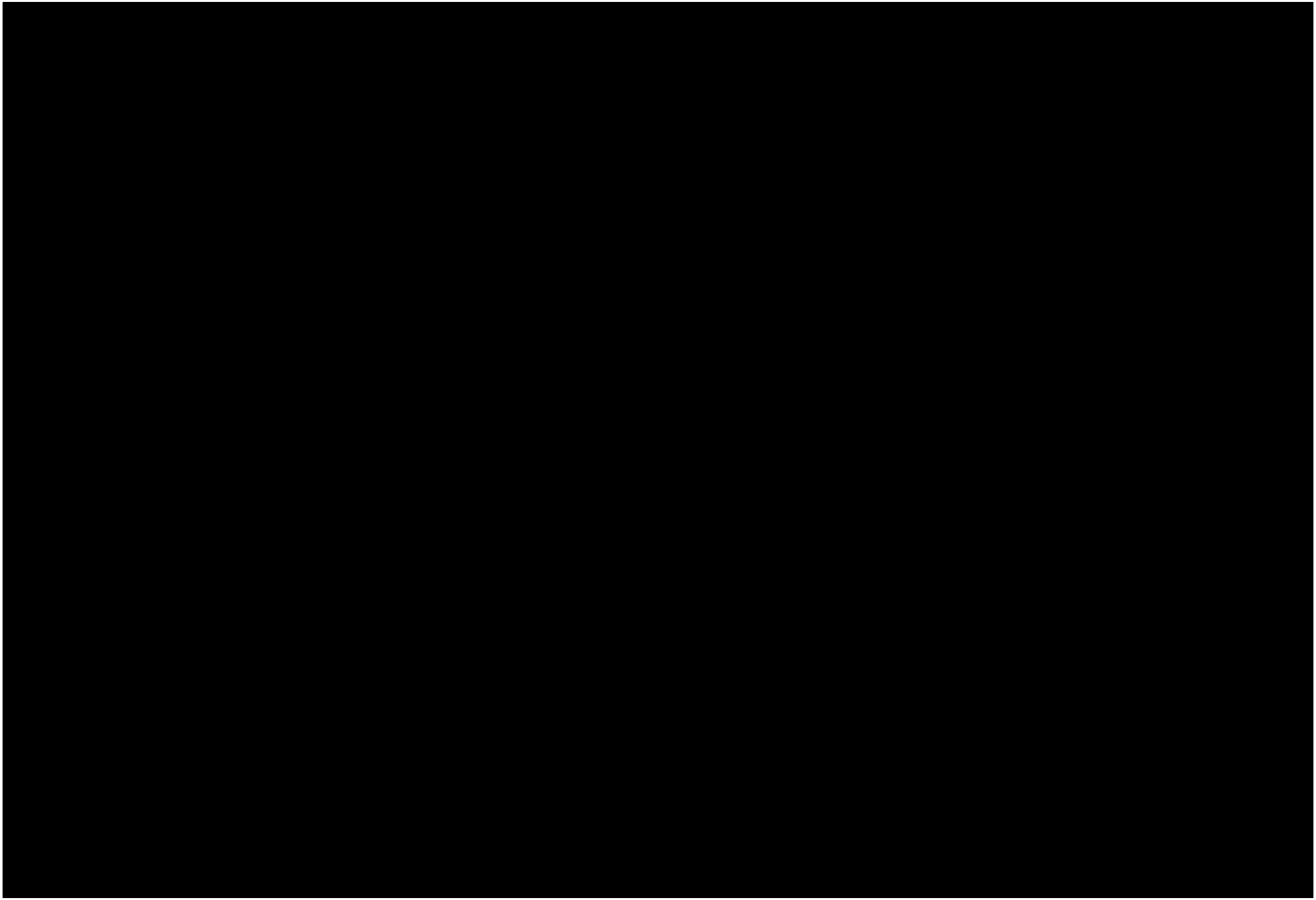
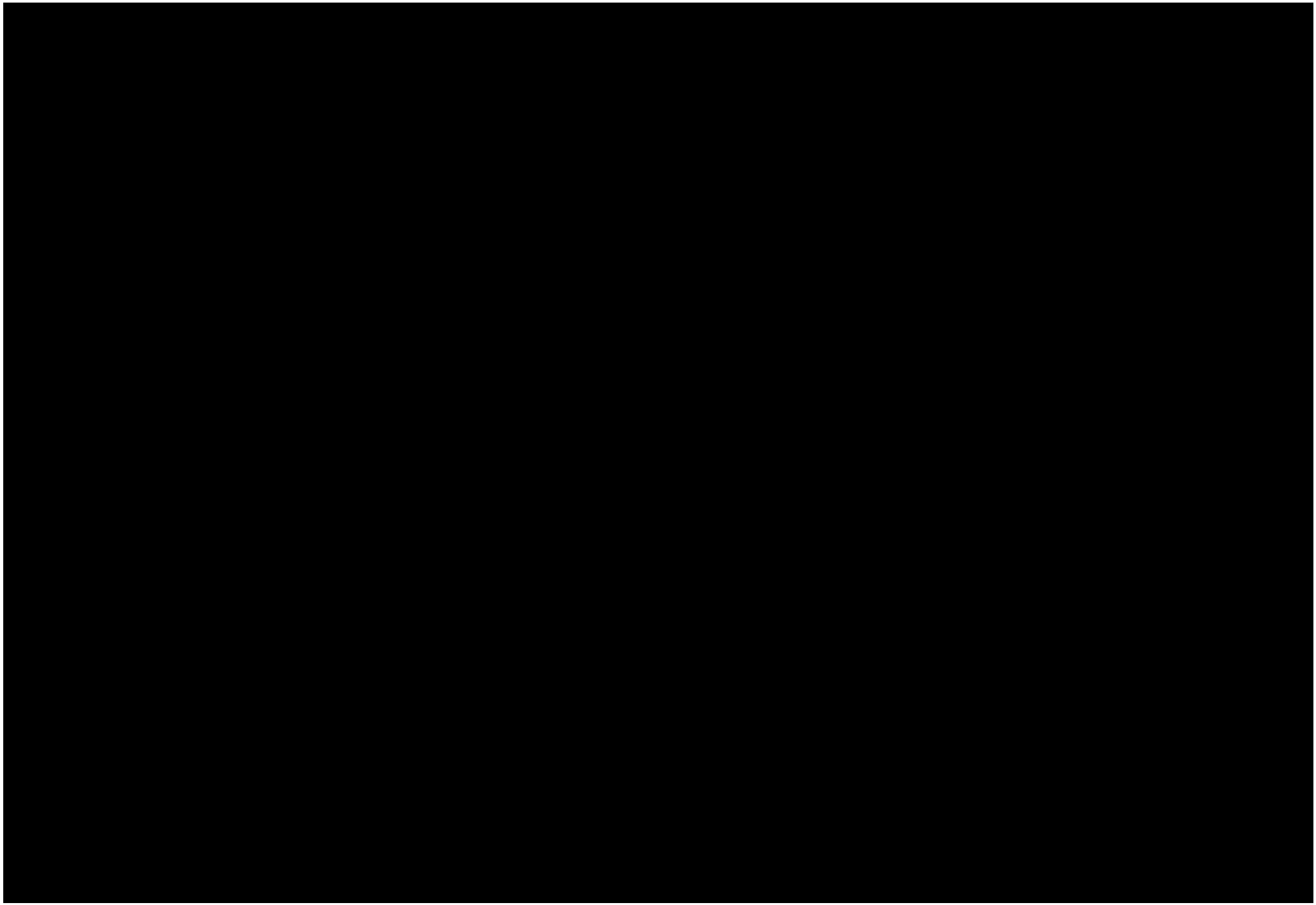
Annual Winter Coincident Peak
K.C. Electric Association, Inc.



Annual Winter Coincident Peak
La Plata Electric Association, Inc.



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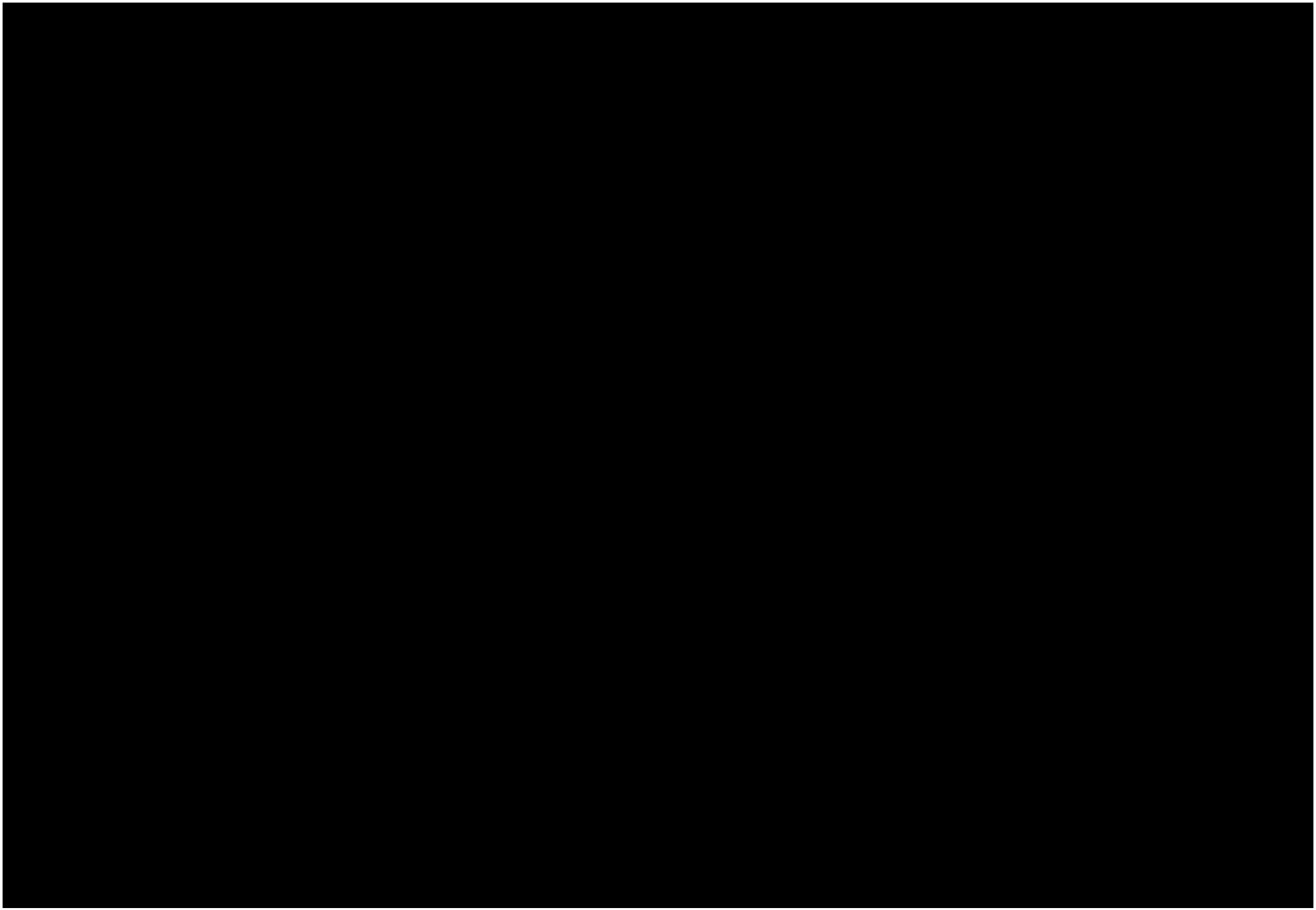
Annual Winter Coincident Peak

Morgan County Rural Electric Association



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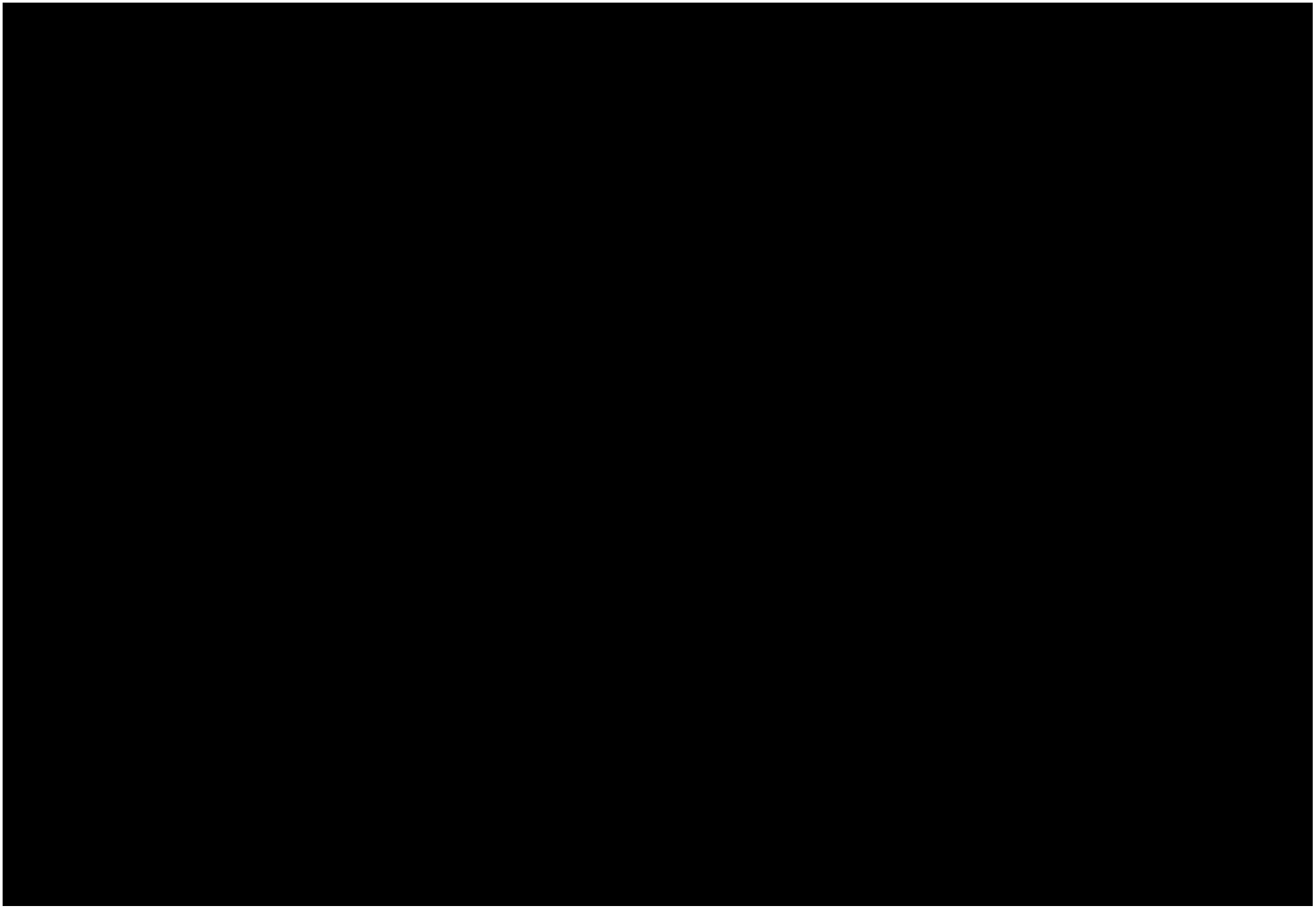
Annual Winter Coincident Peak

Mountain Parks Electric, Inc.



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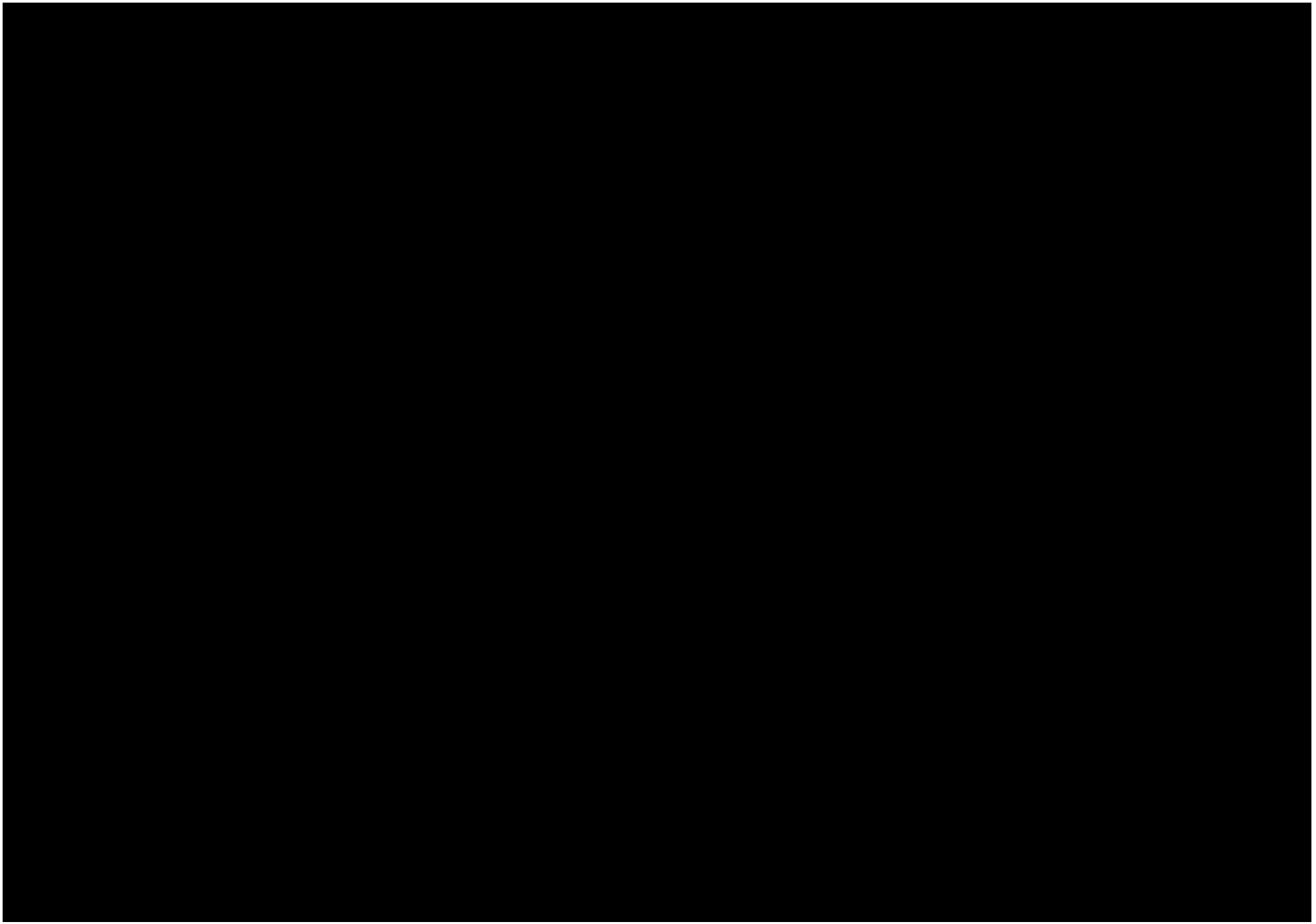
Annual Winter Coincident Peak

Mora-San Miguel Electric Cooperative, Inc.



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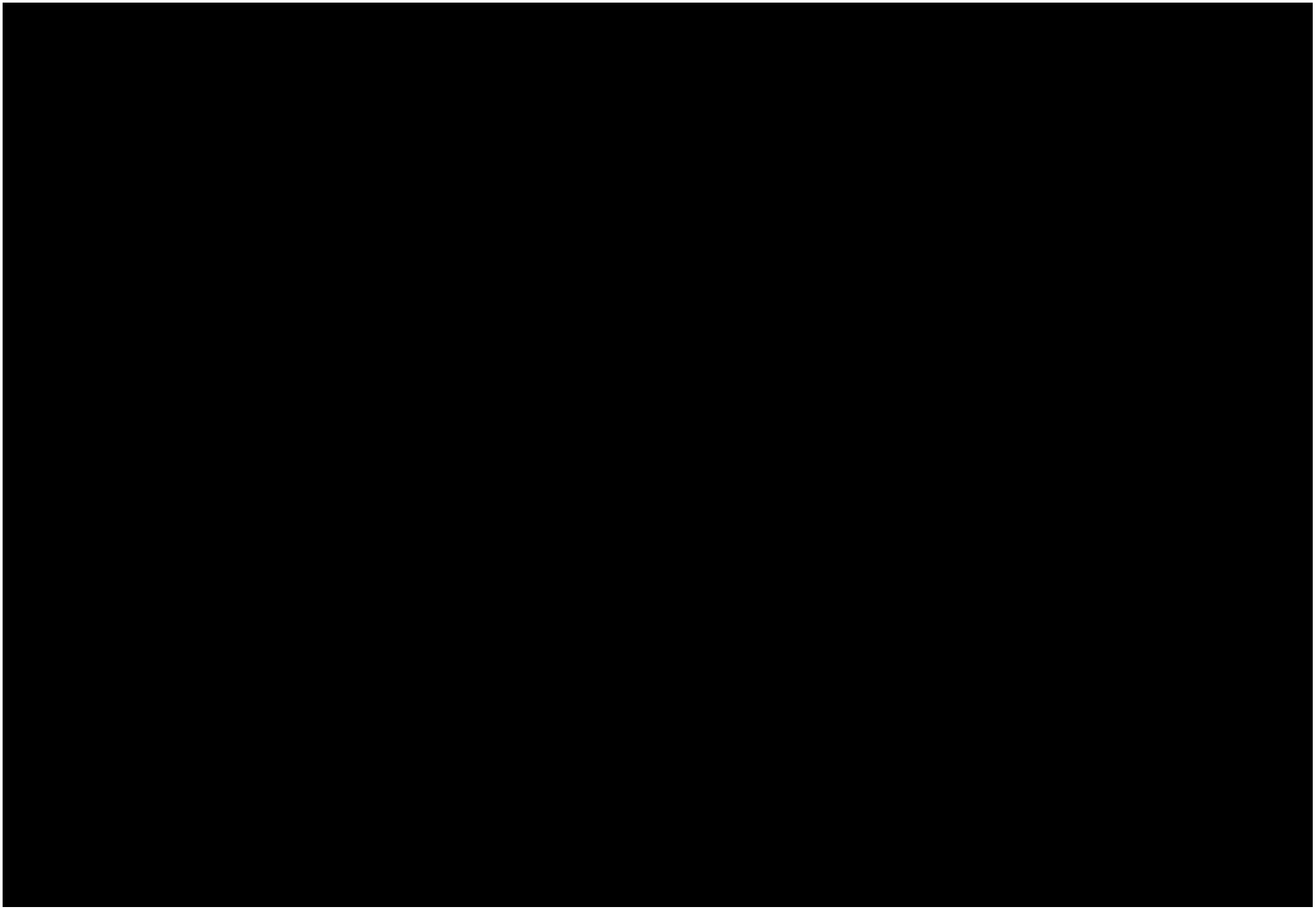
Annual Winter Coincident Peak
Mountain View Electric Association, Inc.



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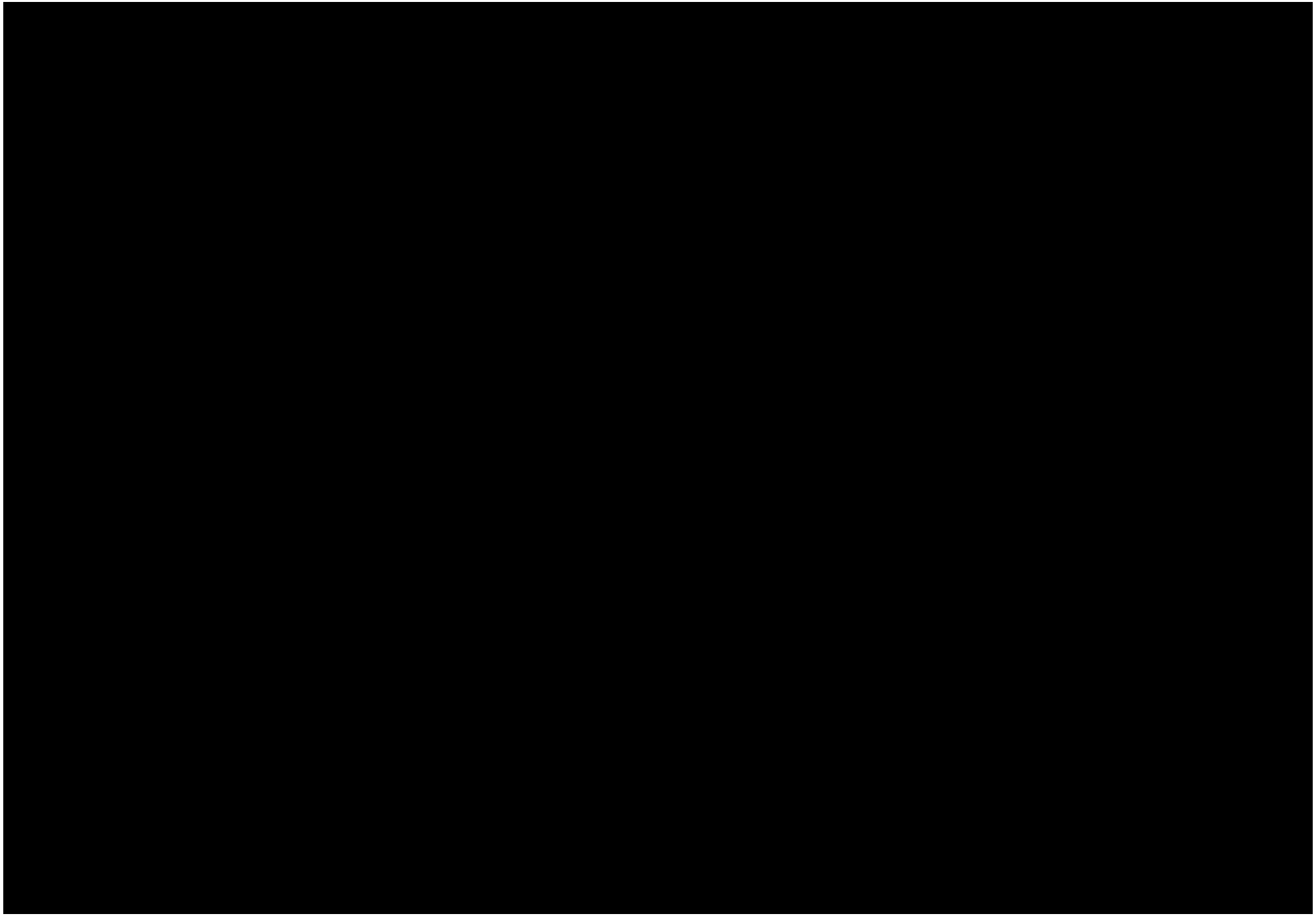
Annual Winter Coincident Peak

Midwest Electric Cooperative Corporation



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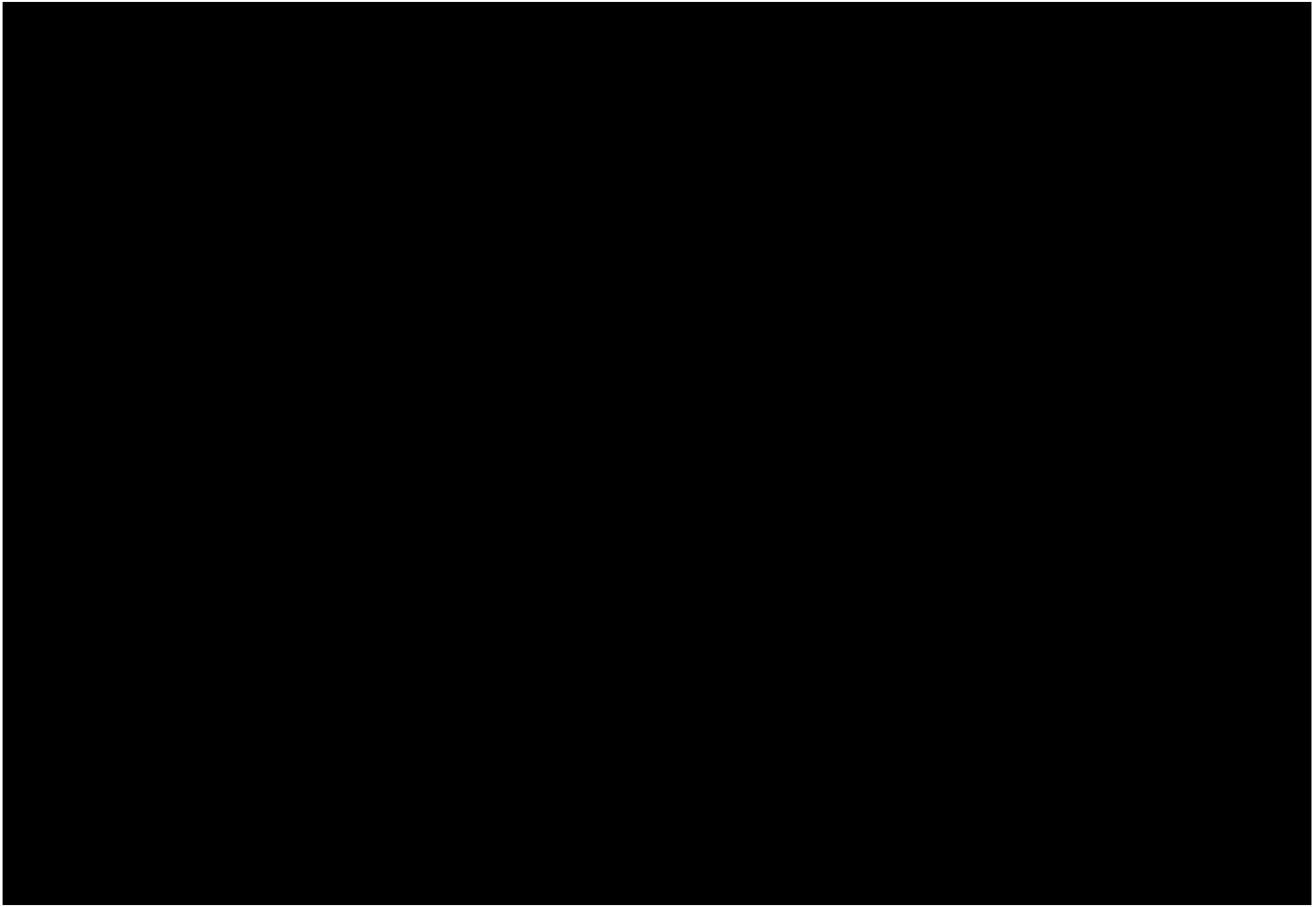
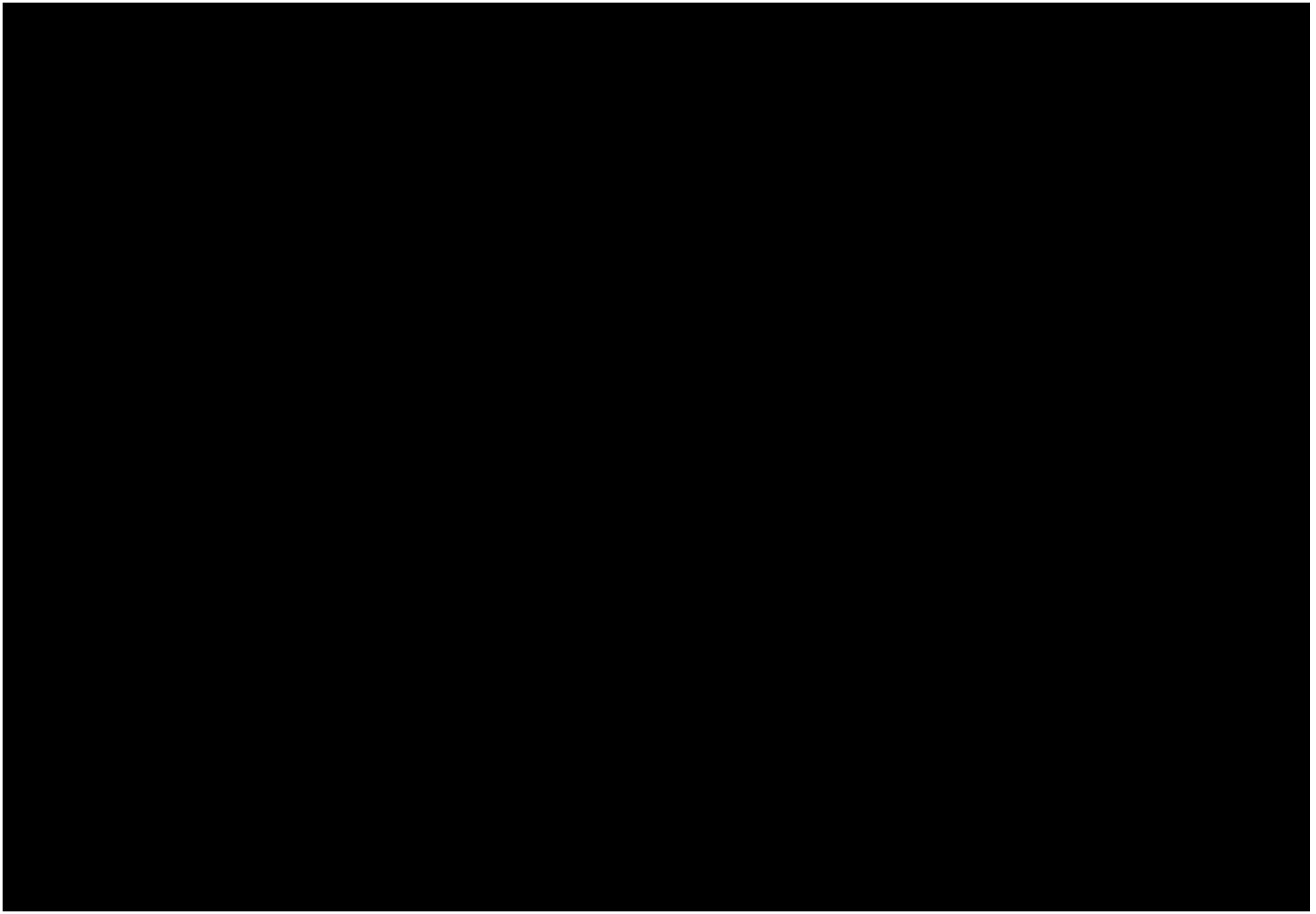
Annual Winter Coincident Peak

Niobrara Electric Association, Inc.



Annual Winter Coincident Peak
Northwest Rural Public Power District



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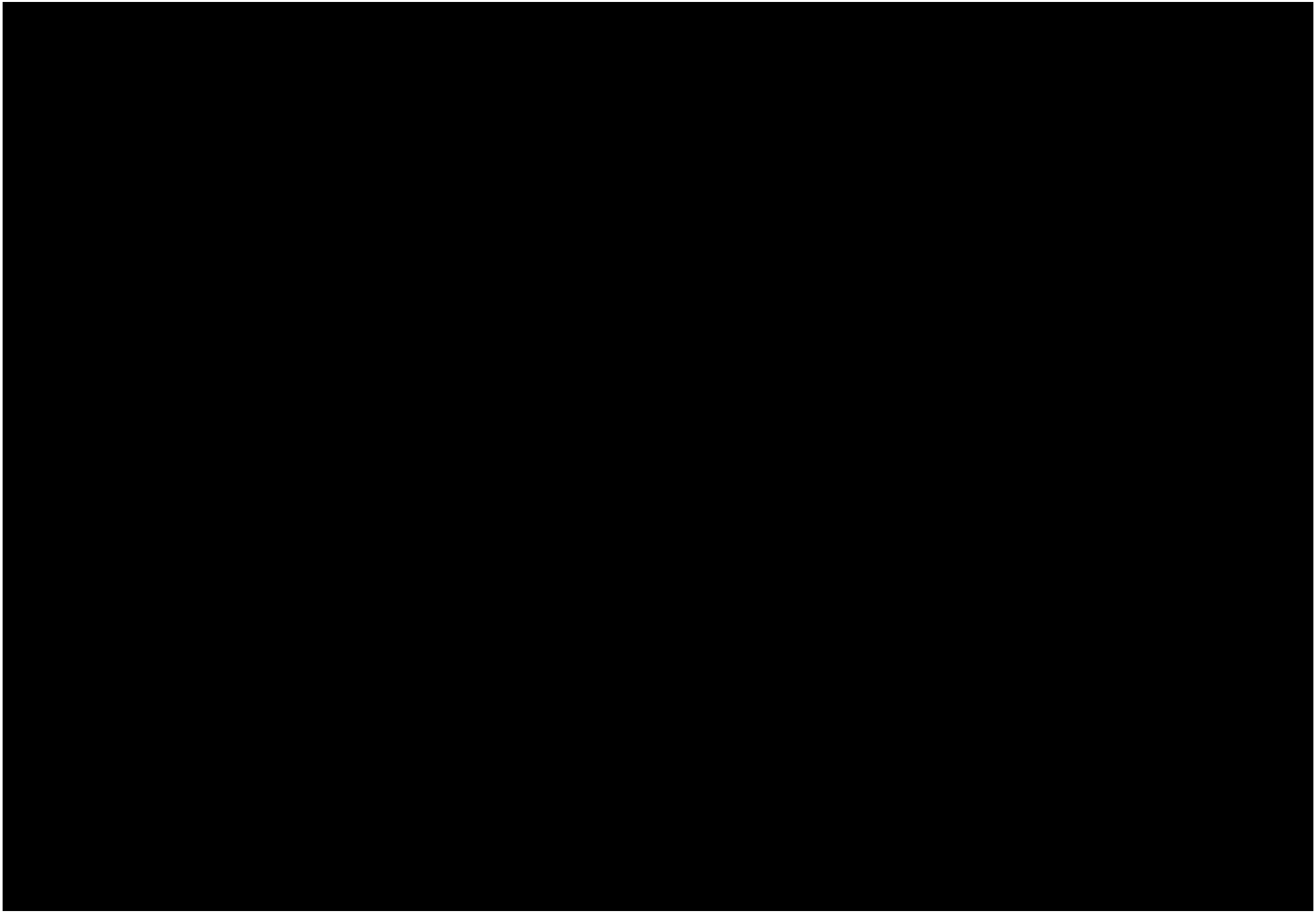
Annual Winter Coincident Peak
Otero County Electric Cooperative, Inc.

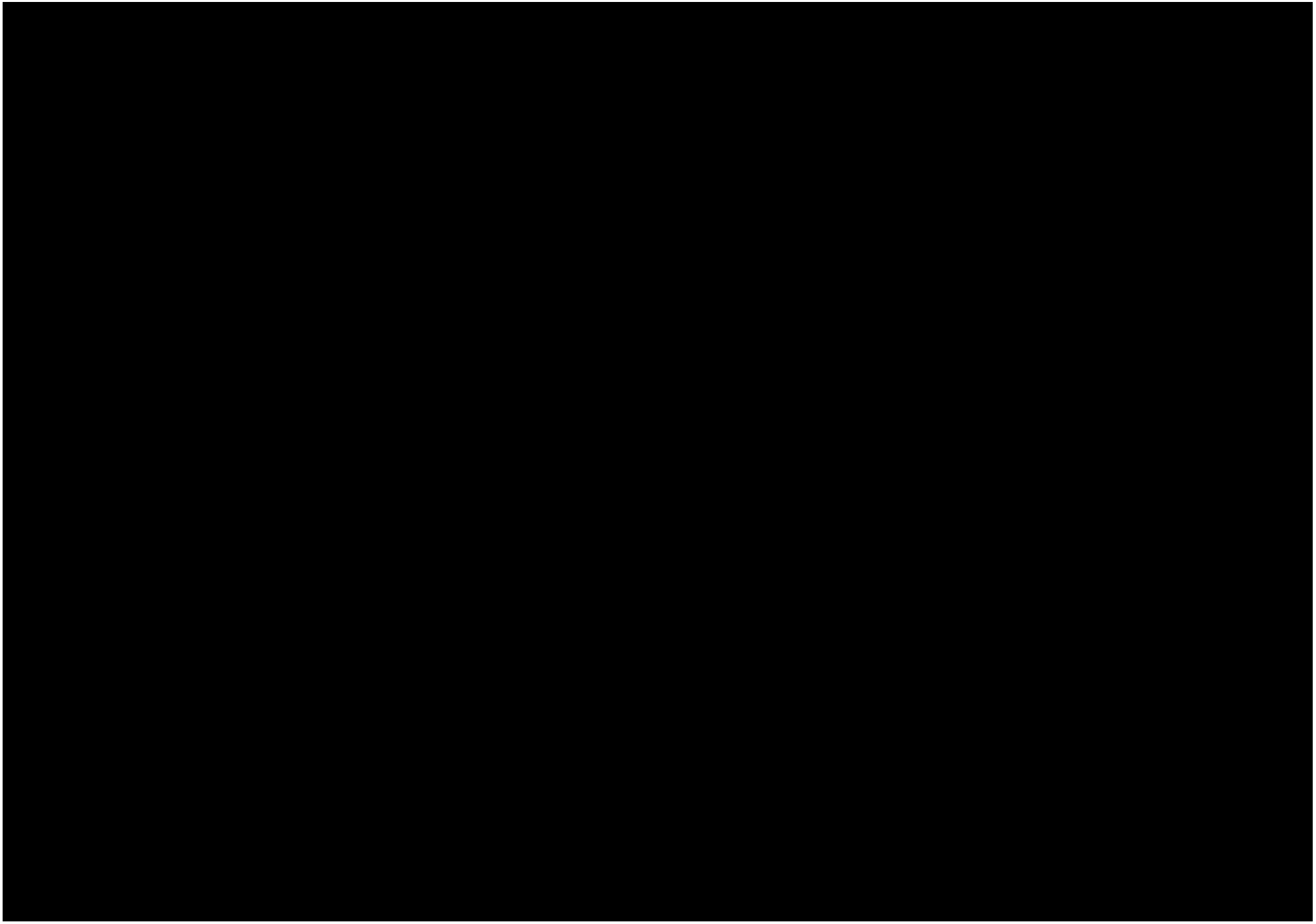
[redacted]

Annual Winter Coincident Peak

Panhandle Rural Electric Membership Association

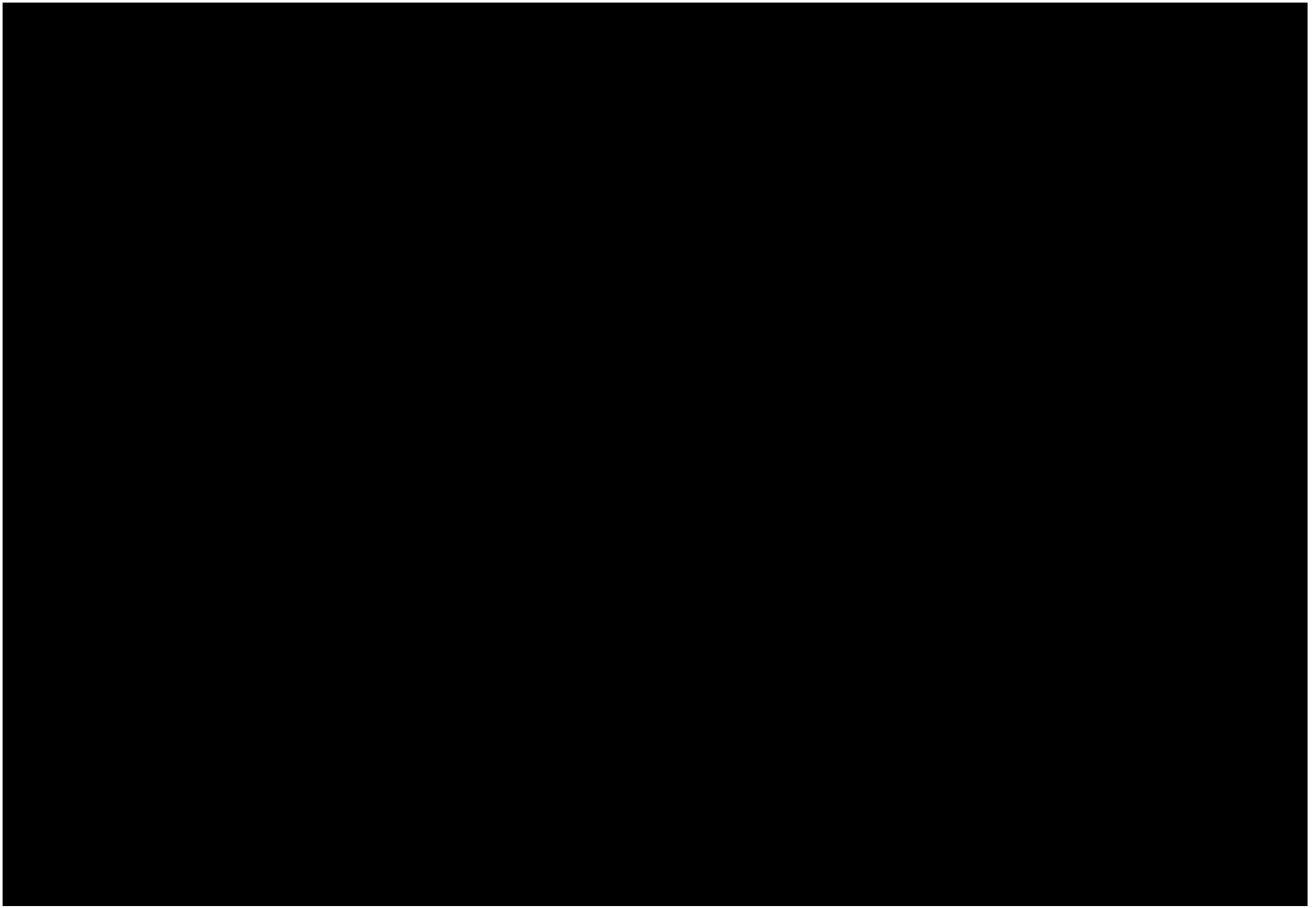


Annual Winter Coincident Peak
Poudre Valley Electric Association, Inc.



Annual Winter Coincident Peak

Northern Rio Arriba Electric Cooperative, Inc.



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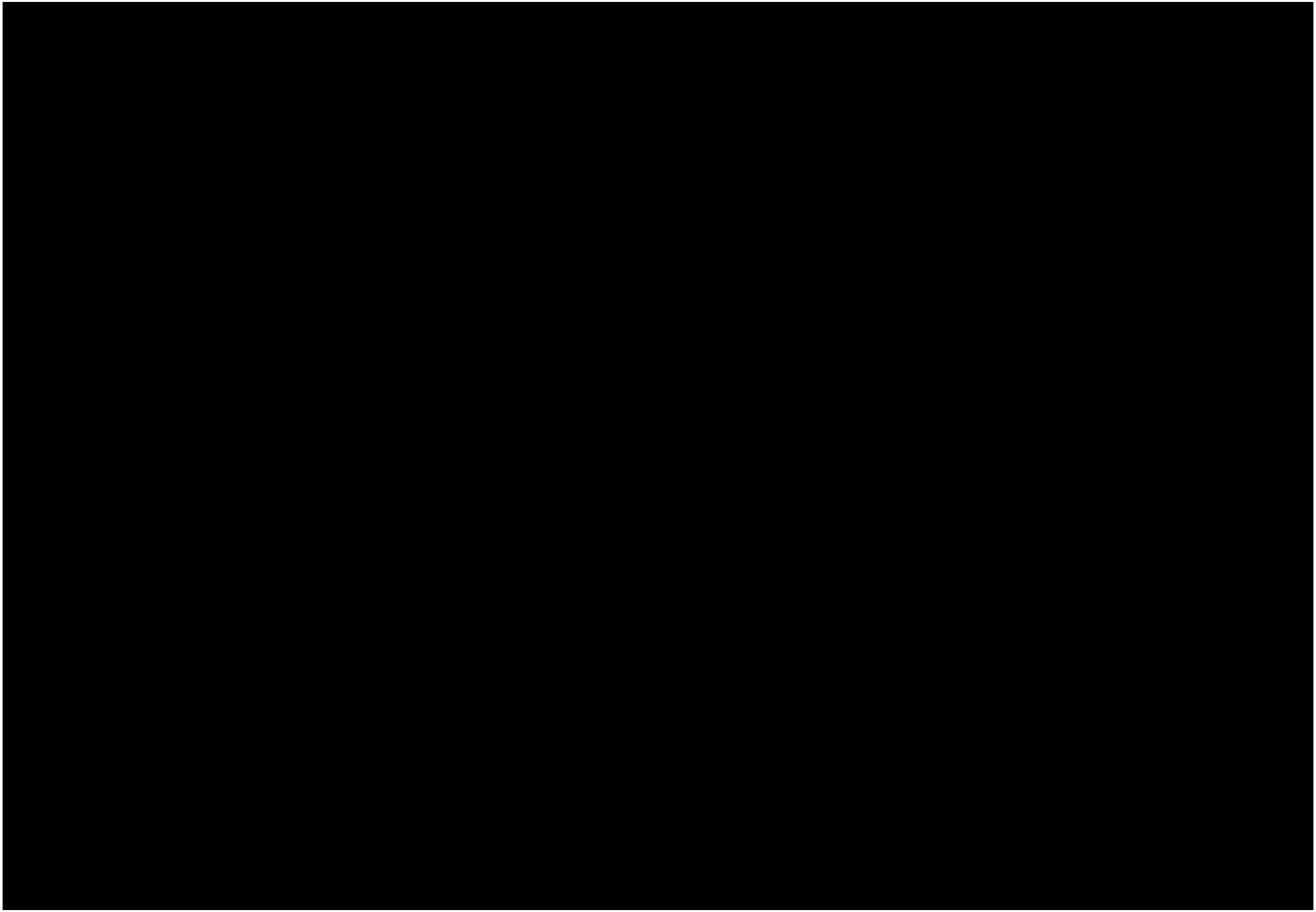
Annual Winter Coincident Peak

Roosevelt Public Power District



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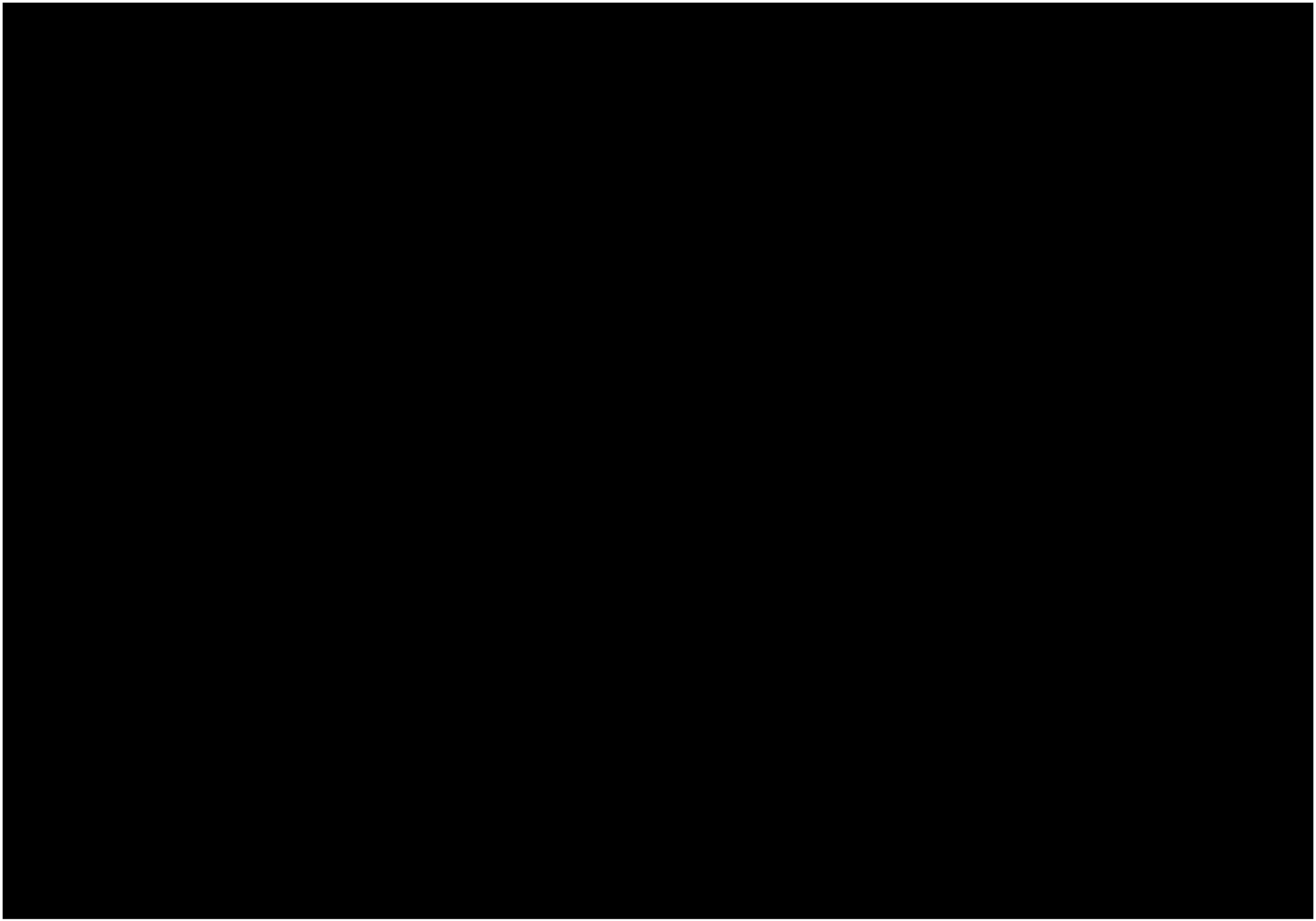
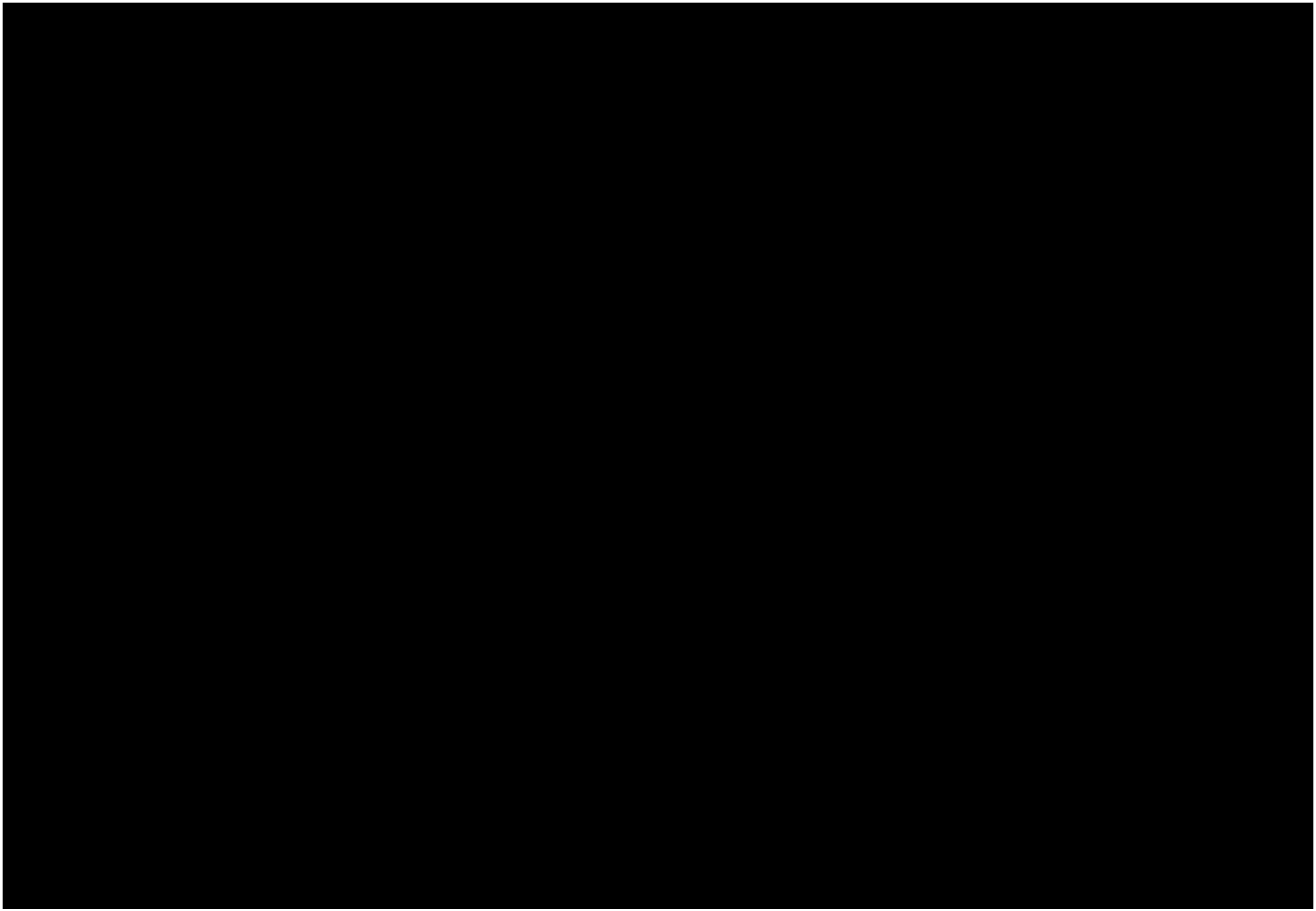
Annual Winter Coincident Peak

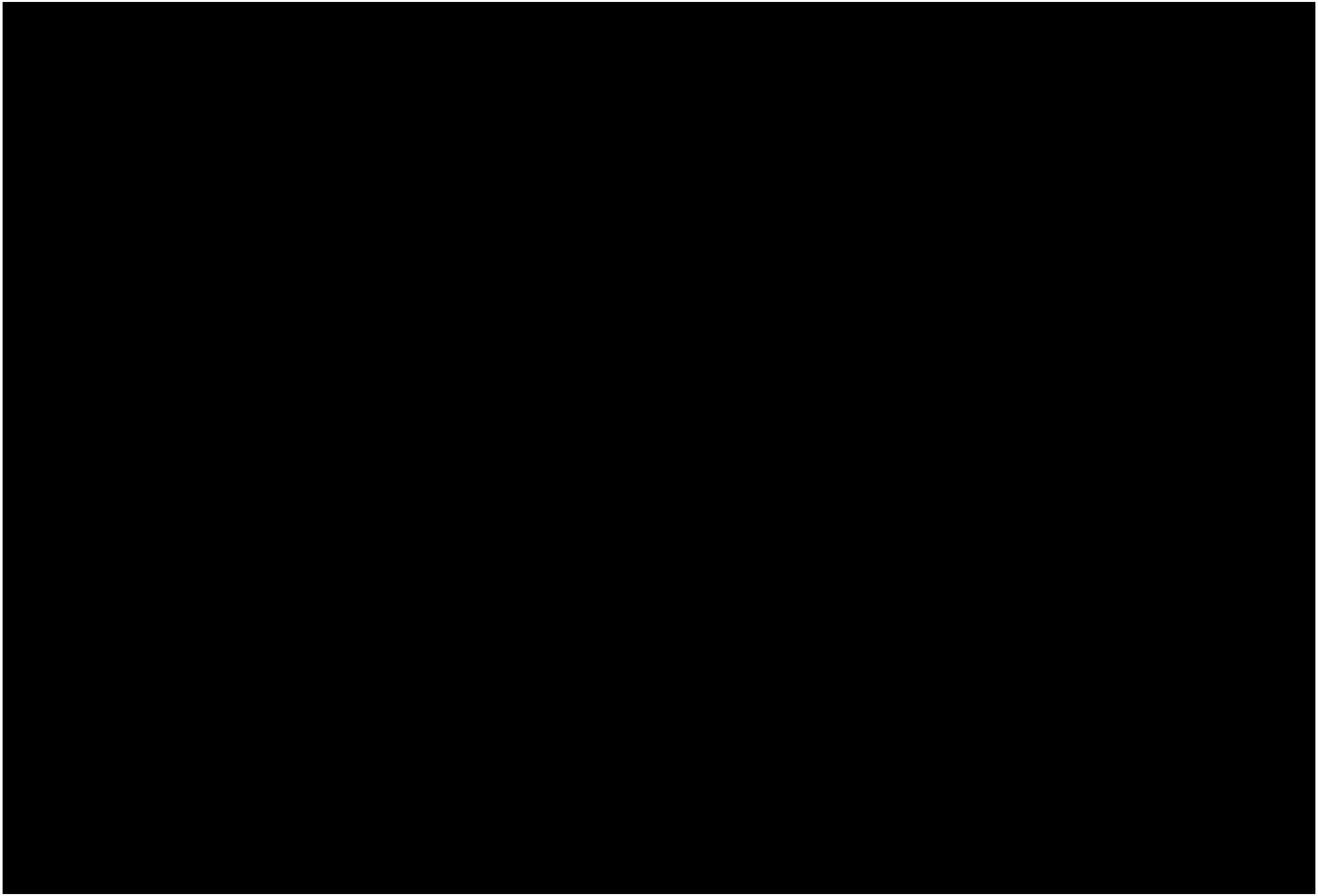
Sierra Electric Cooperative, Inc.



Annual Winter Coincident Peak
Sangre de Cristo Electric Association, Inc.



Annual Winter Coincident Peak
Southeast Colorado Power Association



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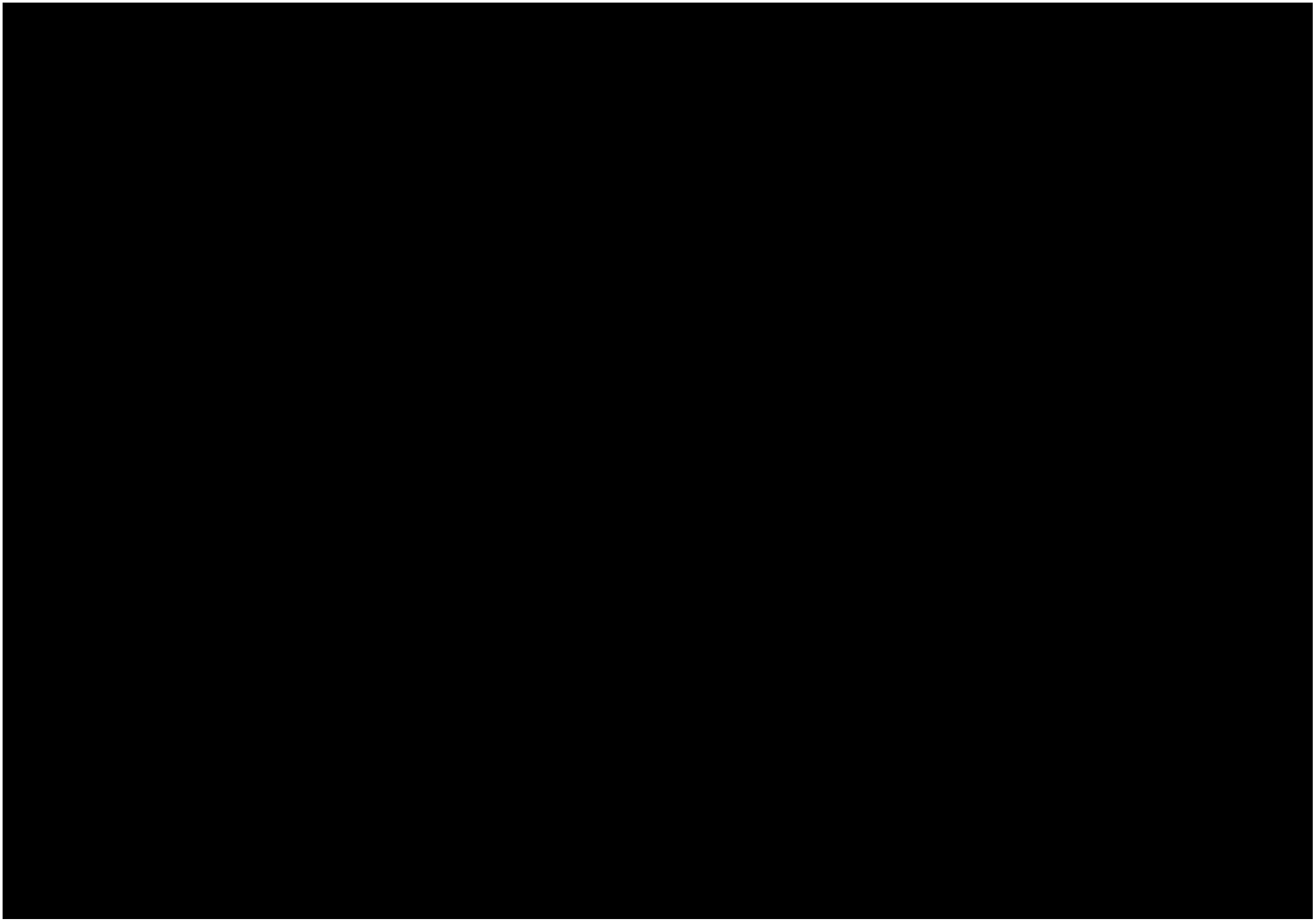
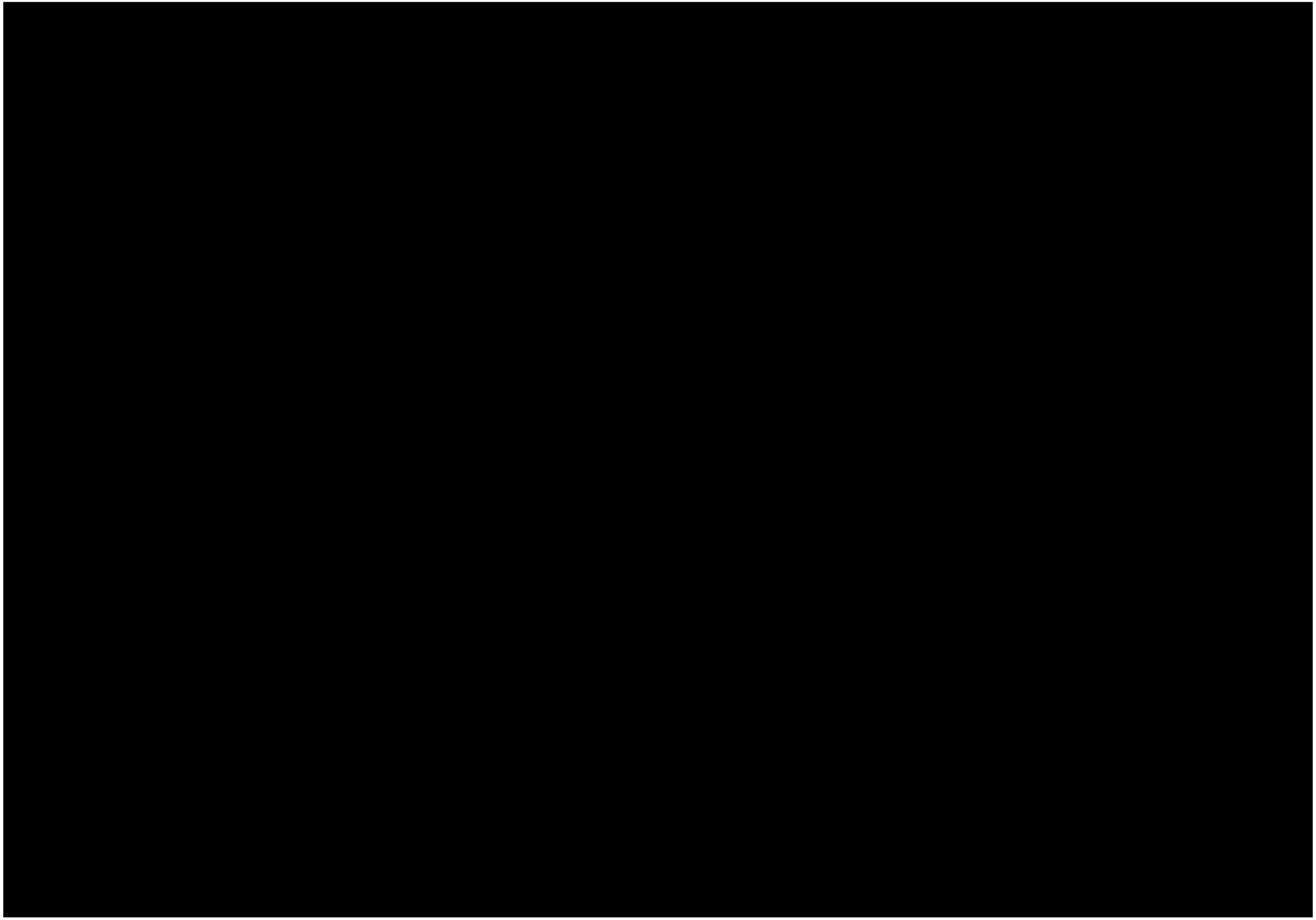
Annual Winter Coincident Peak

San Isabel Electric Association, Inc.



Annual Winter Coincident Peak

San Luis Valley Rural Electric Cooperative, Inc.



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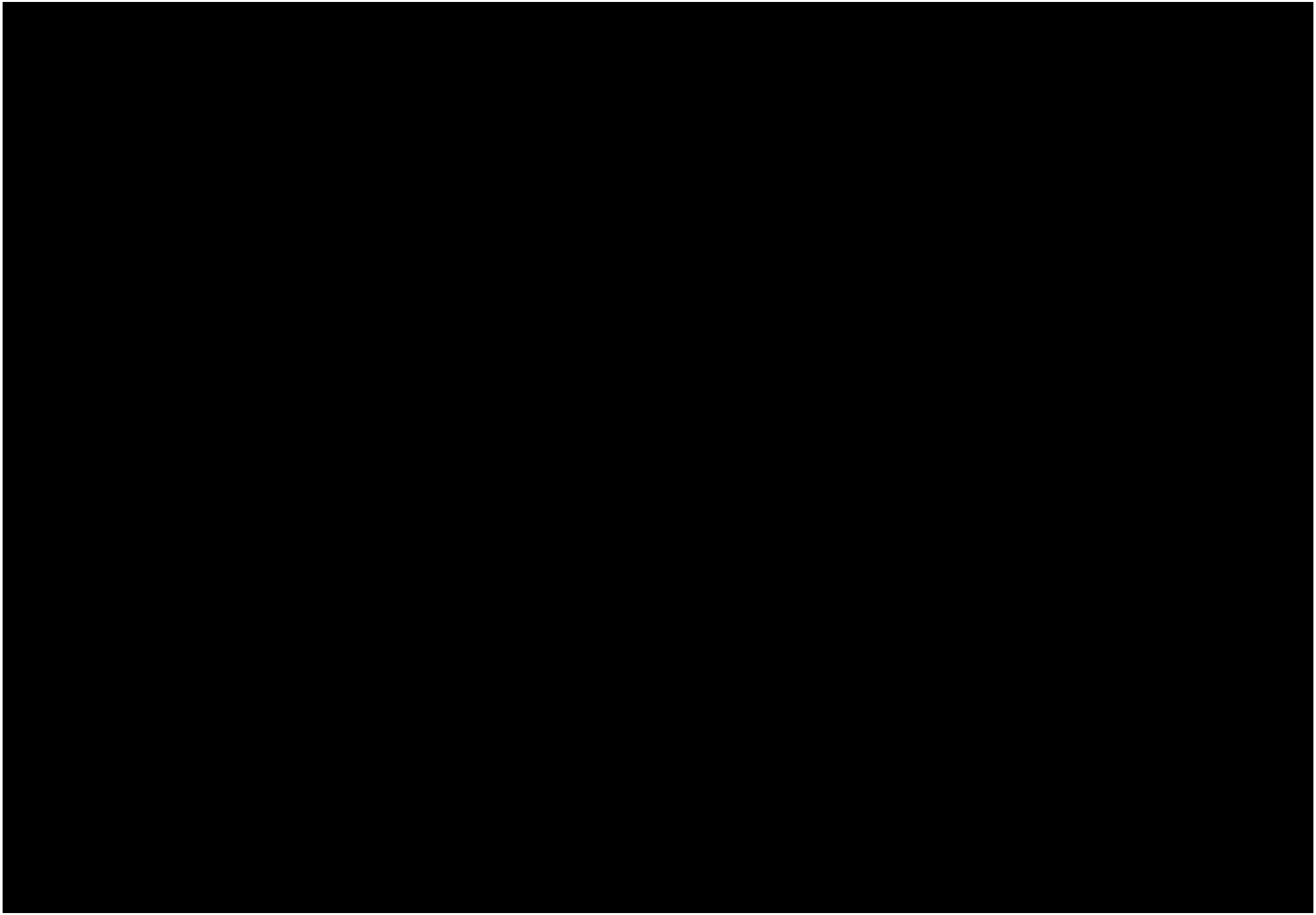
Annual Winter Coincident Peak

San Miguel Power Association, Inc.



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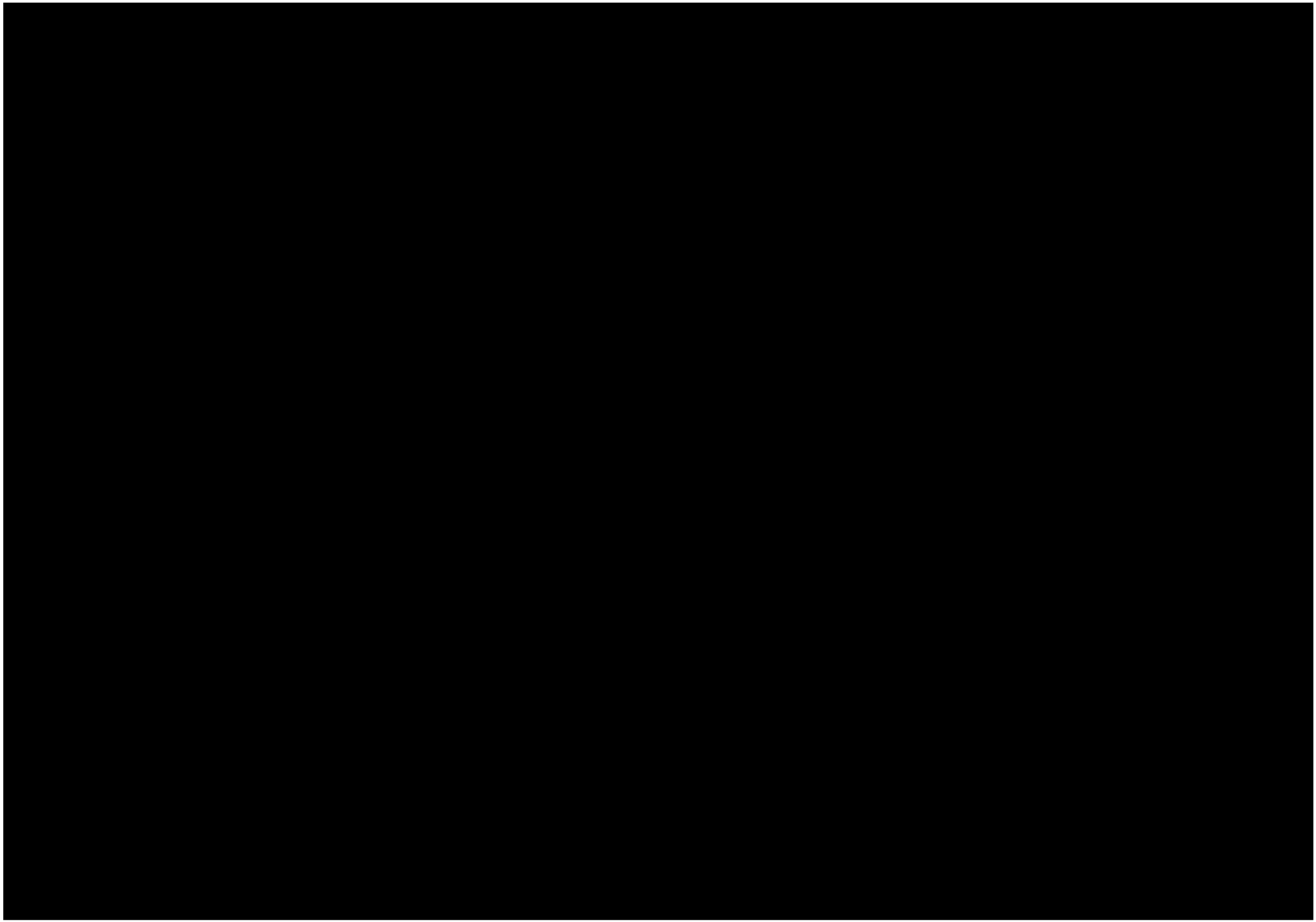
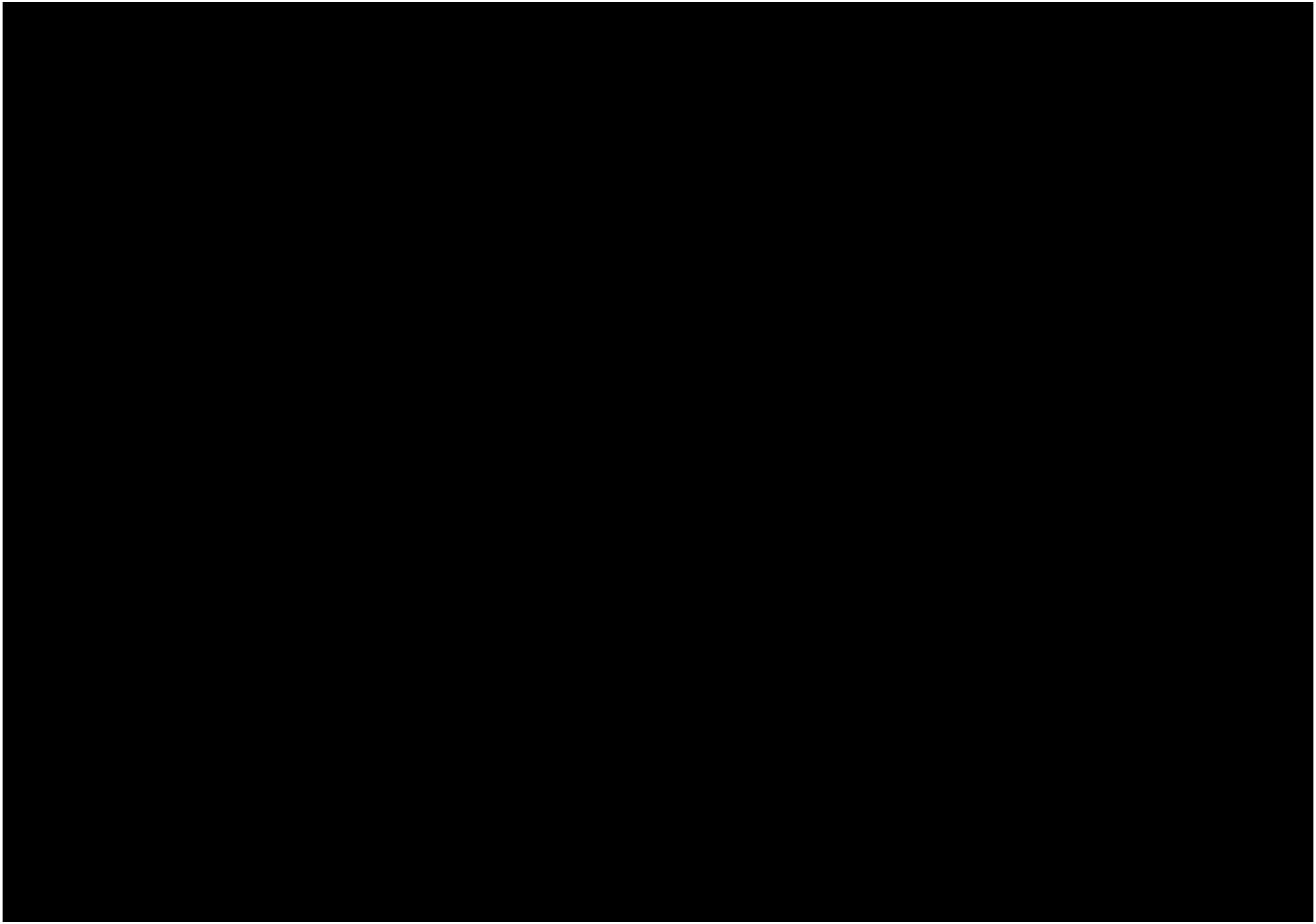
Annual Winter Coincident Peak

Socorro Electric Cooperative, Inc.



Annual Winter Coincident Peak
Springer Electric Cooperative, Inc.



Annual Winter Coincident Peak
Southwestern Electric Cooperative, Inc.

[redacted]

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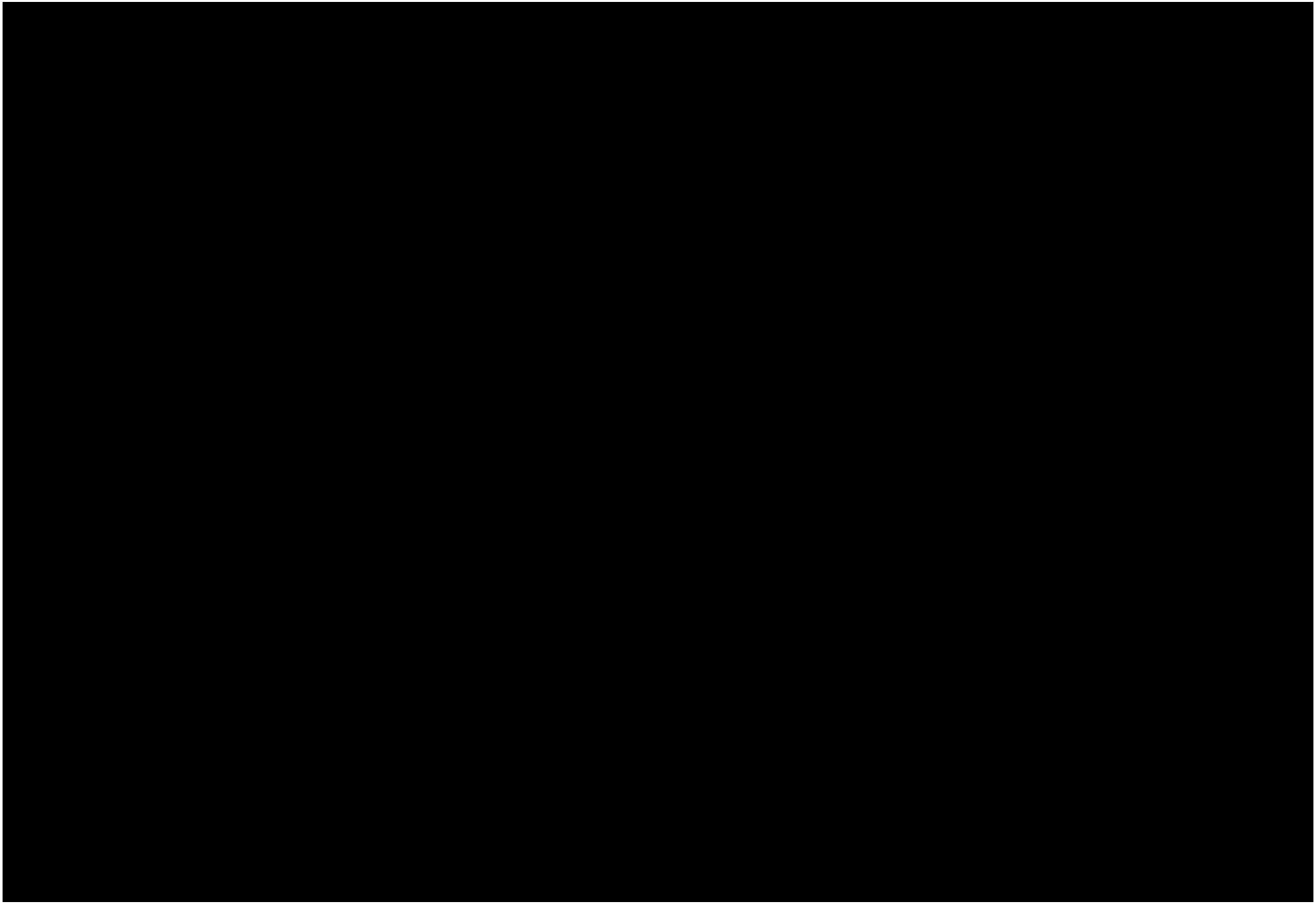
Annual Winter Coincident Peak

United Power, Inc.



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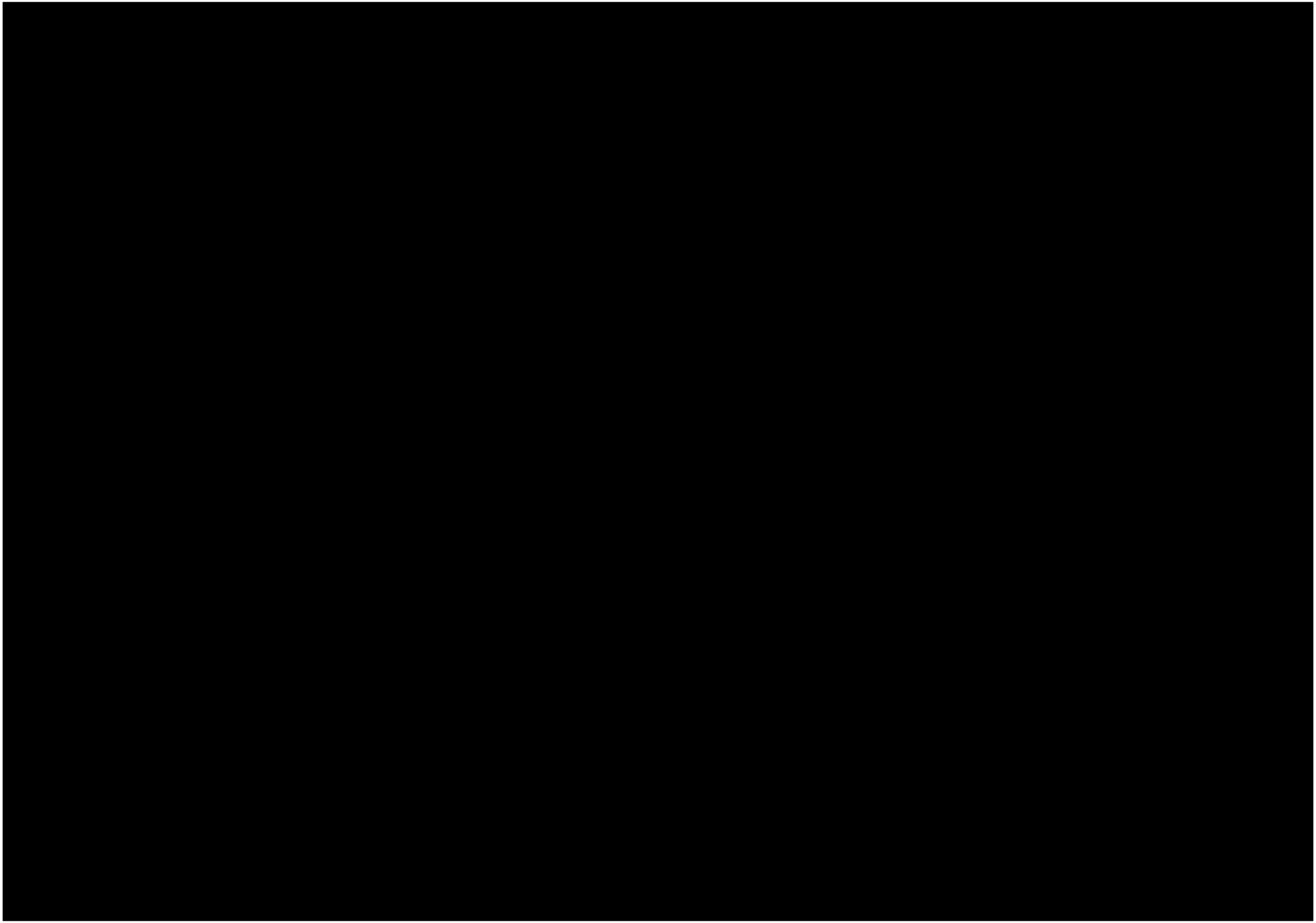
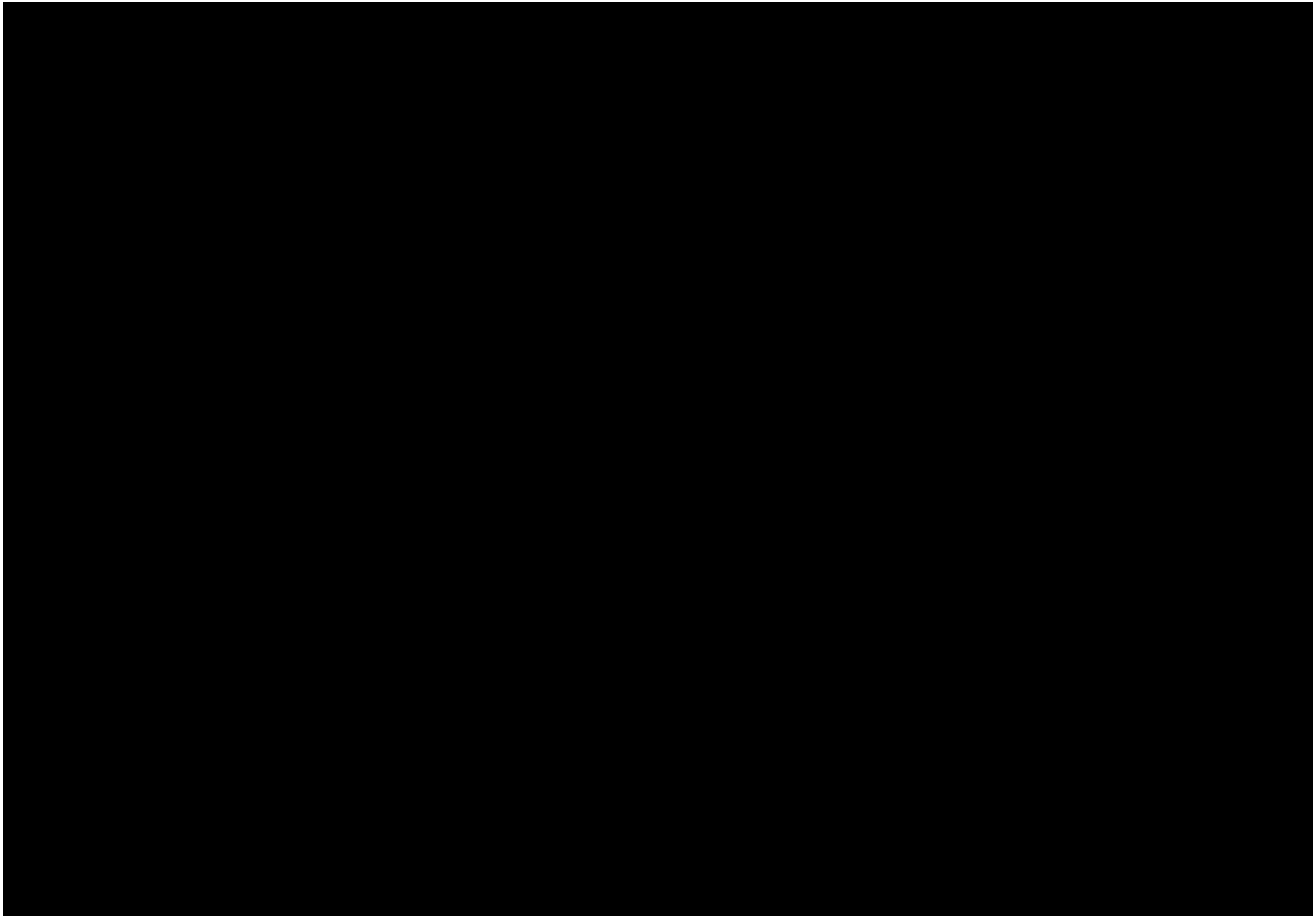
Annual Winter Coincident Peak

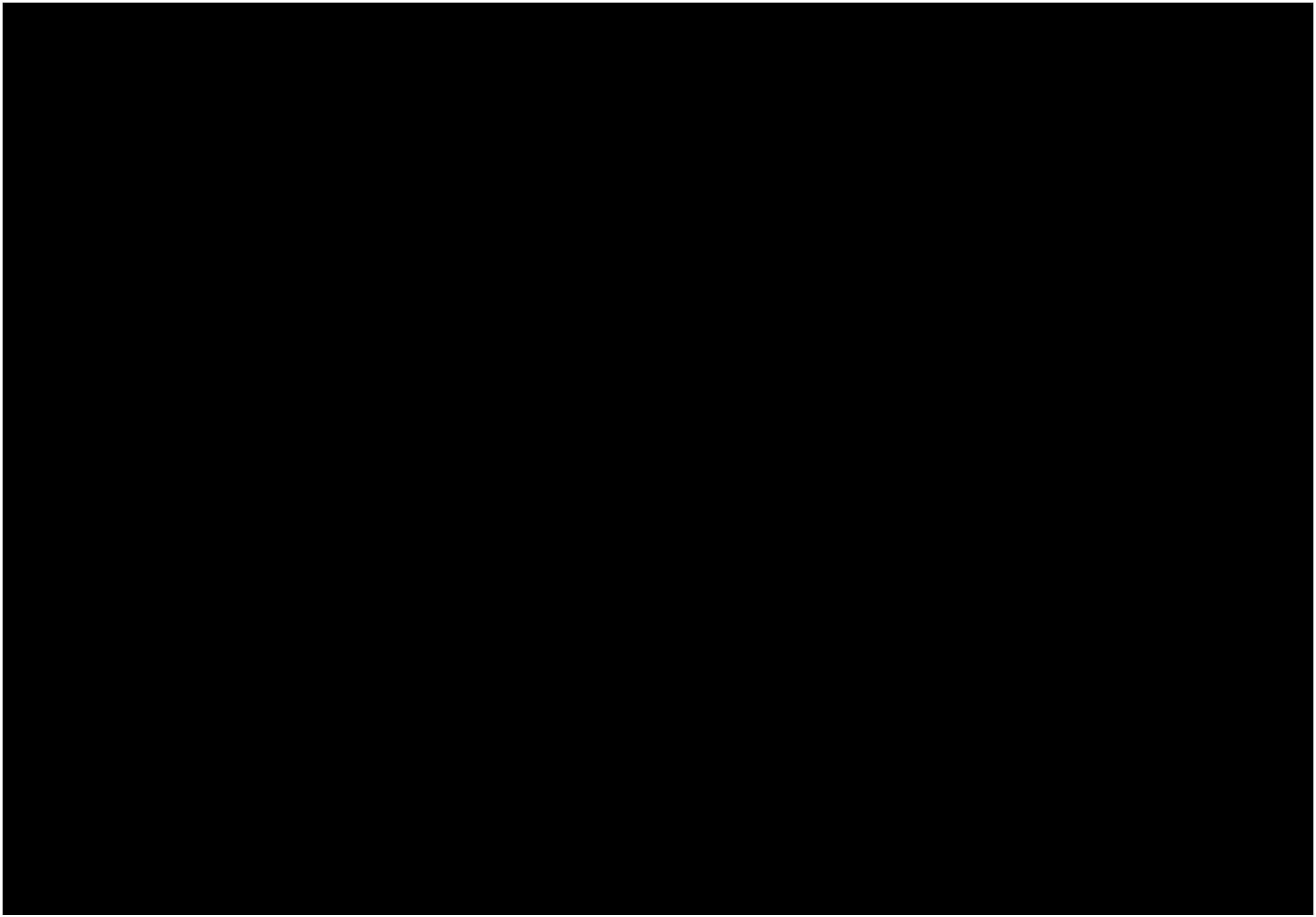
Wheat Belt Public Power District



Annual Winter Coincident Peak
Wheatland Rural Electric Association, Inc.



Annual Winter Coincident Peak
White River Electric Association, Inc.



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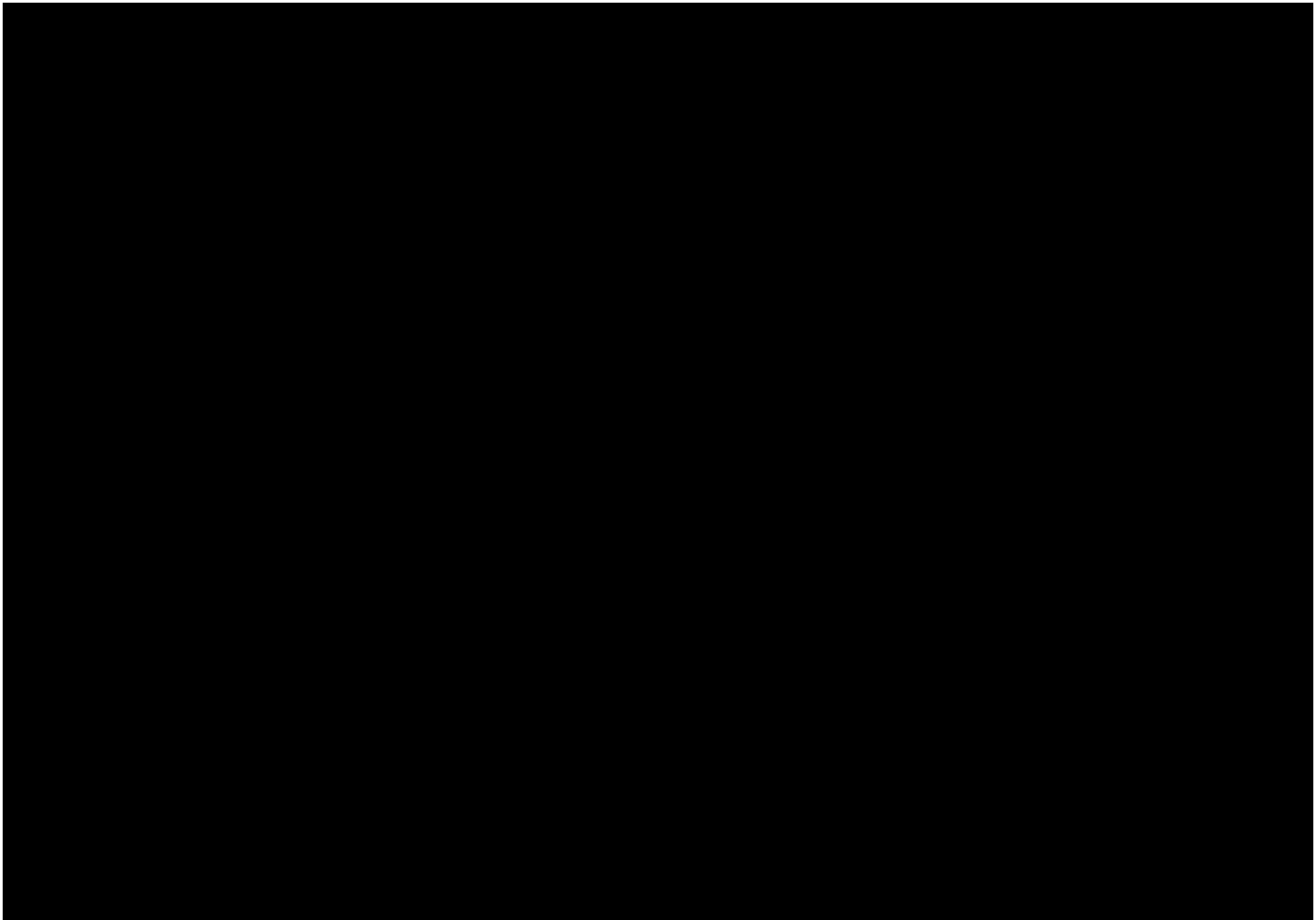
Annual Winter Coincident Peak

Wyrulec Company



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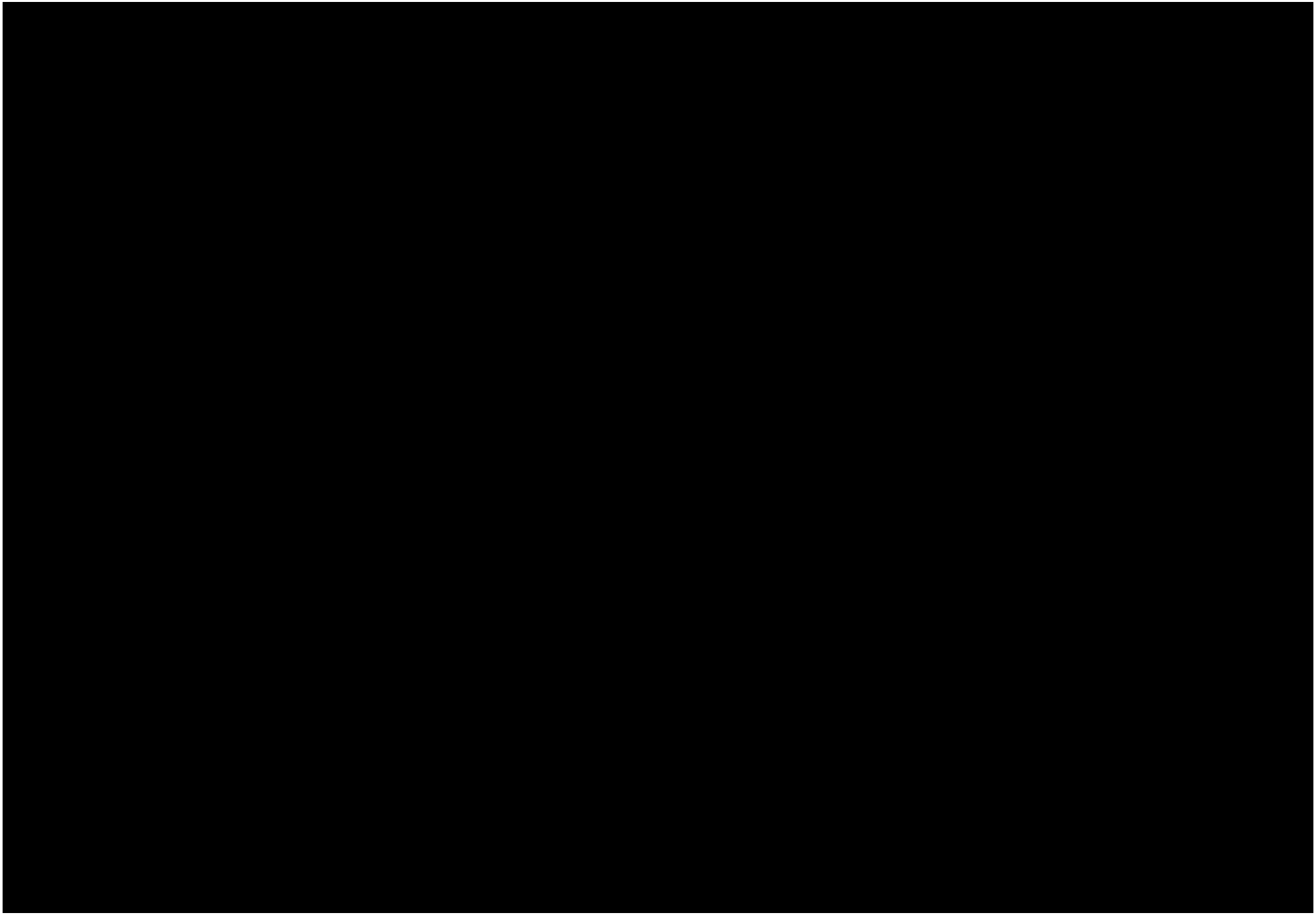
Annual Winter Coincident Peak

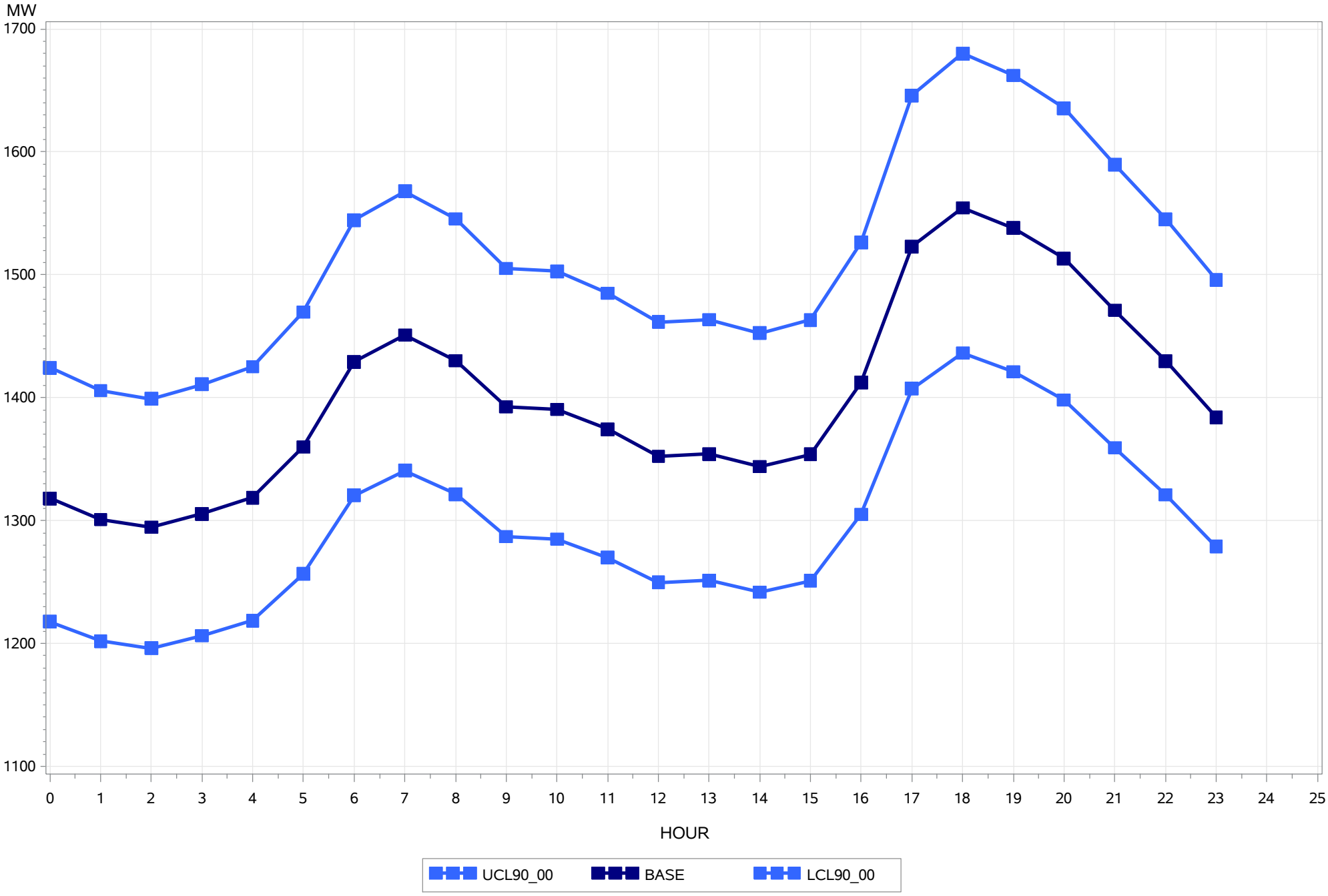
Y-W Electric Association, Inc.



Member Forecasted On Peak Demand Day for January 2021

STATE OF COLORADO

Date of On Peak Day - 01/06/2021



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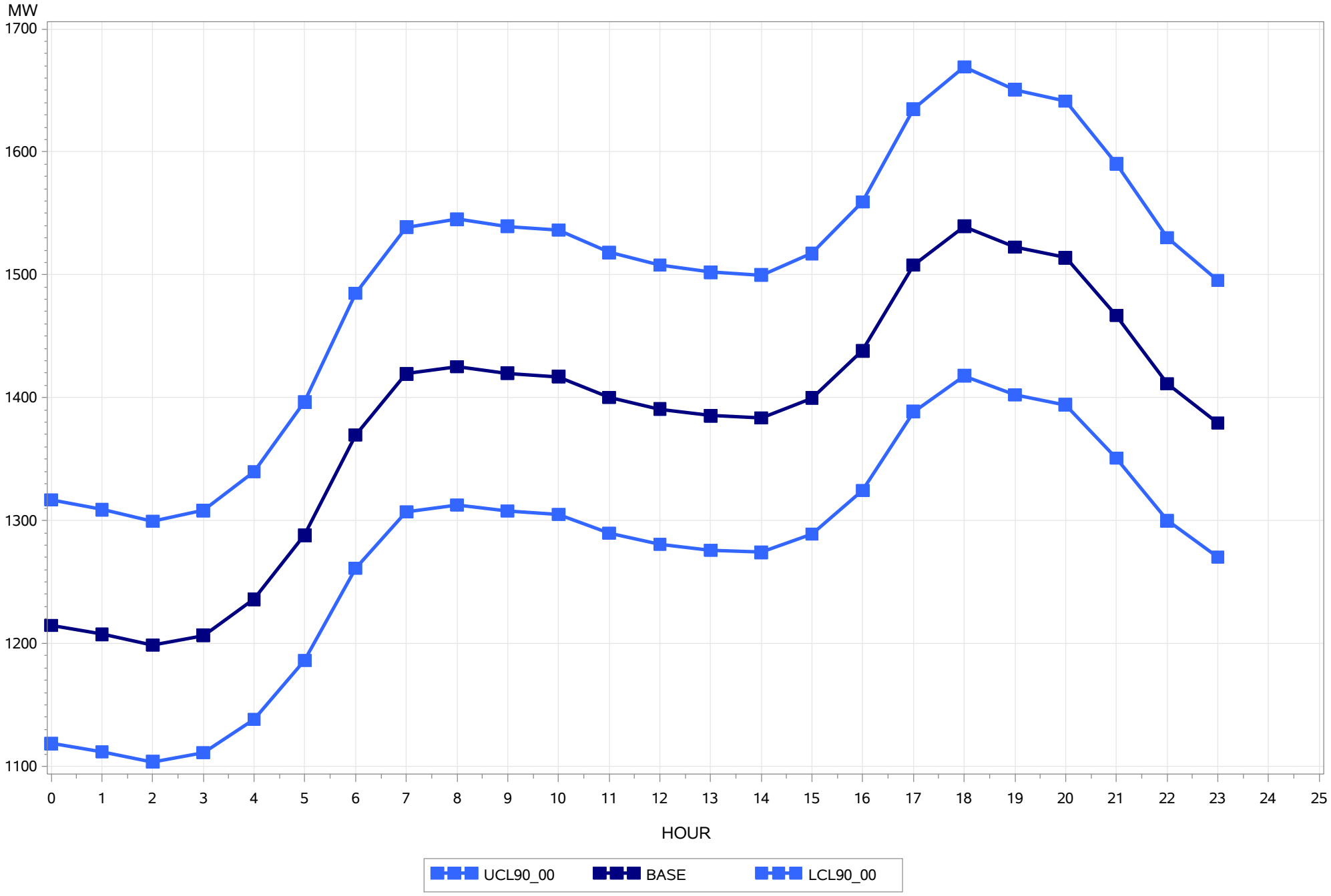
Member Forecasted On Peak Demand Day for February 2021

STATE OF COLORADO

Date of On Peak Day - 02/01/2021



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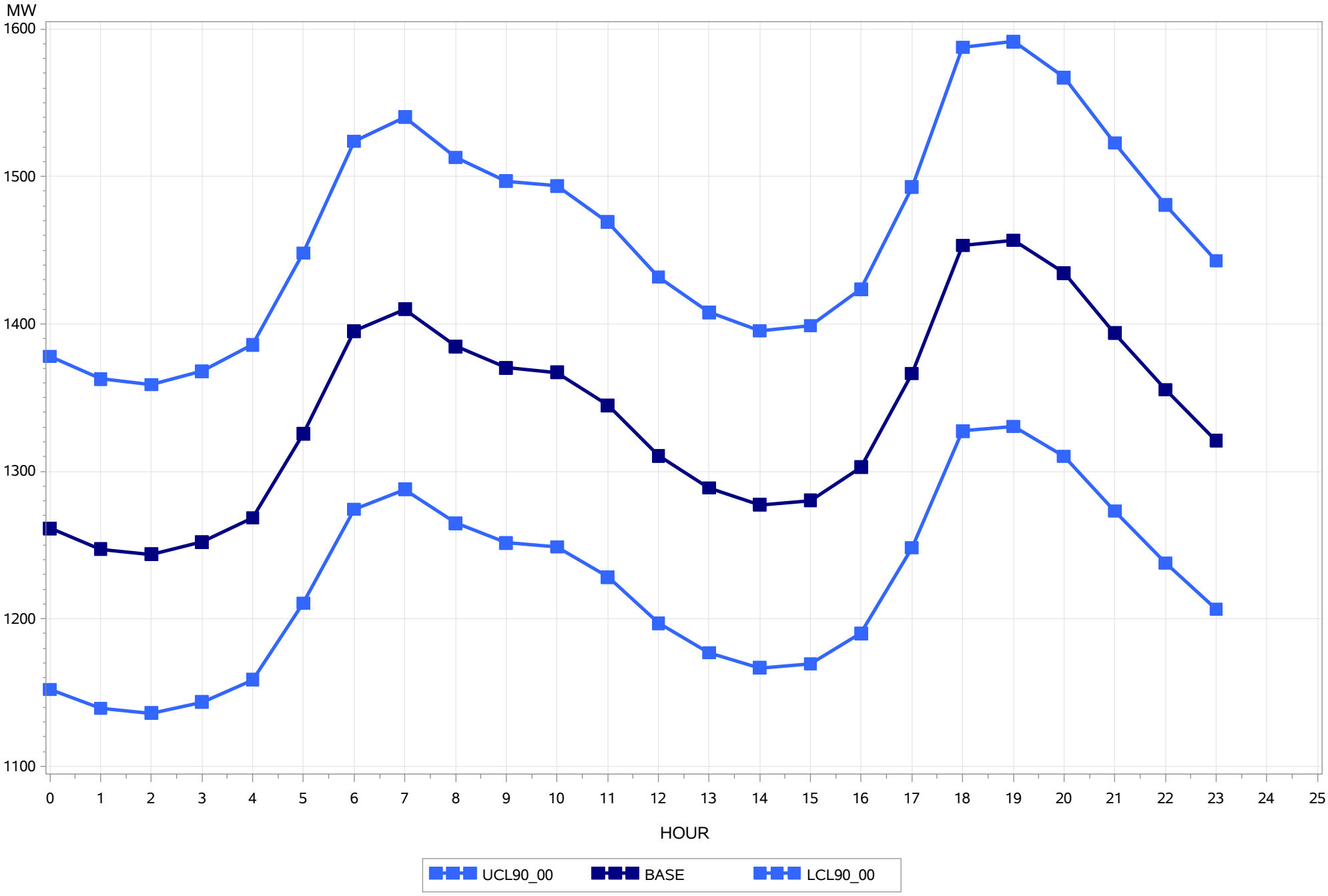
Member Forecasted On Peak Demand Day for March 2021

STATE OF COLORADO

Date of On Peak Day - 03/01/2021



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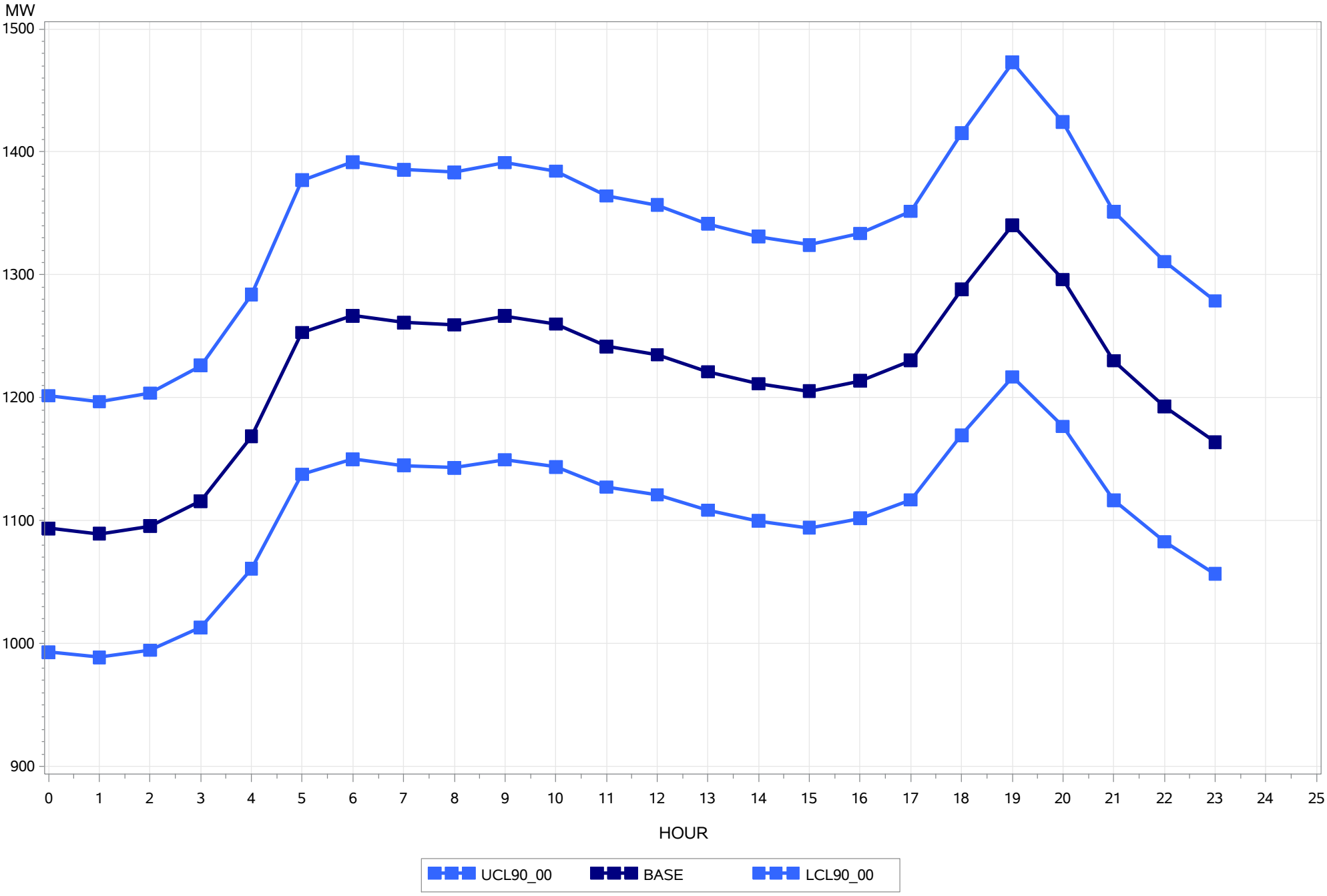
Member Forecasted On Peak Demand Day for April 2021

STATE OF COLORADO

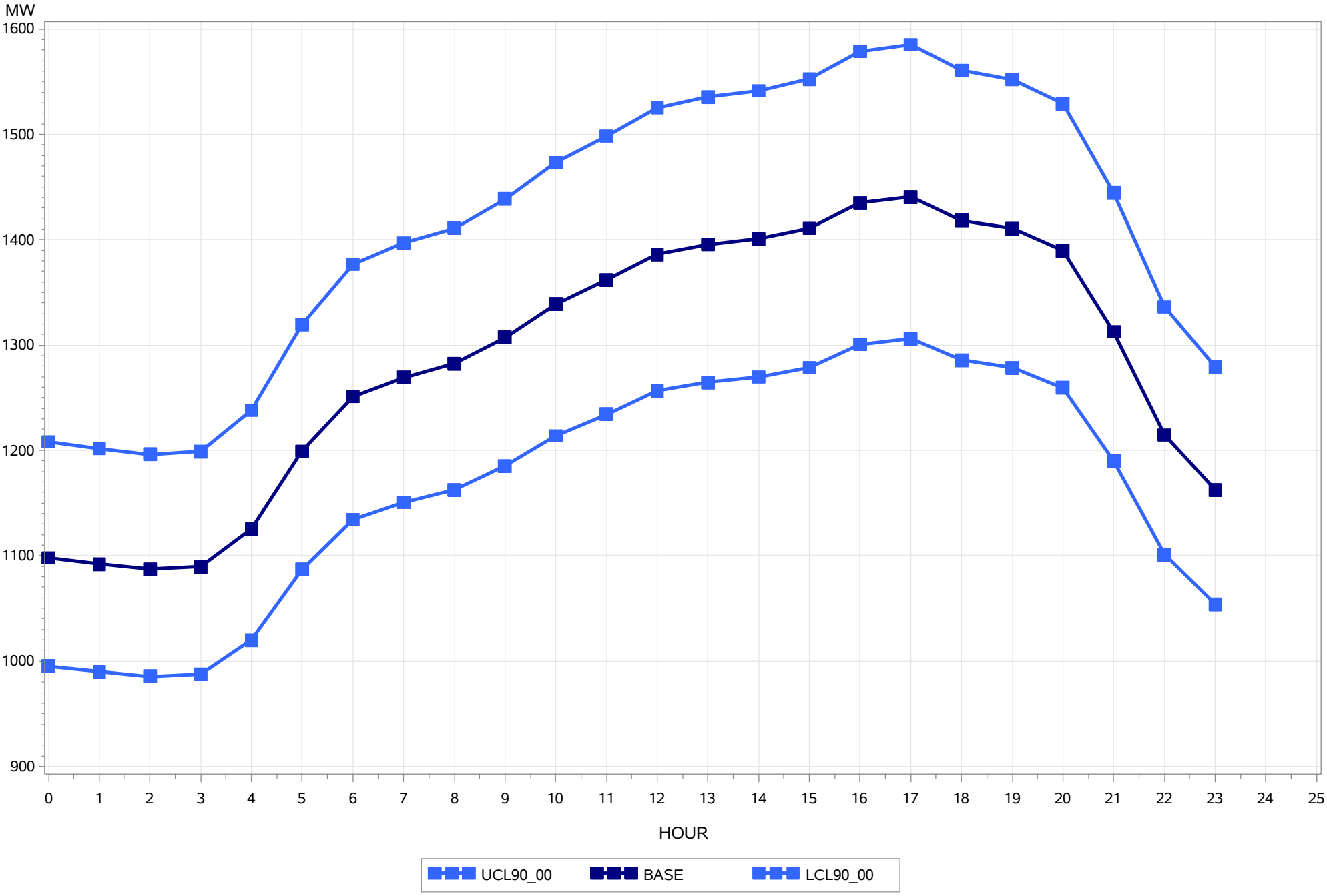
Date of On Peak Day - 04/15/2021



Member Forecasted On Peak Demand Day for May 2021

STATE OF COLORADO

Date of On Peak Day - 05/31/2021



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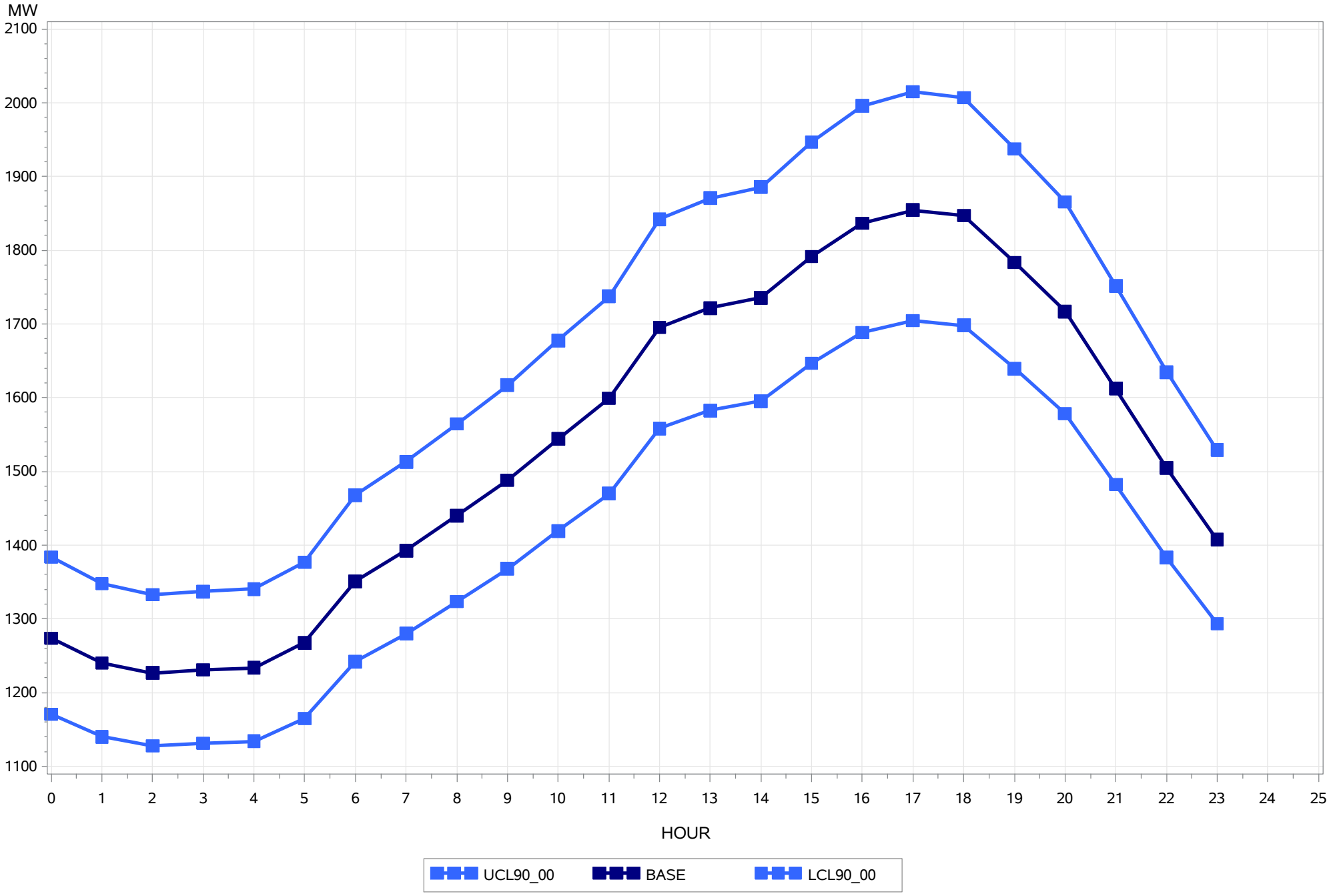
Member Forecasted On Peak Demand Day for June 2021

STATE OF COLORADO

Date of On Peak Day - 06/28/2021



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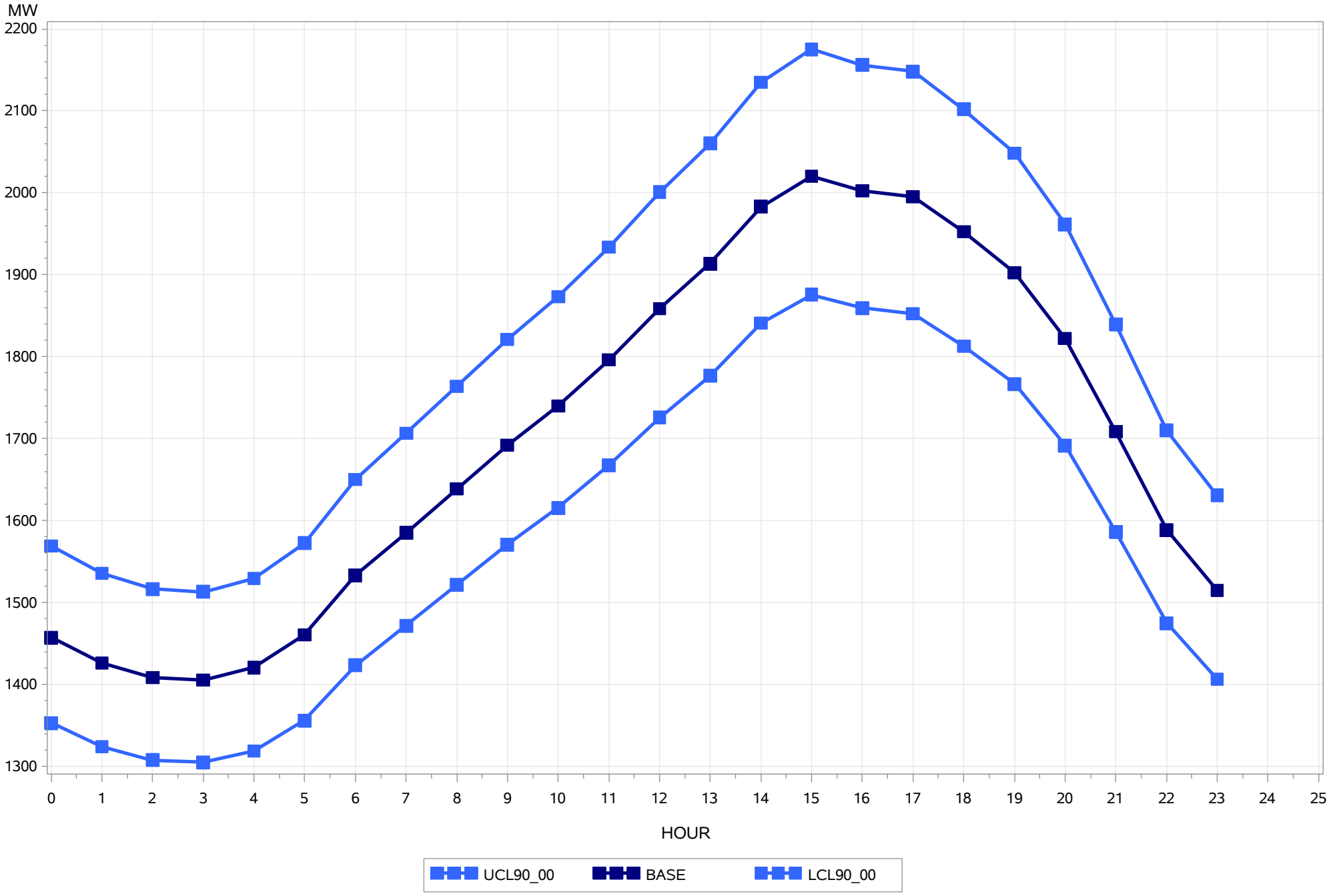
Member Forecasted On Peak Demand Day for July 2021

STATE OF COLORADO

Date of On Peak Day - 07/22/2021



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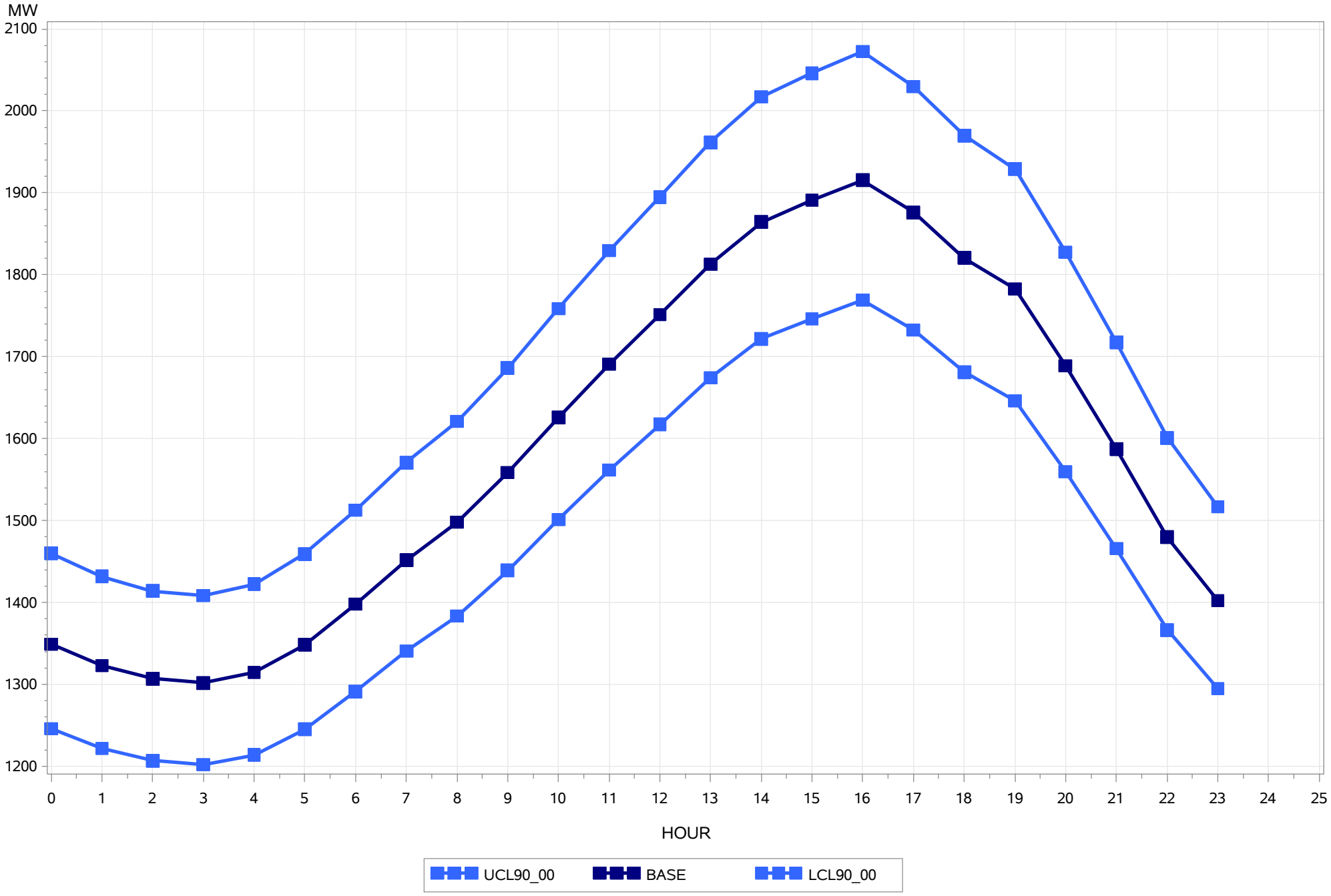
Member Forecasted On Peak Demand Day for August 2021

STATE OF COLORADO

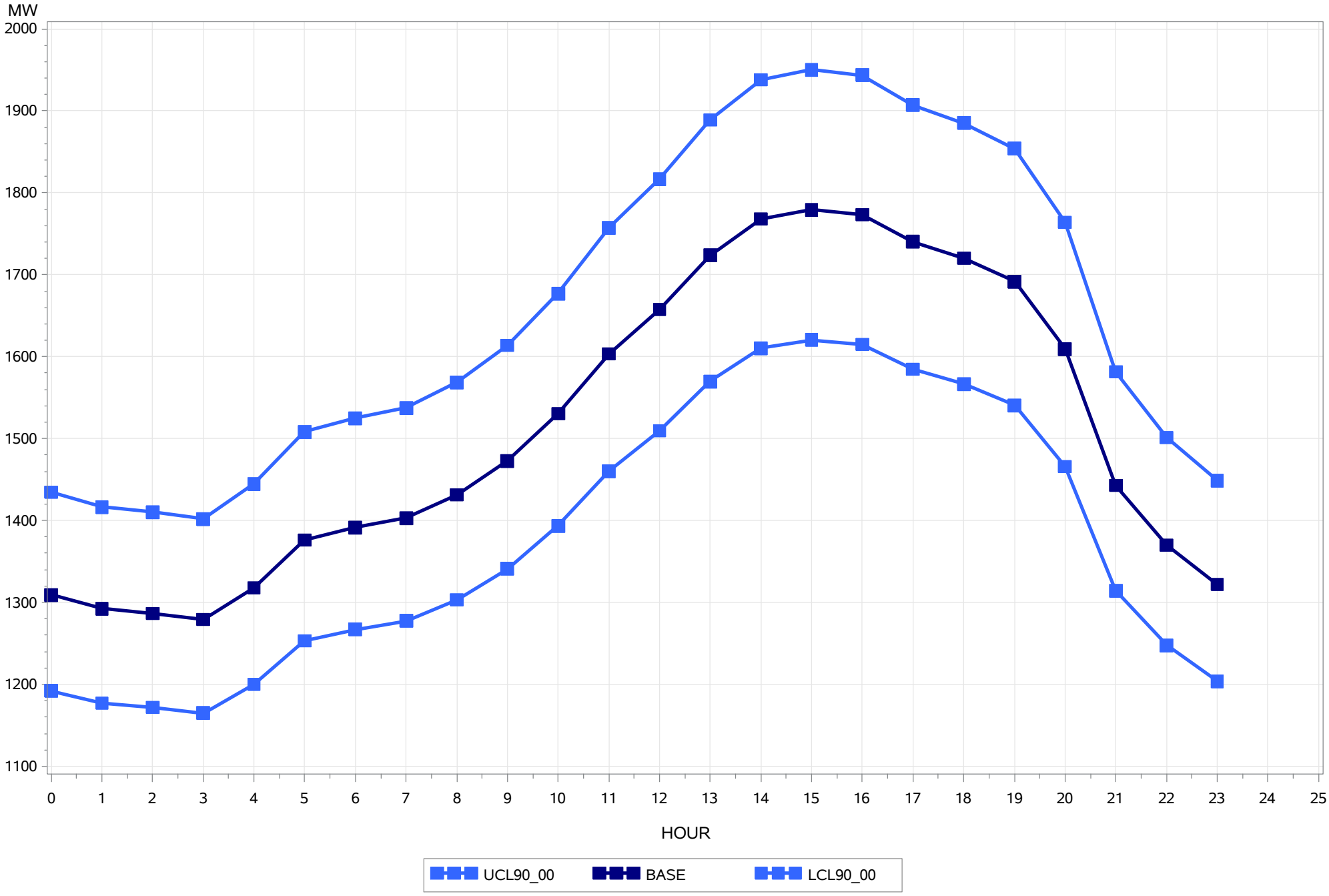
Date of On Peak Day - 08/28/2021



Member Forecasted On Peak Demand Day for September 2021

STATE OF COLORADO

Date of On Peak Day - 09/01/2021



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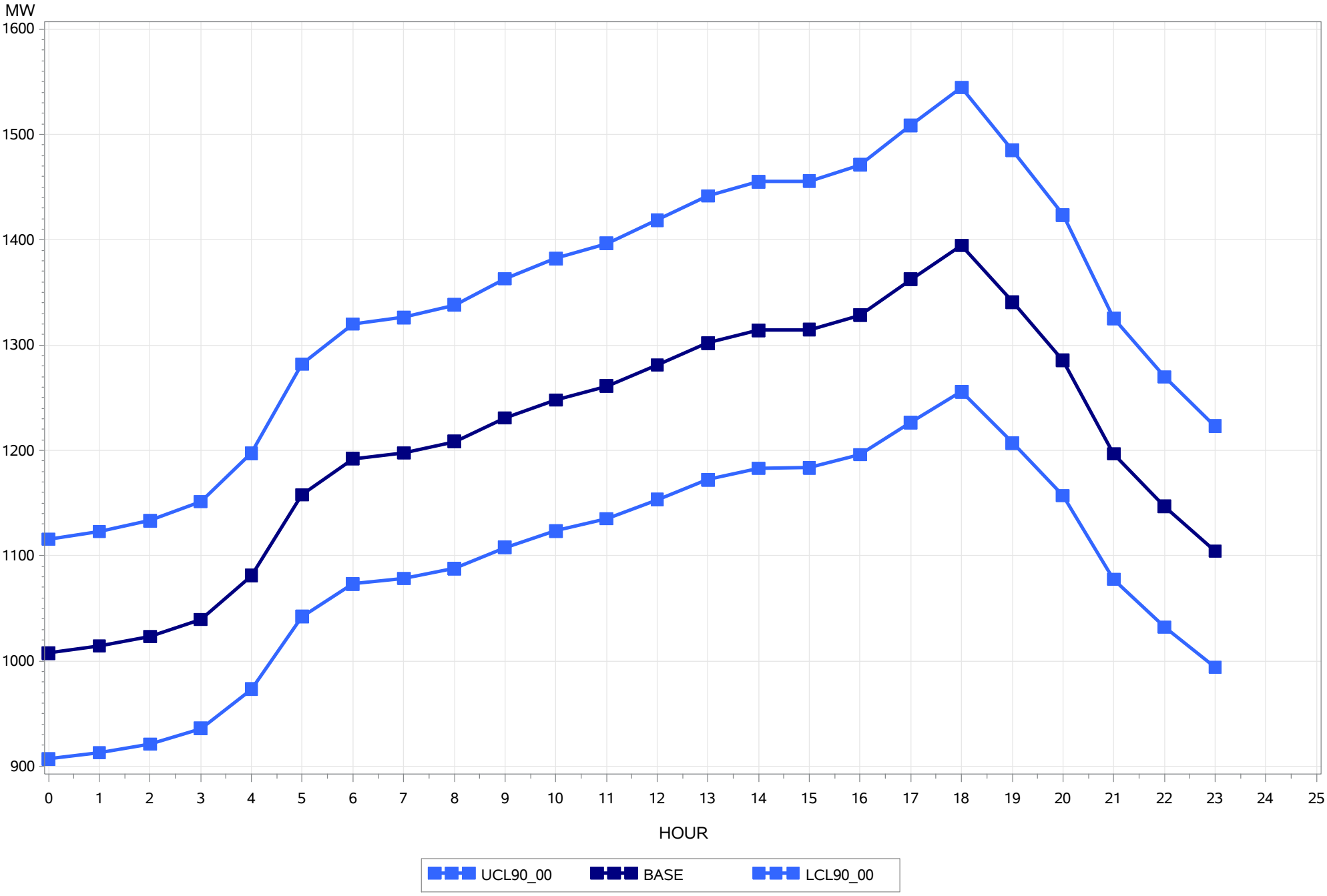
Member Forecasted On Peak Demand Day for October 2021

STATE OF COLORADO

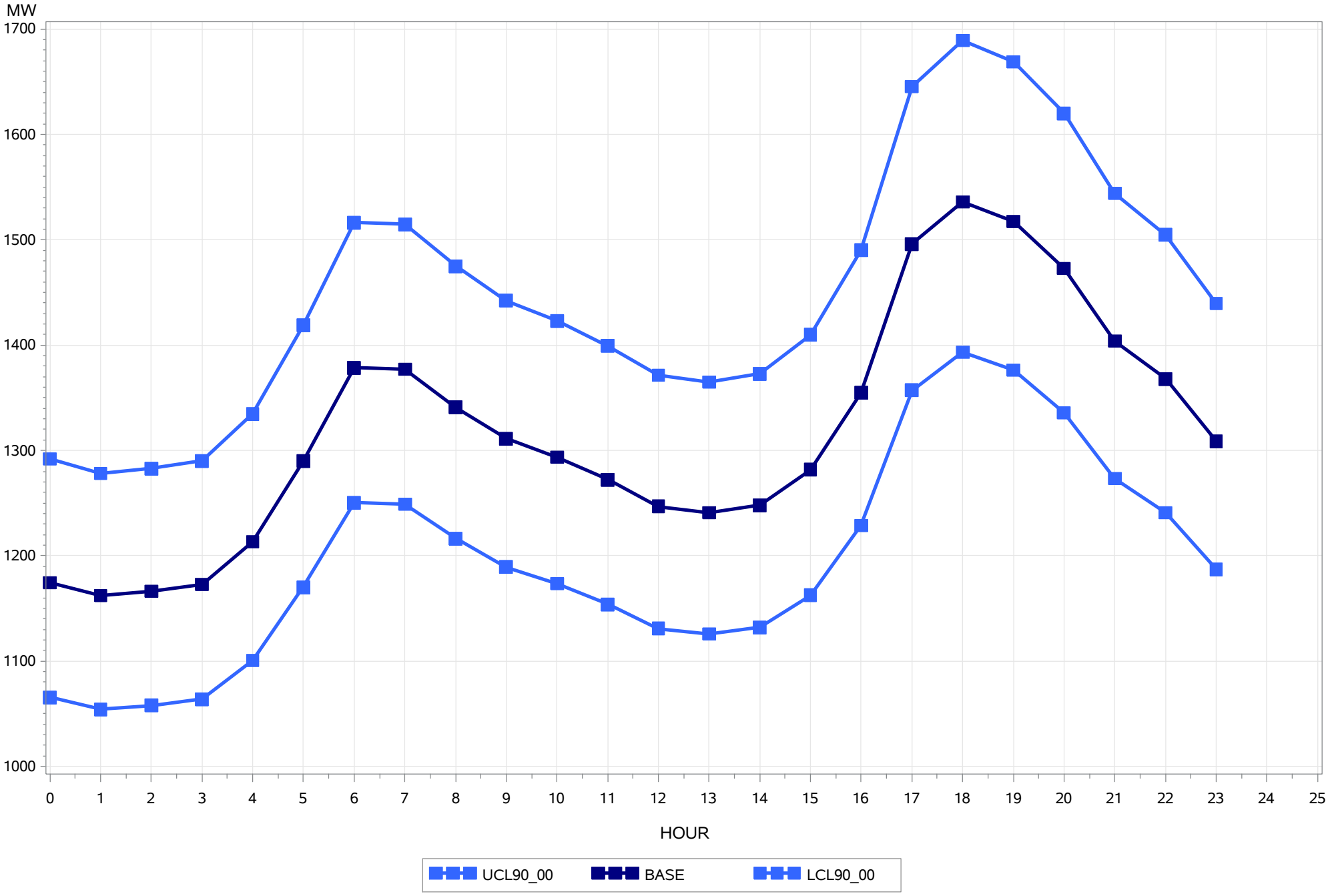
Date of On Peak Day - 10/11/2021



Member Forecasted On Peak Demand Day for November 2021

STATE OF COLORADO

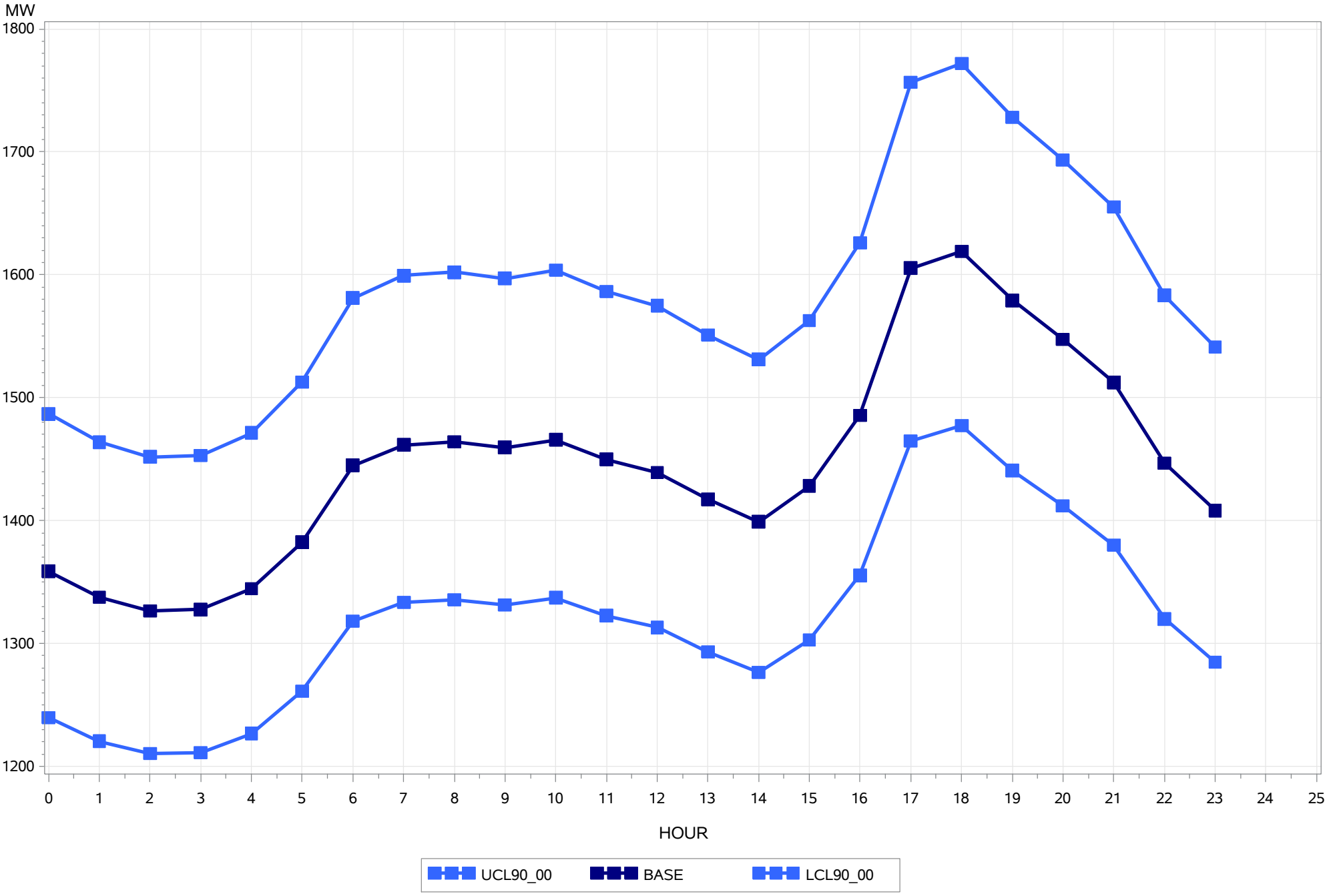
Date of On Peak Day - 11/08/2021



Member Forecasted On Peak Demand Day for December 2021

STATE OF COLORADO

Date of On Peak Day - 12/28/2021



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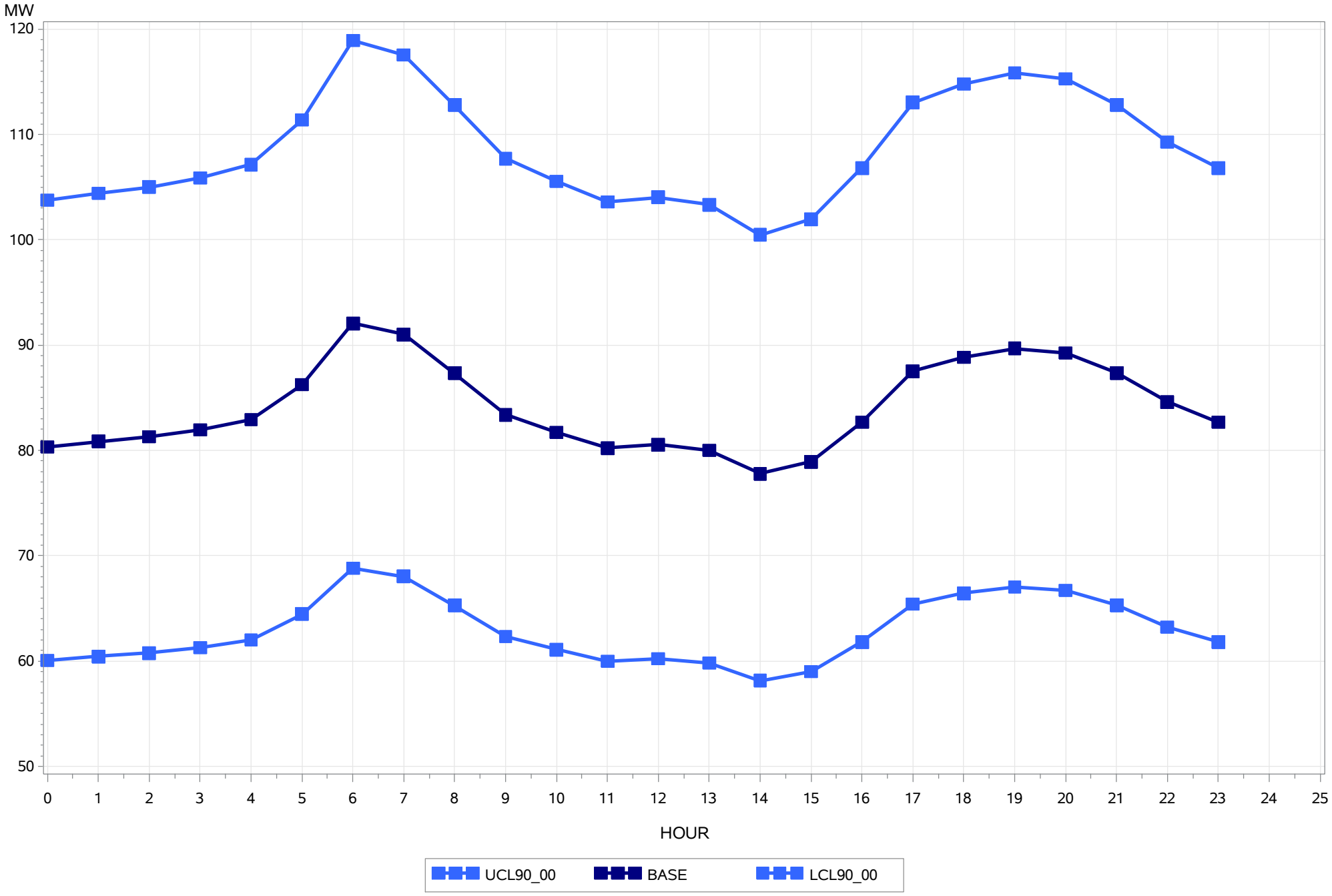
Member Forecasted On Peak Demand Day for January 2021

STATE OF NEBRASKA

Date of On Peak Day - 01/07/2021



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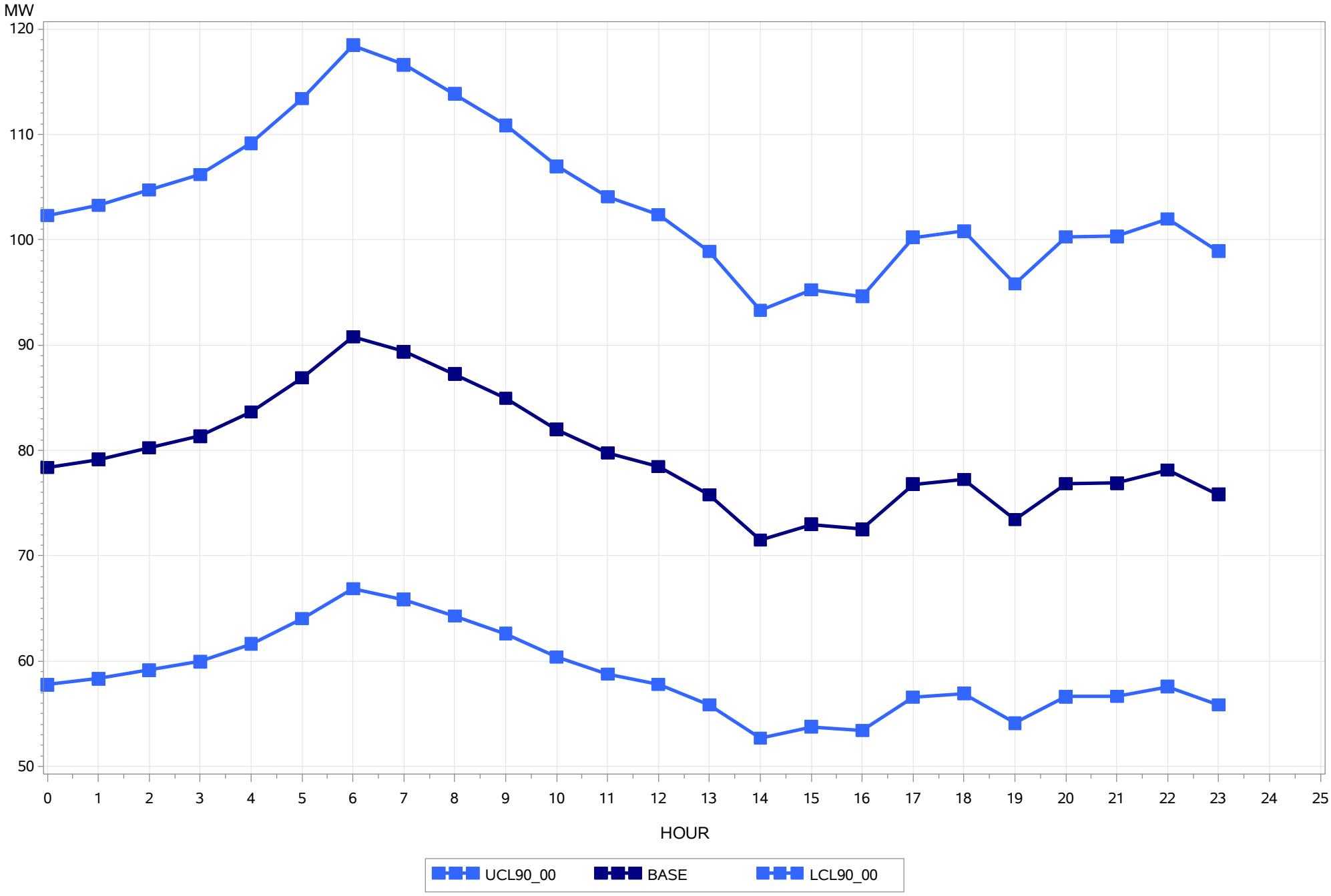
Member Forecasted On Peak Demand Day for February 2021

STATE OF NEBRASKA

Date of On Peak Day - 02/03/2021



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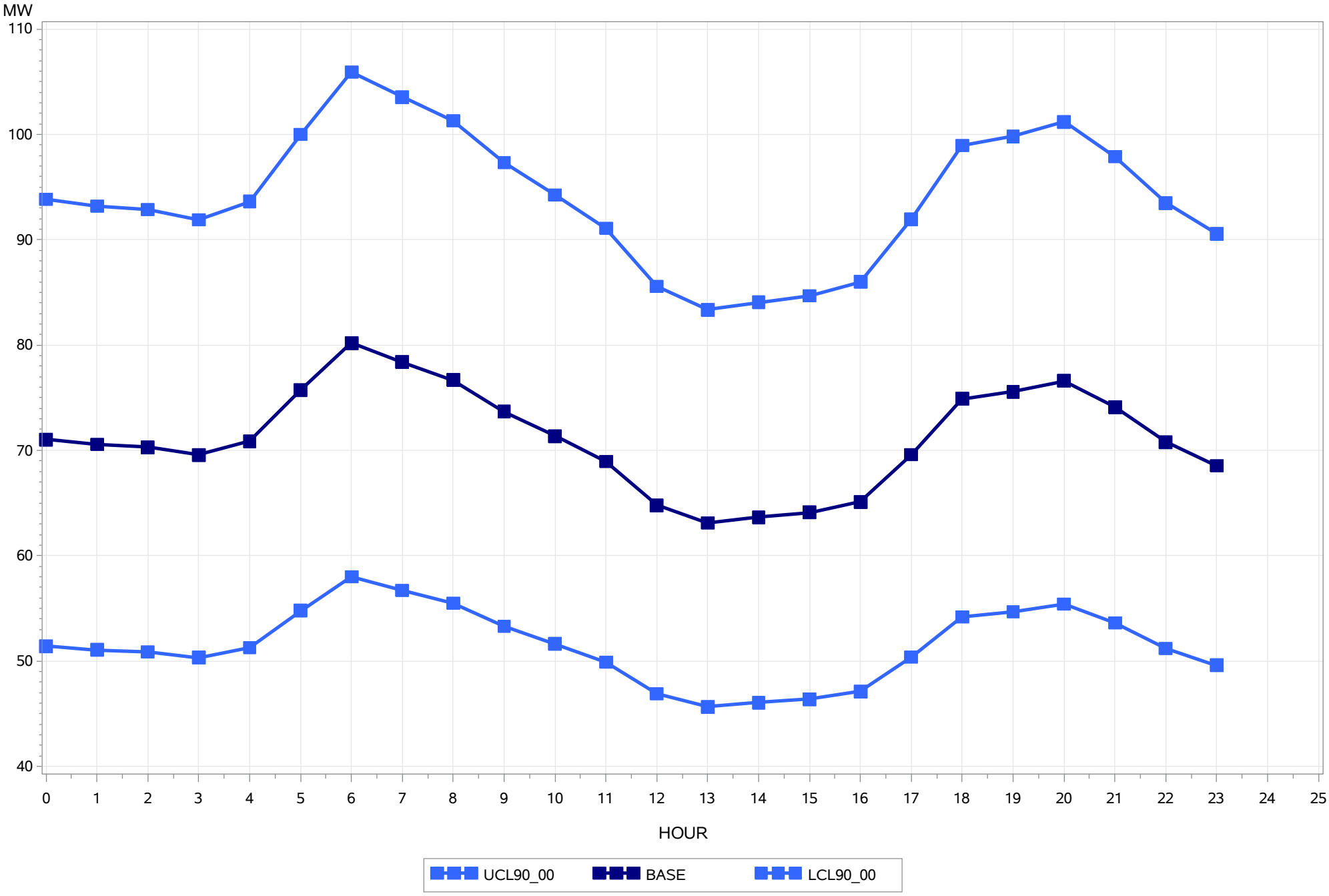
Member Forecasted On Peak Demand Day for March 2021

STATE OF NEBRASKA

Date of On Peak Day - 03/02/2021



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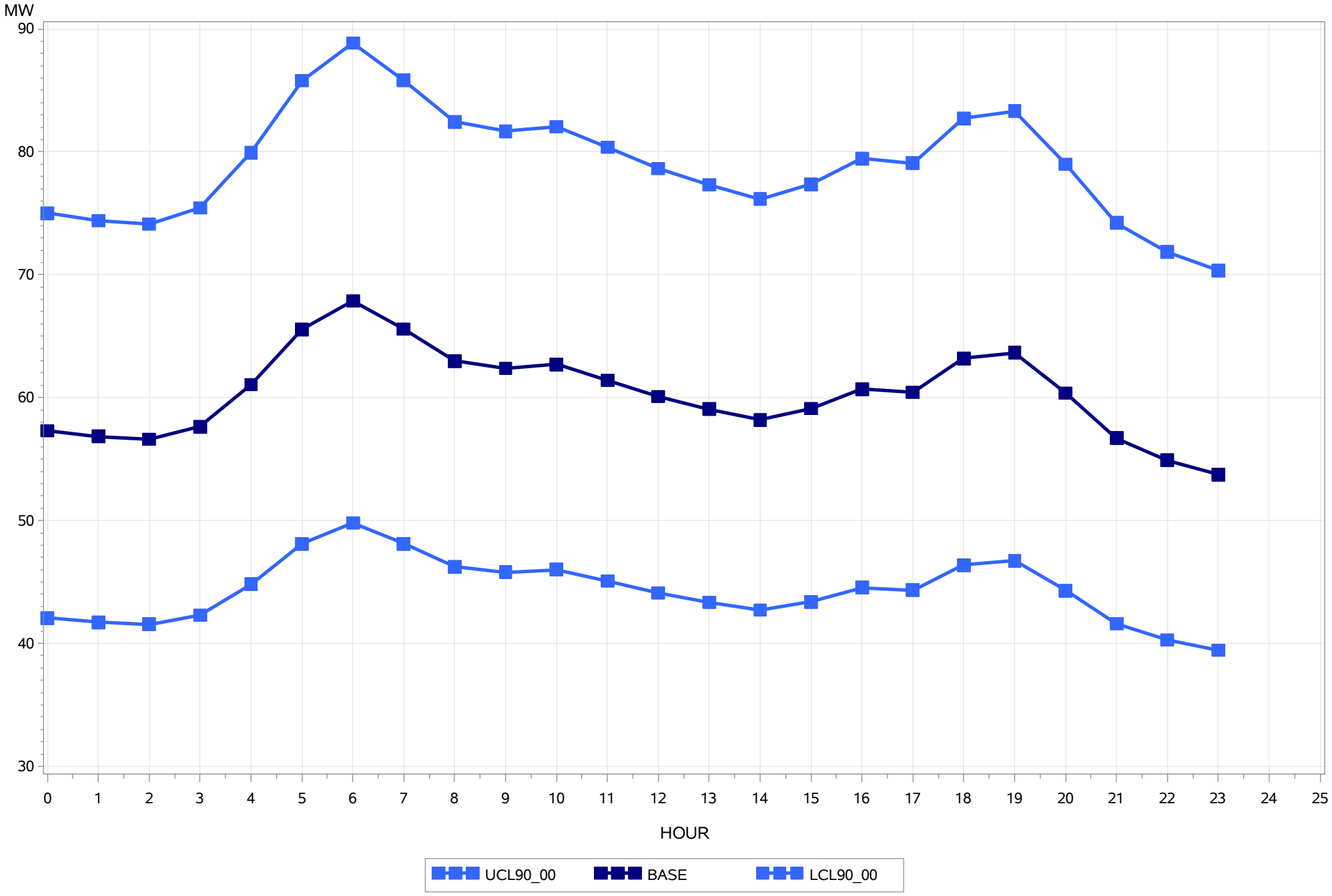
Member Forecasted On Peak Demand Day for April 2021

STATE OF NEBRASKA

Date of On Peak Day - 04/06/2021



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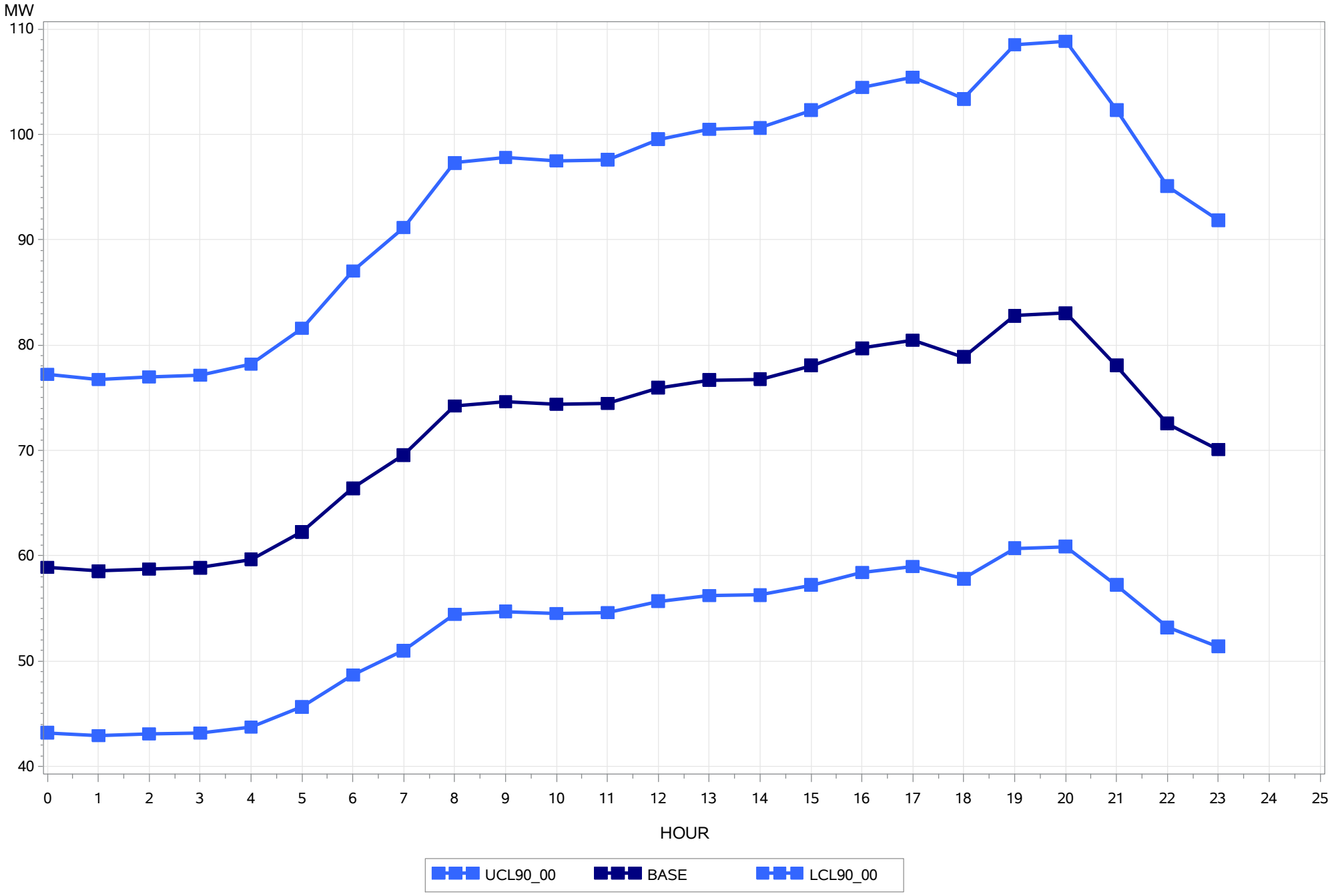
Member Forecasted On Peak Demand Day for May 2021

STATE OF NEBRASKA

Date of On Peak Day - 05/15/2021



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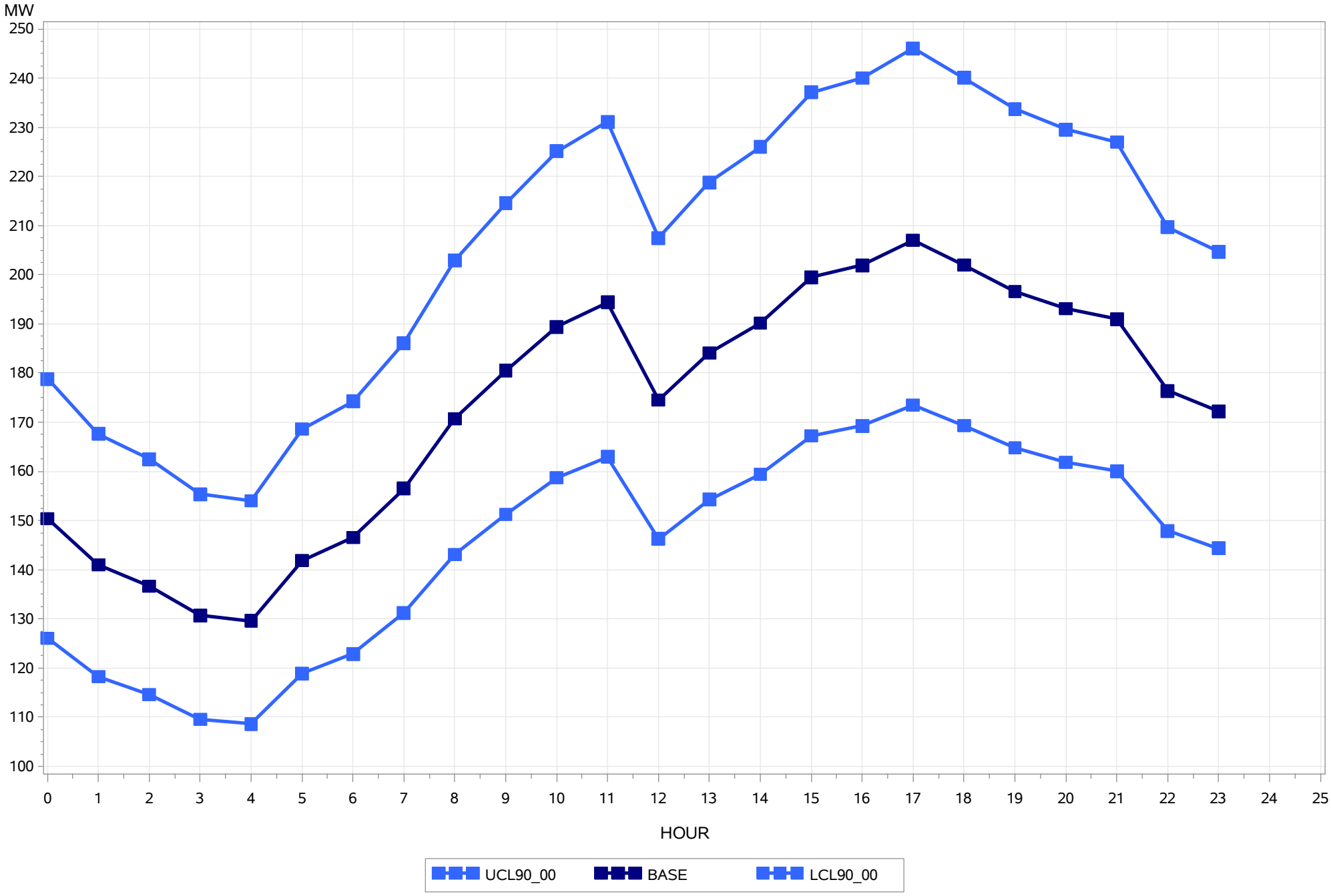
Member Forecasted On Peak Demand Day for June 2021

STATE OF NEBRASKA

Date of On Peak Day - 06/11/2021



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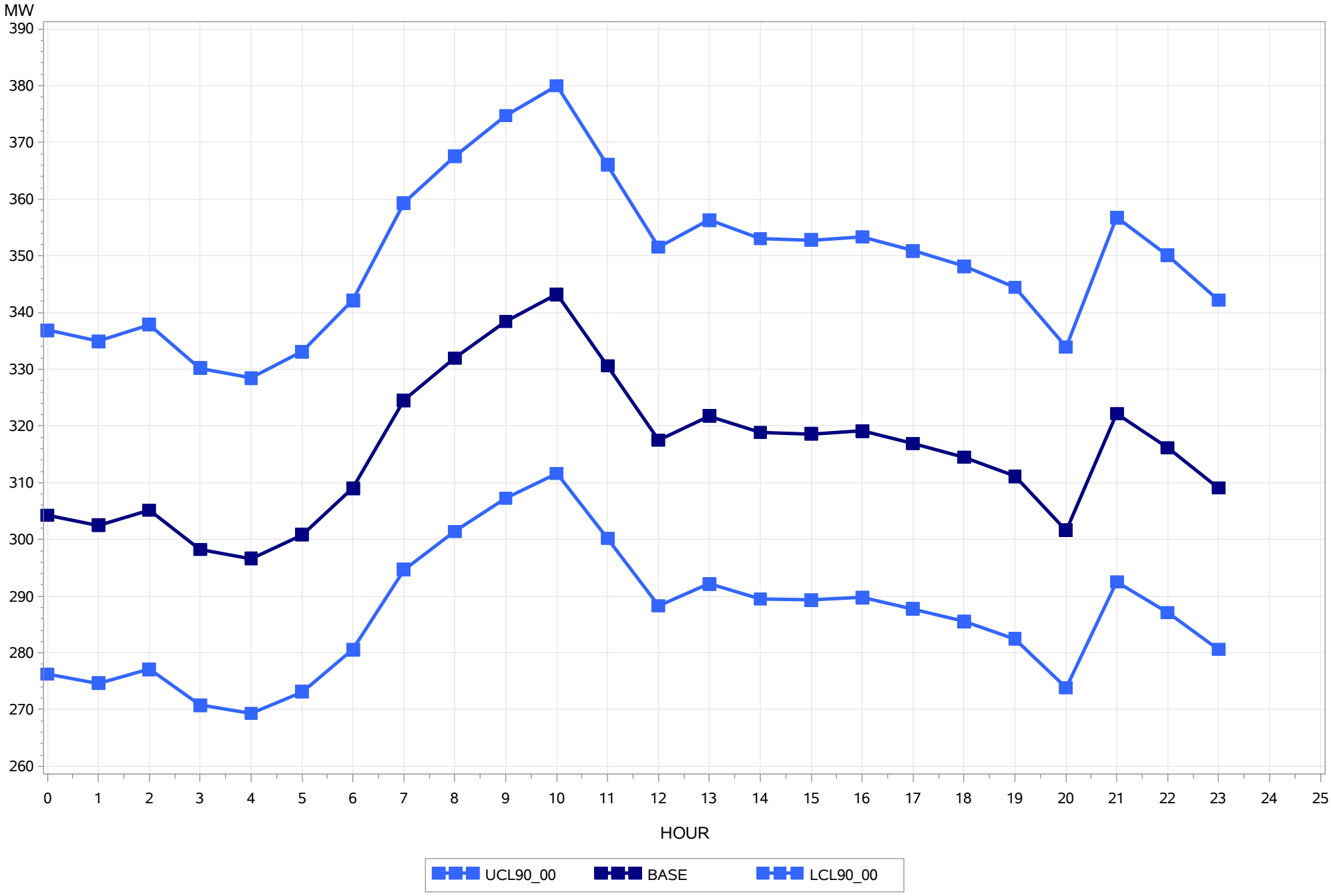
Member Forecasted On Peak Demand Day for July 2021

STATE OF NEBRASKA

Date of On Peak Day - 07/14/2021



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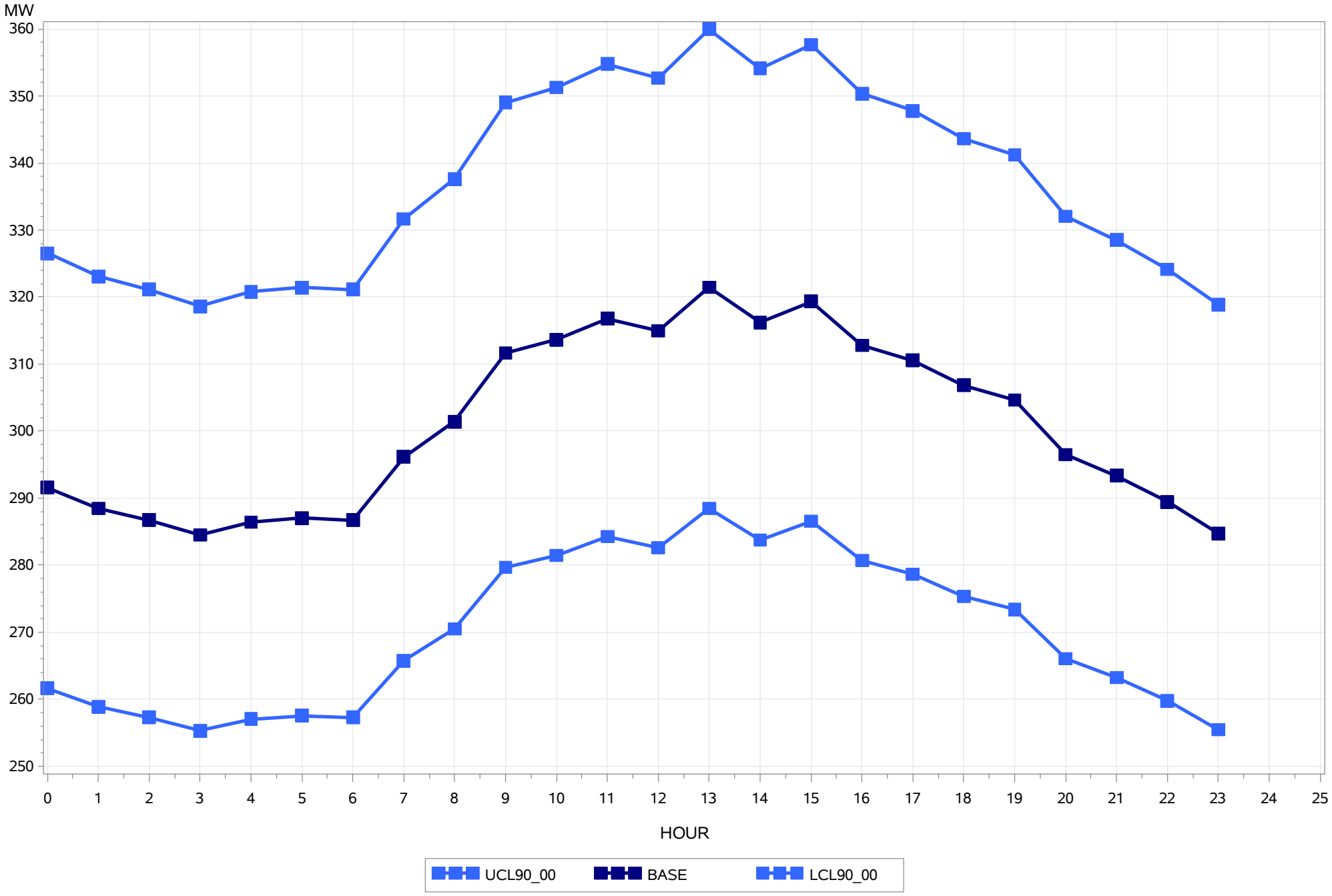
Member Forecasted On Peak Demand Day for August 2021

STATE OF NEBRASKA

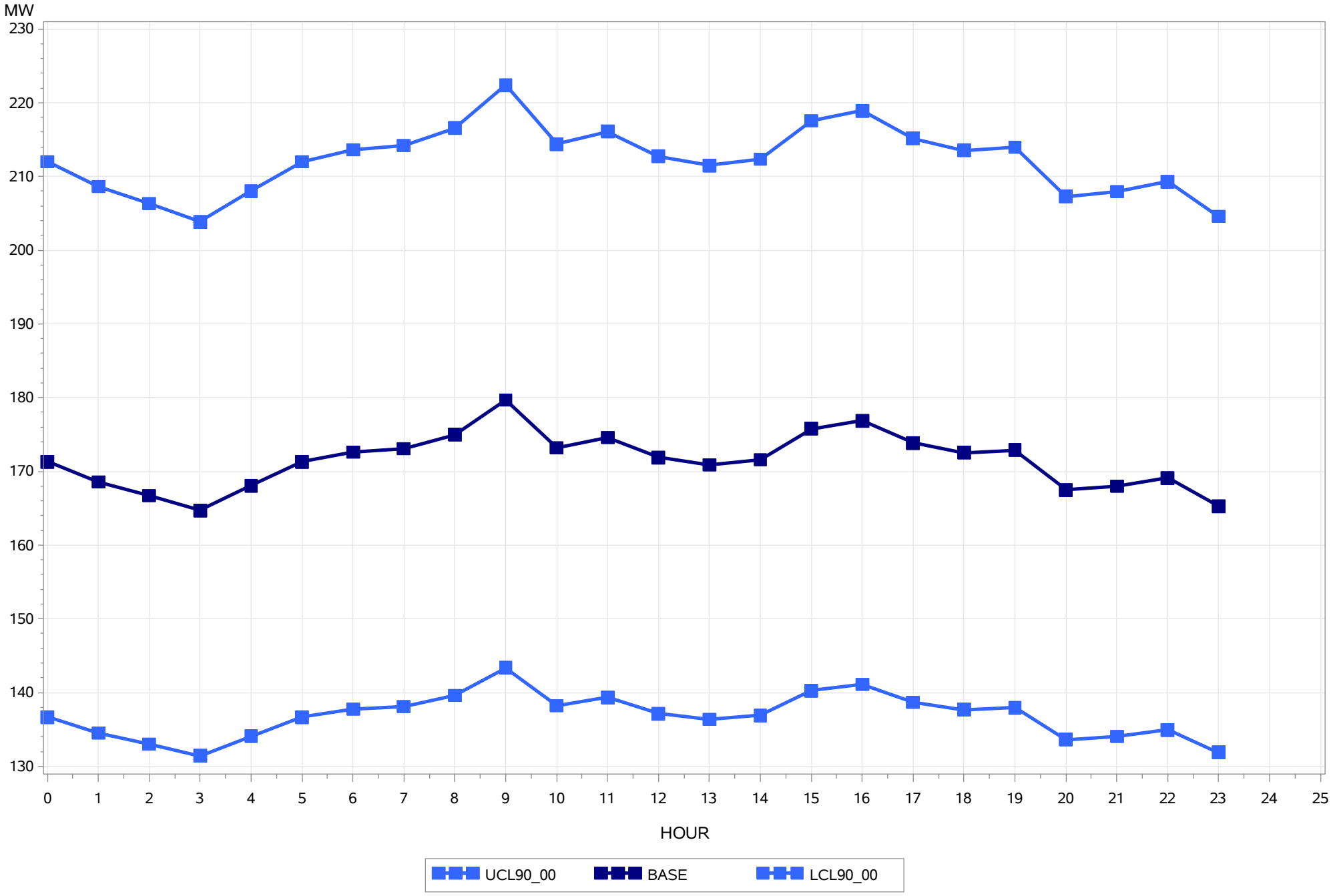
Date of On Peak Day - 08/24/2021



Member Forecasted On Peak Demand Day for September 2021

STATE OF NEBRASKA

Date of On Peak Day - 09/01/2021



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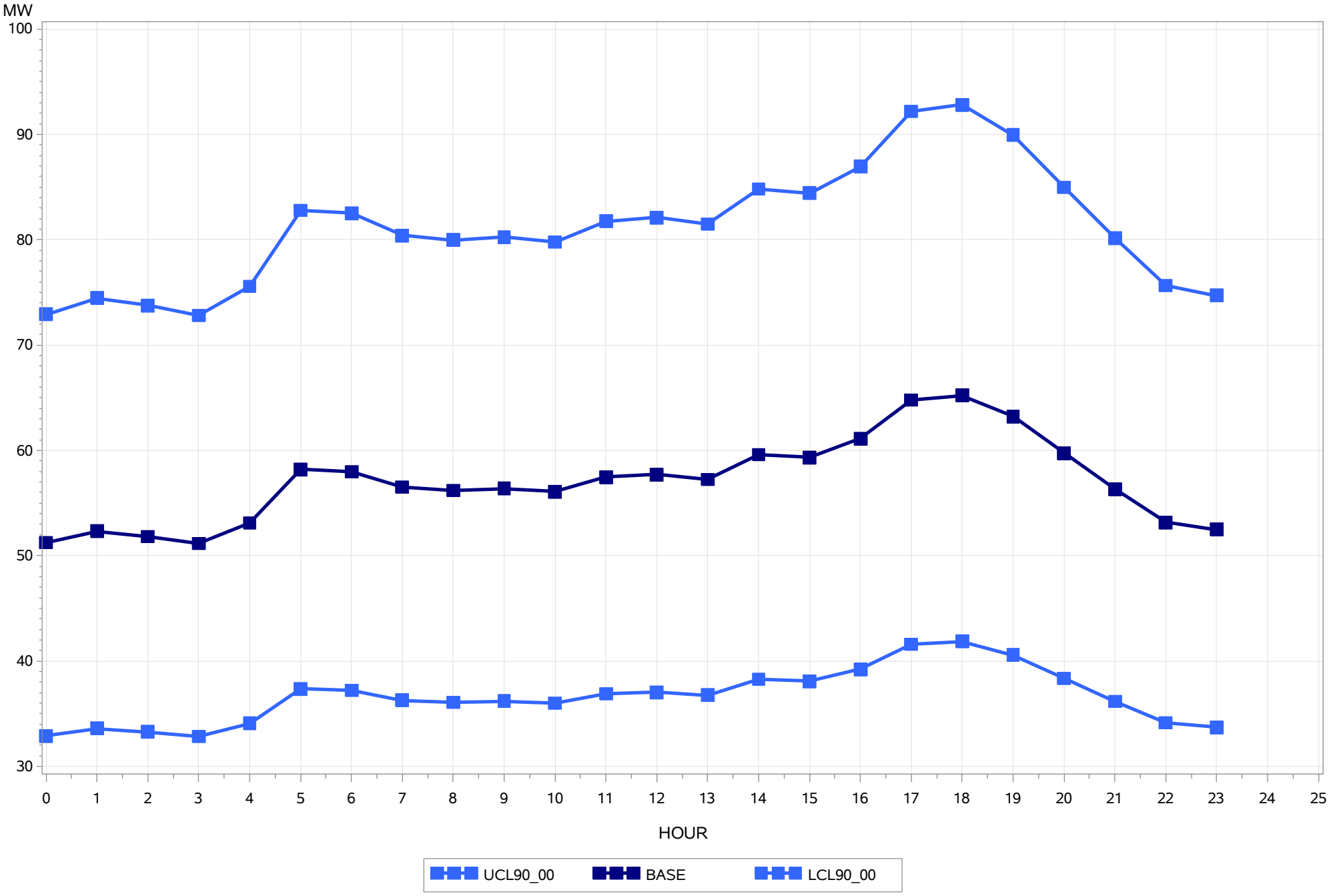
Member Forecasted On Peak Demand Day for October 2021

STATE OF NEBRASKA

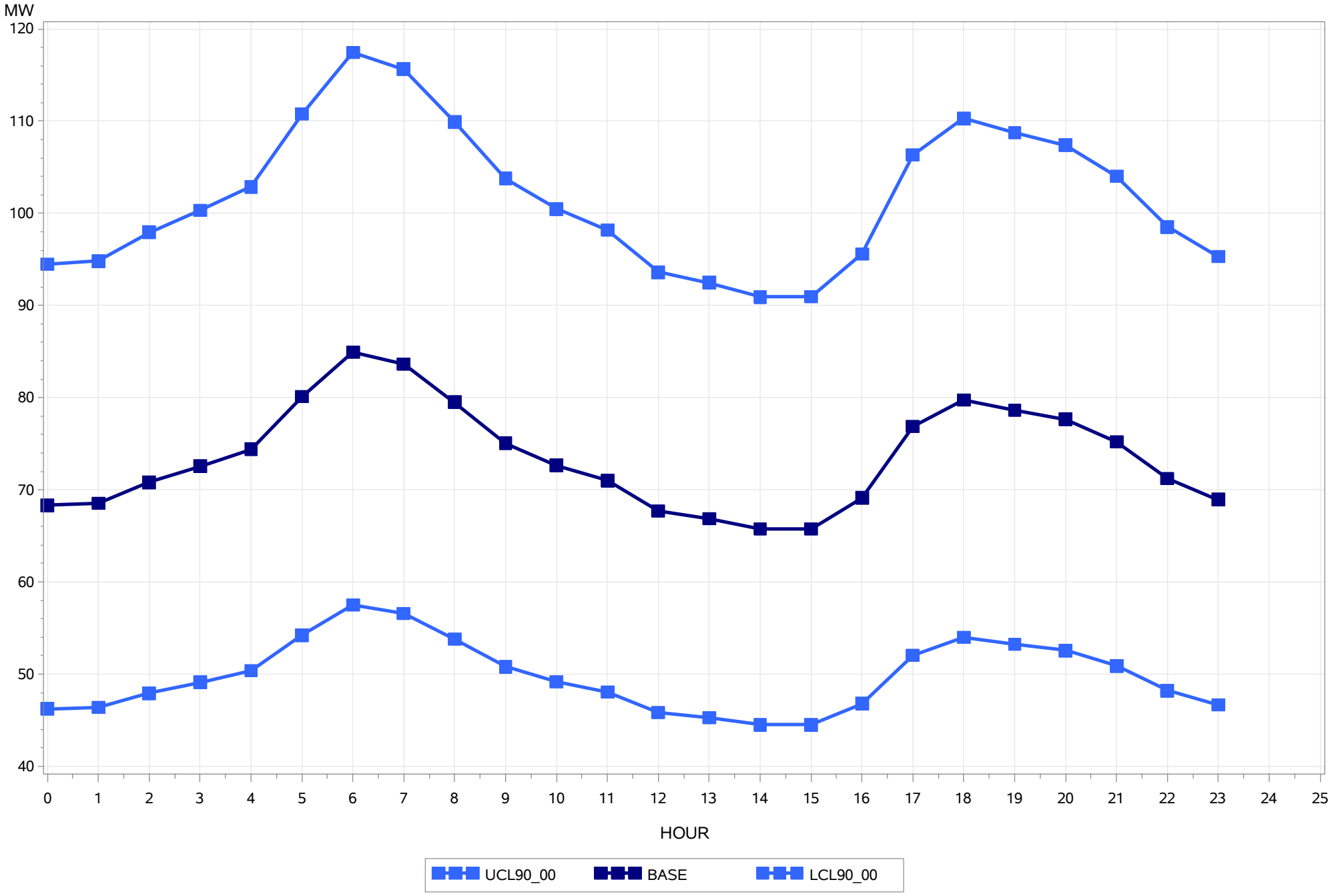
Date of On Peak Day - 10/13/2021



Member Forecasted On Peak Demand Day for November 2021

STATE OF NEBRASKA

Date of On Peak Day - 11/09/2021



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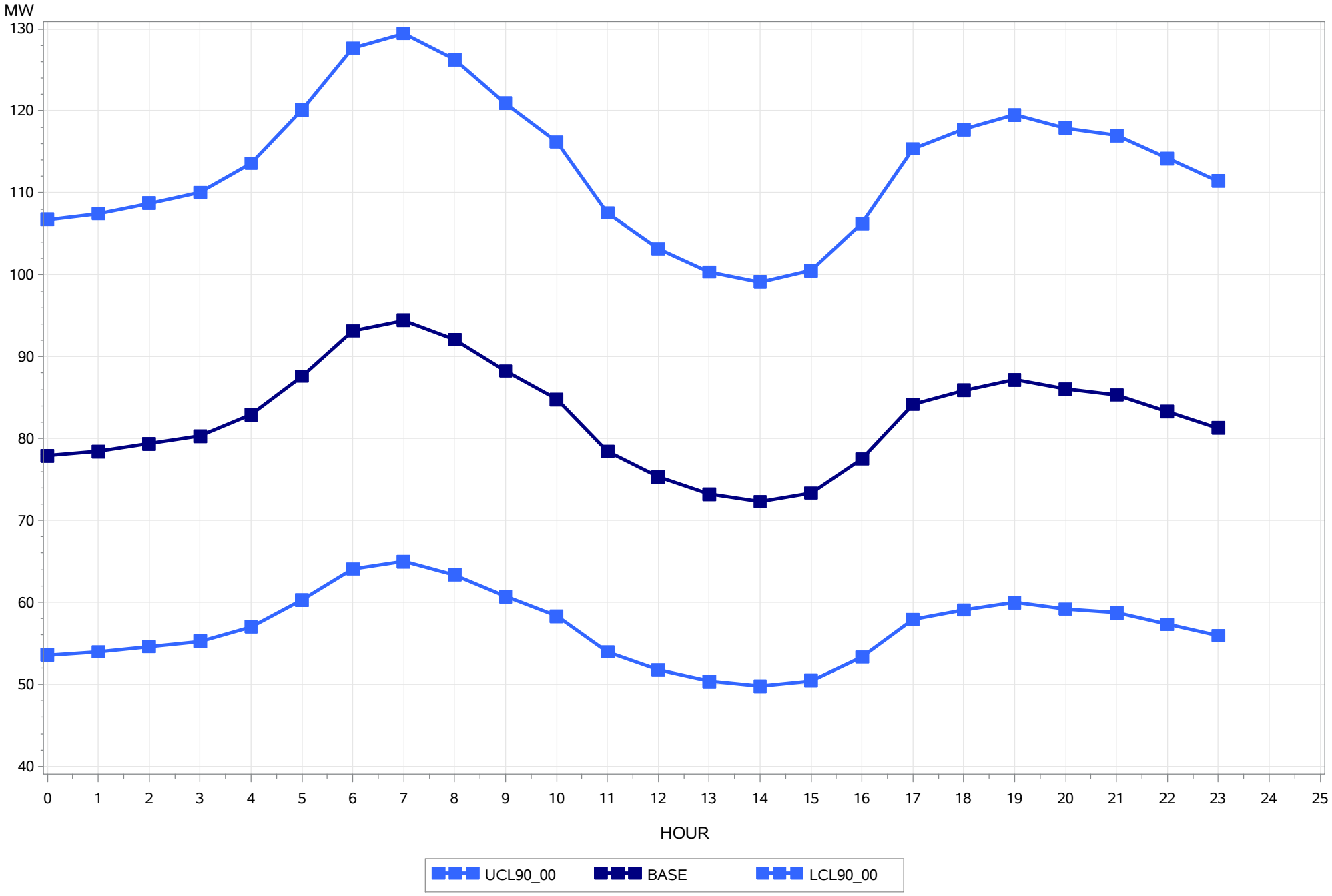
Member Forecasted On Peak Demand Day for December 2021

STATE OF NEBRASKA

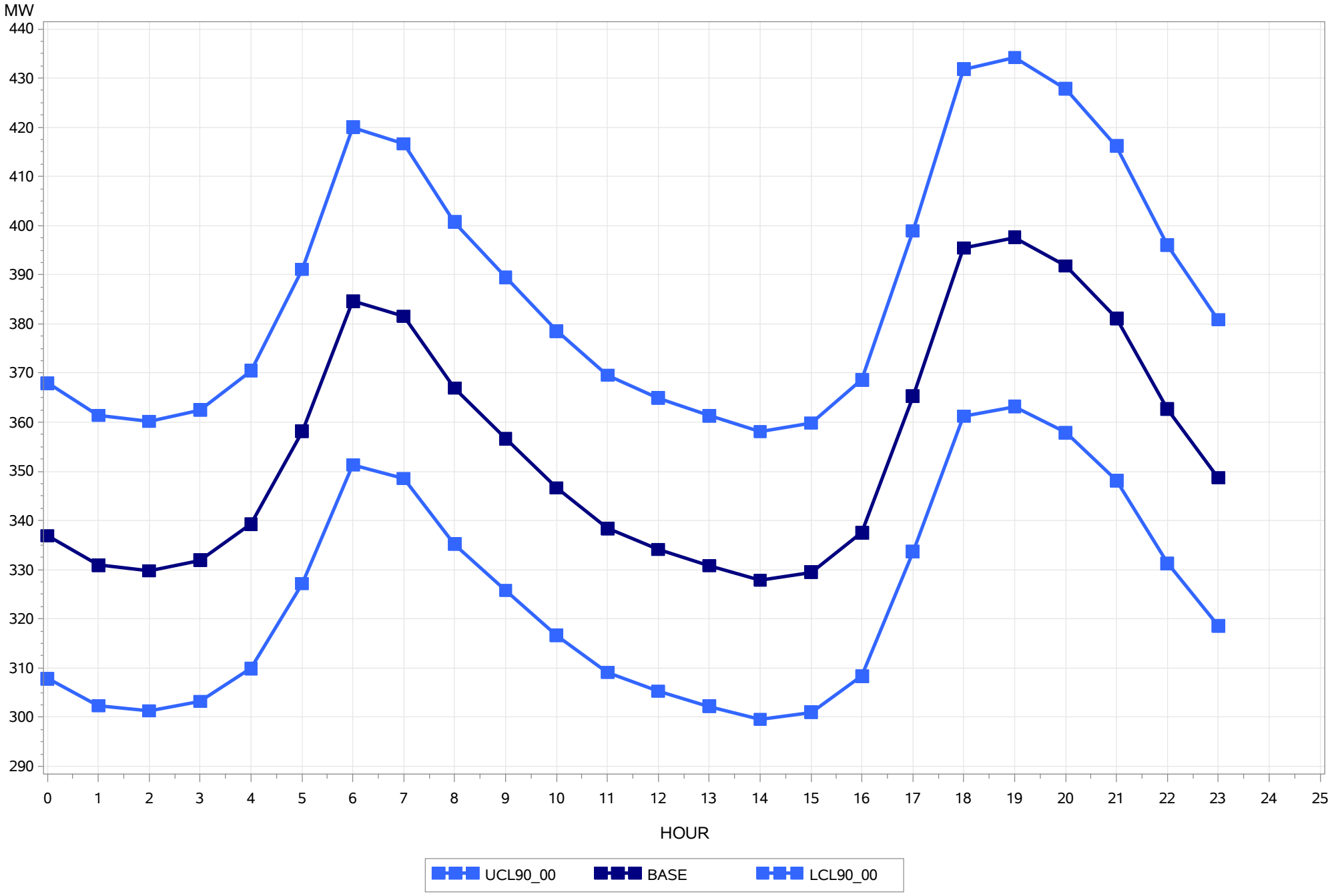
Date of On Peak Day - 12/30/2021



Member Forecasted On Peak Demand Day for January 2021

STATE OF NEW MEXICO

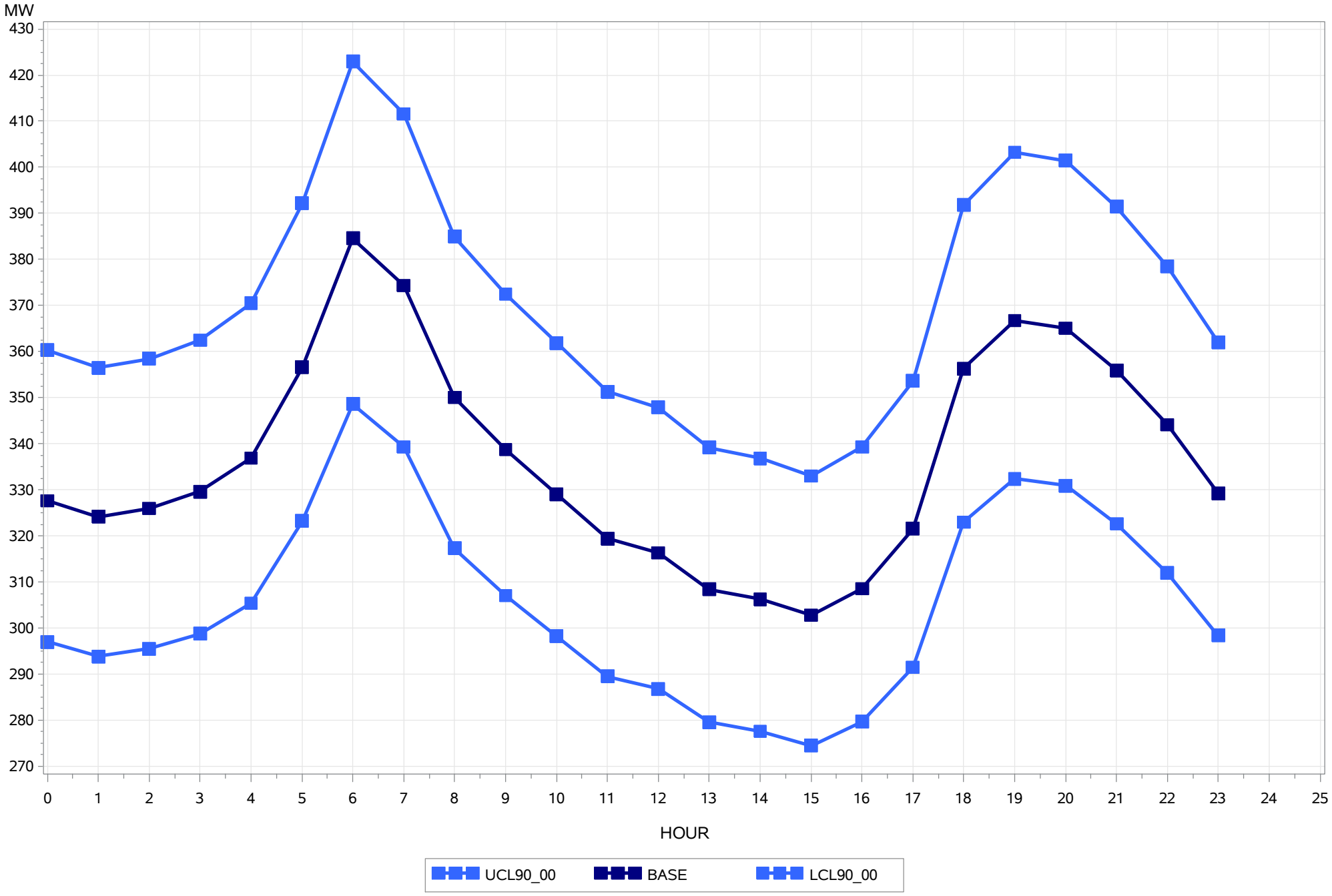
Date of On Peak Day - 01/26/2021



Member Forecasted On Peak Demand Day for February 2021

STATE OF NEW MEXICO

Date of On Peak Day - 02/25/2021



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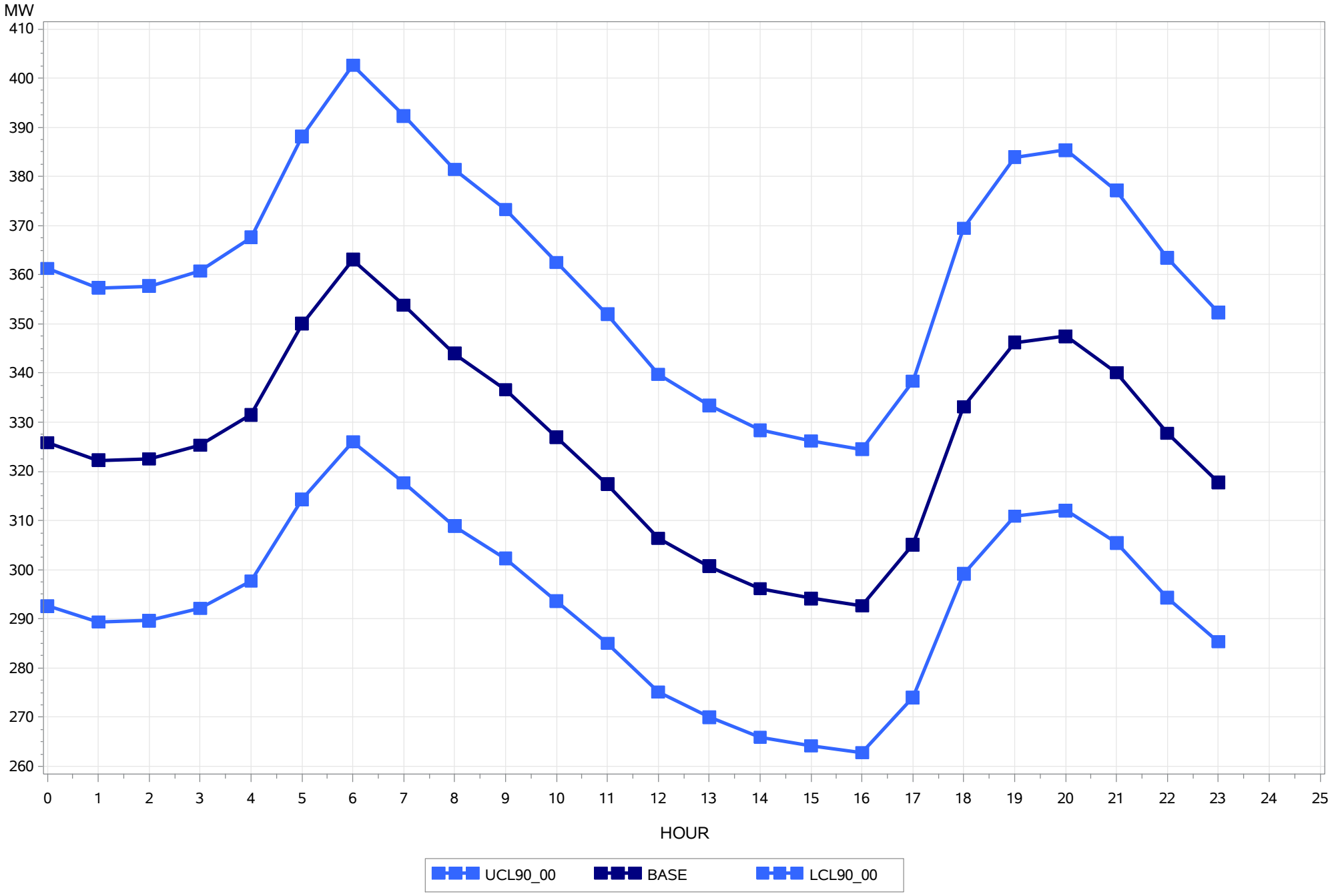
Member Forecasted On Peak Demand Day for March 2021

STATE OF NEW MEXICO

Date of On Peak Day - 03/02/2021



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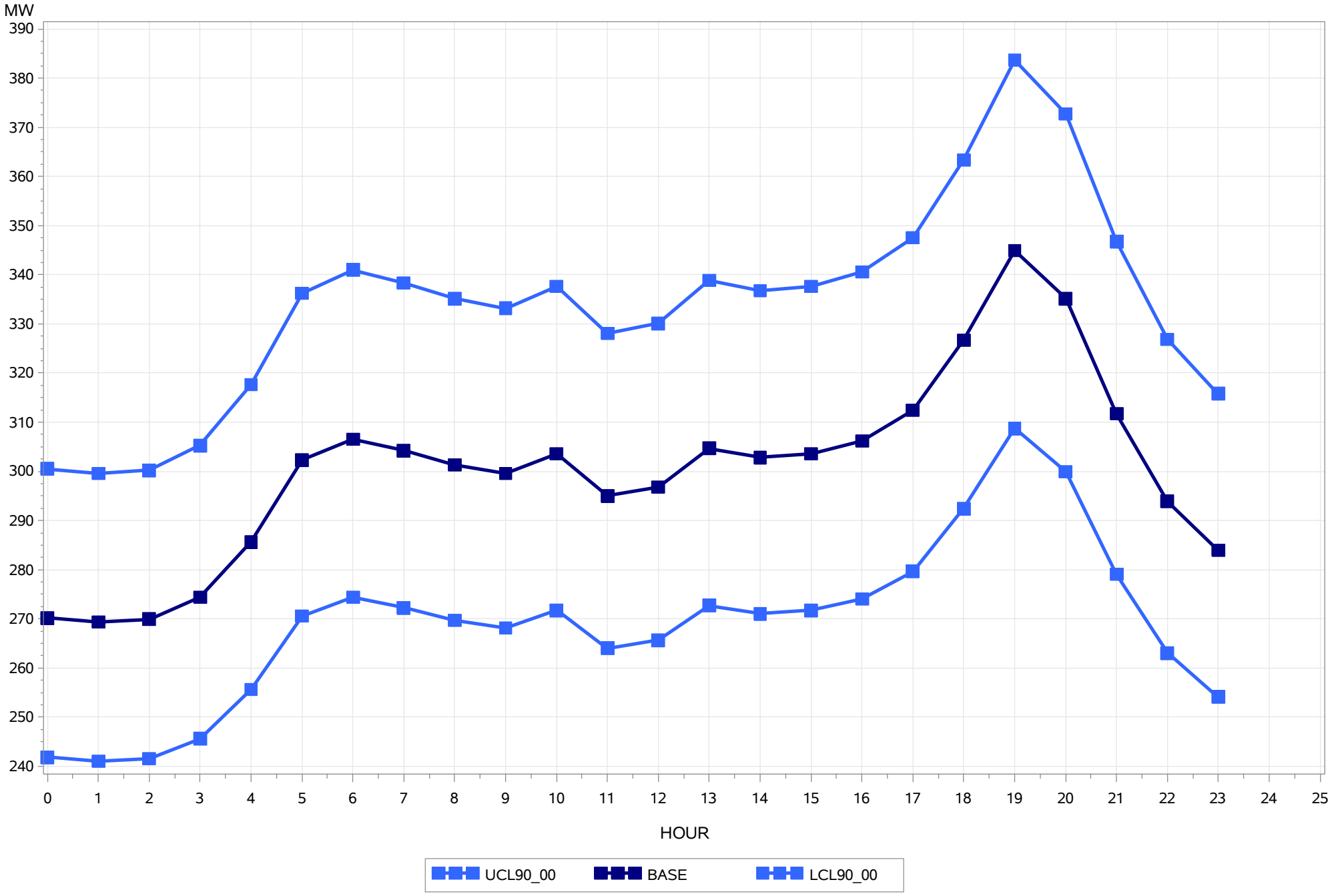
Member Forecasted On Peak Demand Day for April 2021

STATE OF NEW MEXICO

Date of On Peak Day - 04/12/2021



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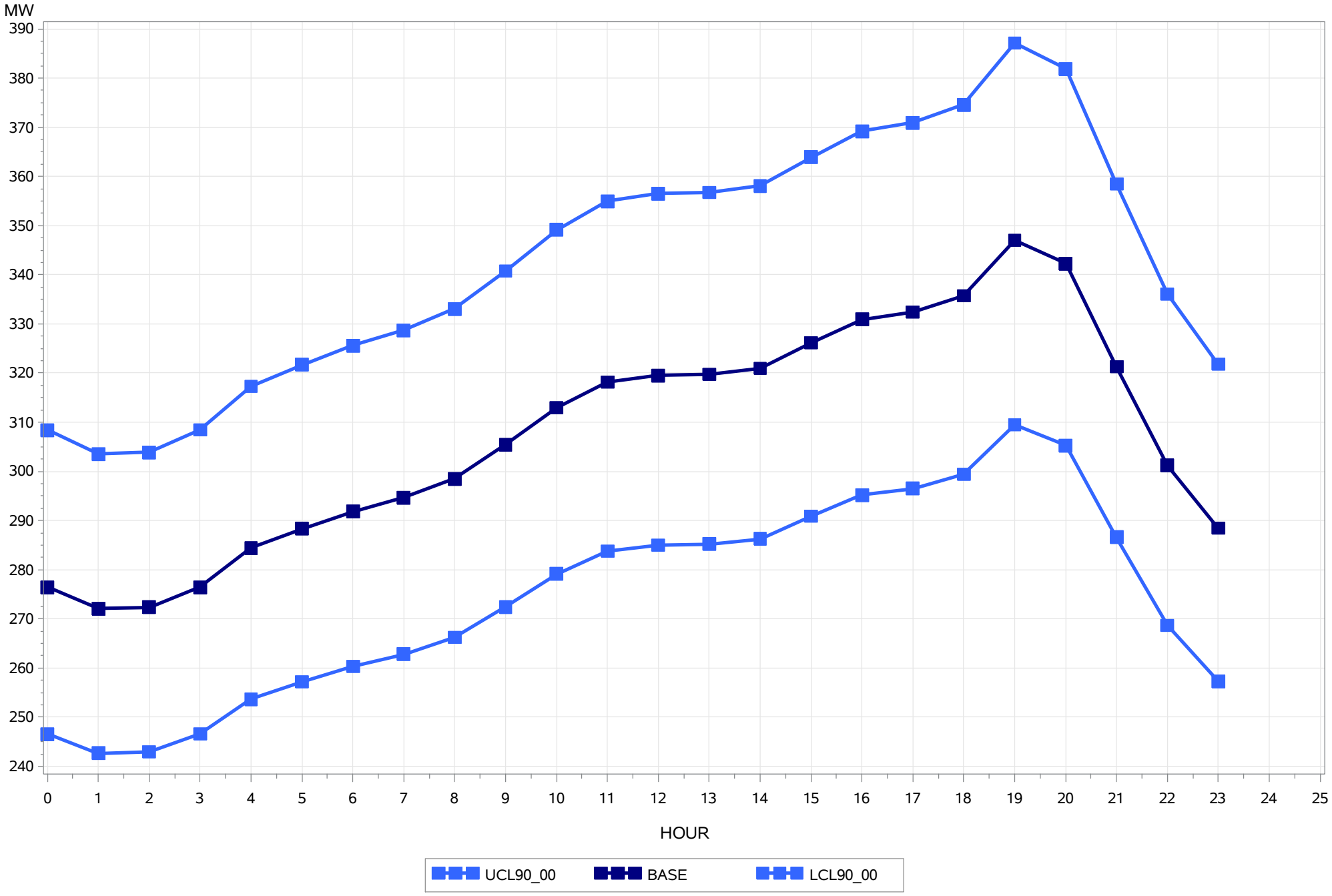
Member Forecasted On Peak Demand Day for May 2021

STATE OF NEW MEXICO

Date of On Peak Day - 05/26/2021



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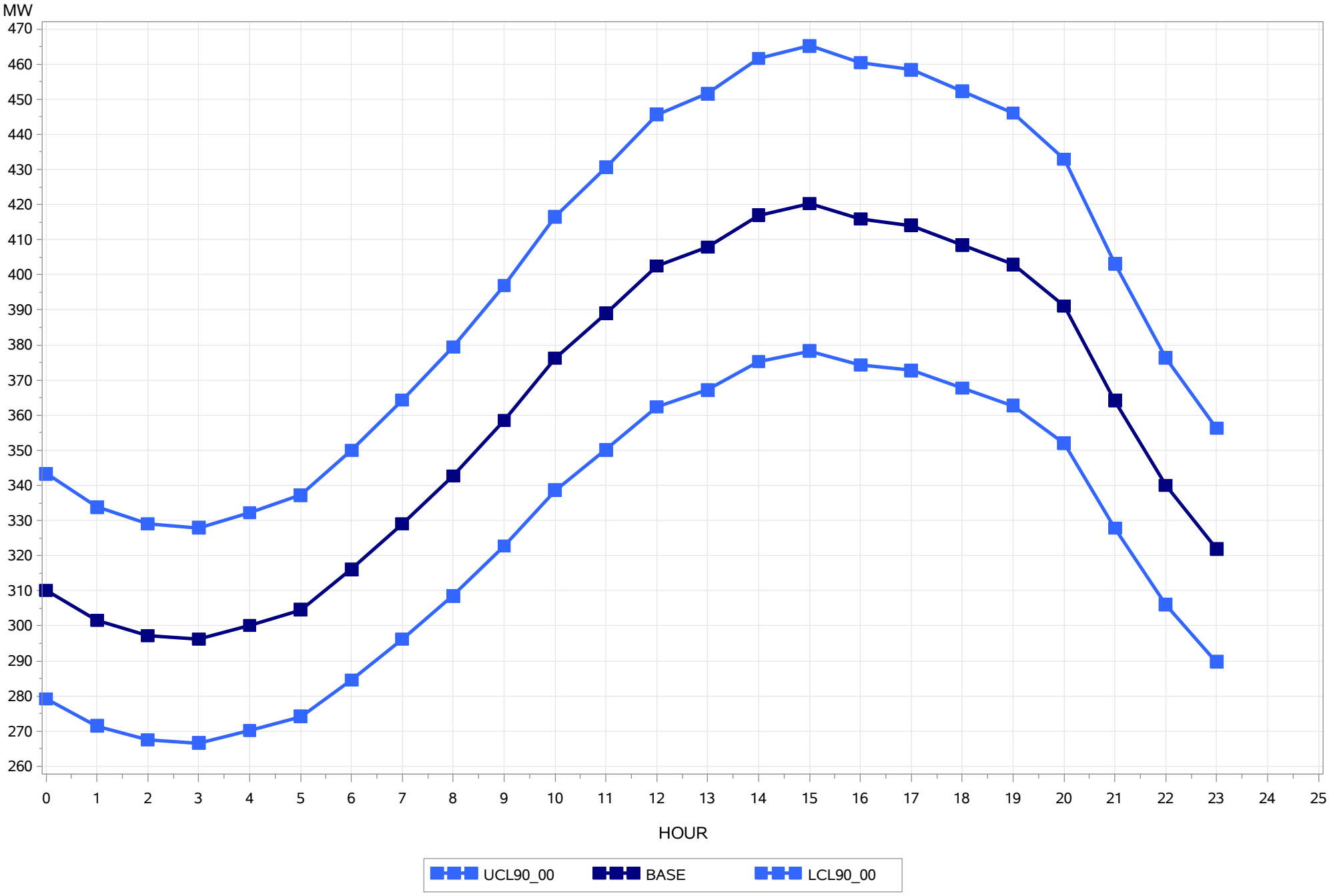
Member Forecasted On Peak Demand Day for June 2021

STATE OF NEW MEXICO

Date of On Peak Day - 06/24/2021



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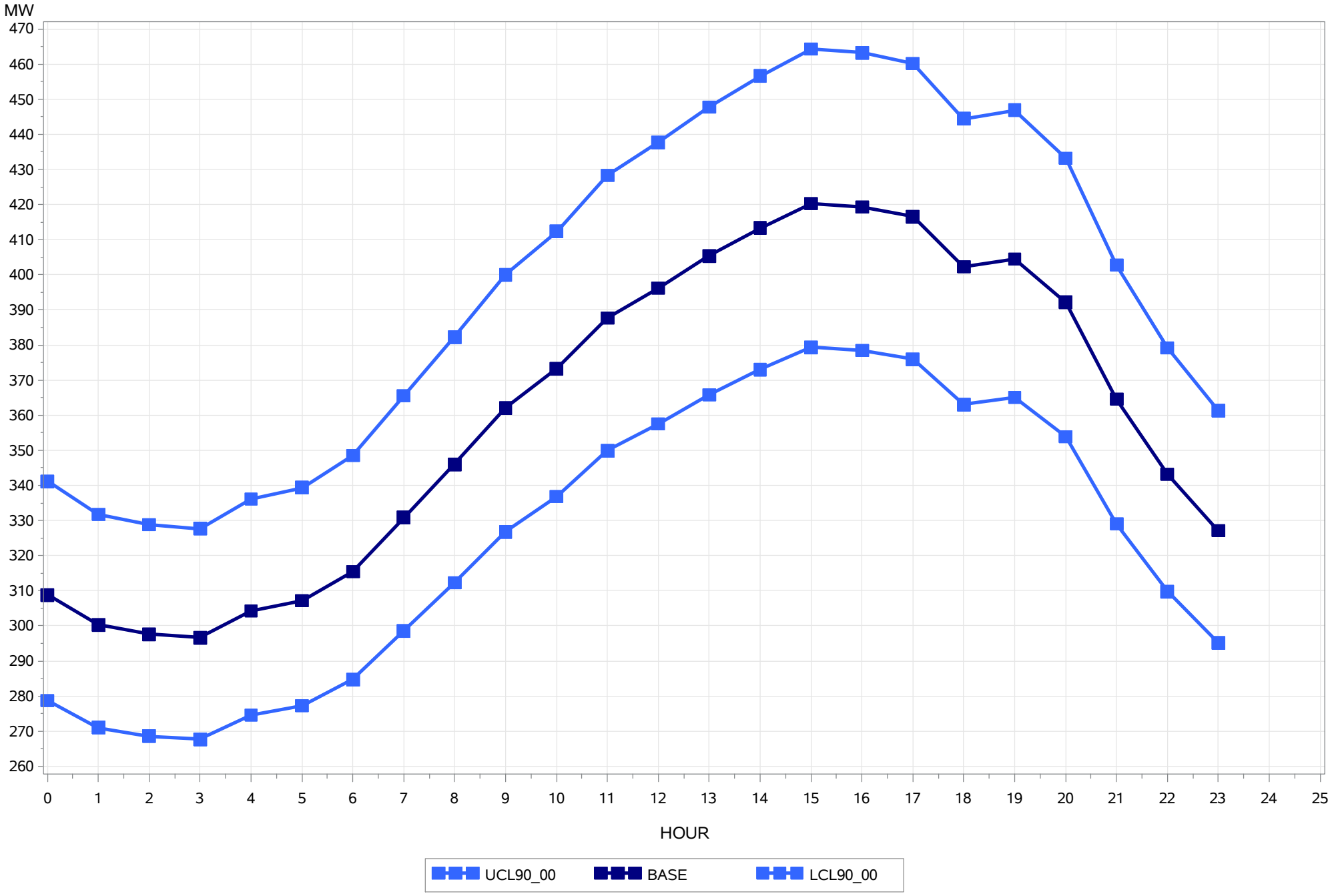
Member Forecasted On Peak Demand Day for July 2021

STATE OF NEW MEXICO

Date of On Peak Day - 07/22/2021



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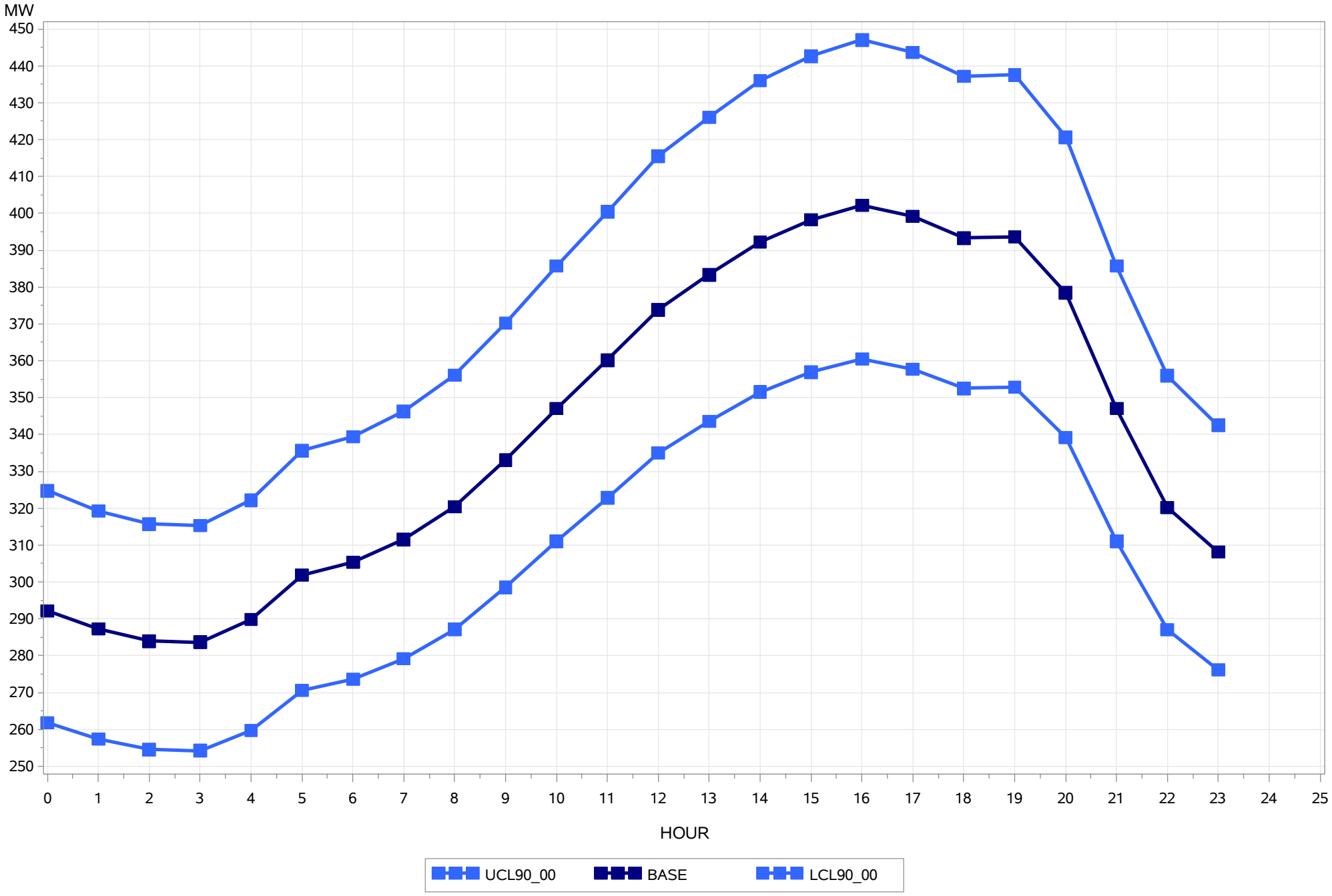
Member Forecasted On Peak Demand Day for August 2021

STATE OF NEW MEXICO

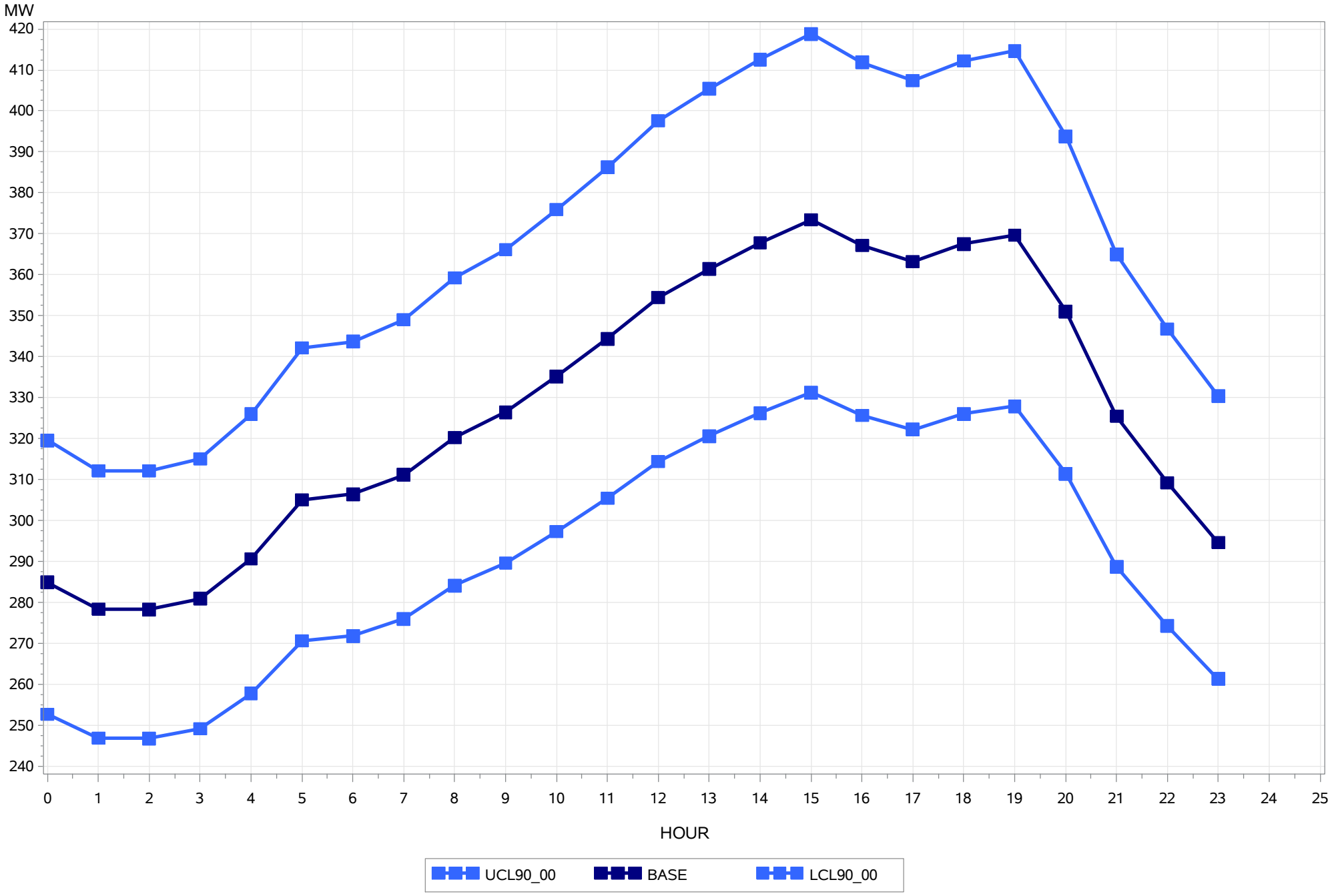
Date of On Peak Day - 08/18/2021



Member Forecasted On Peak Demand Day for September 2021

STATE OF NEW MEXICO

Date of On Peak Day - 09/08/2021



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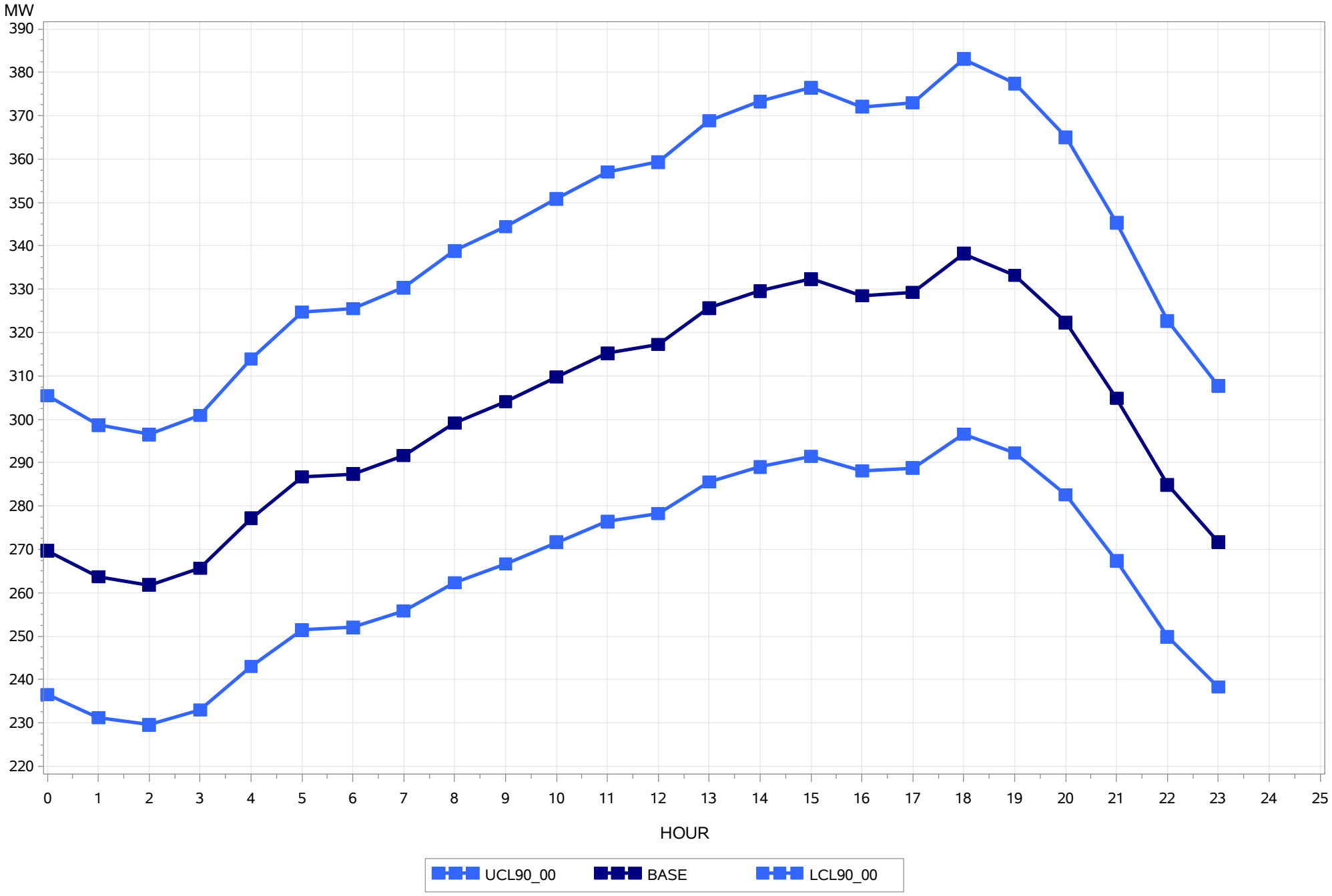
Member Forecasted On Peak Demand Day for October 2021

STATE OF NEW MEXICO

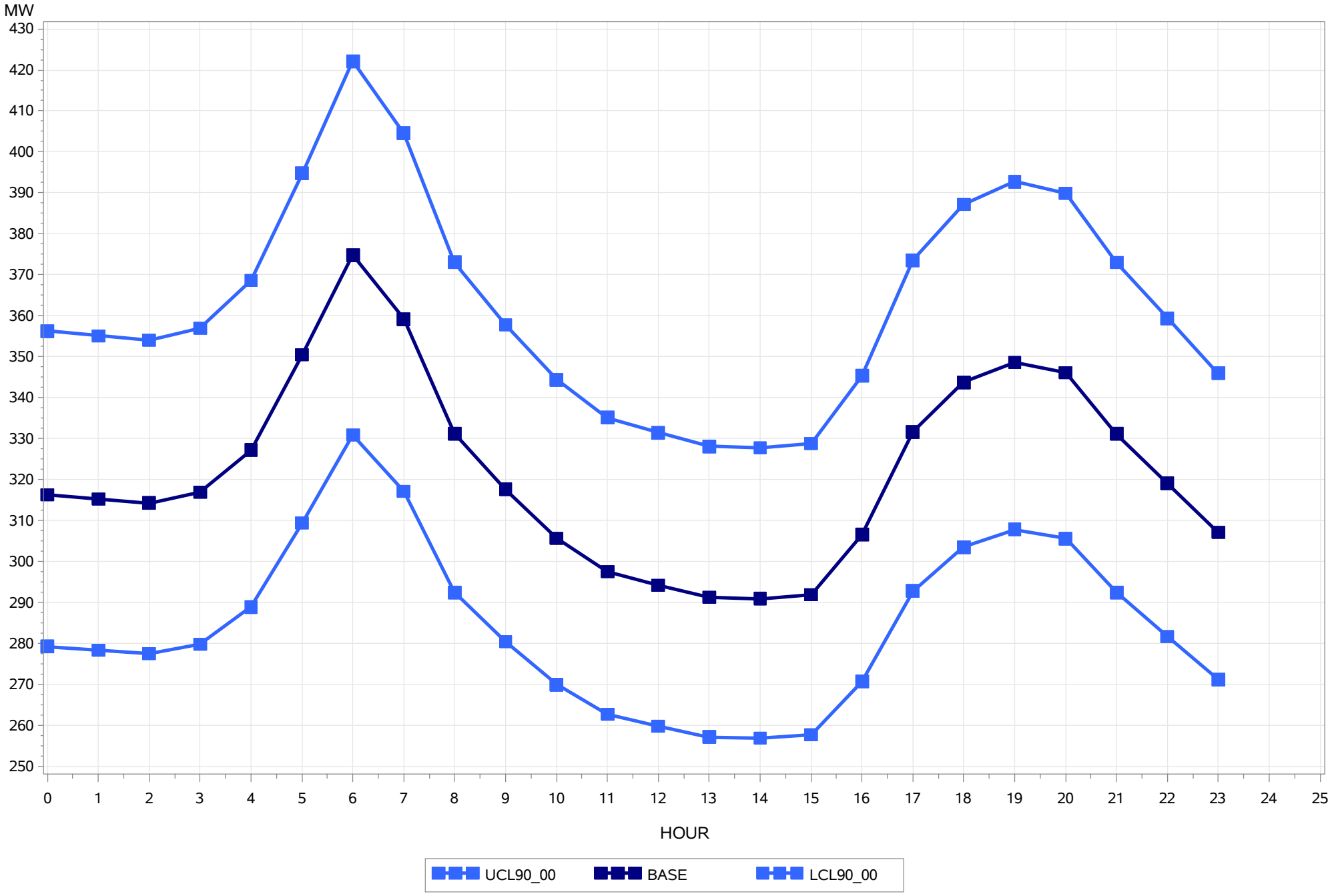
Date of On Peak Day - 10/01/2021



Member Forecasted On Peak Demand Day for November 2021

STATE OF NEW MEXICO

Date of On Peak Day - 11/16/2021



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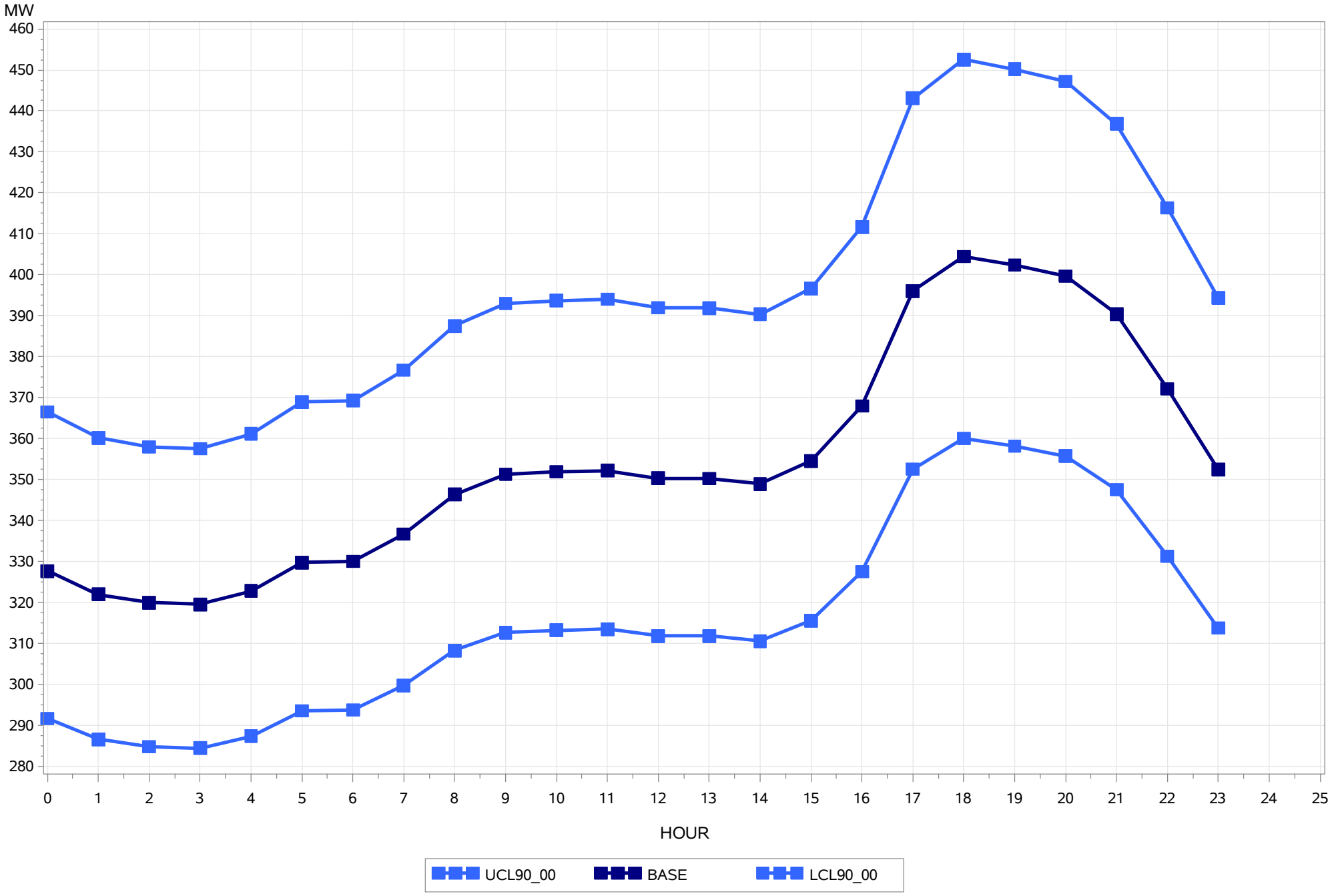
Member Forecasted On Peak Demand Day for December 2021

STATE OF NEW MEXICO

Date of On Peak Day - 12/26/2021



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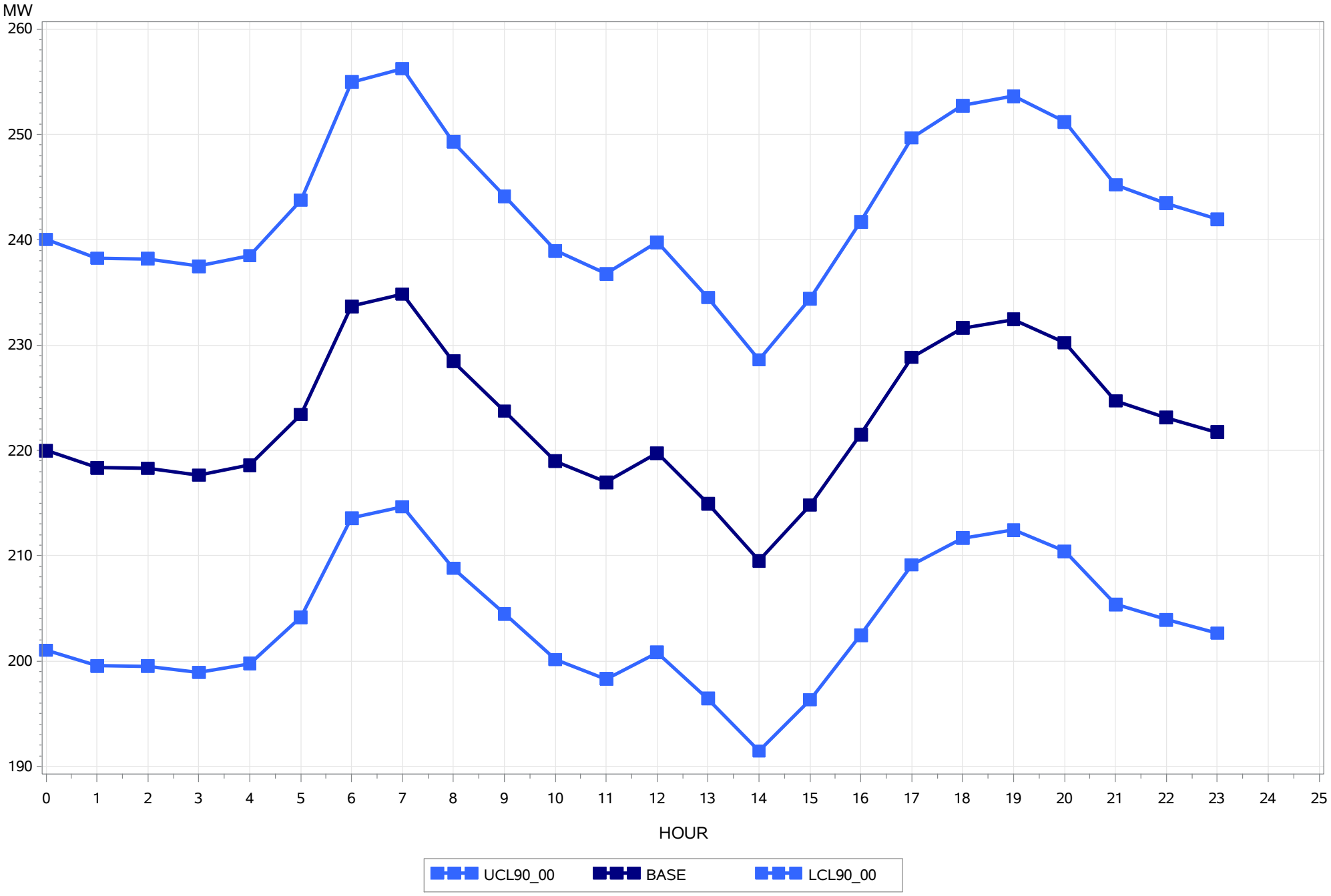
Member Forecasted On Peak Demand Day for January 2021

STATE OF WYOMING

Date of On Peak Day - 01/07/2021



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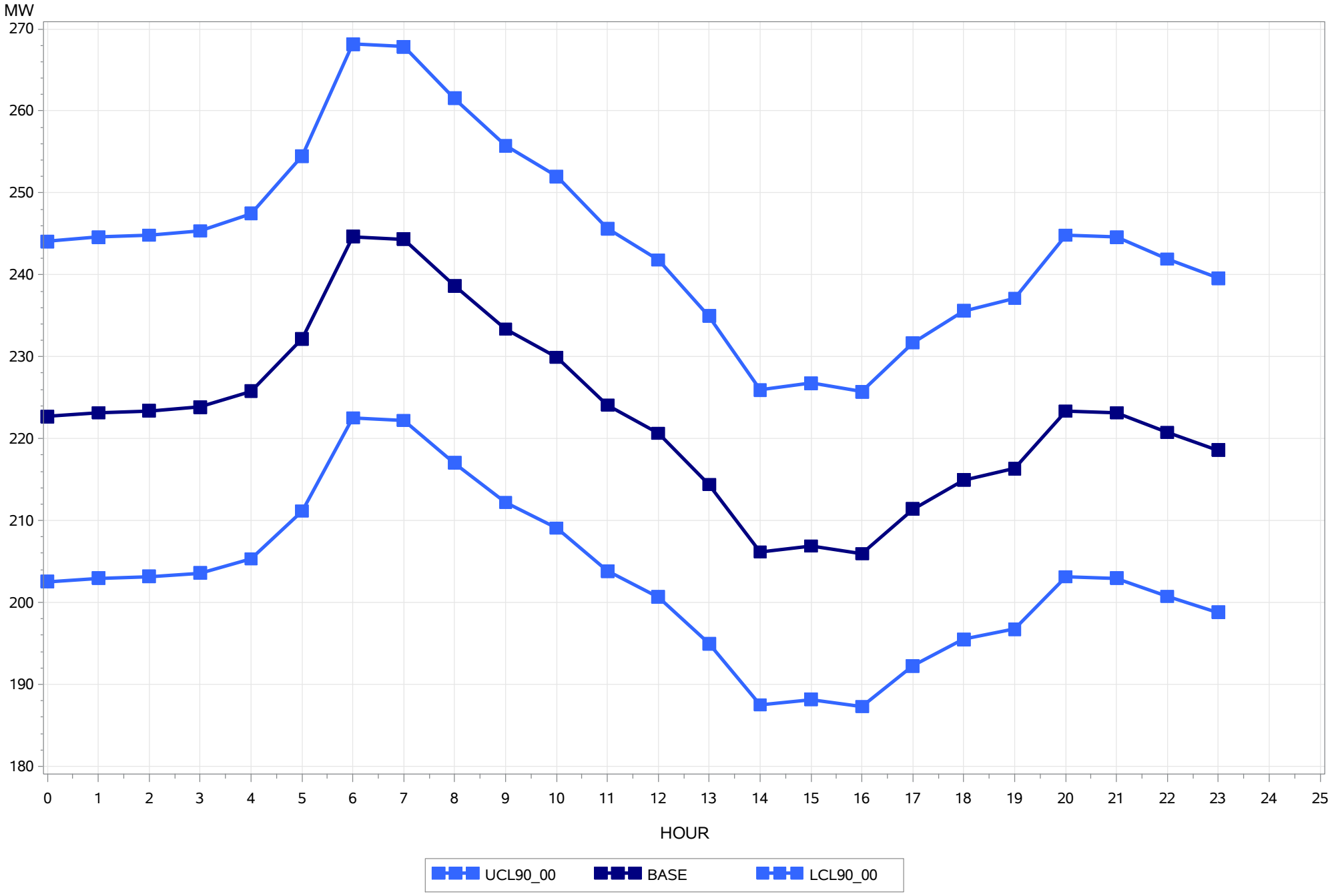
Member Forecasted On Peak Demand Day for February 2021

STATE OF WYOMING

Date of On Peak Day - 02/03/2021



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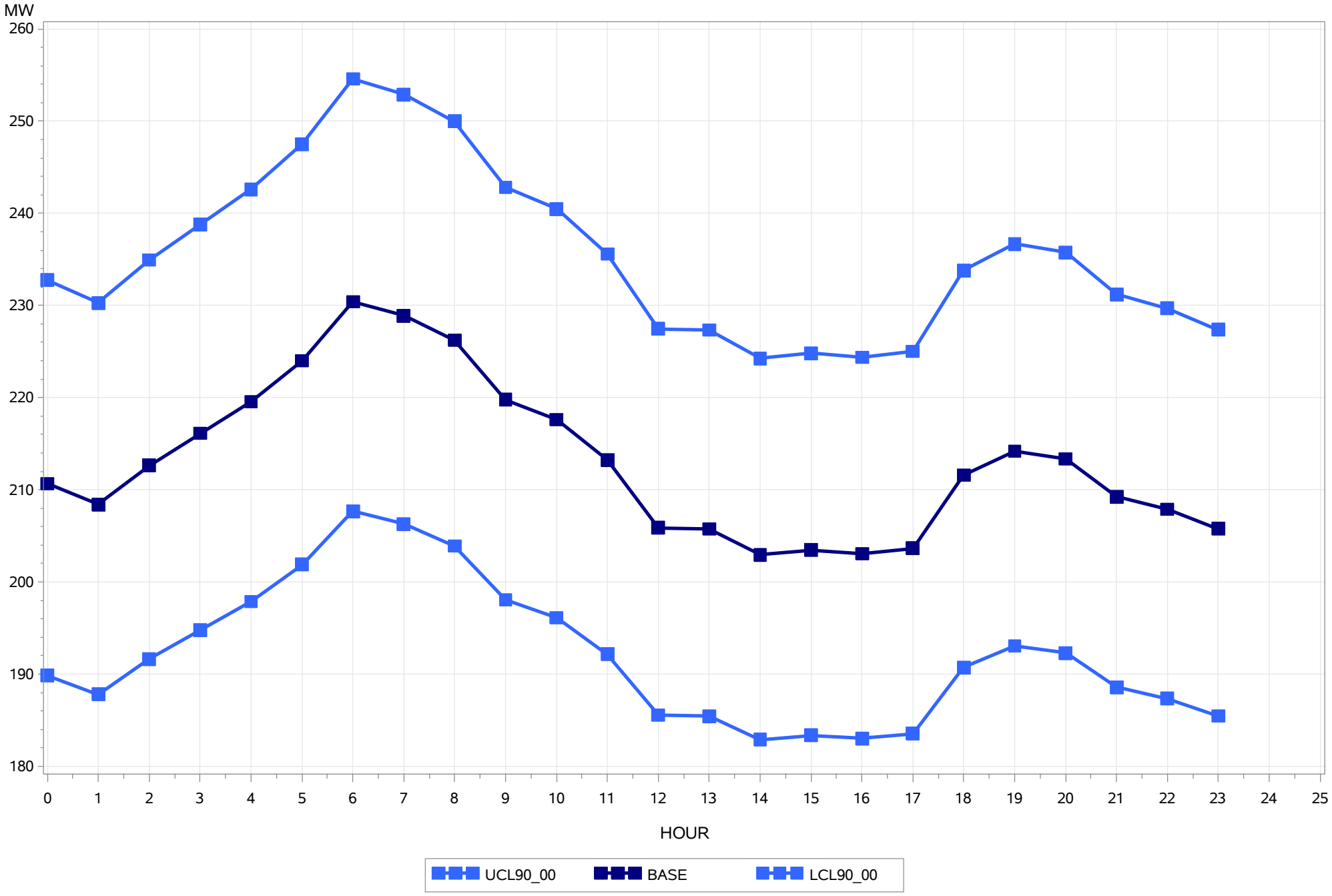
Member Forecasted On Peak Demand Day for March 2021

STATE OF WYOMING

Date of On Peak Day - 03/02/2021



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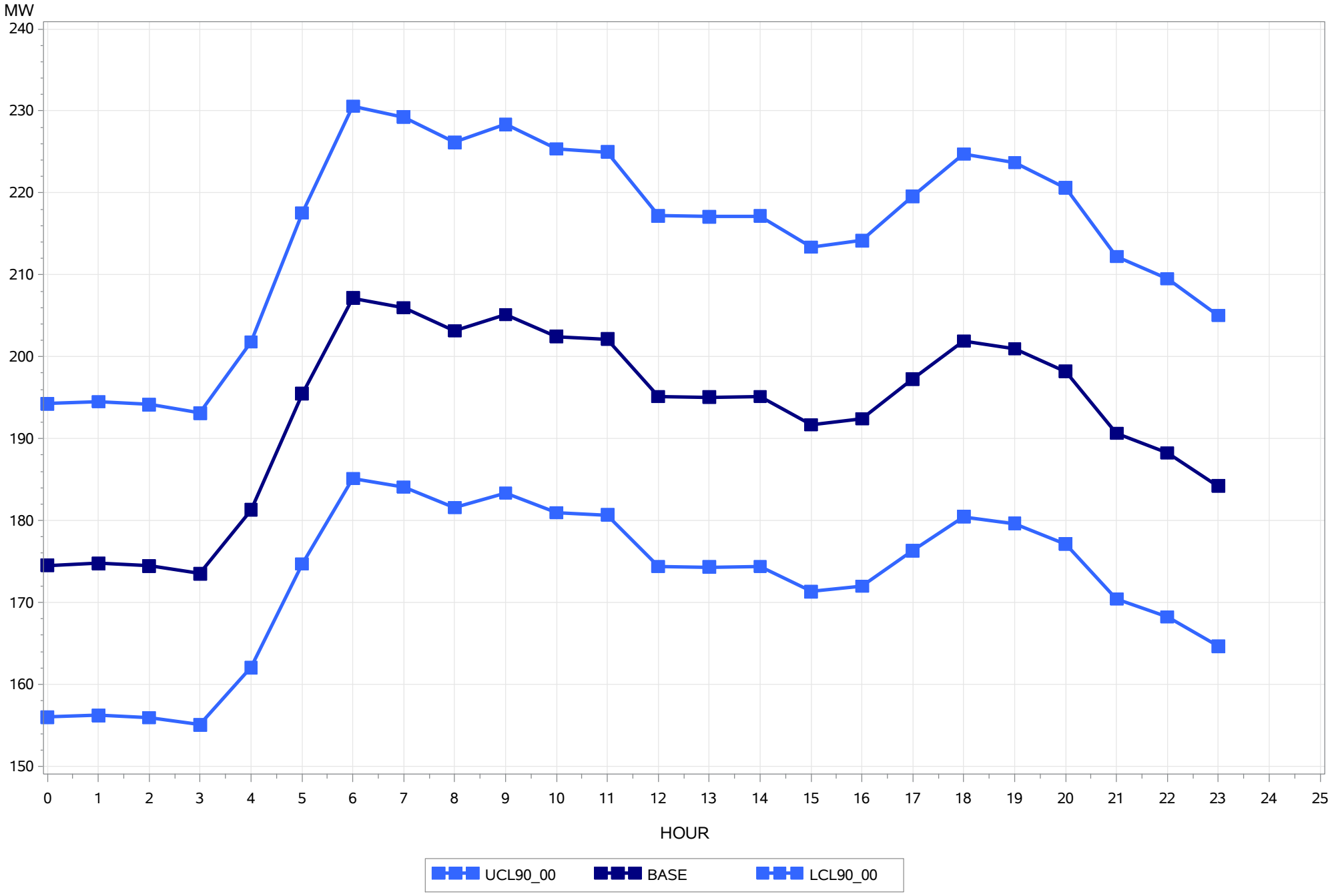
Member Forecasted On Peak Demand Day for April 2021

STATE OF WYOMING

Date of On Peak Day - 04/07/2021



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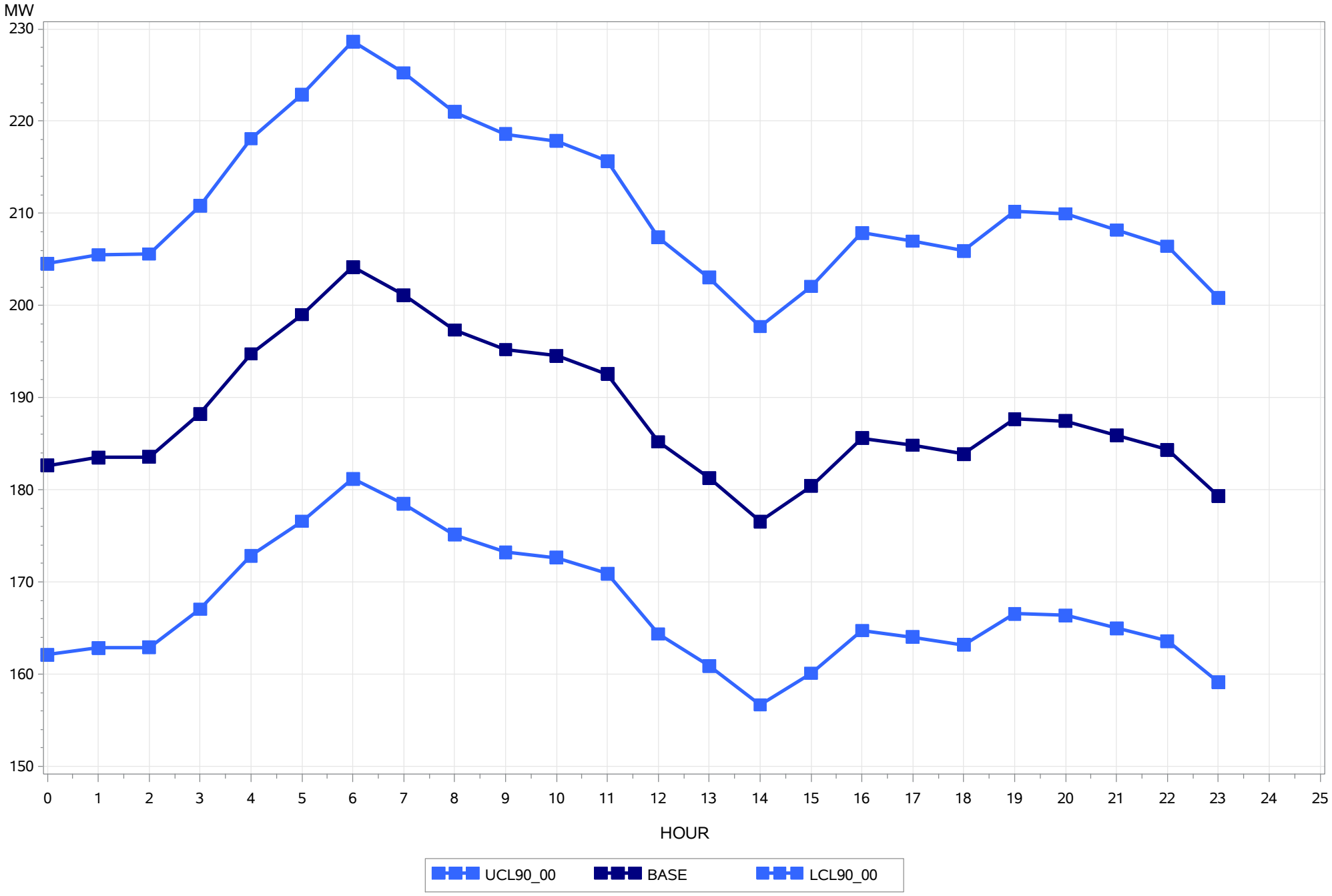
Member Forecasted On Peak Demand Day for May 2021

STATE OF WYOMING

Date of On Peak Day - 05/03/2021



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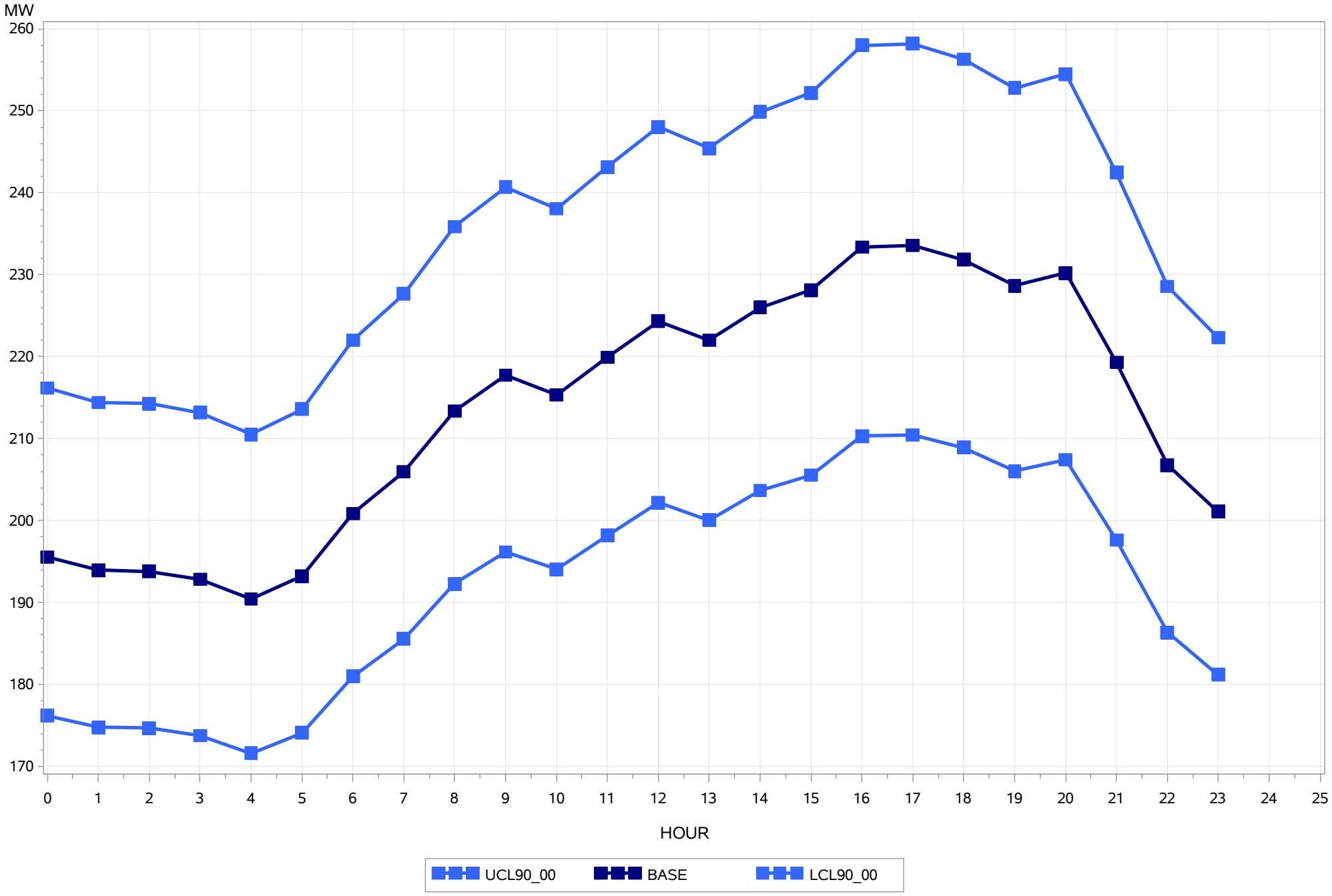
Member Forecasted On Peak Demand Day for June 2021

STATE OF WYOMING

Date of On Peak Day - 06/27/2021



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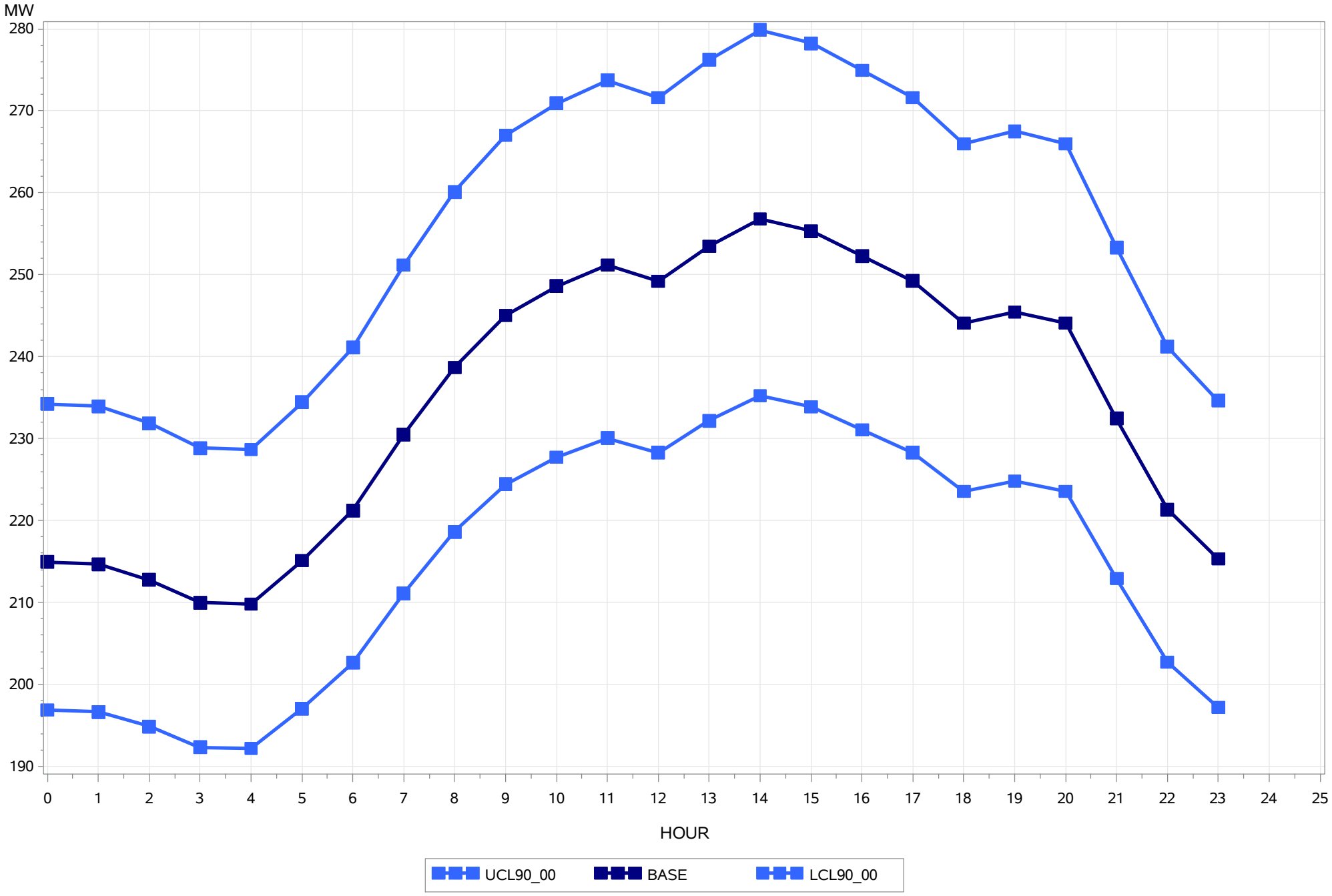
Member Forecasted On Peak Demand Day for July 2021

STATE OF WYOMING

Date of On Peak Day - 07/21/2021



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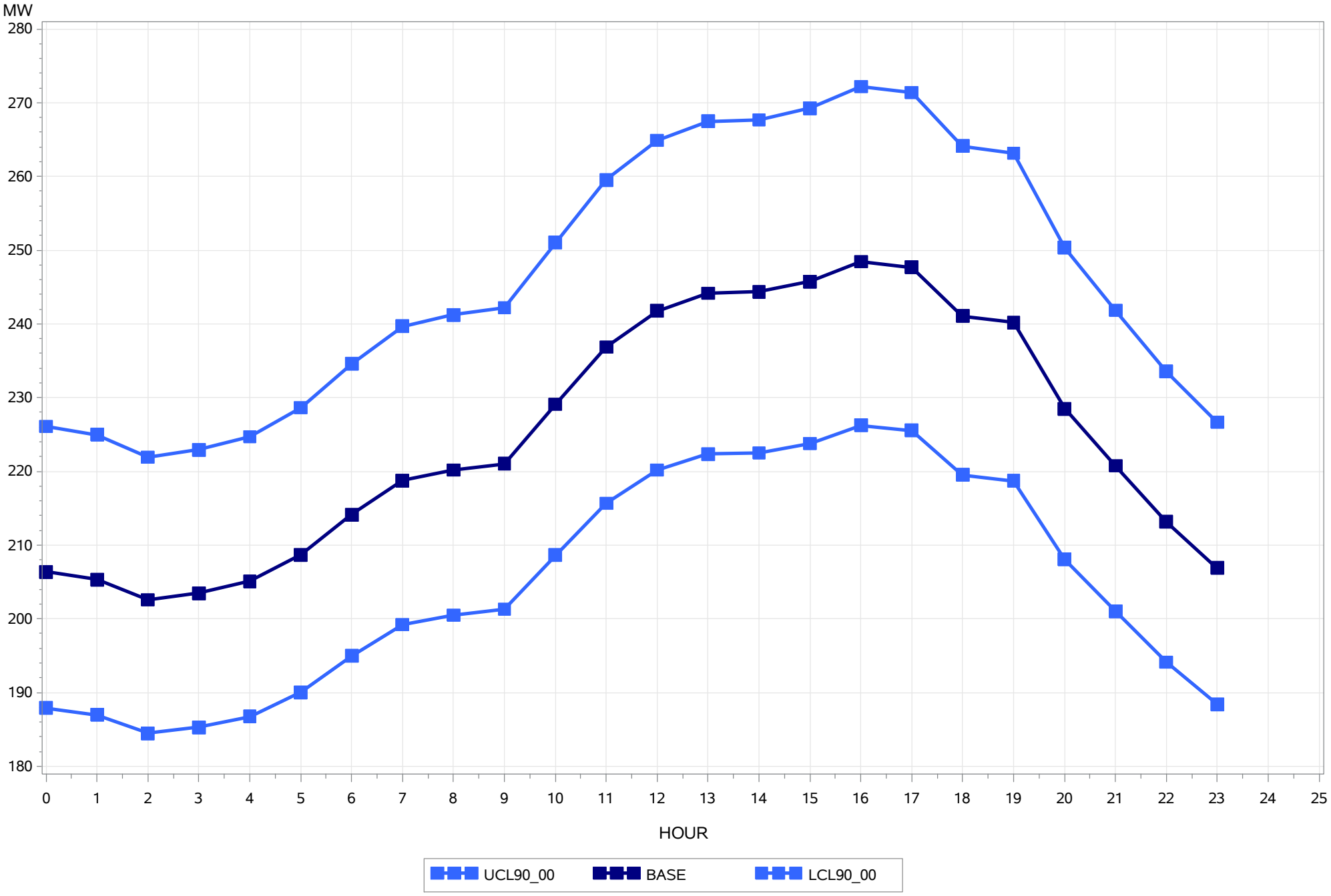
Member Forecasted On Peak Demand Day for August 2021

STATE OF WYOMING

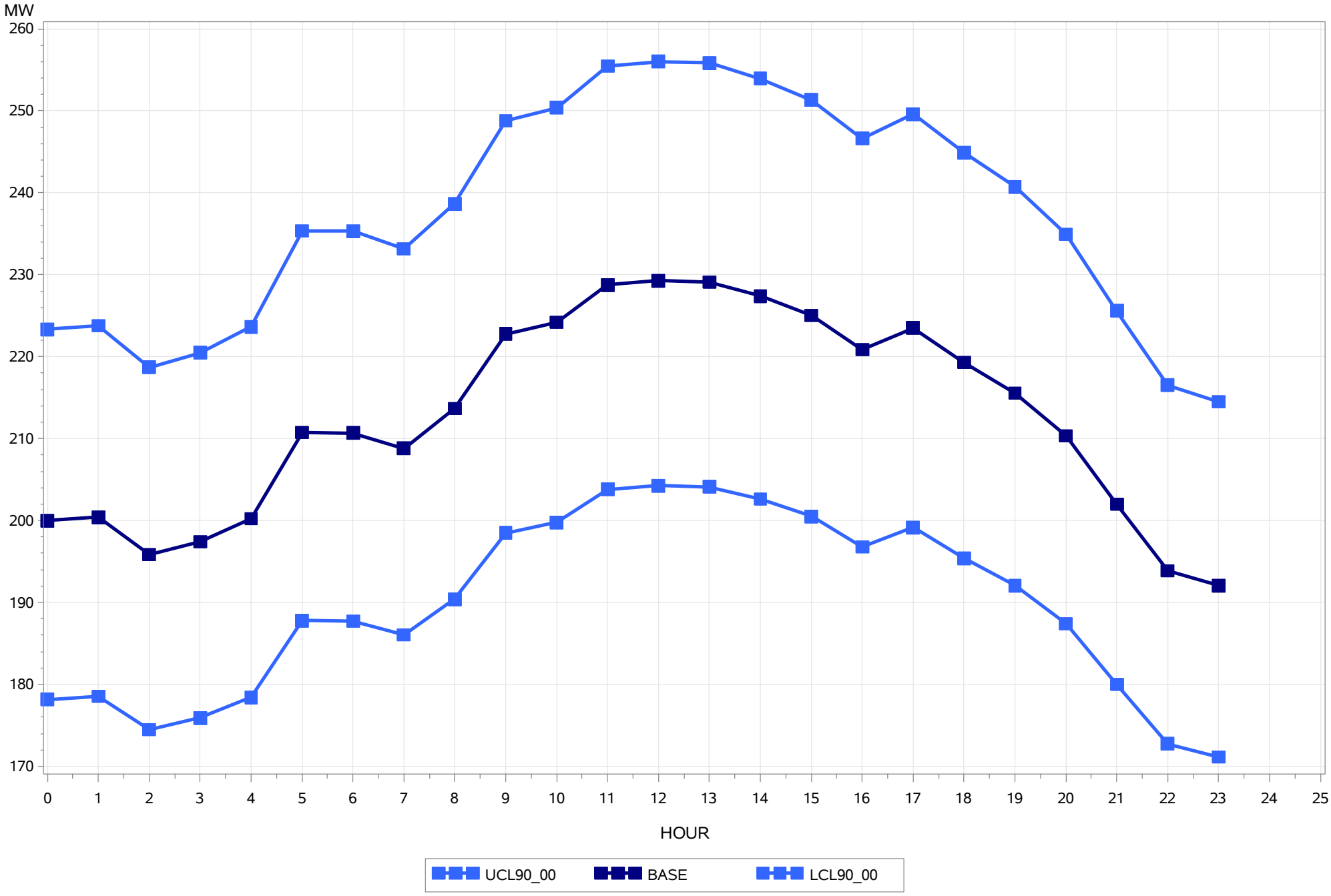
Date of On Peak Day - 08/28/2021



Member Forecasted On Peak Demand Day for September 2021

STATE OF WYOMING

Date of On Peak Day - 09/02/2021



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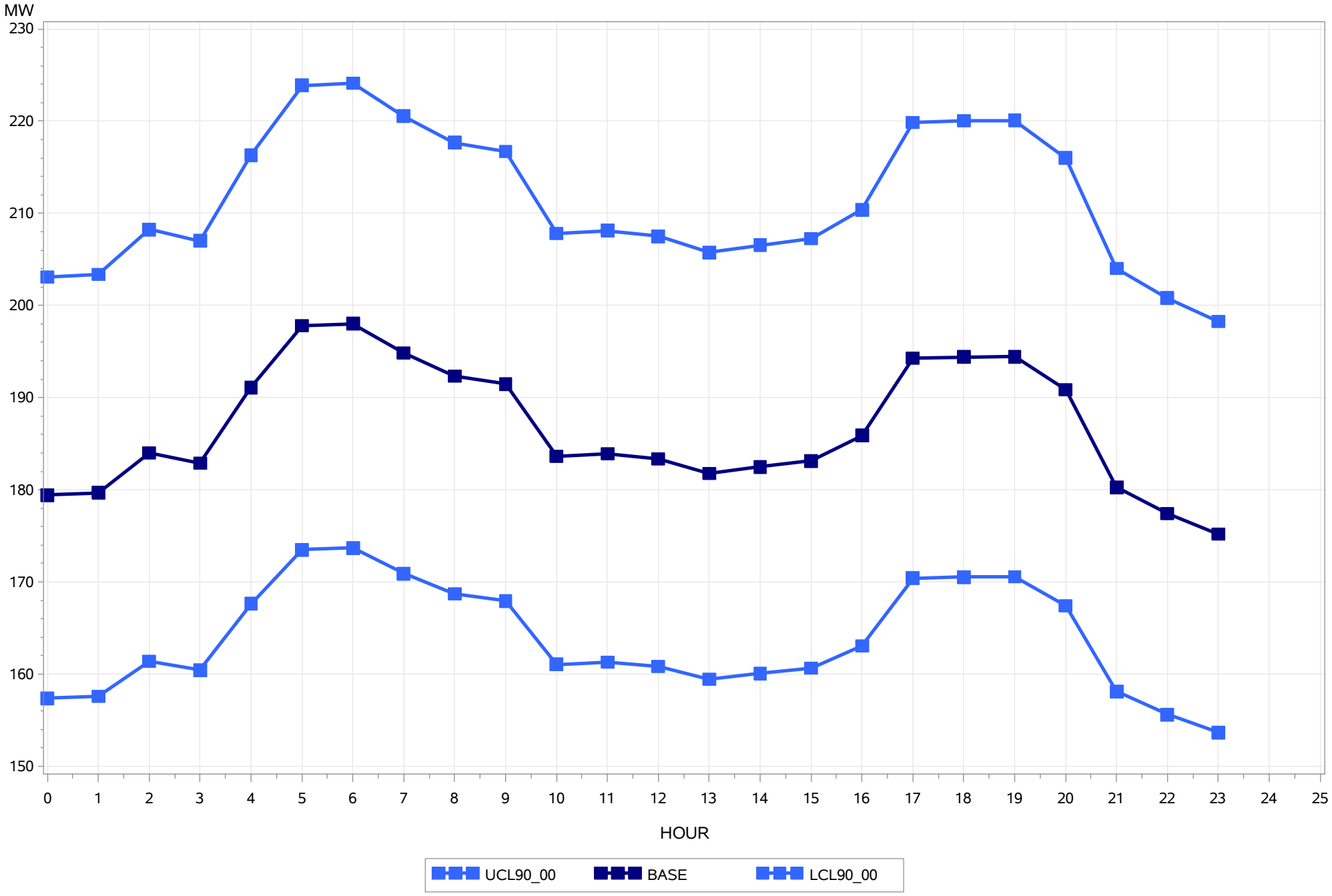
Member Forecasted On Peak Demand Day for October 2021

STATE OF WYOMING

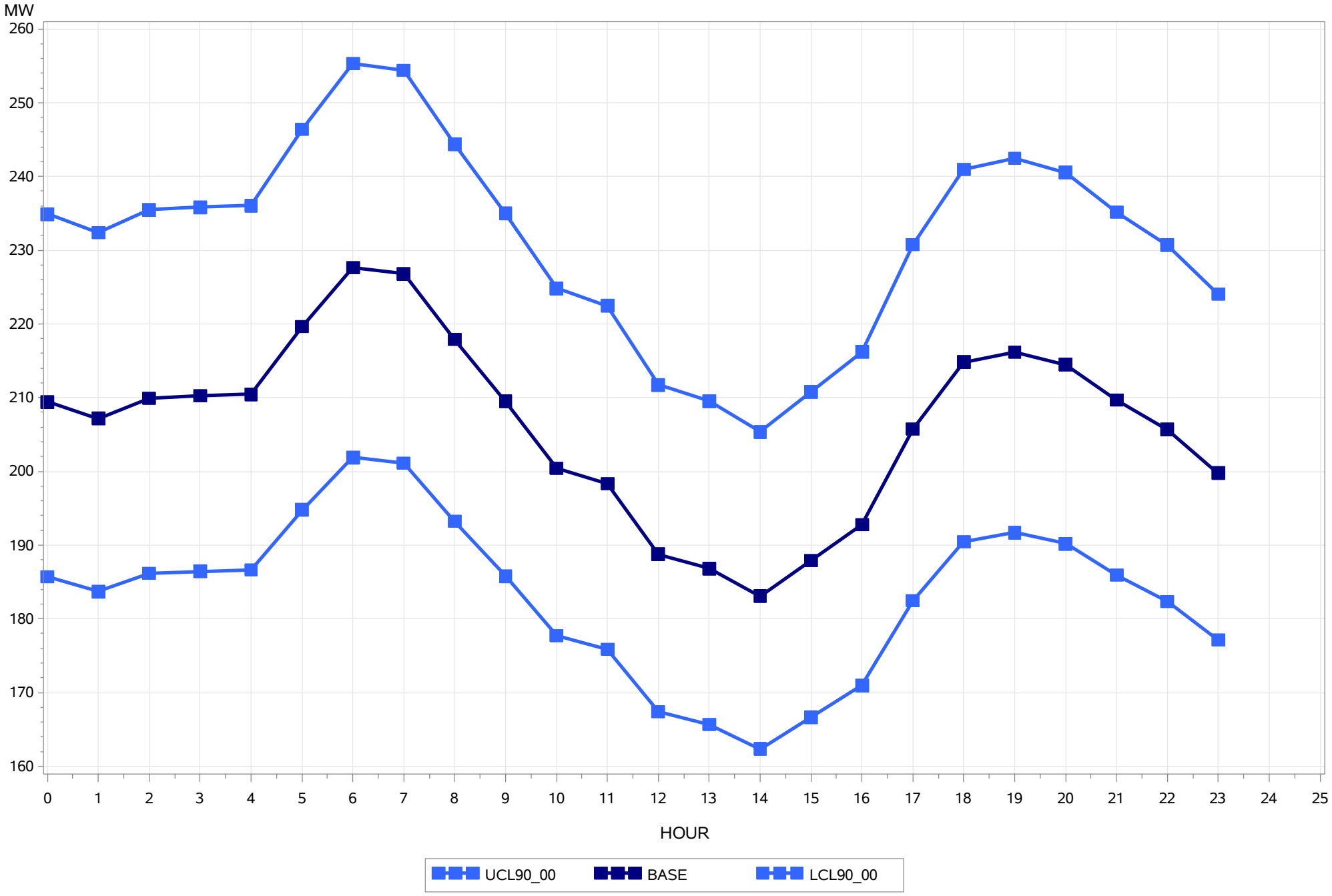
Date of On Peak Day - 10/22/2021



Member Forecasted On Peak Demand Day for November 2021

STATE OF WYOMING

Date of On Peak Day - 11/09/2021



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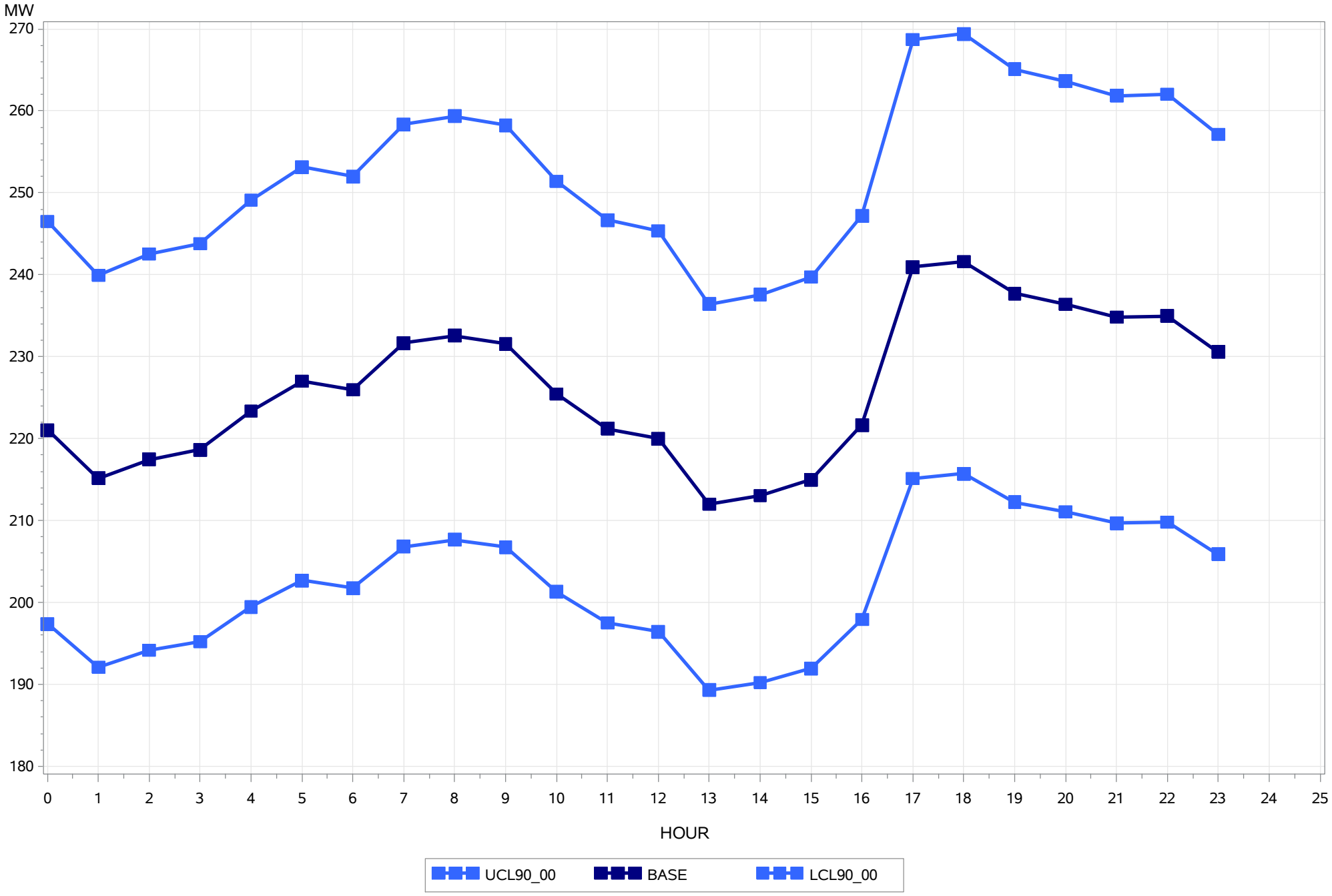
Member Forecasted On Peak Demand Day for December 2021

STATE OF WYOMING

Date of On Peak Day - 12/28/2021



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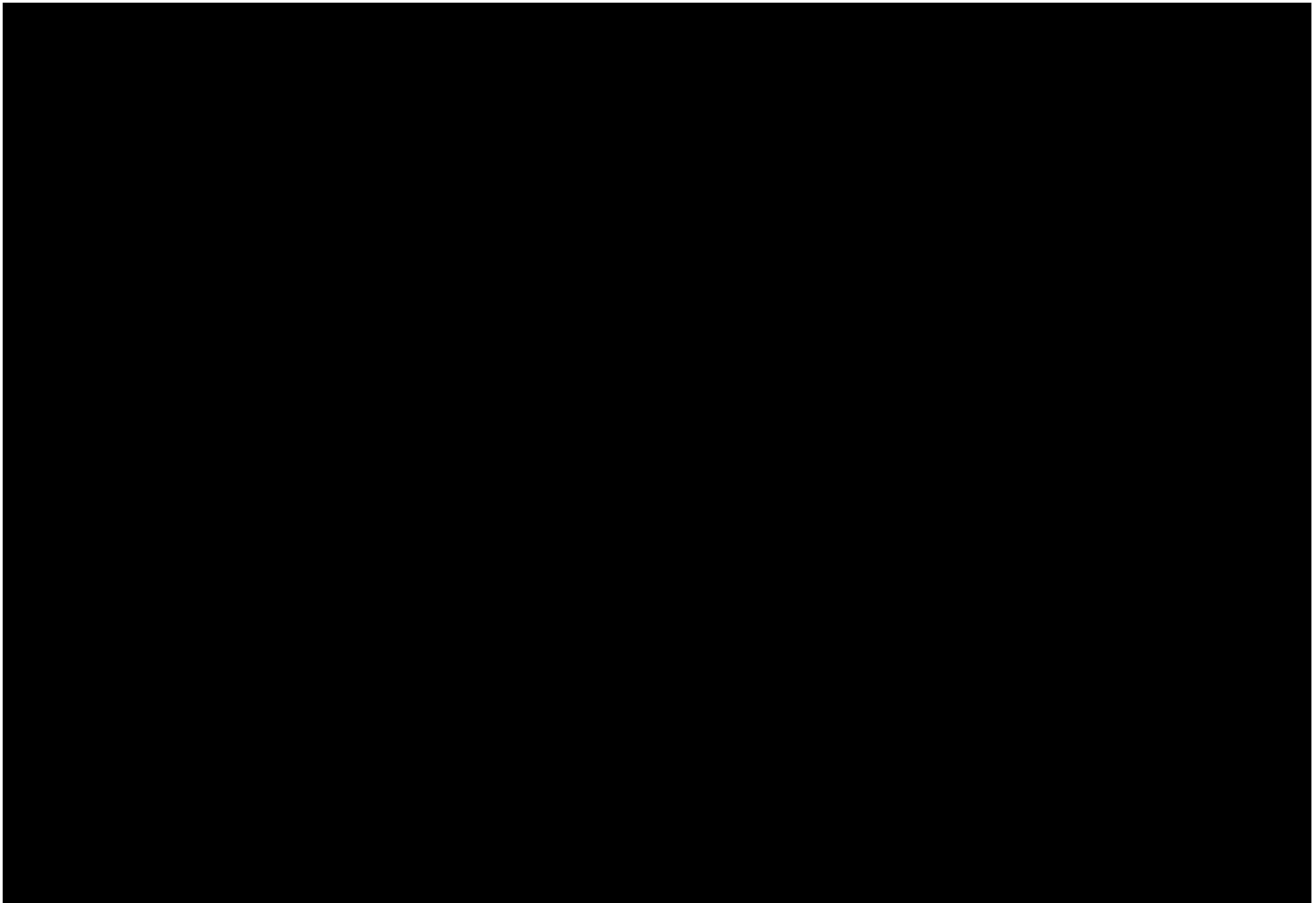
Member Forecasted On Peak Demand Day for January 2021

Big Horn Rural Electric Company

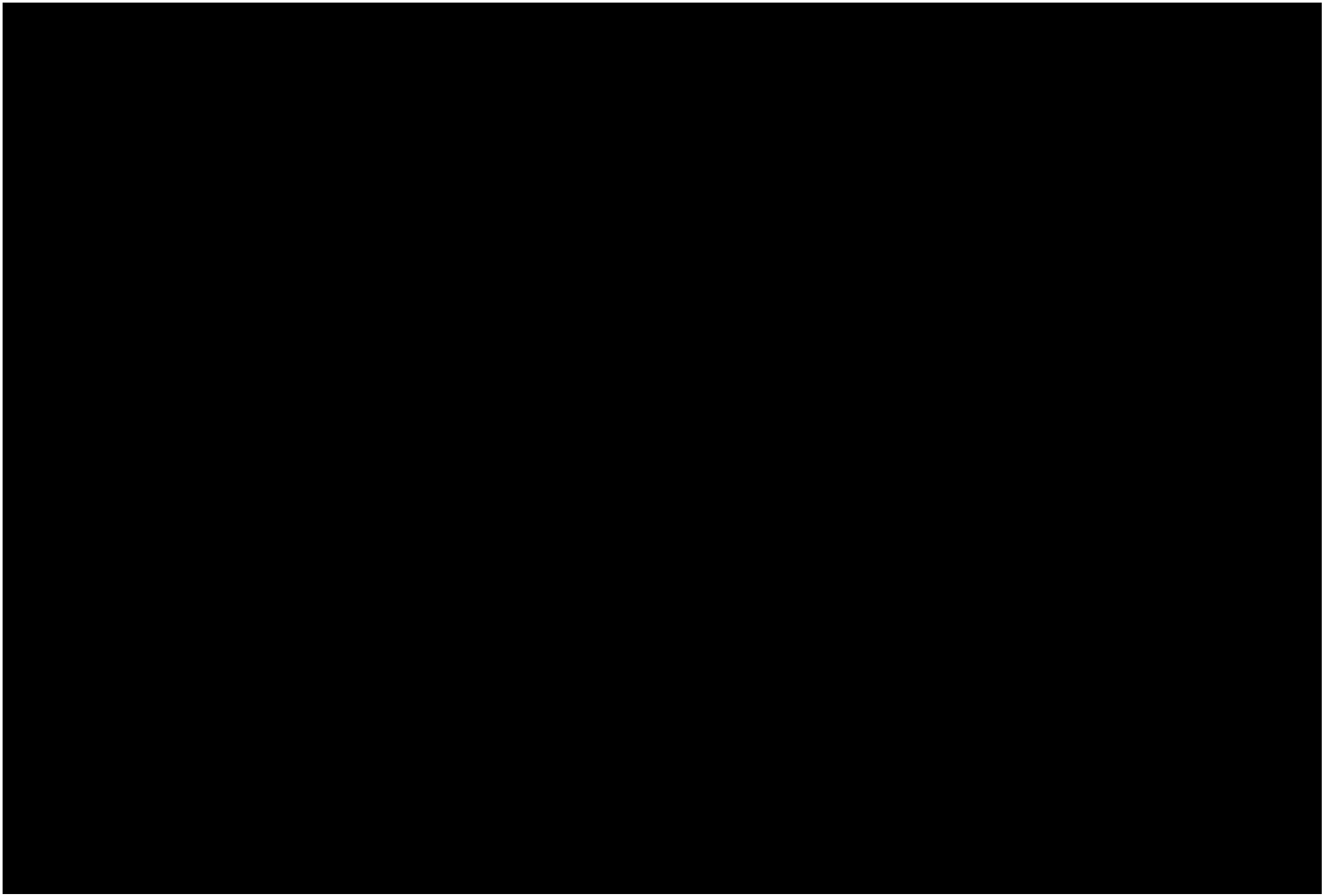
Date of On Peak Day - 01/05/2021



Member Forecasted On Peak Demand Day for February 2021

Big Horn Rural Electric Company

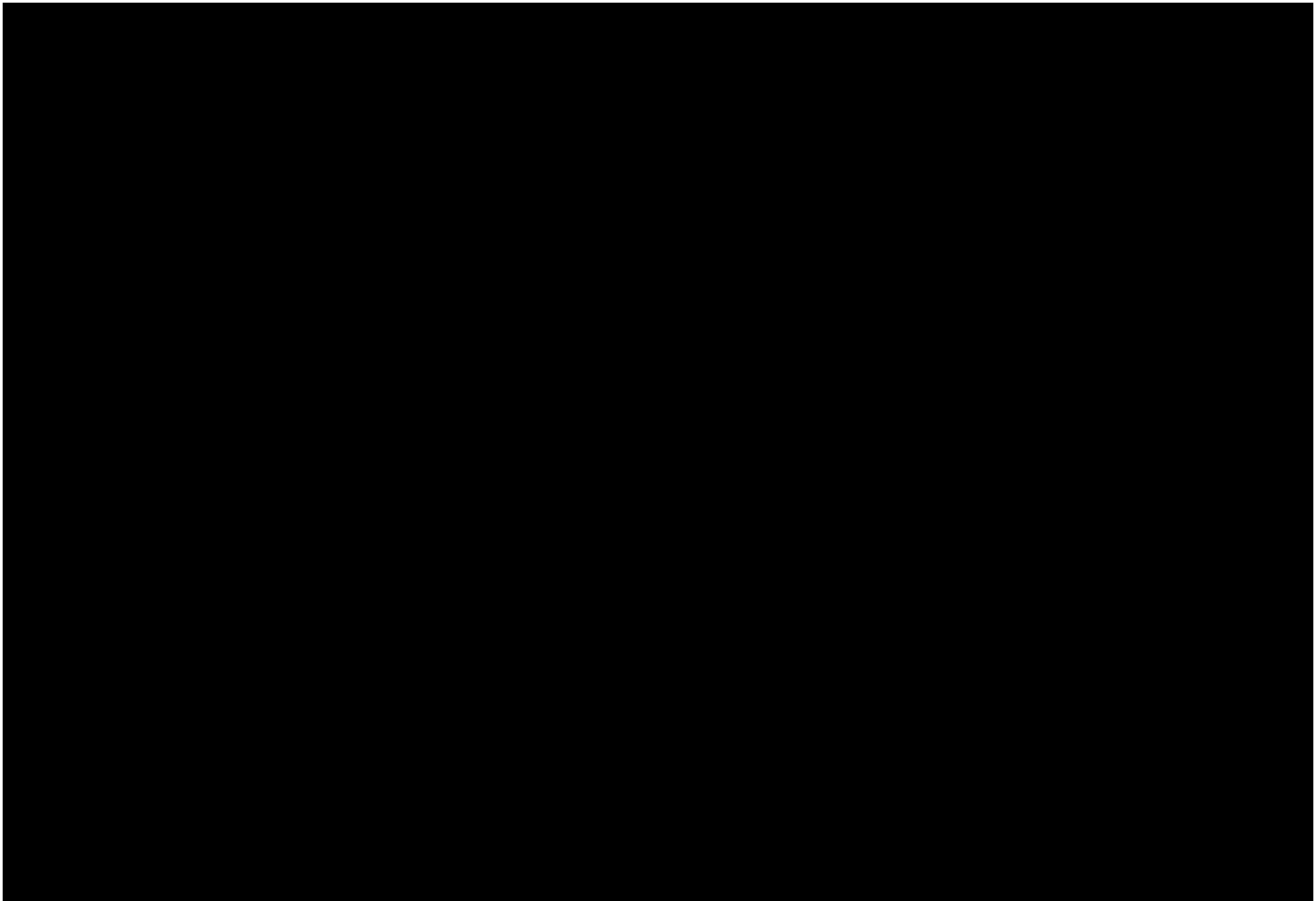
Date of On Peak Day - 02/01/2021



Member Forecasted On Peak Demand Day for March 2021

Big Horn Rural Electric Company

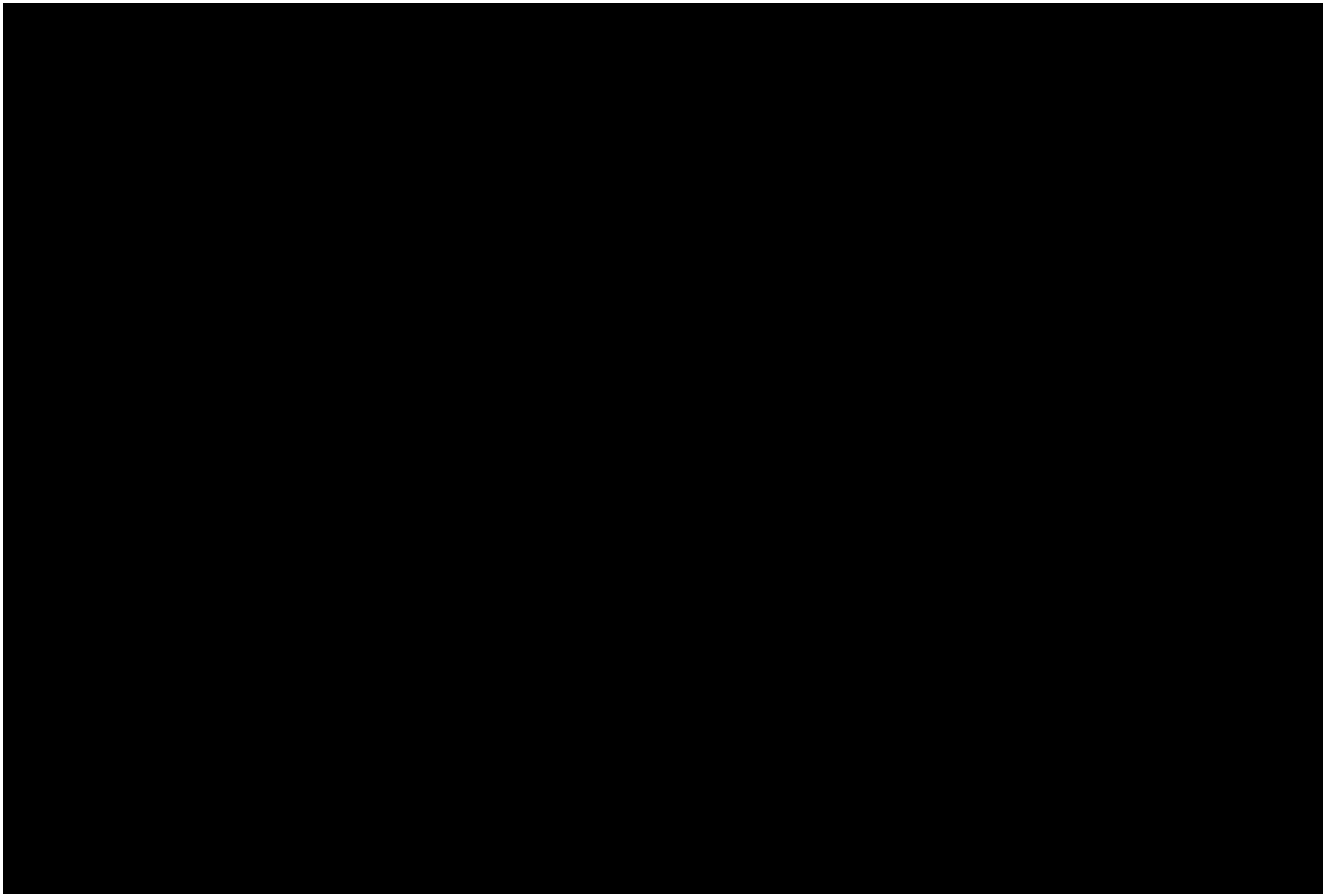
Date of On Peak Day - 03/04/2021



Member Forecasted On Peak Demand Day for April 2021

Big Horn Rural Electric Company

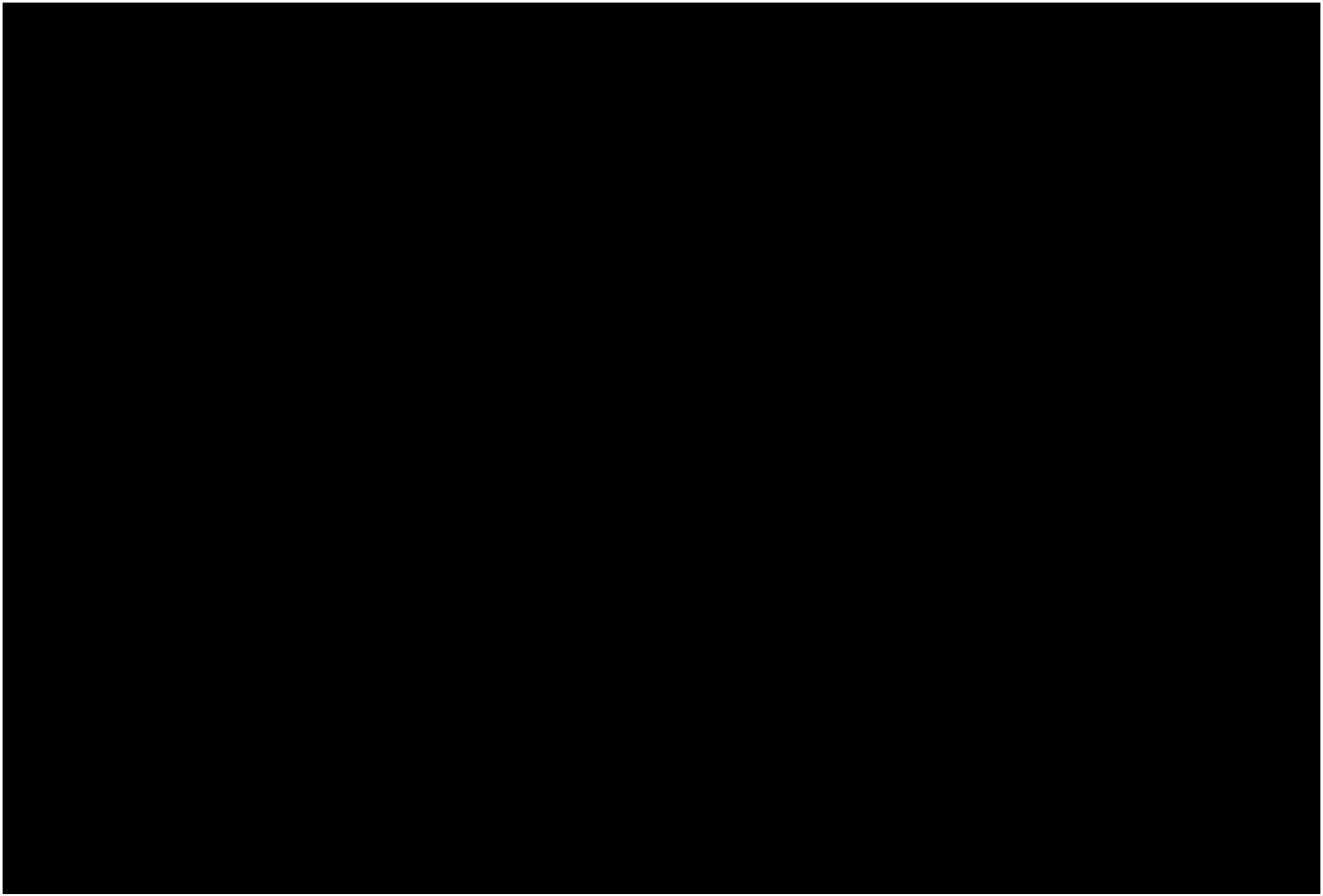
Date of On Peak Day - 04/02/2021



Member Forecasted On Peak Demand Day for May 2021

Big Horn Rural Electric Company

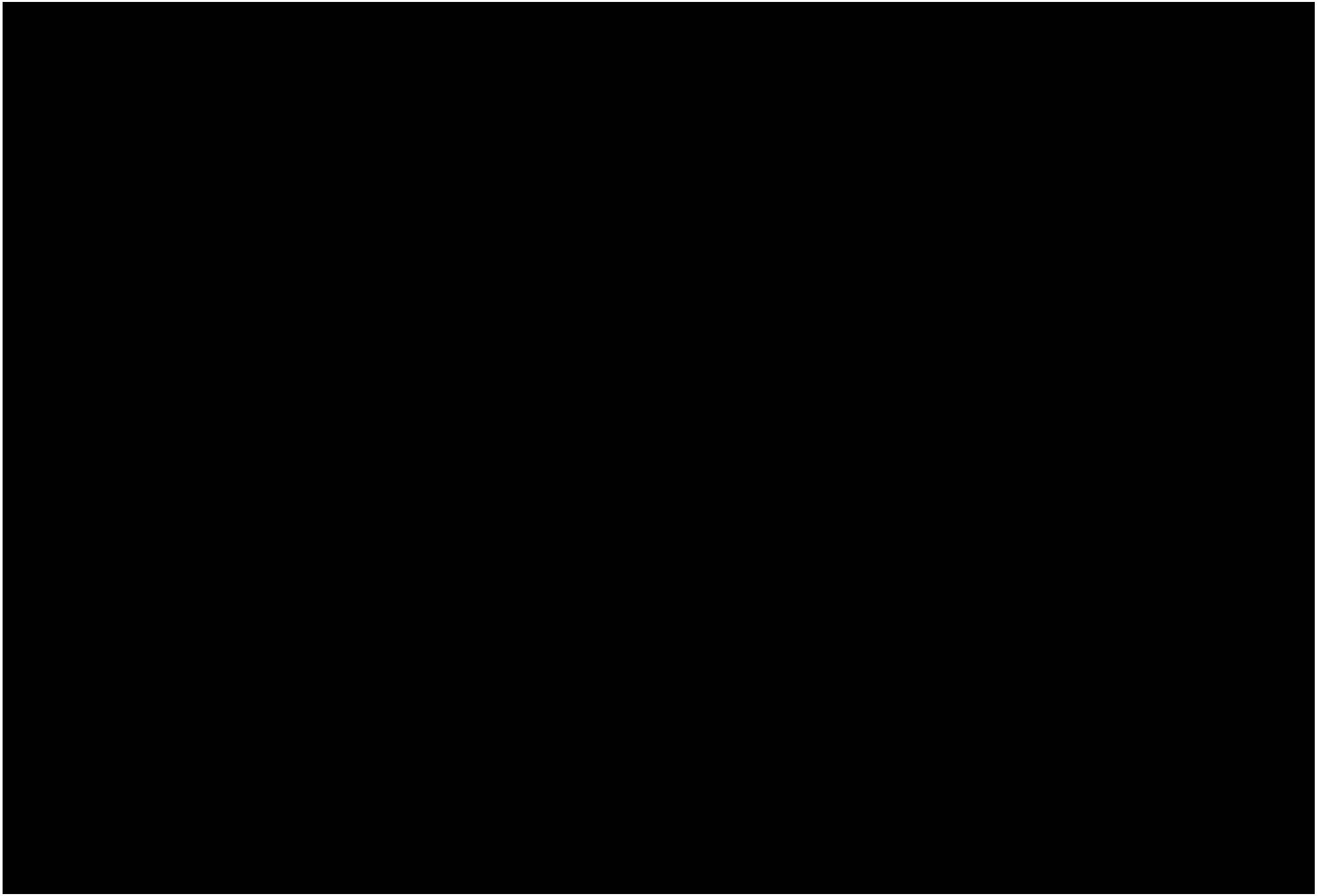
Date of On Peak Day - 05/14/2021



Member Forecasted On Peak Demand Day for June 2021

Big Horn Rural Electric Company

Date of On Peak Day - 06/02/2021



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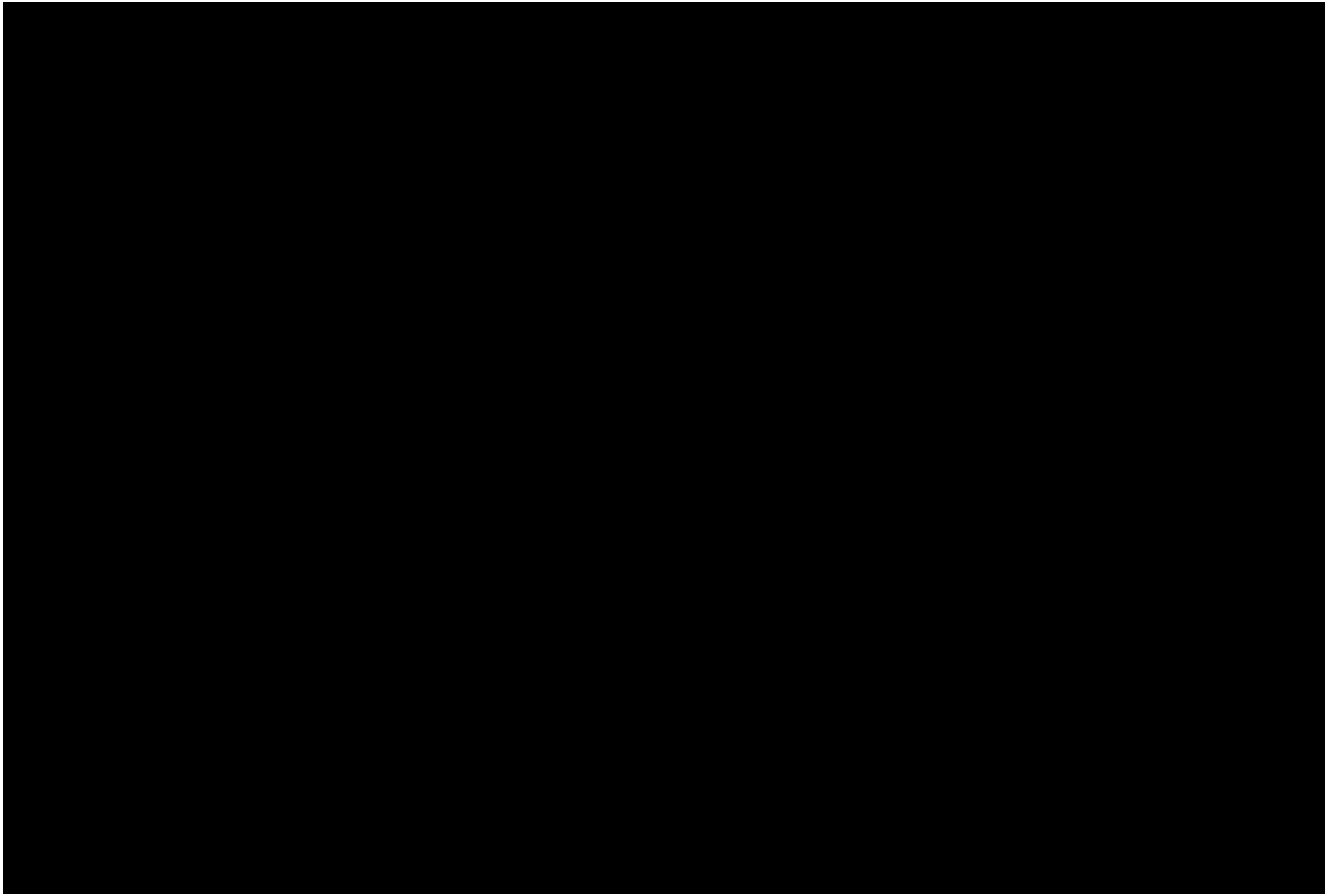
Member Forecasted On Peak Demand Day for July 2021

Big Horn Rural Electric Company

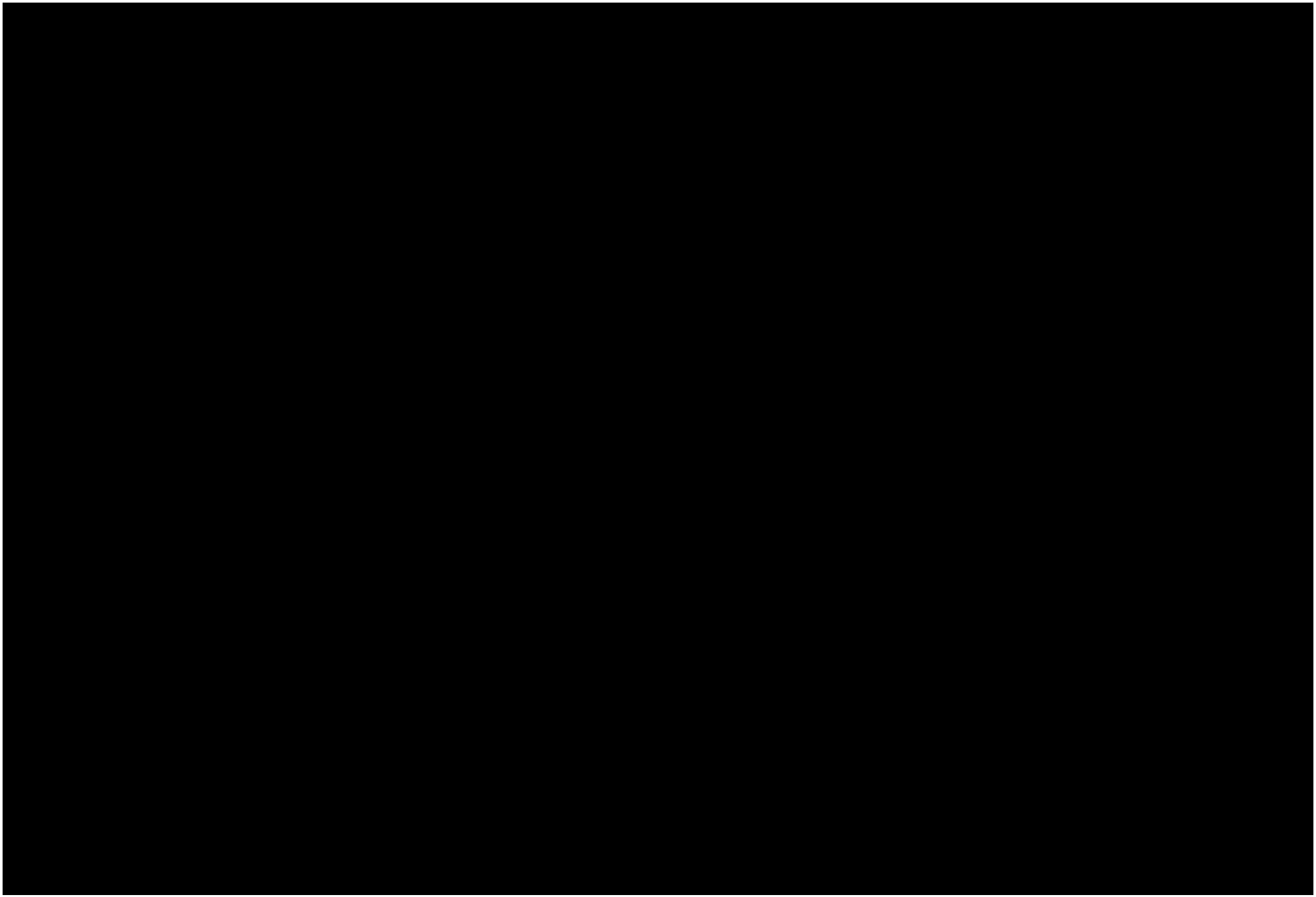
Date of On Peak Day - 07/04/2021



Member Forecasted On Peak Demand Day for August 2021

Big Horn Rural Electric Company

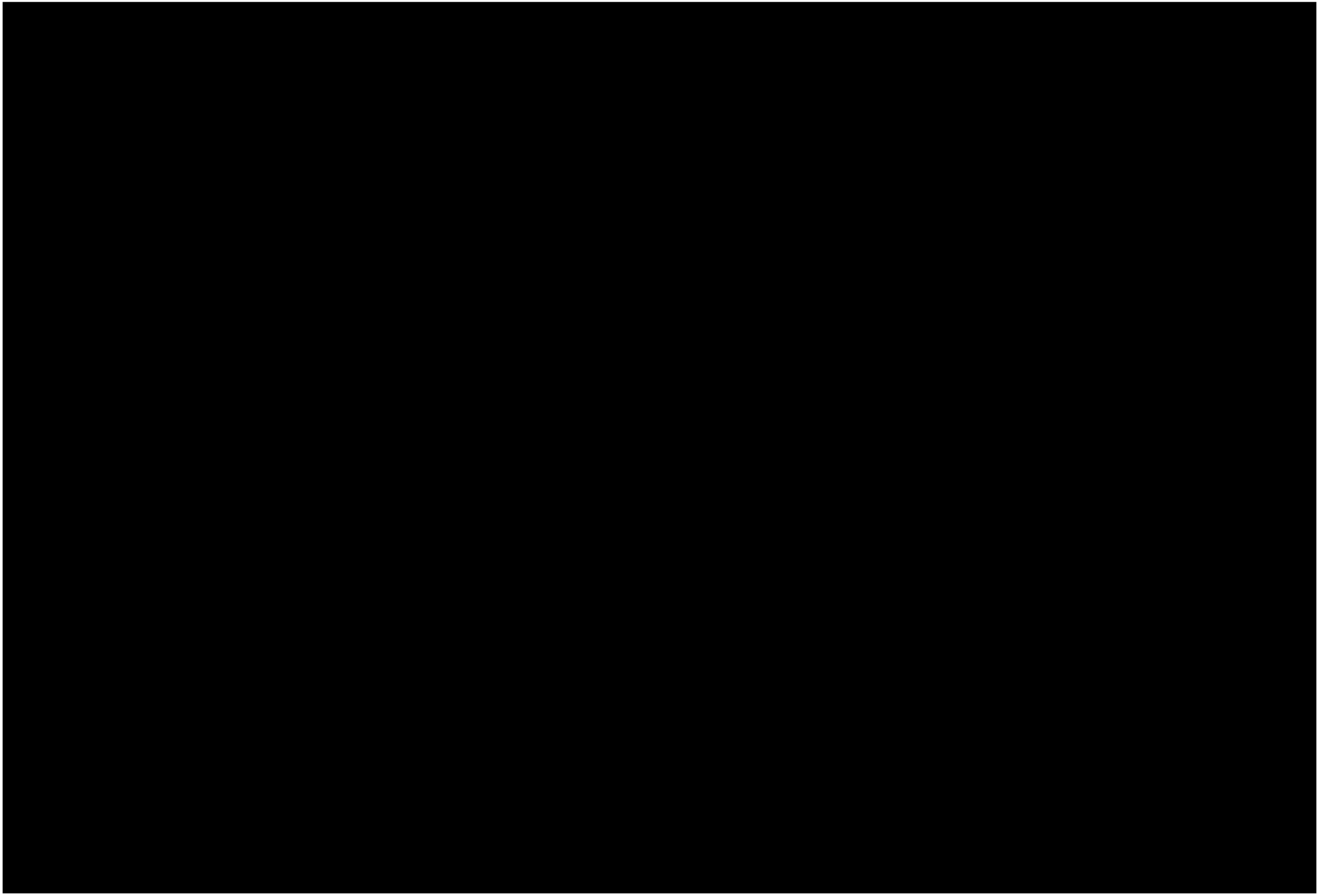
Date of On Peak Day - 08/12/2021



Member Forecasted On Peak Demand Day for September 2021

Big Horn Rural Electric Company

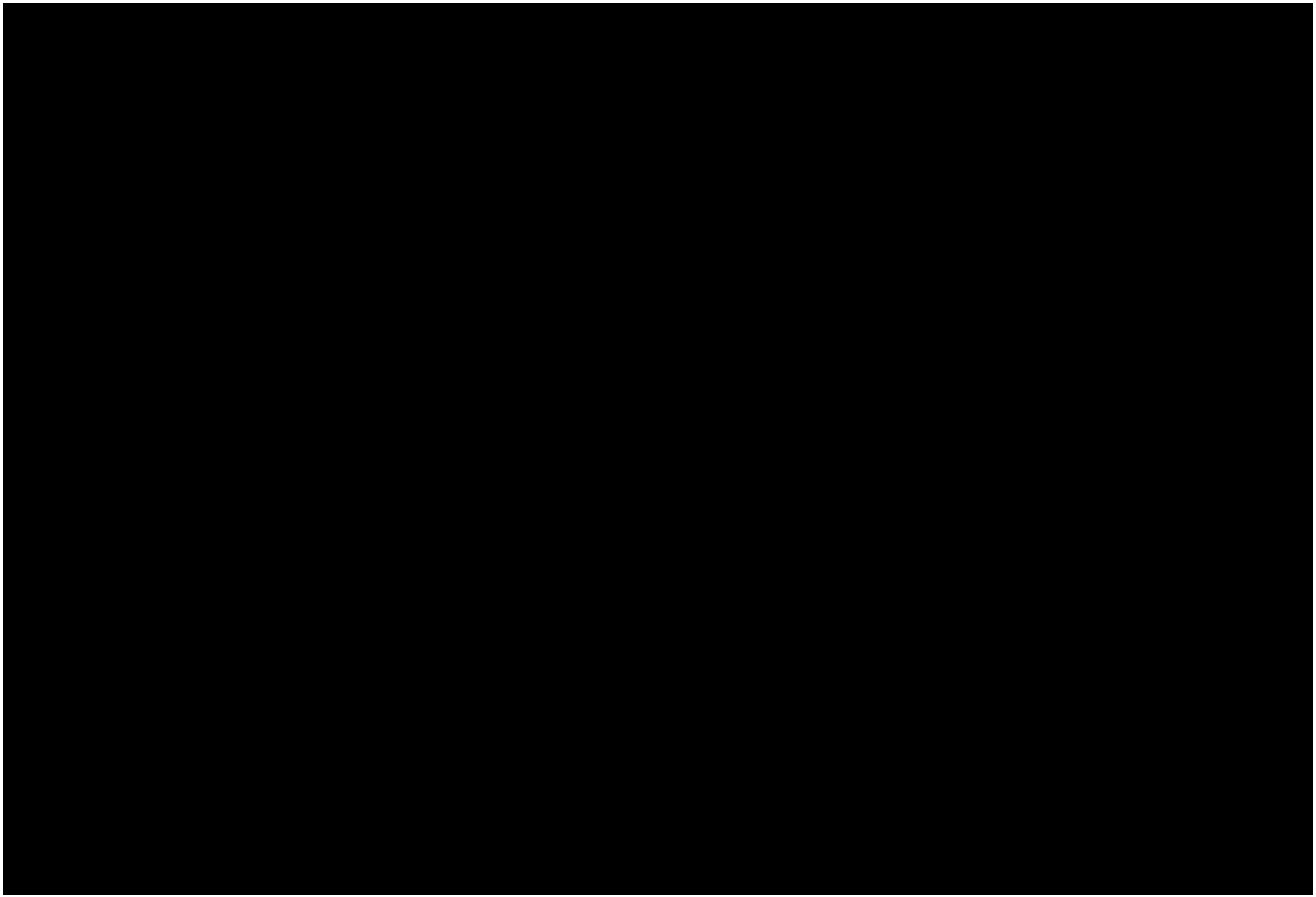
Date of On Peak Day - 09/25/2021



Member Forecasted On Peak Demand Day for October 2021

Big Horn Rural Electric Company

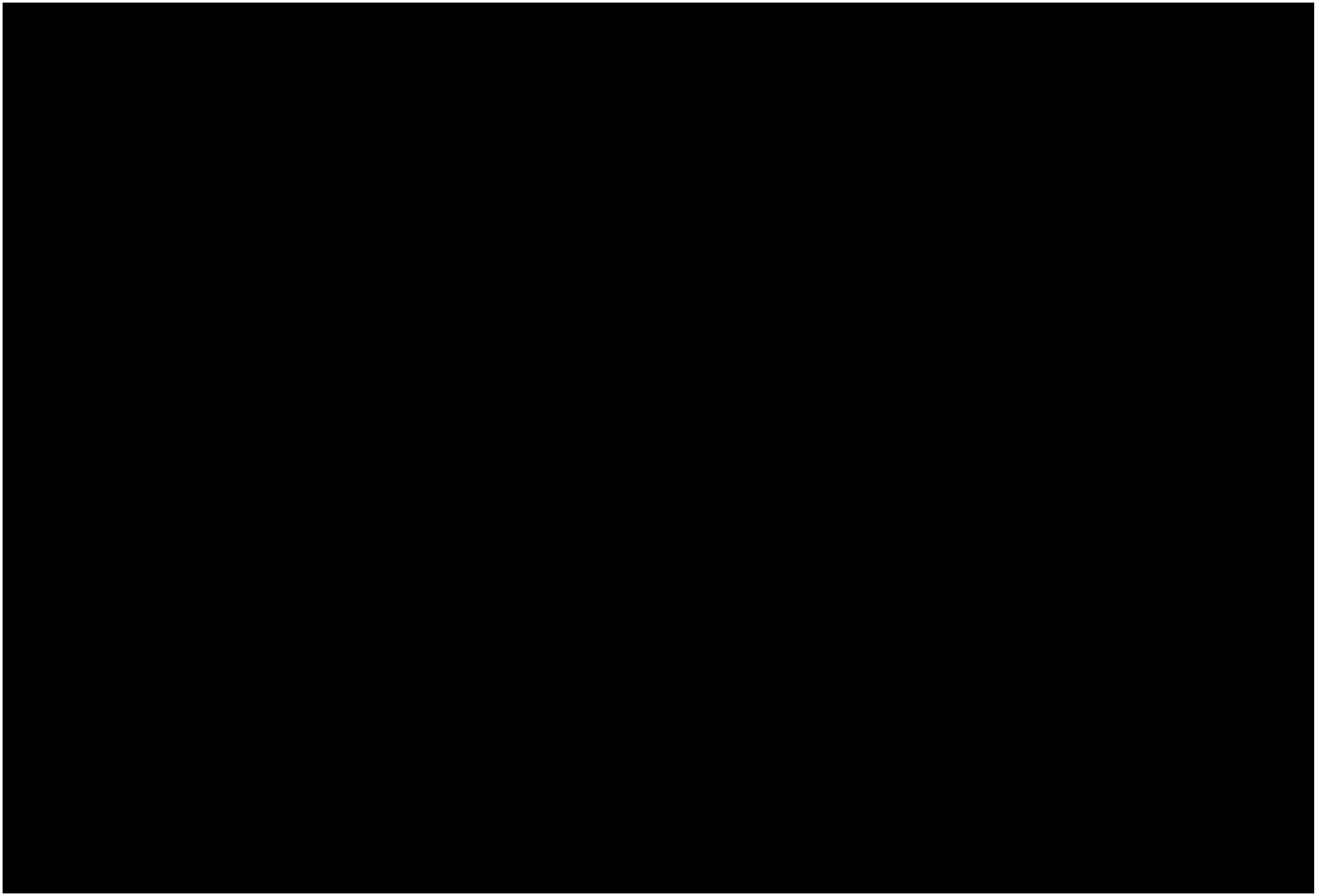
Date of On Peak Day - 10/01/2021



Member Forecasted On Peak Demand Day for November 2021

Big Horn Rural Electric Company

Date of On Peak Day - 11/01/2021



Member Forecasted On Peak Demand Day for December 2021

Big Horn Rural Electric Company

Date of On Peak Day - 12/29/2021

[redacted]

Member Forecasted On Peak Demand Day for January 2021

Carbon Power and Light, Inc.

Date of On Peak Day - 01/05/2021

[redacted]

Member Forecasted On Peak Demand Day for February 2021

Carbon Power and Light, Inc.

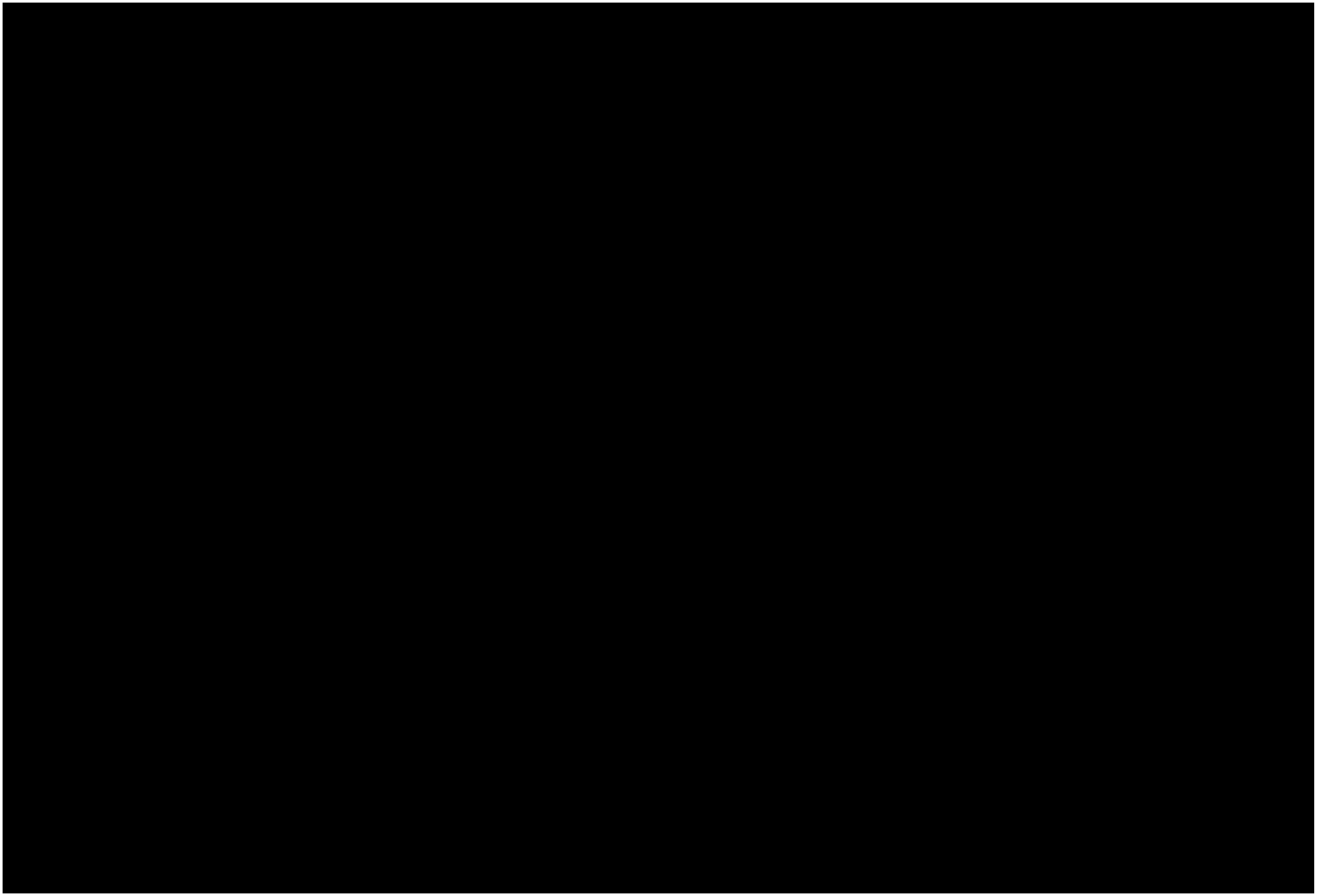
Date of On Peak Day - 02/02/2021

[redacted]

Member Forecasted On Peak Demand Day for March 2021

Carbon Power and Light, Inc.

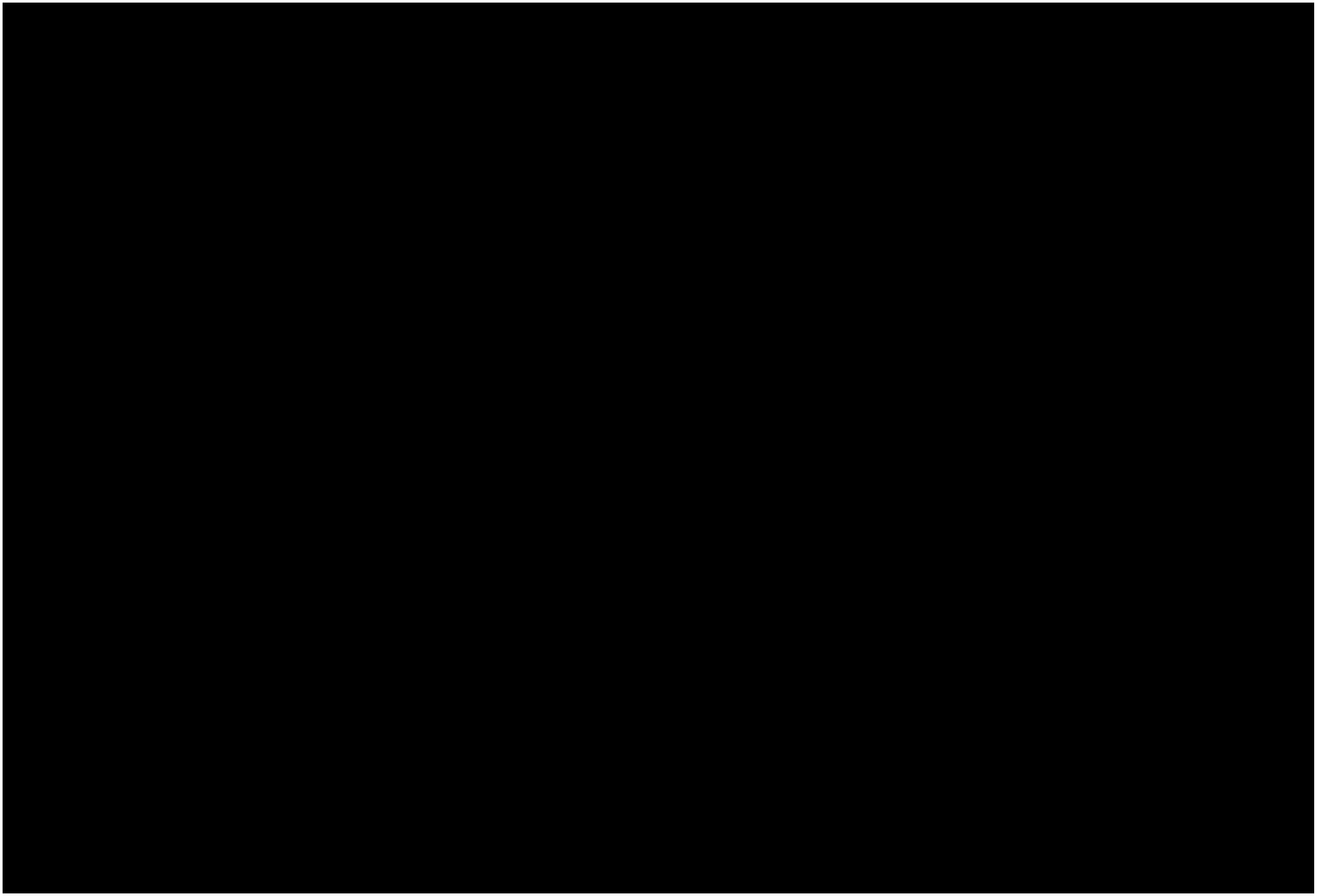
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Carbon Power and Light, Inc.

Date of On Peak Day - 04/07/2021



Member Forecasted On Peak Demand Day for May 2021

Carbon Power and Light, Inc.

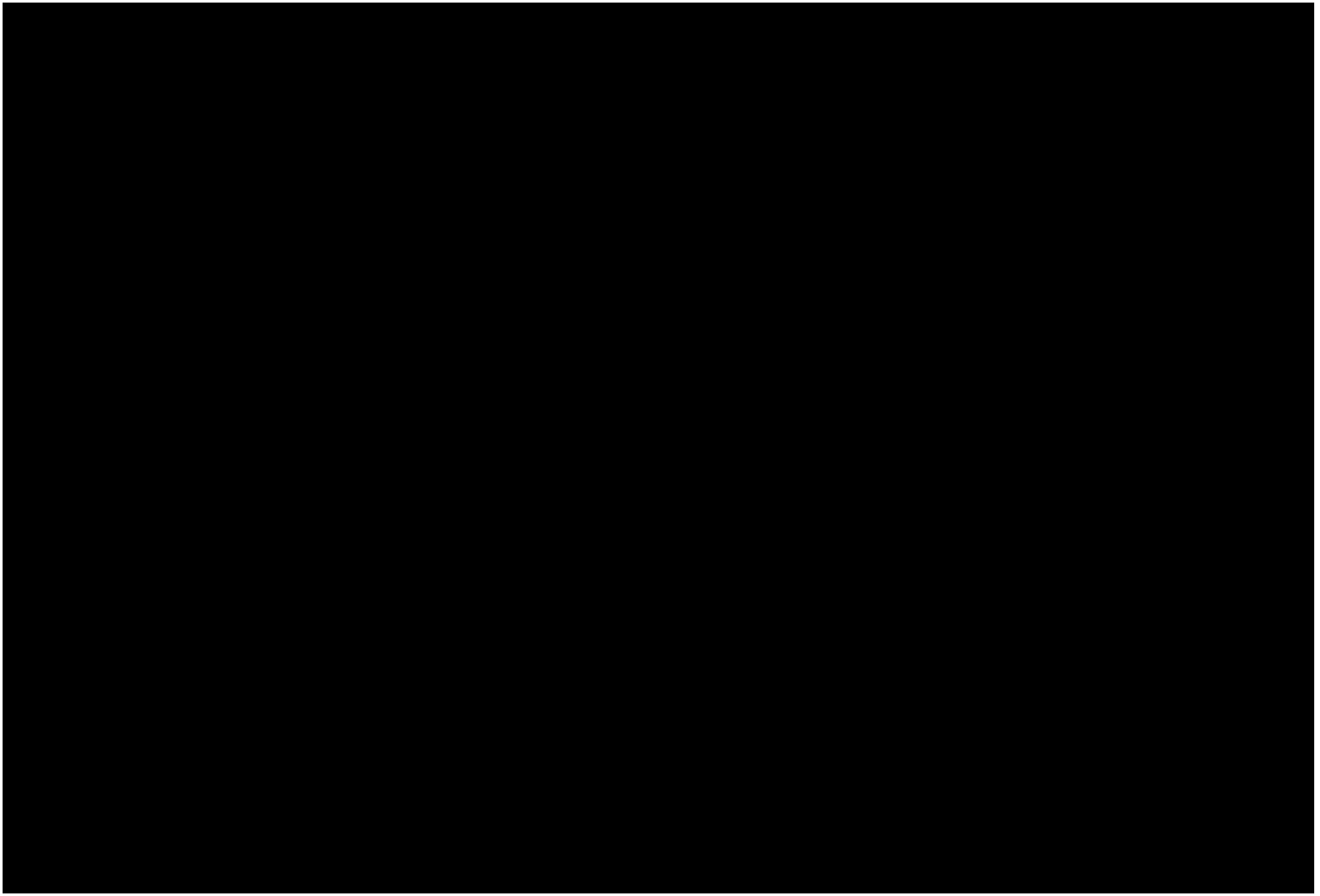
Date of On Peak Day - 05/03/2021

[redacted]

Member Forecasted On Peak Demand Day for June 2021

Carbon Power and Light, Inc.

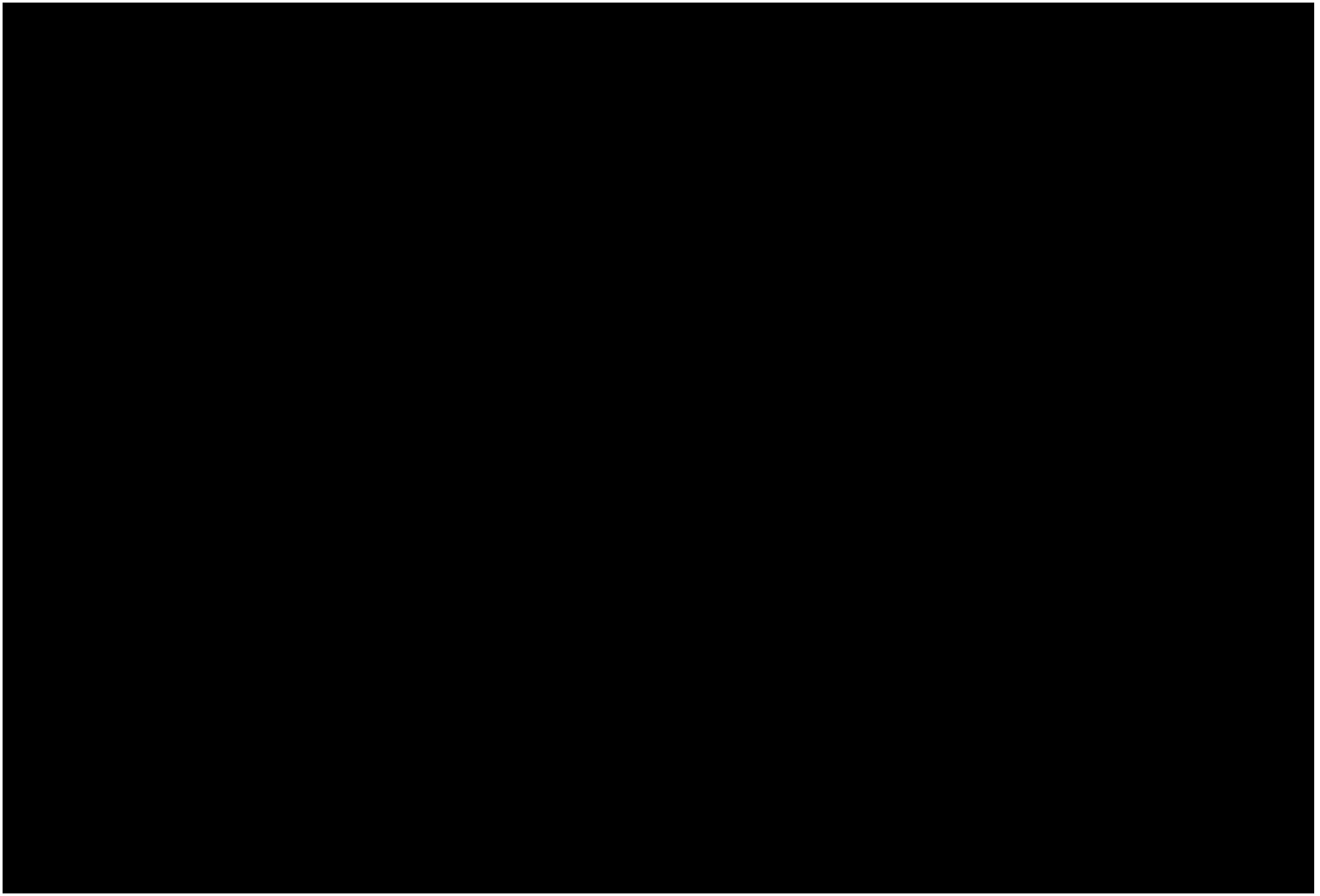
Date of On Peak Day - 06/25/2021



Member Forecasted On Peak Demand Day for July 2021

Carbon Power and Light, Inc.

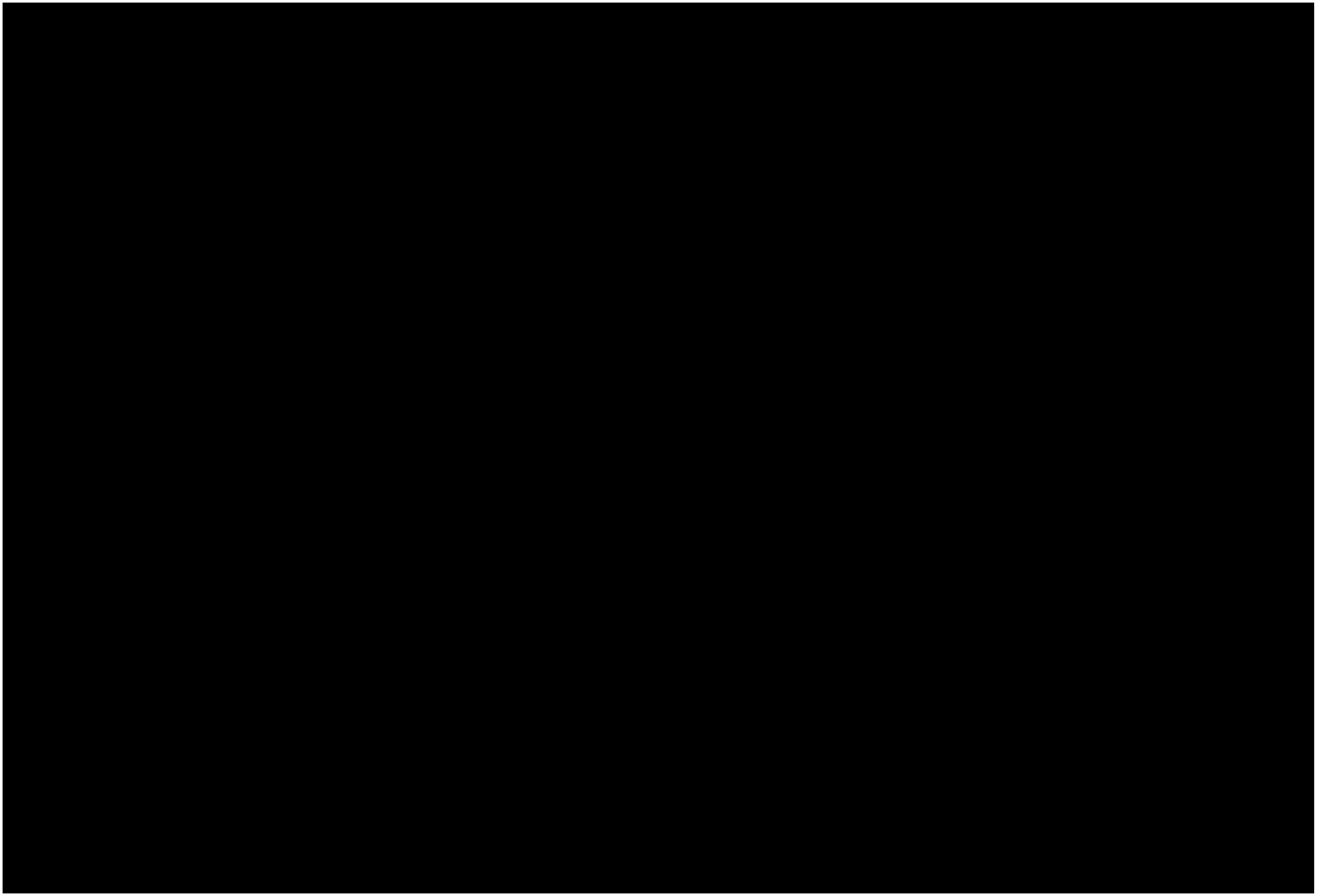
Date of On Peak Day - 07/28/2021



Member Forecasted On Peak Demand Day for August 2021

Carbon Power and Light, Inc.

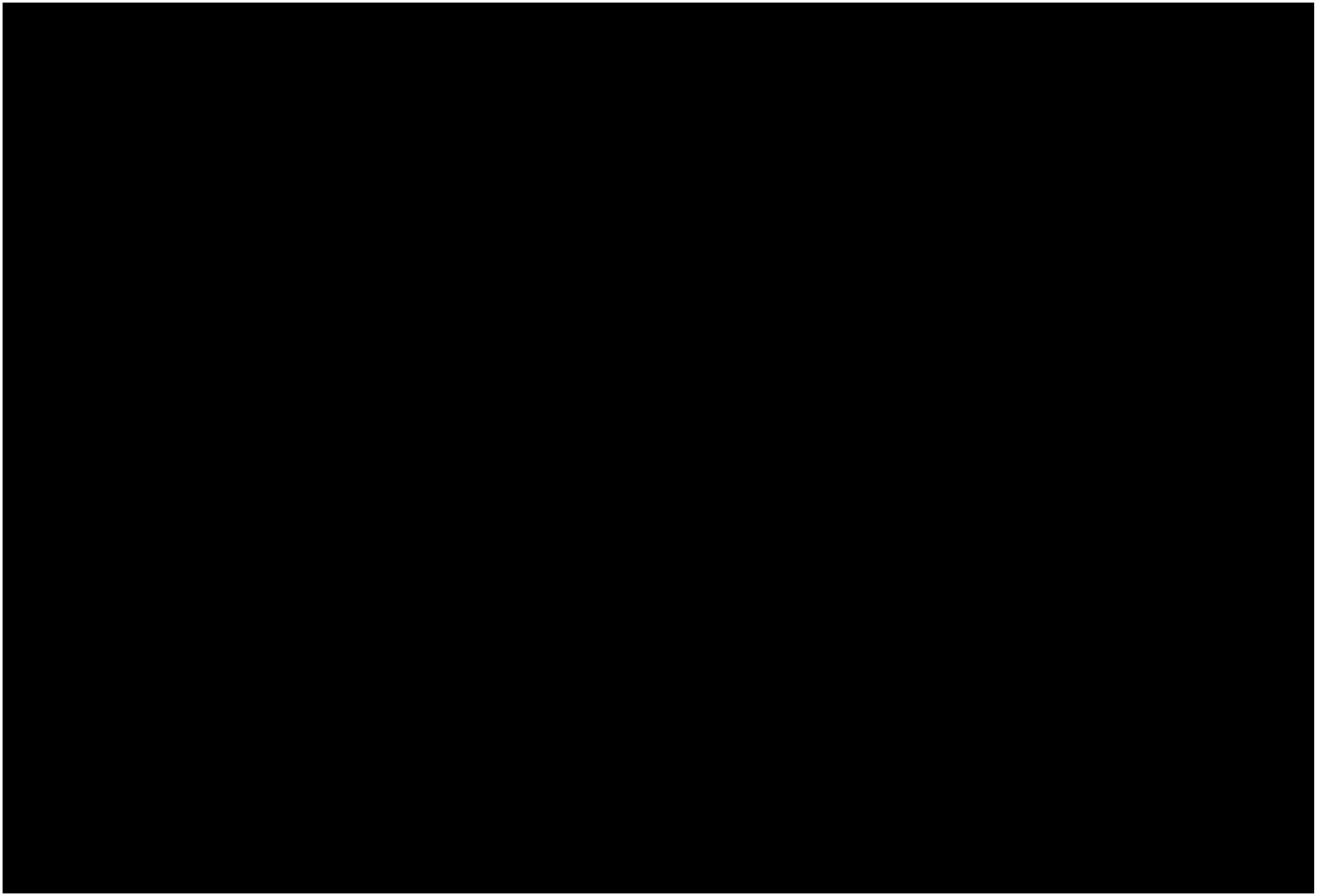
Date of On Peak Day - 08/20/2021



Member Forecasted On Peak Demand Day for September 2021

Carbon Power and Light, Inc.

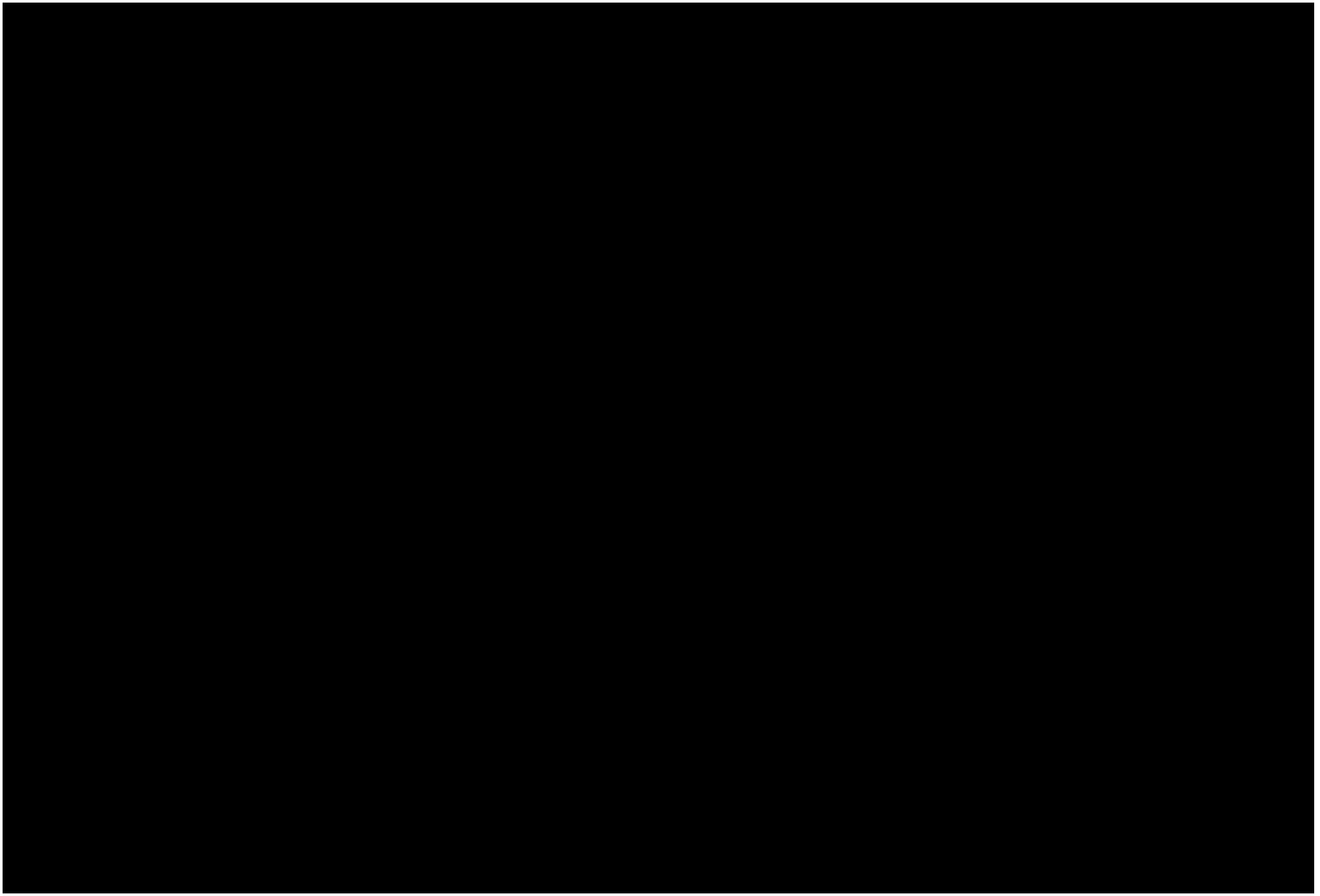
Date of On Peak Day - 09/09/2021



Member Forecasted On Peak Demand Day for October 2021

Carbon Power and Light, Inc.

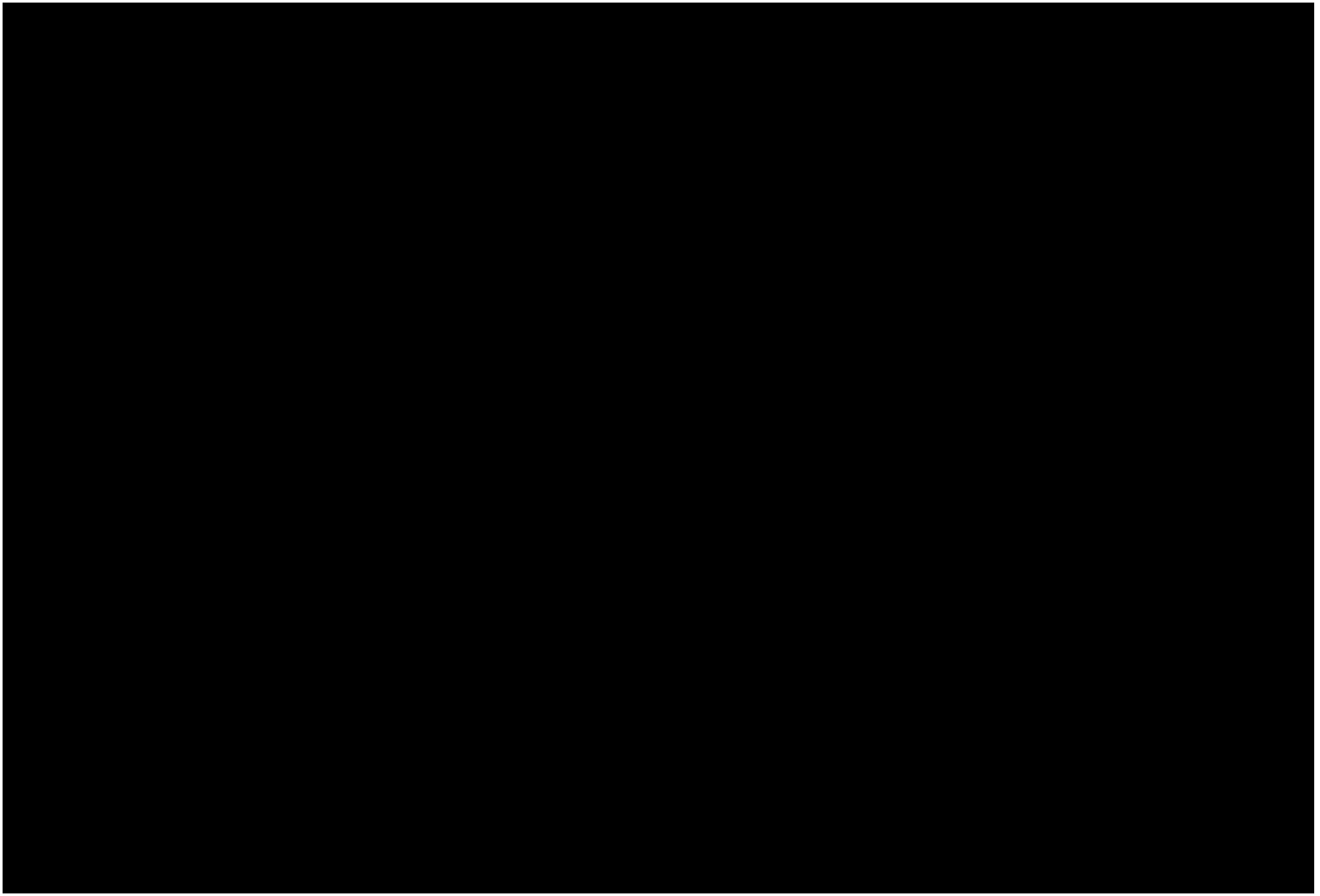
Date of On Peak Day - 10/22/2021



Member Forecasted On Peak Demand Day for November 2021

Carbon Power and Light, Inc.

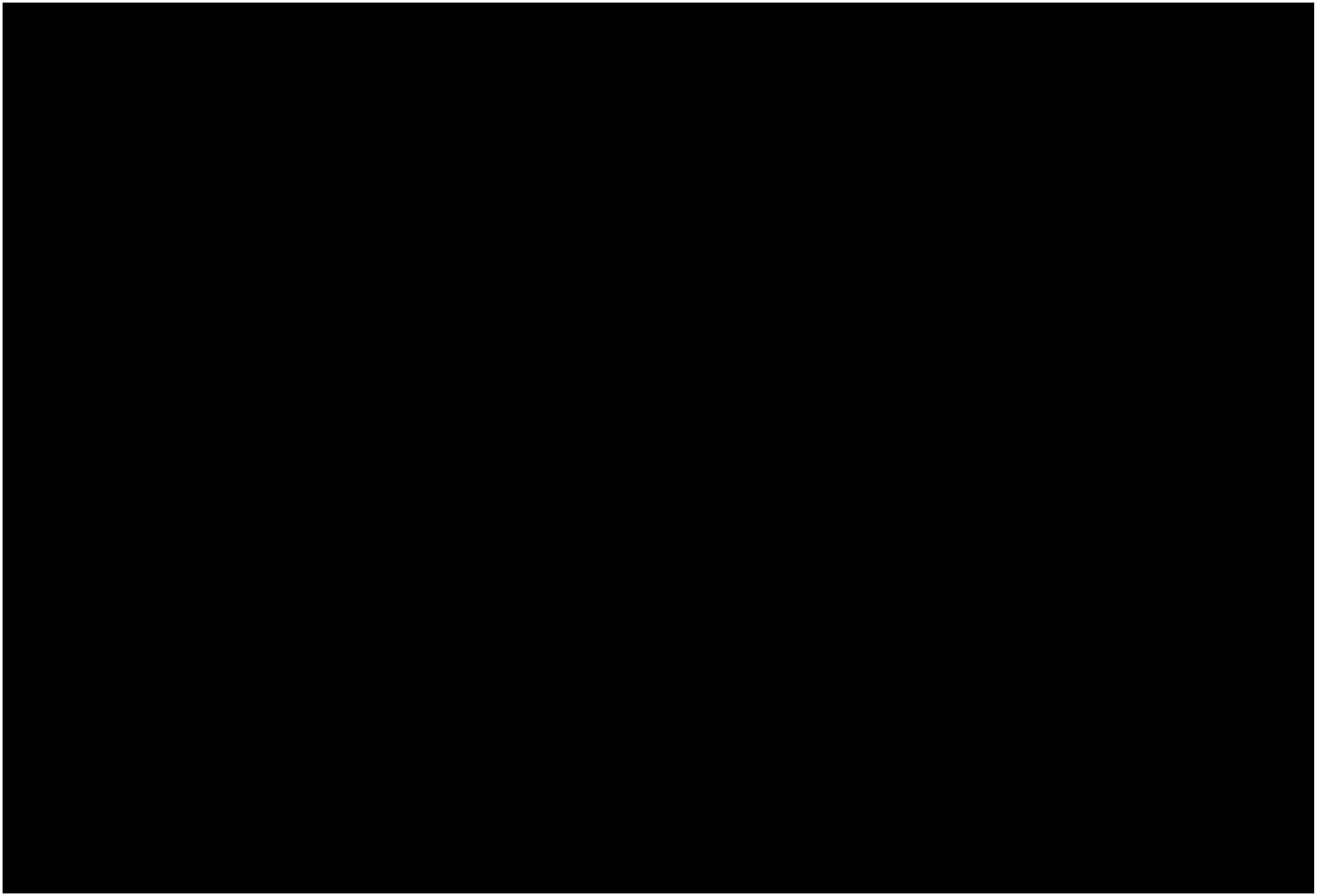
Date of On Peak Day - 11/09/2021



Member Forecasted On Peak Demand Day for December 2021

Carbon Power and Light, Inc.

Date of On Peak Day - 12/28/2021



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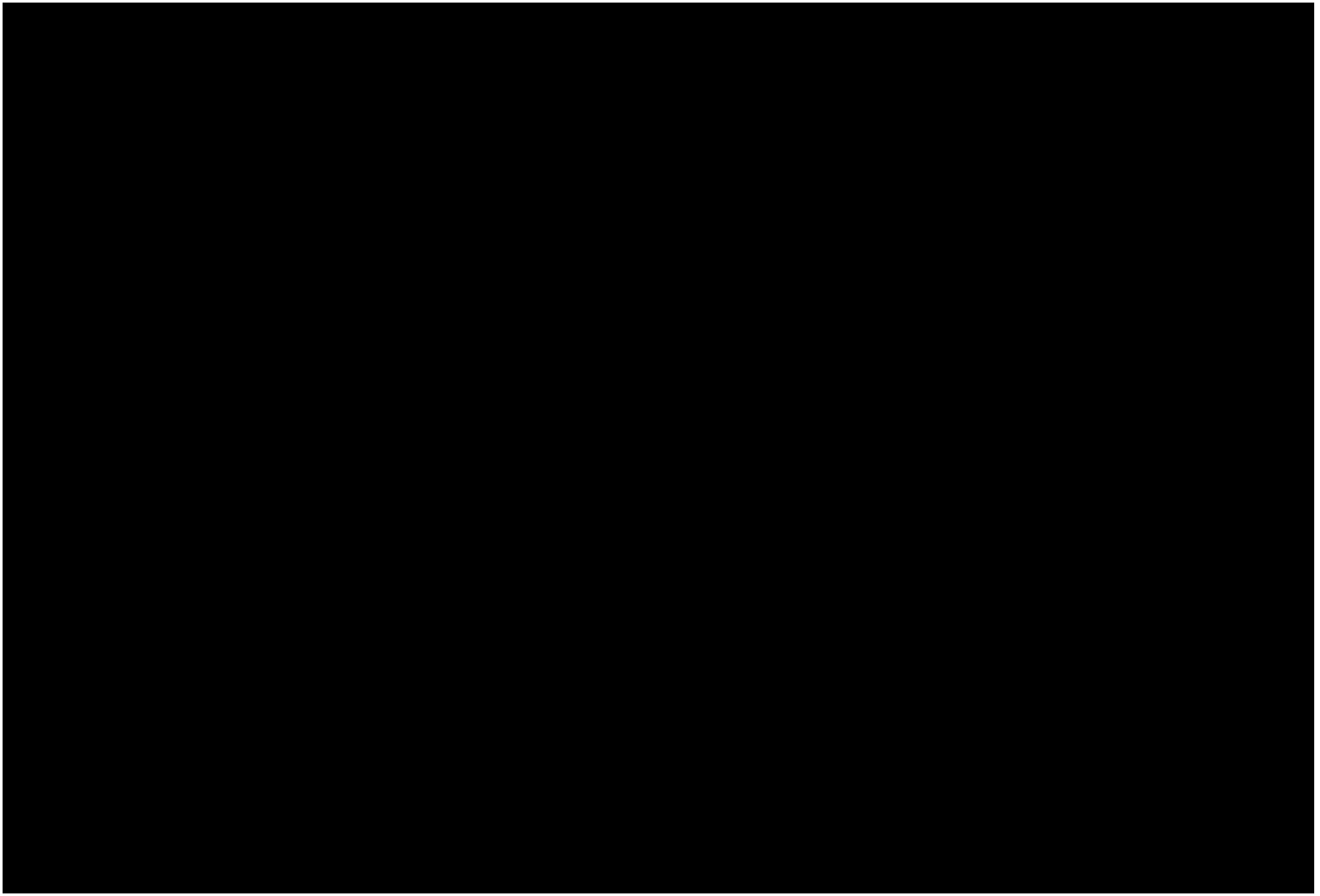
Member Forecasted On Peak Demand Day for January 2021

Continental Divide Electric Cooperative, Inc.

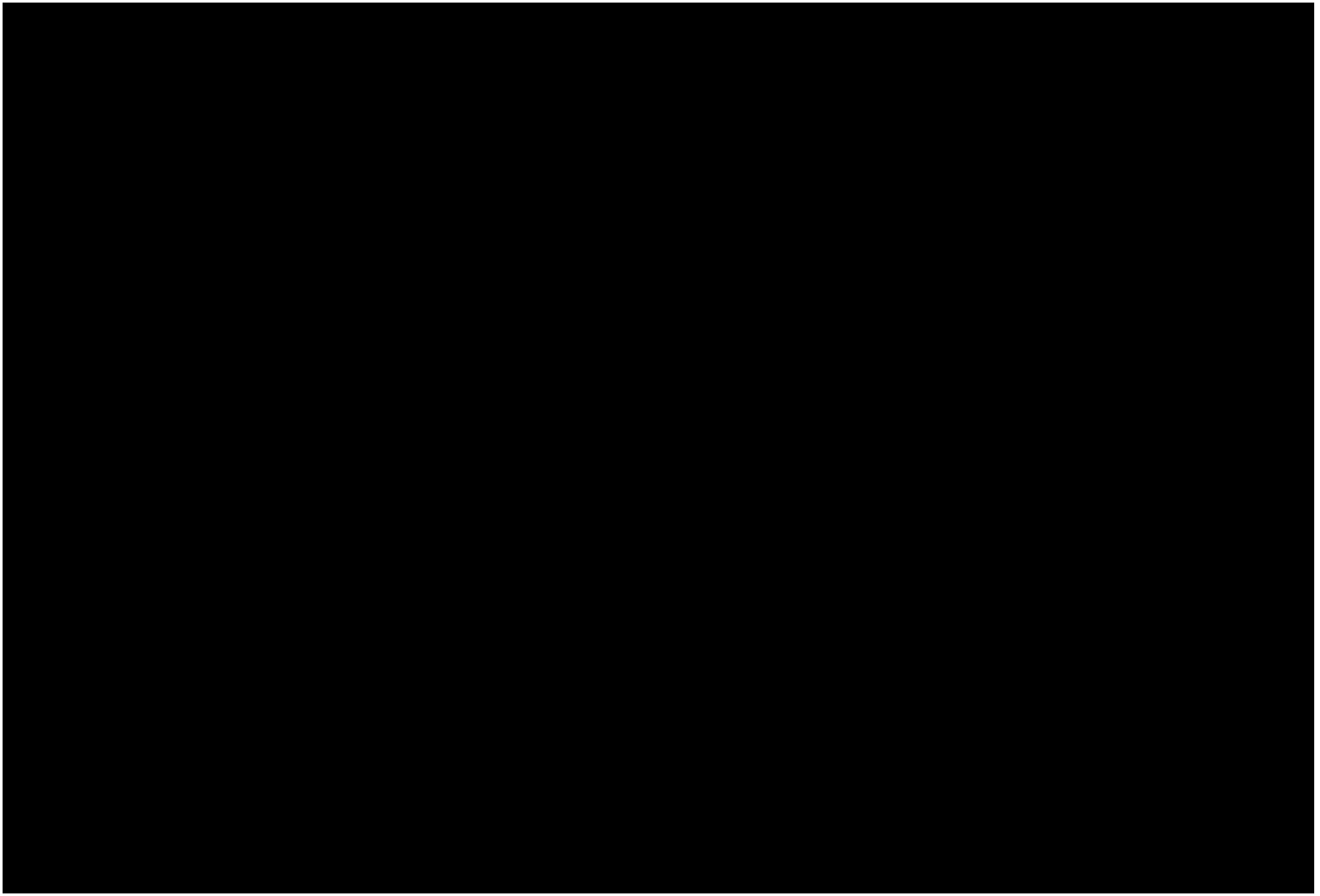
Date of On Peak Day - 01/25/2021



Member Forecasted On Peak Demand Day for February 2021

Continental Divide Electric Cooperative, Inc.

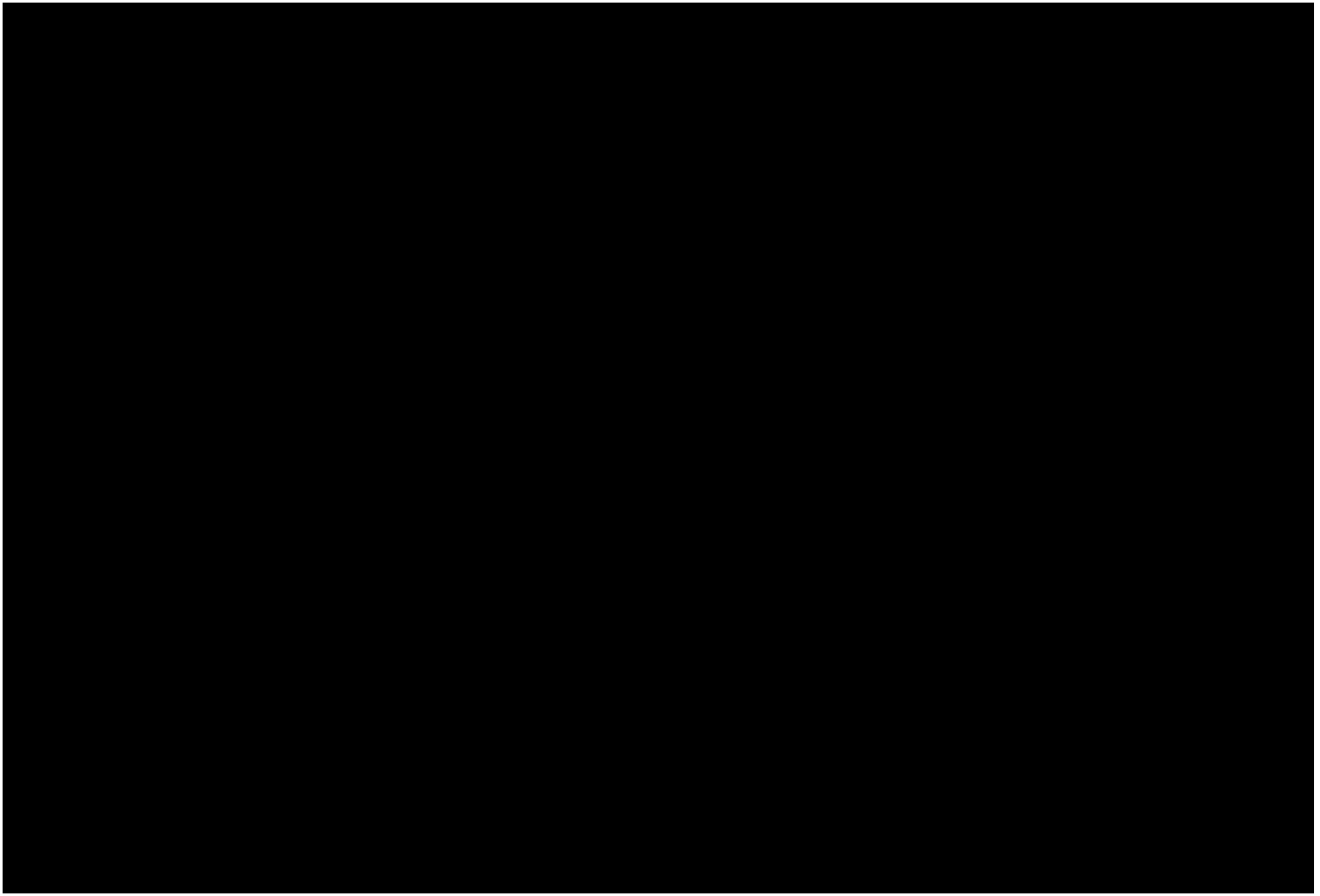
Date of On Peak Day - 02/04/2021



Member Forecasted On Peak Demand Day for March 2021

Continental Divide Electric Cooperative, Inc.

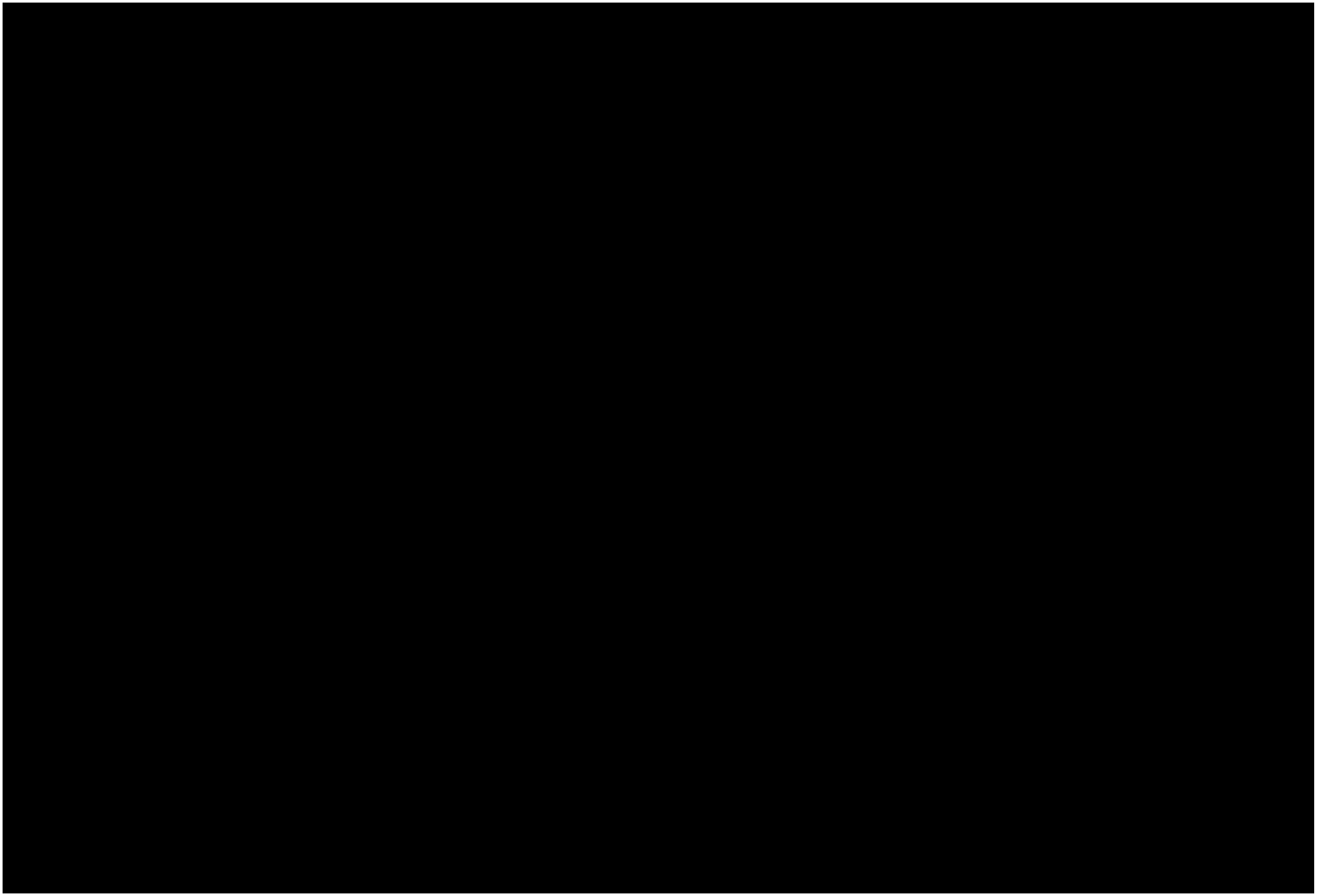
Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

Continental Divide Electric Cooperative, Inc.

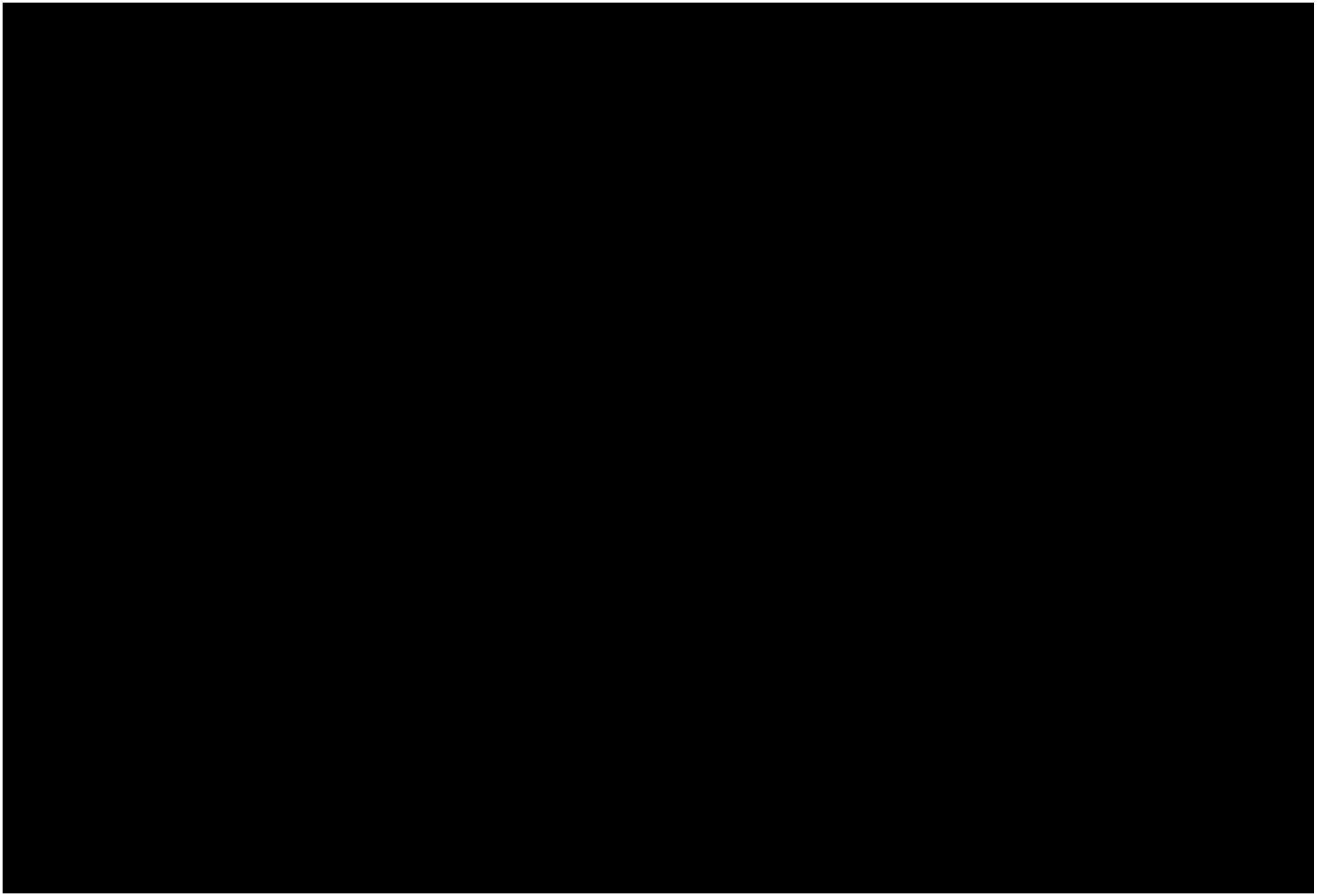
Date of On Peak Day - 04/26/2021



Member Forecasted On Peak Demand Day for May 2021

Continental Divide Electric Cooperative, Inc.

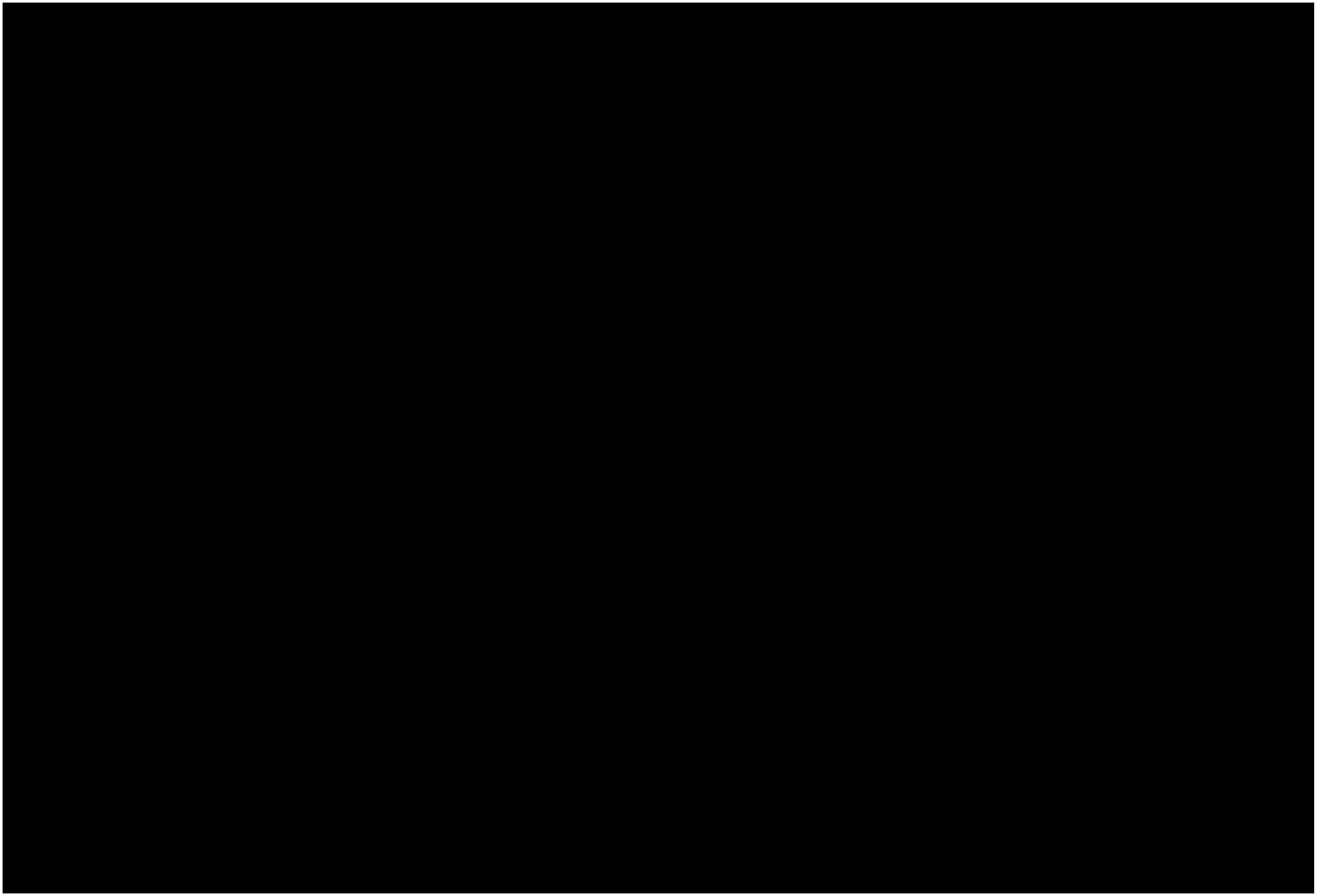
Date of On Peak Day - 05/10/2021



Member Forecasted On Peak Demand Day for June 2021

Continental Divide Electric Cooperative, Inc.

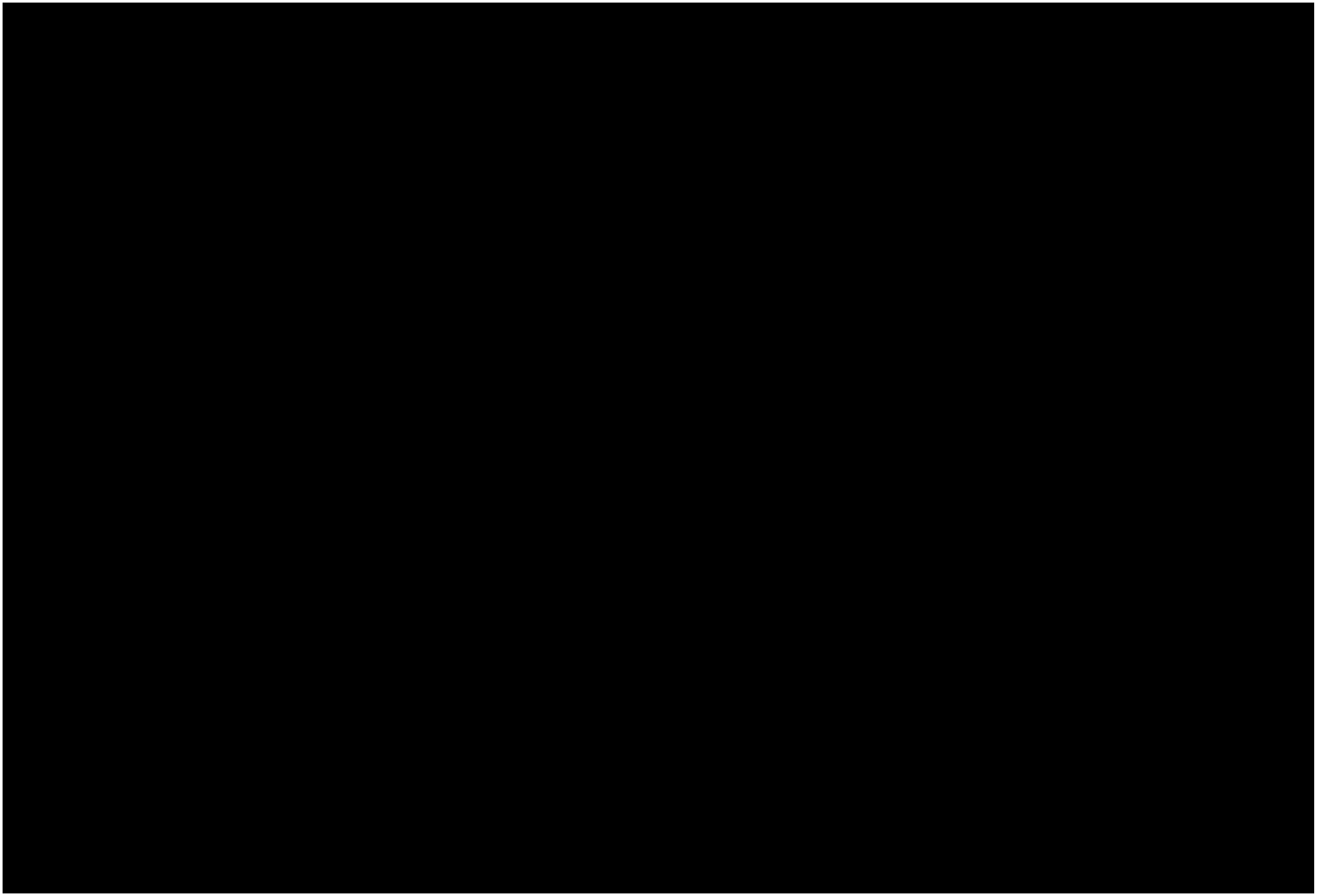
Date of On Peak Day - 06/27/2021



Member Forecasted On Peak Demand Day for July 2021

Continental Divide Electric Cooperative, Inc.

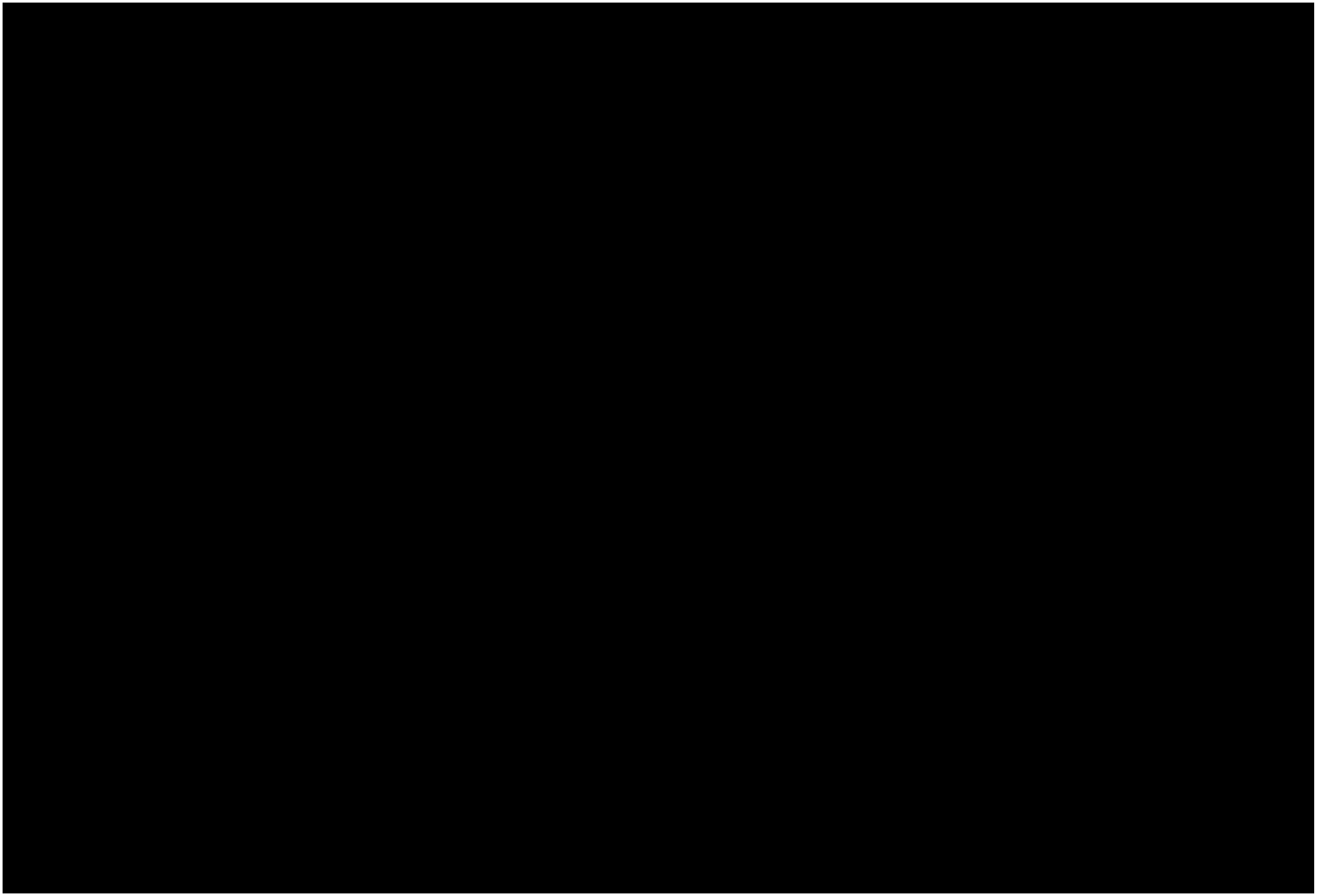
Date of On Peak Day - 07/27/2021



Member Forecasted On Peak Demand Day for August 2021

Continental Divide Electric Cooperative, Inc.

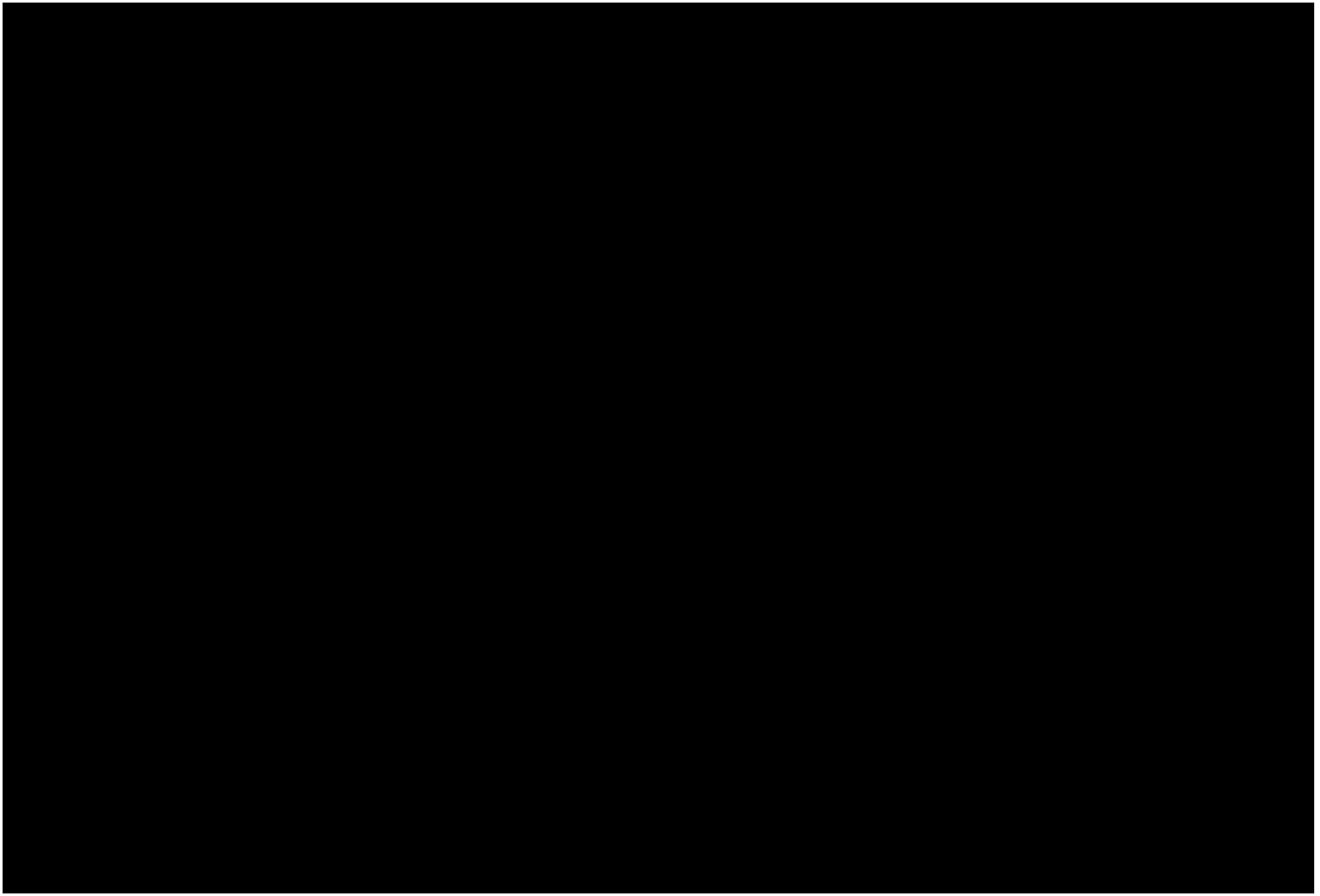
Date of On Peak Day - 08/03/2021



Member Forecasted On Peak Demand Day for September 2021

Continental Divide Electric Cooperative, Inc.

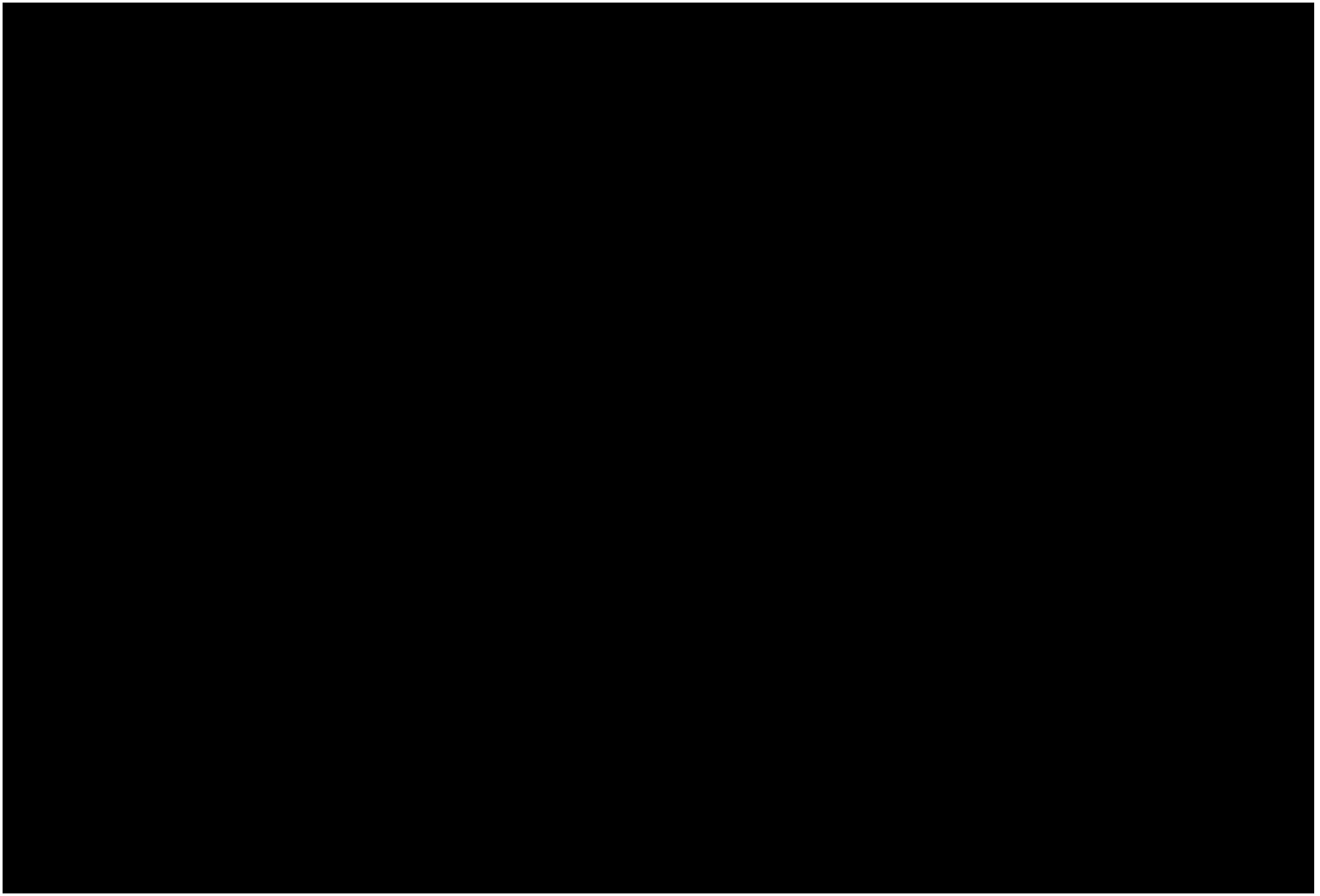
Date of On Peak Day - 09/29/2021



Member Forecasted On Peak Demand Day for October 2021

Continental Divide Electric Cooperative, Inc.

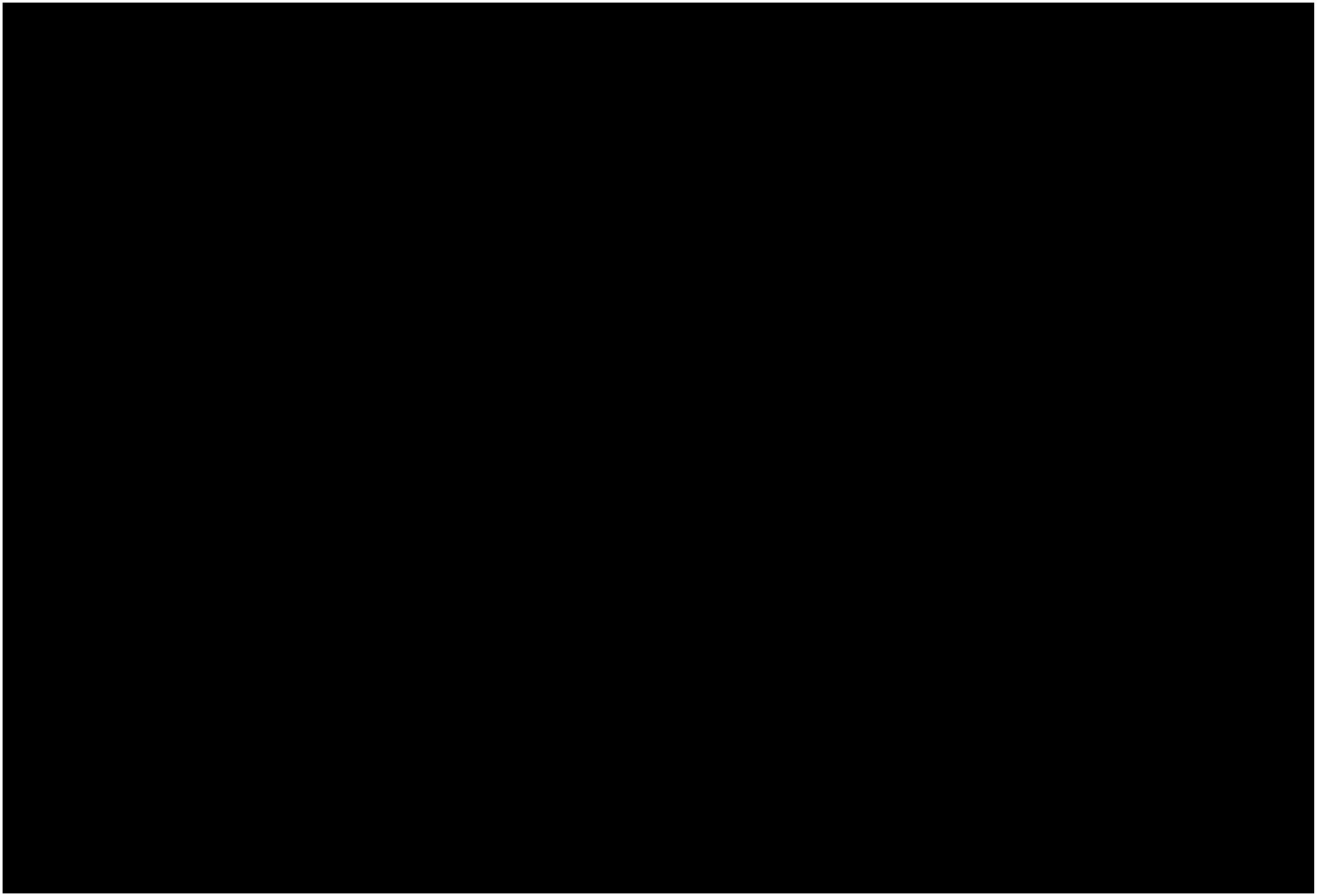
Date of On Peak Day - 10/25/2021



Member Forecasted On Peak Demand Day for November 2021

Continental Divide Electric Cooperative, Inc.

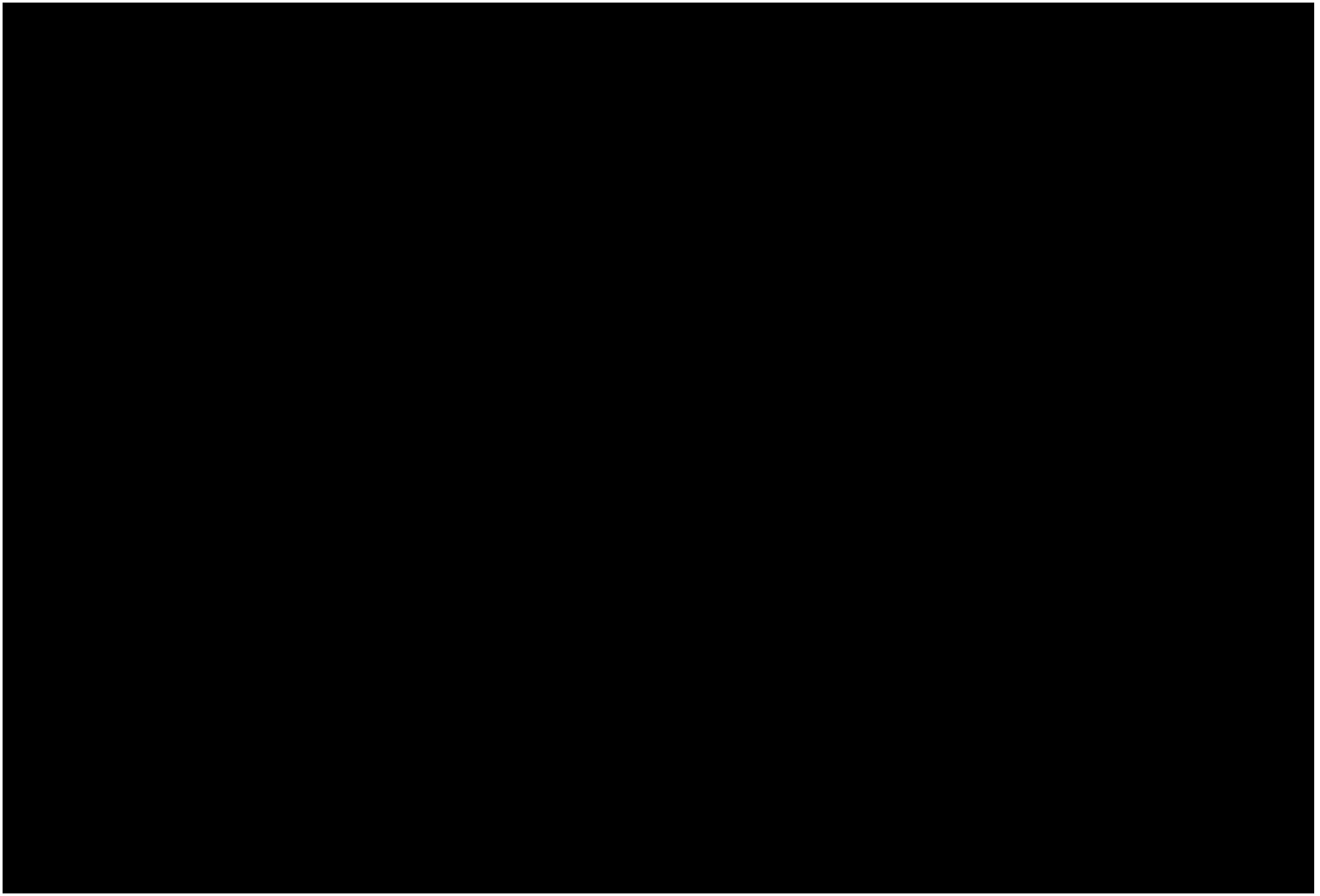
Date of On Peak Day - 11/30/2021



Member Forecasted On Peak Demand Day for December 2021

Continental Divide Electric Cooperative, Inc.

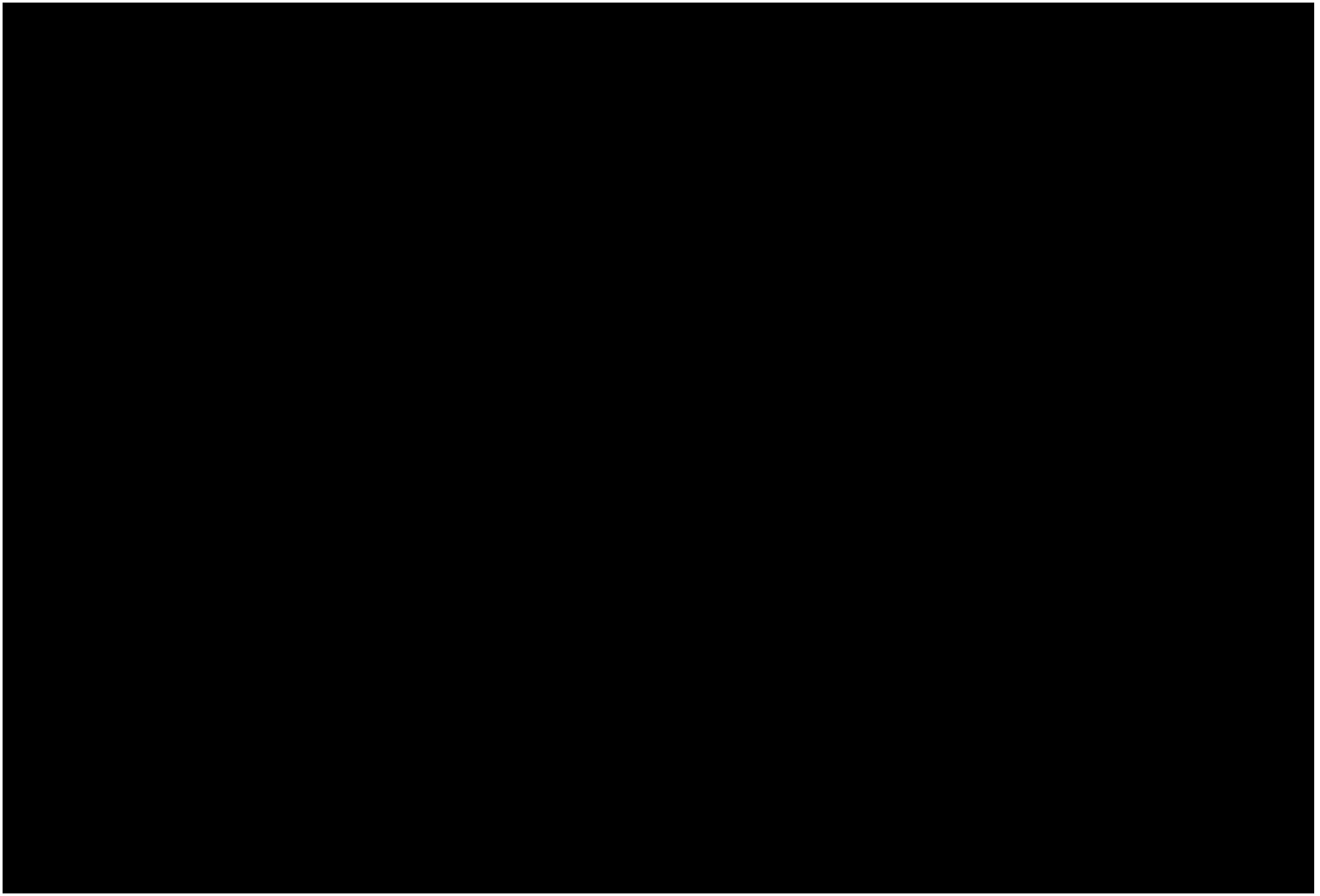
Date of On Peak Day - 12/26/2021



Member Forecasted On Peak Demand Day for January 2021

Columbus Electric Cooperative, Inc.

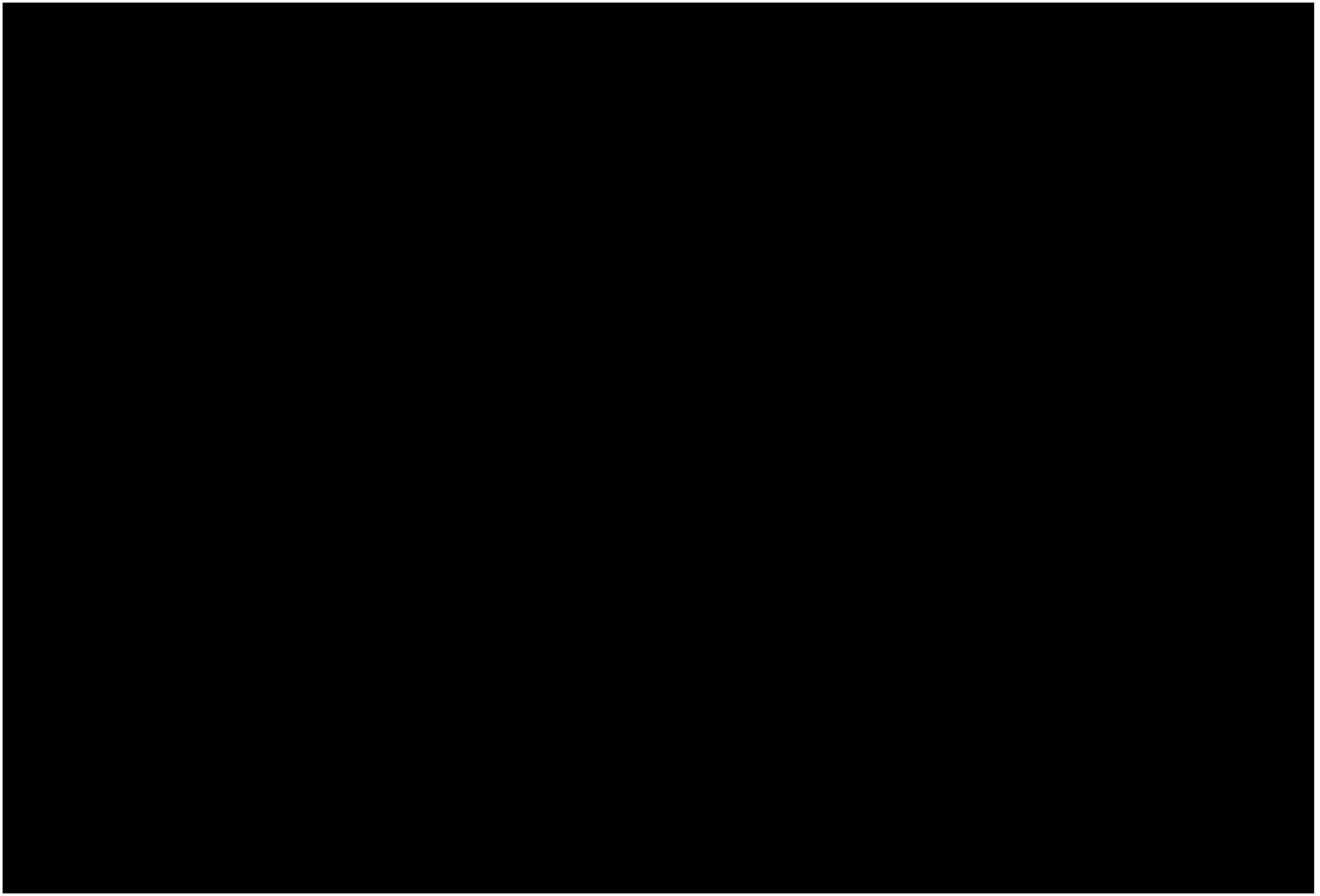
Date of On Peak Day - 01/30/2021



Member Forecasted On Peak Demand Day for February 2021

Columbus Electric Cooperative, Inc.

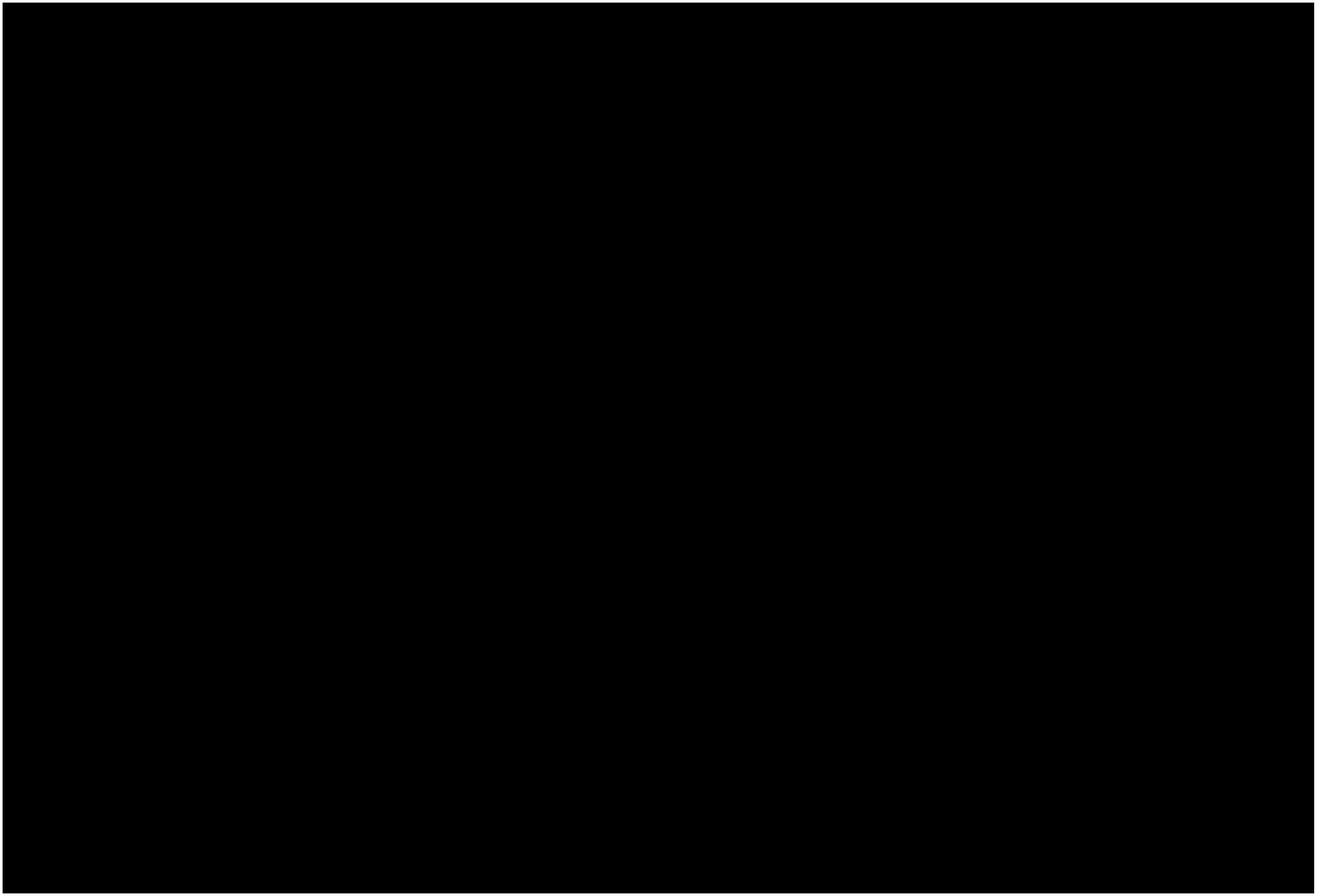
Date of On Peak Day - 02/26/2021



Member Forecasted On Peak Demand Day for March 2021

Columbus Electric Cooperative, Inc.

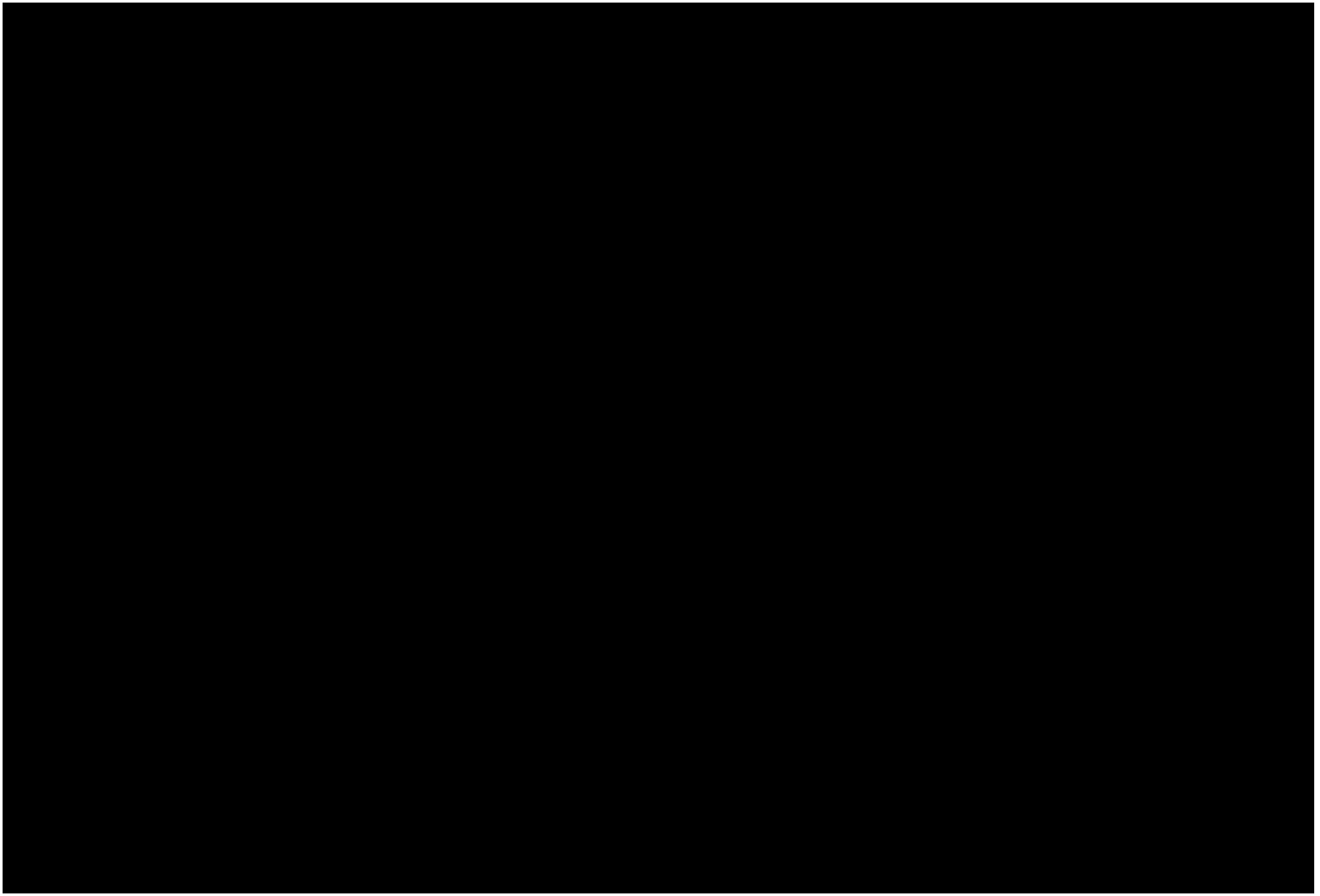
Date of On Peak Day - 03/17/2021



Member Forecasted On Peak Demand Day for April 2021

Columbus Electric Cooperative, Inc.

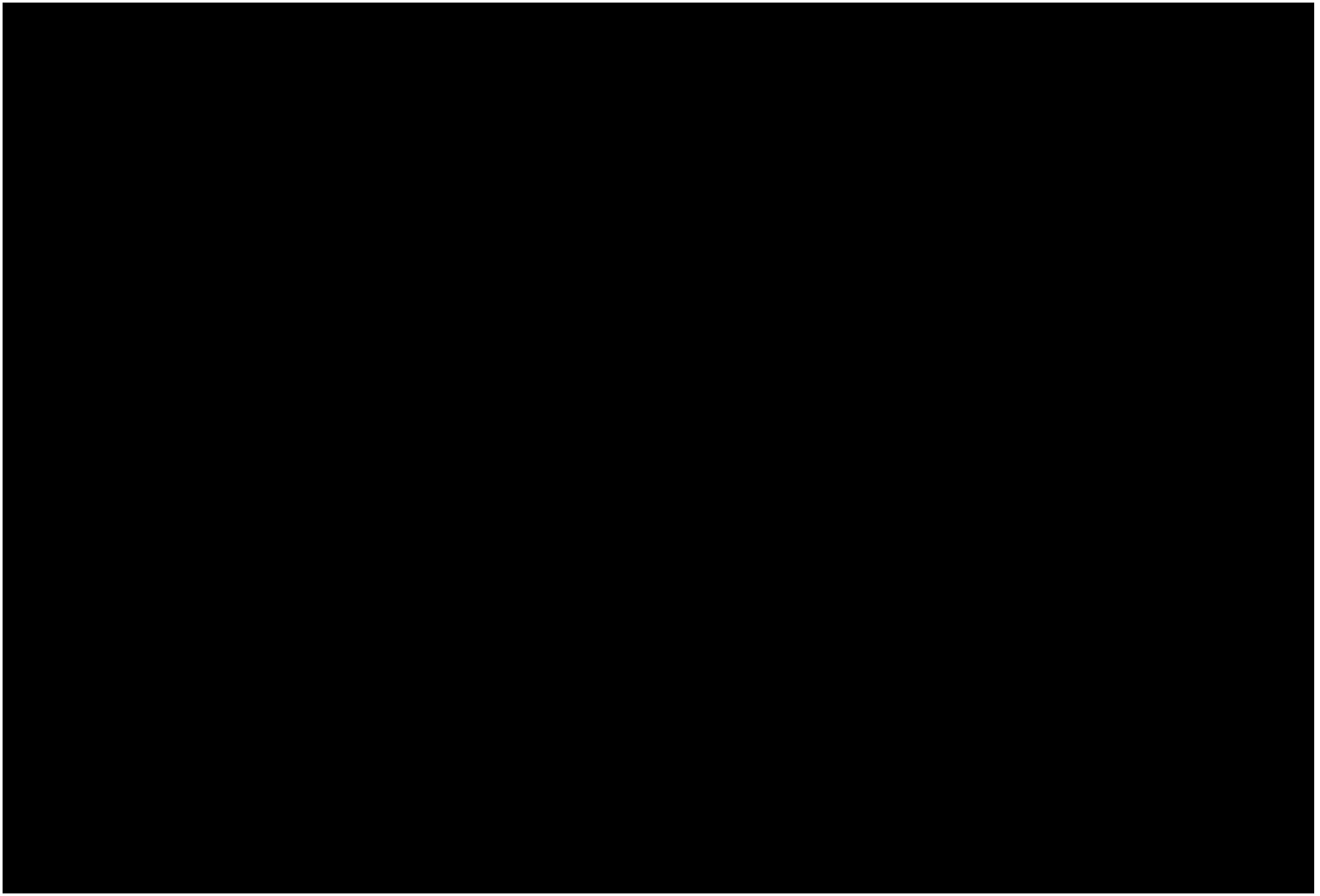
Date of On Peak Day - 04/12/2021



Member Forecasted On Peak Demand Day for May 2021

Columbus Electric Cooperative, Inc.

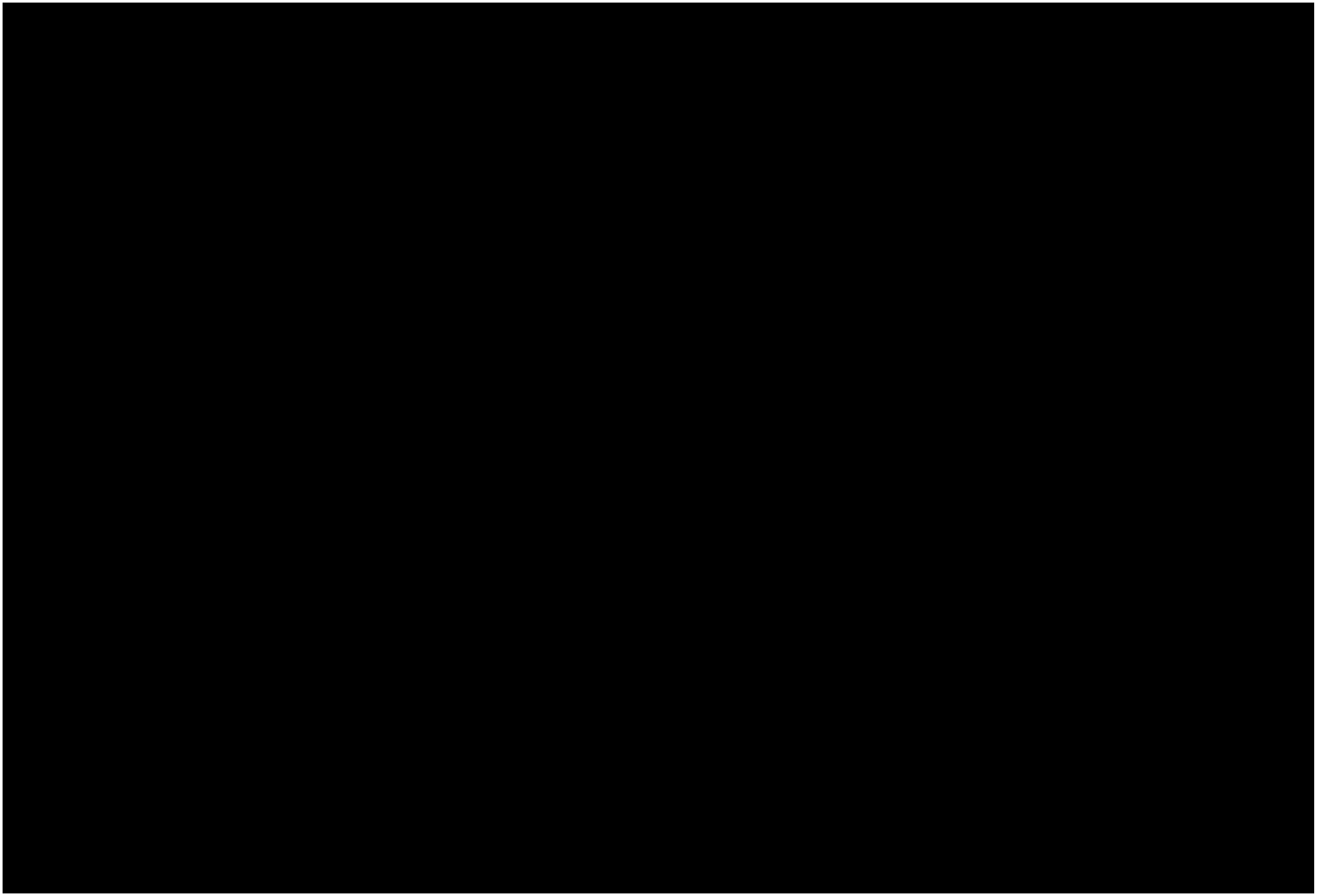
Date of On Peak Day - 05/24/2021



Member Forecasted On Peak Demand Day for June 2021

Columbus Electric Cooperative, Inc.

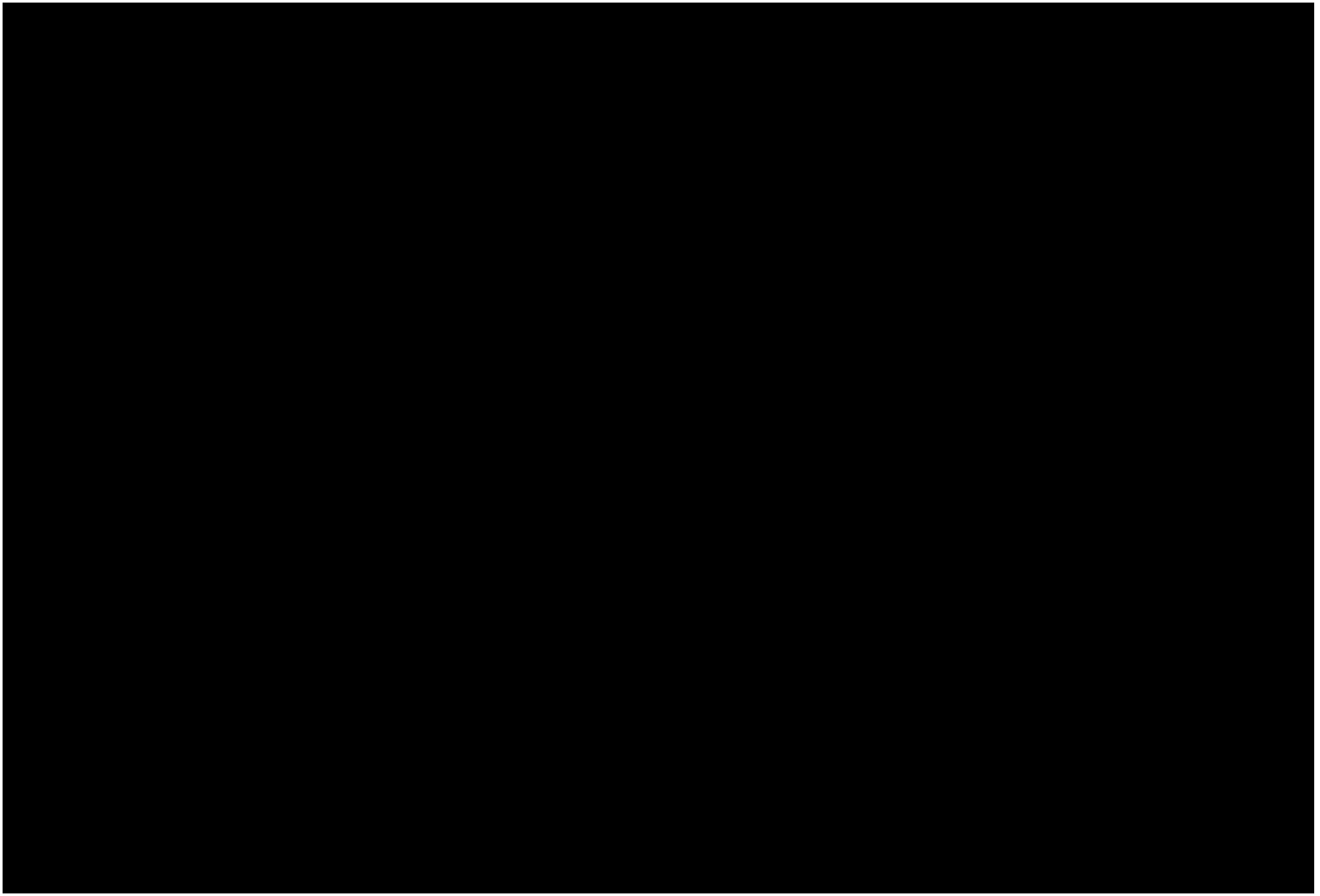
Date of On Peak Day - 06/24/2021



Member Forecasted On Peak Demand Day for July 2021

Columbus Electric Cooperative, Inc.

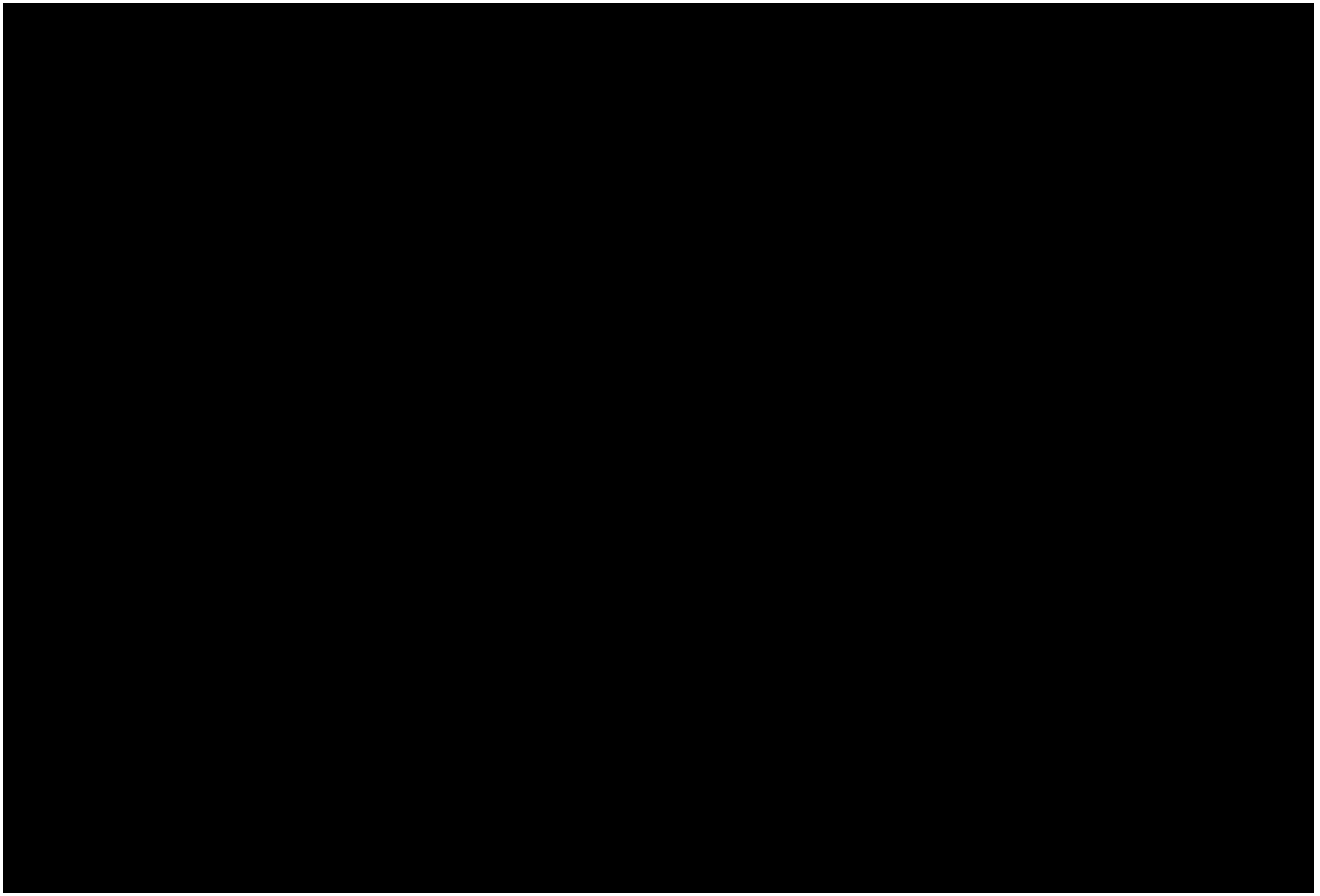
Date of On Peak Day - 07/13/2021



Member Forecasted On Peak Demand Day for August 2021

Columbus Electric Cooperative, Inc.

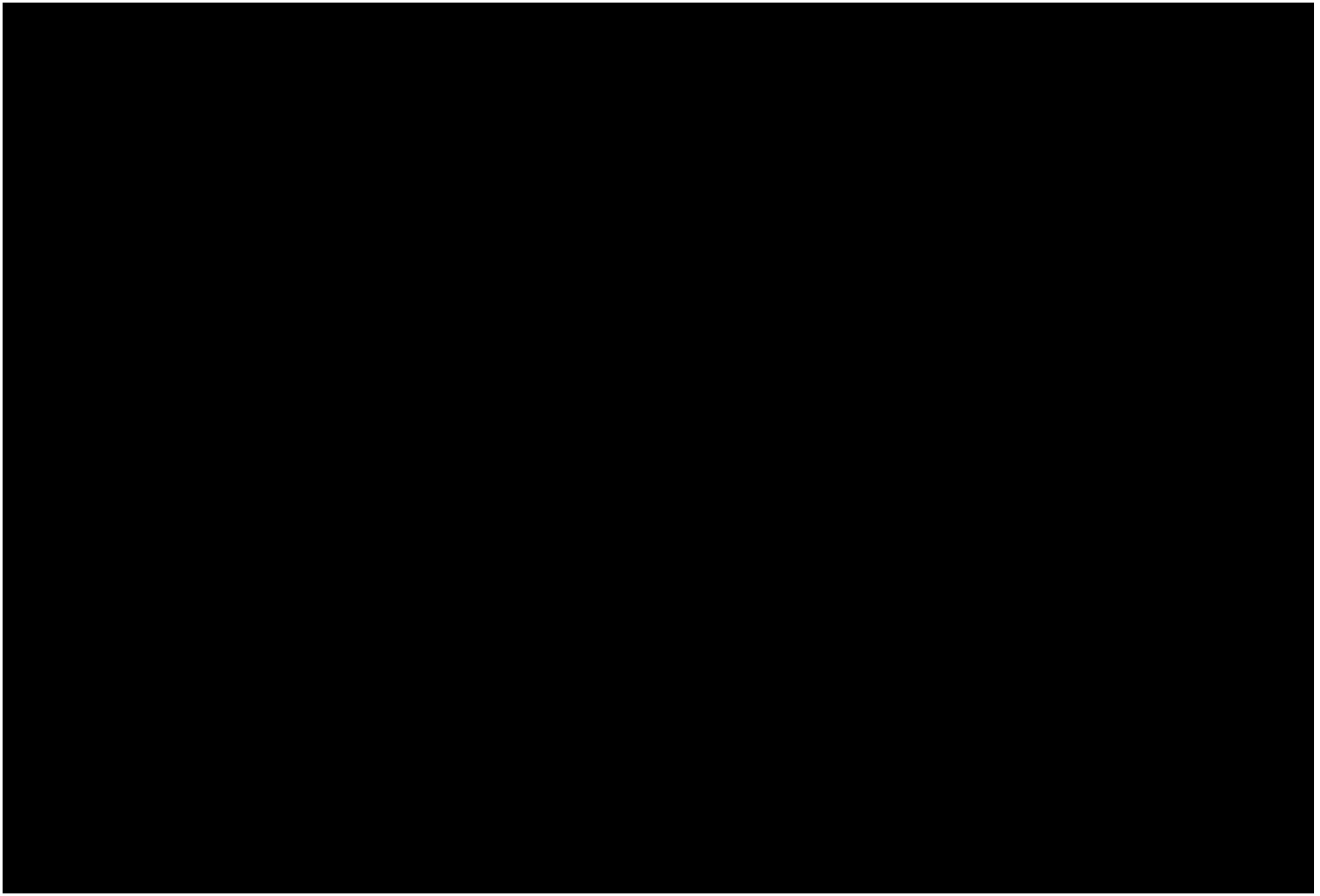
Date of On Peak Day - 08/31/2021



Member Forecasted On Peak Demand Day for September 2021

Columbus Electric Cooperative, Inc.

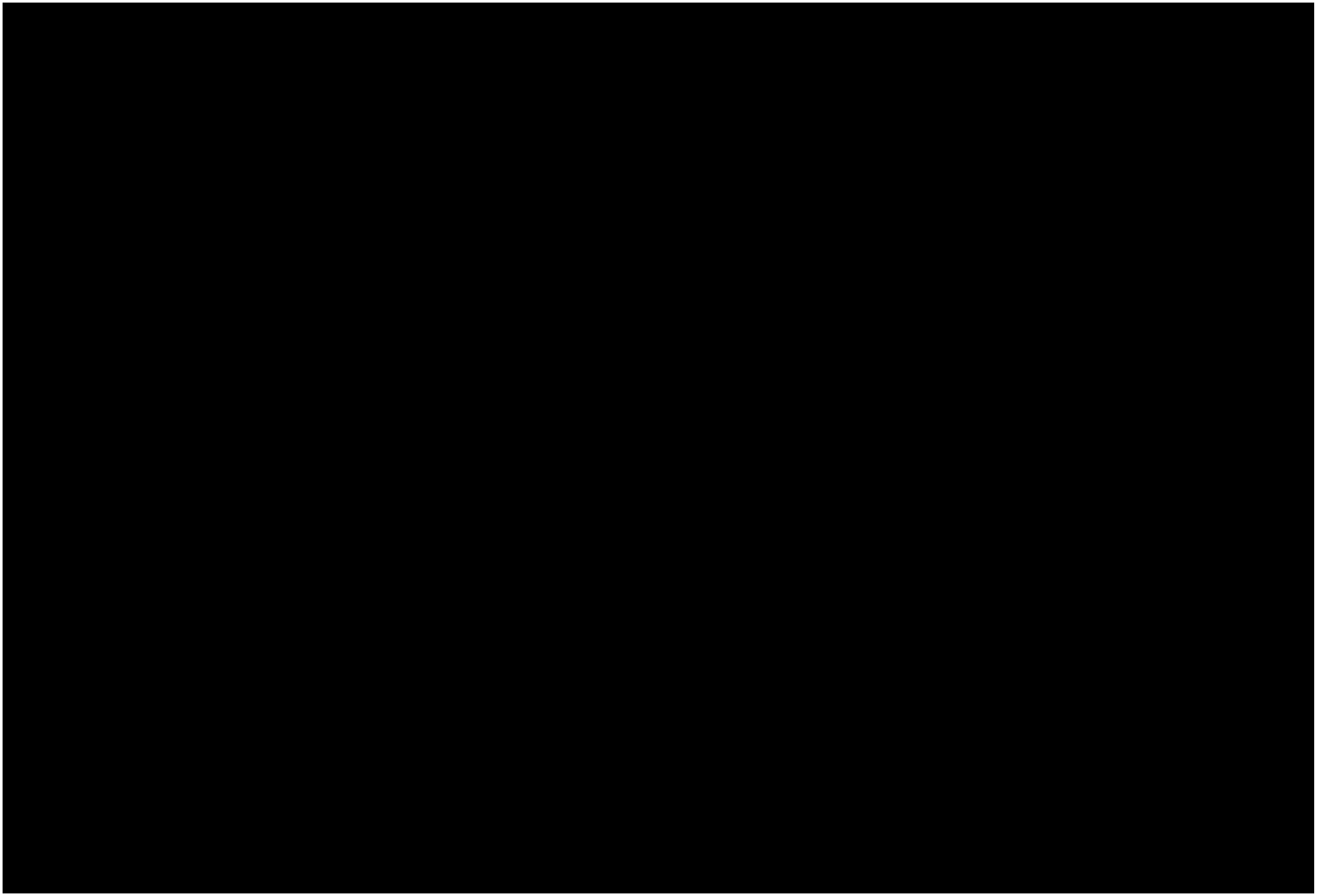
Date of On Peak Day - 09/02/2021



Member Forecasted On Peak Demand Day for October 2021

Columbus Electric Cooperative, Inc.

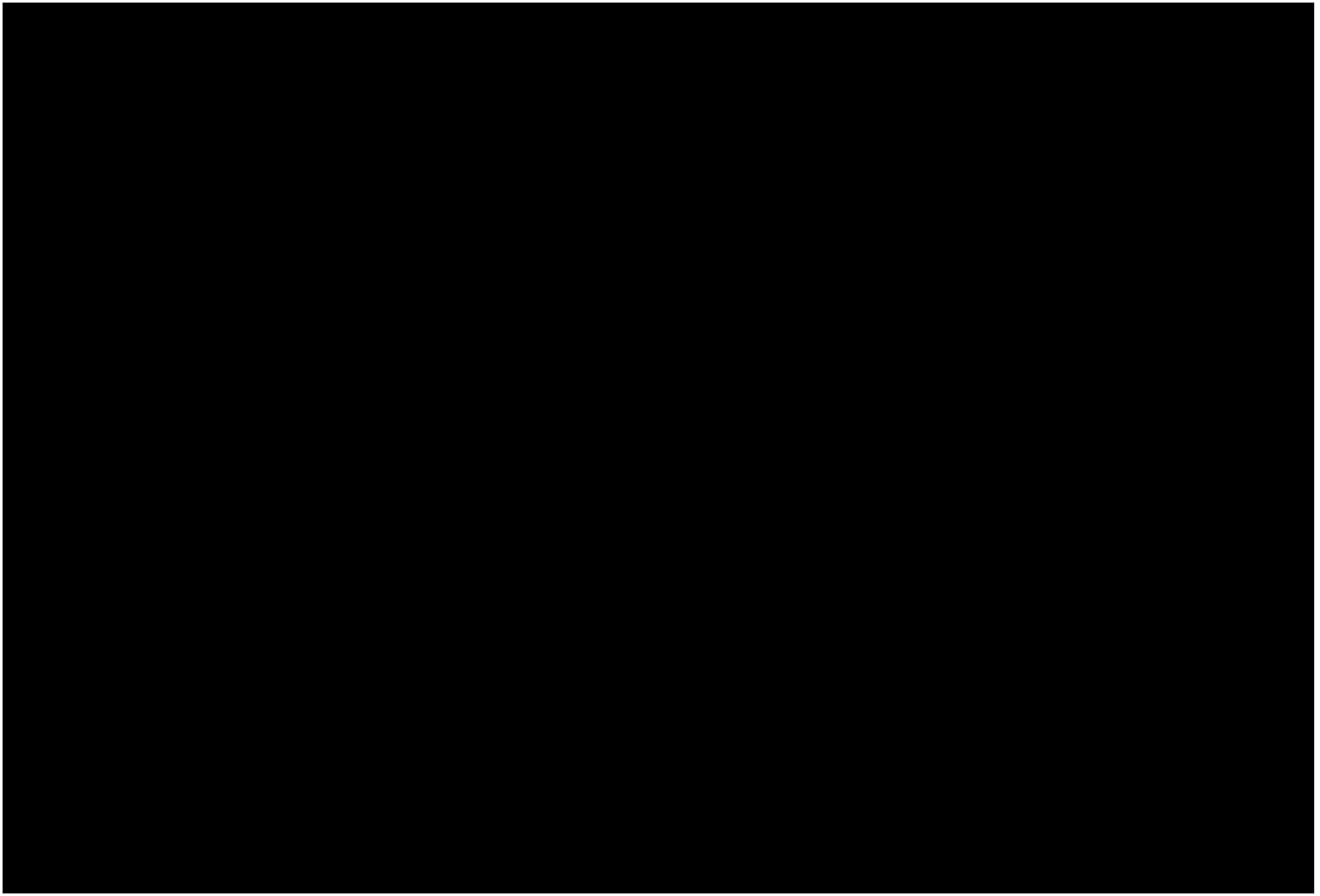
Date of On Peak Day - 10/02/2021



Member Forecasted On Peak Demand Day for November 2021

Columbus Electric Cooperative, Inc.

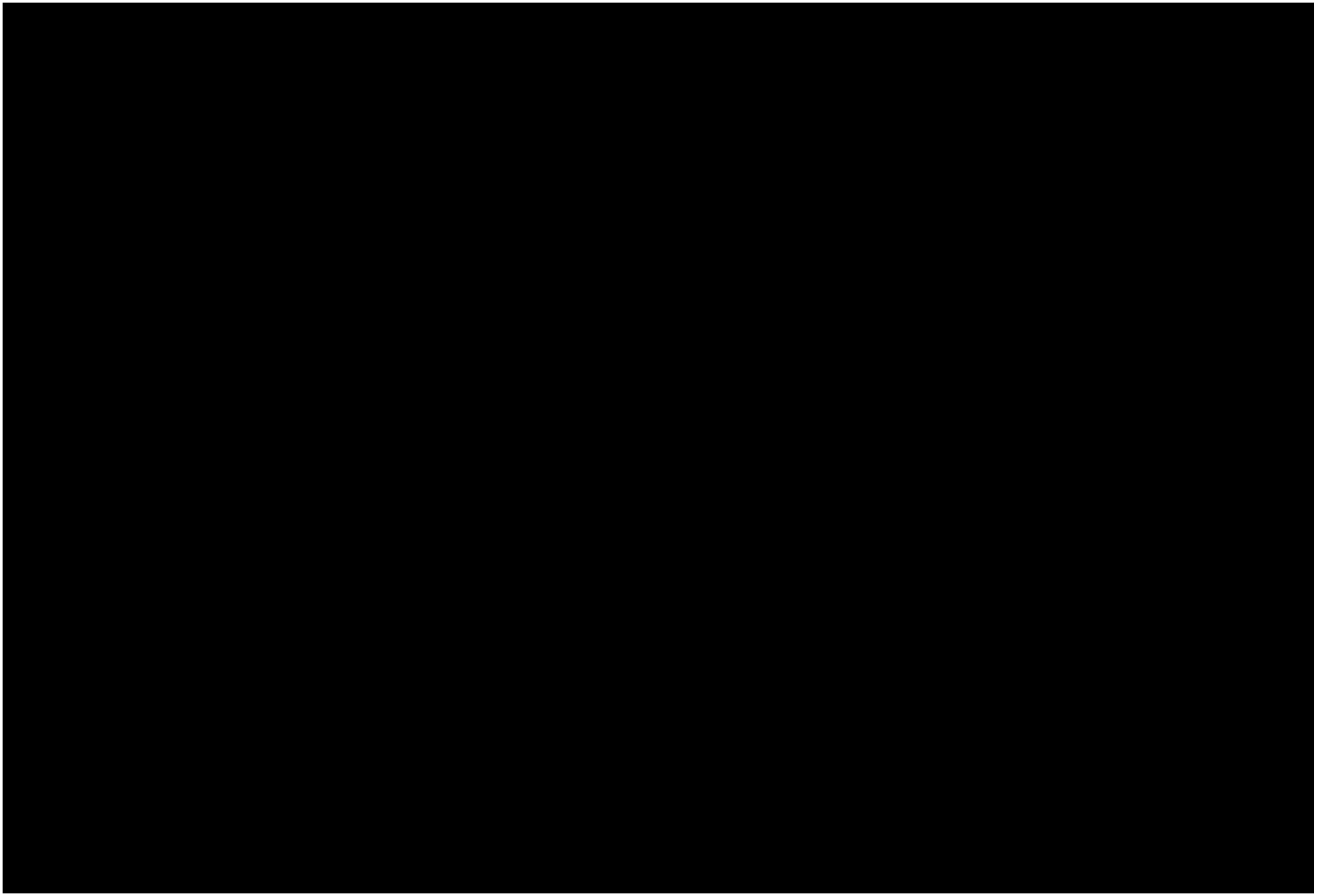
Date of On Peak Day - 11/26/2021



Member Forecasted On Peak Demand Day for December 2021

Columbus Electric Cooperative, Inc.

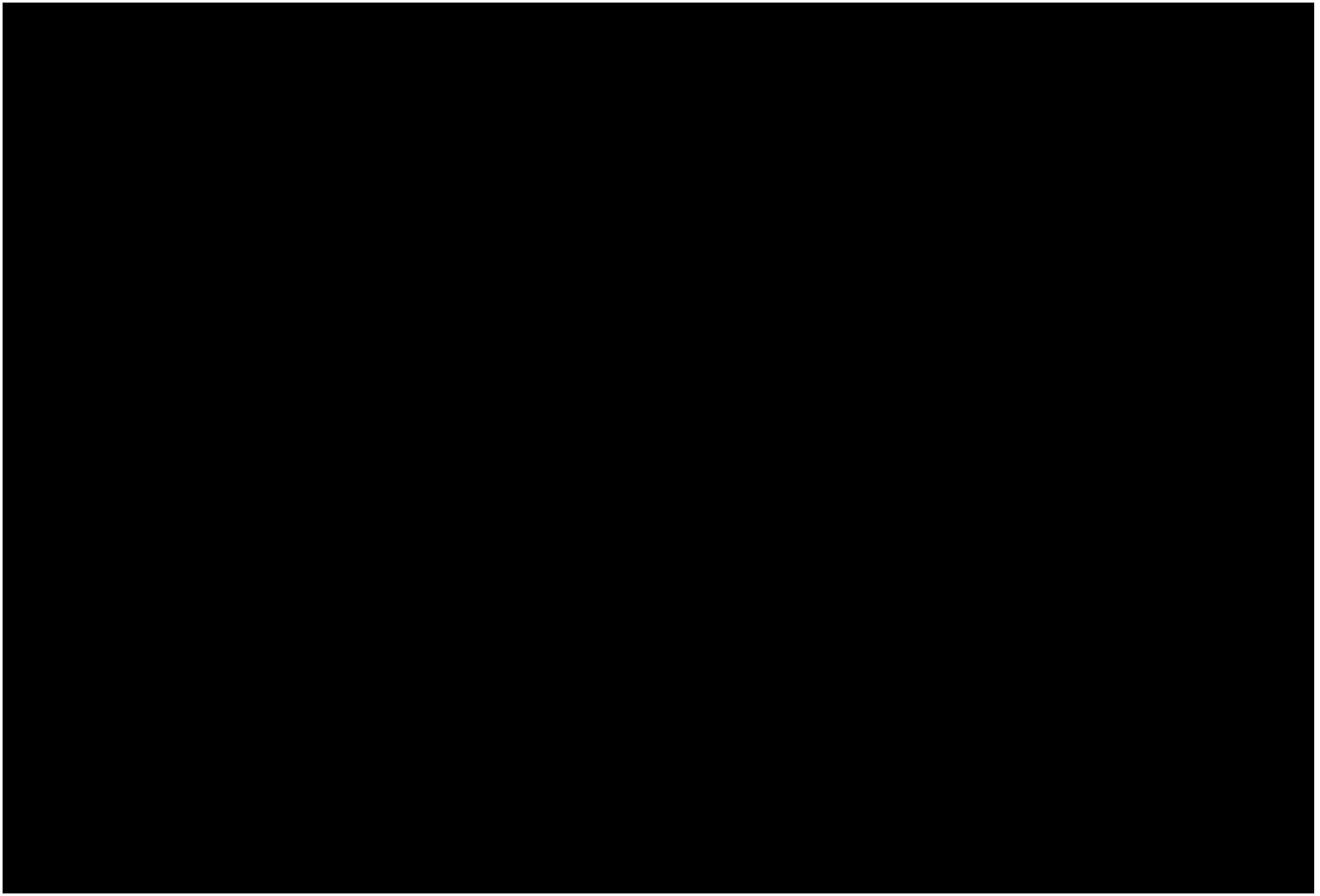
Date of On Peak Day - 12/18/2021



Member Forecasted On Peak Demand Day for January 2021

Central New Mexico Electric Cooperative, Inc.

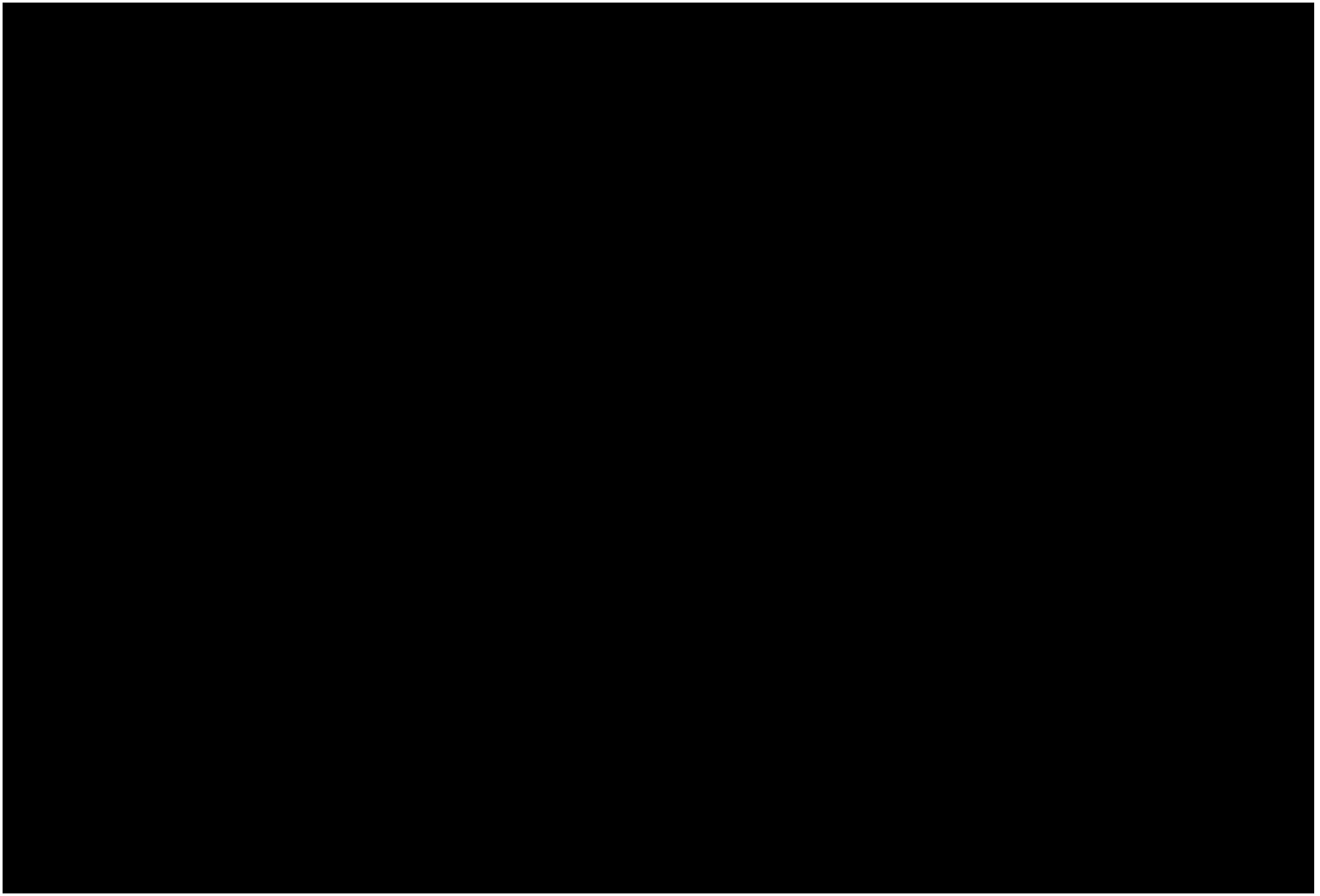
Date of On Peak Day - 01/06/2021



Member Forecasted On Peak Demand Day for February 2021

Central New Mexico Electric Cooperative, Inc.

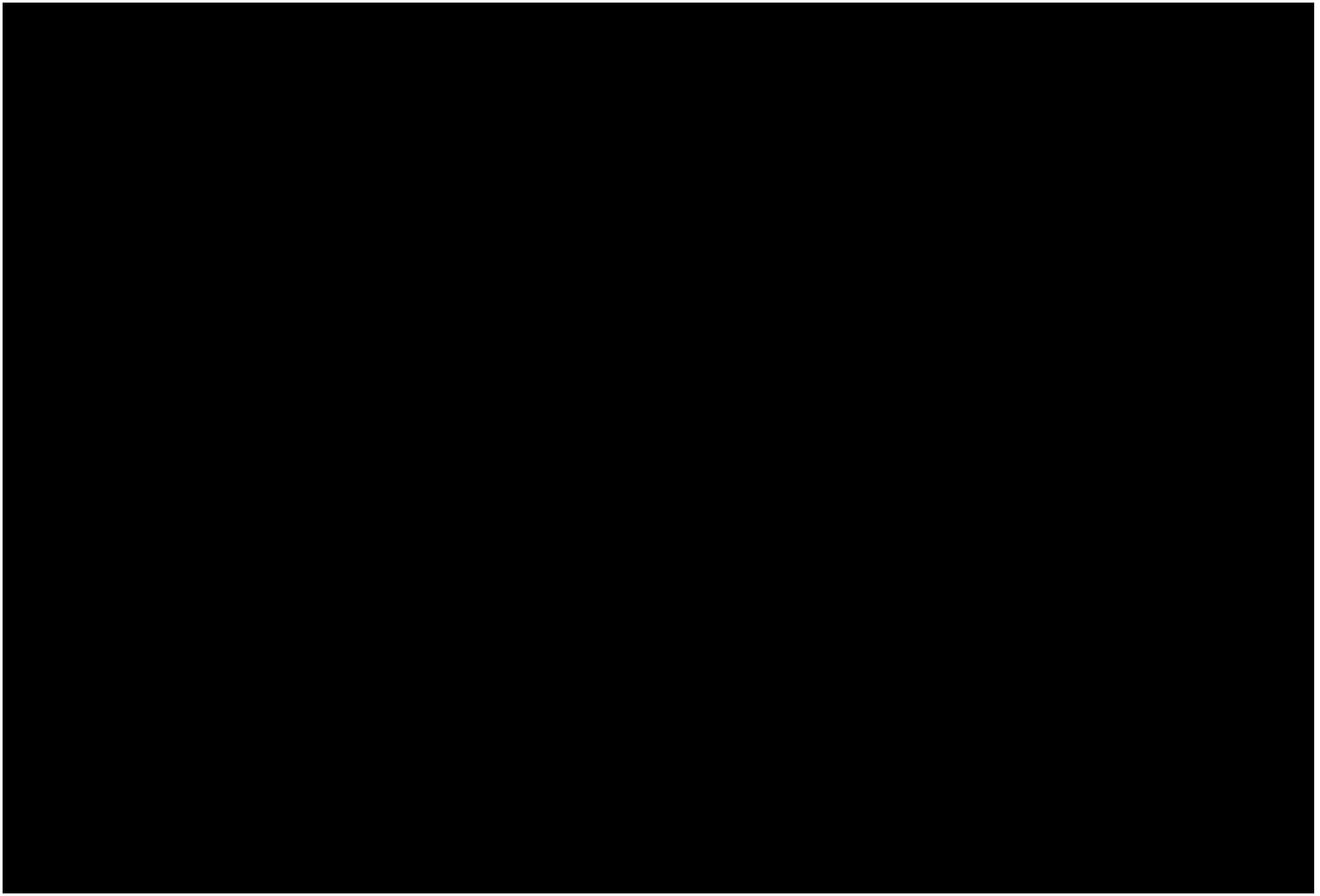
Date of On Peak Day - 02/14/2021



Member Forecasted On Peak Demand Day for March 2021

Central New Mexico Electric Cooperative, Inc.

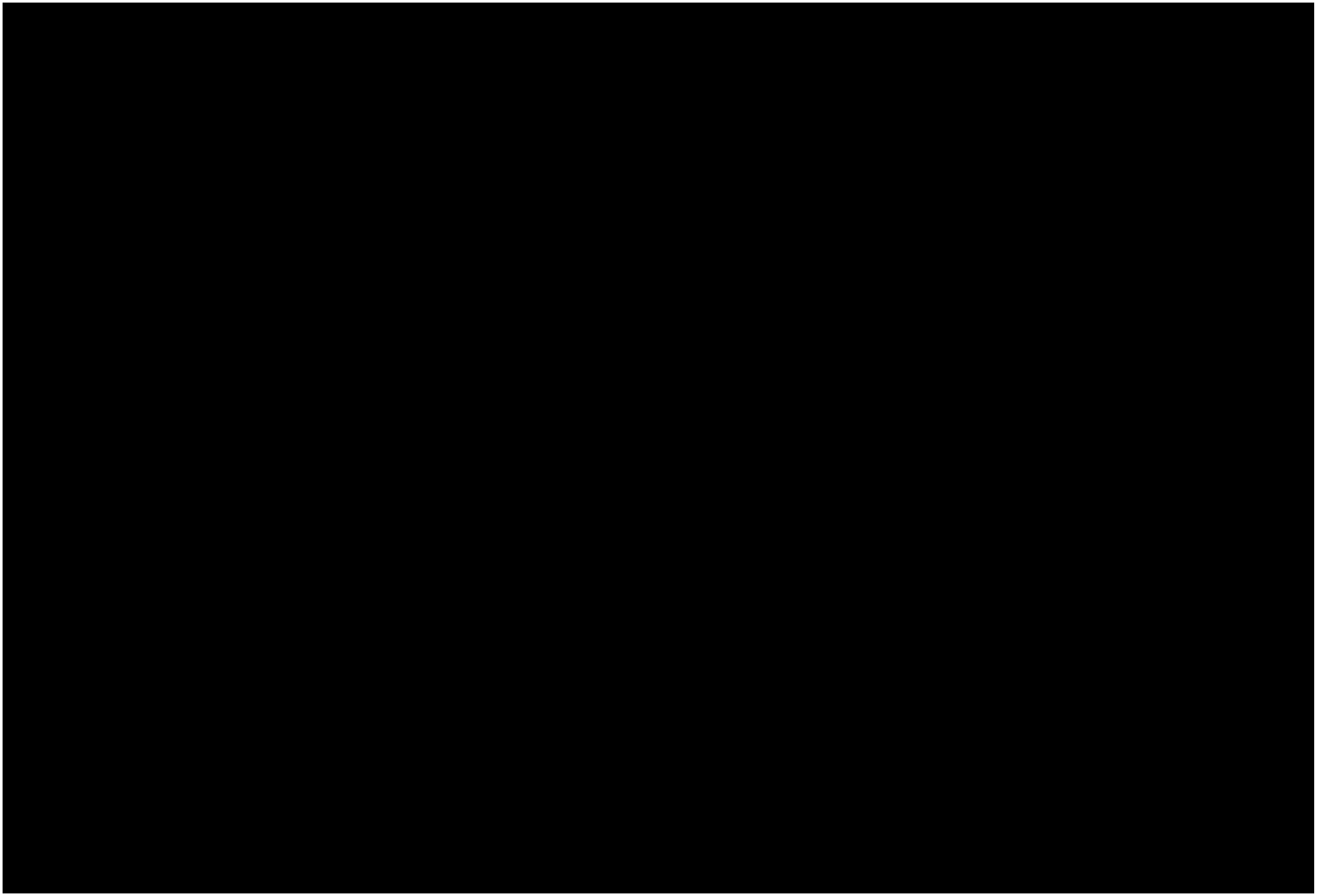
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Central New Mexico Electric Cooperative, Inc.

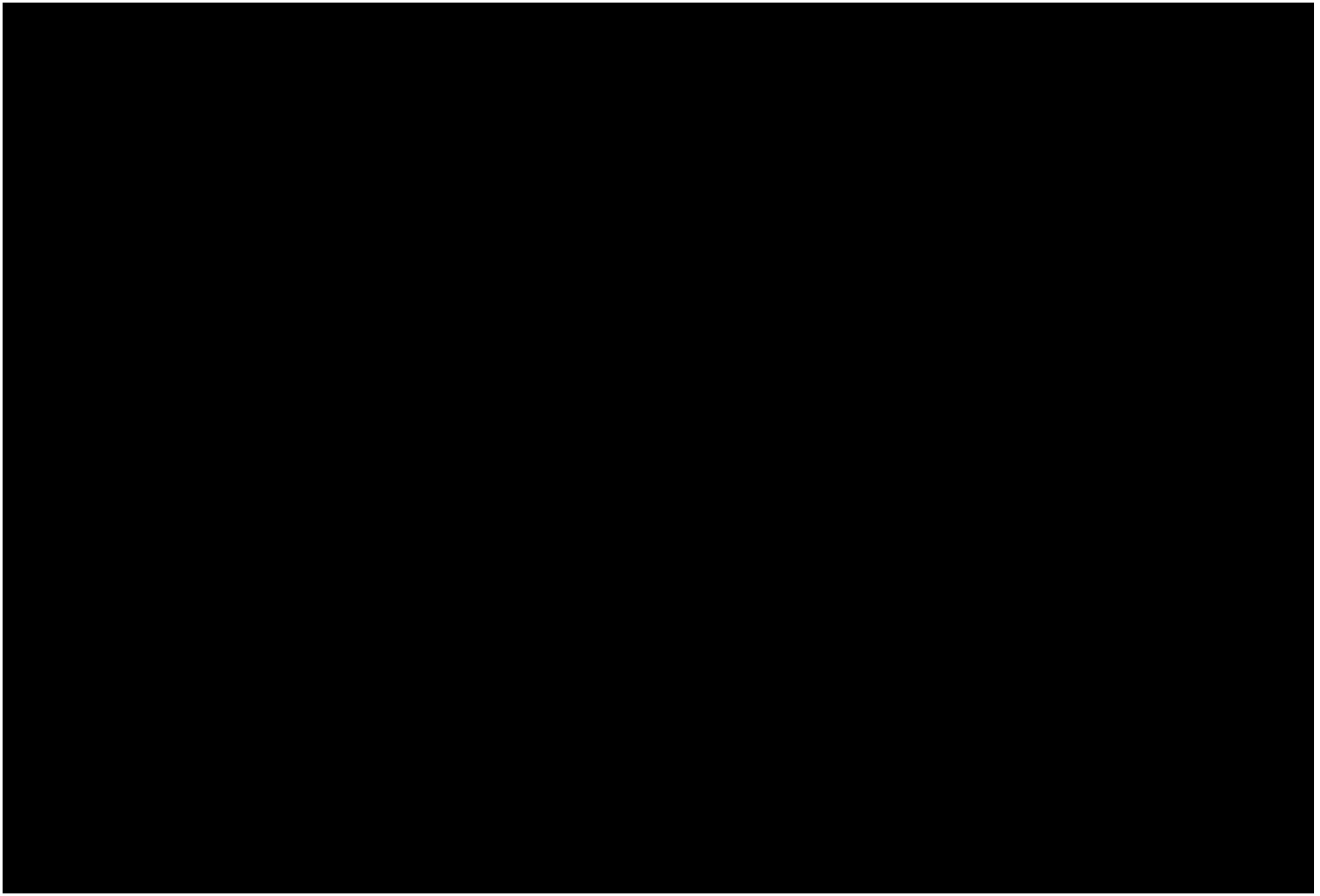
Date of On Peak Day - 04/07/2021



Member Forecasted On Peak Demand Day for May 2021

Central New Mexico Electric Cooperative, Inc.

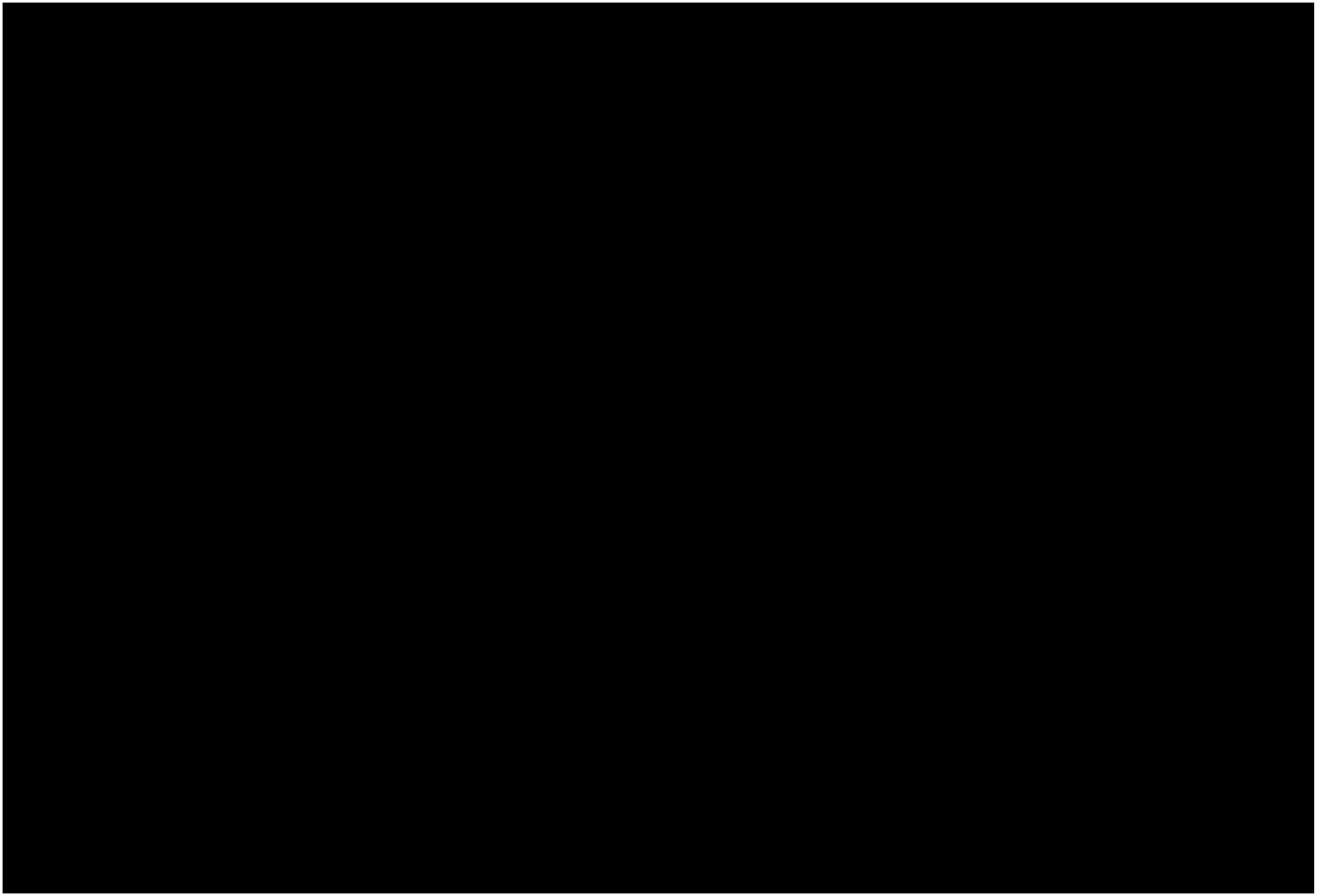
Date of On Peak Day - 05/30/2021



Member Forecasted On Peak Demand Day for June 2021

Central New Mexico Electric Cooperative, Inc.

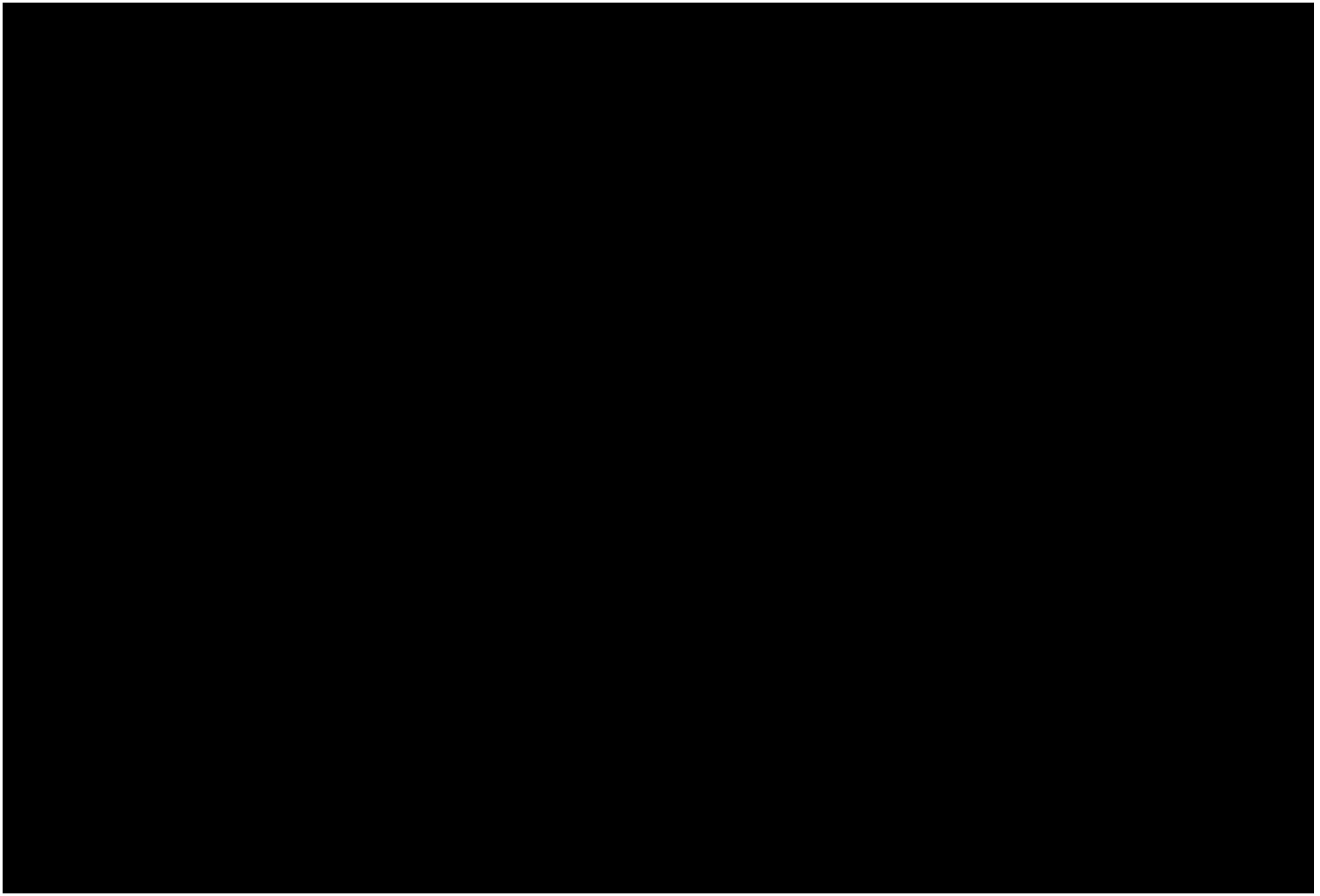
Date of On Peak Day - 06/24/2021



Member Forecasted On Peak Demand Day for July 2021

Central New Mexico Electric Cooperative, Inc.

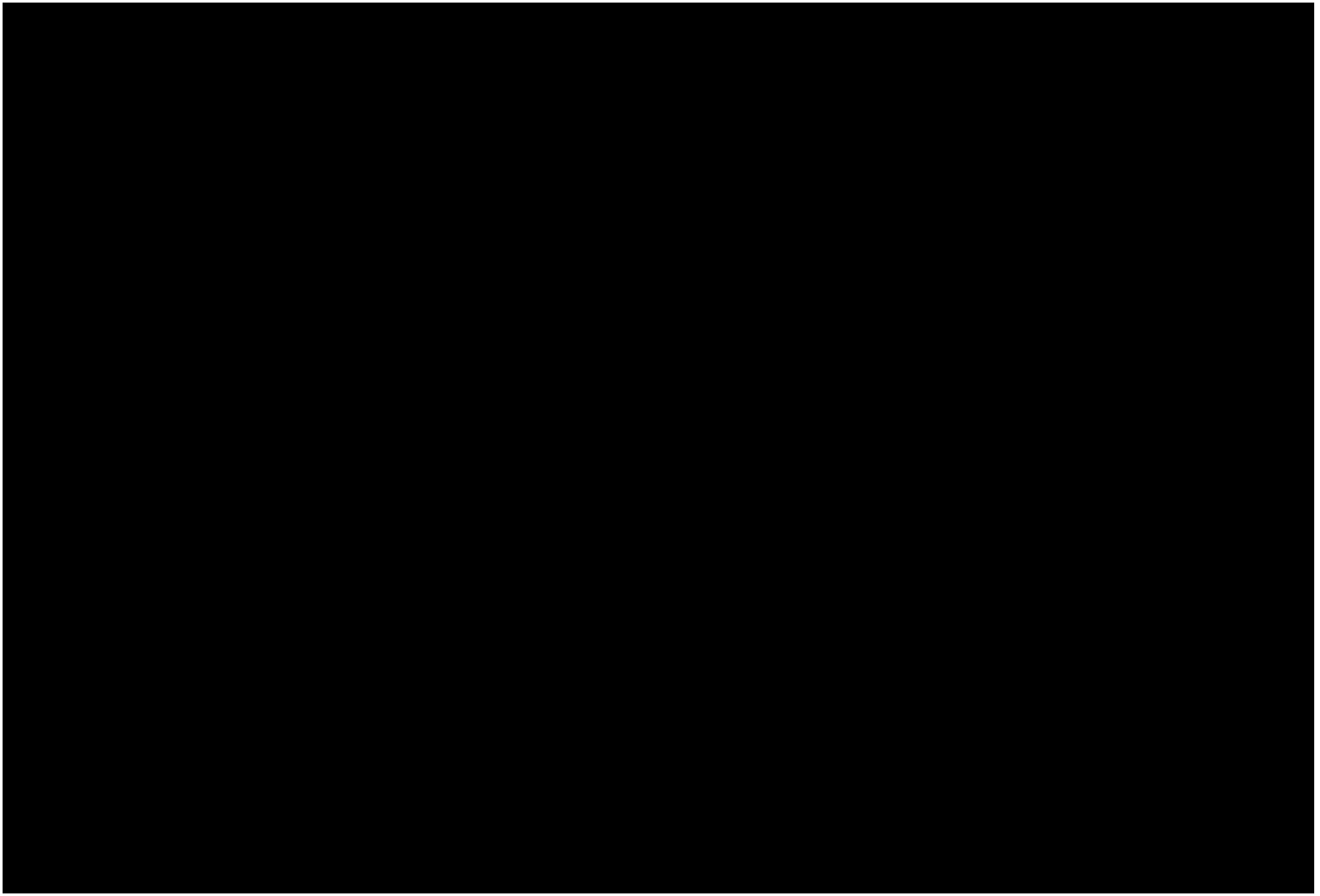
Date of On Peak Day - 07/10/2021



Member Forecasted On Peak Demand Day for August 2021

Central New Mexico Electric Cooperative, Inc.

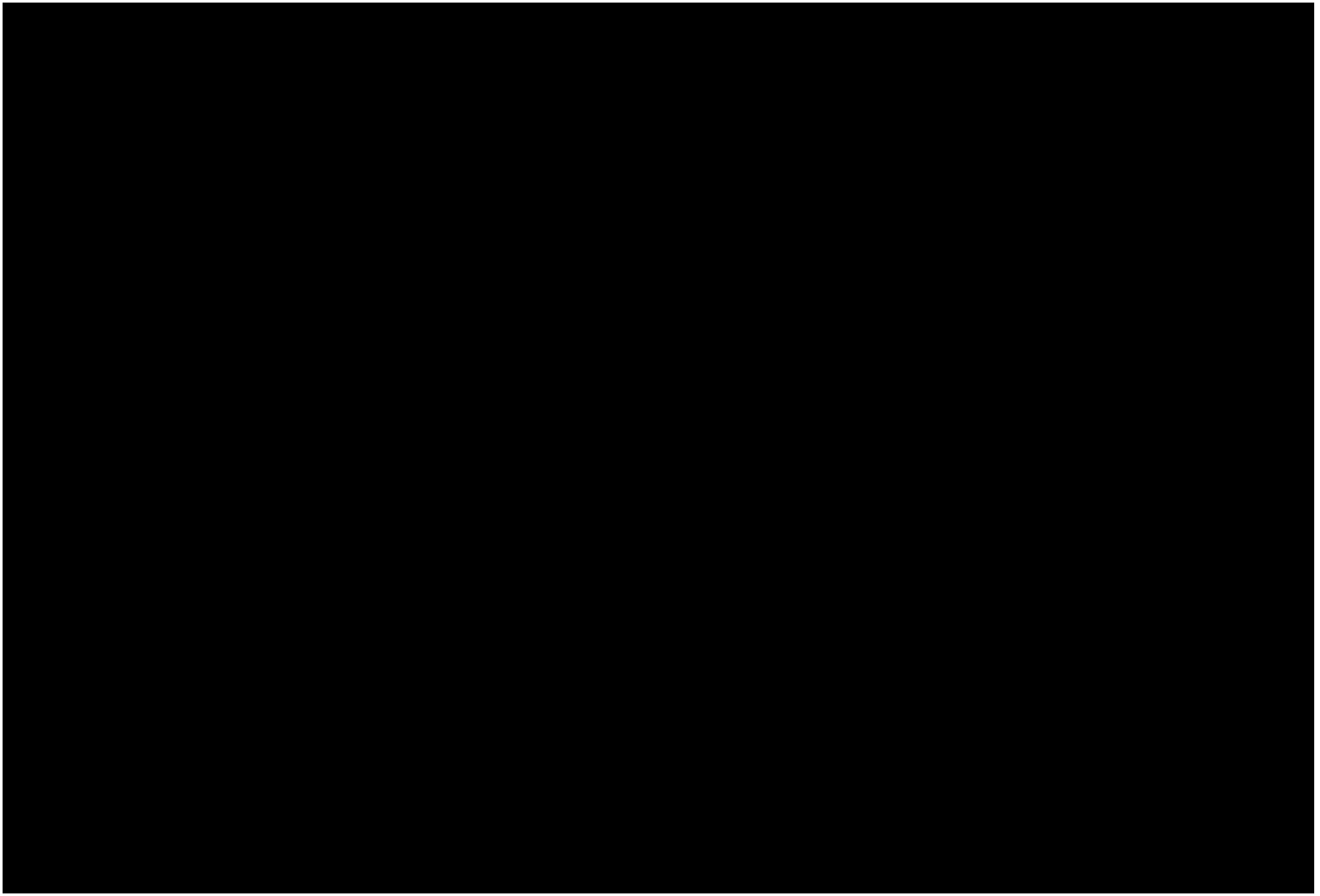
Date of On Peak Day - 08/18/2021



Member Forecasted On Peak Demand Day for September 2021

Central New Mexico Electric Cooperative, Inc.

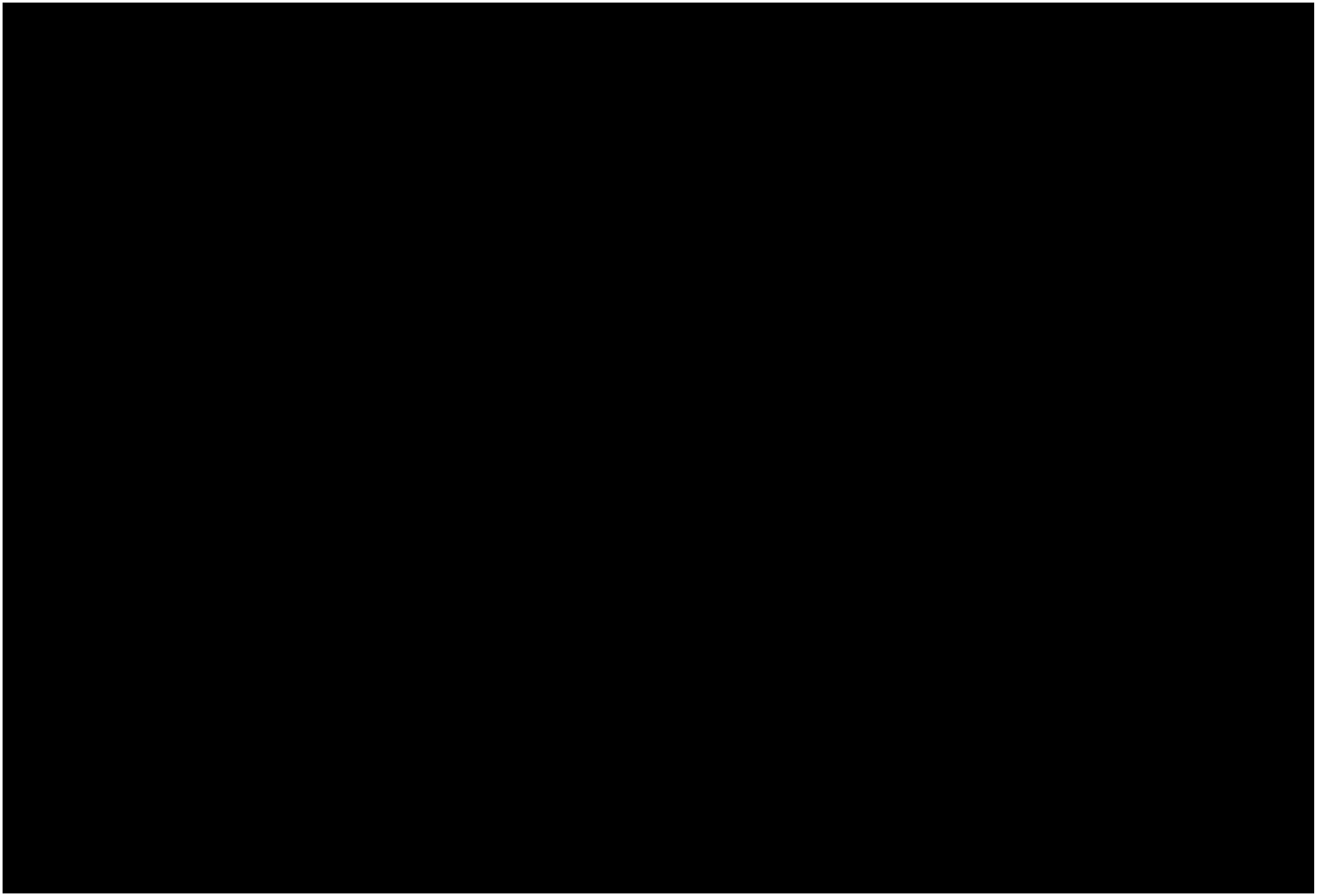
Date of On Peak Day - 09/02/2021



Member Forecasted On Peak Demand Day for October 2021

Central New Mexico Electric Cooperative, Inc.

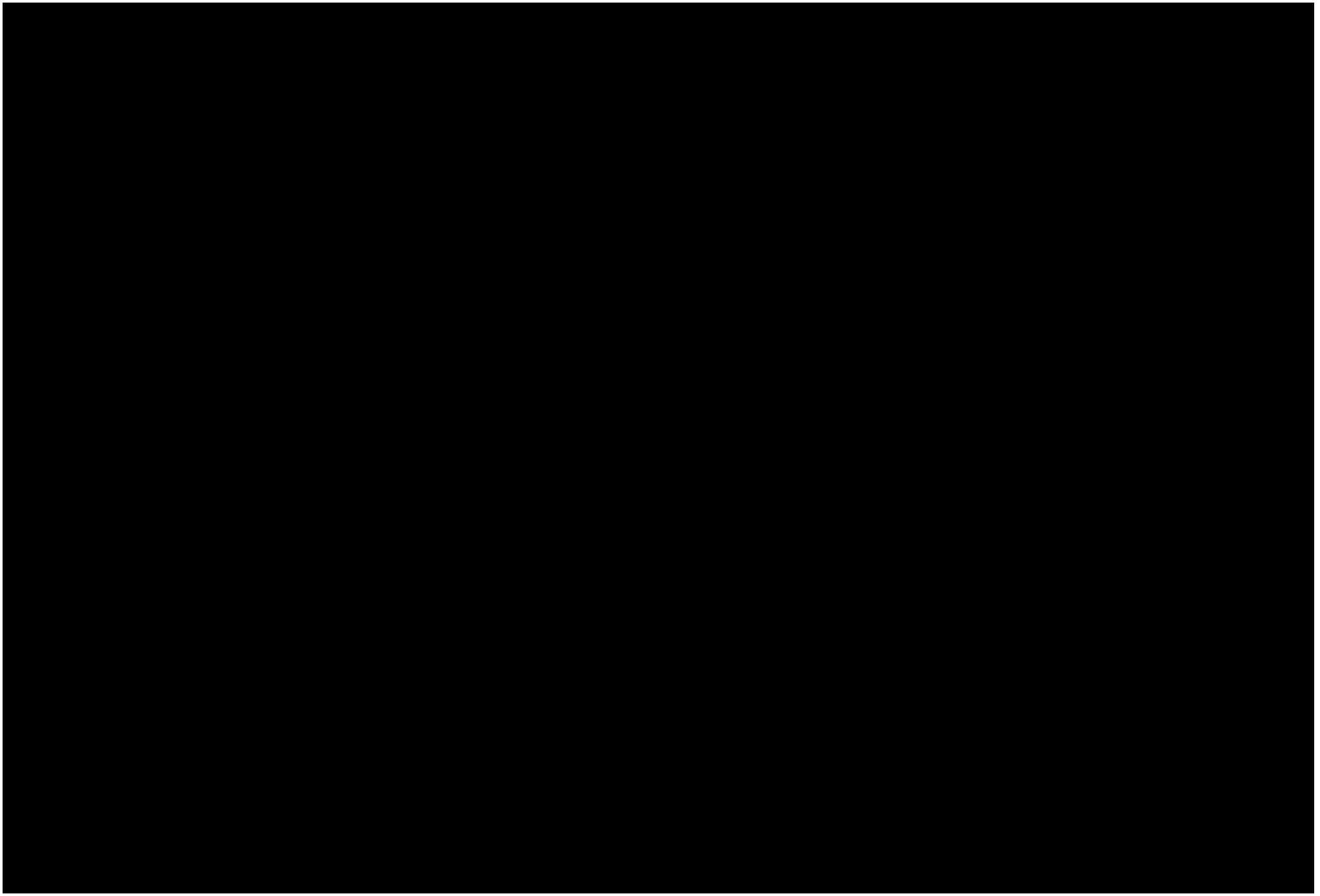
Date of On Peak Day - 10/01/2021



Member Forecasted On Peak Demand Day for November 2021

Central New Mexico Electric Cooperative, Inc.

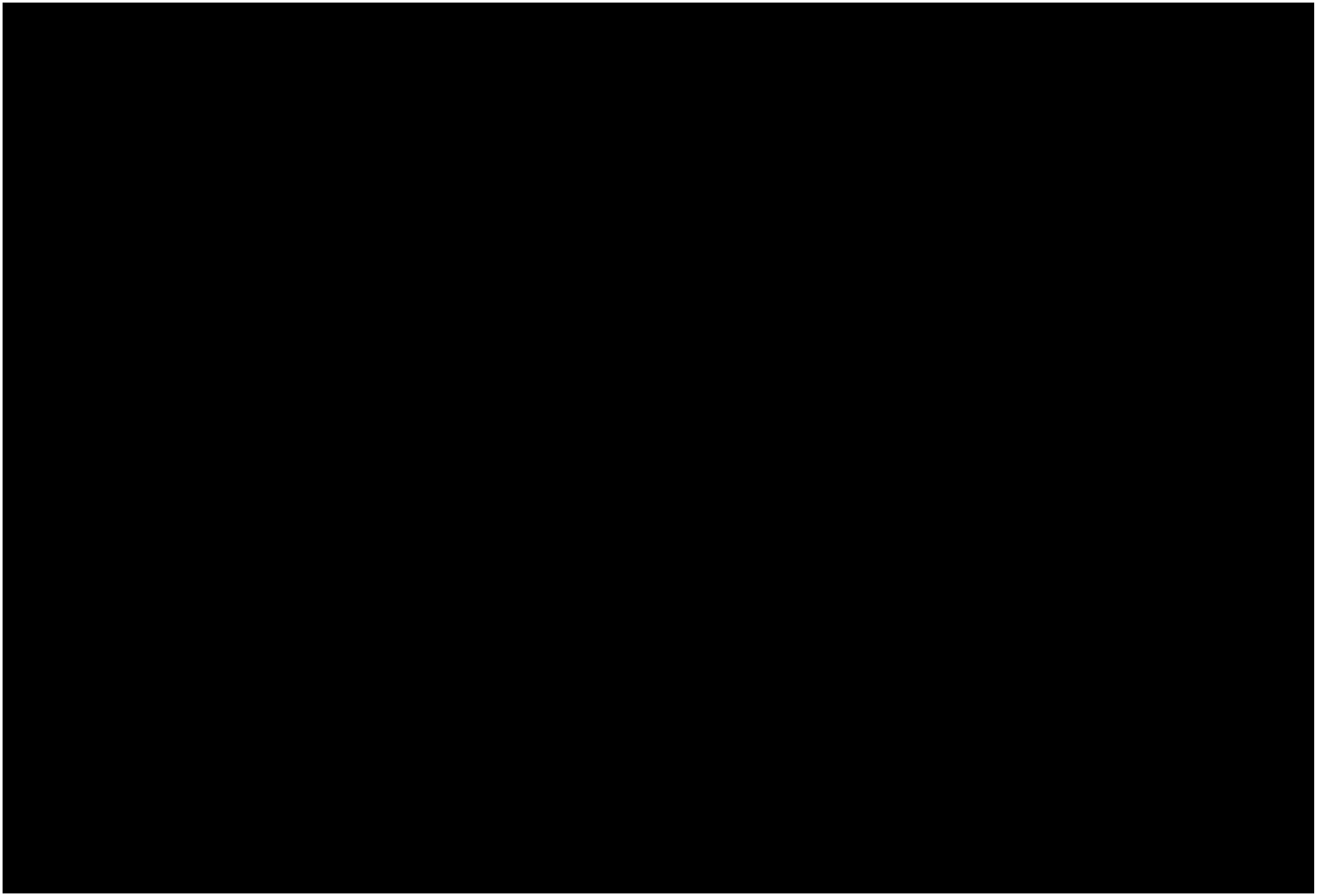
Date of On Peak Day - 11/14/2021



Member Forecasted On Peak Demand Day for December 2021

Central New Mexico Electric Cooperative, Inc.

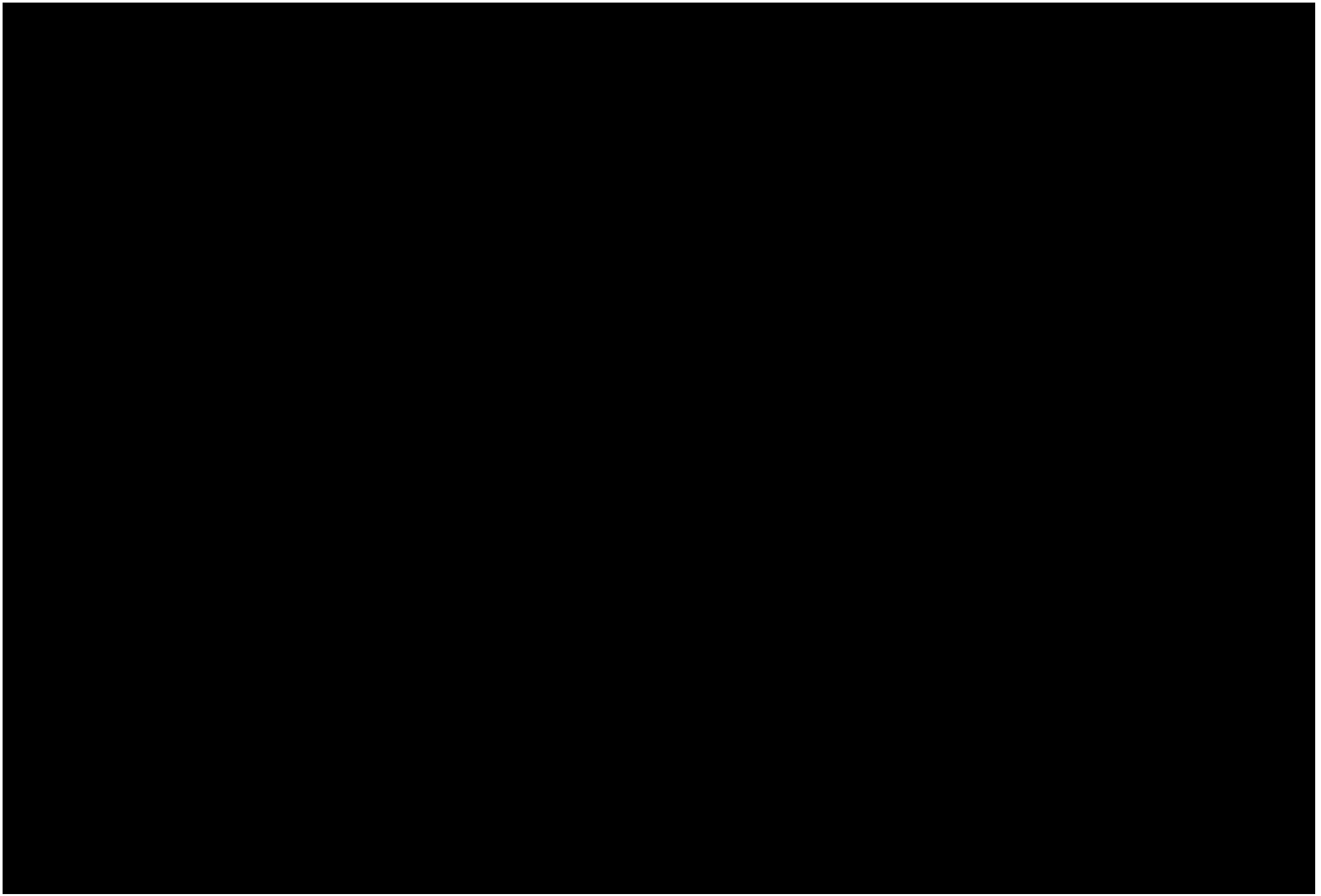
Date of On Peak Day - 12/26/2021



Member Forecasted On Peak Demand Day for January 2021

Chimney Rock Public Power District

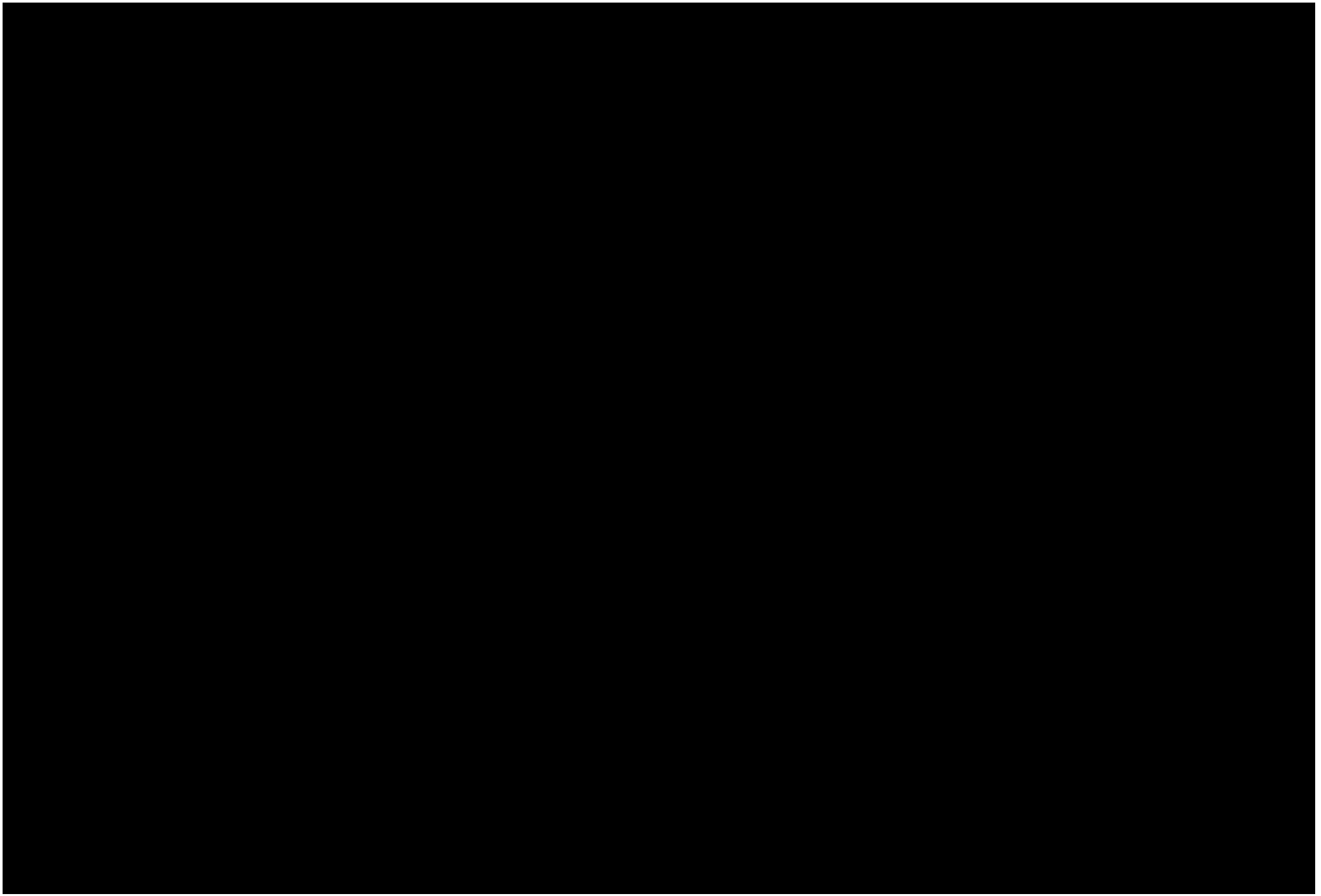
Date of On Peak Day - 01/07/2021



Member Forecasted On Peak Demand Day for February 2021

Chimney Rock Public Power District

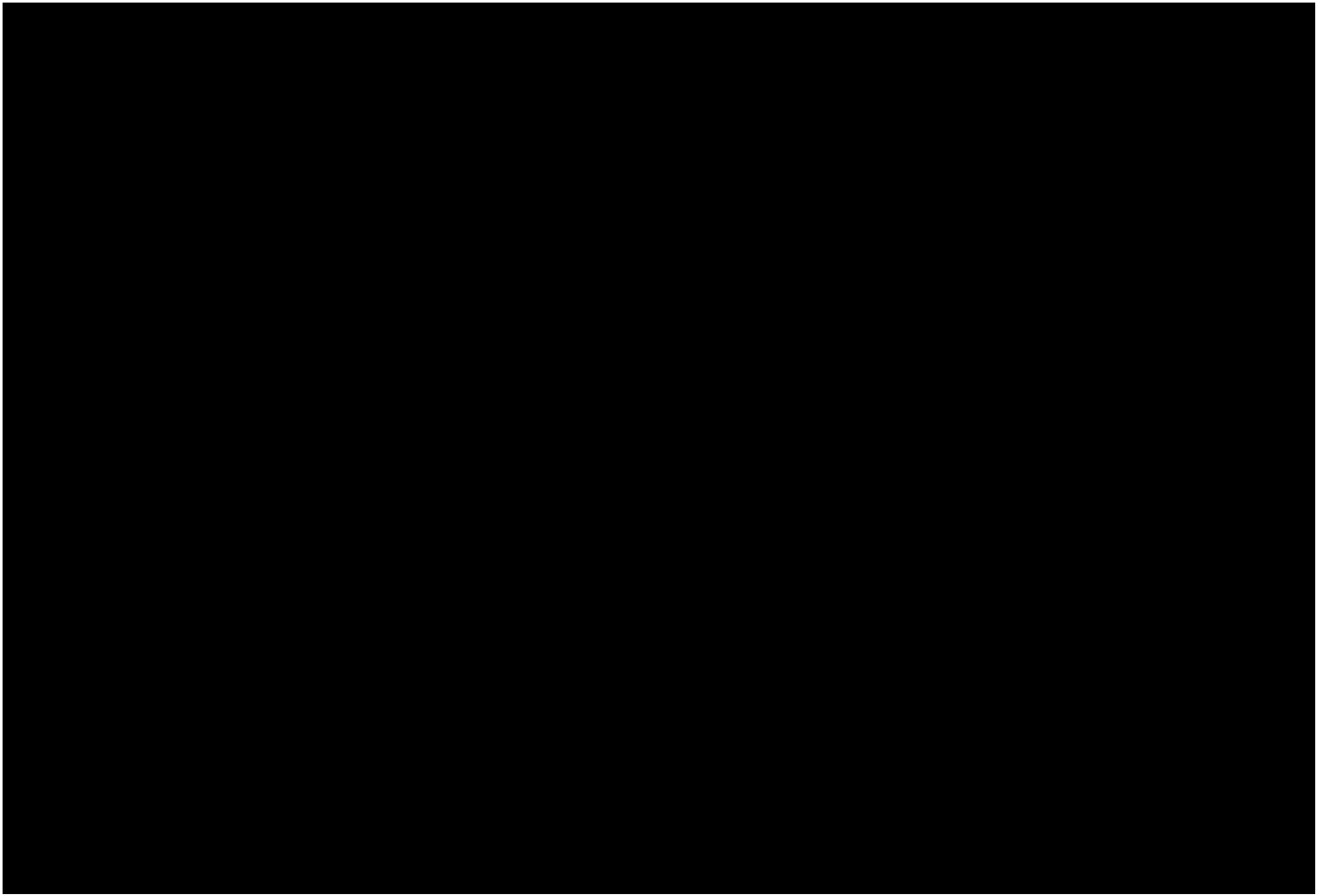
Date of On Peak Day - 02/03/2021



Member Forecasted On Peak Demand Day for March 2021

Chimney Rock Public Power District

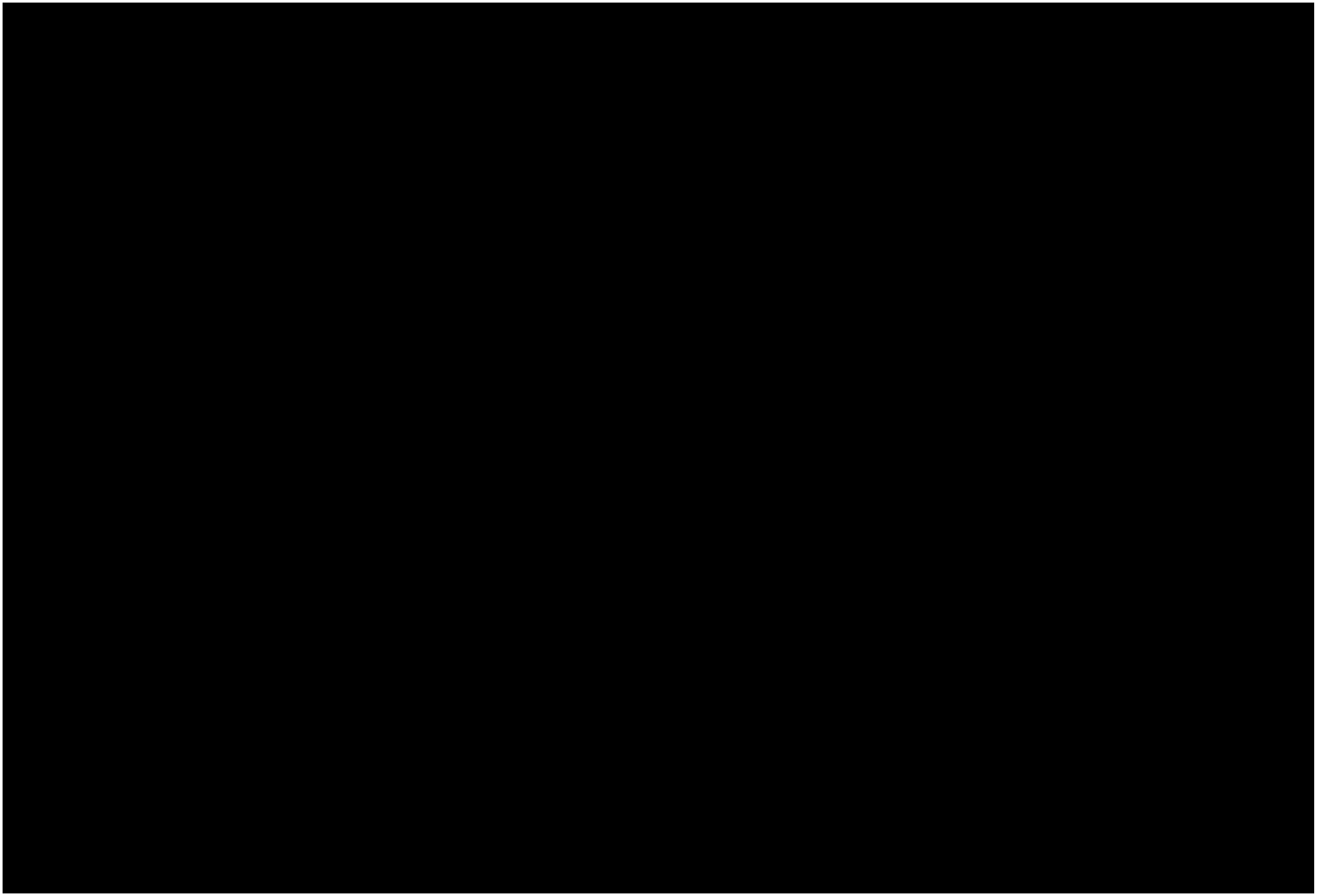
Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

Chimney Rock Public Power District

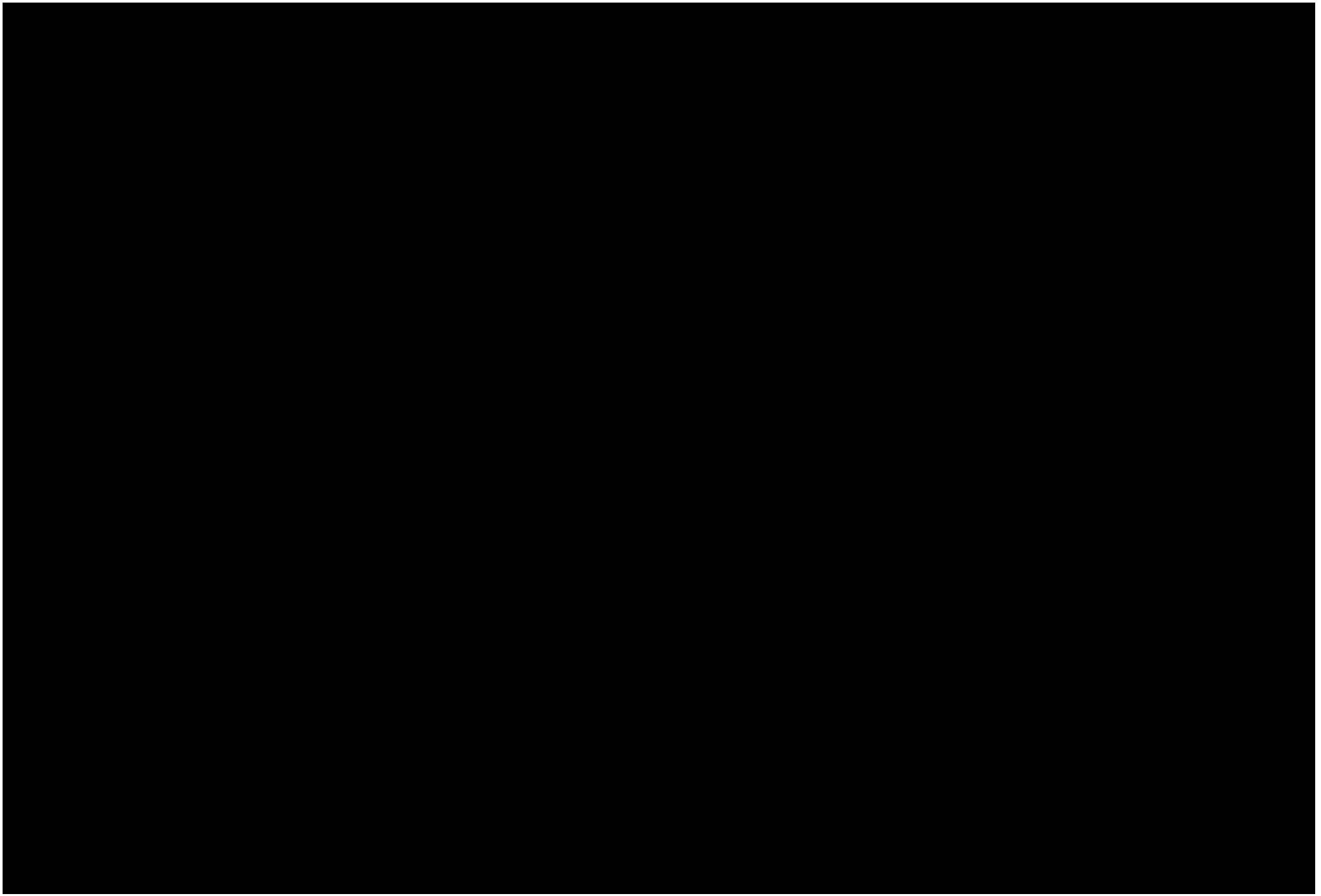
Date of On Peak Day - 04/05/2021



Member Forecasted On Peak Demand Day for May 2021

Chimney Rock Public Power District

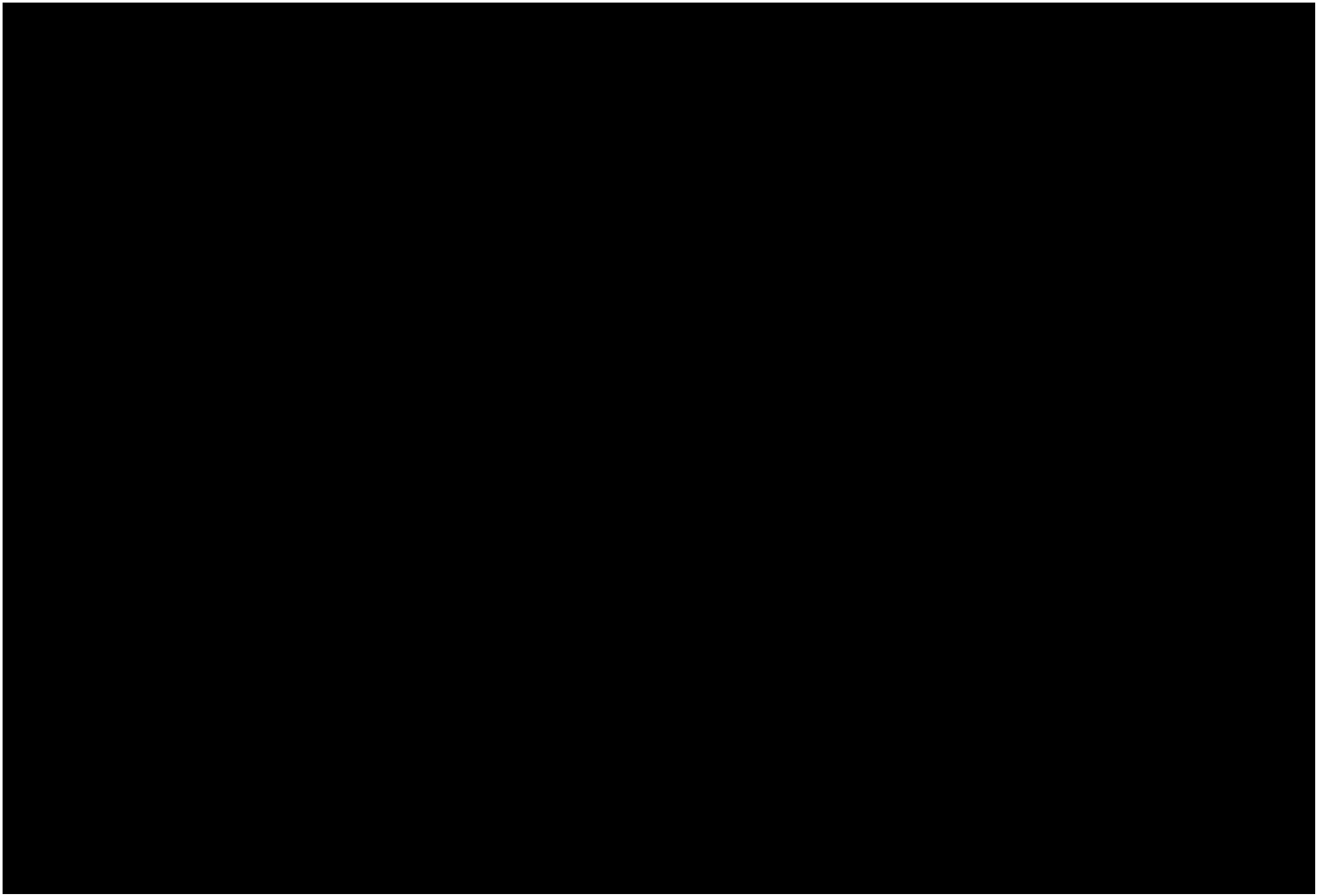
Date of On Peak Day - 05/16/2021



Member Forecasted On Peak Demand Day for June 2021

Chimney Rock Public Power District

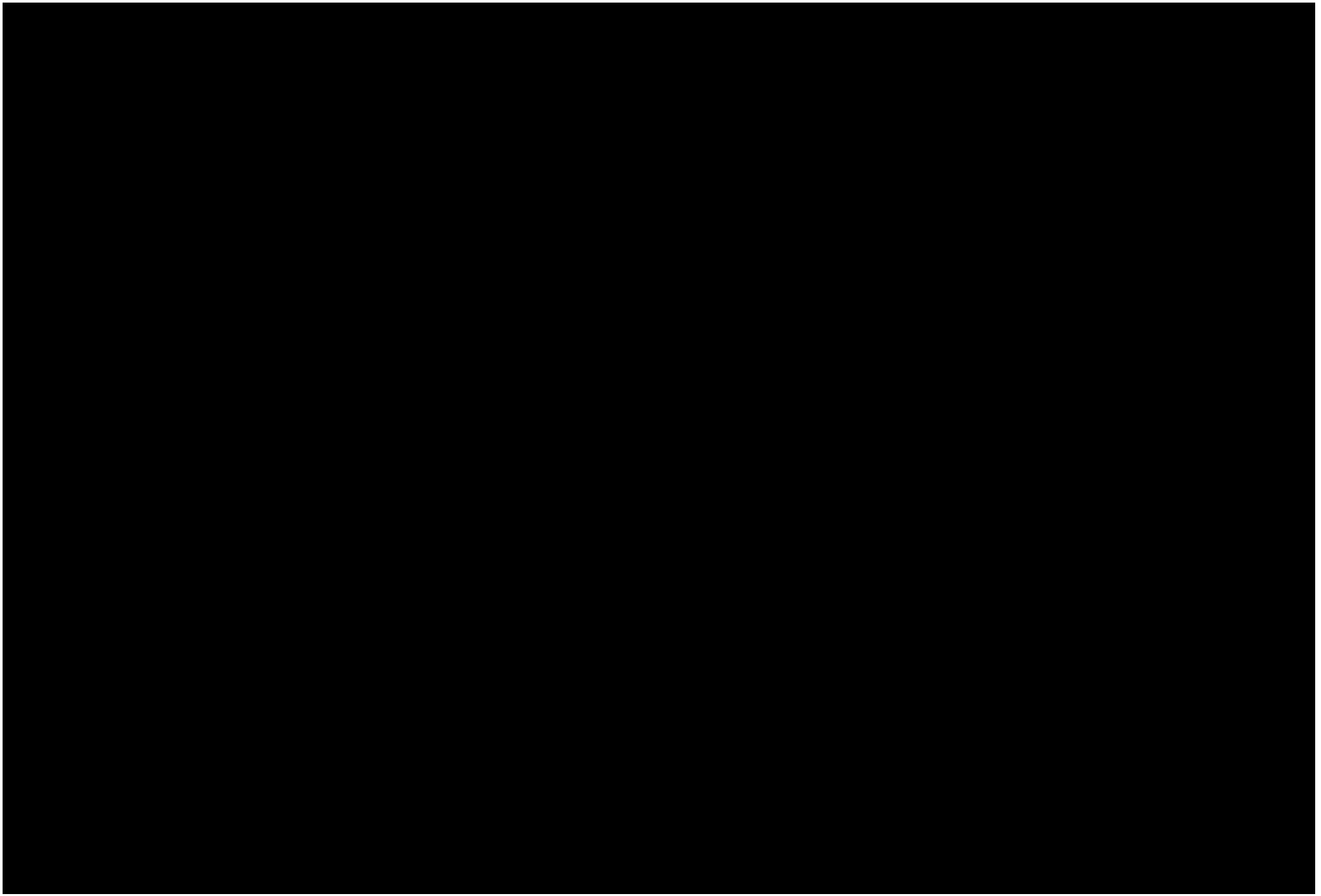
Date of On Peak Day - 06/26/2021



Member Forecasted On Peak Demand Day for July 2021

Chimney Rock Public Power District

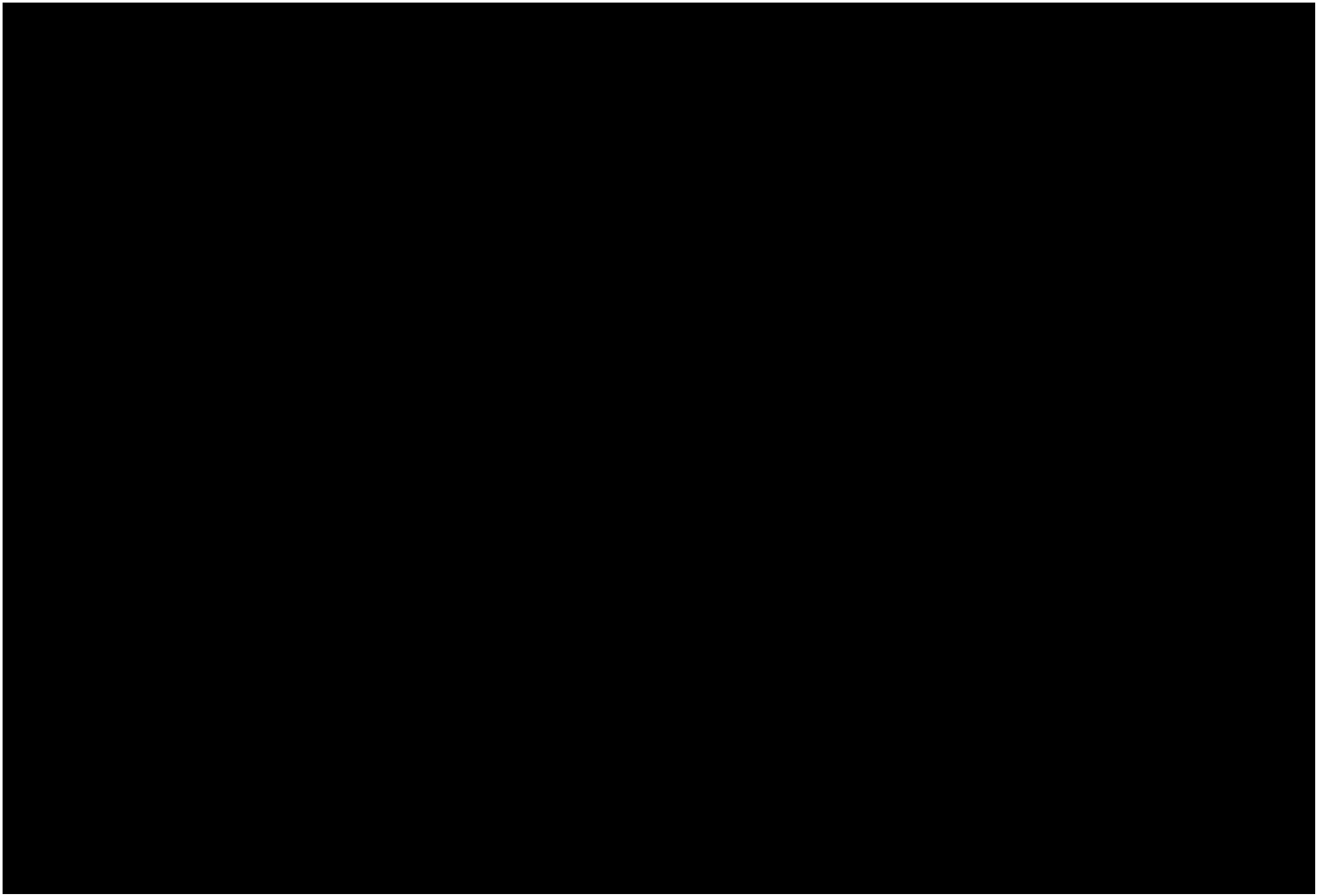
Date of On Peak Day - 07/21/2021



Member Forecasted On Peak Demand Day for August 2021

Chimney Rock Public Power District

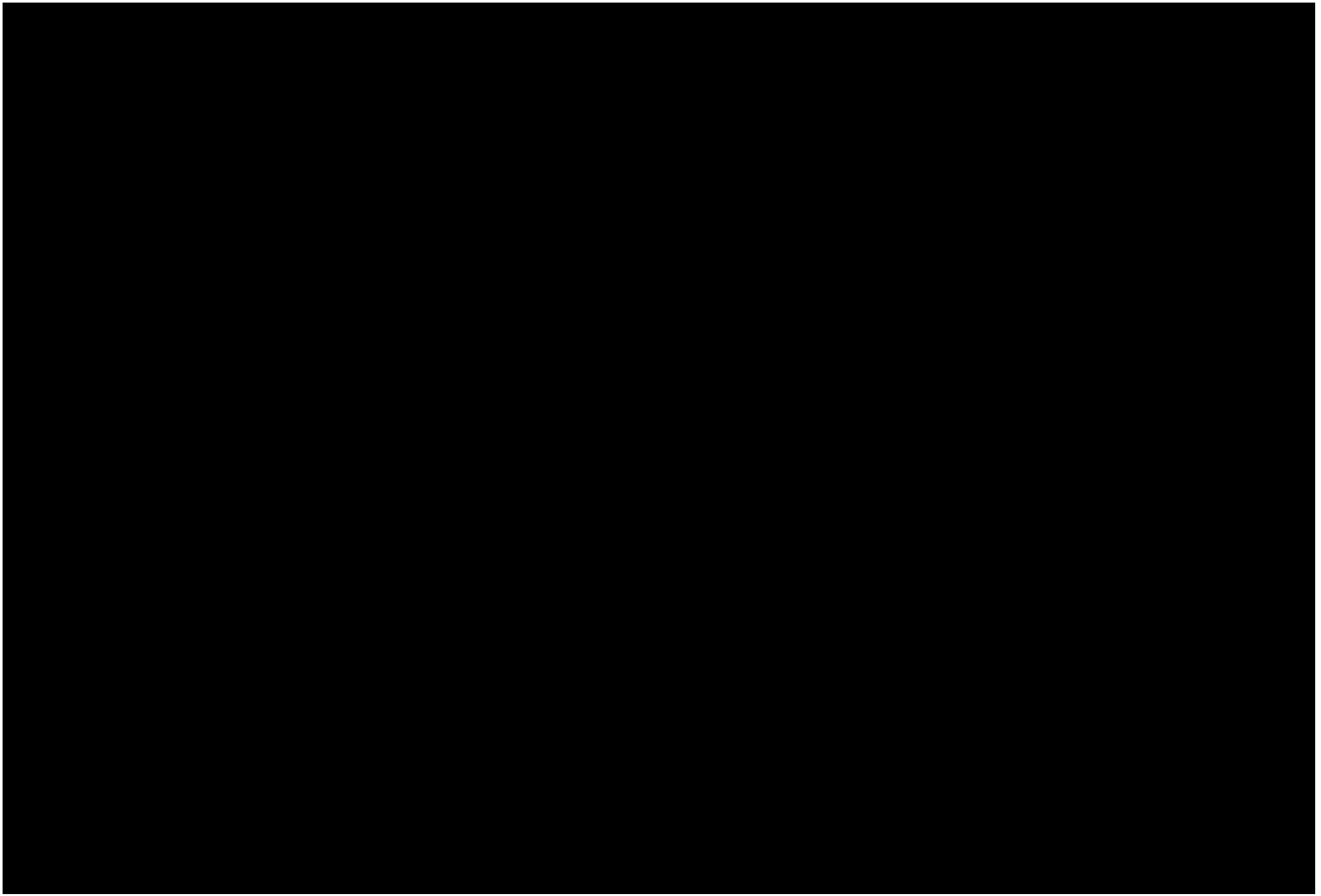
Date of On Peak Day - 08/02/2021



Member Forecasted On Peak Demand Day for September 2021

Chimney Rock Public Power District

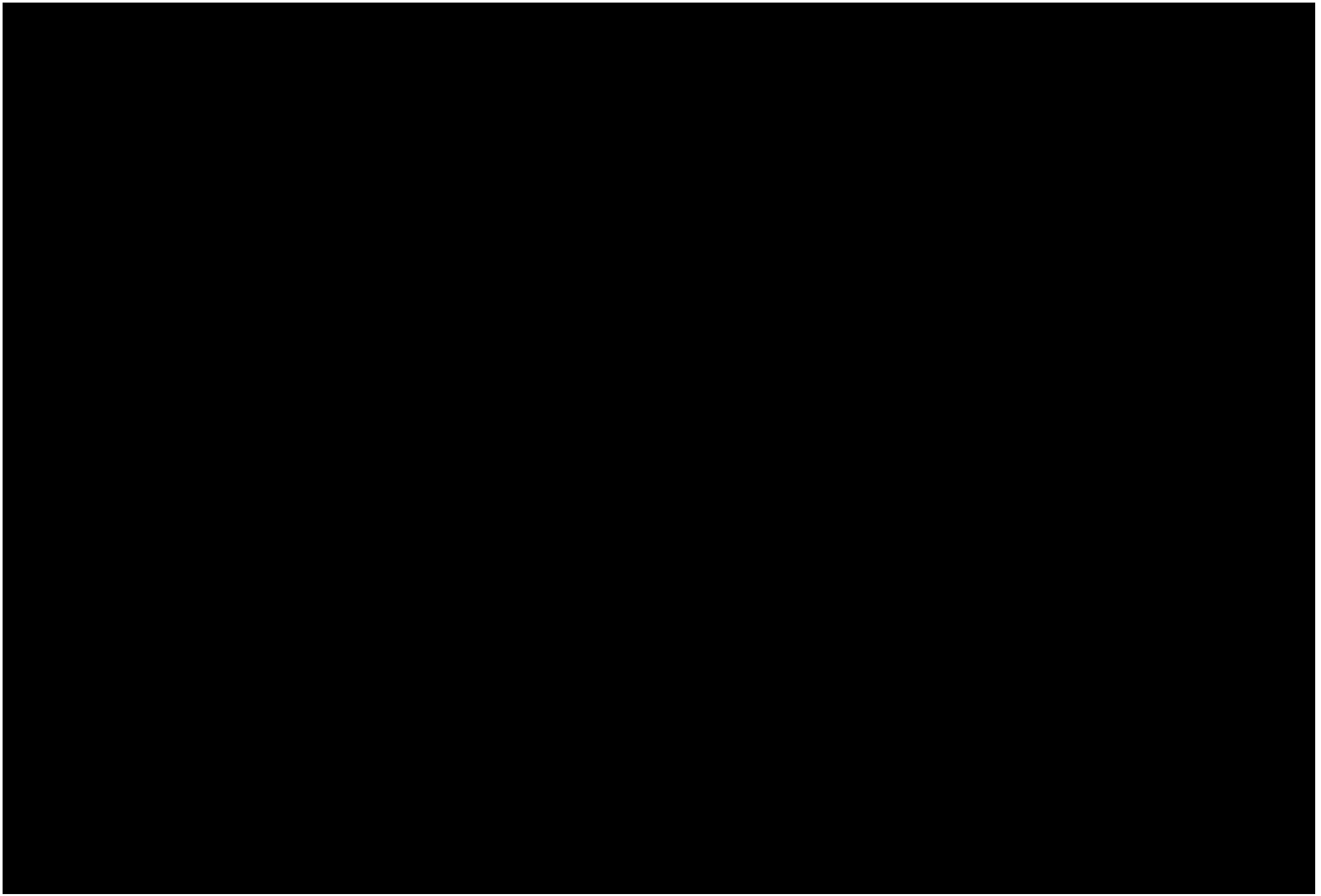
Date of On Peak Day - 09/01/2021



Member Forecasted On Peak Demand Day for October 2021

Chimney Rock Public Power District

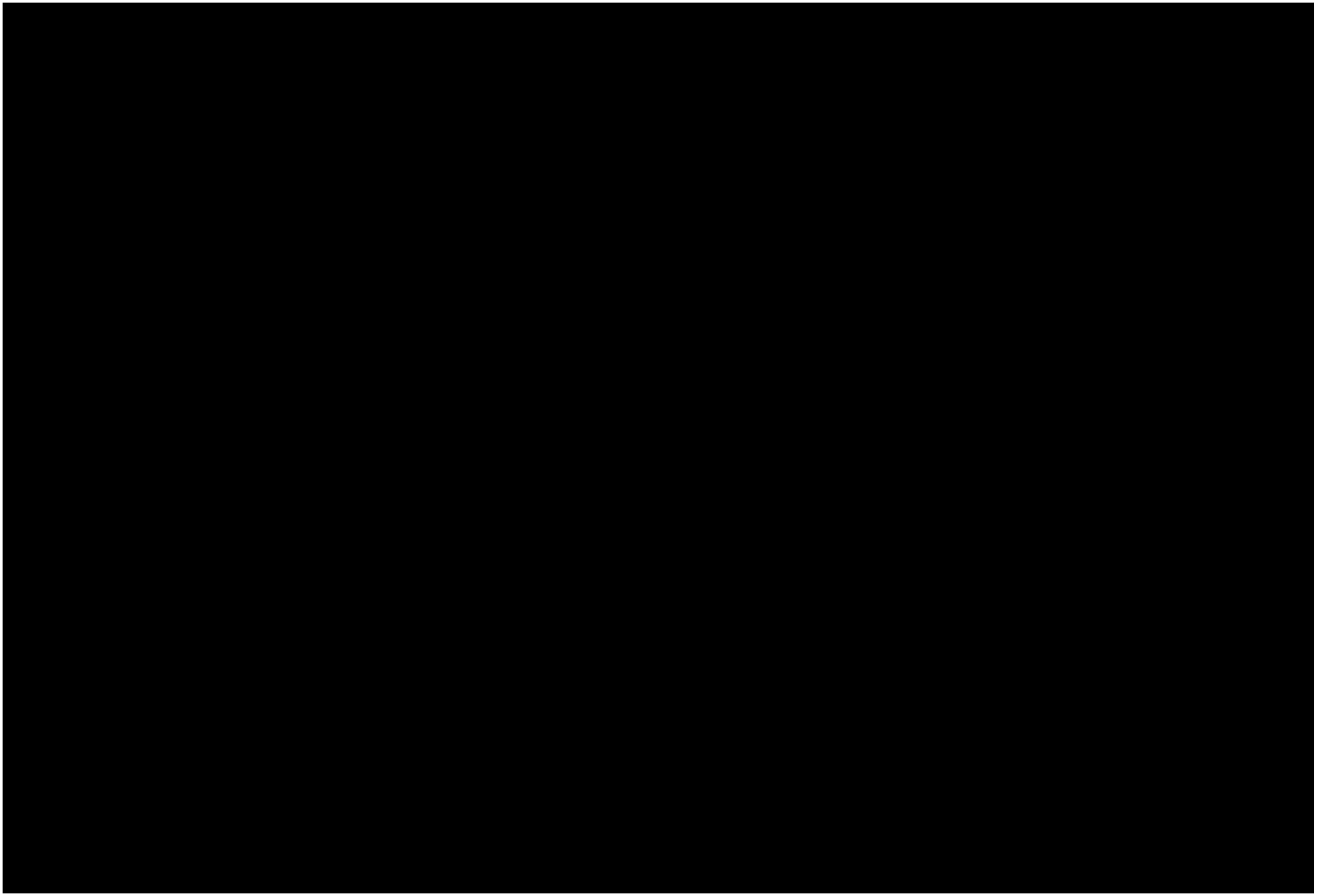
Date of On Peak Day - 10/29/2021



Member Forecasted On Peak Demand Day for November 2021

Chimney Rock Public Power District

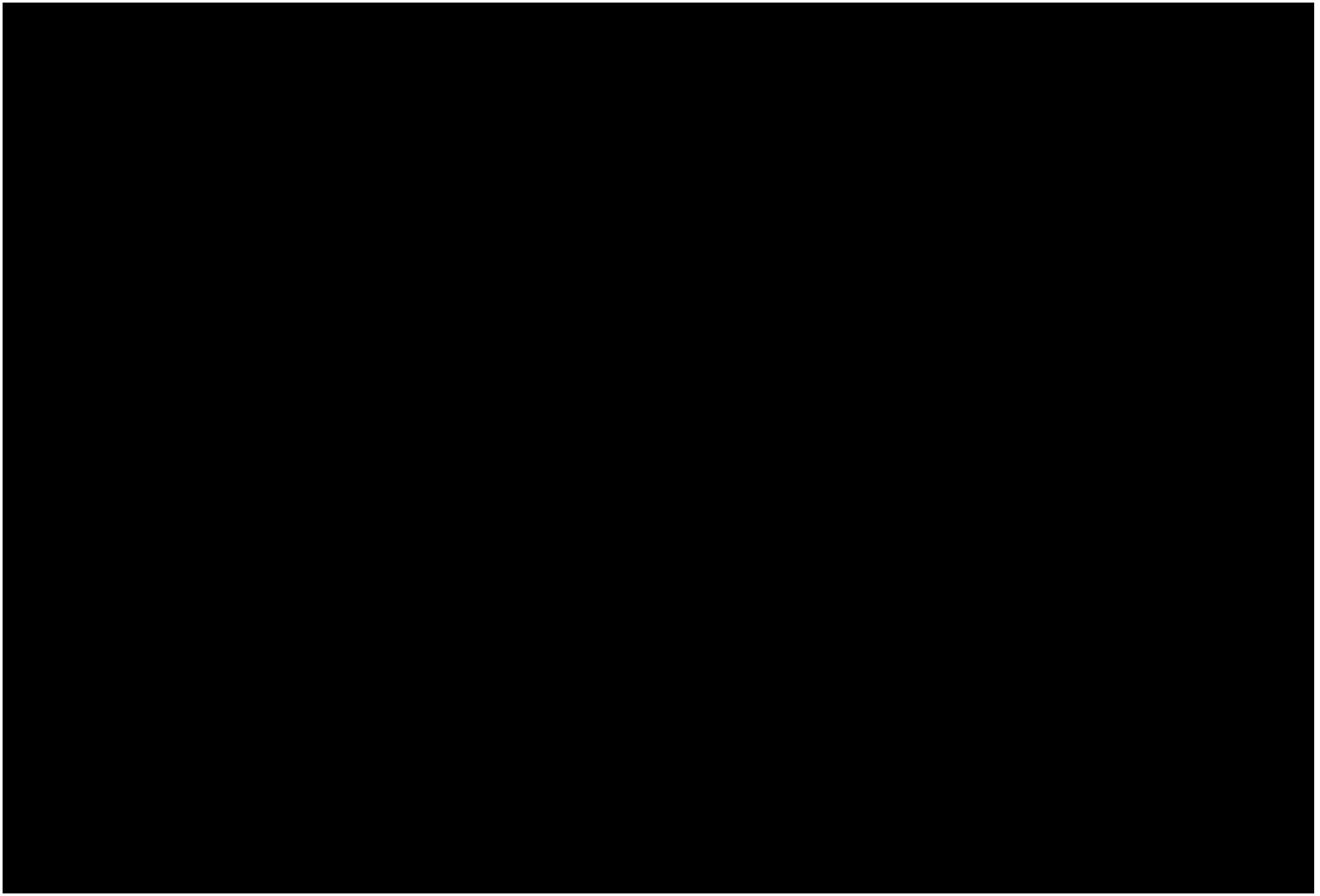
Date of On Peak Day - 11/27/2021



Member Forecasted On Peak Demand Day for December 2021

Chimney Rock Public Power District

Date of On Peak Day - 12/30/2021



Member Forecasted On Peak Demand Day for January 2021

Empire Electric Association, Inc.

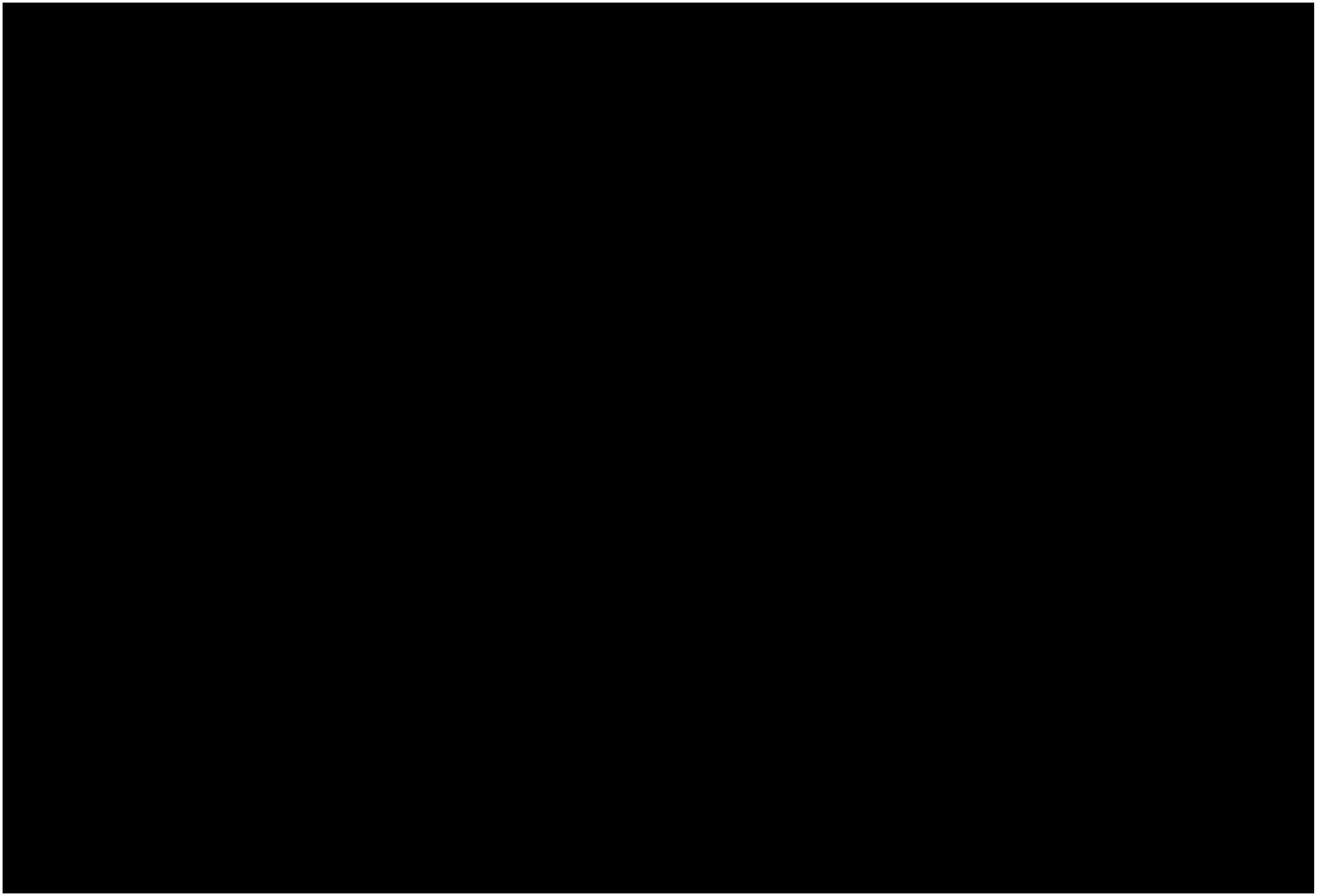
Date of On Peak Day - 01/27/2021

[redacted]

Member Forecasted On Peak Demand Day for February 2021

Empire Electric Association, Inc.

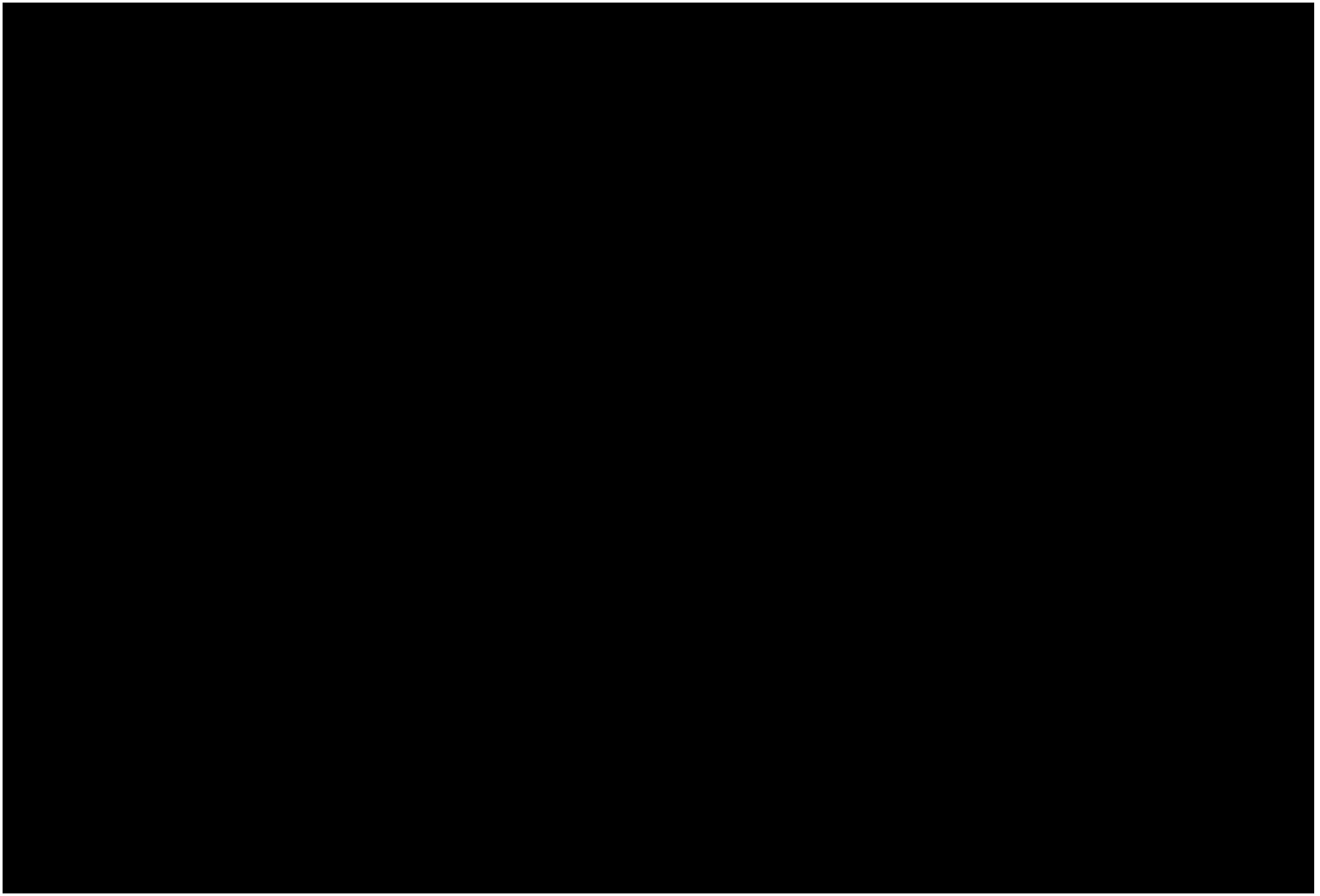
Date of On Peak Day - 02/01/2021



Member Forecasted On Peak Demand Day for March 2021

Empire Electric Association, Inc.

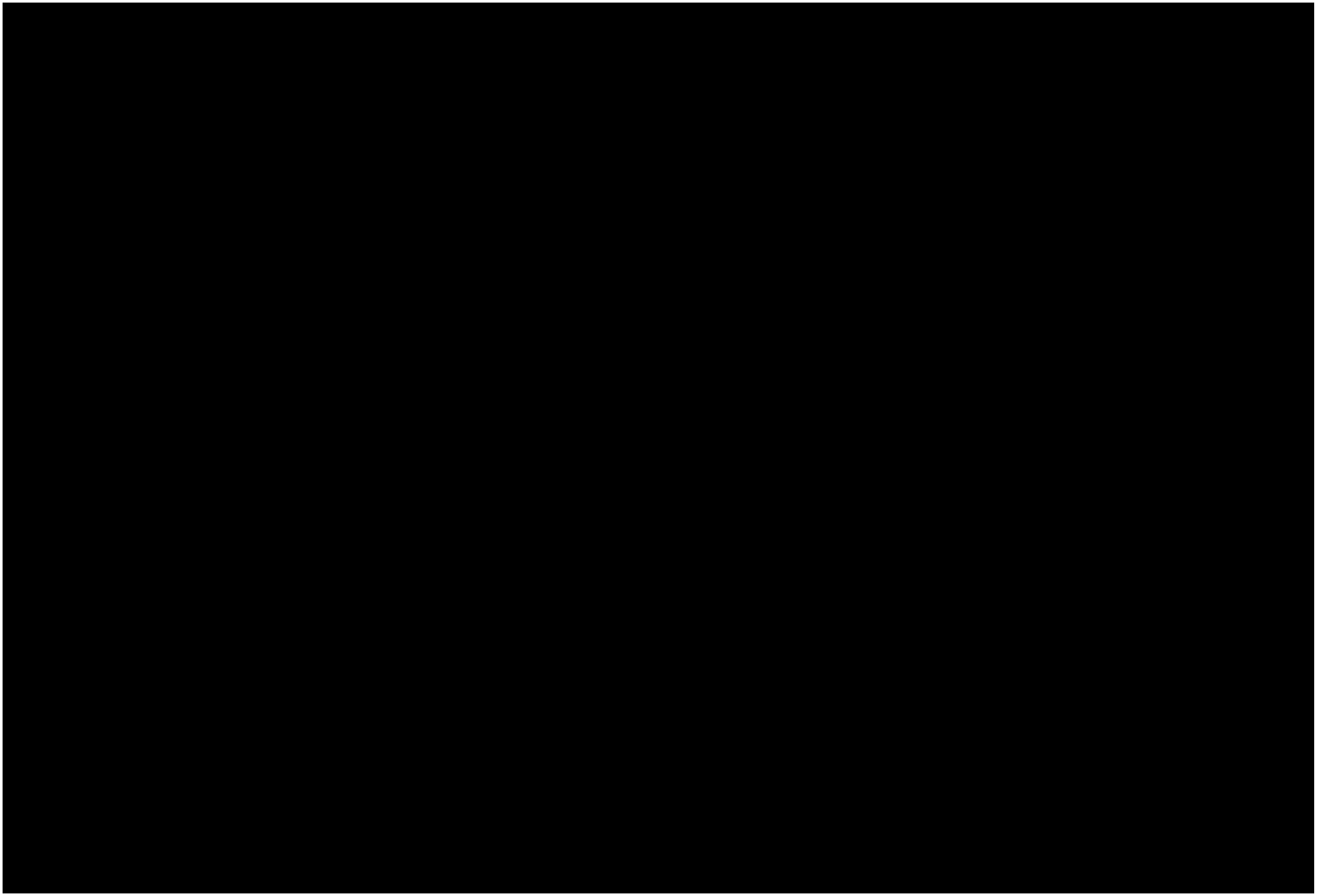
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Empire Electric Association, Inc.

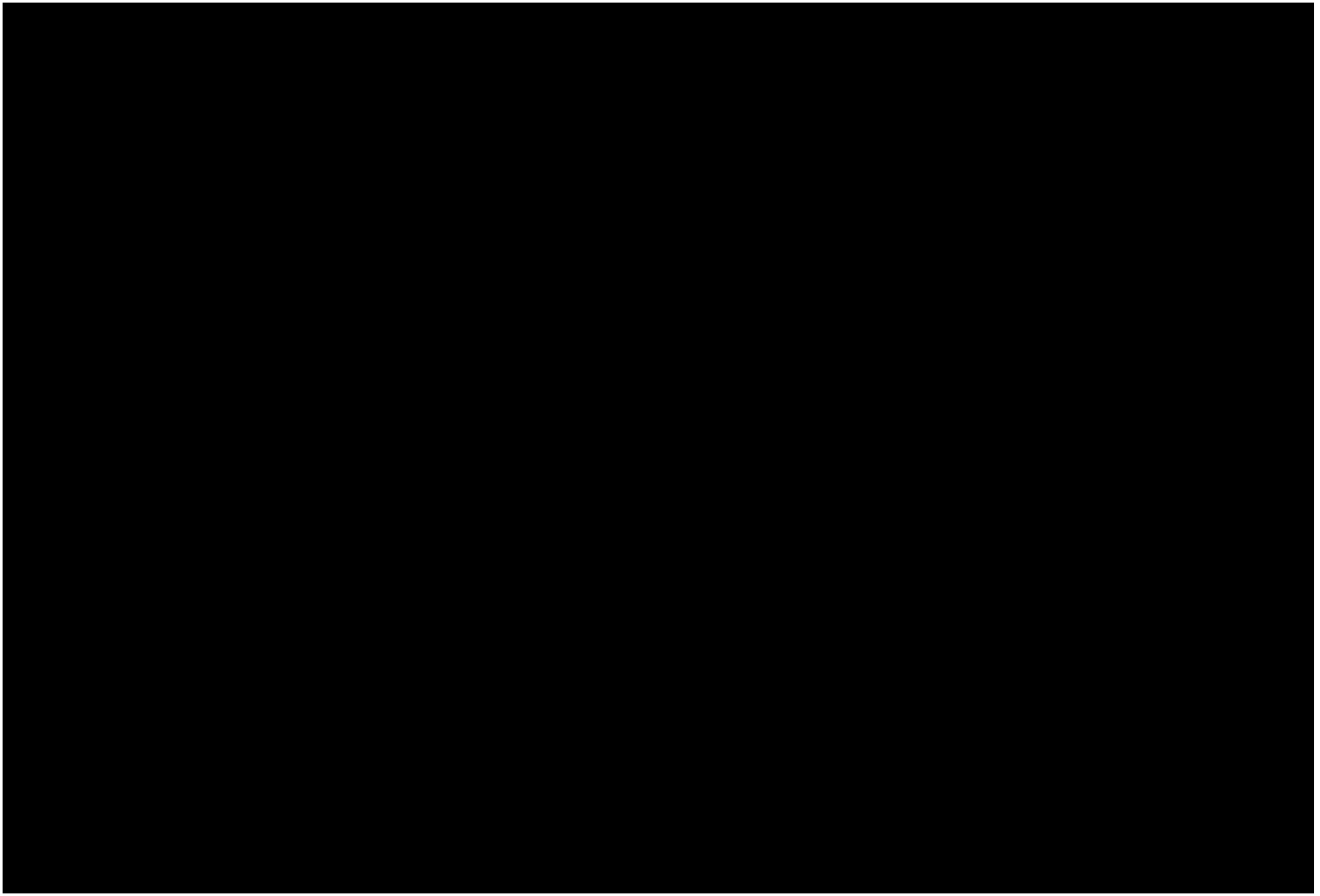
Date of On Peak Day - 04/15/2021



Member Forecasted On Peak Demand Day for May 2021

Empire Electric Association, Inc.

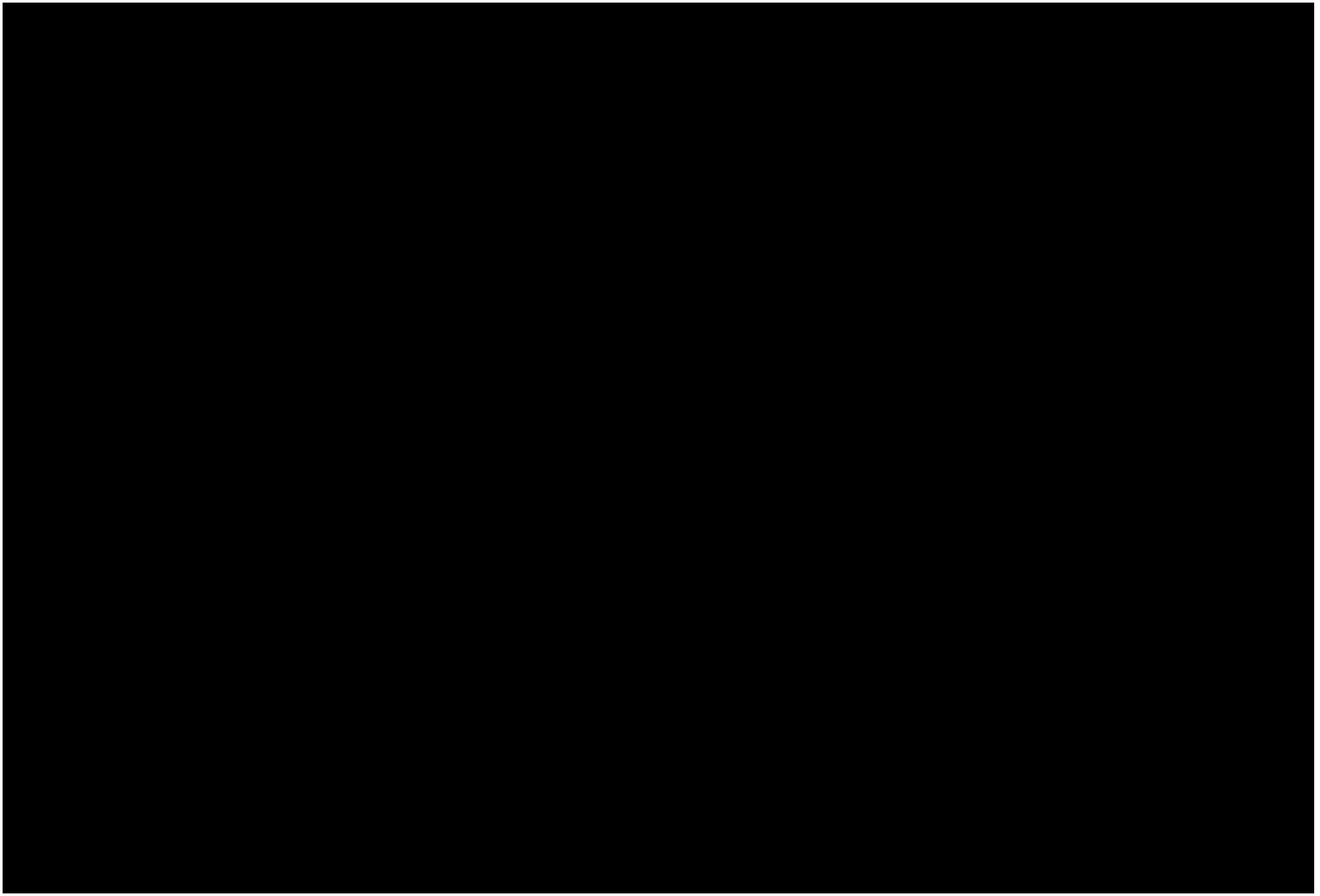
Date of On Peak Day - 05/05/2021



Member Forecasted On Peak Demand Day for June 2021

Empire Electric Association, Inc.

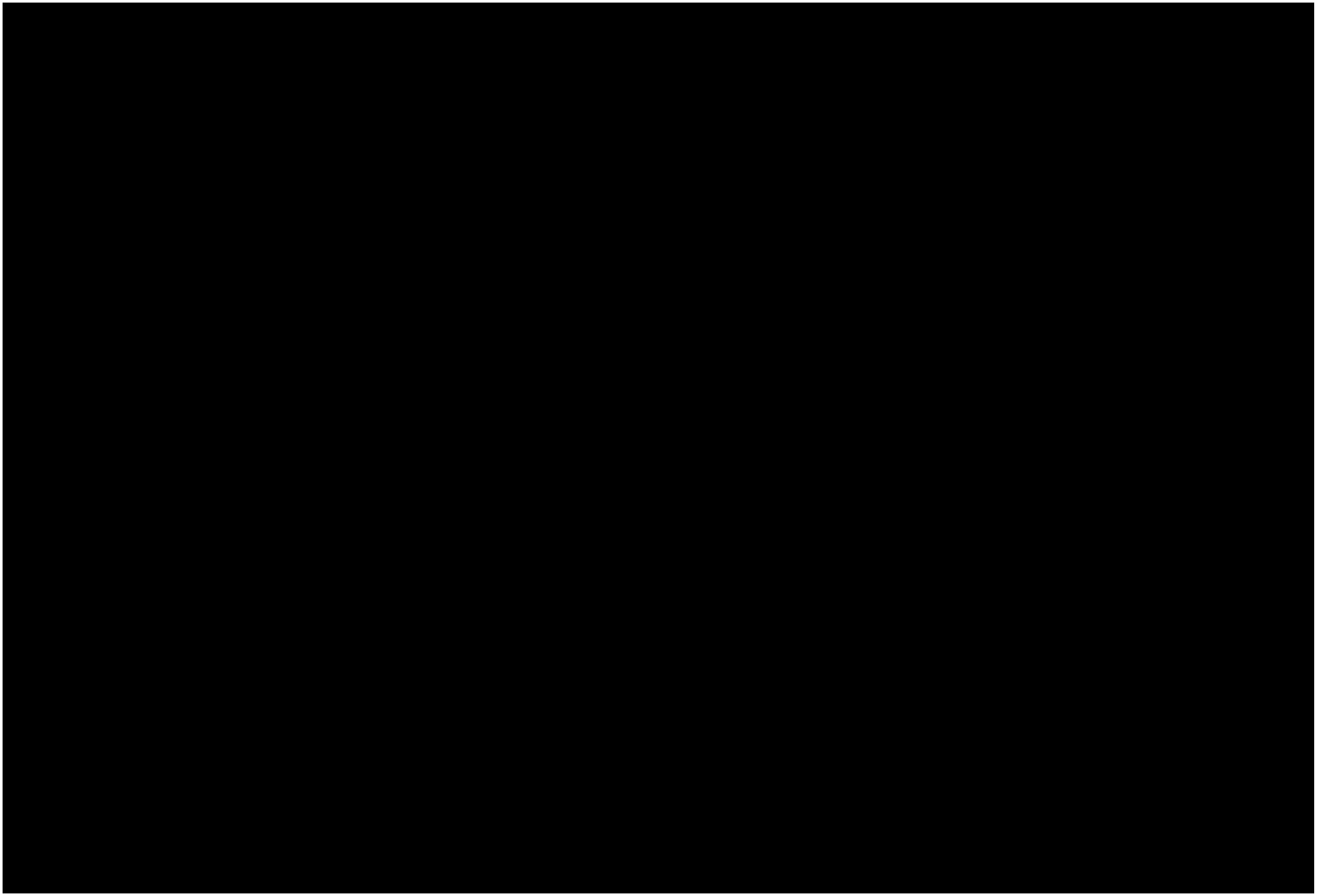
Date of On Peak Day - 06/03/2021



Member Forecasted On Peak Demand Day for July 2021

Empire Electric Association, Inc.

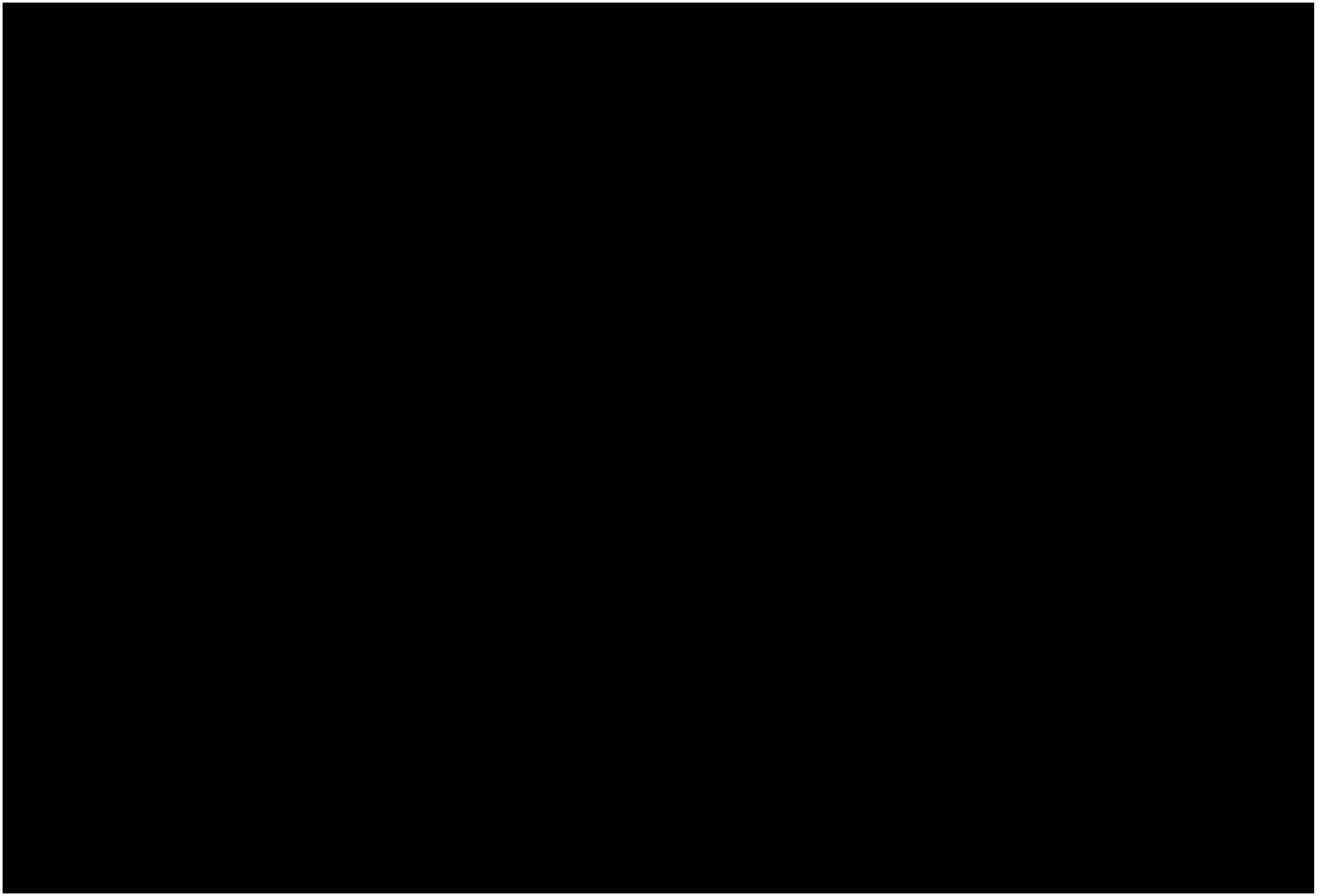
Date of On Peak Day - 07/28/2021



Member Forecasted On Peak Demand Day for August 2021

Empire Electric Association, Inc.

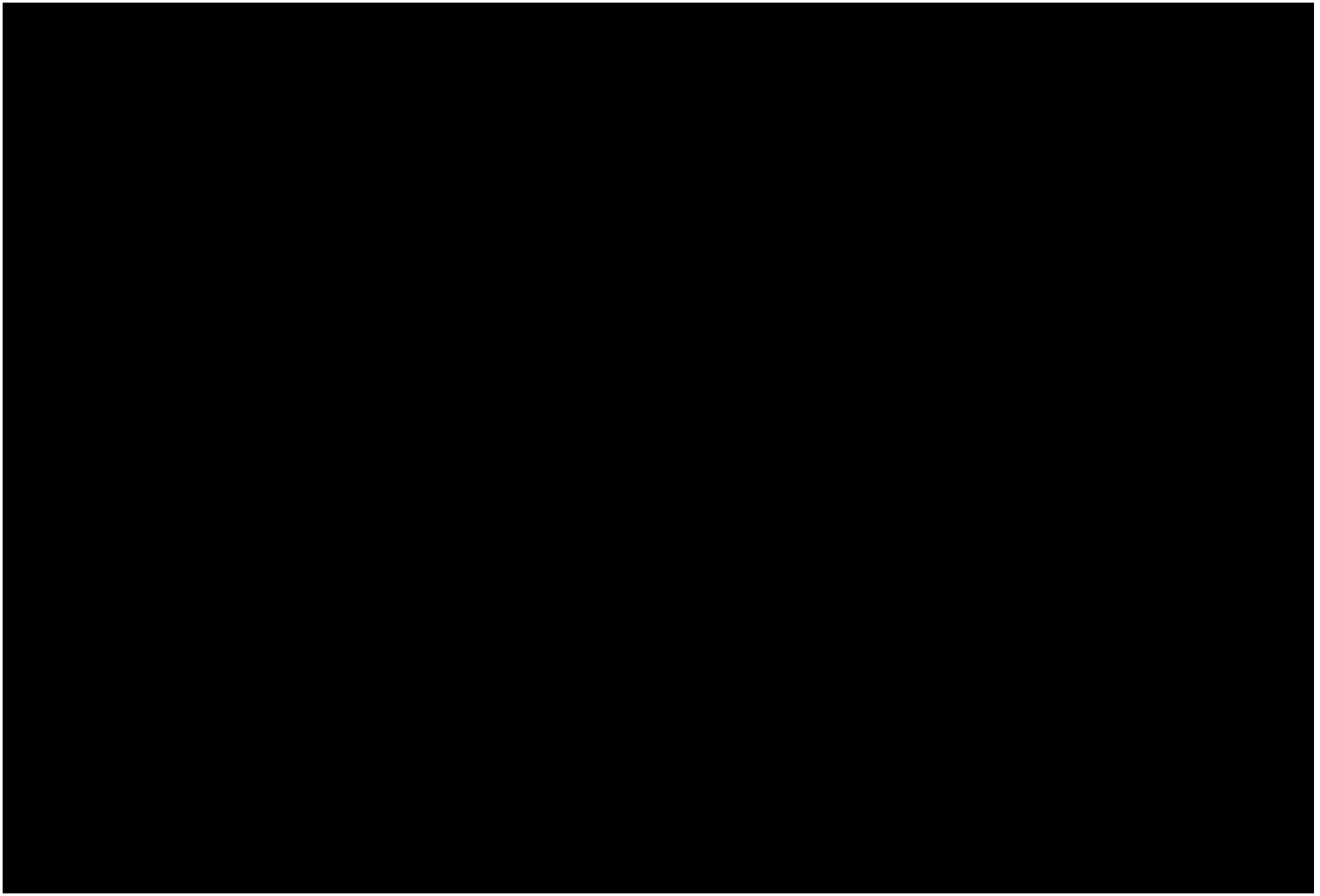
Date of On Peak Day - 08/28/2021



Member Forecasted On Peak Demand Day for September 2021

Empire Electric Association, Inc.

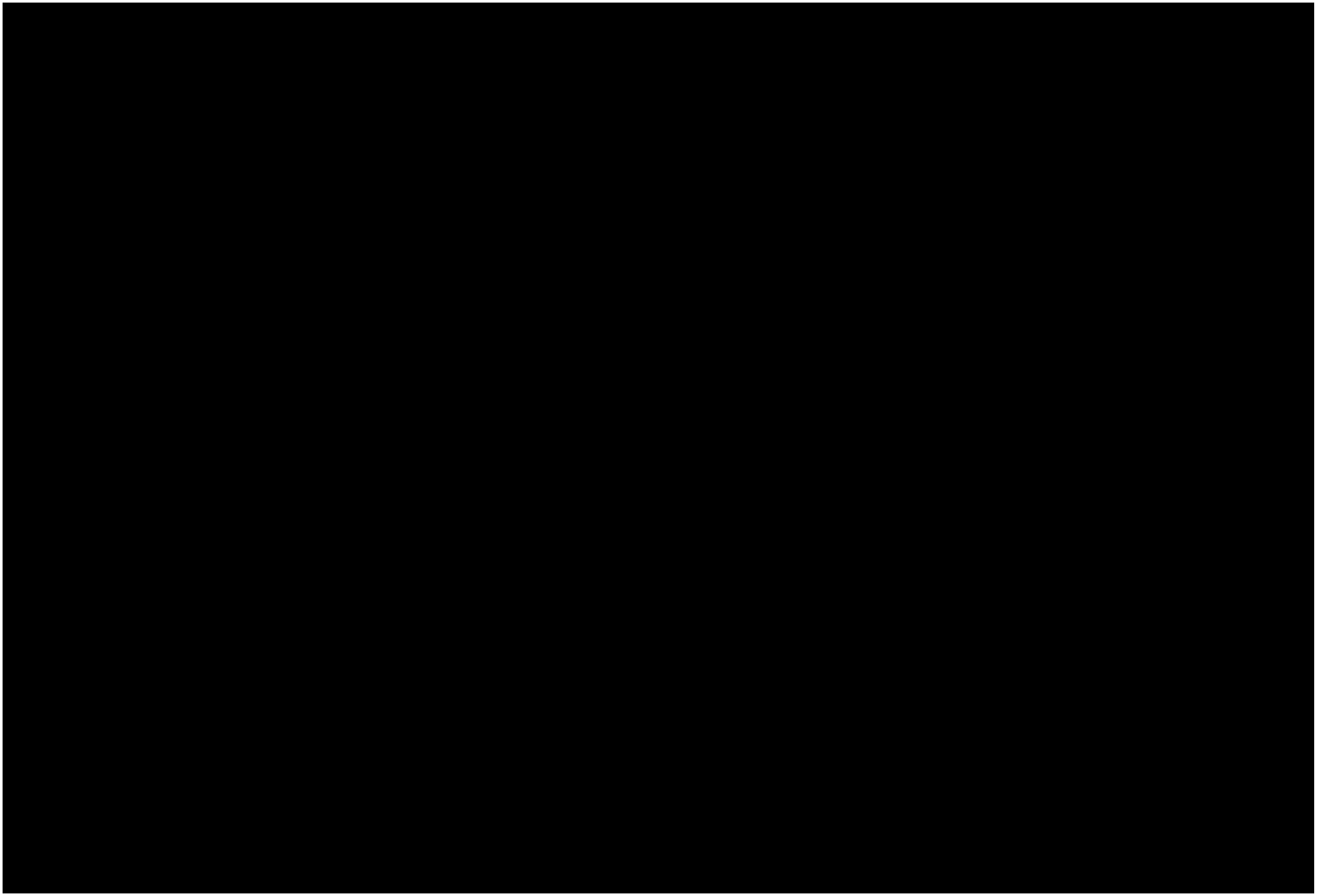
Date of On Peak Day - 09/03/2021



Member Forecasted On Peak Demand Day for October 2021

Empire Electric Association, Inc.

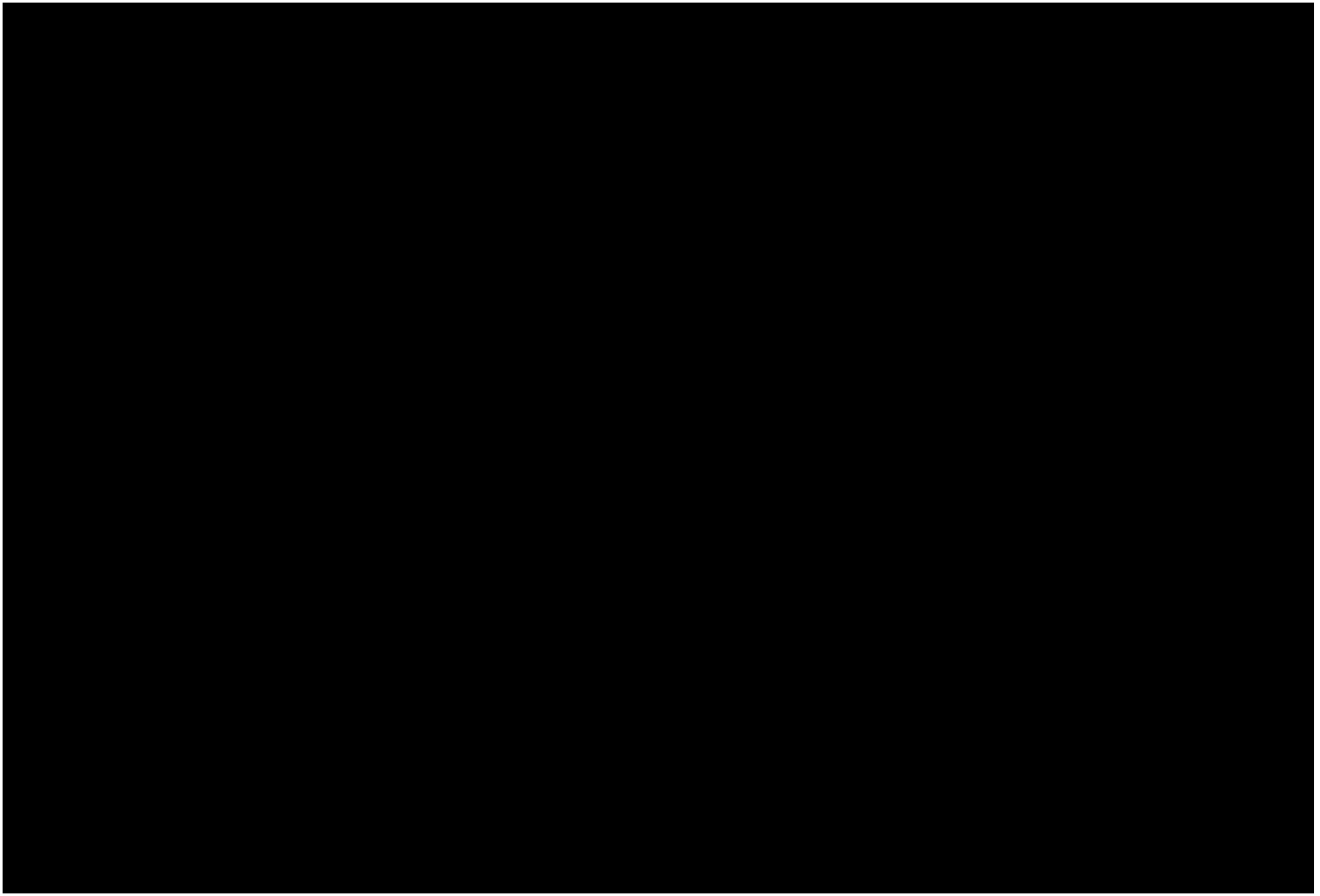
Date of On Peak Day - 10/18/2021



Member Forecasted On Peak Demand Day for November 2021

Empire Electric Association, Inc.

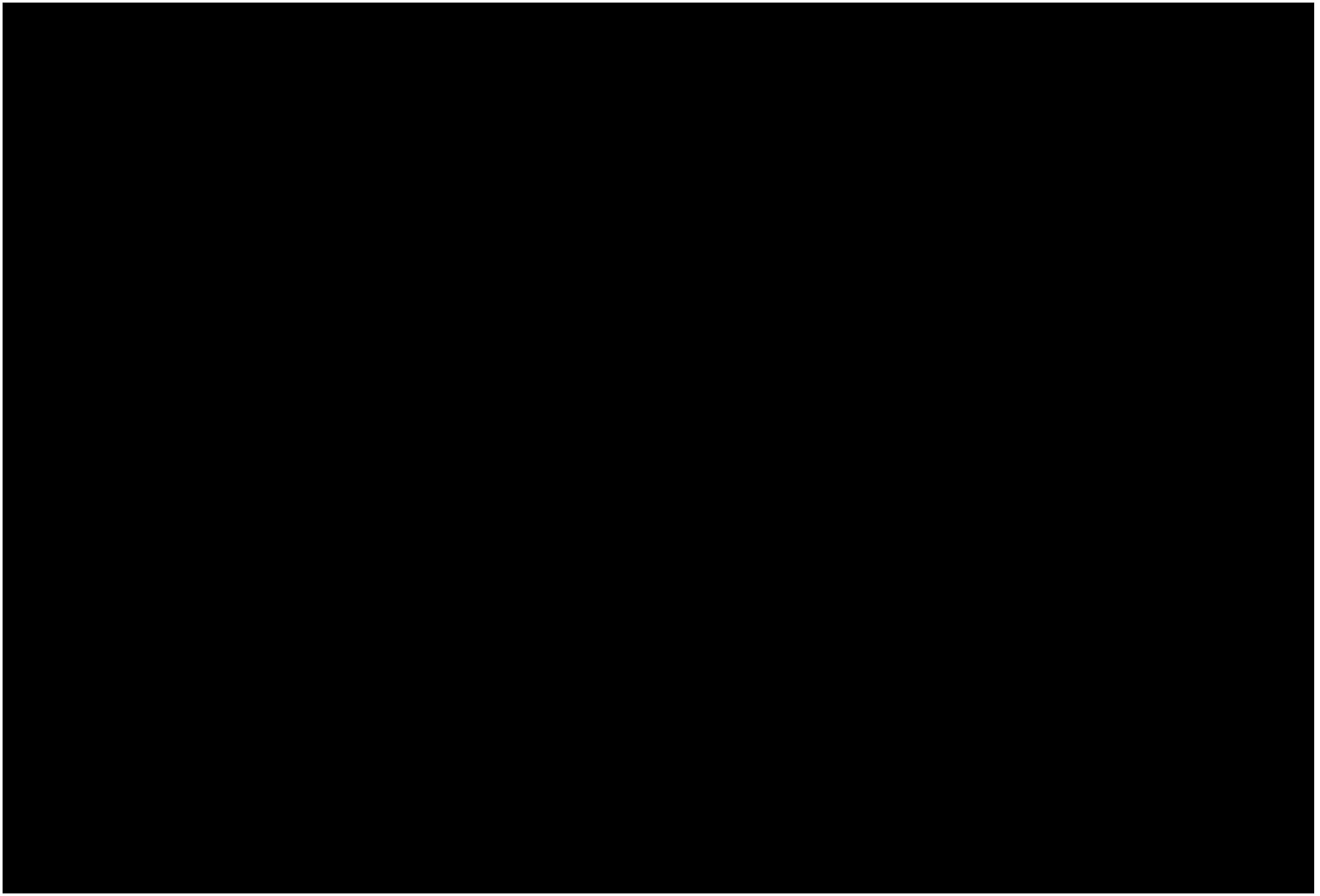
Date of On Peak Day - 11/29/2021



Member Forecasted On Peak Demand Day for December 2021

Empire Electric Association, Inc.

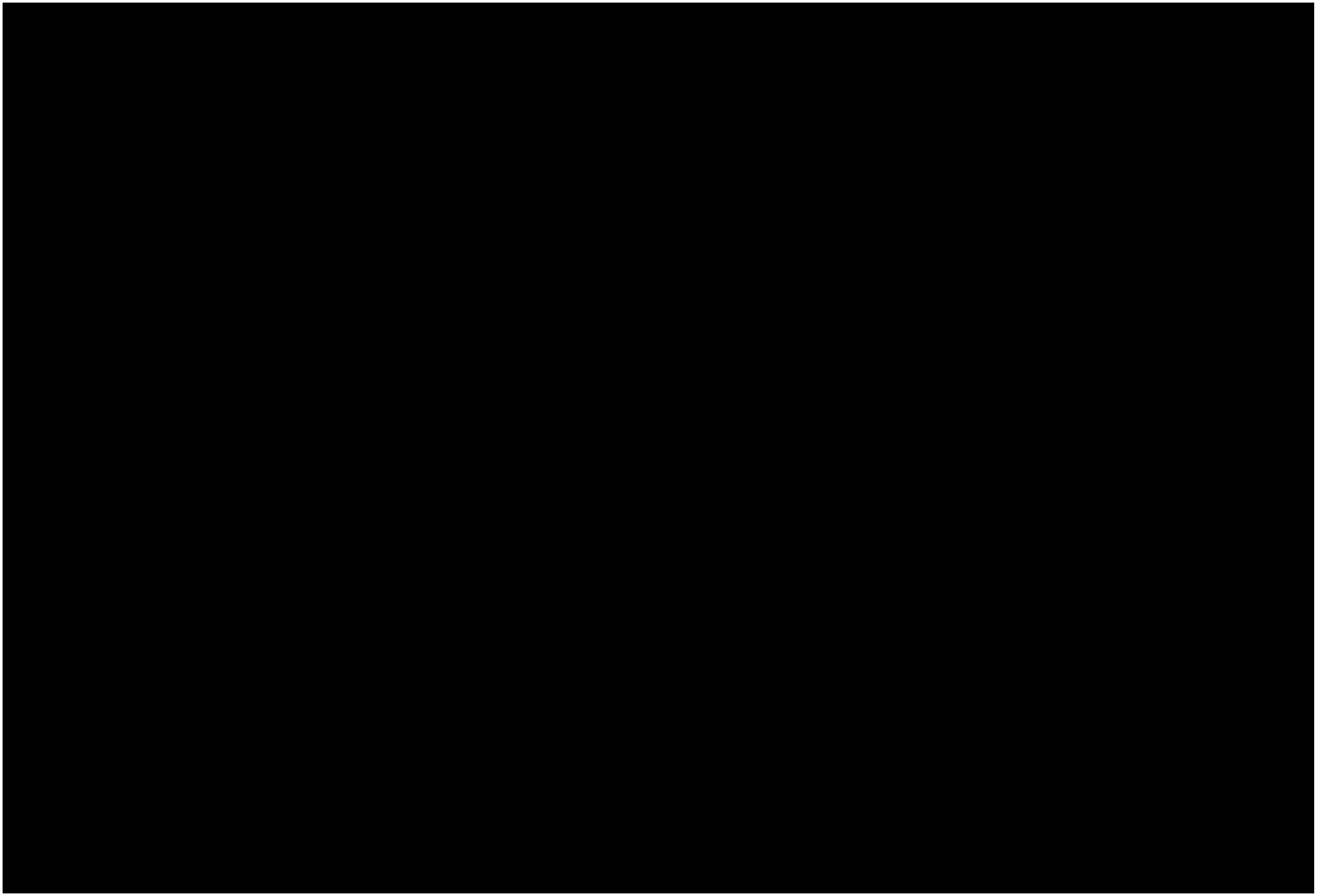
Date of On Peak Day - 12/15/2021



Member Forecasted On Peak Demand Day for January 2021

Gunnison County Electric Association, Inc.

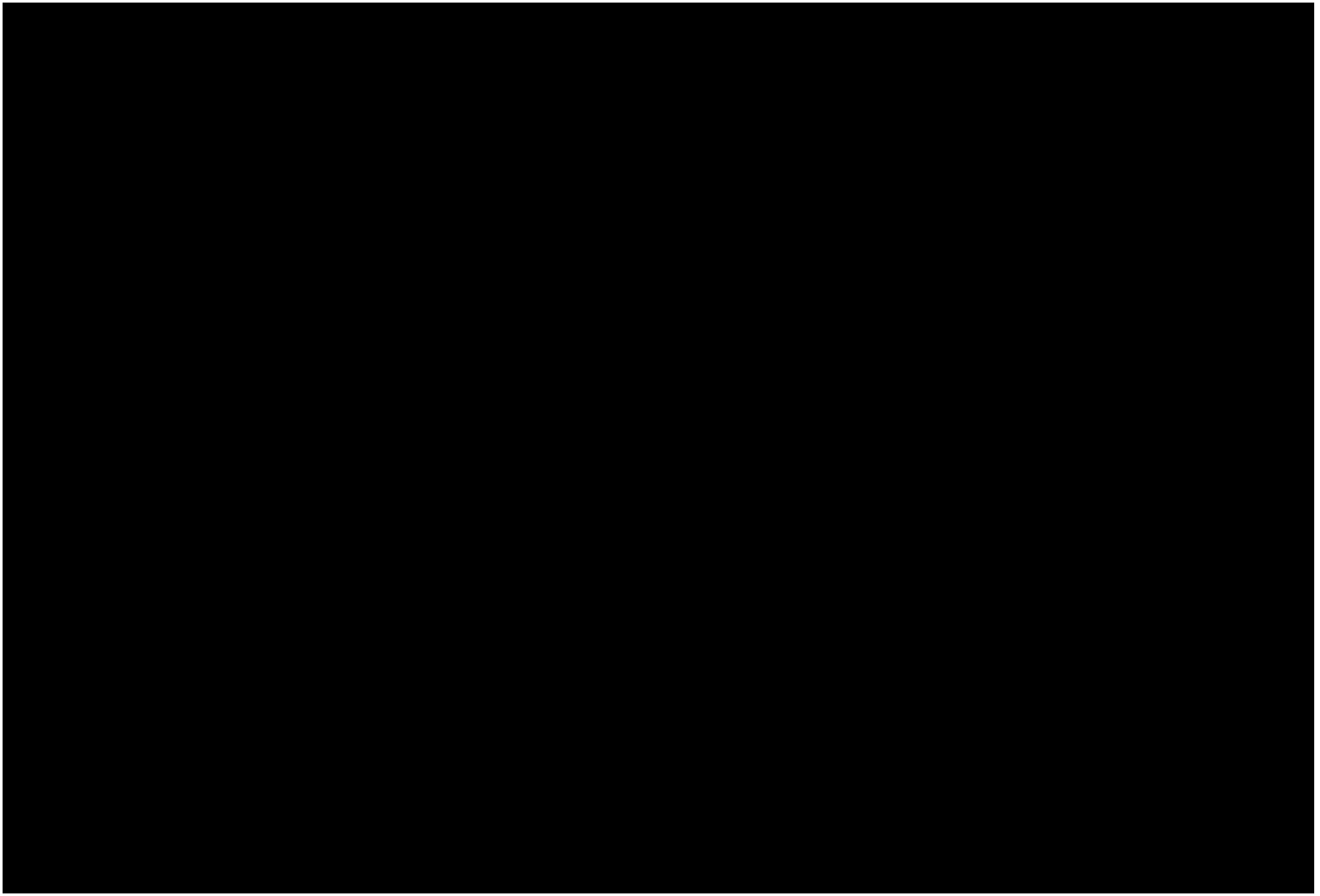
Date of On Peak Day - 01/02/2021



Member Forecasted On Peak Demand Day for February 2021

Gunnison County Electric Association, Inc.

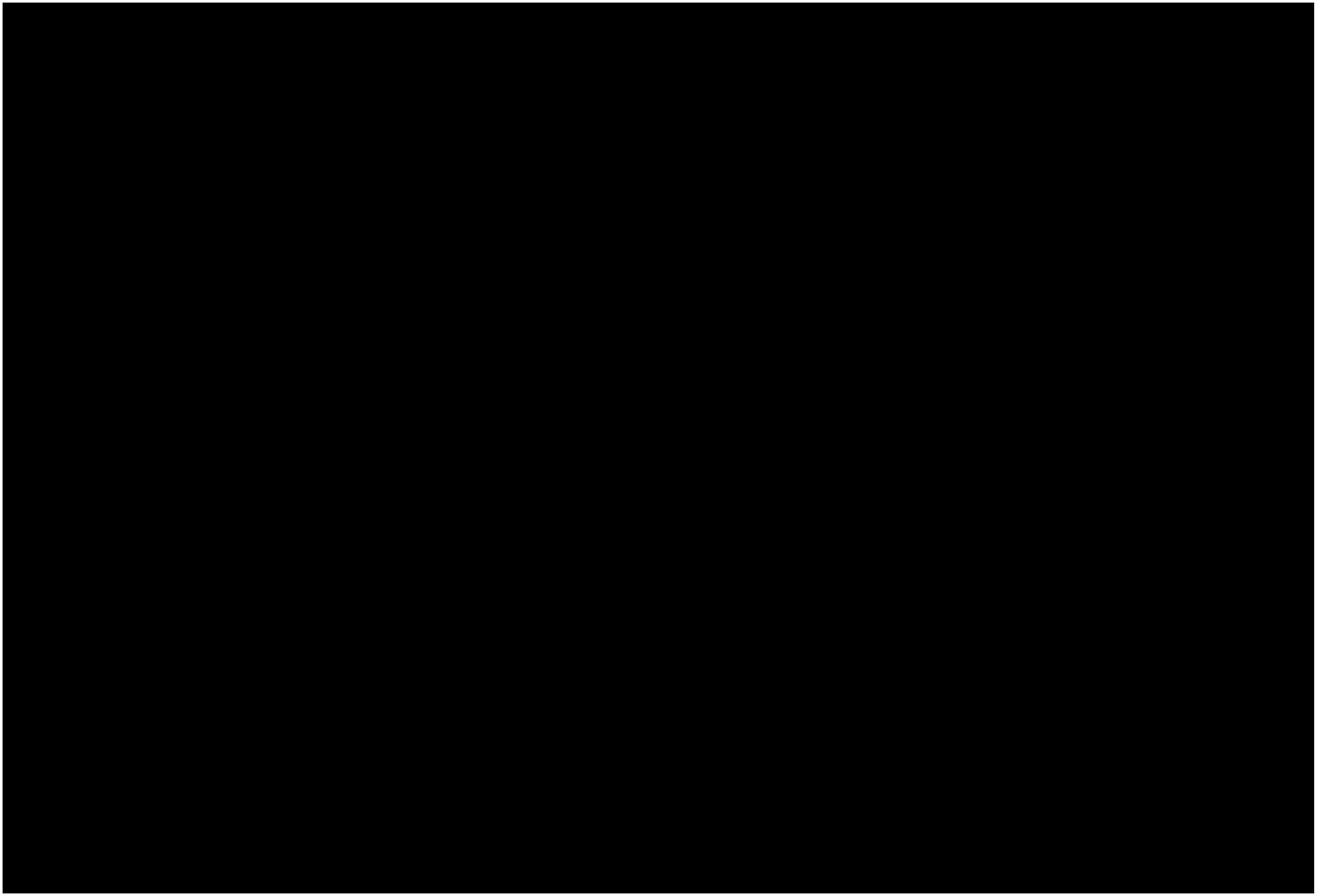
Date of On Peak Day - 02/26/2021



Member Forecasted On Peak Demand Day for March 2021

Gunnison County Electric Association, Inc.

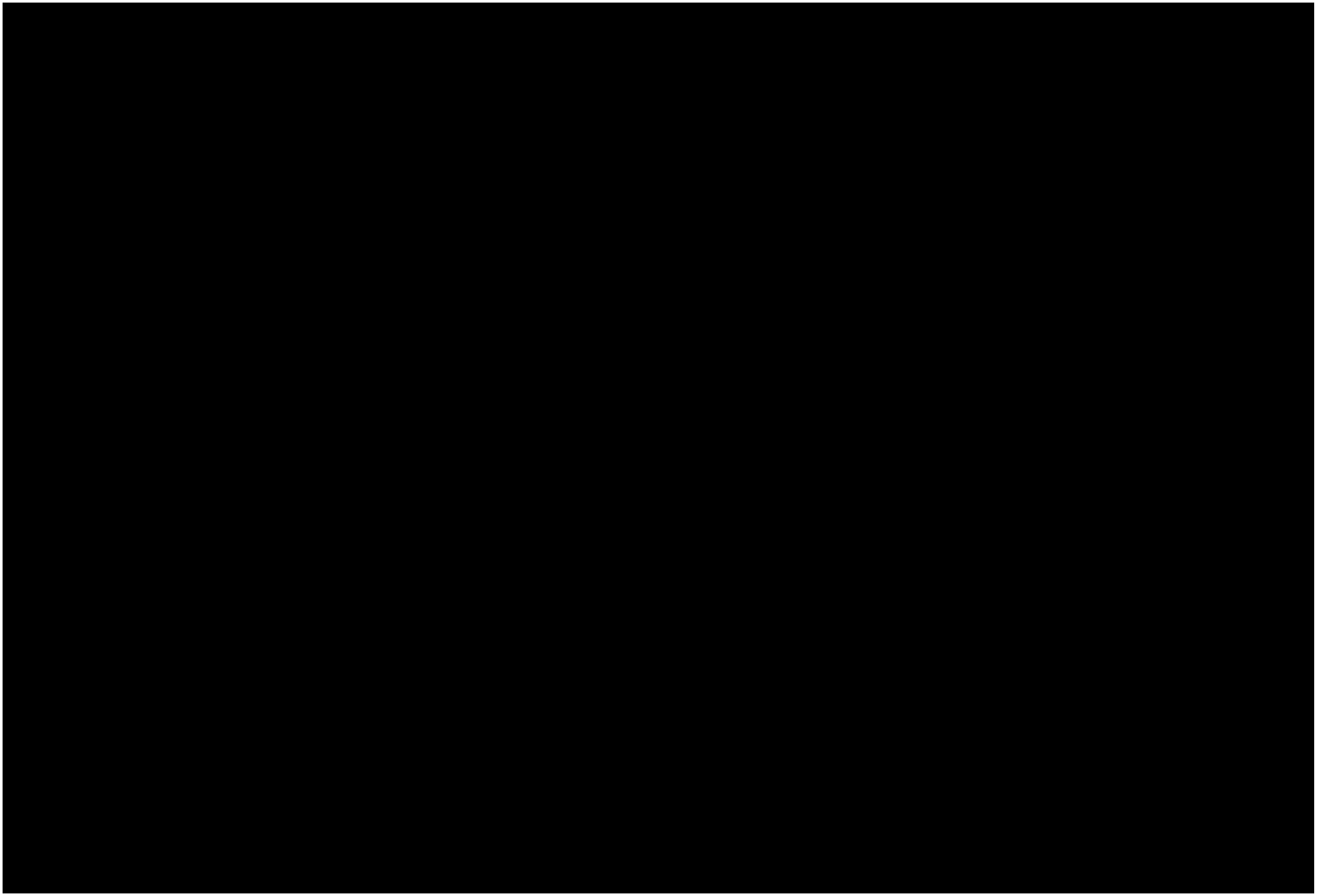
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Gunnison County Electric Association, Inc.

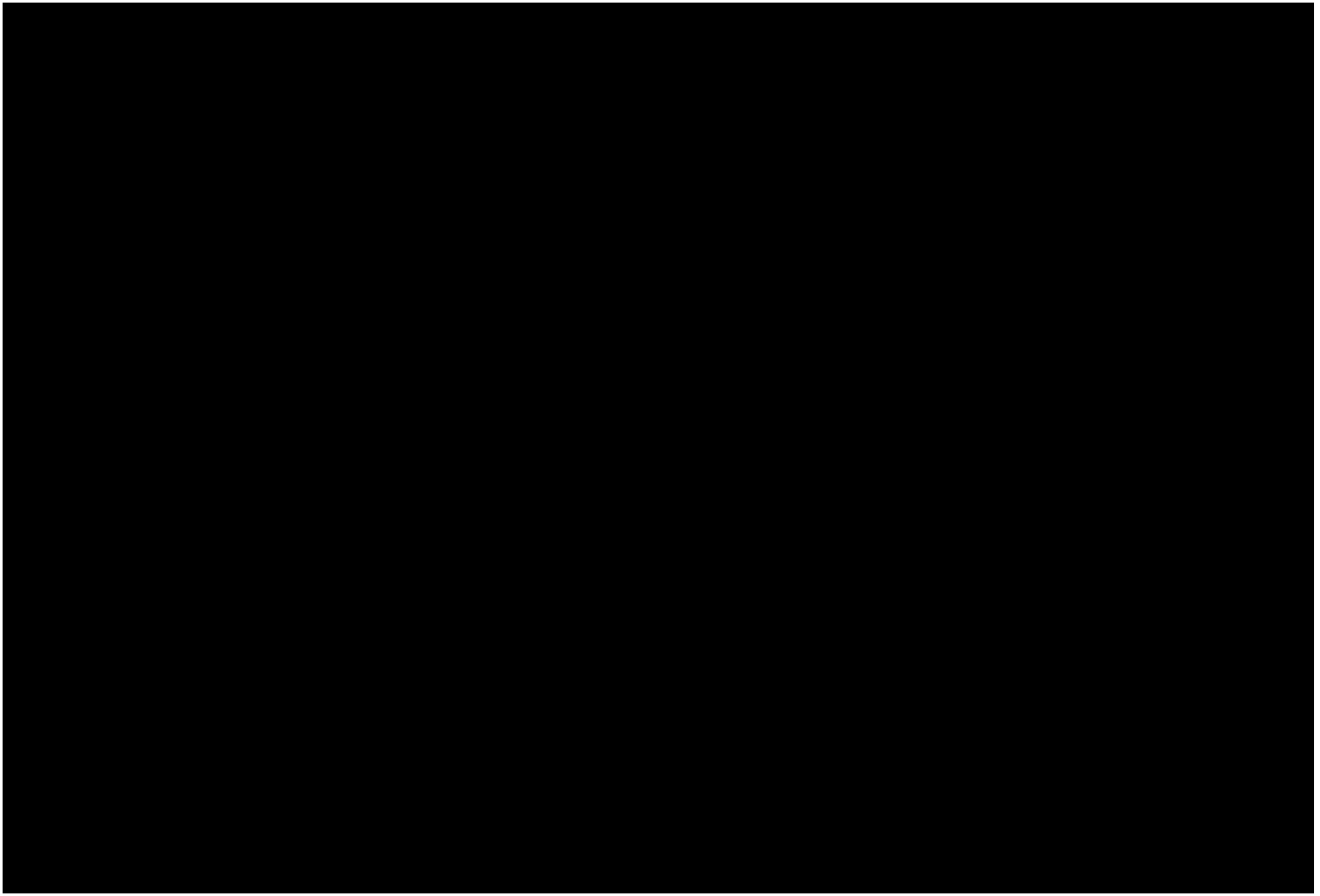
Date of On Peak Day - 04/03/2021



Member Forecasted On Peak Demand Day for May 2021

Gunnison County Electric Association, Inc.

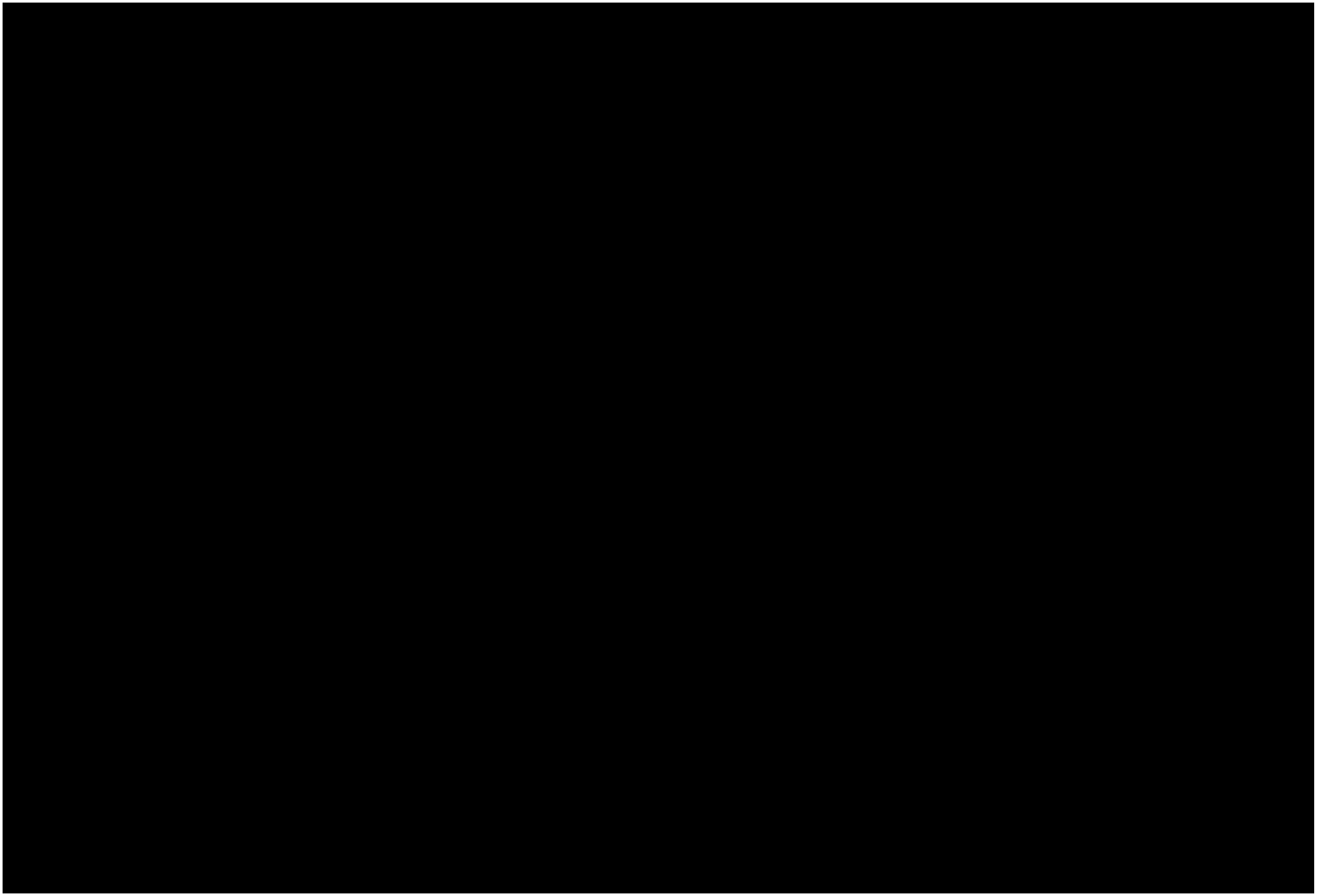
Date of On Peak Day - 05/20/2021



Member Forecasted On Peak Demand Day for June 2021

Gunnison County Electric Association, Inc.

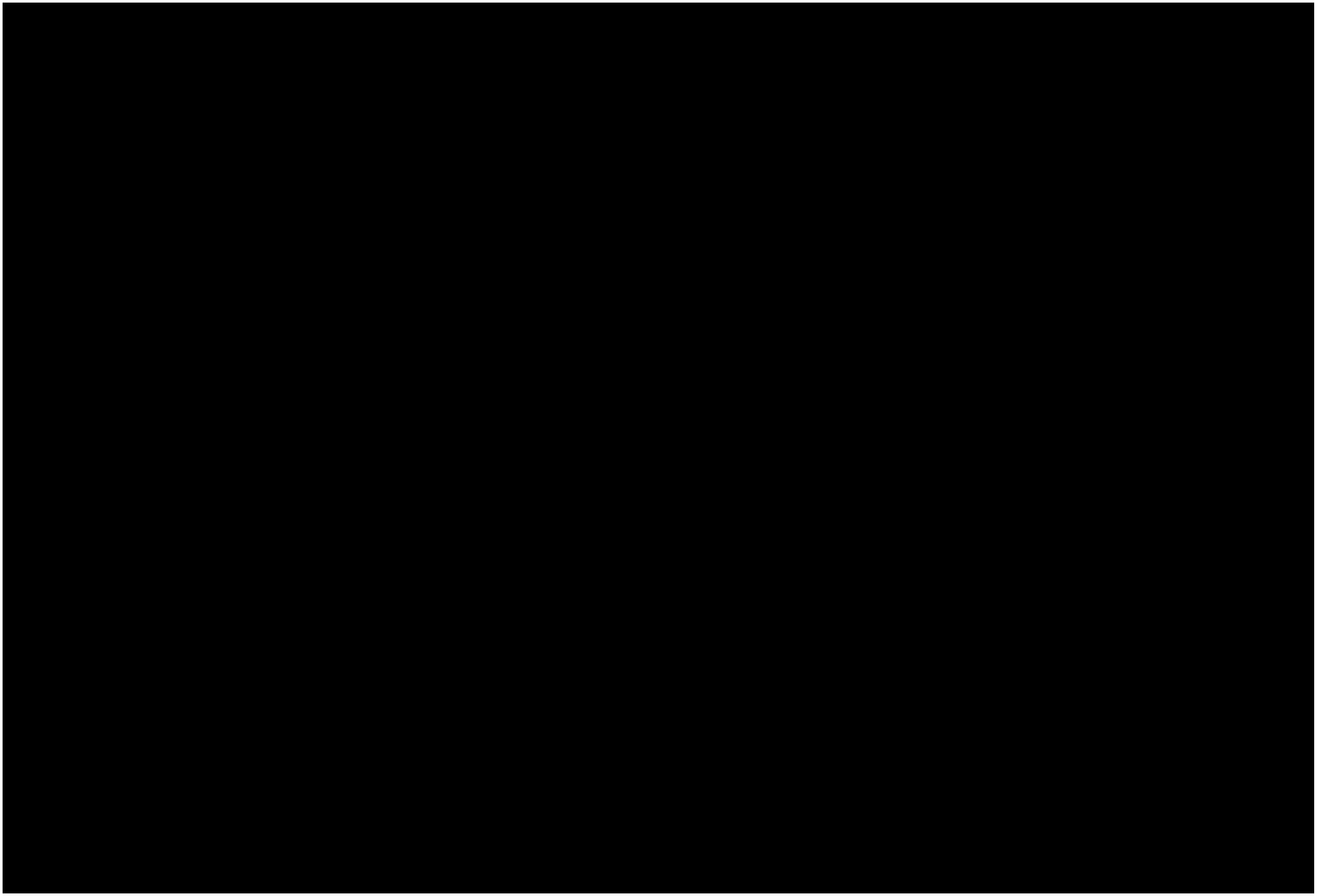
Date of On Peak Day - 06/30/2021



Member Forecasted On Peak Demand Day for July 2021

Gunnison County Electric Association, Inc.

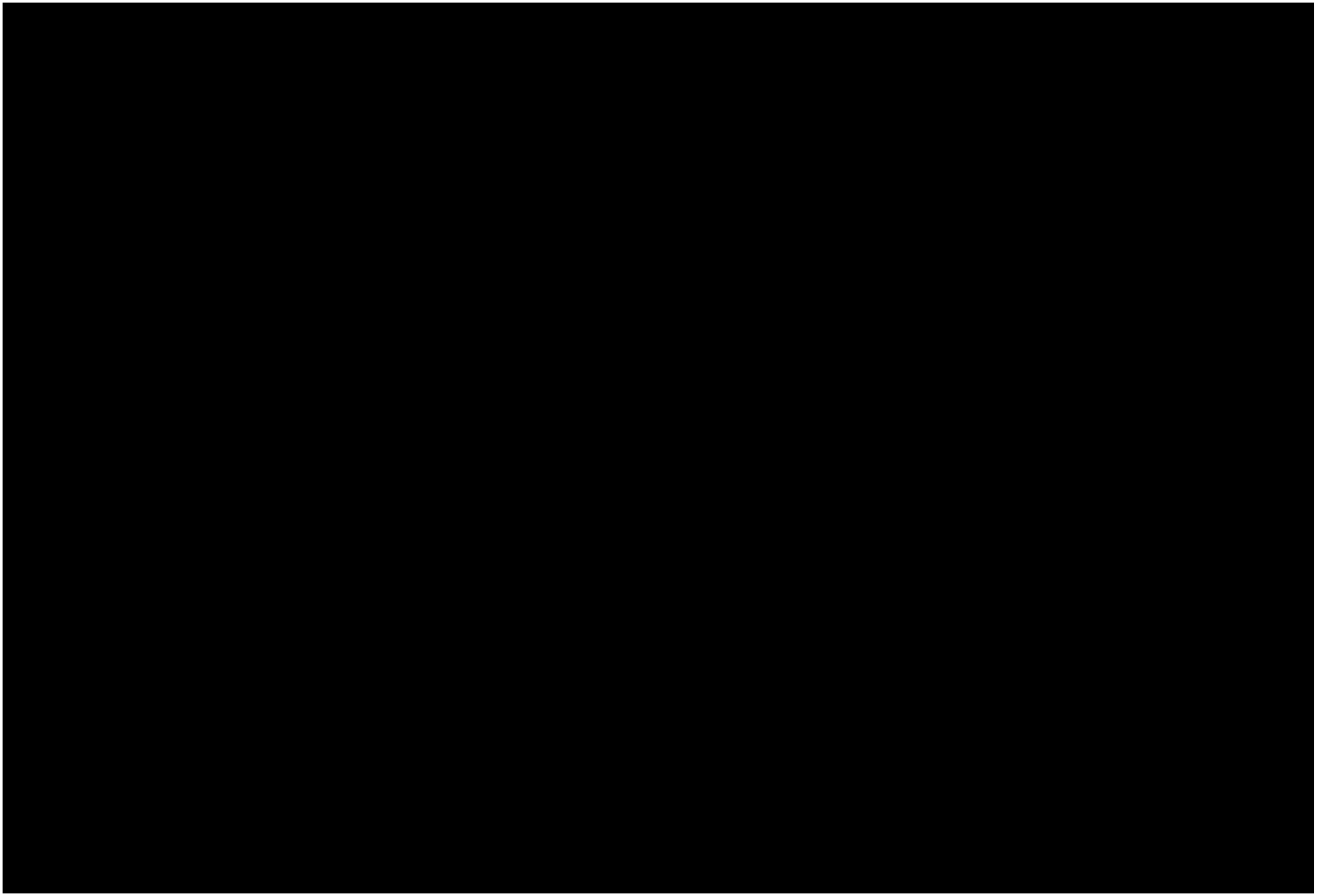
Date of On Peak Day - 07/02/2021



Member Forecasted On Peak Demand Day for August 2021

Gunnison County Electric Association, Inc.

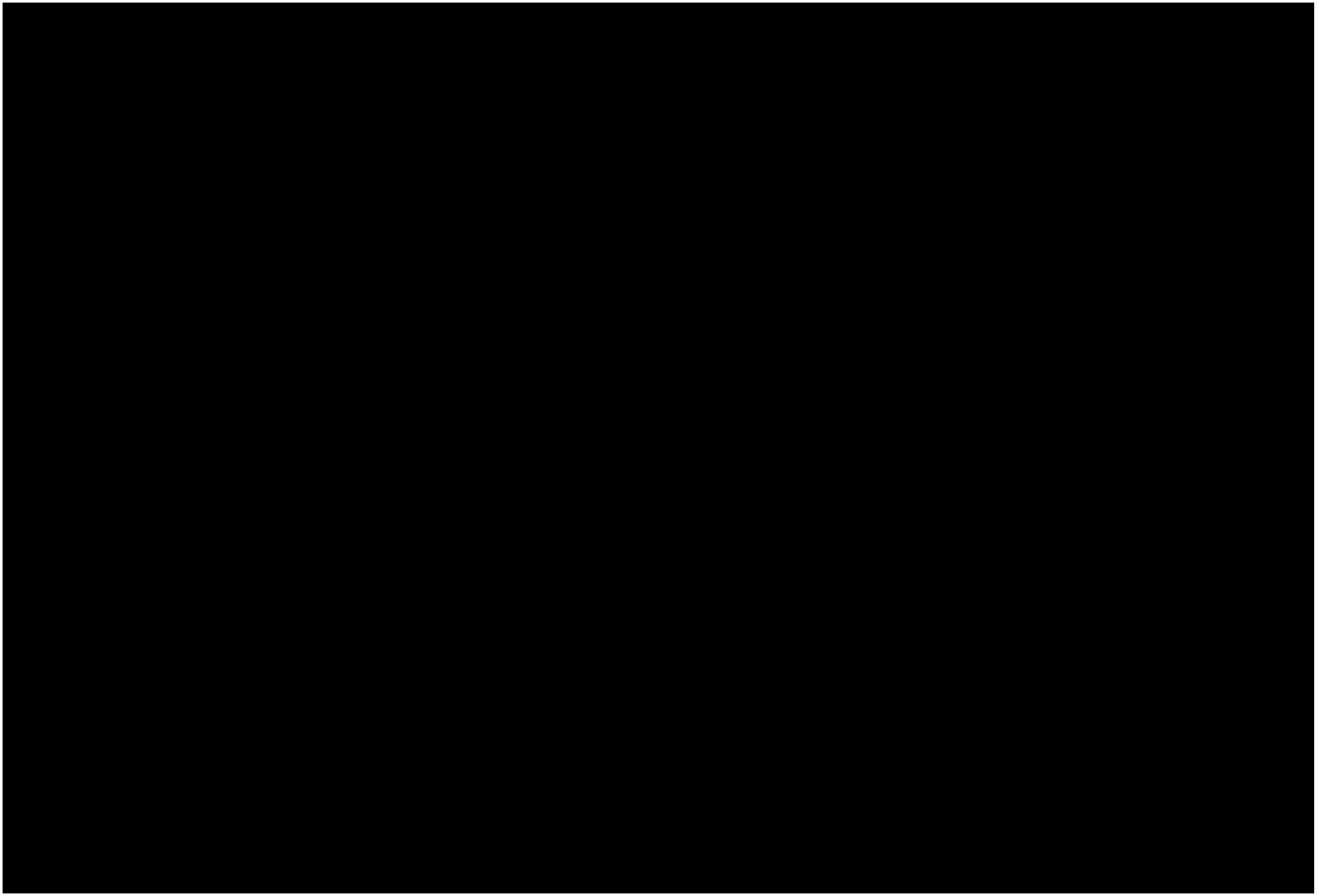
Date of On Peak Day - 08/05/2021



Member Forecasted On Peak Demand Day for September 2021

Gunnison County Electric Association, Inc.

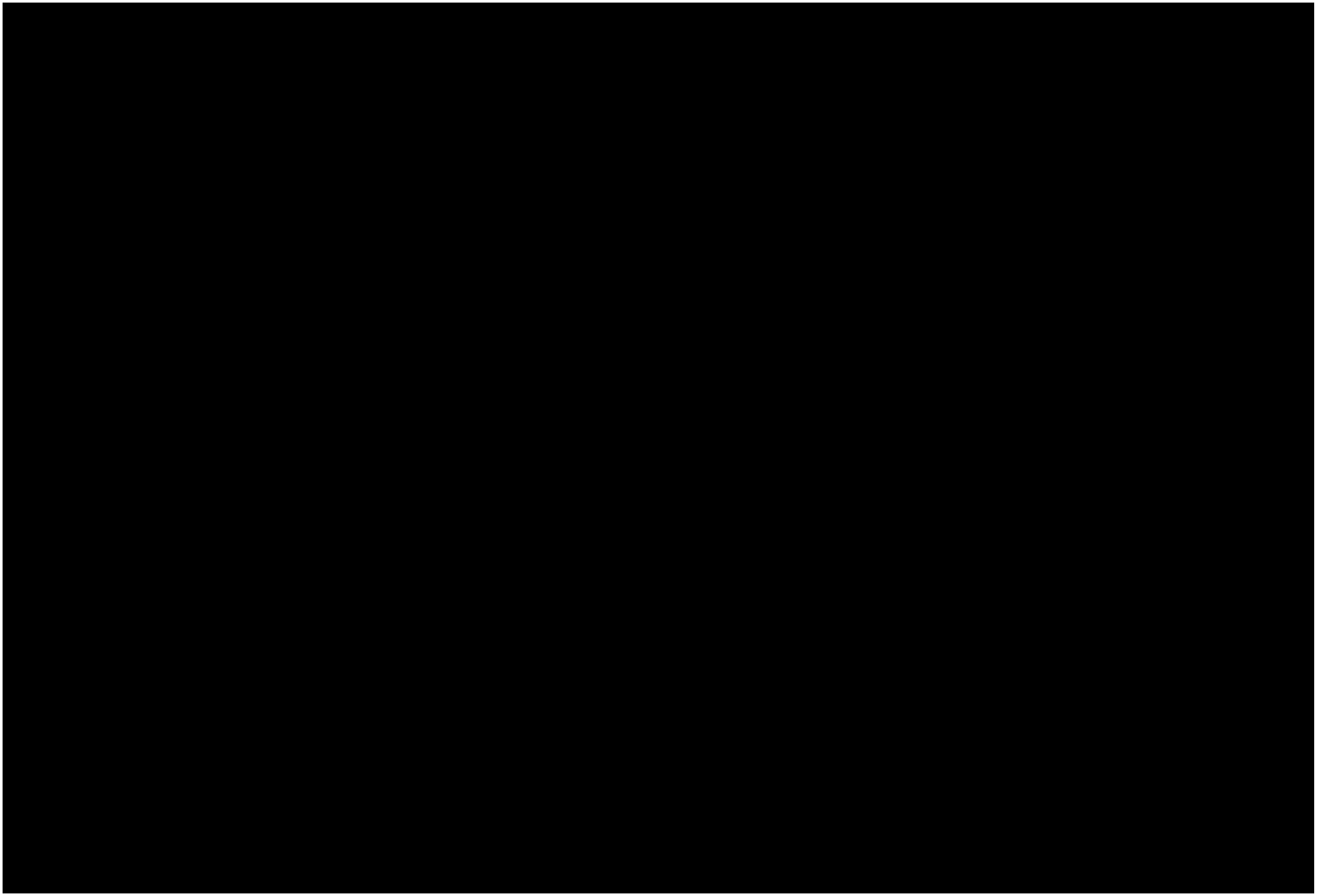
Date of On Peak Day - 09/19/2021



Member Forecasted On Peak Demand Day for October 2021

Gunnison County Electric Association, Inc.

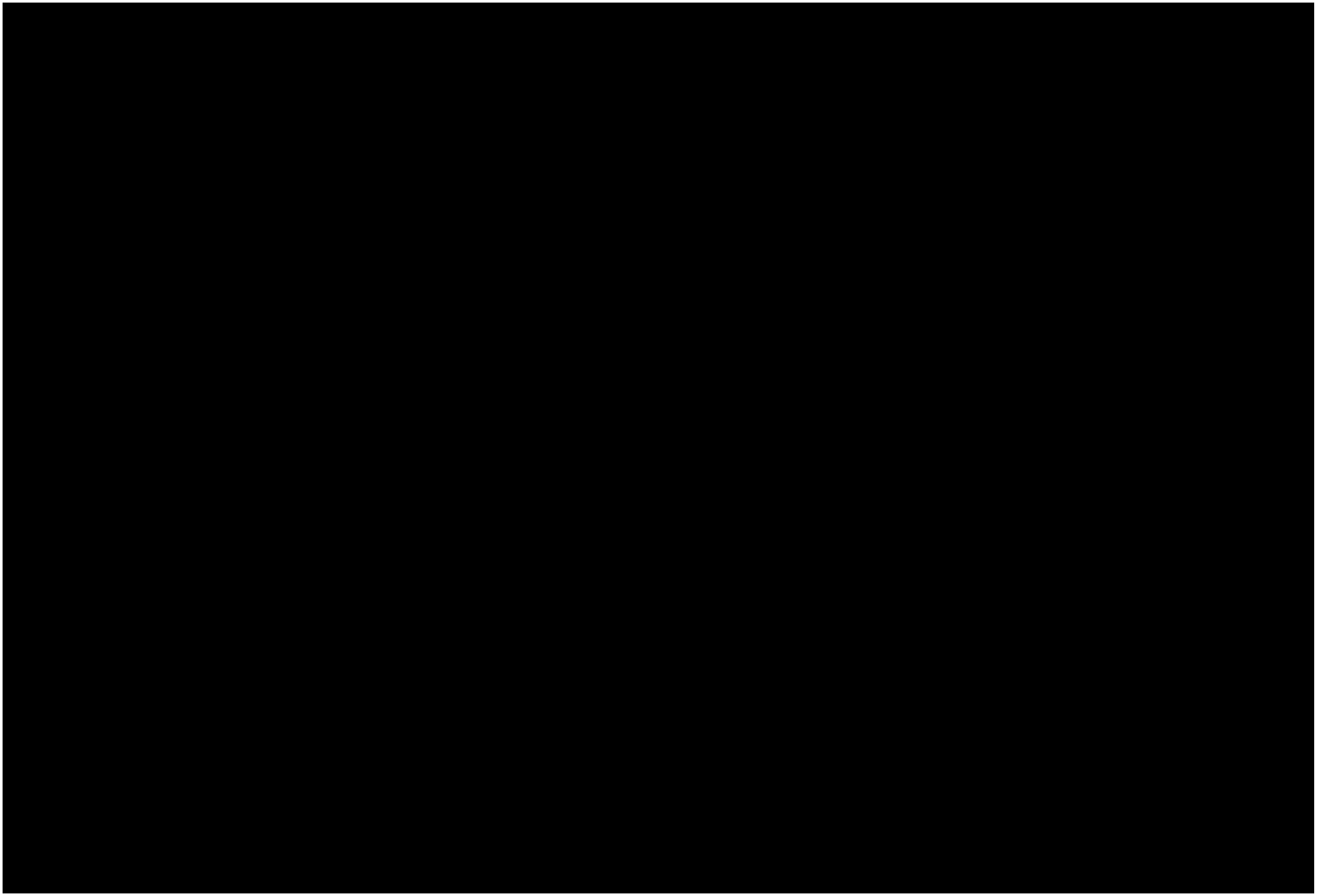
Date of On Peak Day - 10/28/2021



Member Forecasted On Peak Demand Day for November 2021

Gunnison County Electric Association, Inc.

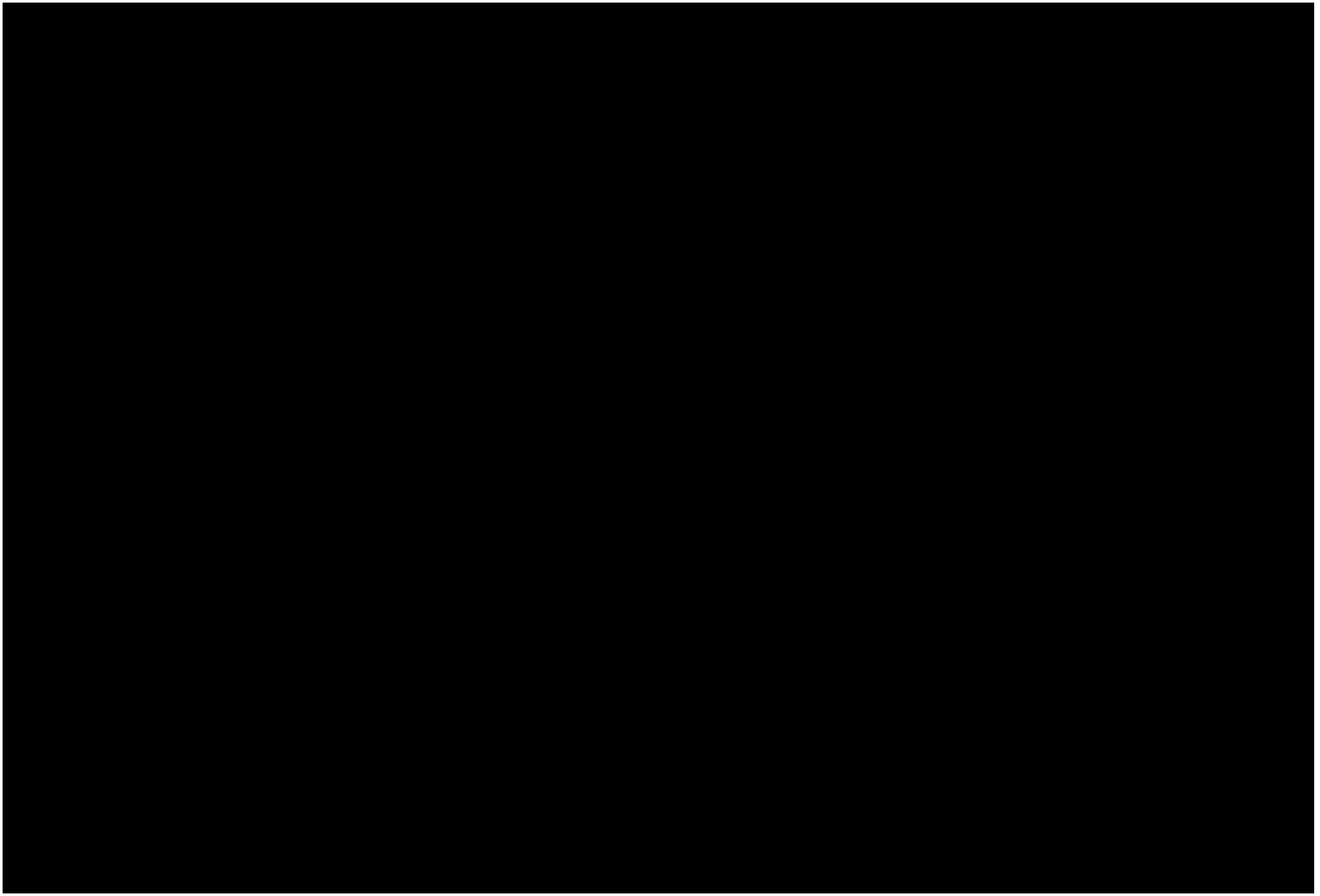
Date of On Peak Day - 11/10/2021



Member Forecasted On Peak Demand Day for December 2021

Gunnison County Electric Association, Inc.

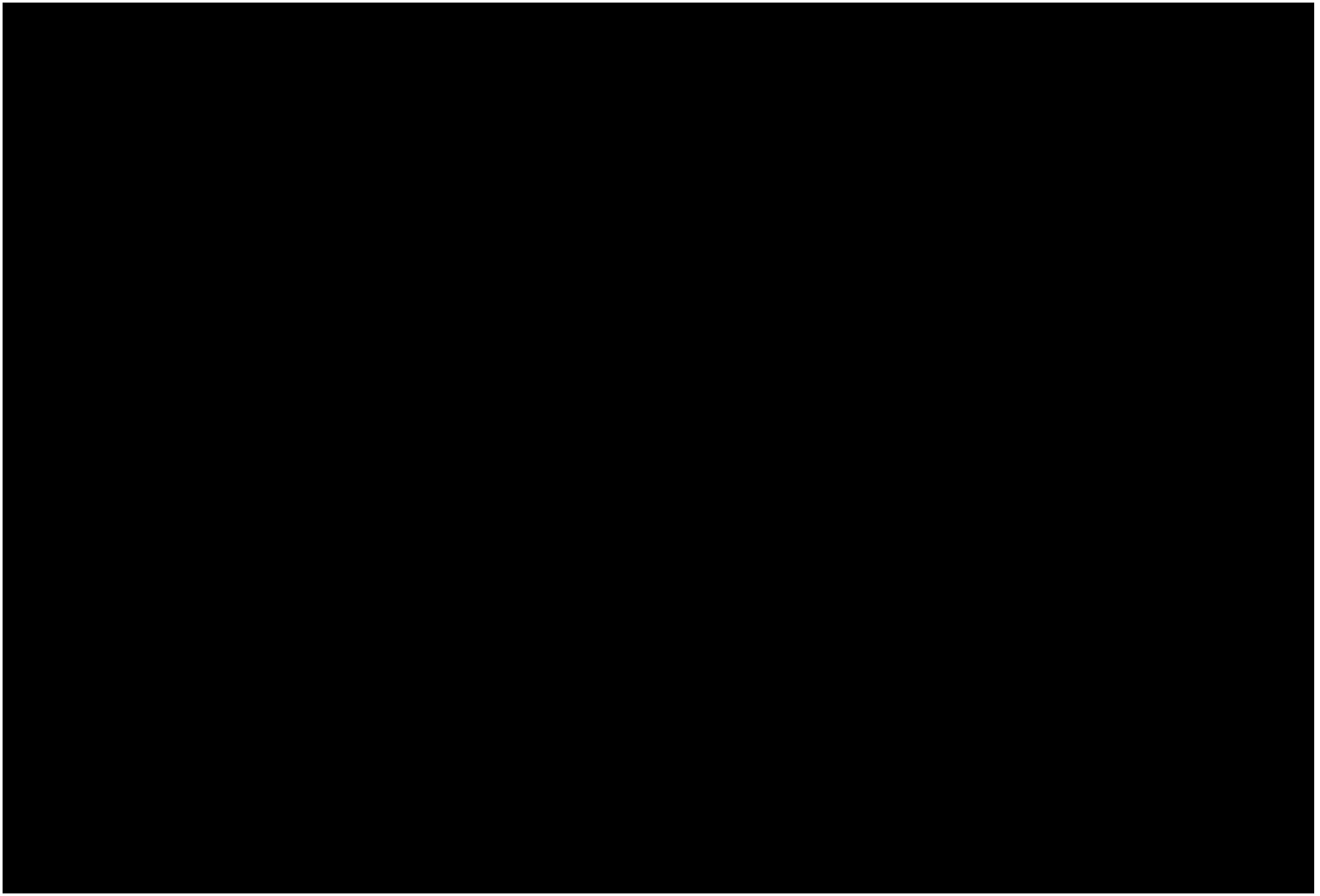
Date of On Peak Day - 12/30/2021



Member Forecasted On Peak Demand Day for January 2021

Garland Light and Power Company

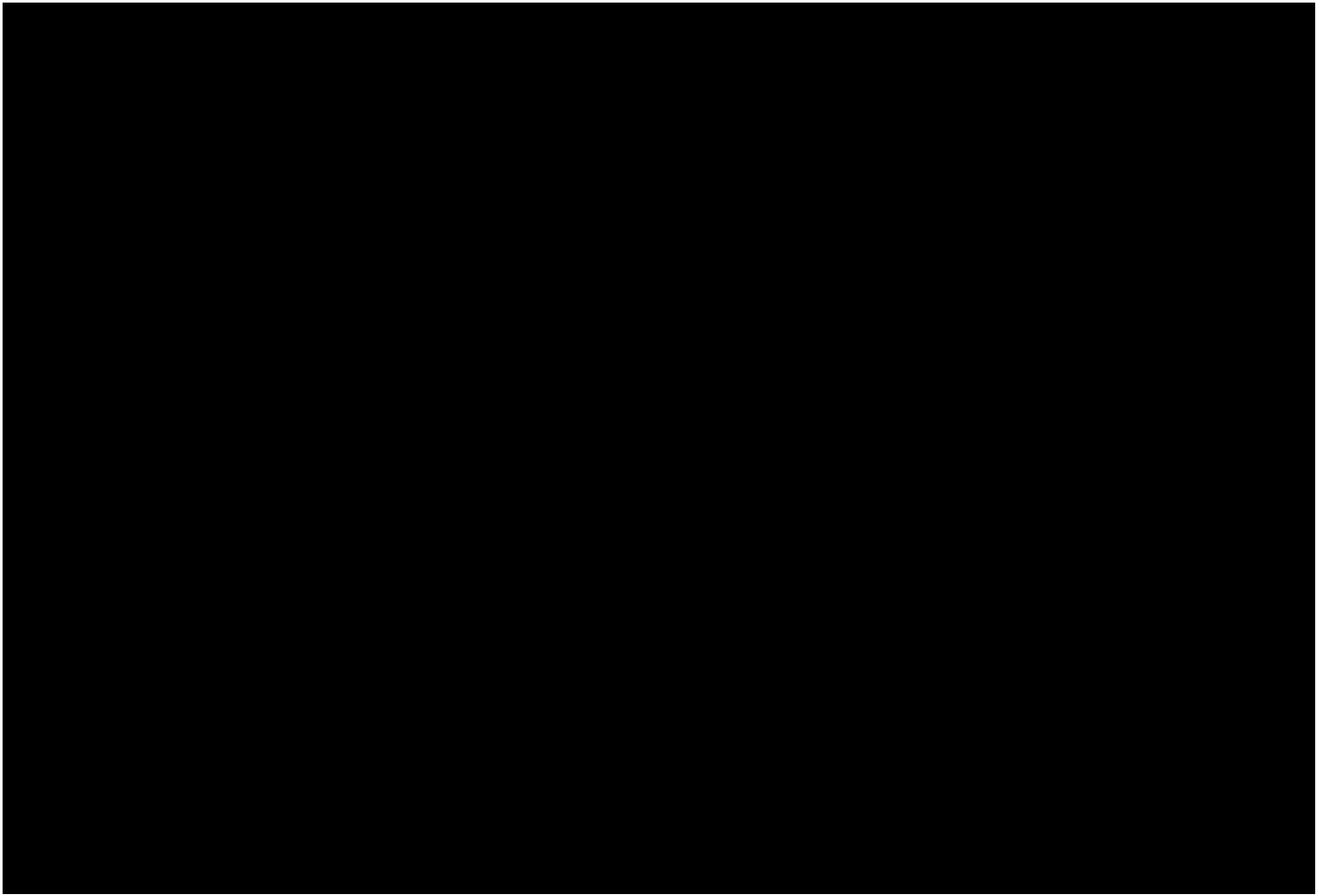
Date of On Peak Day - 01/03/2021



Member Forecasted On Peak Demand Day for February 2021

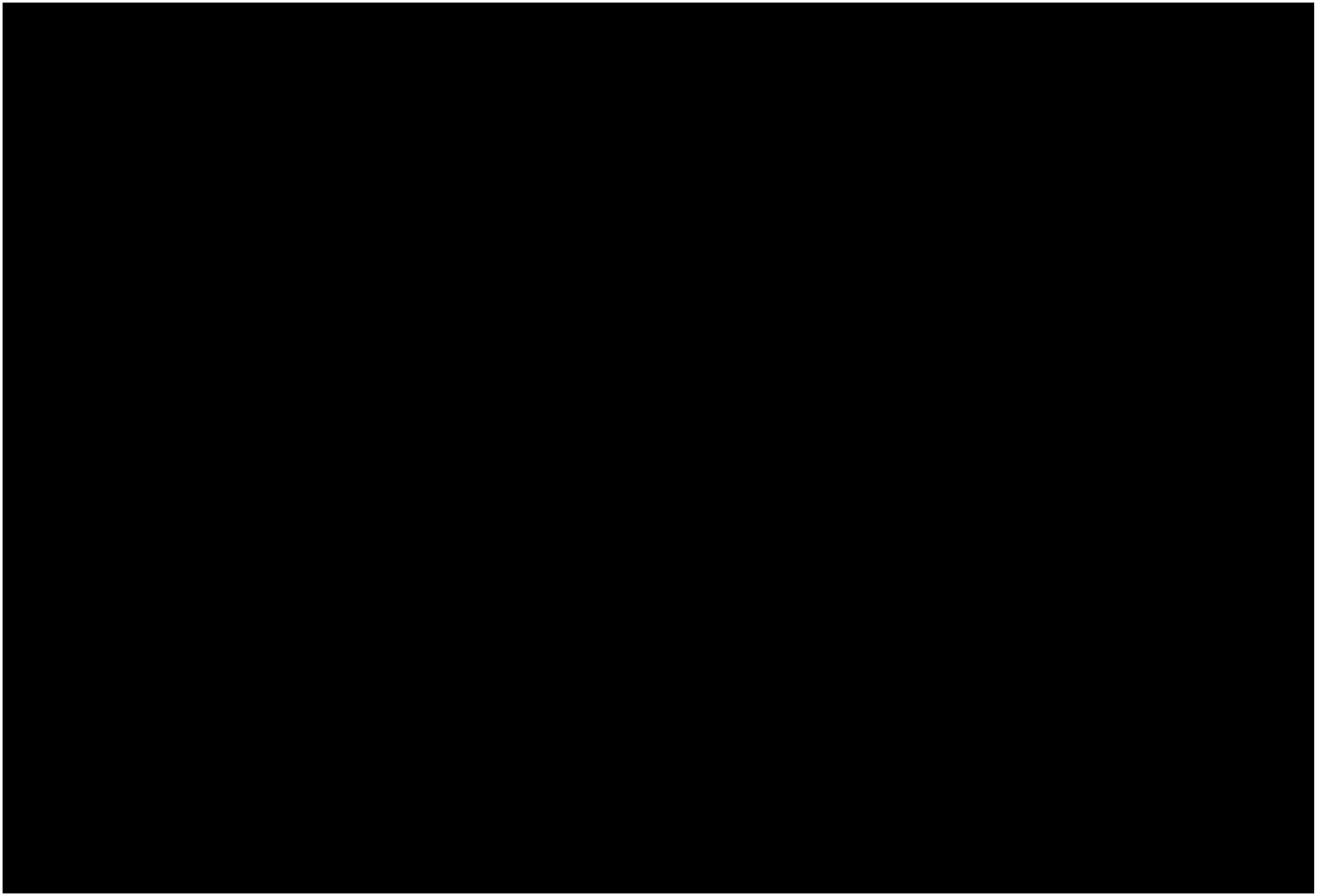
Garland Light and Power Company

Date of On Peak Day - 02/03/2021



Member Forecasted On Peak Demand Day for March 2021

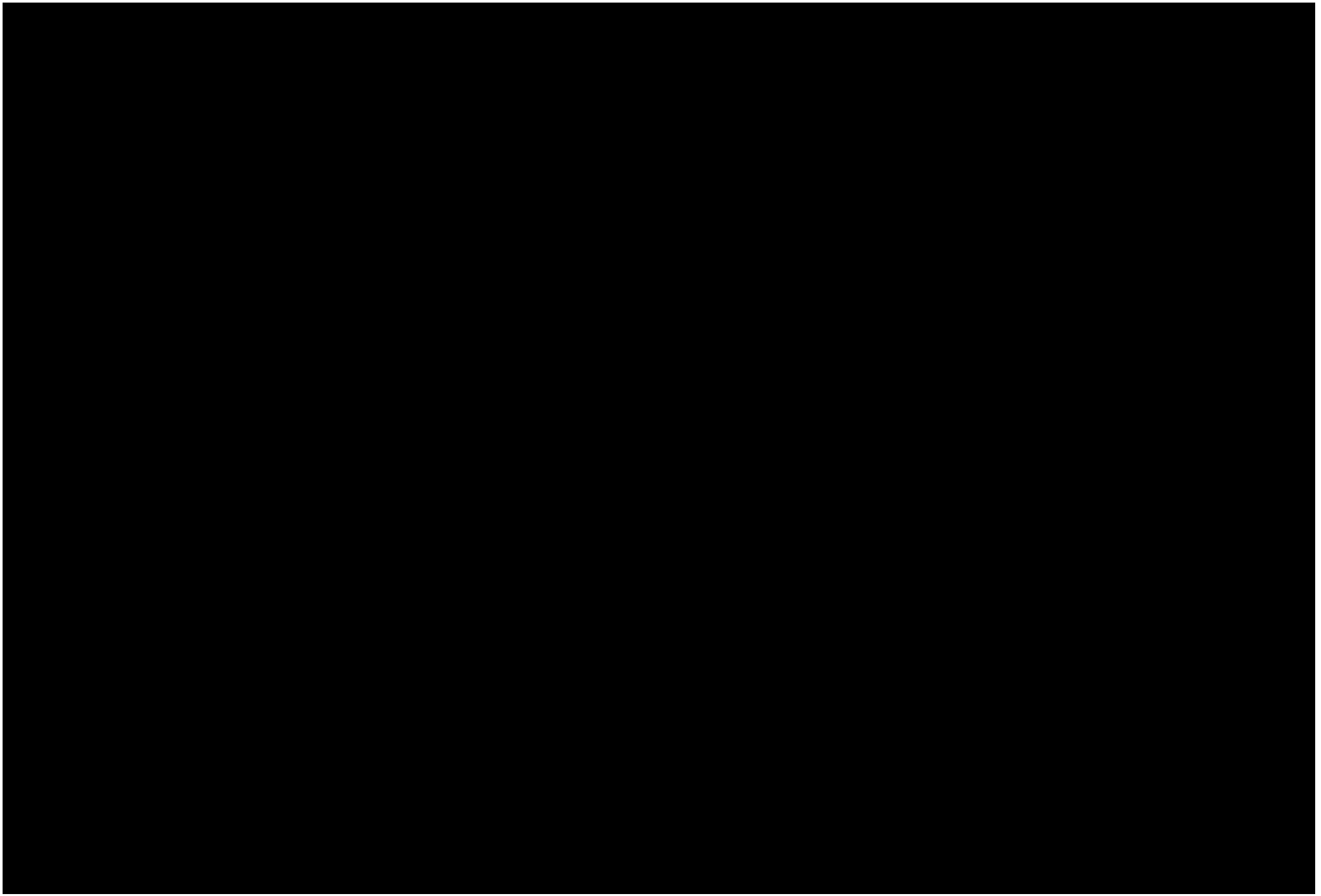
Garland Light and Power Company
Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

Garland Light and Power Company

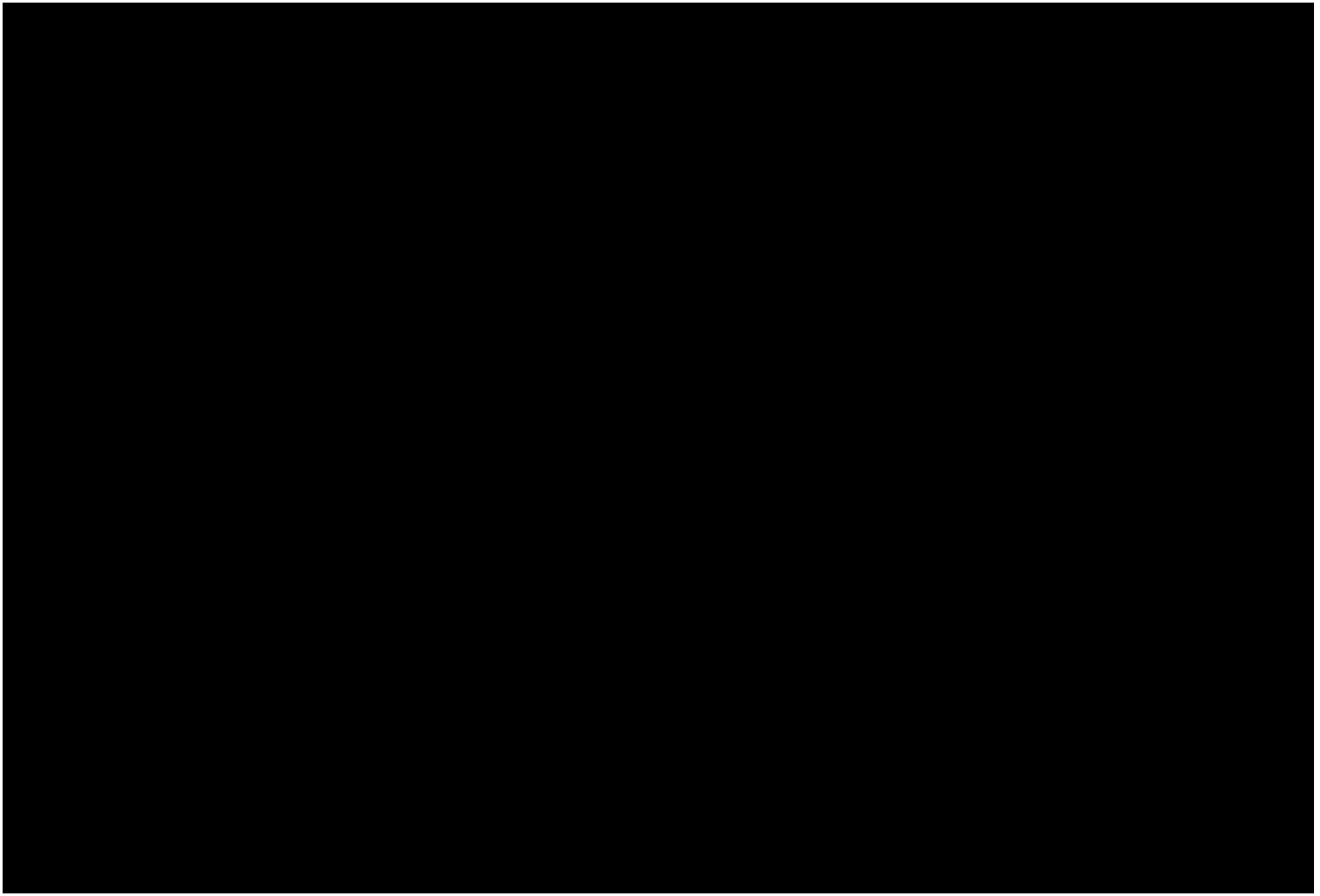
Date of On Peak Day - 04/07/2021



Member Forecasted On Peak Demand Day for May 2021

Garland Light and Power Company

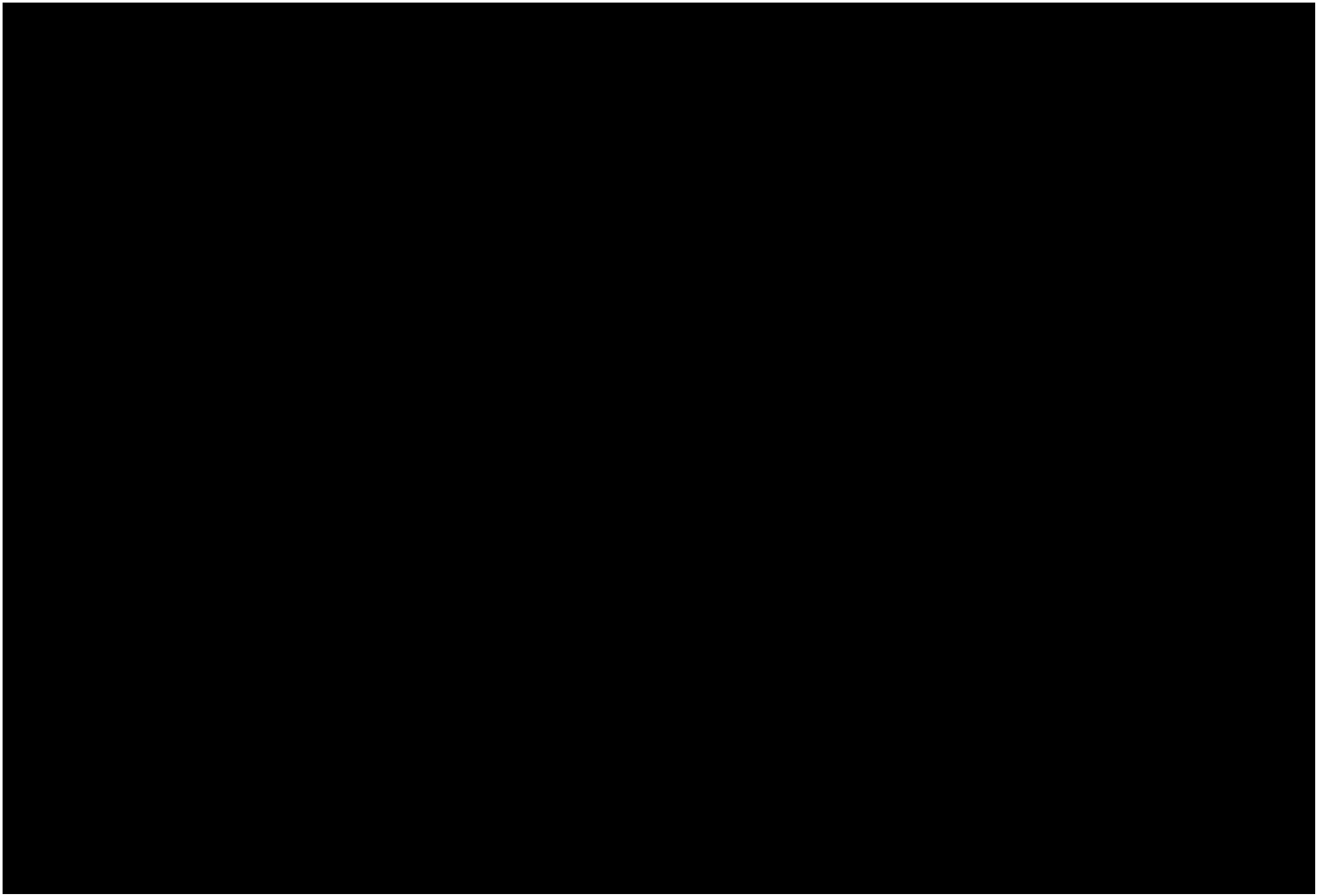
Date of On Peak Day - 05/30/2021



Member Forecasted On Peak Demand Day for June 2021

Garland Light and Power Company

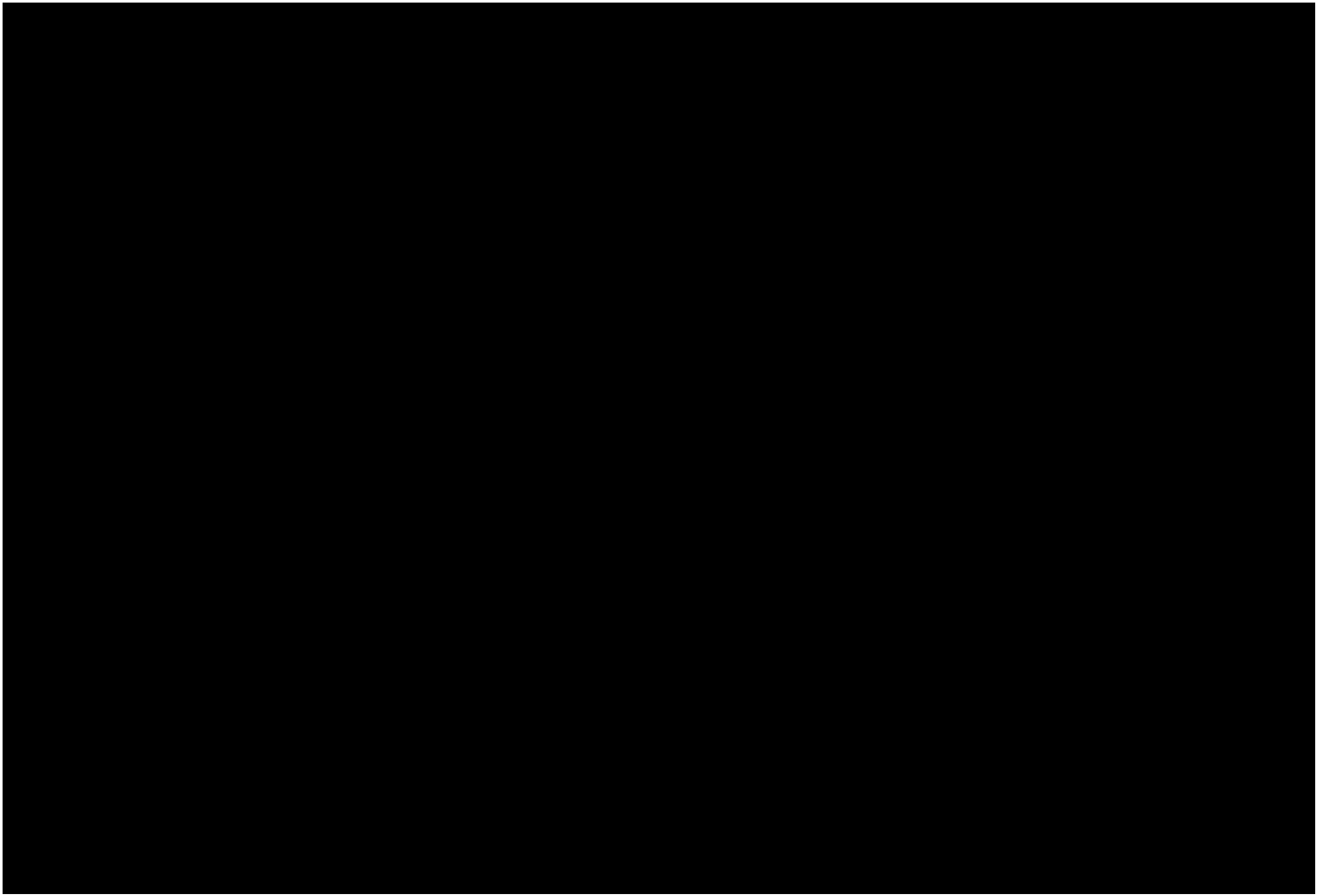
Date of On Peak Day - 06/09/2021



Member Forecasted On Peak Demand Day for July 2021

Garland Light and Power Company

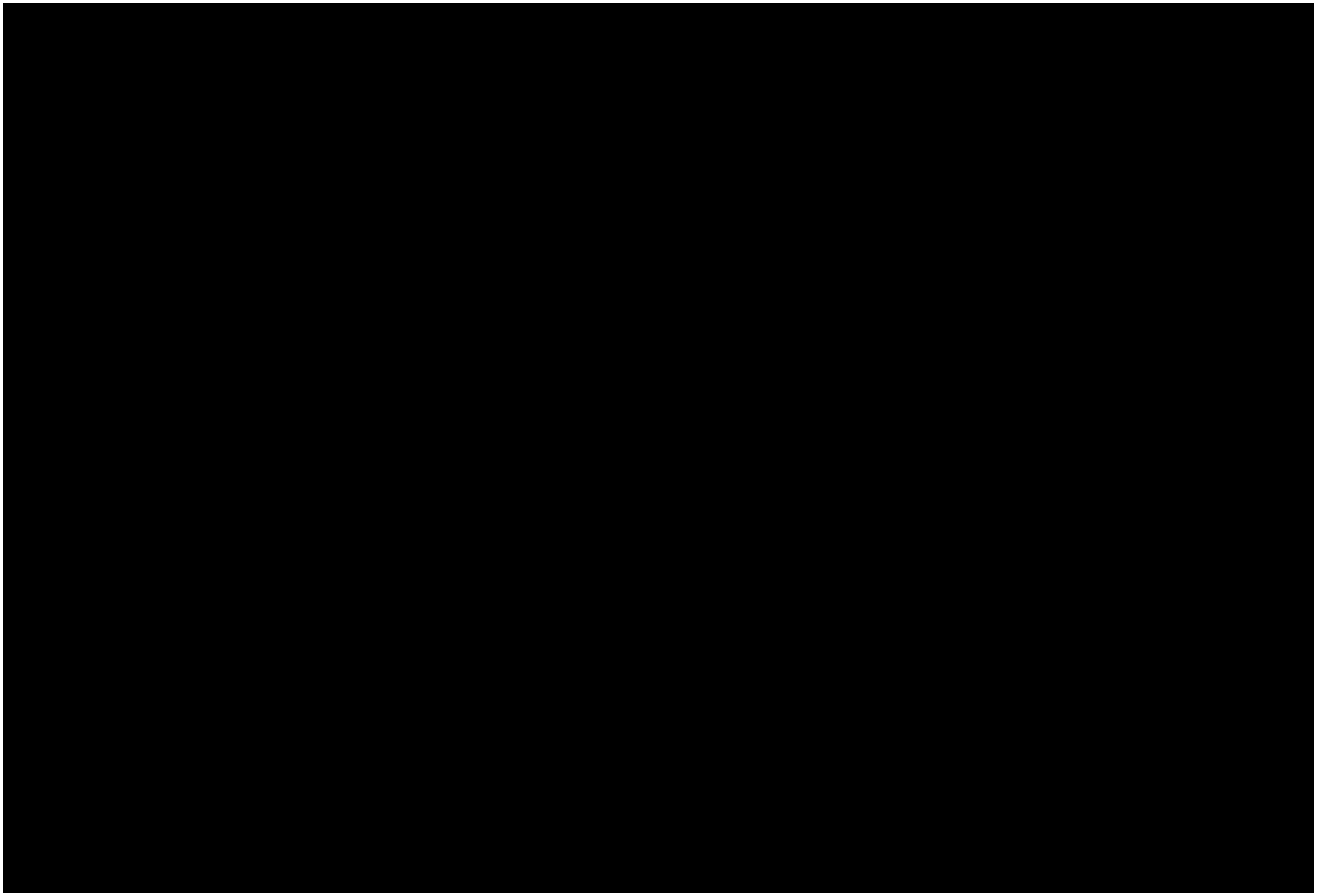
Date of On Peak Day - 07/25/2021



Member Forecasted On Peak Demand Day for August 2021

Garland Light and Power Company

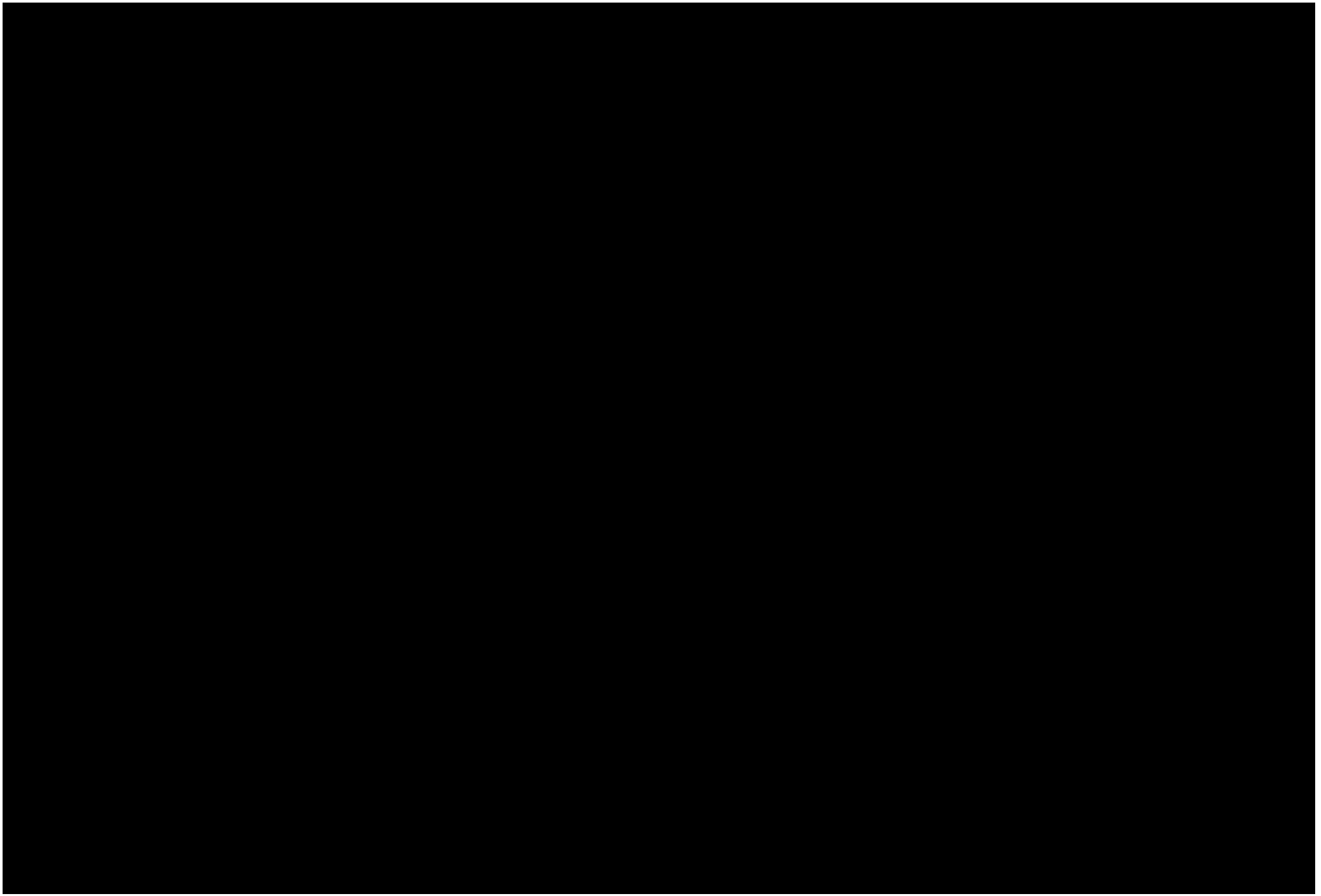
Date of On Peak Day - 08/28/2021



Member Forecasted On Peak Demand Day for September 2021

Garland Light and Power Company

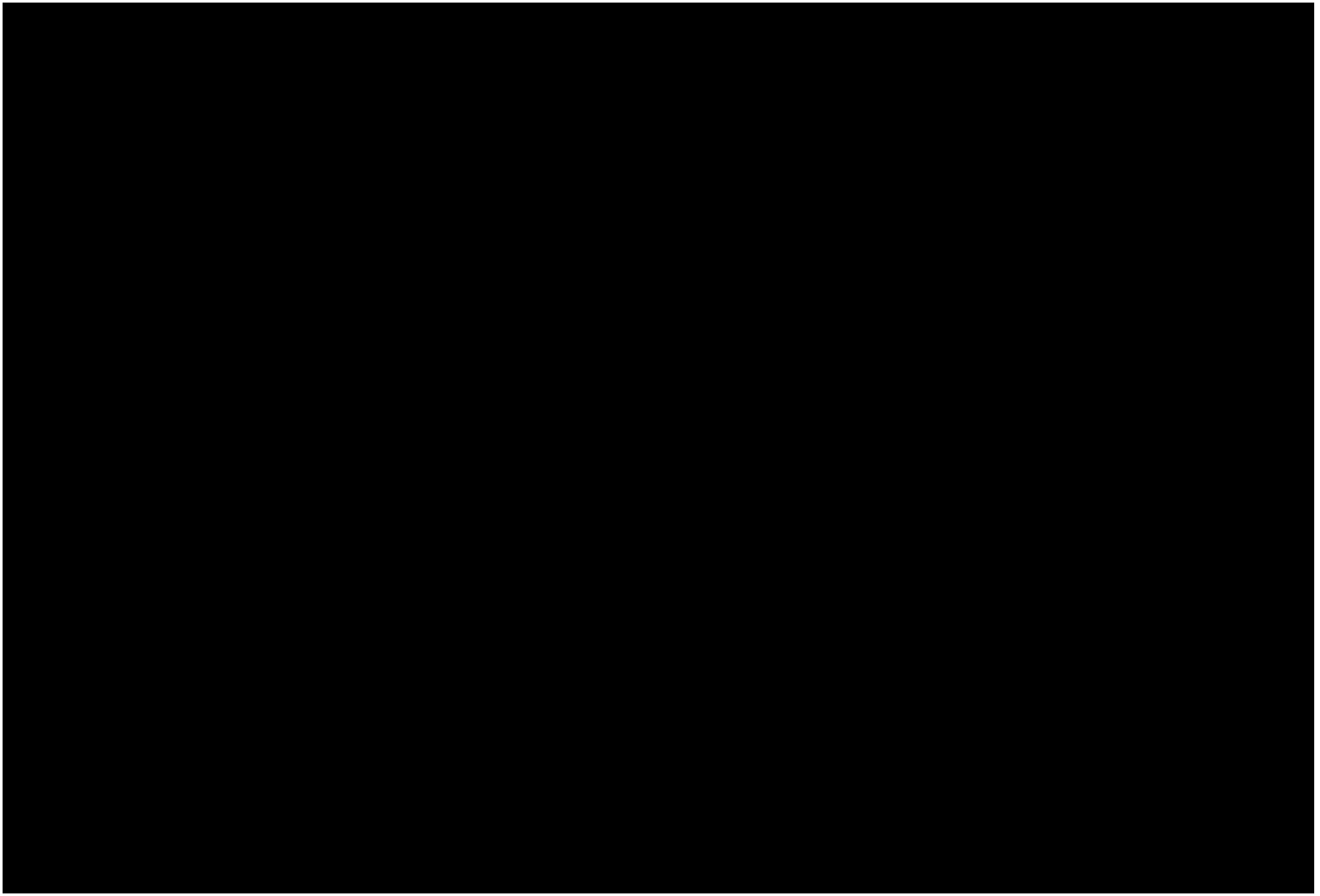
Date of On Peak Day - 09/01/2021



Member Forecasted On Peak Demand Day for October 2021

Garland Light and Power Company

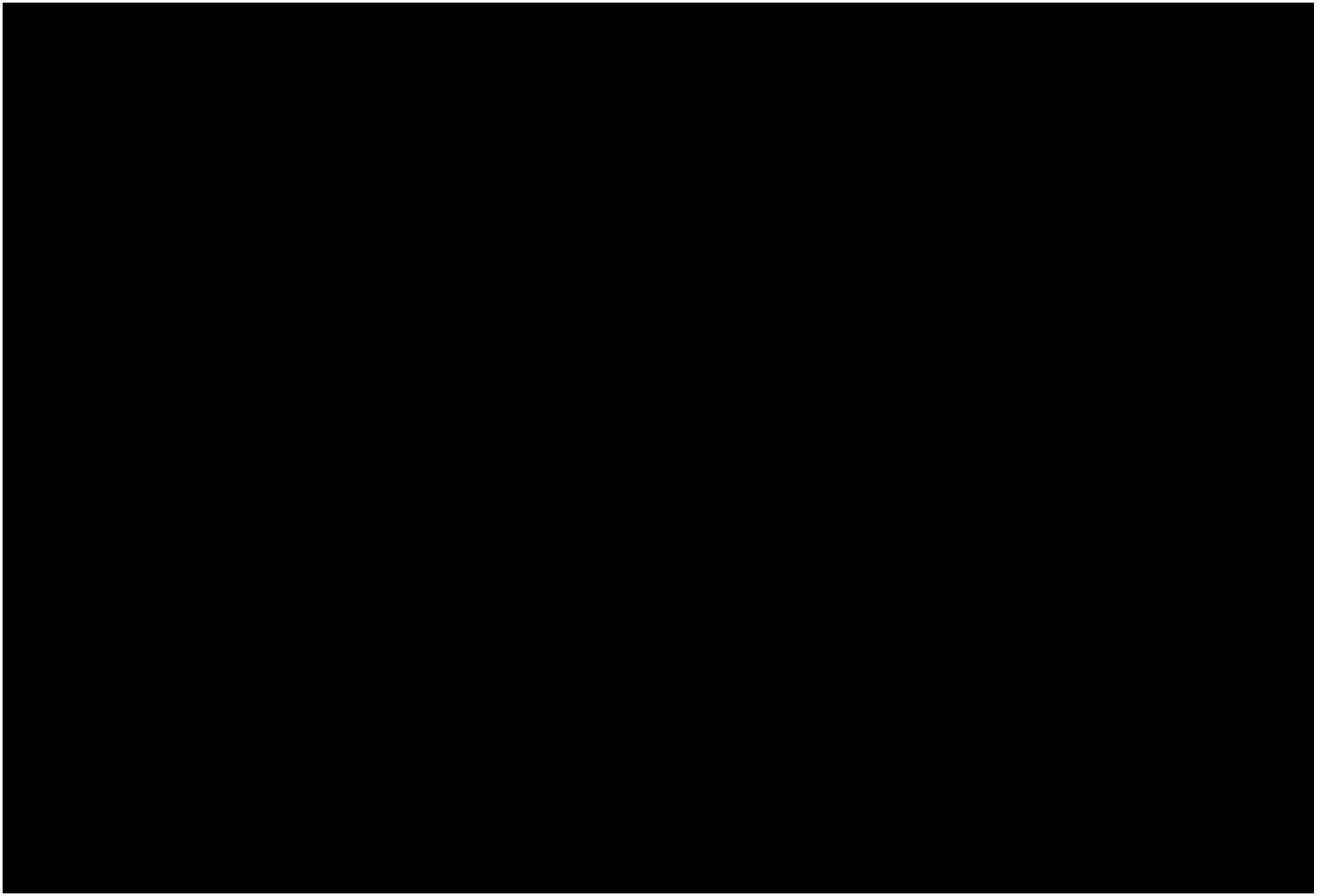
Date of On Peak Day - 10/12/2021



Member Forecasted On Peak Demand Day for November 2021

Garland Light and Power Company

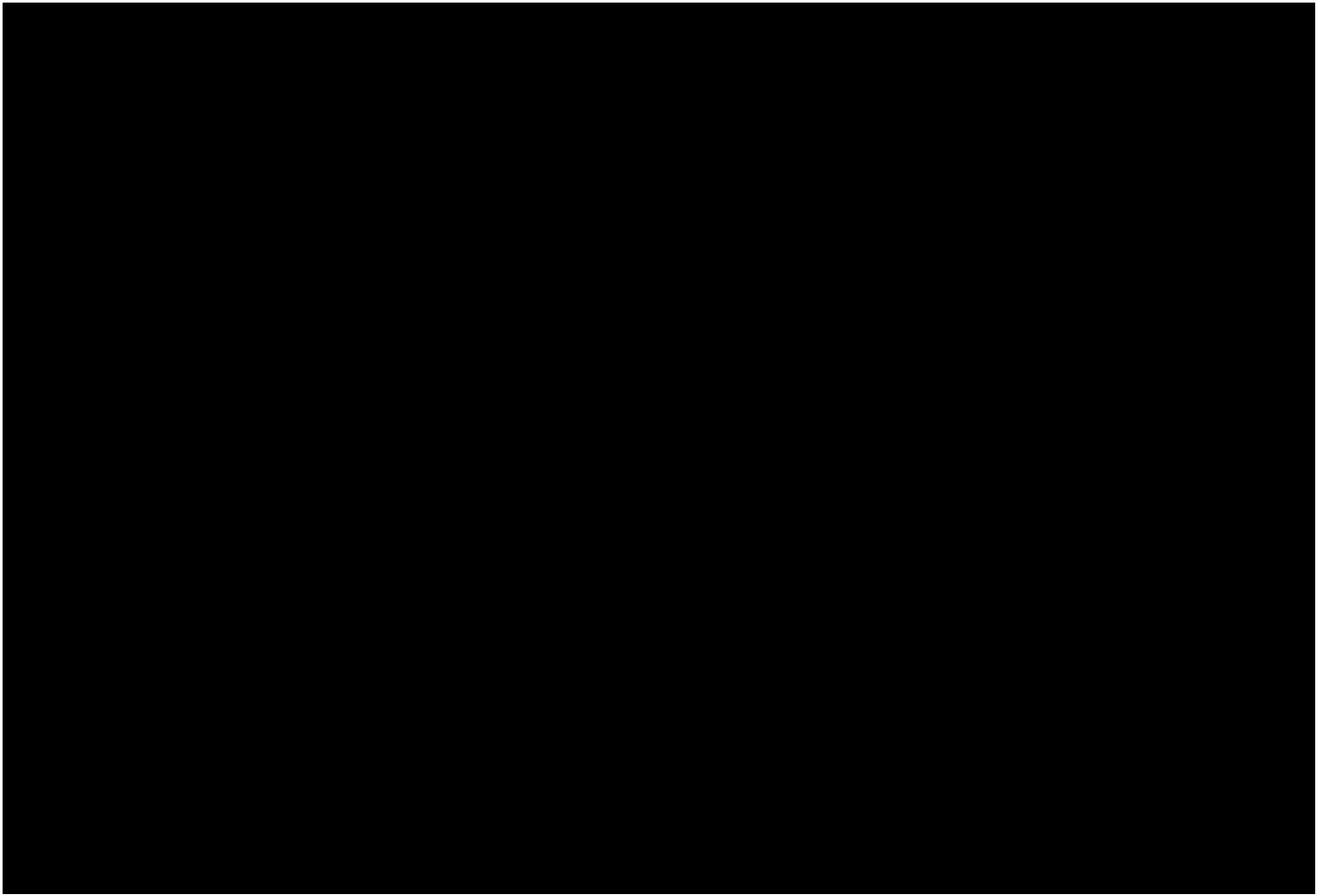
Date of On Peak Day - 11/07/2021



Member Forecasted On Peak Demand Day for December 2021

Garland Light and Power Company

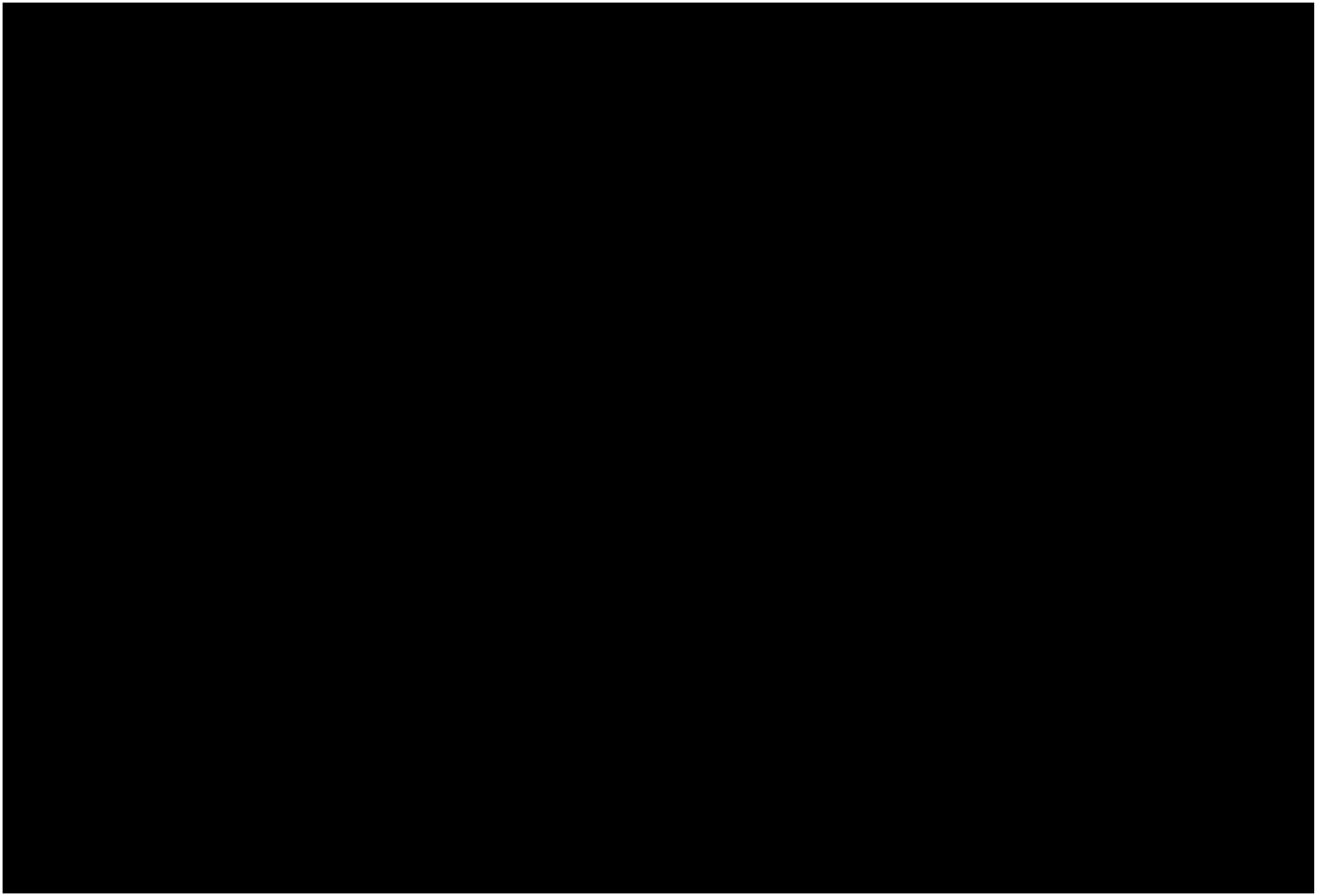
Date of On Peak Day - 12/02/2021



Member Forecasted On Peak Demand Day for January 2021

Highline Electric Association

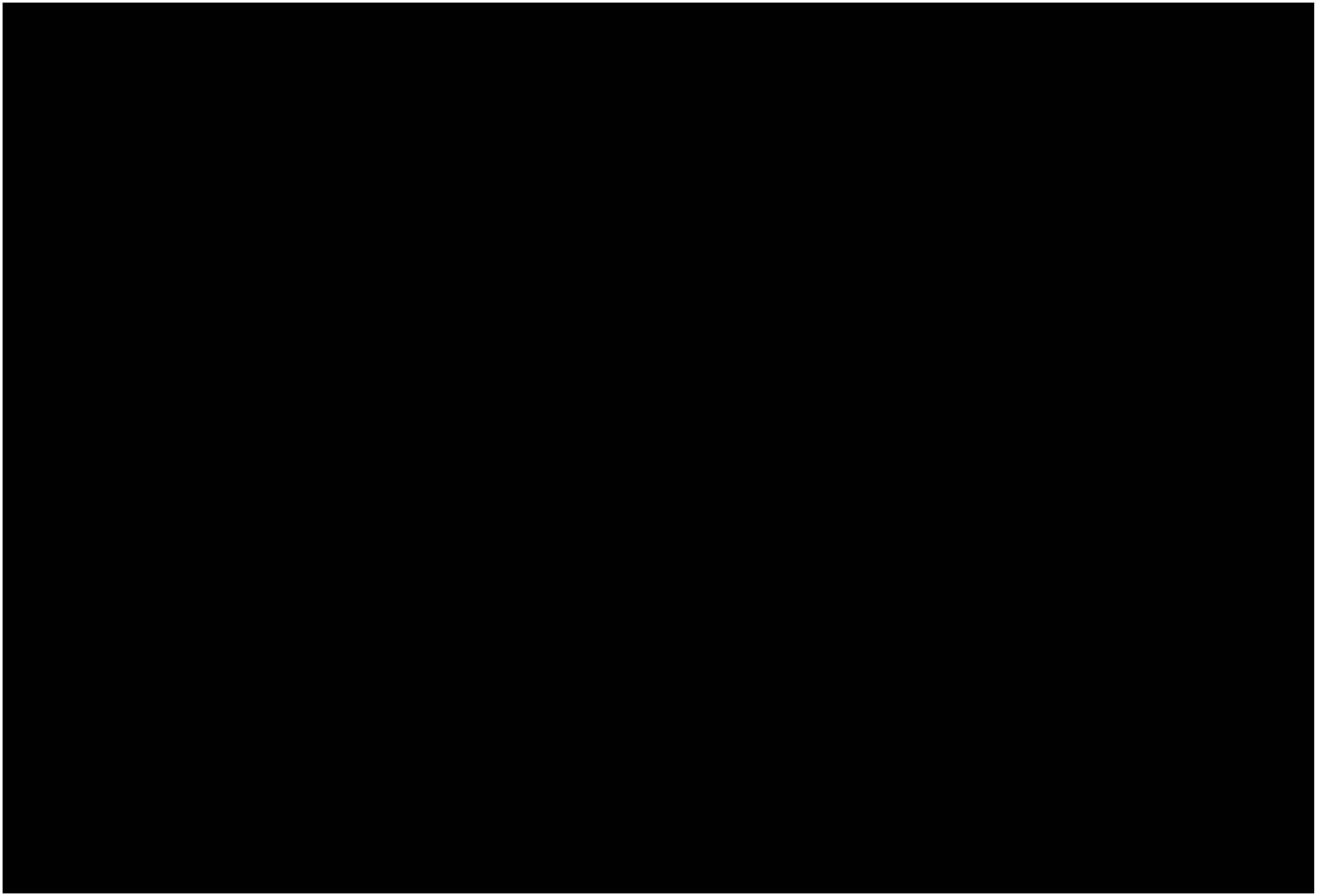
Date of On Peak Day - 01/30/2021



Member Forecasted On Peak Demand Day for February 2021

Highline Electric Association

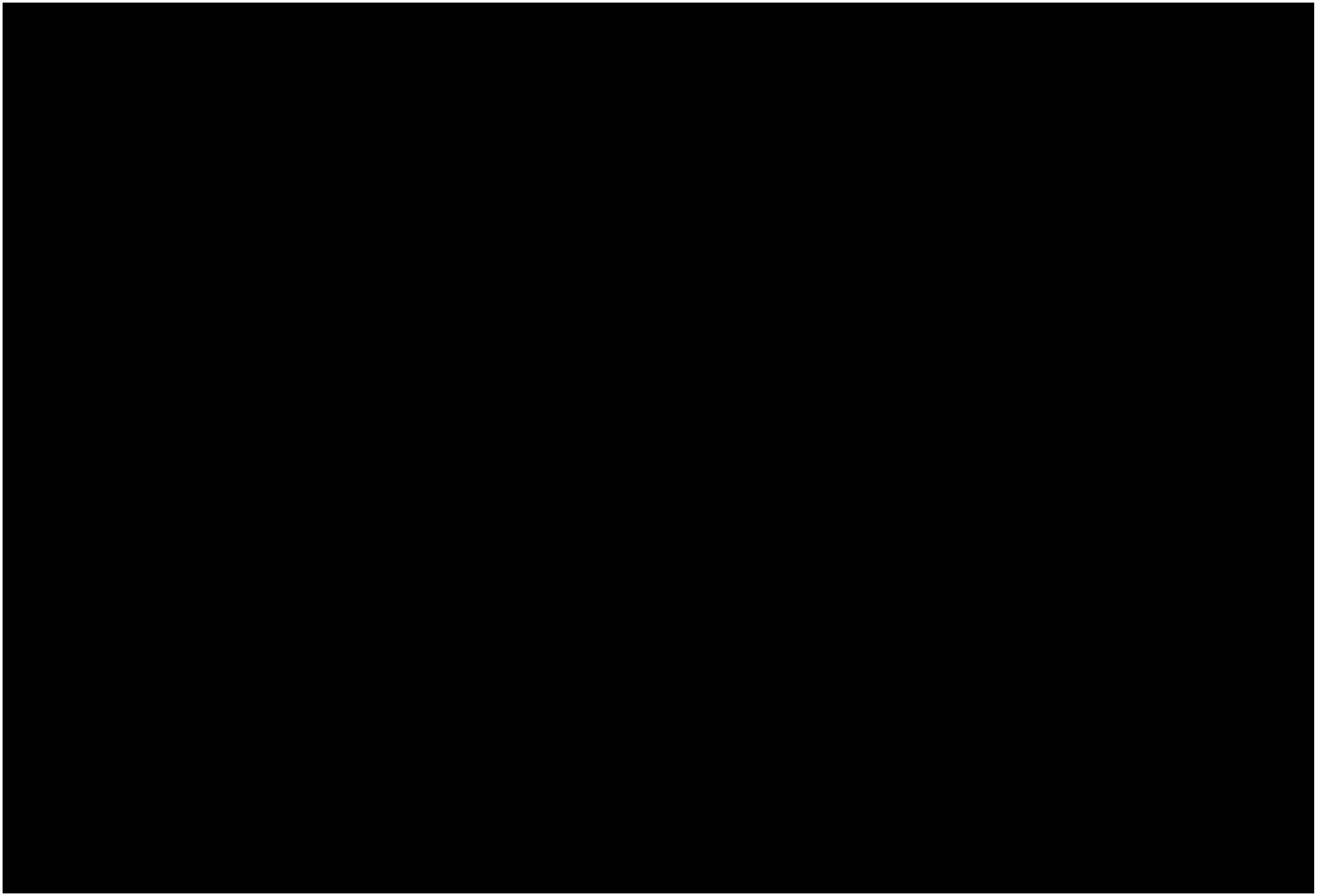
Date of On Peak Day - 02/26/2021



Member Forecasted On Peak Demand Day for March 2021

Highline Electric Association

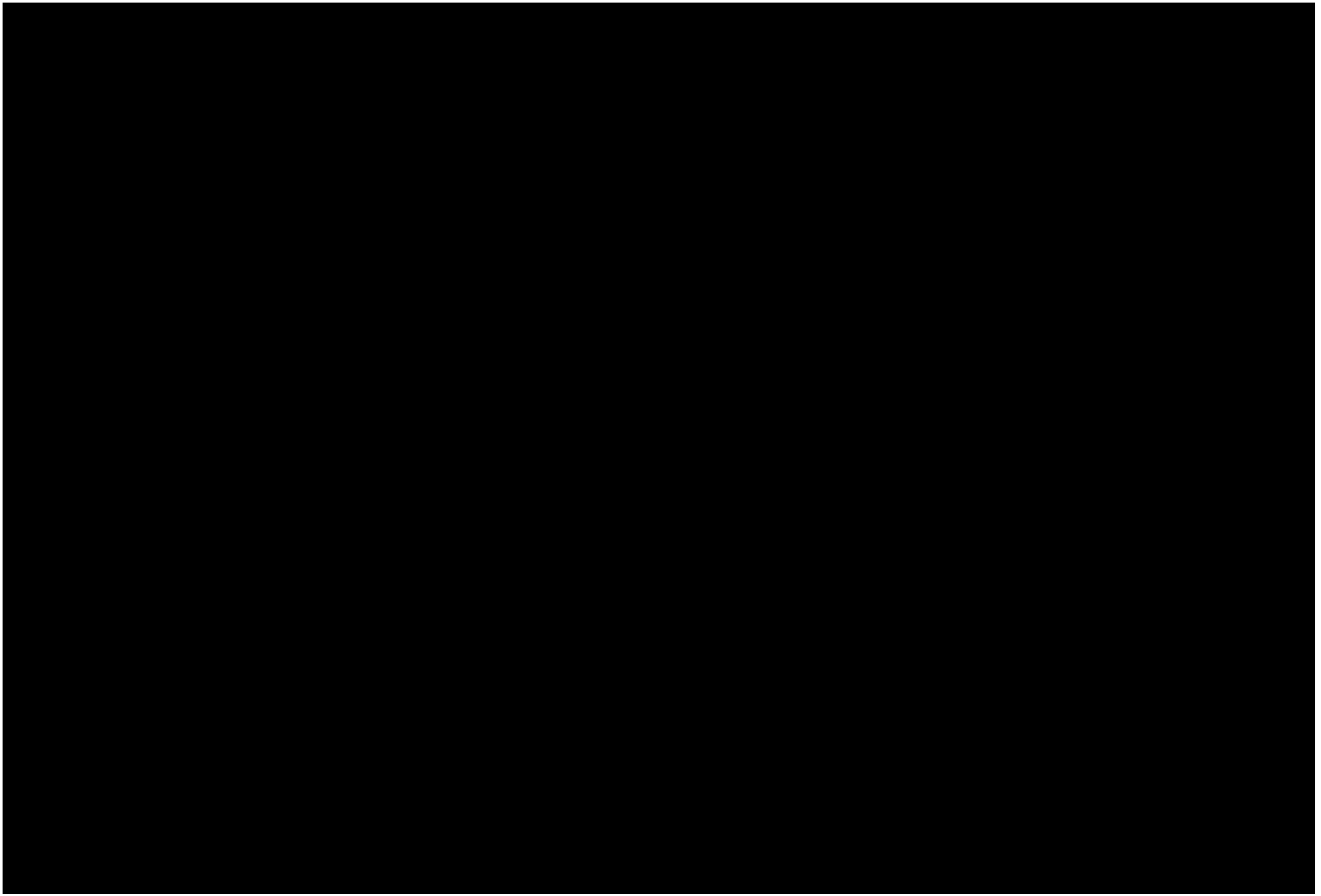
Date of On Peak Day - 03/19/2021



Member Forecasted On Peak Demand Day for April 2021

Highline Electric Association

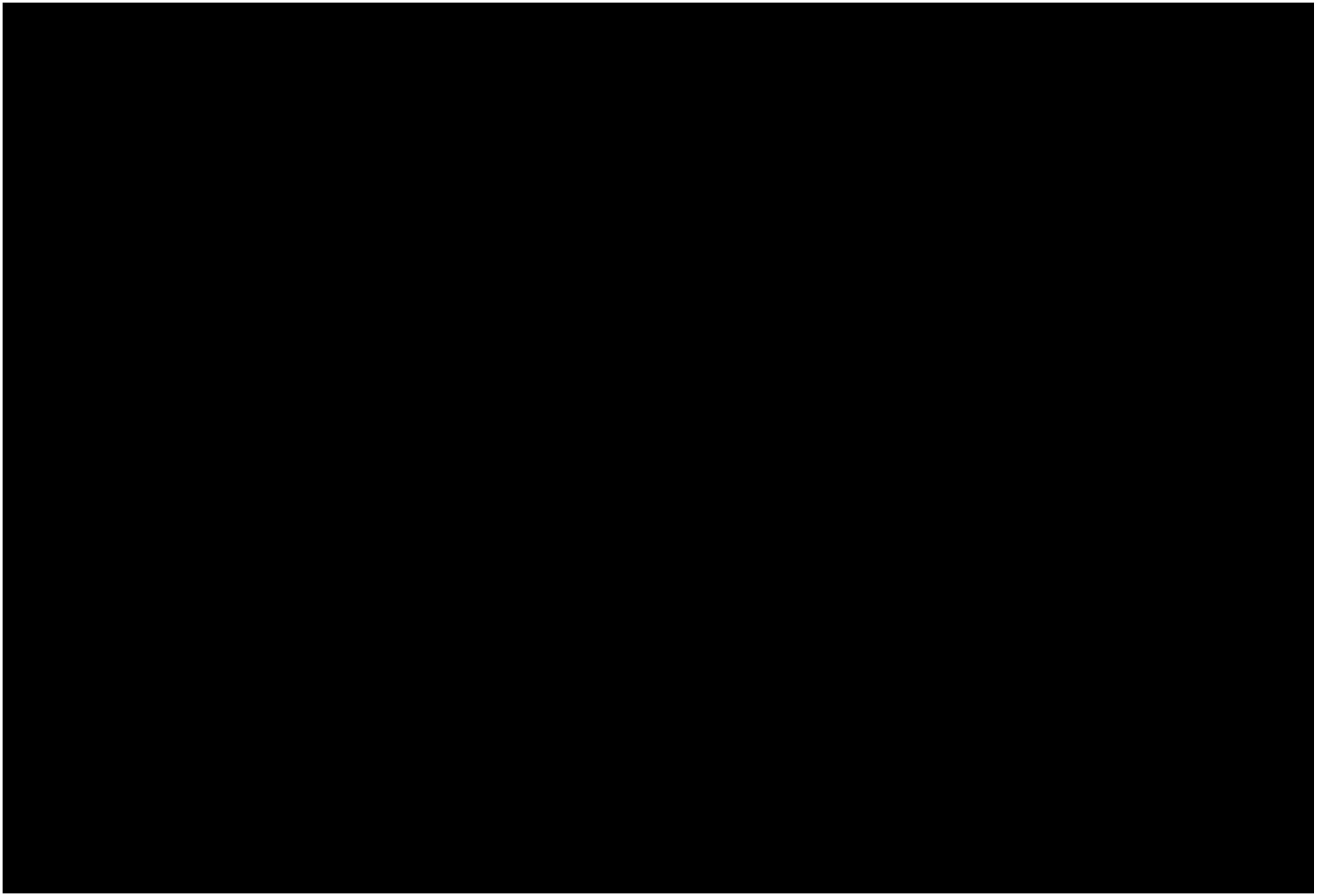
Date of On Peak Day - 04/30/2021



Member Forecasted On Peak Demand Day for May 2021

Highline Electric Association

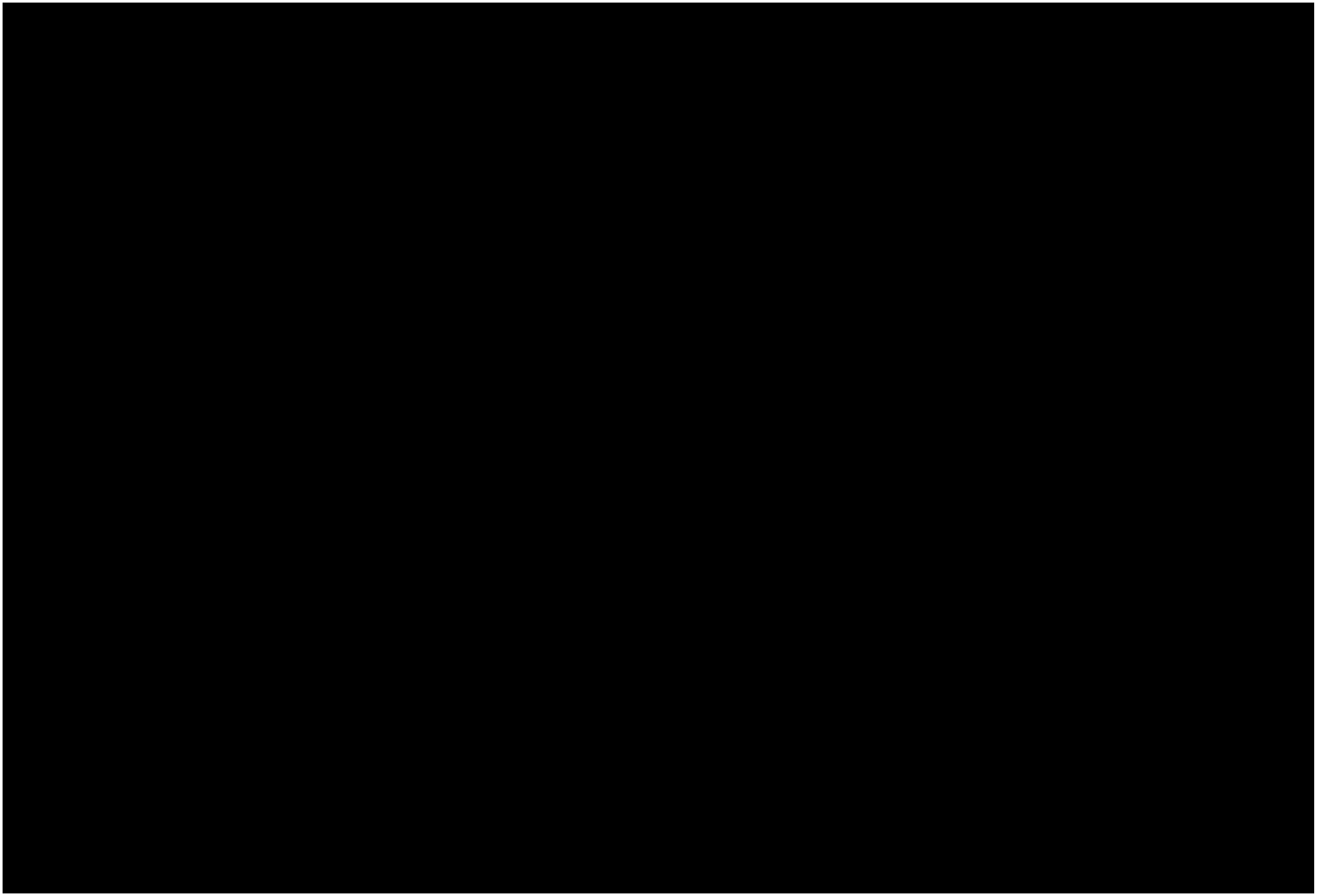
Date of On Peak Day - 05/31/2021



Member Forecasted On Peak Demand Day for June 2021

Highline Electric Association

Date of On Peak Day - 06/11/2021



Hearing Exhibit 101
PUBLIC Attachment BN-2
Proceeding No. 20A-0528E
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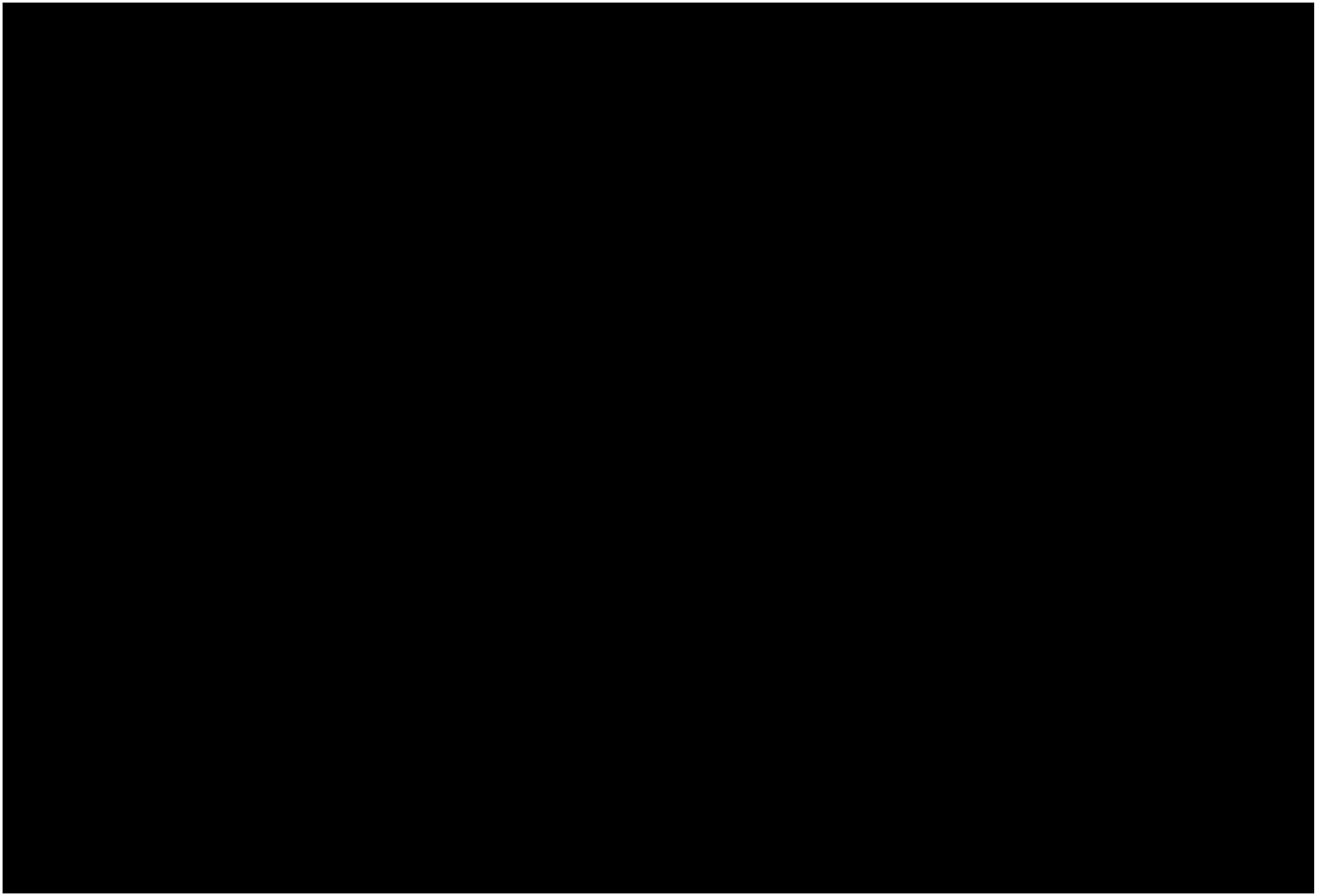
Member Forecasted On Peak Demand Day for July 2021

Highline Electric Association

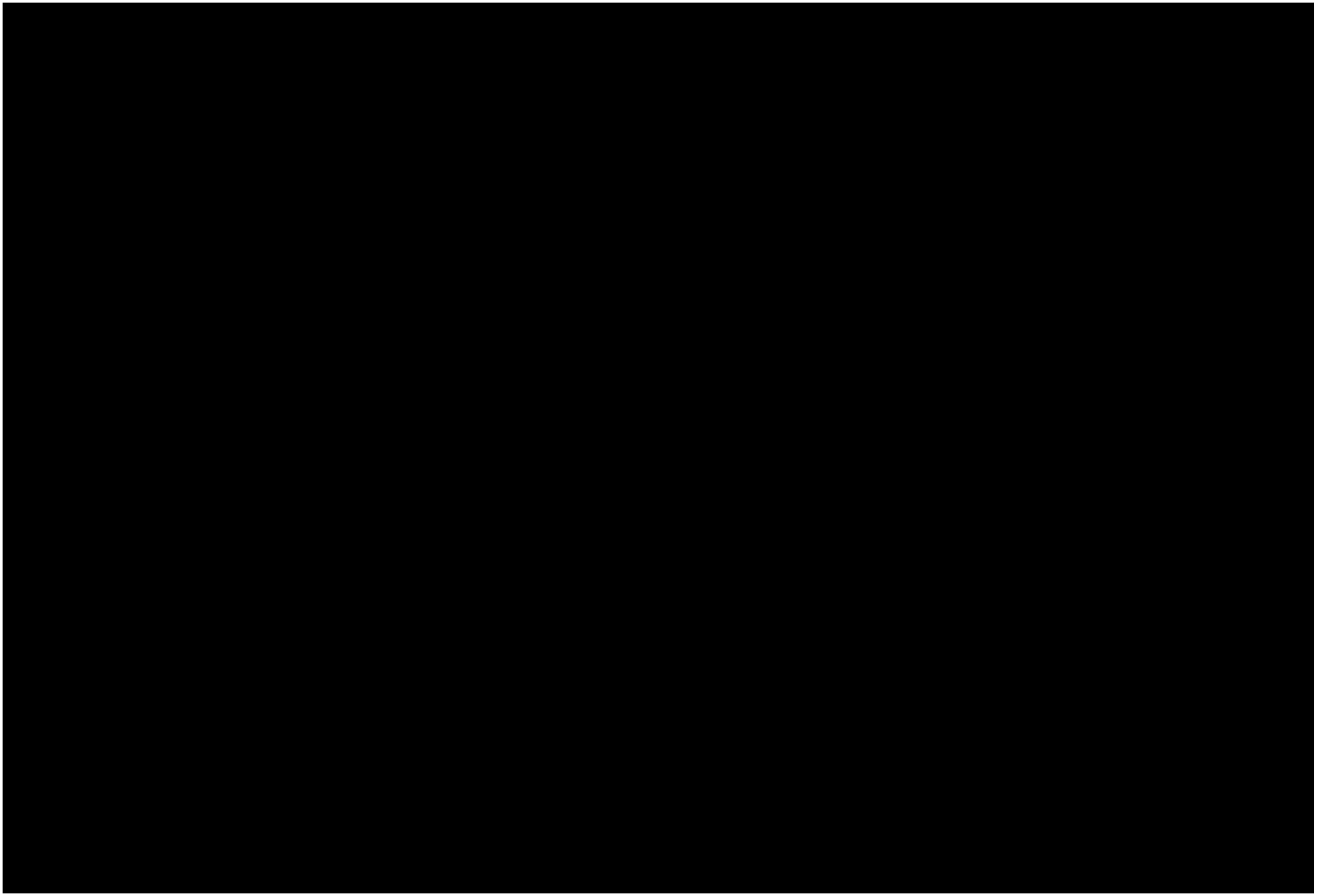
Date of On Peak Day - 07/21/2021



Member Forecasted On Peak Demand Day for August 2021

Highline Electric Association

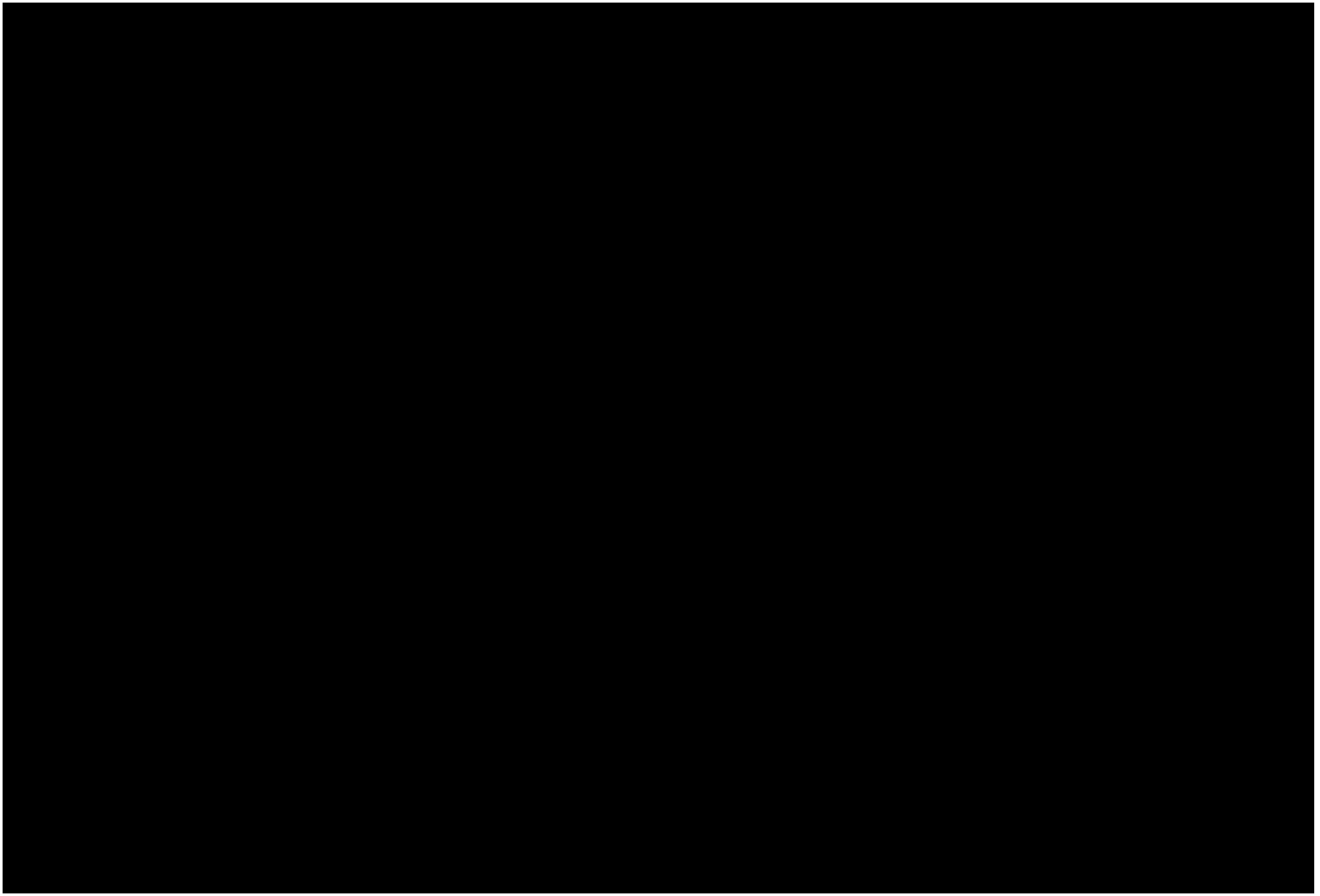
Date of On Peak Day - 08/31/2021



Member Forecasted On Peak Demand Day for September 2021

Highline Electric Association

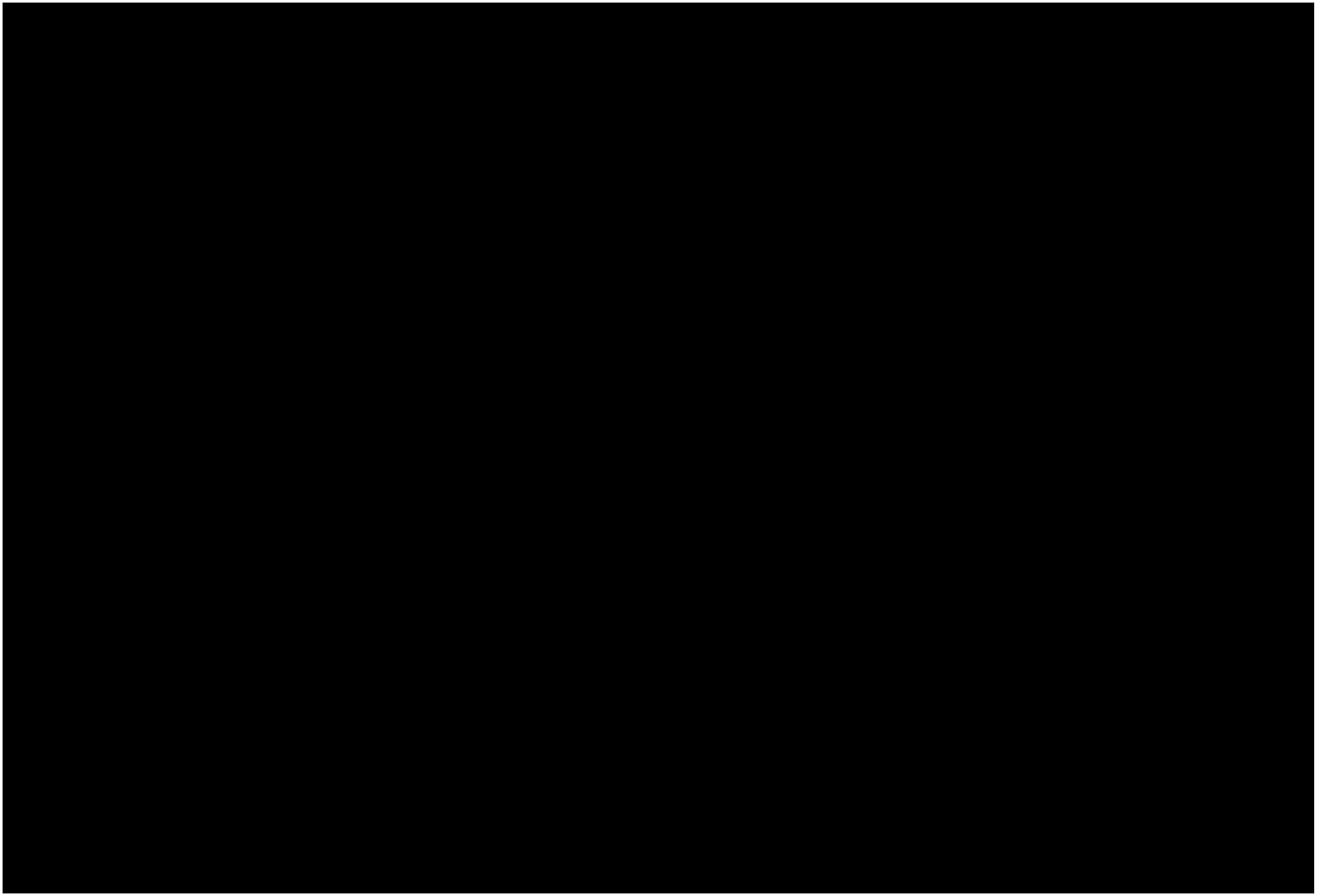
Date of On Peak Day - 09/01/2021



Member Forecasted On Peak Demand Day for October 2021

Highline Electric Association

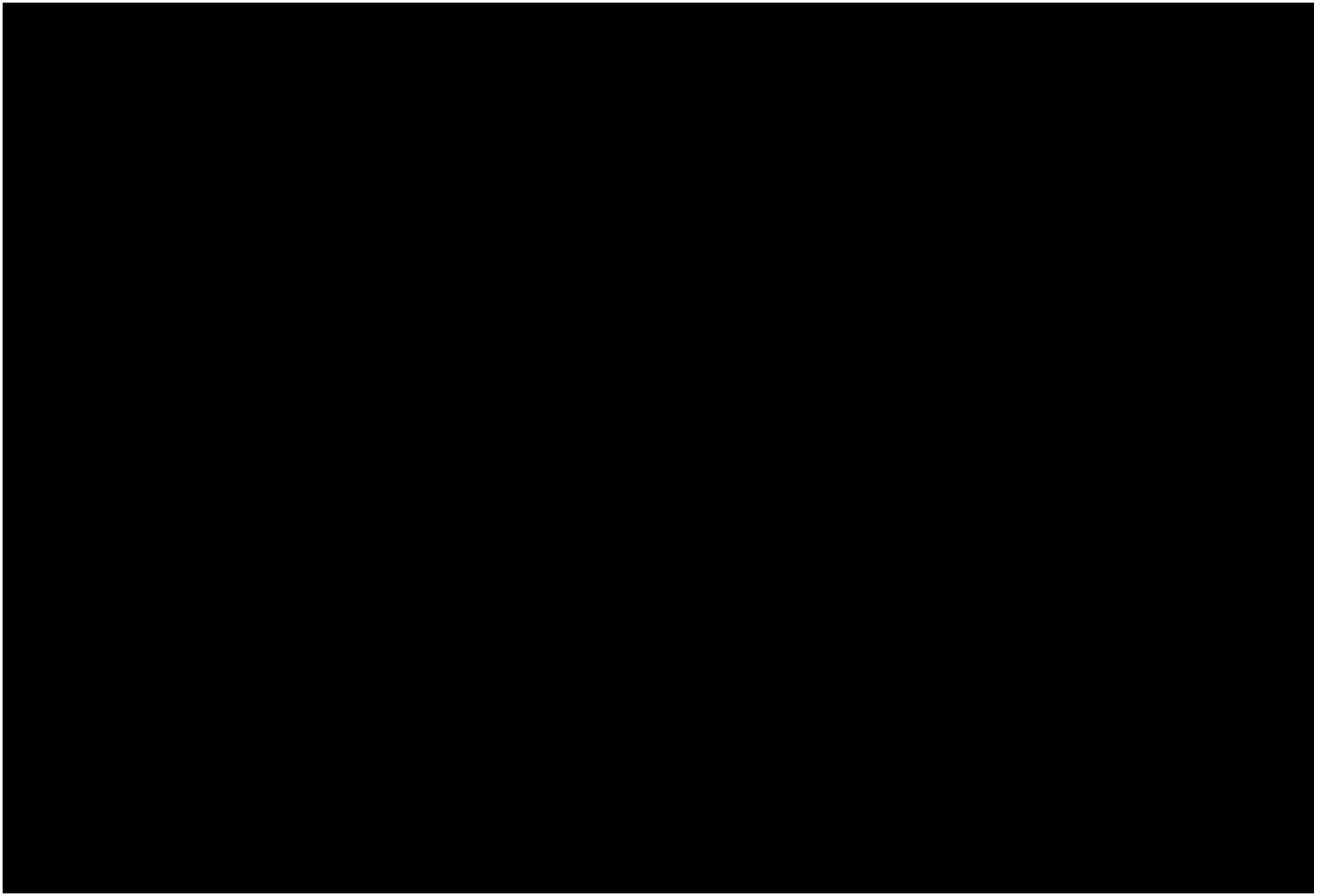
Date of On Peak Day - 10/17/2021



Member Forecasted On Peak Demand Day for November 2021

Highline Electric Association

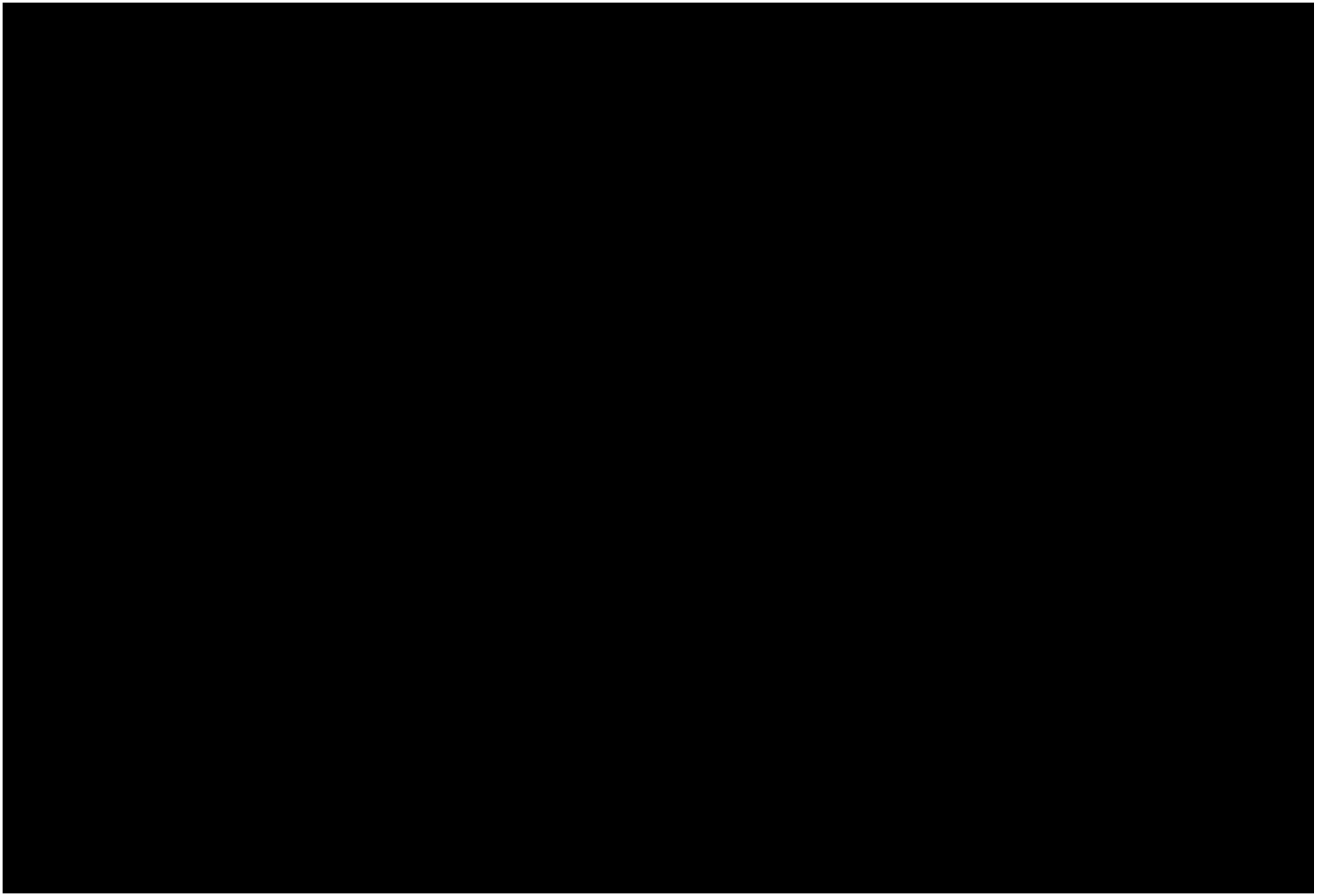
Date of On Peak Day - 11/17/2021



Member Forecasted On Peak Demand Day for December 2021

Highline Electric Association

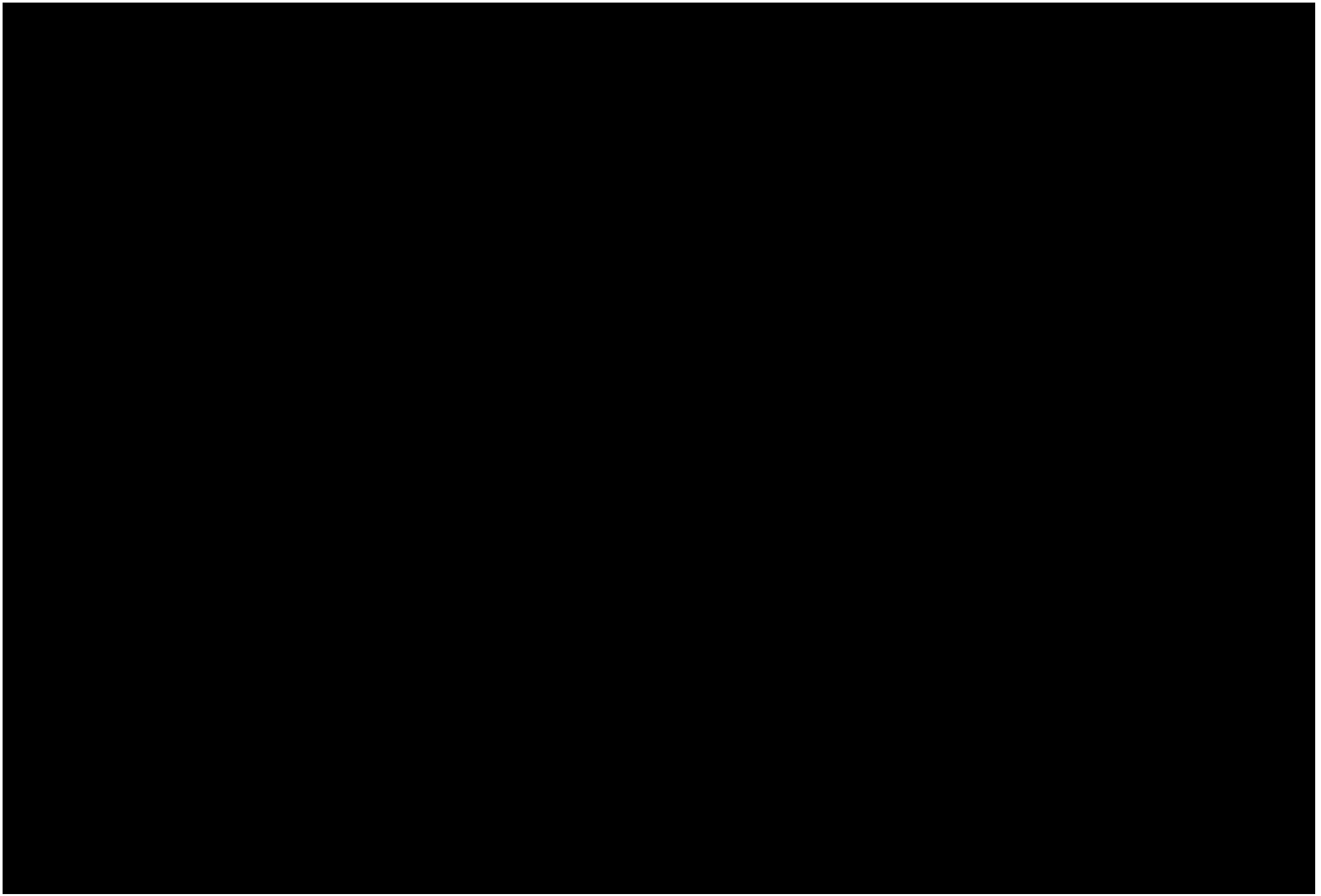
Date of On Peak Day - 12/28/2021



Member Forecasted On Peak Demand Day for January 2021

High Plains Power, Inc.

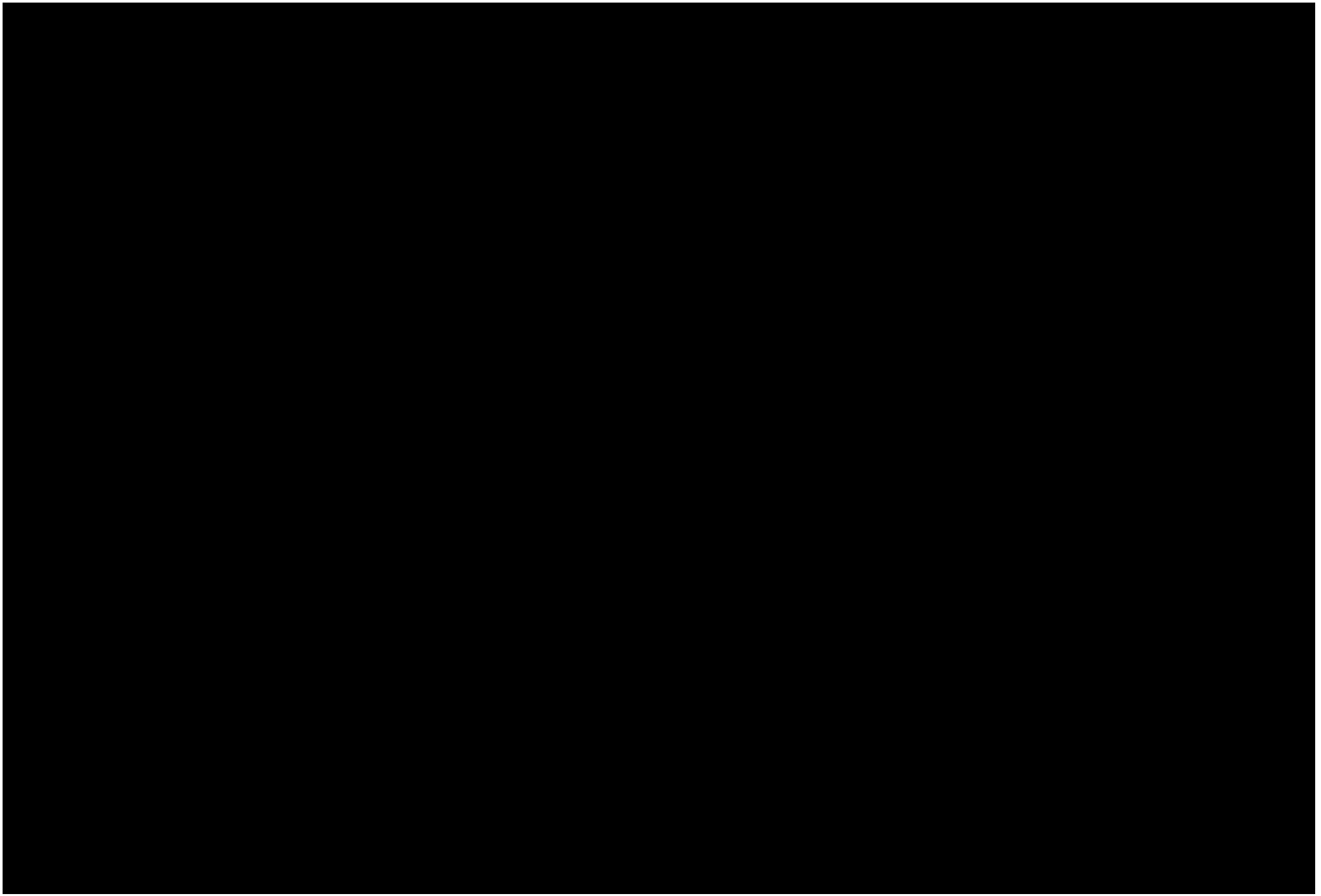
Date of On Peak Day - 01/06/2021



Member Forecasted On Peak Demand Day for February 2021

High Plains Power, Inc.

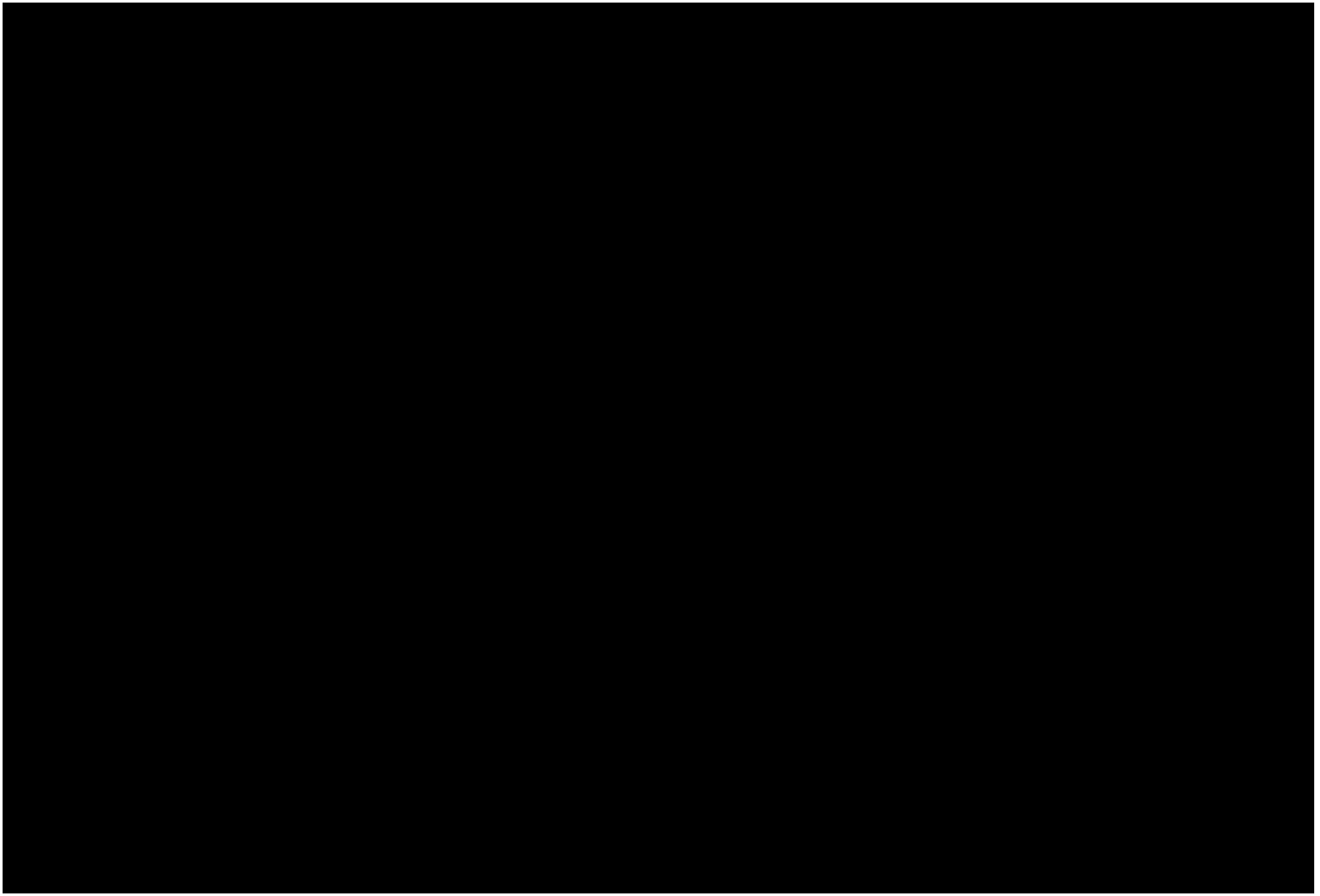
Date of On Peak Day - 02/03/2021



Member Forecasted On Peak Demand Day for March 2021

High Plains Power, Inc.

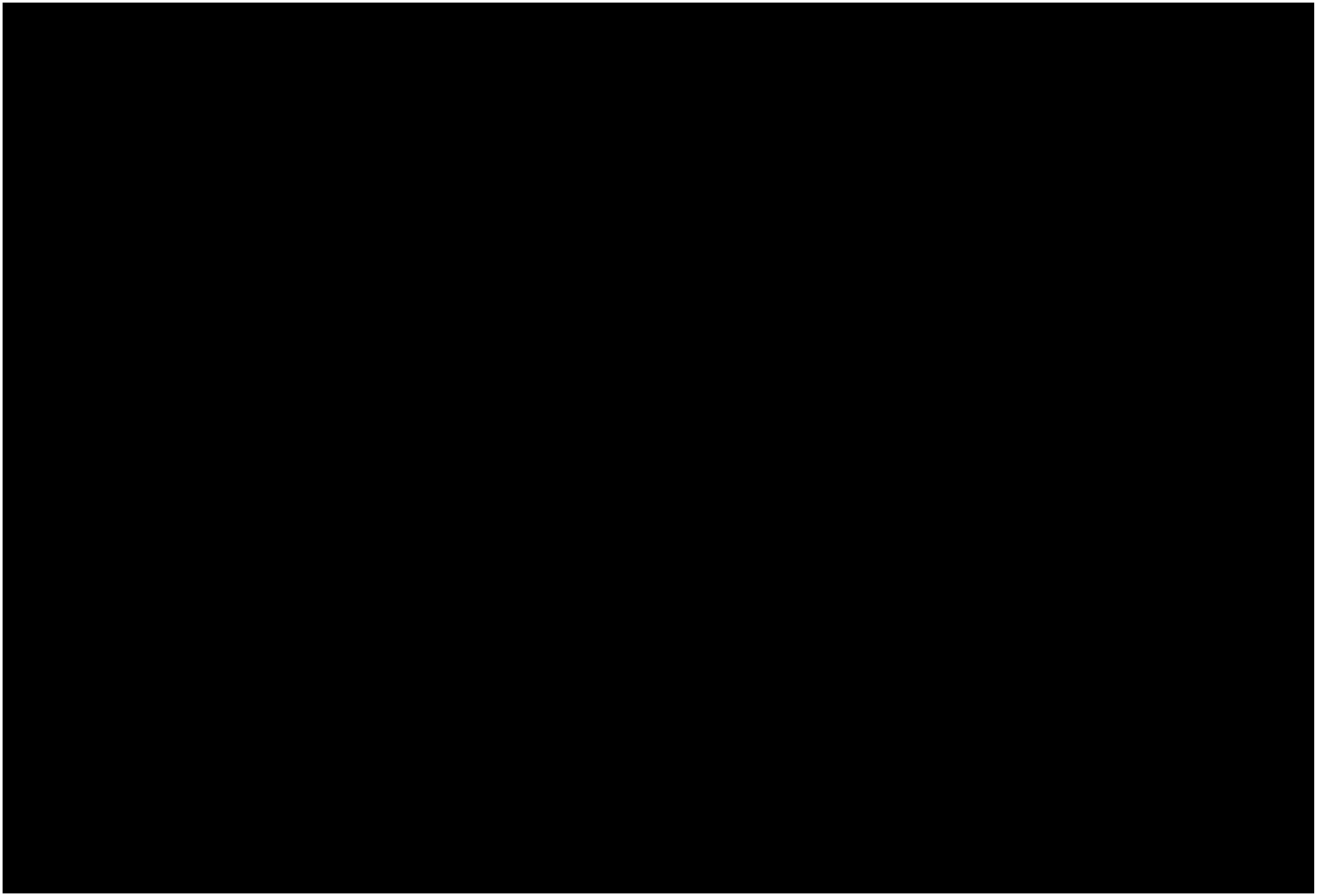
Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

High Plains Power, Inc.

Date of On Peak Day - 04/09/2021



Member Forecasted On Peak Demand Day for May 2021

High Plains Power, Inc.

Date of On Peak Day - 05/03/2021

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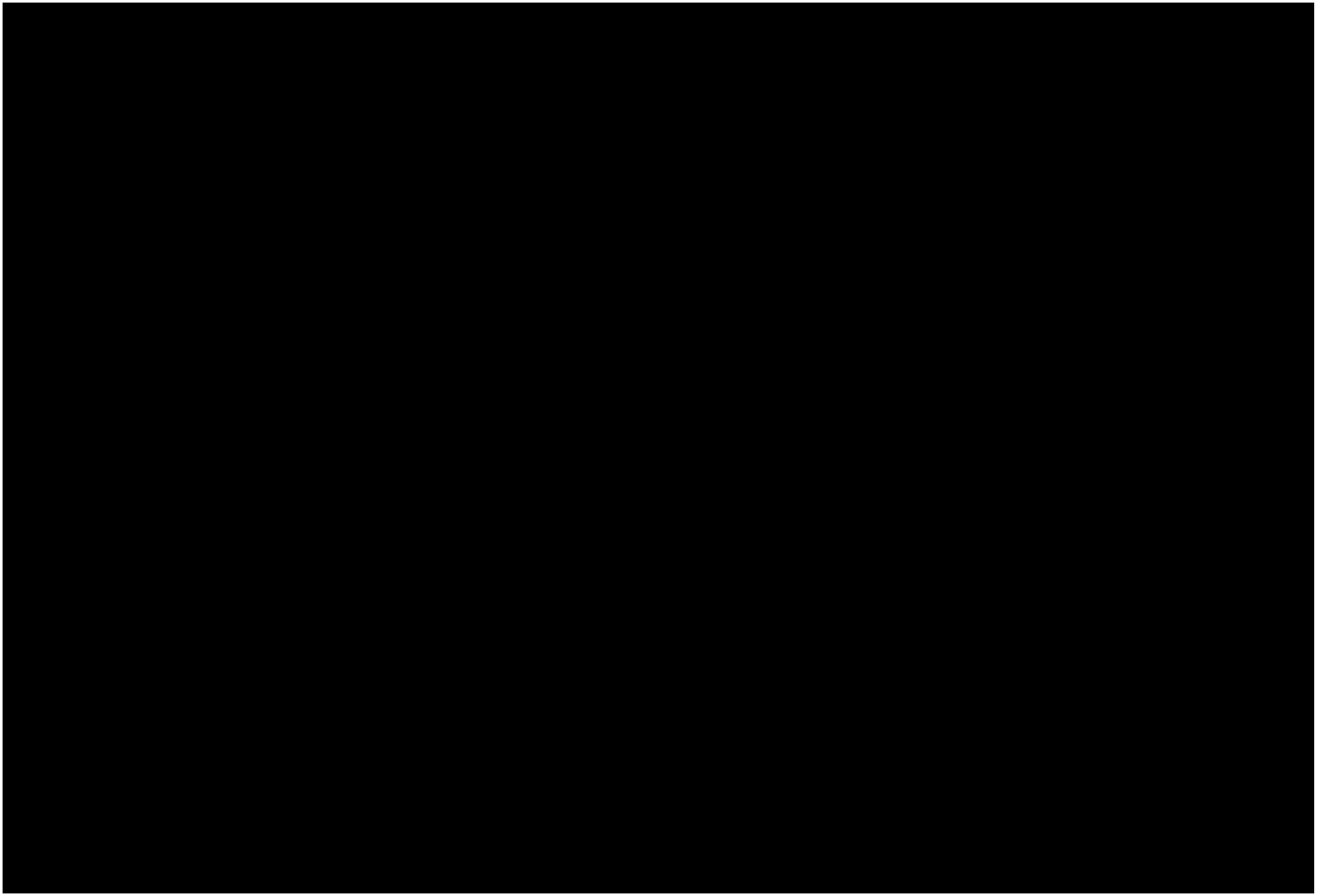
Member Forecasted On Peak Demand Day for June 2021

High Plains Power, Inc.

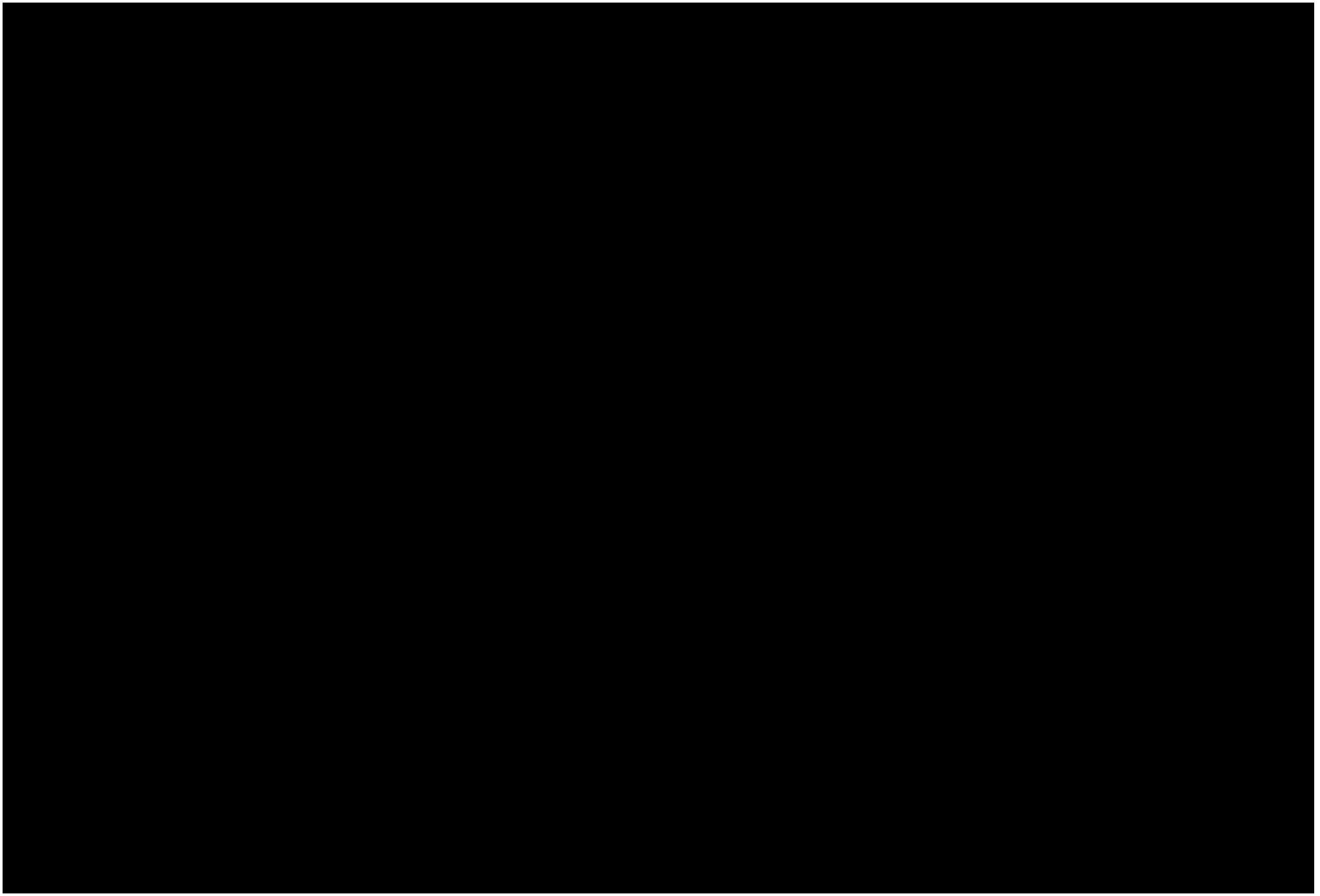
Date of On Peak Day - 06/09/2021



Member Forecasted On Peak Demand Day for July 2021

High Plains Power, Inc.

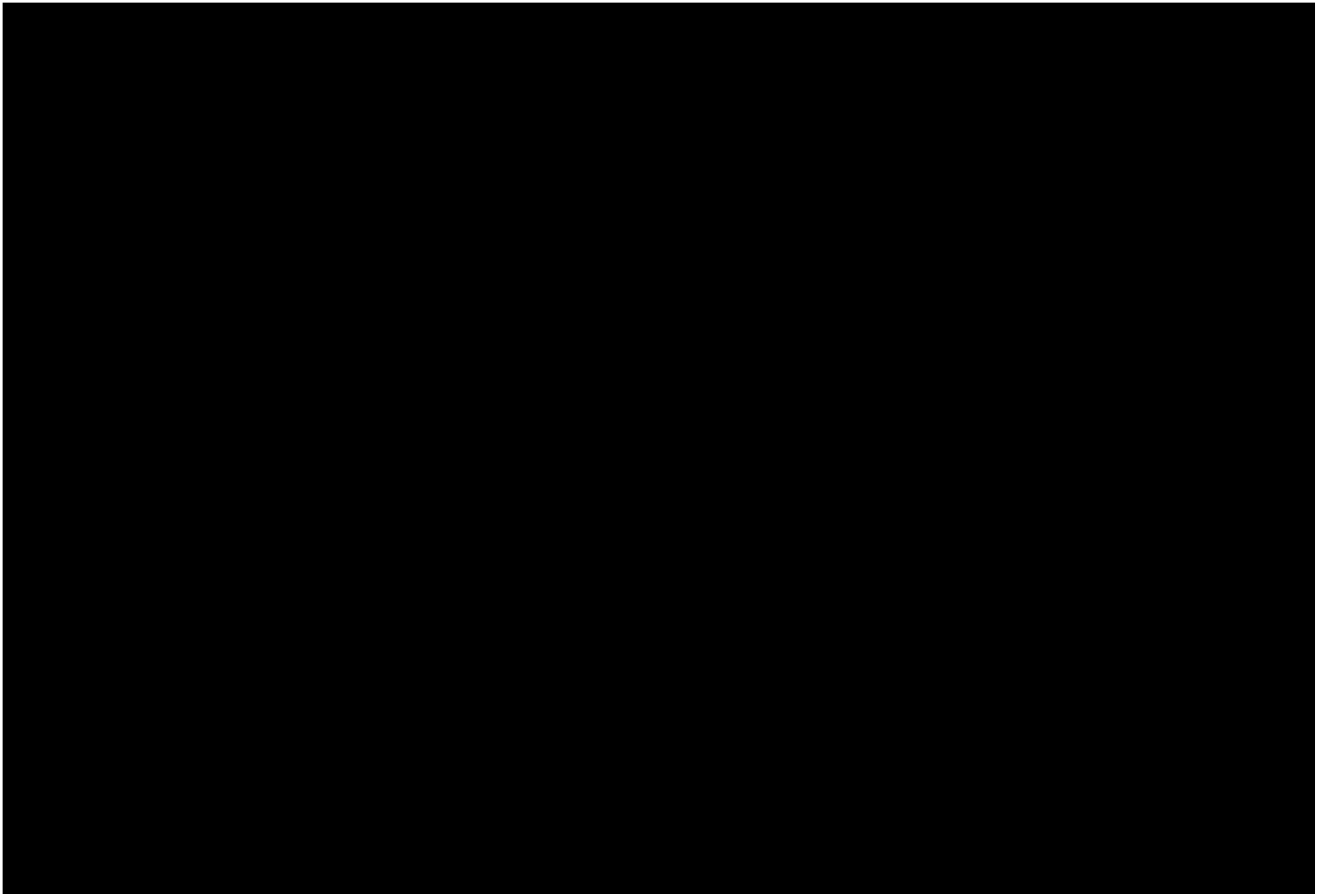
Date of On Peak Day - 07/20/2021



Member Forecasted On Peak Demand Day for August 2021

High Plains Power, Inc.

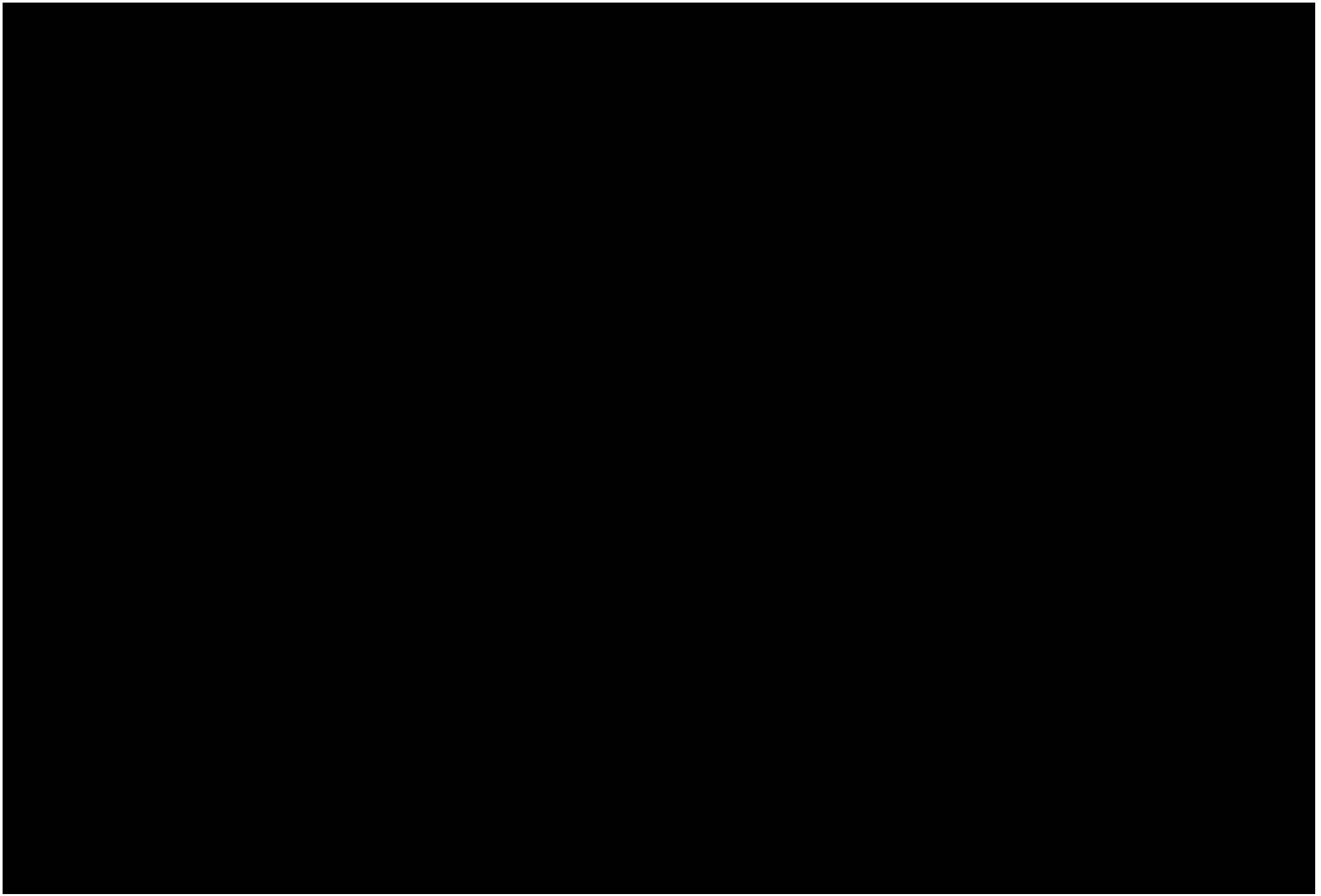
Date of On Peak Day - 08/28/2021



Member Forecasted On Peak Demand Day for September 2021

High Plains Power, Inc.

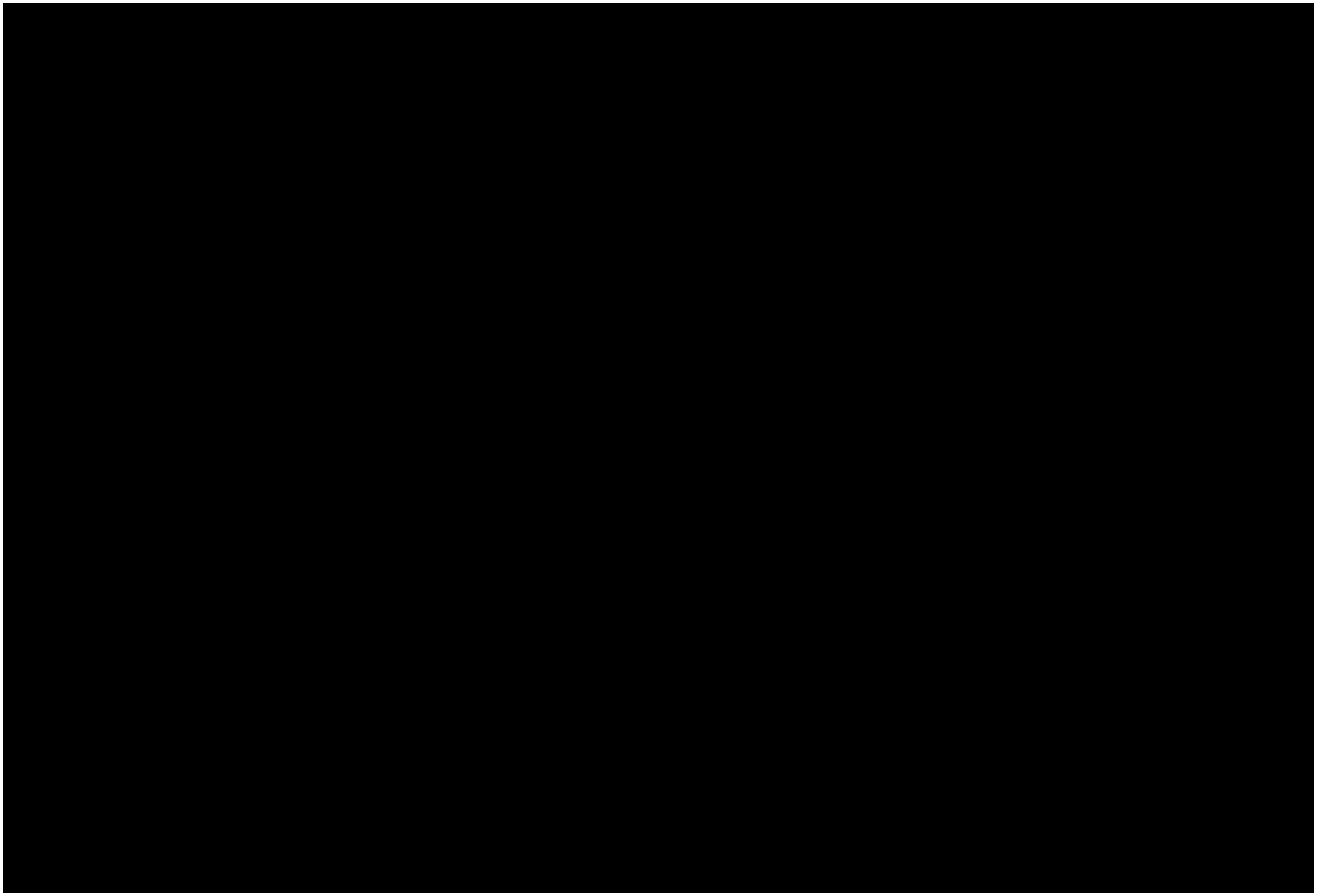
Date of On Peak Day - 09/02/2021



Member Forecasted On Peak Demand Day for October 2021

High Plains Power, Inc.

Date of On Peak Day - 10/30/2021



Member Forecasted On Peak Demand Day for November 2021

High Plains Power, Inc.

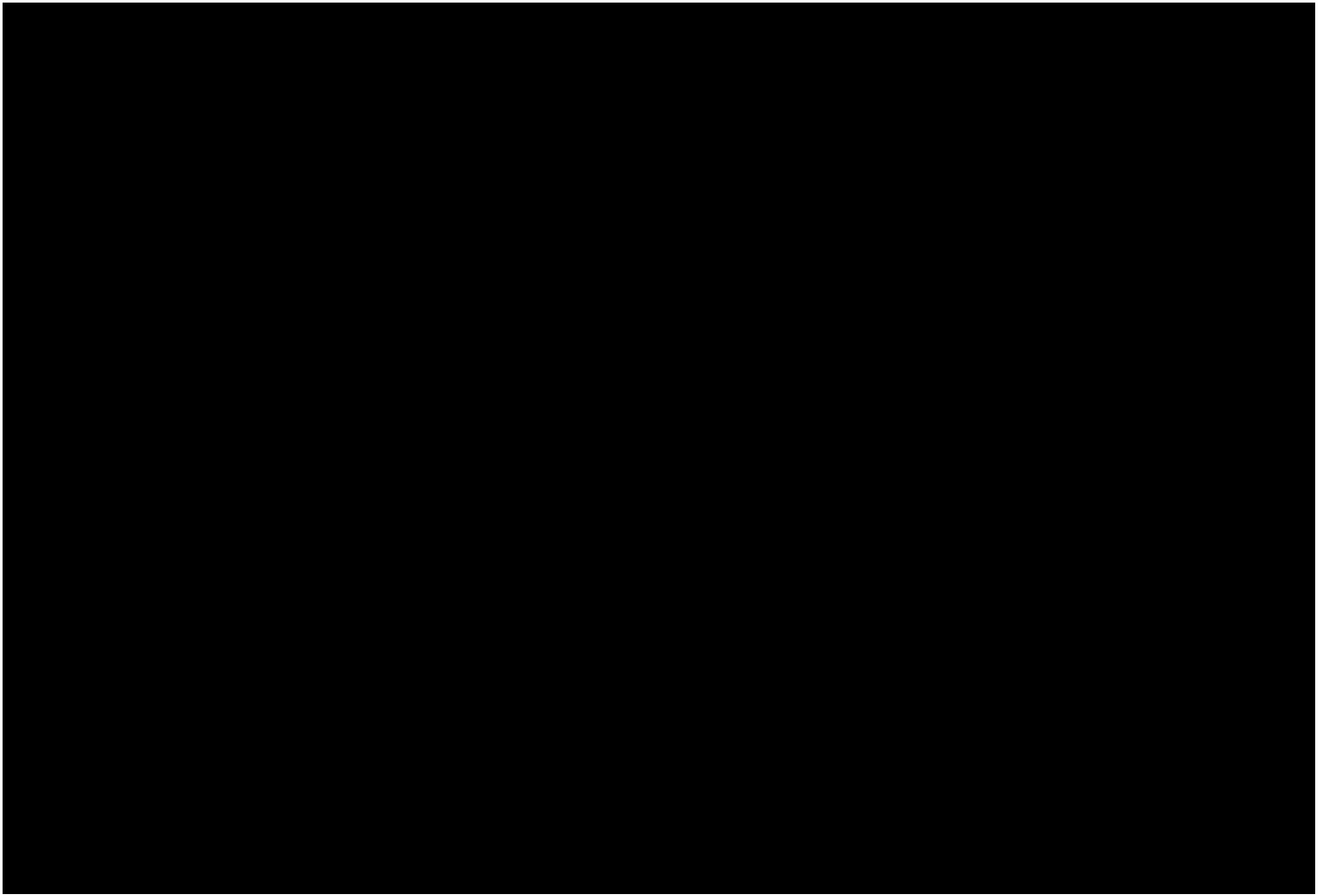
Date of On Peak Day - 11/09/2021

[redacted]

Member Forecasted On Peak Demand Day for December 2021

High Plains Power, Inc.

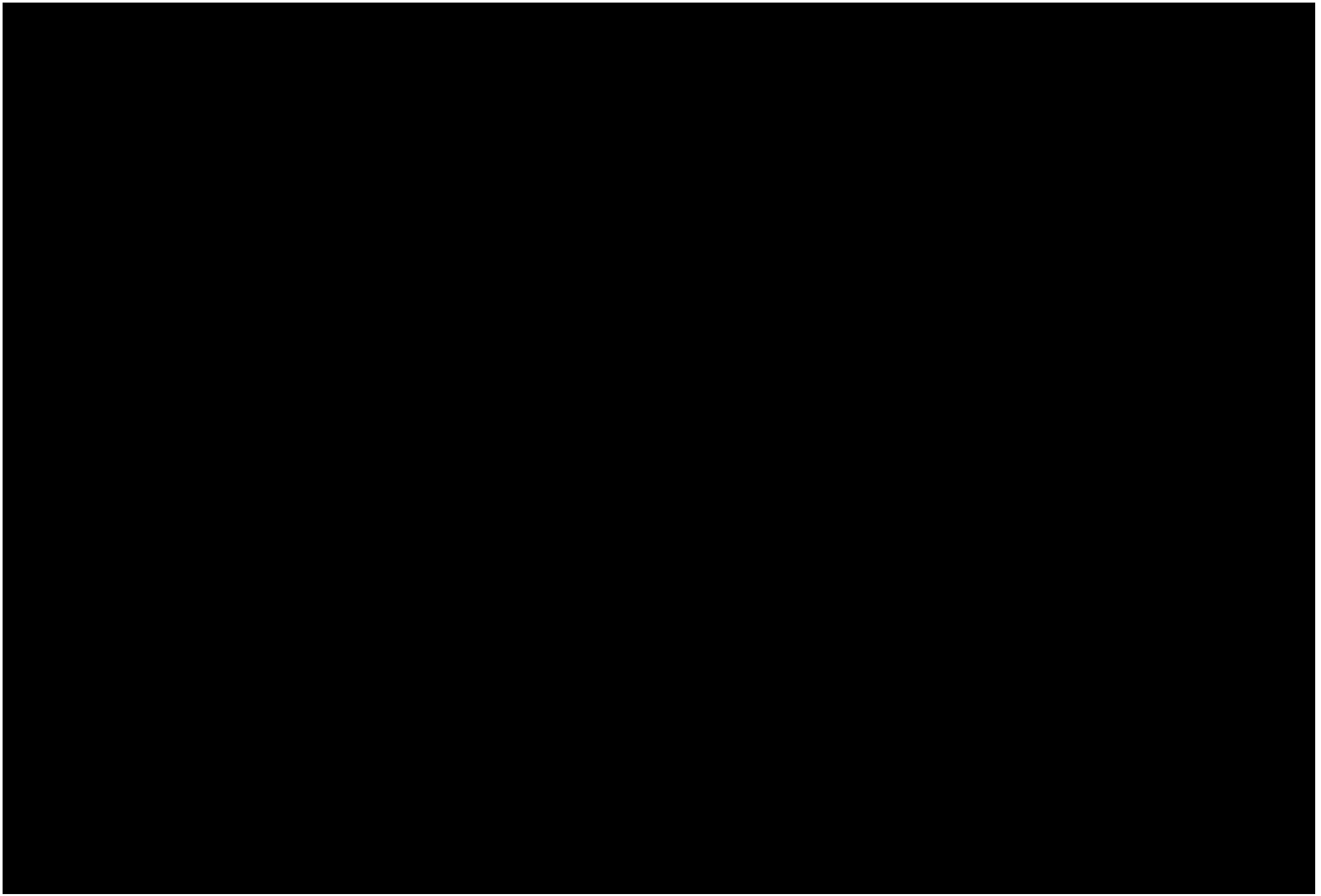
Date of On Peak Day - 12/29/2021



Member Forecasted On Peak Demand Day for January 2021

High West Energy, Inc.

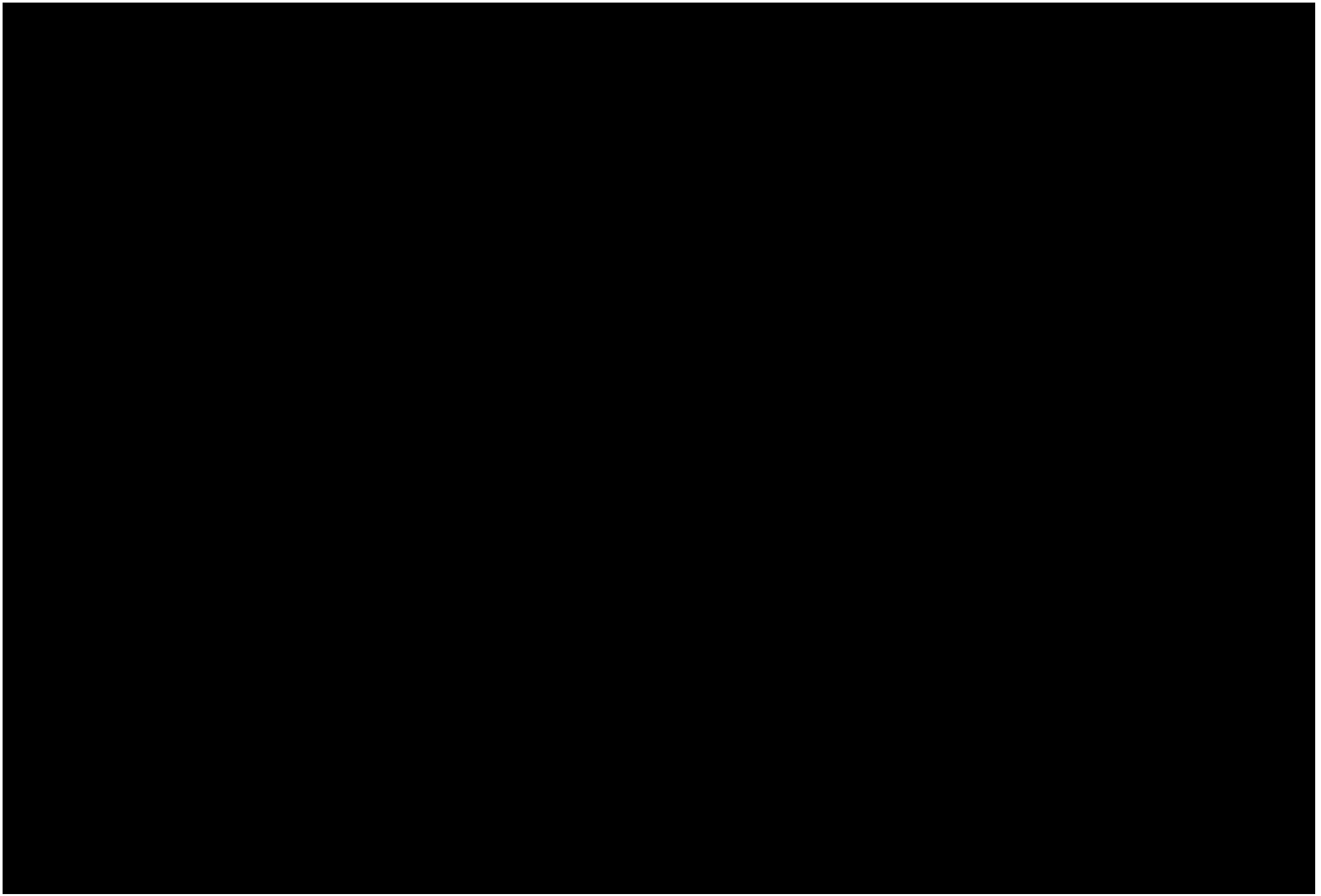
Date of On Peak Day - 01/05/2021



Member Forecasted On Peak Demand Day for February 2021

High West Energy, Inc.

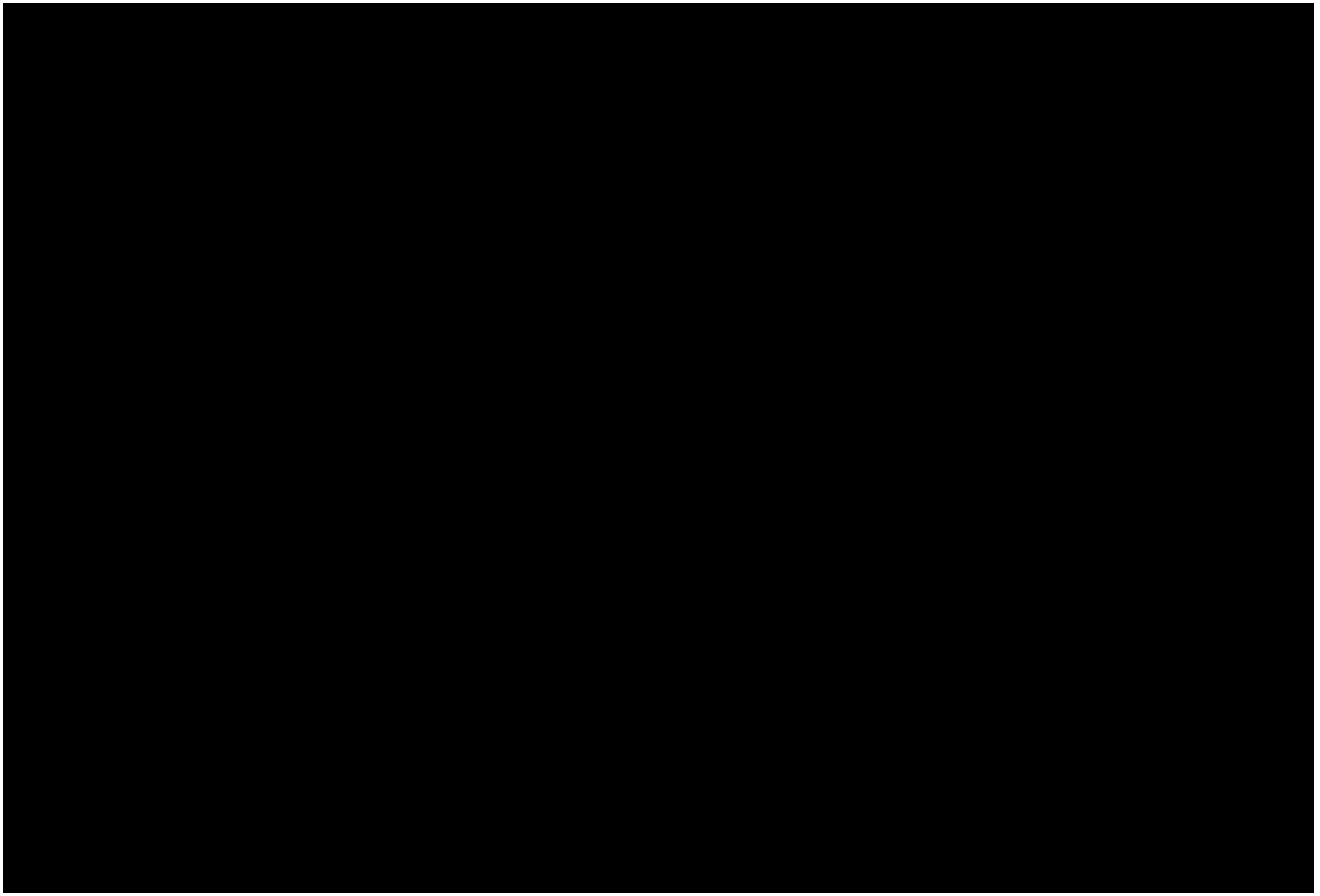
Date of On Peak Day - 02/01/2021



Member Forecasted On Peak Demand Day for March 2021

High West Energy, Inc.

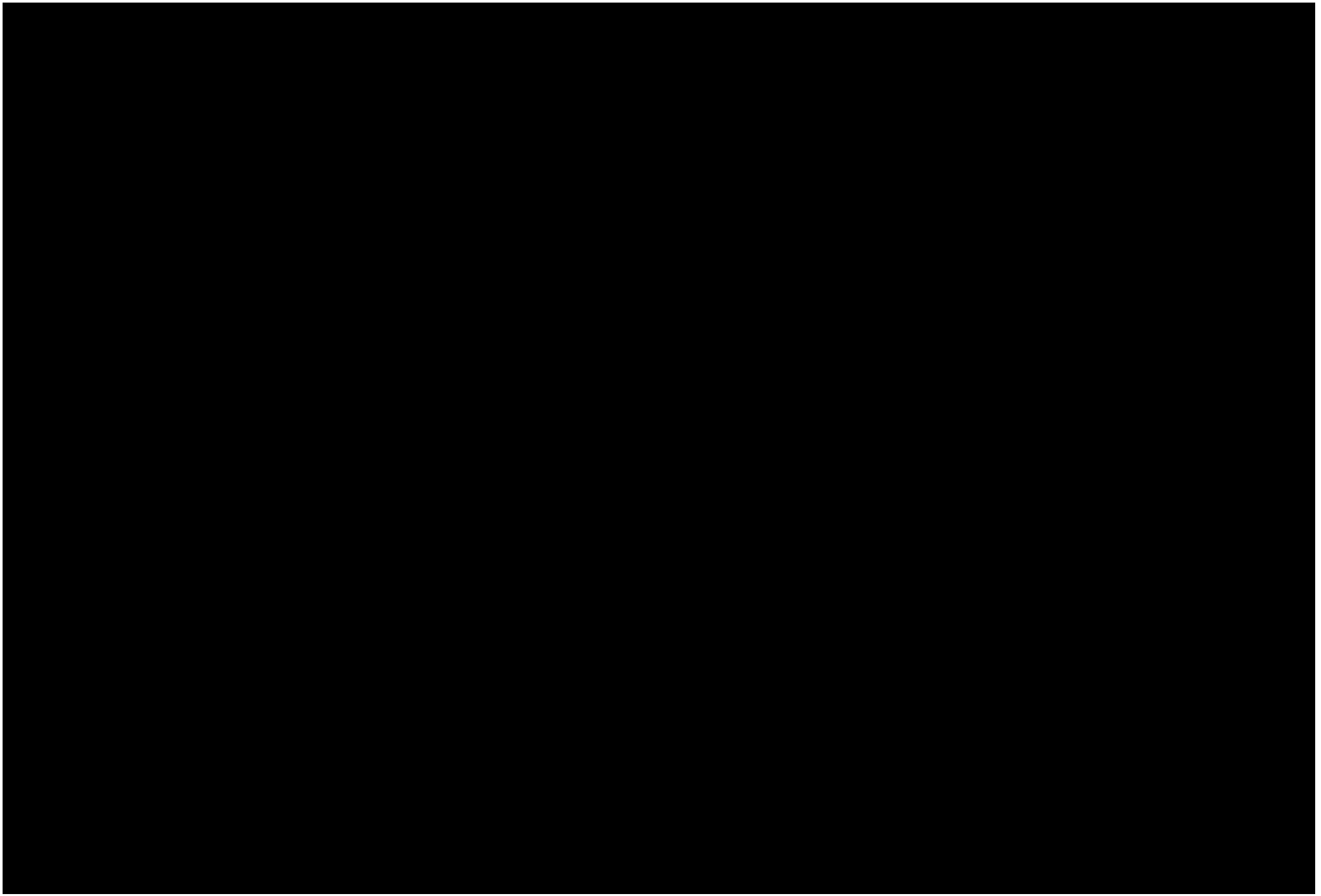
Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

High West Energy, Inc.

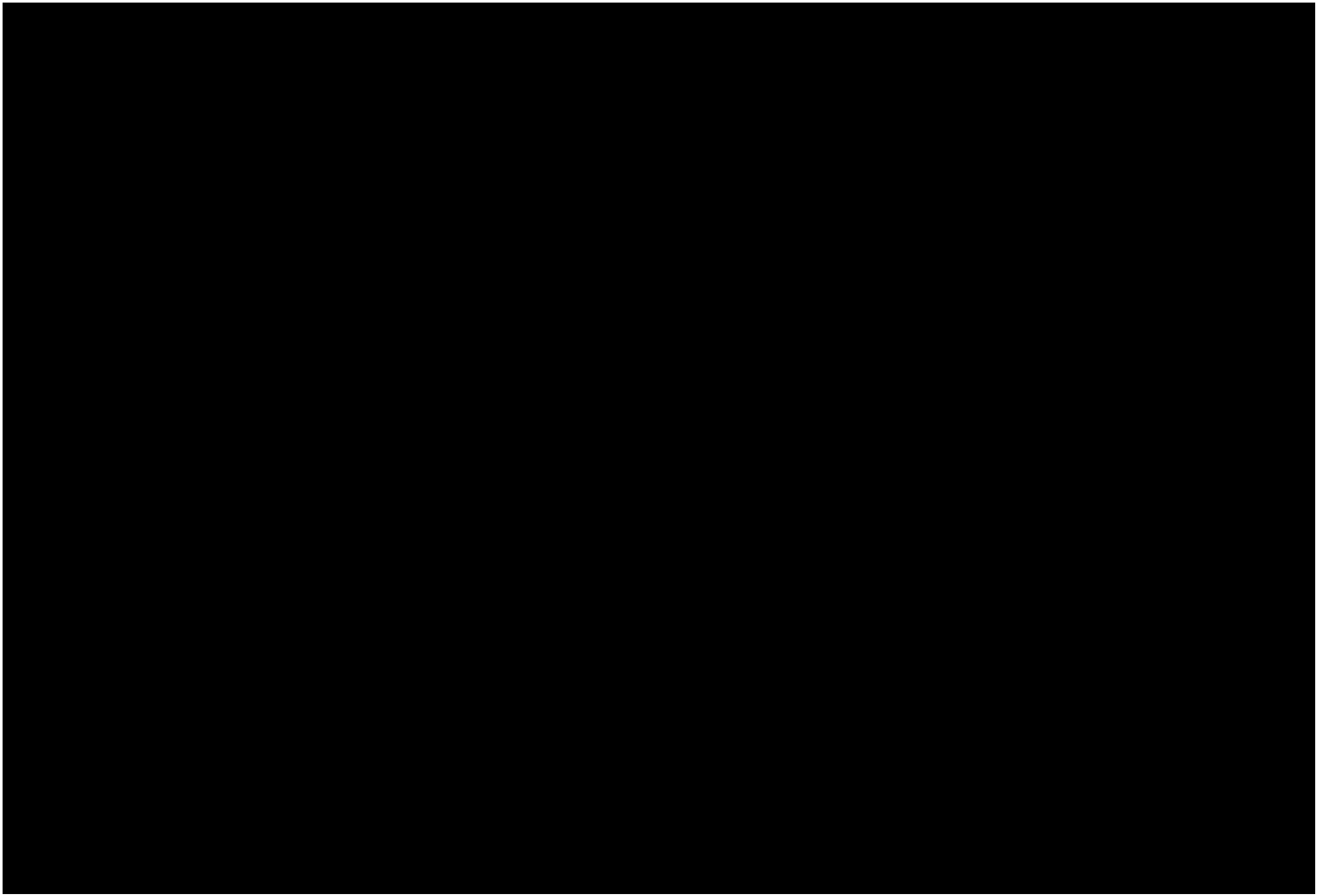
Date of On Peak Day - 04/13/2021



Member Forecasted On Peak Demand Day for May 2021

High West Energy, Inc.

Date of On Peak Day - 05/07/2021



Hearing Exhibit 101
PUBLIC Attachment BN-2
Proceeding No. 20A-0528E
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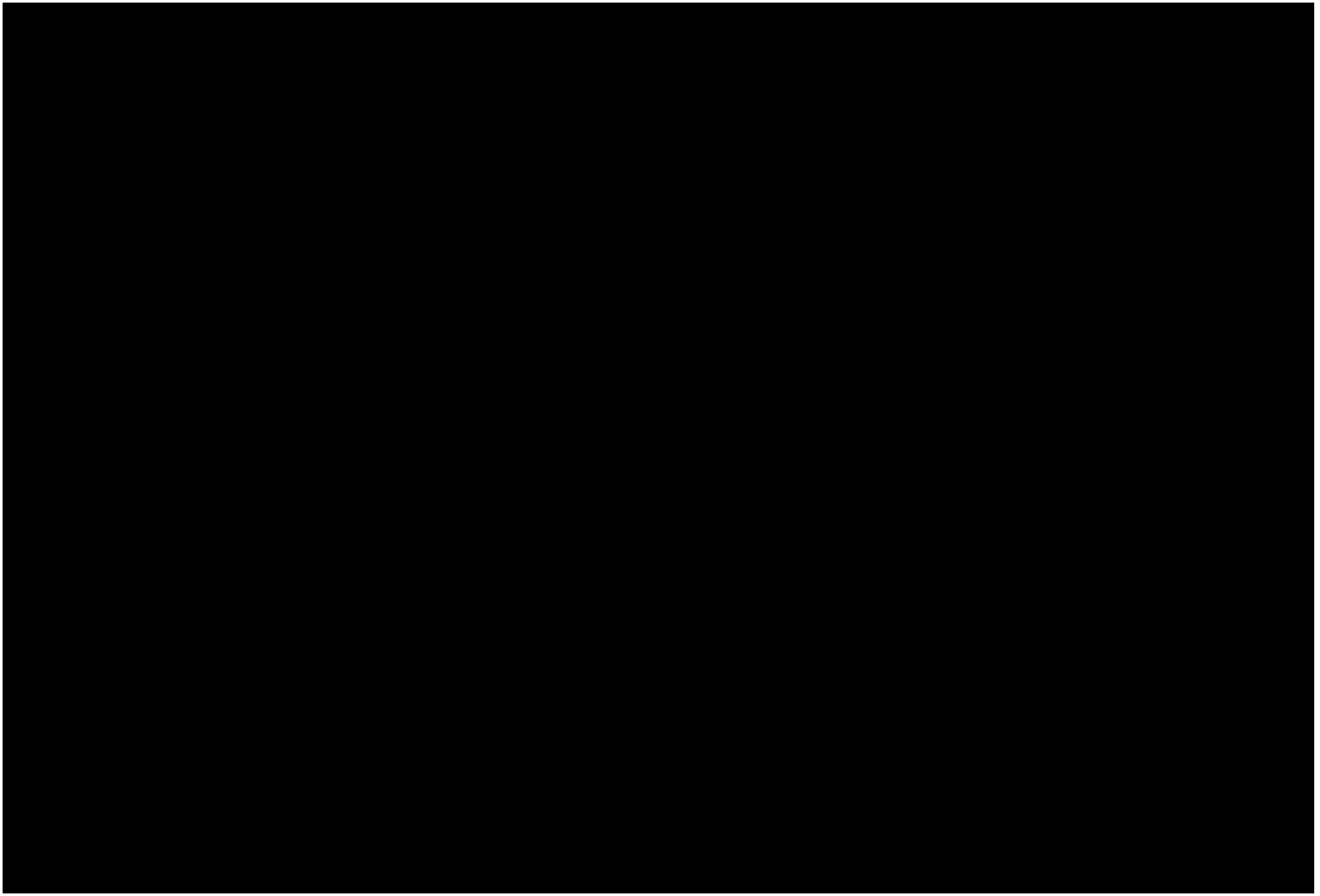
Member Forecasted On Peak Demand Day for June 2021

High West Energy, Inc.

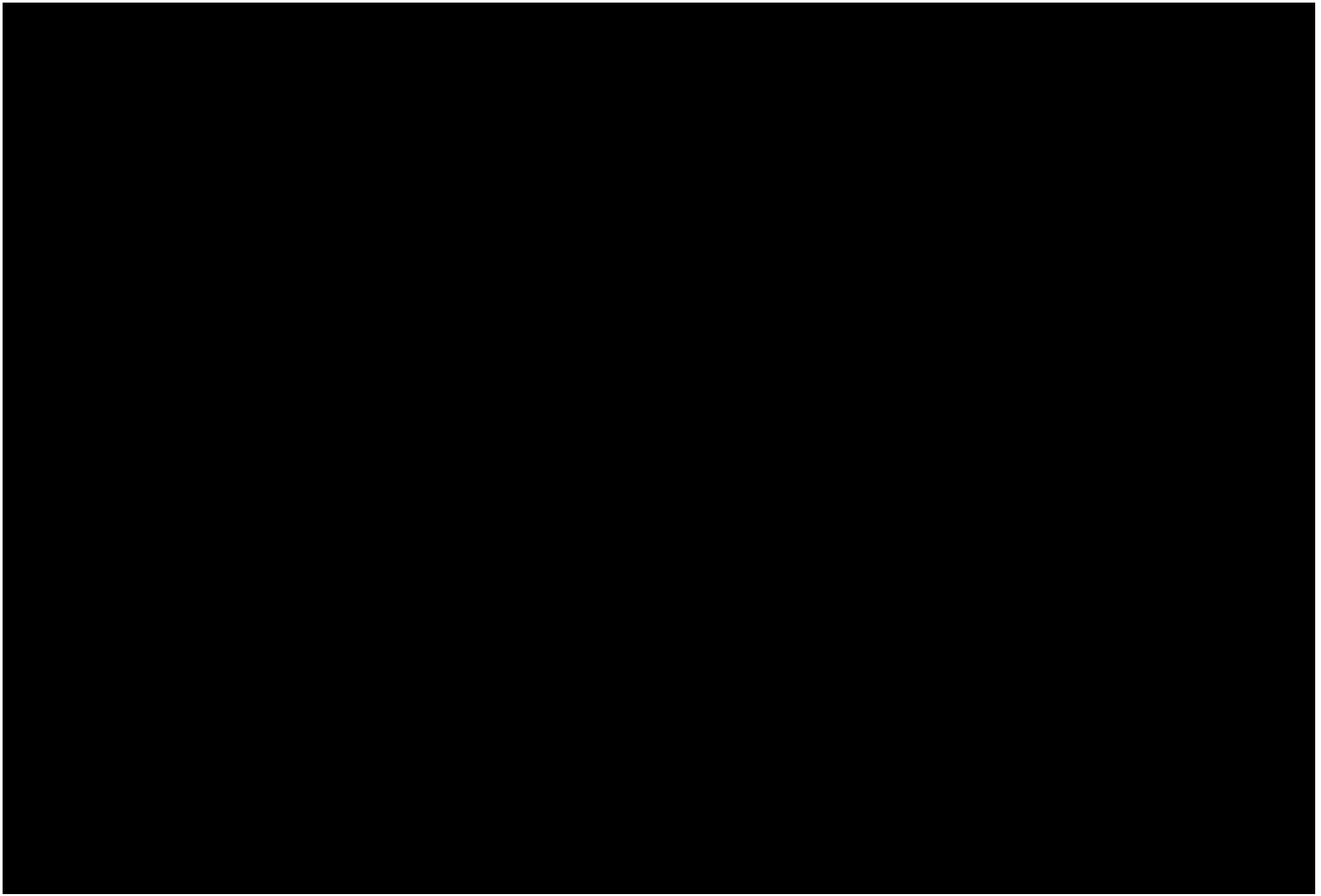
Date of On Peak Day - 06/28/2021



Member Forecasted On Peak Demand Day for July 2021

High West Energy, Inc.

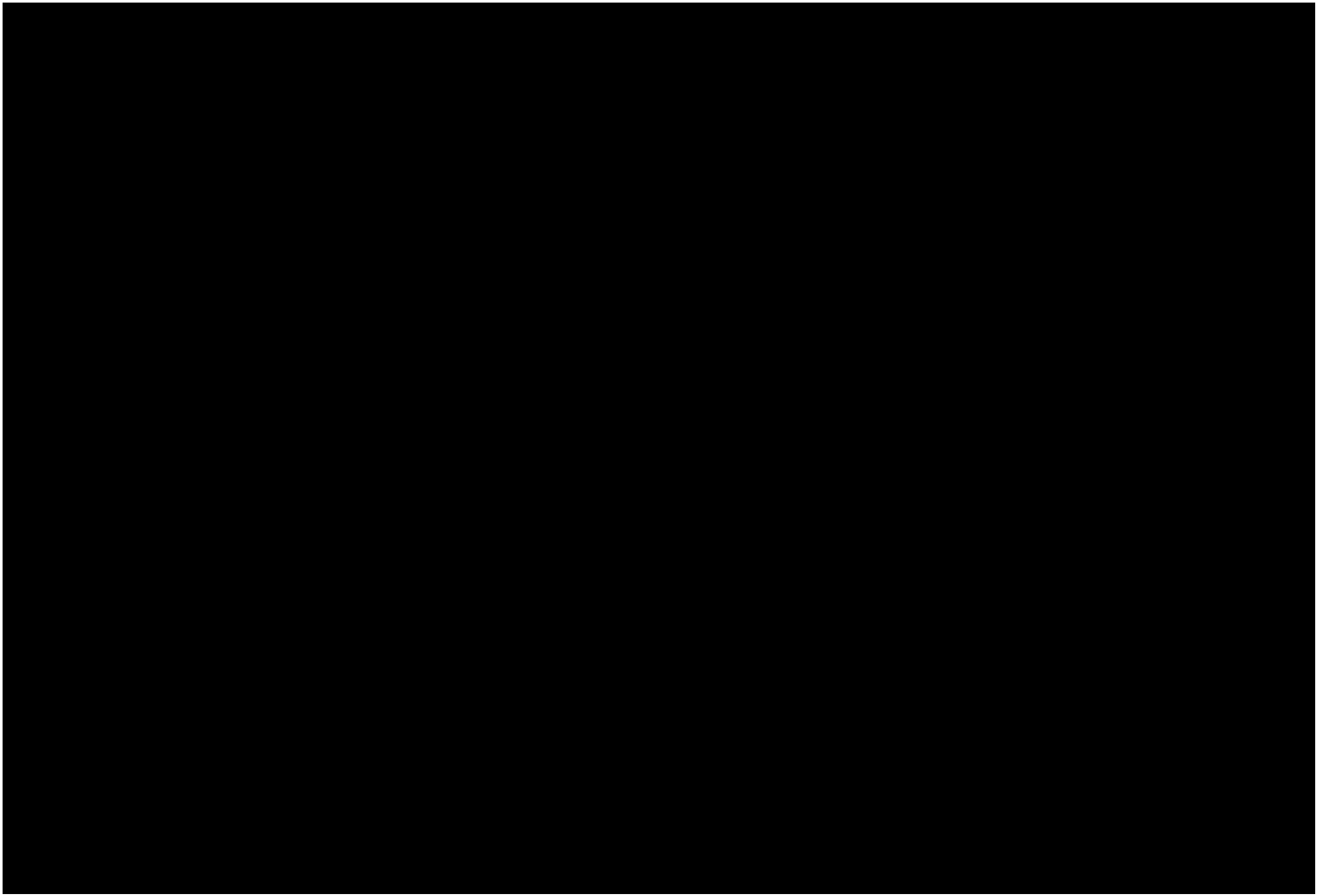
Date of On Peak Day - 07/10/2021



Member Forecasted On Peak Demand Day for August 2021

High West Energy, Inc.

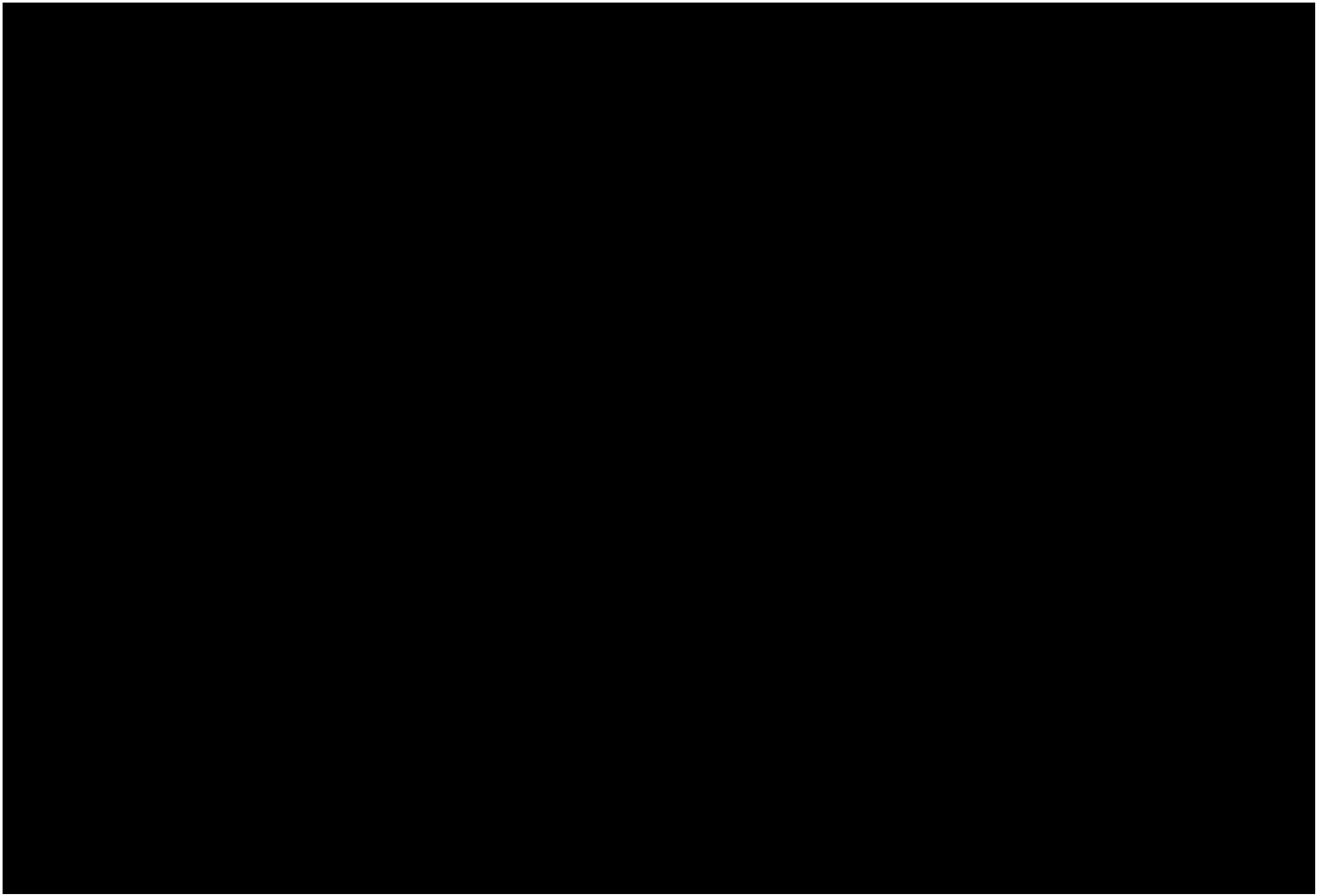
Date of On Peak Day - 08/02/2021



Member Forecasted On Peak Demand Day for September 2021

High West Energy, Inc.

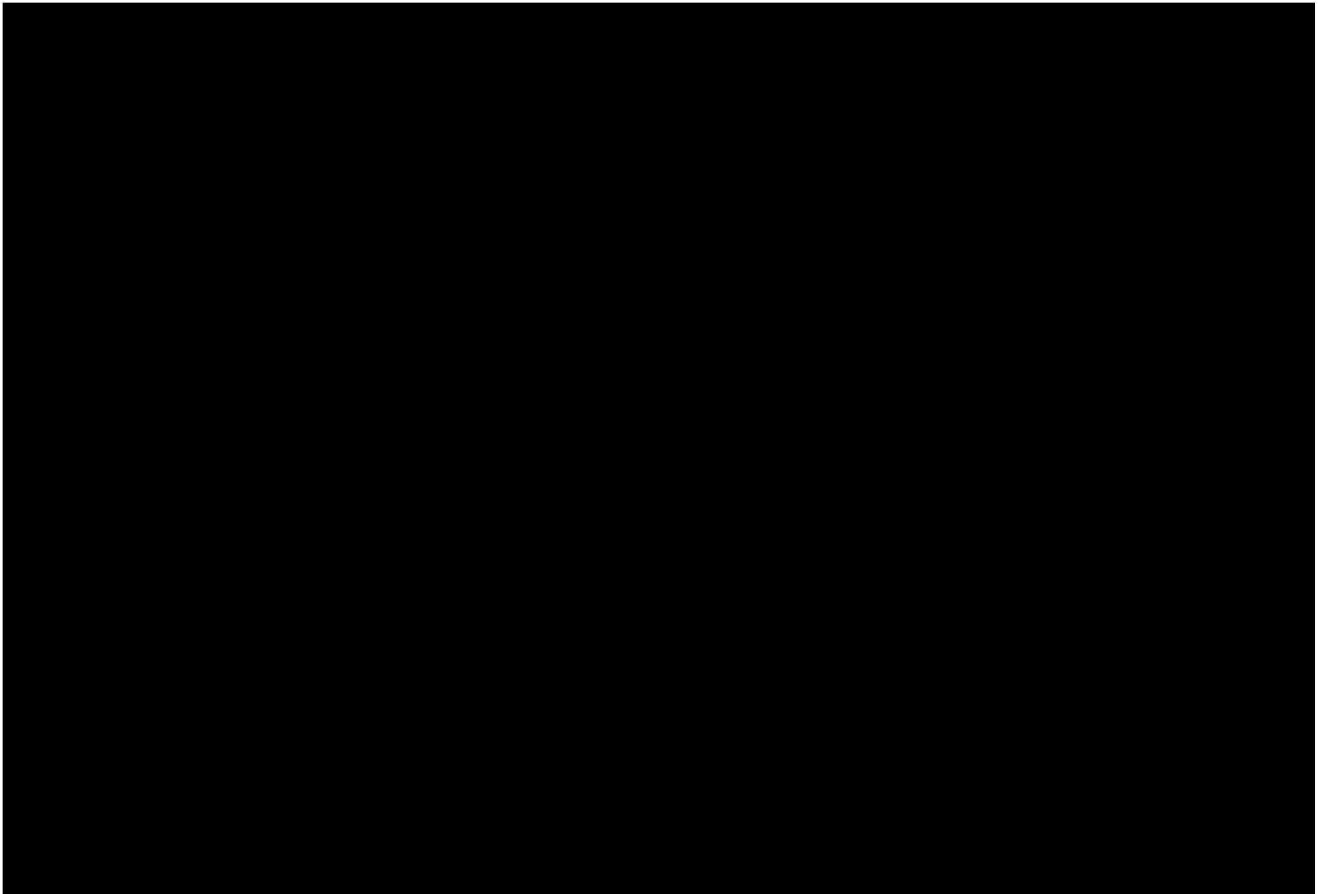
Date of On Peak Day - 09/02/2021



Member Forecasted On Peak Demand Day for October 2021

High West Energy, Inc.

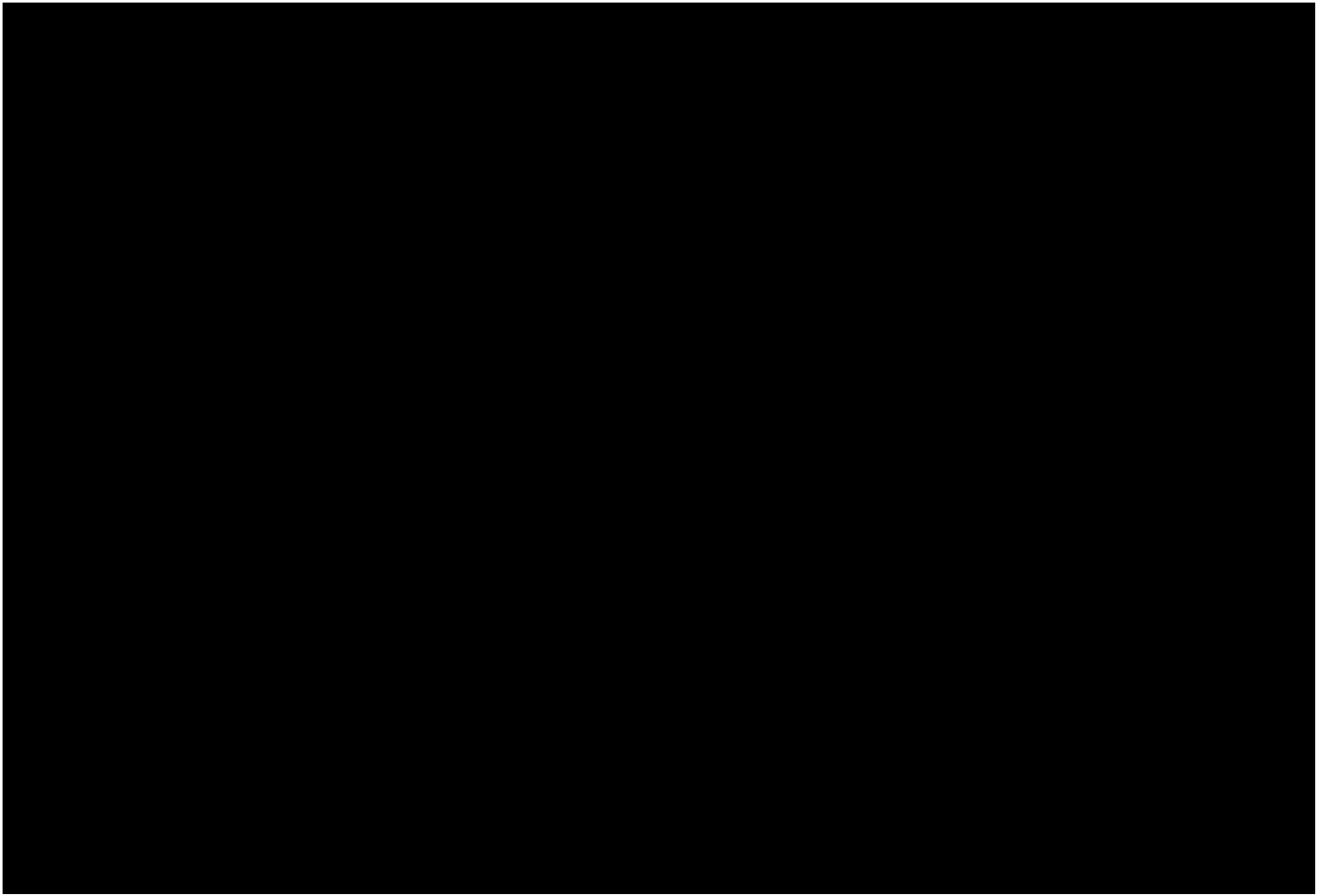
Date of On Peak Day - 10/06/2021



Member Forecasted On Peak Demand Day for November 2021

High West Energy, Inc.

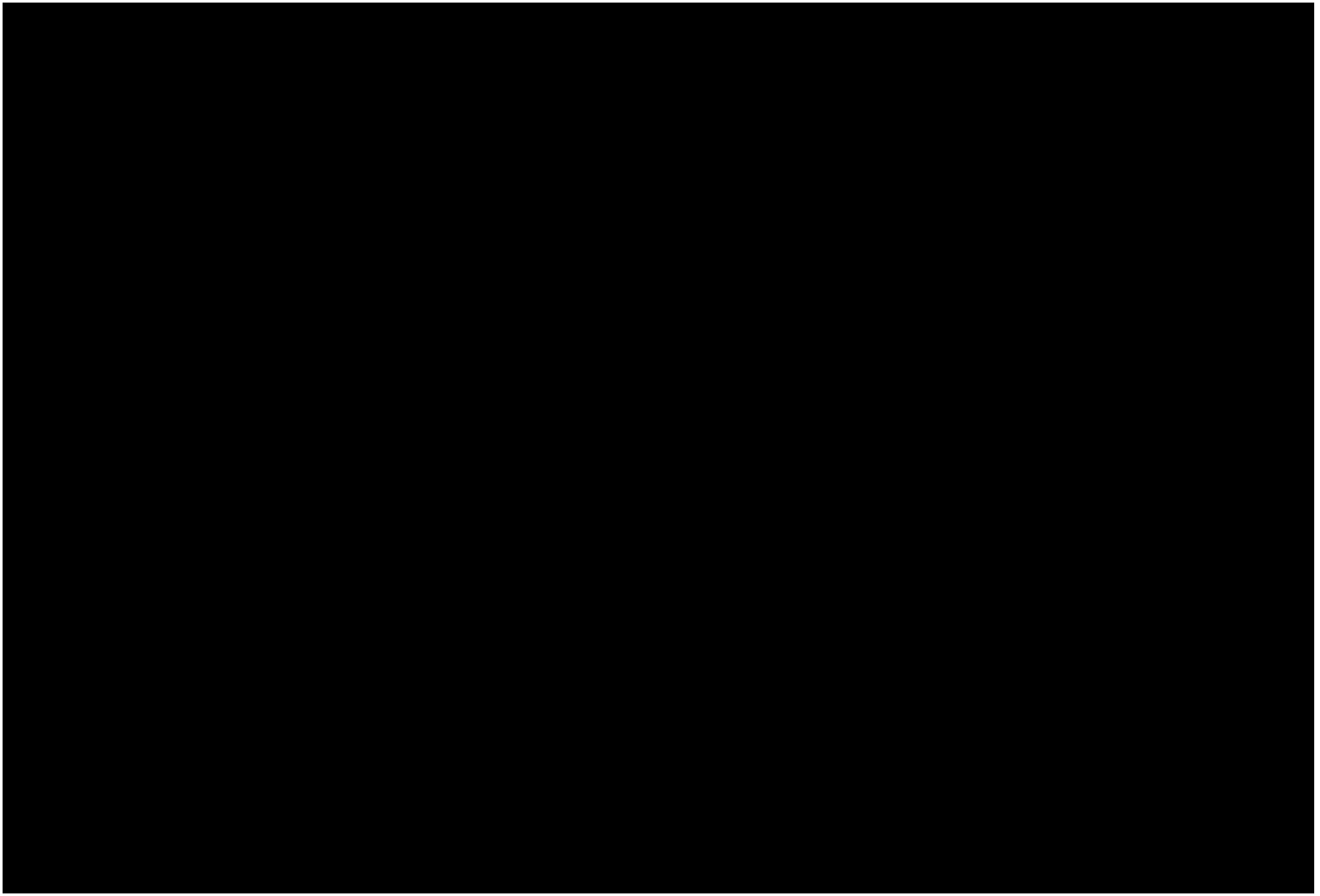
Date of On Peak Day - 11/08/2021



Member Forecasted On Peak Demand Day for December 2021

High West Energy, Inc.

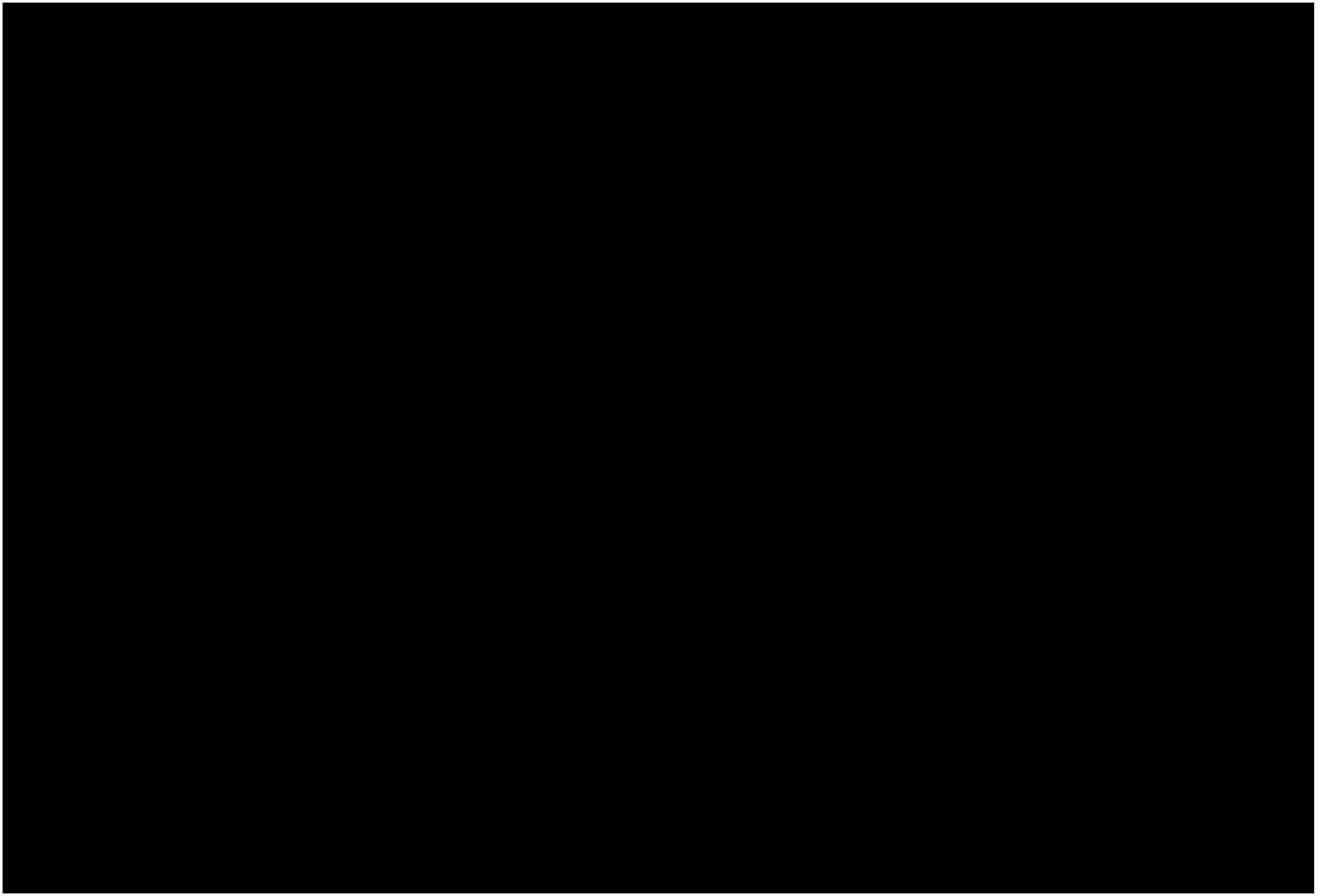
Date of On Peak Day - 12/28/2021



Member Forecasted On Peak Demand Day for January 2021

Jemez Mountains Electric Cooperative, Inc.

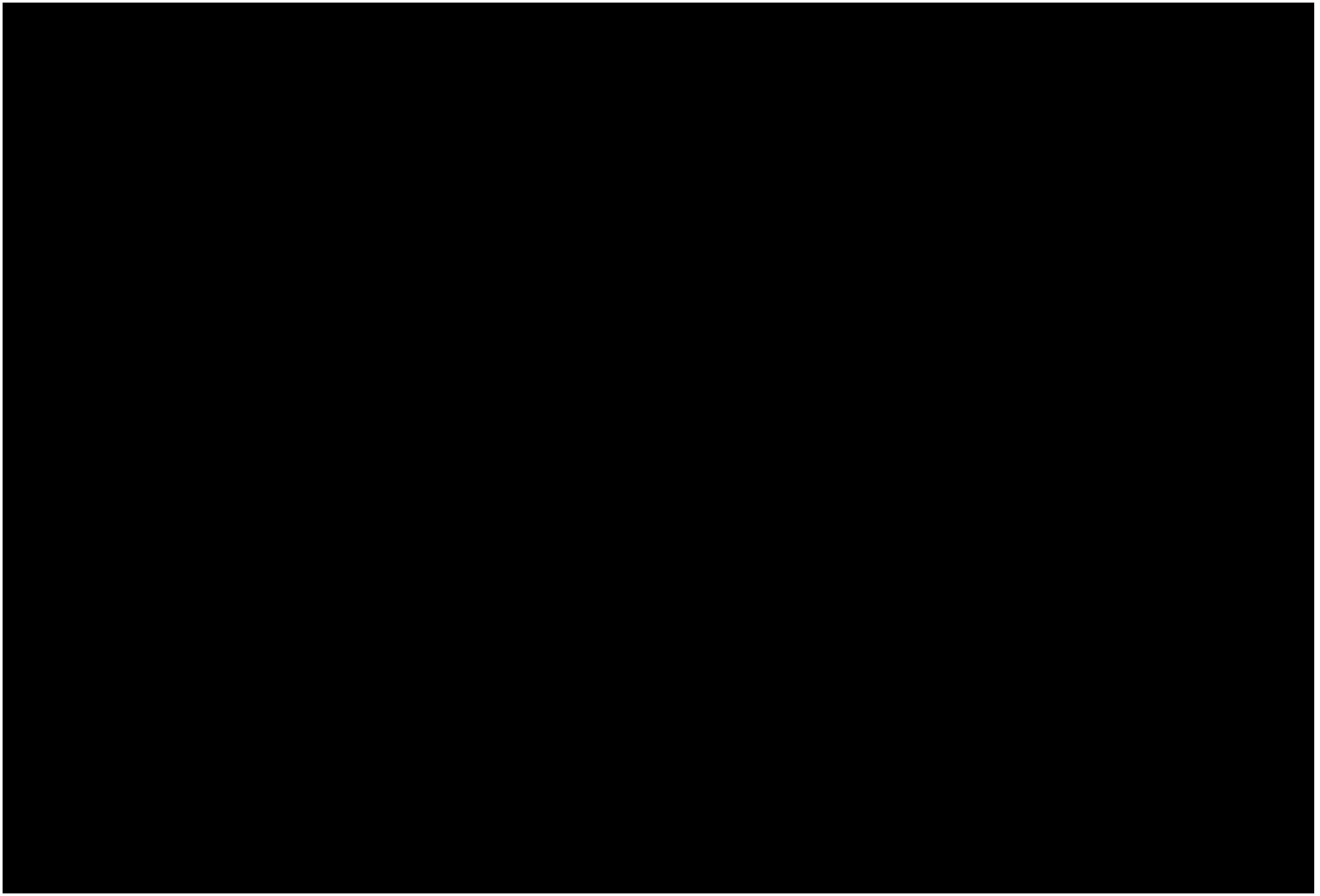
Date of On Peak Day - 01/26/2021



Member Forecasted On Peak Demand Day for February 2021

Jemez Mountains Electric Cooperative, Inc.

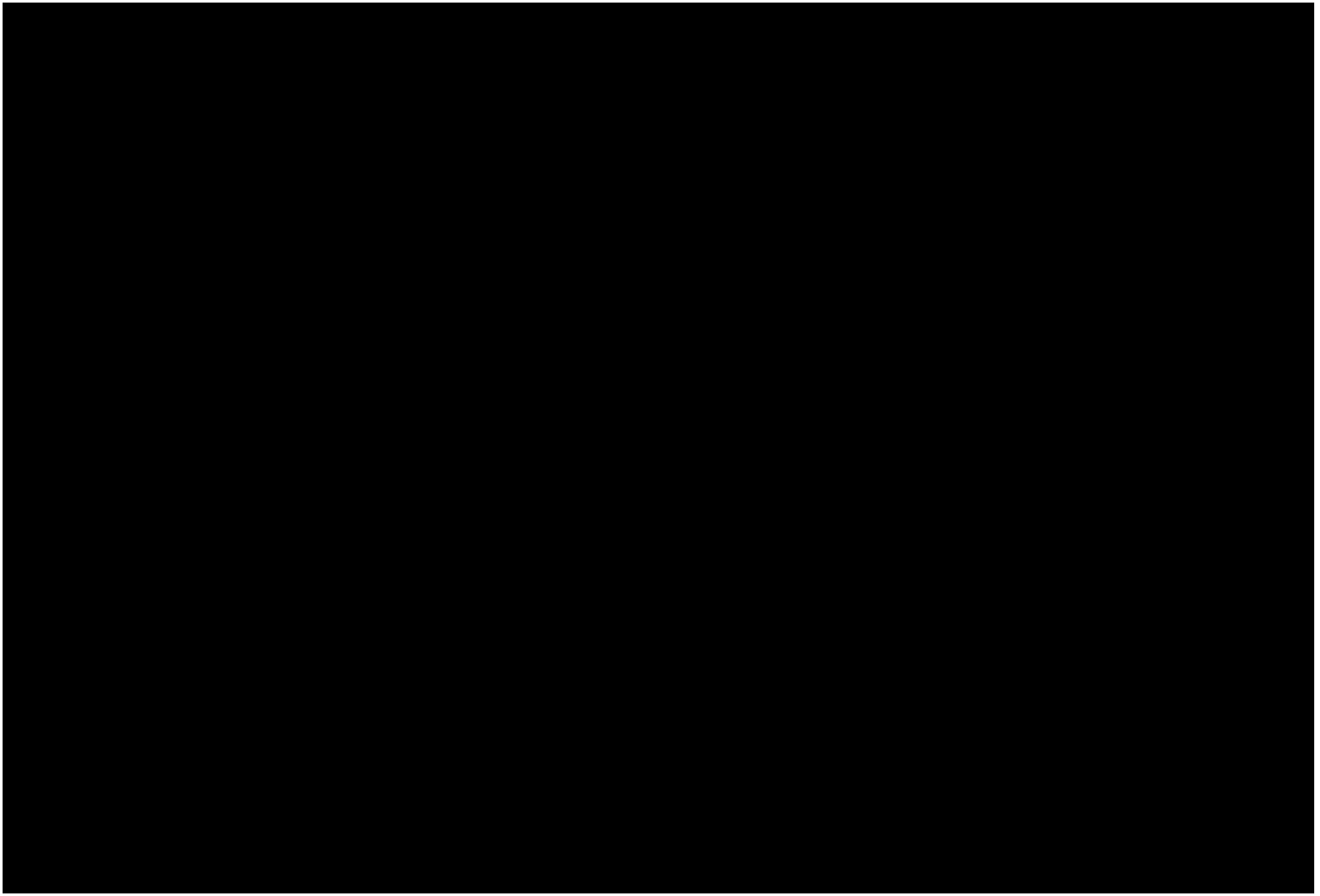
Date of On Peak Day - 02/02/2021



Member Forecasted On Peak Demand Day for March 2021

Jemez Mountains Electric Cooperative, Inc.

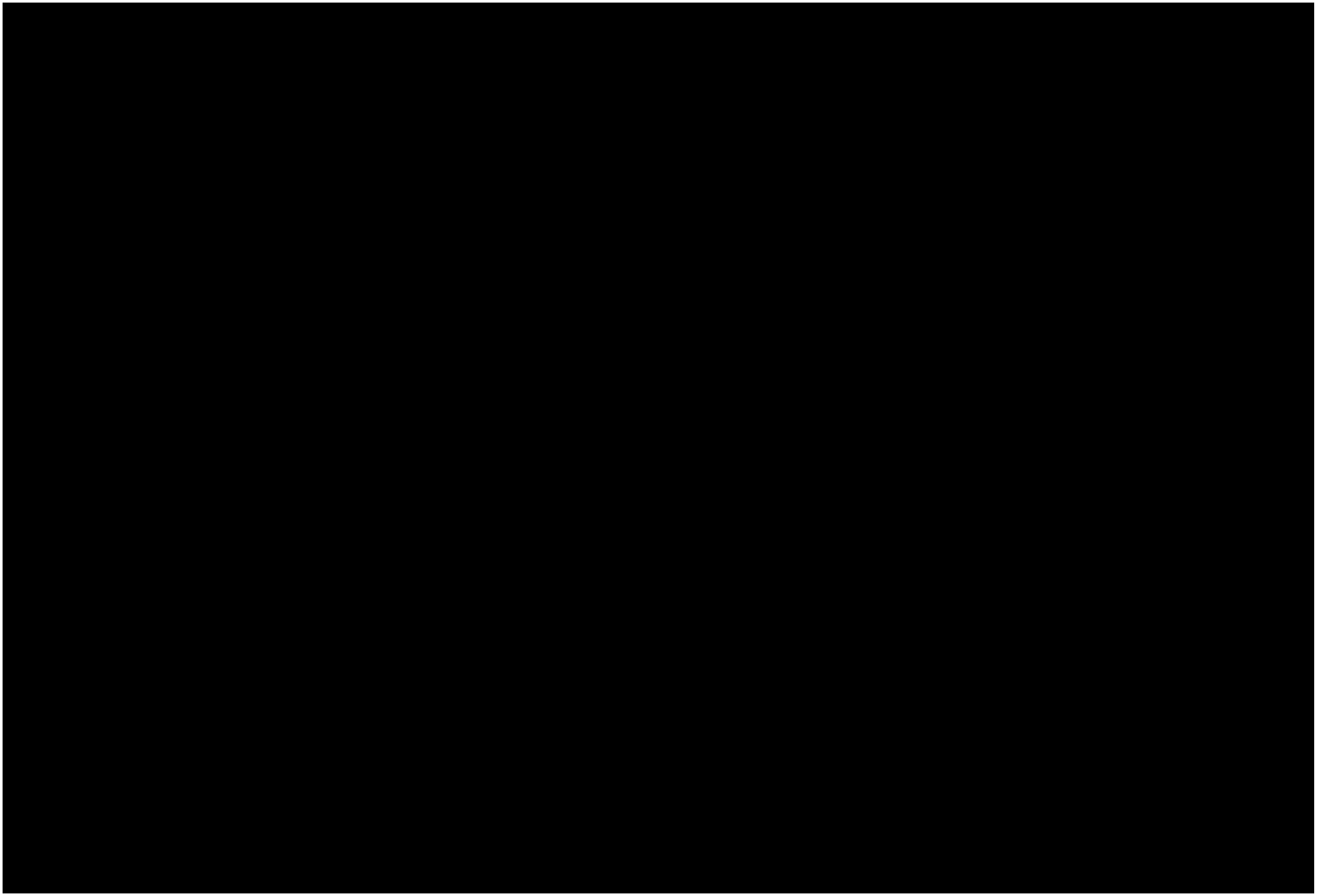
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Jemez Mountains Electric Cooperative, Inc.

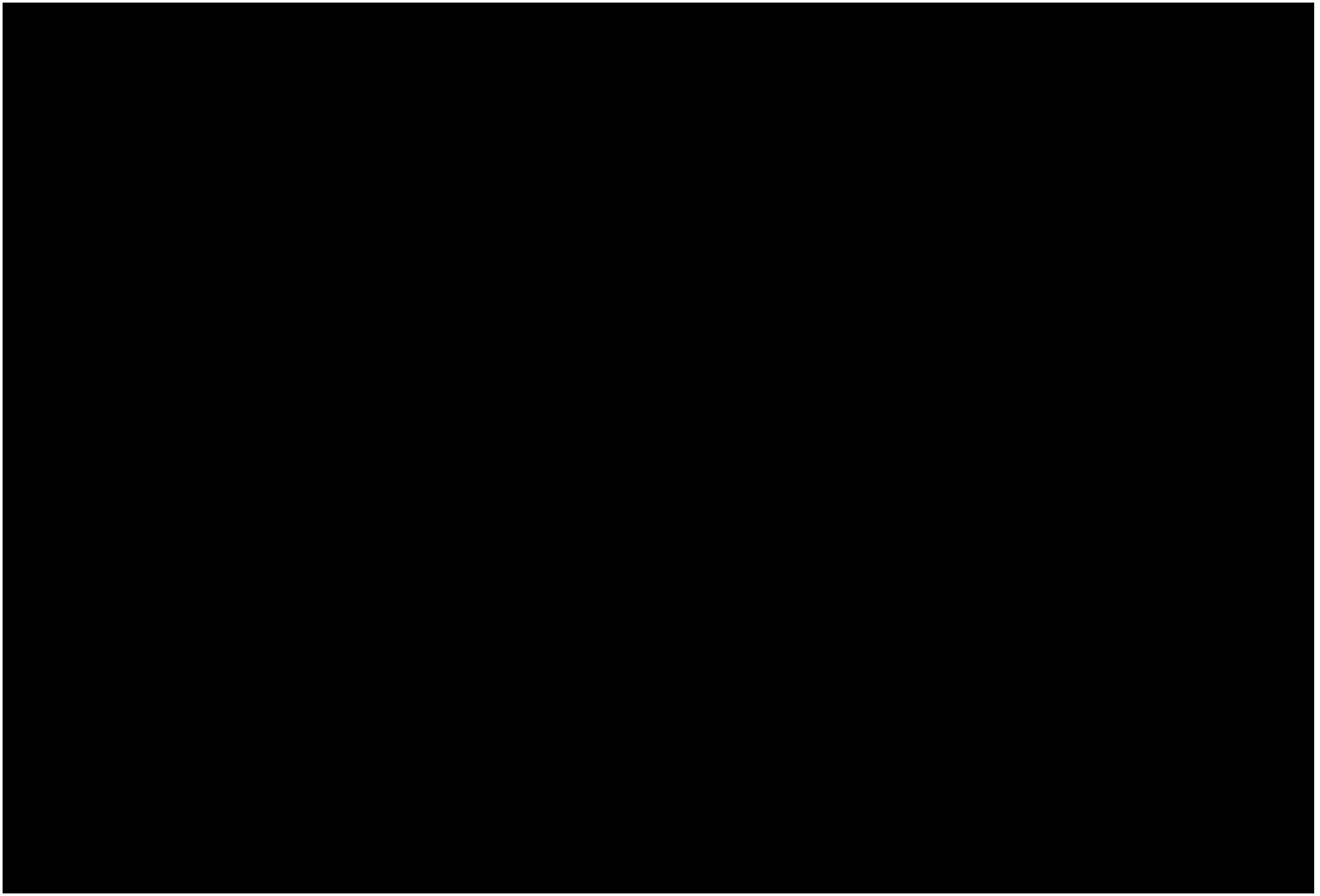
Date of On Peak Day - 04/26/2021



Member Forecasted On Peak Demand Day for May 2021

Jemez Mountains Electric Cooperative, Inc.

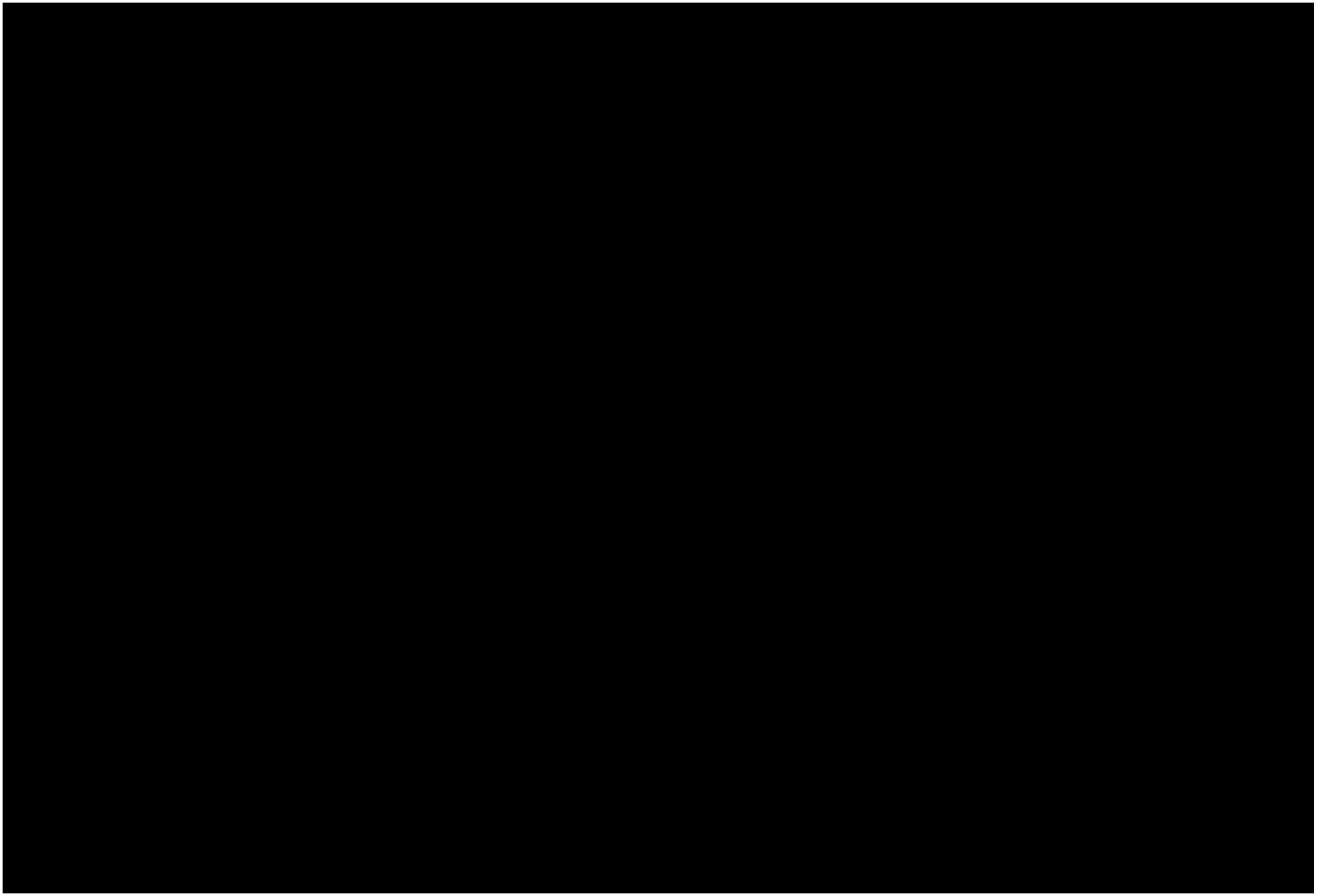
Date of On Peak Day - 05/26/2021



Member Forecasted On Peak Demand Day for June 2021

Jemez Mountains Electric Cooperative, Inc.

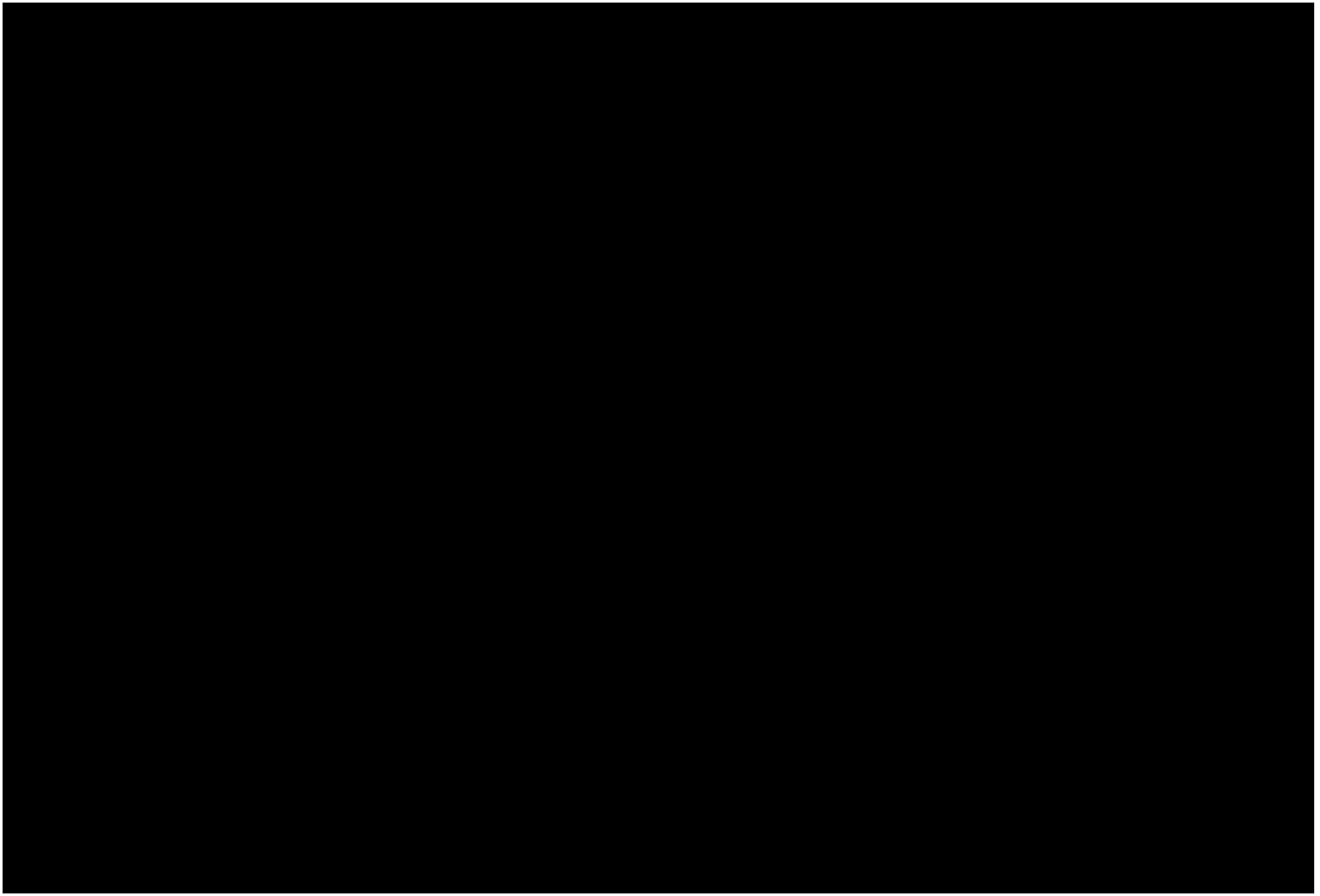
Date of On Peak Day - 06/30/2021



Member Forecasted On Peak Demand Day for July 2021

Jemez Mountains Electric Cooperative, Inc.

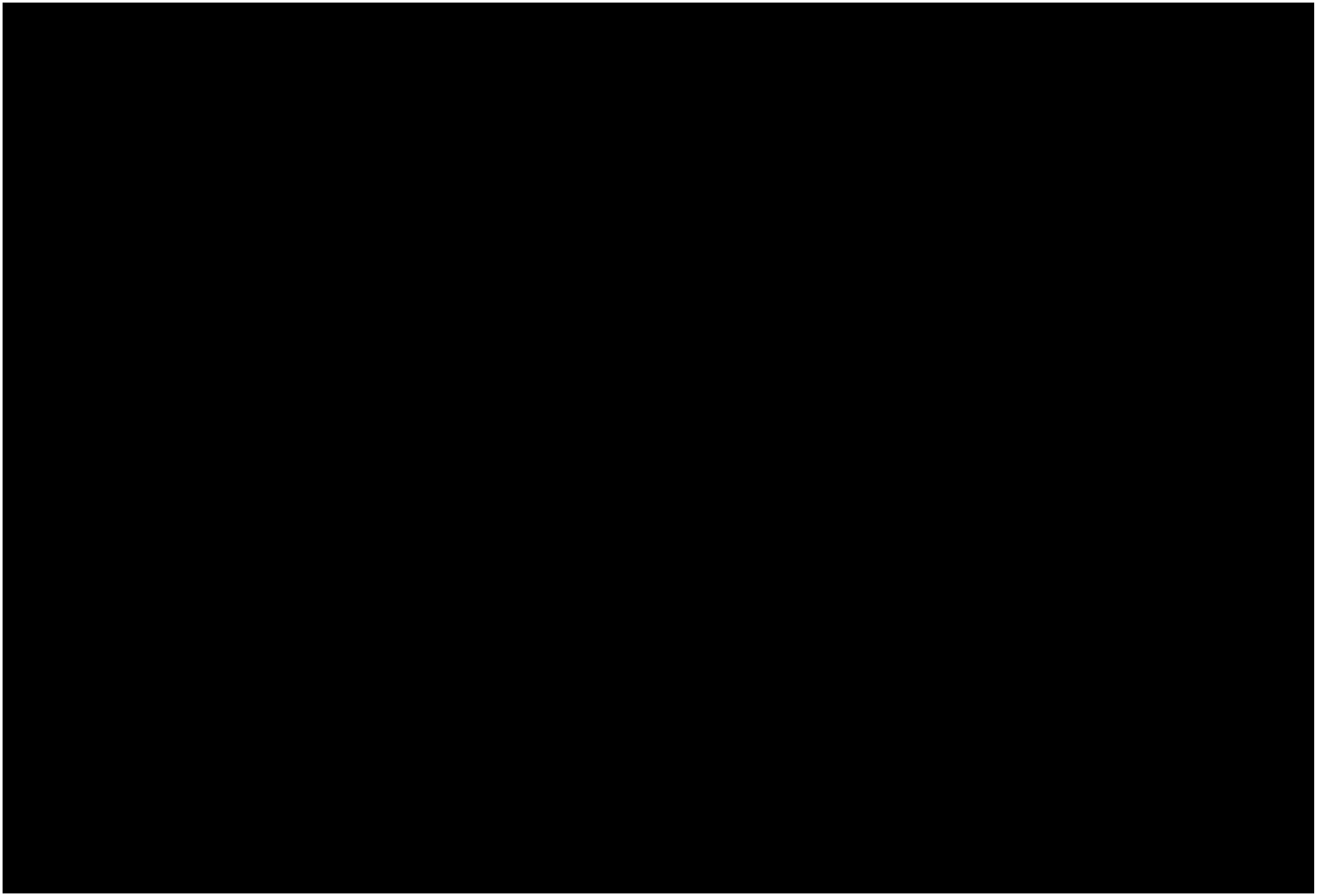
Date of On Peak Day - 07/22/2021



Member Forecasted On Peak Demand Day for August 2021

Jemez Mountains Electric Cooperative, Inc.

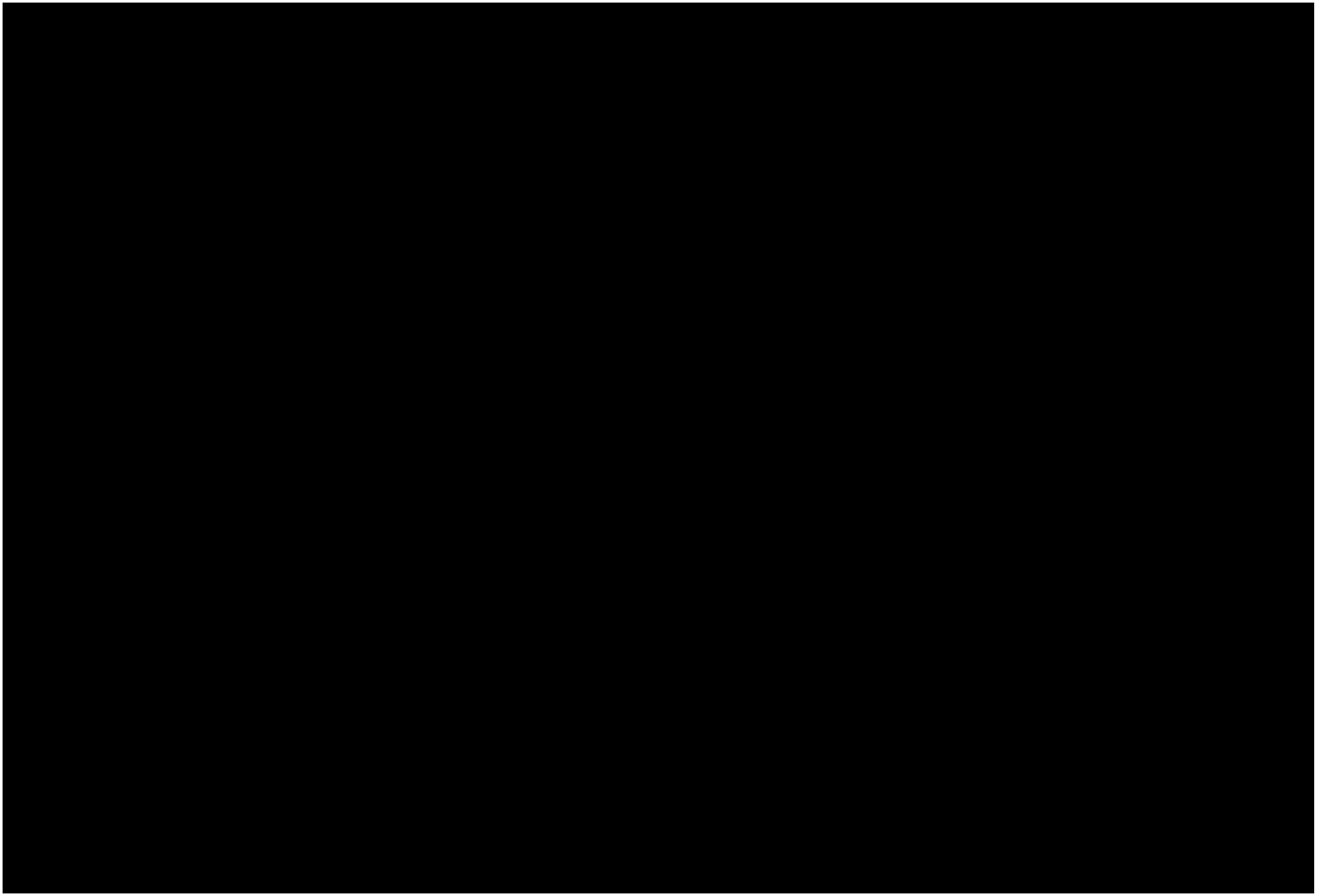
Date of On Peak Day - 08/18/2021



Member Forecasted On Peak Demand Day for September 2021

Jemez Mountains Electric Cooperative, Inc.

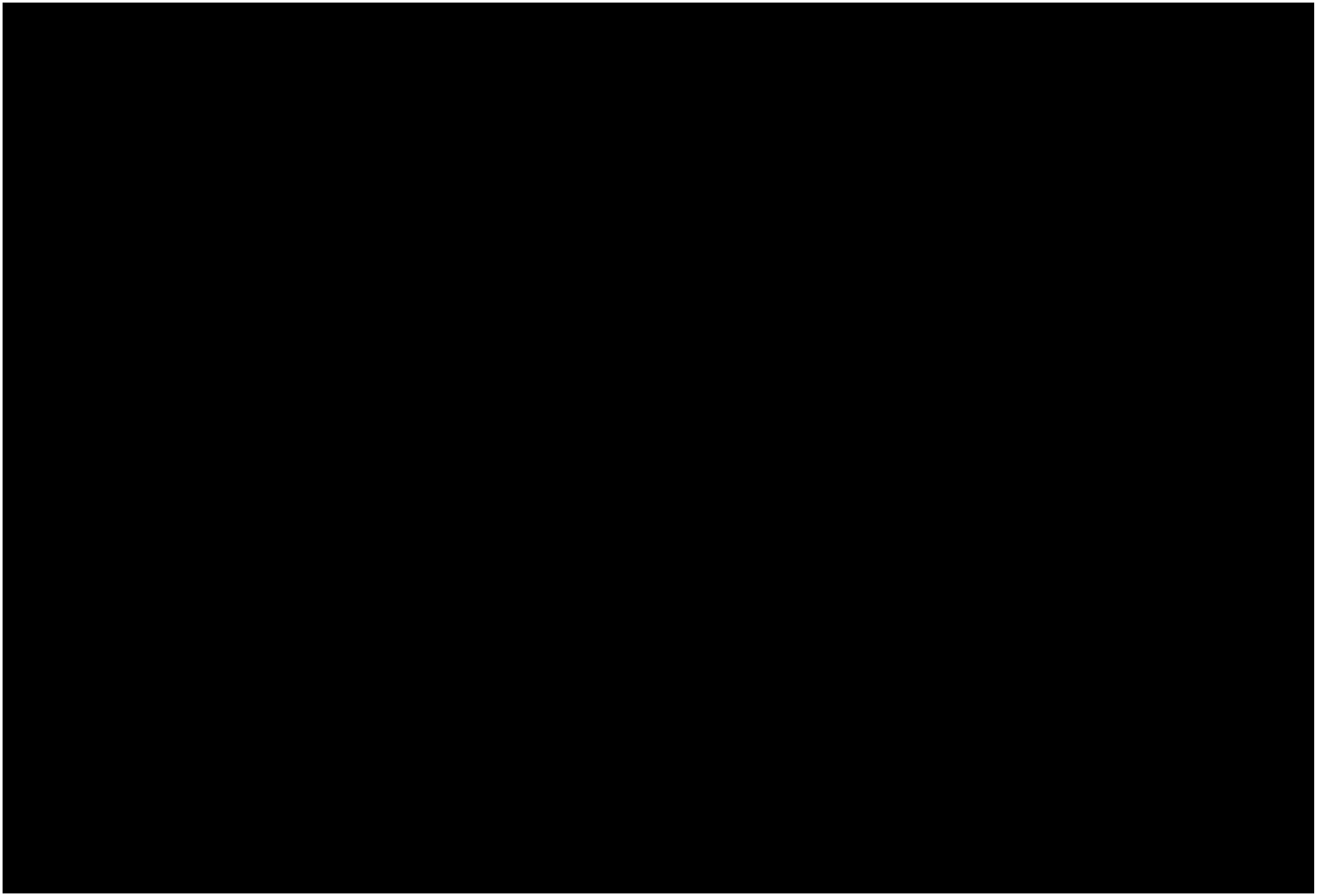
Date of On Peak Day - 09/01/2021



Member Forecasted On Peak Demand Day for October 2021

Jemez Mountains Electric Cooperative, Inc.

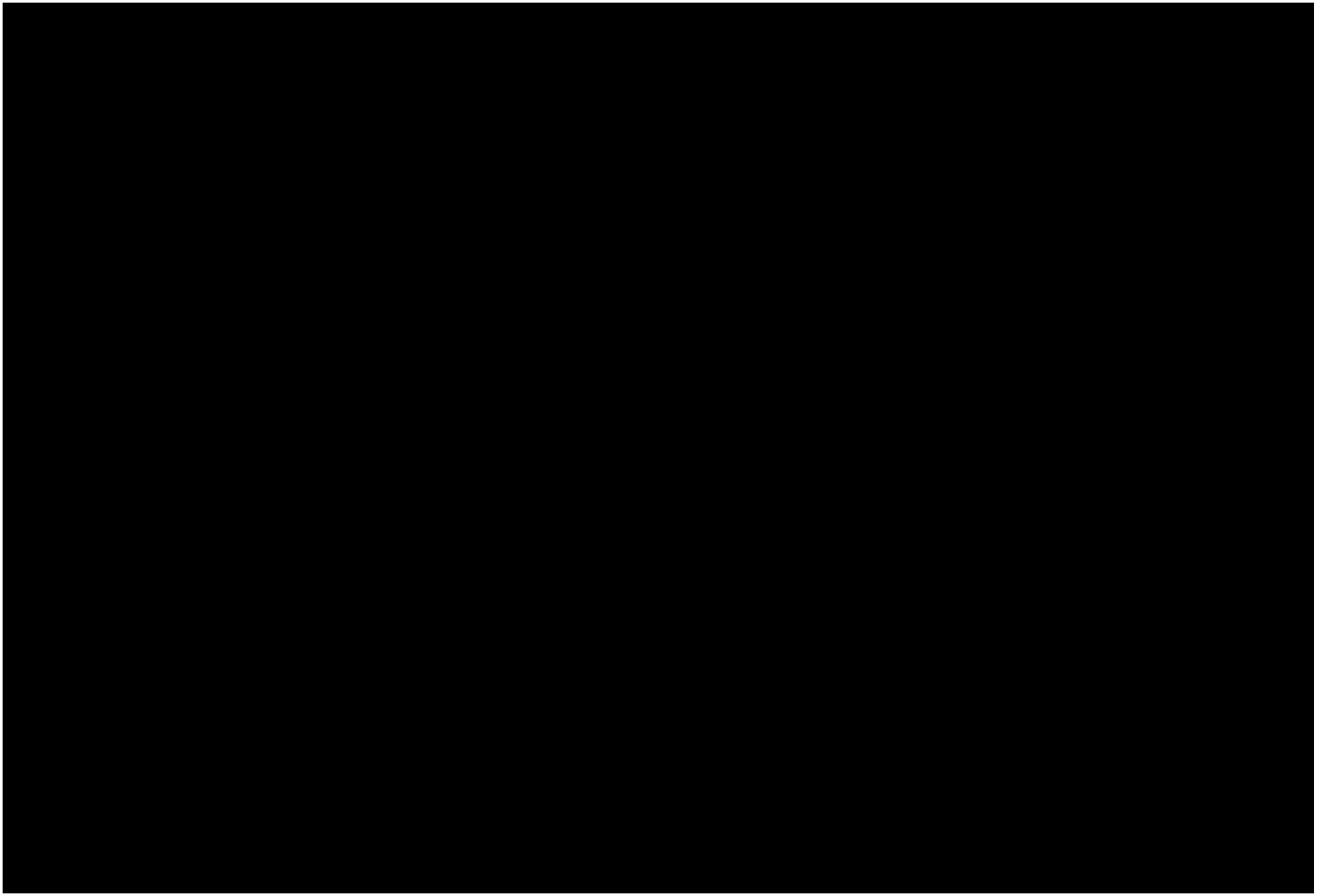
Date of On Peak Day - 10/21/2021



Member Forecasted On Peak Demand Day for November 2021

Jemez Mountains Electric Cooperative, Inc.

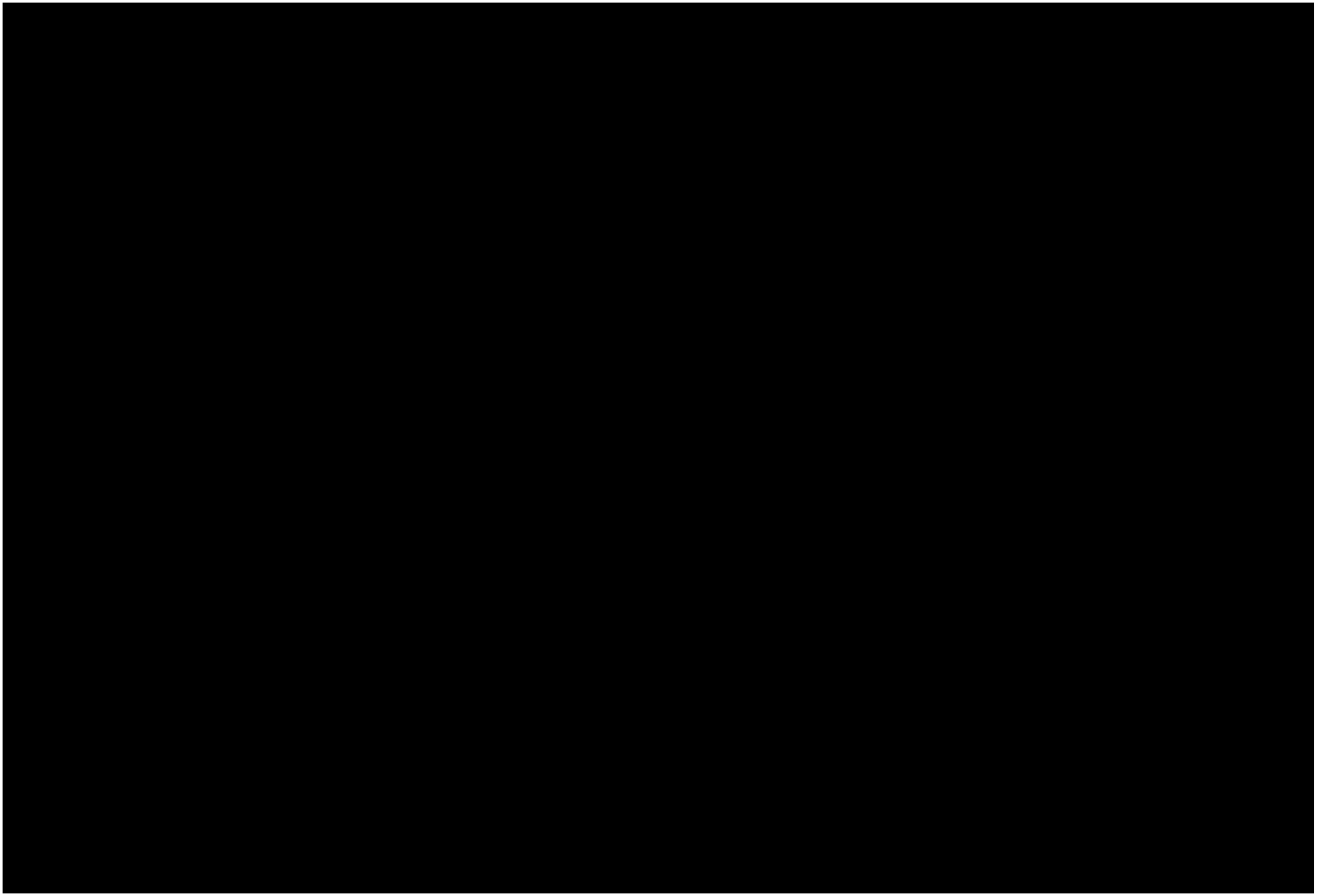
Date of On Peak Day - 11/29/2021



Member Forecasted On Peak Demand Day for December 2021

Jemez Mountains Electric Cooperative, Inc.

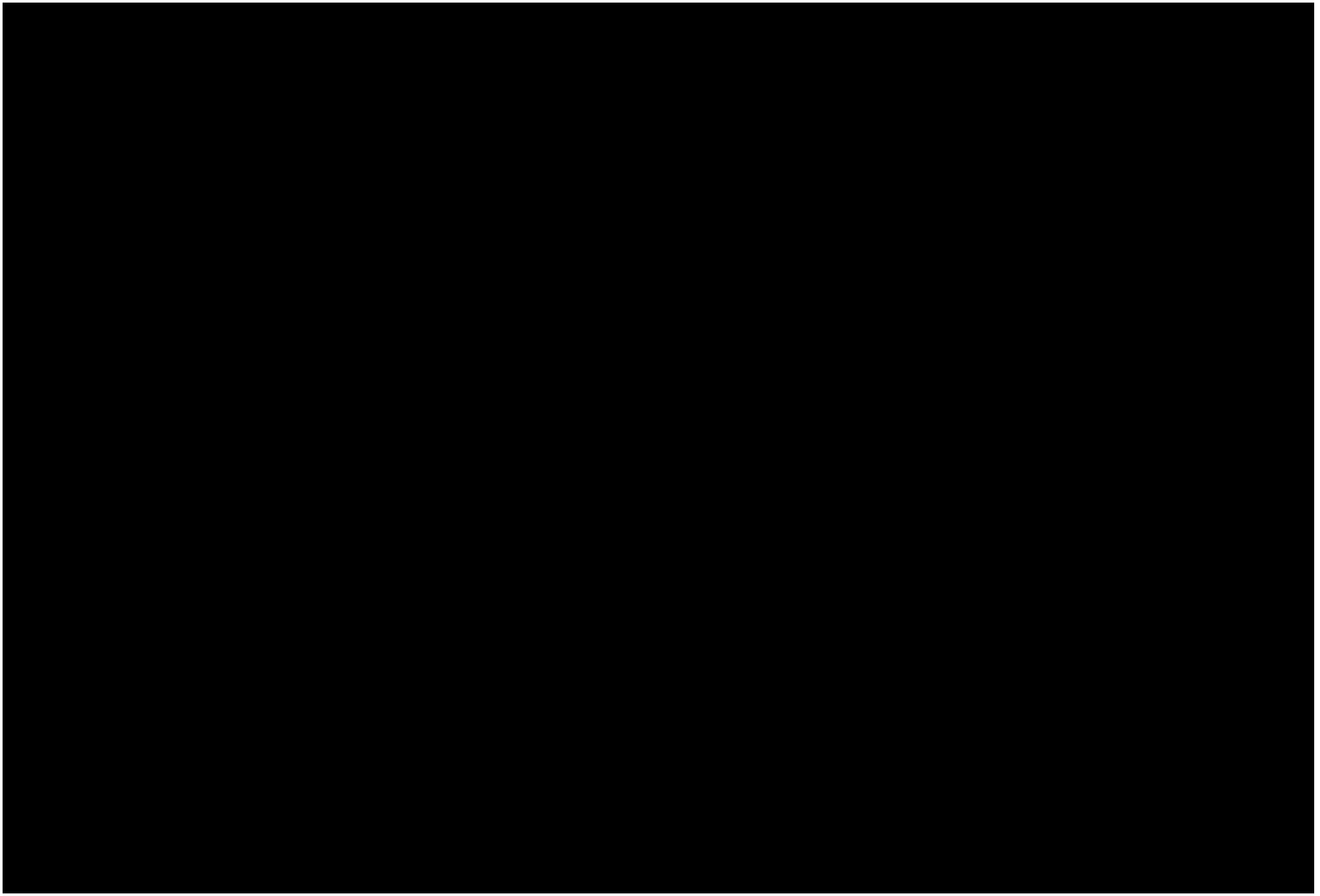
Date of On Peak Day - 12/26/2021



Member Forecasted On Peak Demand Day for January 2021

K.C. Electric Association, Inc.

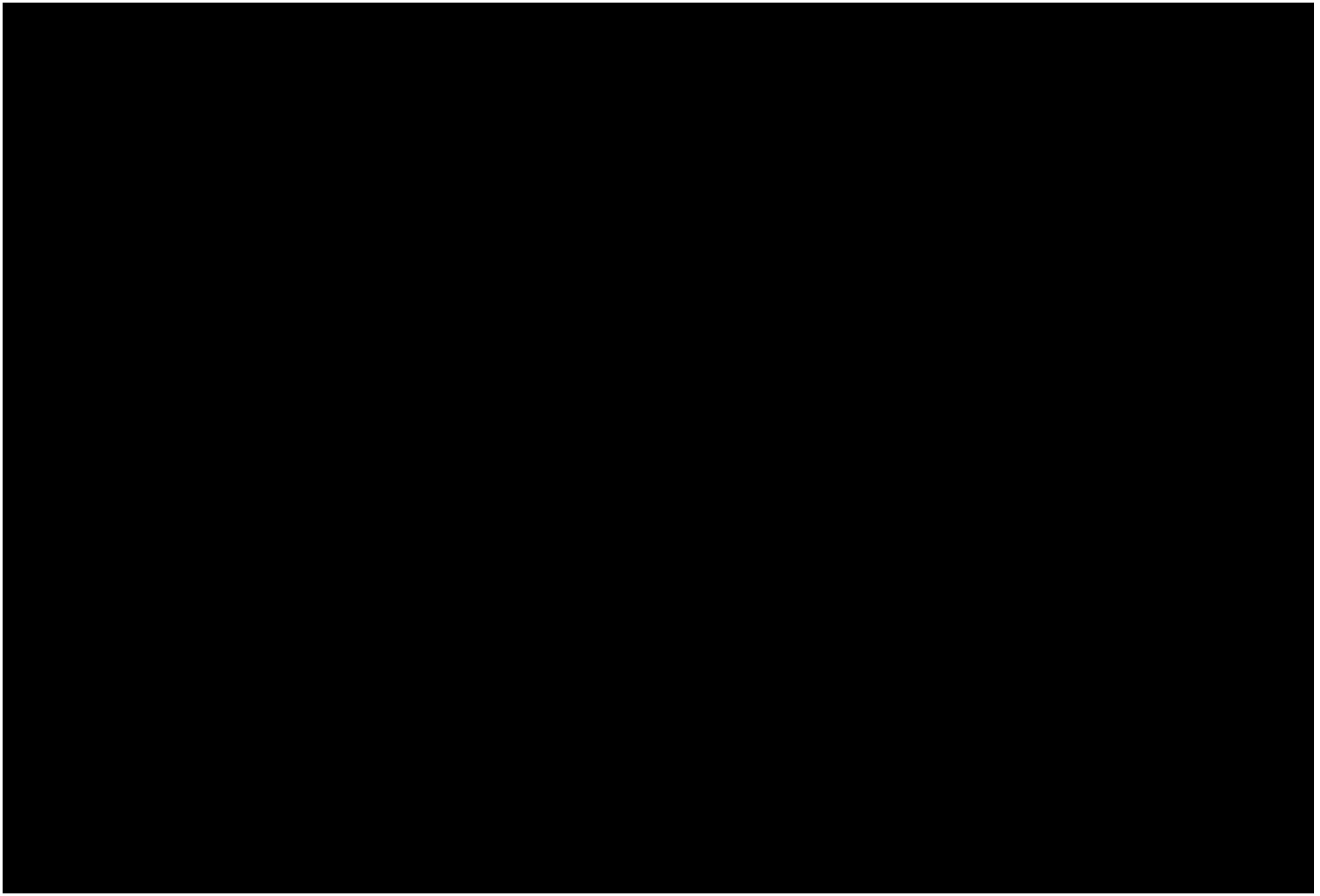
Date of On Peak Day - 01/15/2021



Member Forecasted On Peak Demand Day for February 2021

K.C. Electric Association, Inc.

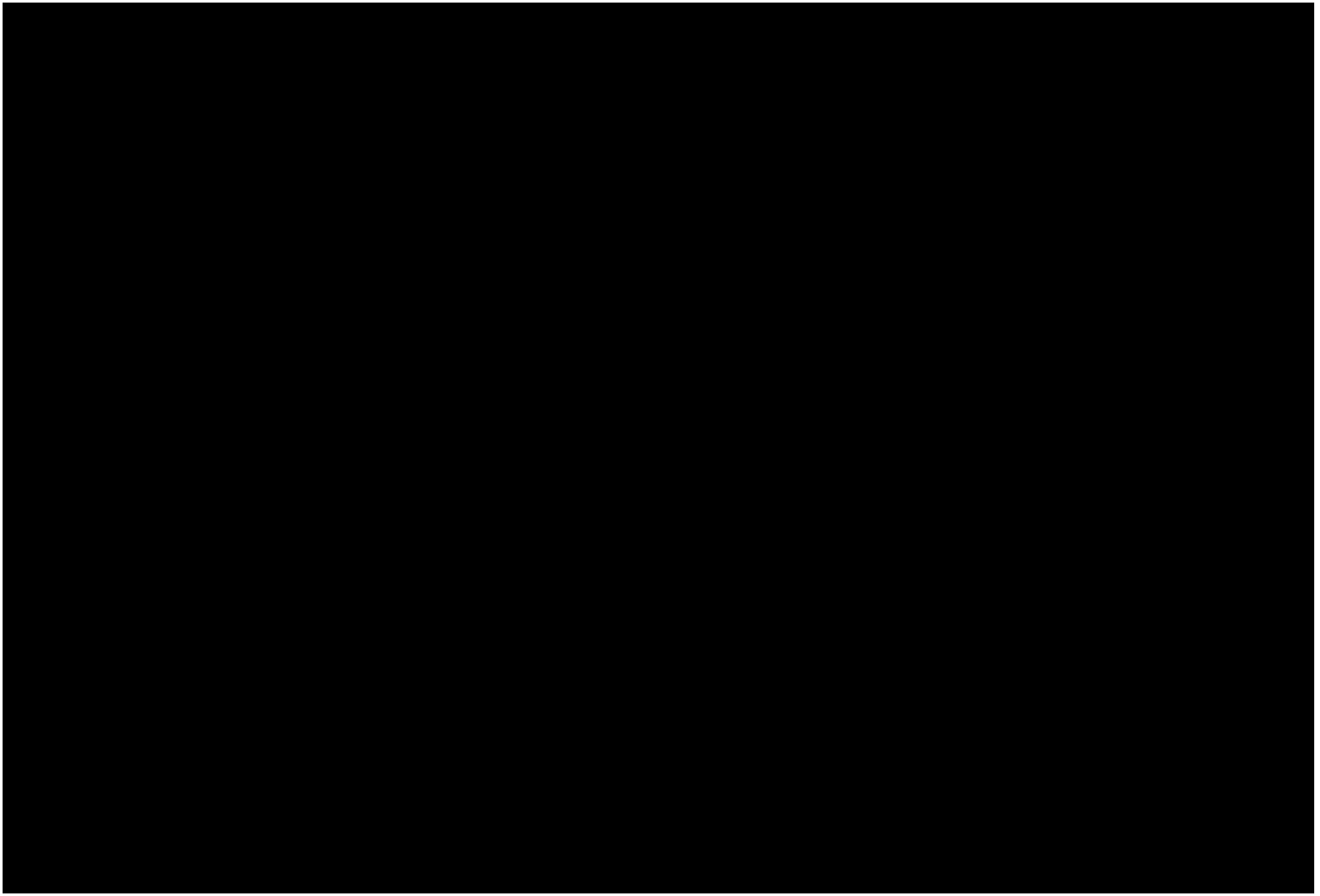
Date of On Peak Day - 02/02/2021



Member Forecasted On Peak Demand Day for March 2021

K.C. Electric Association, Inc.

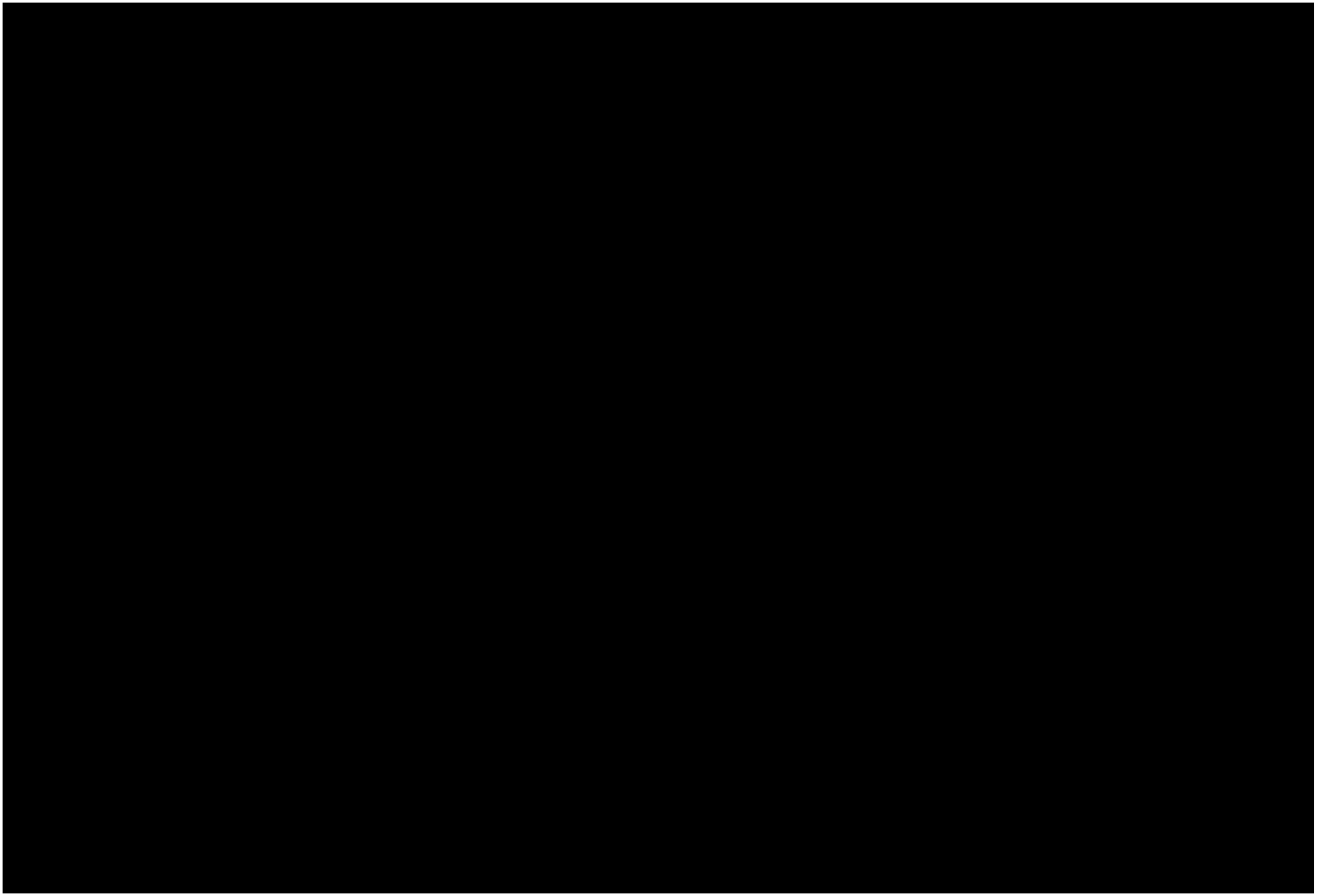
Date of On Peak Day - 03/22/2021



Member Forecasted On Peak Demand Day for April 2021

K.C. Electric Association, Inc.

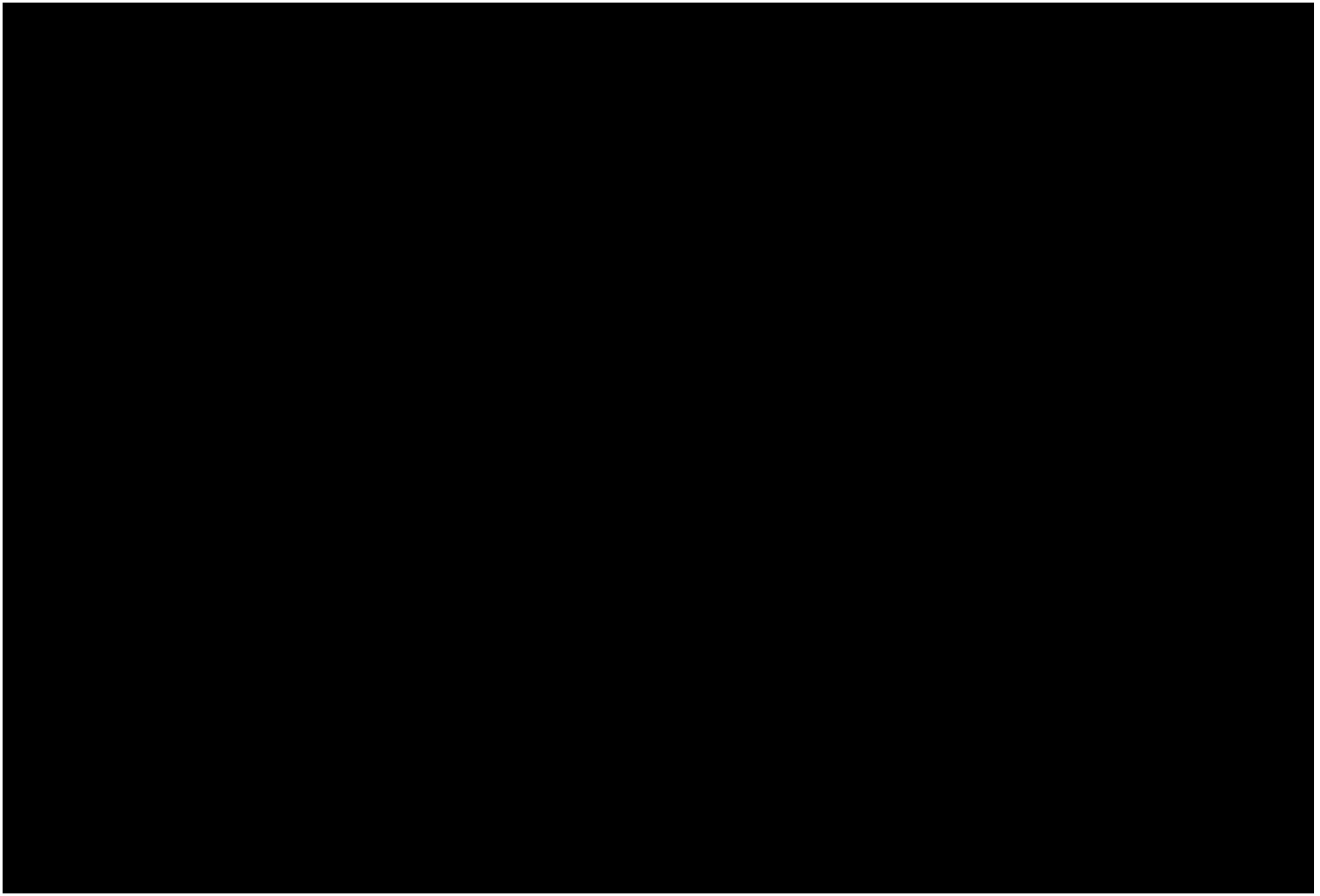
Date of On Peak Day - 04/14/2021



Member Forecasted On Peak Demand Day for May 2021

K.C. Electric Association, Inc.

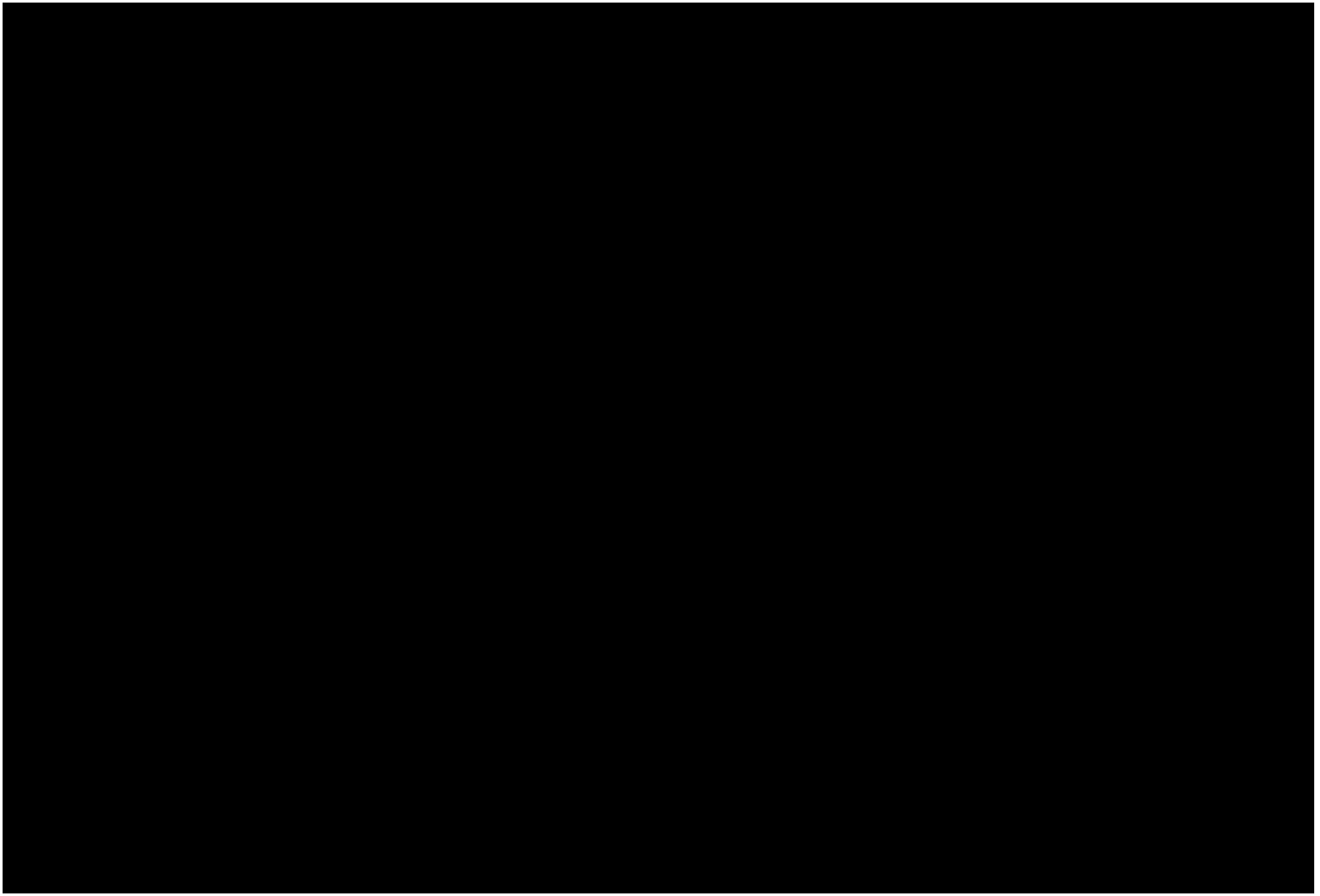
Date of On Peak Day - 05/31/2021



Member Forecasted On Peak Demand Day for June 2021

K.C. Electric Association, Inc.

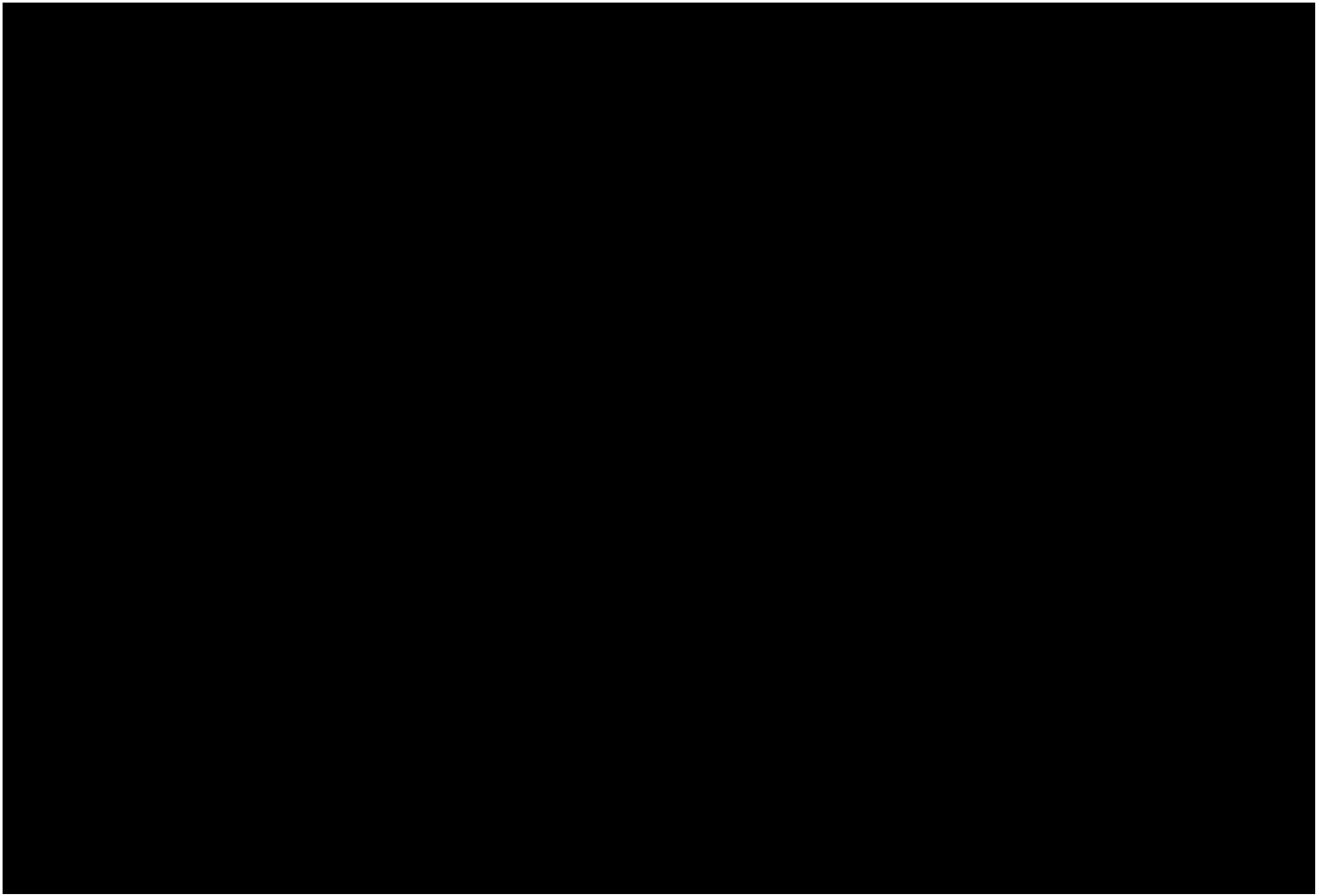
Date of On Peak Day - 06/17/2021



Member Forecasted On Peak Demand Day for July 2021

K.C. Electric Association, Inc.

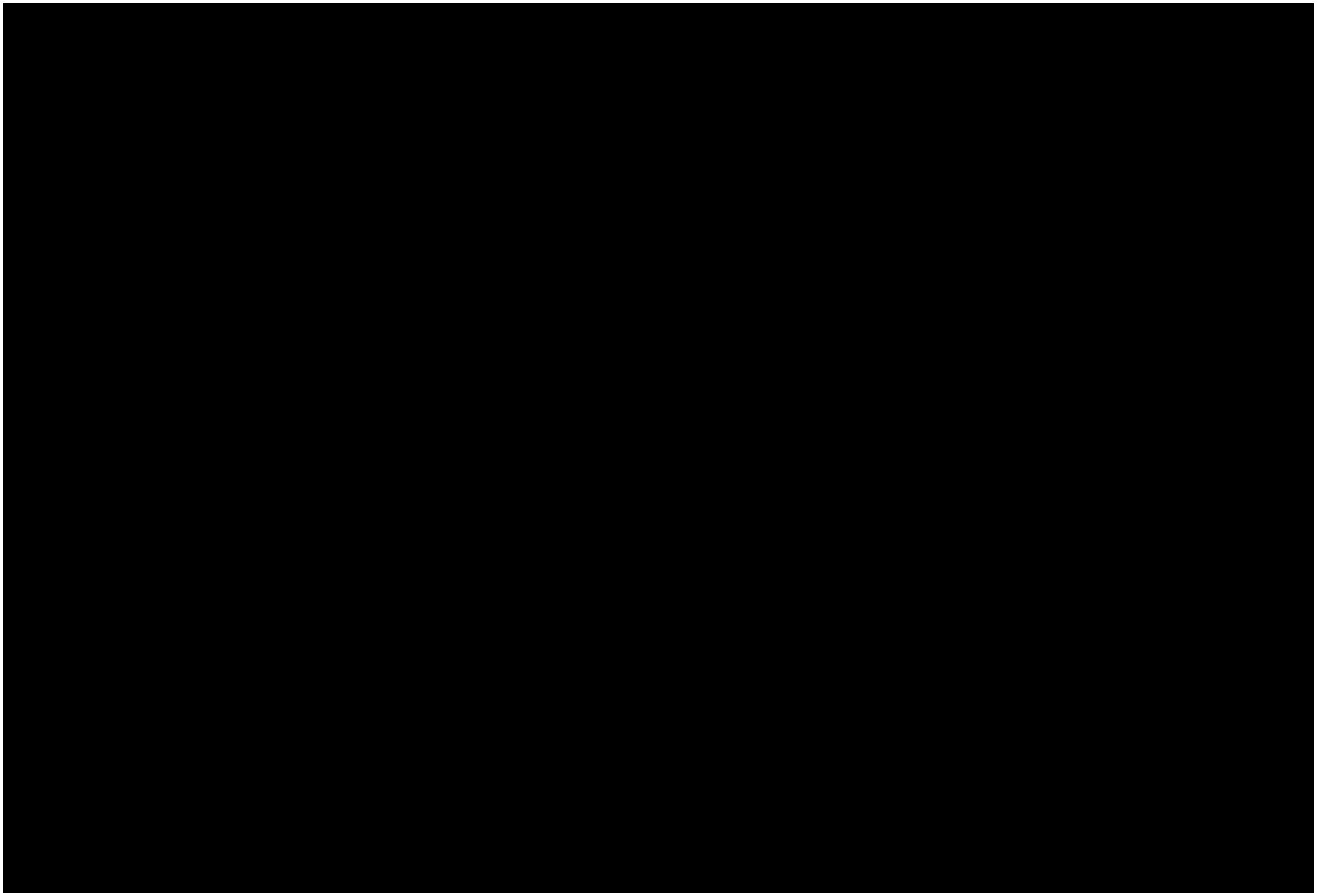
Date of On Peak Day - 07/22/2021



Member Forecasted On Peak Demand Day for August 2021

K.C. Electric Association, Inc.

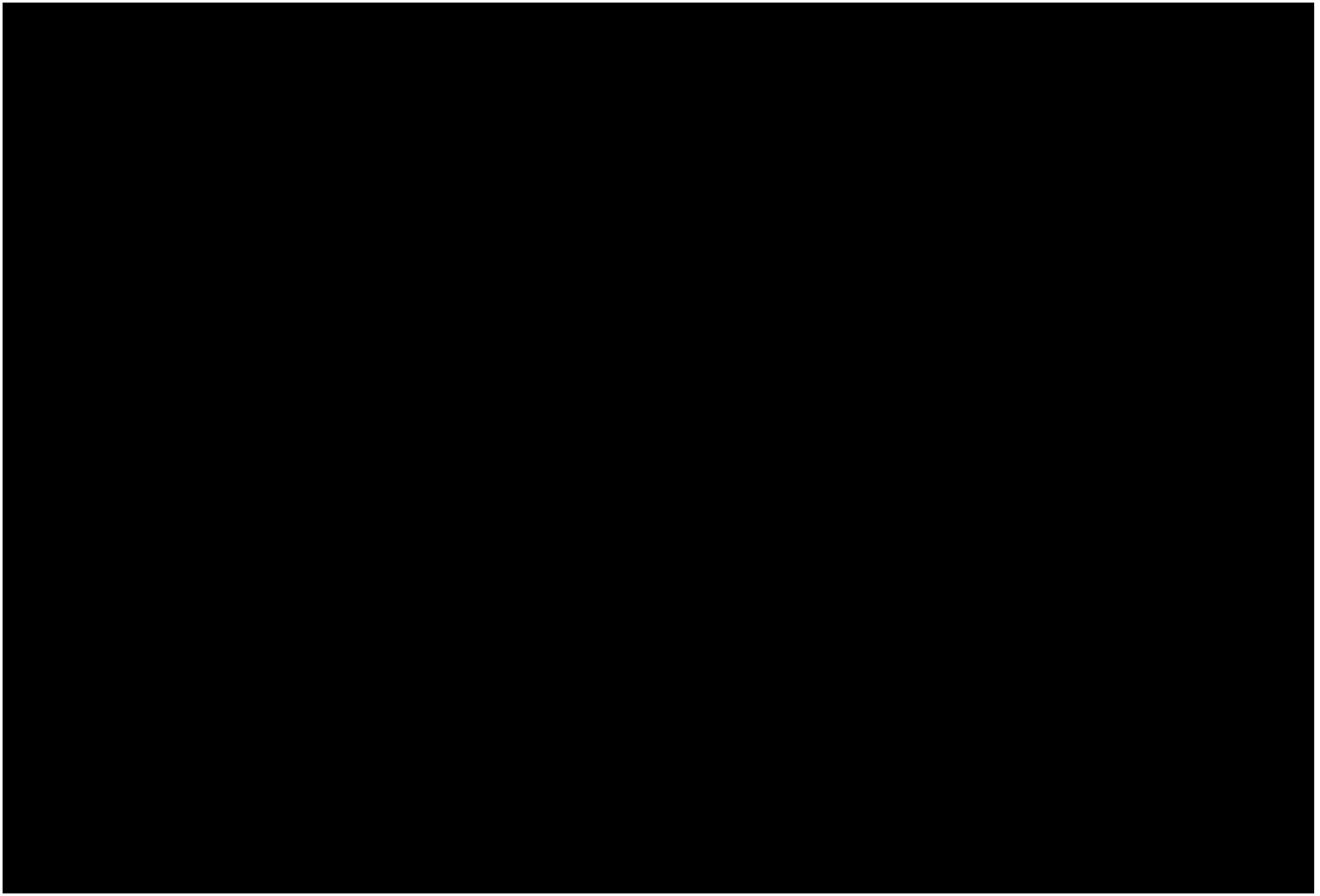
Date of On Peak Day - 08/29/2021



Member Forecasted On Peak Demand Day for September 2021

K.C. Electric Association, Inc.

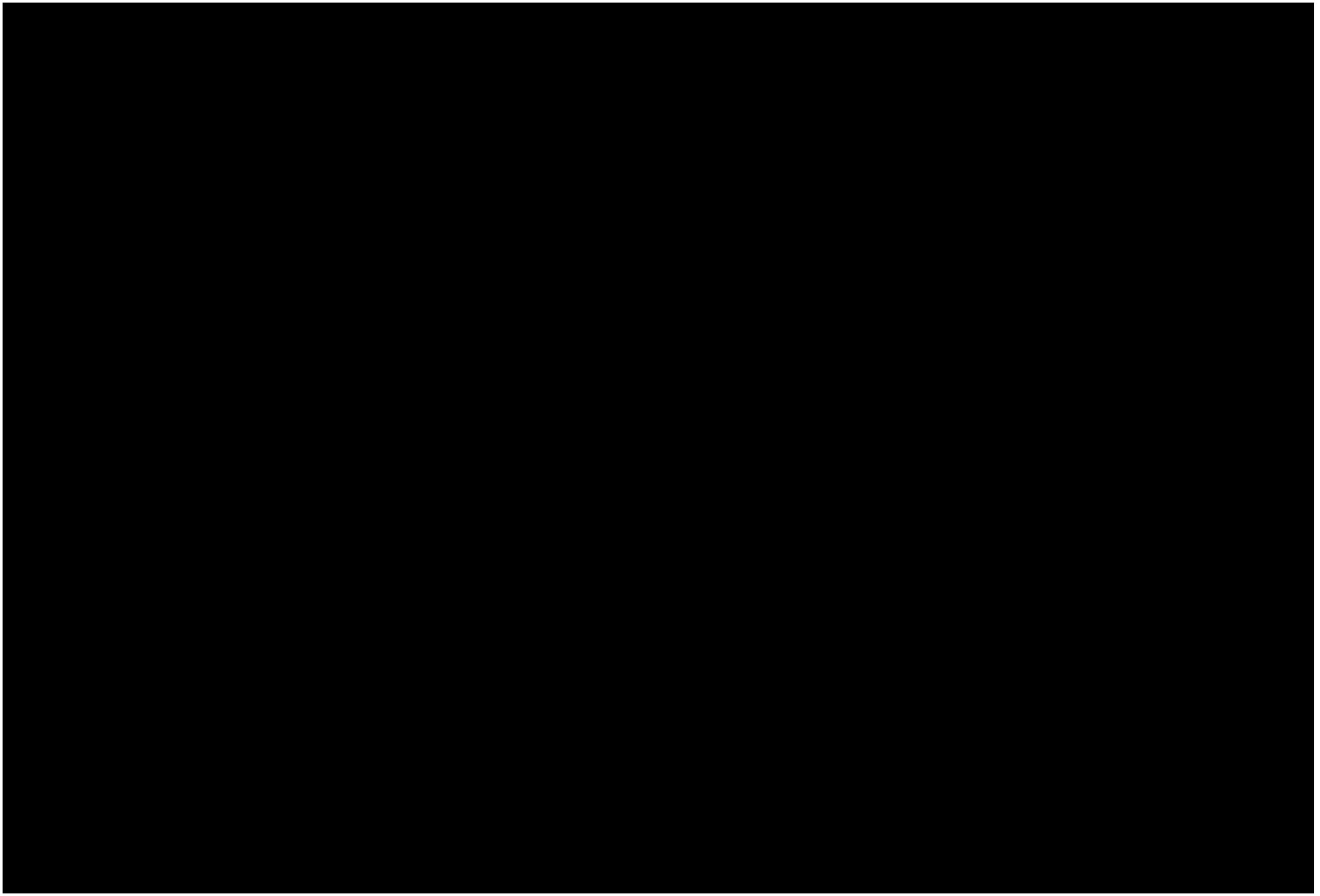
Date of On Peak Day - 09/02/2021



Member Forecasted On Peak Demand Day for October 2021

K.C. Electric Association, Inc.

Date of On Peak Day - 10/19/2021



Member Forecasted On Peak Demand Day for November 2021

K.C. Electric Association, Inc.

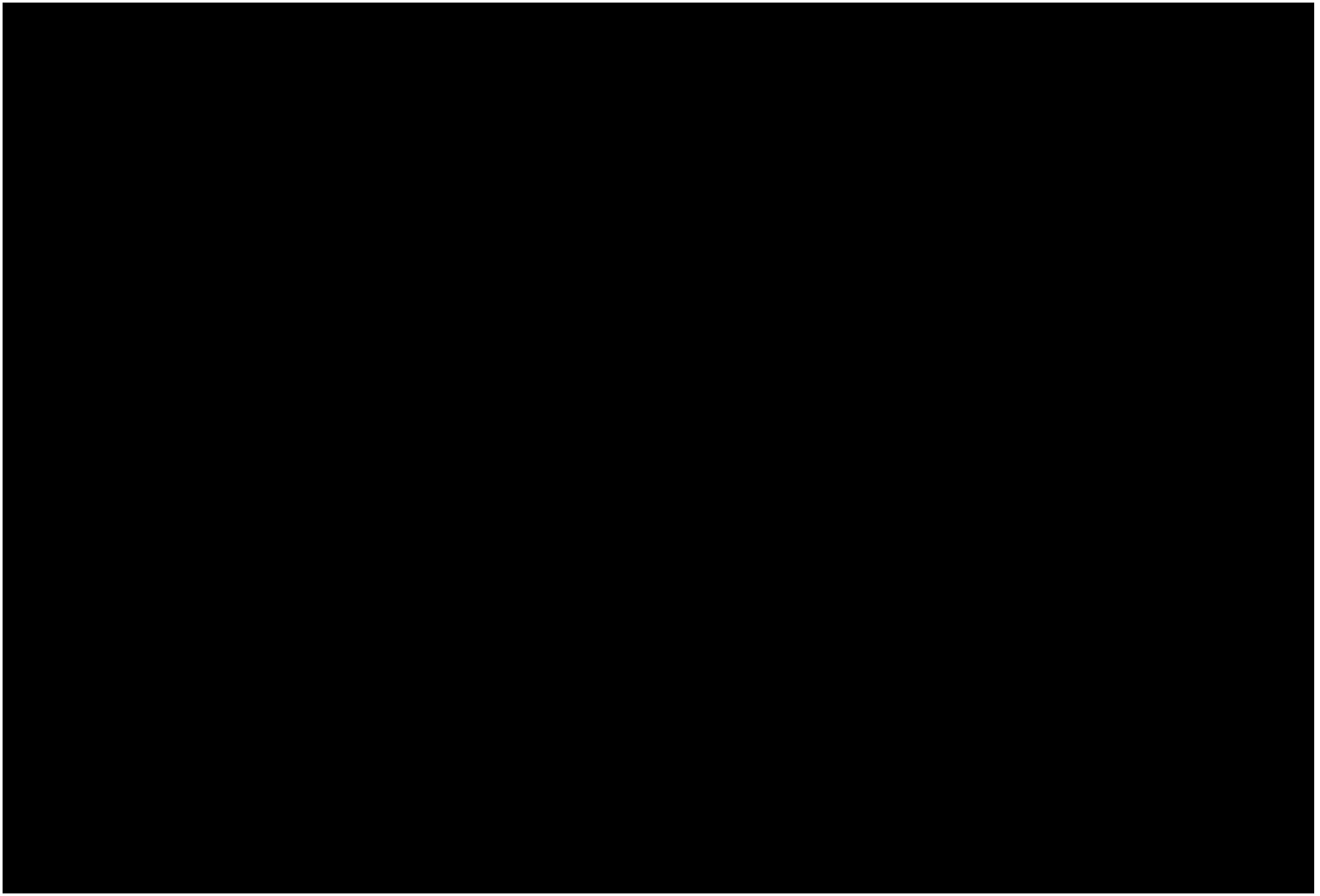
Date of On Peak Day - 11/08/2021

[redacted]

Member Forecasted On Peak Demand Day for December 2021

K.C. Electric Association, Inc.

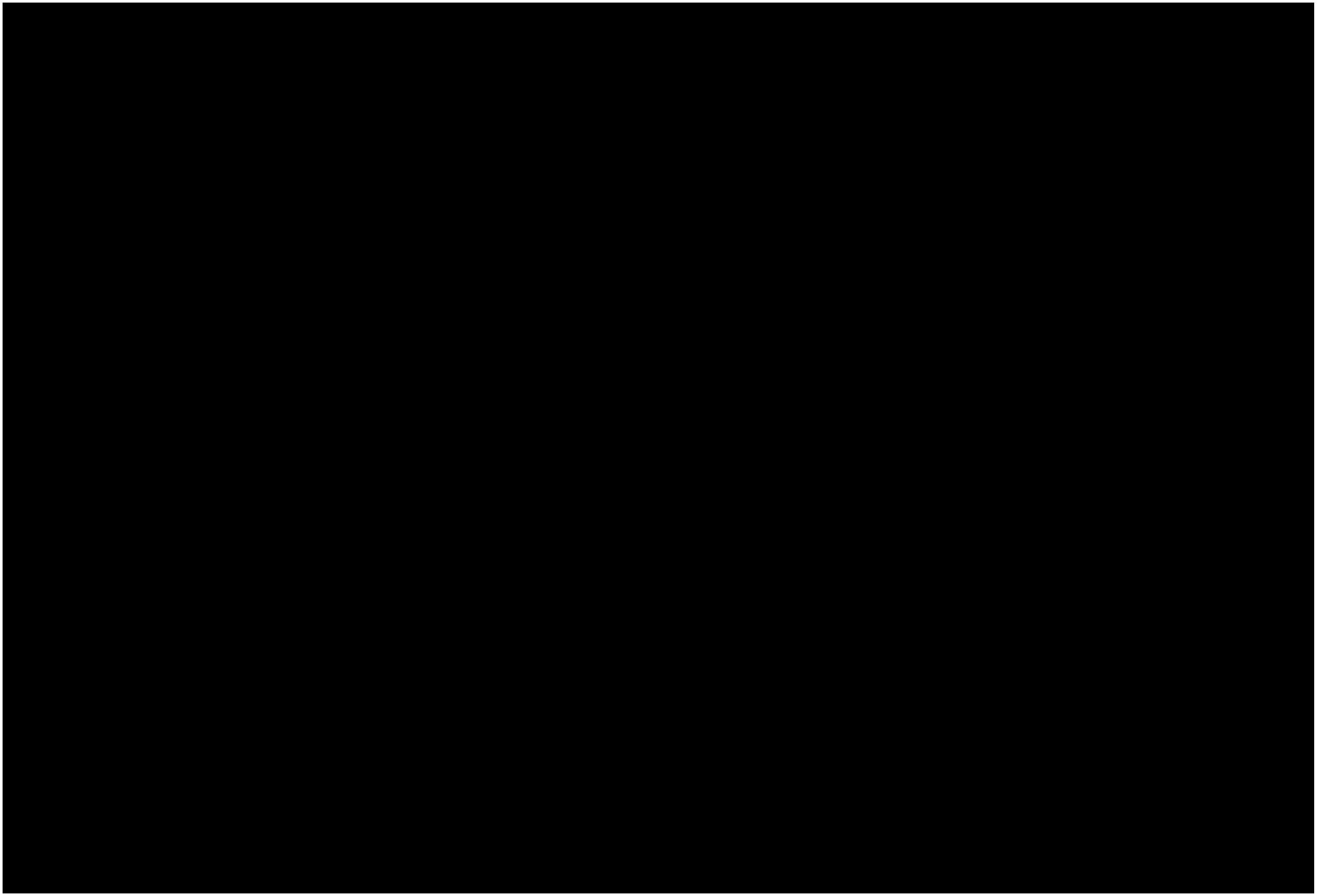
Date of On Peak Day - 12/29/2021



Member Forecasted On Peak Demand Day for January 2021

La Plata Electric Association, Inc.

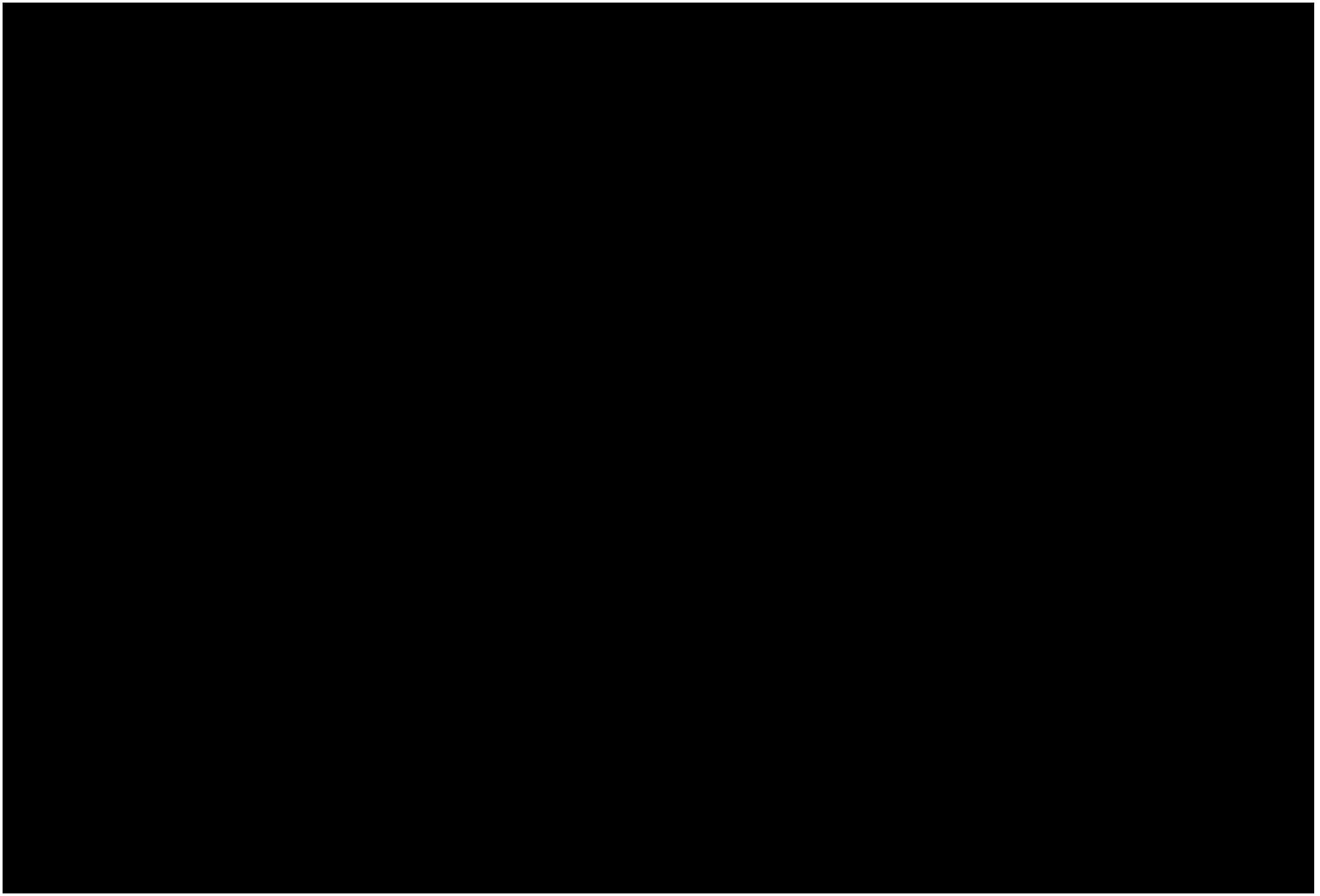
Date of On Peak Day - 01/25/2021



Member Forecasted On Peak Demand Day for February 2021

La Plata Electric Association, Inc.

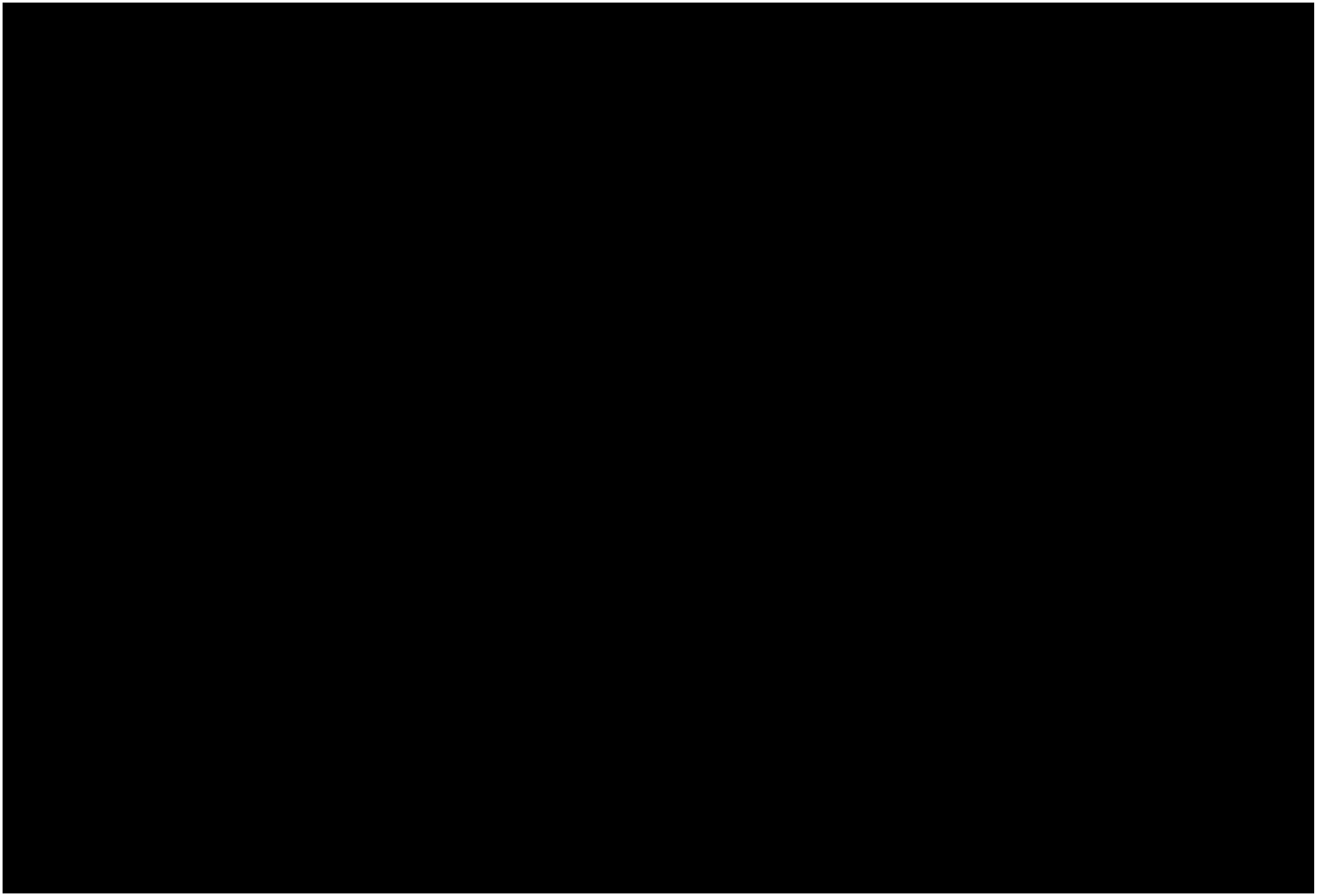
Date of On Peak Day - 02/01/2021



Member Forecasted On Peak Demand Day for March 2021

La Plata Electric Association, Inc.

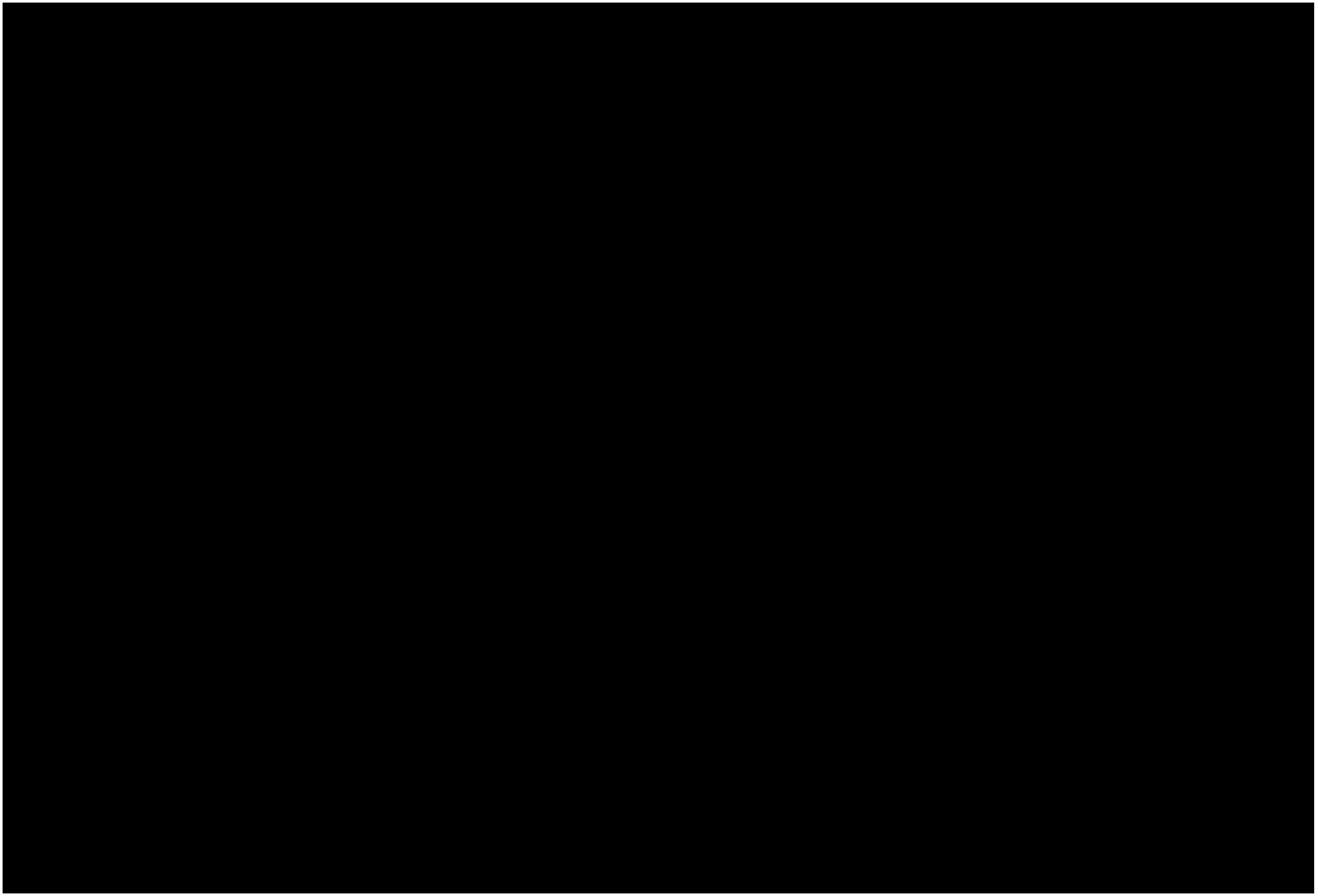
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

La Plata Electric Association, Inc.

Date of On Peak Day - 04/16/2021



Member Forecasted On Peak Demand Day for May 2021

La Plata Electric Association, Inc.

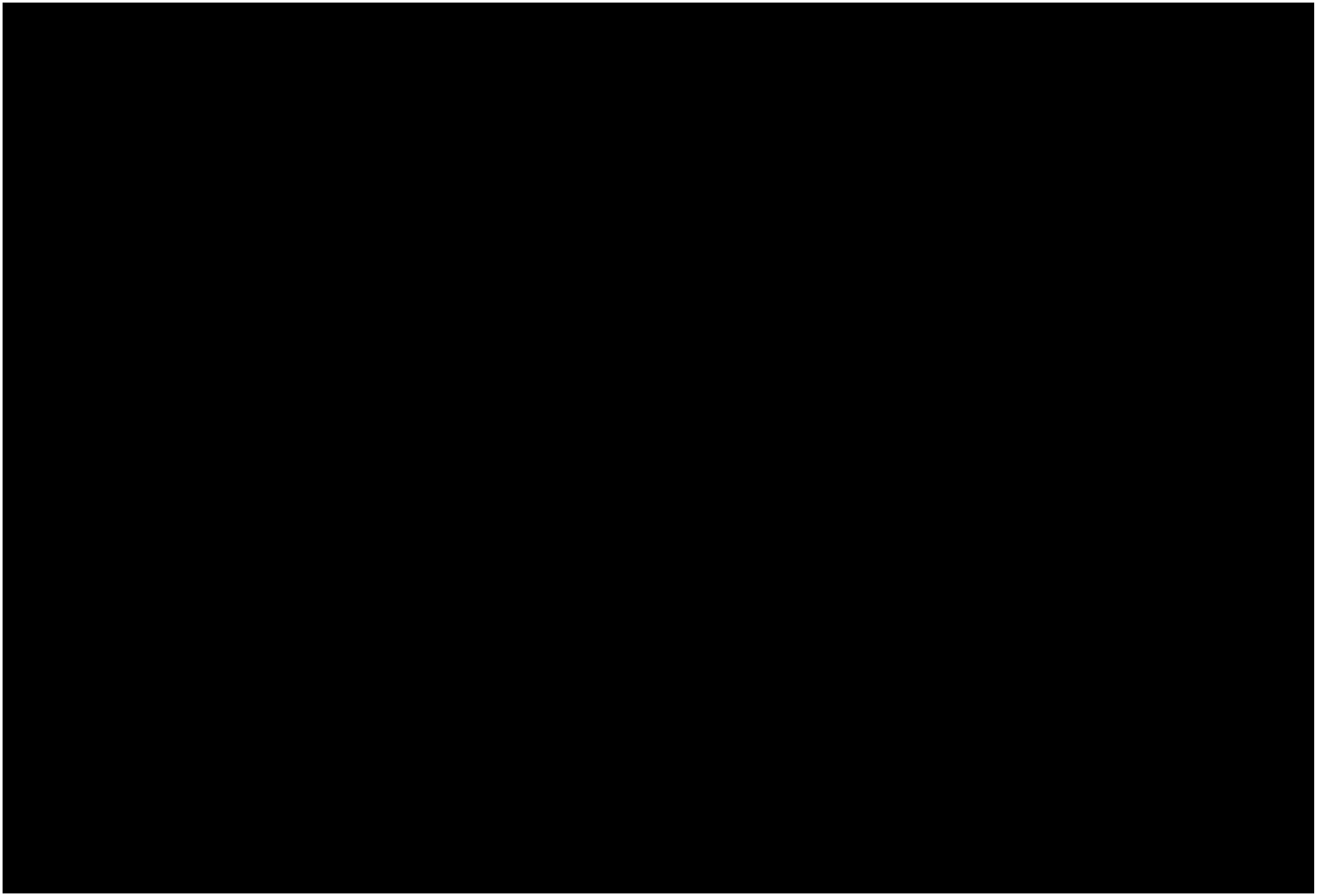
Date of On Peak Day - 05/19/2021

[redacted]

Member Forecasted On Peak Demand Day for June 2021

La Plata Electric Association, Inc.

Date of On Peak Day - 06/24/2021



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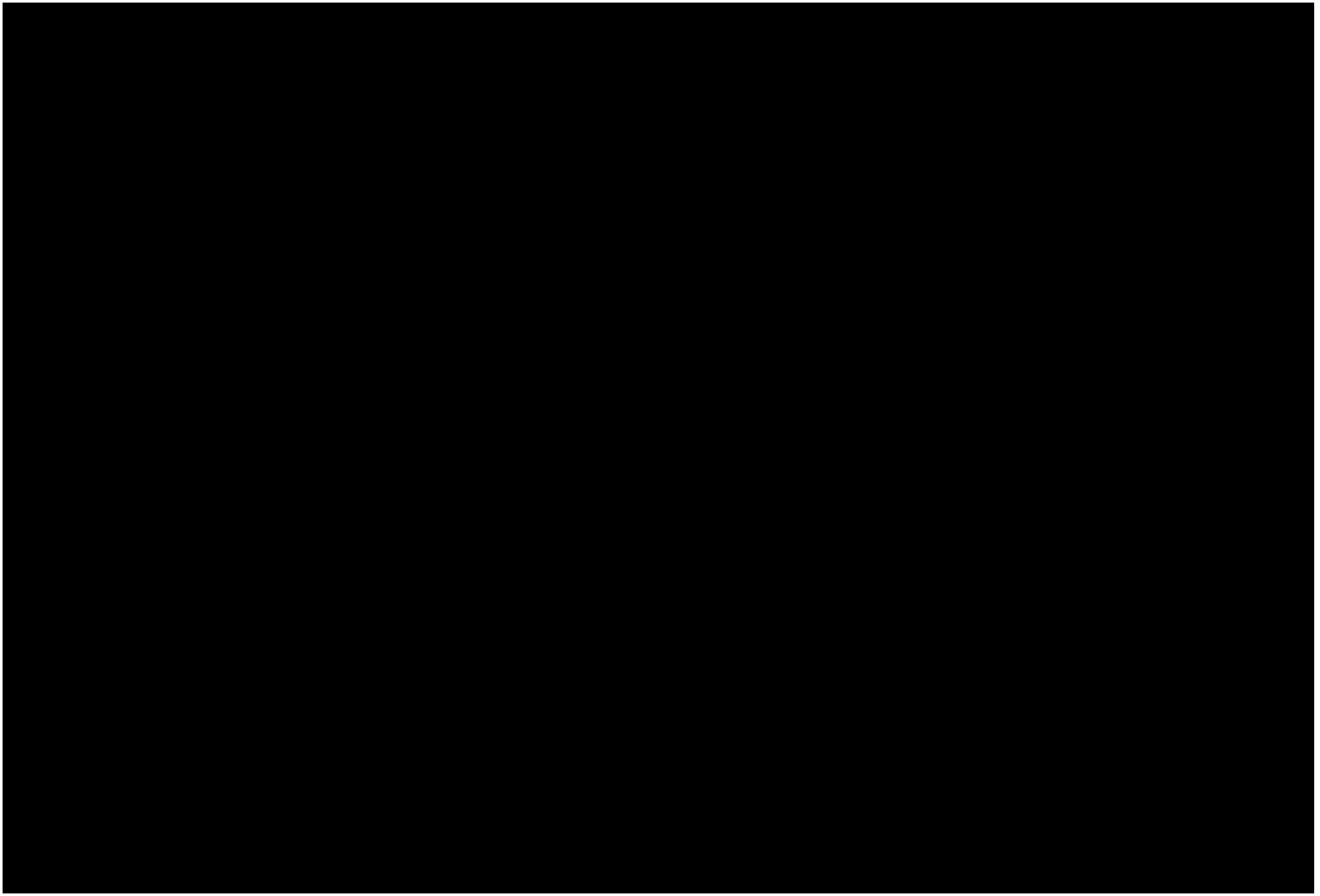
Member Forecasted On Peak Demand Day for July 2021

La Plata Electric Association, Inc.

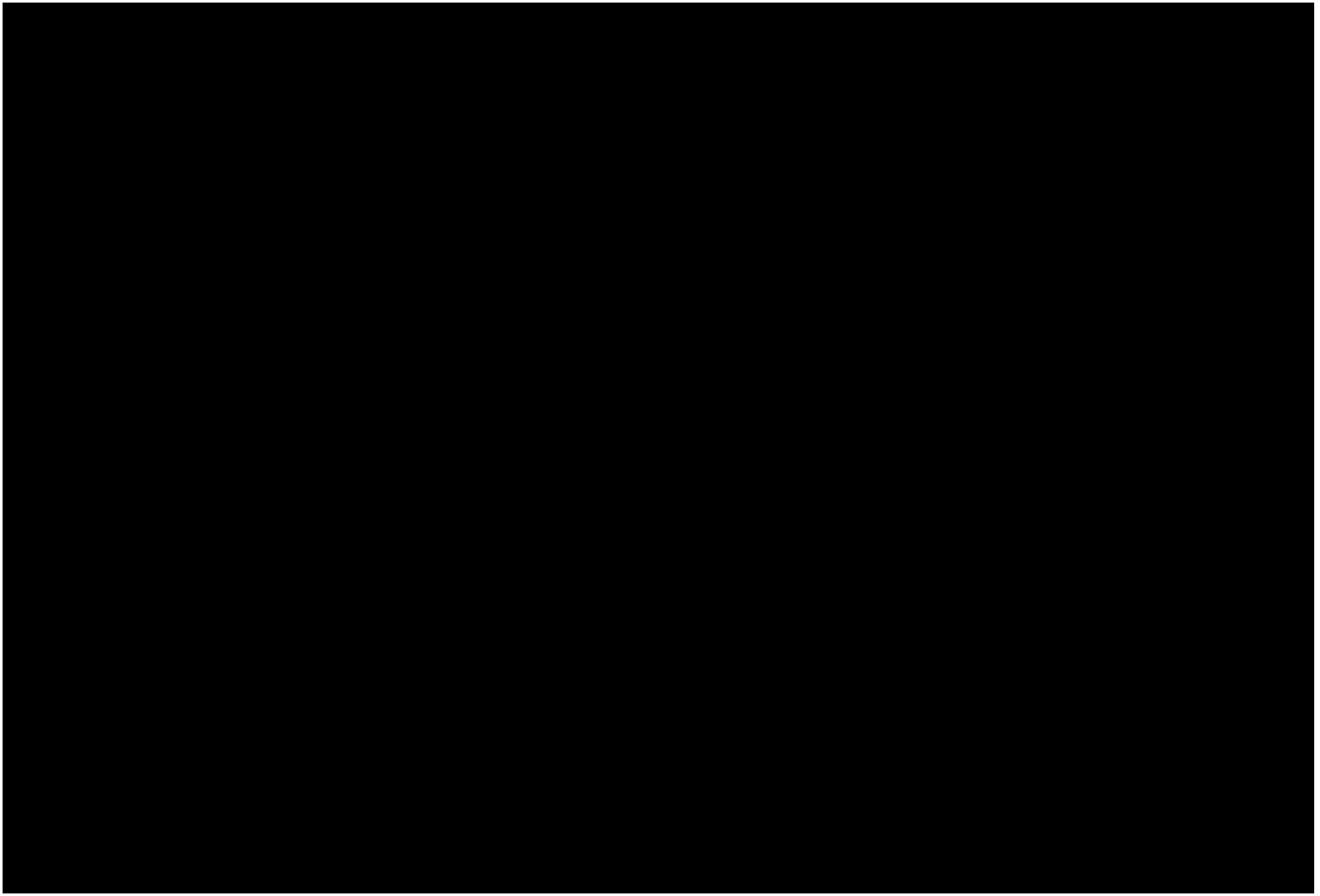
Date of On Peak Day - 07/19/2021



Member Forecasted On Peak Demand Day for August 2021

La Plata Electric Association, Inc.

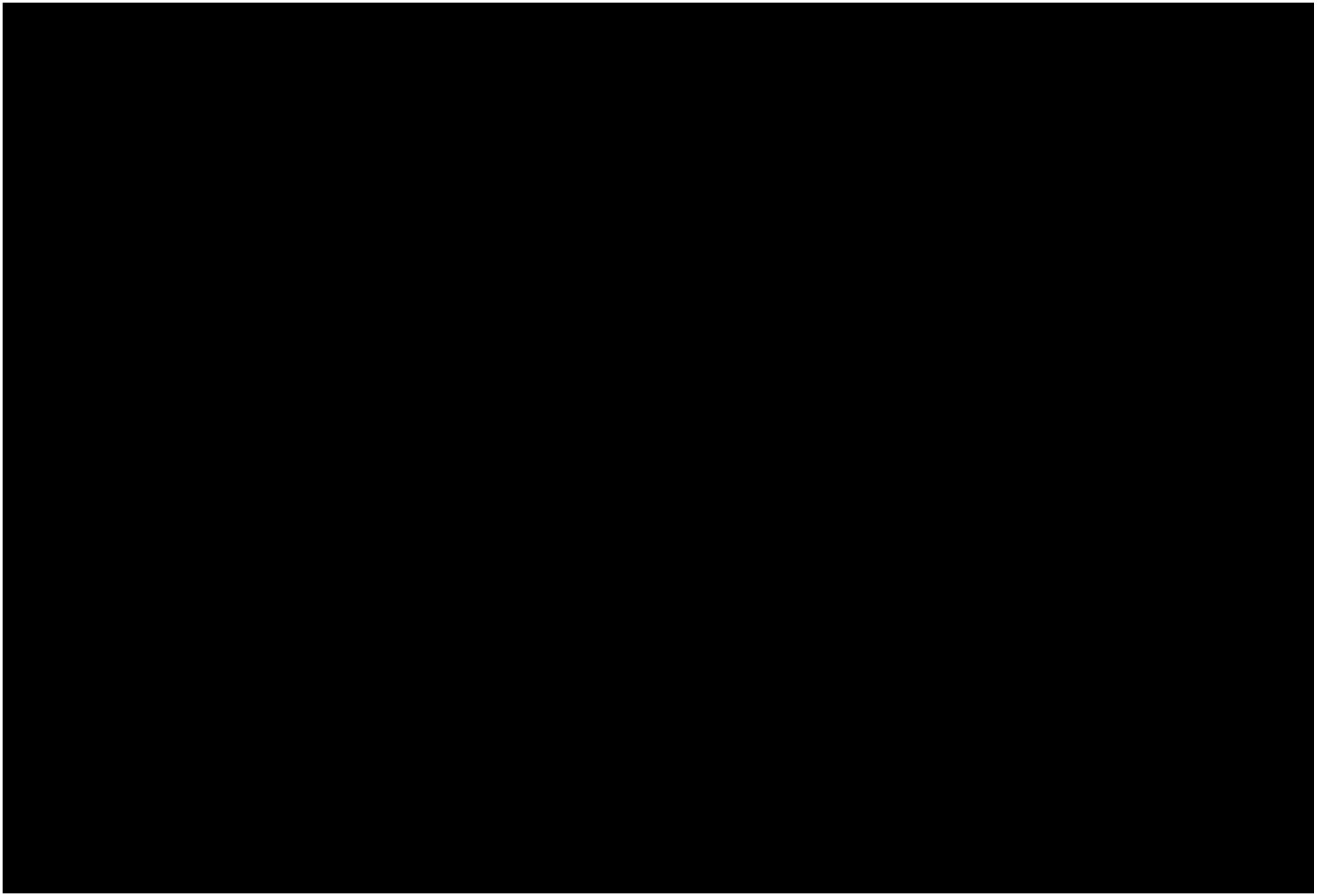
Date of On Peak Day - 08/26/2021



Member Forecasted On Peak Demand Day for September 2021

La Plata Electric Association, Inc.

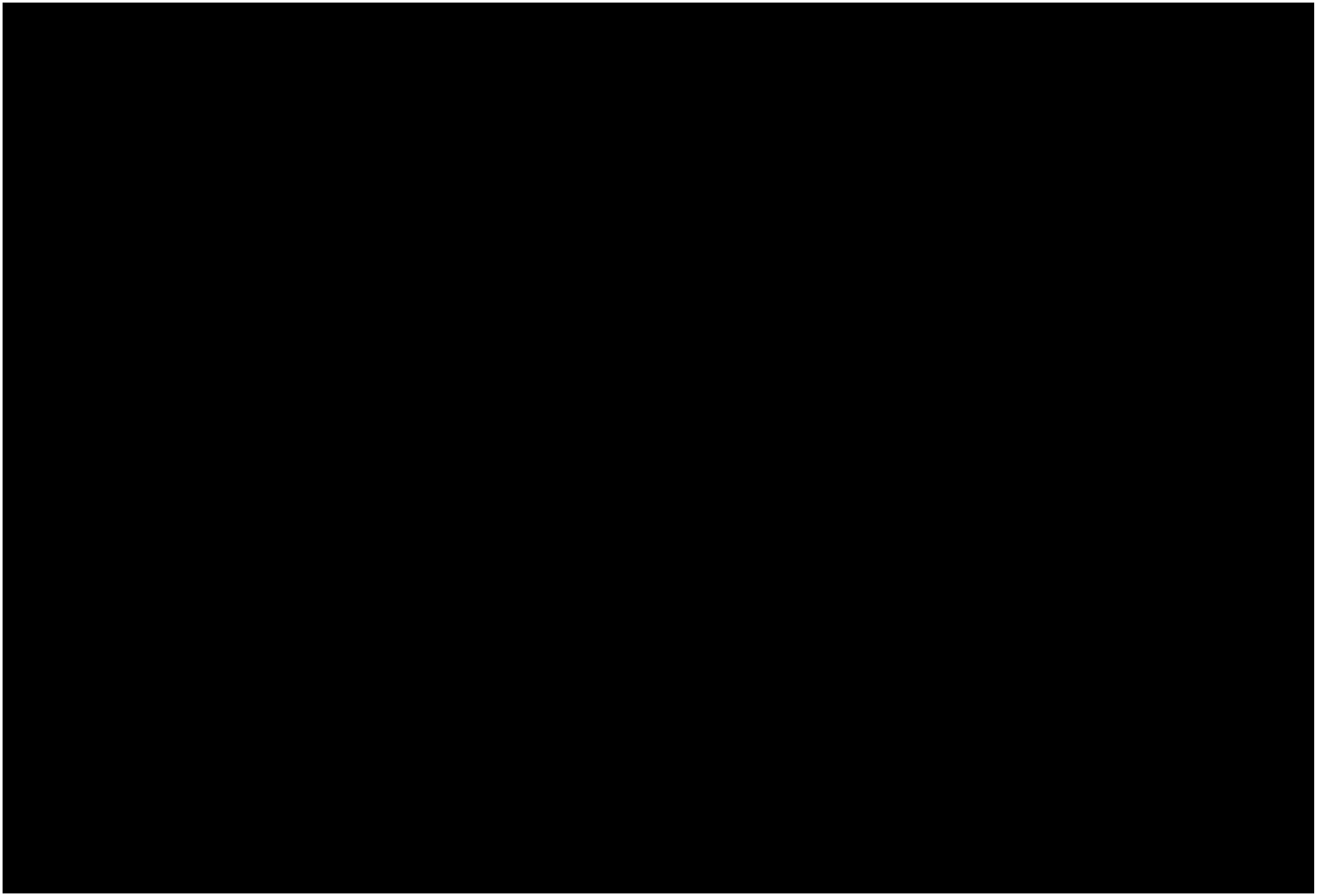
Date of On Peak Day - 09/01/2021



Member Forecasted On Peak Demand Day for October 2021

La Plata Electric Association, Inc.

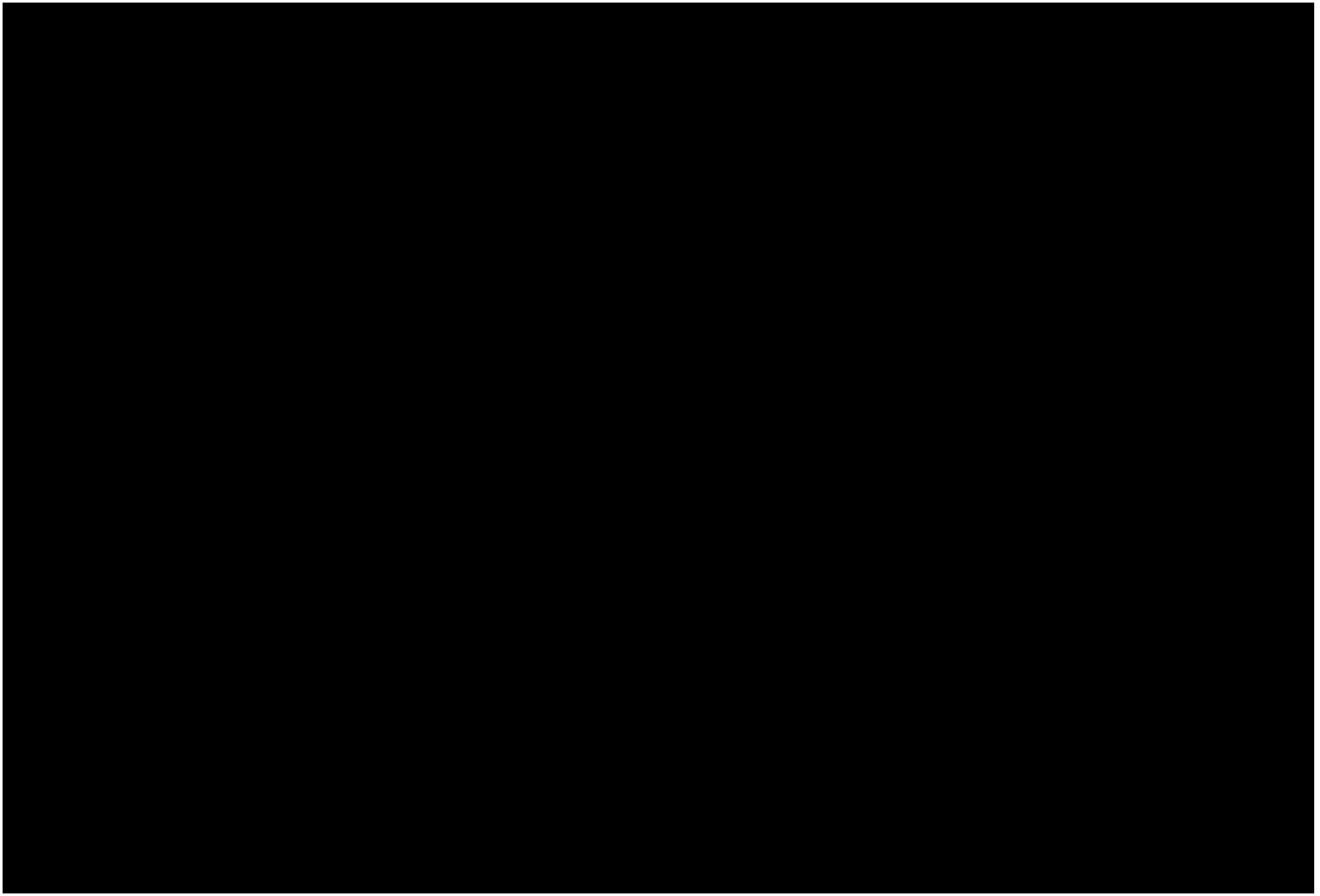
Date of On Peak Day - 10/28/2021



Member Forecasted On Peak Demand Day for November 2021

La Plata Electric Association, Inc.

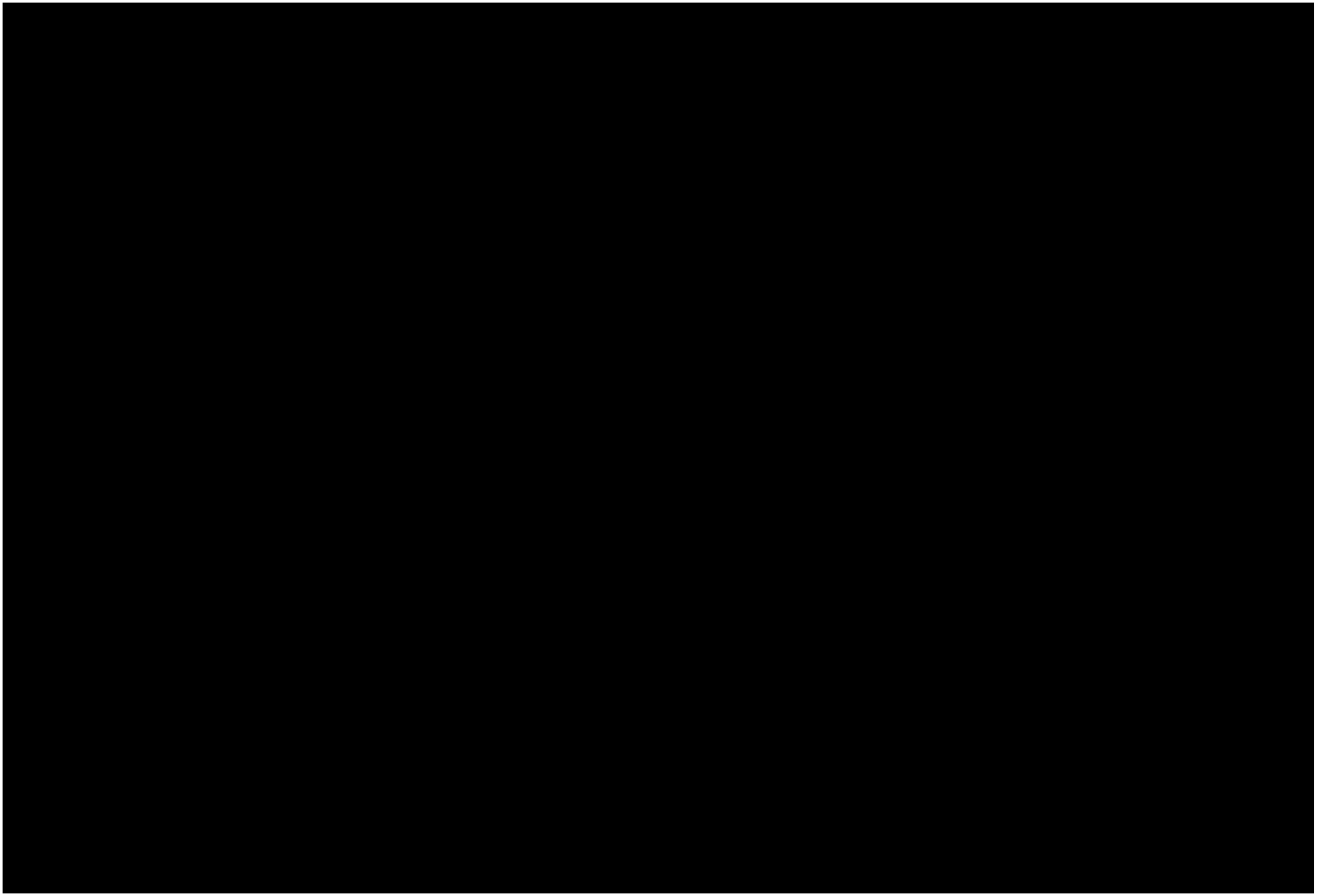
Date of On Peak Day - 11/30/2021



Member Forecasted On Peak Demand Day for December 2021

La Plata Electric Association, Inc.

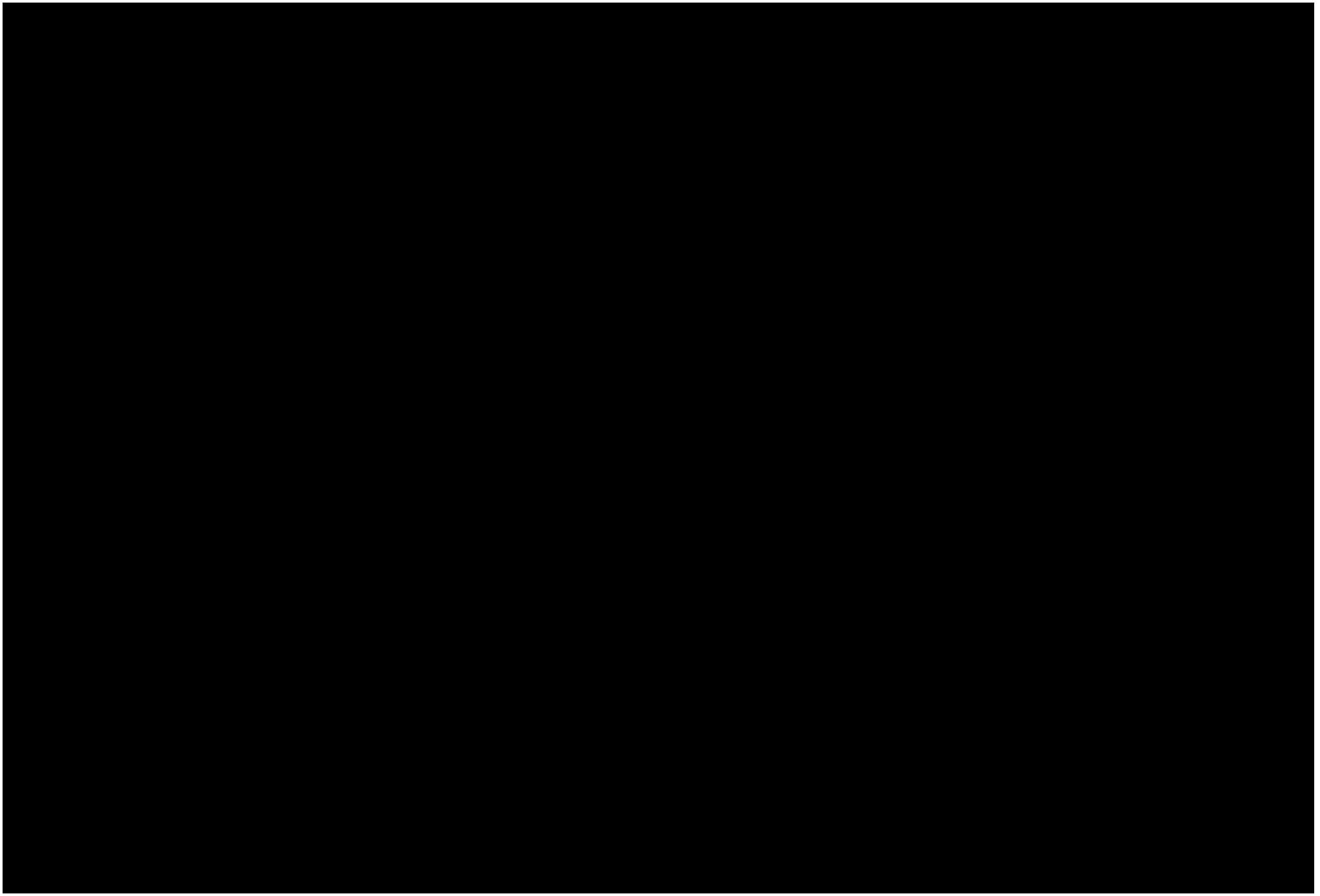
Date of On Peak Day - 12/26/2021



Member Forecasted On Peak Demand Day for January 2021

Morgan County Rural Electric Association

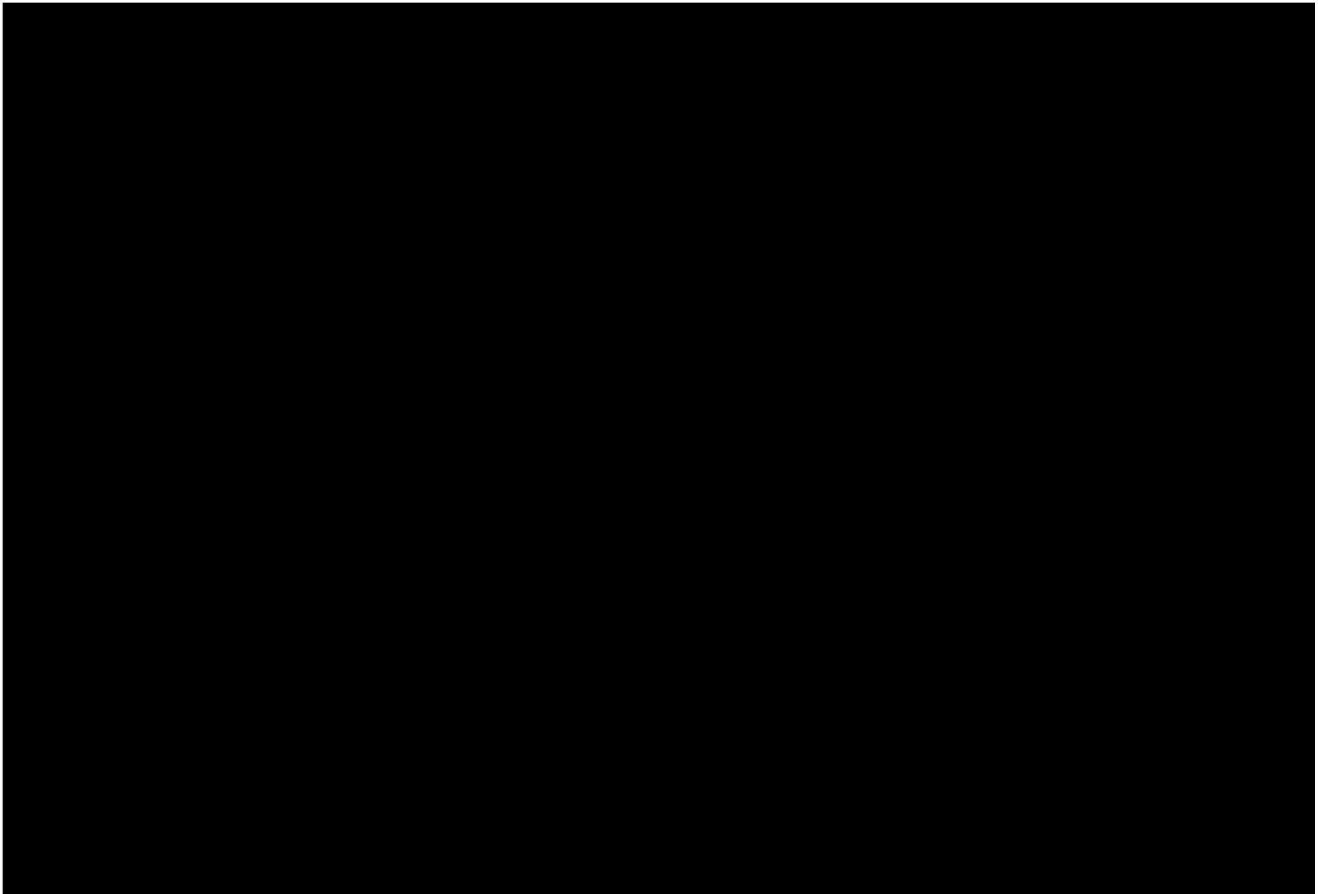
Date of On Peak Day - 01/06/2021



Member Forecasted On Peak Demand Day for February 2021

Morgan County Rural Electric Association

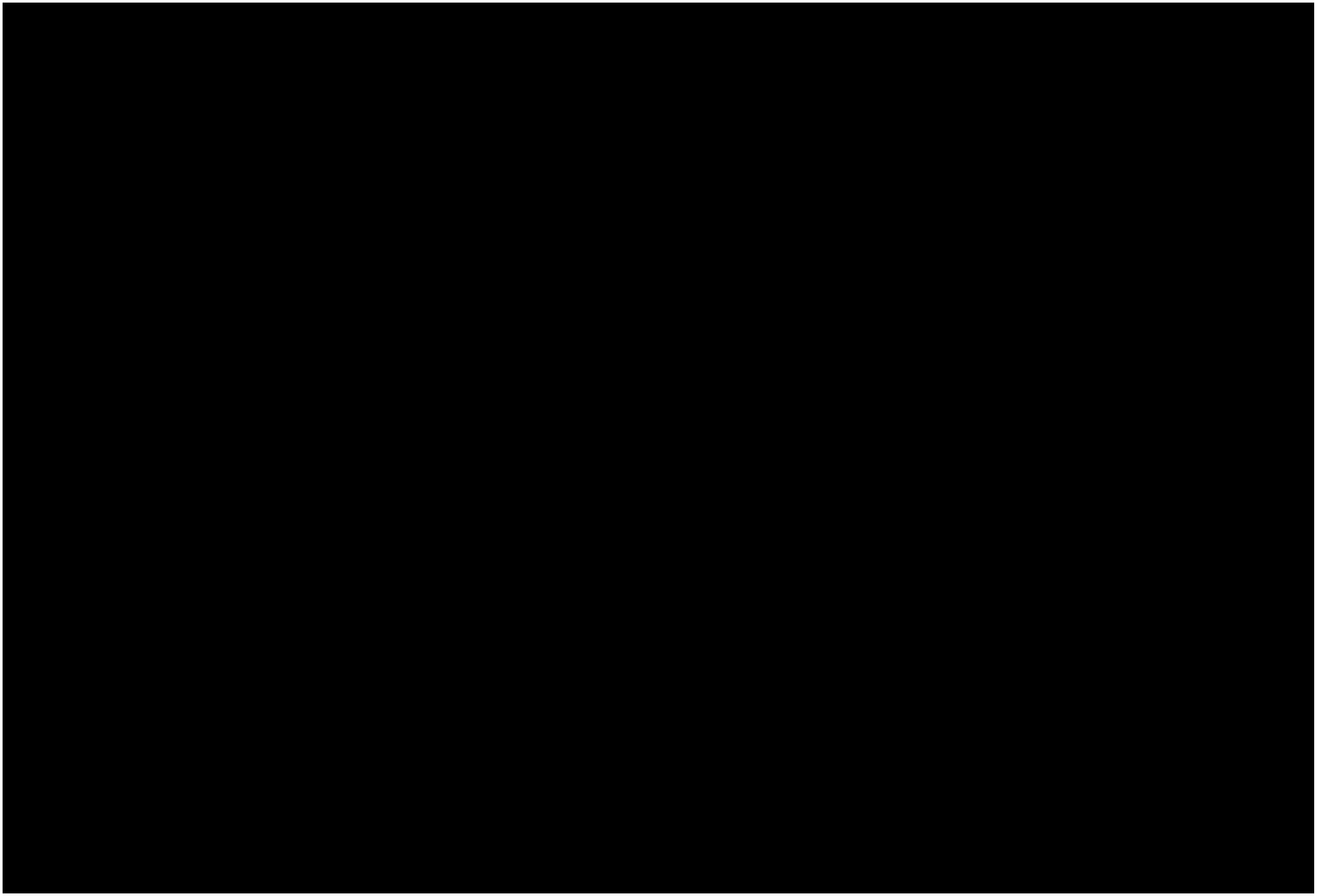
Date of On Peak Day - 02/01/2021



Member Forecasted On Peak Demand Day for March 2021

Morgan County Rural Electric Association

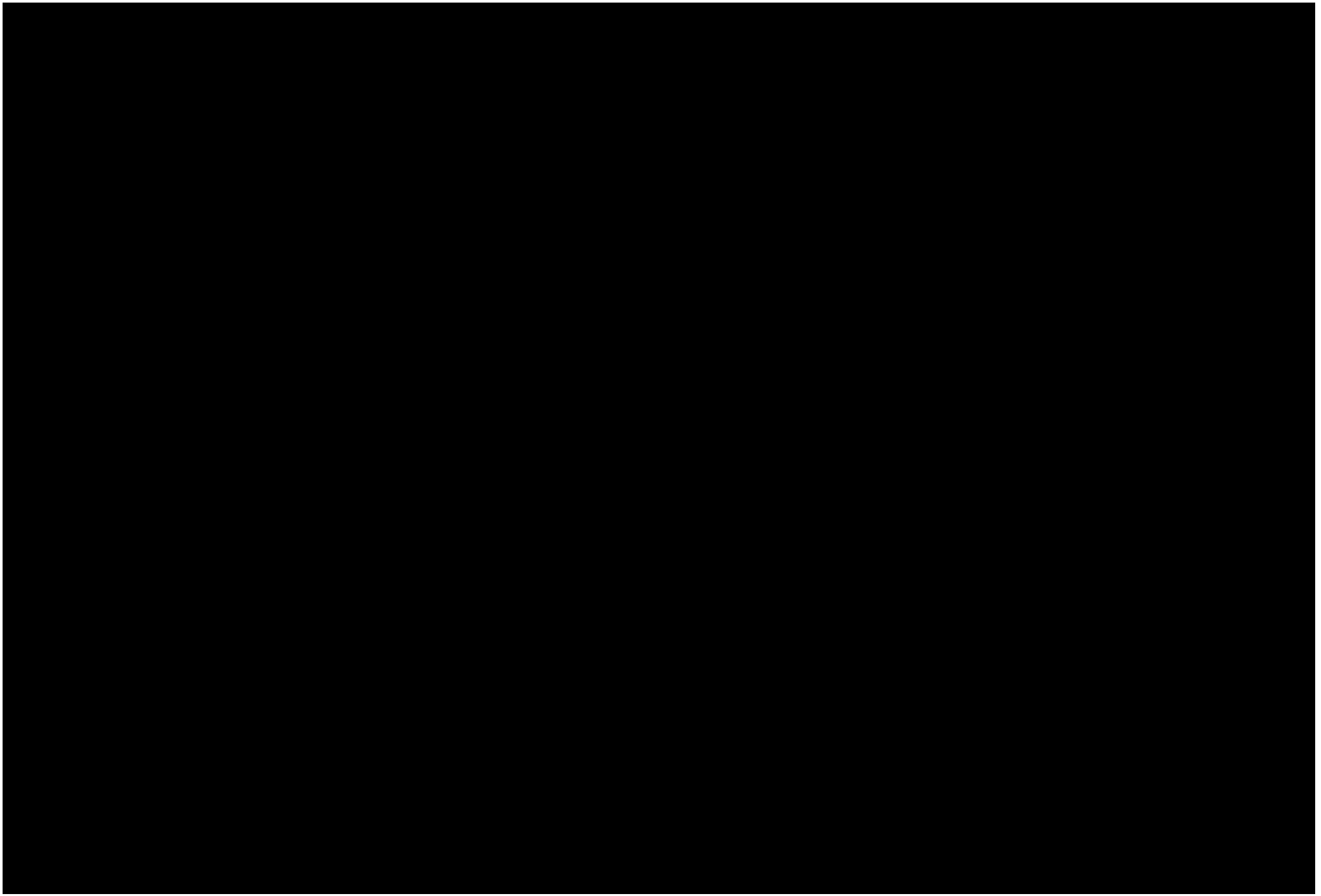
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Morgan County Rural Electric Association

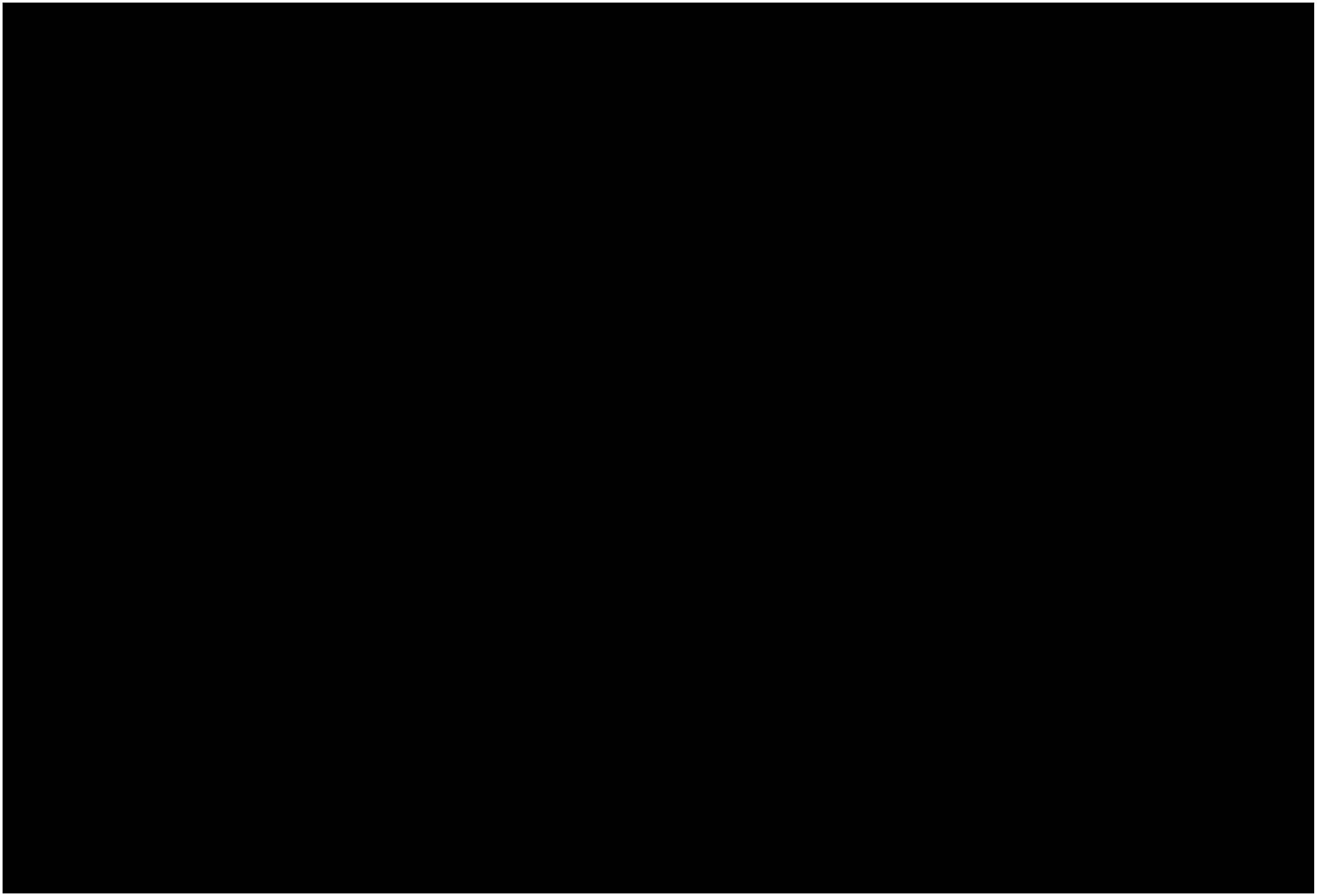
Date of On Peak Day - 04/13/2021



Member Forecasted On Peak Demand Day for May 2021

Morgan County Rural Electric Association

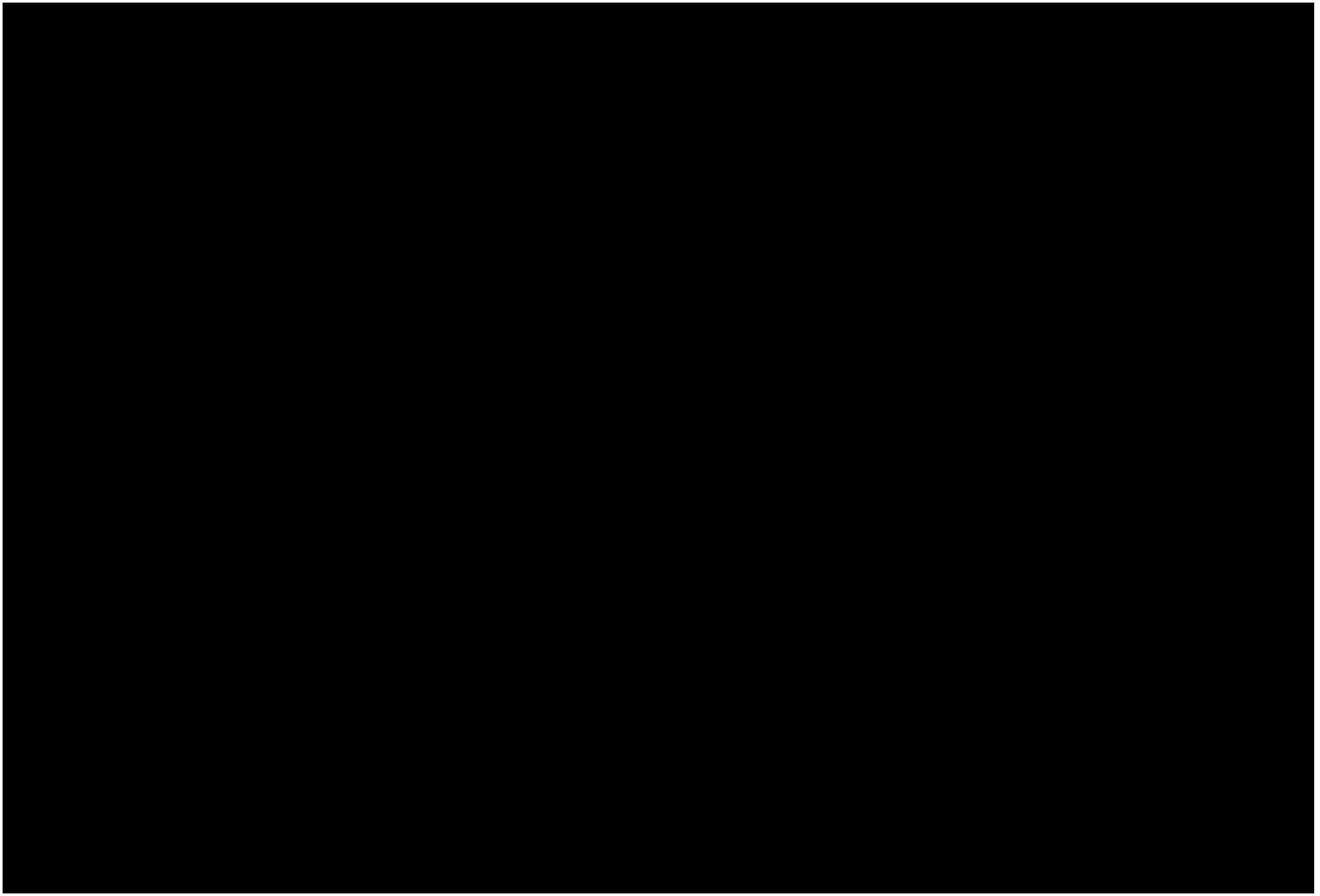
Date of On Peak Day - 05/15/2021



Member Forecasted On Peak Demand Day for June 2021

Morgan County Rural Electric Association

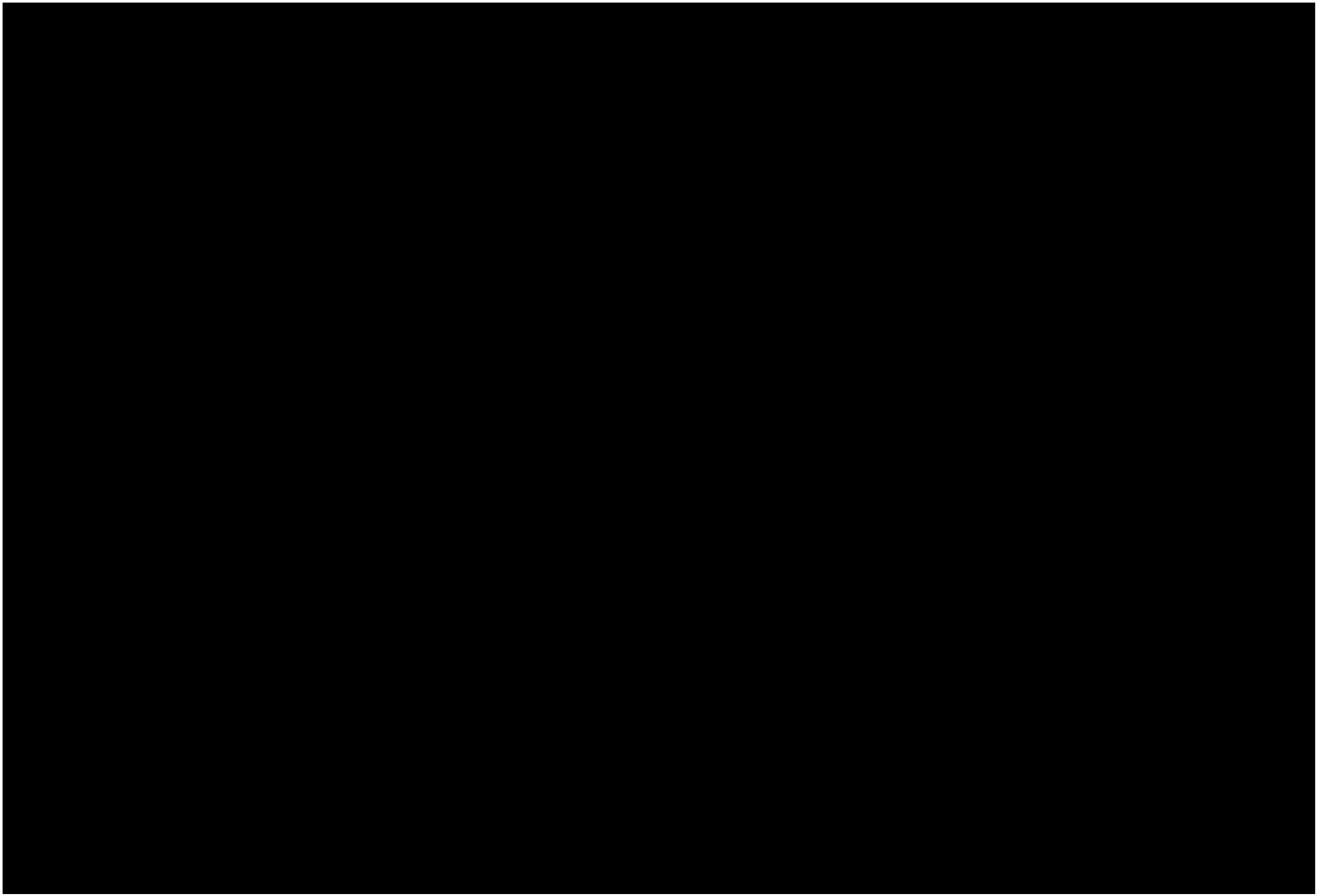
Date of On Peak Day - 06/10/2021



Member Forecasted On Peak Demand Day for July 2021

Morgan County Rural Electric Association

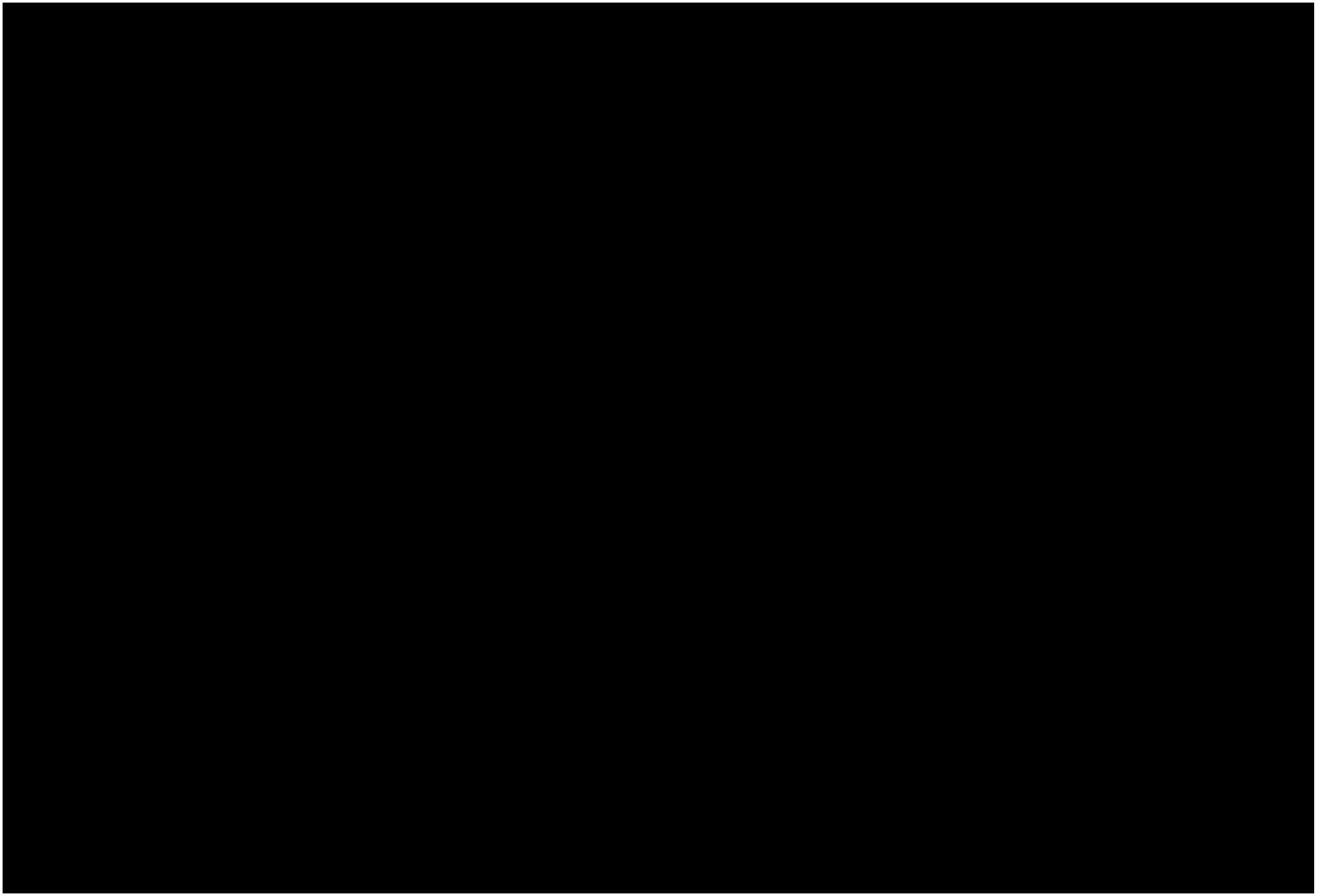
Date of On Peak Day - 07/17/2021



Member Forecasted On Peak Demand Day for August 2021

Morgan County Rural Electric Association

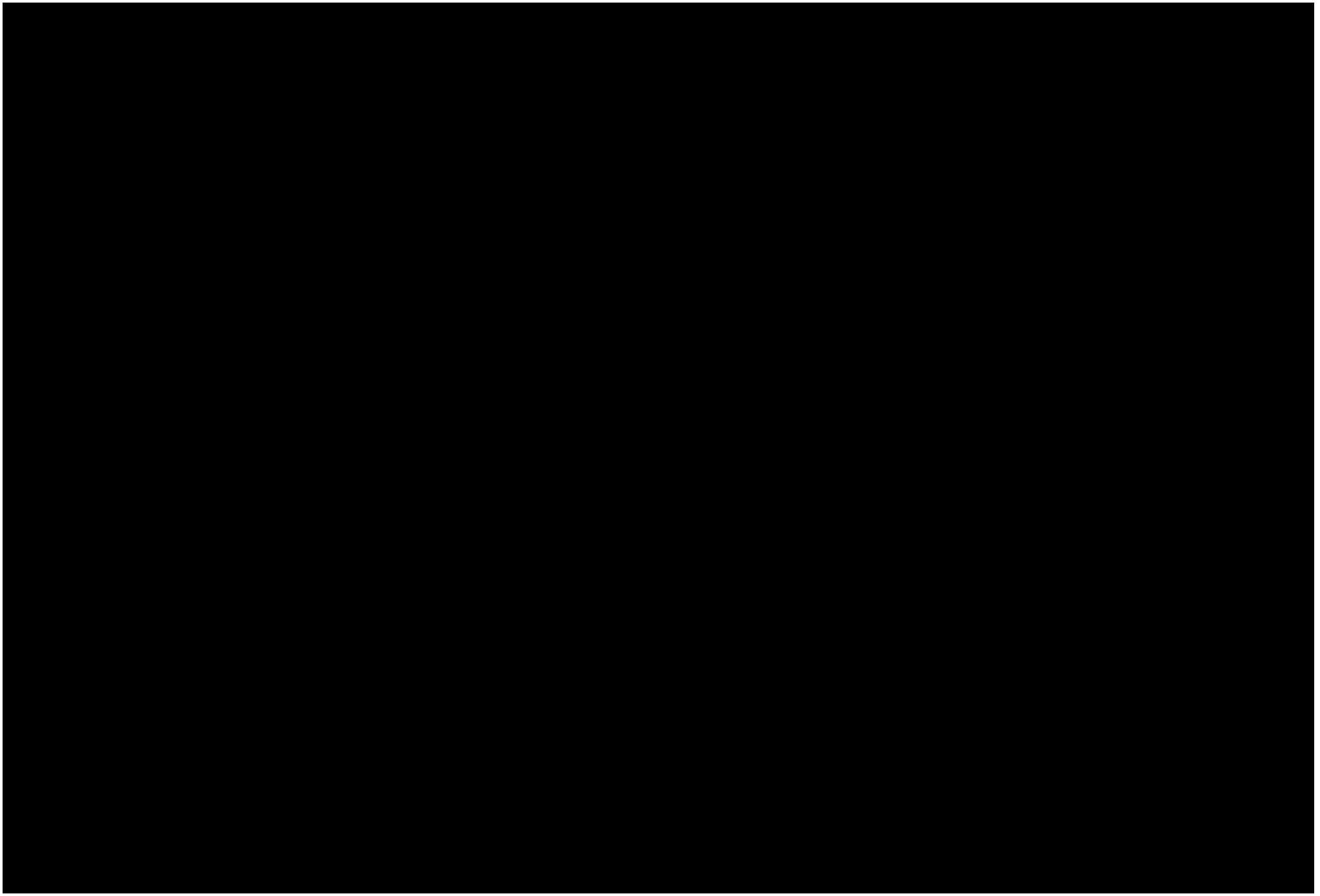
Date of On Peak Day - 08/28/2021



Member Forecasted On Peak Demand Day for September 2021

Morgan County Rural Electric Association

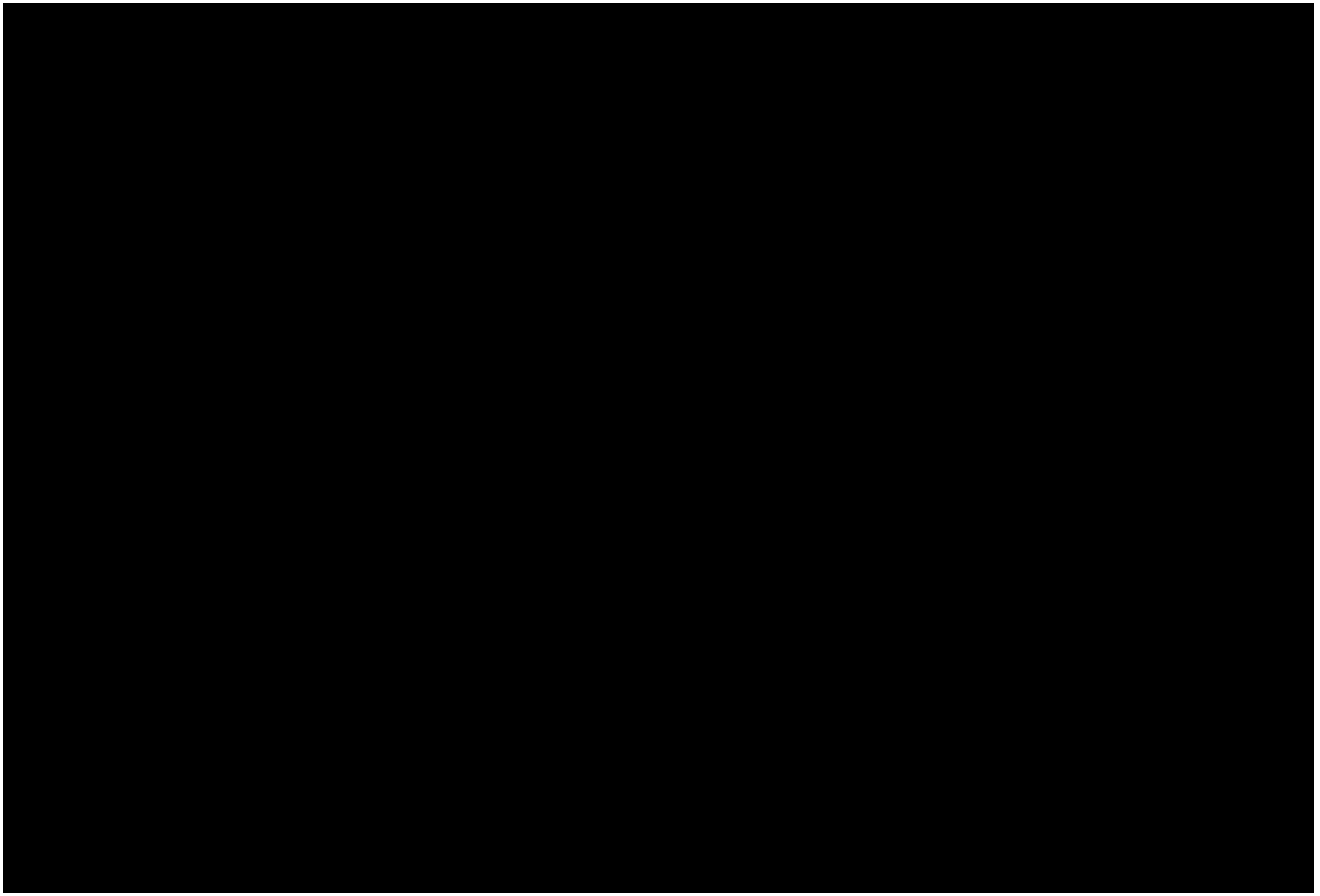
Date of On Peak Day - 09/01/2021



Member Forecasted On Peak Demand Day for October 2021

Morgan County Rural Electric Association

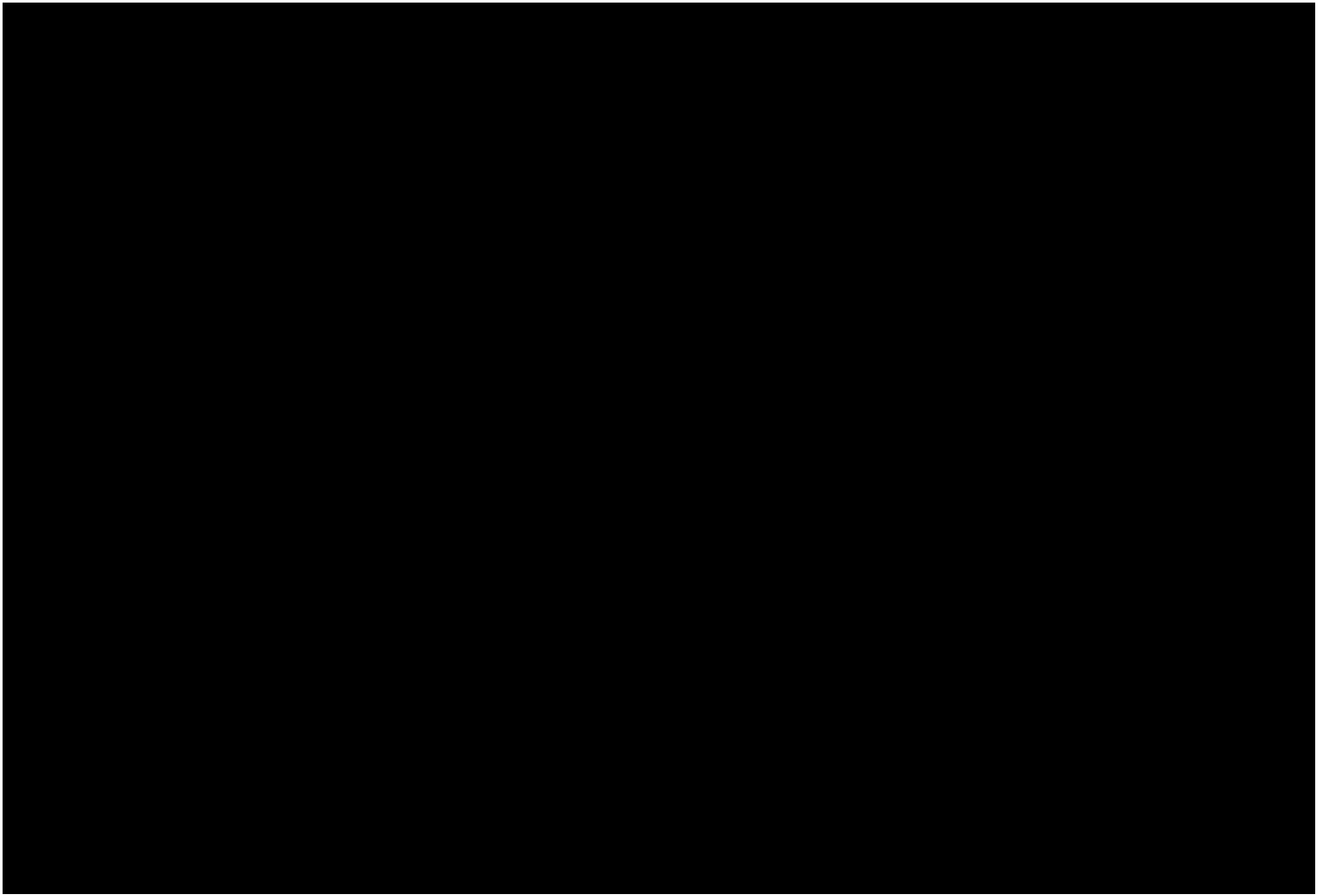
Date of On Peak Day - 10/18/2021



Member Forecasted On Peak Demand Day for November 2021

Morgan County Rural Electric Association

Date of On Peak Day - 11/08/2021



Member Forecasted On Peak Demand Day for December 2021

Morgan County Rural Electric Association

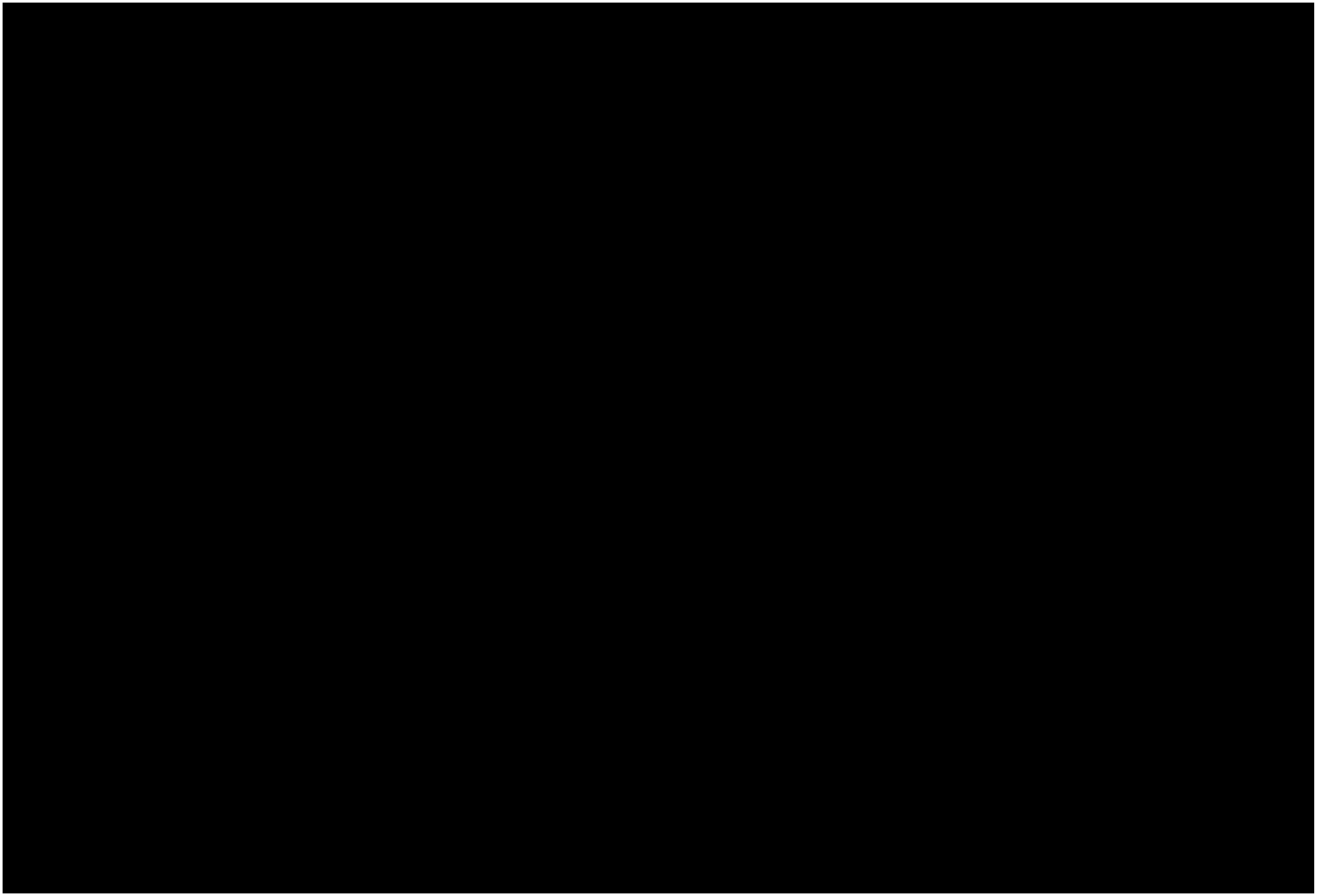
Date of On Peak Day - 12/28/2021

[redacted]

Member Forecasted On Peak Demand Day for January 2021

Mountain Parks Electric, Inc.

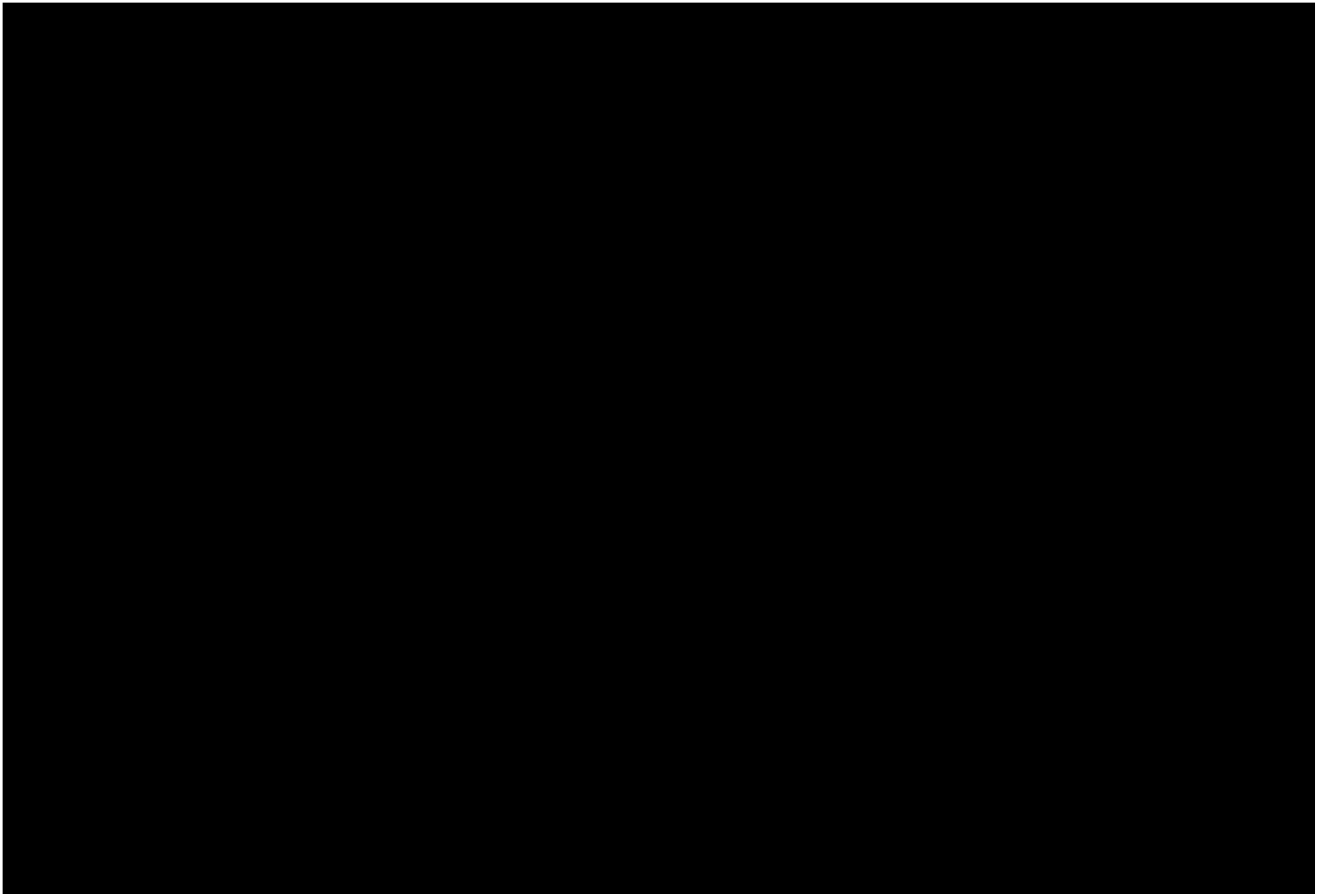
Date of On Peak Day - 01/02/2021



Member Forecasted On Peak Demand Day for February 2021

Mountain Parks Electric, Inc.

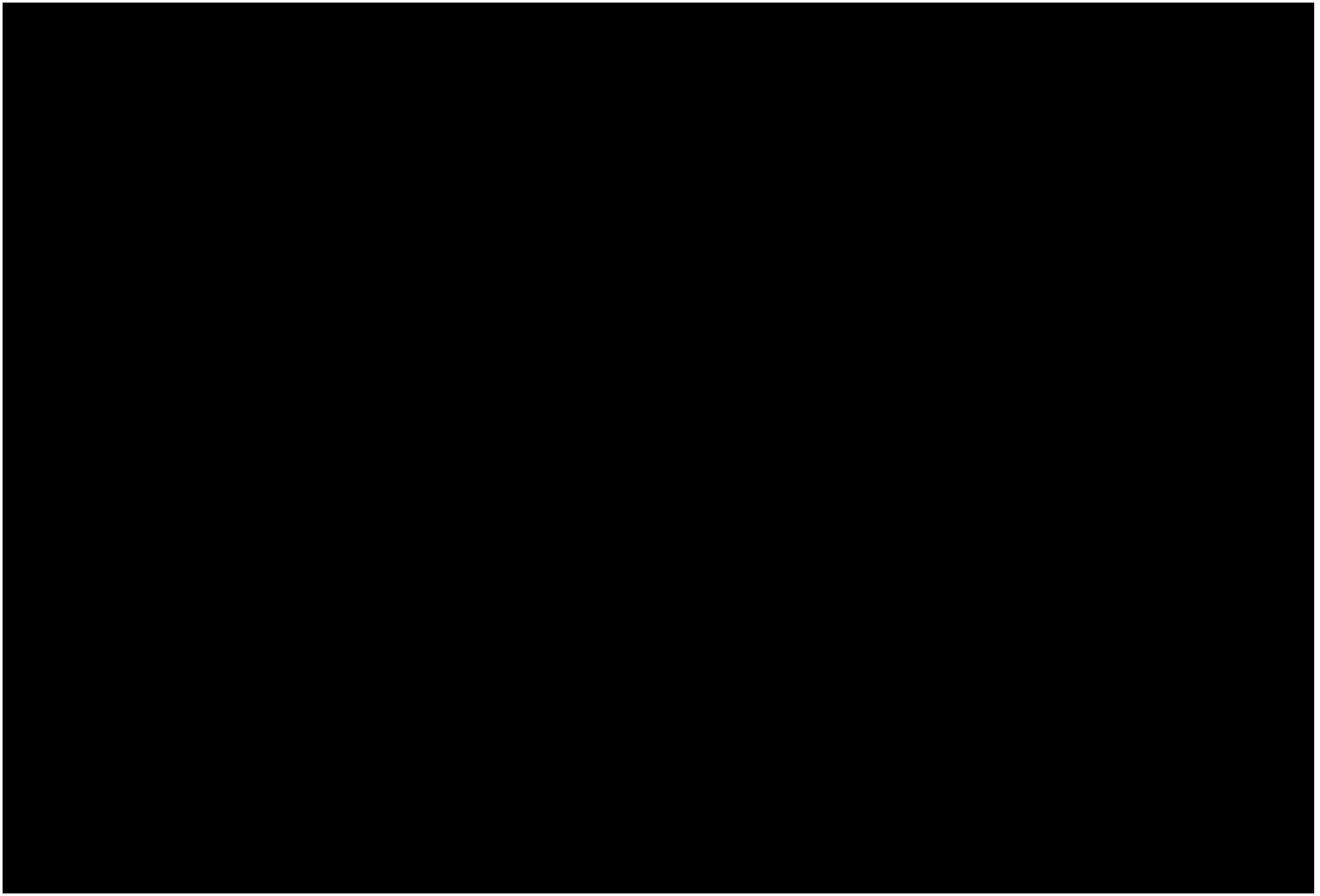
Date of On Peak Day - 02/16/2021



Member Forecasted On Peak Demand Day for March 2021

Mountain Parks Electric, Inc.

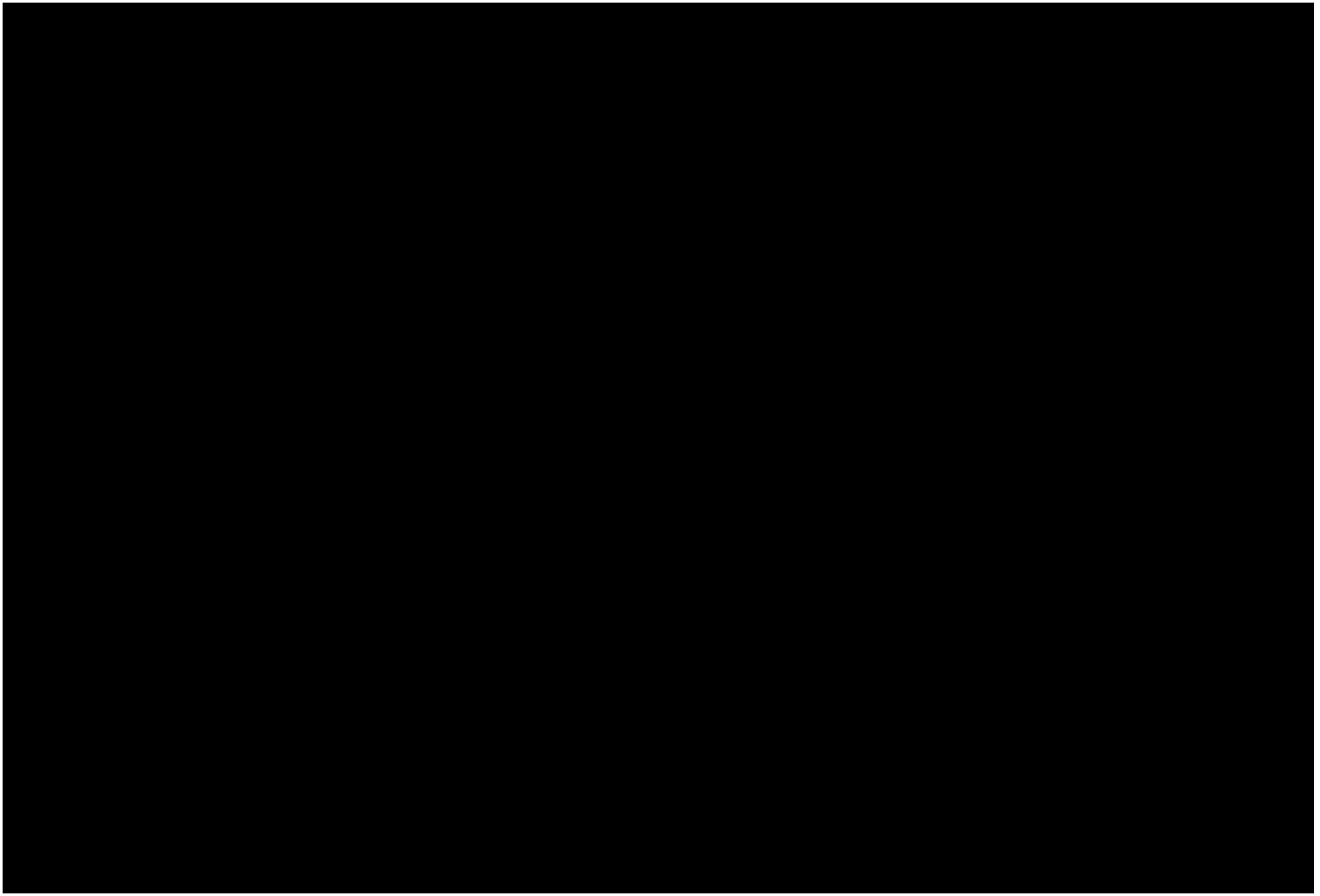
Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

Mountain Parks Electric, Inc.

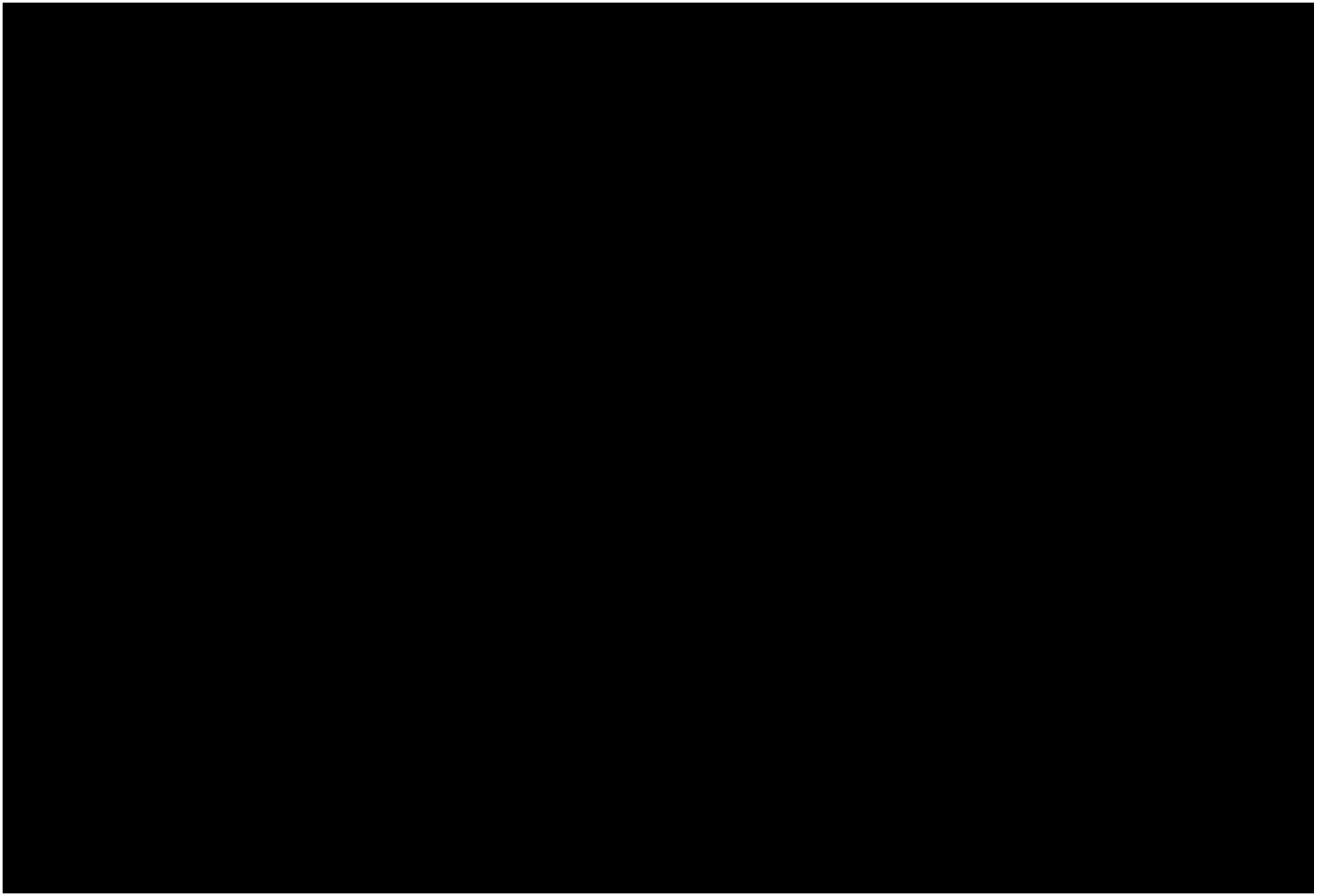
Date of On Peak Day - 04/03/2021



Member Forecasted On Peak Demand Day for May 2021

Mountain Parks Electric, Inc.

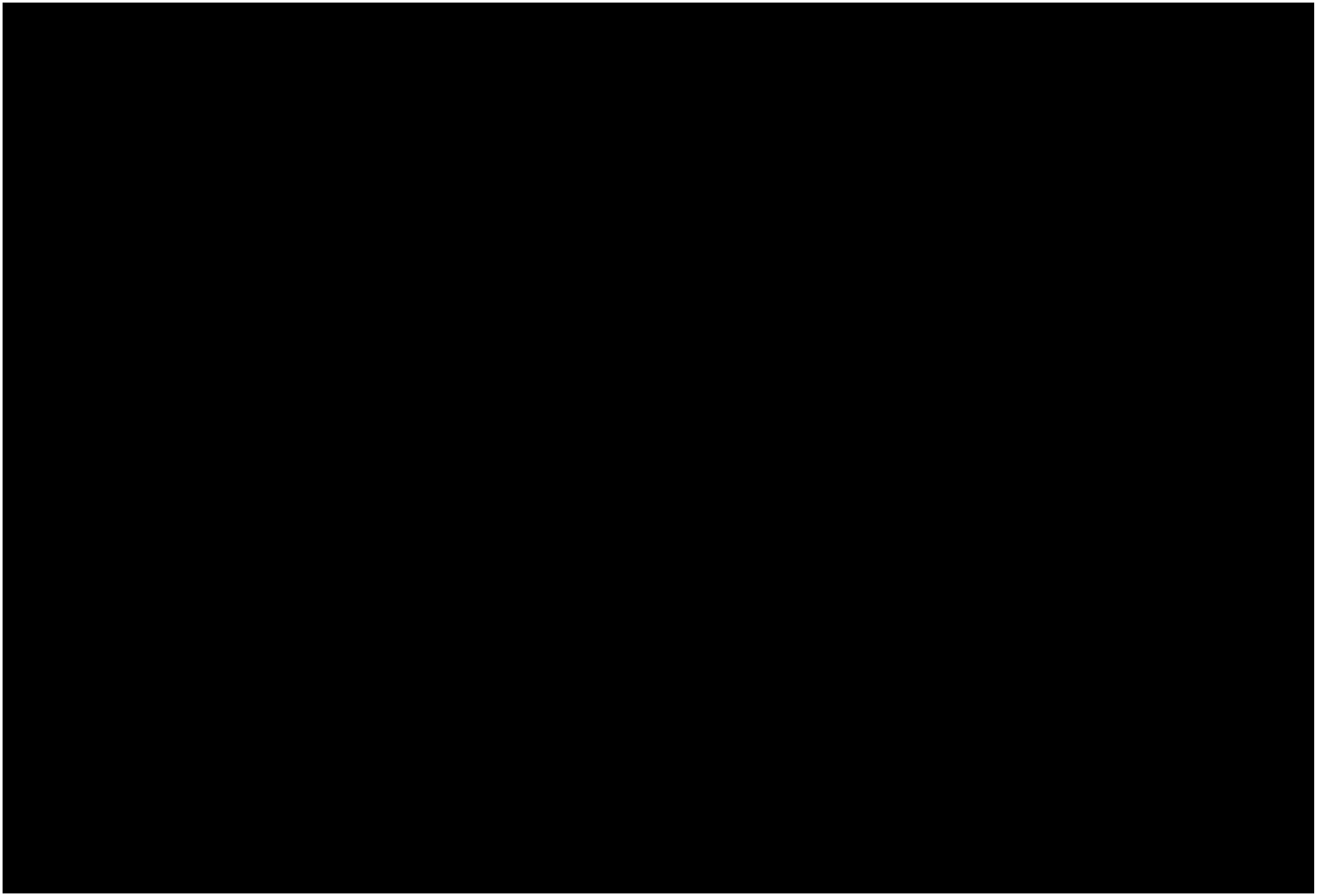
Date of On Peak Day - 05/01/2021



Member Forecasted On Peak Demand Day for June 2021

Mountain Parks Electric, Inc.

Date of On Peak Day - 06/25/2021



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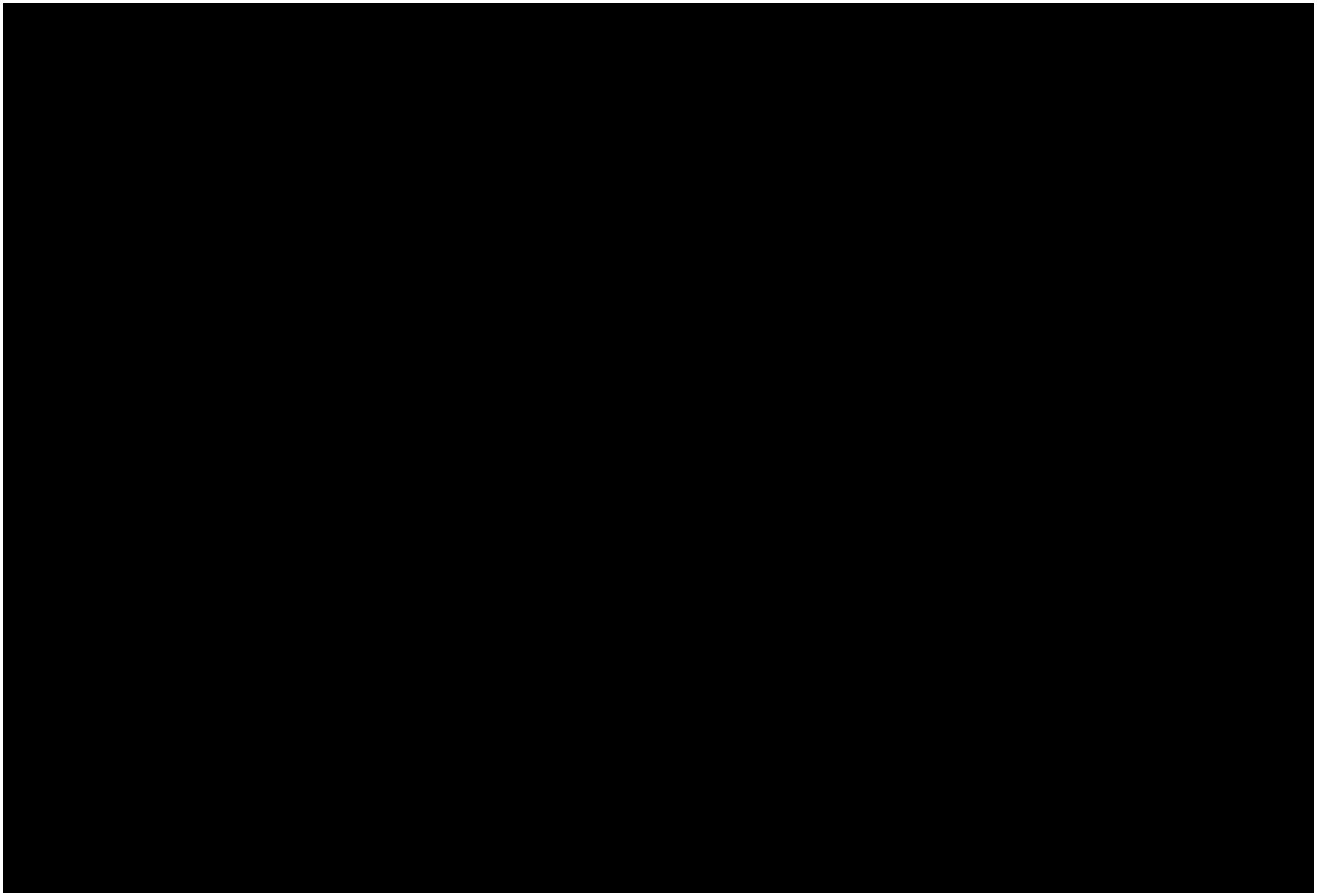
Member Forecasted On Peak Demand Day for July 2021

Mountain Parks Electric, Inc.

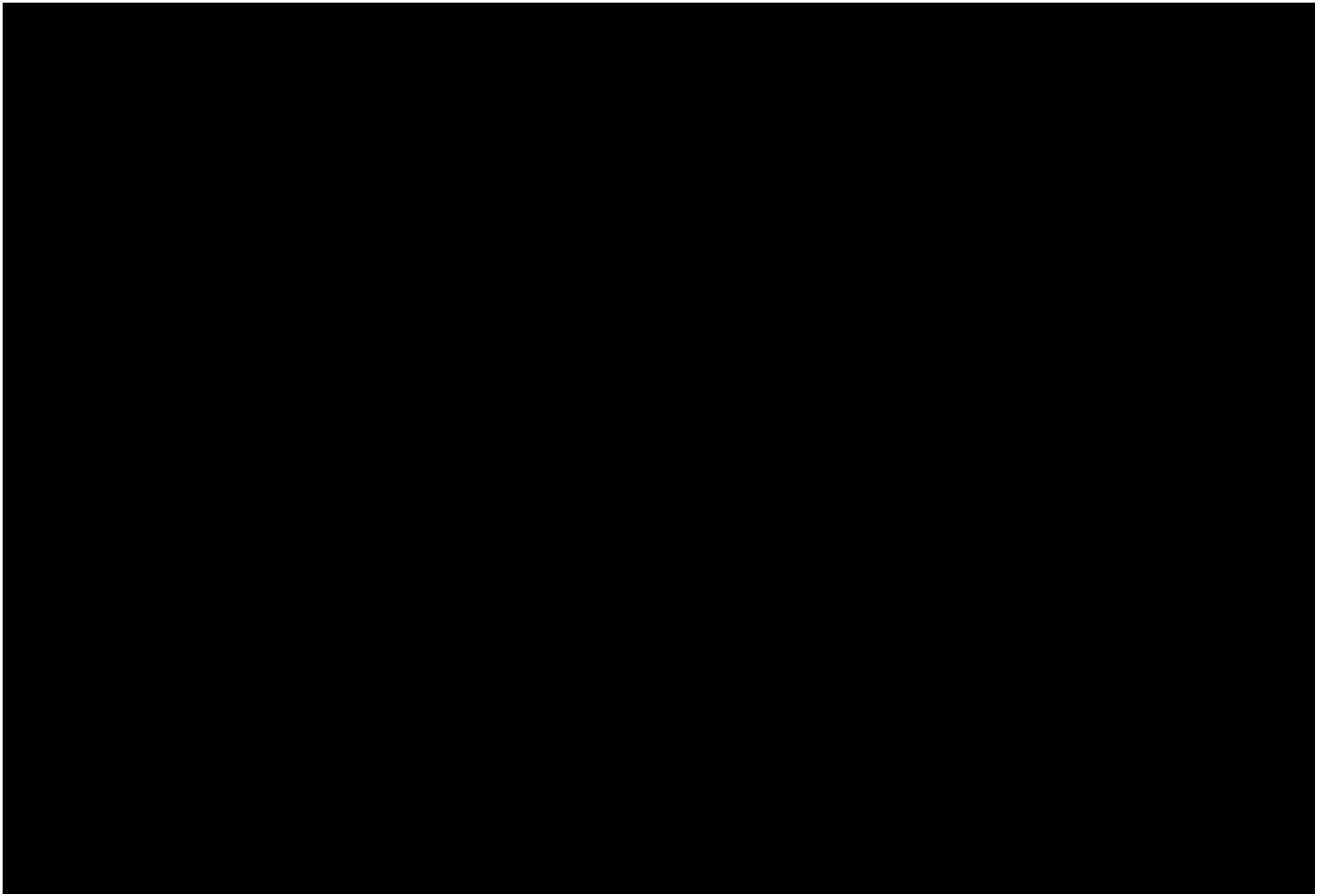
Date of On Peak Day - 07/03/2021



Member Forecasted On Peak Demand Day for August 2021

Mountain Parks Electric, Inc.

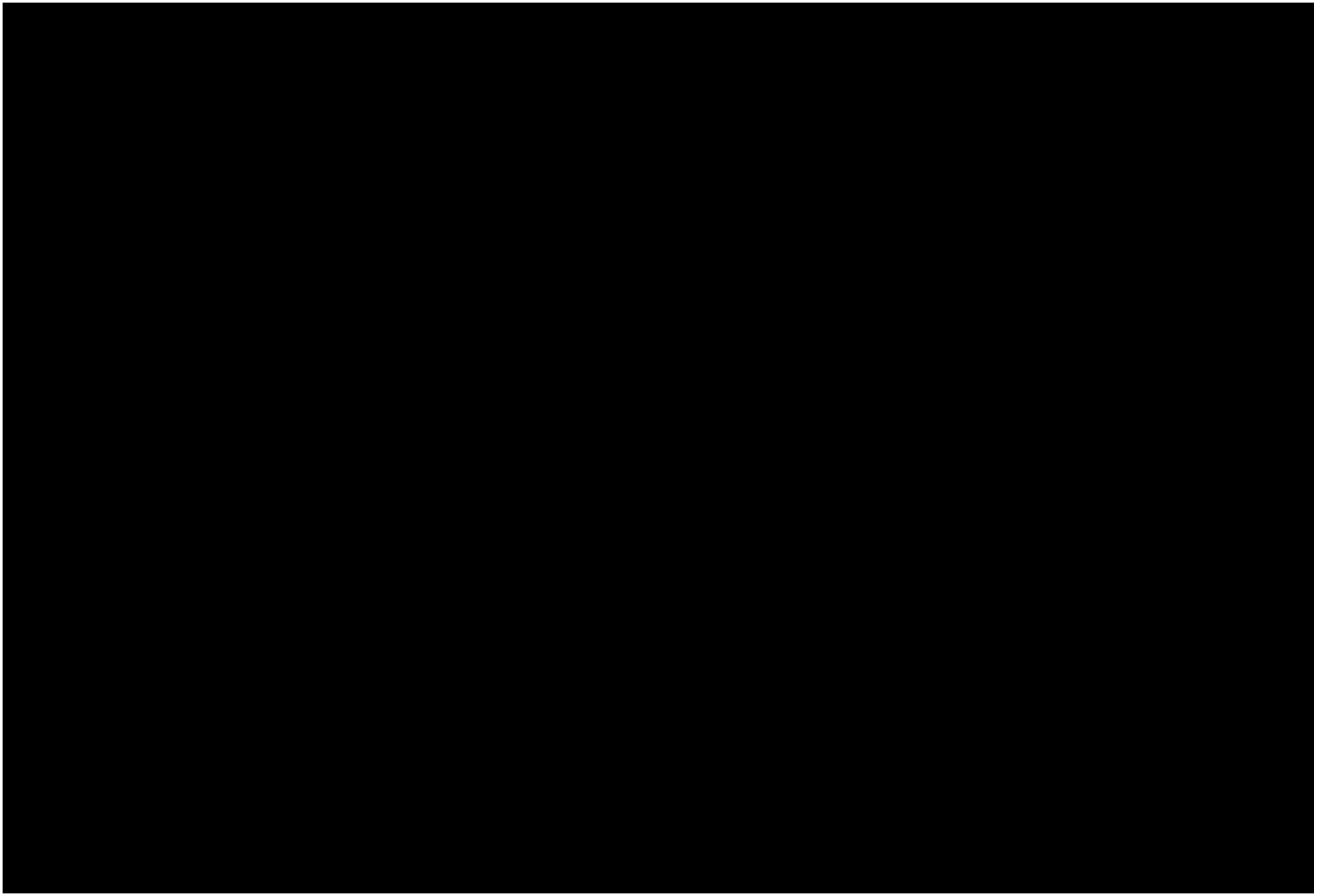
Date of On Peak Day - 08/07/2021



Member Forecasted On Peak Demand Day for September 2021

Mountain Parks Electric, Inc.

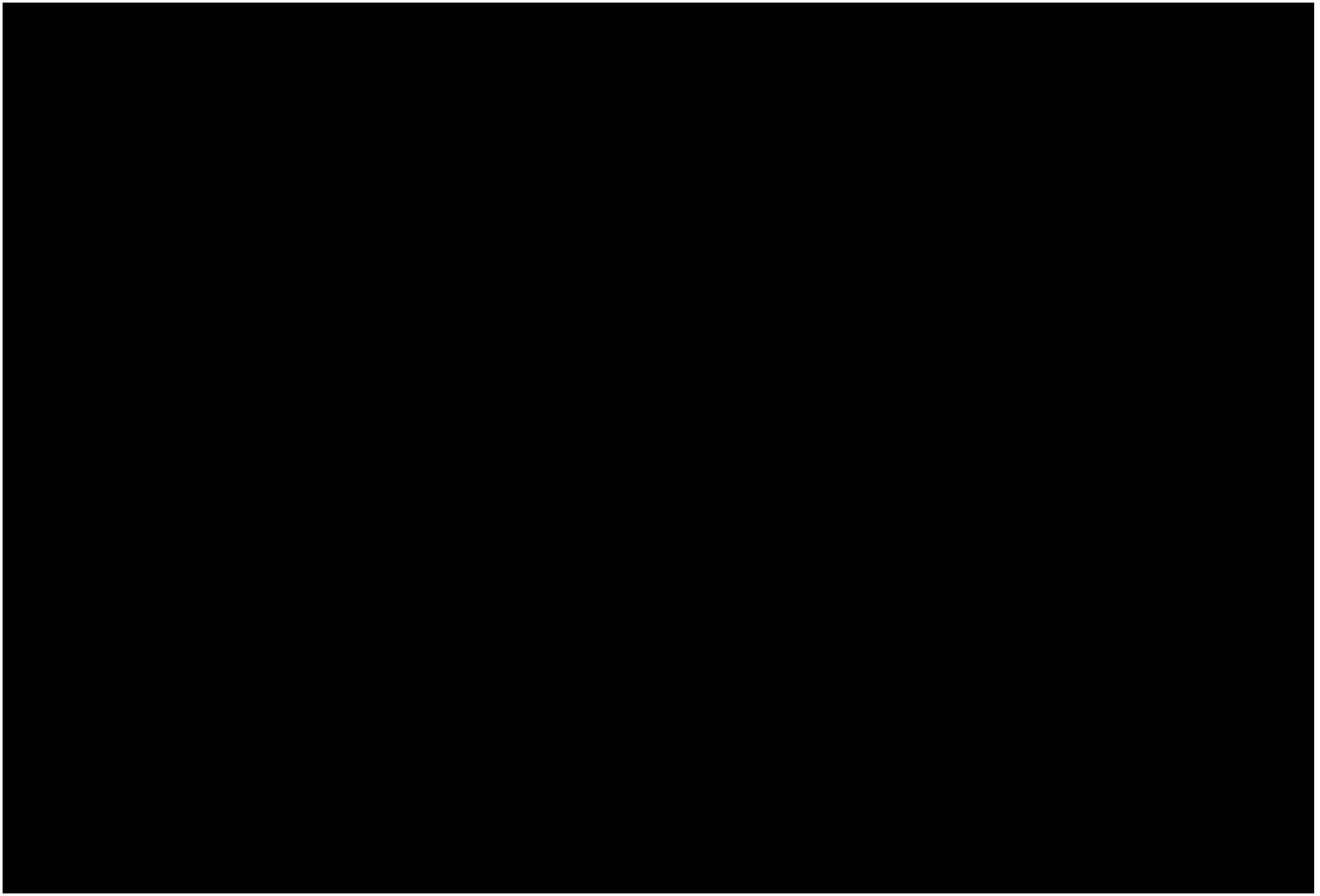
Date of On Peak Day - 09/07/2021



Member Forecasted On Peak Demand Day for October 2021

Mountain Parks Electric, Inc.

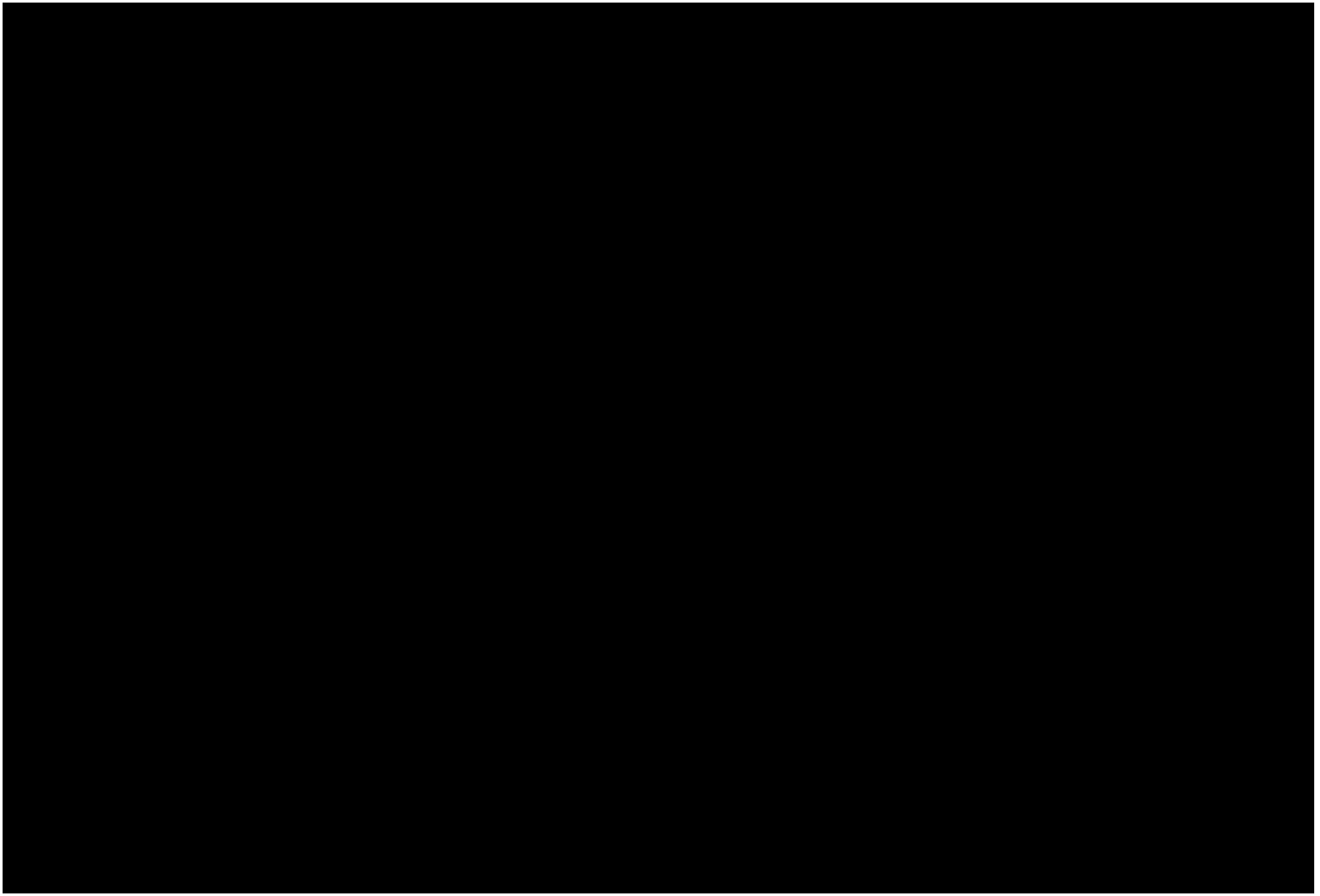
Date of On Peak Day - 10/28/2021



Member Forecasted On Peak Demand Day for November 2021

Mountain Parks Electric, Inc.

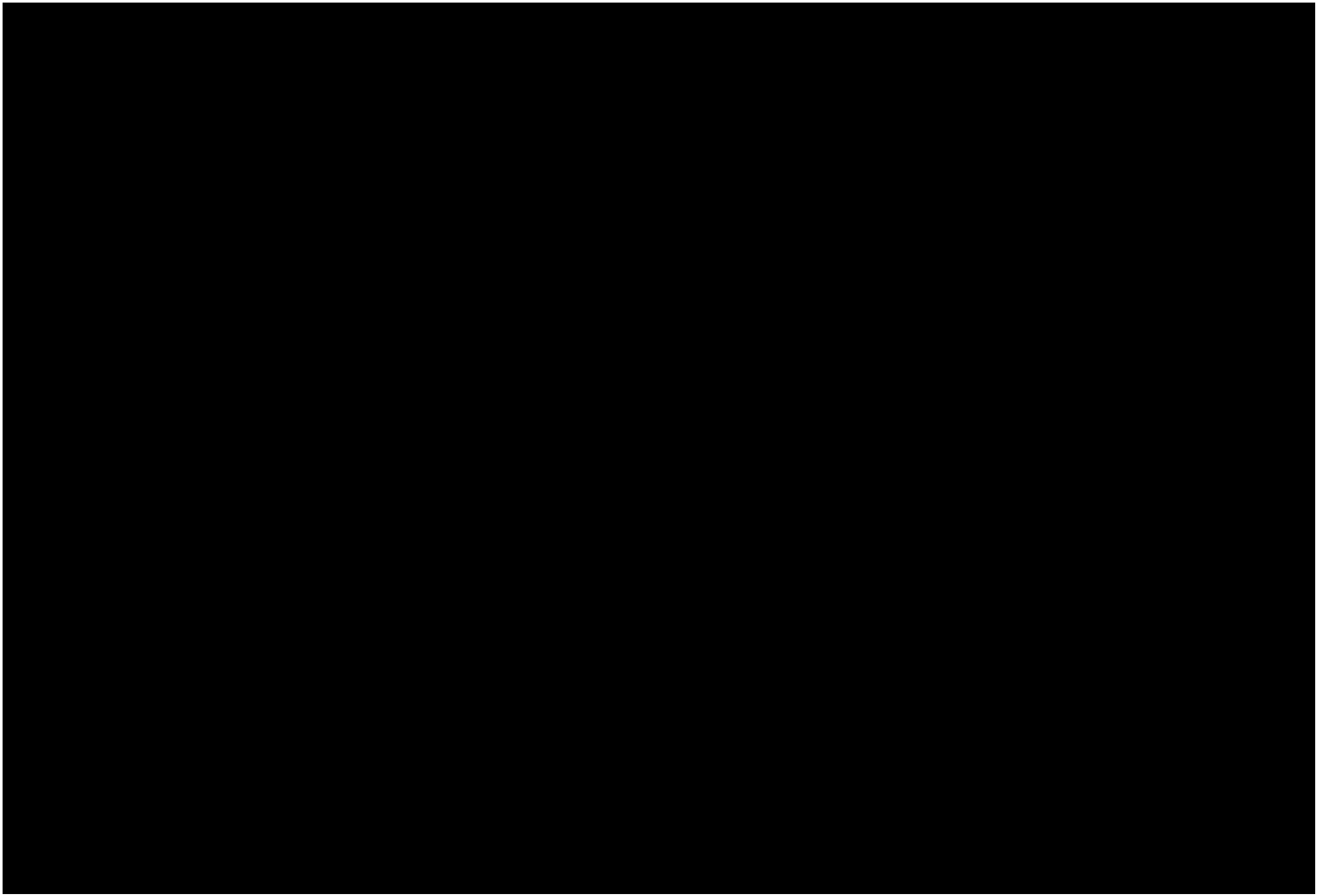
Date of On Peak Day - 11/24/2021



Member Forecasted On Peak Demand Day for December 2021

Mountain Parks Electric, Inc.

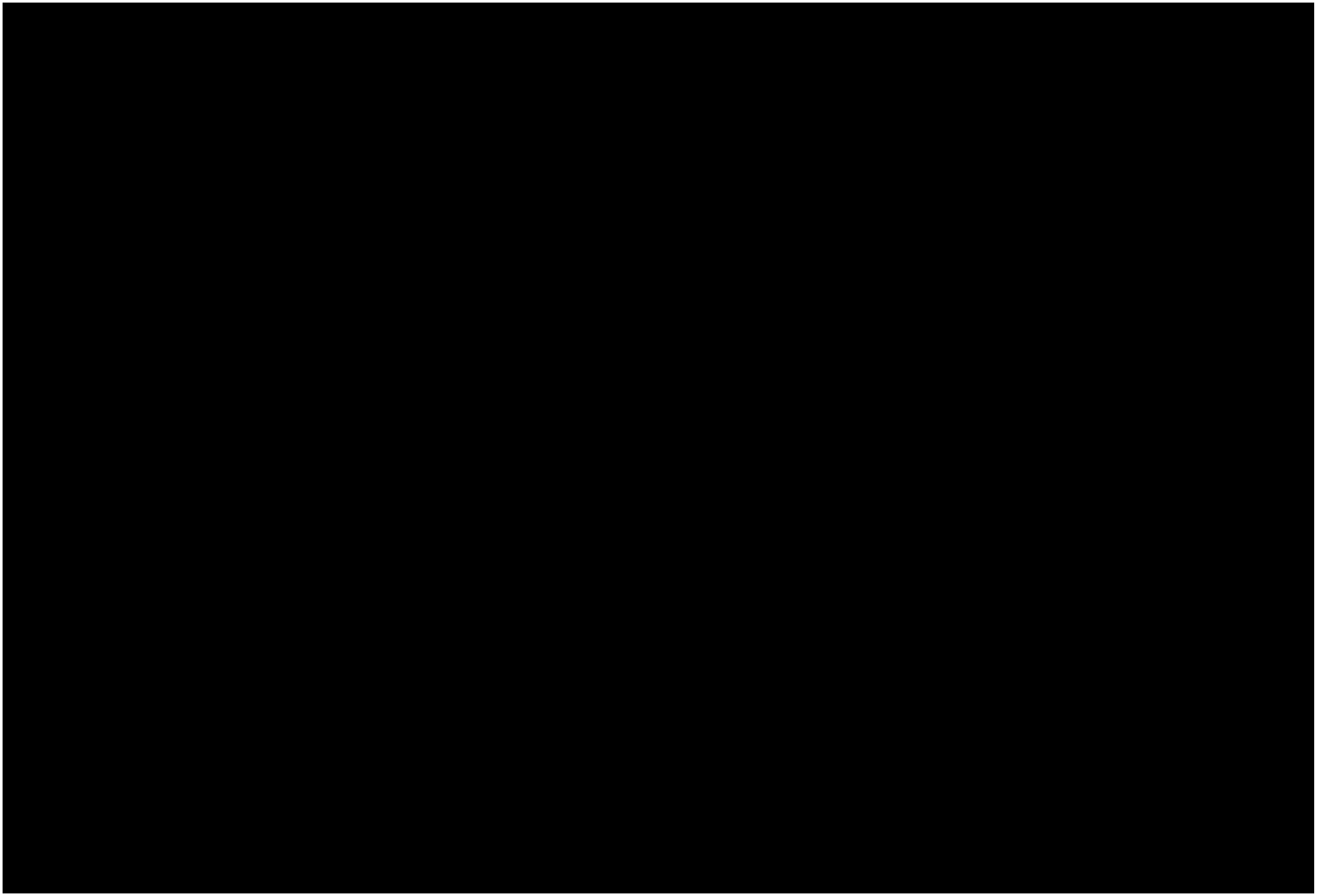
Date of On Peak Day - 12/31/2021



Member Forecasted On Peak Demand Day for January 2021

Mora-San Miguel Electric Cooperative, Inc.

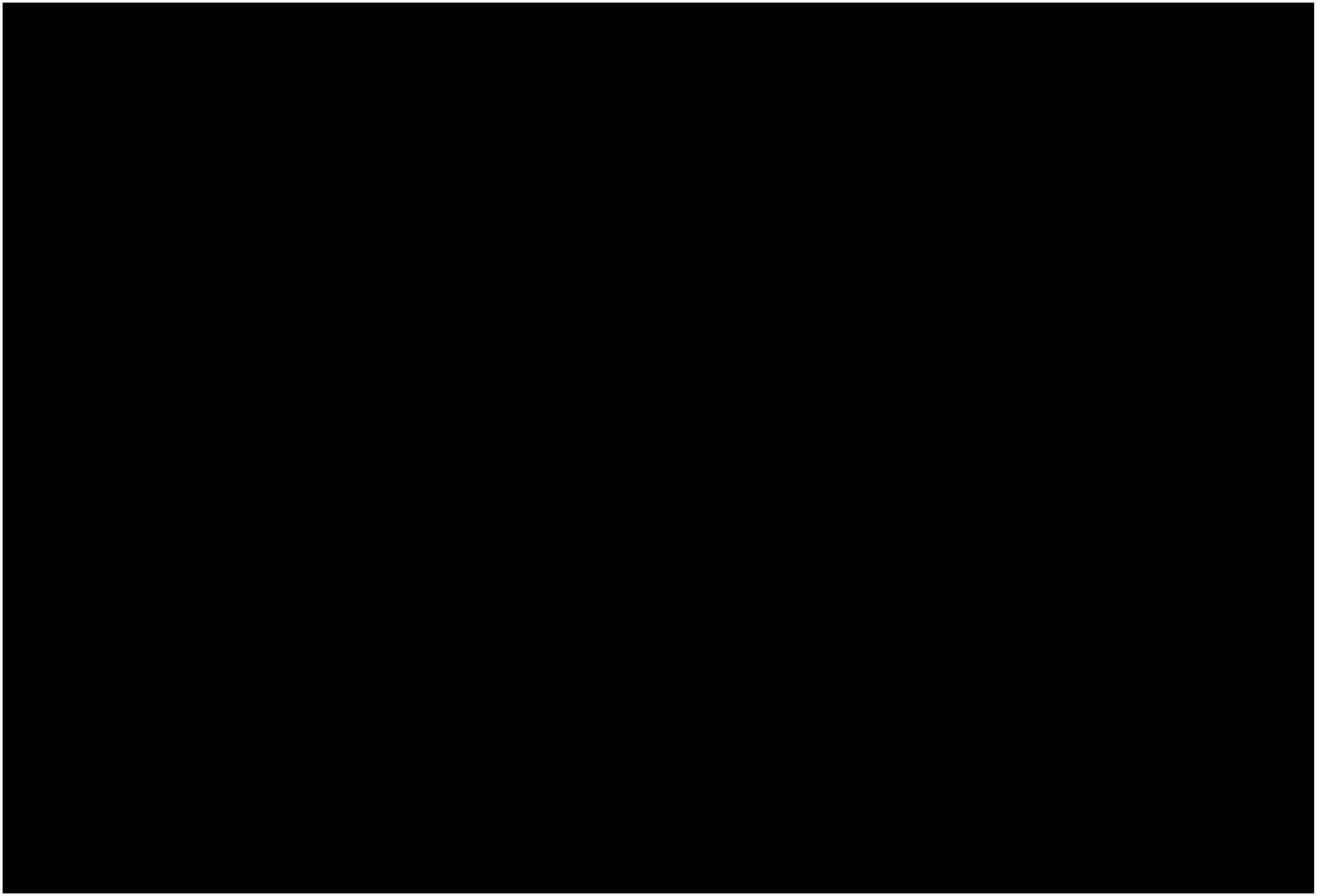
Date of On Peak Day - 01/02/2021



Member Forecasted On Peak Demand Day for February 2021

Mora-San Miguel Electric Cooperative, Inc.

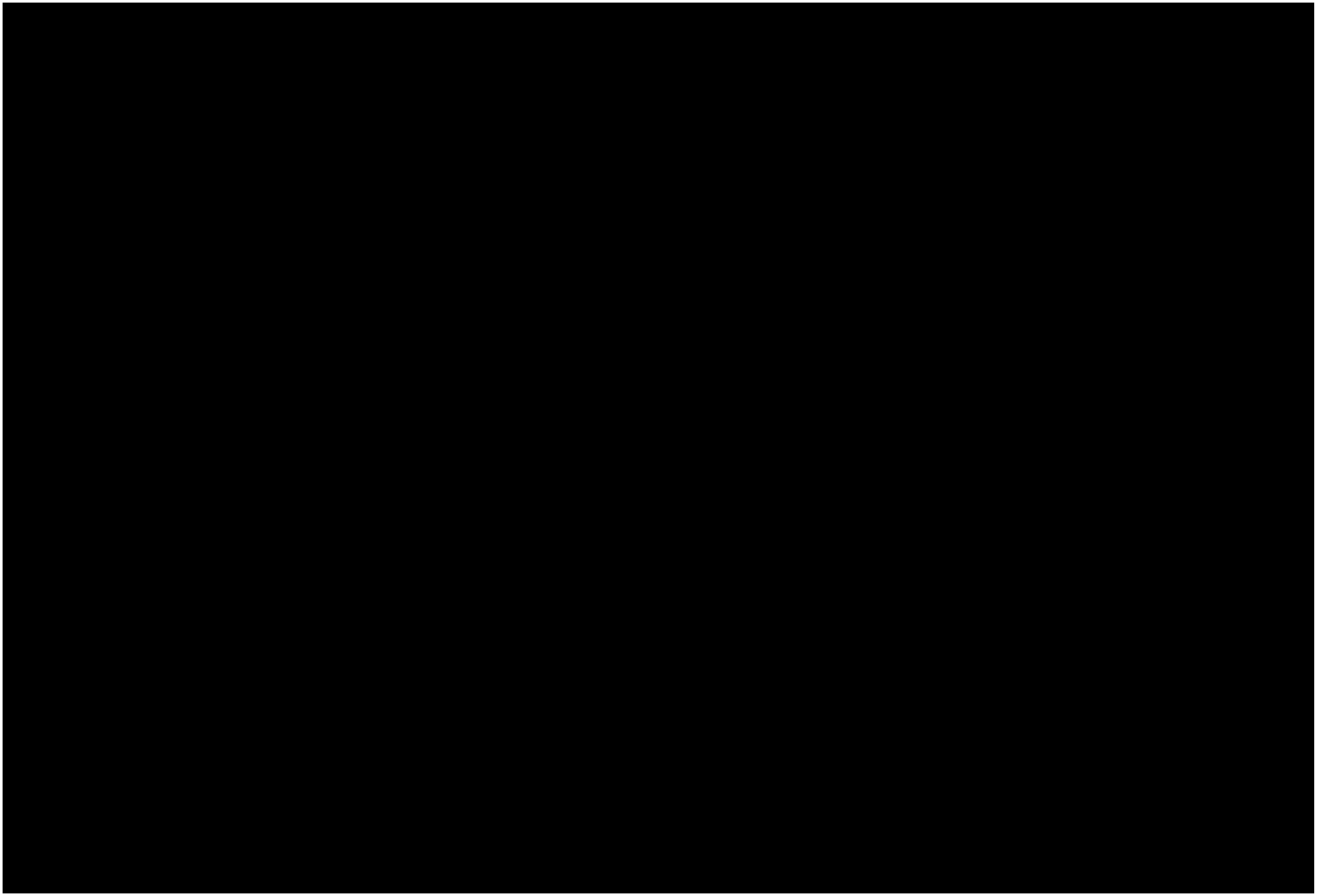
Date of On Peak Day - 02/25/2021



Member Forecasted On Peak Demand Day for March 2021

Mora-San Miguel Electric Cooperative, Inc.

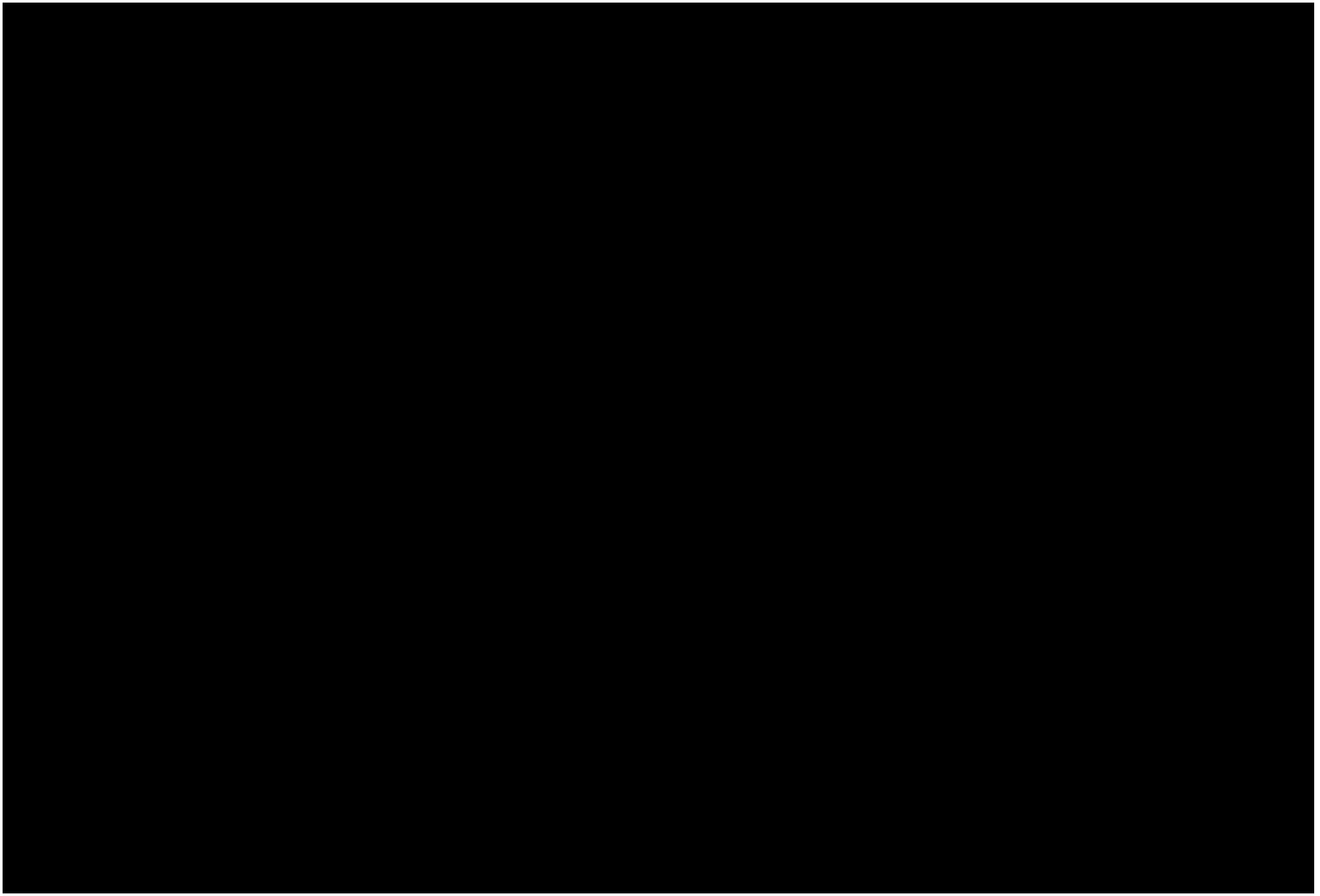
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Mora-San Miguel Electric Cooperative, Inc.

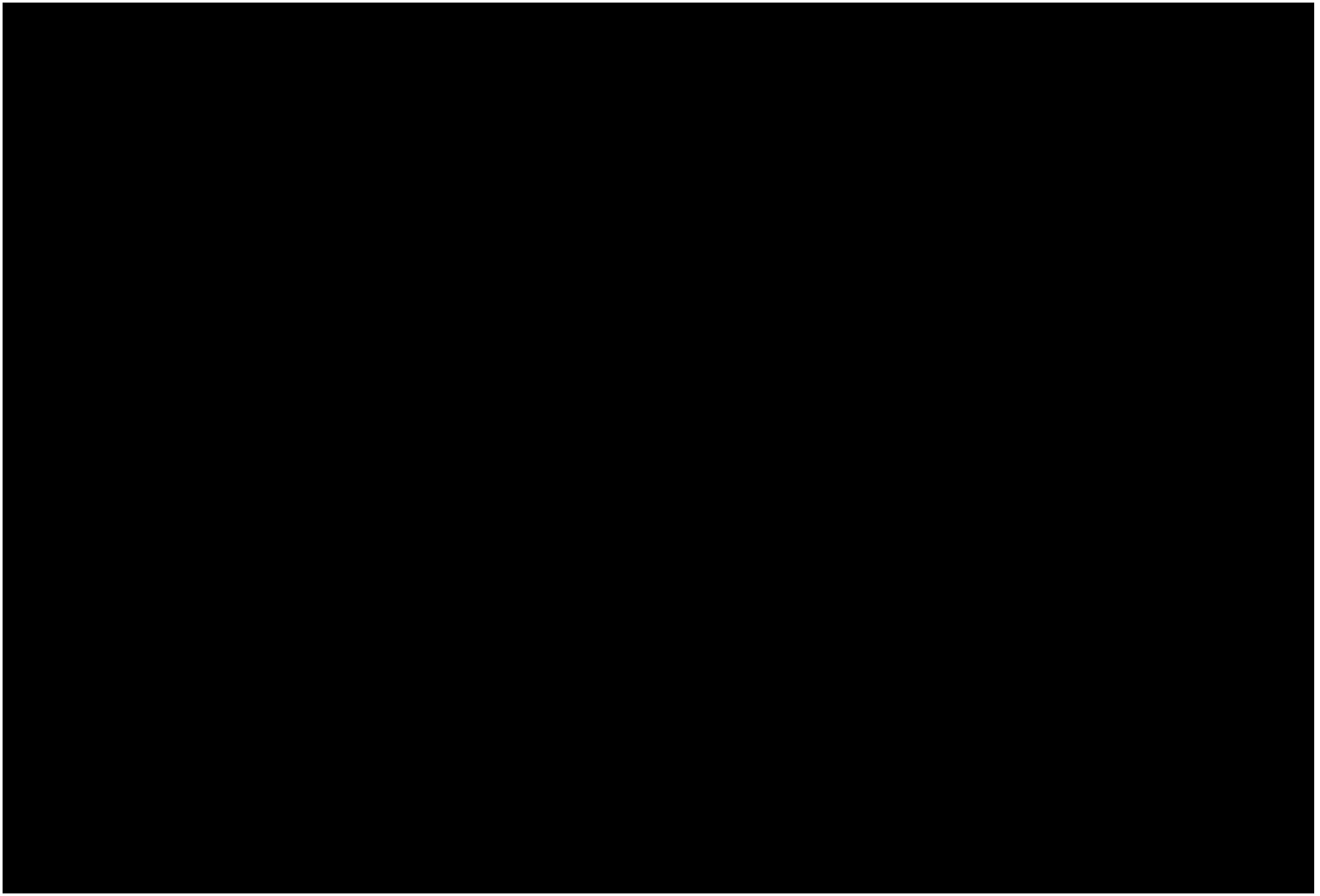
Date of On Peak Day - 04/20/2021



Member Forecasted On Peak Demand Day for May 2021

Mora-San Miguel Electric Cooperative, Inc.

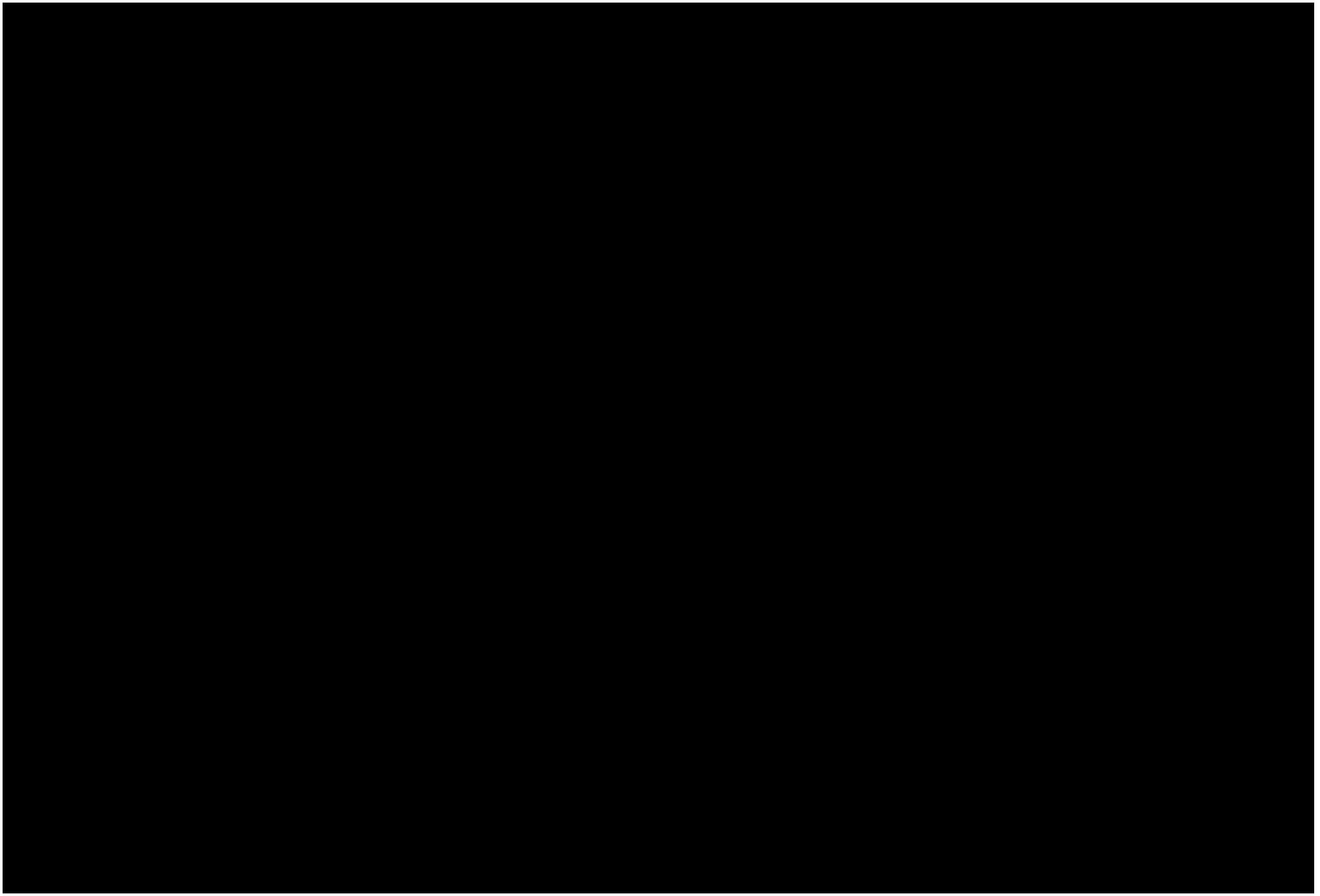
Date of On Peak Day - 05/18/2021



Member Forecasted On Peak Demand Day for June 2021

Mora-San Miguel Electric Cooperative, Inc.

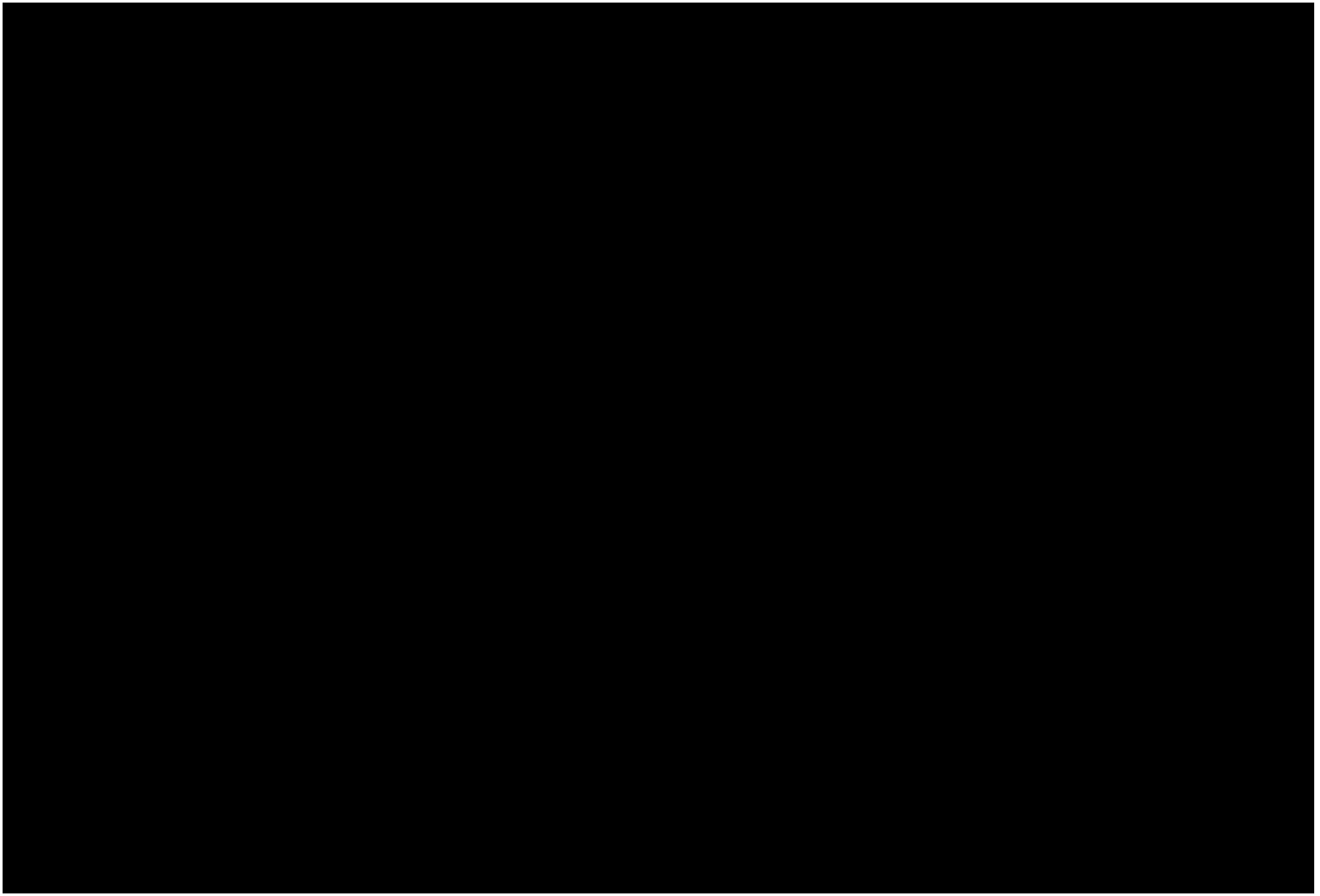
Date of On Peak Day - 06/30/2021



Member Forecasted On Peak Demand Day for July 2021

Mora-San Miguel Electric Cooperative, Inc.

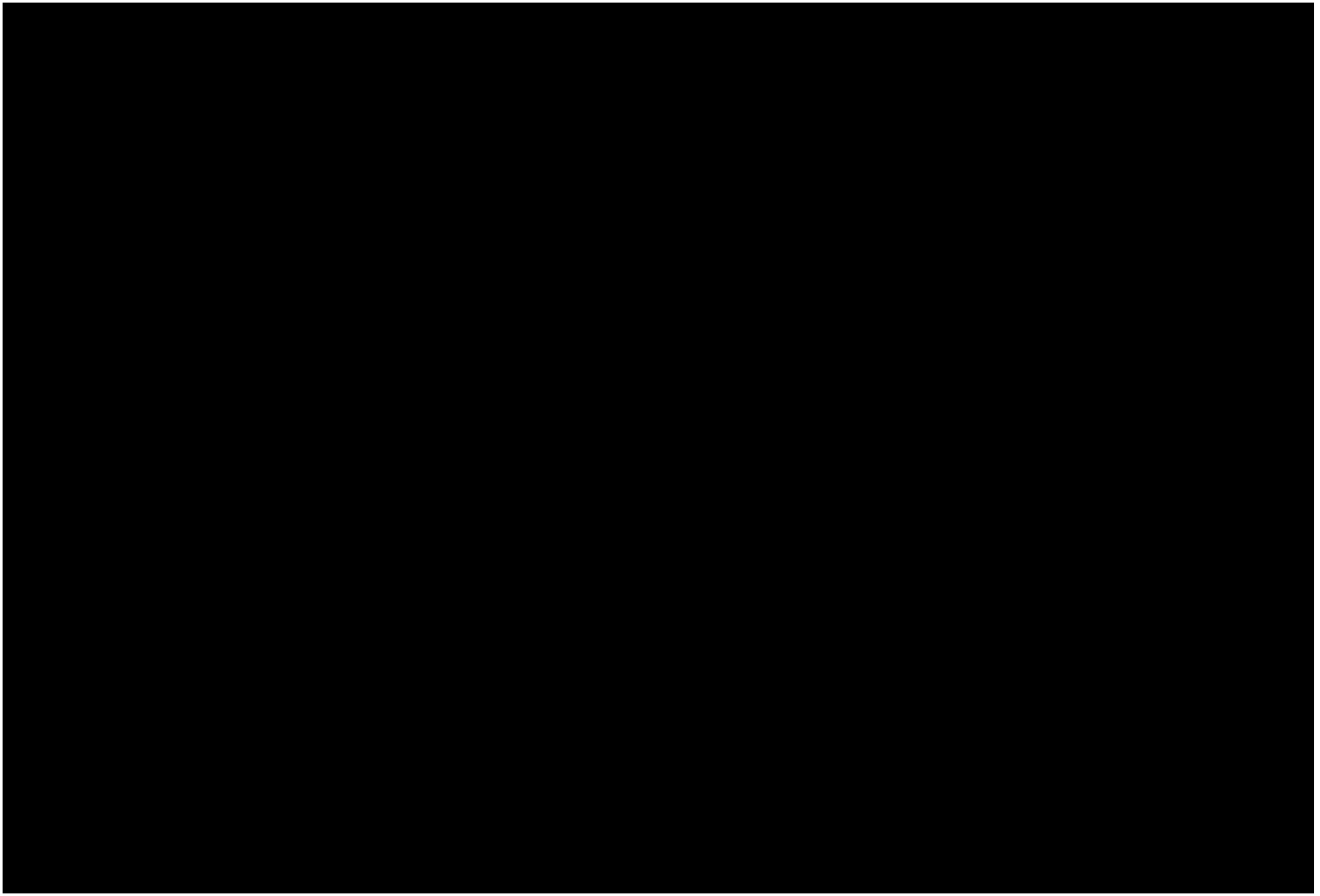
Date of On Peak Day - 07/22/2021



Member Forecasted On Peak Demand Day for August 2021

Mora-San Miguel Electric Cooperative, Inc.

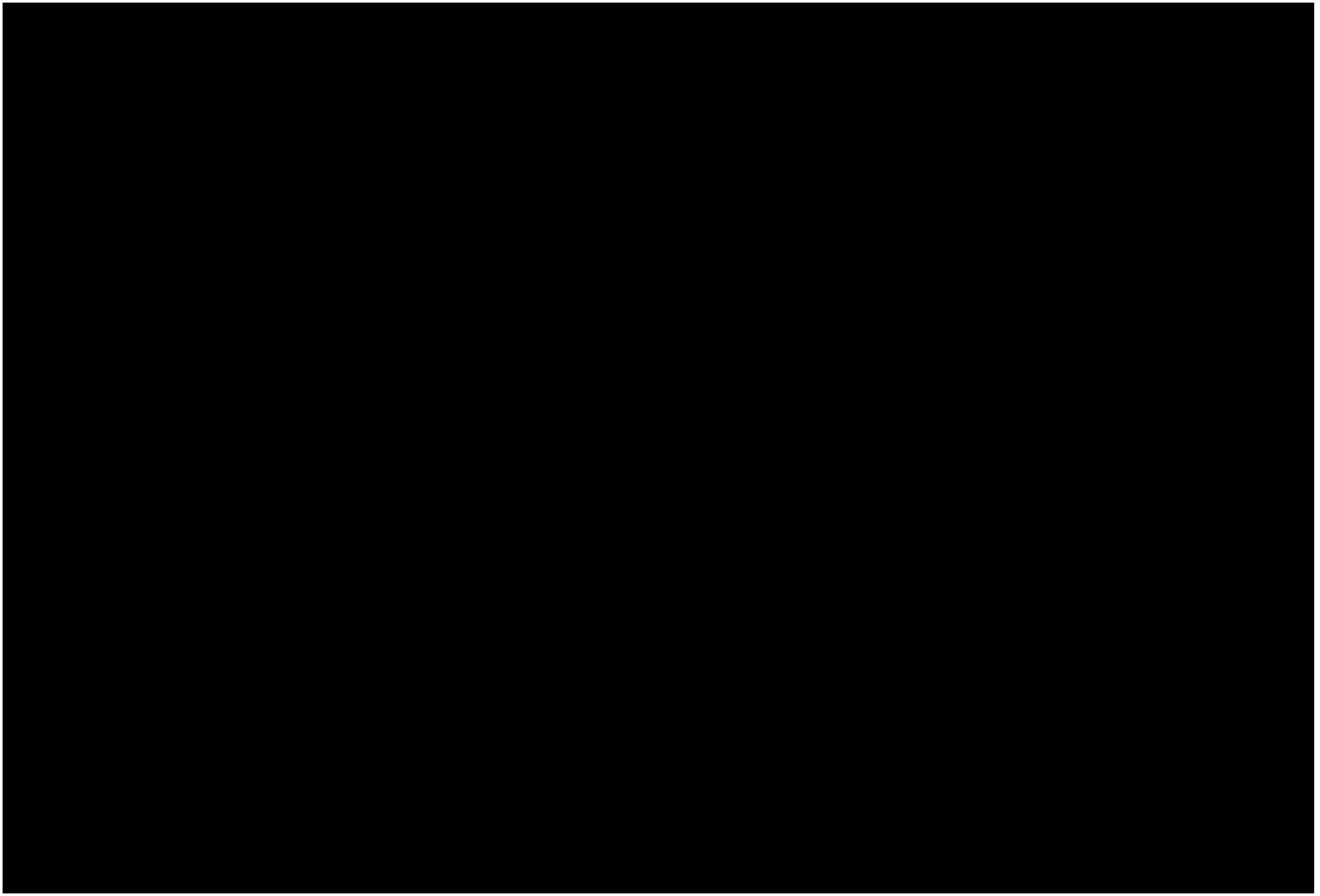
Date of On Peak Day - 08/18/2021



Member Forecasted On Peak Demand Day for September 2021

Mora-San Miguel Electric Cooperative, Inc.

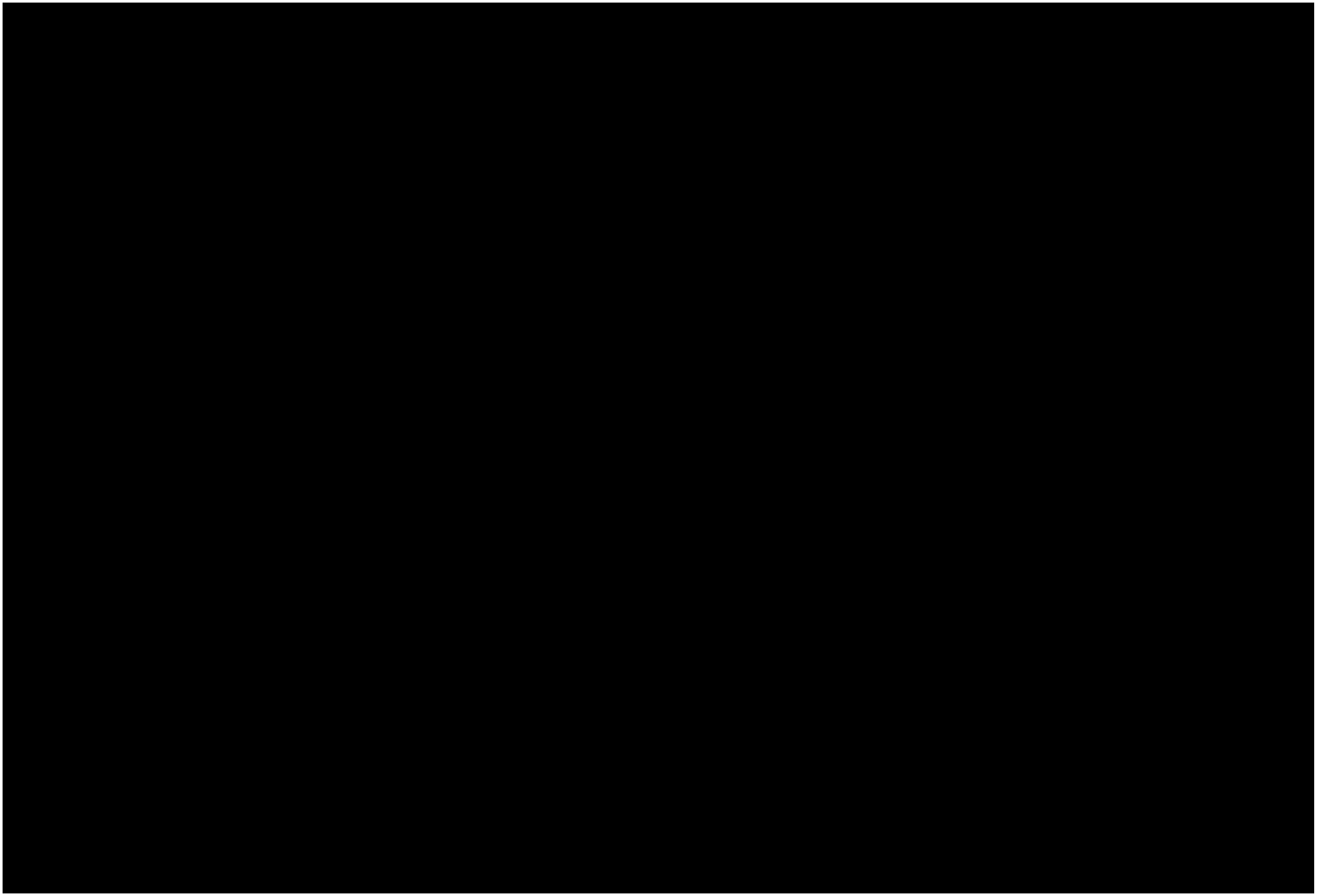
Date of On Peak Day - 09/13/2021



Member Forecasted On Peak Demand Day for October 2021

Mora-San Miguel Electric Cooperative, Inc.

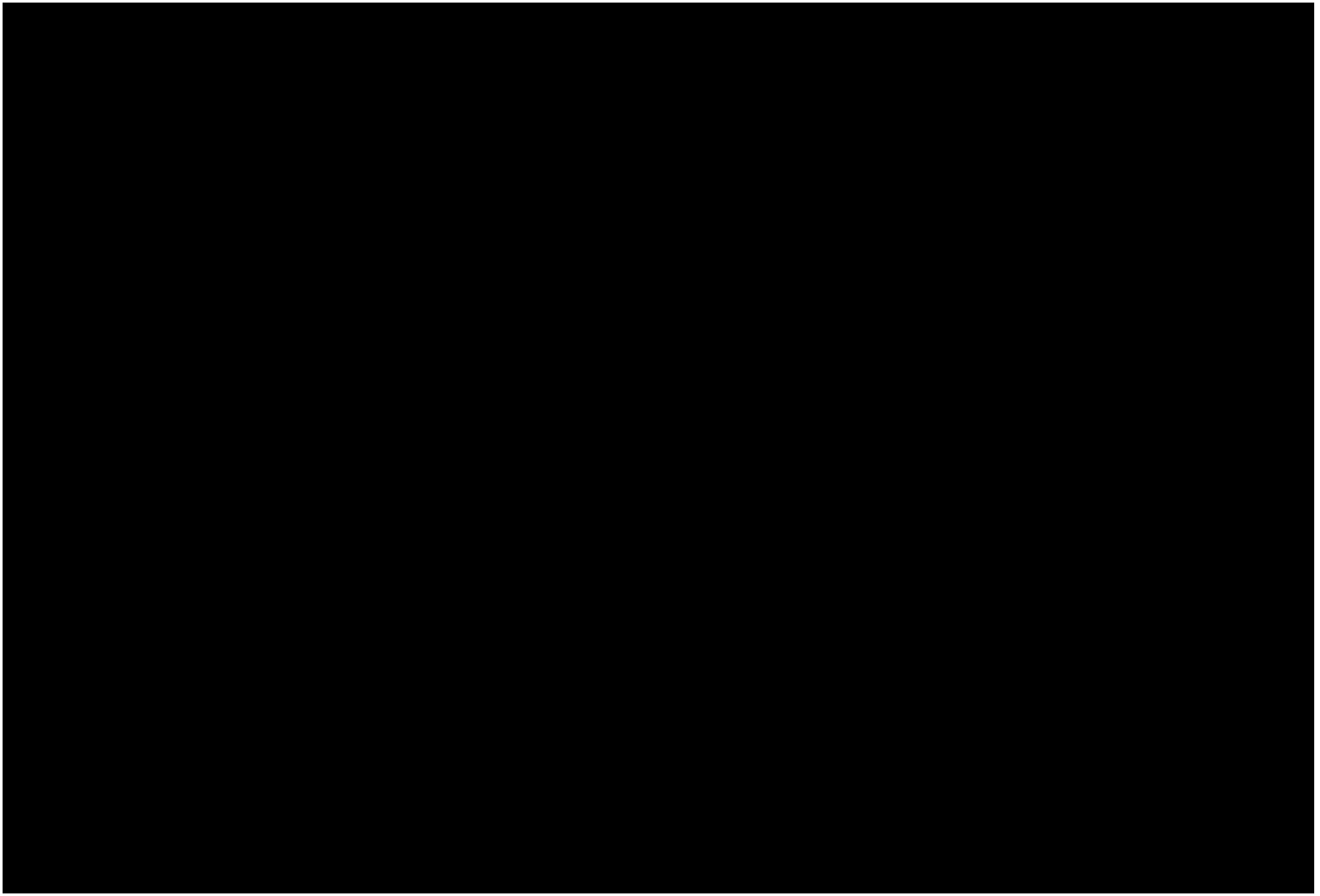
Date of On Peak Day - 10/21/2021



Member Forecasted On Peak Demand Day for November 2021

Mora-San Miguel Electric Cooperative, Inc.

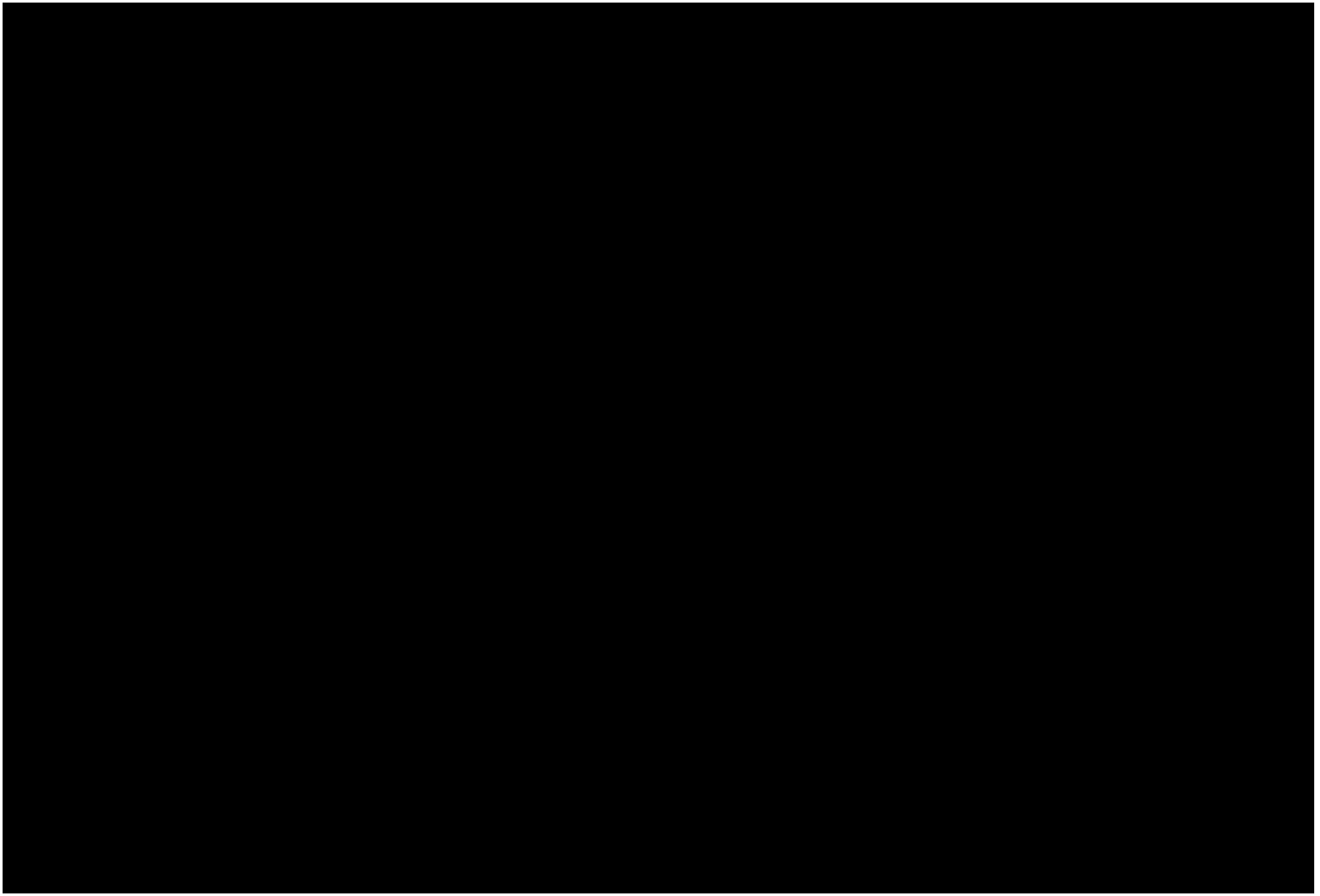
Date of On Peak Day - 11/16/2021



Member Forecasted On Peak Demand Day for December 2021

Mora-San Miguel Electric Cooperative, Inc.

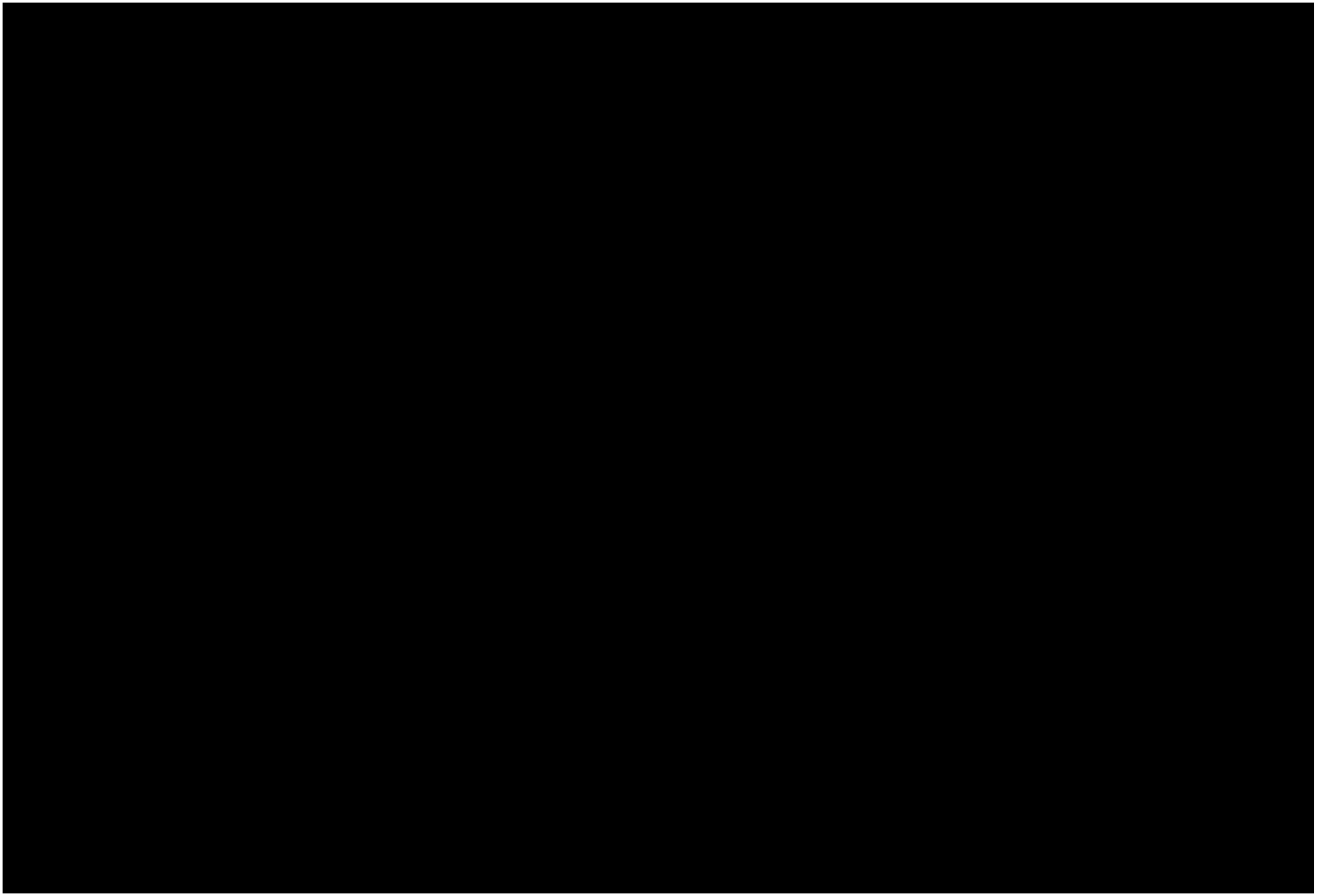
Date of On Peak Day - 12/26/2021



Member Forecasted On Peak Demand Day for January 2021

Mountain View Electric Association, Inc.

Date of On Peak Day - 01/05/2021



Member Forecasted On Peak Demand Day for February 2021

Mountain View Electric Association, Inc.

Date of On Peak Day - 02/02/2021

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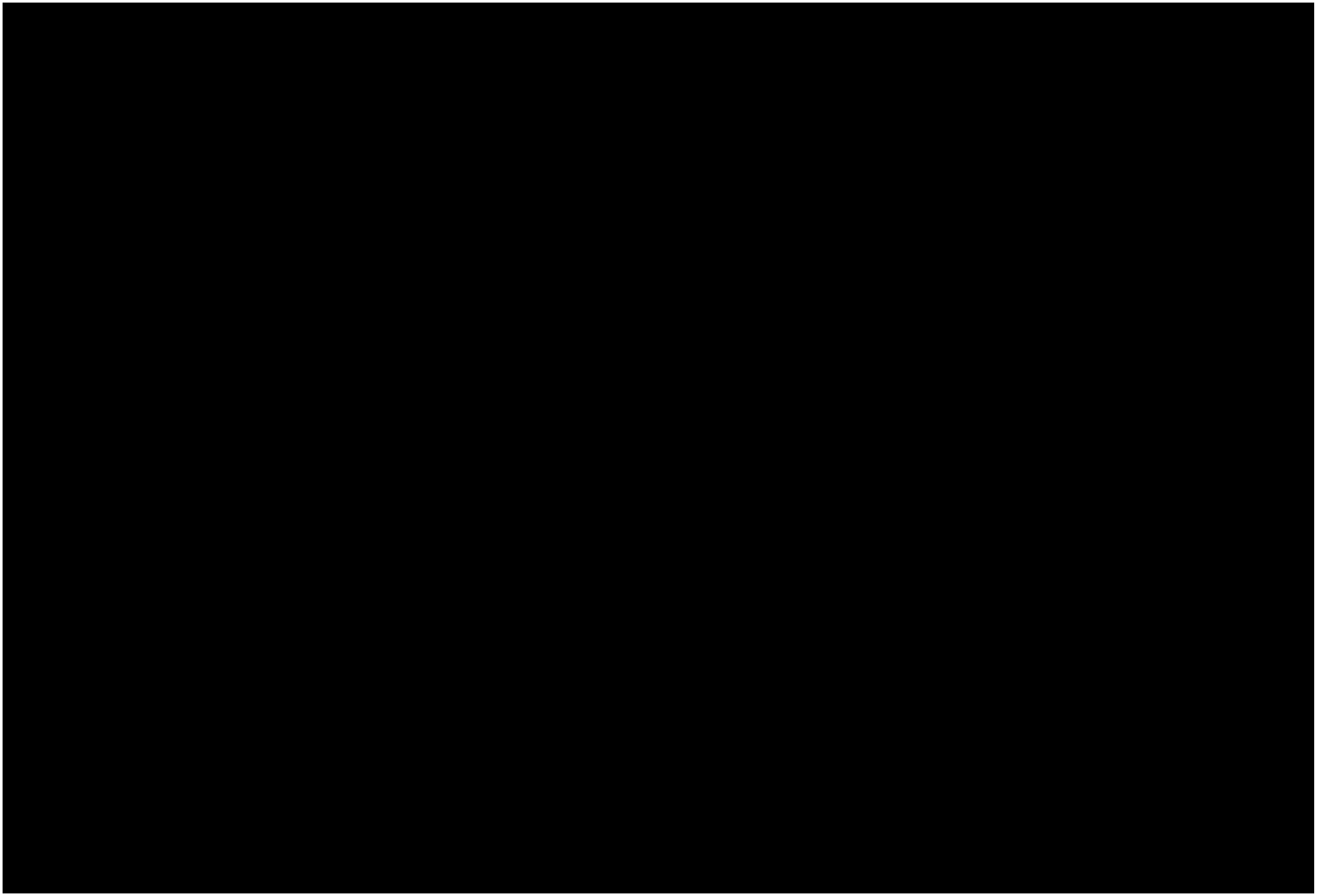
Member Forecasted On Peak Demand Day for March 2021

Mountain View Electric Association, Inc.

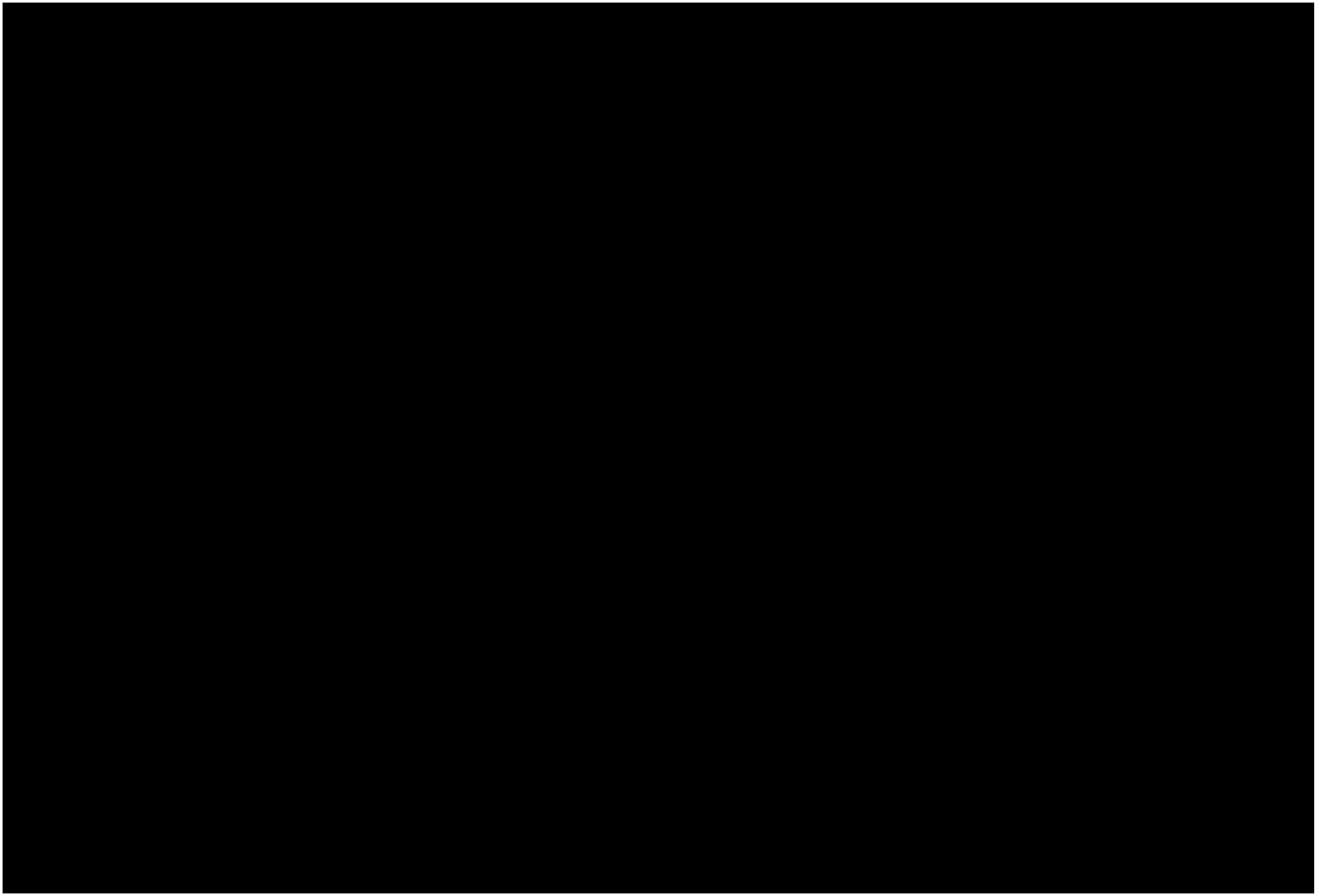
Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

Mountain View Electric Association, Inc.

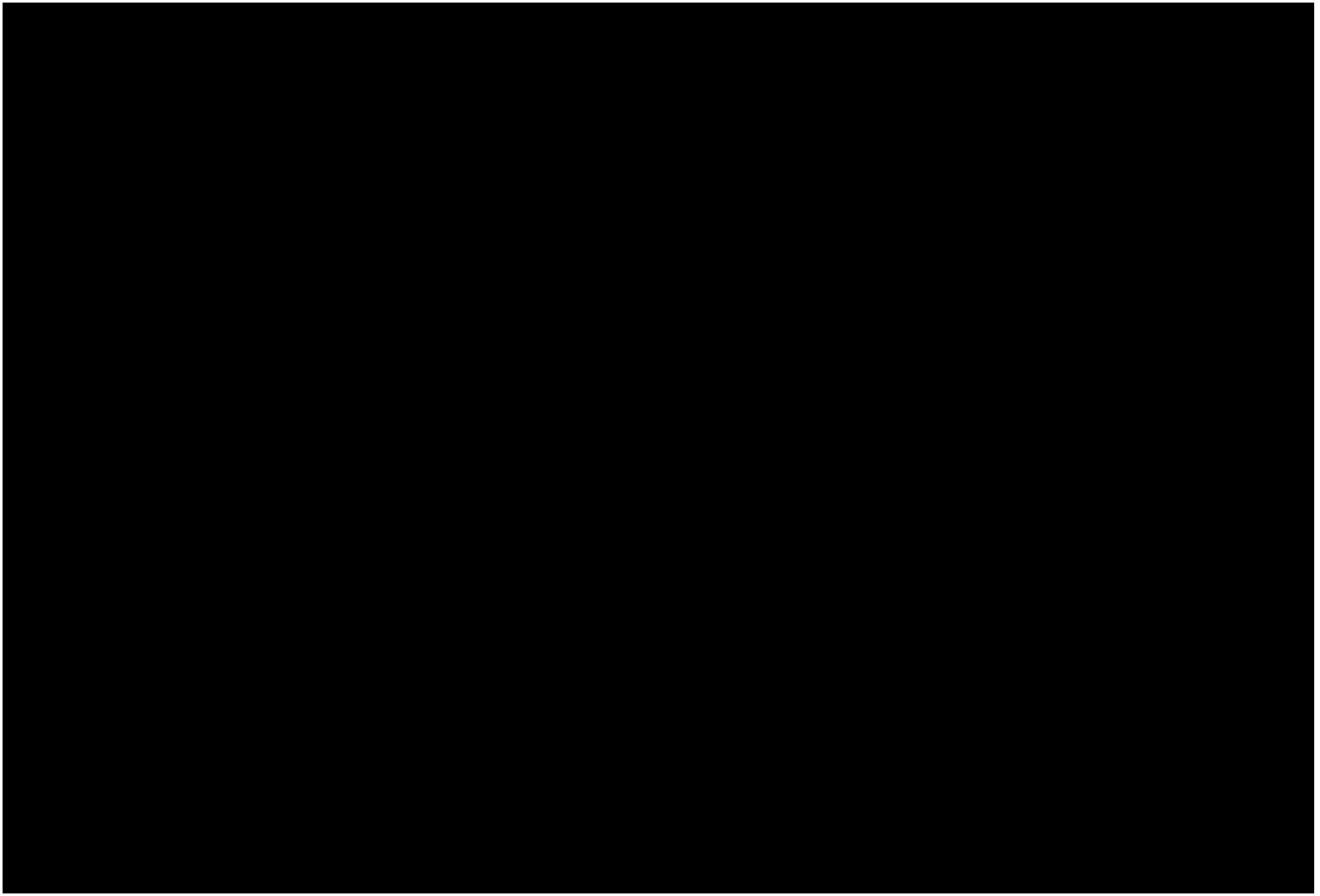
Date of On Peak Day - 04/04/2021



Member Forecasted On Peak Demand Day for May 2021

Mountain View Electric Association, Inc.

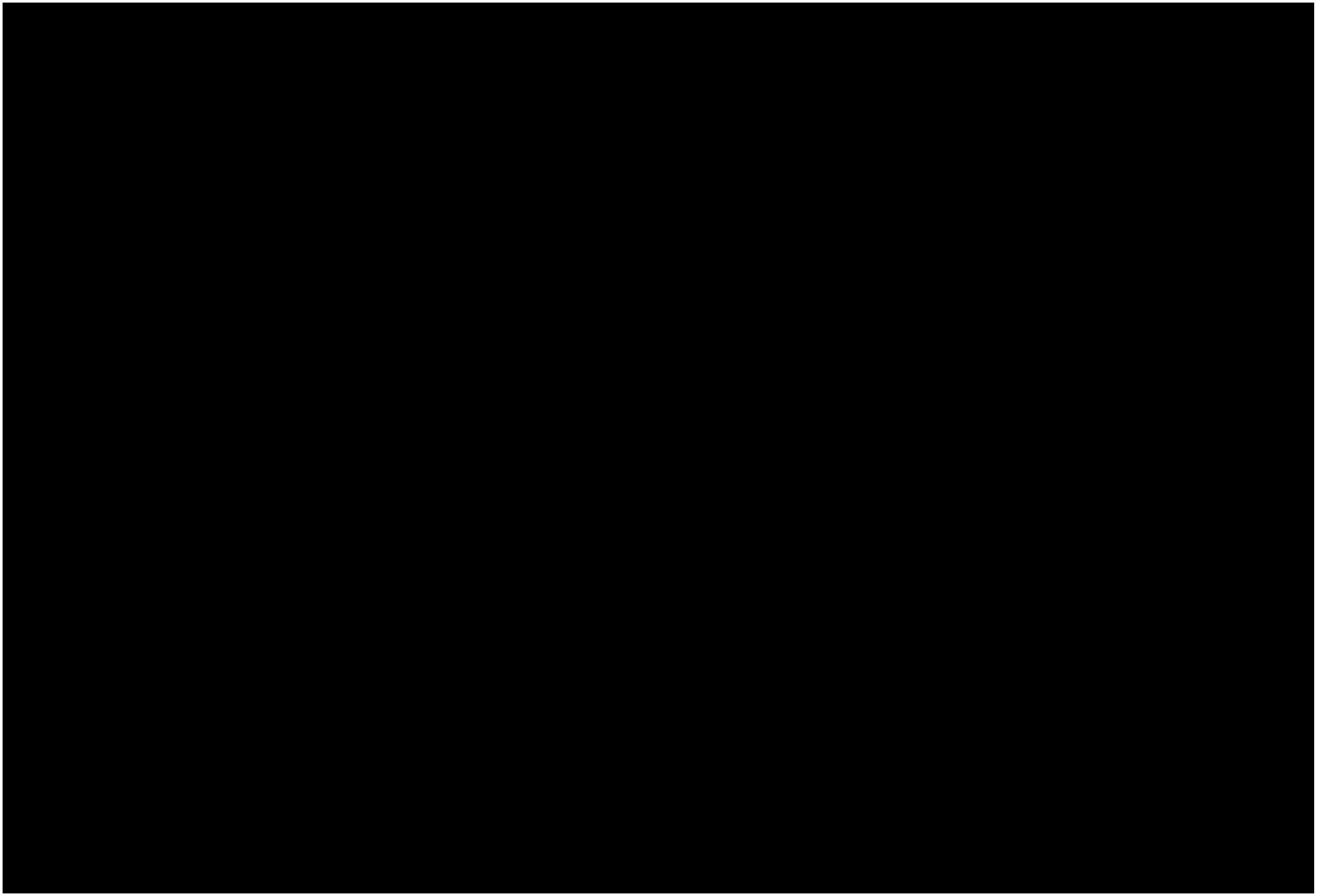
Date of On Peak Day - 05/19/2021



Member Forecasted On Peak Demand Day for June 2021

Mountain View Electric Association, Inc.

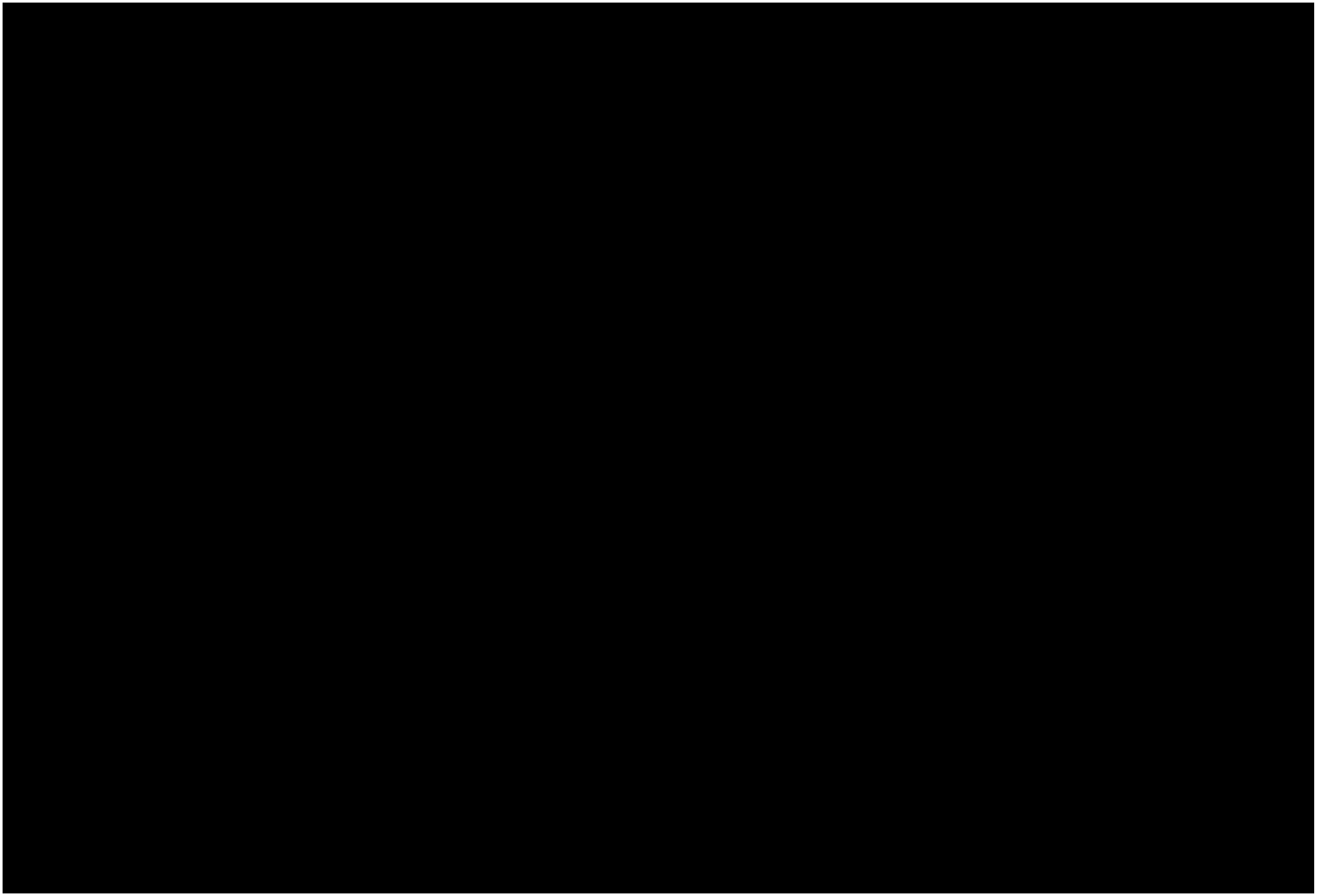
Date of On Peak Day - 06/28/2021



Member Forecasted On Peak Demand Day for July 2021

Mountain View Electric Association, Inc.

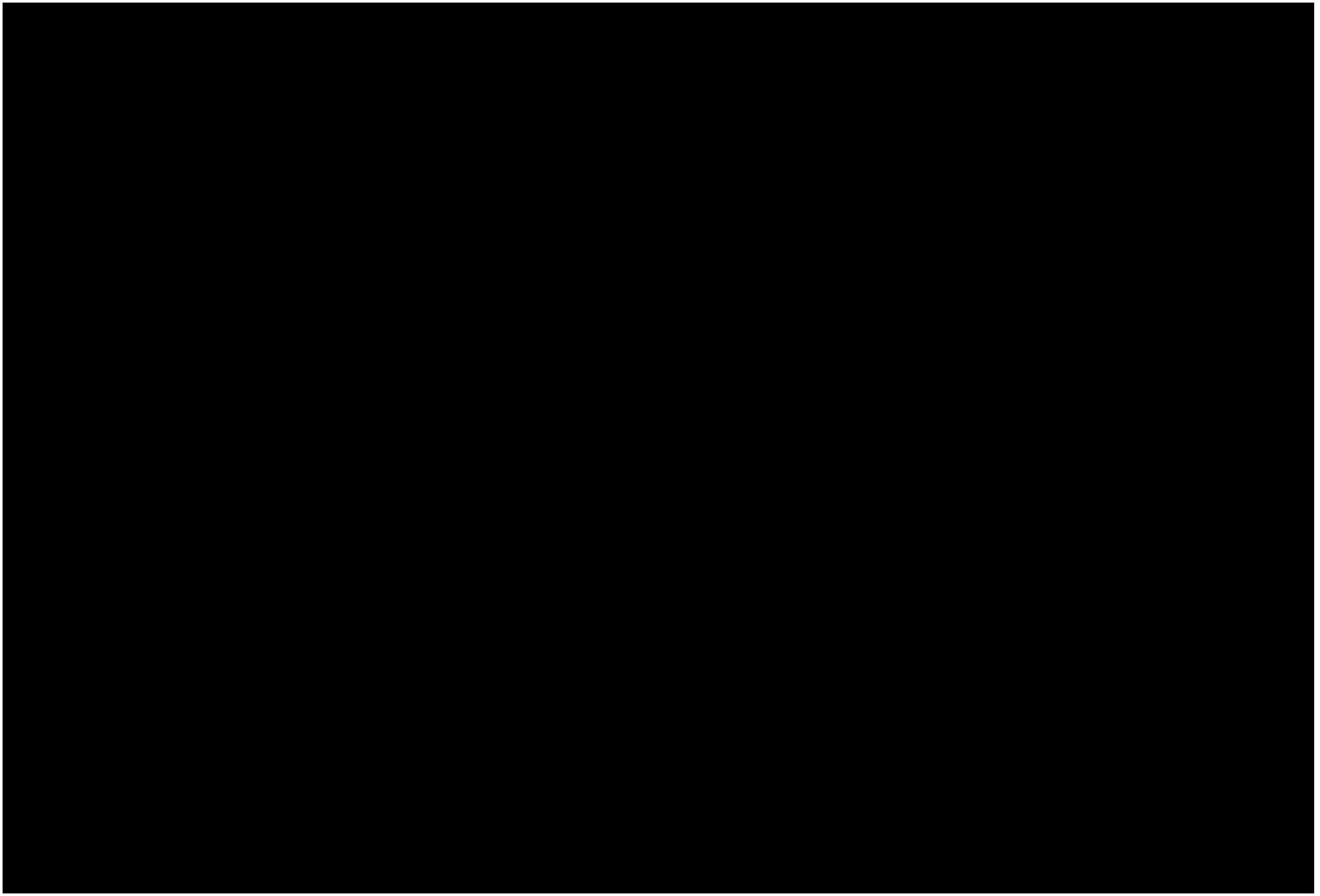
Date of On Peak Day - 07/28/2021



Member Forecasted On Peak Demand Day for August 2021

Mountain View Electric Association, Inc.

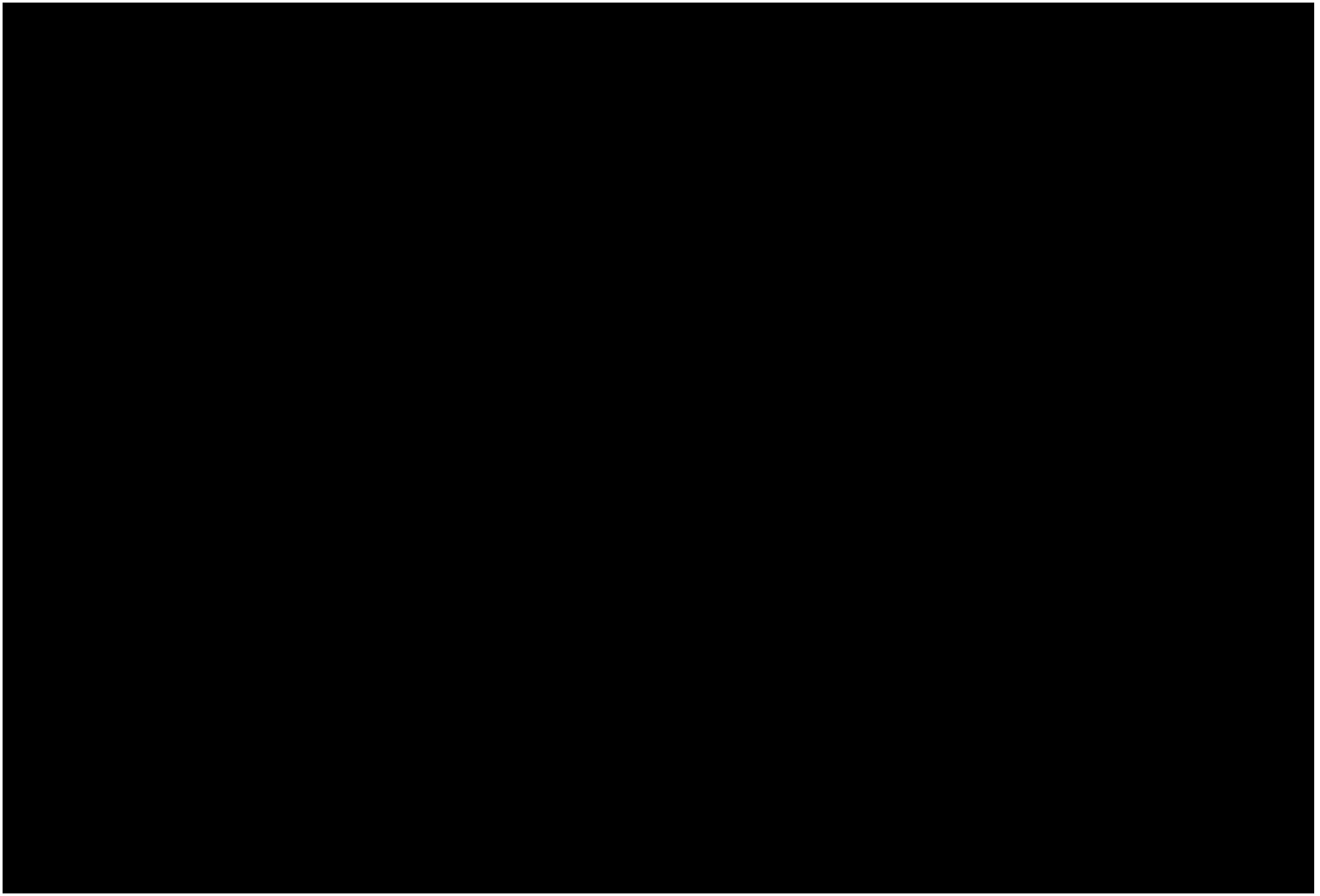
Date of On Peak Day - 08/29/2021



Member Forecasted On Peak Demand Day for September 2021

Mountain View Electric Association, Inc.

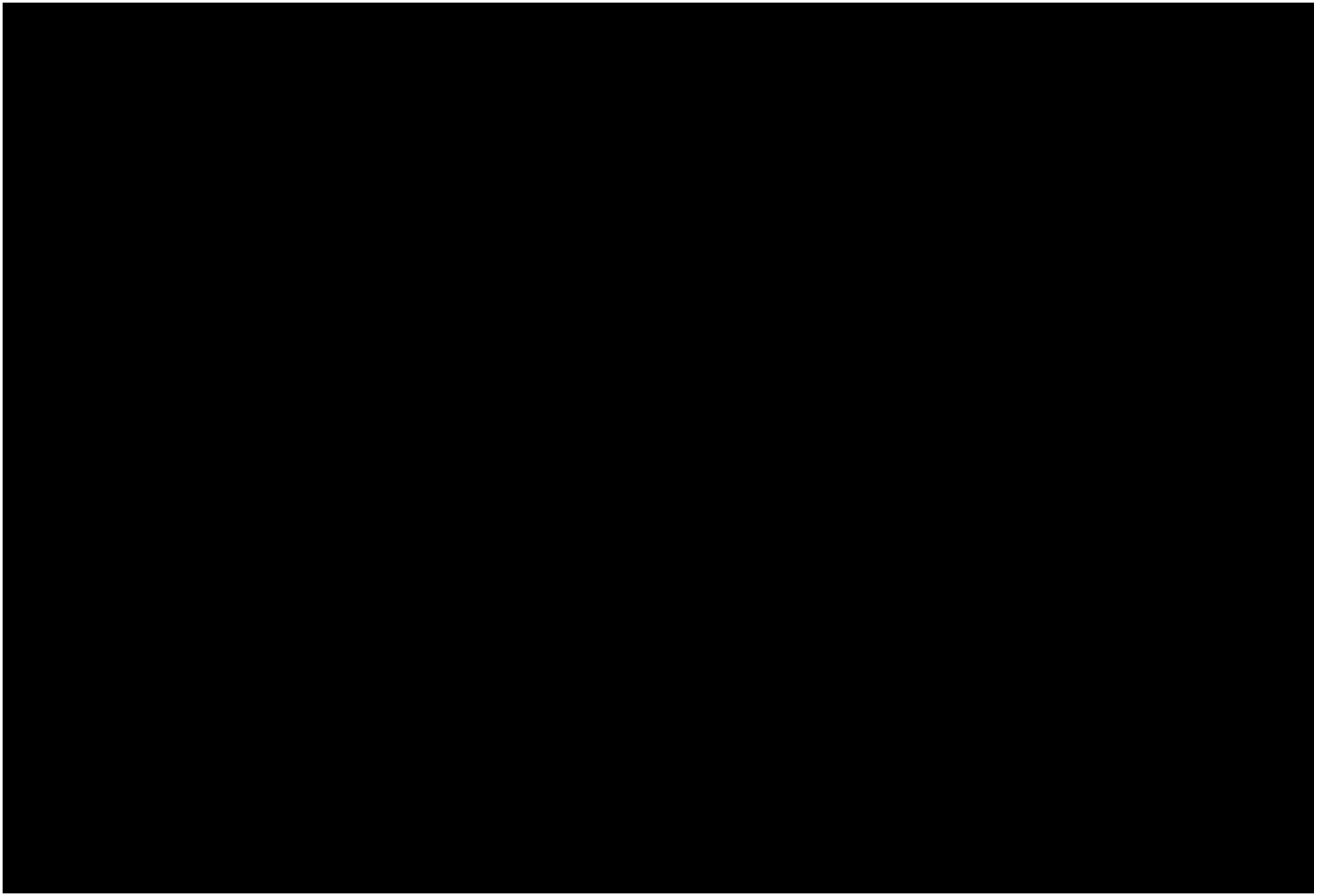
Date of On Peak Day - 09/02/2021



Member Forecasted On Peak Demand Day for October 2021

Mountain View Electric Association, Inc.

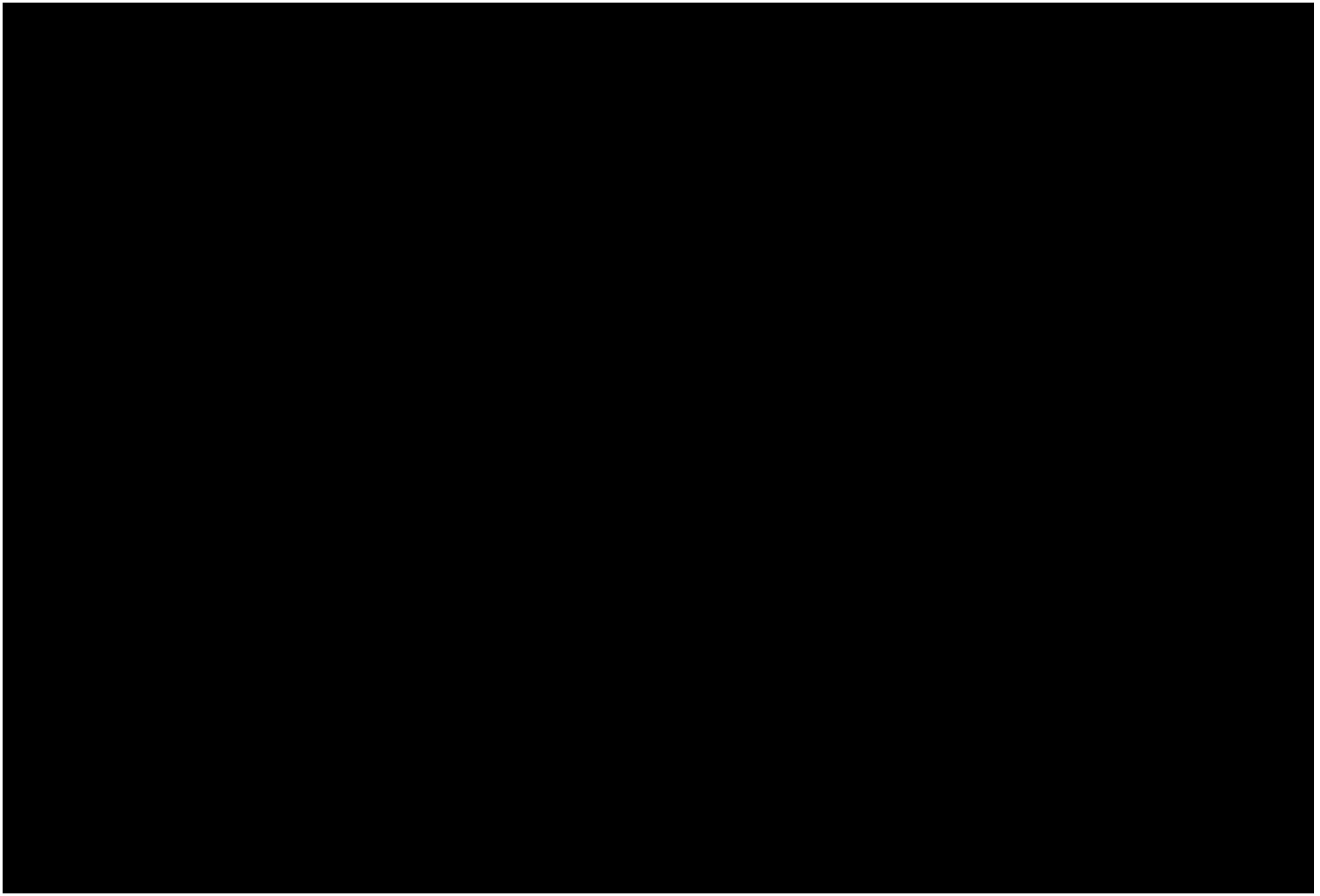
Date of On Peak Day - 10/28/2021



Member Forecasted On Peak Demand Day for November 2021

Mountain View Electric Association, Inc.

Date of On Peak Day - 11/08/2021



Member Forecasted On Peak Demand Day for December 2021

Mountain View Electric Association, Inc.

Date of On Peak Day - 12/26/2021

[redacted]

Hearing Exhibit 101
PUBLIC Attachment BN-2
Proceeding No. 20A-0528E
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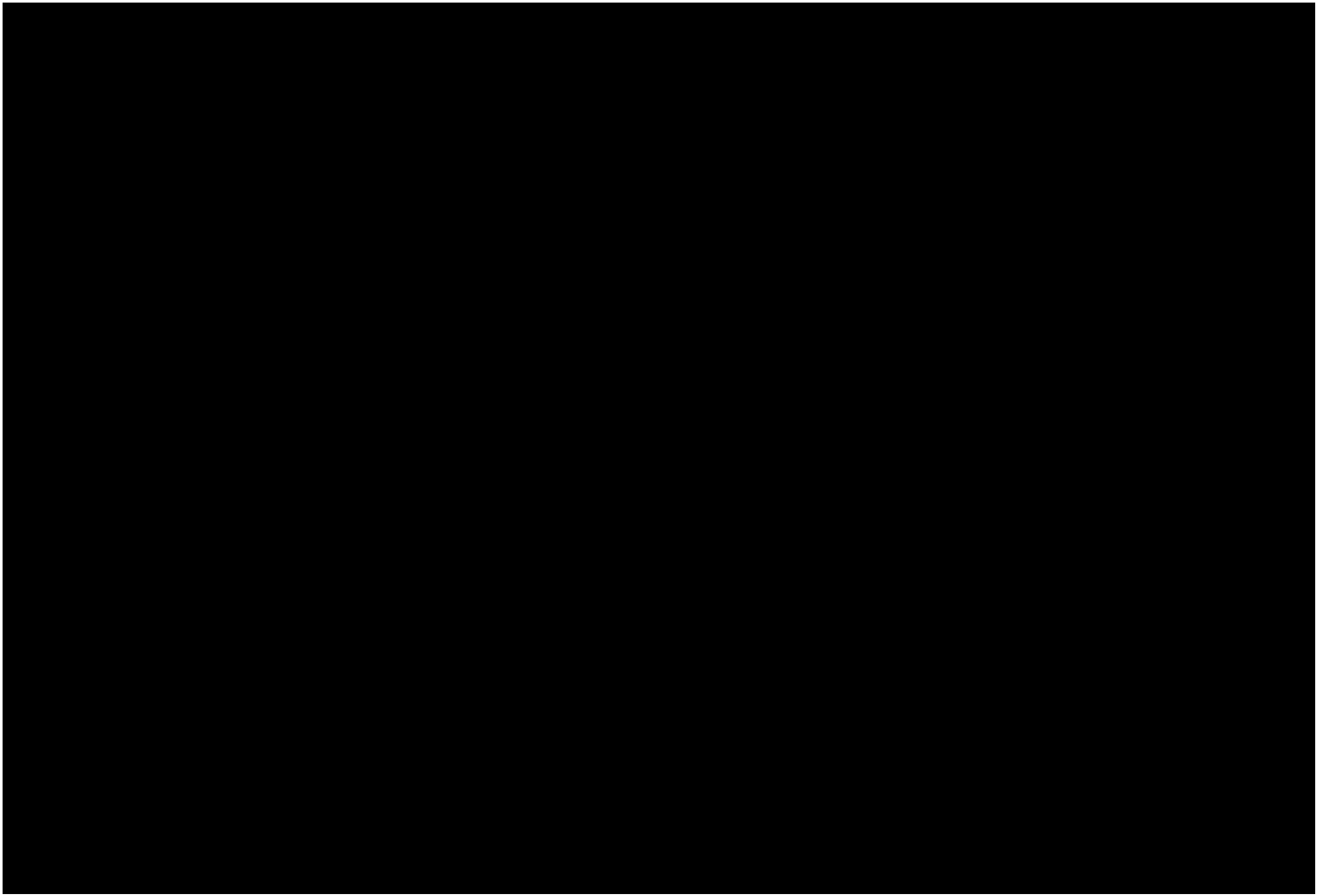
Member Forecasted On Peak Demand Day for January 2021

Midwest Electric Cooperative Corporation

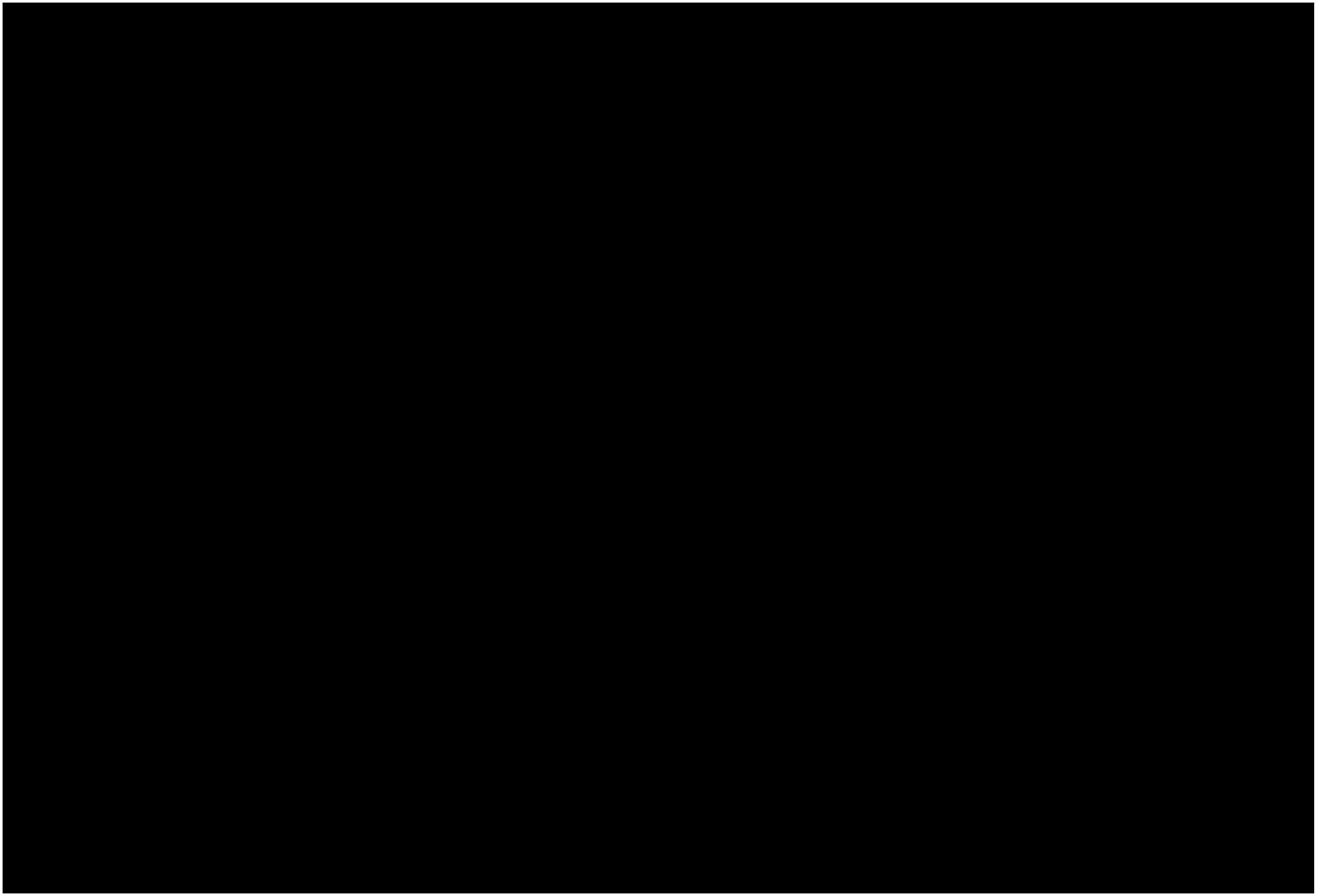
Date of On Peak Day - 01/06/2021



Member Forecasted On Peak Demand Day for February 2021

Midwest Electric Cooperative Corporation

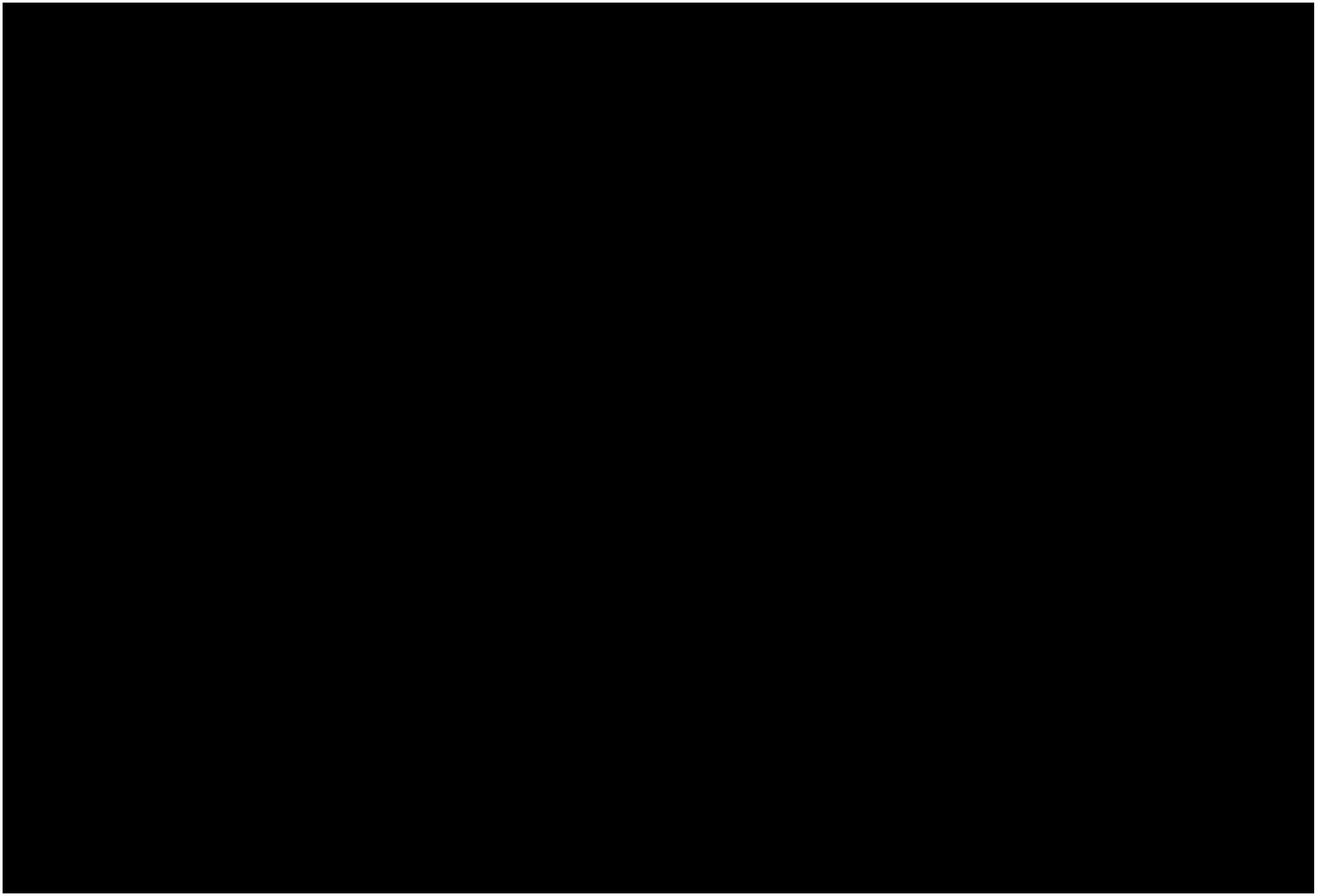
Date of On Peak Day - 02/25/2021



Member Forecasted On Peak Demand Day for March 2021

Midwest Electric Cooperative Corporation

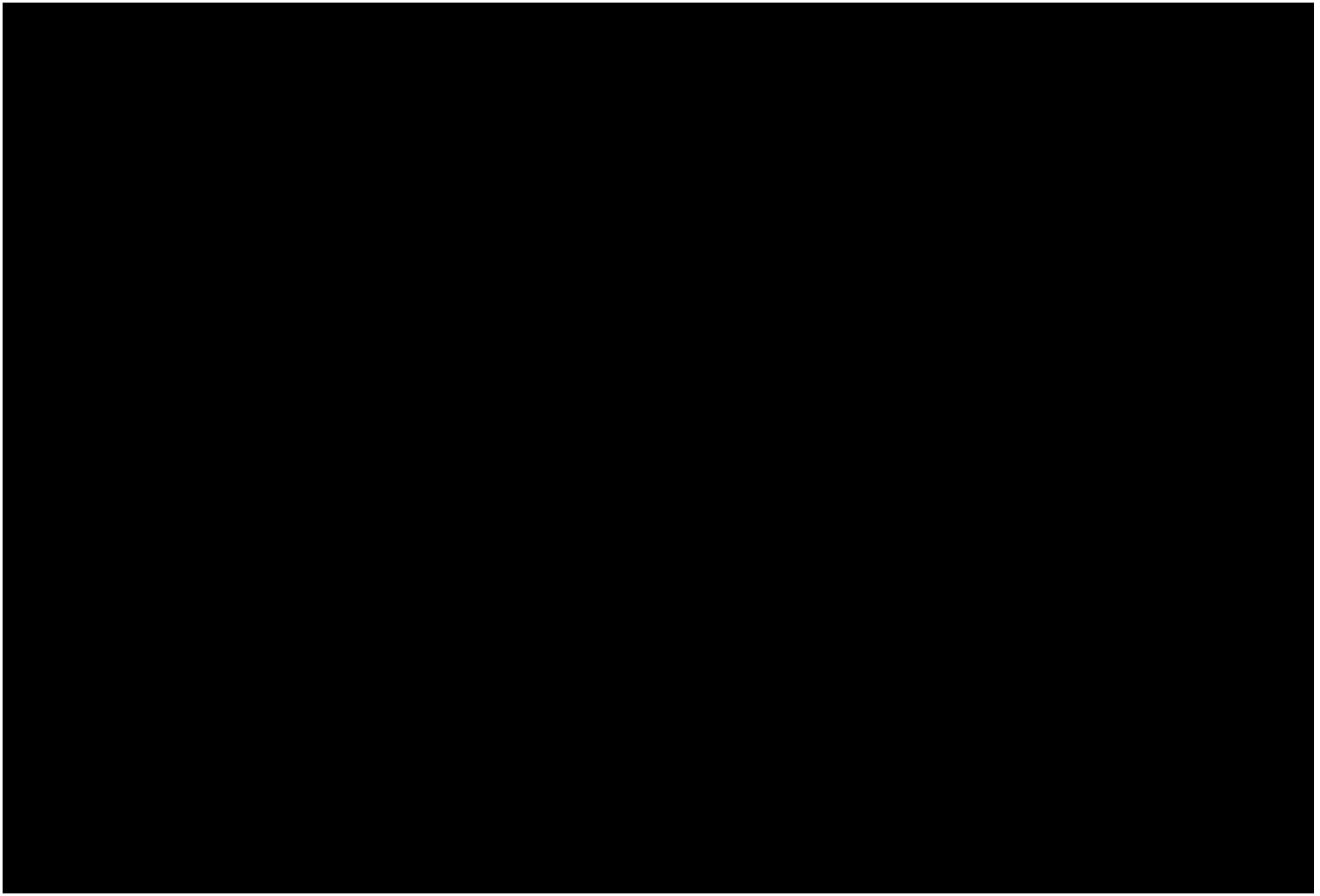
Date of On Peak Day - 03/03/2021



Member Forecasted On Peak Demand Day for April 2021

Midwest Electric Cooperative Corporation

Date of On Peak Day - 04/01/2021



Hearing Exhibit 101
PUBLIC Attachment BN-2
Proceeding No. 20A-0528E
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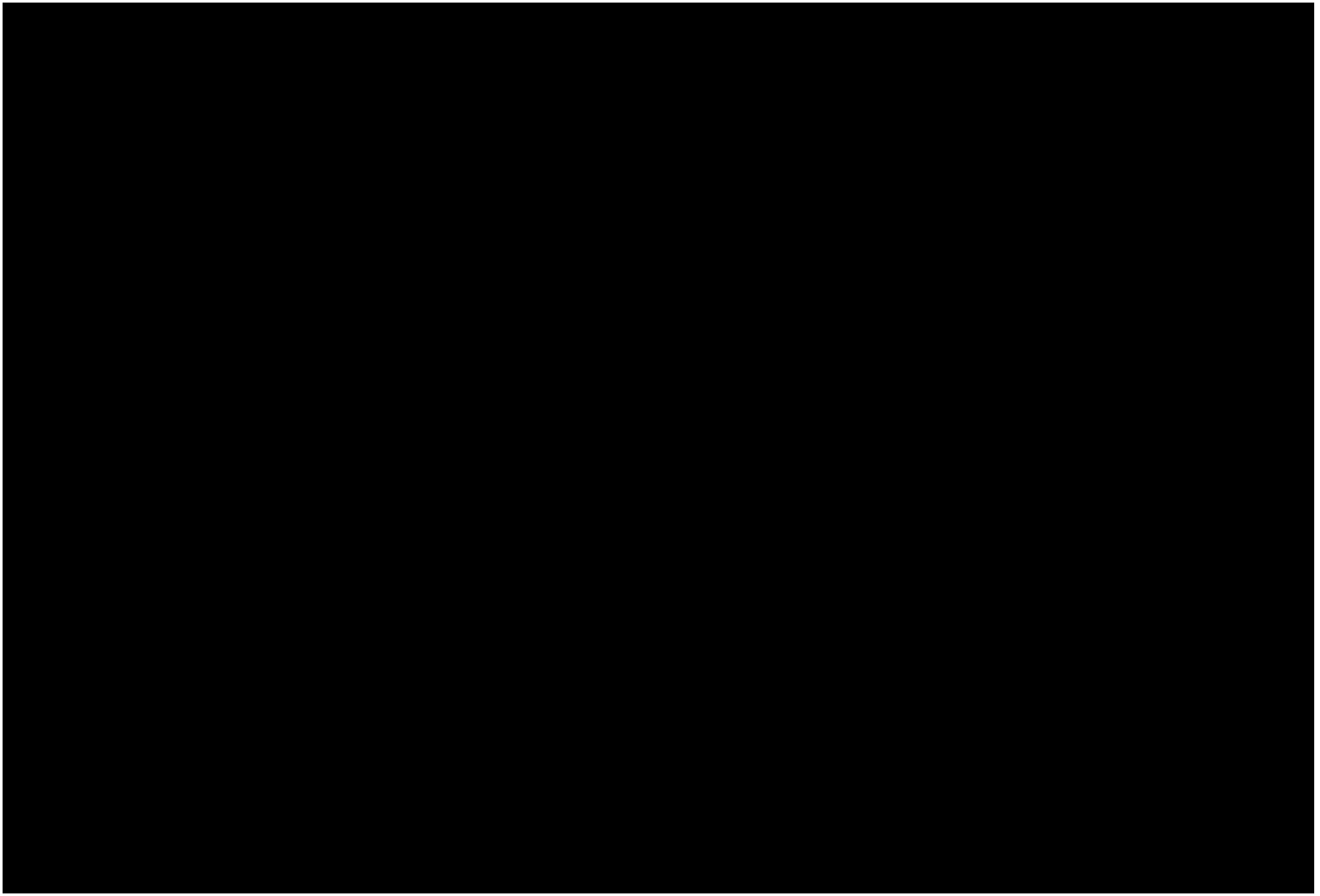
Member Forecasted On Peak Demand Day for May 2021

Midwest Electric Cooperative Corporation

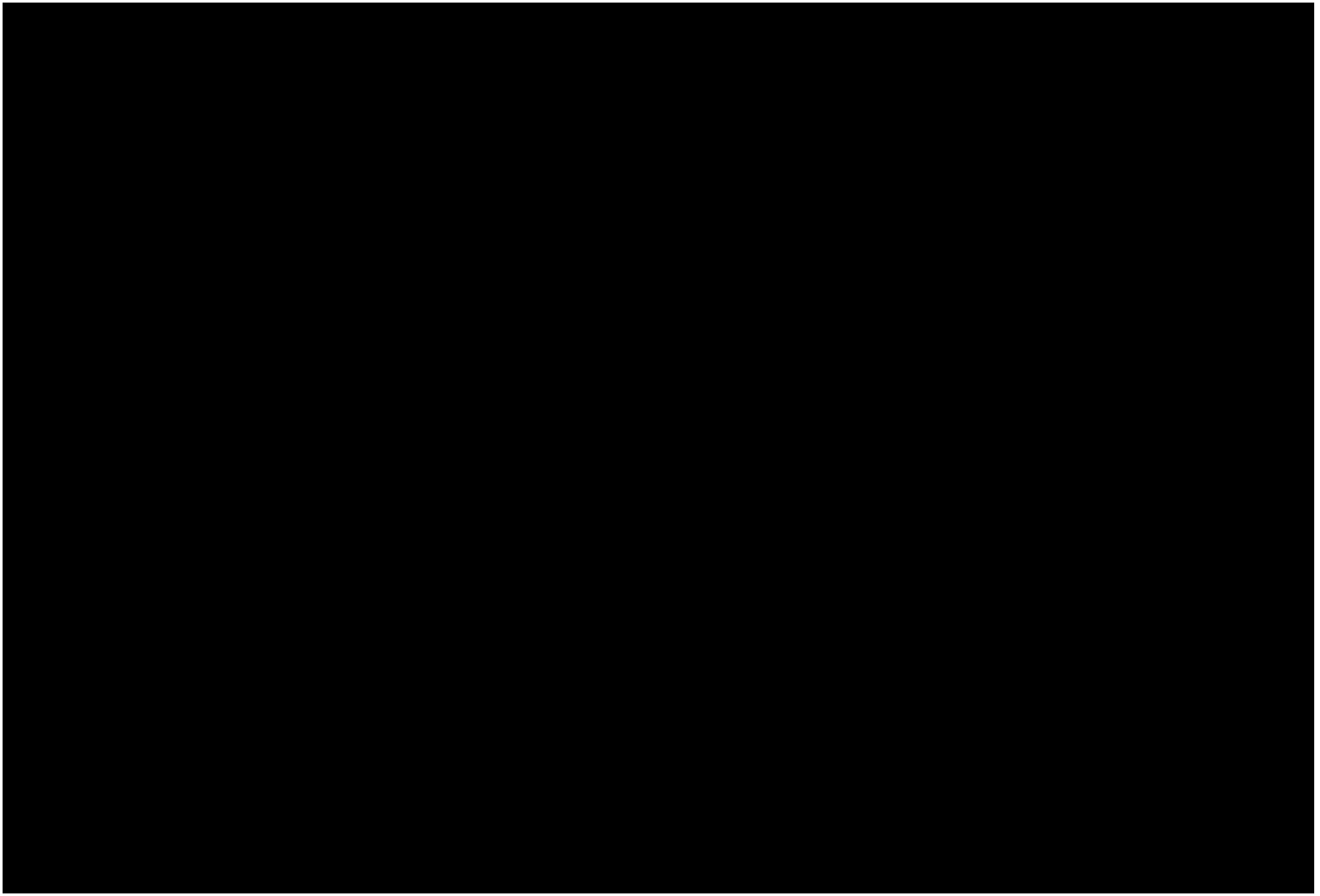
Date of On Peak Day - 05/31/2021



Member Forecasted On Peak Demand Day for June 2021

Midwest Electric Cooperative Corporation

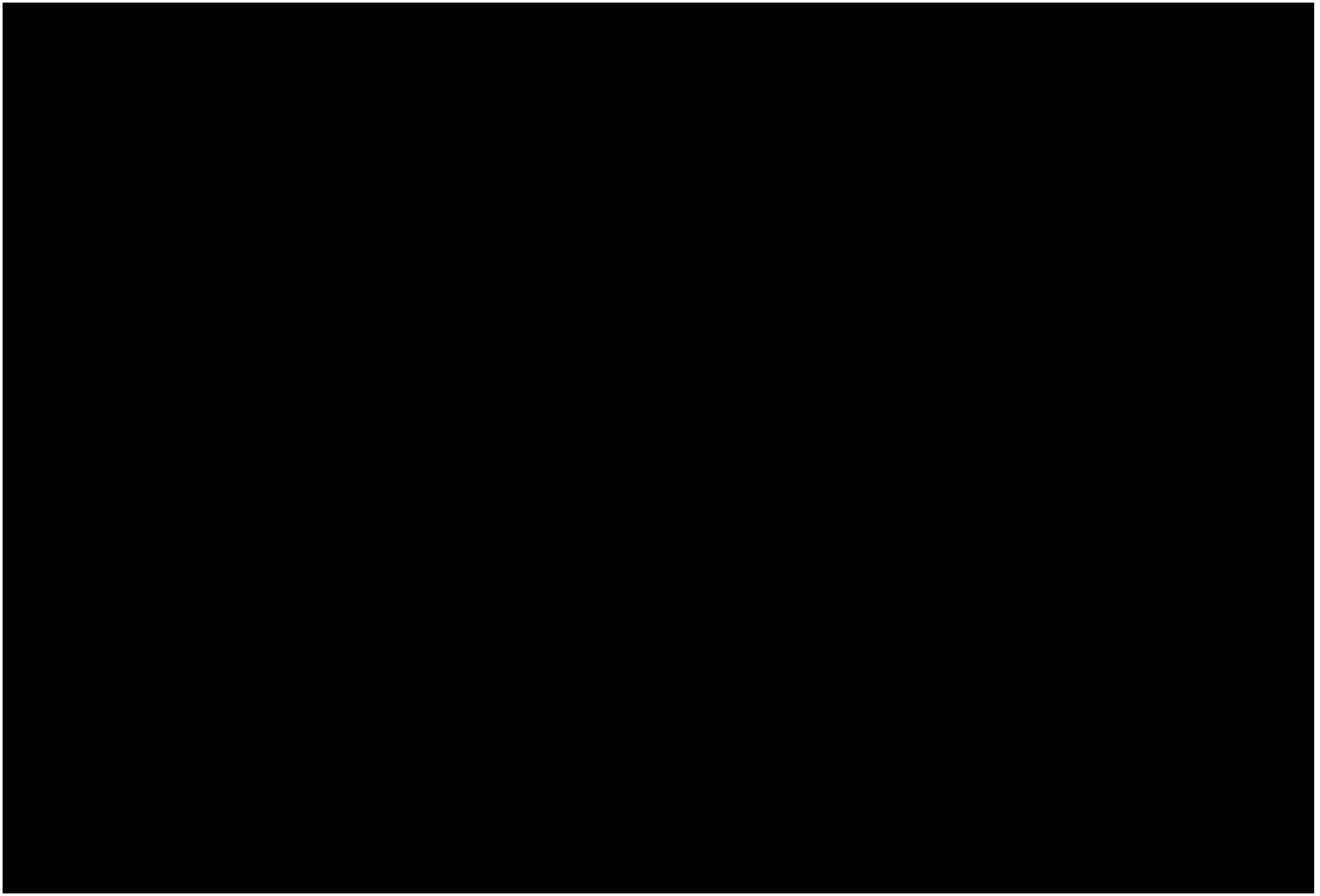
Date of On Peak Day - 06/12/2021



Member Forecasted On Peak Demand Day for July 2021

Midwest Electric Cooperative Corporation

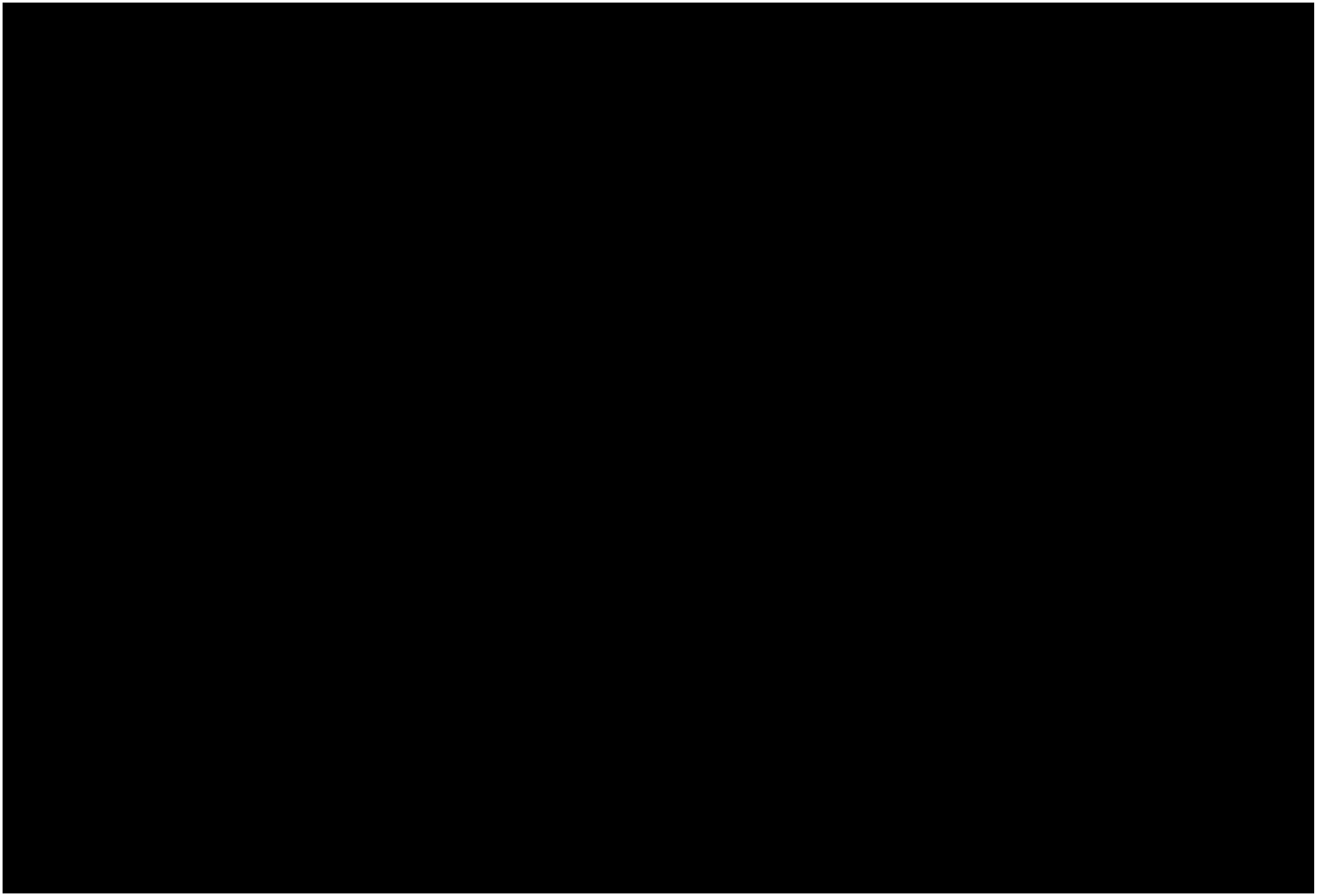
Date of On Peak Day - 07/12/2021



Member Forecasted On Peak Demand Day for August 2021

Midwest Electric Cooperative Corporation

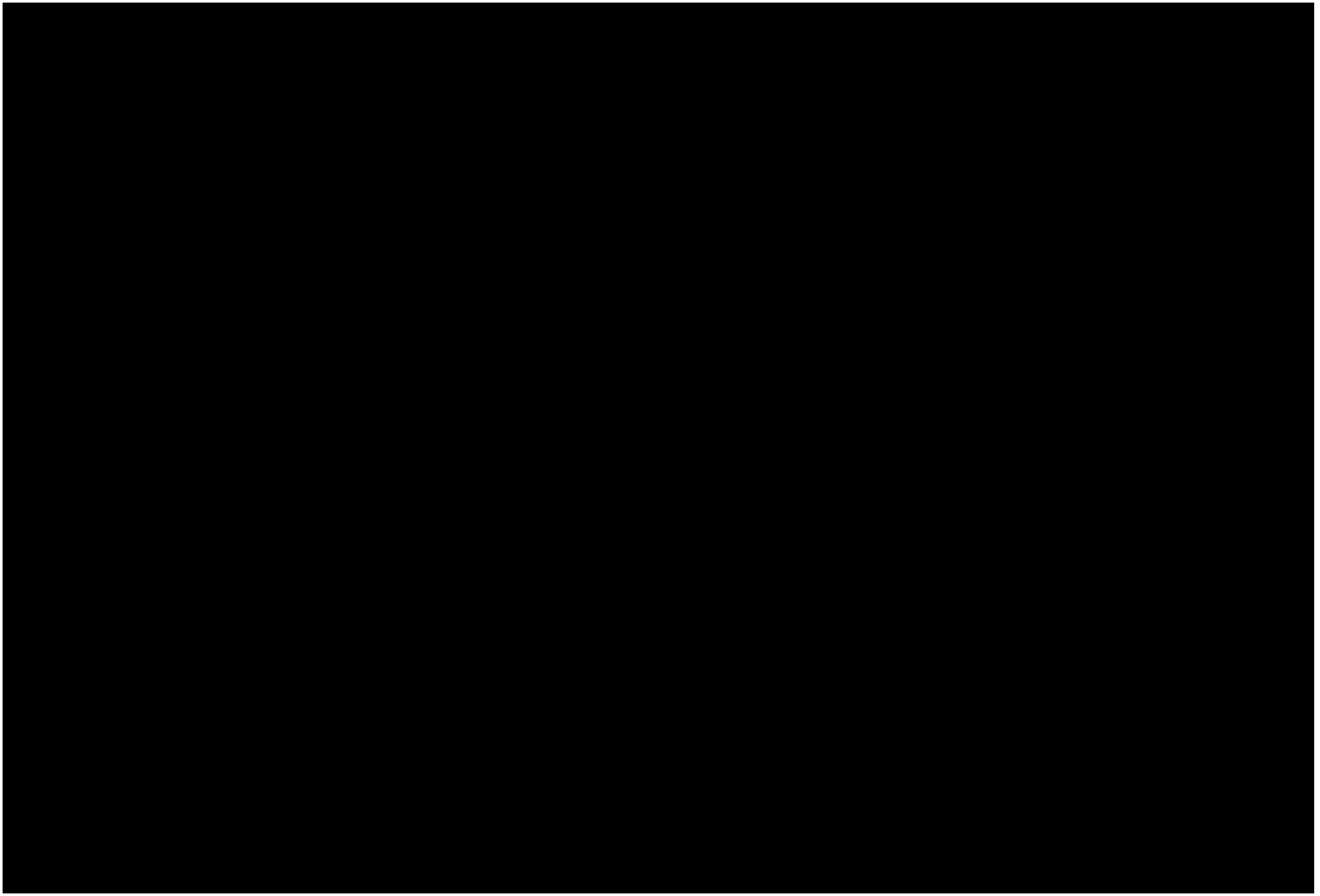
Date of On Peak Day - 08/31/2021



Member Forecasted On Peak Demand Day for September 2021

Midwest Electric Cooperative Corporation

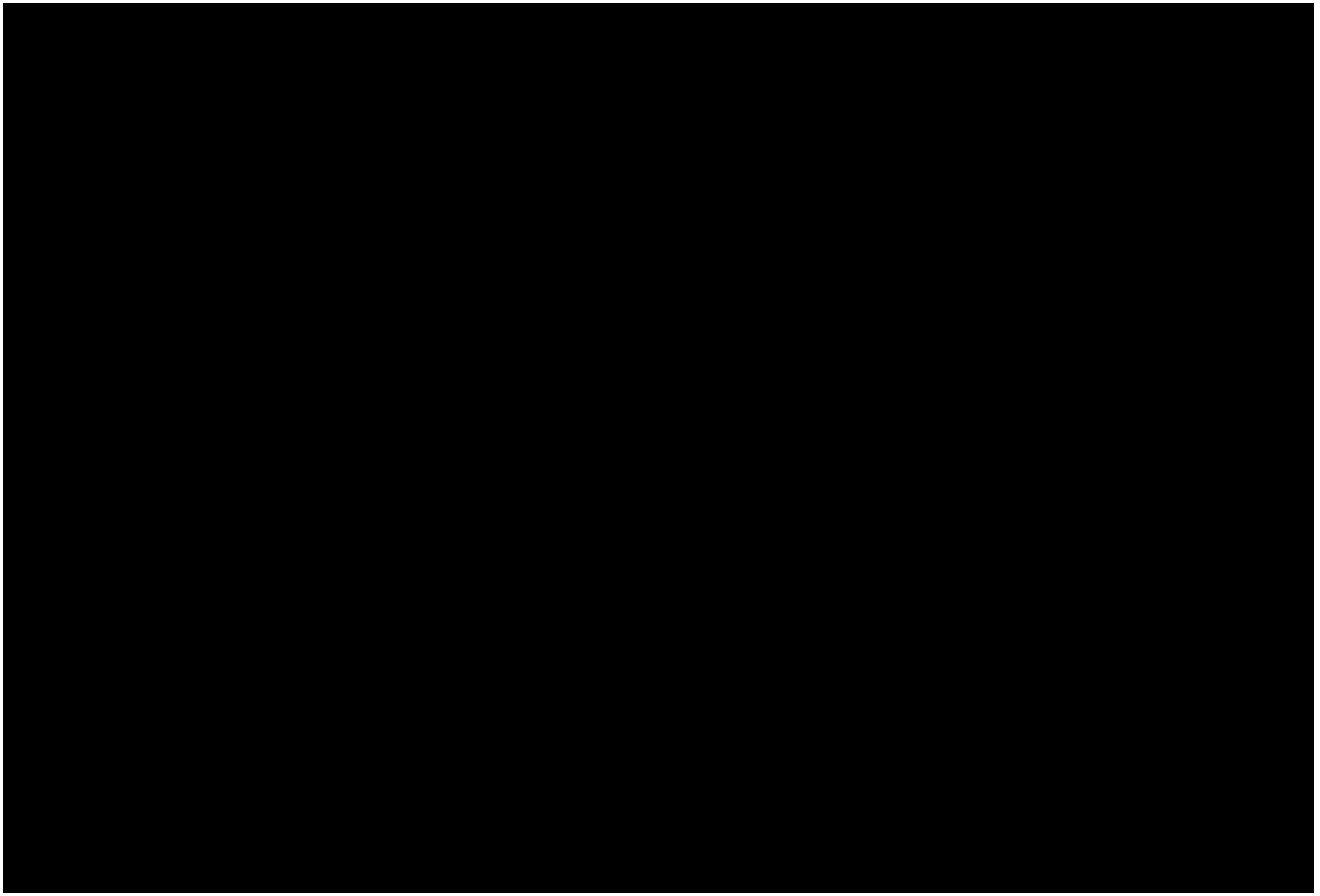
Date of On Peak Day - 09/03/2021



Member Forecasted On Peak Demand Day for October 2021

Midwest Electric Cooperative Corporation

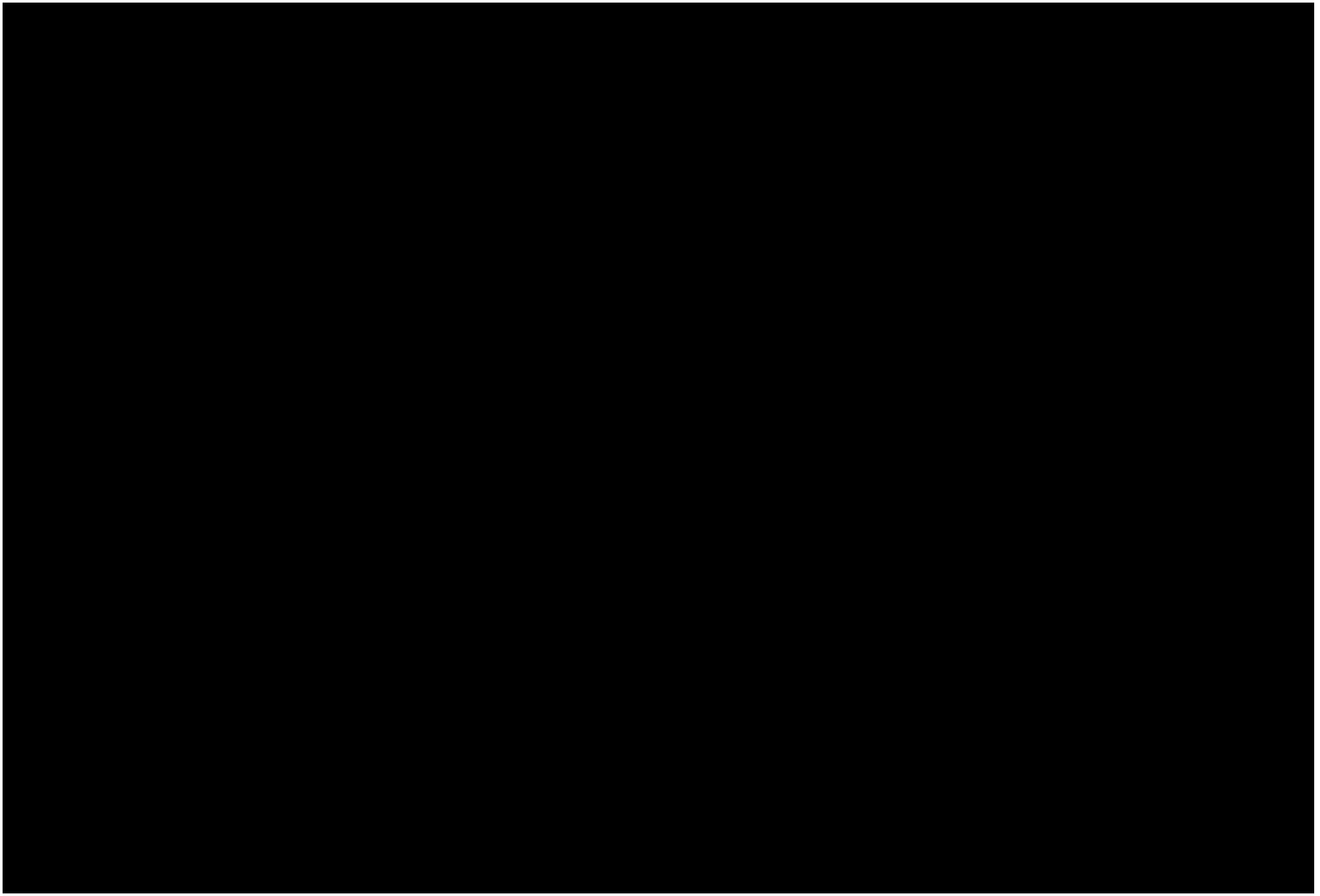
Date of On Peak Day - 10/20/2021



Member Forecasted On Peak Demand Day for November 2021

Midwest Electric Cooperative Corporation

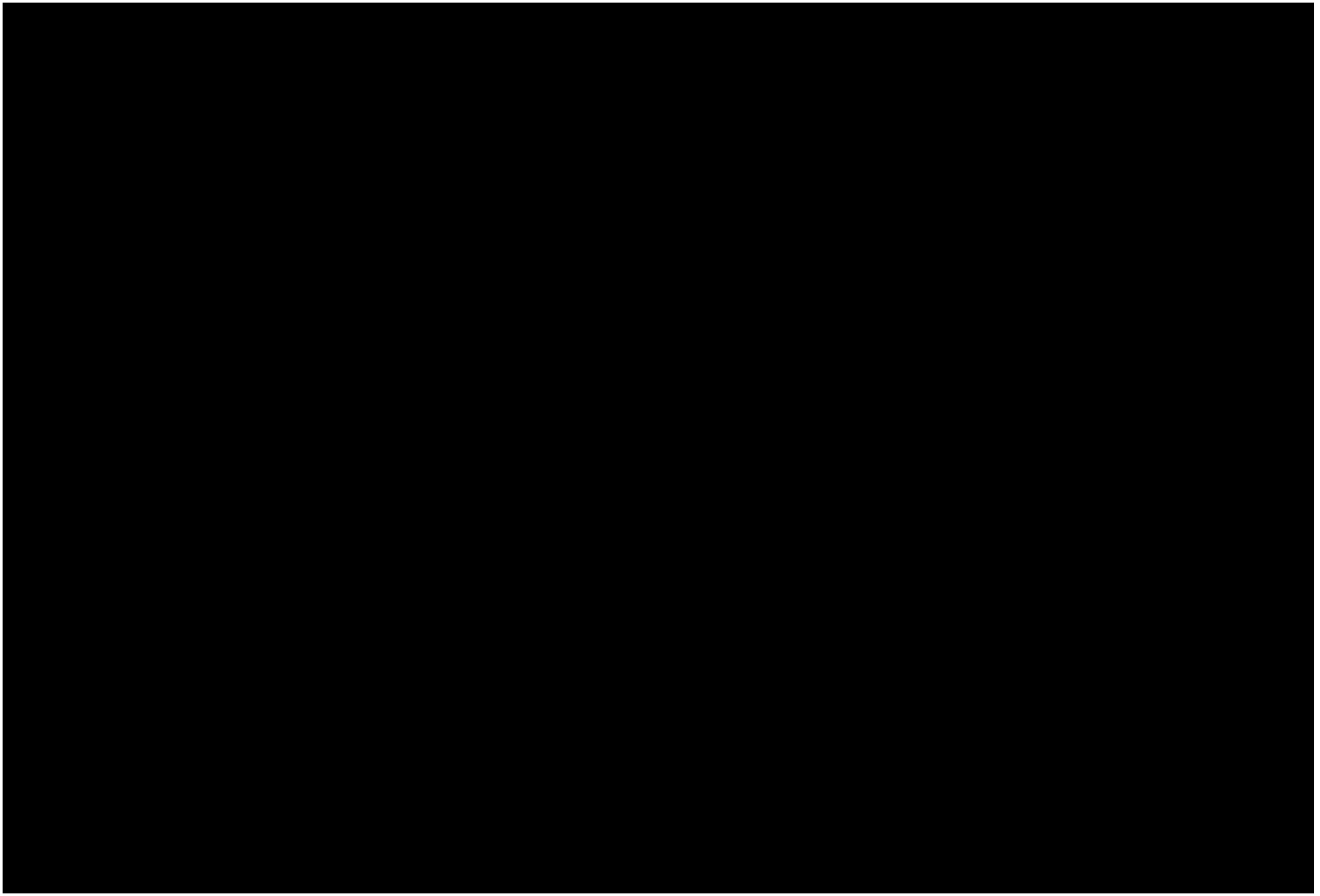
Date of On Peak Day - 11/09/2021



Member Forecasted On Peak Demand Day for December 2021

Midwest Electric Cooperative Corporation

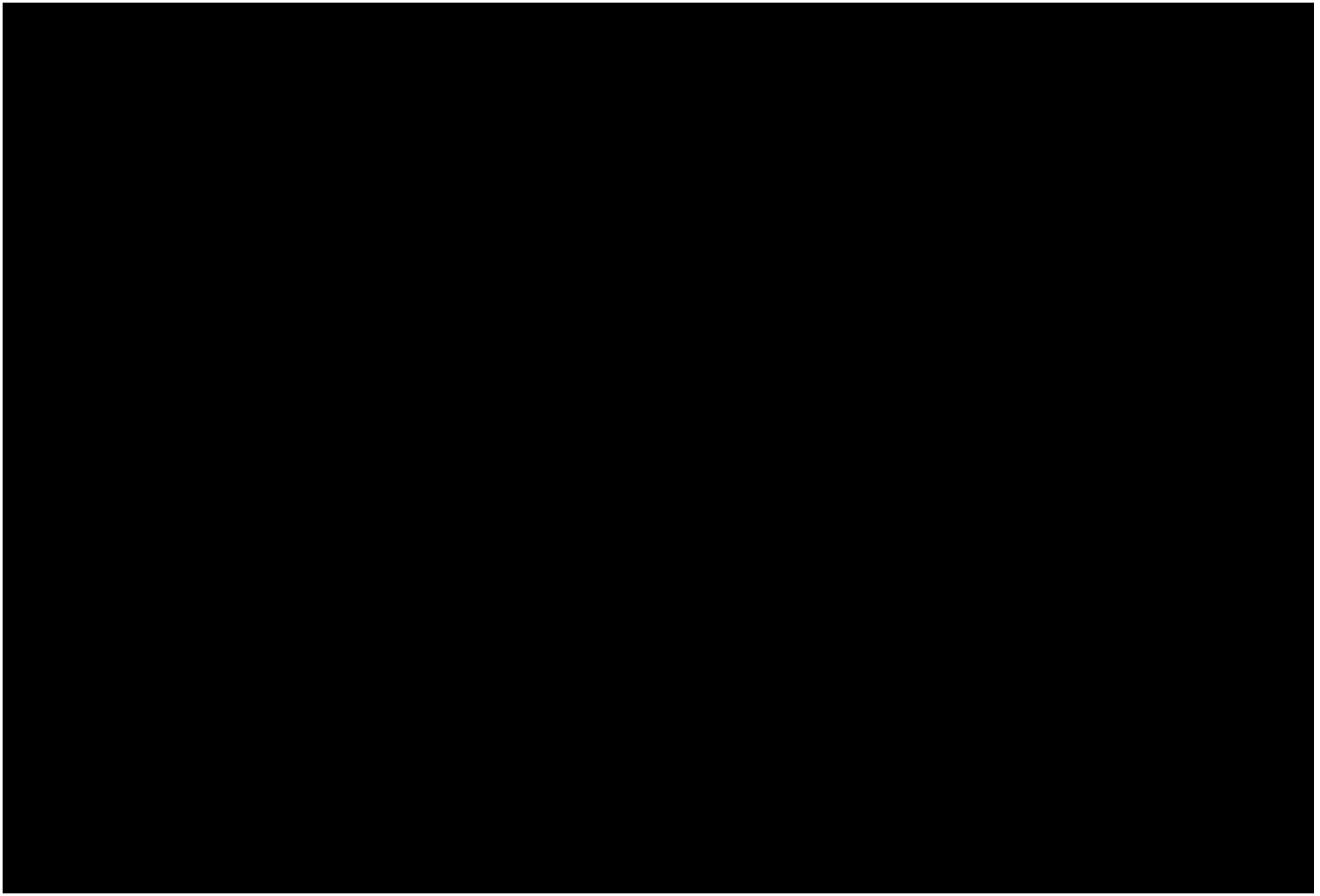
Date of On Peak Day - 12/30/2021



Member Forecasted On Peak Demand Day for January 2021

Niobrara Electric Association, Inc.

Date of On Peak Day - 01/29/2021



Member Forecasted On Peak Demand Day for February 2021

Niobrara Electric Association, Inc.

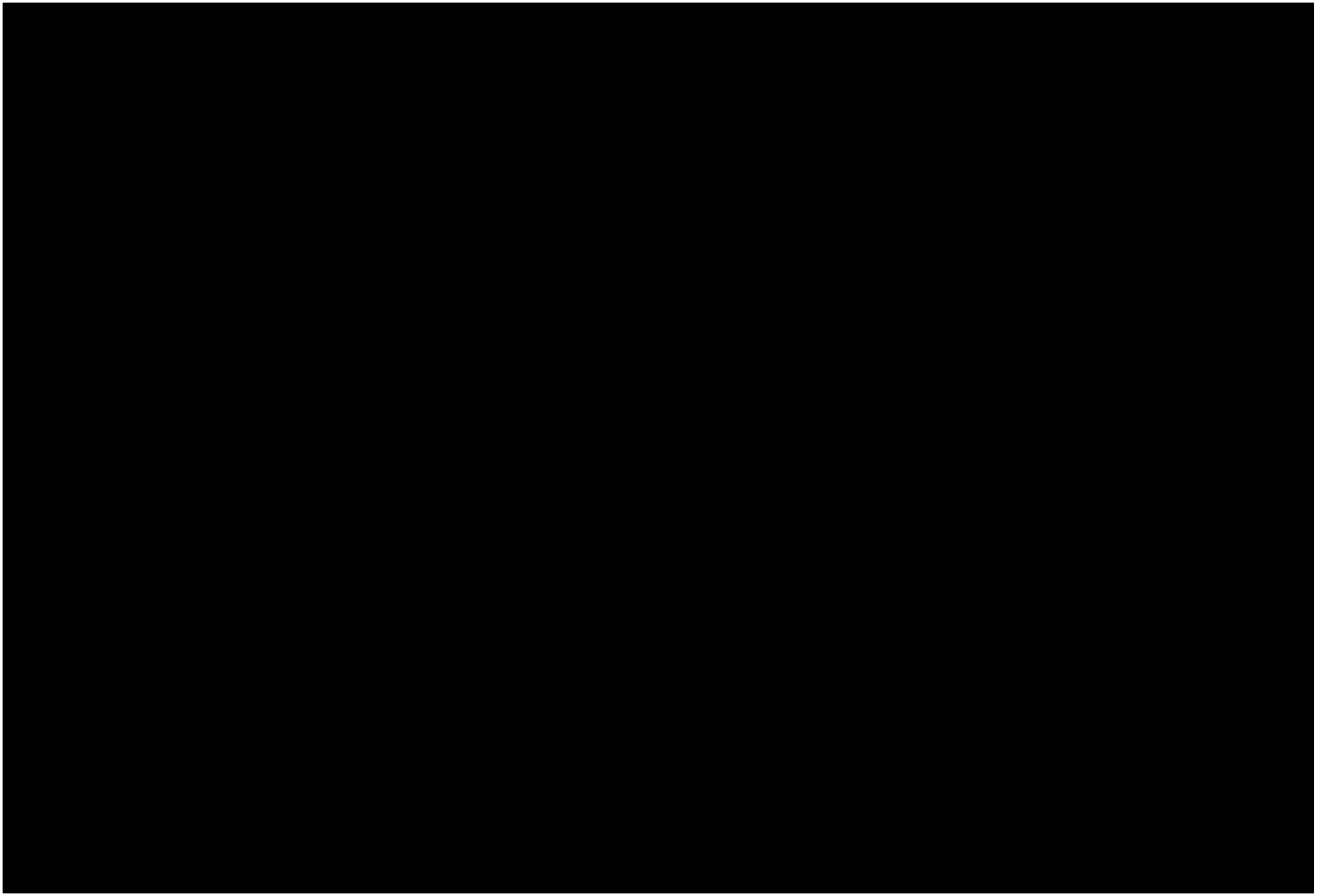
Date of On Peak Day - 02/15/2021

[redacted]

Member Forecasted On Peak Demand Day for March 2021

Niobrara Electric Association, Inc.

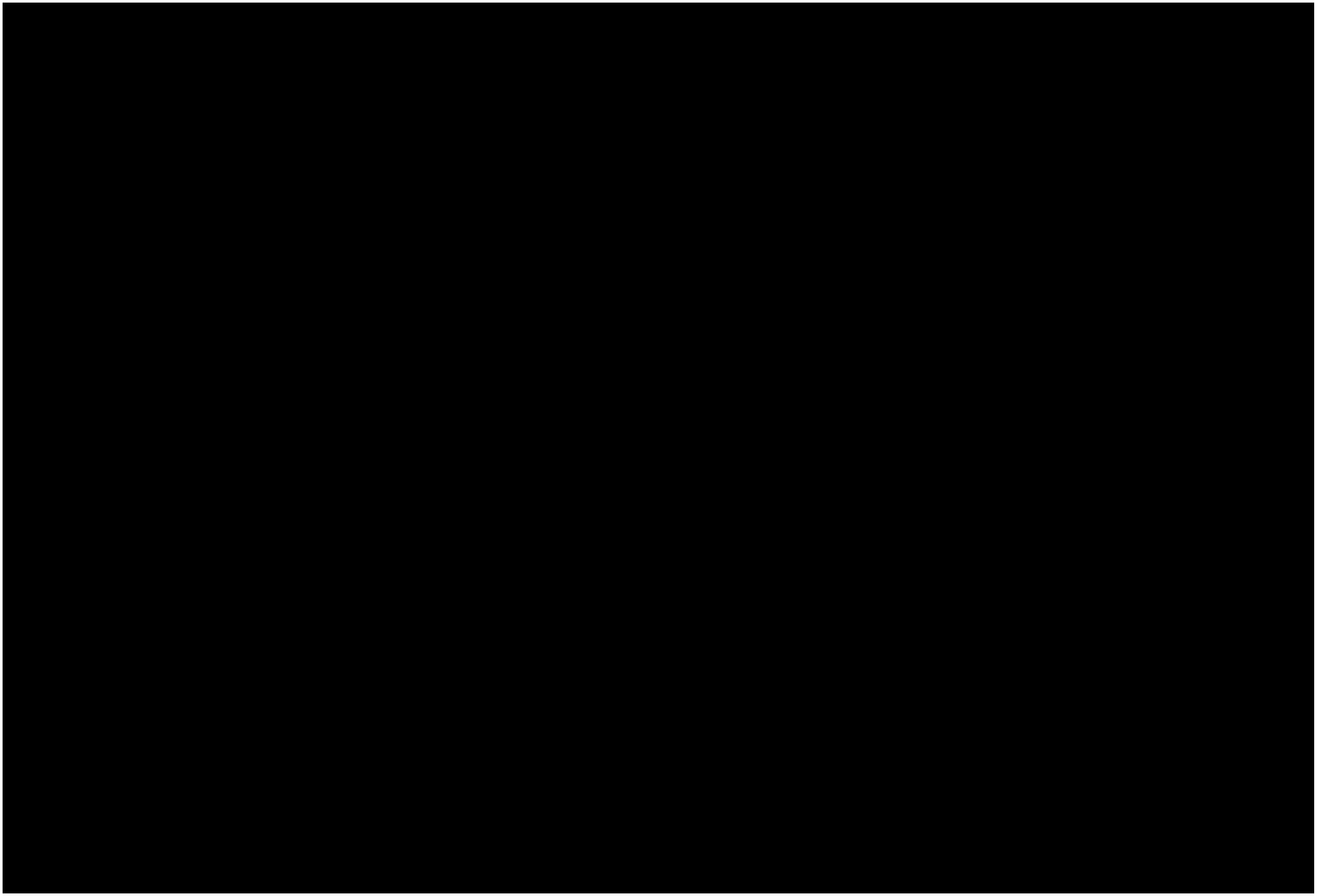
Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

Niobrara Electric Association, Inc.

Date of On Peak Day - 04/04/2021



Member Forecasted On Peak Demand Day for May 2021

Niobrara Electric Association, Inc.

Date of On Peak Day - 05/31/2021

[redacted]

Member Forecasted On Peak Demand Day for June 2021

Niobrara Electric Association, Inc.

Date of On Peak Day - 06/05/2021

[redacted]

Member Forecasted On Peak Demand Day for July 2021

Niobrara Electric Association, Inc.

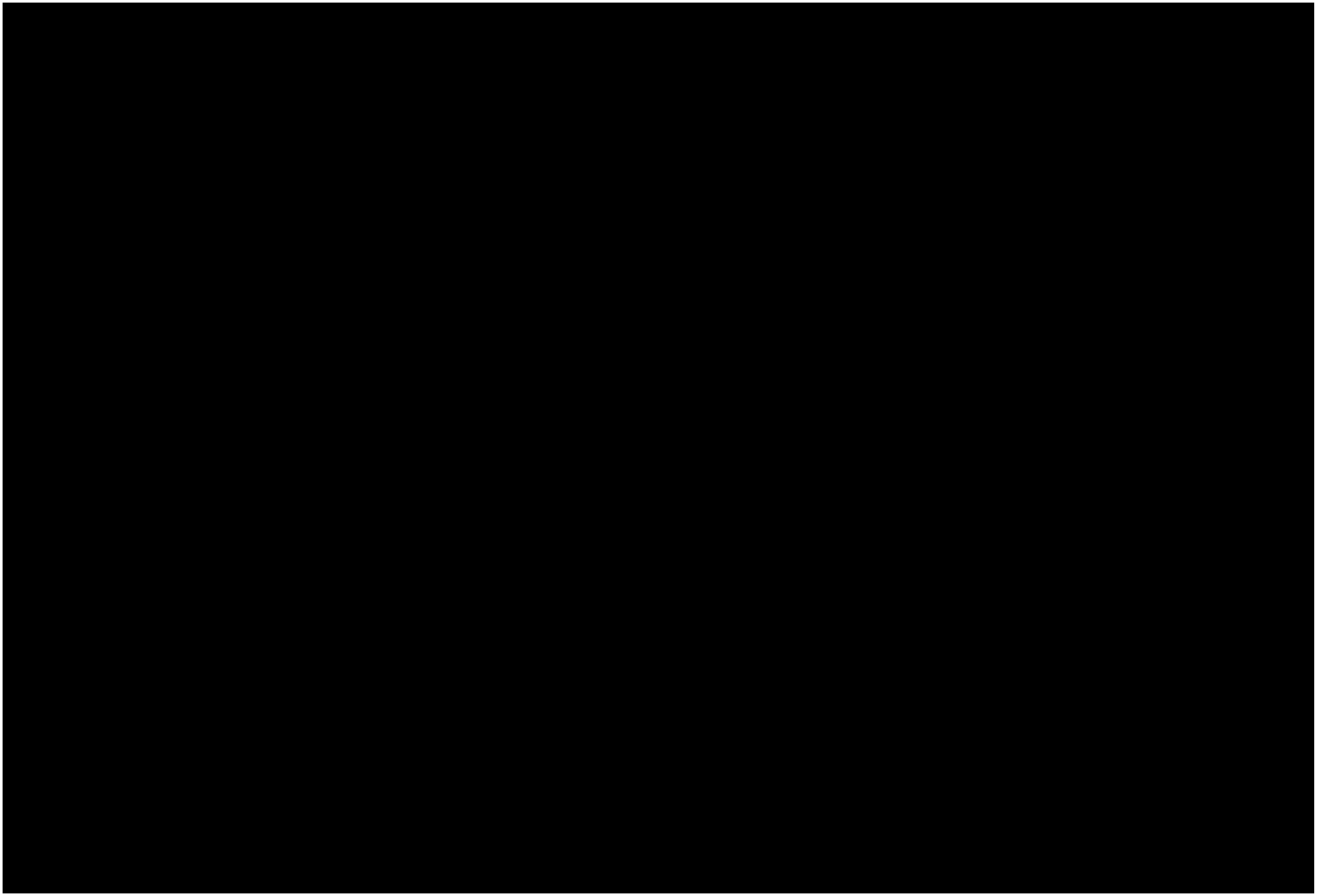
Date of On Peak Day - 07/10/2021

[redacted]

Member Forecasted On Peak Demand Day for August 2021

Niobrara Electric Association, Inc.

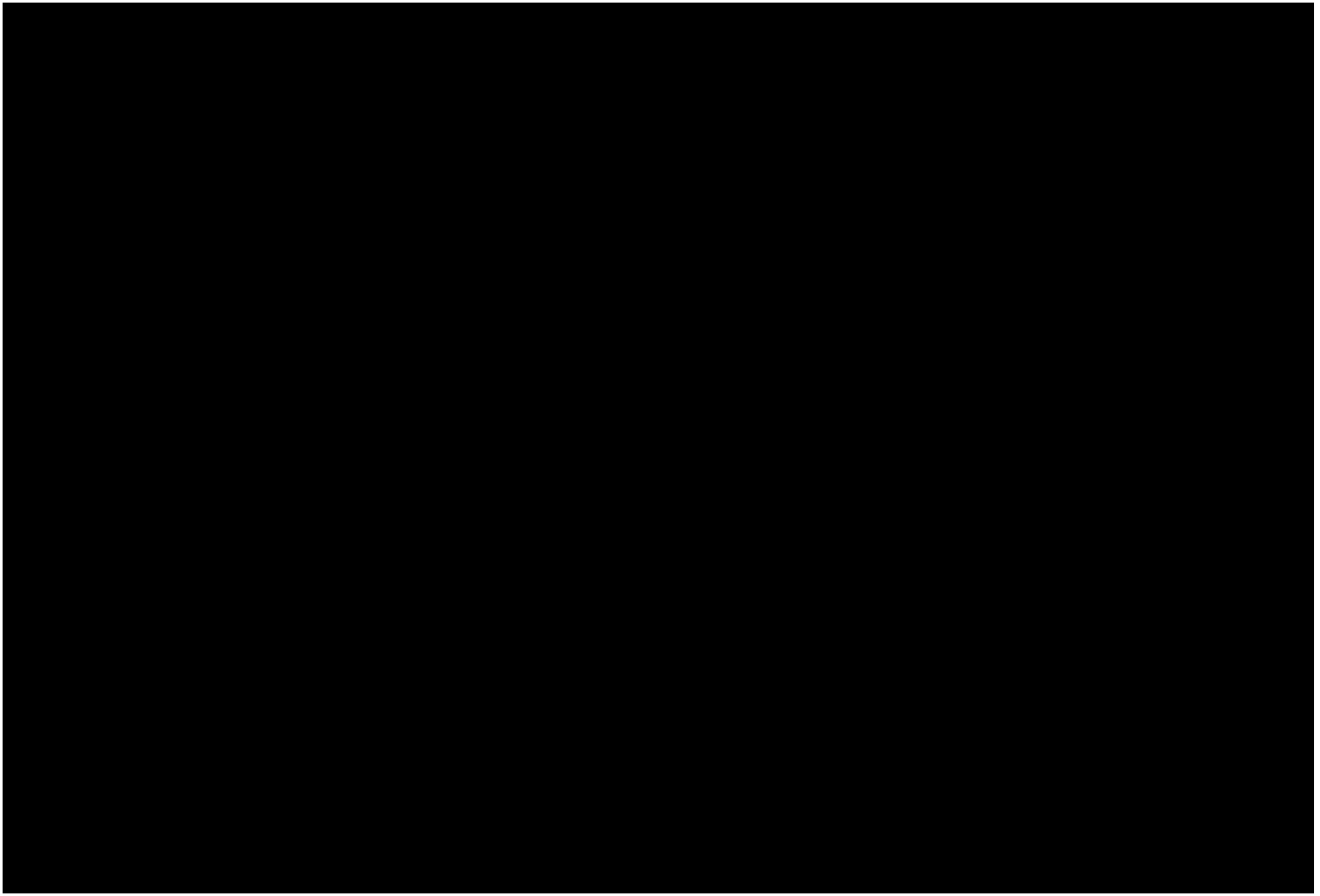
Date of On Peak Day - 08/02/2021



Member Forecasted On Peak Demand Day for September 2021

Niobrara Electric Association, Inc.

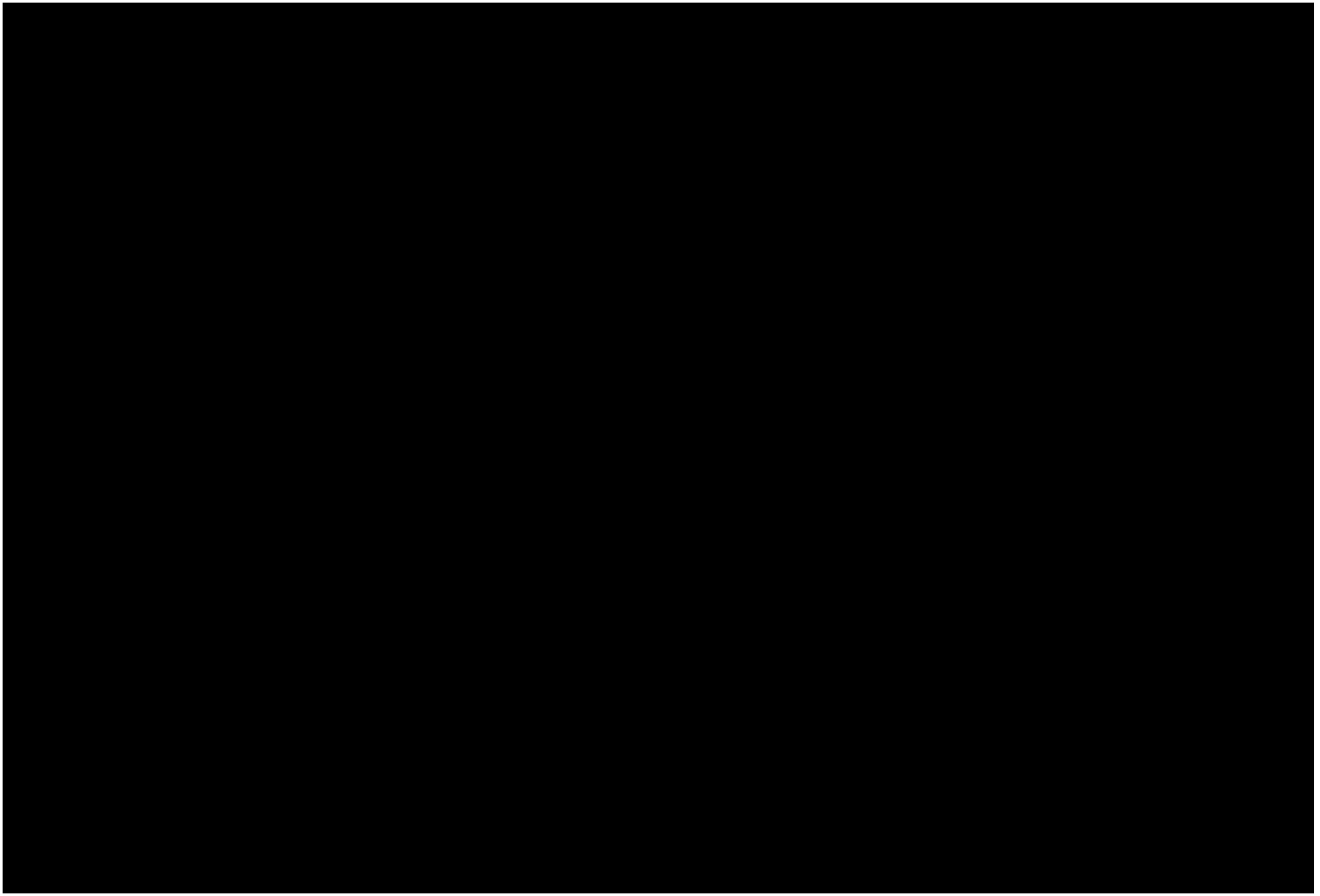
Date of On Peak Day - 09/07/2021



Member Forecasted On Peak Demand Day for October 2021

Niobrara Electric Association, Inc.

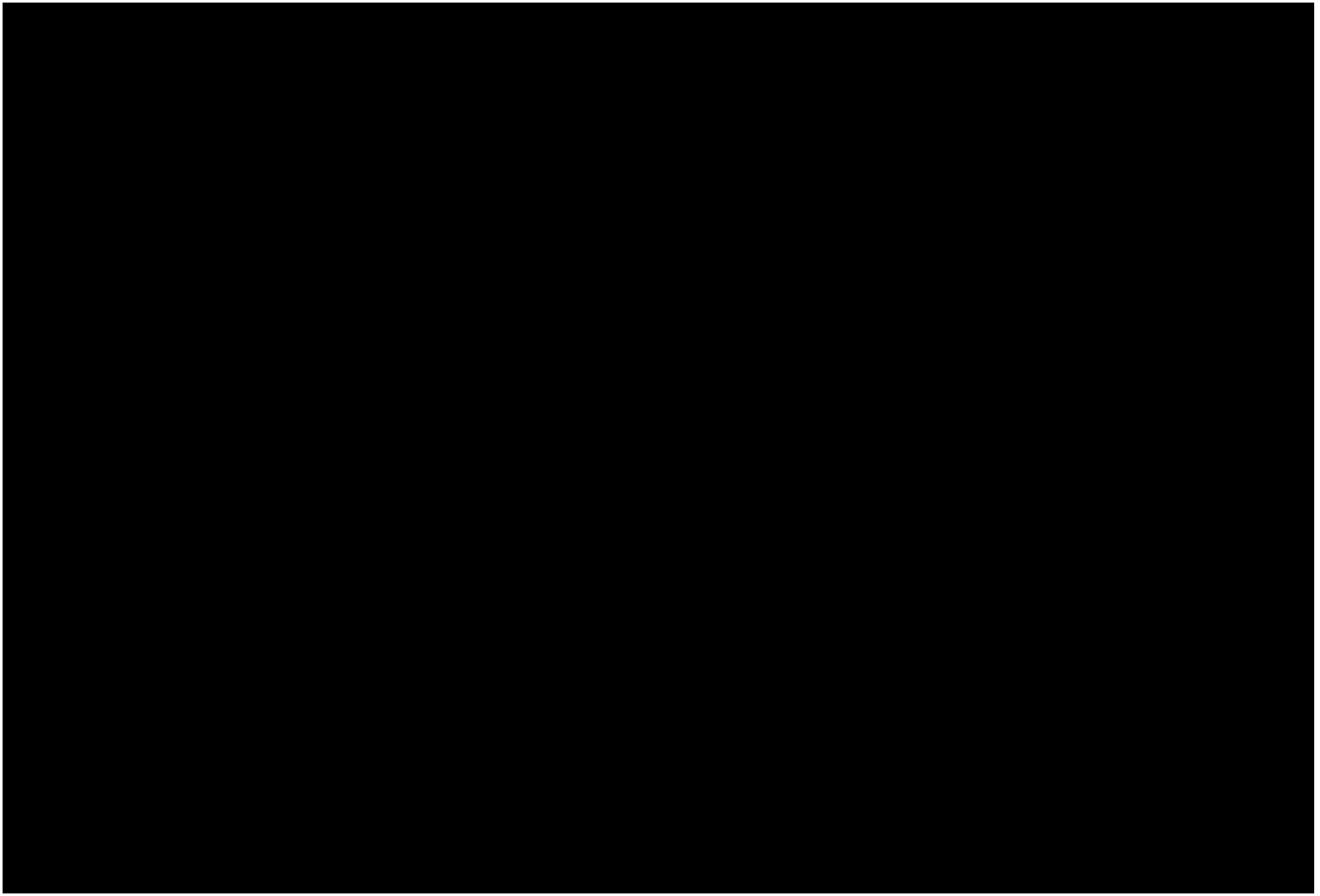
Date of On Peak Day - 10/03/2021



Member Forecasted On Peak Demand Day for November 2021

Niobrara Electric Association, Inc.

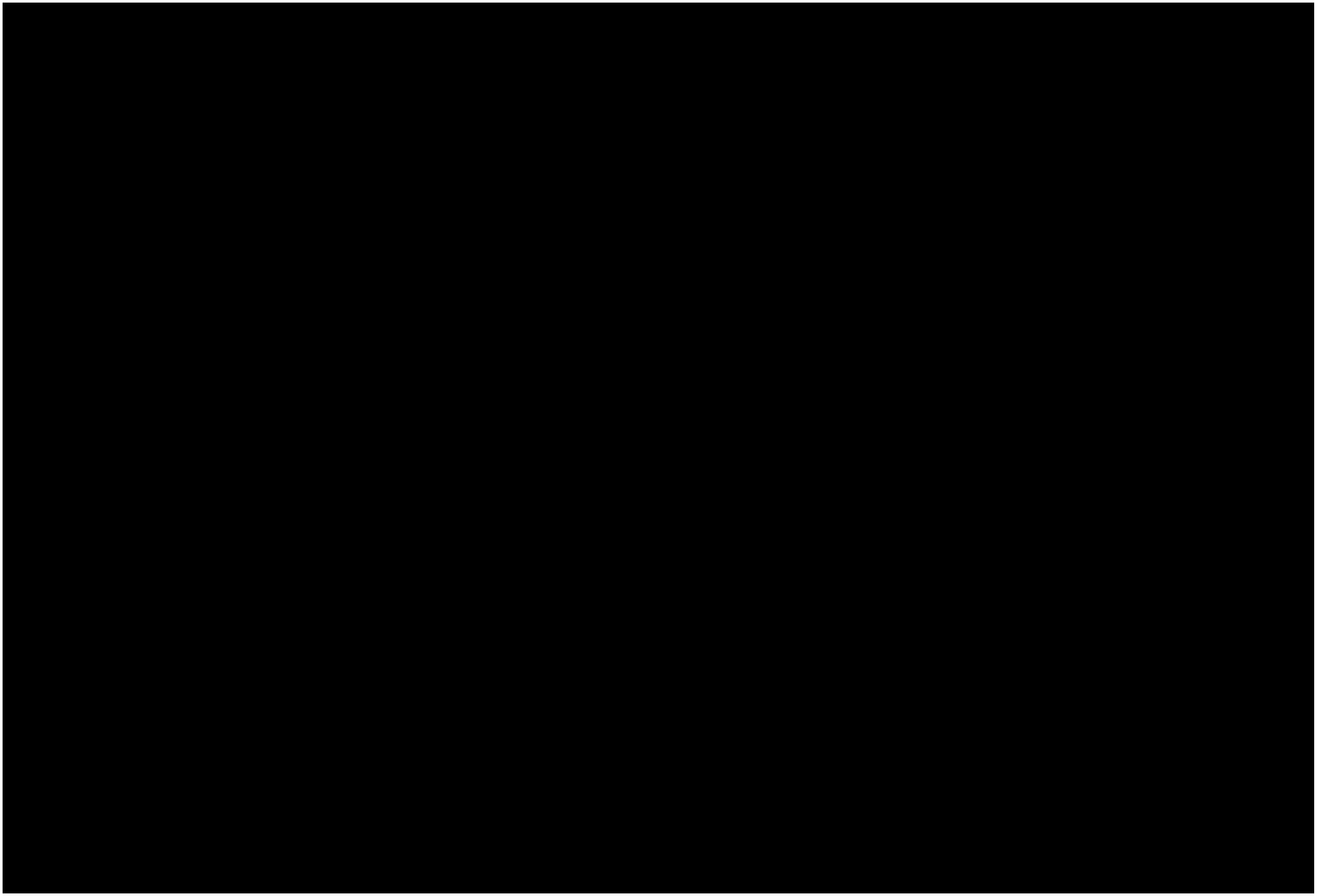
Date of On Peak Day - 11/21/2021



Member Forecasted On Peak Demand Day for December 2021

Niobrara Electric Association, Inc.

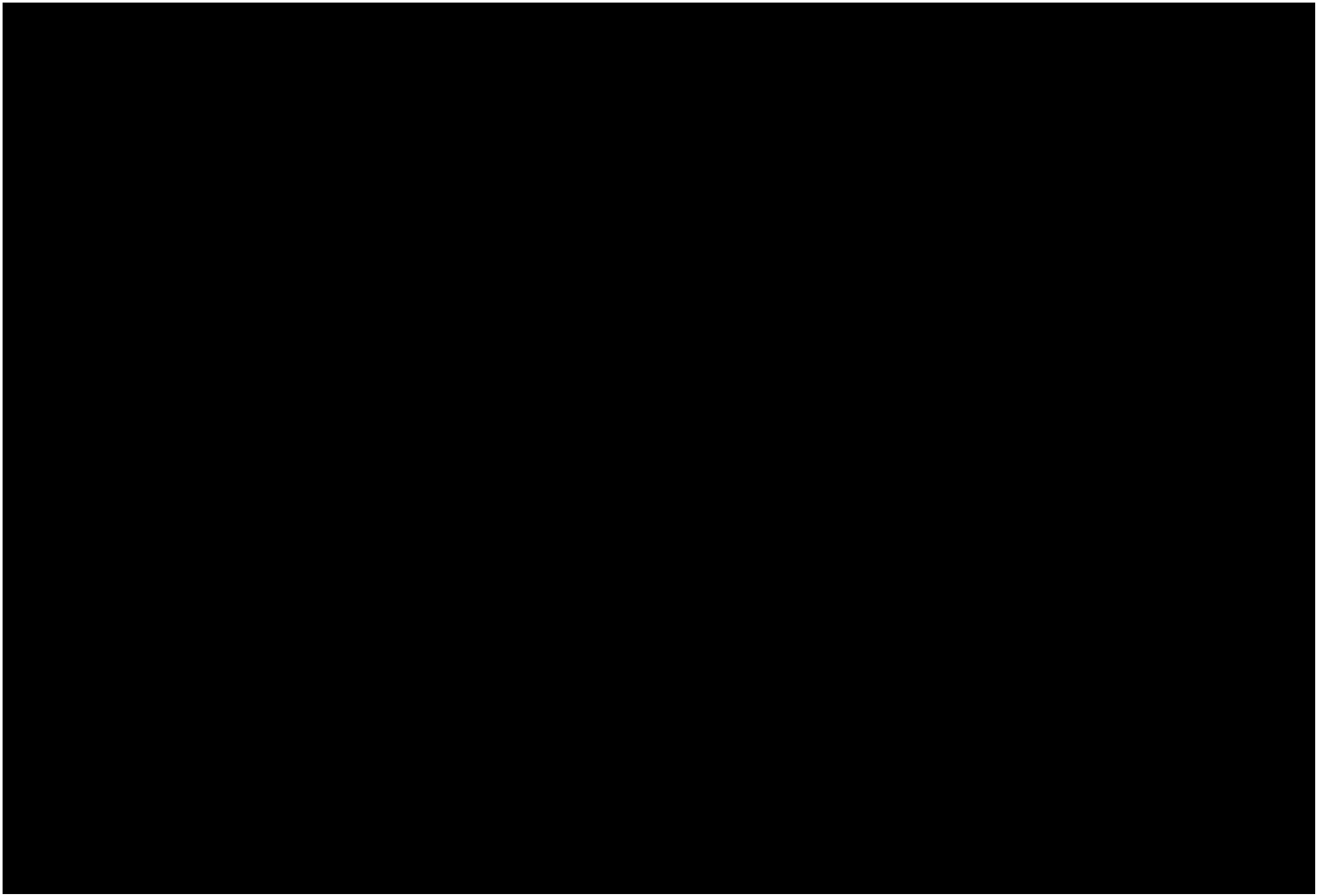
Date of On Peak Day - 12/28/2021



Member Forecasted On Peak Demand Day for January 2021

Northwest Rural Public Power District

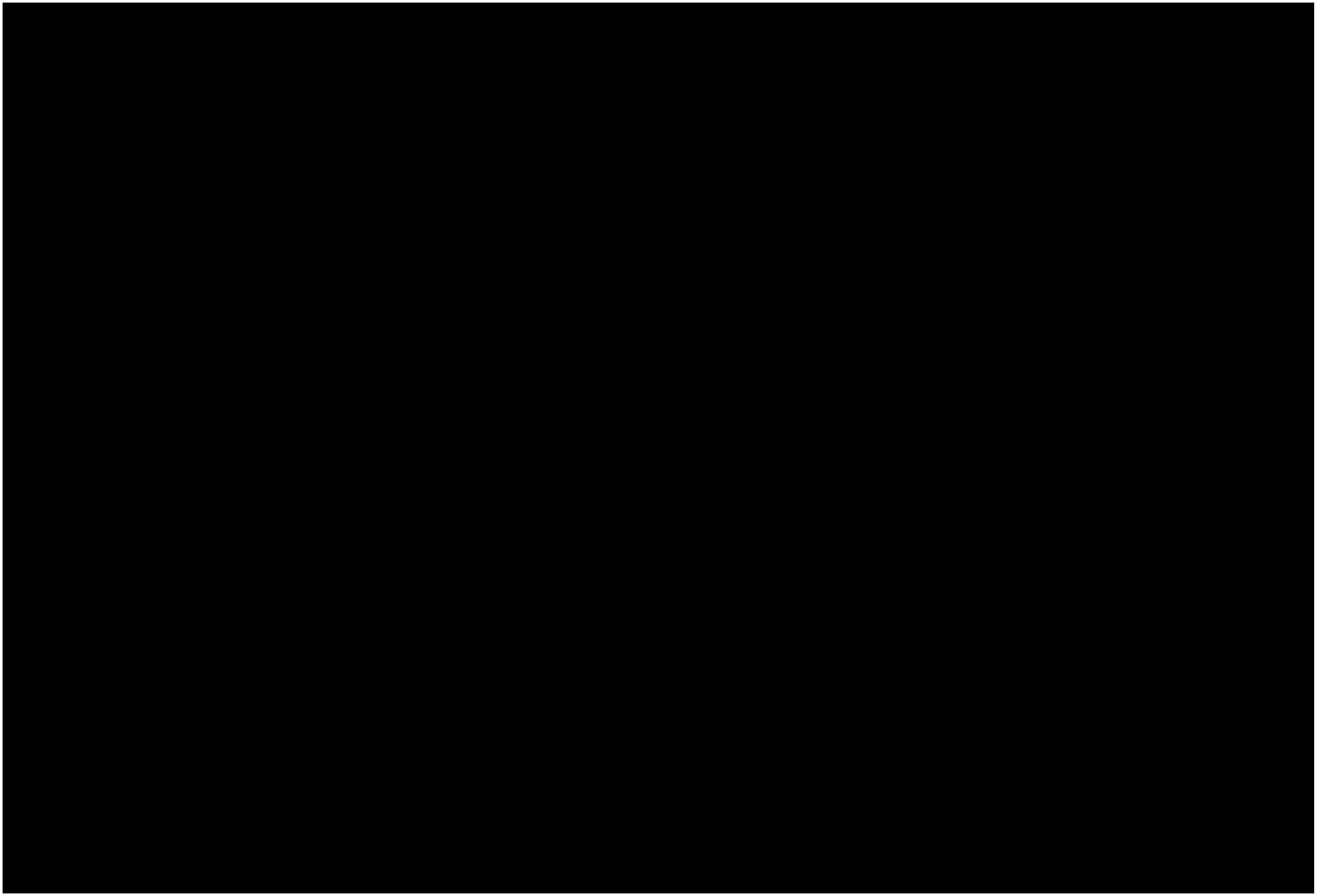
Date of On Peak Day - 01/07/2021



Member Forecasted On Peak Demand Day for February 2021

Northwest Rural Public Power District

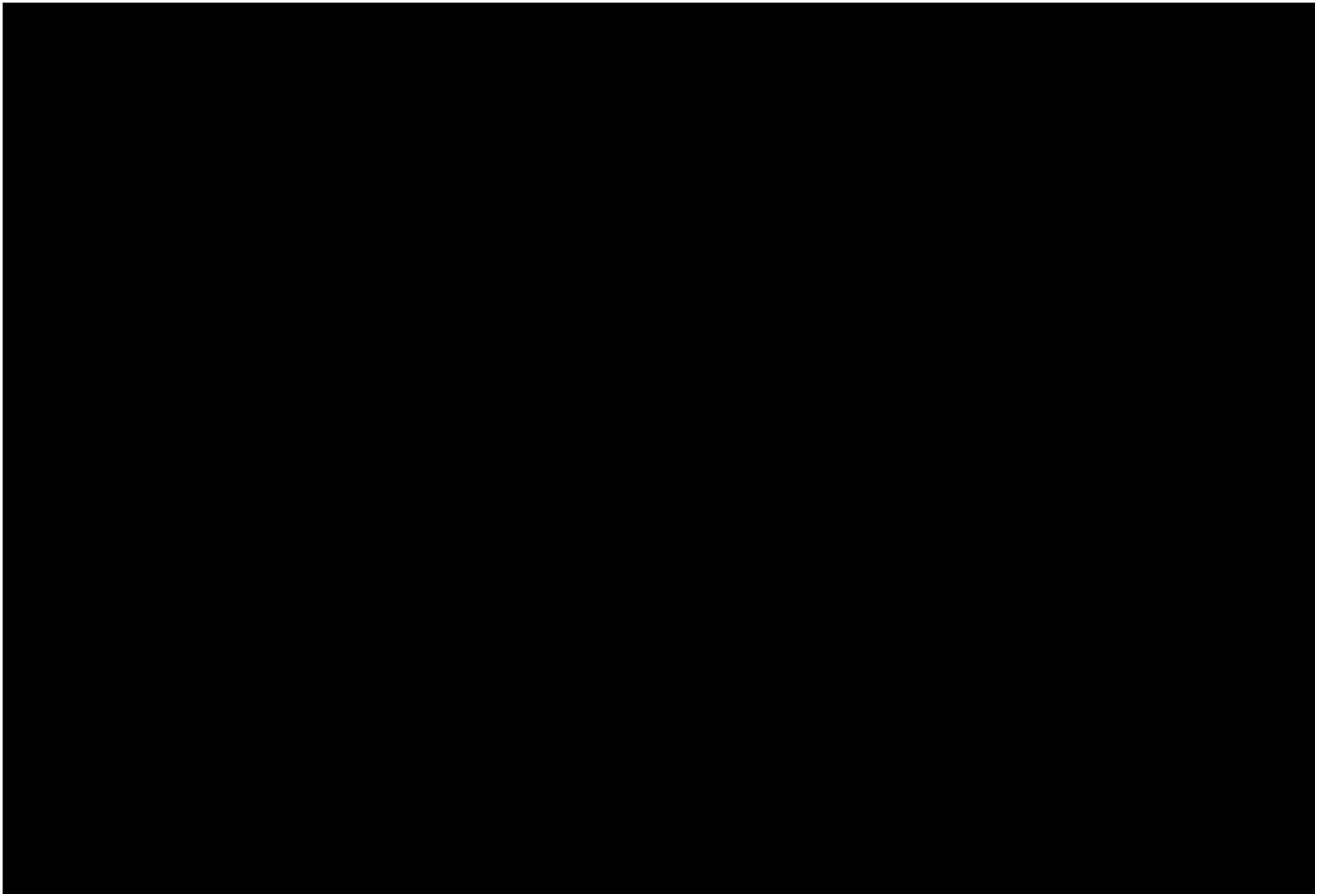
Date of On Peak Day - 02/03/2021



Member Forecasted On Peak Demand Day for March 2021

Northwest Rural Public Power District

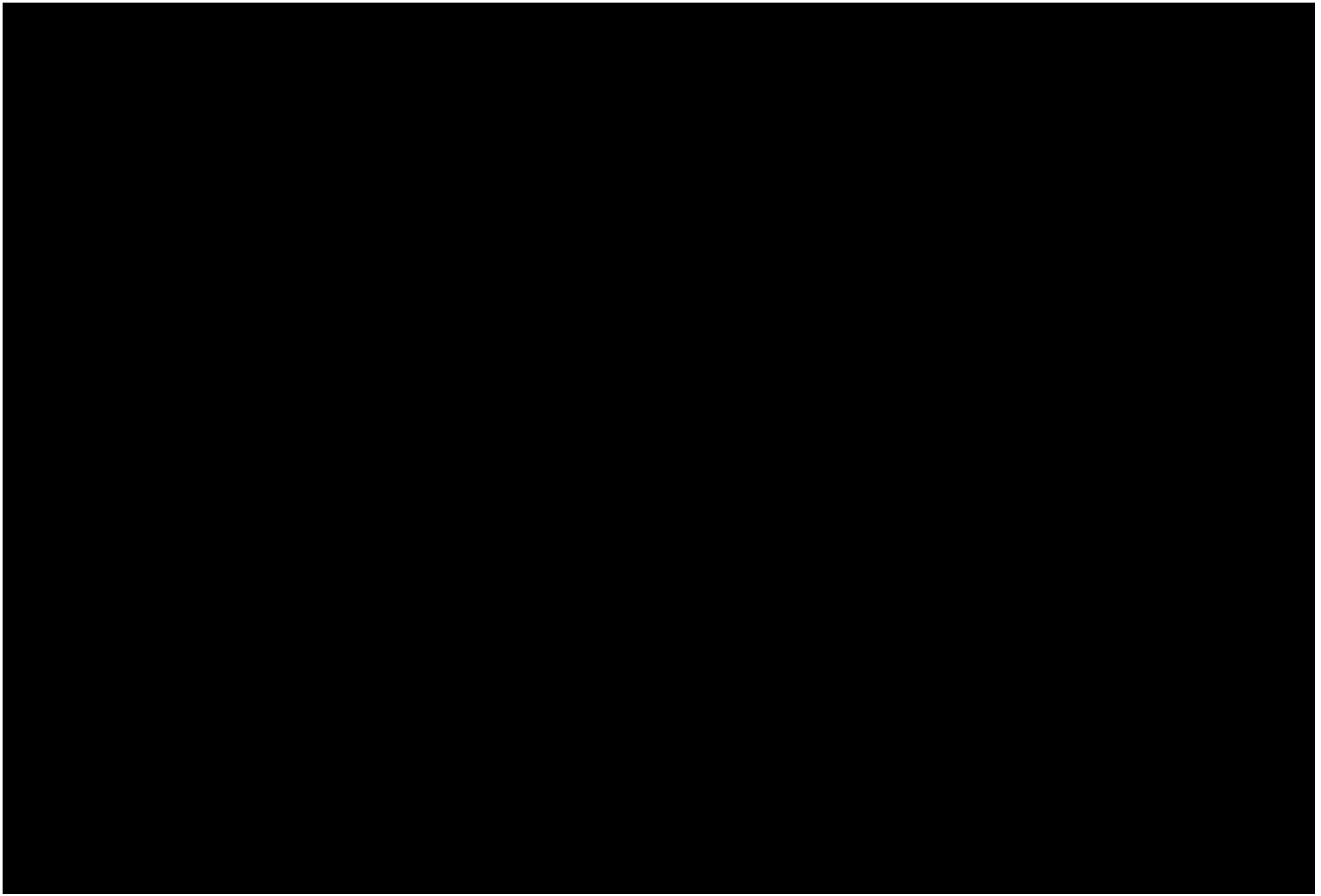
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Northwest Rural Public Power District

Date of On Peak Day - 04/13/2021



Member Forecasted On Peak Demand Day for May 2021

Northwest Rural Public Power District

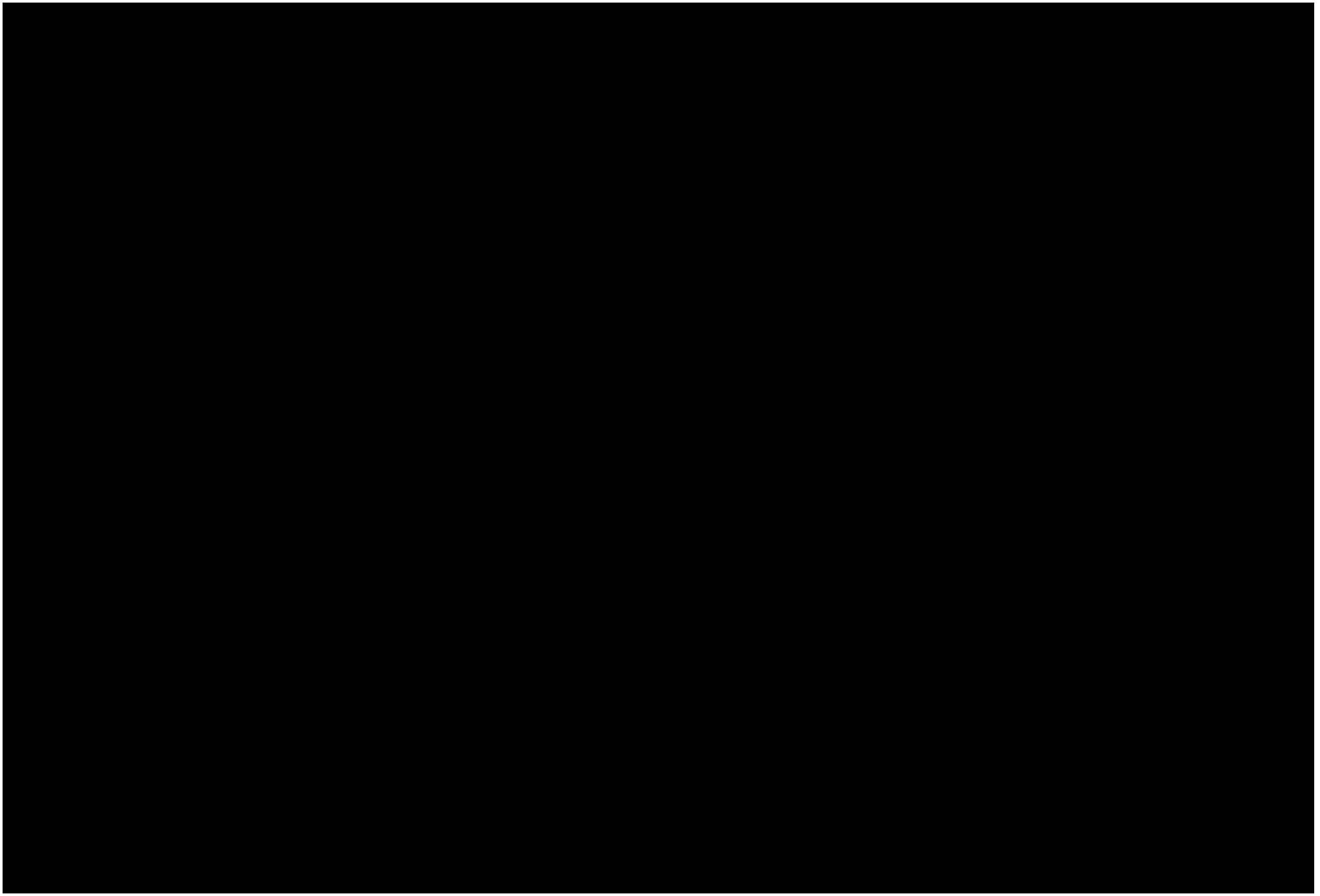
Date of On Peak Day - 05/09/2021

[redacted]

Member Forecasted On Peak Demand Day for June 2021

Northwest Rural Public Power District

Date of On Peak Day - 06/28/2021



Member Forecasted On Peak Demand Day for July 2021

Northwest Rural Public Power District

Date of On Peak Day - 07/20/2021

[redacted]

Member Forecasted On Peak Demand Day for August 2021

Northwest Rural Public Power District

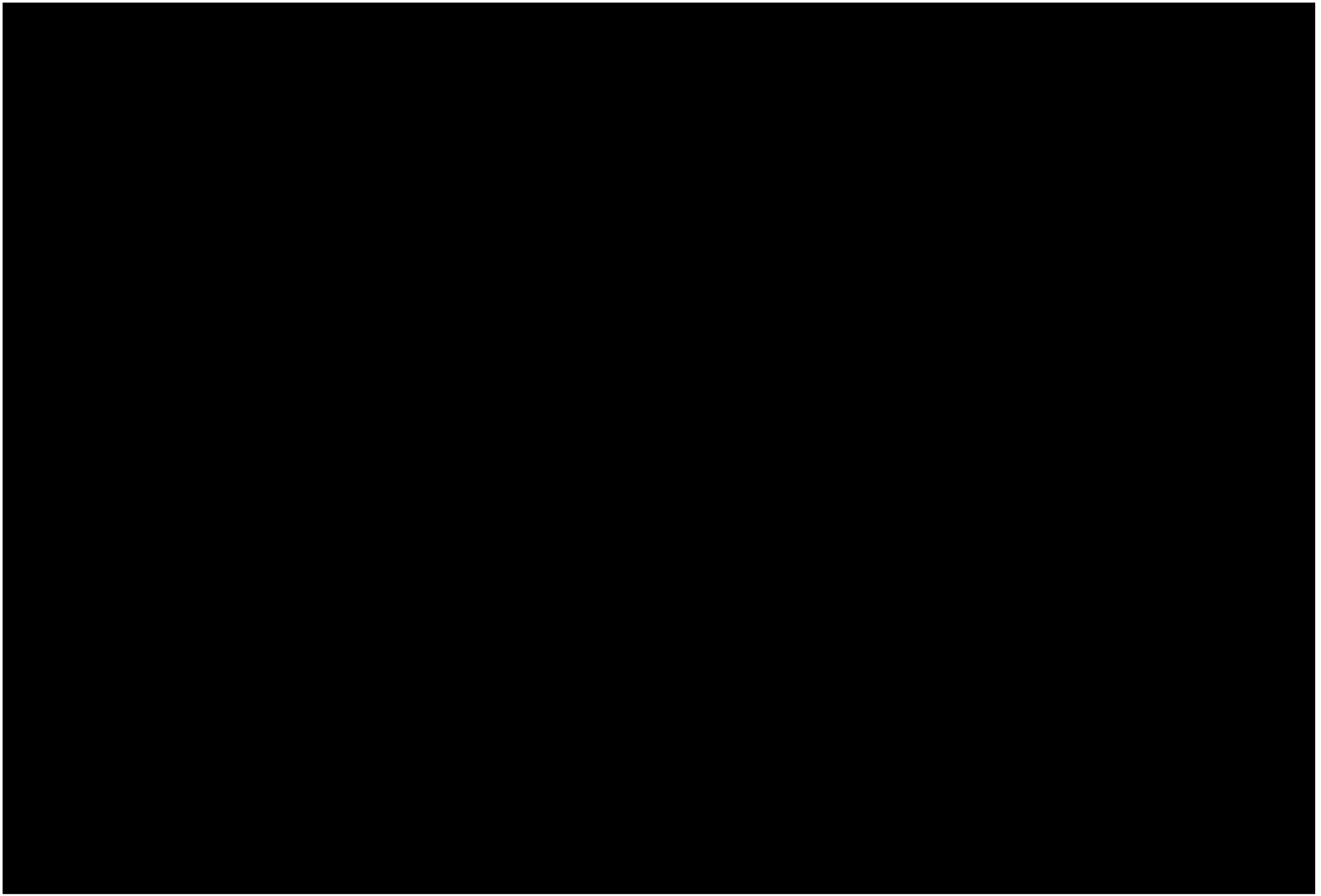
Date of On Peak Day - 08/23/2021

[redacted]

Member Forecasted On Peak Demand Day for September 2021

Northwest Rural Public Power District

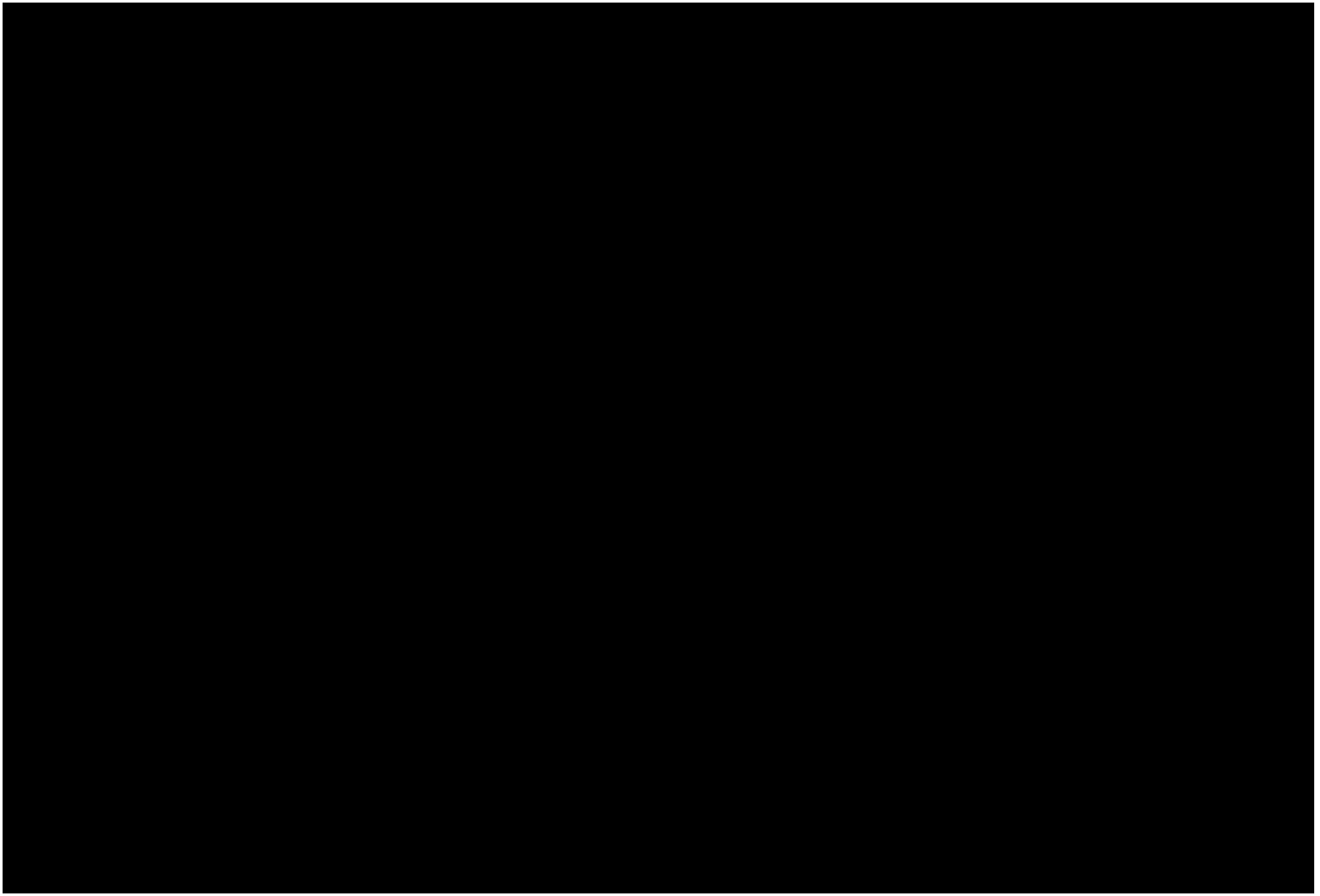
Date of On Peak Day - 09/02/2021



Member Forecasted On Peak Demand Day for October 2021

Northwest Rural Public Power District

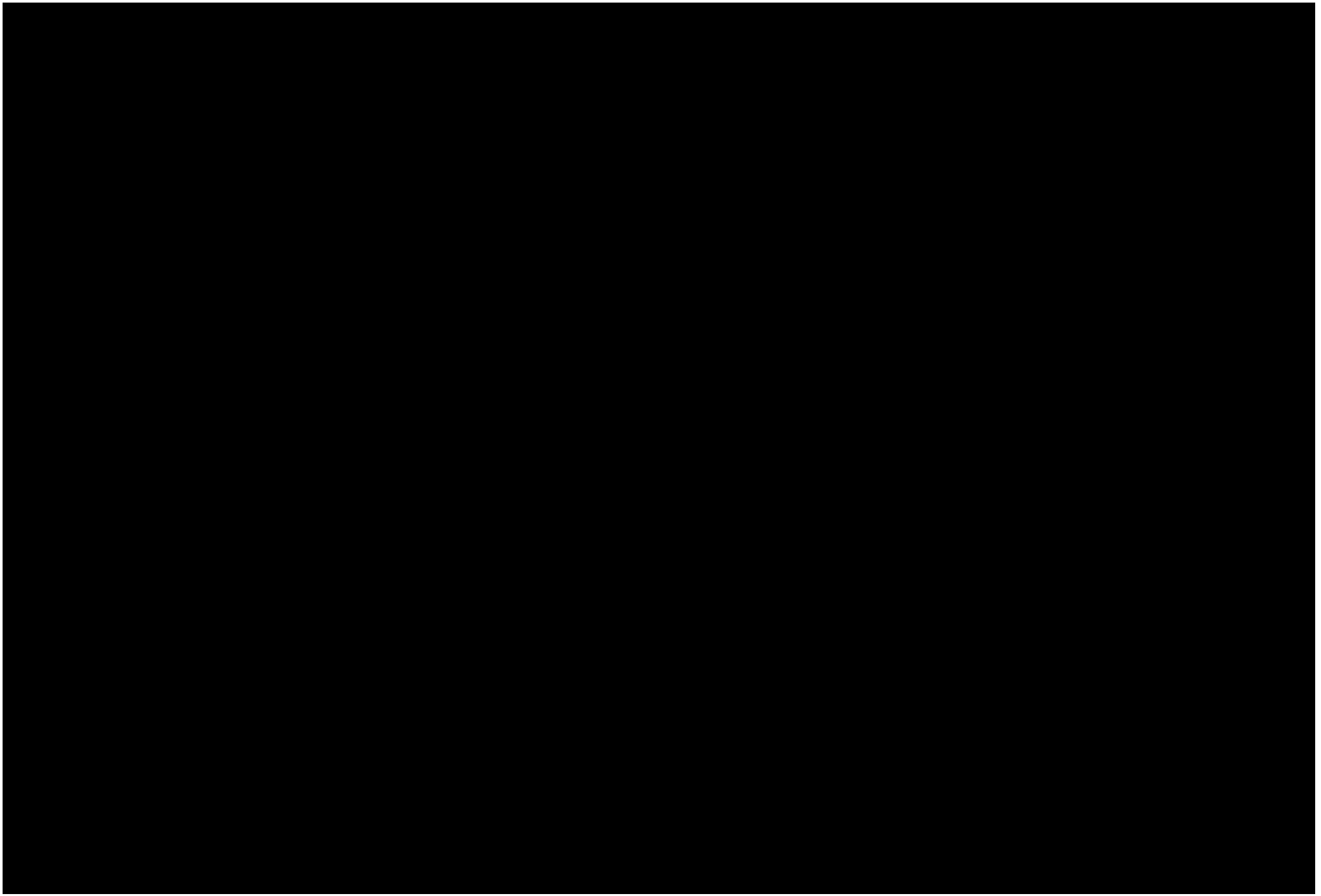
Date of On Peak Day - 10/10/2021



Member Forecasted On Peak Demand Day for November 2021

Northwest Rural Public Power District

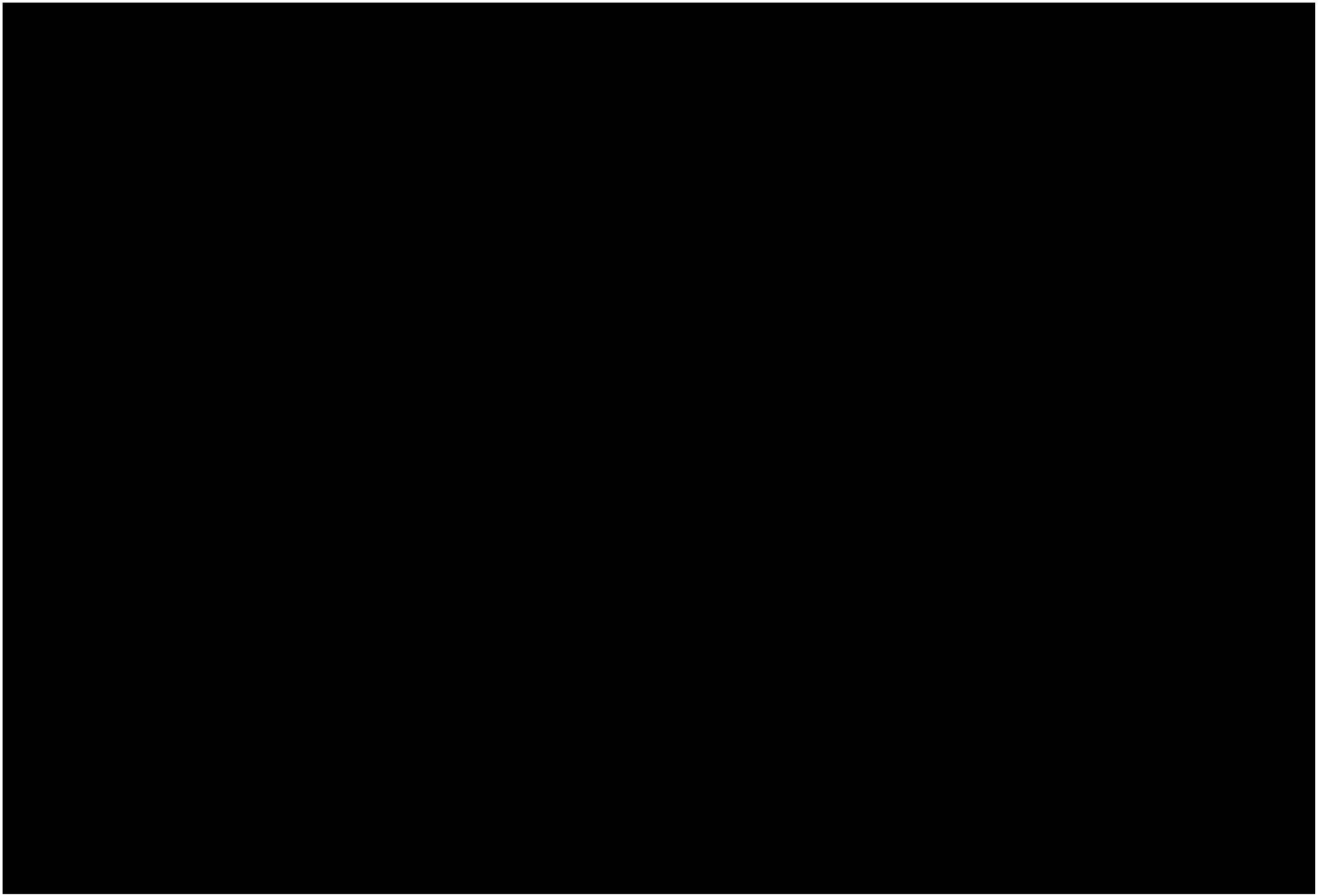
Date of On Peak Day - 11/27/2021



Member Forecasted On Peak Demand Day for December 2021

Northwest Rural Public Power District

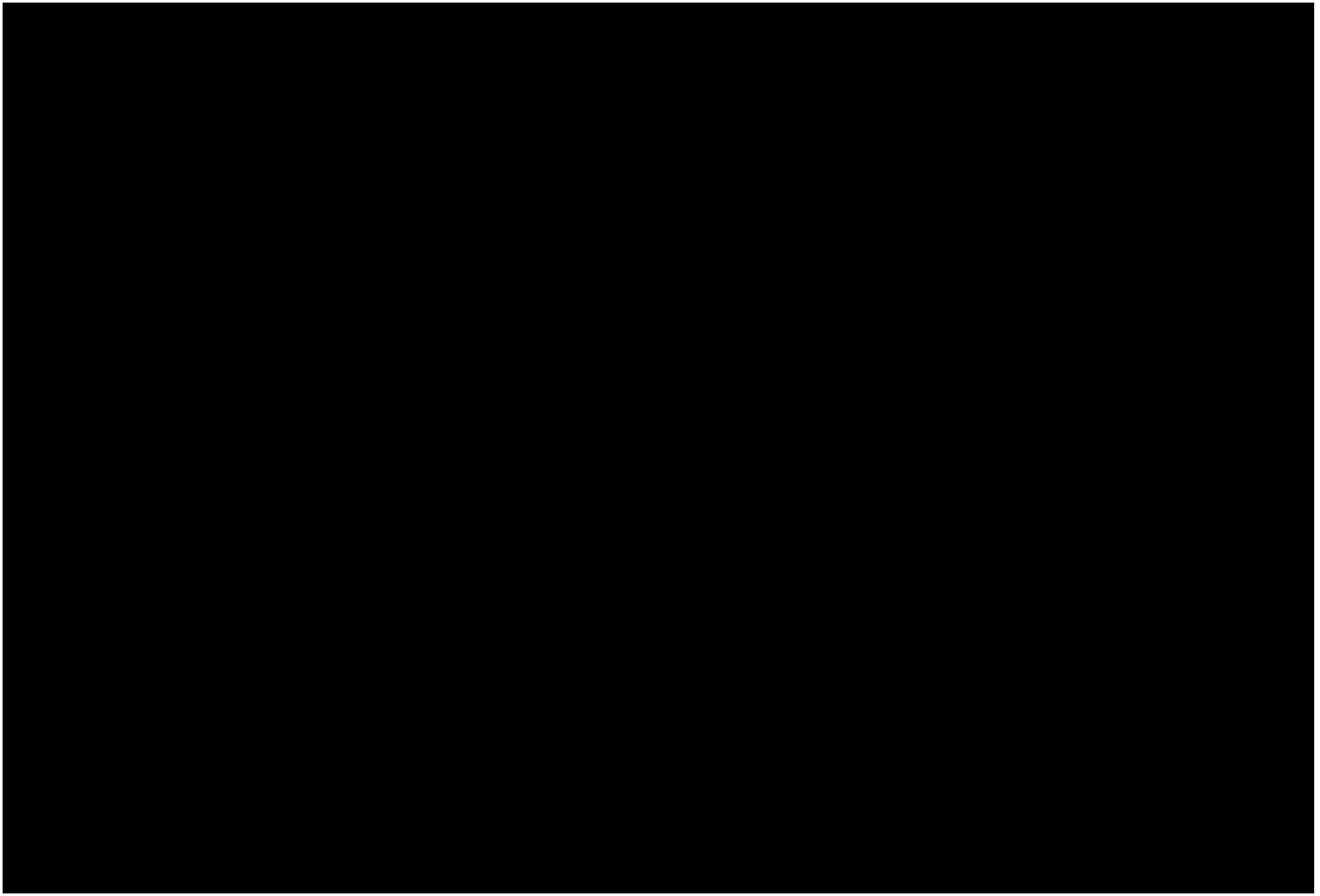
Date of On Peak Day - 12/29/2021



Member Forecasted On Peak Demand Day for January 2021

Otero County Electric Cooperative, Inc.

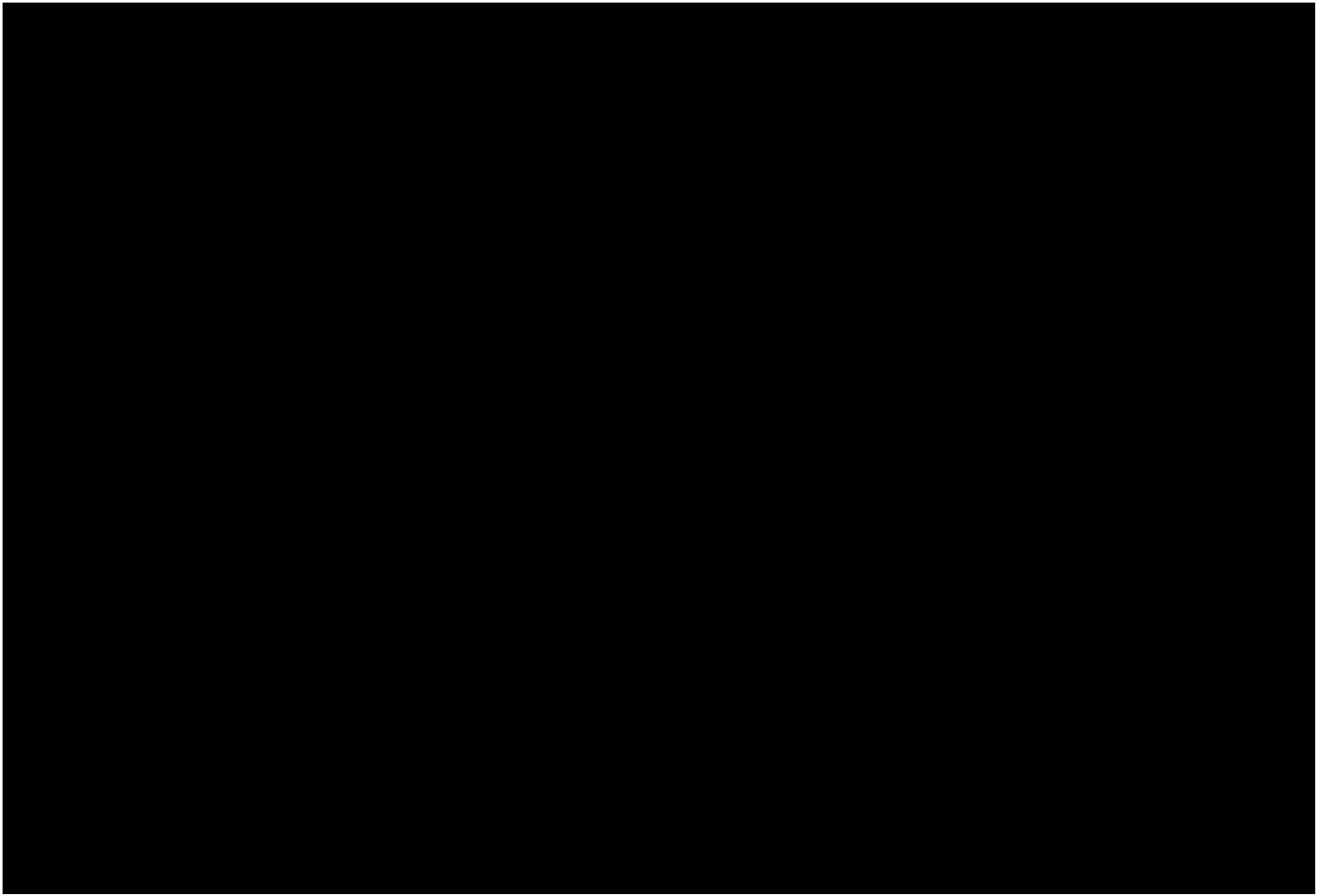
Date of On Peak Day - 01/02/2021



Member Forecasted On Peak Demand Day for February 2021

Otero County Electric Cooperative, Inc.

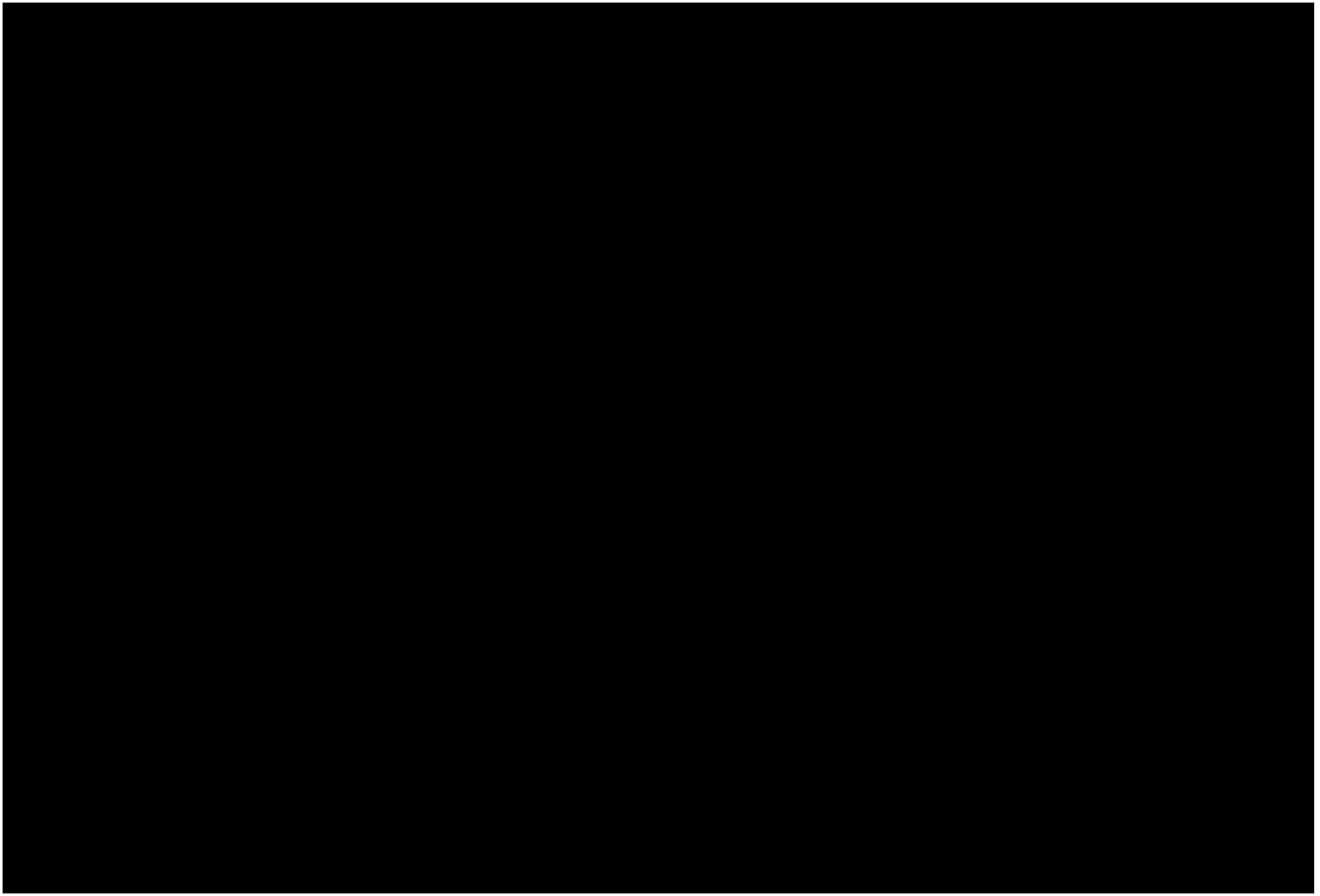
Date of On Peak Day - 02/14/2021



Member Forecasted On Peak Demand Day for March 2021

Otero County Electric Cooperative, Inc.

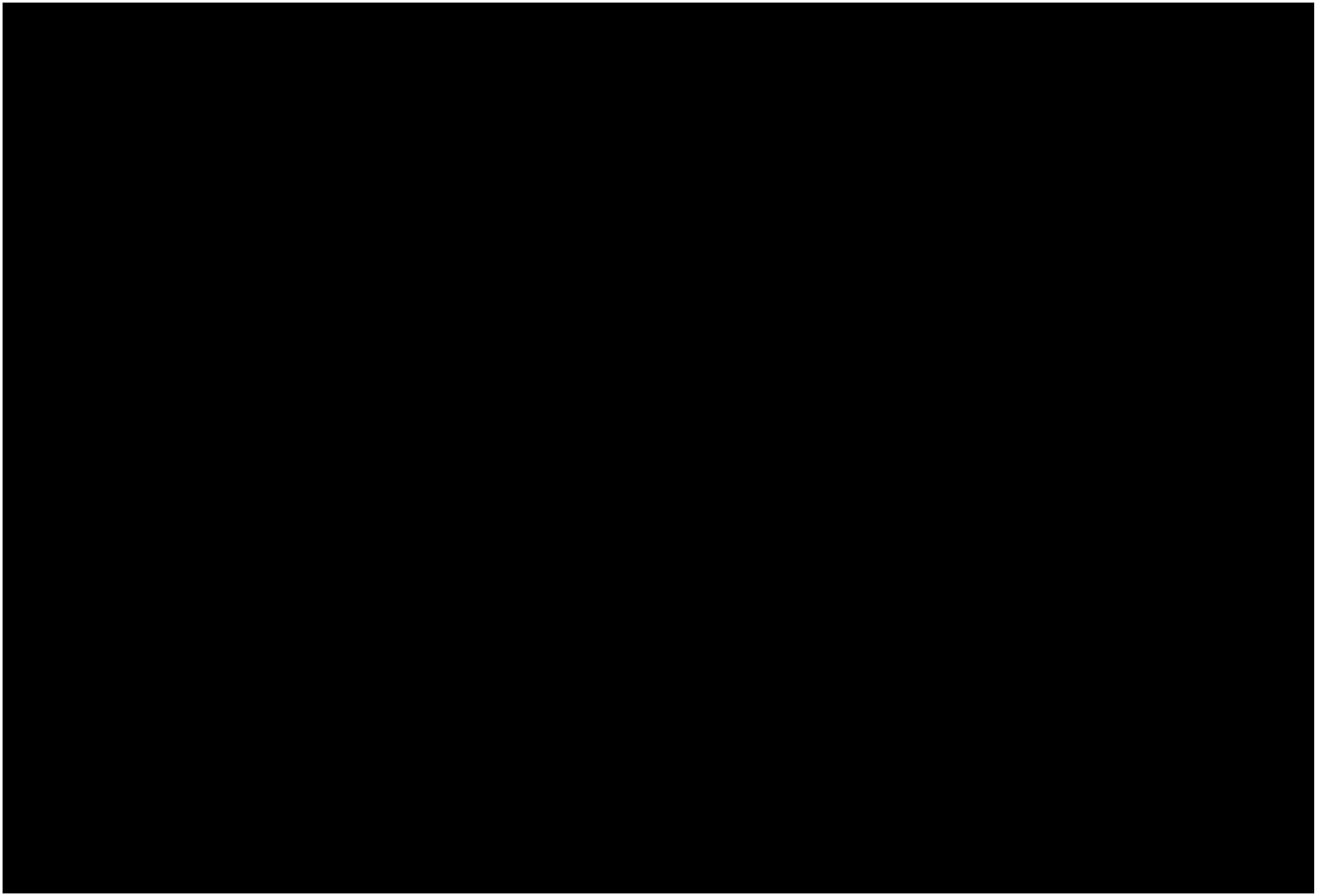
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Otero County Electric Cooperative, Inc.

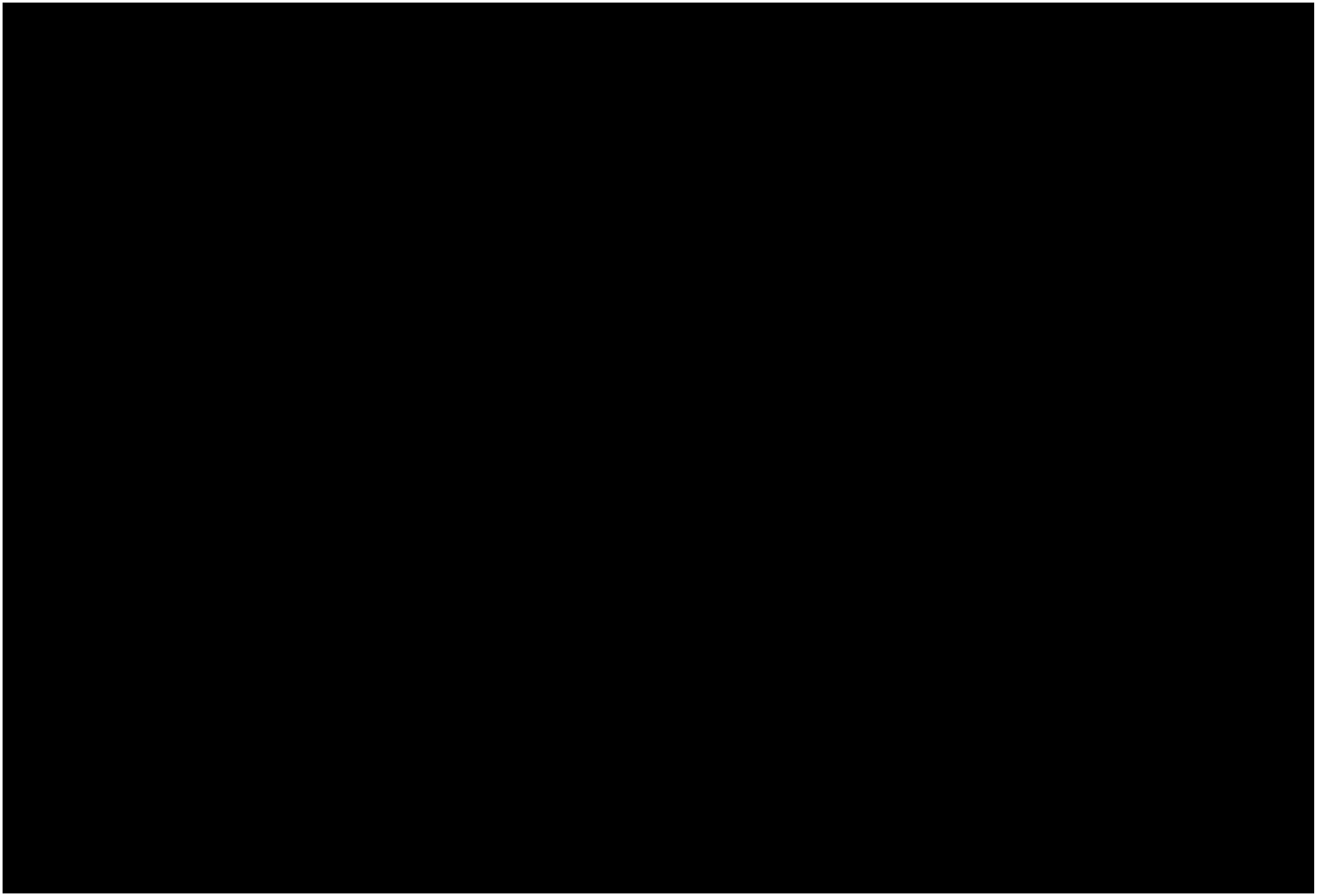
Date of On Peak Day - 04/27/2021



Member Forecasted On Peak Demand Day for May 2021

Otero County Electric Cooperative, Inc.

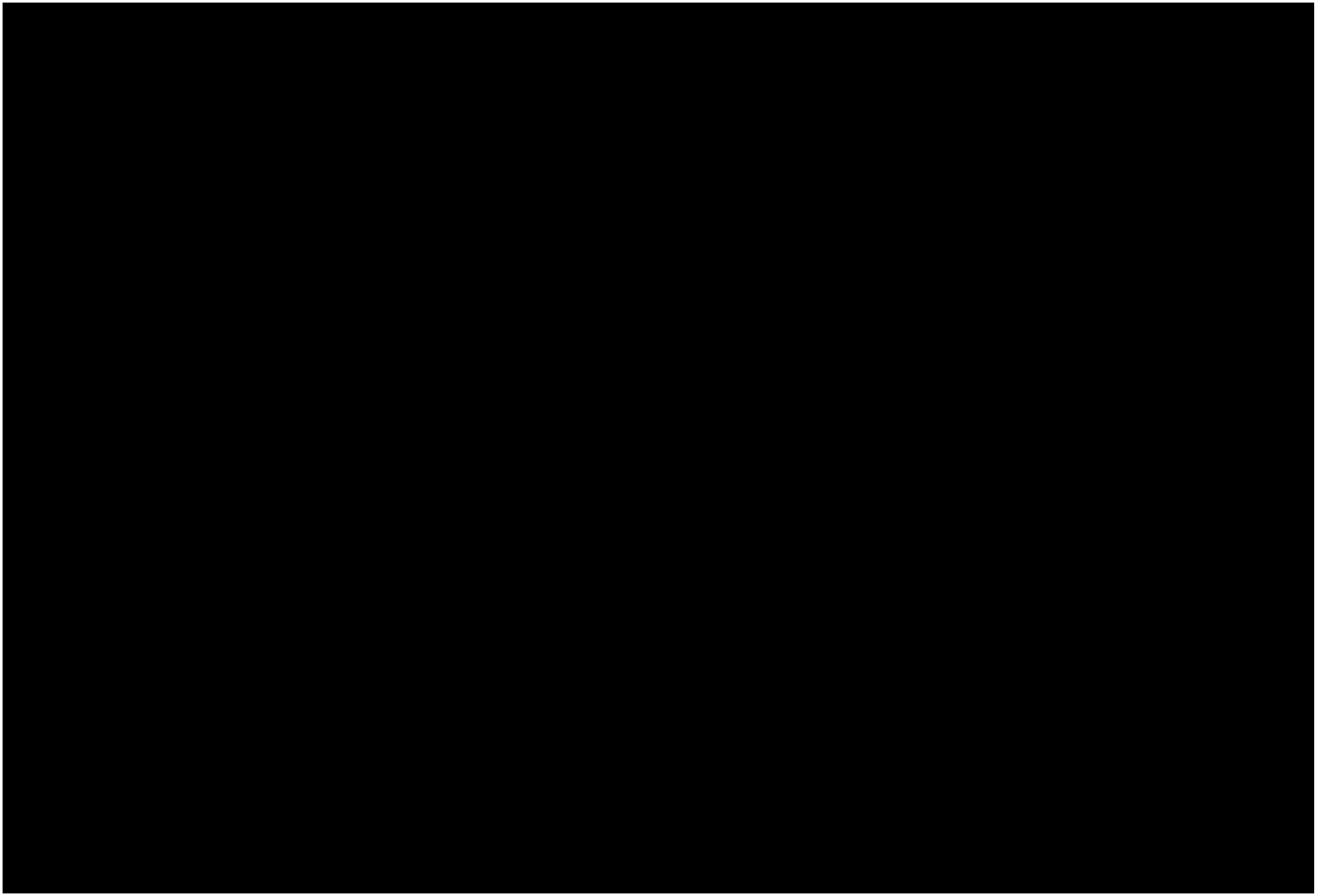
Date of On Peak Day - 05/30/2021



Member Forecasted On Peak Demand Day for June 2021

Otero County Electric Cooperative, Inc.

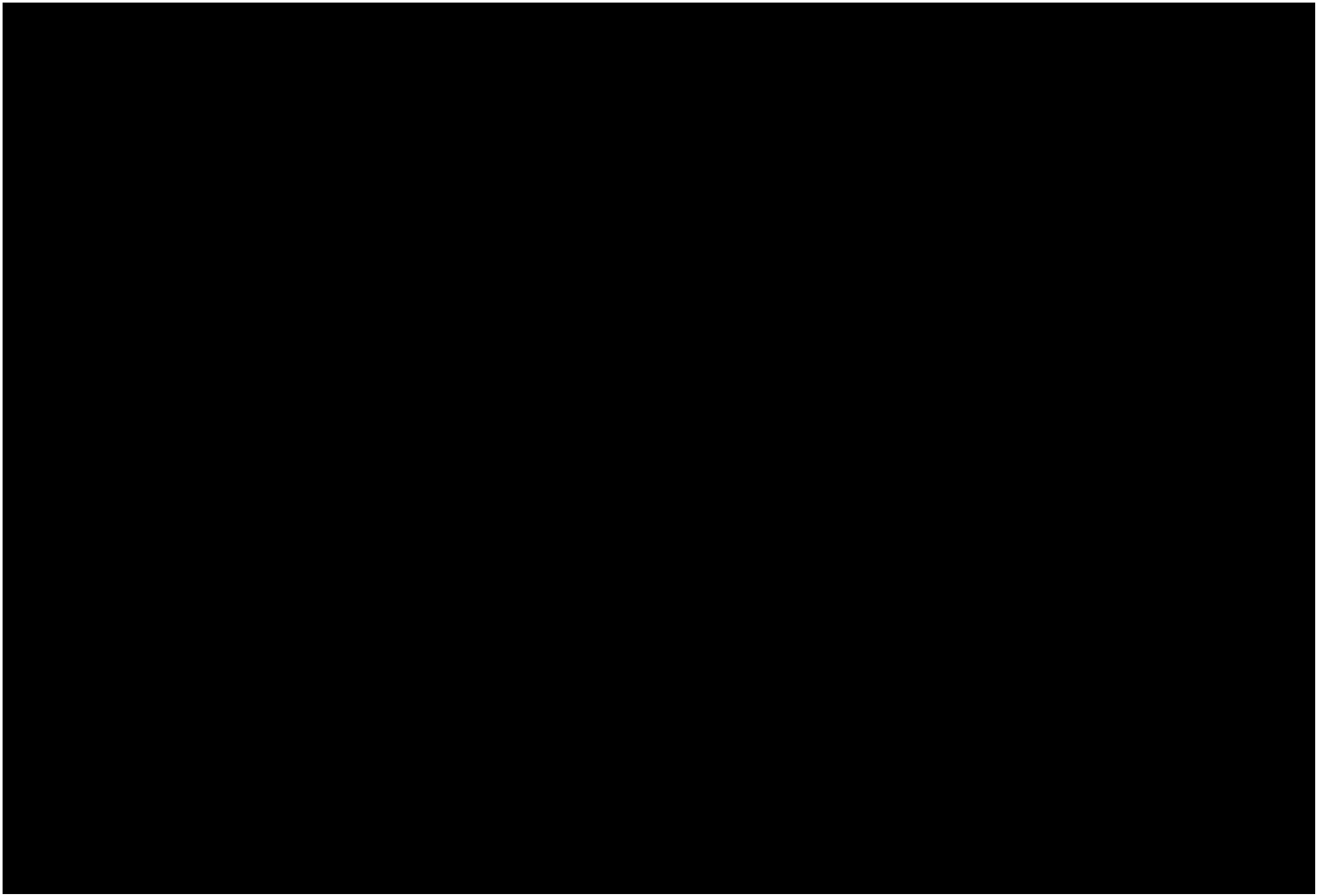
Date of On Peak Day - 06/23/2021



Member Forecasted On Peak Demand Day for July 2021

Otero County Electric Cooperative, Inc.

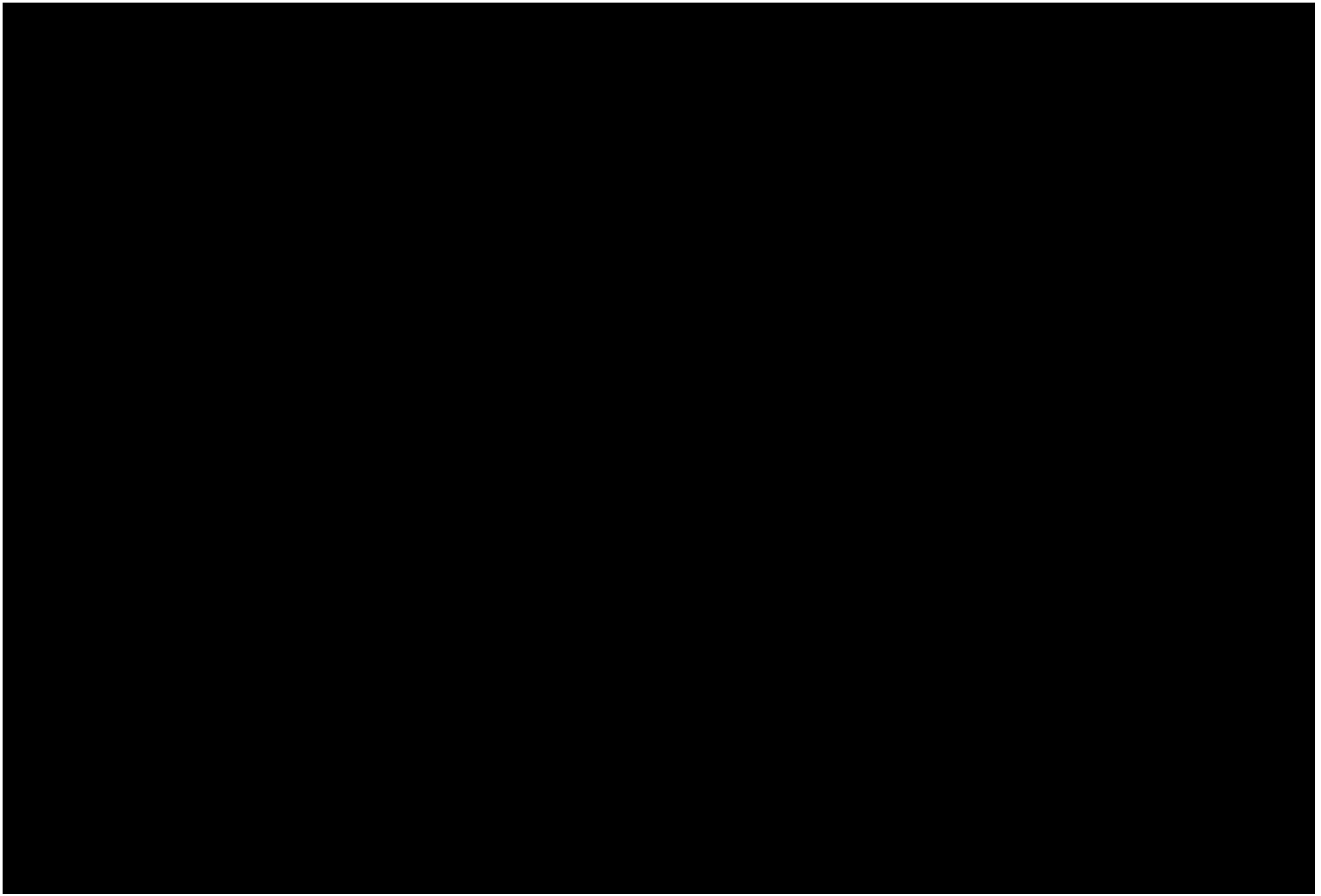
Date of On Peak Day - 07/14/2021



Member Forecasted On Peak Demand Day for August 2021

Otero County Electric Cooperative, Inc.

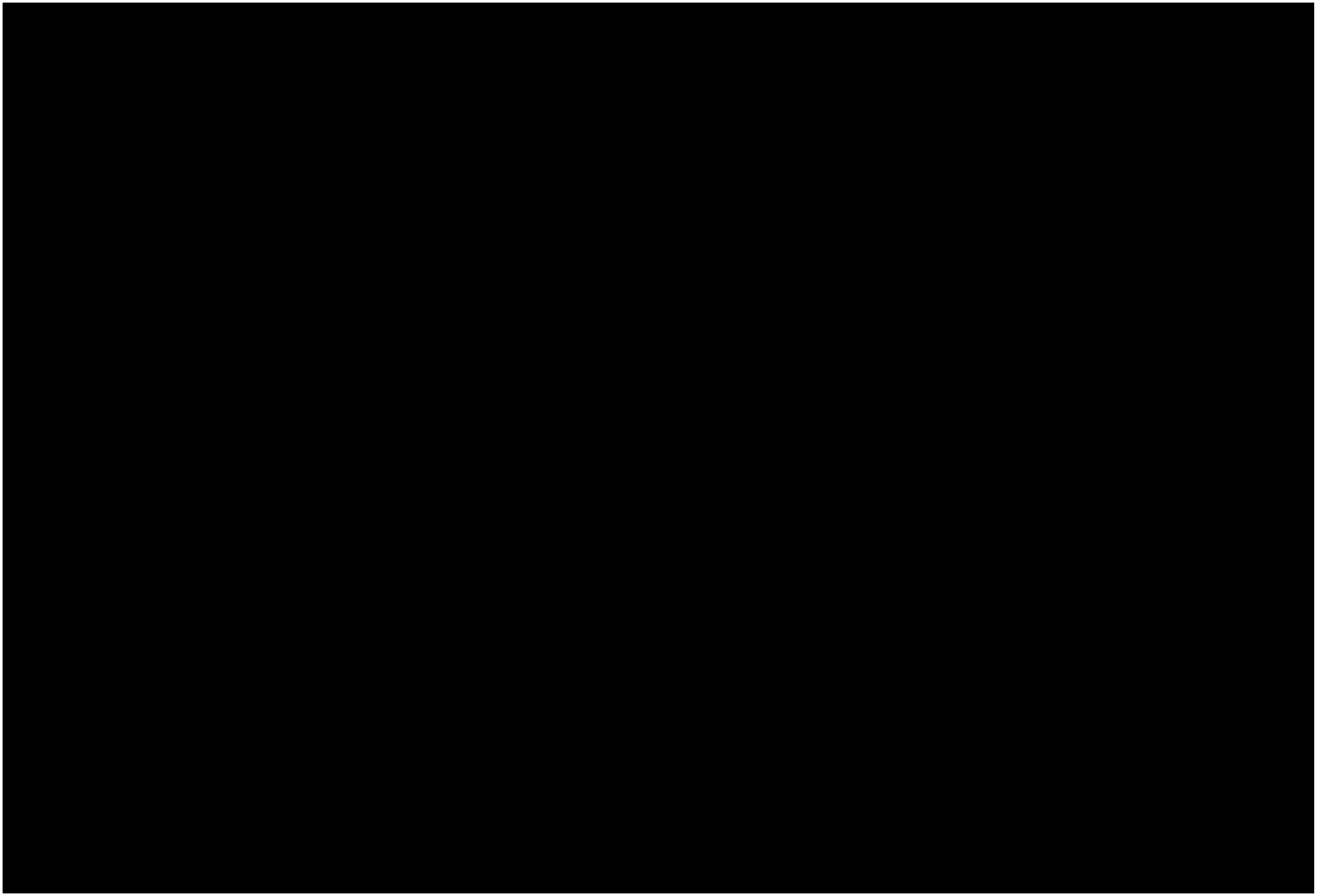
Date of On Peak Day - 08/18/2021



Member Forecasted On Peak Demand Day for September 2021

Otero County Electric Cooperative, Inc.

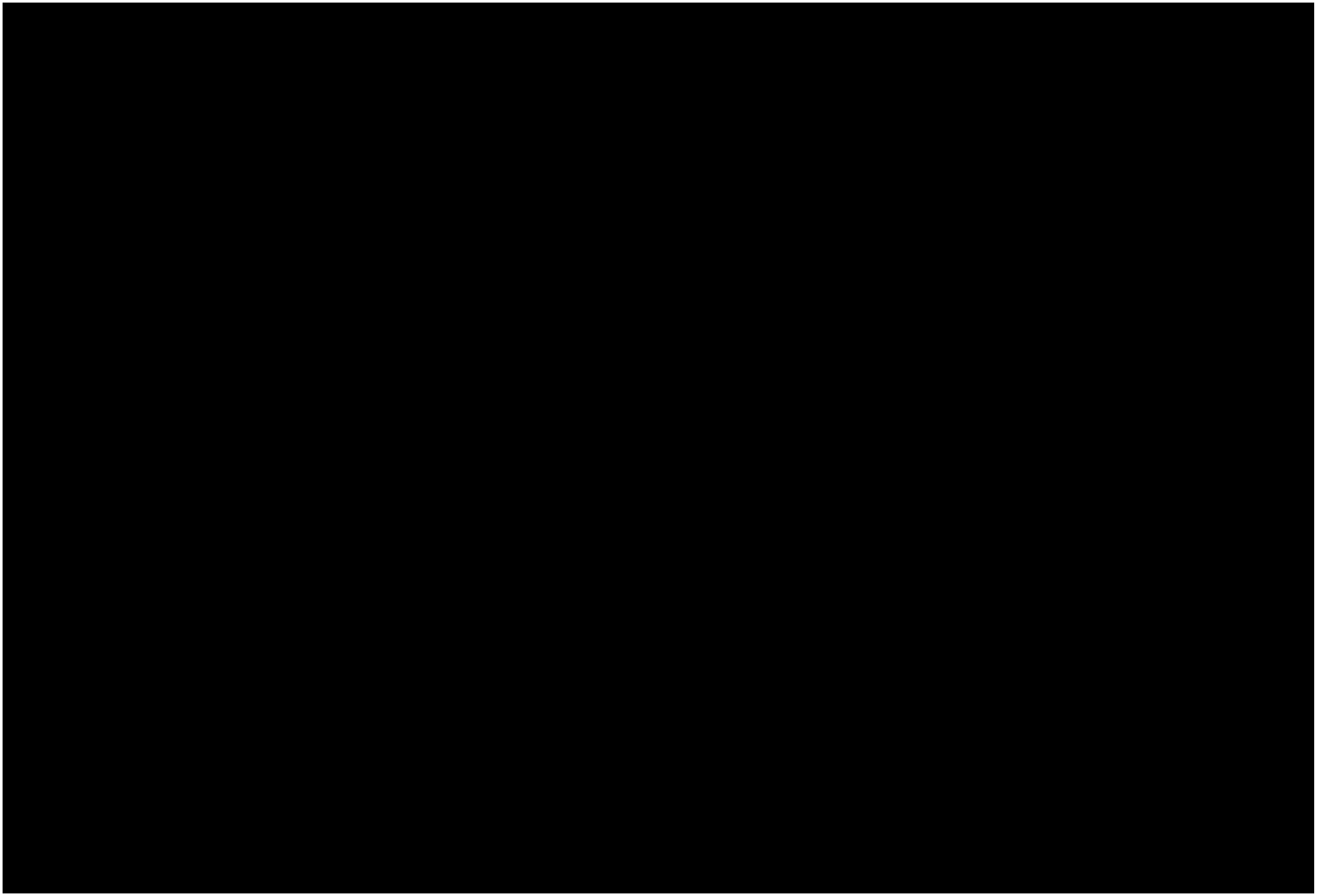
Date of On Peak Day - 09/05/2021



Member Forecasted On Peak Demand Day for October 2021

Otero County Electric Cooperative, Inc.

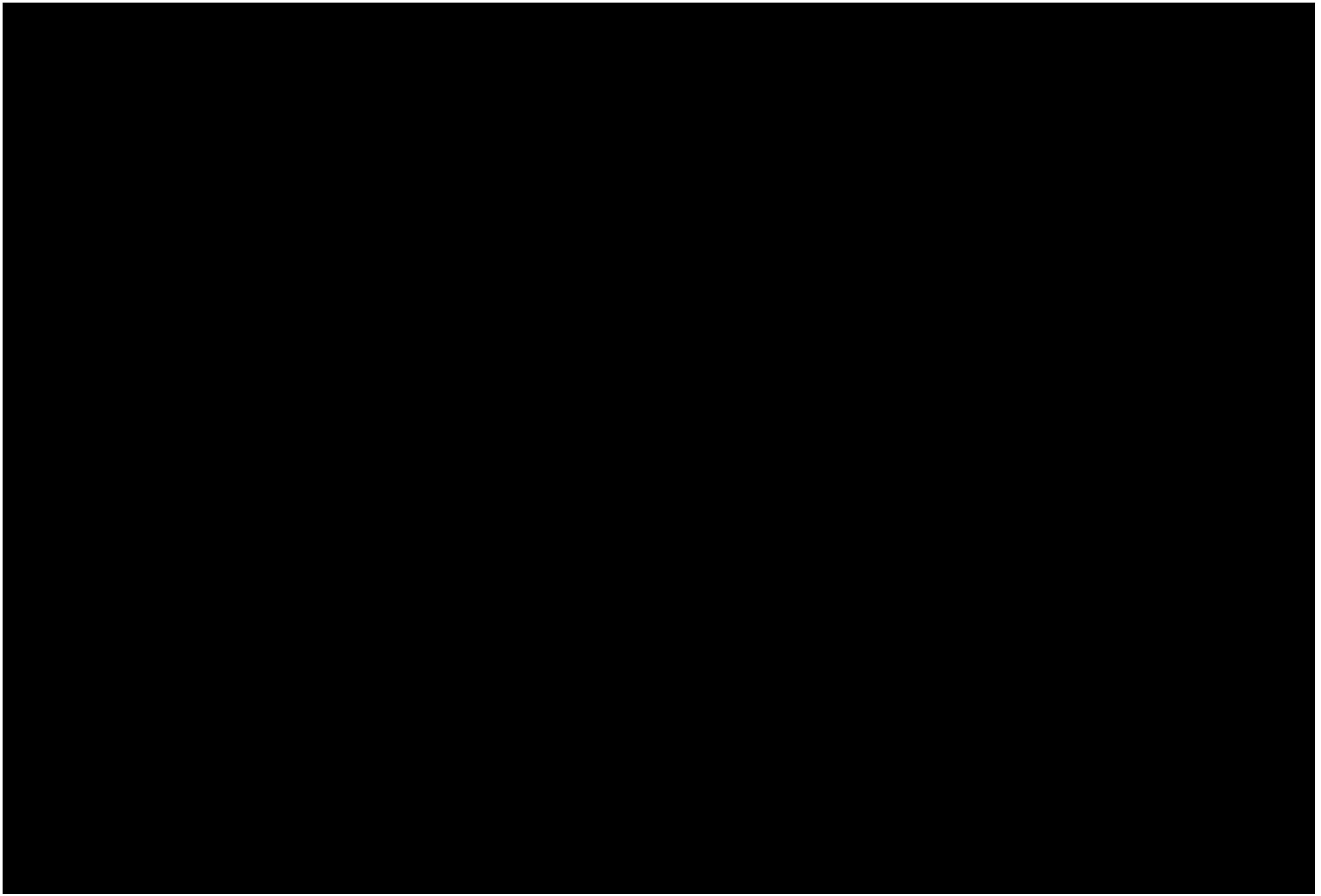
Date of On Peak Day - 10/02/2021



Member Forecasted On Peak Demand Day for November 2021

Otero County Electric Cooperative, Inc.

Date of On Peak Day - 11/16/2021



Member Forecasted On Peak Demand Day for December 2021

Otero County Electric Cooperative, Inc.

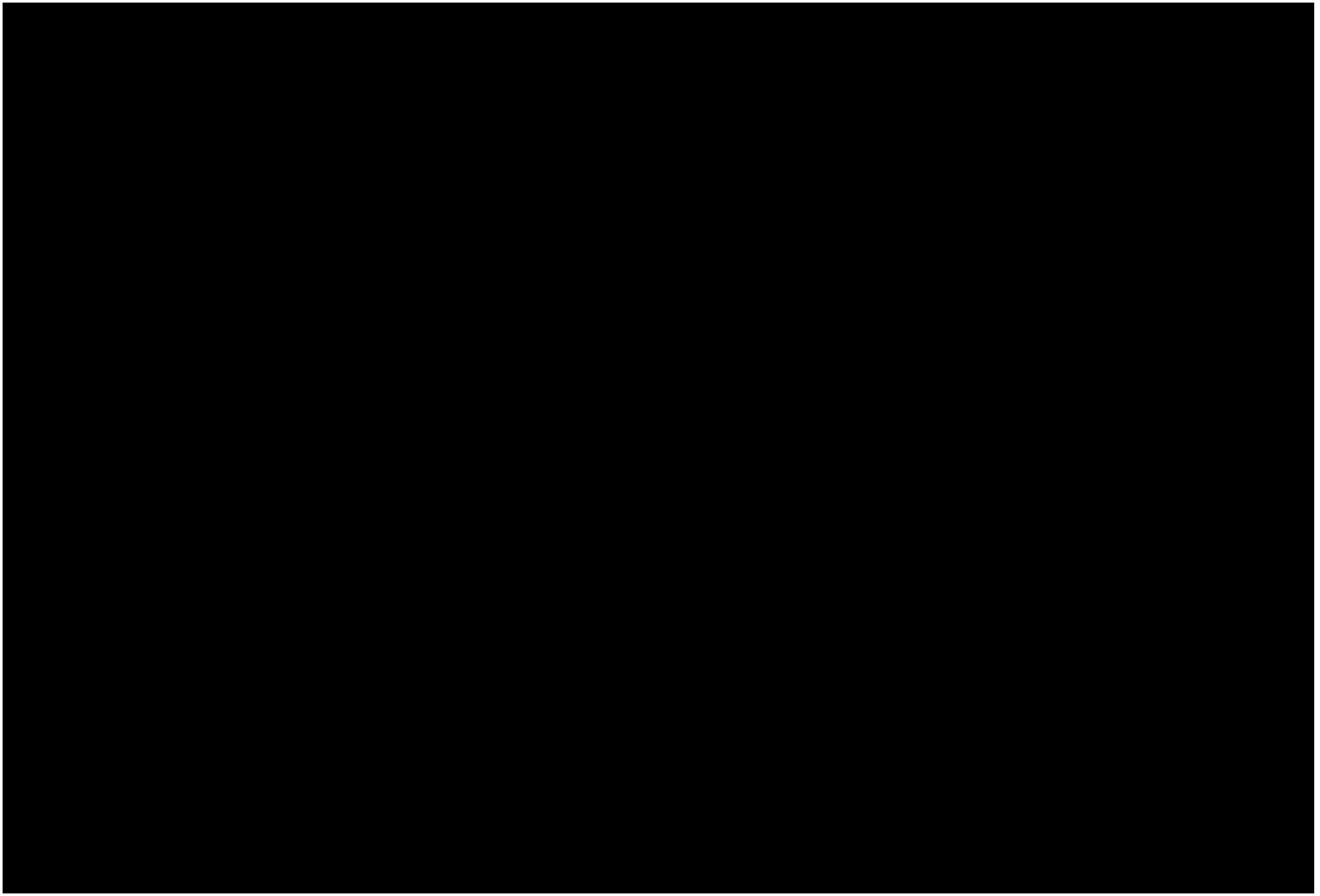
Date of On Peak Day - 12/26/2021

[redacted]

Member Forecasted On Peak Demand Day for January 2021

Panhandle Rural Electric Membership Association

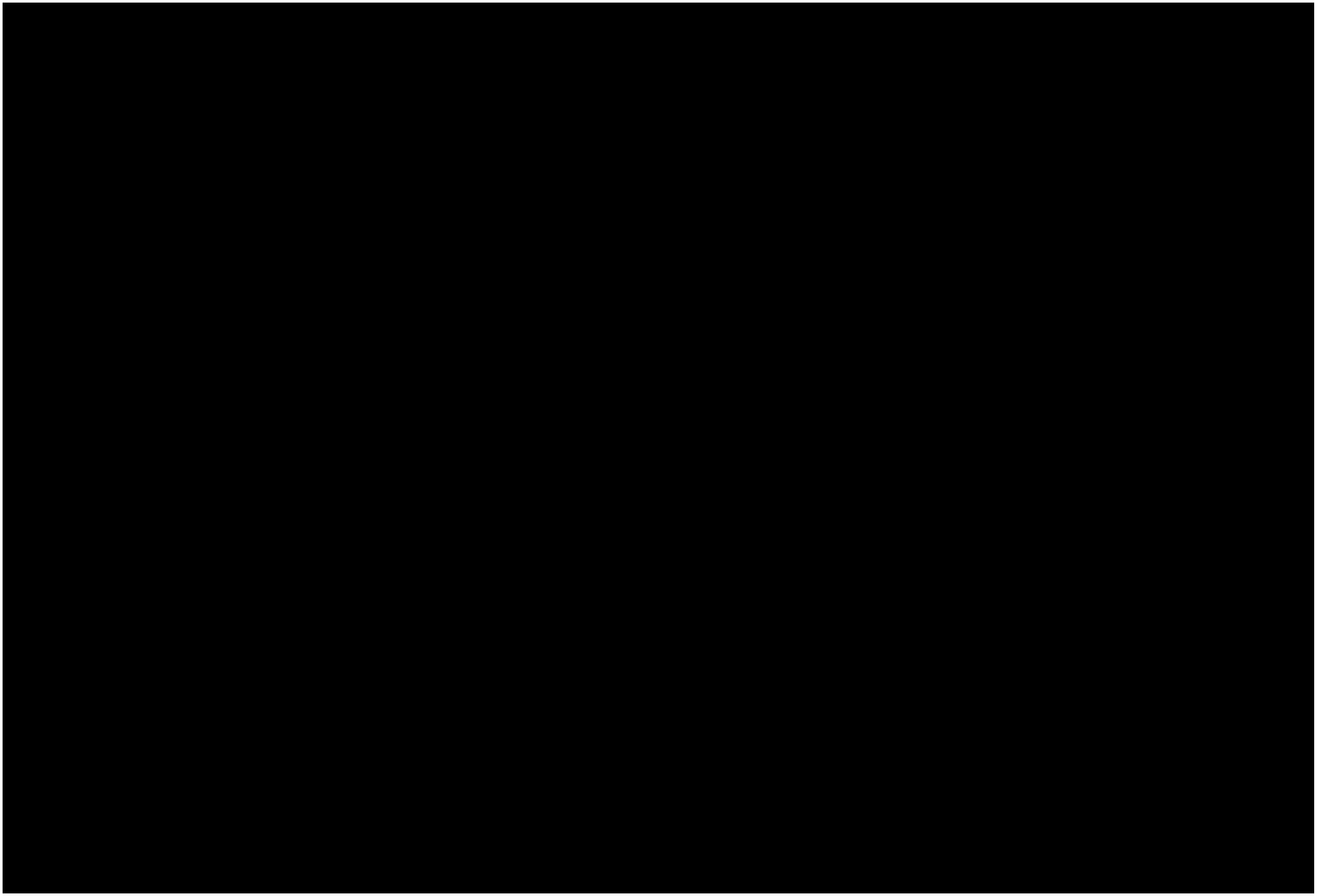
Date of On Peak Day - 01/07/2021



Member Forecasted On Peak Demand Day for February 2021

Panhandle Rural Electric Membership Association

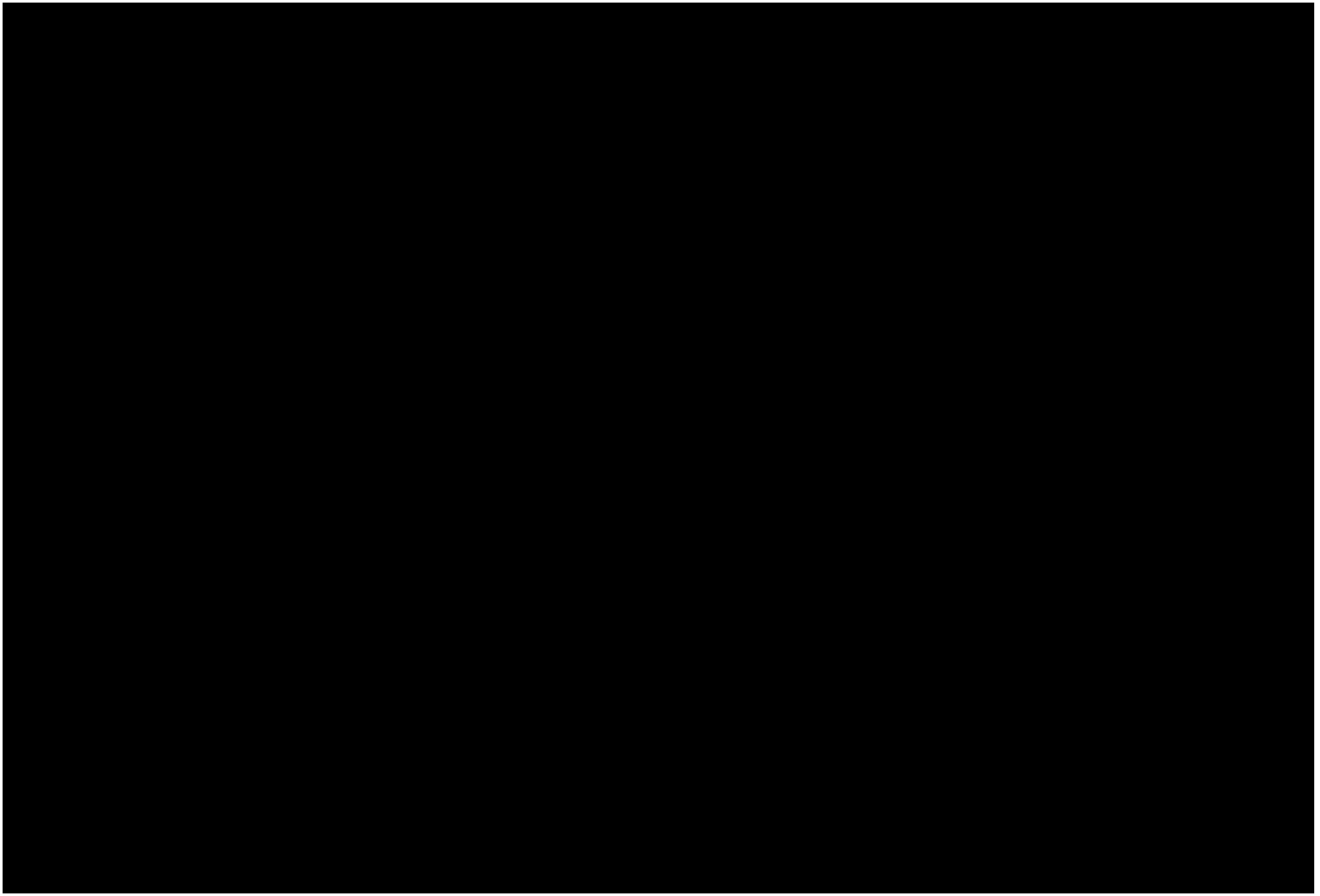
Date of On Peak Day - 02/03/2021



Member Forecasted On Peak Demand Day for March 2021

Panhandle Rural Electric Membership Association

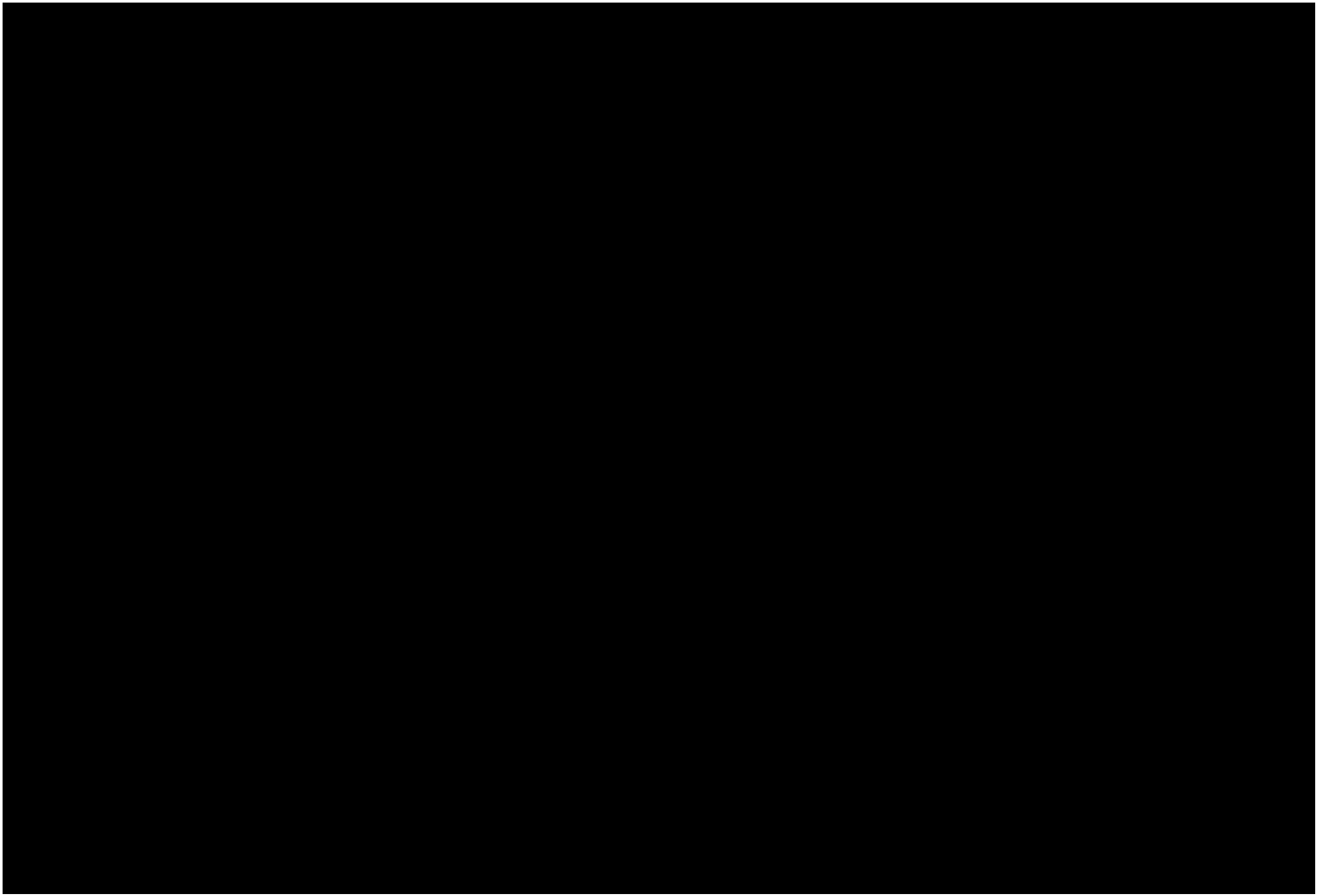
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Panhandle Rural Electric Membership Association

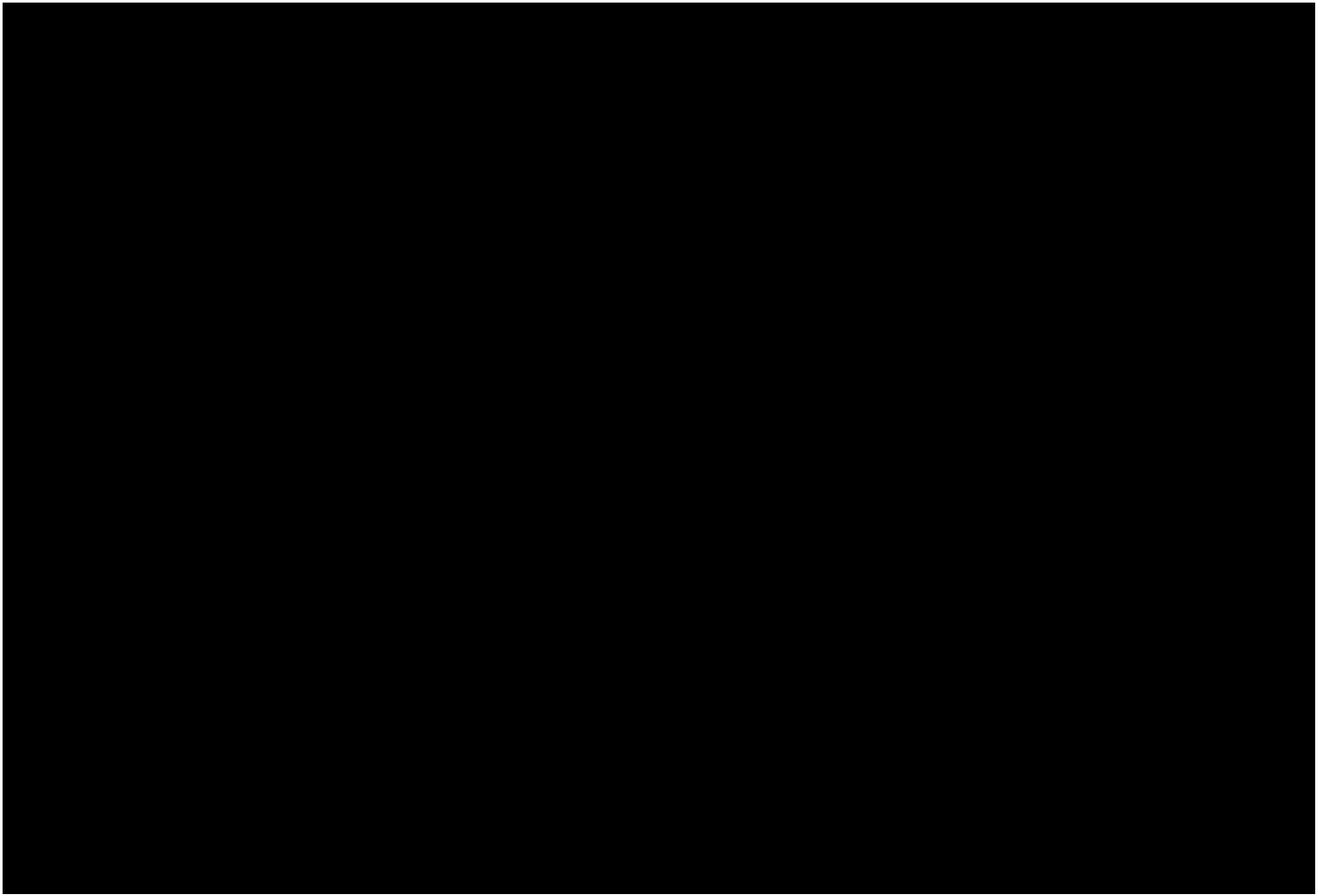
Date of On Peak Day - 04/05/2021



Member Forecasted On Peak Demand Day for May 2021

Panhandle Rural Electric Membership Association

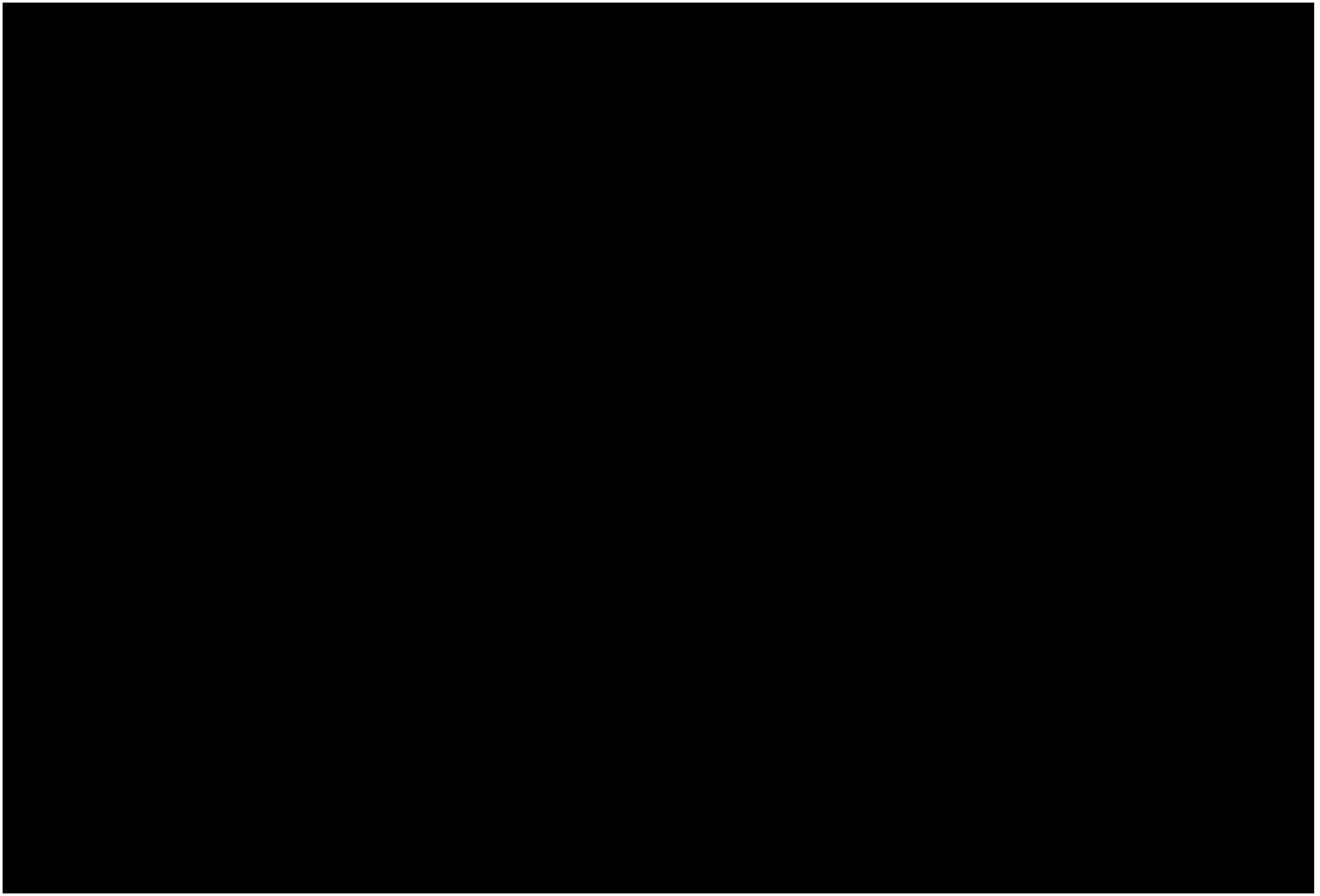
Date of On Peak Day - 05/15/2021



Member Forecasted On Peak Demand Day for June 2021

Panhandle Rural Electric Membership Association

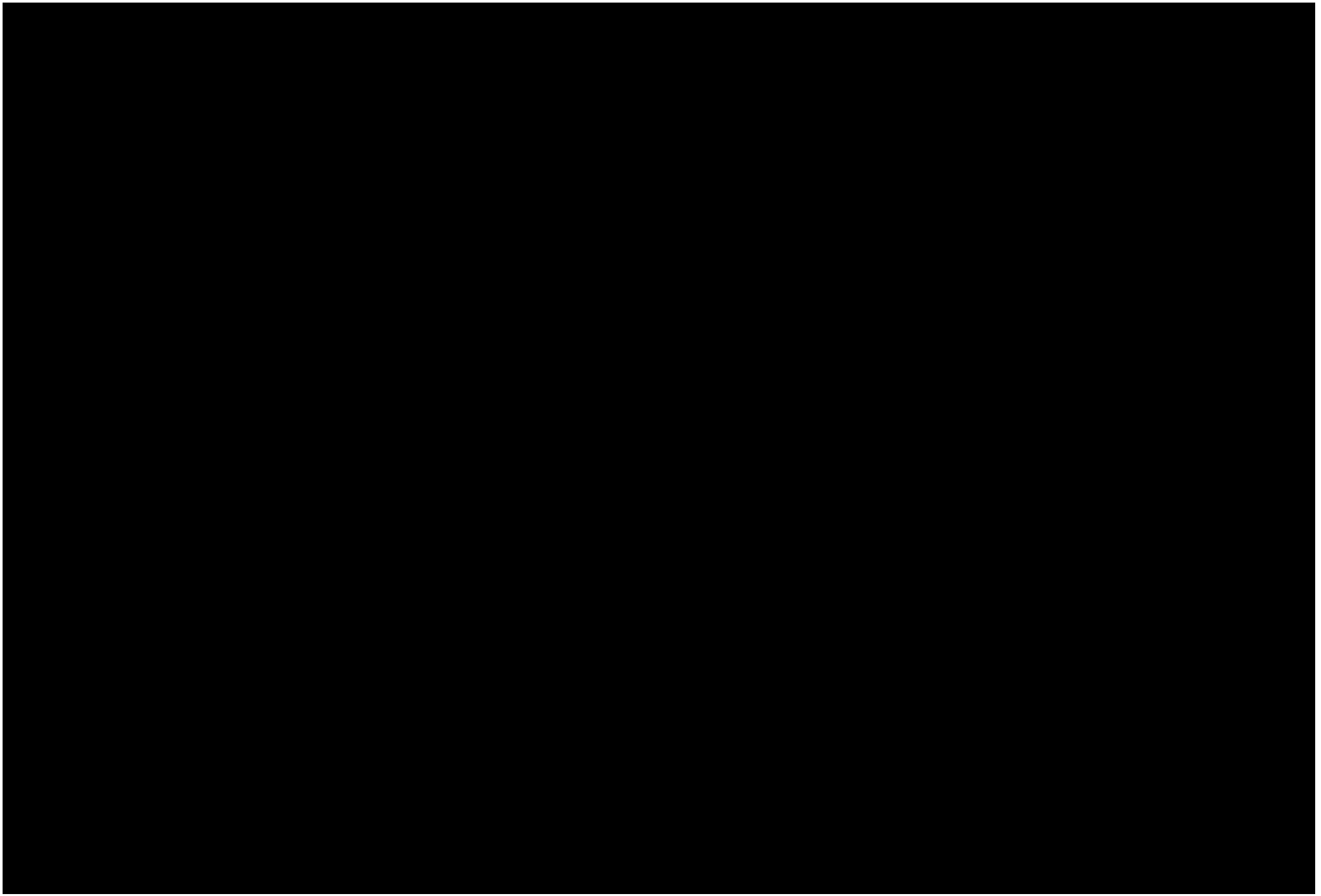
Date of On Peak Day - 06/10/2021



Member Forecasted On Peak Demand Day for July 2021

Panhandle Rural Electric Membership Association

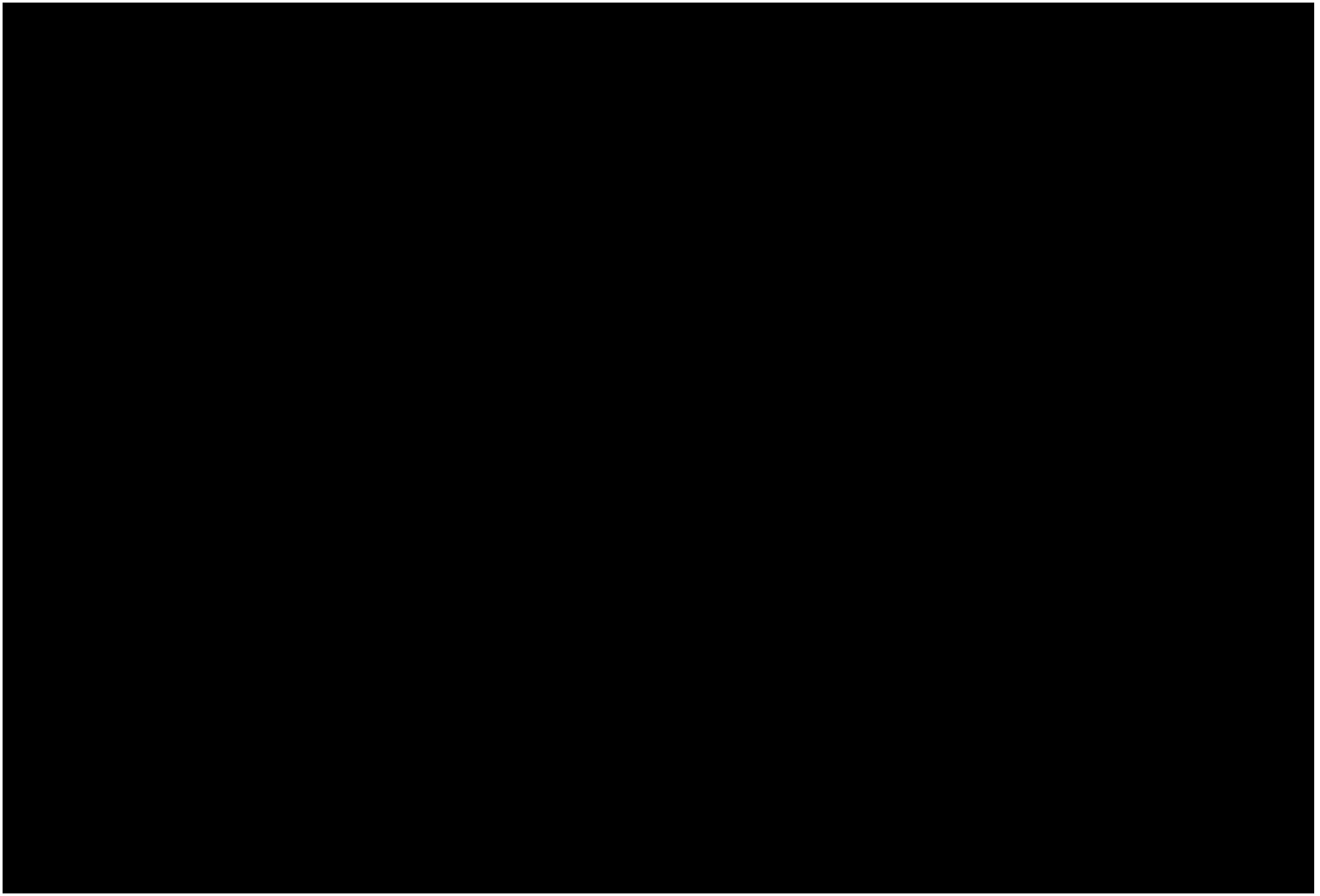
Date of On Peak Day - 07/21/2021



Member Forecasted On Peak Demand Day for August 2021

Panhandle Rural Electric Membership Association

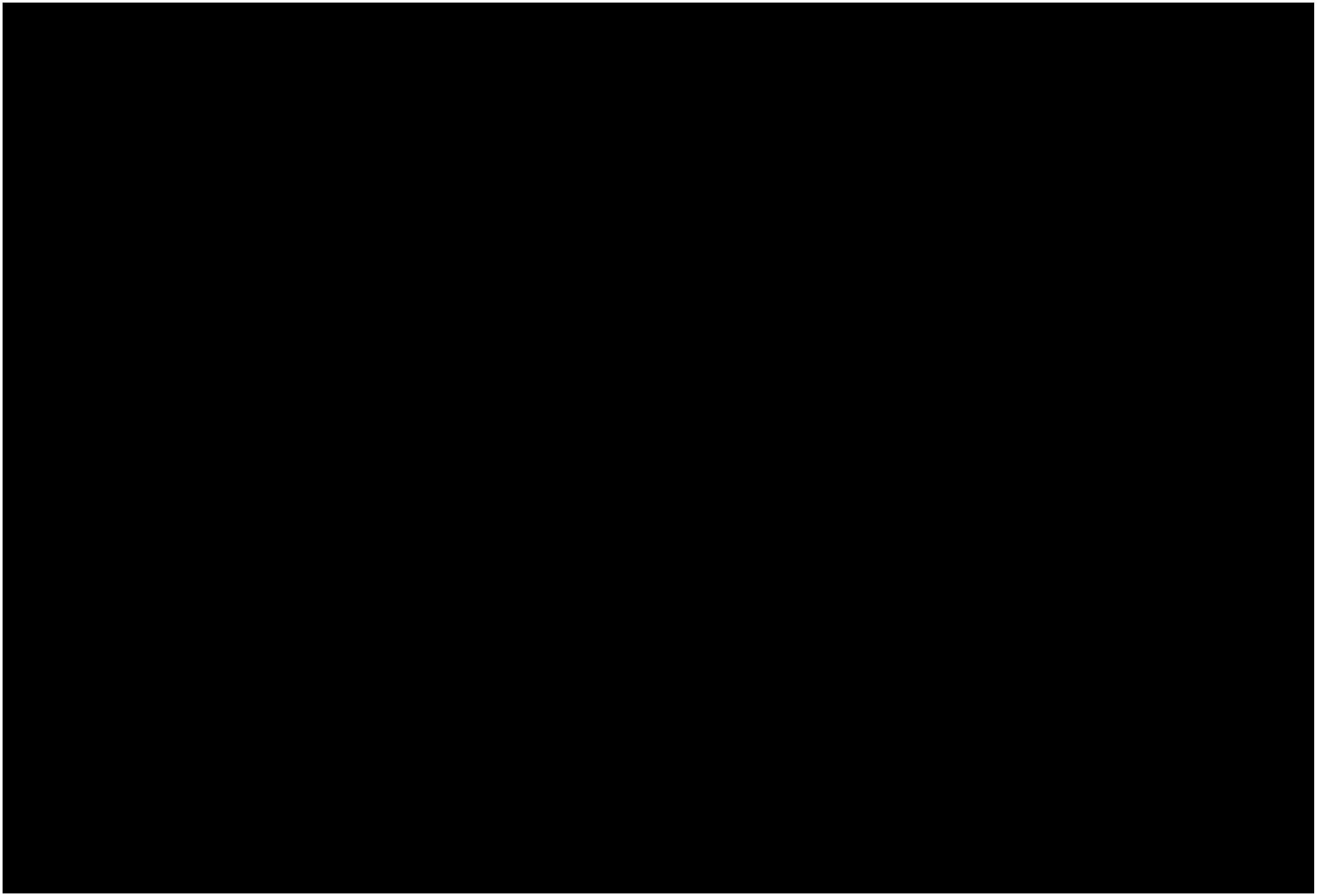
Date of On Peak Day - 08/24/2021



Member Forecasted On Peak Demand Day for September 2021

Panhandle Rural Electric Membership Association

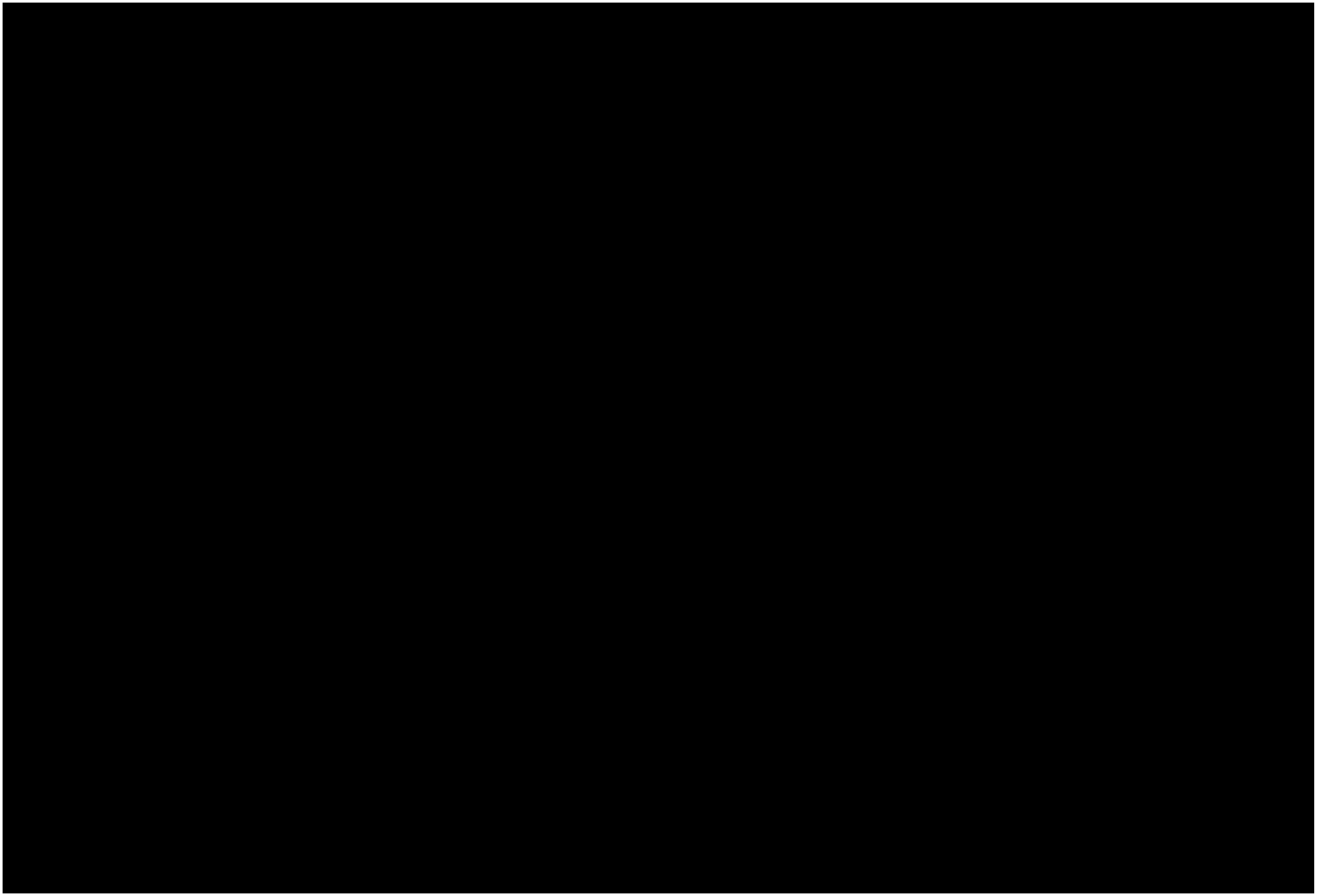
Date of On Peak Day - 09/02/2021



Member Forecasted On Peak Demand Day for October 2021

Panhandle Rural Electric Membership Association

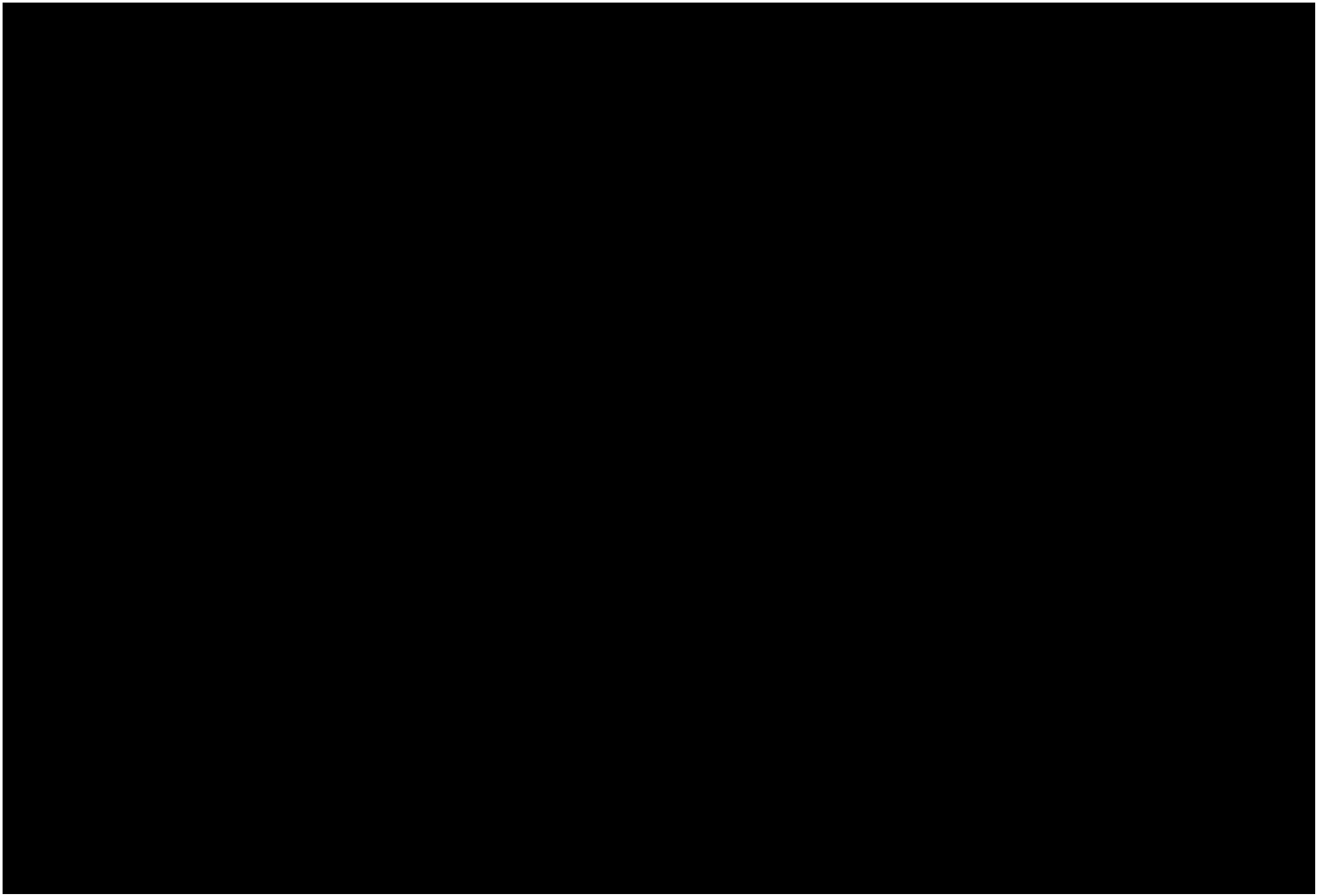
Date of On Peak Day - 10/17/2021



Member Forecasted On Peak Demand Day for November 2021

Panhandle Rural Electric Membership Association

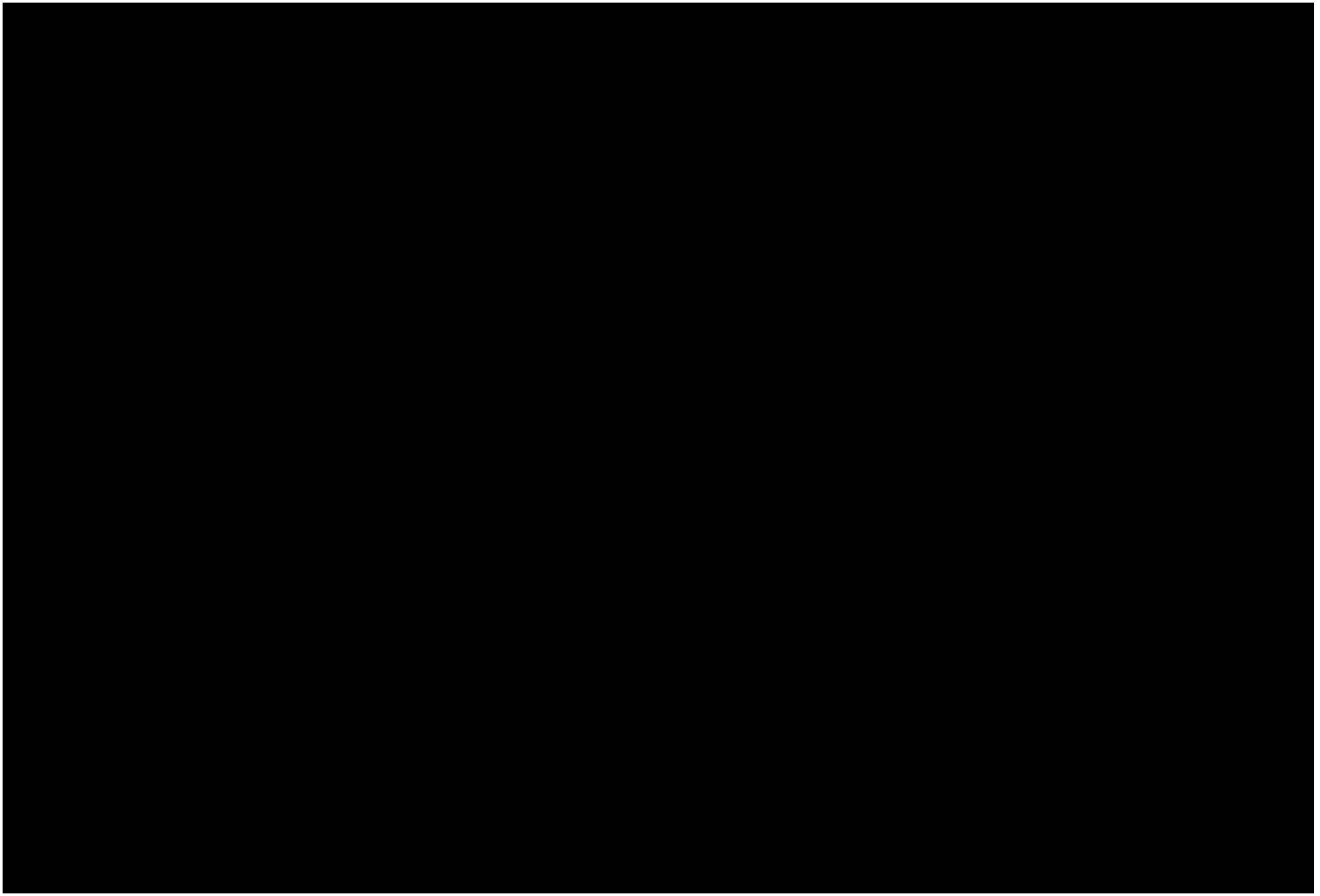
Date of On Peak Day - 11/09/2021



Member Forecasted On Peak Demand Day for December 2021

Panhandle Rural Electric Membership Association

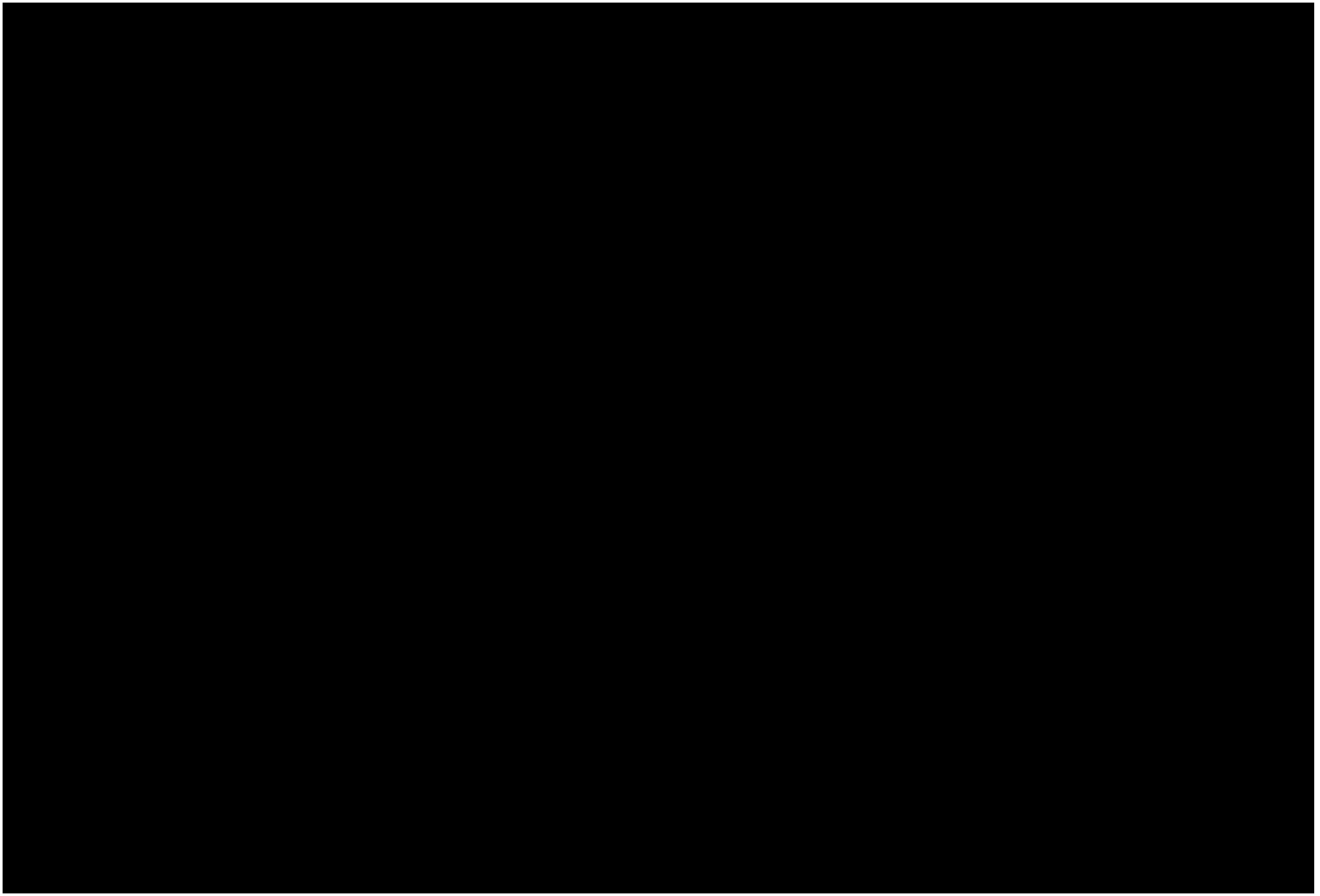
Date of On Peak Day - 12/29/2021



Member Forecasted On Peak Demand Day for January 2021

Poudre Valley Electric Association, Inc.

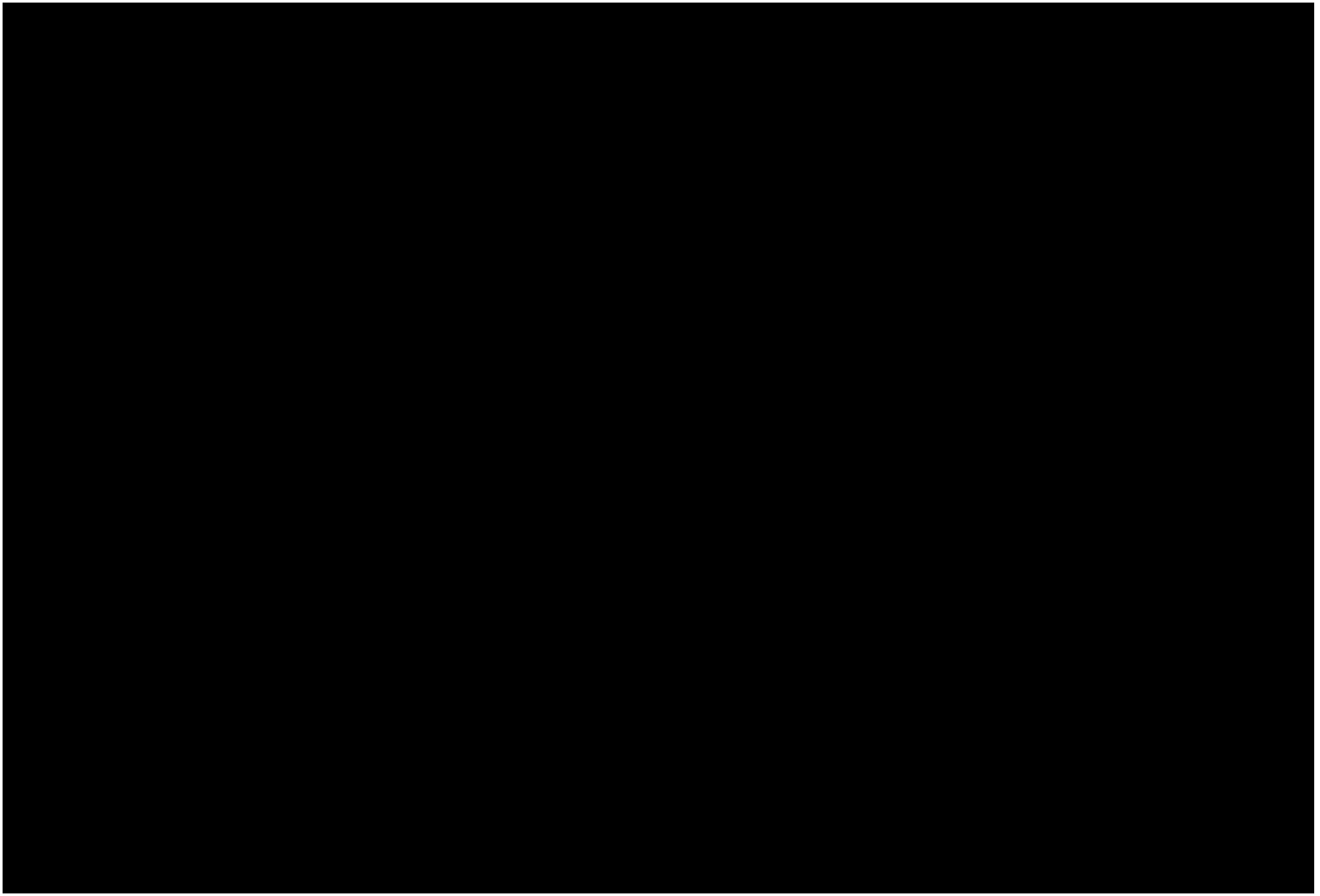
Date of On Peak Day - 01/06/2021



Member Forecasted On Peak Demand Day for February 2021

Poudre Valley Electric Association, Inc.

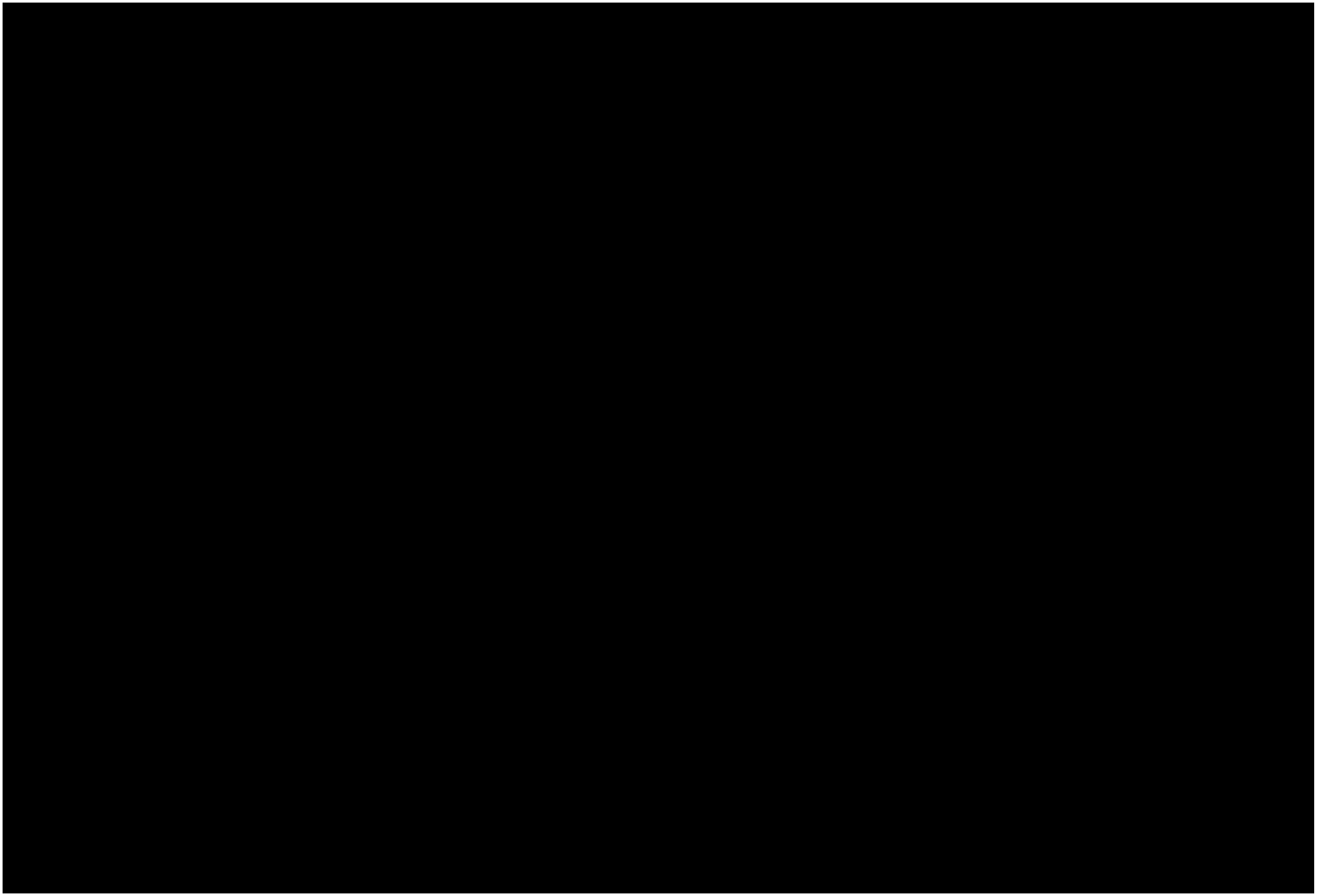
Date of On Peak Day - 02/01/2021



Member Forecasted On Peak Demand Day for March 2021

Poudre Valley Electric Association, Inc.

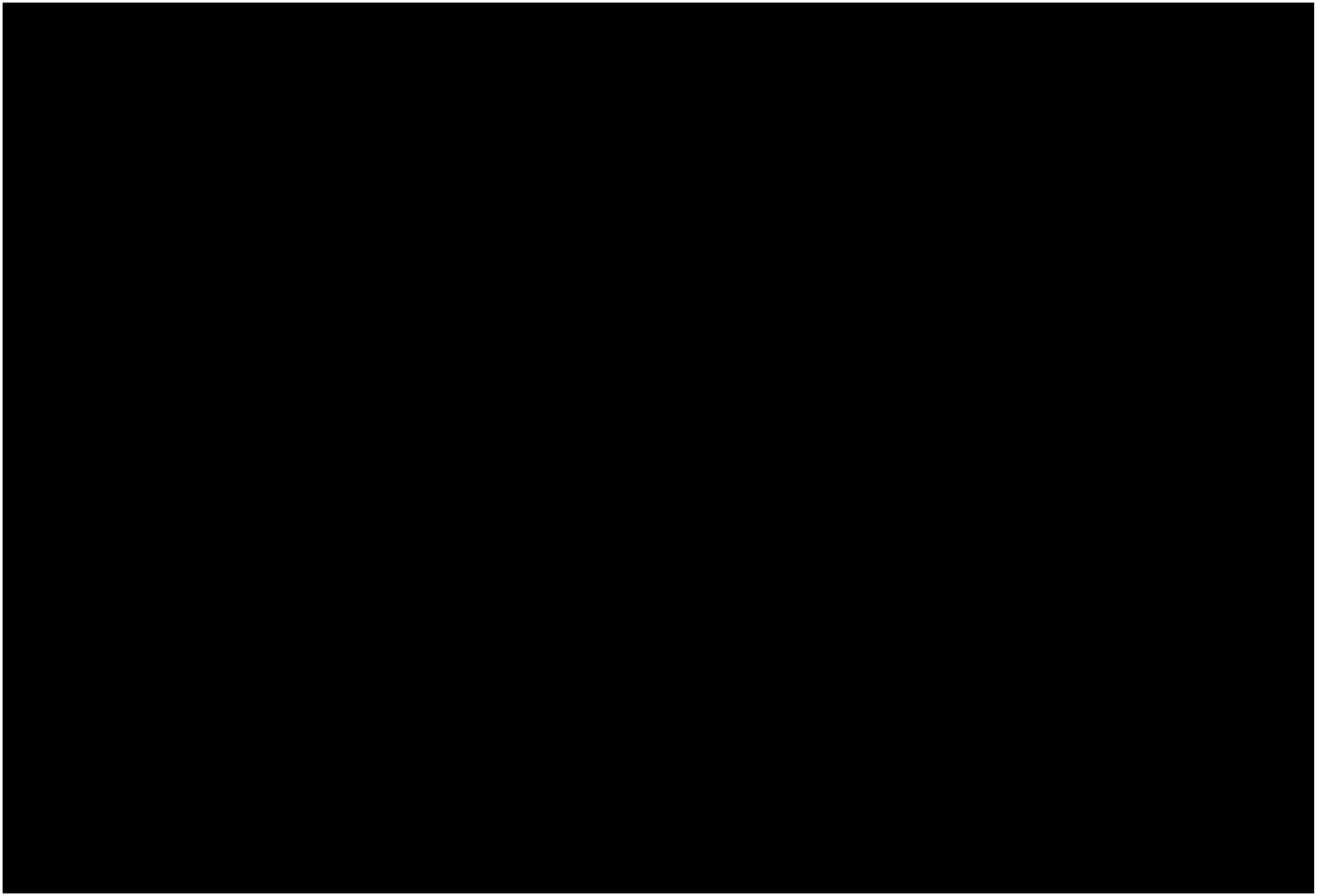
Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

Poudre Valley Electric Association, Inc.

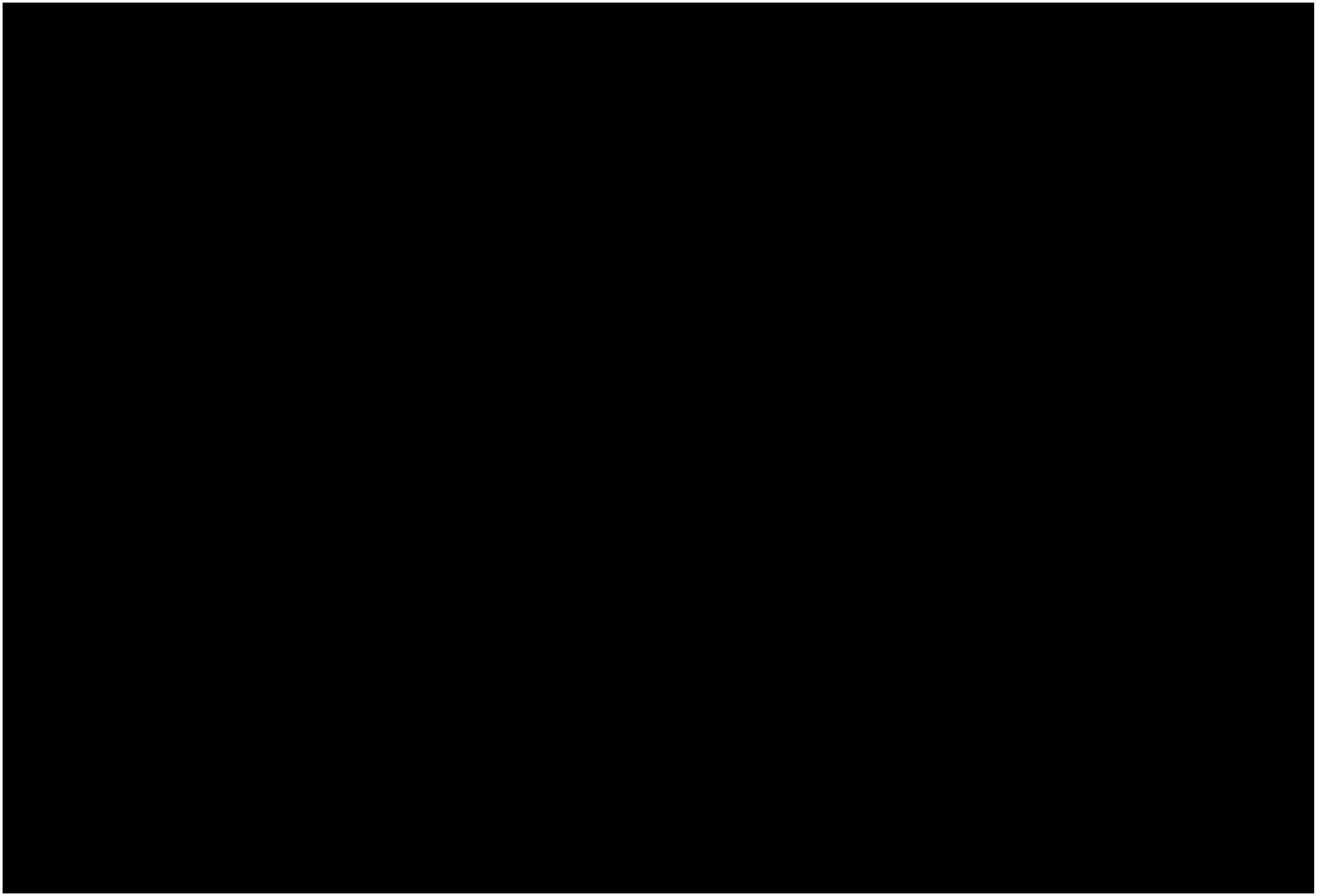
Date of On Peak Day - 04/02/2021



Member Forecasted On Peak Demand Day for May 2021

Poudre Valley Electric Association, Inc.

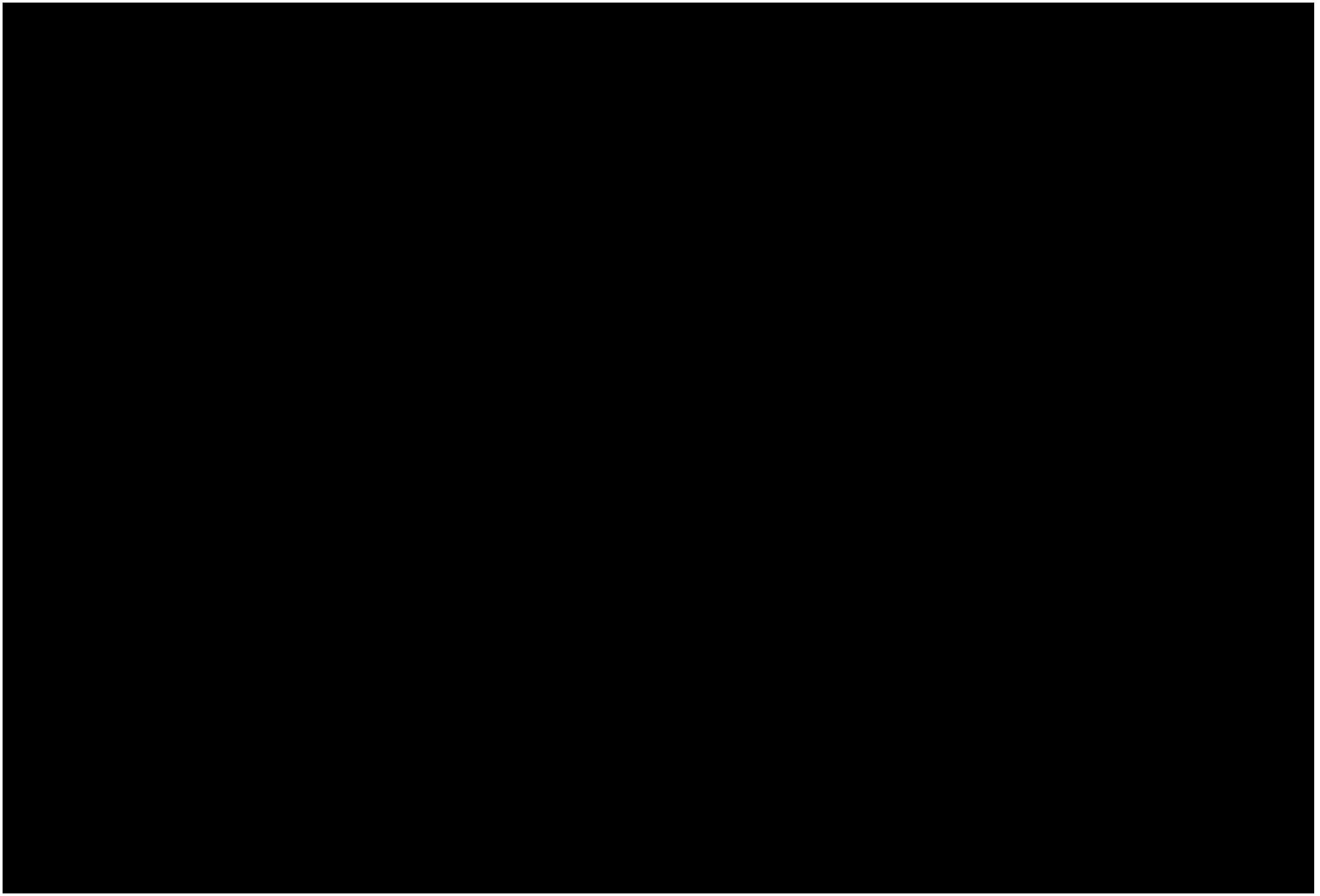
Date of On Peak Day - 05/31/2021



Member Forecasted On Peak Demand Day for June 2021

Poudre Valley Electric Association, Inc.

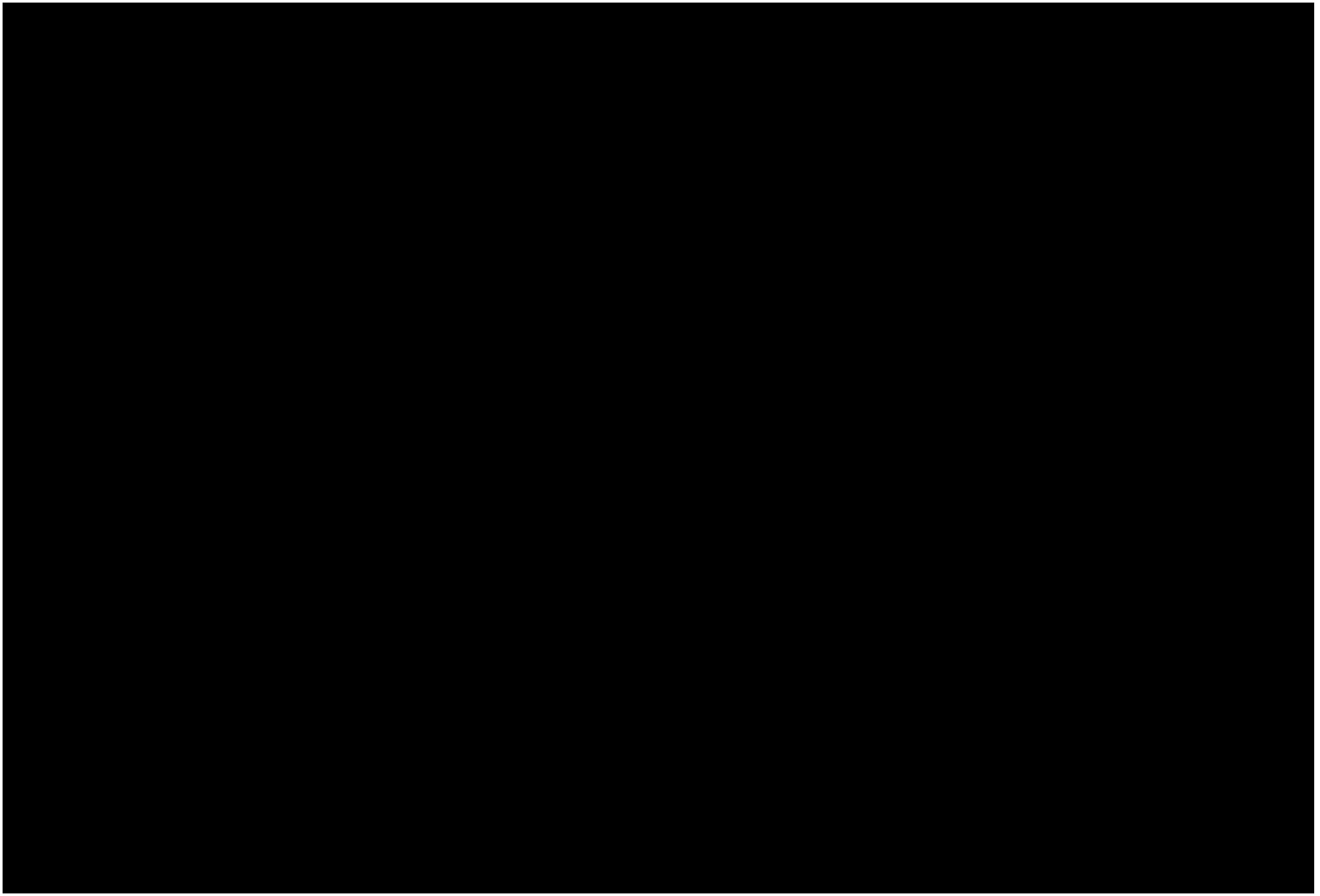
Date of On Peak Day - 06/10/2021



Member Forecasted On Peak Demand Day for July 2021

Poudre Valley Electric Association, Inc.

Date of On Peak Day - 07/19/2021



Hearing Exhibit 101
PUBLIC Attachment BN-2
Proceeding No. 20A-0528E
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Member Forecasted On Peak Demand Day for August 2021

Poudre Valley Electric Association, Inc.

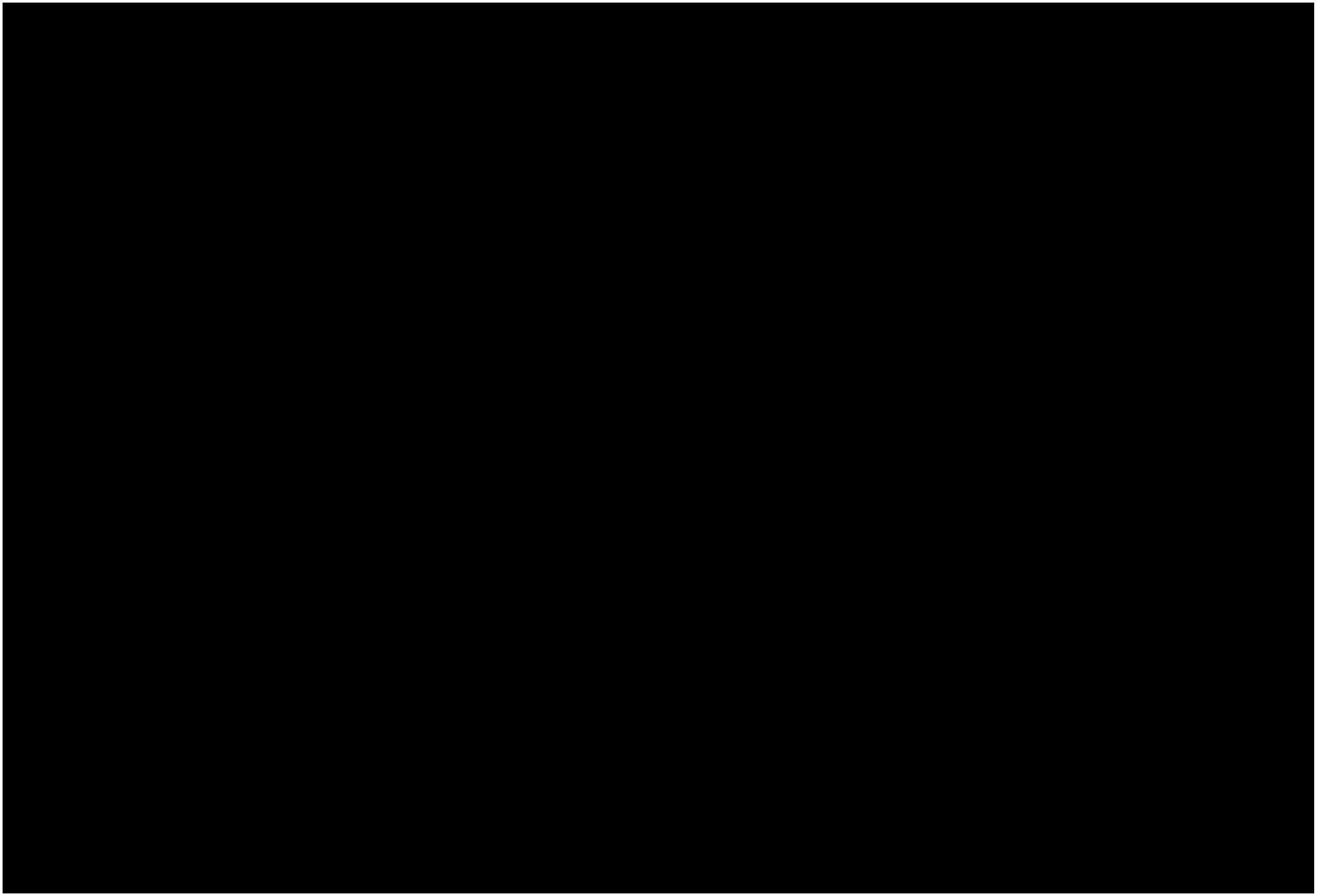
Date of On Peak Day - 08/28/2021

[redacted]

Member Forecasted On Peak Demand Day for September 2021

Poudre Valley Electric Association, Inc.

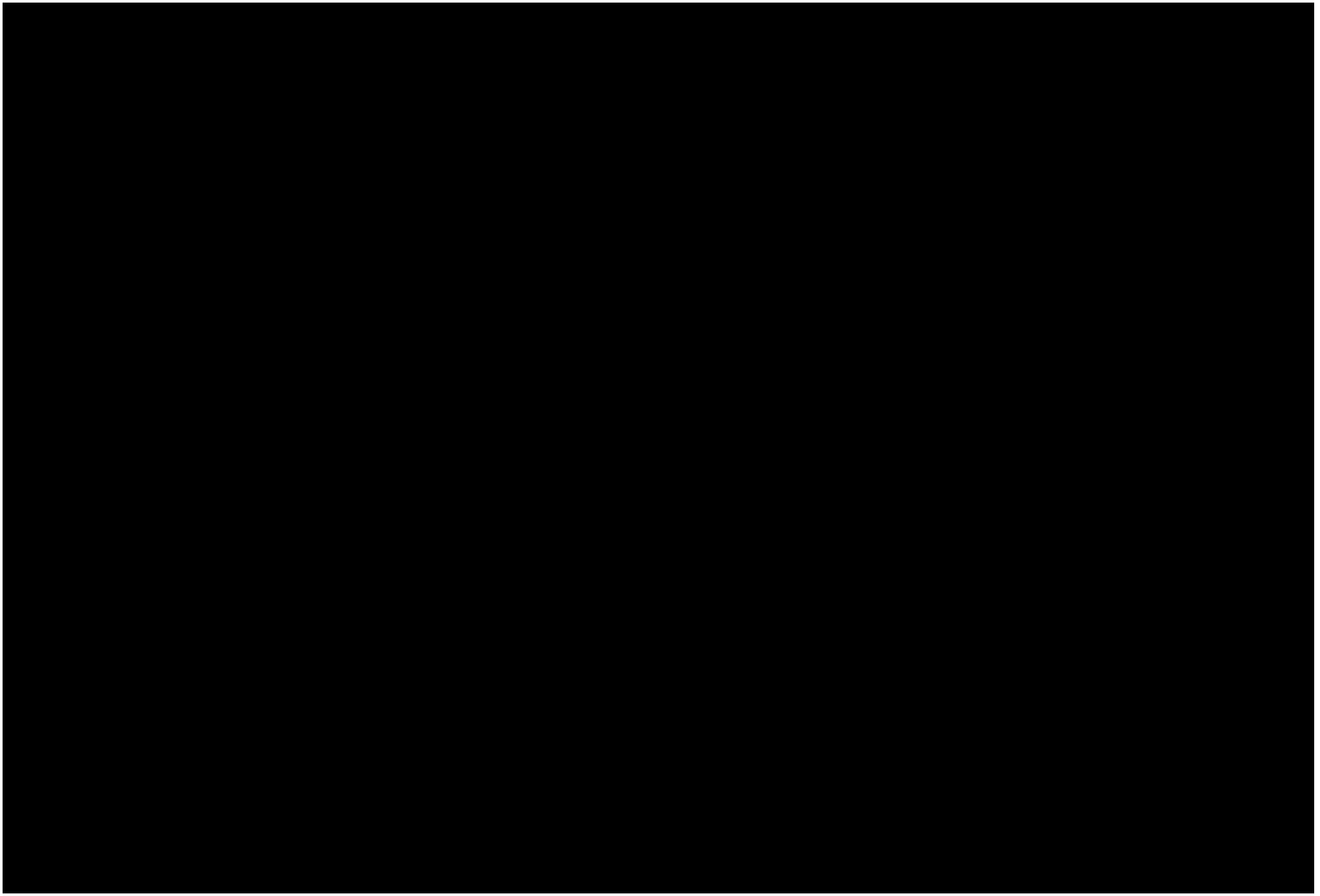
Date of On Peak Day - 09/01/2021



Member Forecasted On Peak Demand Day for October 2021

Poudre Valley Electric Association, Inc.

Date of On Peak Day - 10/11/2021



Member Forecasted On Peak Demand Day for November 2021

Poudre Valley Electric Association, Inc.

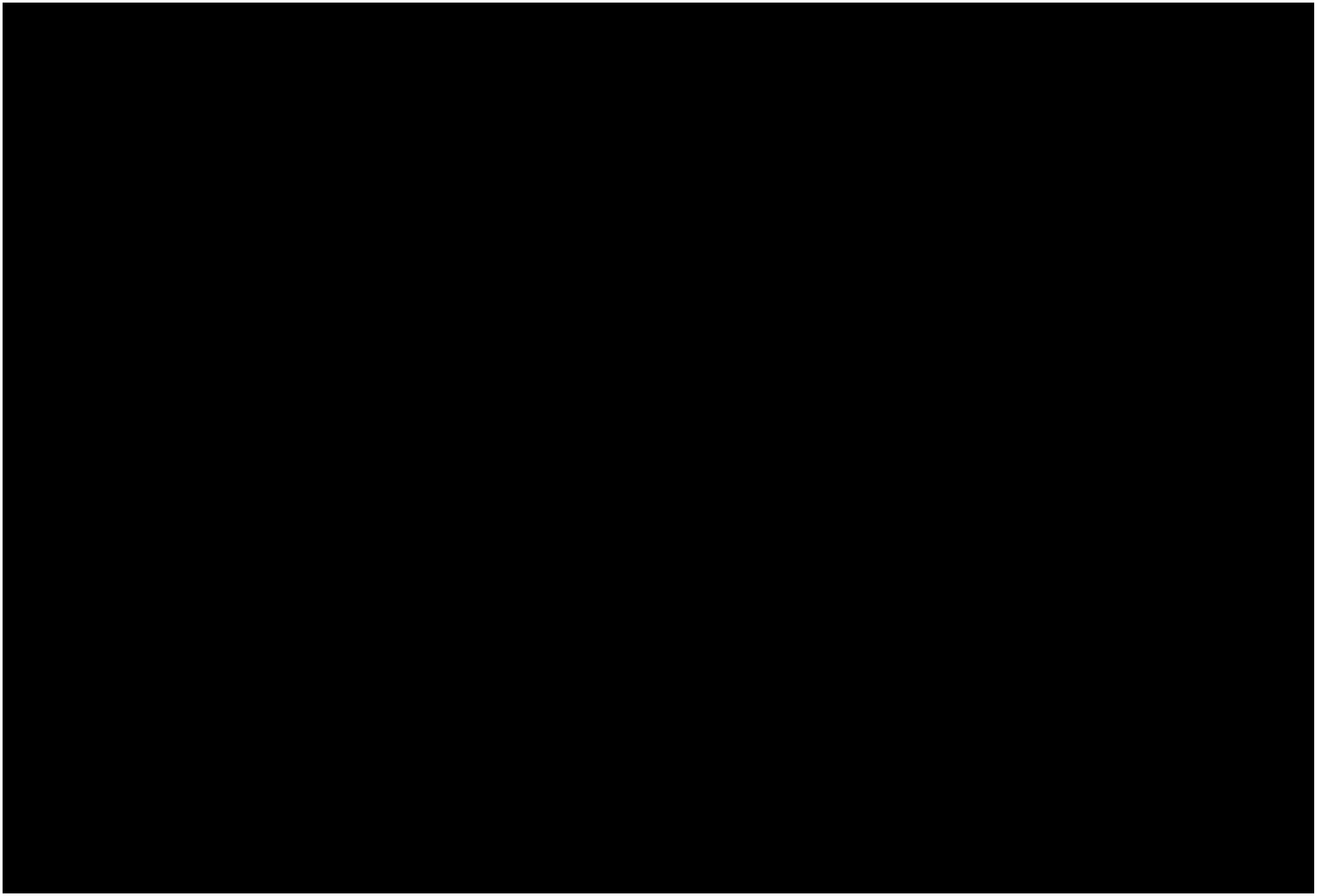
Date of On Peak Day - 11/08/2021

[redacted]

Member Forecasted On Peak Demand Day for December 2021

Poudre Valley Electric Association, Inc.

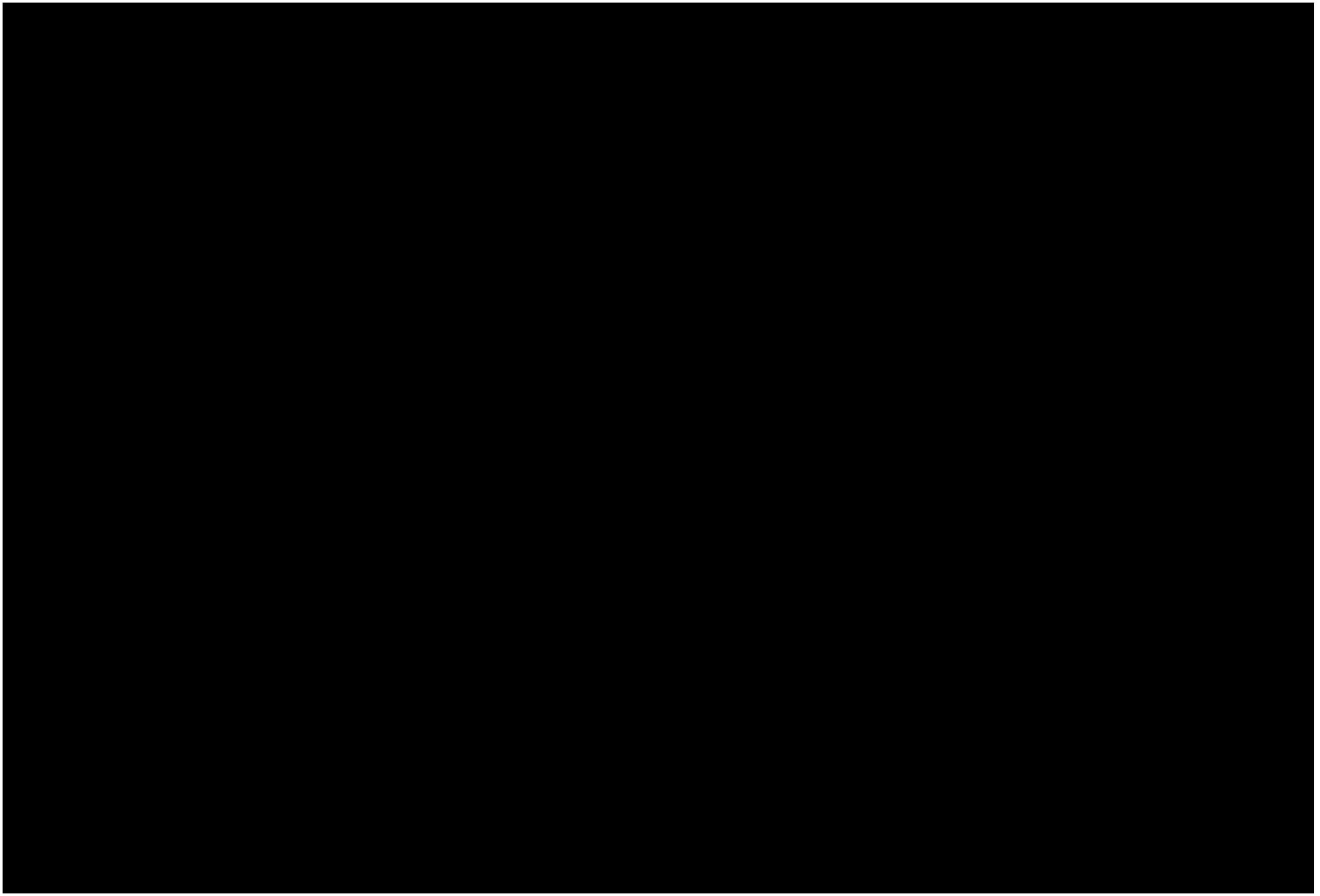
Date of On Peak Day - 12/15/2021



Member Forecasted On Peak Demand Day for January 2021

Northern Rio Arriba Electric Cooperative, Inc.

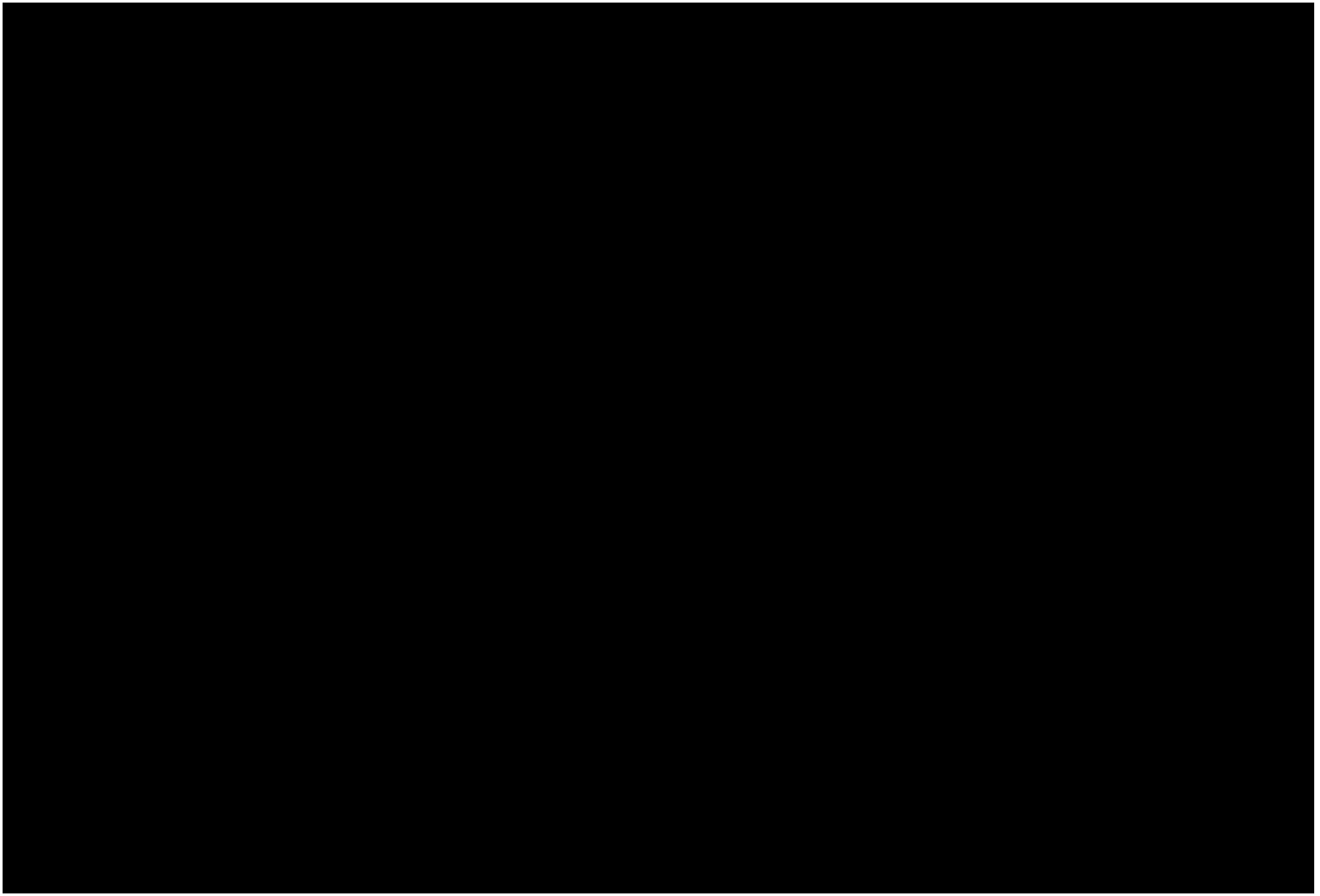
Date of On Peak Day - 01/27/2021



Member Forecasted On Peak Demand Day for February 2021

Northern Rio Arriba Electric Cooperative, Inc.

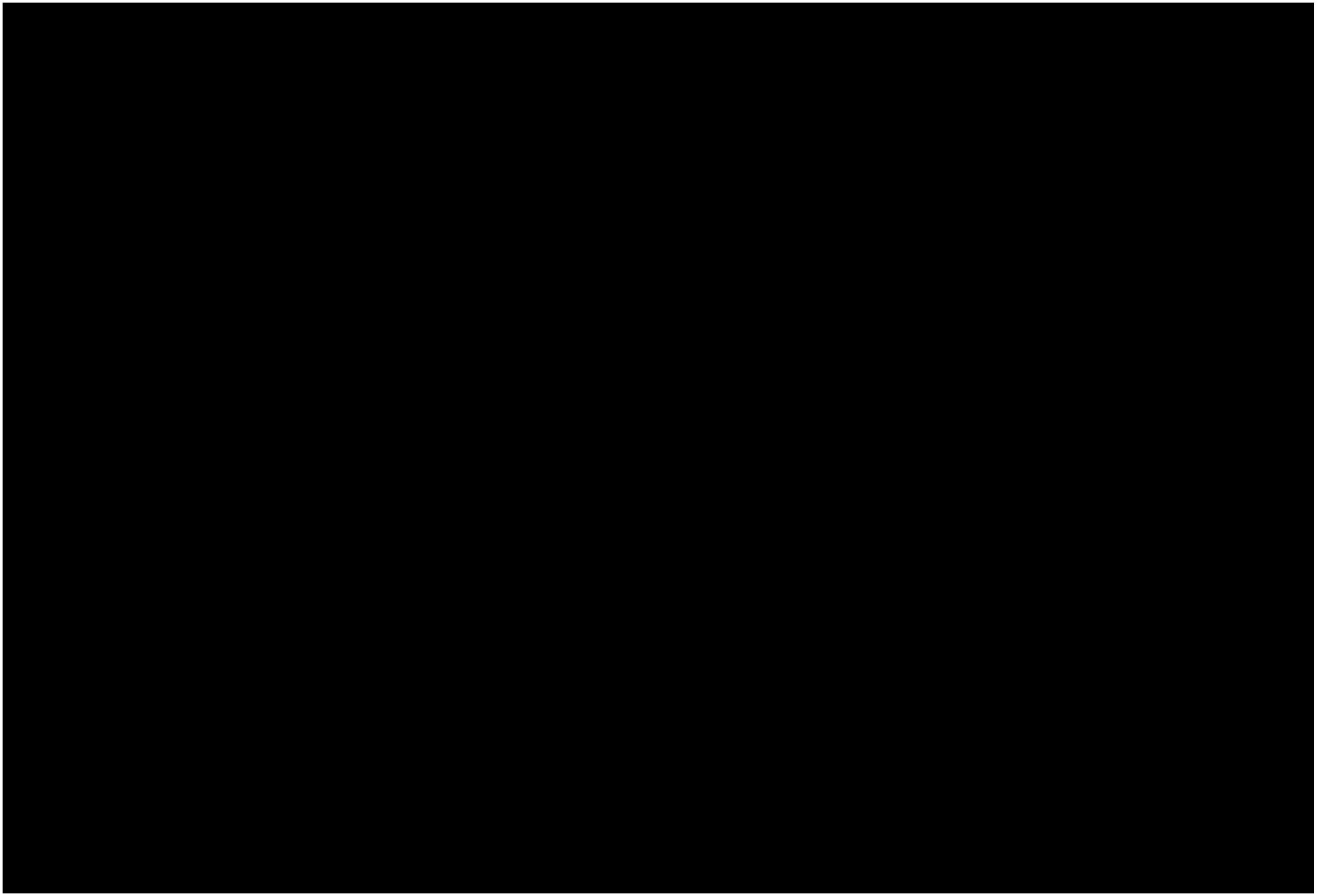
Date of On Peak Day - 02/01/2021



Member Forecasted On Peak Demand Day for March 2021

Northern Rio Arriba Electric Cooperative, Inc.

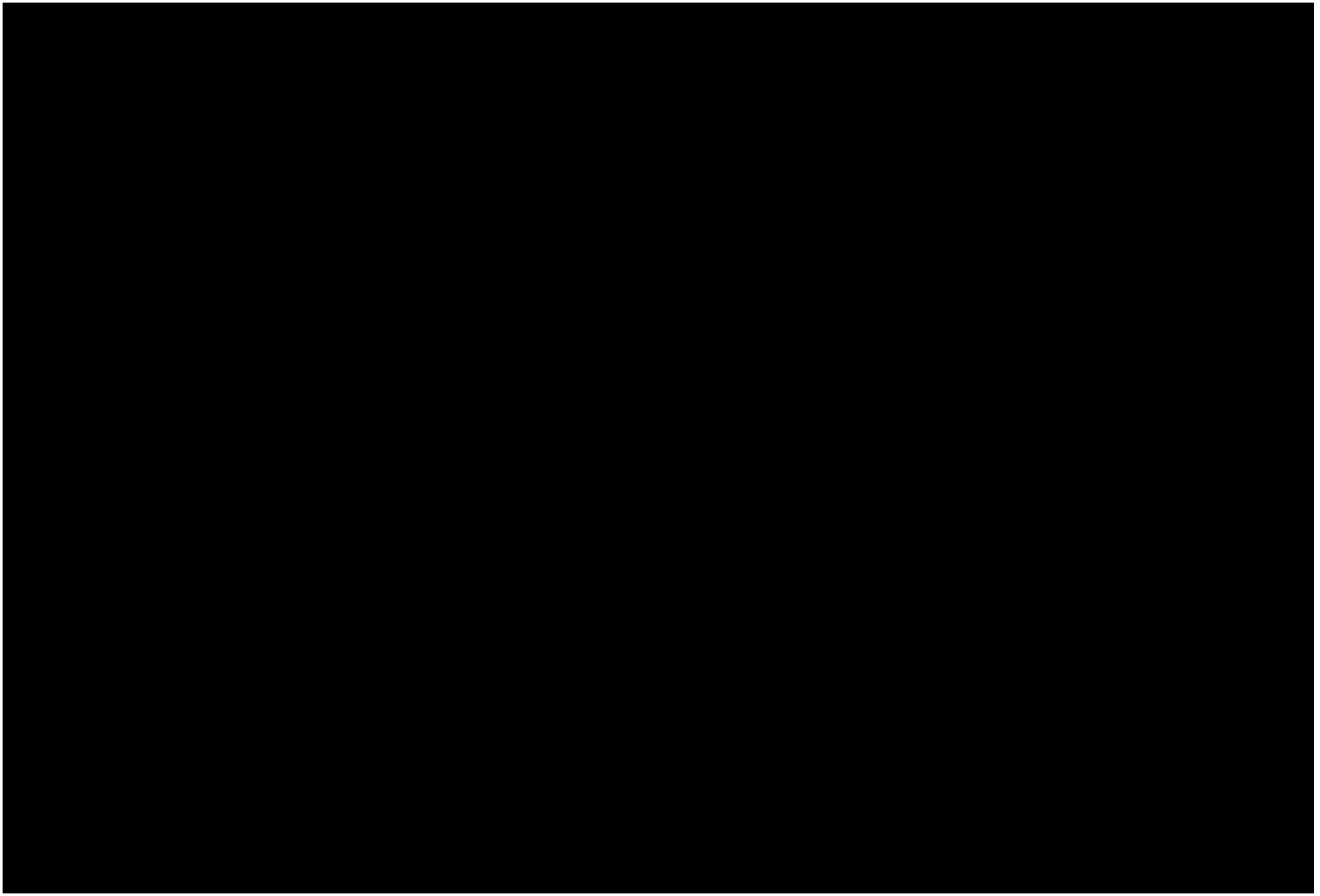
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Northern Rio Arriba Electric Cooperative, Inc.

Date of On Peak Day - 04/04/2021



Member Forecasted On Peak Demand Day for May 2021

Northern Rio Arriba Electric Cooperative, Inc.

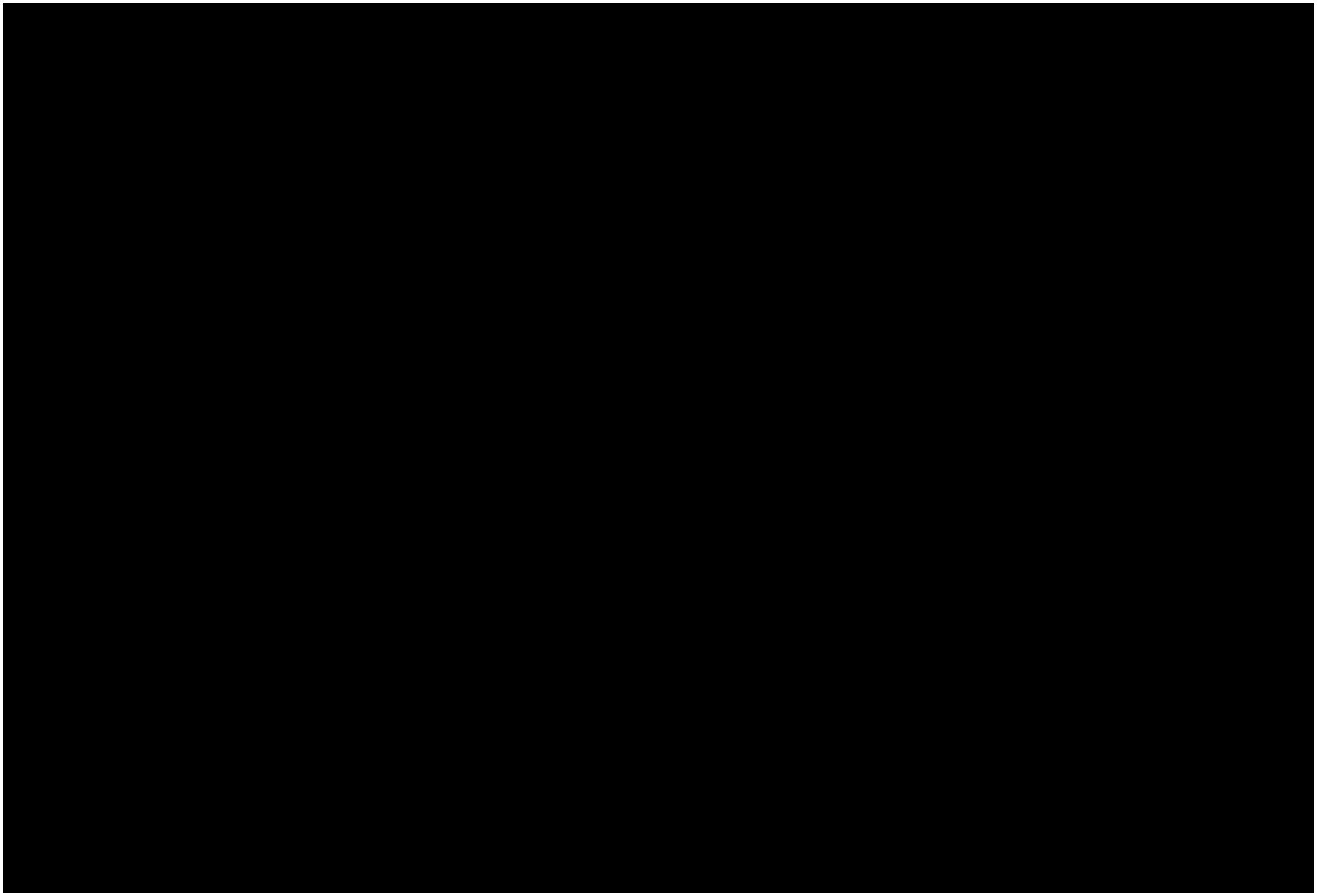
Date of On Peak Day - 05/19/2021

[redacted]

Member Forecasted On Peak Demand Day for June 2021

Northern Rio Arriba Electric Cooperative, Inc.

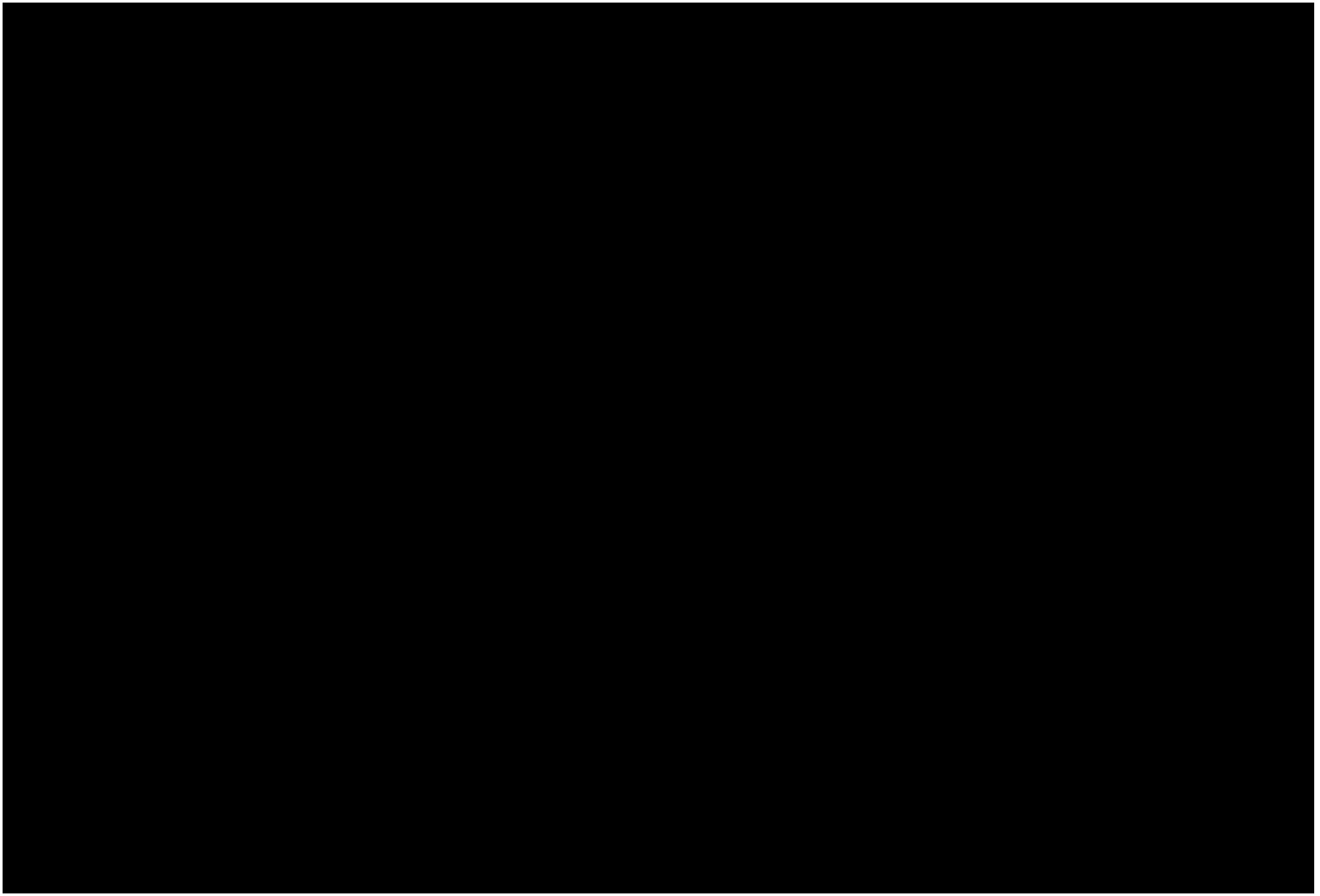
Date of On Peak Day - 06/24/2021



Member Forecasted On Peak Demand Day for July 2021

Northern Rio Arriba Electric Cooperative, Inc.

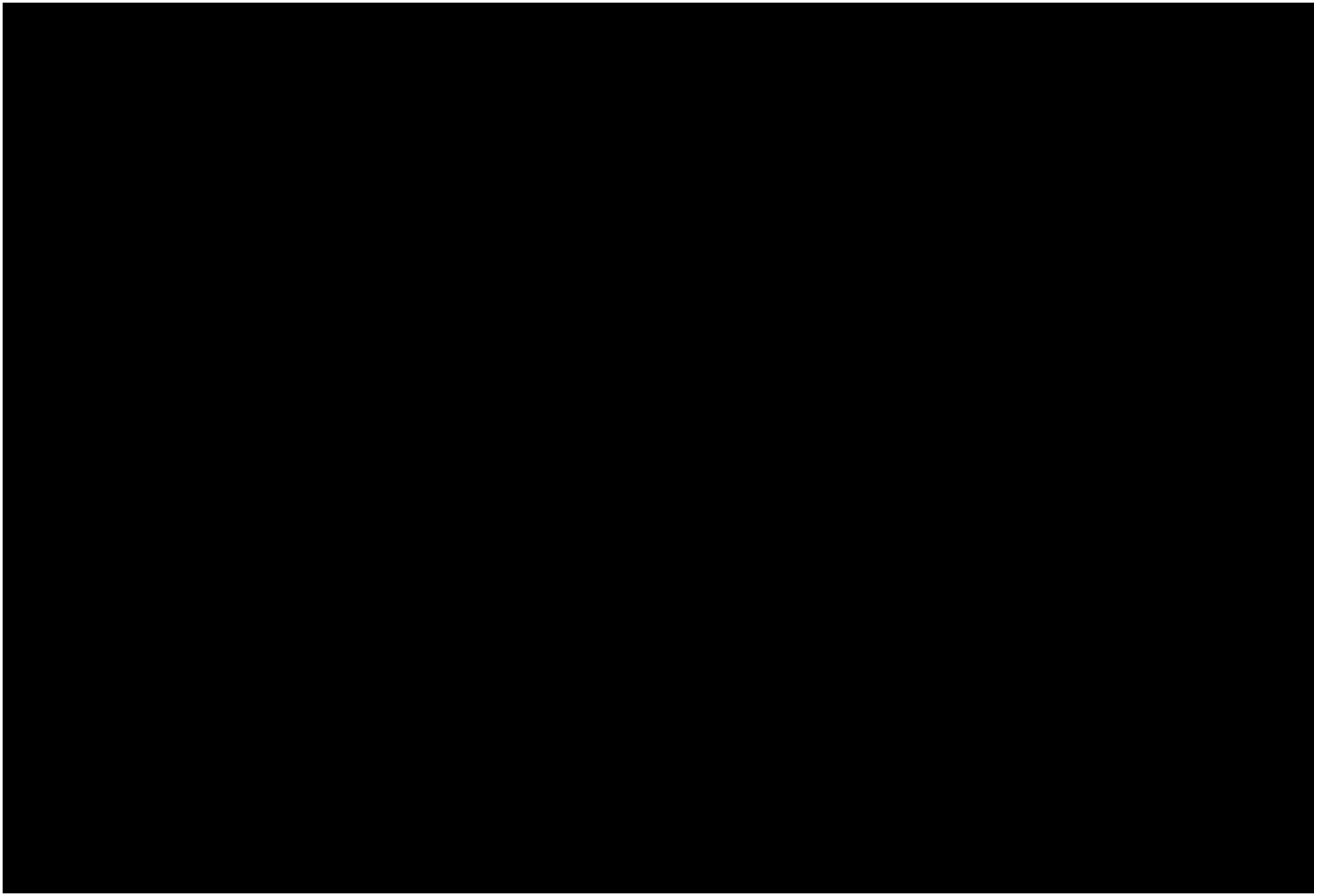
Date of On Peak Day - 07/17/2021



Member Forecasted On Peak Demand Day for August 2021

Northern Rio Arriba Electric Cooperative, Inc.

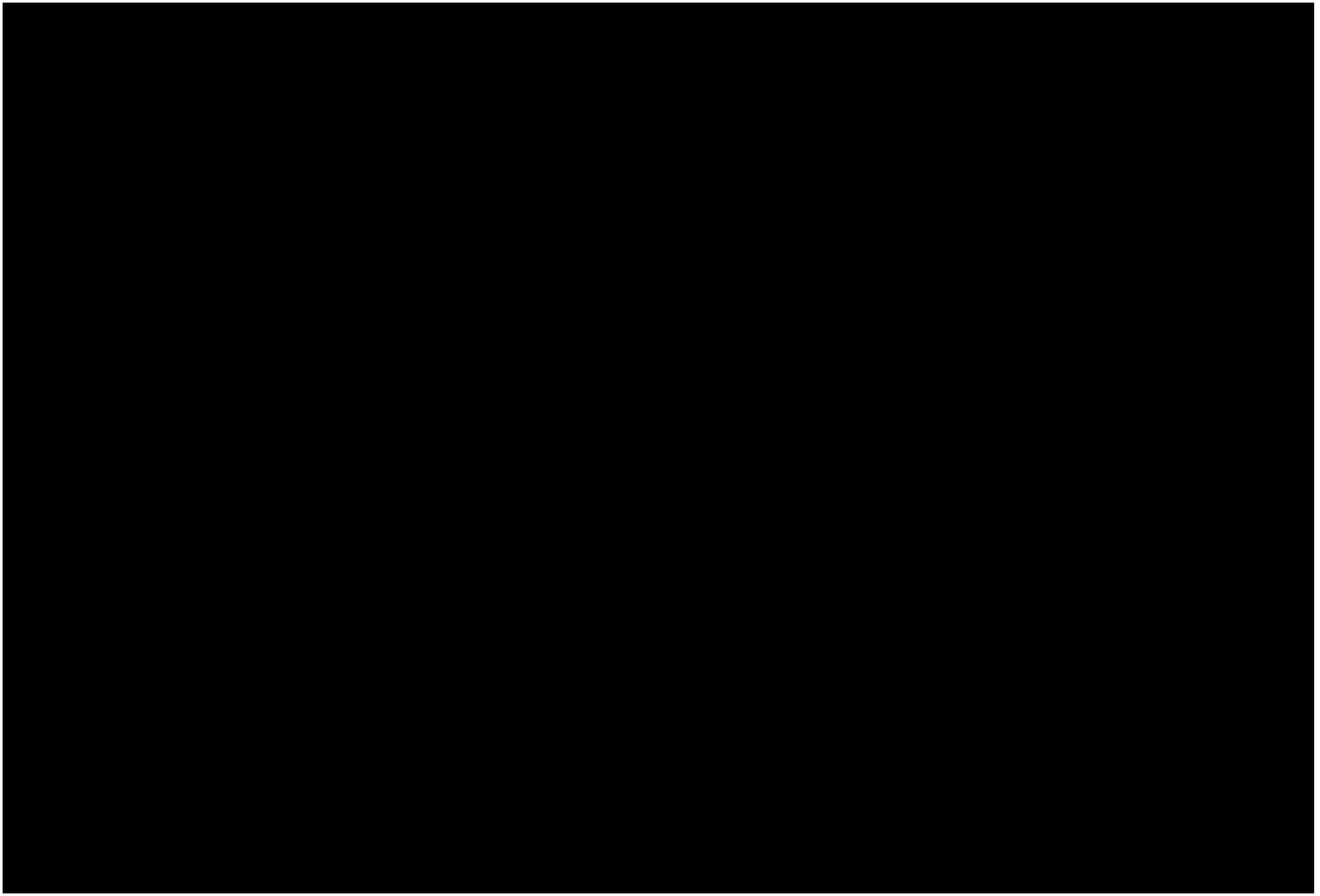
Date of On Peak Day - 08/10/2021



Member Forecasted On Peak Demand Day for September 2021

Northern Rio Arriba Electric Cooperative, Inc.

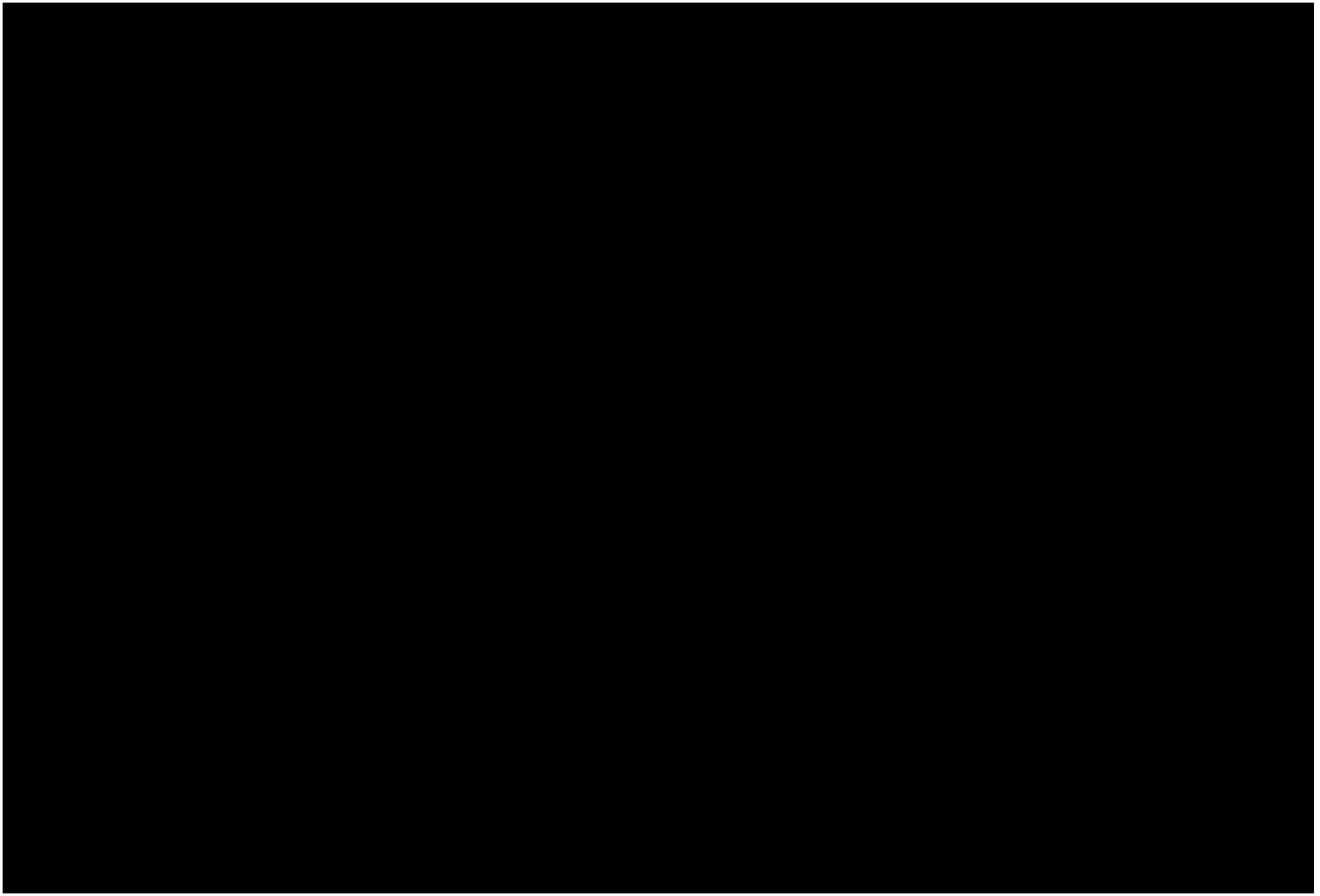
Date of On Peak Day - 09/04/2021



Member Forecasted On Peak Demand Day for October 2021

Northern Rio Arriba Electric Cooperative, Inc.

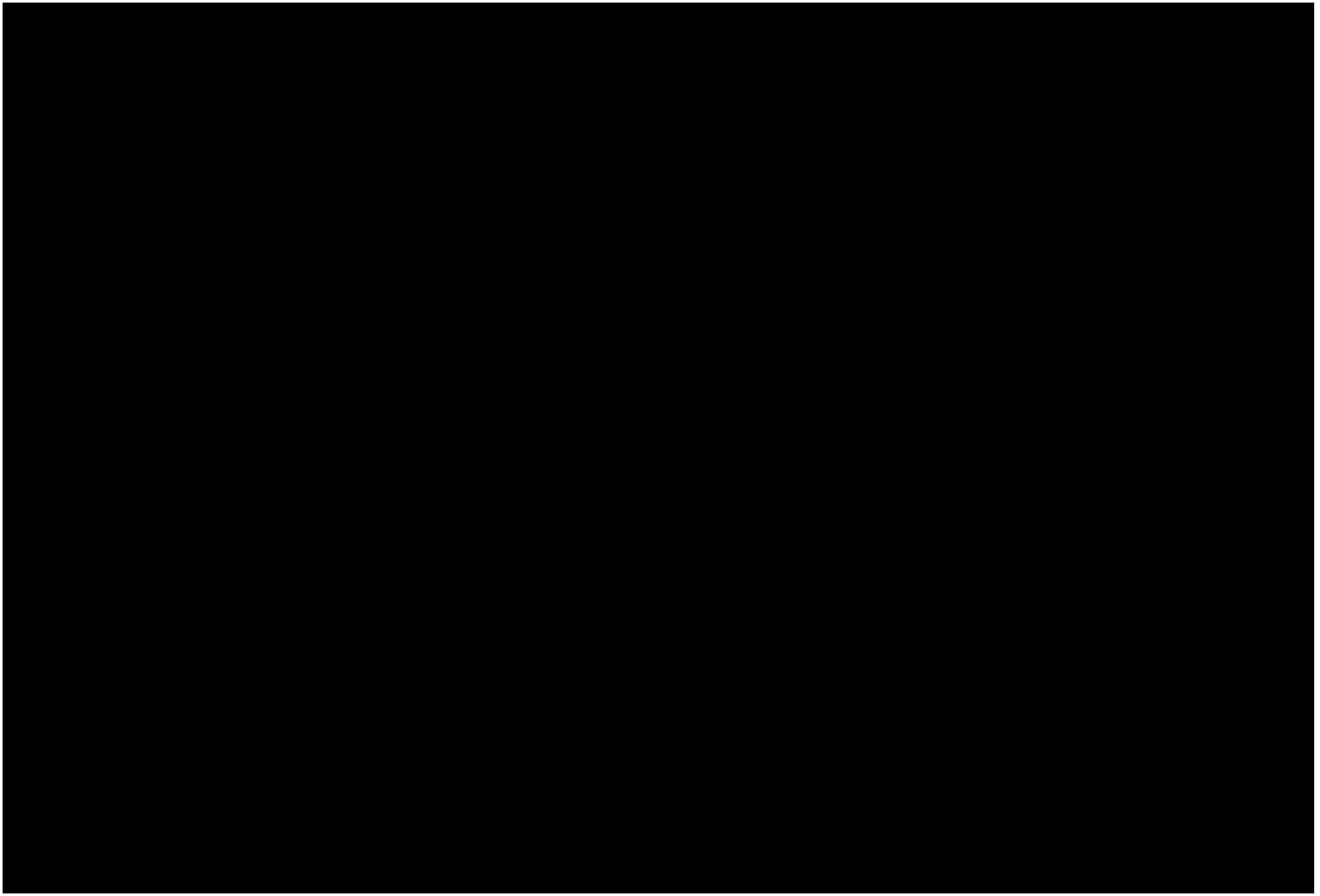
Date of On Peak Day - 10/21/2021



Member Forecasted On Peak Demand Day for November 2021

Northern Rio Arriba Electric Cooperative, Inc.

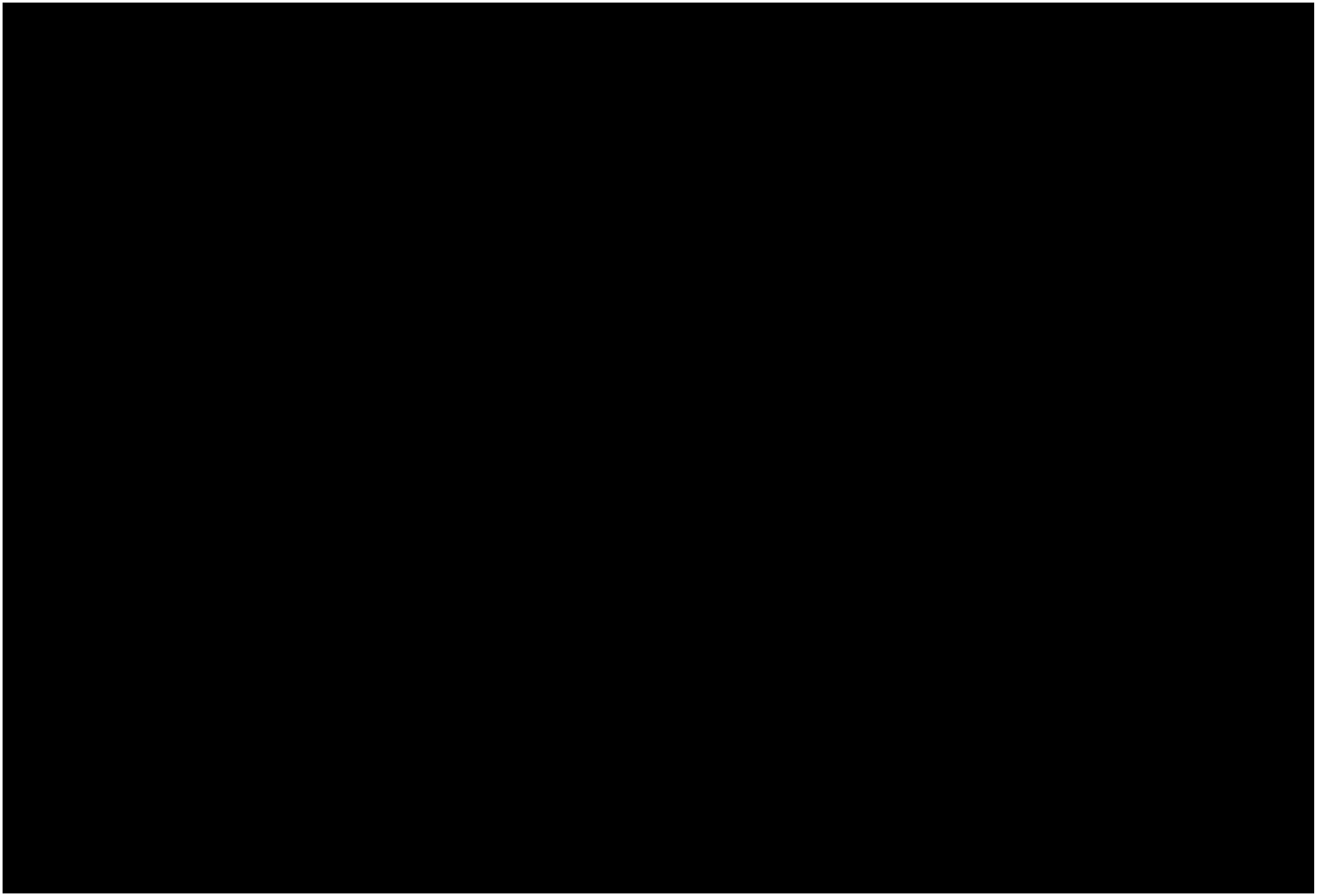
Date of On Peak Day - 11/09/2021



Member Forecasted On Peak Demand Day for December 2021

Northern Rio Arriba Electric Cooperative, Inc.

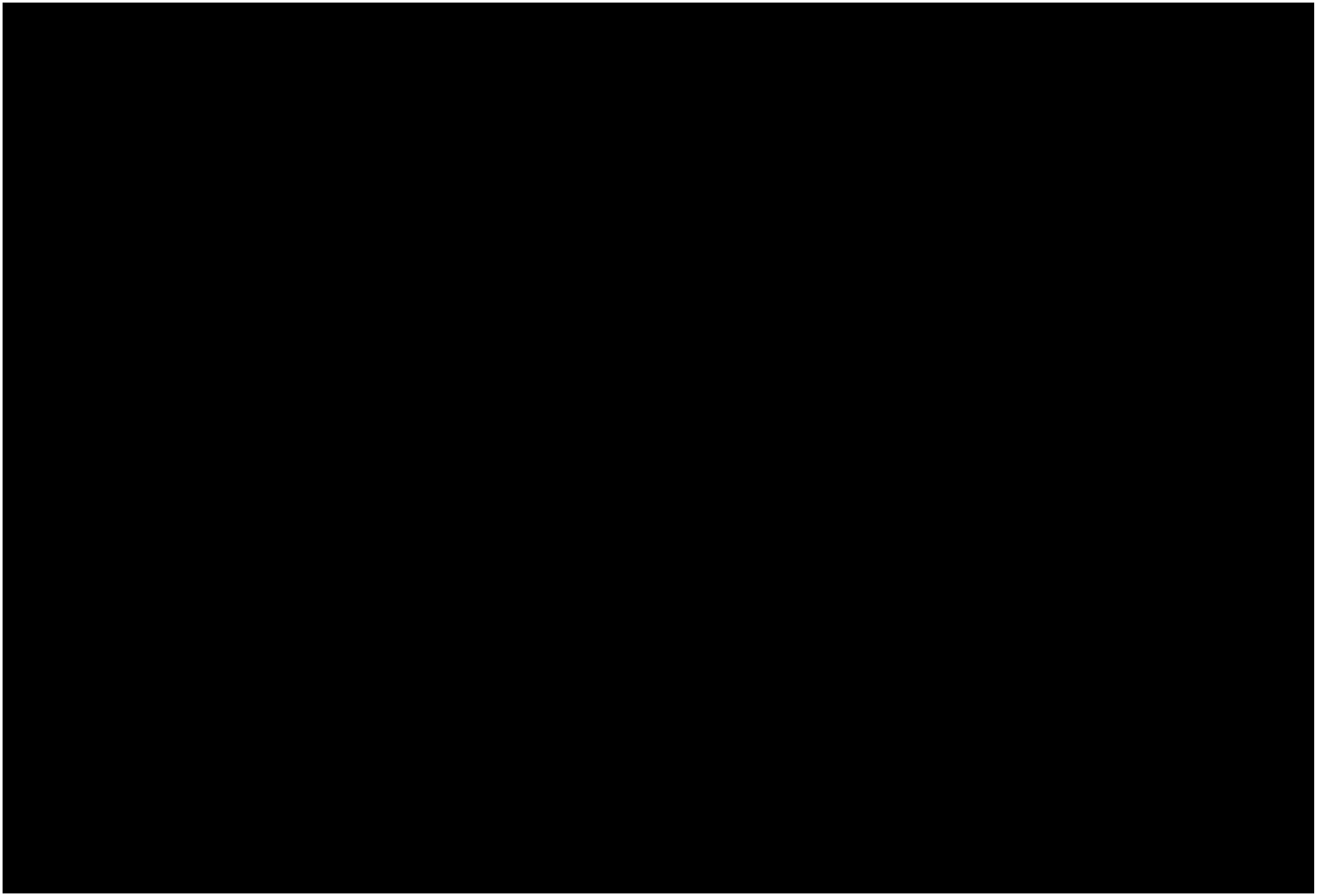
Date of On Peak Day - 12/24/2021



Member Forecasted On Peak Demand Day for January 2021

Roosevelt Public Power District

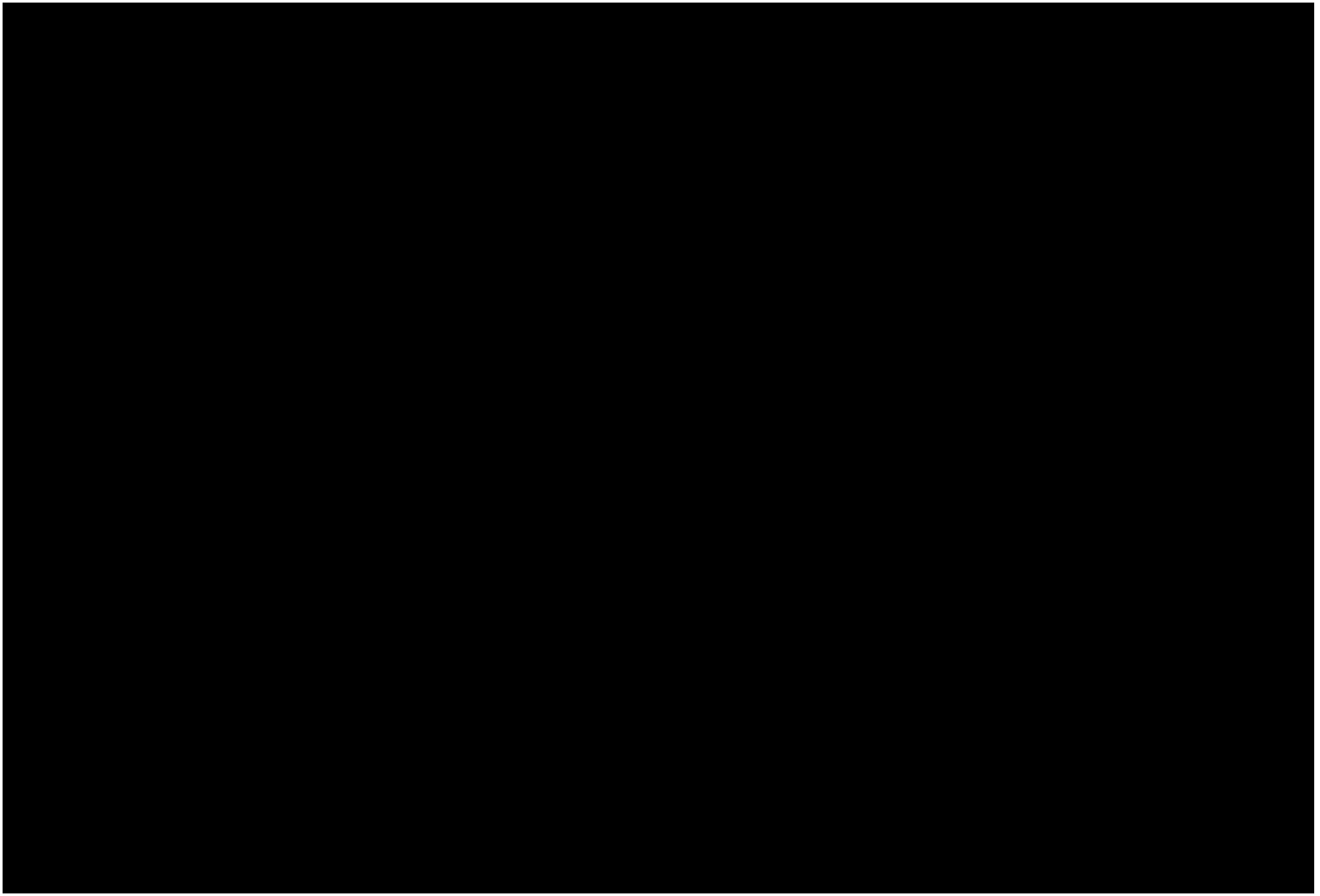
Date of On Peak Day - 01/07/2021



Member Forecasted On Peak Demand Day for February 2021

Roosevelt Public Power District

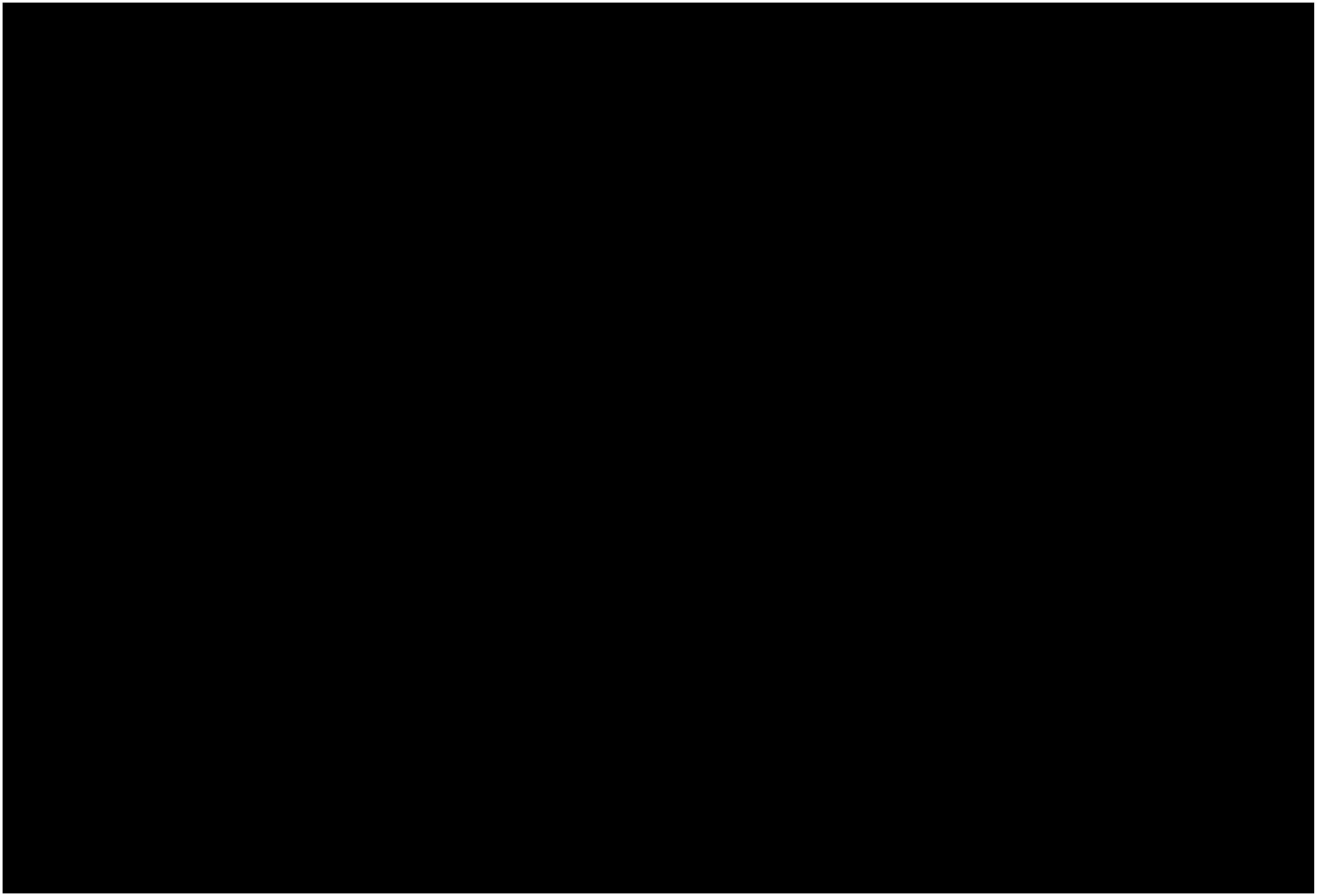
Date of On Peak Day - 02/03/2021



Member Forecasted On Peak Demand Day for March 2021

Roosevelt Public Power District

Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

Roosevelt Public Power District

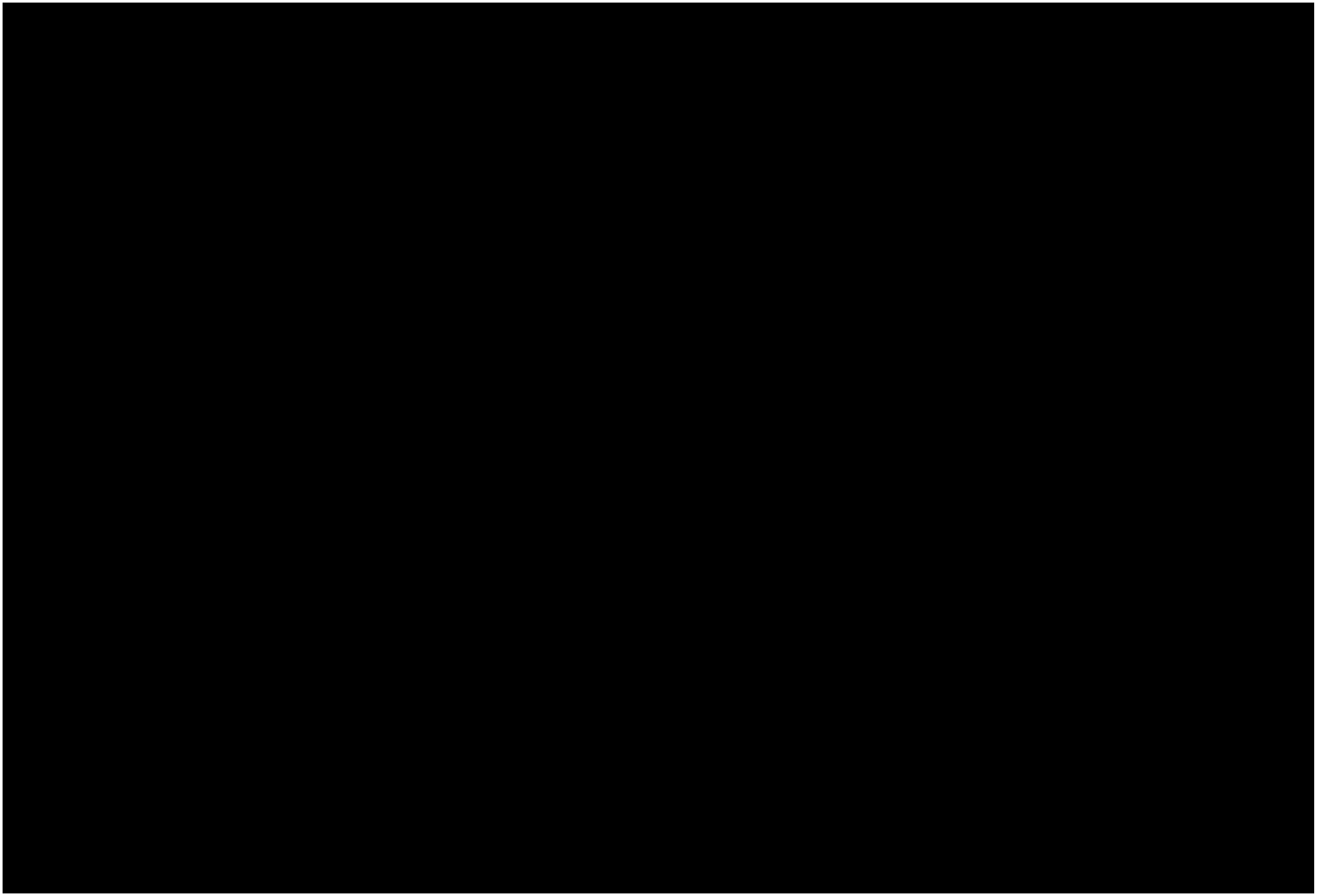
Date of On Peak Day - 04/05/2021

[redacted]

Member Forecasted On Peak Demand Day for May 2021

Roosevelt Public Power District

Date of On Peak Day - 05/13/2021



Member Forecasted On Peak Demand Day for June 2021

Roosevelt Public Power District

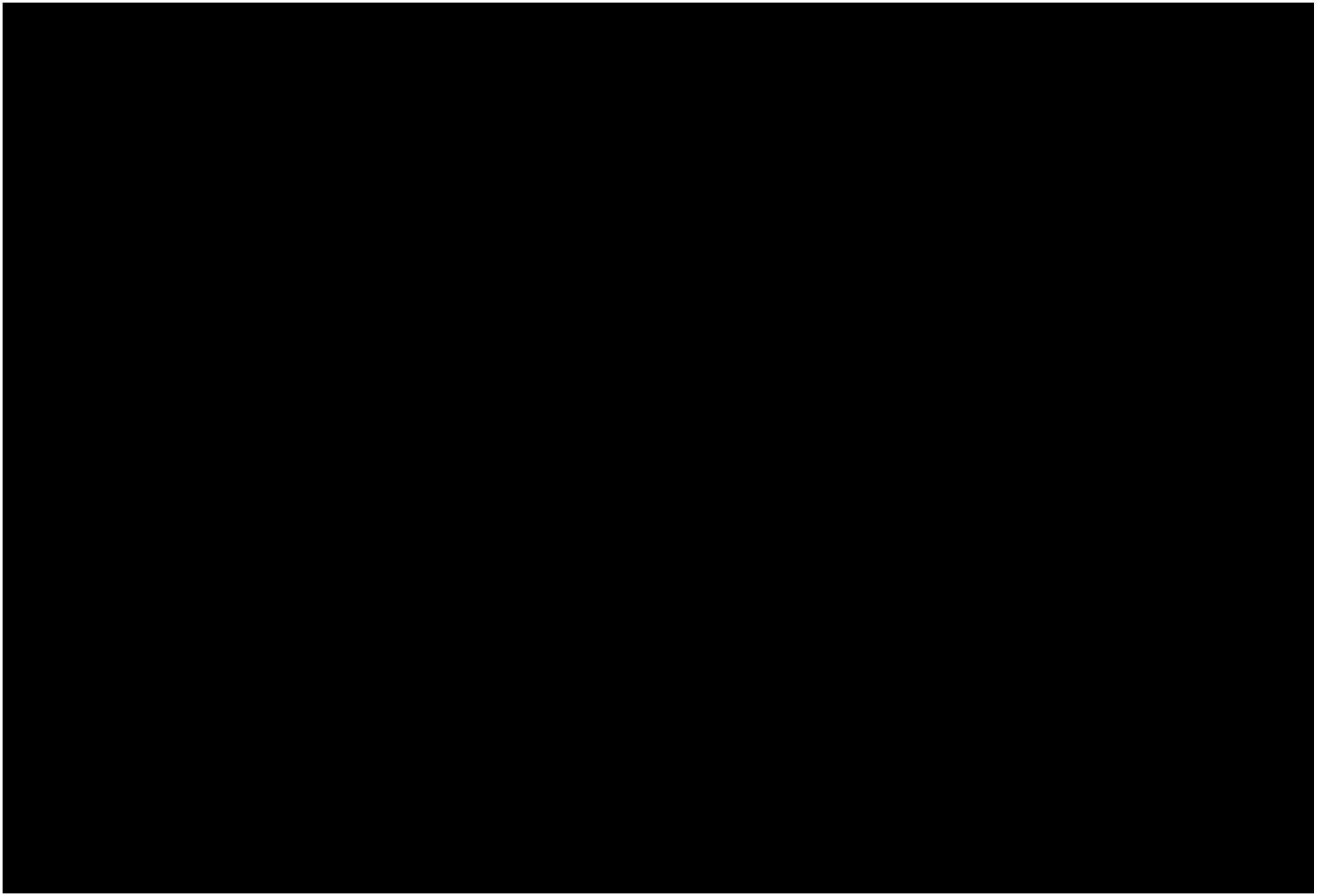
Date of On Peak Day - 06/28/2021

[redacted]

Member Forecasted On Peak Demand Day for July 2021

Roosevelt Public Power District

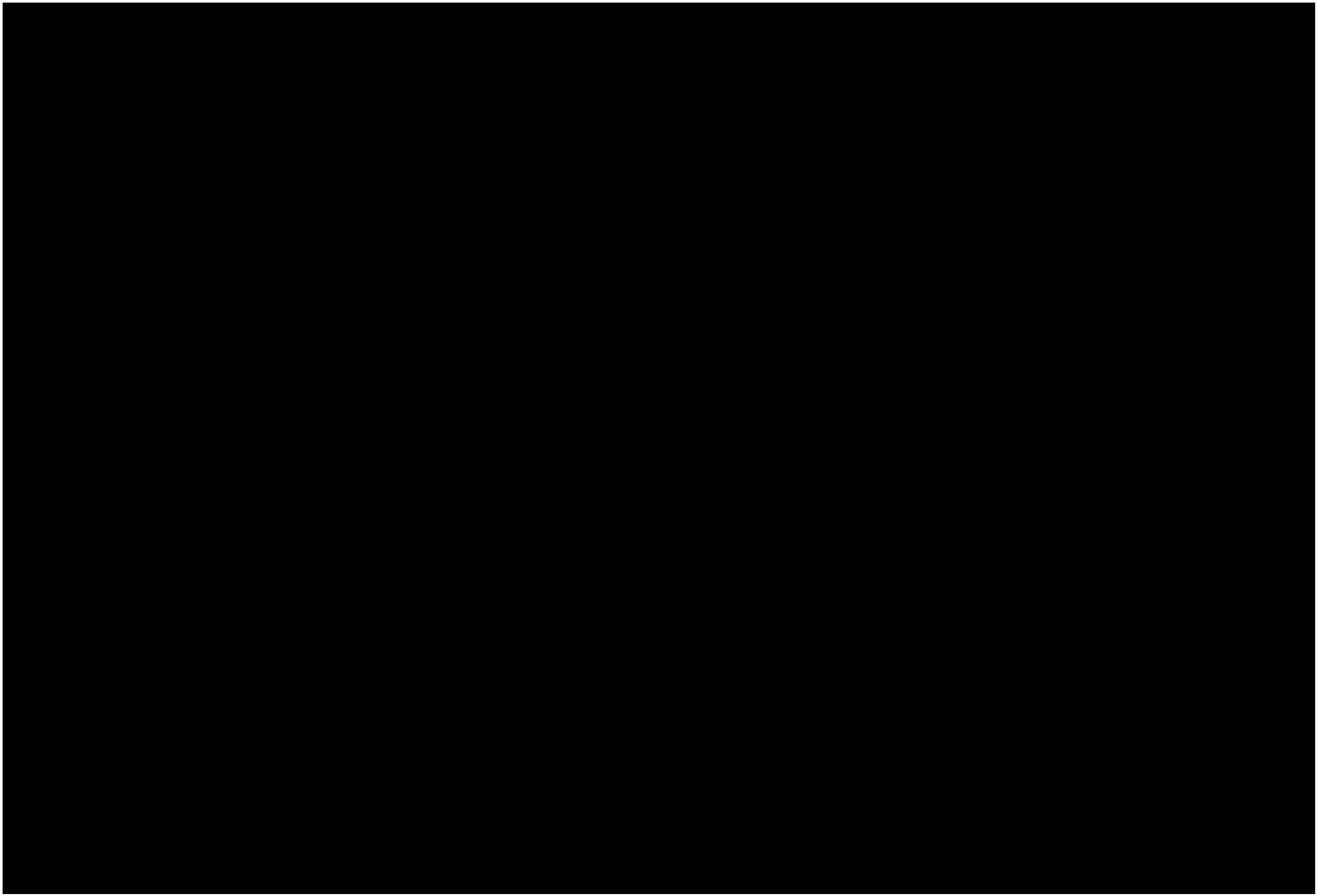
Date of On Peak Day - 07/10/2021



Member Forecasted On Peak Demand Day for August 2021

Roosevelt Public Power District

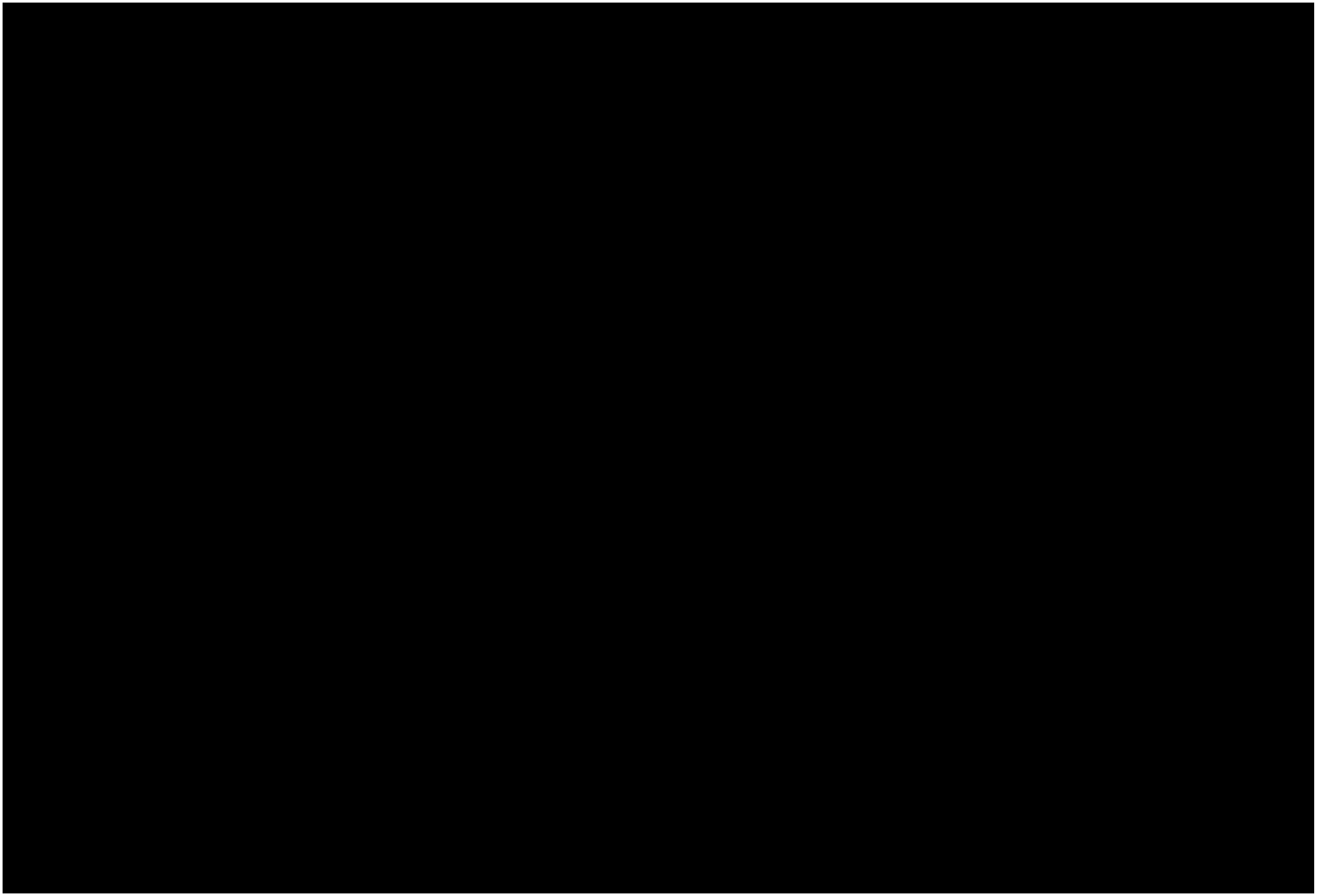
Date of On Peak Day - 08/28/2021



Member Forecasted On Peak Demand Day for September 2021

Roosevelt Public Power District

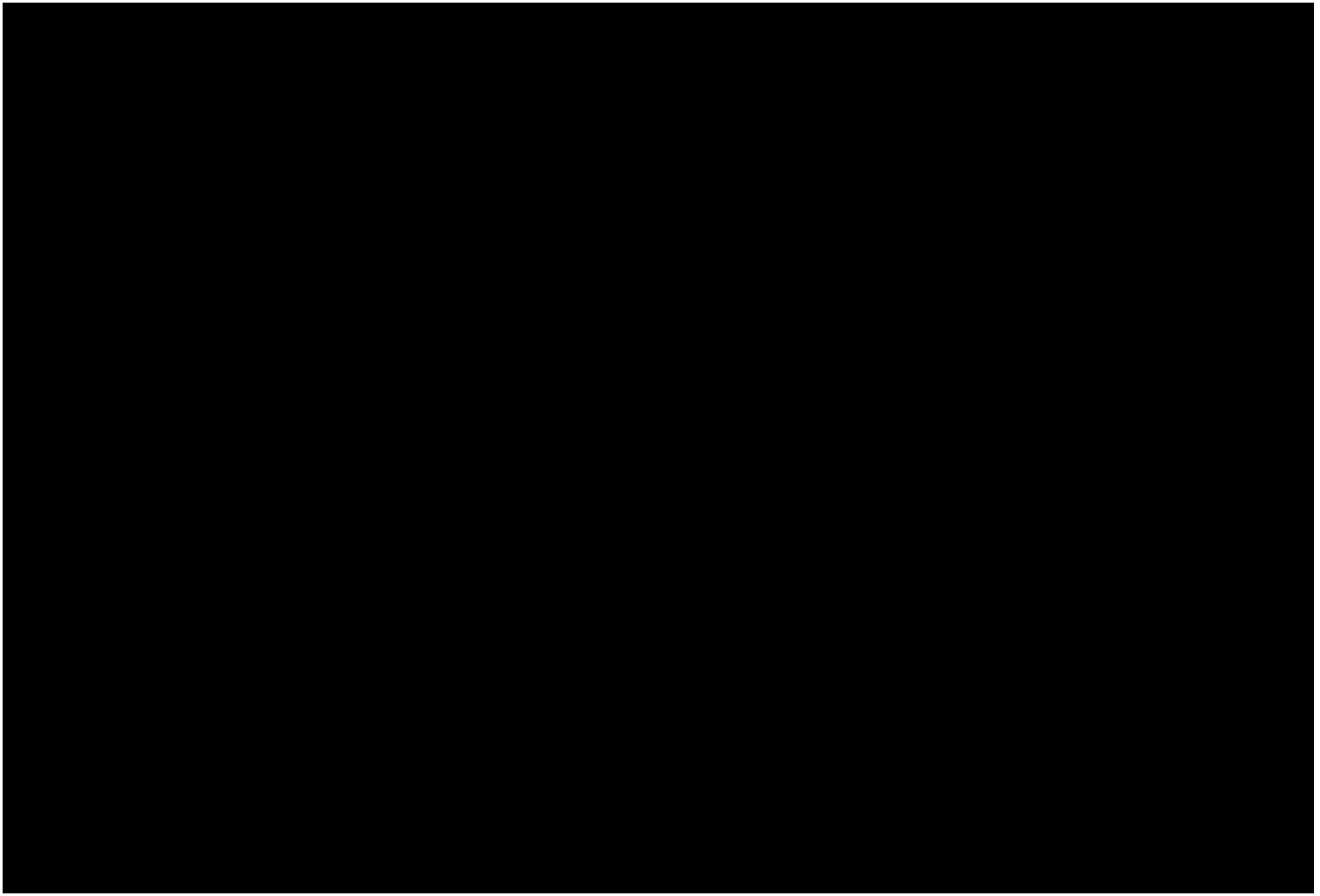
Date of On Peak Day - 09/04/2021



Member Forecasted On Peak Demand Day for October 2021

Roosevelt Public Power District

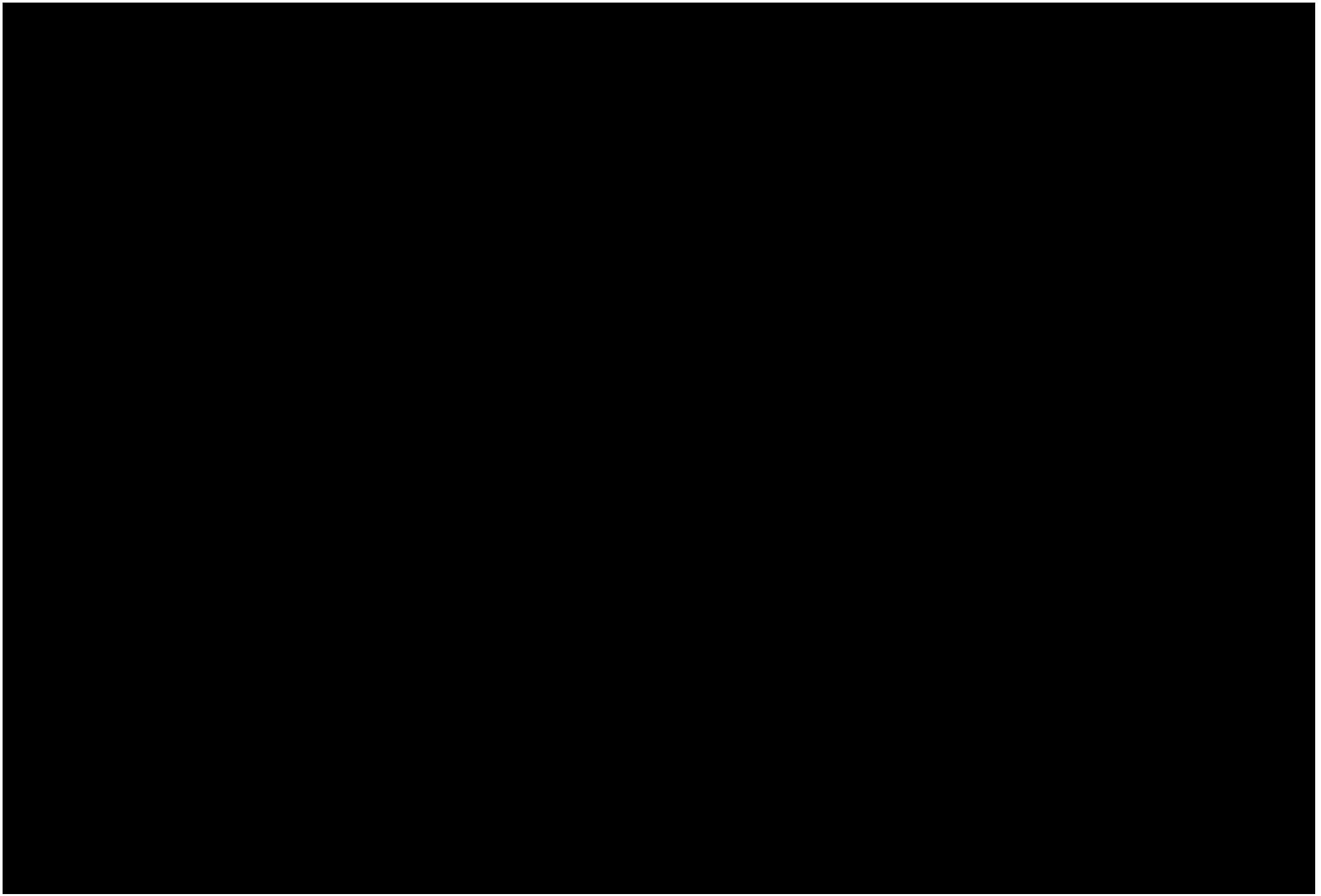
Date of On Peak Day - 10/29/2021



Member Forecasted On Peak Demand Day for November 2021

Roosevelt Public Power District

Date of On Peak Day - 11/21/2021



Member Forecasted On Peak Demand Day for December 2021

Roosevelt Public Power District

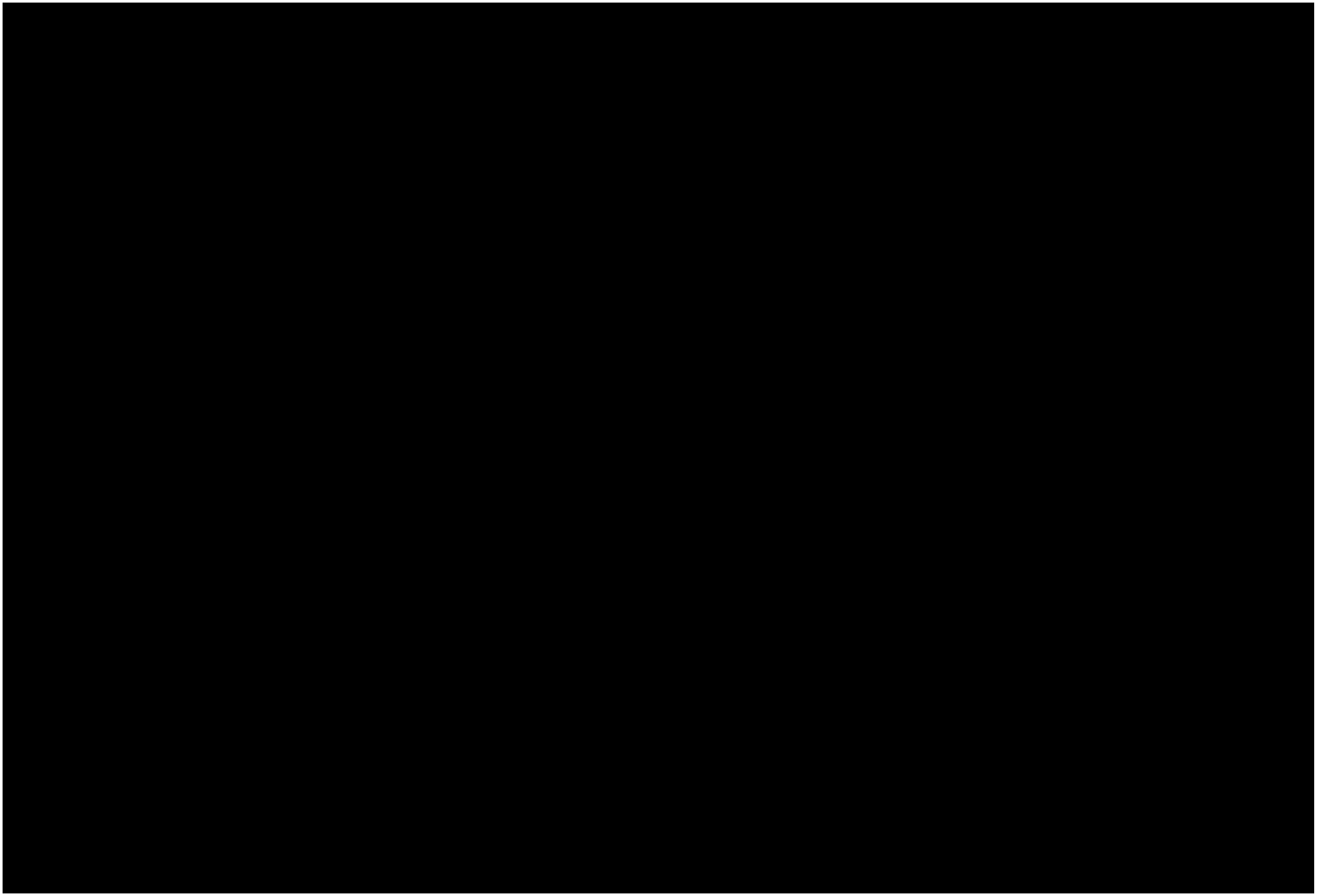
Date of On Peak Day - 12/30/2021

[redacted]

Member Forecasted On Peak Demand Day for January 2021

Sierra Electric Cooperative, Inc.

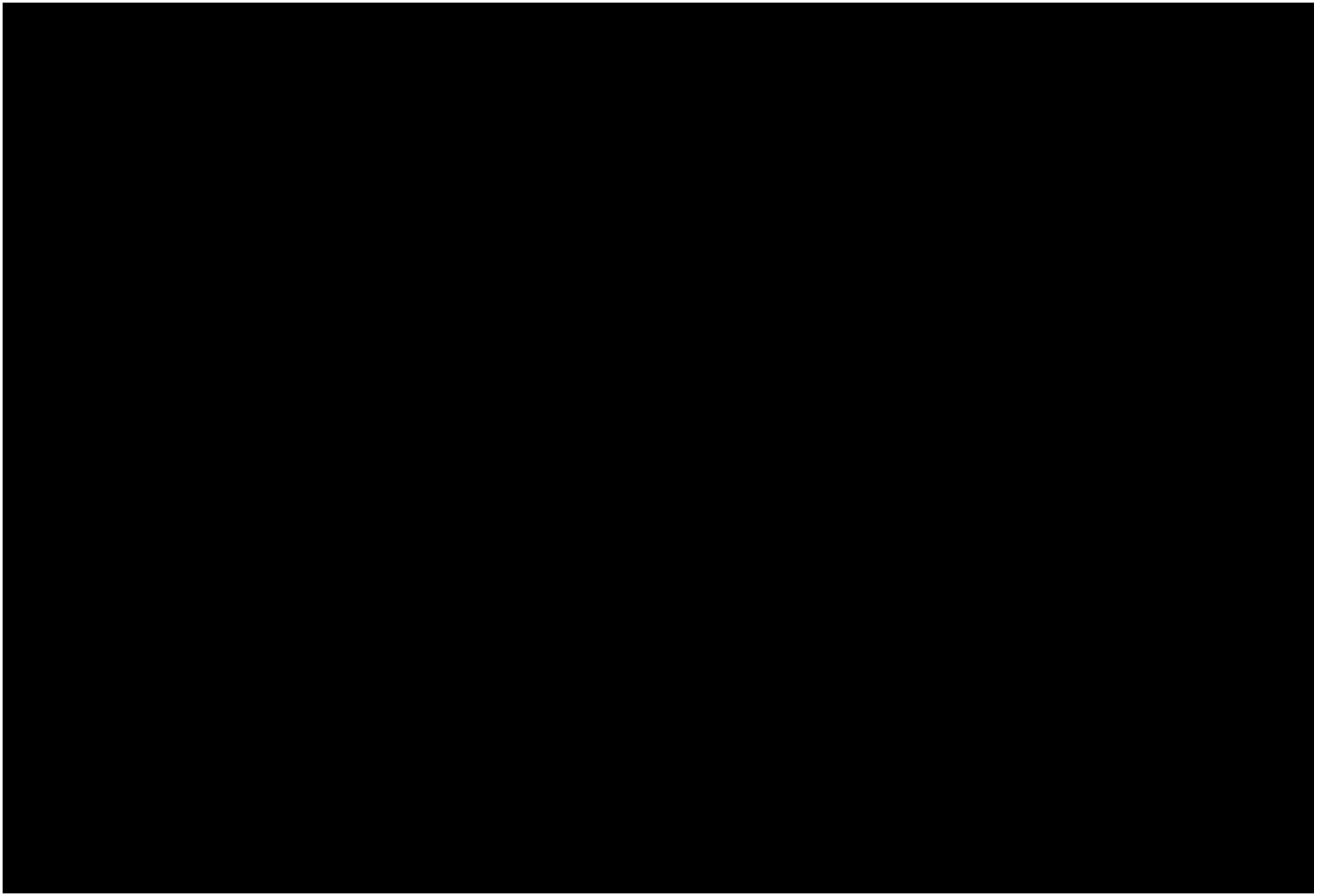
Date of On Peak Day - 01/27/2021



Member Forecasted On Peak Demand Day for February 2021

Sierra Electric Cooperative, Inc.

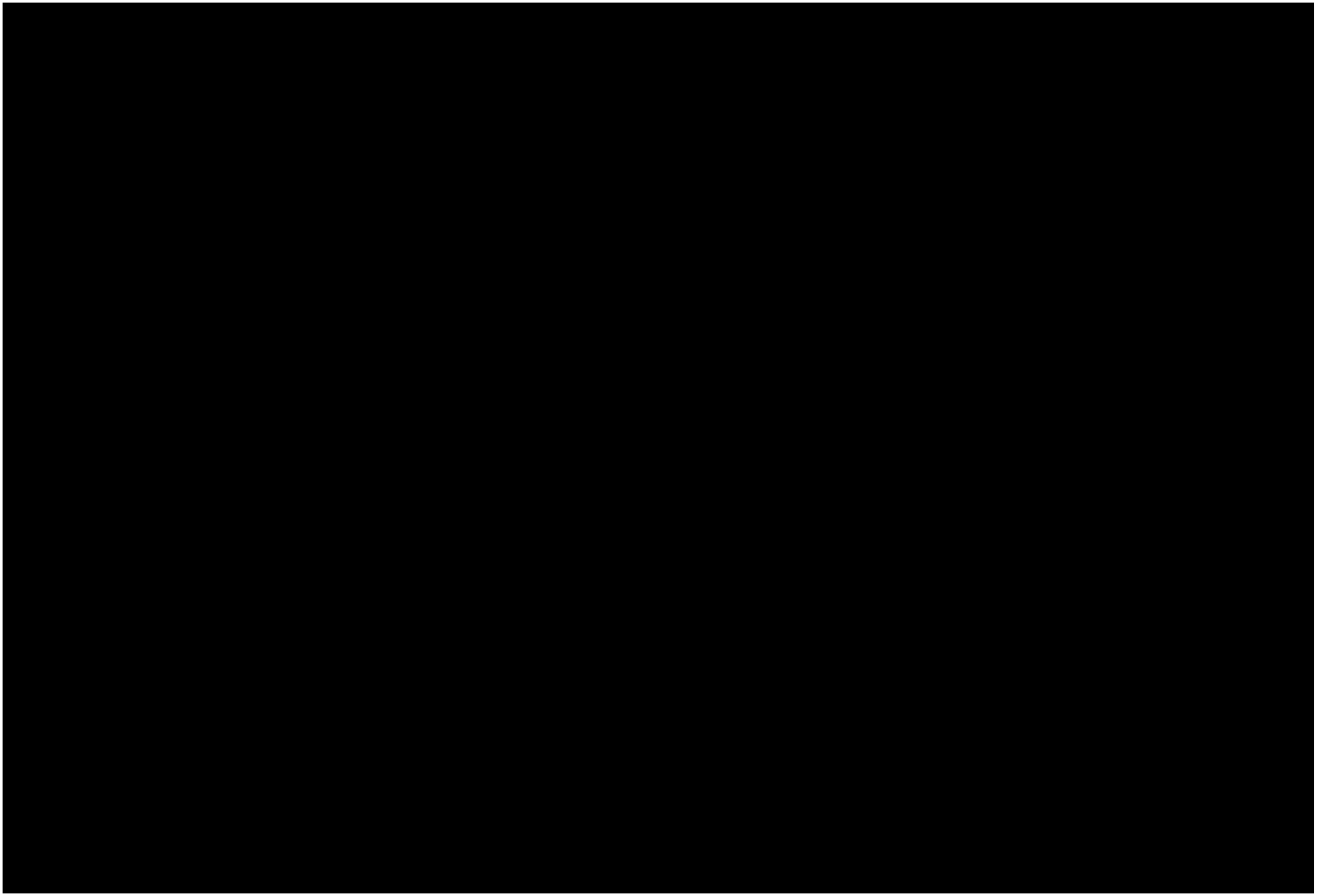
Date of On Peak Day - 02/02/2021



Member Forecasted On Peak Demand Day for March 2021

Sierra Electric Cooperative, Inc.

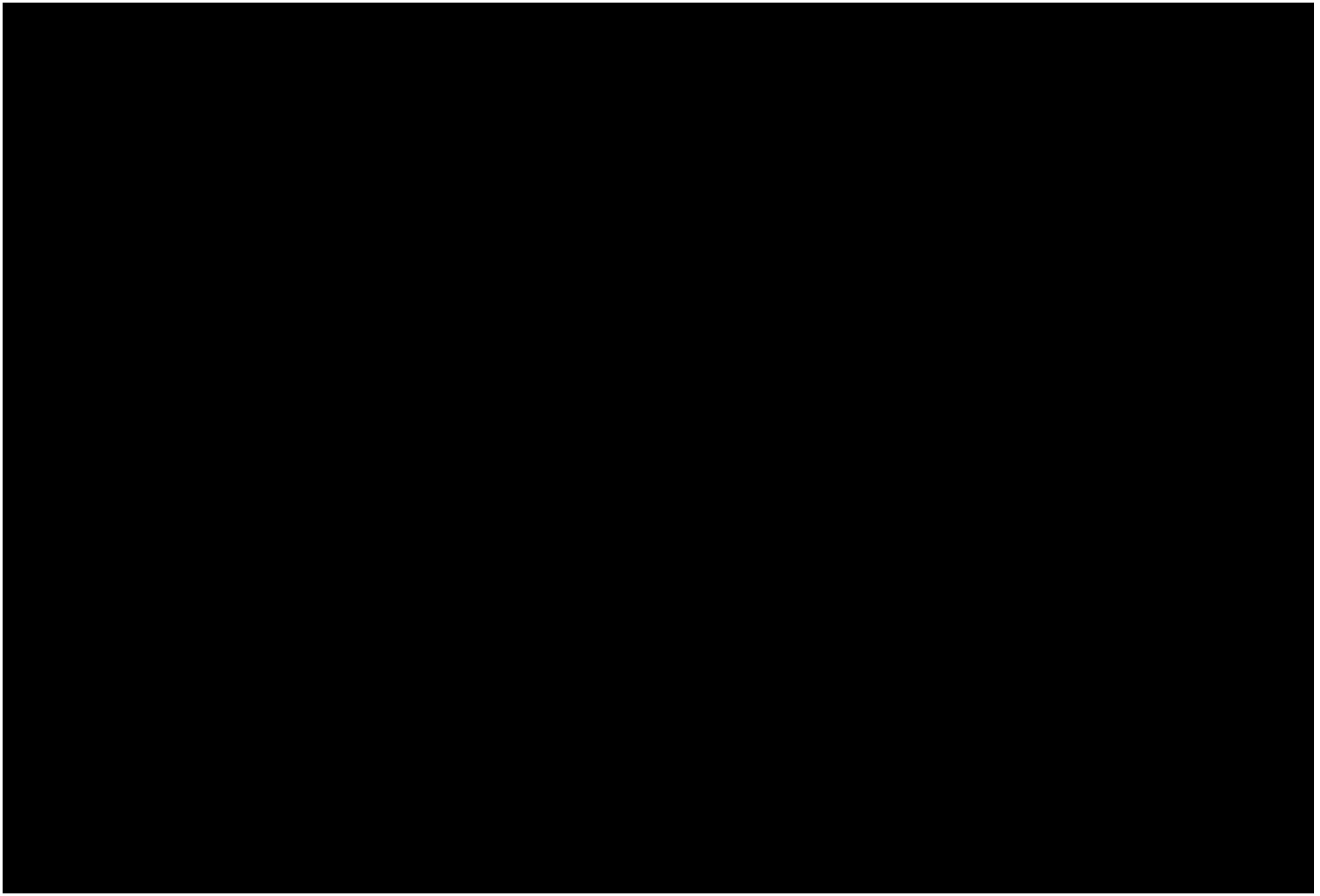
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Sierra Electric Cooperative, Inc.

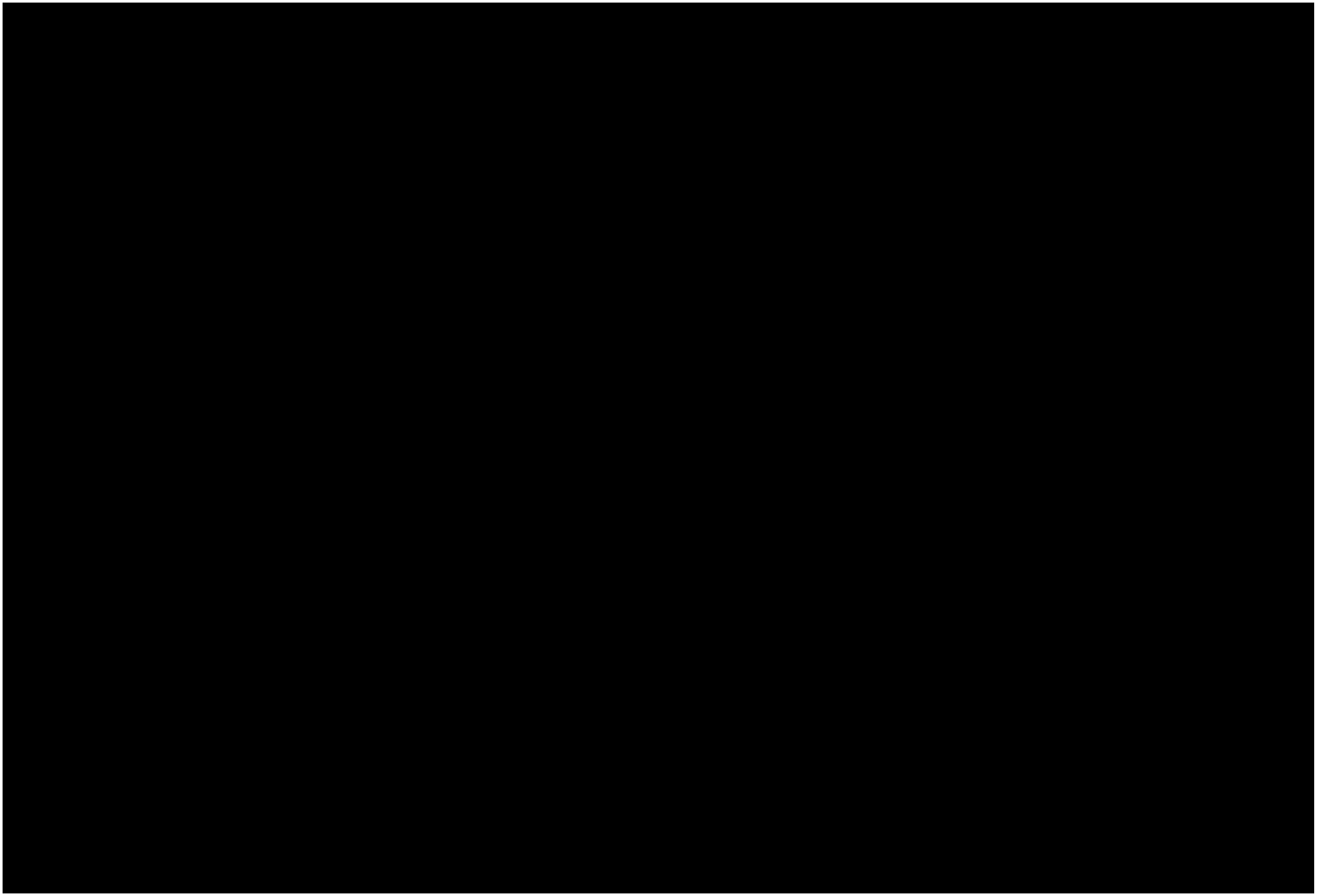
Date of On Peak Day - 04/30/2021



Member Forecasted On Peak Demand Day for May 2021

Sierra Electric Cooperative, Inc.

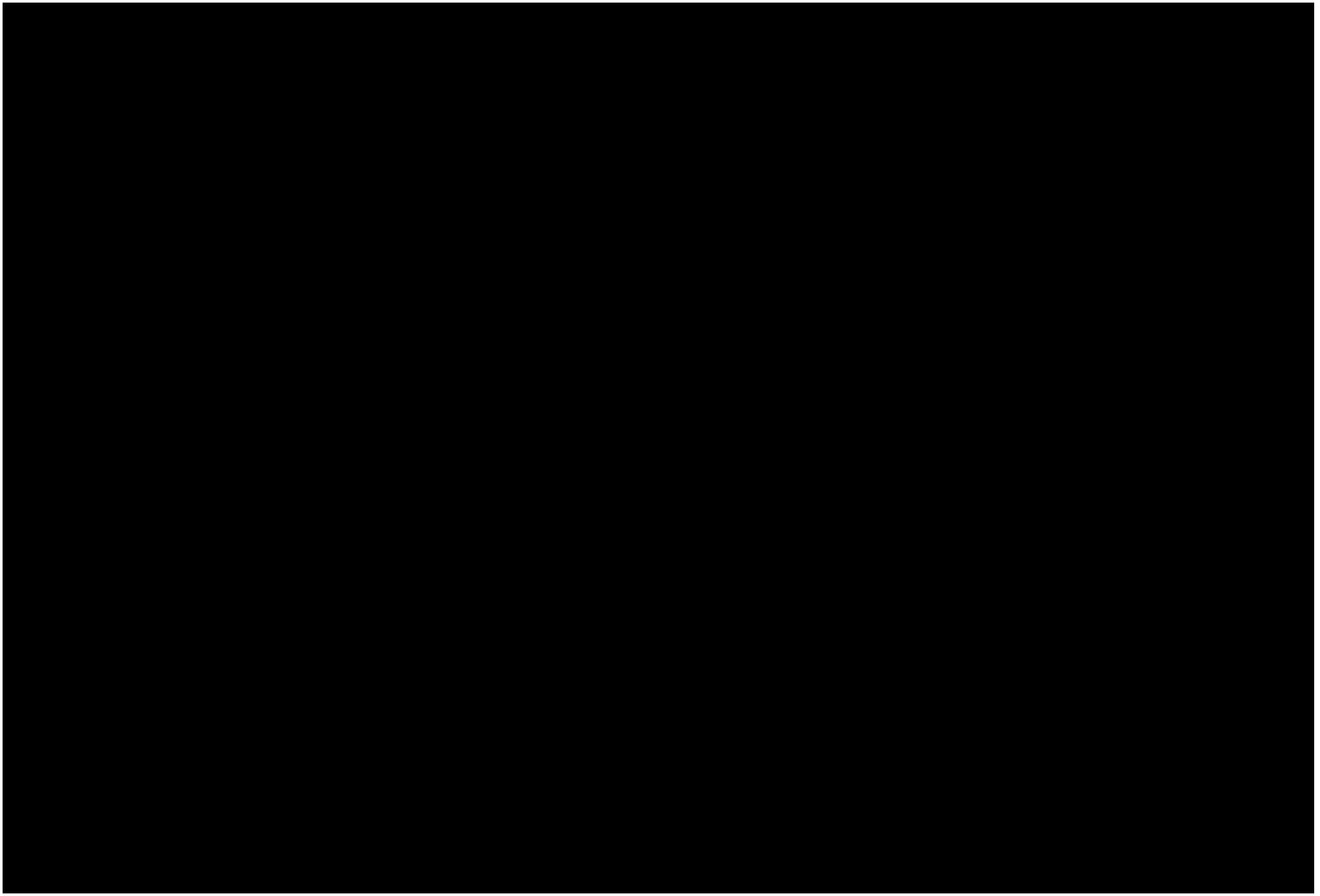
Date of On Peak Day - 05/24/2021



Member Forecasted On Peak Demand Day for June 2021

Sierra Electric Cooperative, Inc.

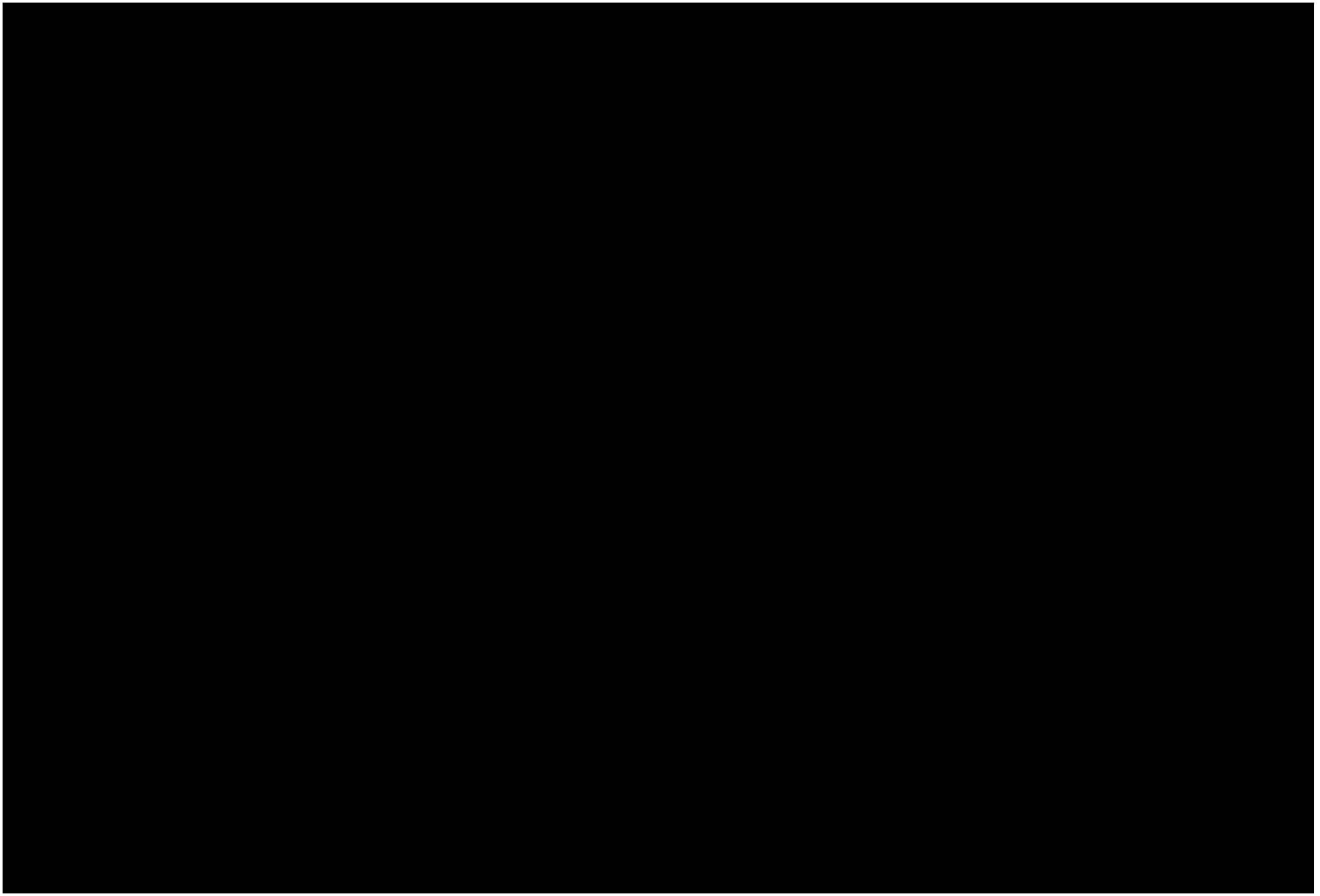
Date of On Peak Day - 06/27/2021



Member Forecasted On Peak Demand Day for July 2021

Sierra Electric Cooperative, Inc.

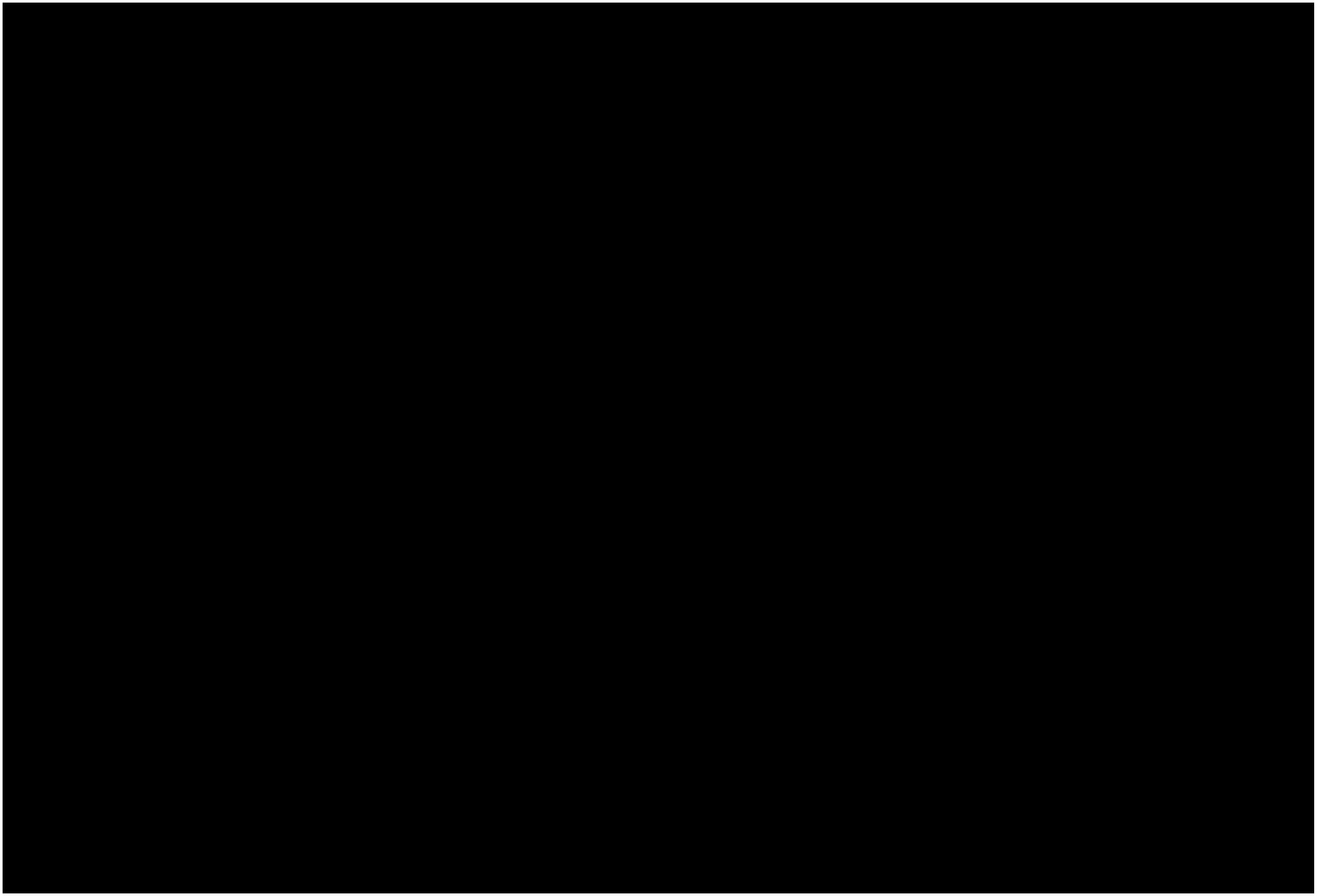
Date of On Peak Day - 07/15/2021



Member Forecasted On Peak Demand Day for August 2021

Sierra Electric Cooperative, Inc.

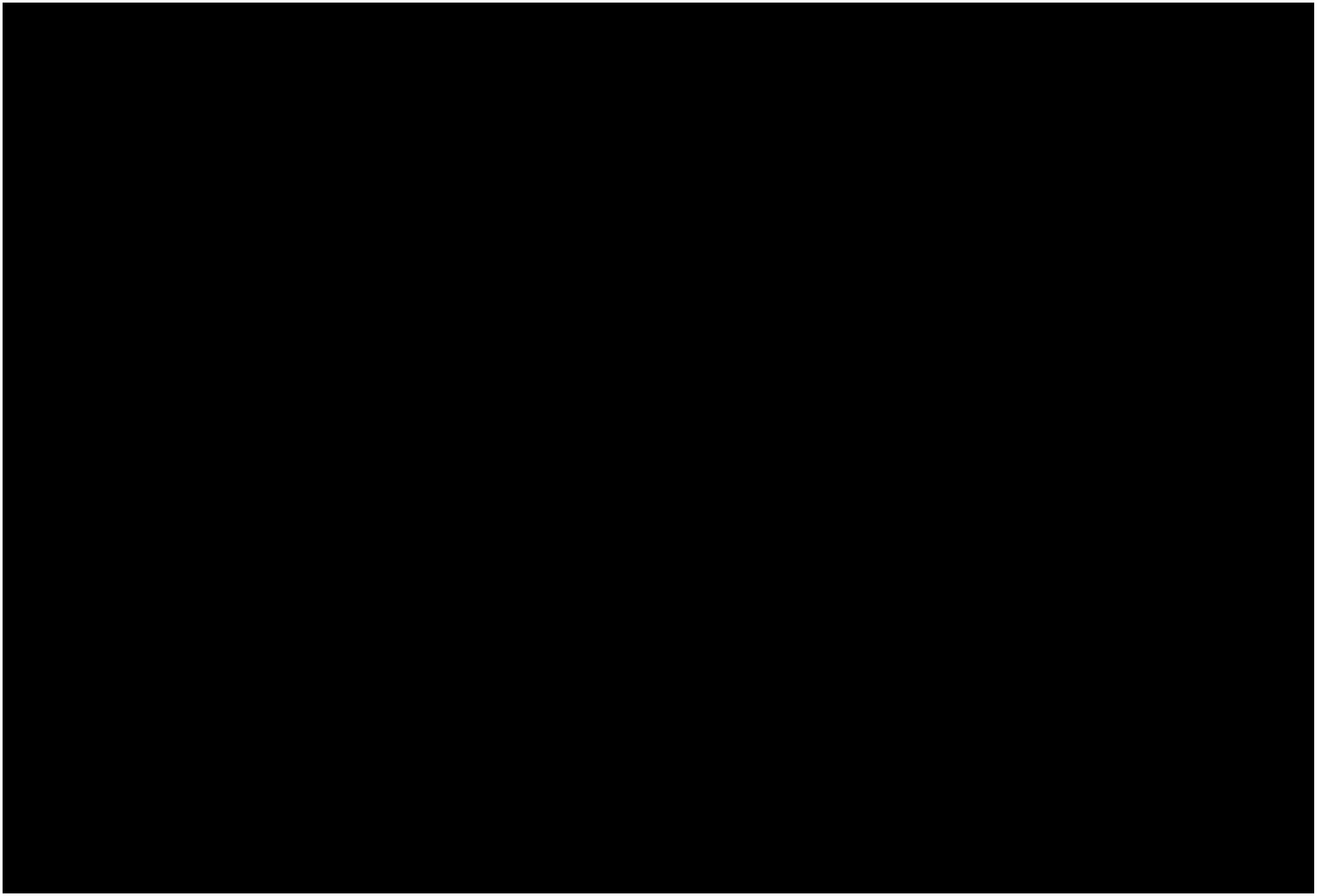
Date of On Peak Day - 08/06/2021



Member Forecasted On Peak Demand Day for September 2021

Sierra Electric Cooperative, Inc.

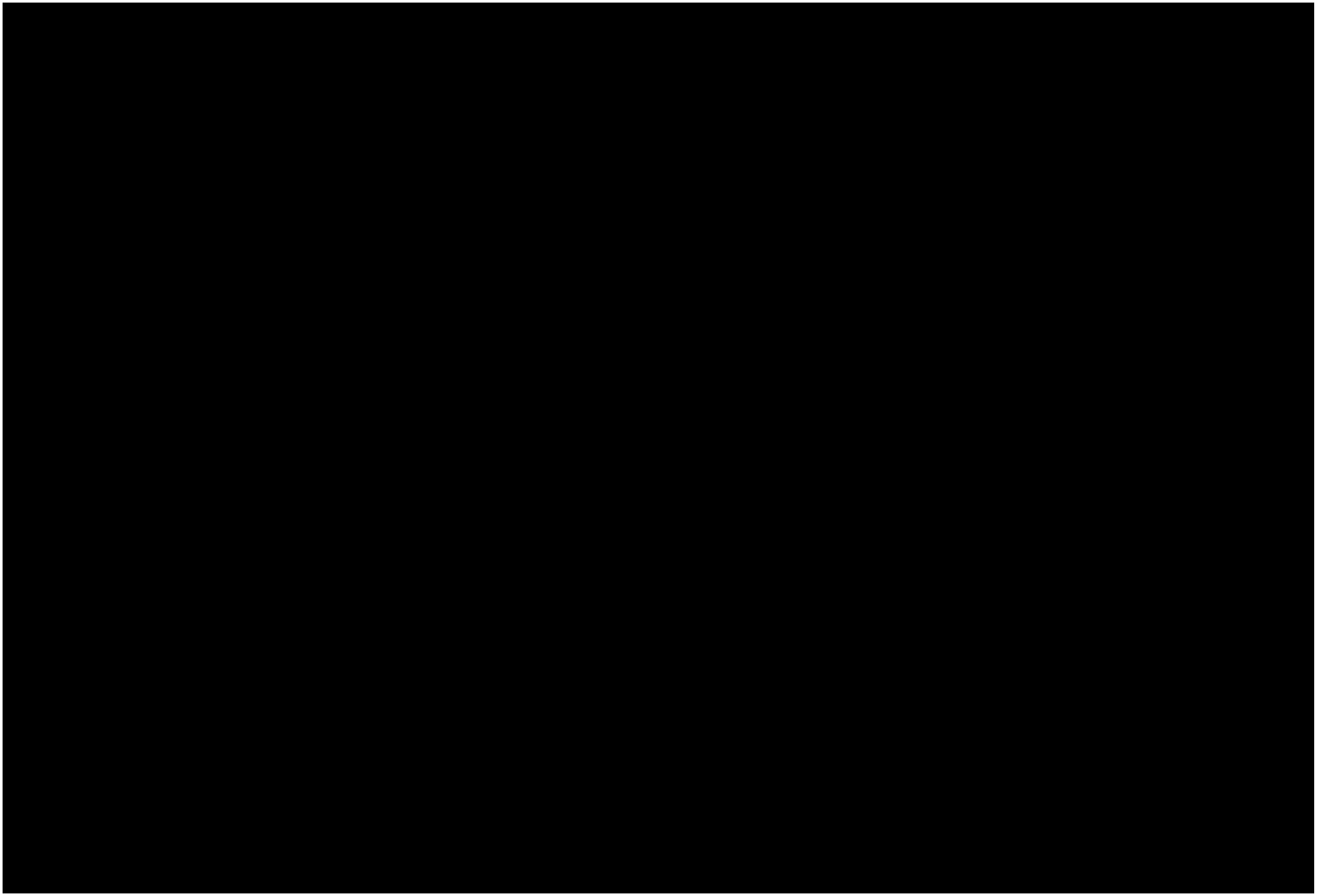
Date of On Peak Day - 09/01/2021



Member Forecasted On Peak Demand Day for October 2021

Sierra Electric Cooperative, Inc.

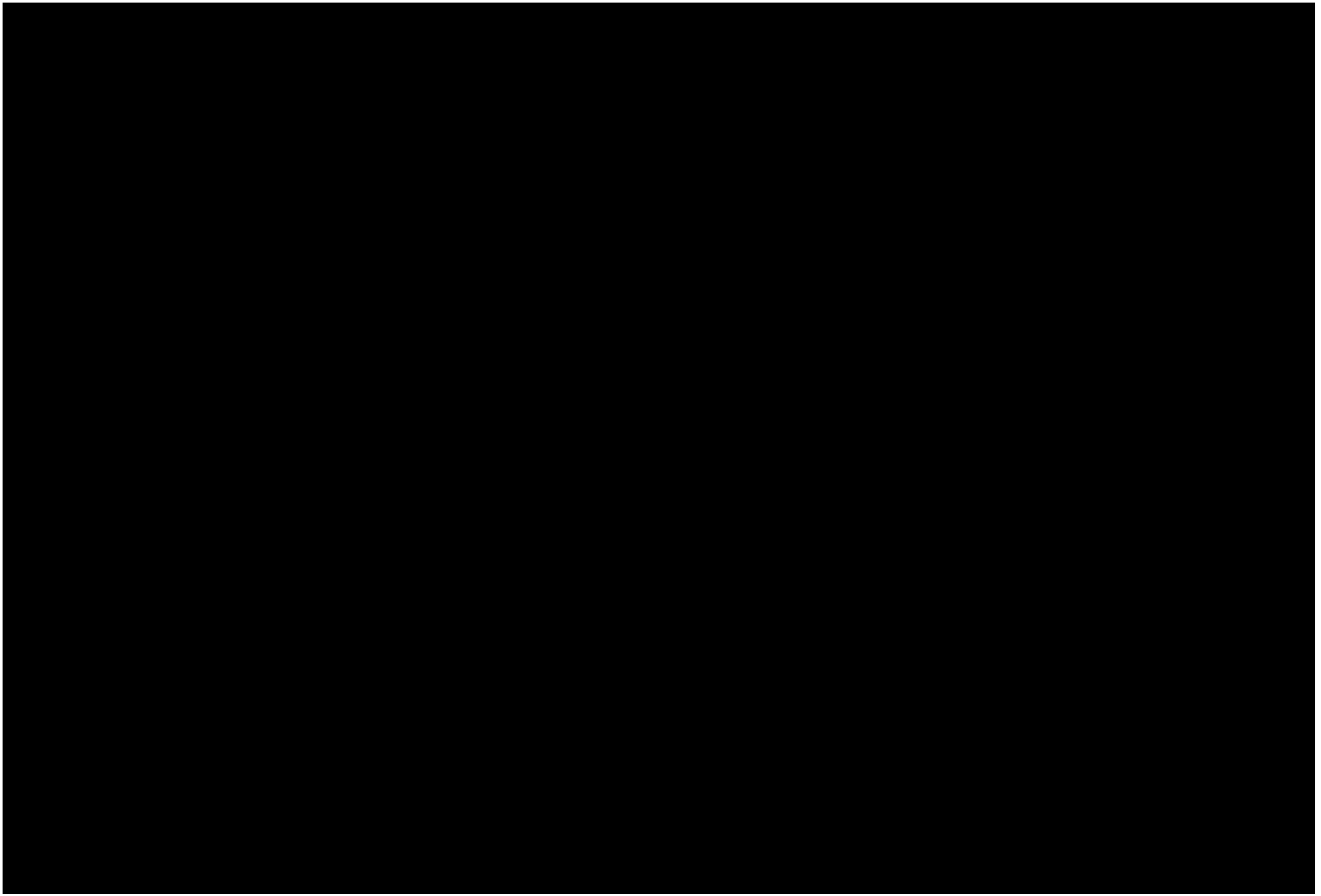
Date of On Peak Day - 10/01/2021



Member Forecasted On Peak Demand Day for November 2021

Sierra Electric Cooperative, Inc.

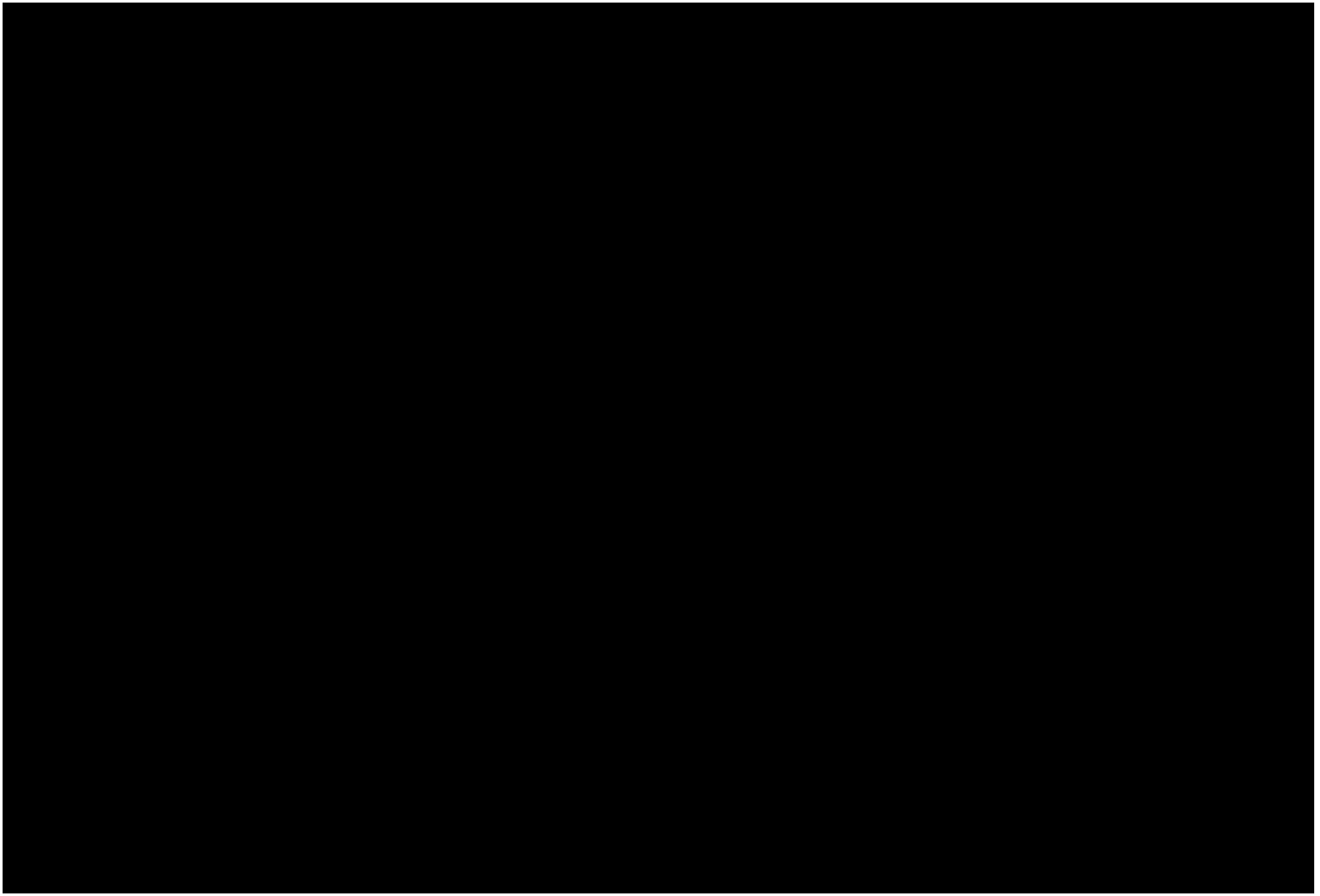
Date of On Peak Day - 11/16/2021



Member Forecasted On Peak Demand Day for December 2021

Sierra Electric Cooperative, Inc.

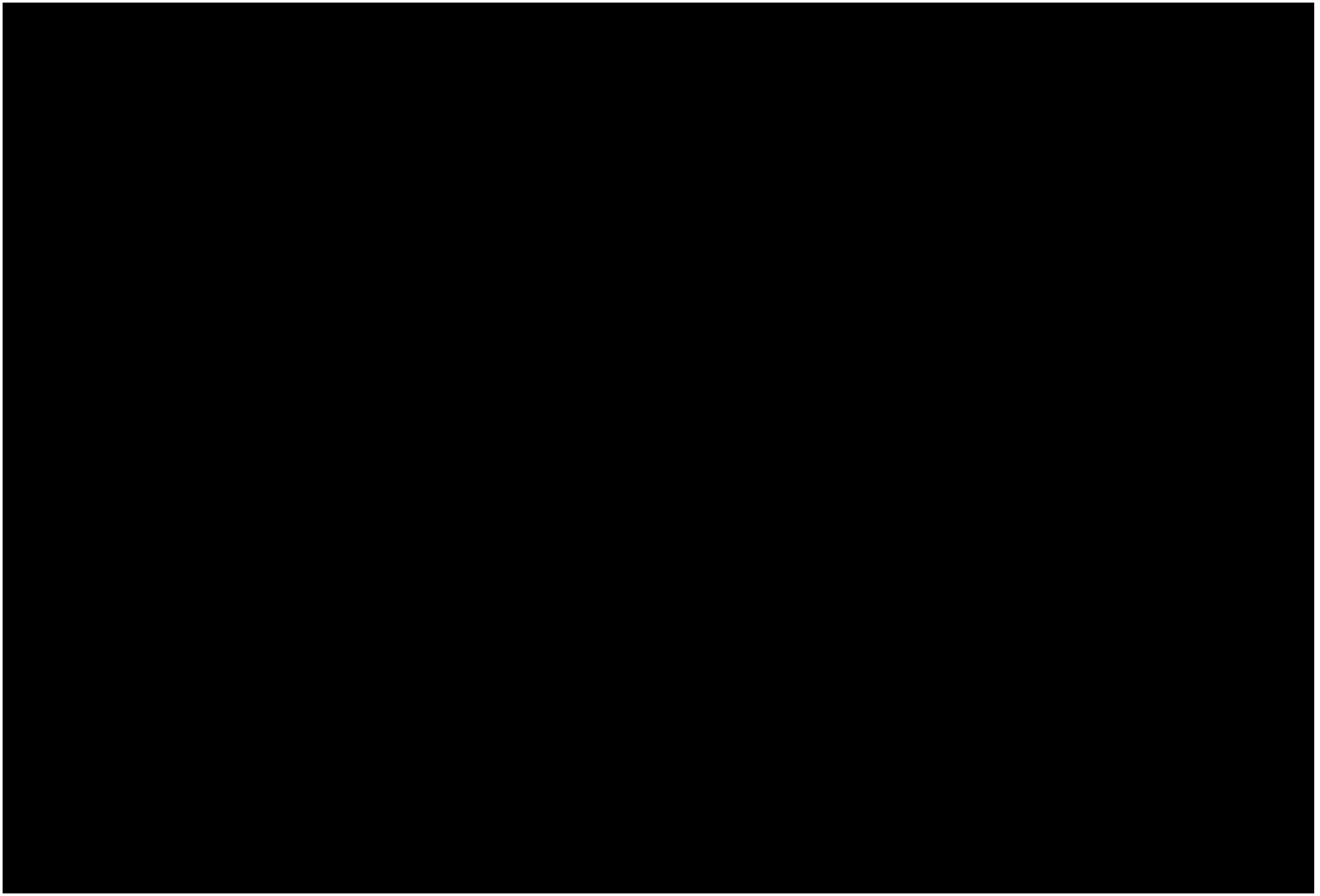
Date of On Peak Day - 12/28/2021



Member Forecasted On Peak Demand Day for January 2021

Sangre de Cristo Electric Association, Inc.

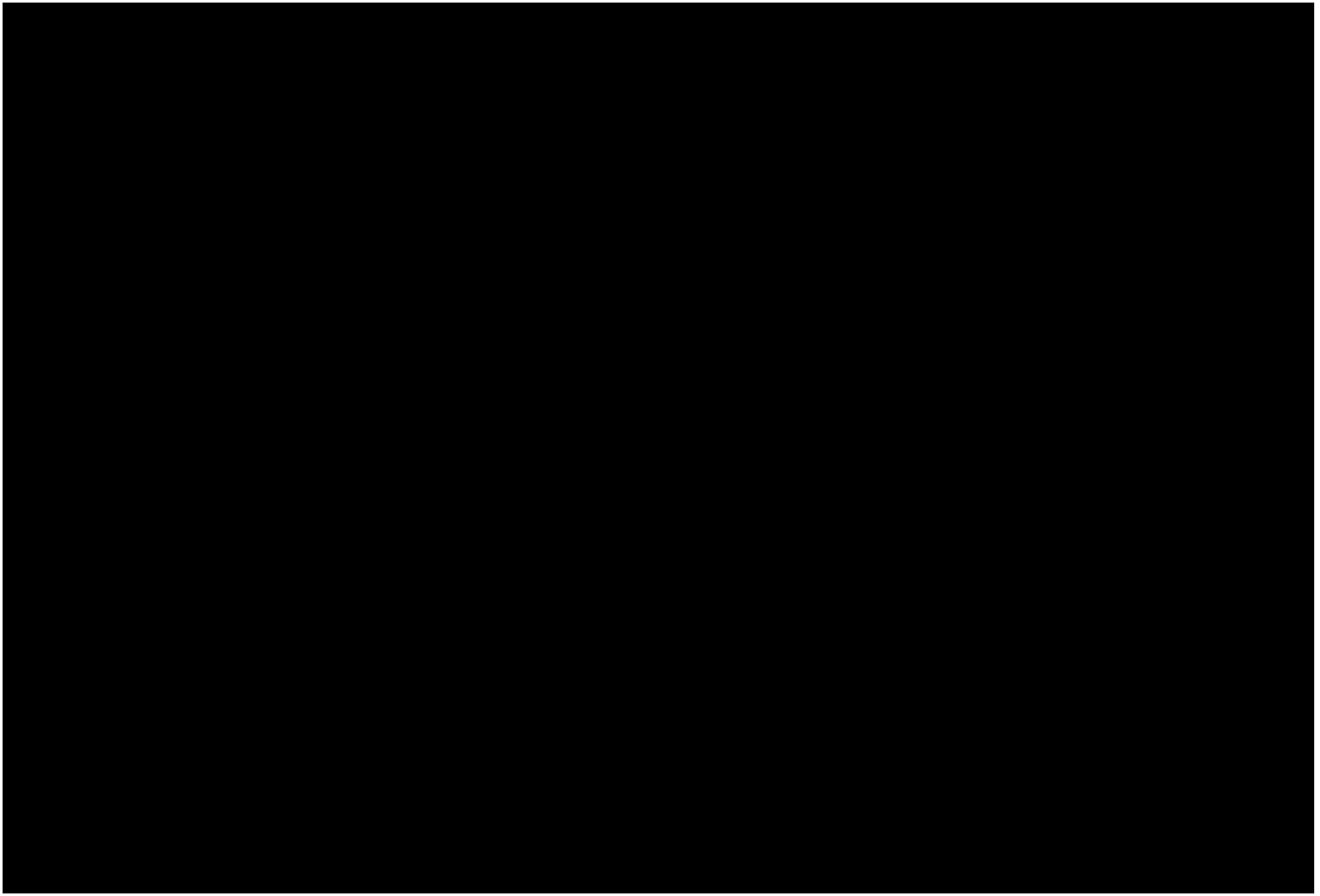
Date of On Peak Day - 01/27/2021



Member Forecasted On Peak Demand Day for February 2021

Sangre de Cristo Electric Association, Inc.

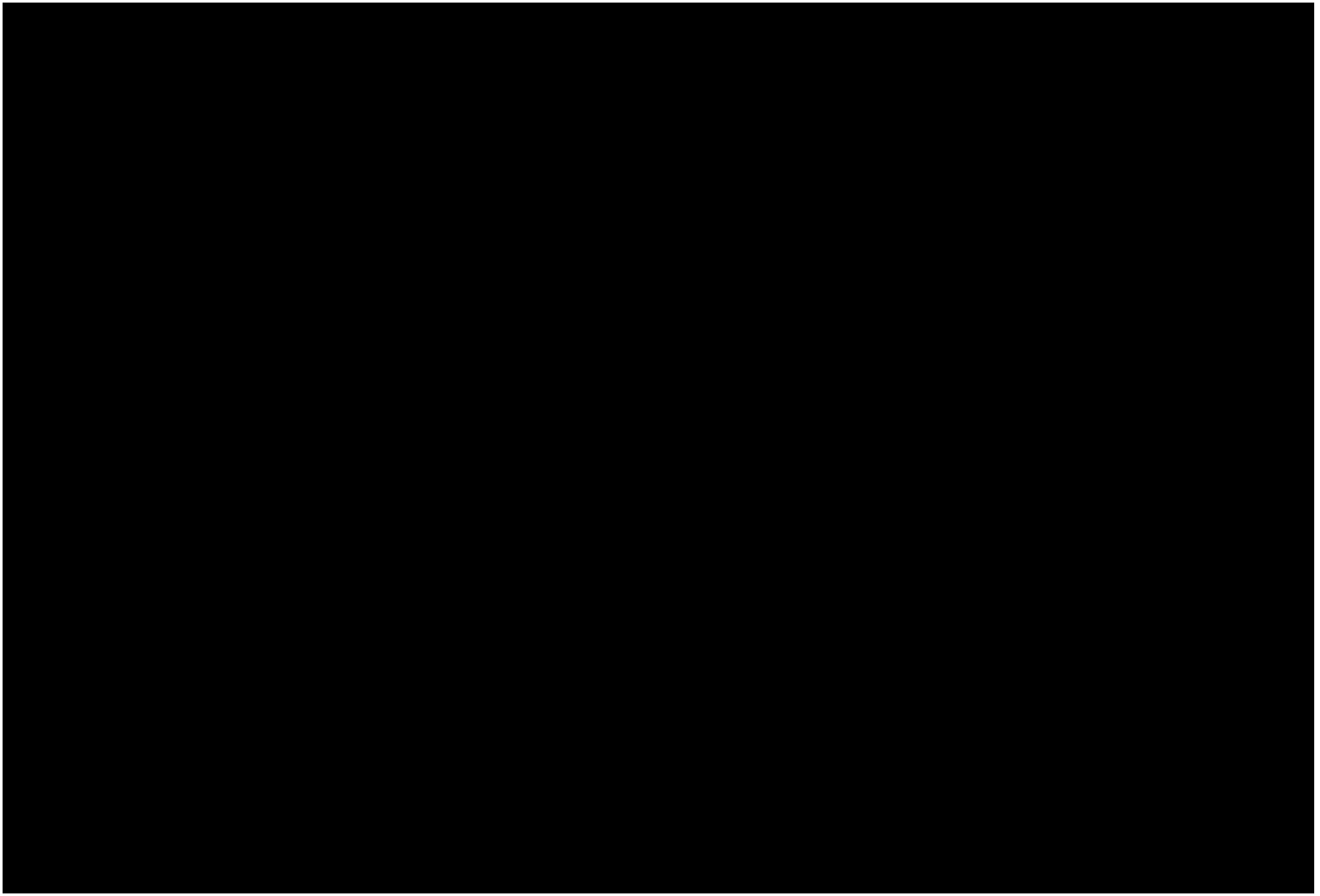
Date of On Peak Day - 02/25/2021



Member Forecasted On Peak Demand Day for March 2021

Sangre de Cristo Electric Association, Inc.

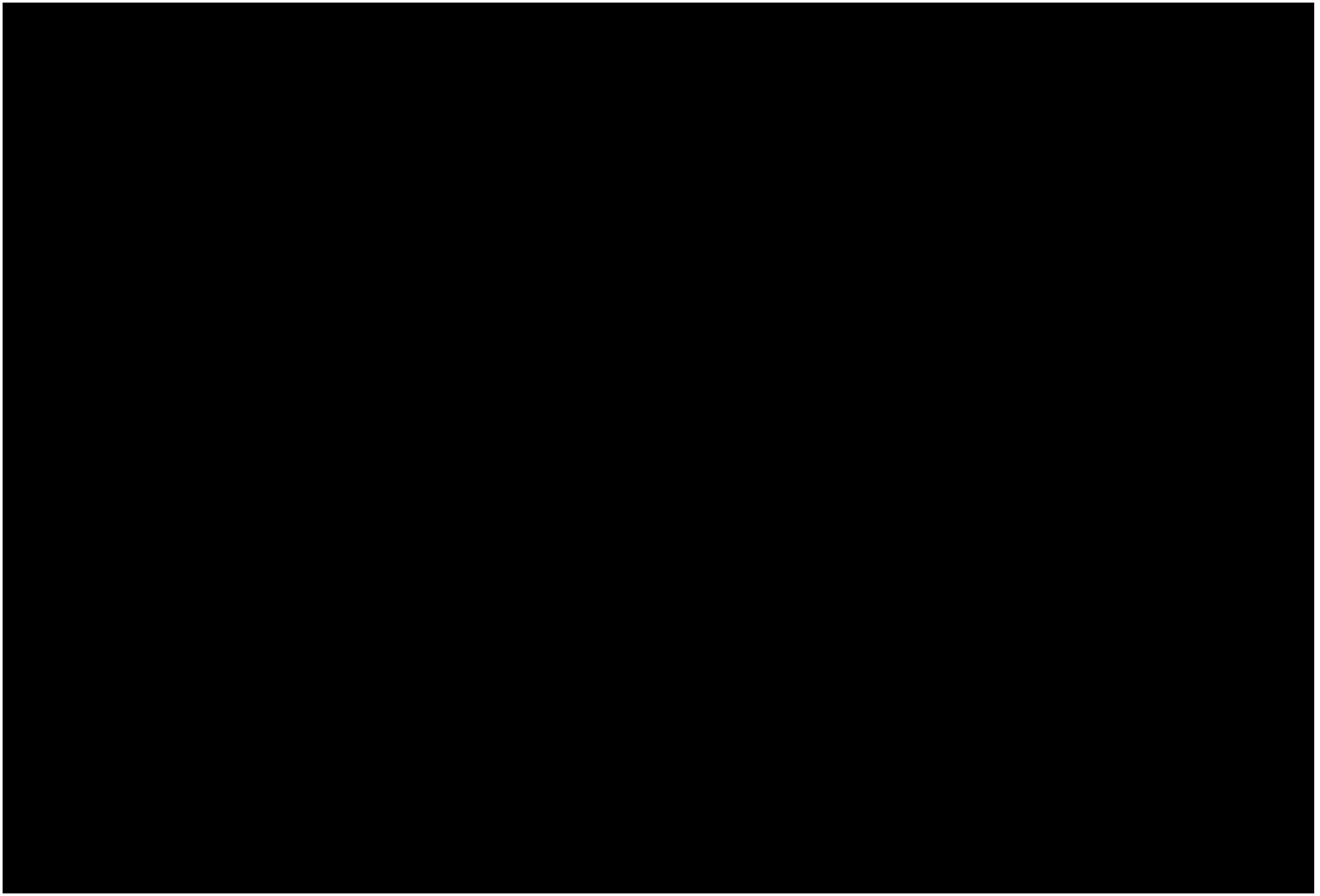
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Sangre de Cristo Electric Association, Inc.

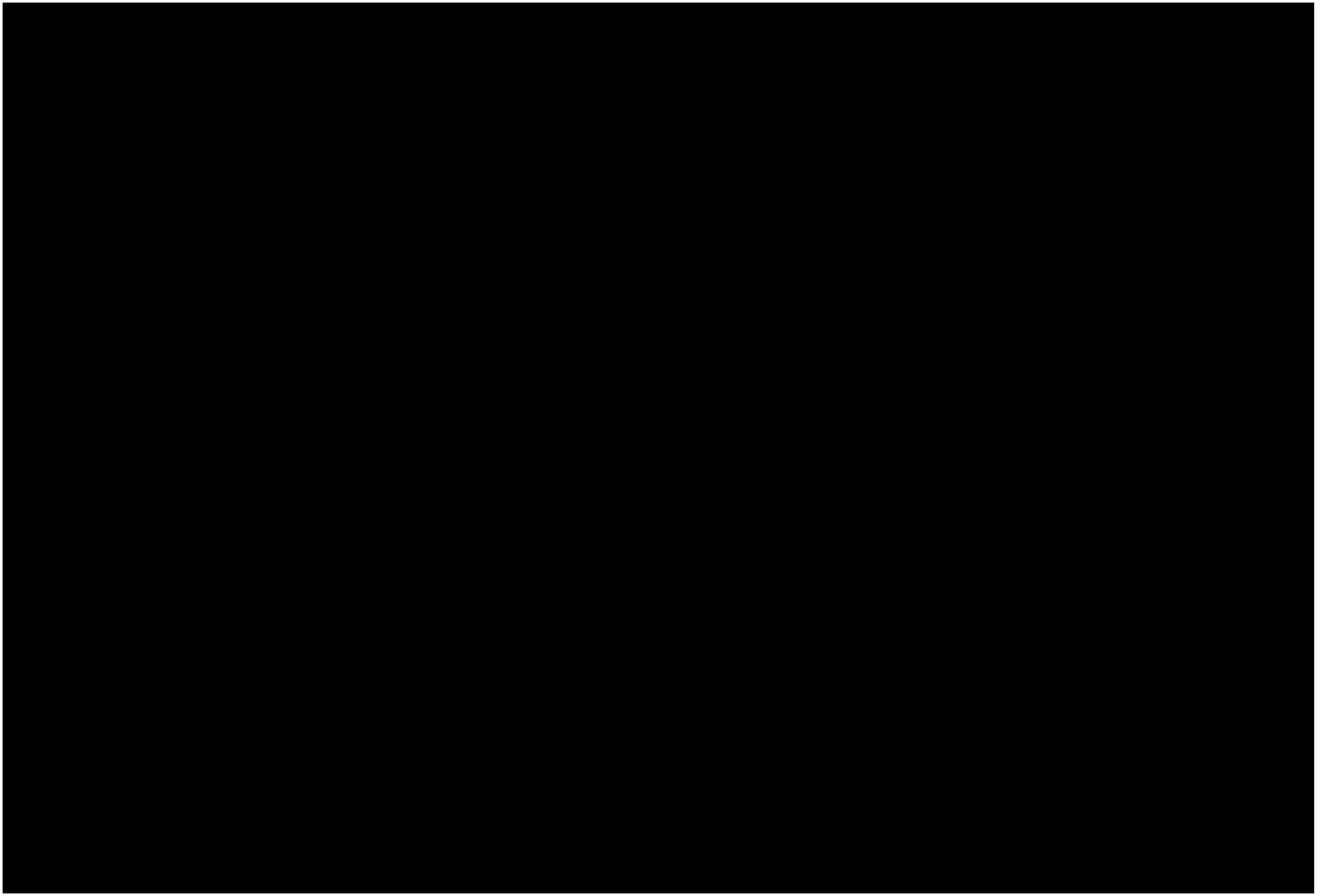
Date of On Peak Day - 04/16/2021



Member Forecasted On Peak Demand Day for May 2021

Sangre de Cristo Electric Association, Inc.

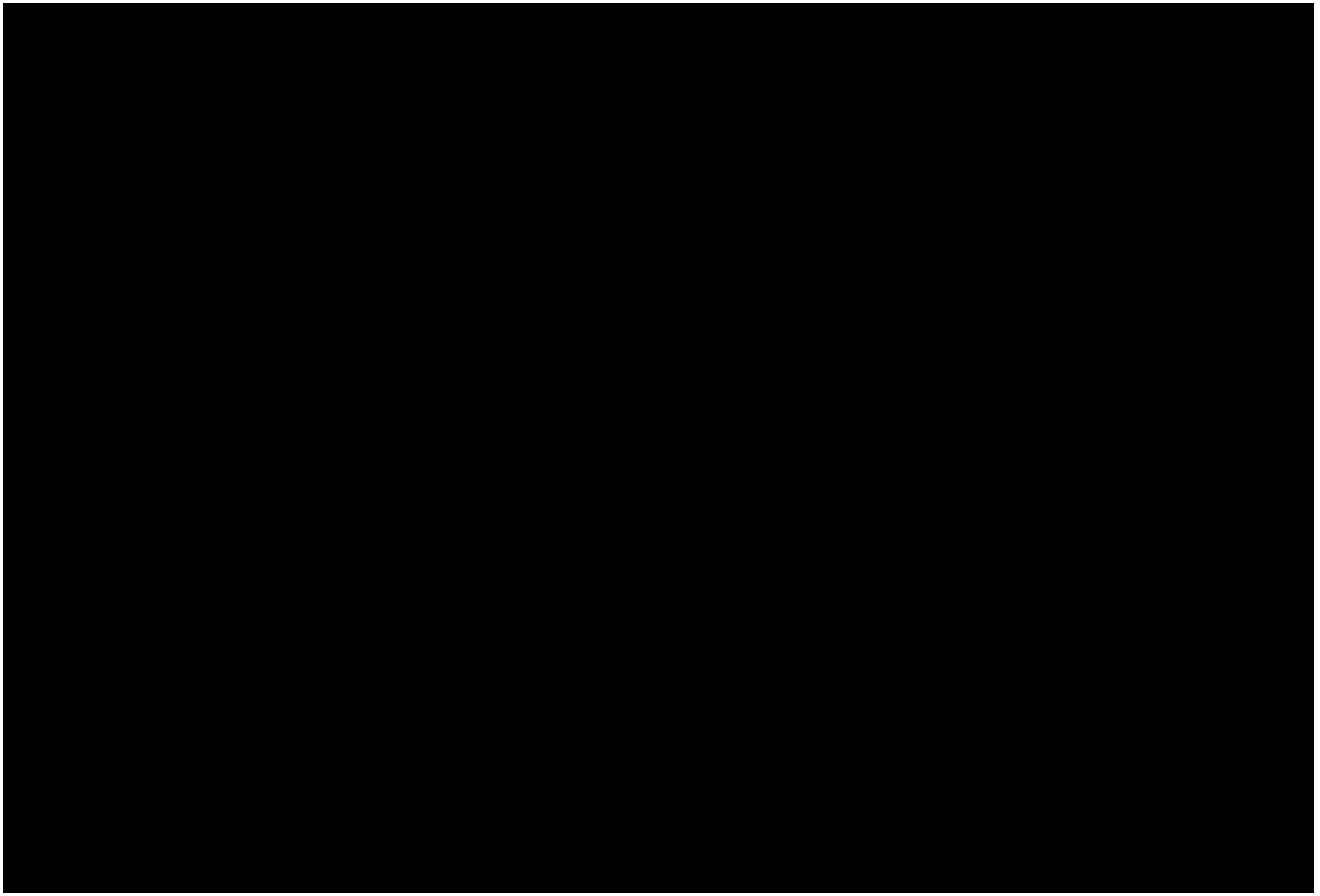
Date of On Peak Day - 05/18/2021



Member Forecasted On Peak Demand Day for June 2021

Sangre de Cristo Electric Association, Inc.

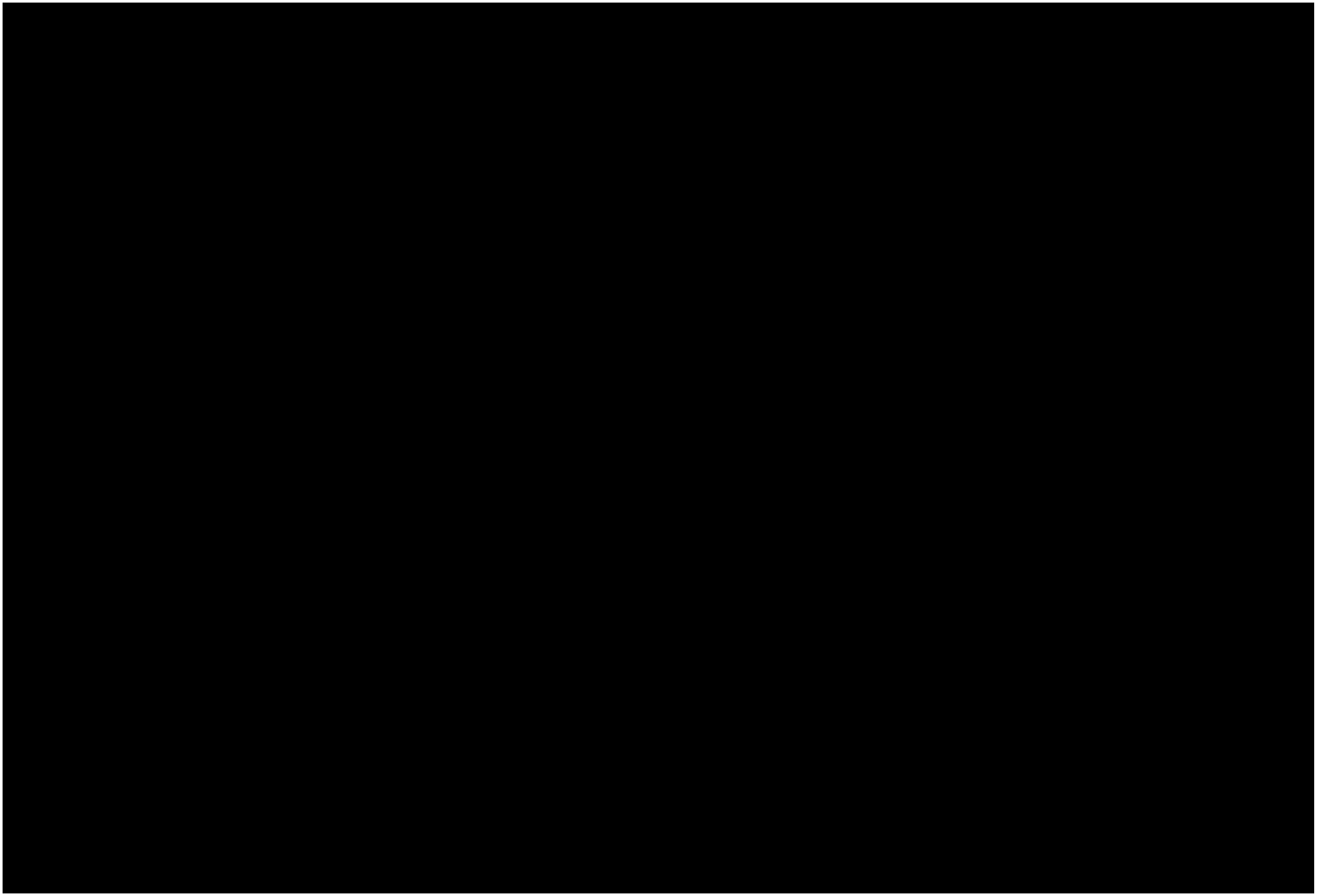
Date of On Peak Day - 06/30/2021



Member Forecasted On Peak Demand Day for July 2021

Sangre de Cristo Electric Association, Inc.

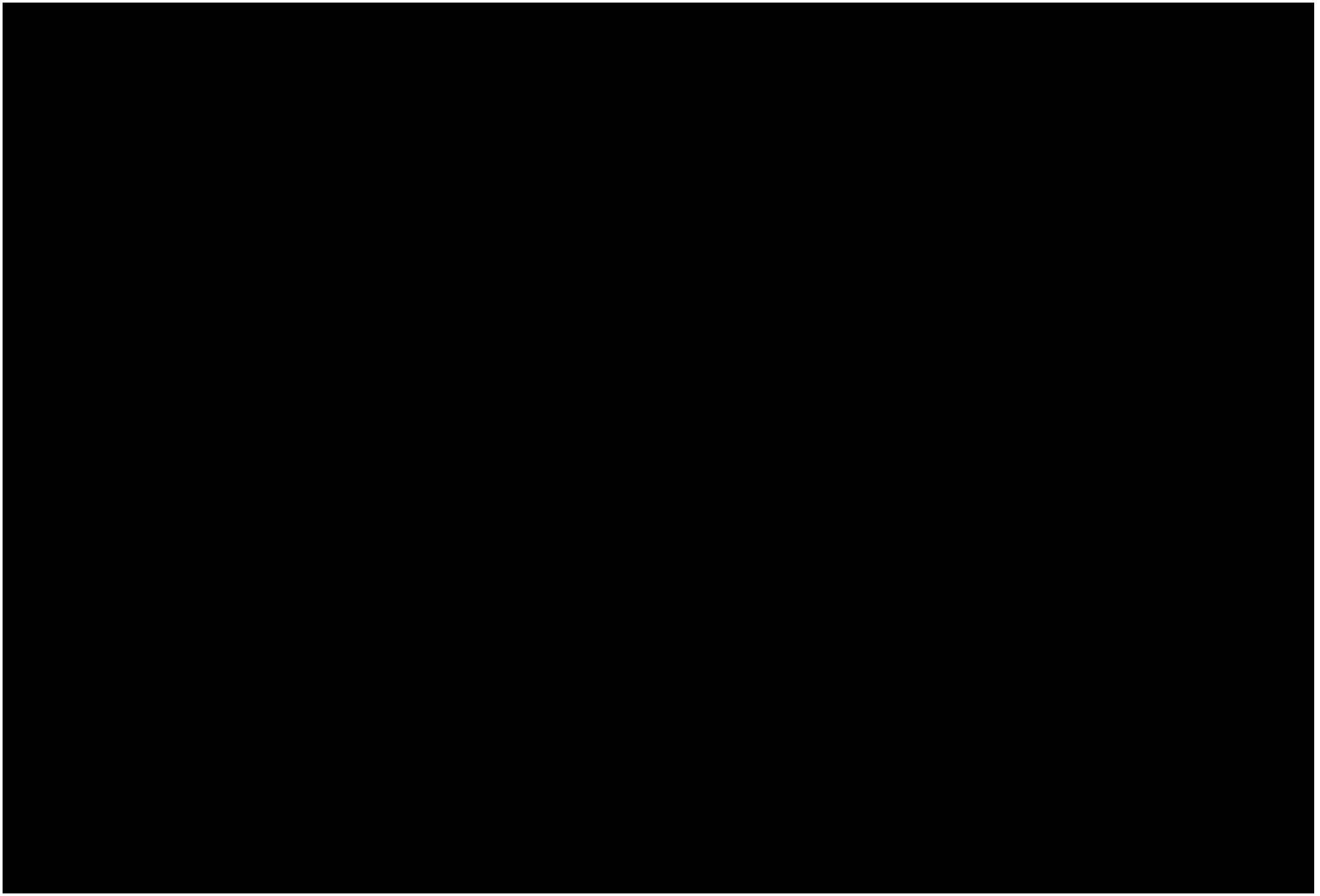
Date of On Peak Day - 07/28/2021



Member Forecasted On Peak Demand Day for August 2021

Sangre de Cristo Electric Association, Inc.

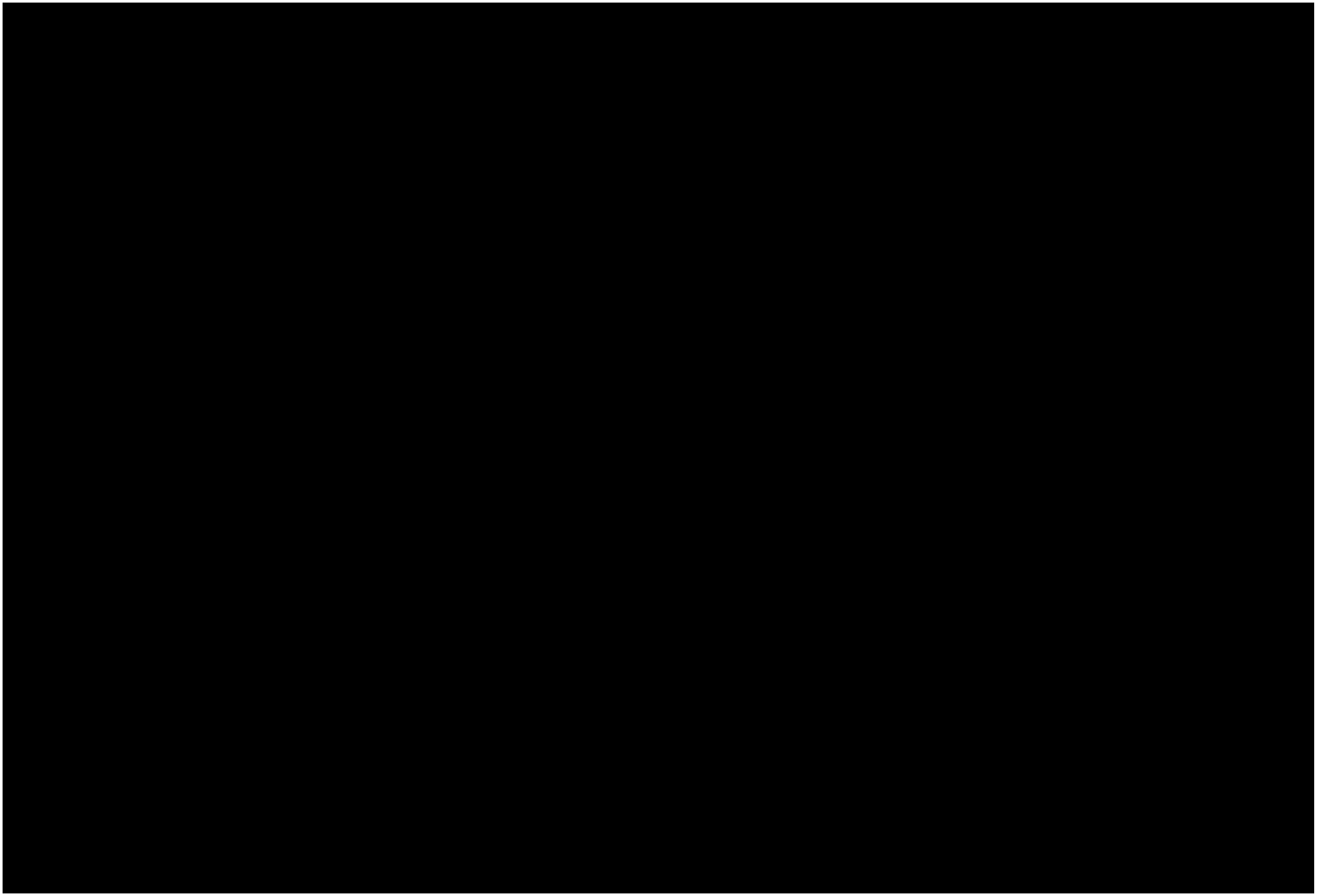
Date of On Peak Day - 08/07/2021



Member Forecasted On Peak Demand Day for September 2021

Sangre de Cristo Electric Association, Inc.

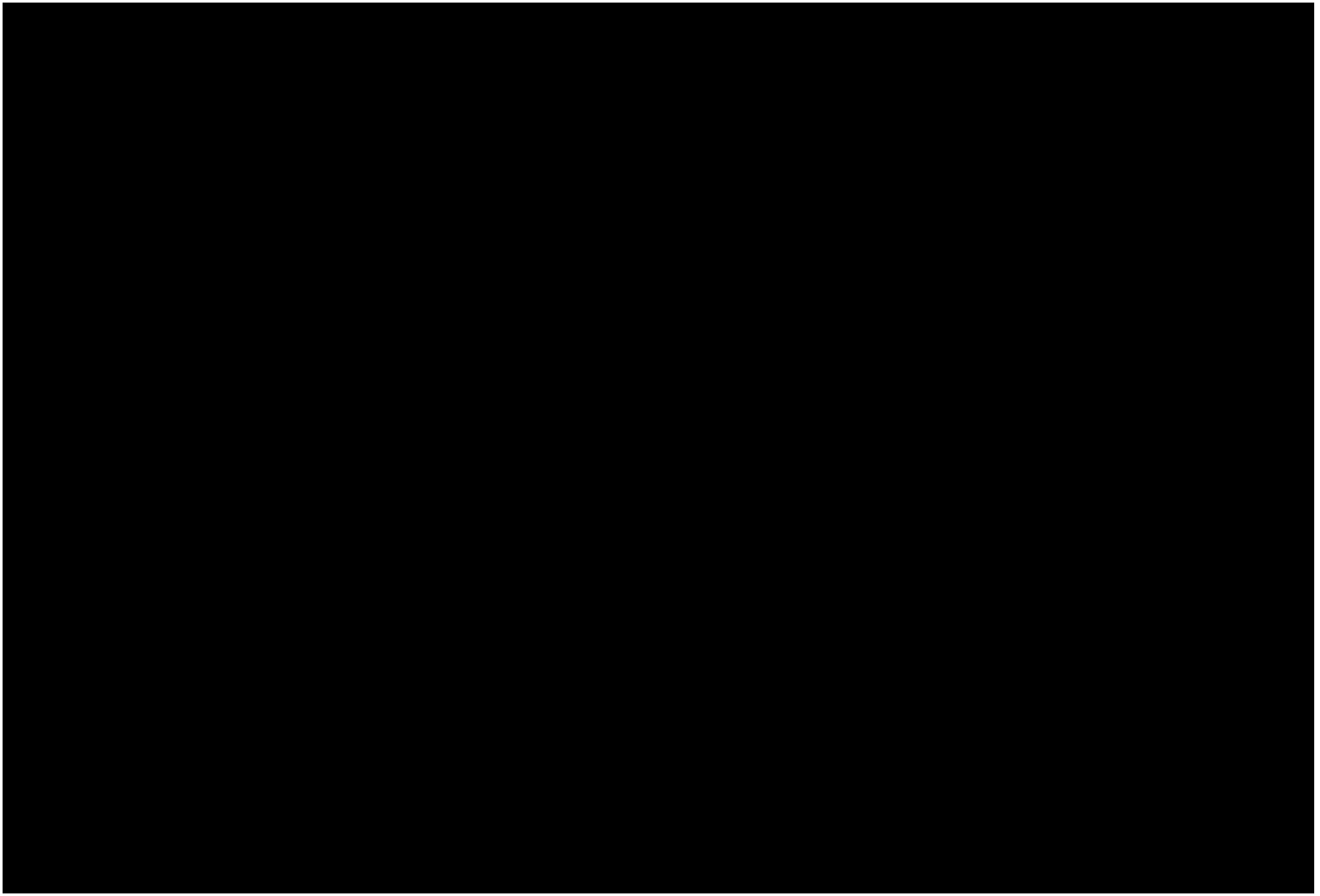
Date of On Peak Day - 09/05/2021



Member Forecasted On Peak Demand Day for October 2021

Sangre de Cristo Electric Association, Inc.

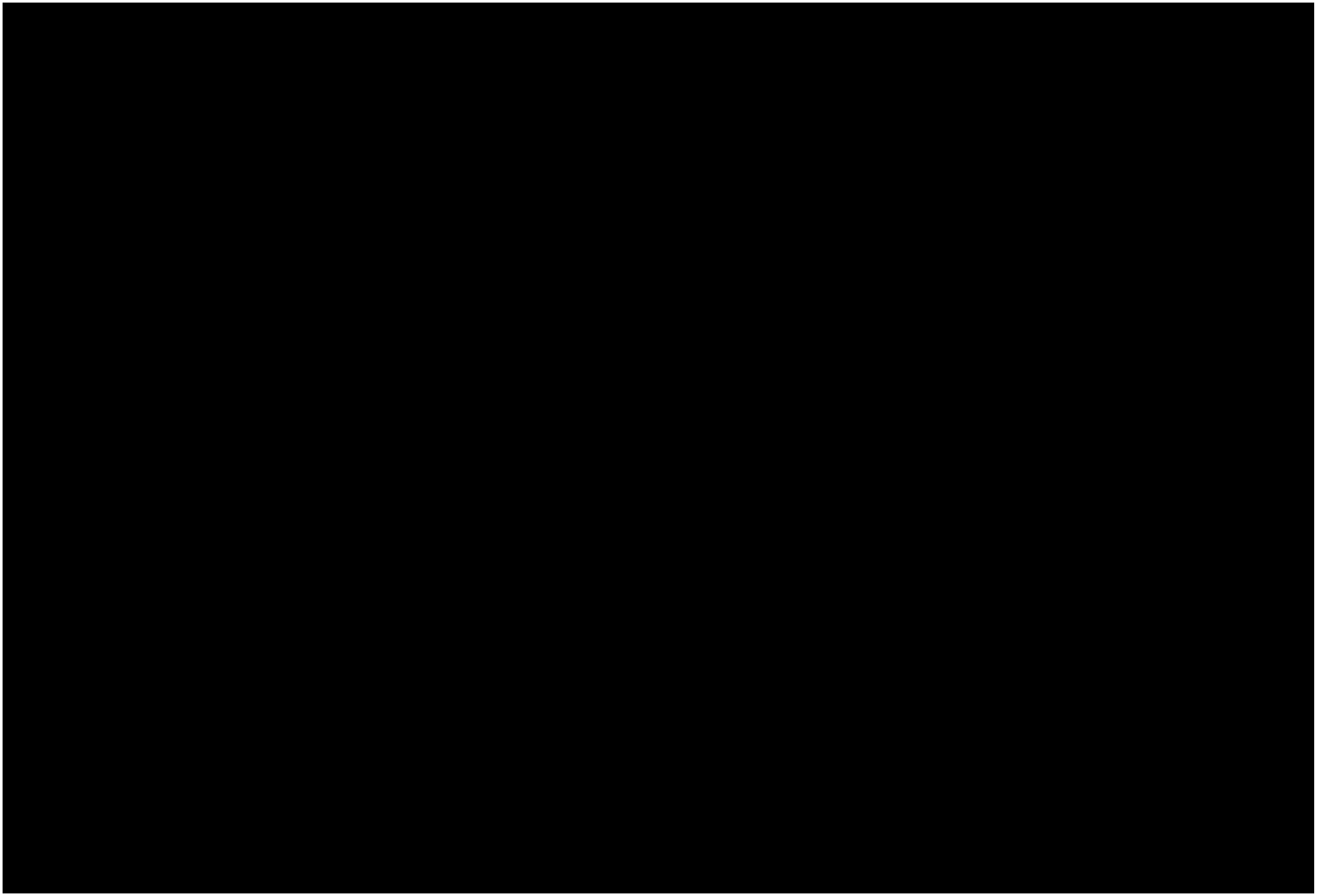
Date of On Peak Day - 10/27/2021



Member Forecasted On Peak Demand Day for November 2021

Sangre de Cristo Electric Association, Inc.

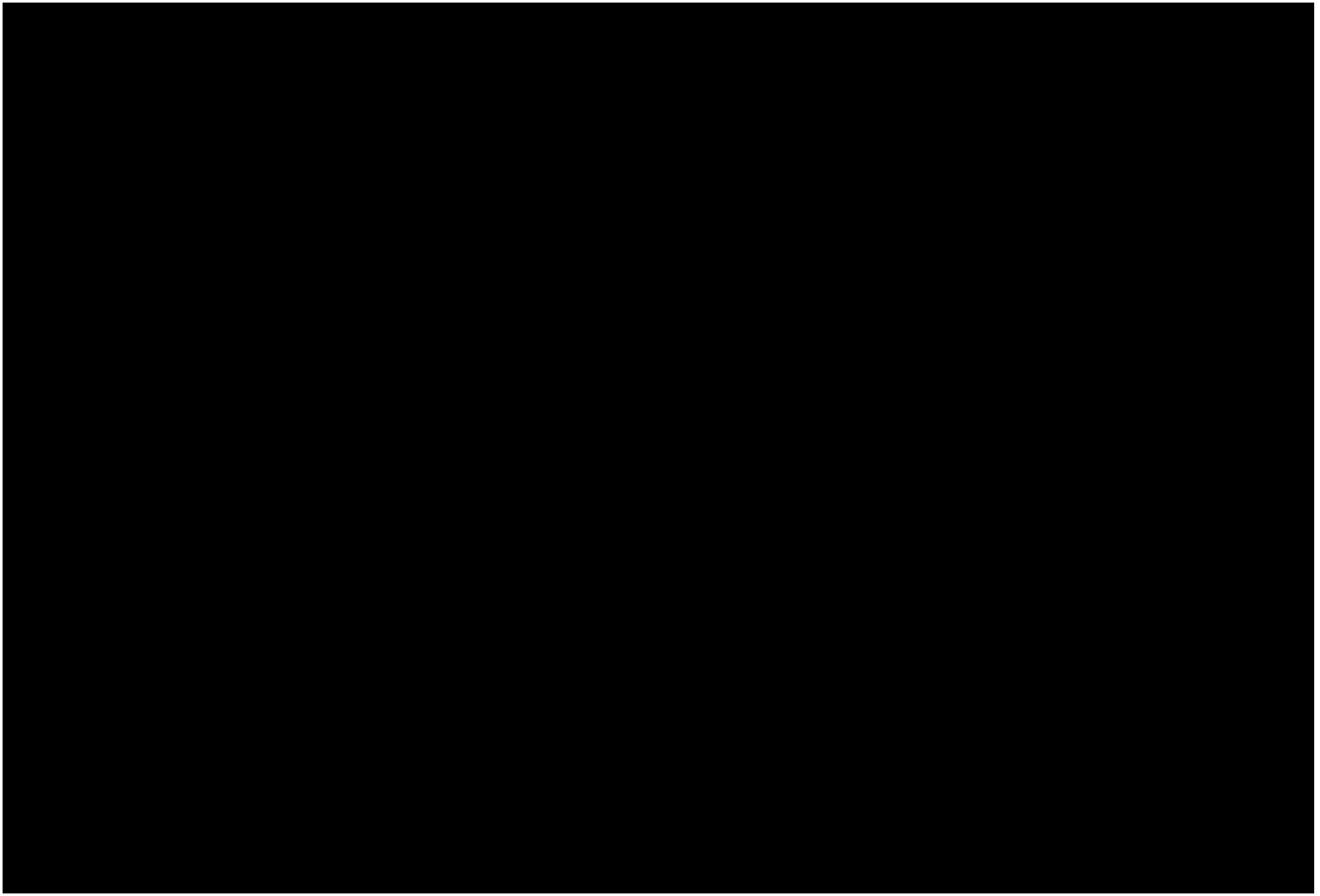
Date of On Peak Day - 11/09/2021



Member Forecasted On Peak Demand Day for December 2021

Sangre de Cristo Electric Association, Inc.

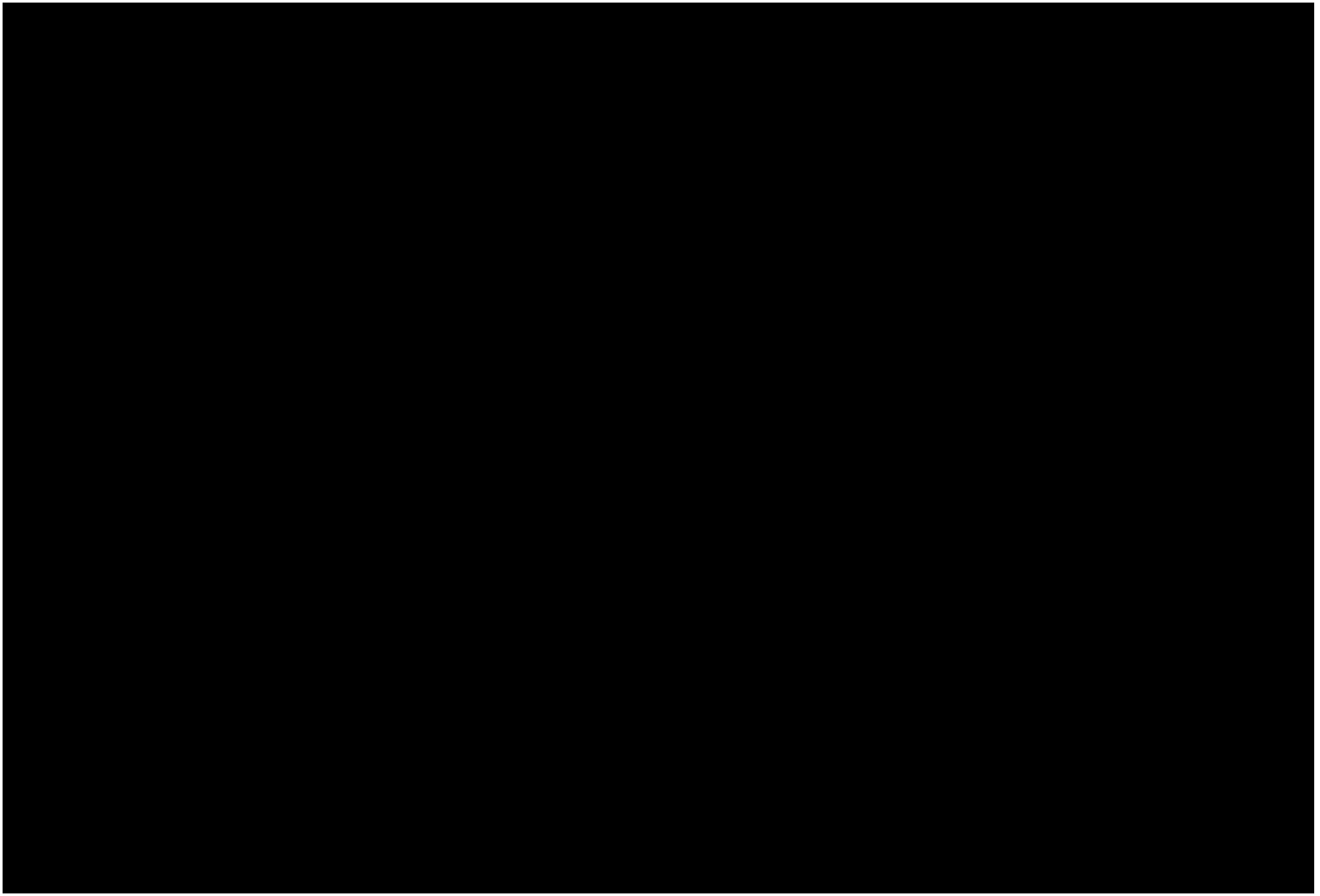
Date of On Peak Day - 12/30/2021



Member Forecasted On Peak Demand Day for January 2021

Southeast Colorado Power Association

Date of On Peak Day - 01/03/2021



Member Forecasted On Peak Demand Day for February 2021

Southeast Colorado Power Association

Date of On Peak Day - 02/02/2021

[redacted]

Member Forecasted On Peak Demand Day for March 2021

Southeast Colorado Power Association

Date of On Peak Day - 03/30/2021

[redacted]

Member Forecasted On Peak Demand Day for April 2021

Southeast Colorado Power Association

Date of On Peak Day - 04/13/2021

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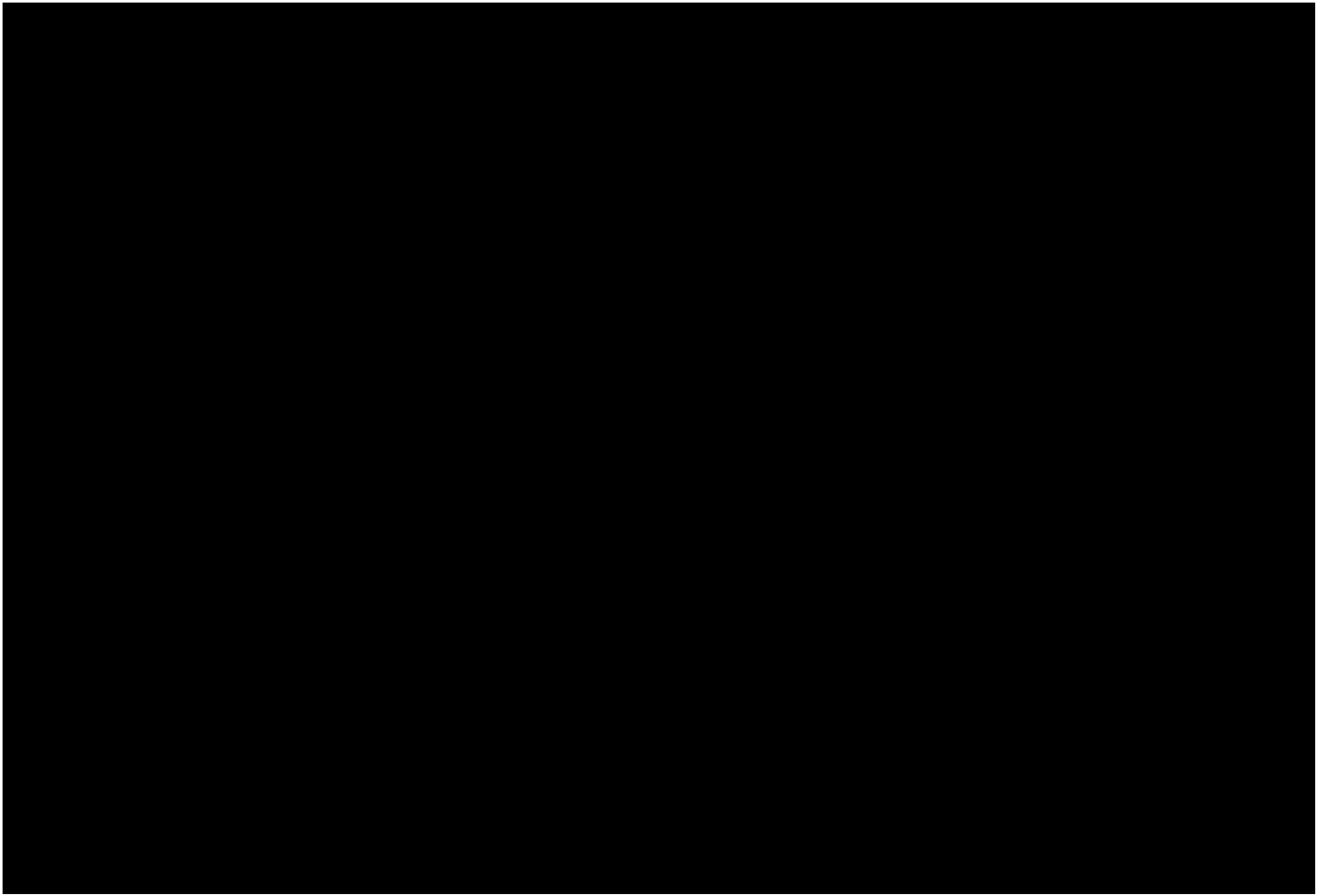
Member Forecasted On Peak Demand Day for May 2021

Southeast Colorado Power Association

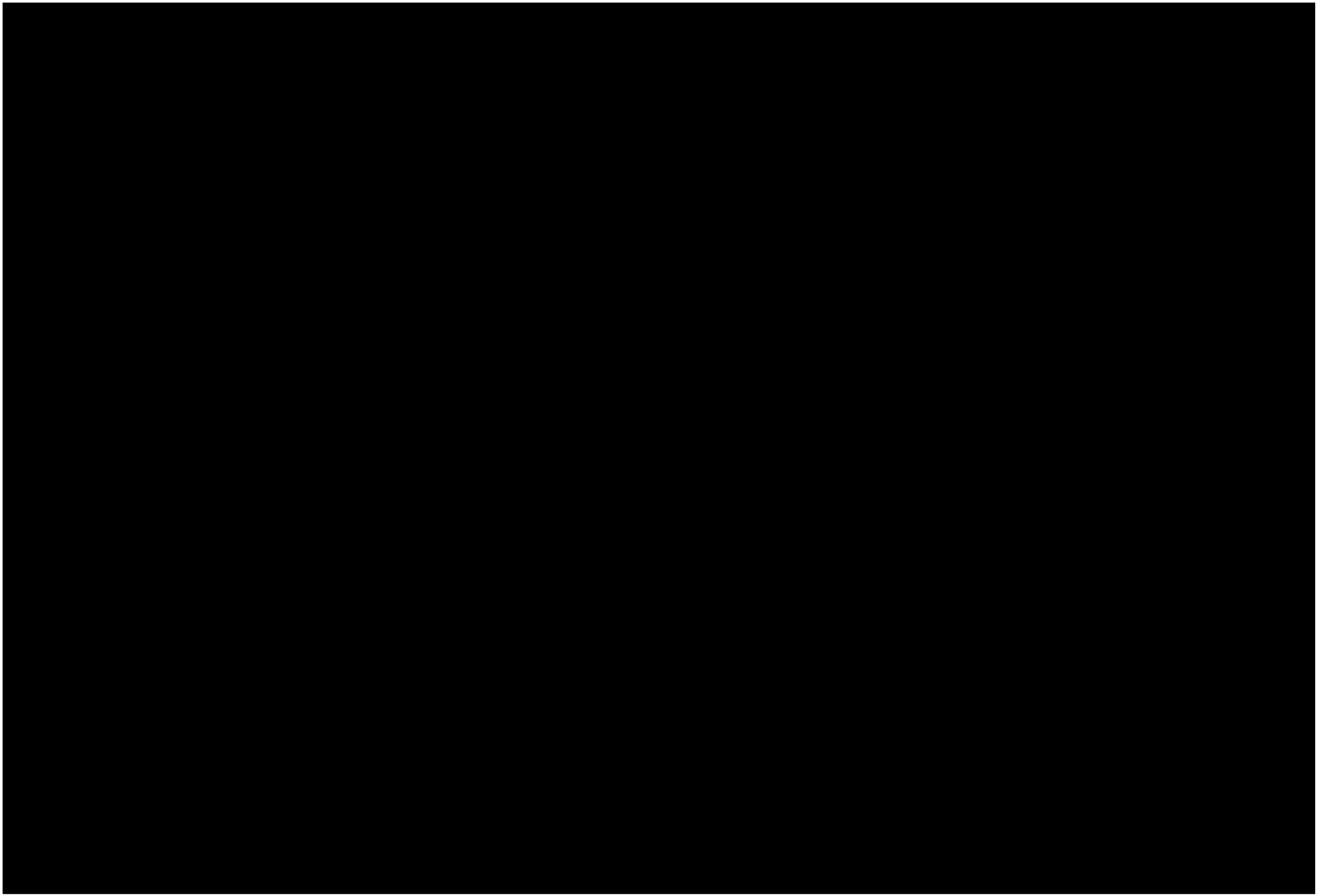
Date of On Peak Day - 05/31/2021



Member Forecasted On Peak Demand Day for June 2021

Southeast Colorado Power Association

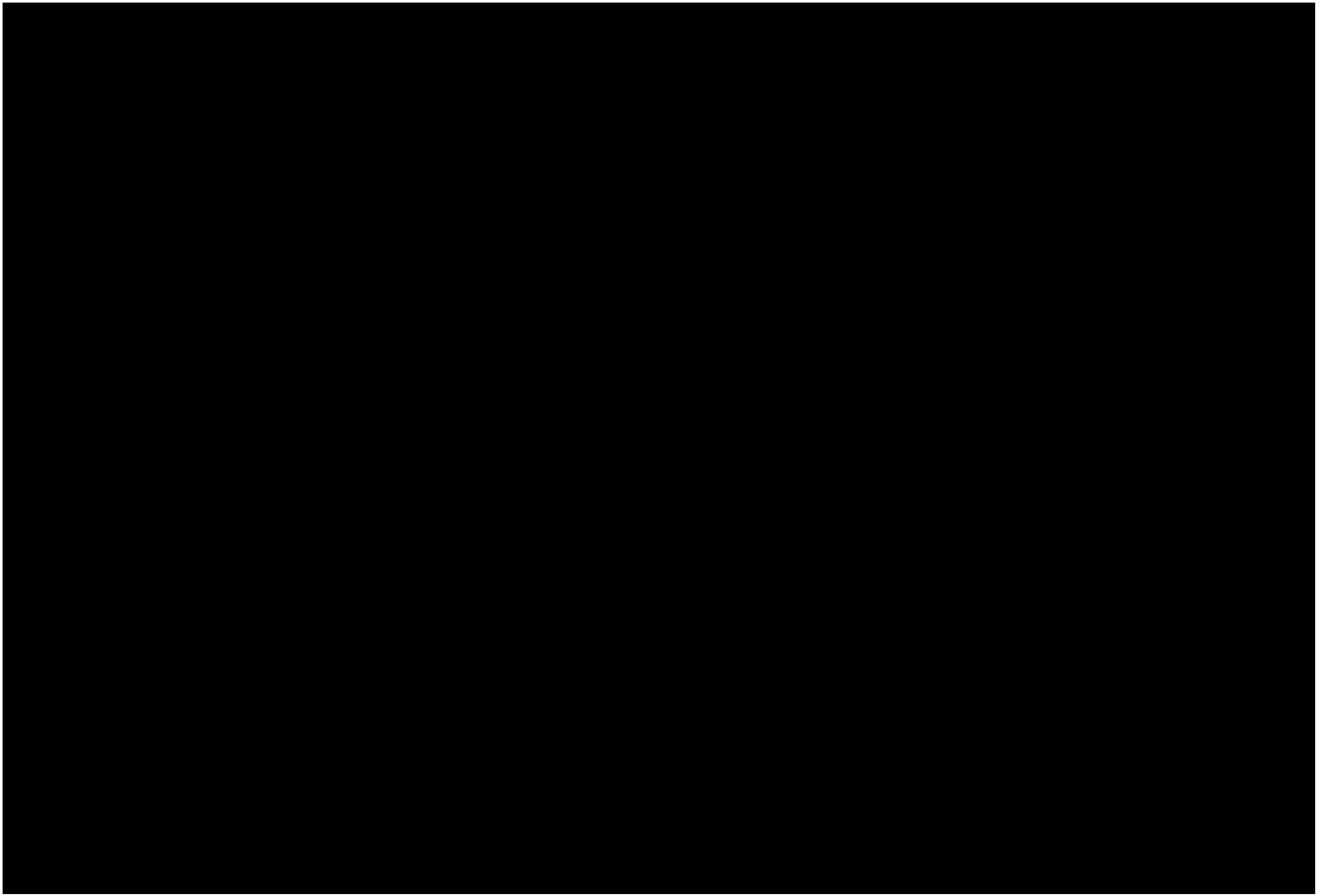
Date of On Peak Day - 06/15/2021



Member Forecasted On Peak Demand Day for July 2021

Southeast Colorado Power Association

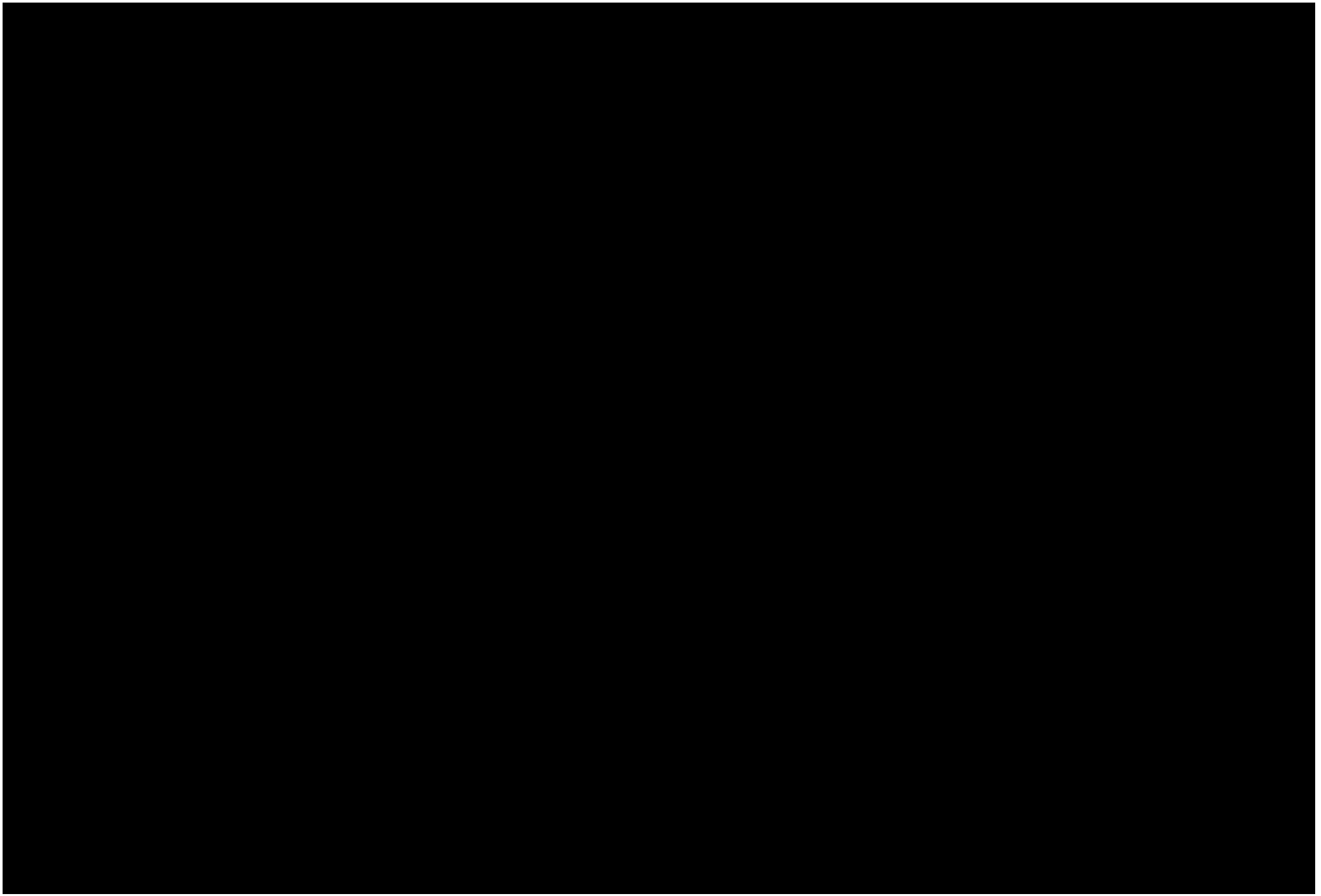
Date of On Peak Day - 07/21/2021



Member Forecasted On Peak Demand Day for August 2021

Southeast Colorado Power Association

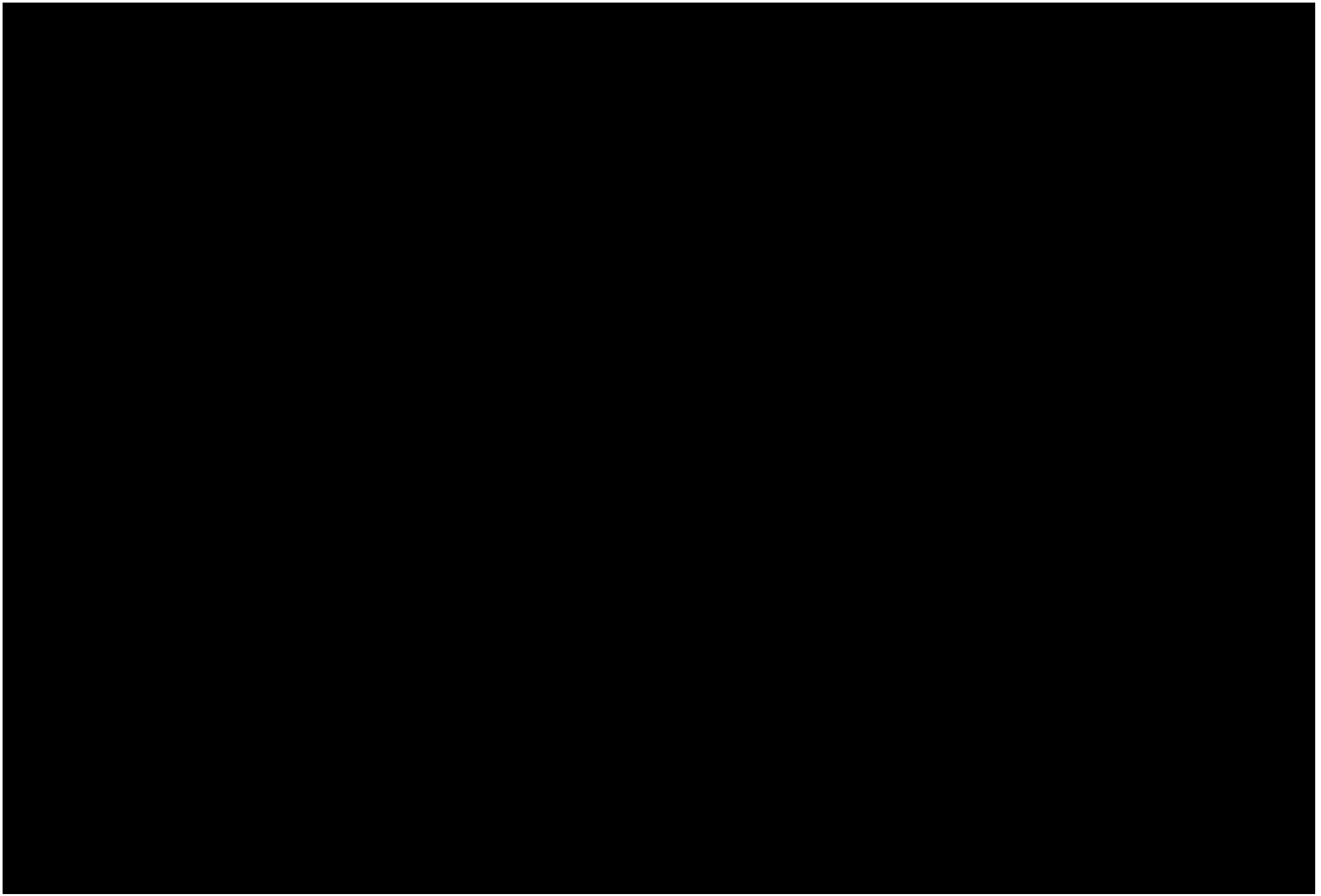
Date of On Peak Day - 08/29/2021



Member Forecasted On Peak Demand Day for September 2021

Southeast Colorado Power Association

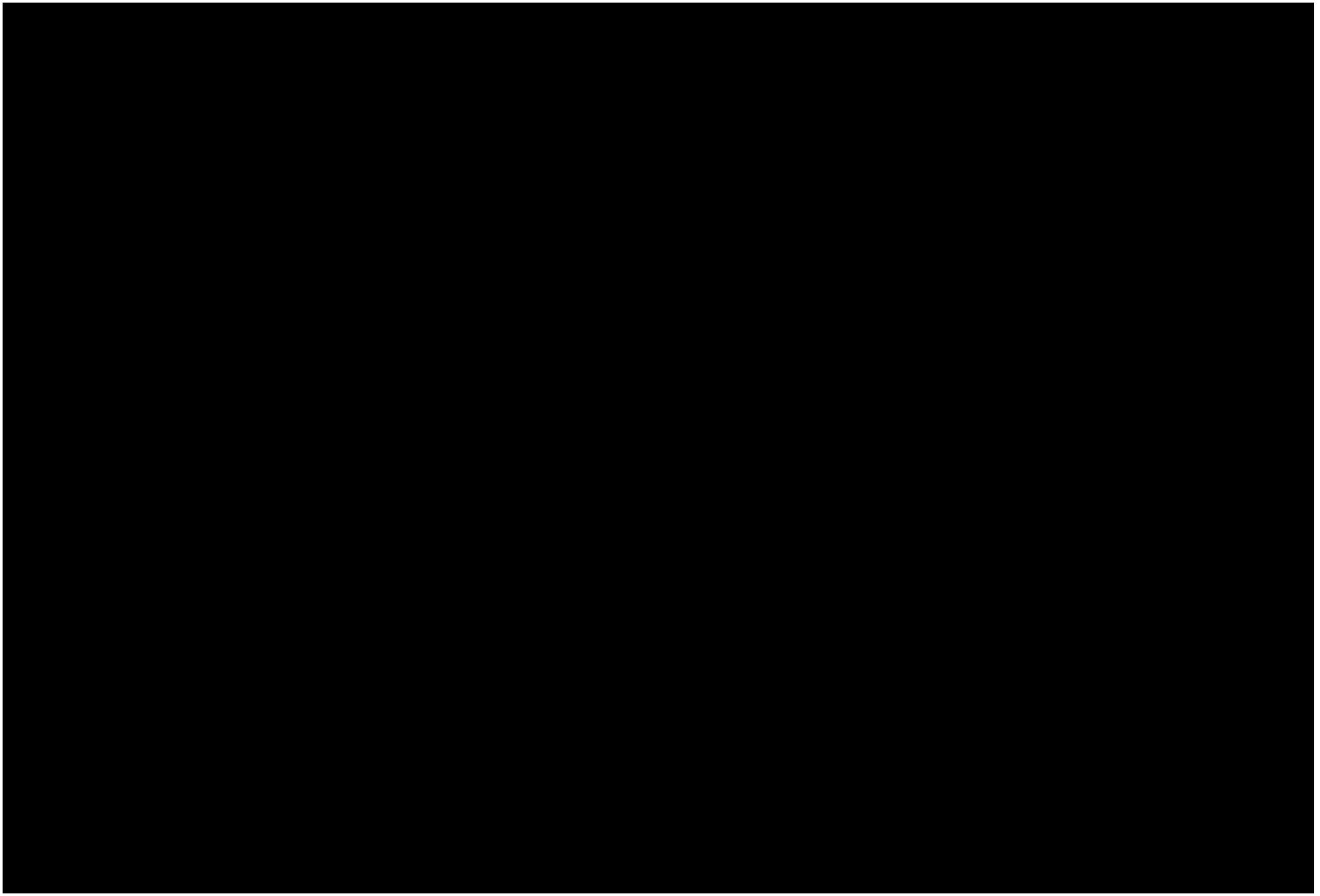
Date of On Peak Day - 09/05/2021



Member Forecasted On Peak Demand Day for October 2021

Southeast Colorado Power Association

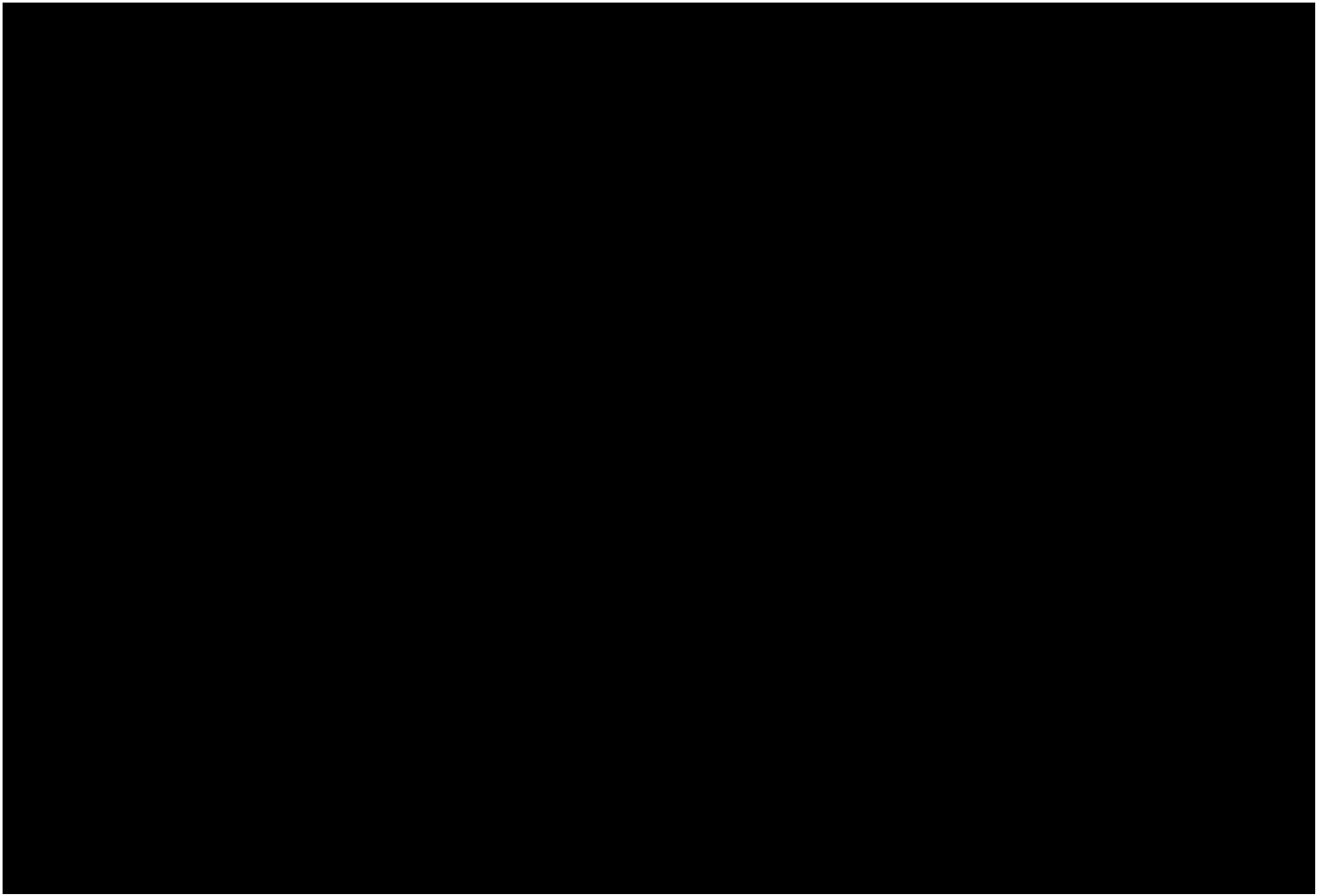
Date of On Peak Day - 10/13/2021



Member Forecasted On Peak Demand Day for November 2021

Southeast Colorado Power Association

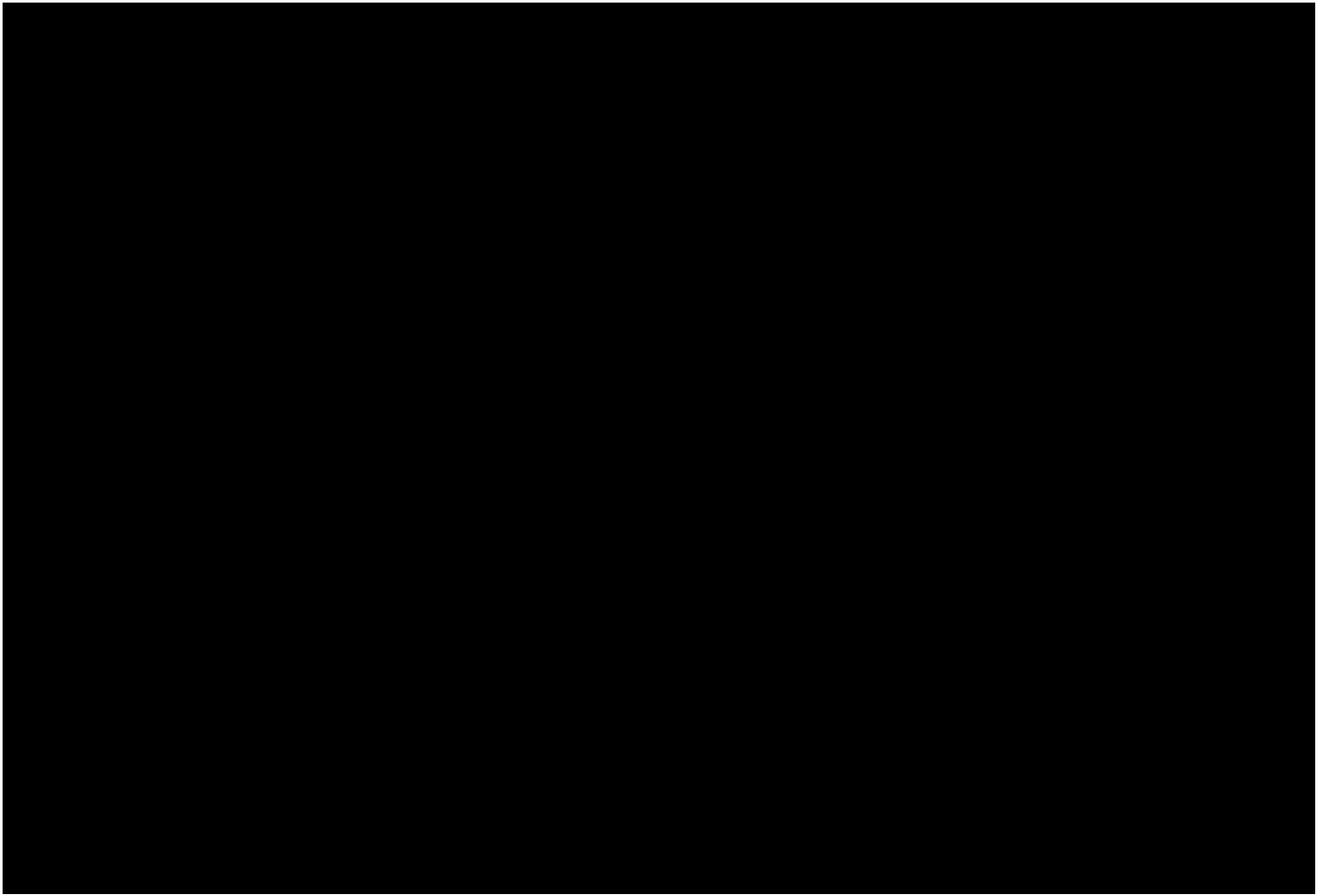
Date of On Peak Day - 11/18/2021



Member Forecasted On Peak Demand Day for December 2021

Southeast Colorado Power Association

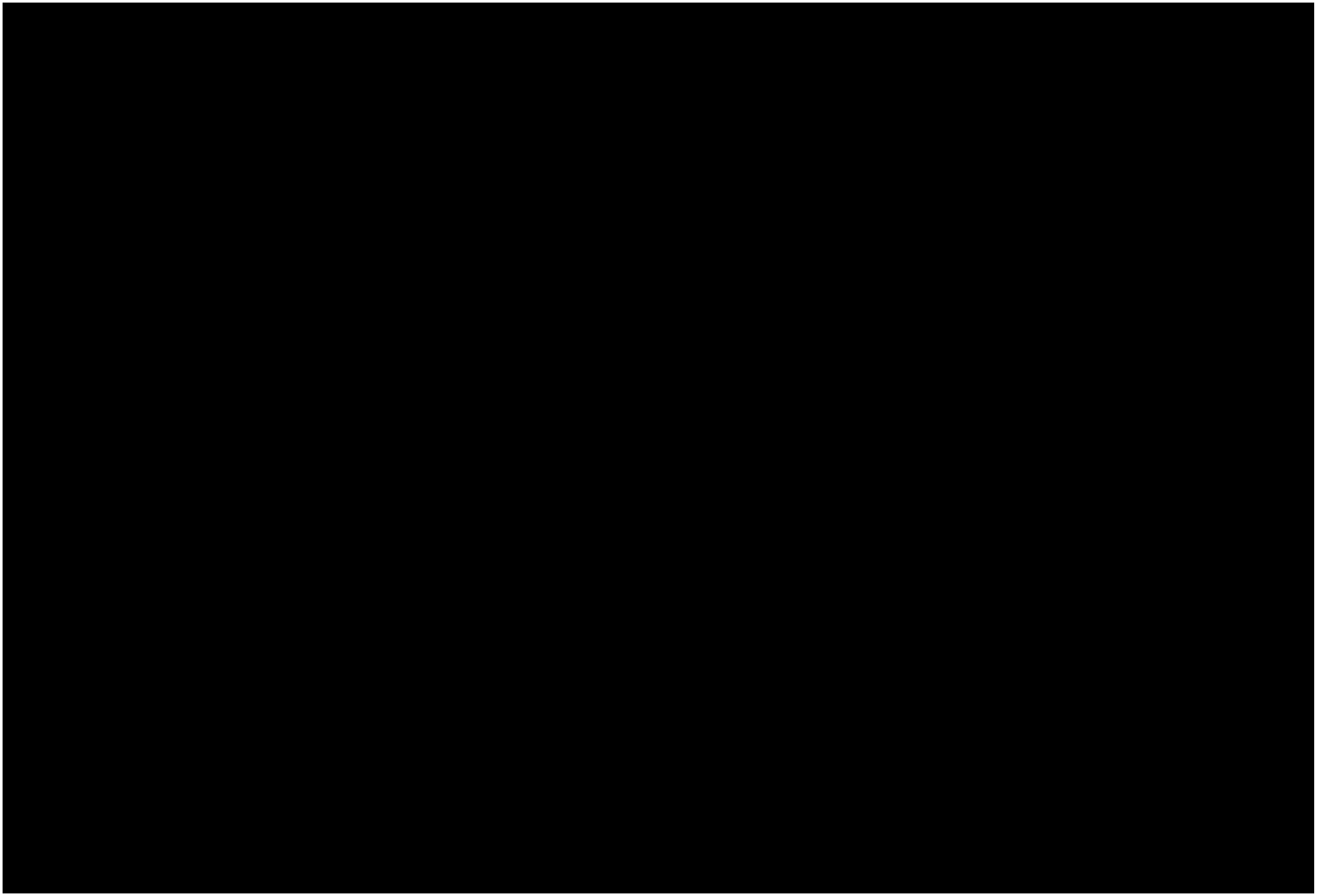
Date of On Peak Day - 12/29/2021



Member Forecasted On Peak Demand Day for January 2021

San Isabel Electric Association, Inc.

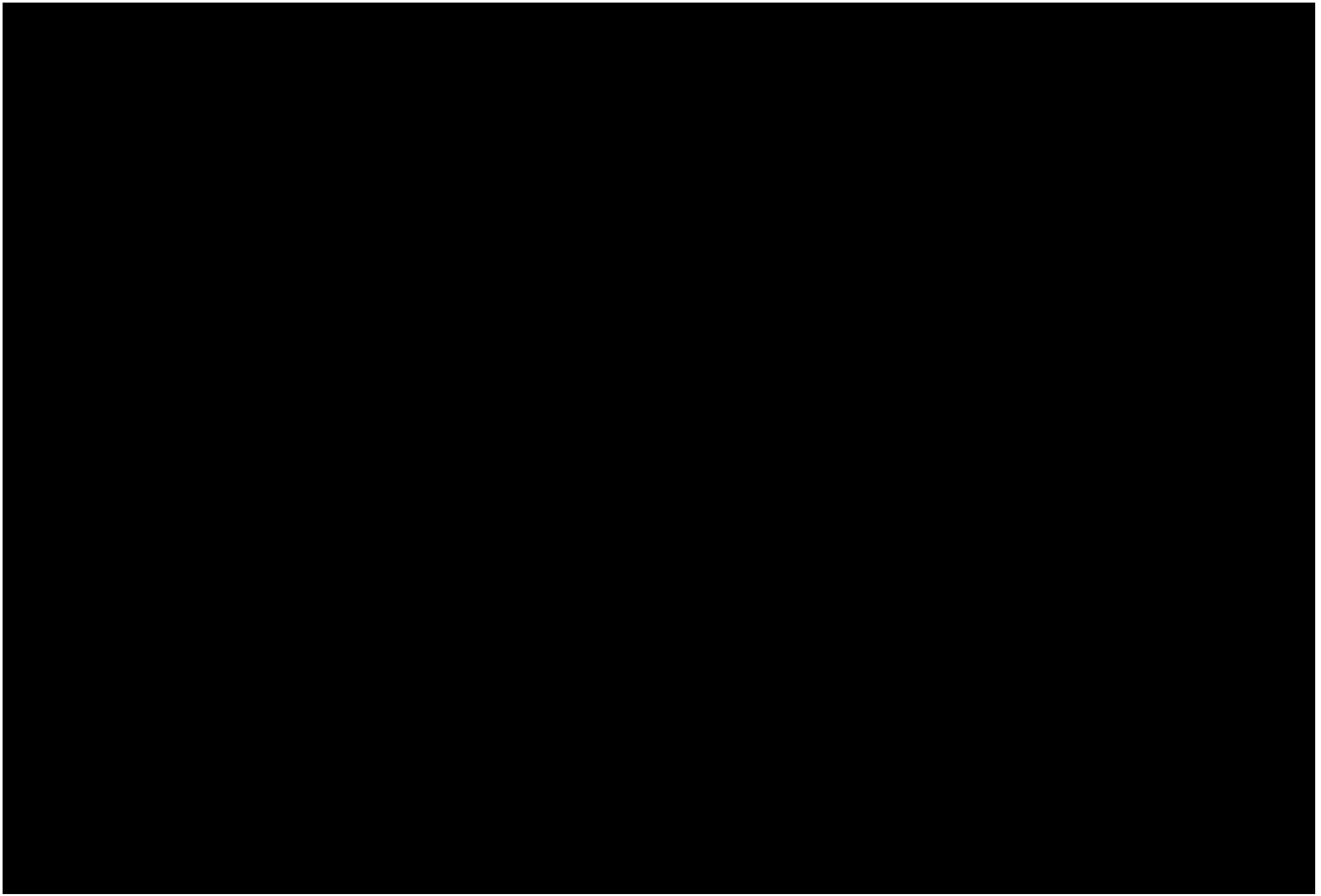
Date of On Peak Day - 01/16/2021



Member Forecasted On Peak Demand Day for February 2021

San Isabel Electric Association, Inc.

Date of On Peak Day - 02/25/2021



Member Forecasted On Peak Demand Day for March 2021

San Isabel Electric Association, Inc.

Date of On Peak Day - 03/02/2021

[redacted]

Member Forecasted On Peak Demand Day for April 2021

San Isabel Electric Association, Inc.

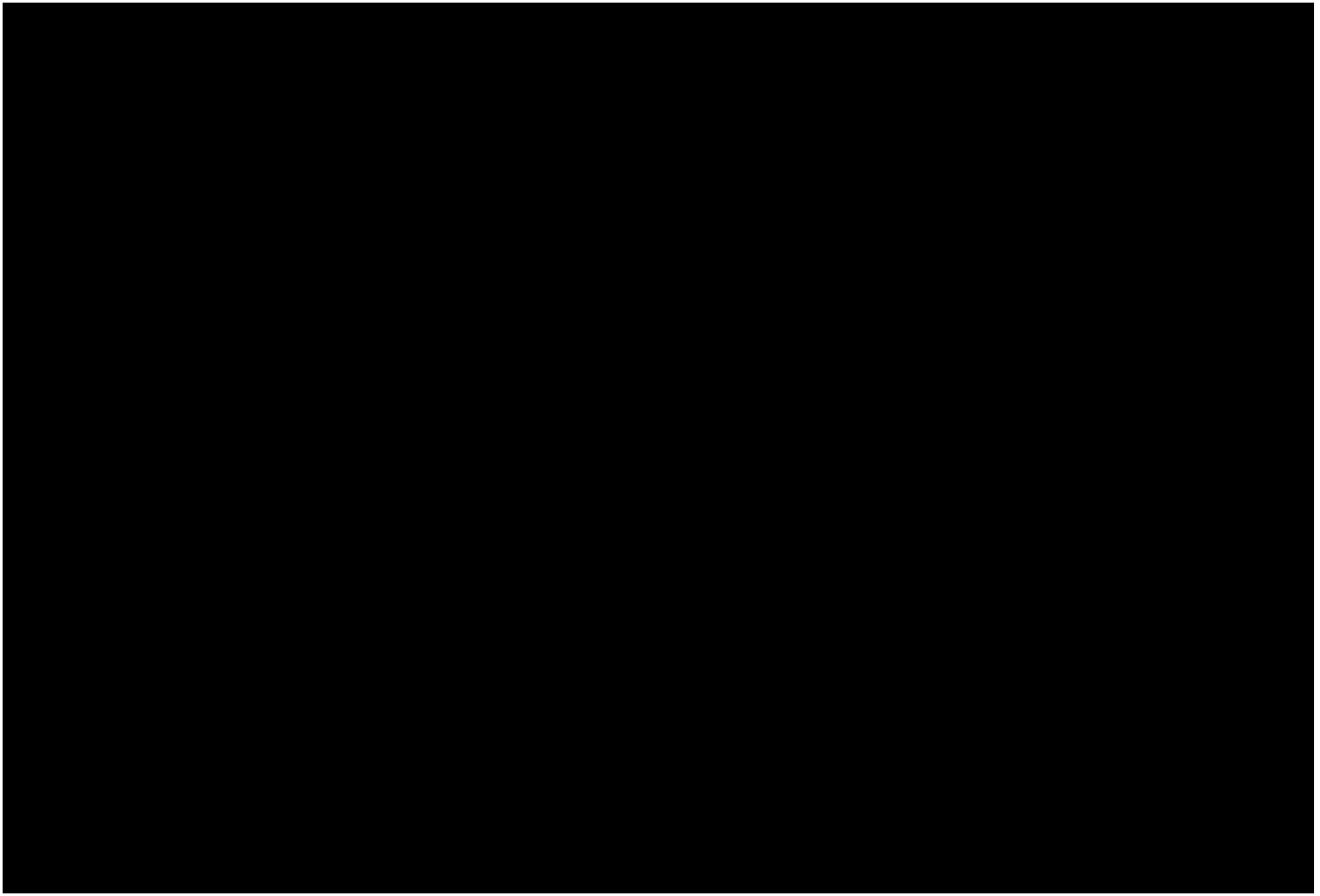
Date of On Peak Day - 04/15/2021

[redacted]

Member Forecasted On Peak Demand Day for May 2021

San Isabel Electric Association, Inc.

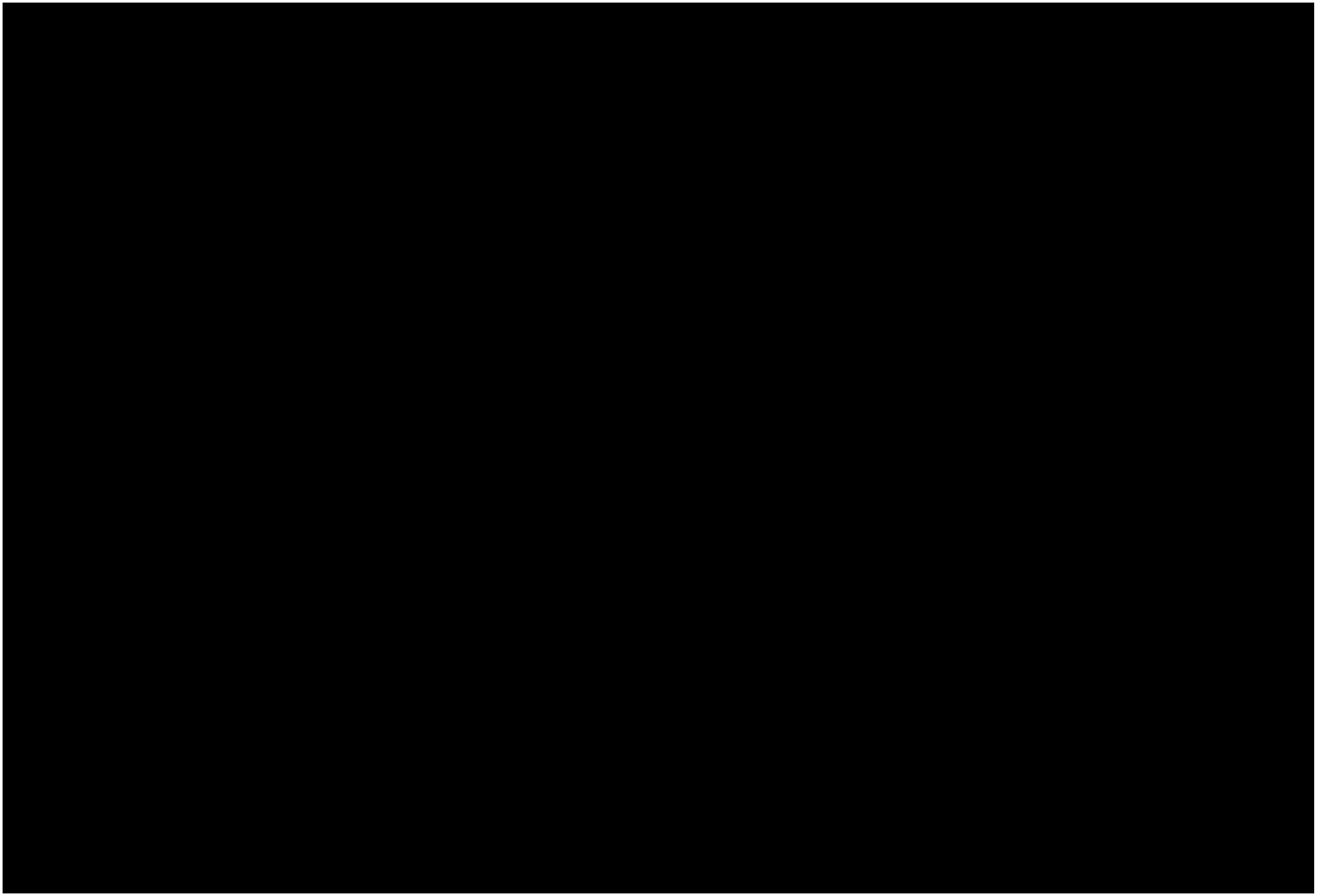
Date of On Peak Day - 05/01/2021



Member Forecasted On Peak Demand Day for June 2021

San Isabel Electric Association, Inc.

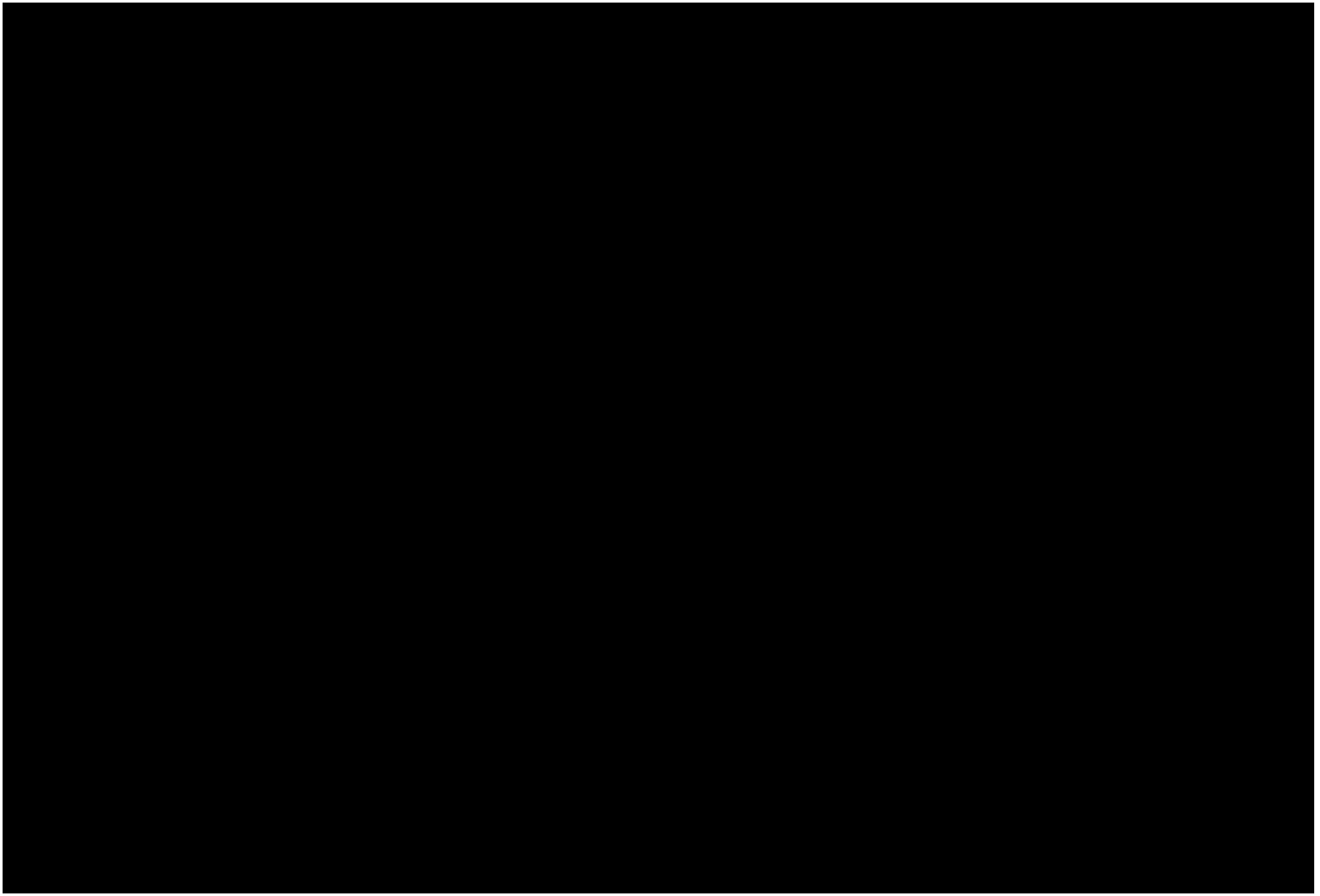
Date of On Peak Day - 06/27/2021



Member Forecasted On Peak Demand Day for July 2021

San Isabel Electric Association, Inc.

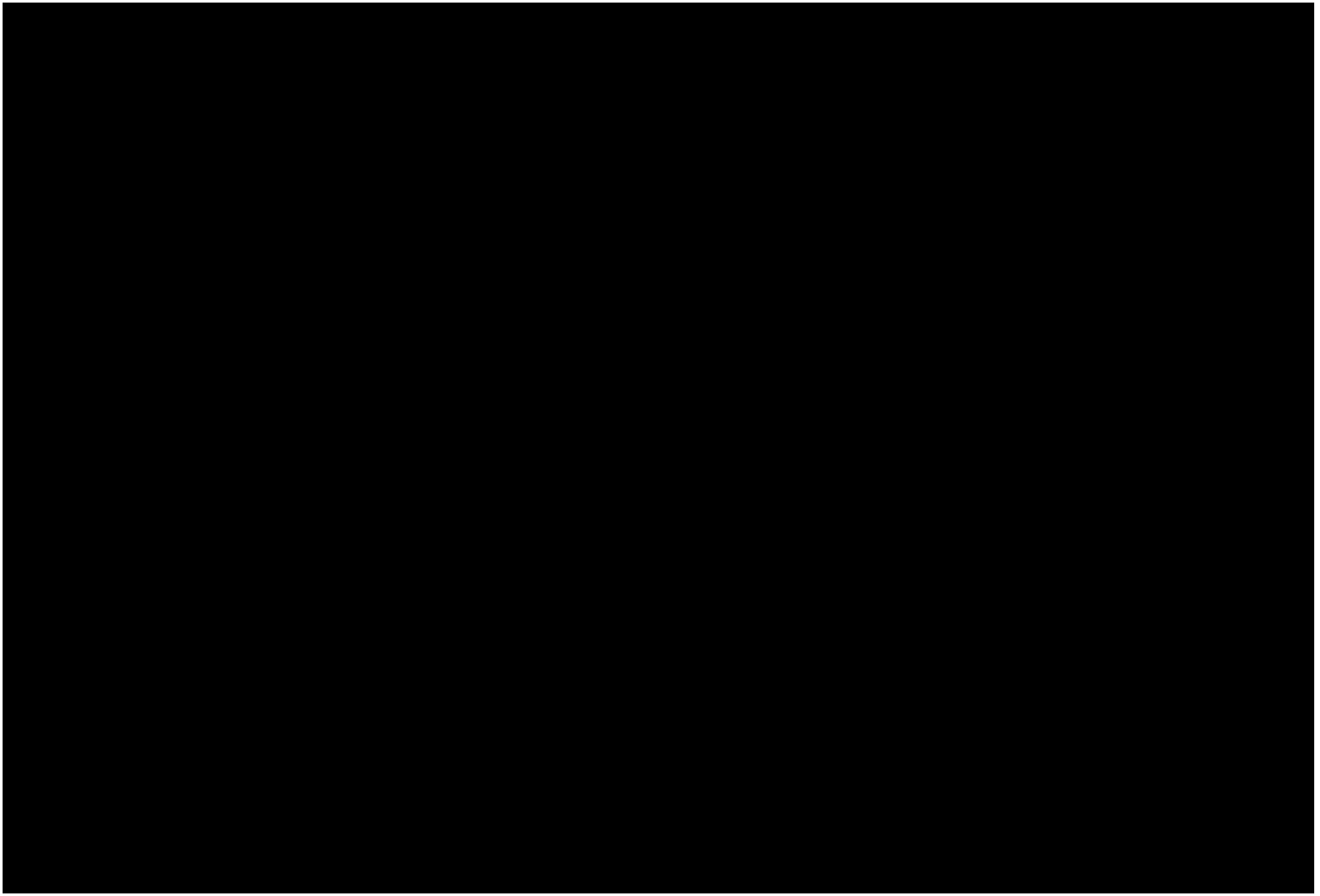
Date of On Peak Day - 07/10/2021



Member Forecasted On Peak Demand Day for August 2021

San Isabel Electric Association, Inc.

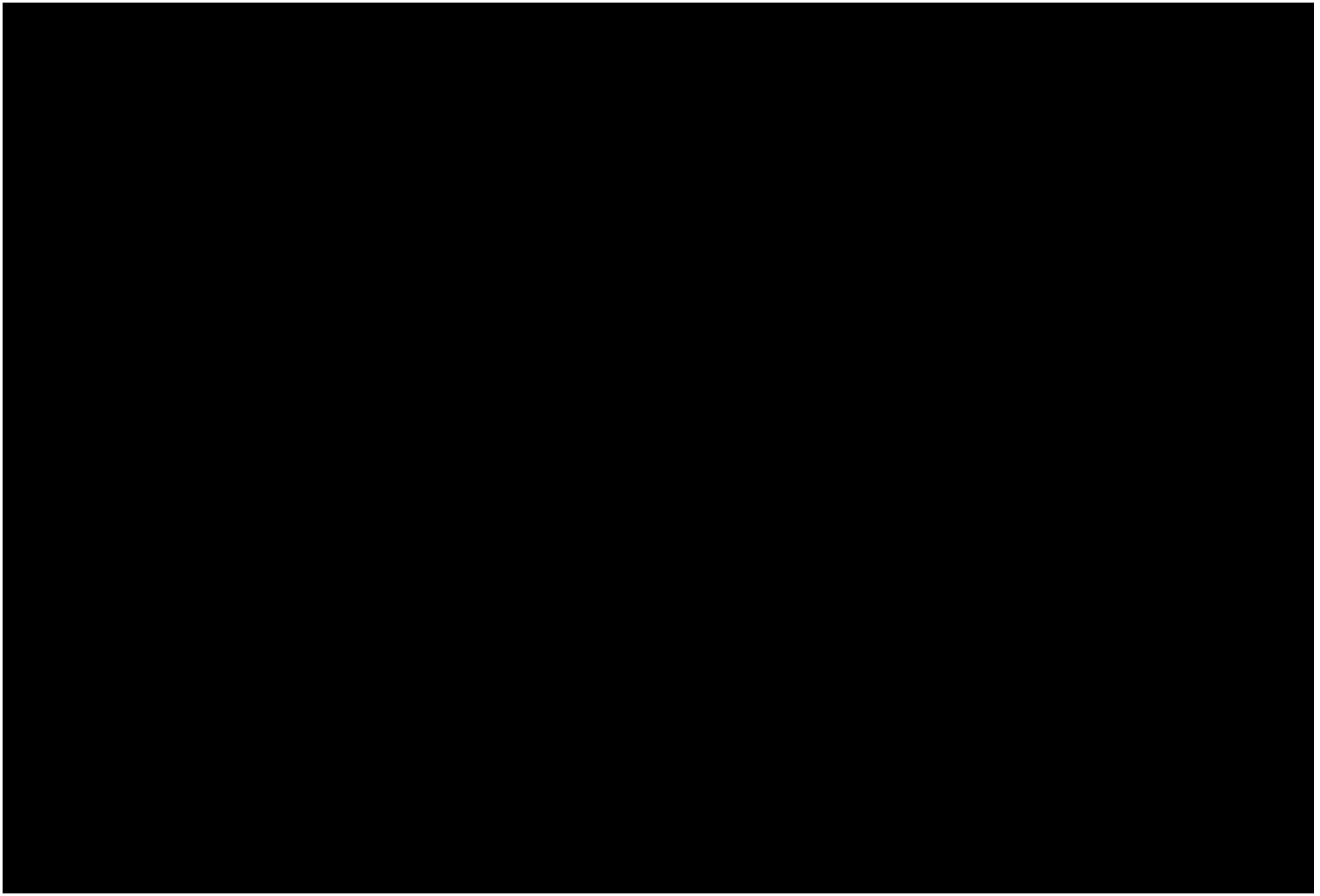
Date of On Peak Day - 08/21/2021



Member Forecasted On Peak Demand Day for September 2021

San Isabel Electric Association, Inc.

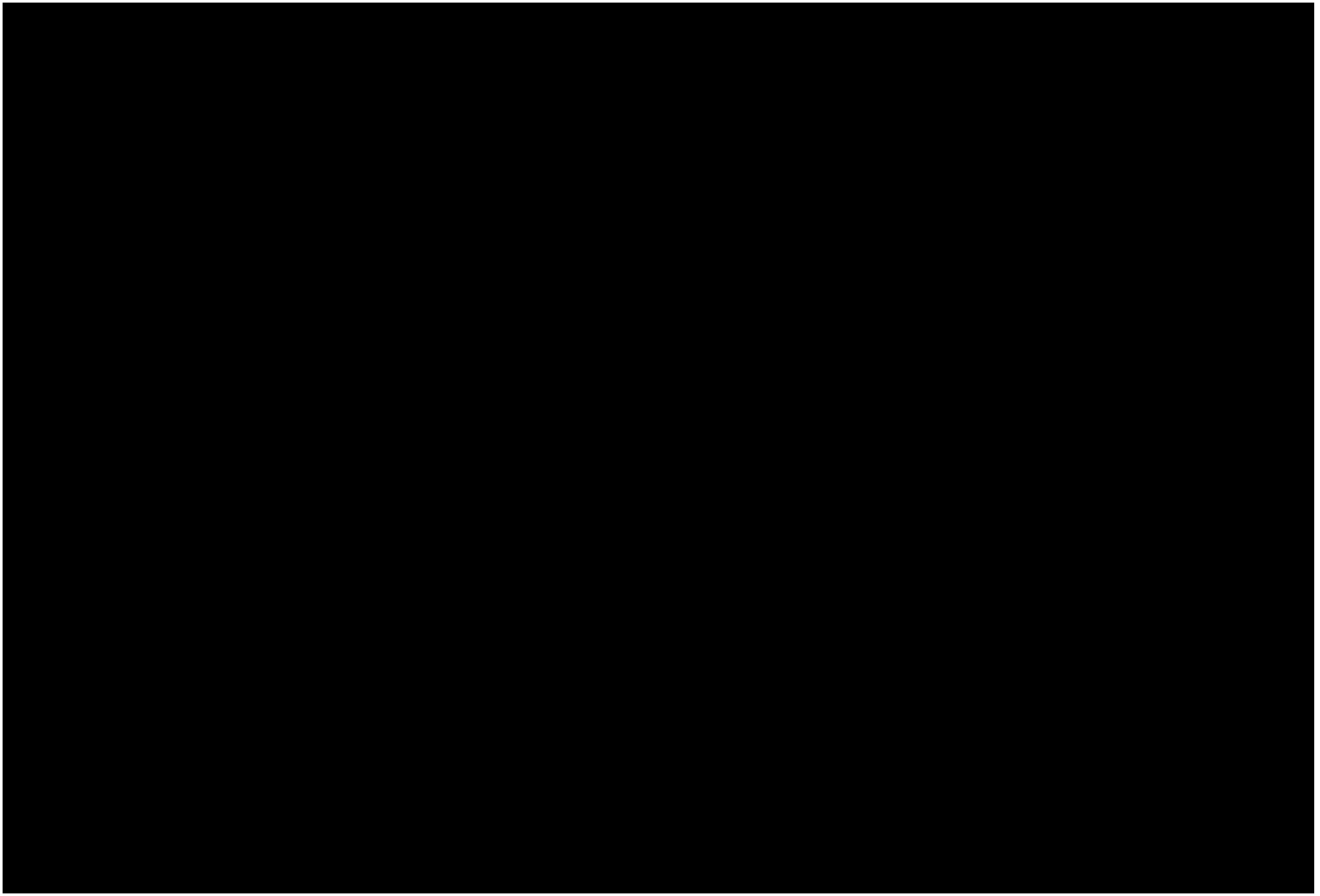
Date of On Peak Day - 09/13/2021



Member Forecasted On Peak Demand Day for October 2021

San Isabel Electric Association, Inc.

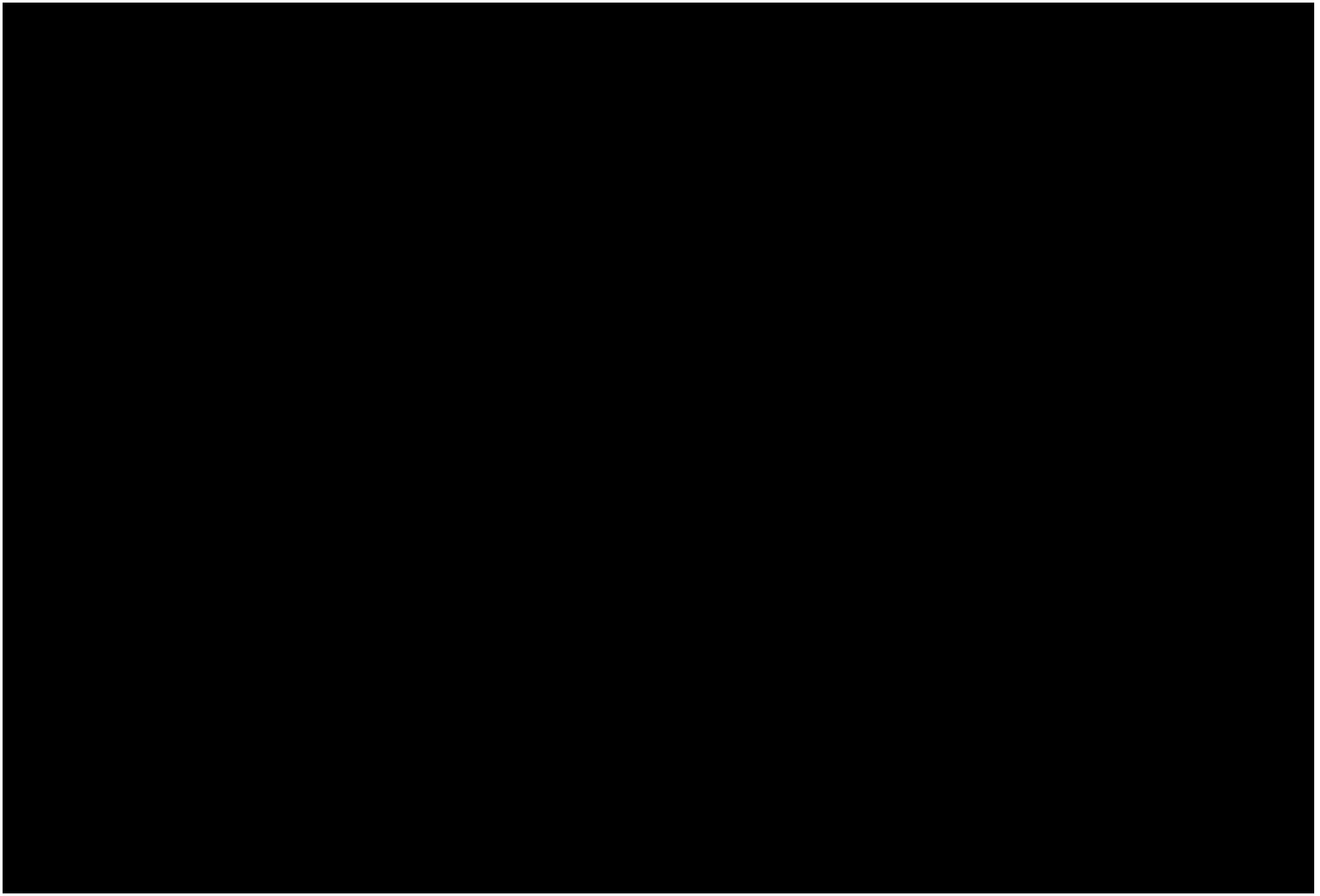
Date of On Peak Day - 10/01/2021



Member Forecasted On Peak Demand Day for November 2021

San Isabel Electric Association, Inc.

Date of On Peak Day - 11/08/2021



Member Forecasted On Peak Demand Day for December 2021

San Isabel Electric Association, Inc.

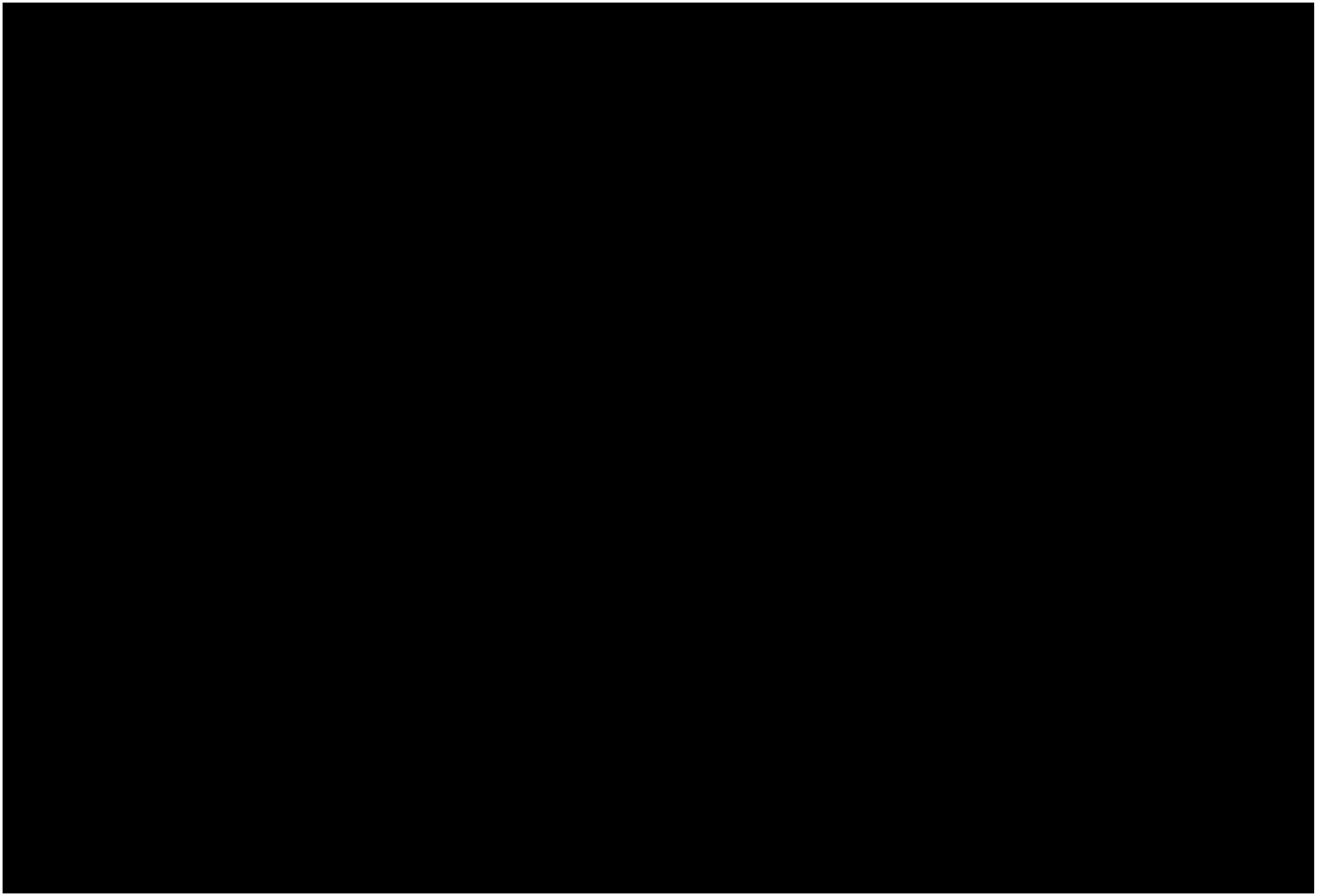
Date of On Peak Day - 12/29/2021

[redacted]

Member Forecasted On Peak Demand Day for January 2021

San Luis Valley Rural Electric Cooperative, Inc.

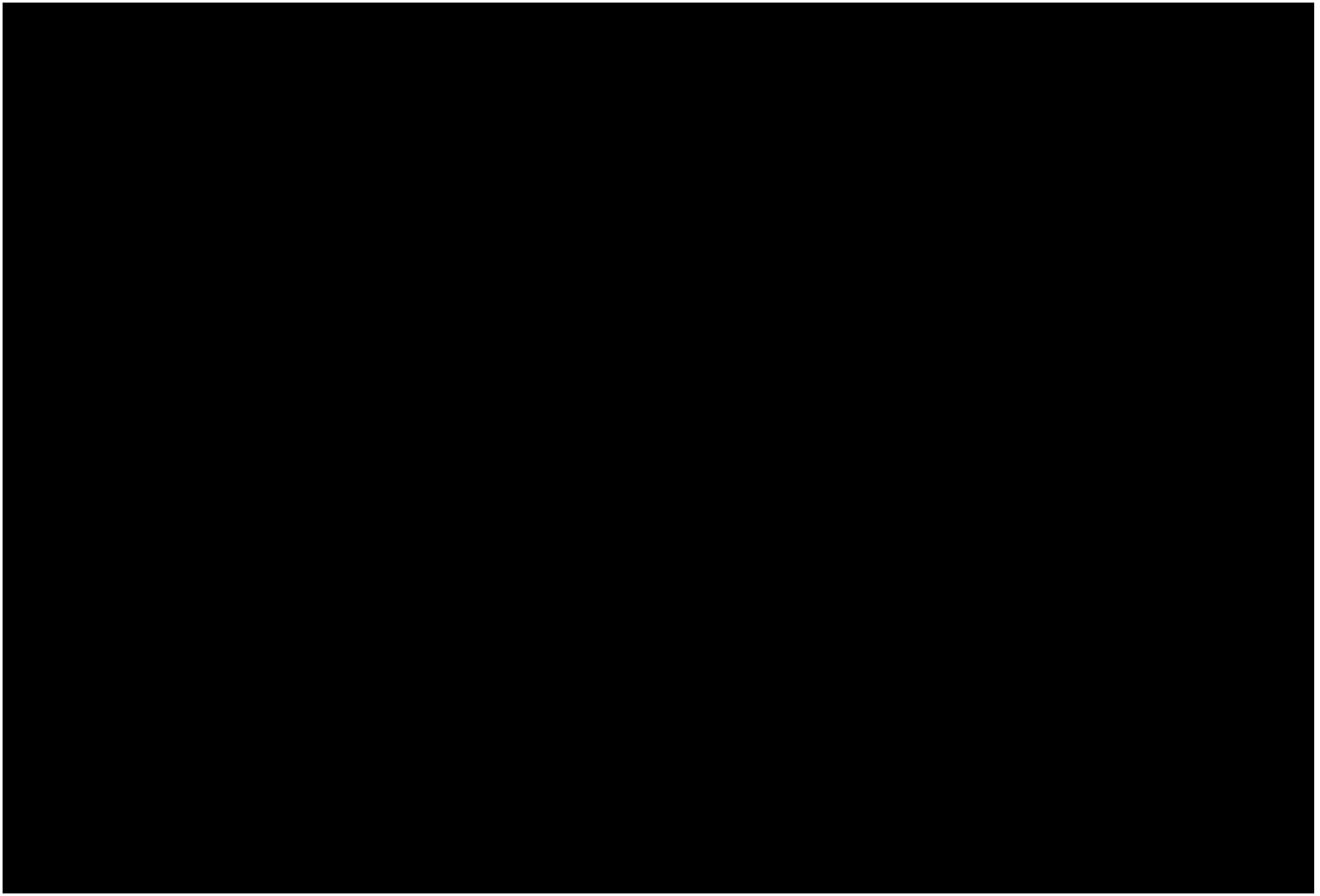
Date of On Peak Day - 01/29/2021



Member Forecasted On Peak Demand Day for February 2021

San Luis Valley Rural Electric Cooperative, Inc.

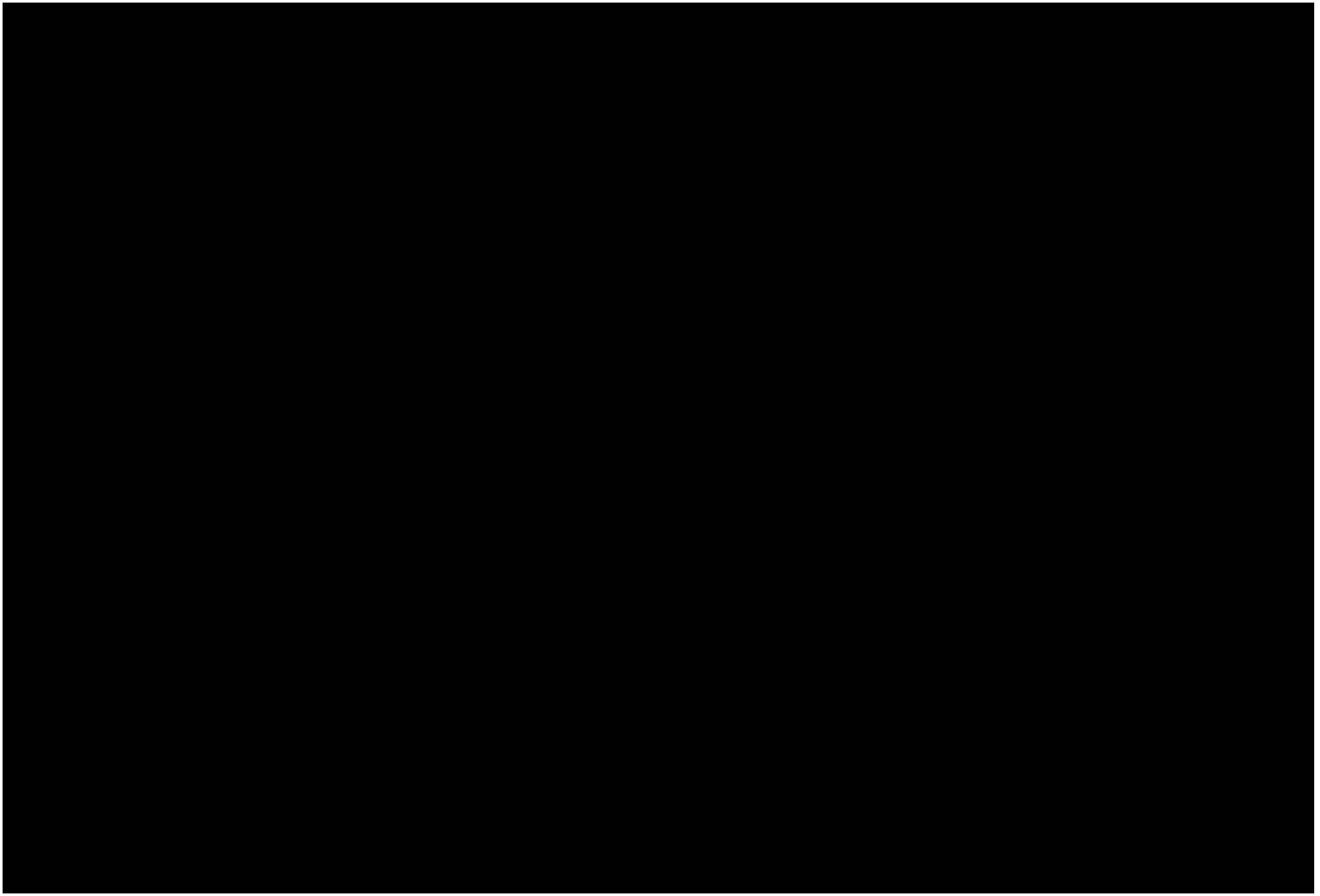
Date of On Peak Day - 02/25/2021



Member Forecasted On Peak Demand Day for March 2021

San Luis Valley Rural Electric Cooperative, Inc.

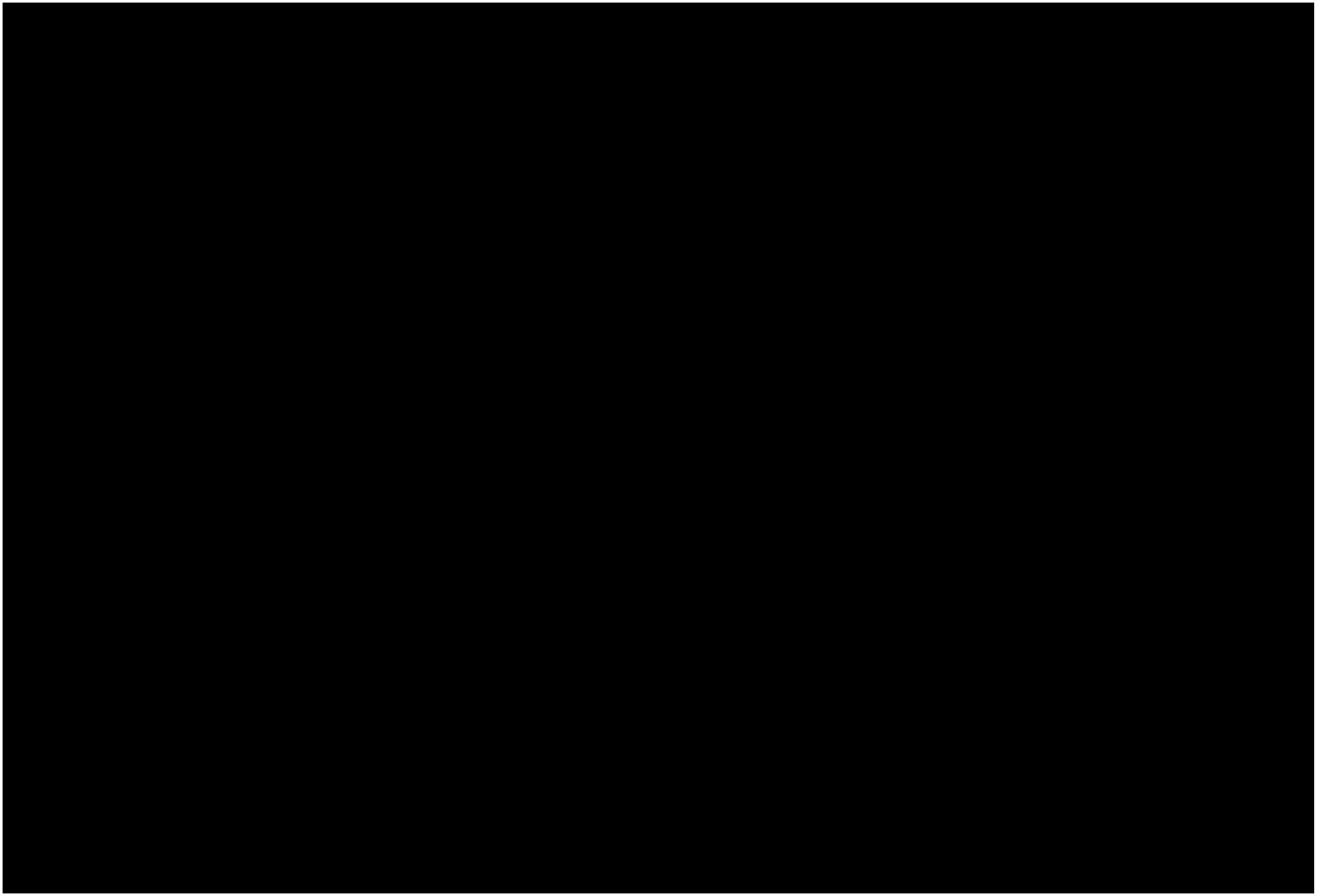
Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

San Luis Valley Rural Electric Cooperative, Inc.

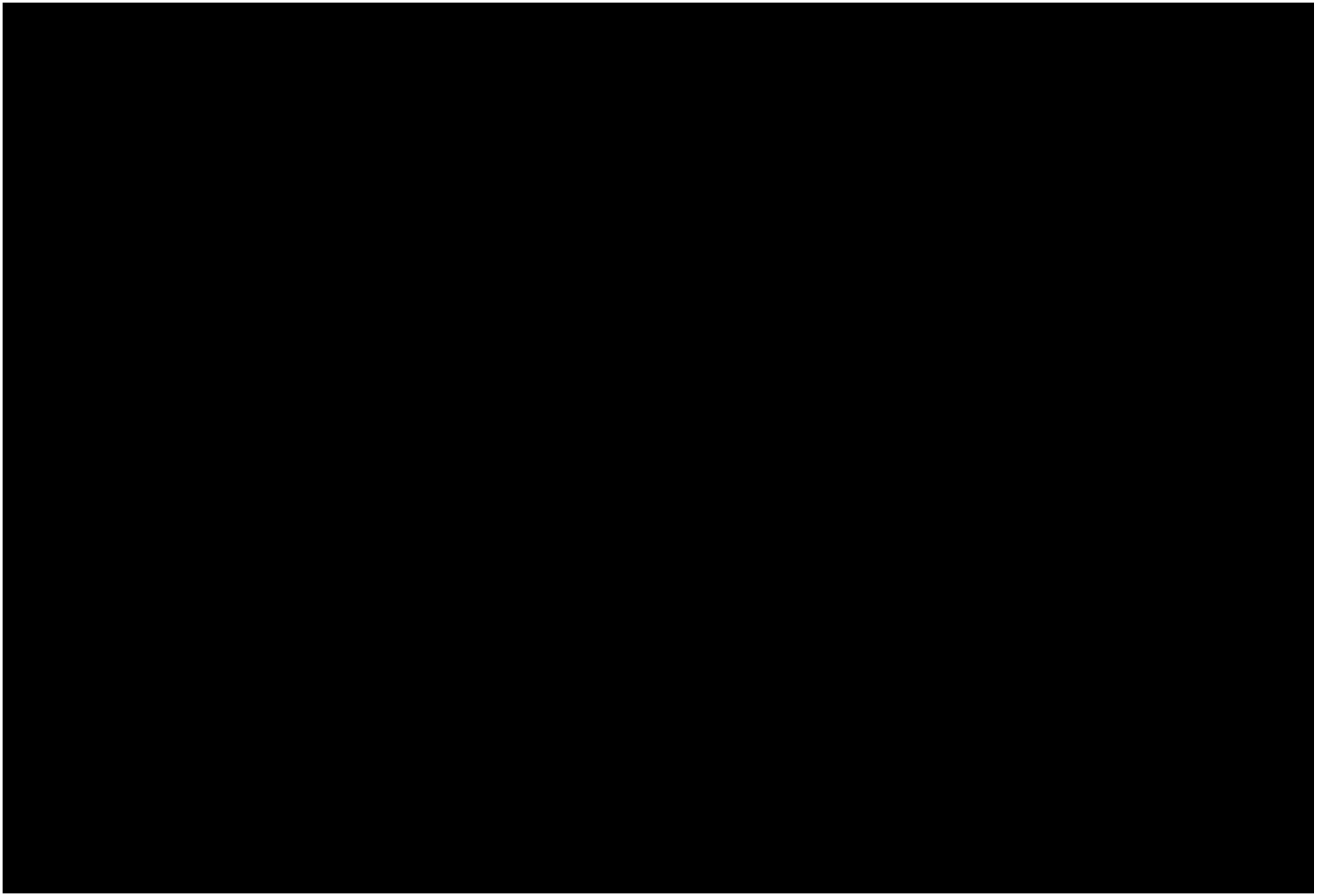
Date of On Peak Day - 04/22/2021



Member Forecasted On Peak Demand Day for May 2021

San Luis Valley Rural Electric Cooperative, Inc.

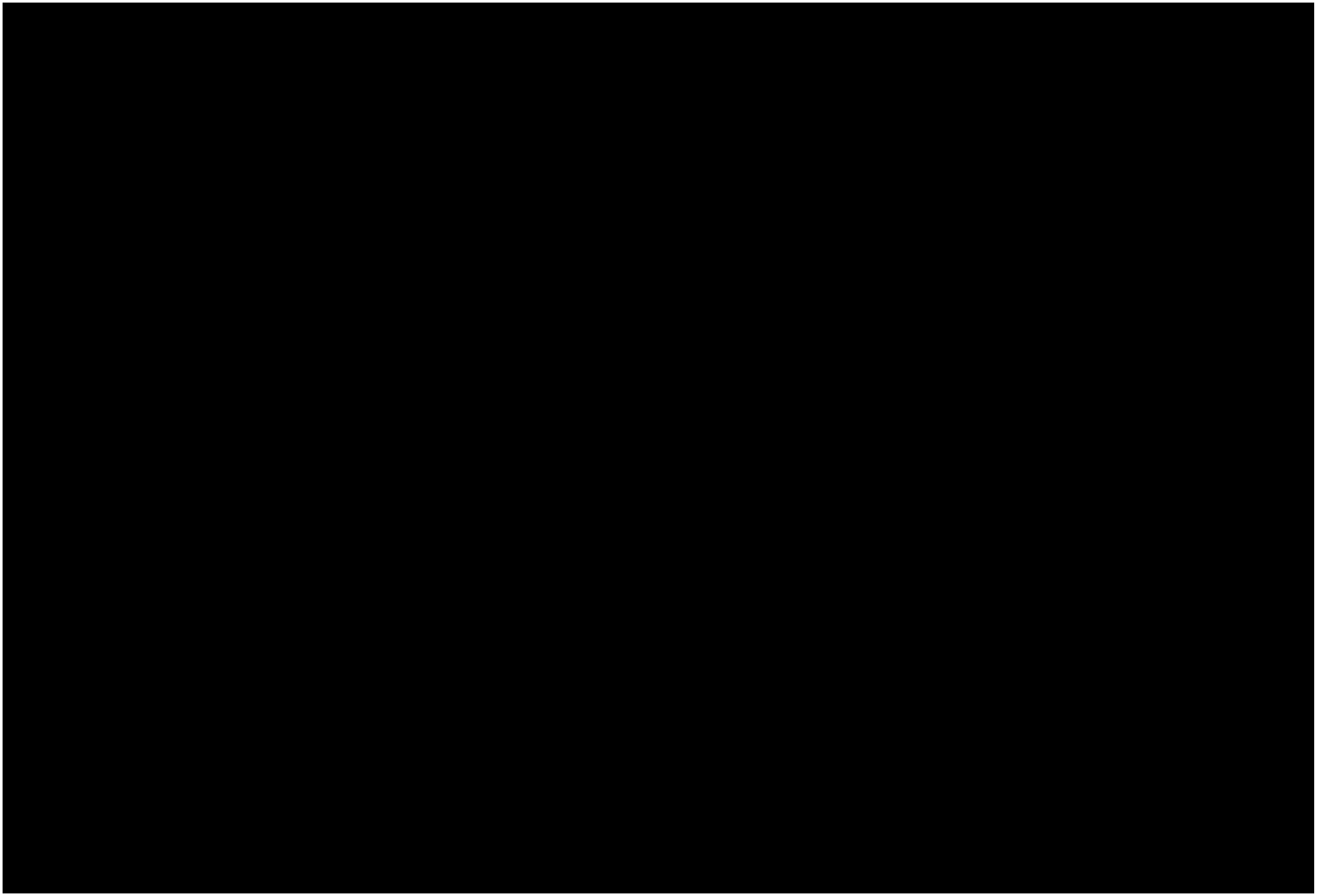
Date of On Peak Day - 05/24/2021



Member Forecasted On Peak Demand Day for June 2021

San Luis Valley Rural Electric Cooperative, Inc.

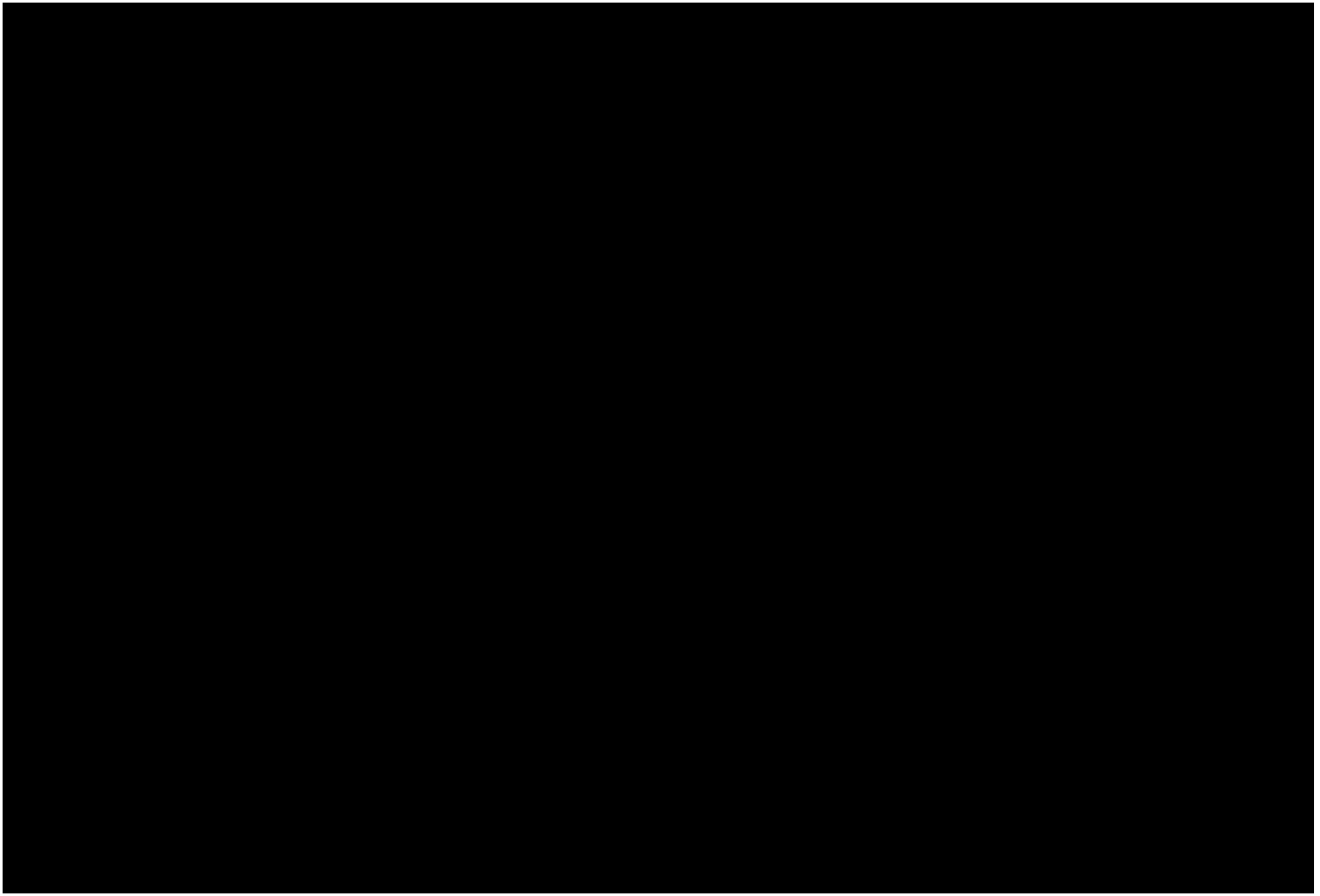
Date of On Peak Day - 06/30/2021



Member Forecasted On Peak Demand Day for July 2021

San Luis Valley Rural Electric Cooperative, Inc.

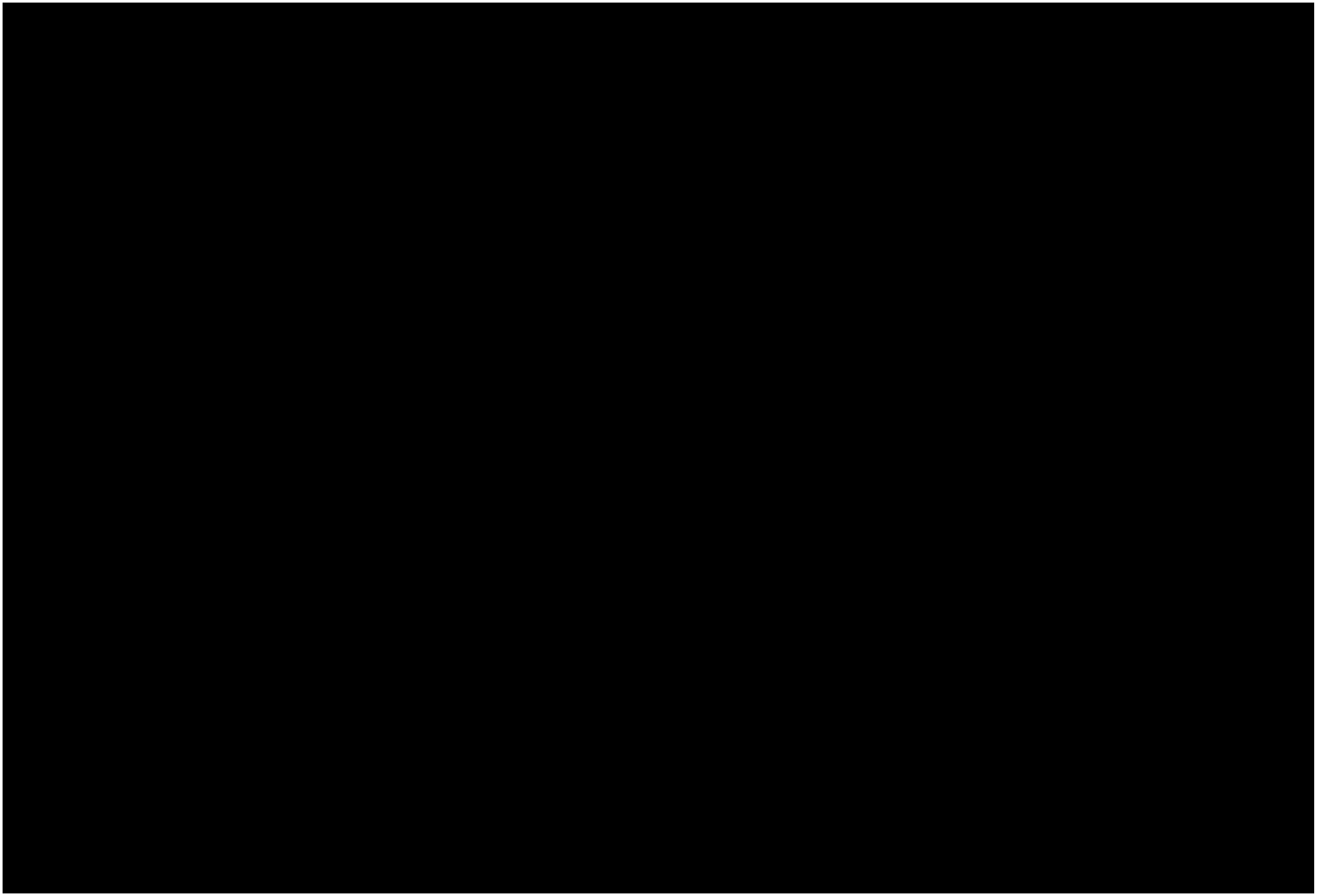
Date of On Peak Day - 07/12/2021



Member Forecasted On Peak Demand Day for August 2021

San Luis Valley Rural Electric Cooperative, Inc.

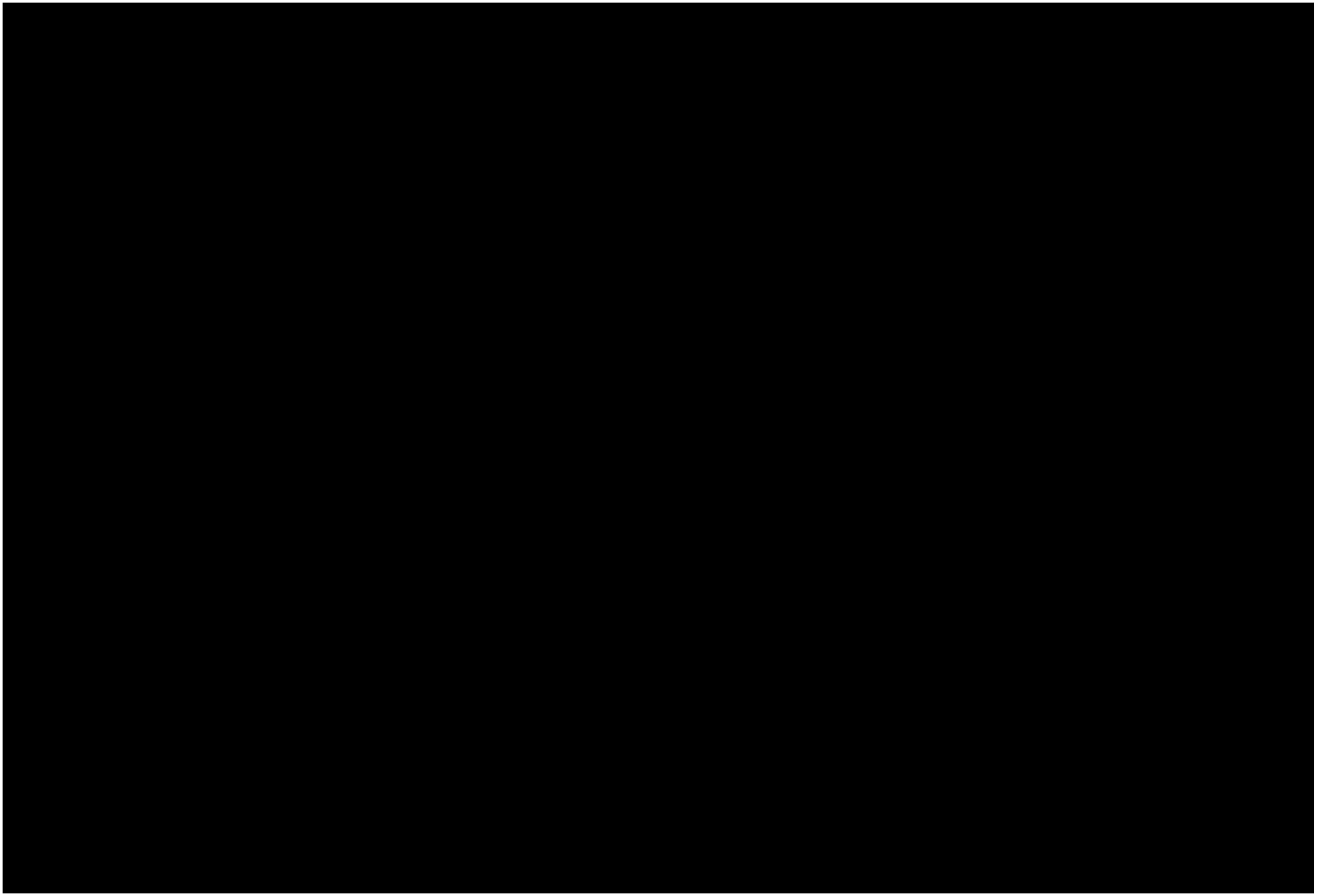
Date of On Peak Day - 08/16/2021



Member Forecasted On Peak Demand Day for September 2021

San Luis Valley Rural Electric Cooperative, Inc.

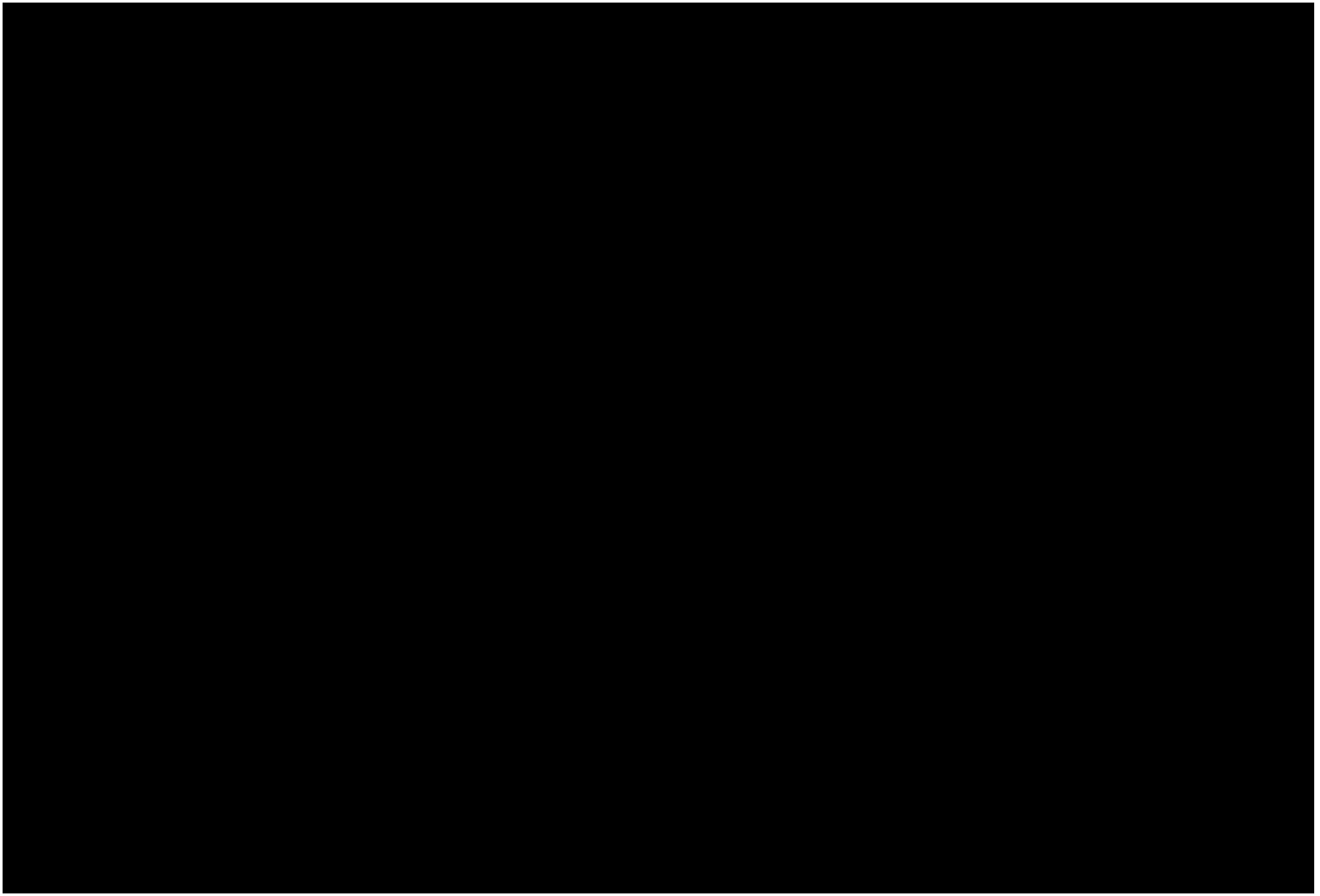
Date of On Peak Day - 09/02/2021



Member Forecasted On Peak Demand Day for October 2021

San Luis Valley Rural Electric Cooperative, Inc.

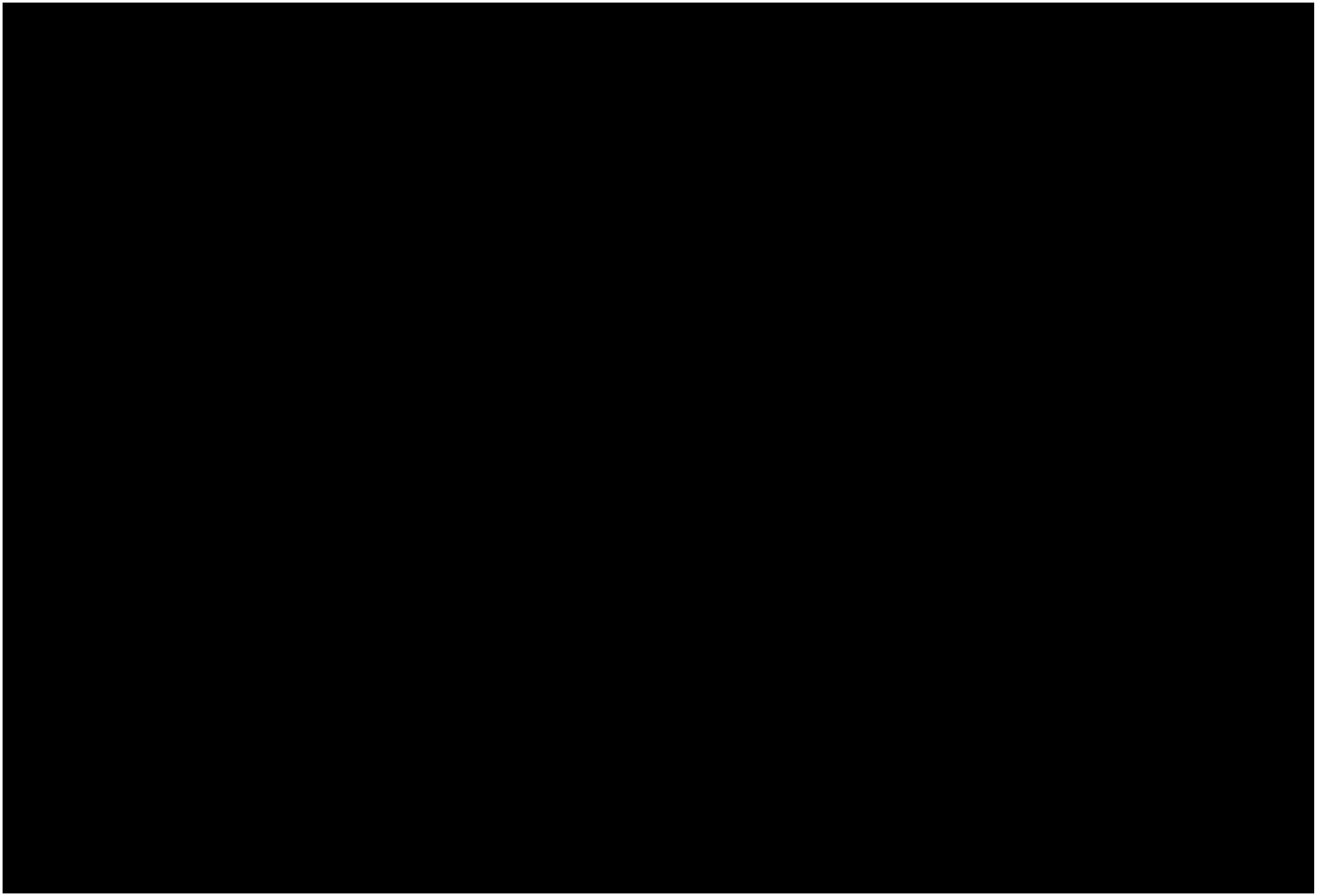
Date of On Peak Day - 10/16/2021



Member Forecasted On Peak Demand Day for November 2021

San Luis Valley Rural Electric Cooperative, Inc.

Date of On Peak Day - 11/12/2021



Member Forecasted On Peak Demand Day for December 2021

San Luis Valley Rural Electric Cooperative, Inc.

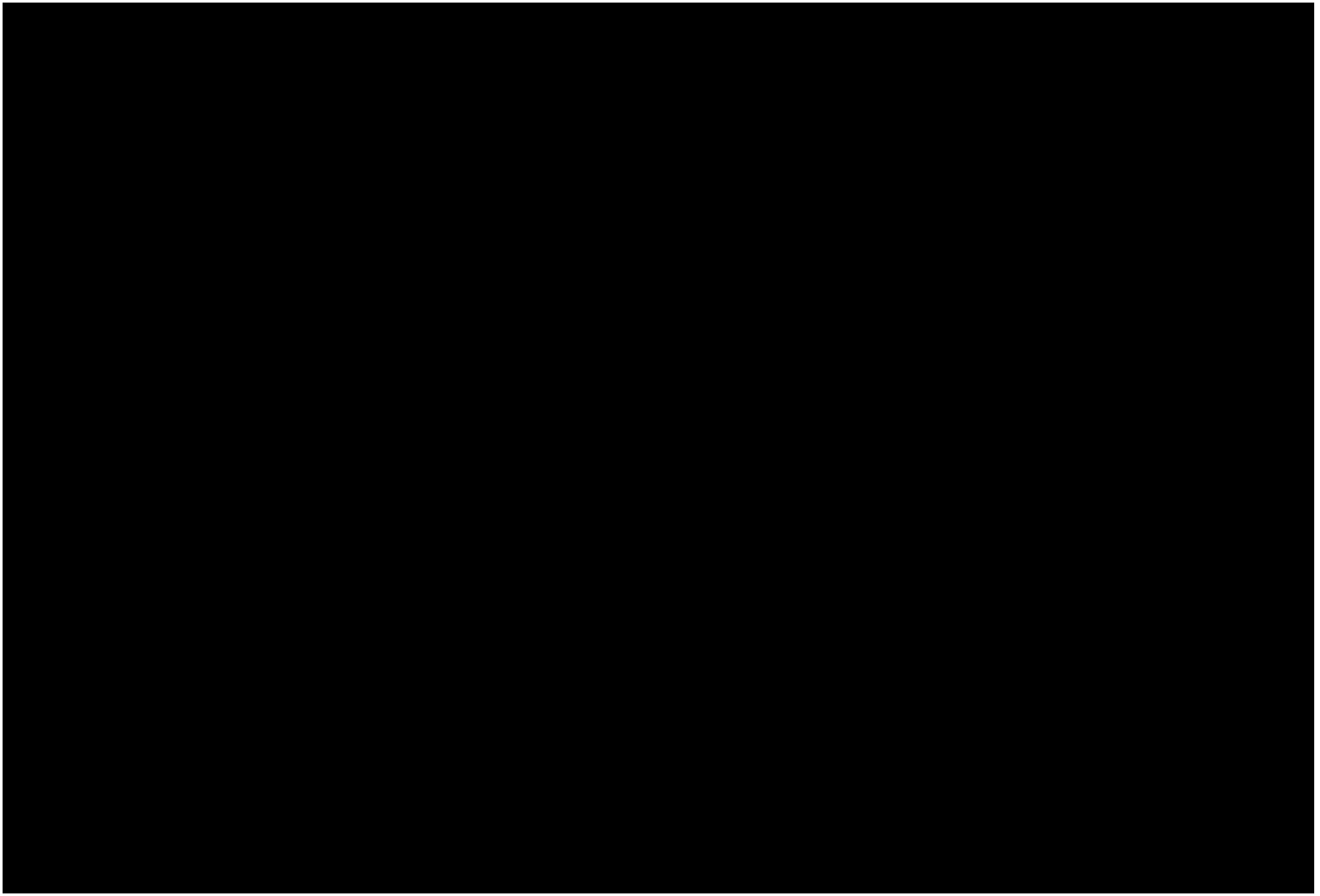
Date of On Peak Day - 12/31/2021

[redacted]

Member Forecasted On Peak Demand Day for January 2021

San Miguel Power Association, Inc.

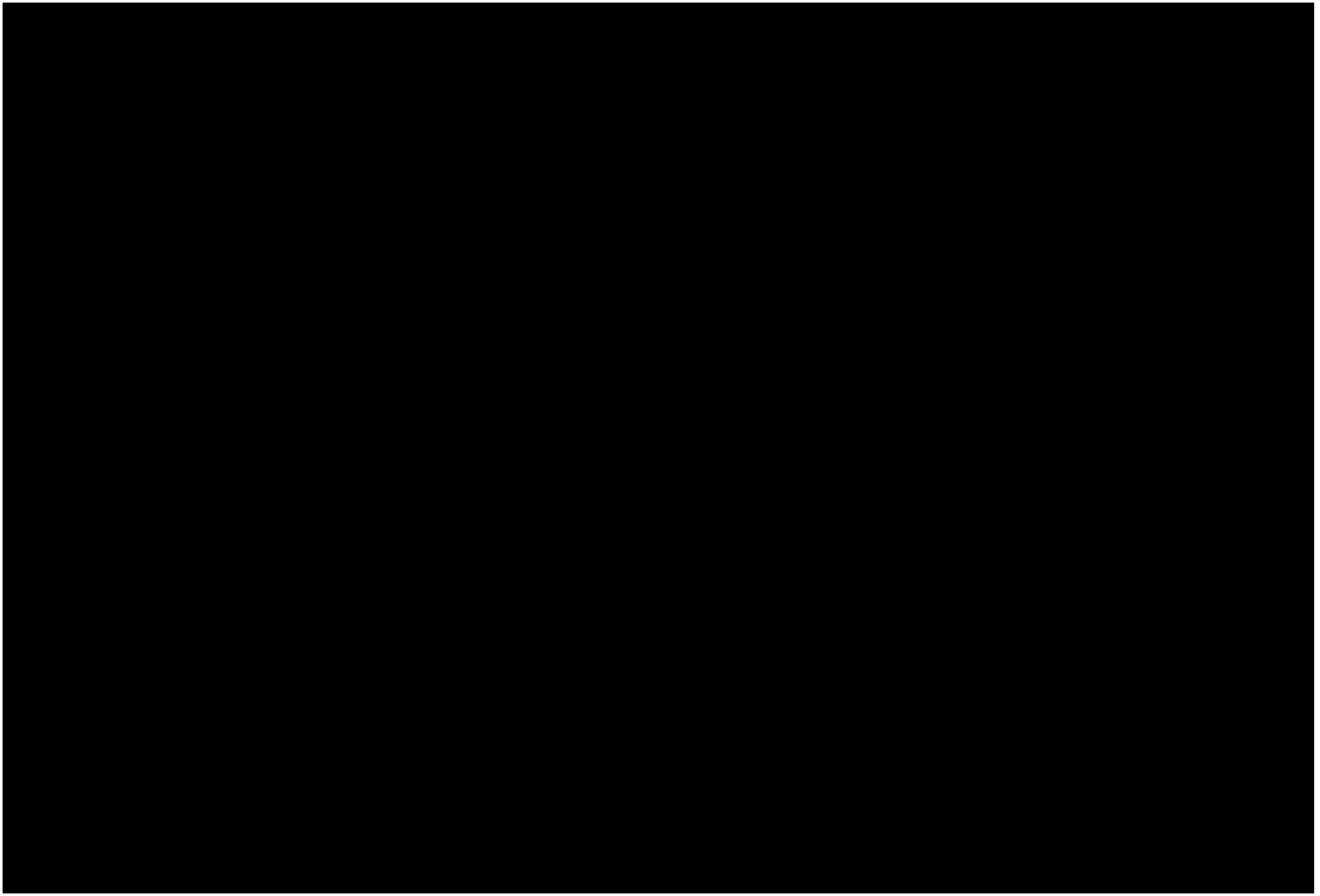
Date of On Peak Day - 01/01/2021



Member Forecasted On Peak Demand Day for February 2021

San Miguel Power Association, Inc.

Date of On Peak Day - 02/25/2021



Member Forecasted On Peak Demand Day for March 2021

San Miguel Power Association, Inc.

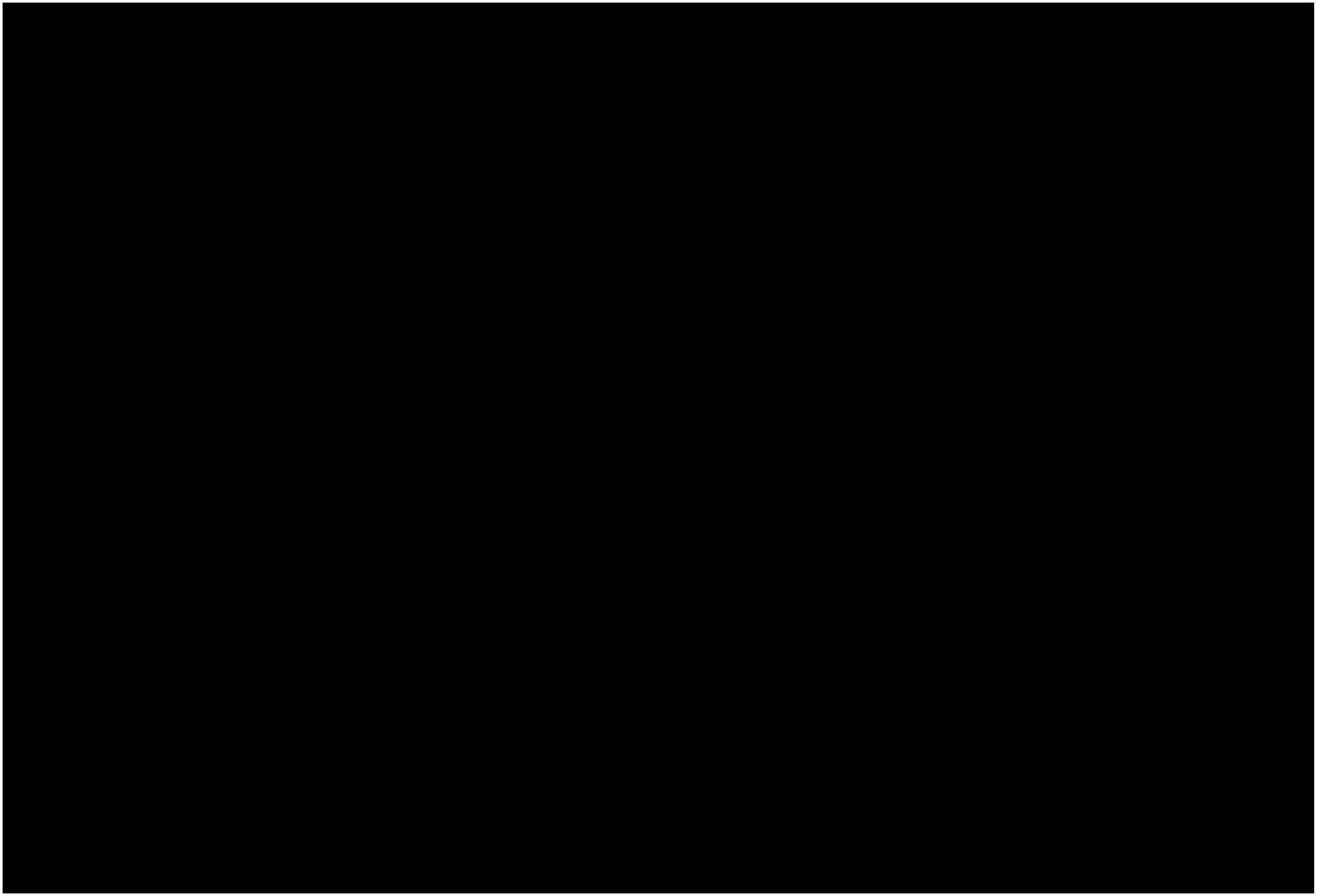
Date of On Peak Day - 03/01/2021

[redacted]

Member Forecasted On Peak Demand Day for April 2021

San Miguel Power Association, Inc.

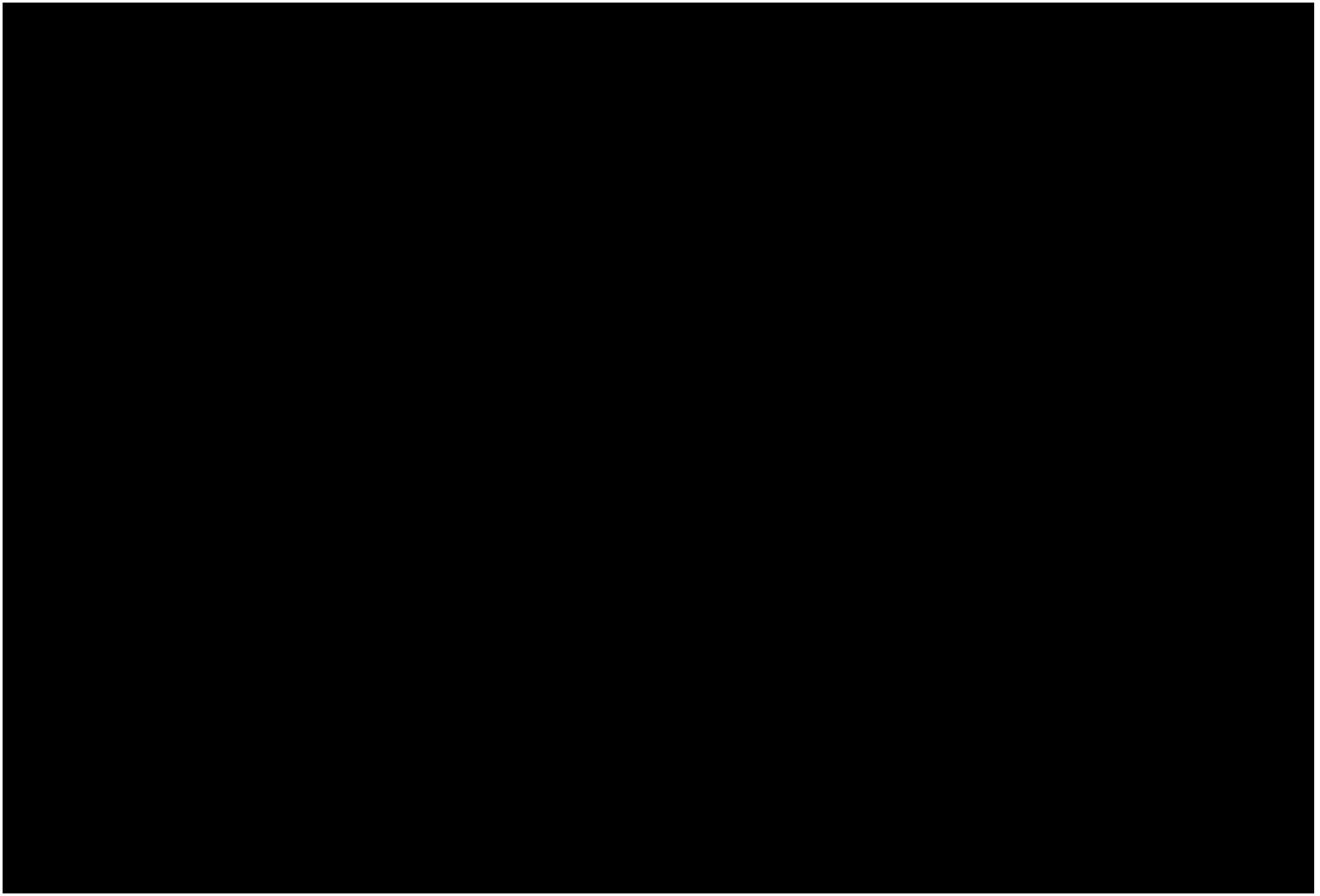
Date of On Peak Day - 04/03/2021



Member Forecasted On Peak Demand Day for May 2021

San Miguel Power Association, Inc.

Date of On Peak Day - 05/18/2021



Member Forecasted On Peak Demand Day for June 2021

San Miguel Power Association, Inc.

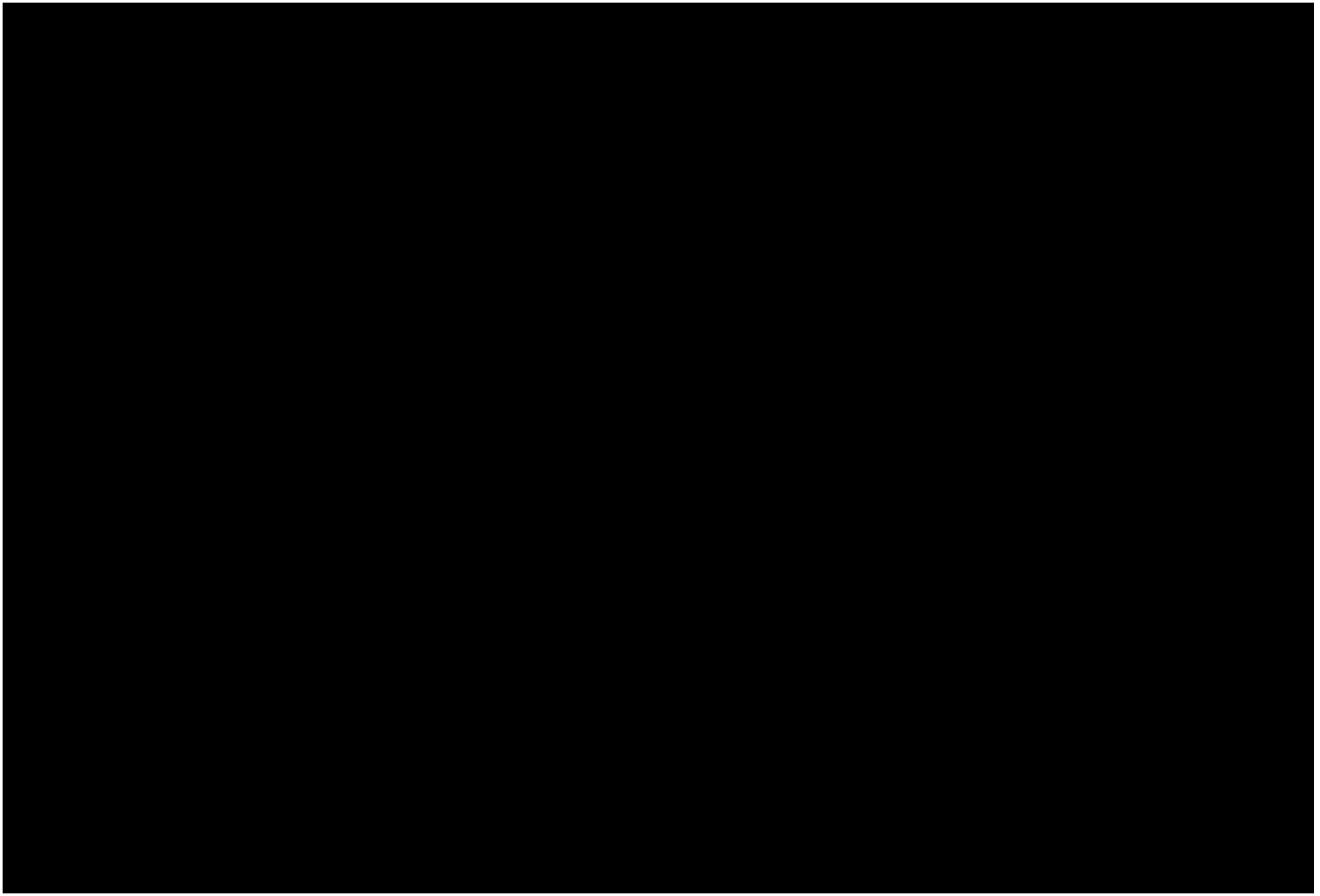
Date of On Peak Day - 06/30/2021

[redacted]

Member Forecasted On Peak Demand Day for July 2021

San Miguel Power Association, Inc.

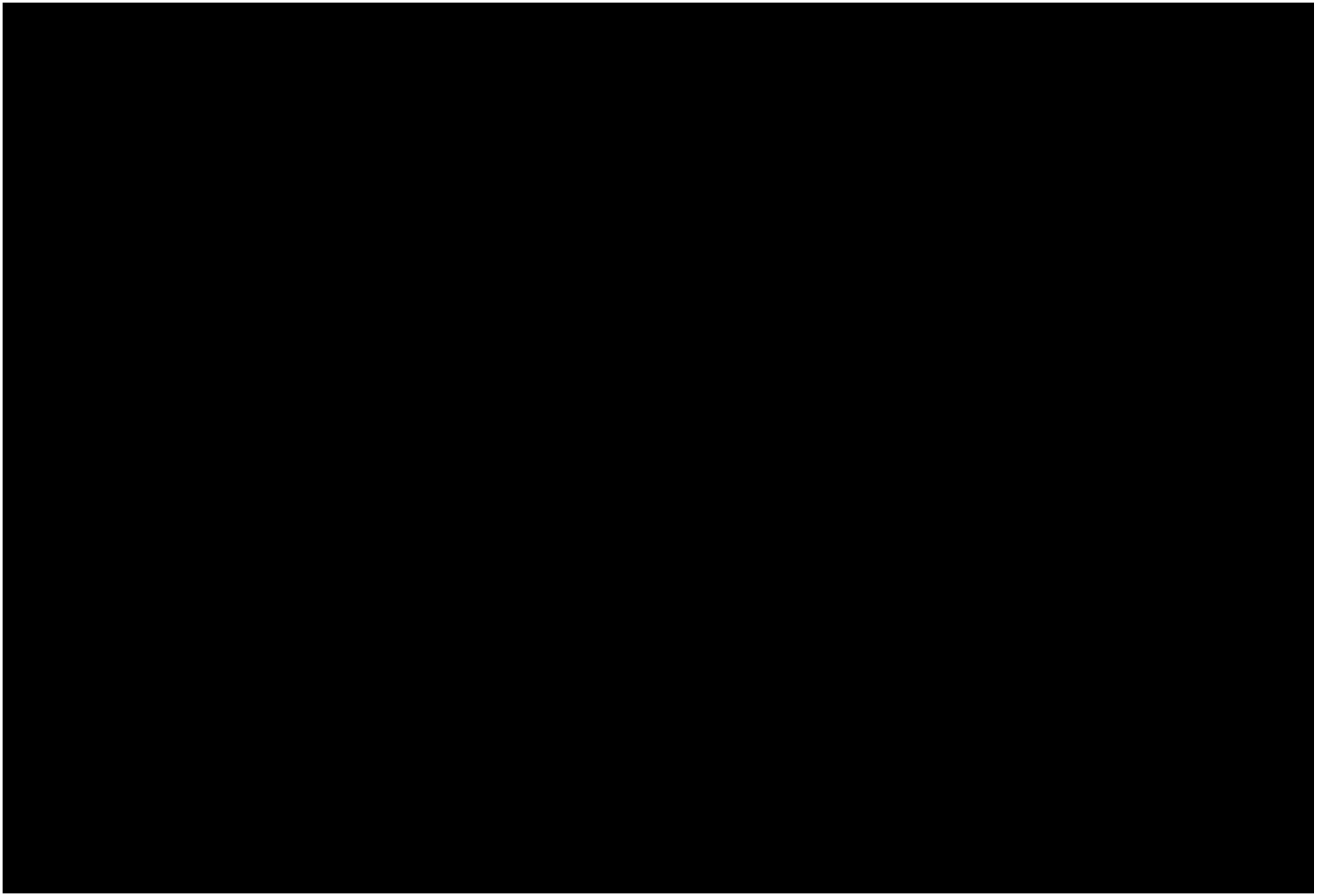
Date of On Peak Day - 07/30/2021



Member Forecasted On Peak Demand Day for August 2021

San Miguel Power Association, Inc.

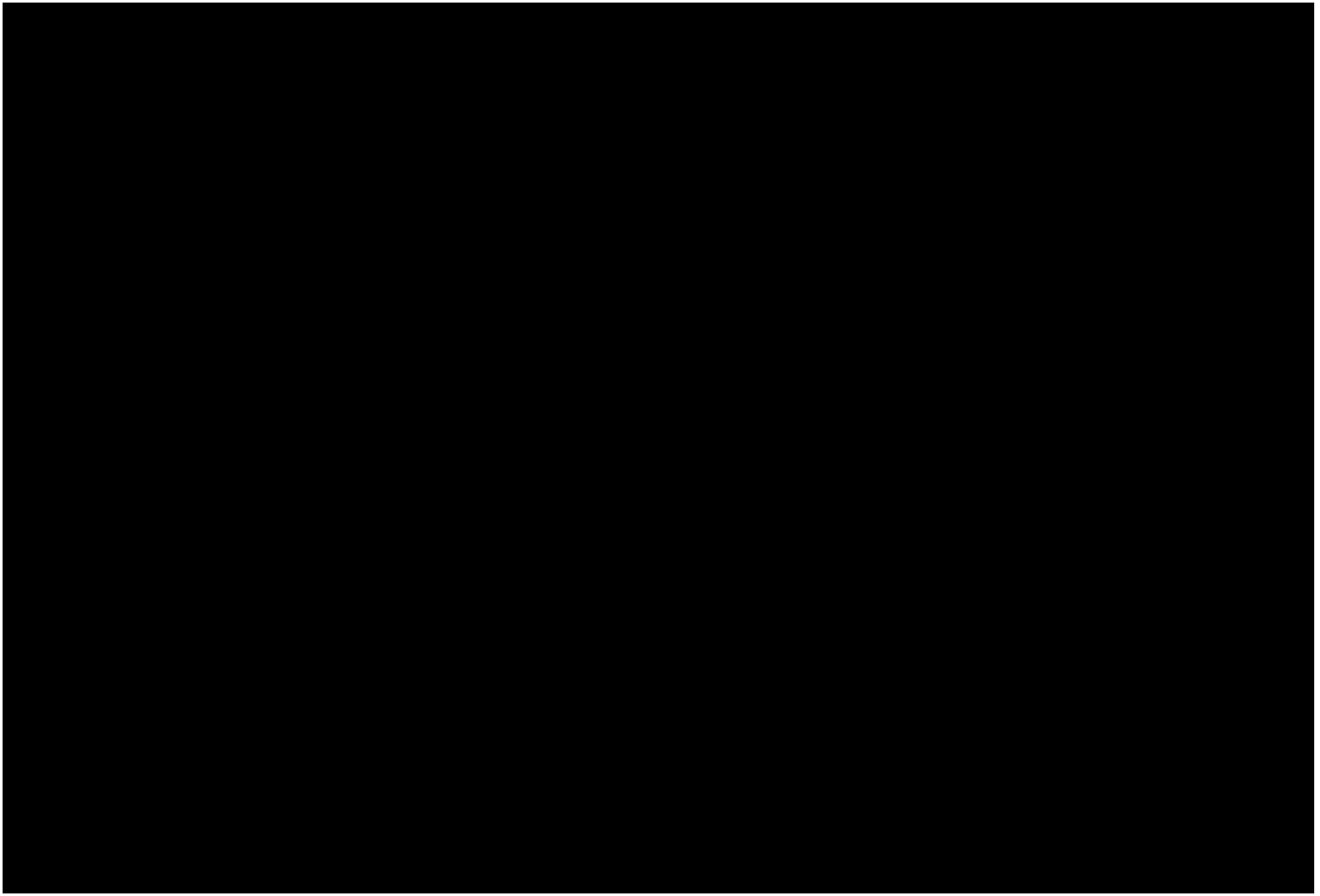
Date of On Peak Day - 08/28/2021



Member Forecasted On Peak Demand Day for September 2021

San Miguel Power Association, Inc.

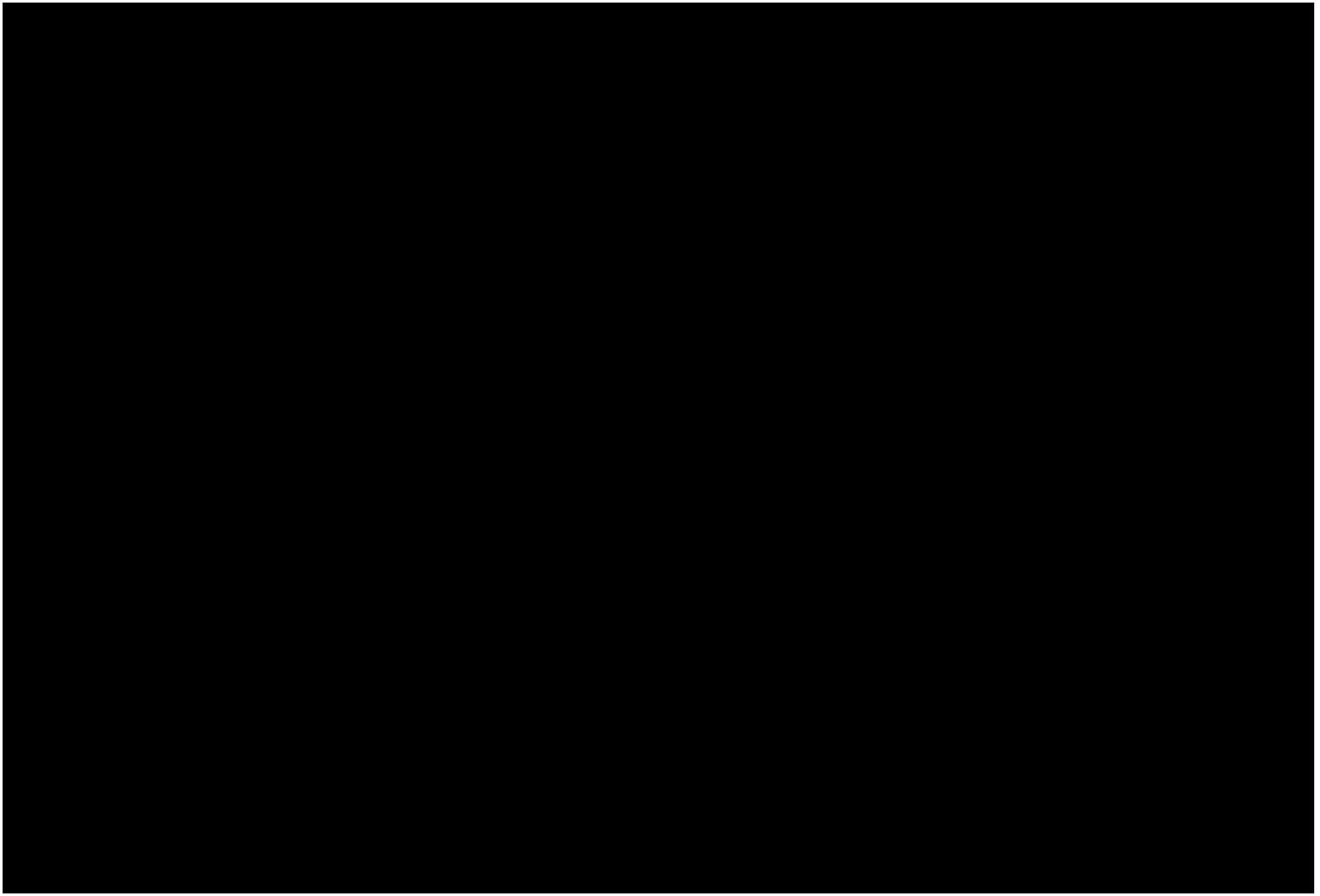
Date of On Peak Day - 09/03/2021



Member Forecasted On Peak Demand Day for October 2021

San Miguel Power Association, Inc.

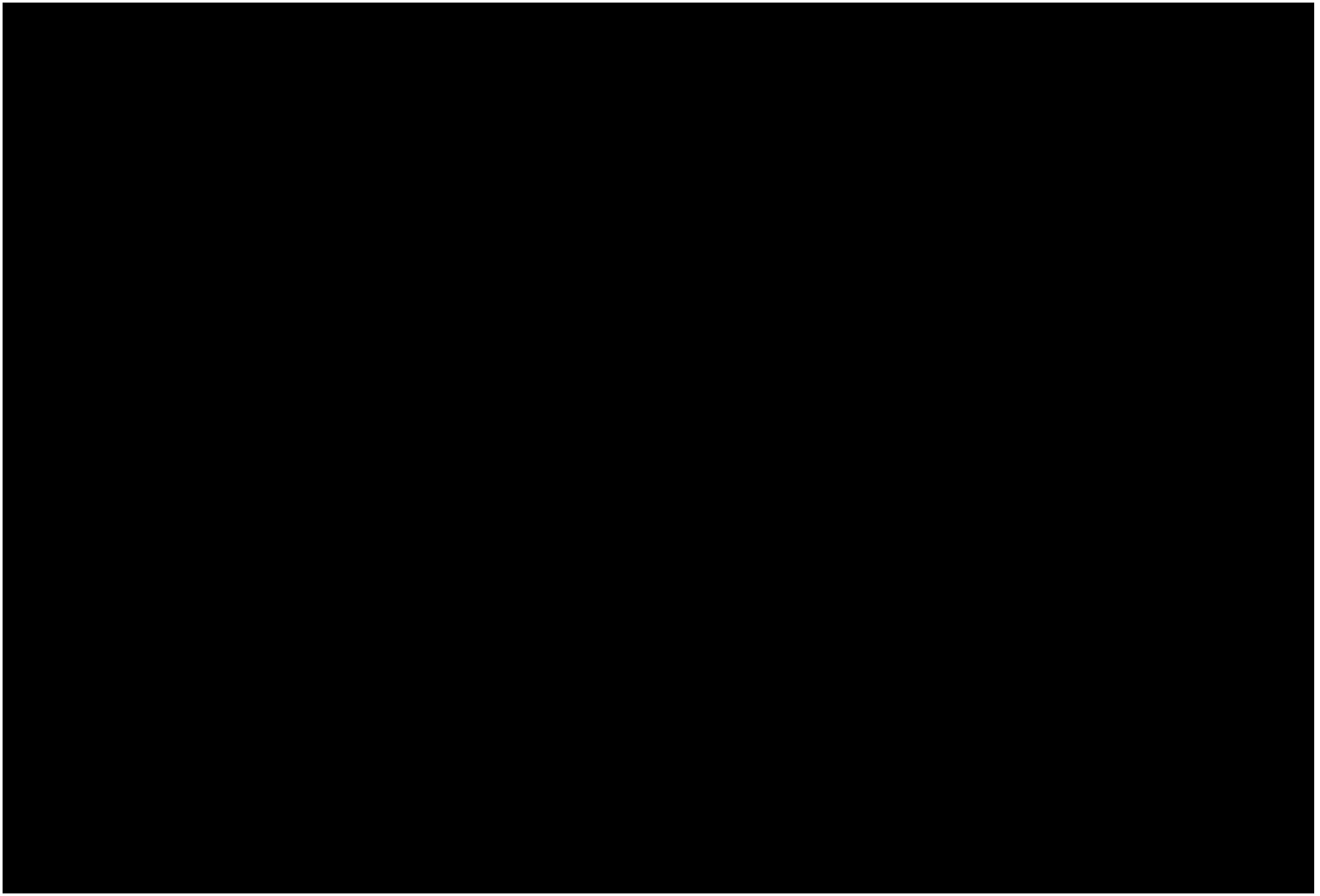
Date of On Peak Day - 10/28/2021



Member Forecasted On Peak Demand Day for November 2021

San Miguel Power Association, Inc.

Date of On Peak Day - 11/24/2021



Member Forecasted On Peak Demand Day for December 2021

San Miguel Power Association, Inc.

Date of On Peak Day - 12/25/2021

[redacted]

Member Forecasted On Peak Demand Day for January 2021

Socorro Electric Cooperative, Inc.

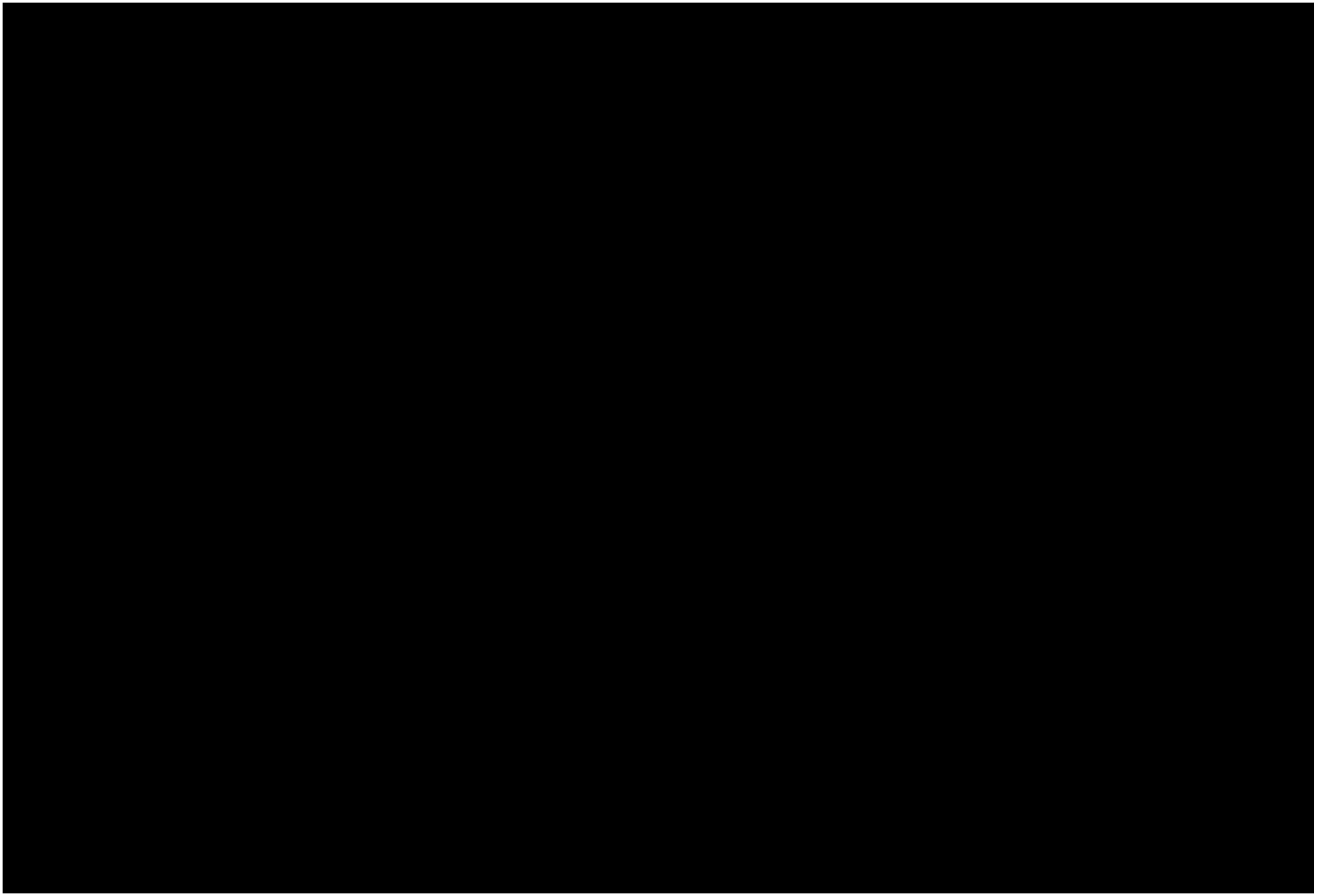
Date of On Peak Day - 01/29/2021

[redacted]

Member Forecasted On Peak Demand Day for February 2021

Socorro Electric Cooperative, Inc.

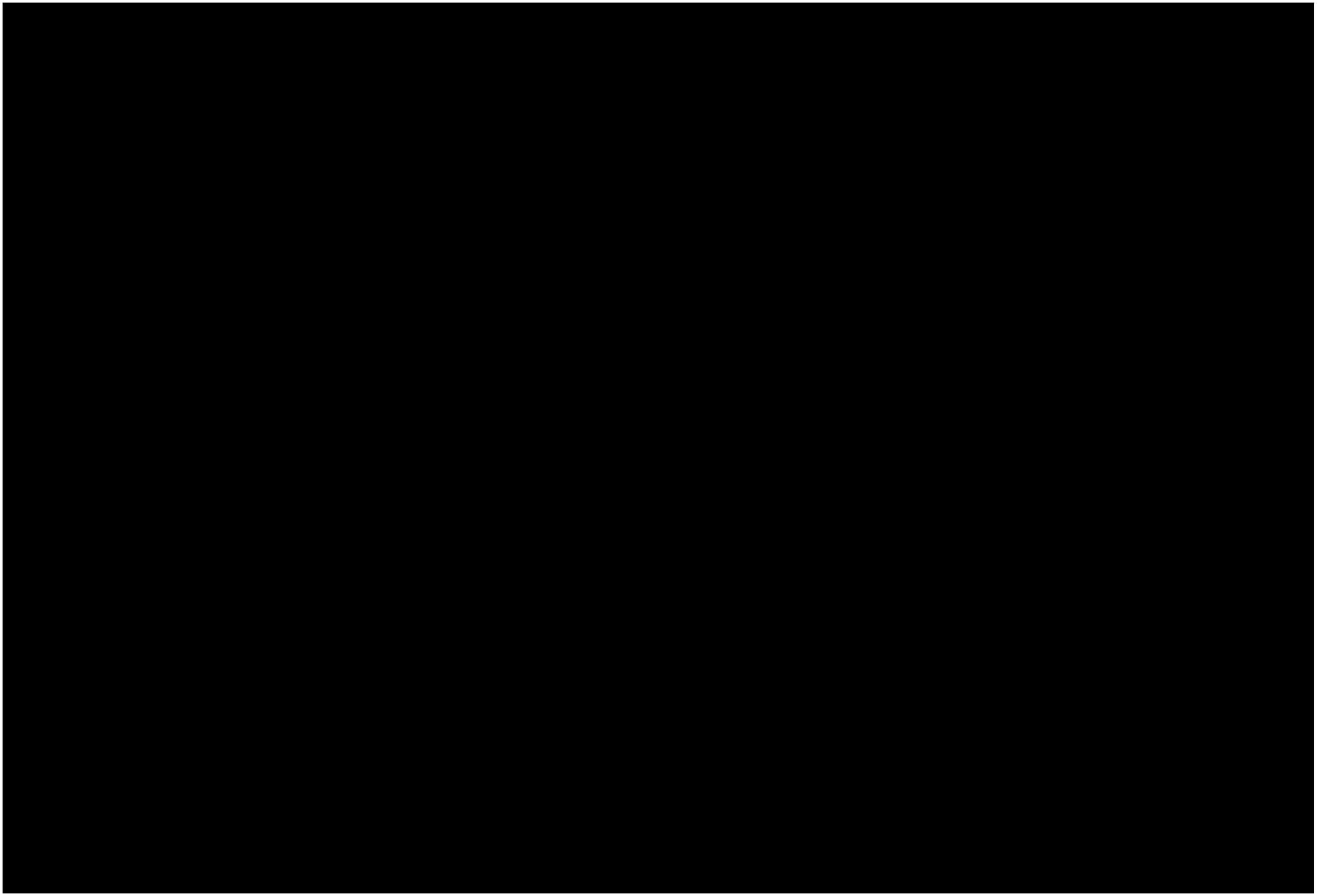
Date of On Peak Day - 02/02/2021



Member Forecasted On Peak Demand Day for March 2021

Socorro Electric Cooperative, Inc.

Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Socorro Electric Cooperative, Inc.

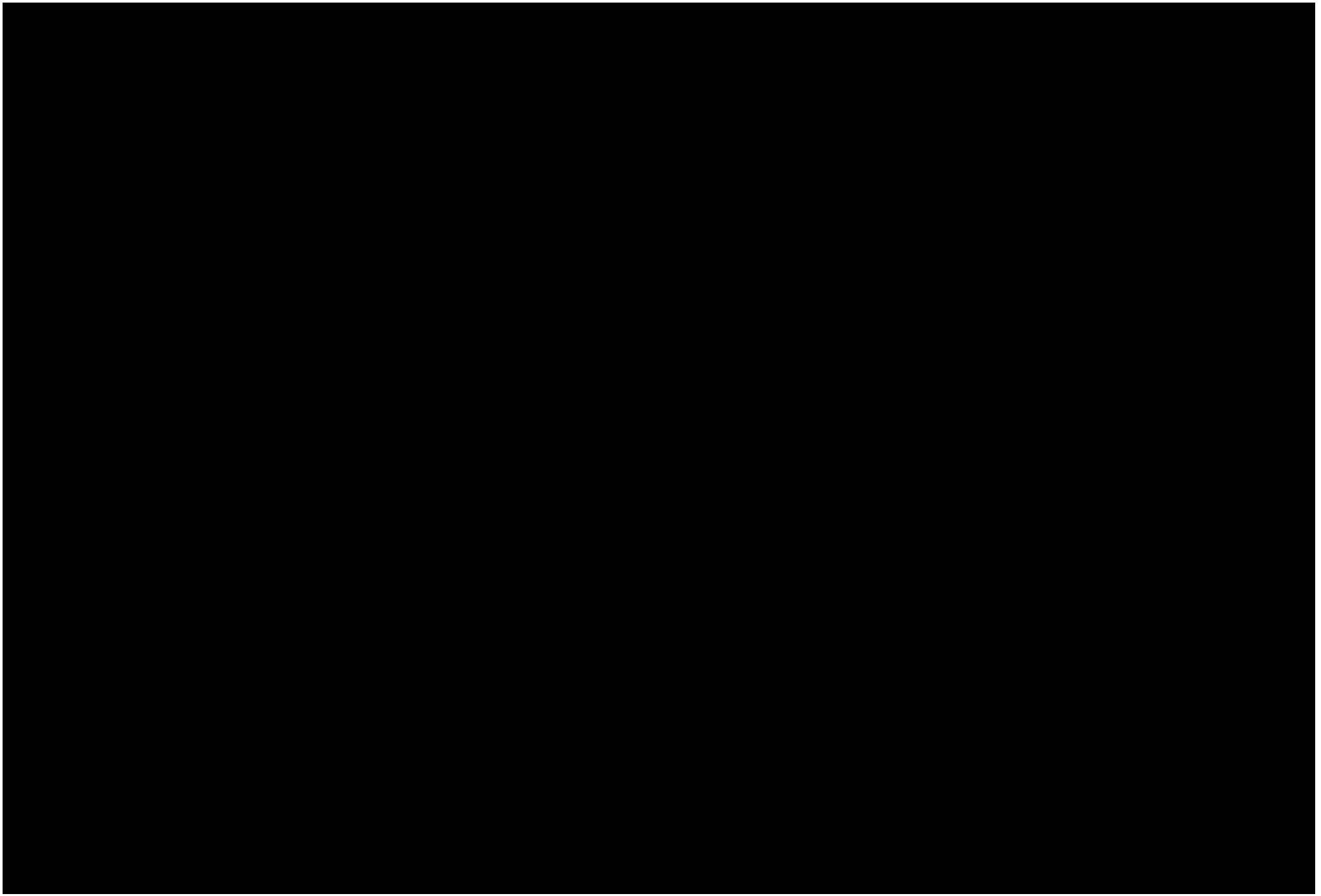
Date of On Peak Day - 04/06/2021

[redacted]

Member Forecasted On Peak Demand Day for May 2021

Socorro Electric Cooperative, Inc.

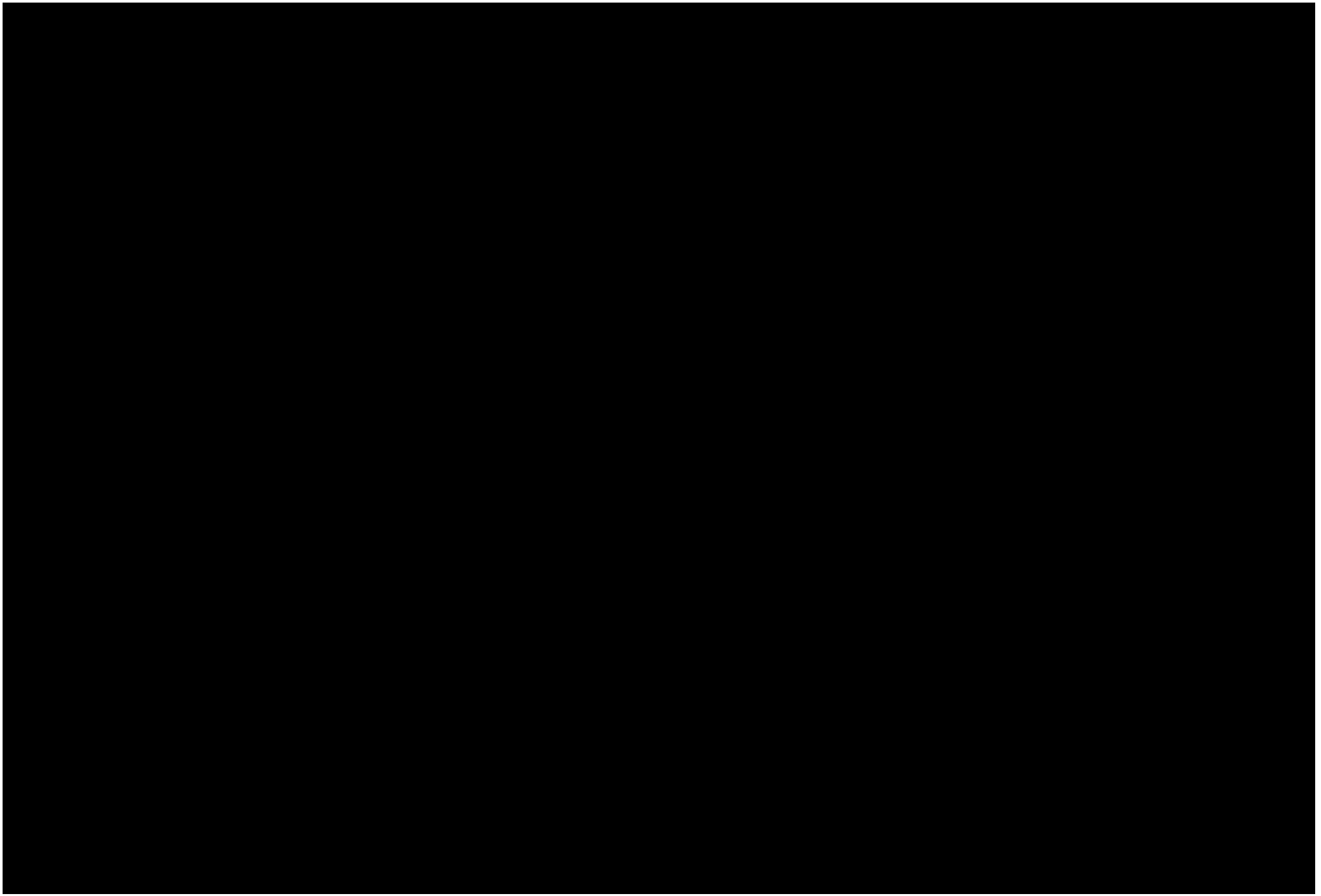
Date of On Peak Day - 05/26/2021



Member Forecasted On Peak Demand Day for June 2021

Socorro Electric Cooperative, Inc.

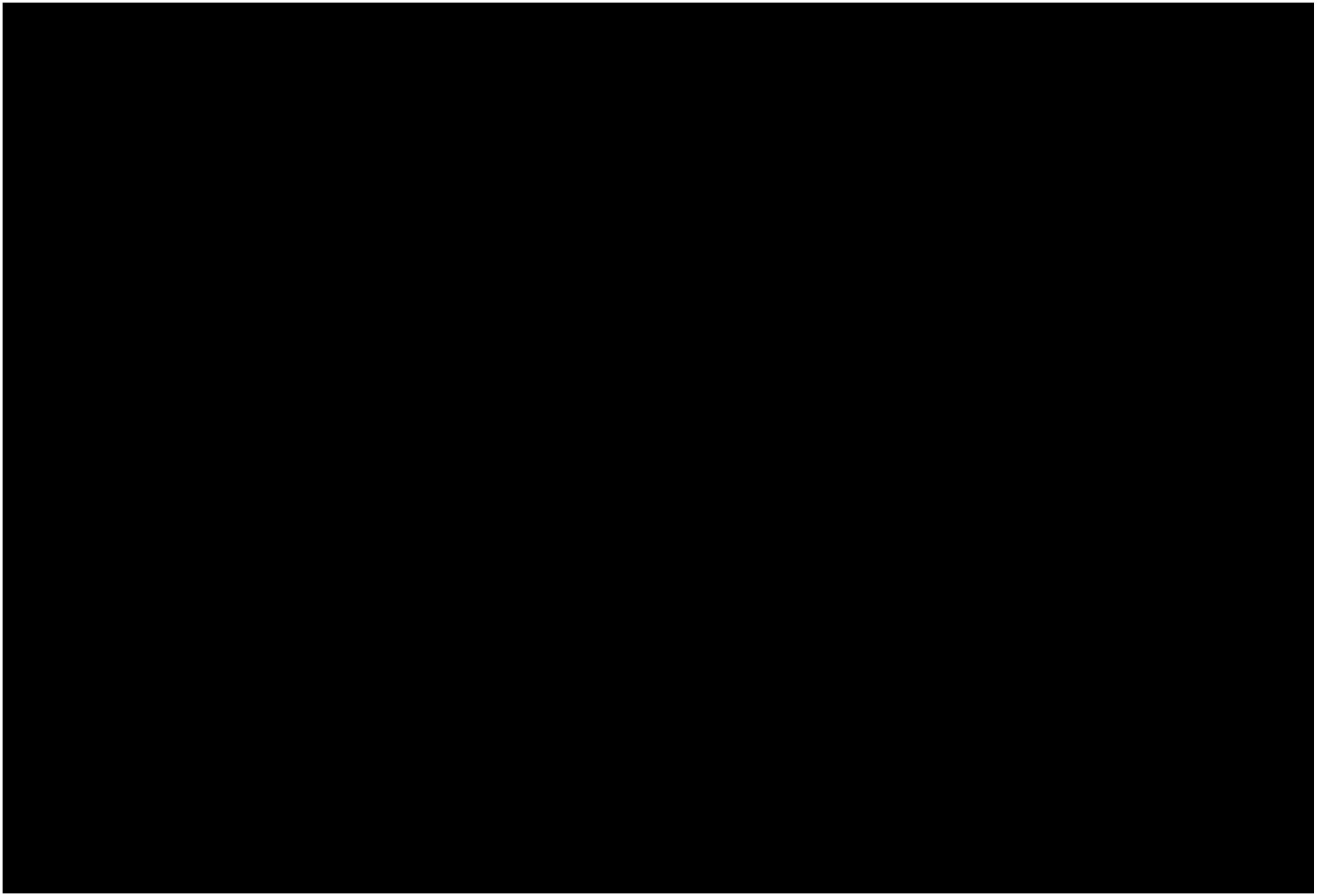
Date of On Peak Day - 06/27/2021



Member Forecasted On Peak Demand Day for July 2021

Socorro Electric Cooperative, Inc.

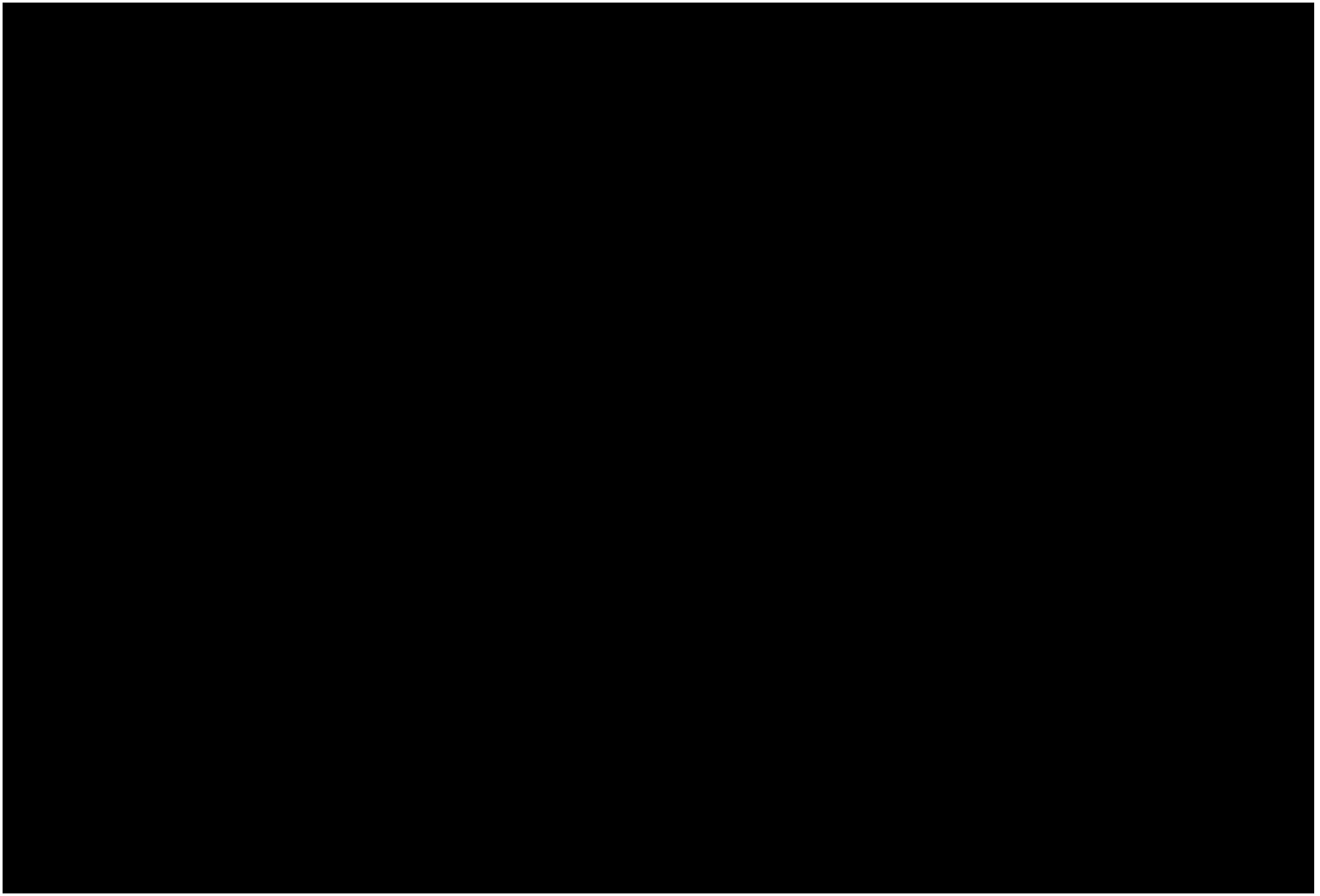
Date of On Peak Day - 07/14/2021



Member Forecasted On Peak Demand Day for August 2021

Socorro Electric Cooperative, Inc.

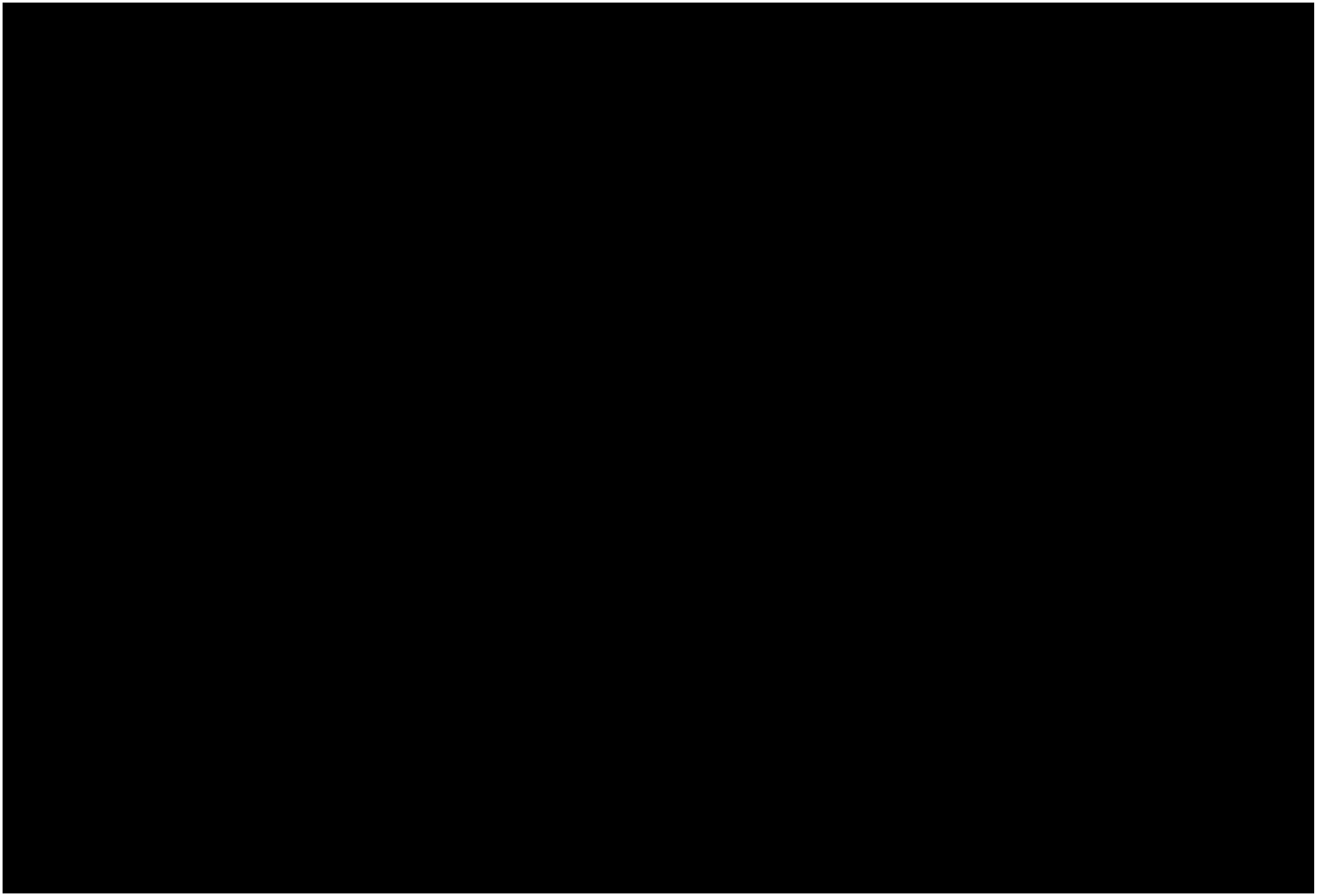
Date of On Peak Day - 08/18/2021



Member Forecasted On Peak Demand Day for September 2021

Socorro Electric Cooperative, Inc.

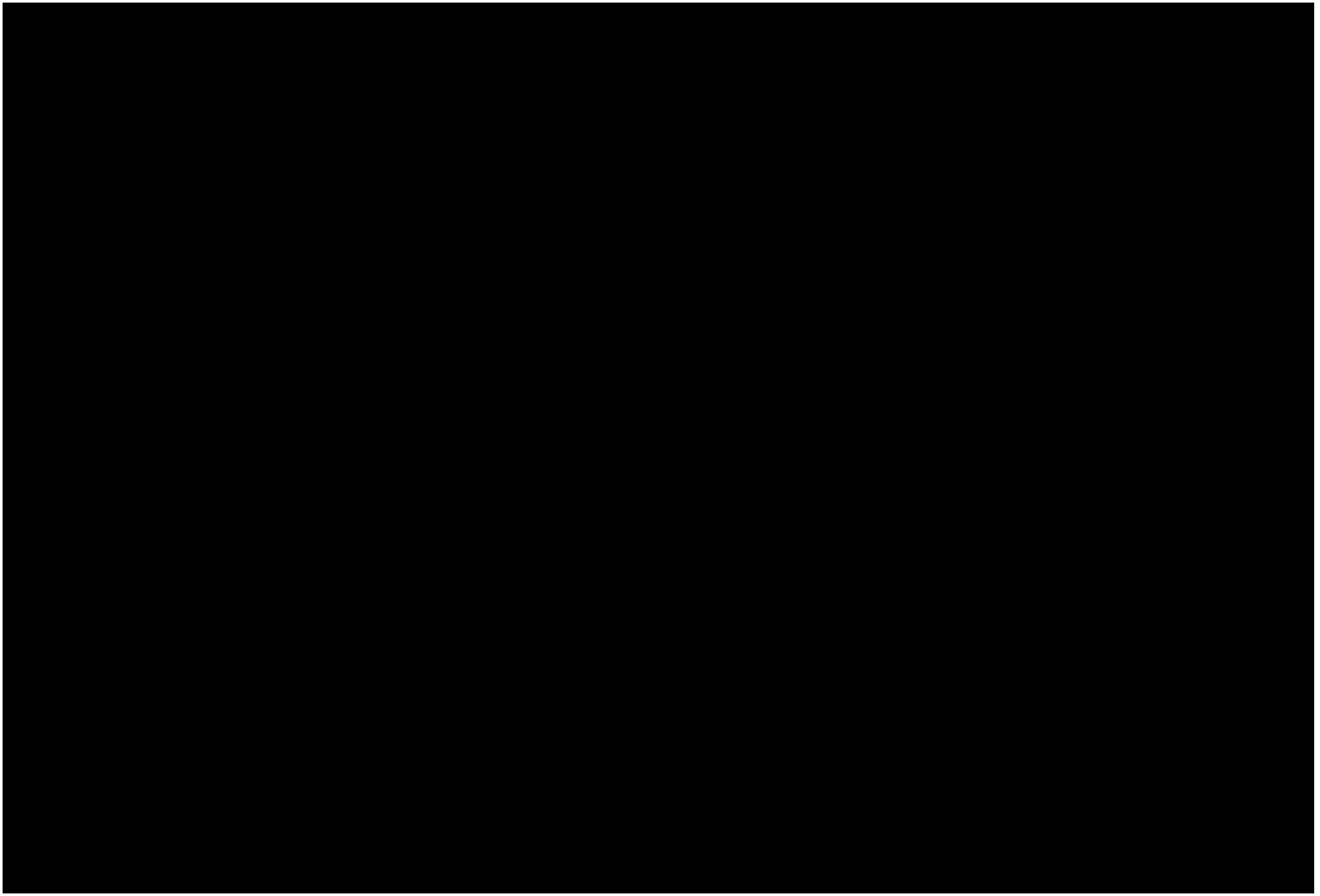
Date of On Peak Day - 09/02/2021



Member Forecasted On Peak Demand Day for October 2021

Socorro Electric Cooperative, Inc.

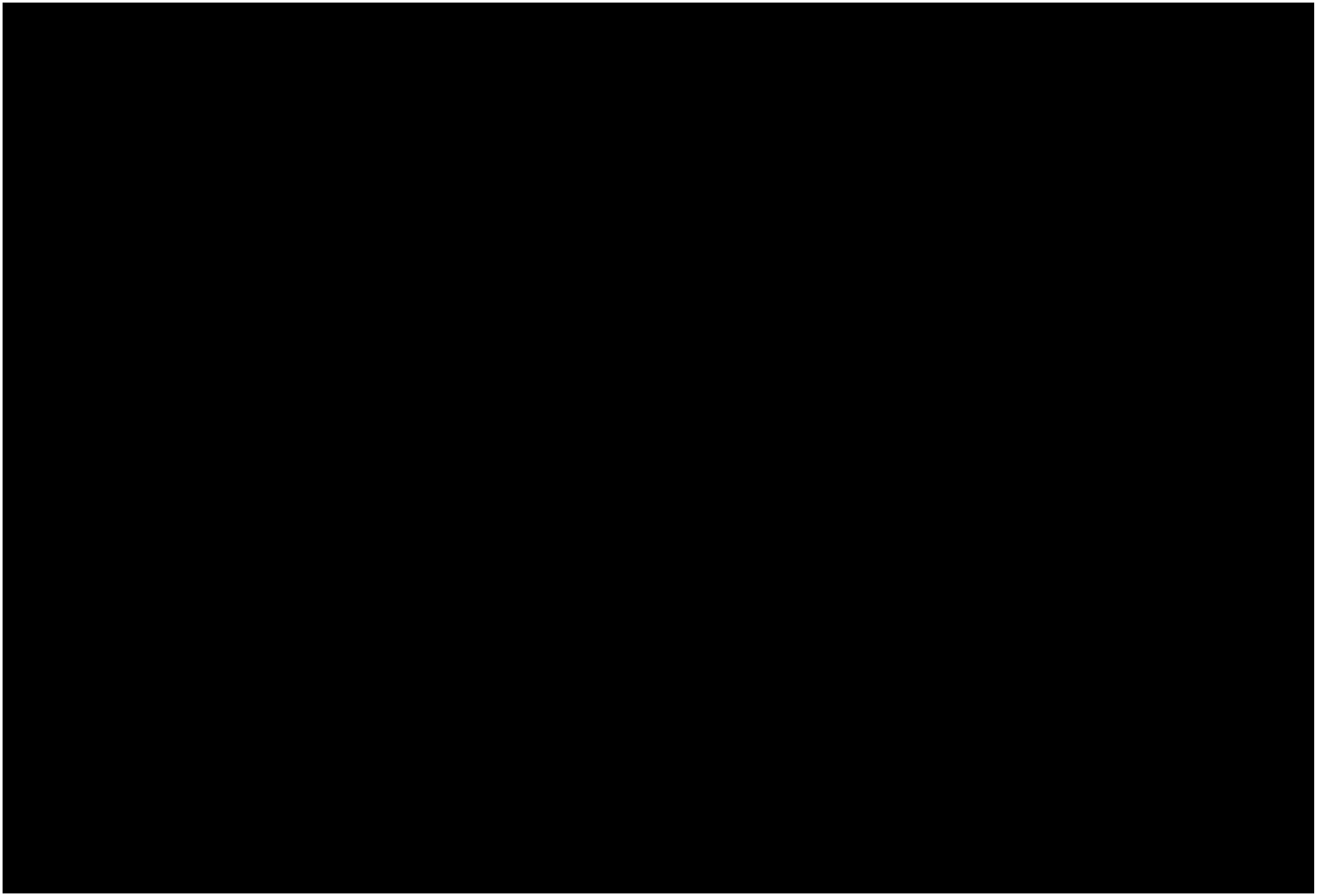
Date of On Peak Day - 10/02/2021



Member Forecasted On Peak Demand Day for November 2021

Socorro Electric Cooperative, Inc.

Date of On Peak Day - 11/16/2021



Member Forecasted On Peak Demand Day for December 2021

Socorro Electric Cooperative, Inc.

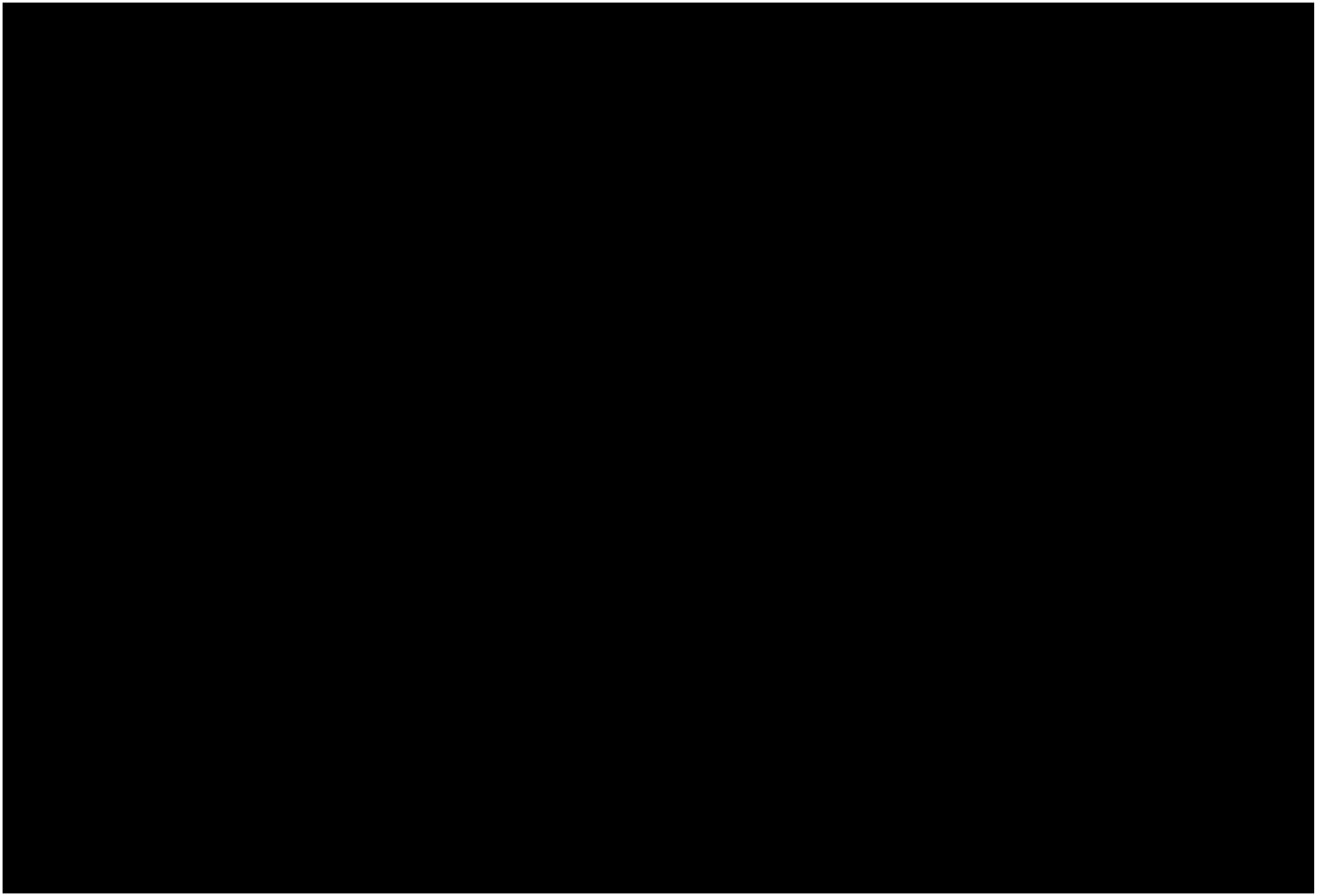
Date of On Peak Day - 12/28/2021

[redacted]

Member Forecasted On Peak Demand Day for January 2021

Springer Electric Cooperative, Inc.

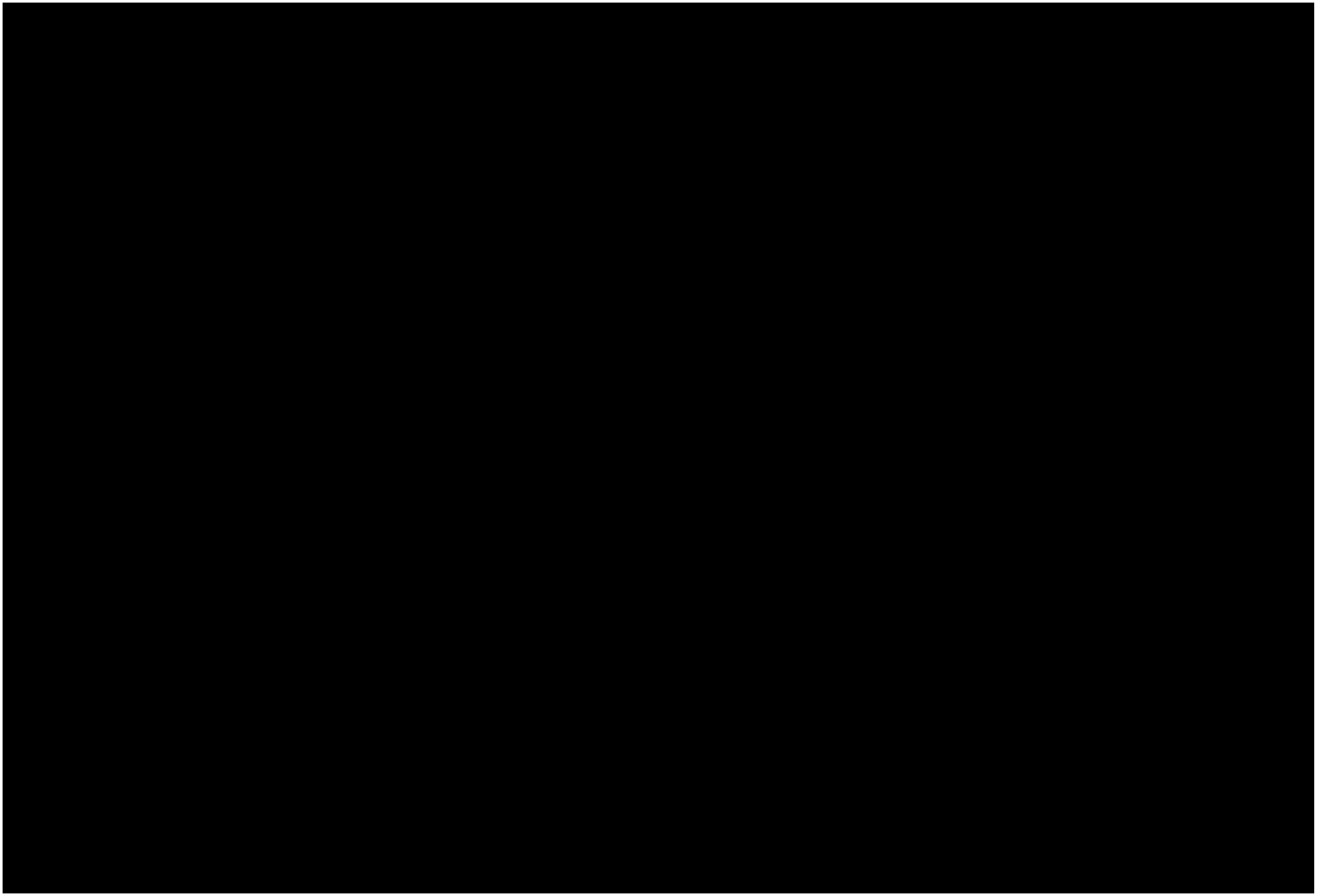
Date of On Peak Day - 01/06/2021



Member Forecasted On Peak Demand Day for February 2021

Springer Electric Cooperative, Inc.

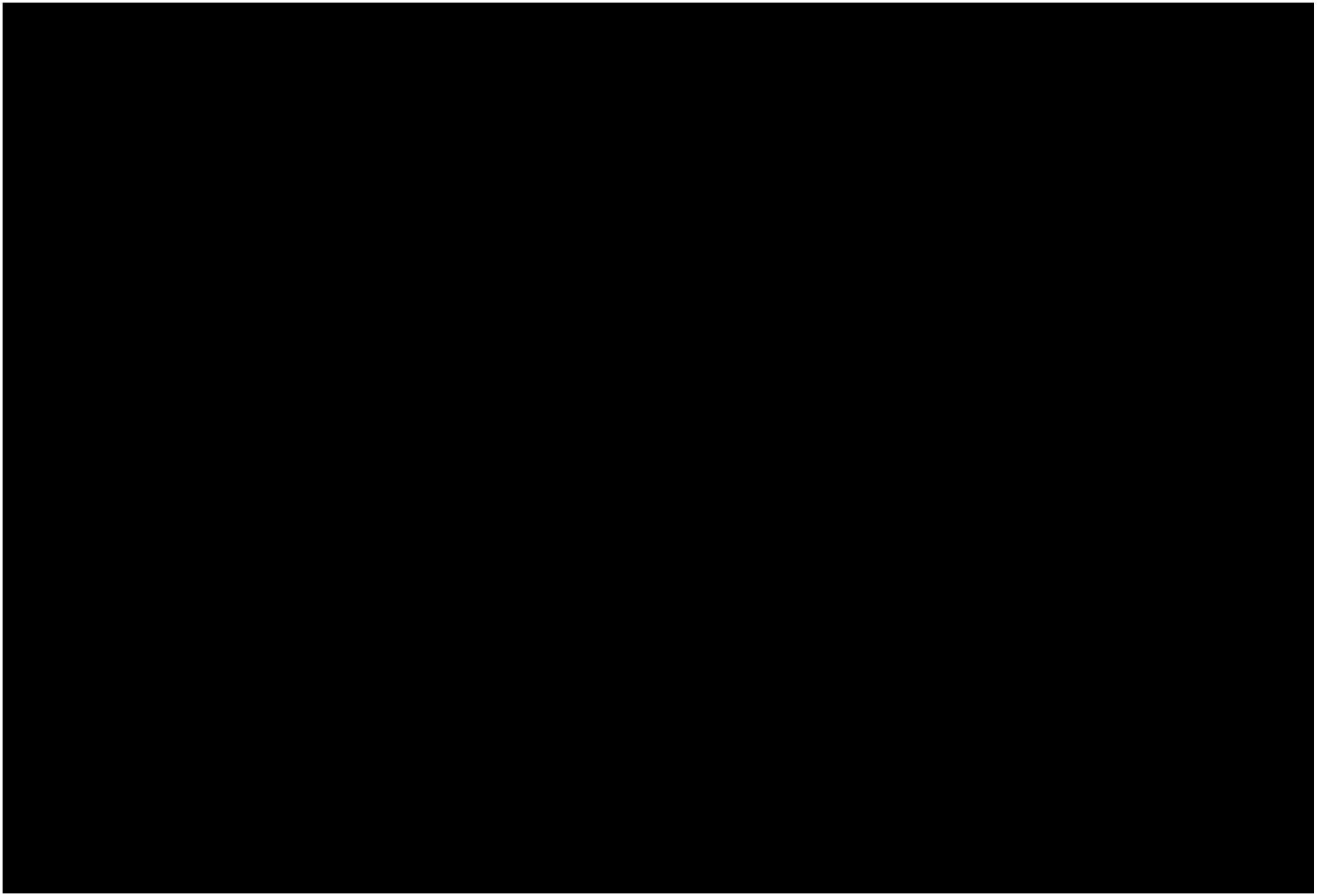
Date of On Peak Day - 02/14/2021



Member Forecasted On Peak Demand Day for March 2021

Springer Electric Cooperative, Inc.

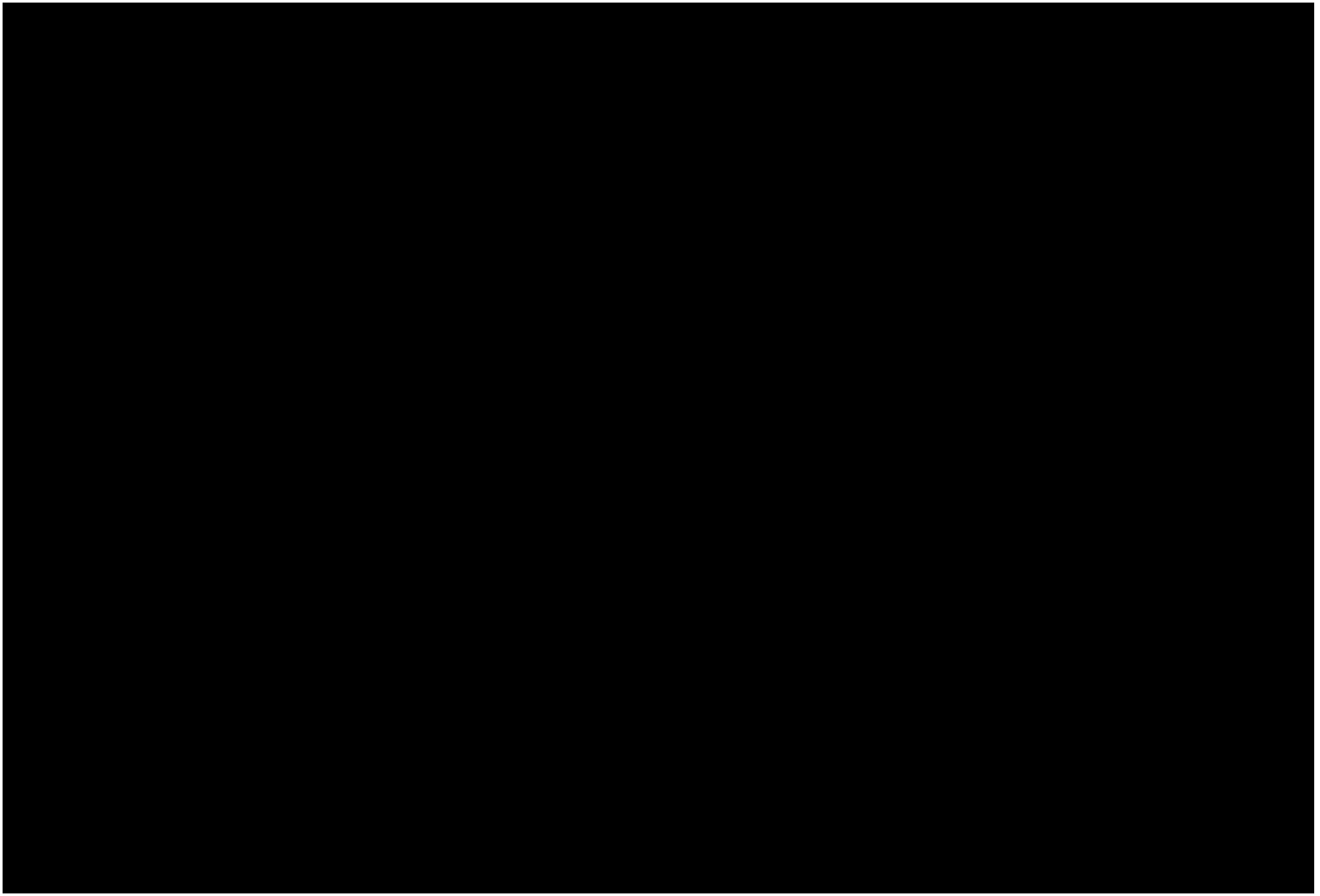
Date of On Peak Day - 03/03/2021



Member Forecasted On Peak Demand Day for April 2021

Springer Electric Cooperative, Inc.

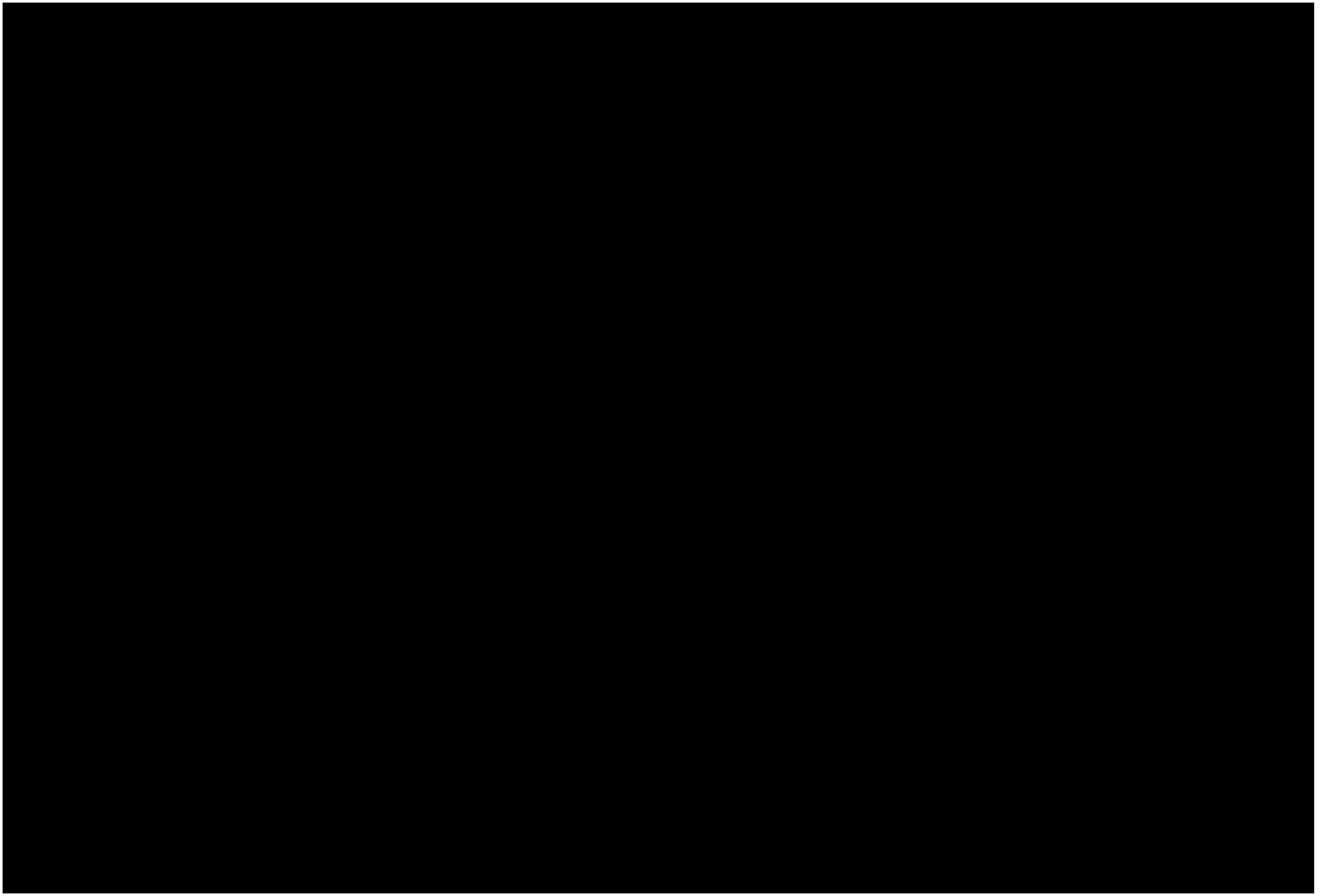
Date of On Peak Day - 04/12/2021



Member Forecasted On Peak Demand Day for May 2021

Springer Electric Cooperative, Inc.

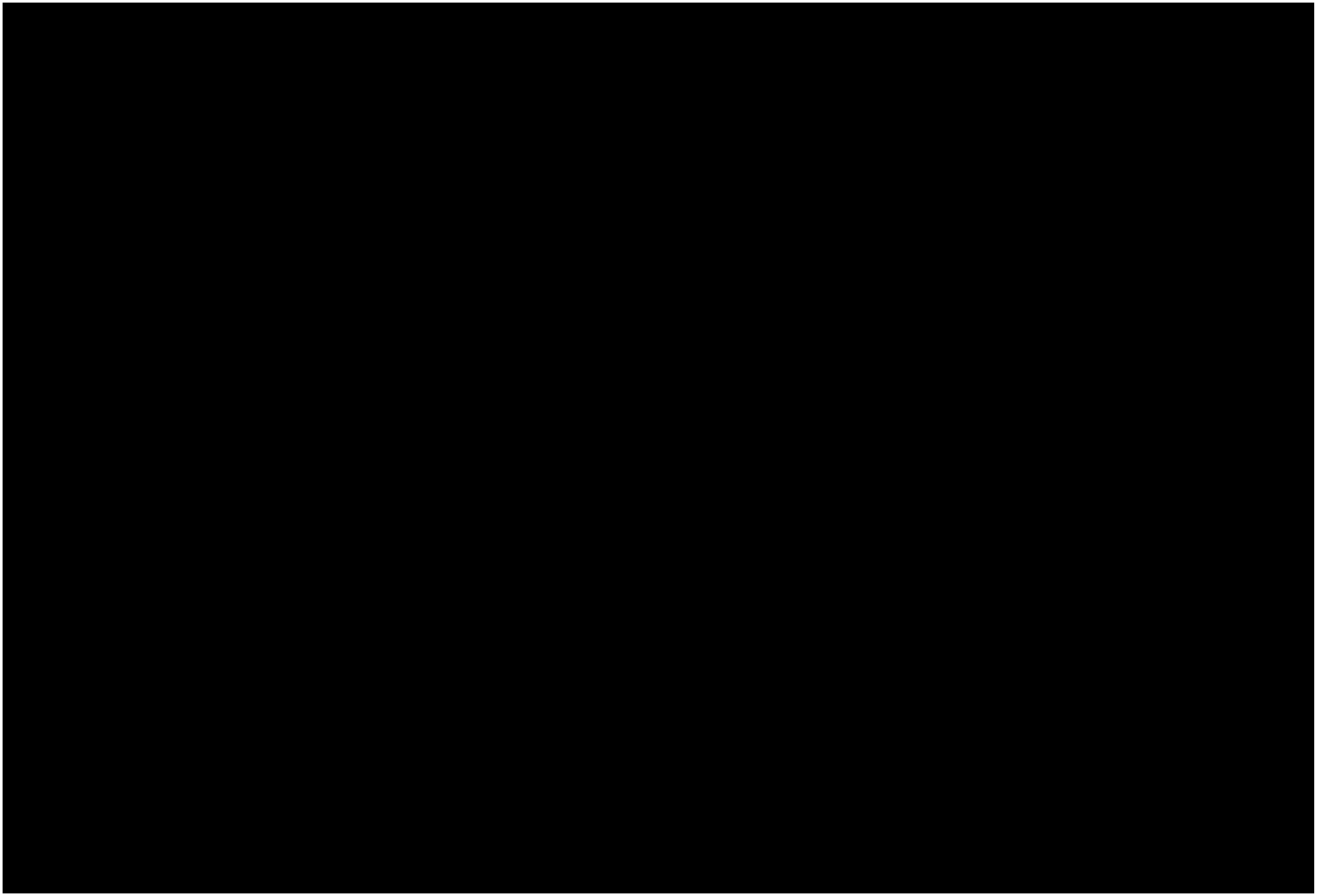
Date of On Peak Day - 05/01/2021



Member Forecasted On Peak Demand Day for June 2021

Springer Electric Cooperative, Inc.

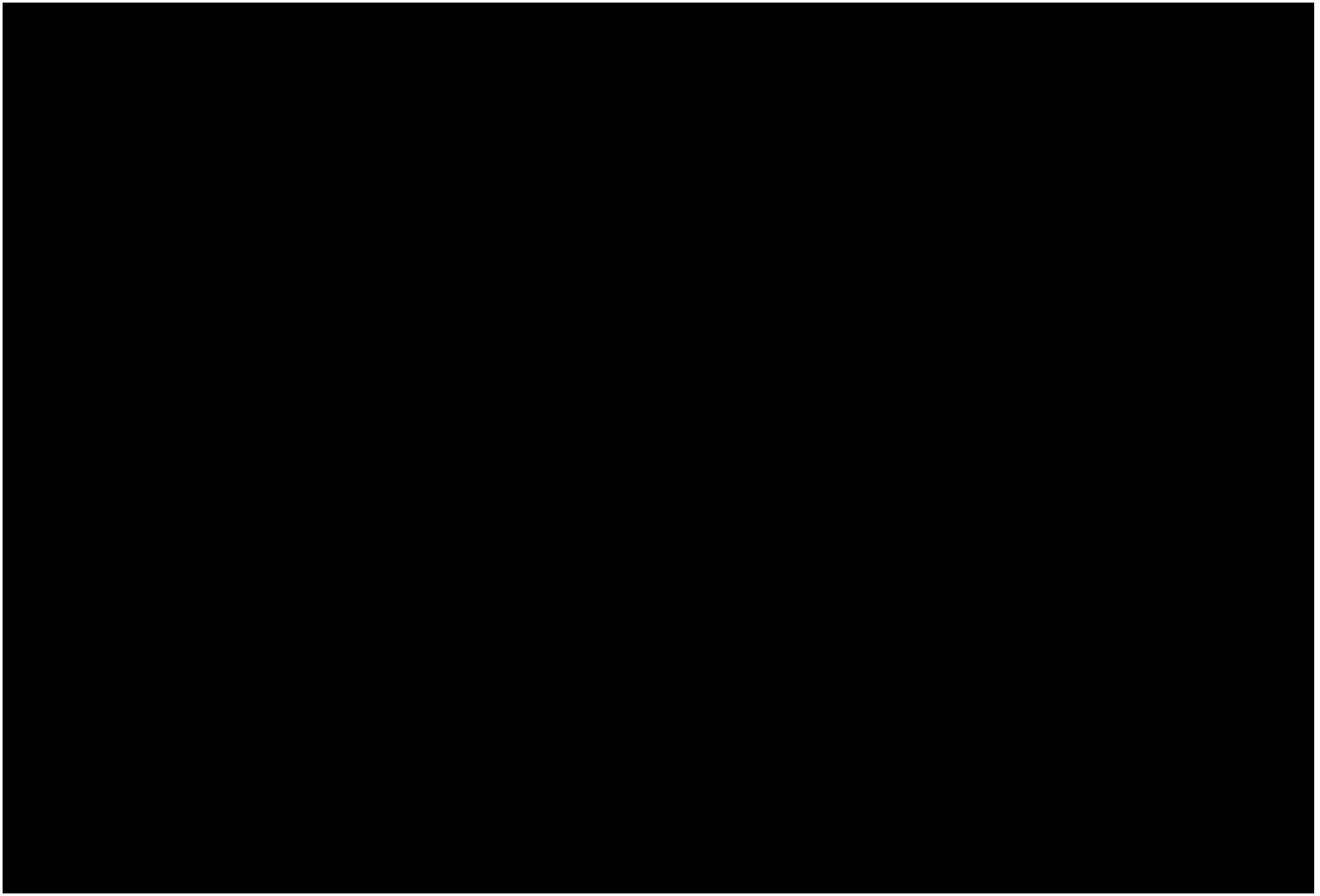
Date of On Peak Day - 06/30/2021



Member Forecasted On Peak Demand Day for July 2021

Springer Electric Cooperative, Inc.

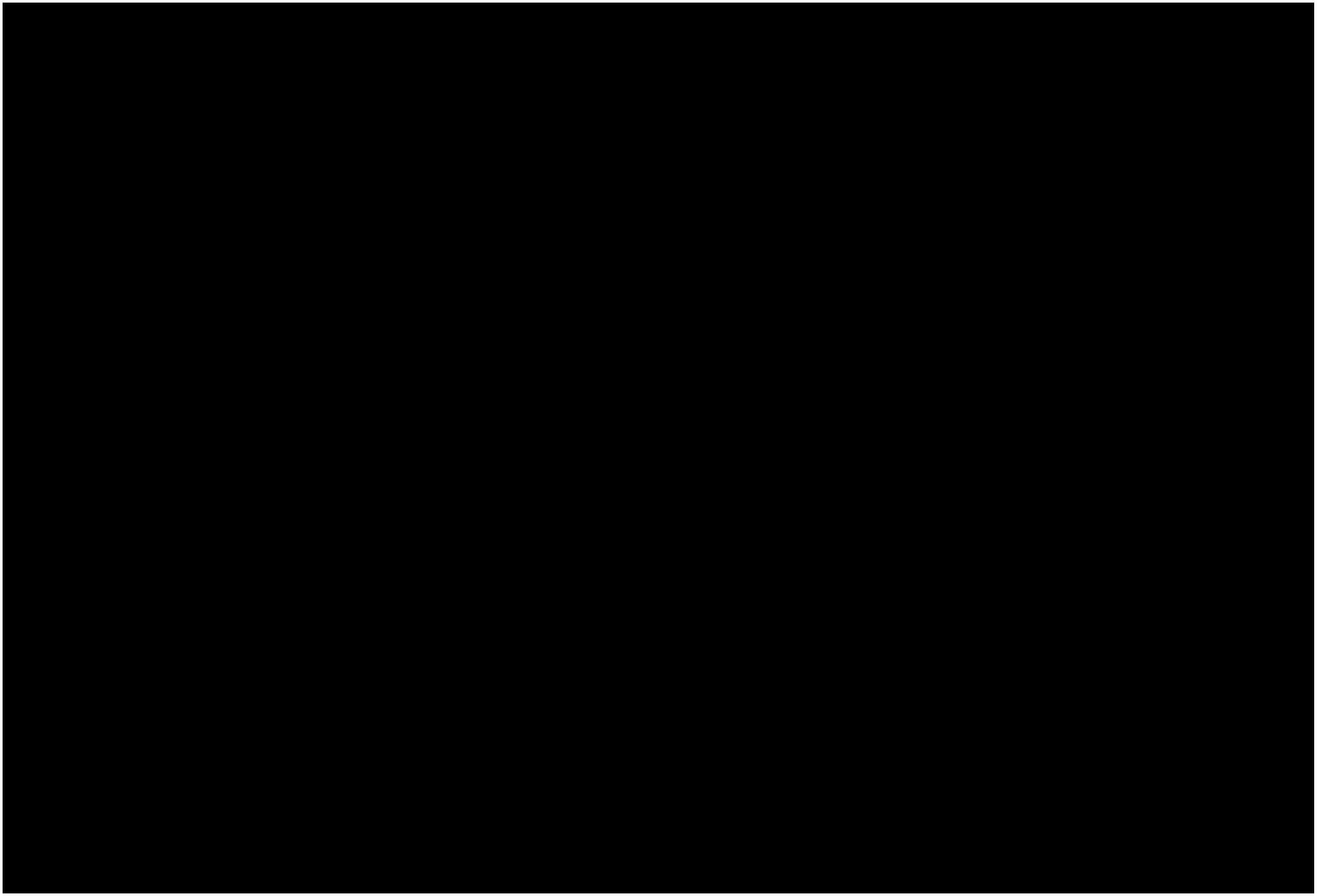
Date of On Peak Day - 07/18/2021



Member Forecasted On Peak Demand Day for August 2021

Springer Electric Cooperative, Inc.

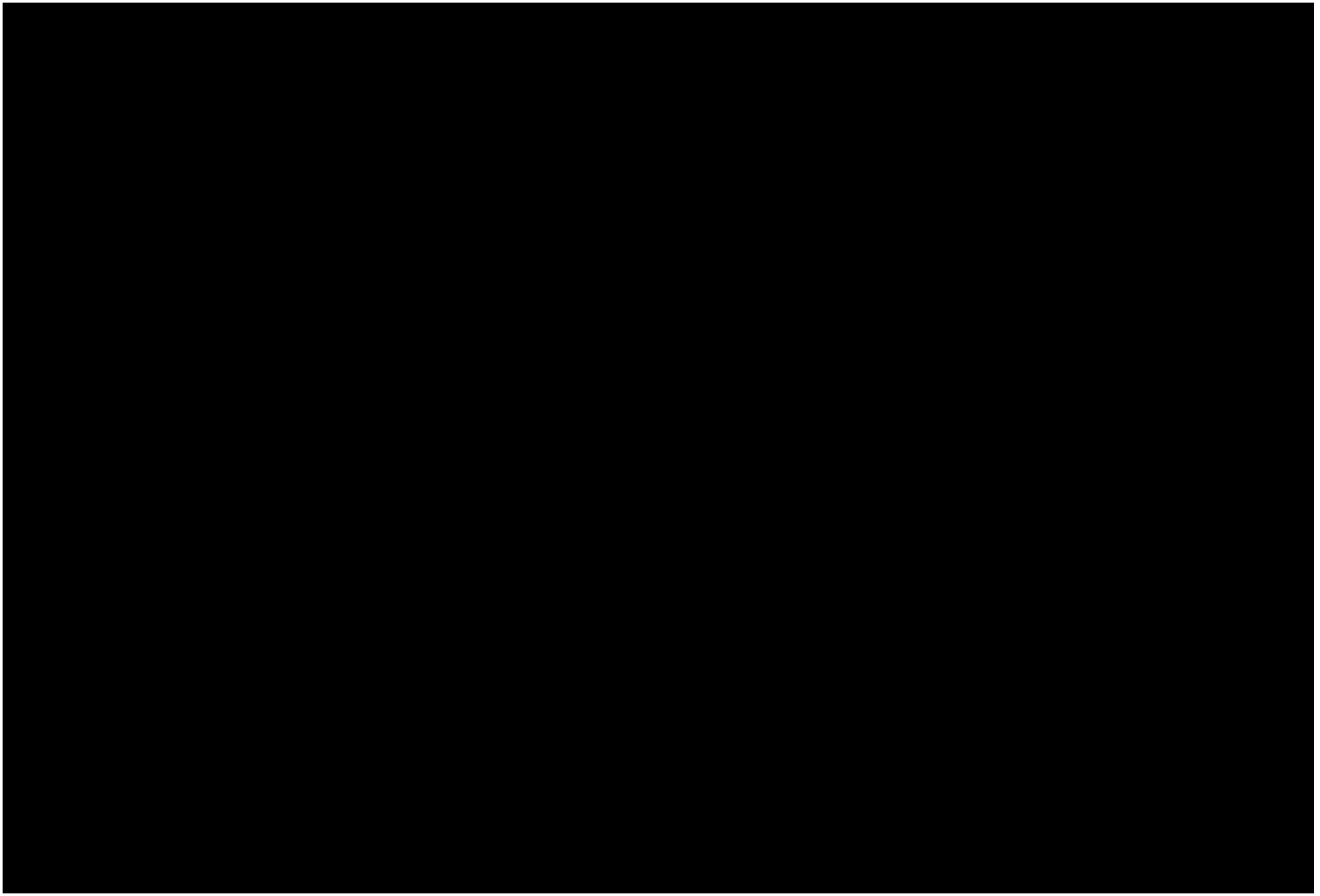
Date of On Peak Day - 08/02/2021



Member Forecasted On Peak Demand Day for September 2021

Springer Electric Cooperative, Inc.

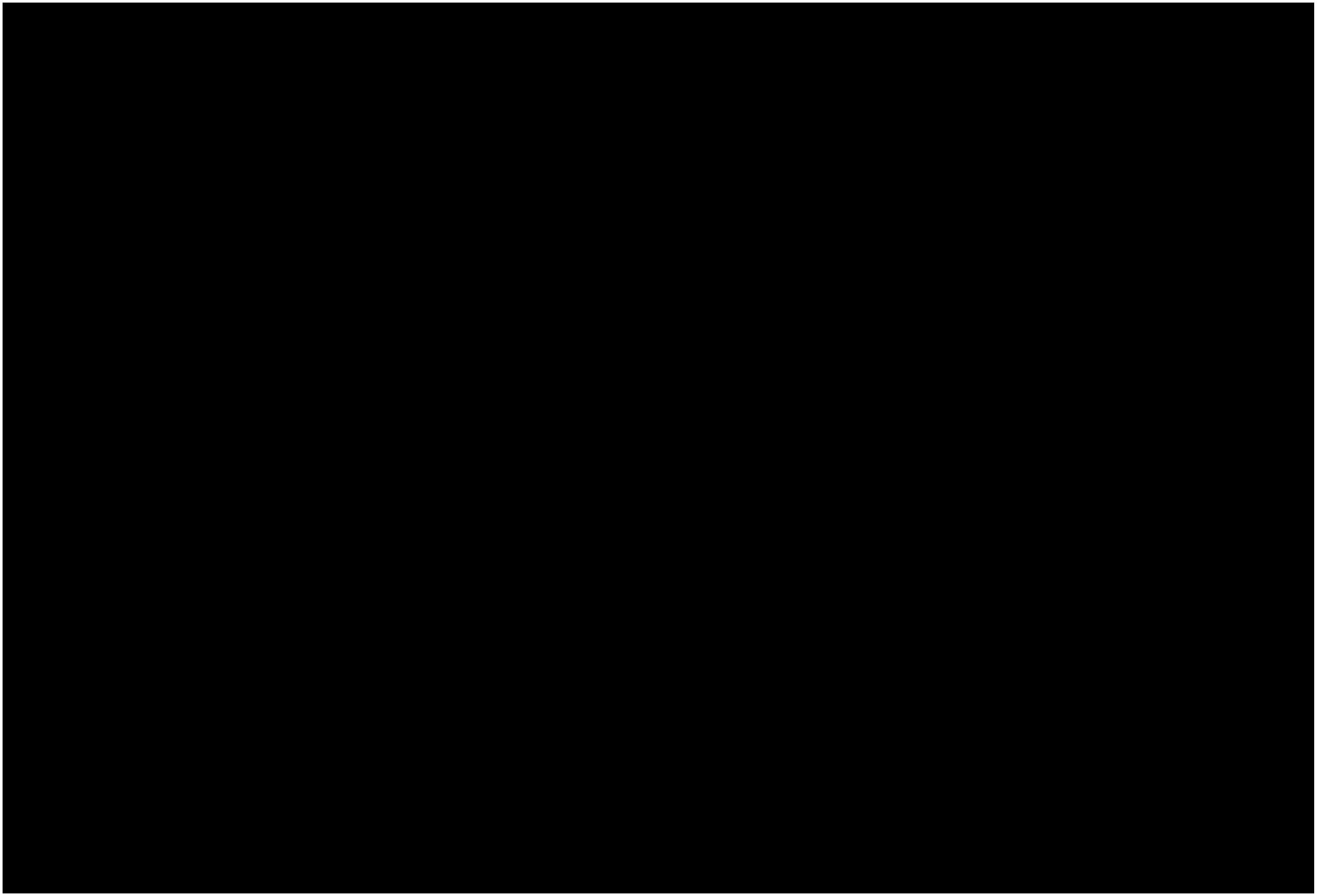
Date of On Peak Day - 09/08/2021



Member Forecasted On Peak Demand Day for October 2021

Springer Electric Cooperative, Inc.

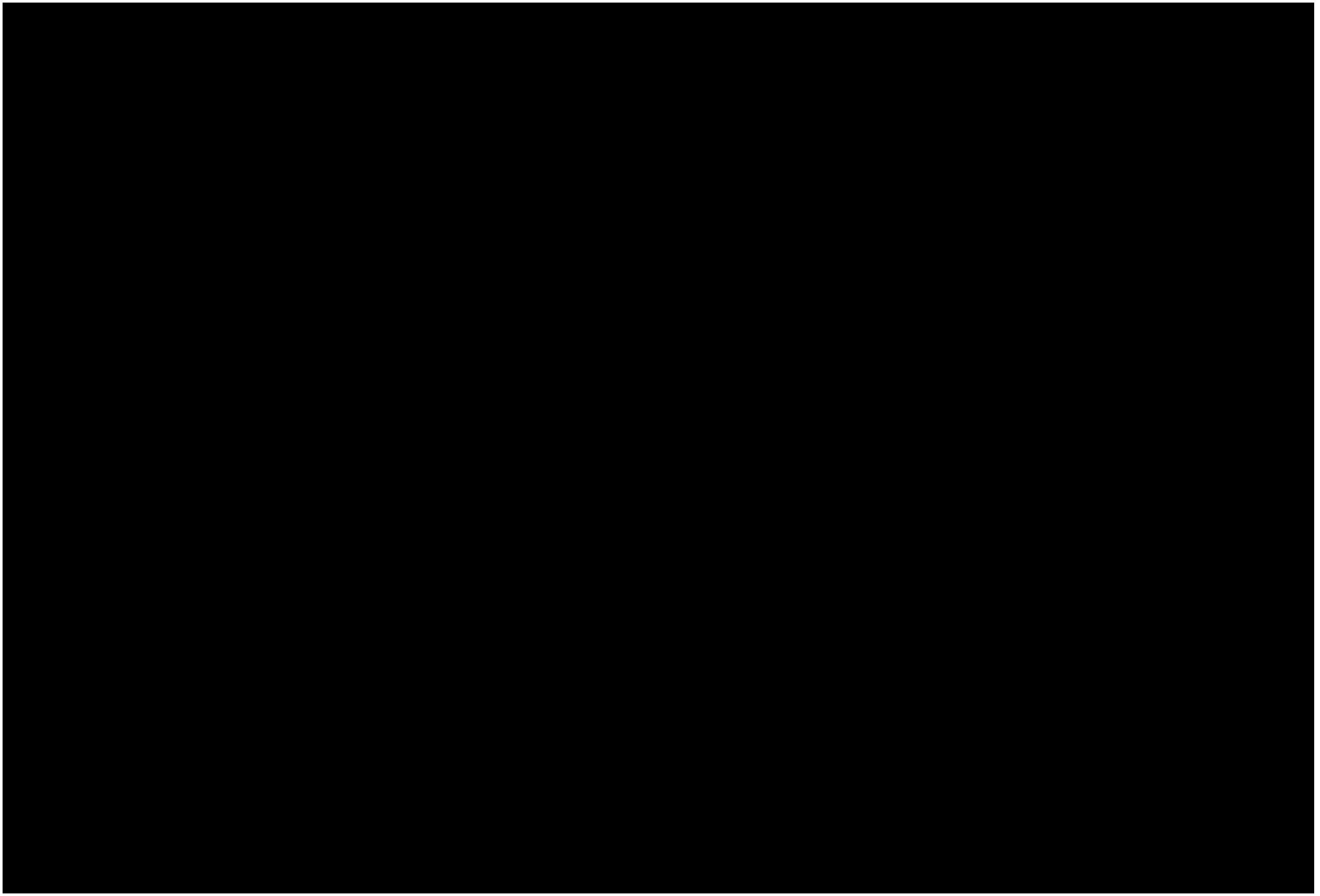
Date of On Peak Day - 10/13/2021



Member Forecasted On Peak Demand Day for November 2021

Springer Electric Cooperative, Inc.

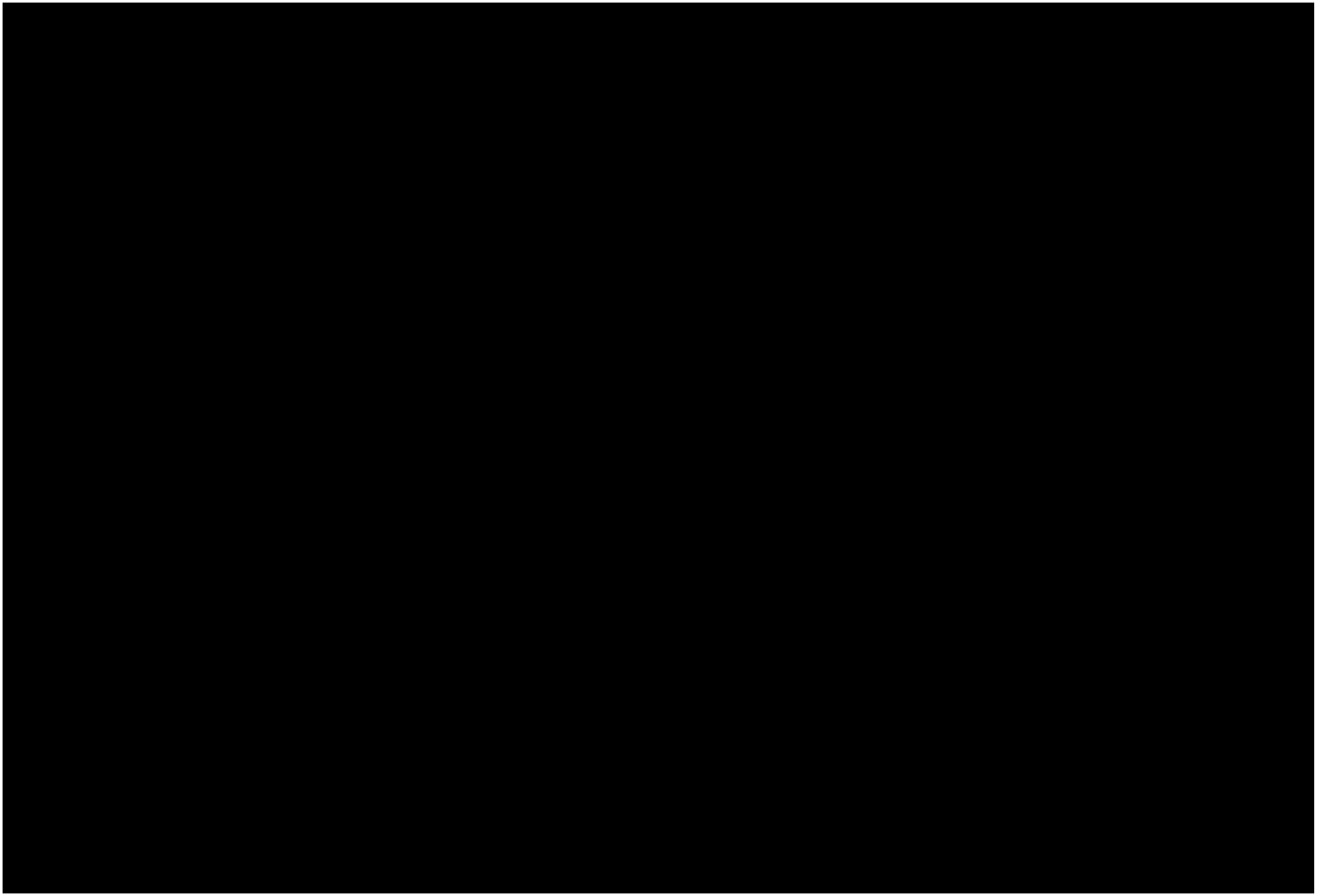
Date of On Peak Day - 11/11/2021



Member Forecasted On Peak Demand Day for December 2021

Springer Electric Cooperative, Inc.

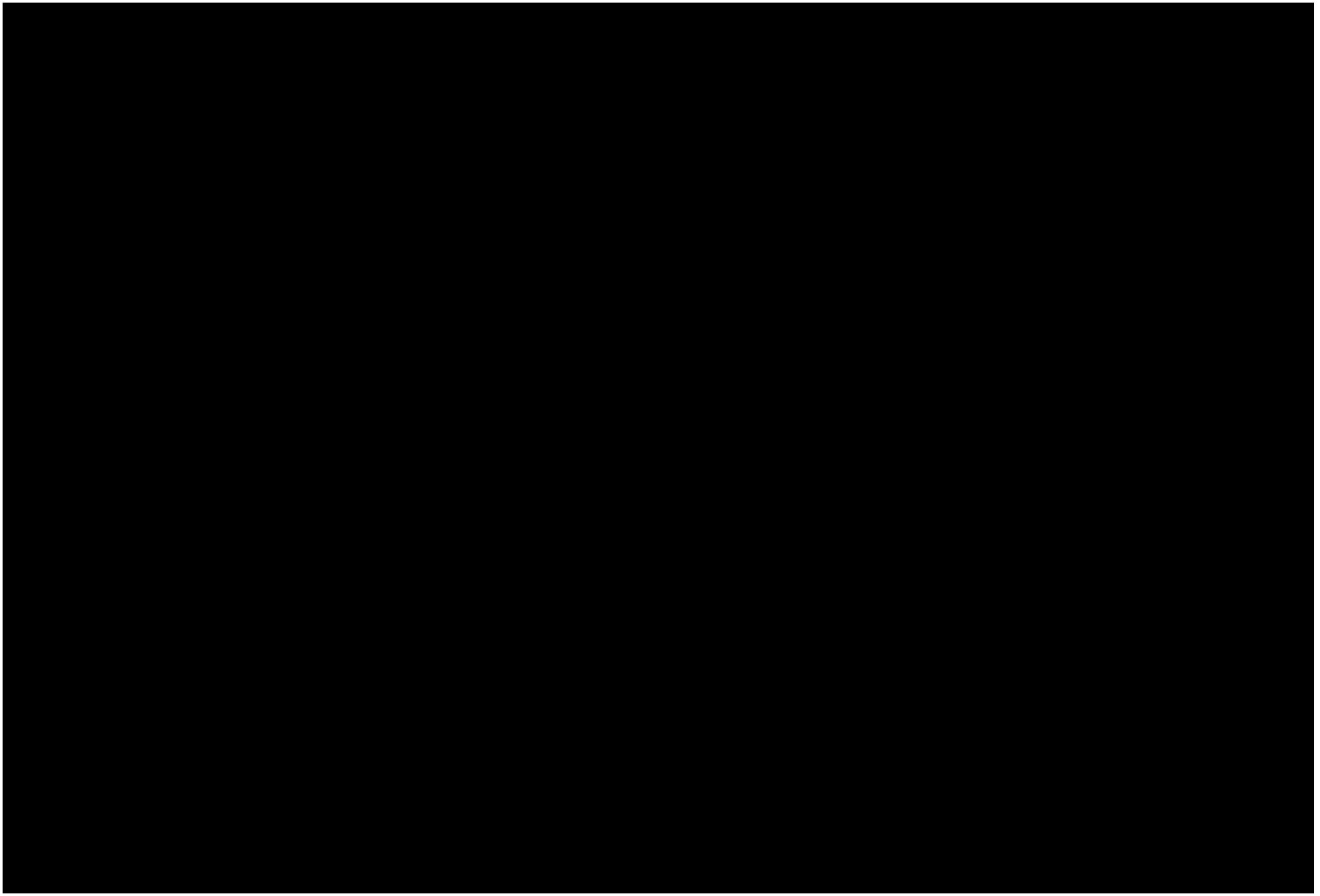
Date of On Peak Day - 12/01/2021



Member Forecasted On Peak Demand Day for January 2021

Southwestern Electric Cooperative, Inc.

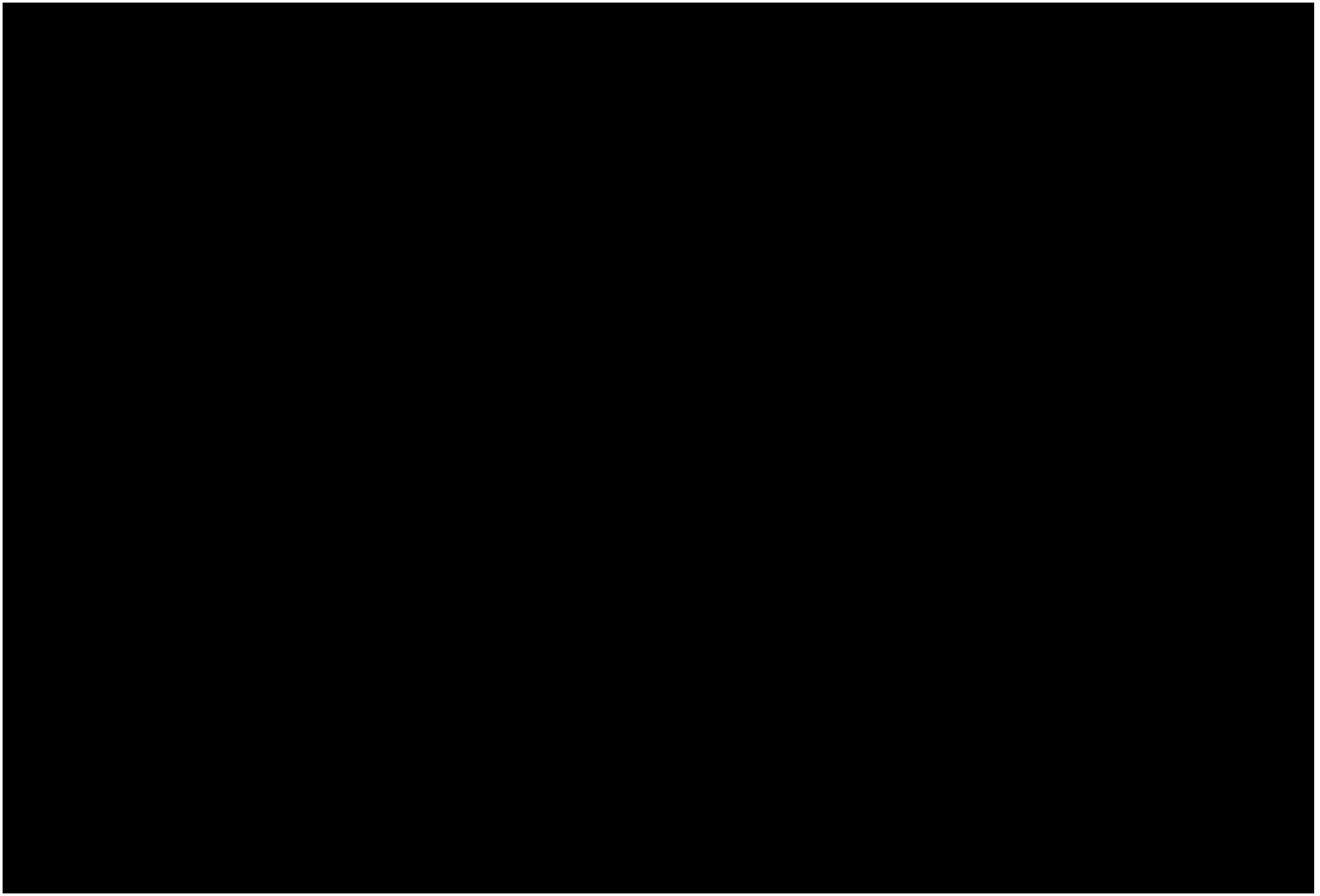
Date of On Peak Day - 01/15/2021



Member Forecasted On Peak Demand Day for February 2021

Southwestern Electric Cooperative, Inc.

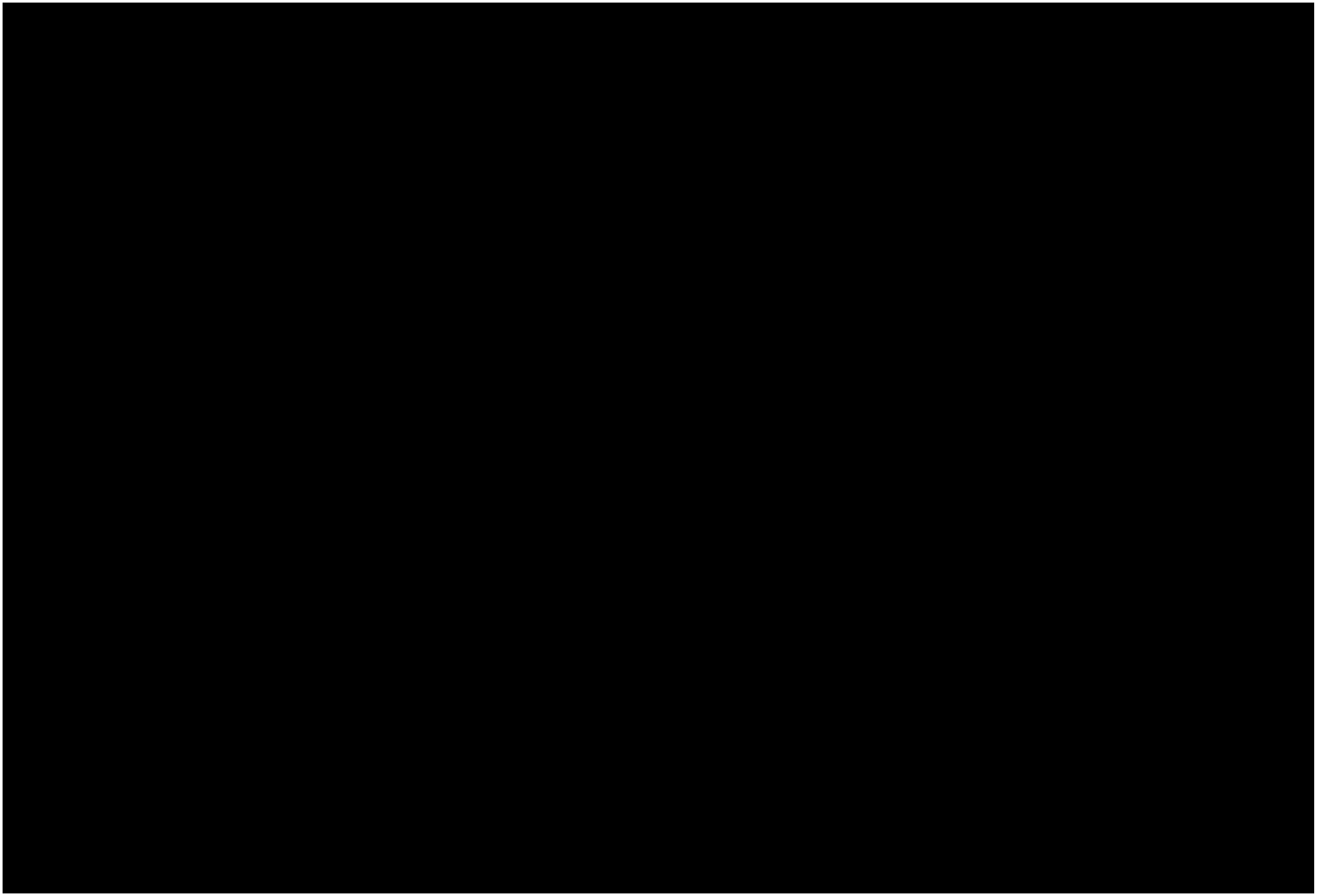
Date of On Peak Day - 02/28/2021



Member Forecasted On Peak Demand Day for March 2021

Southwestern Electric Cooperative, Inc.

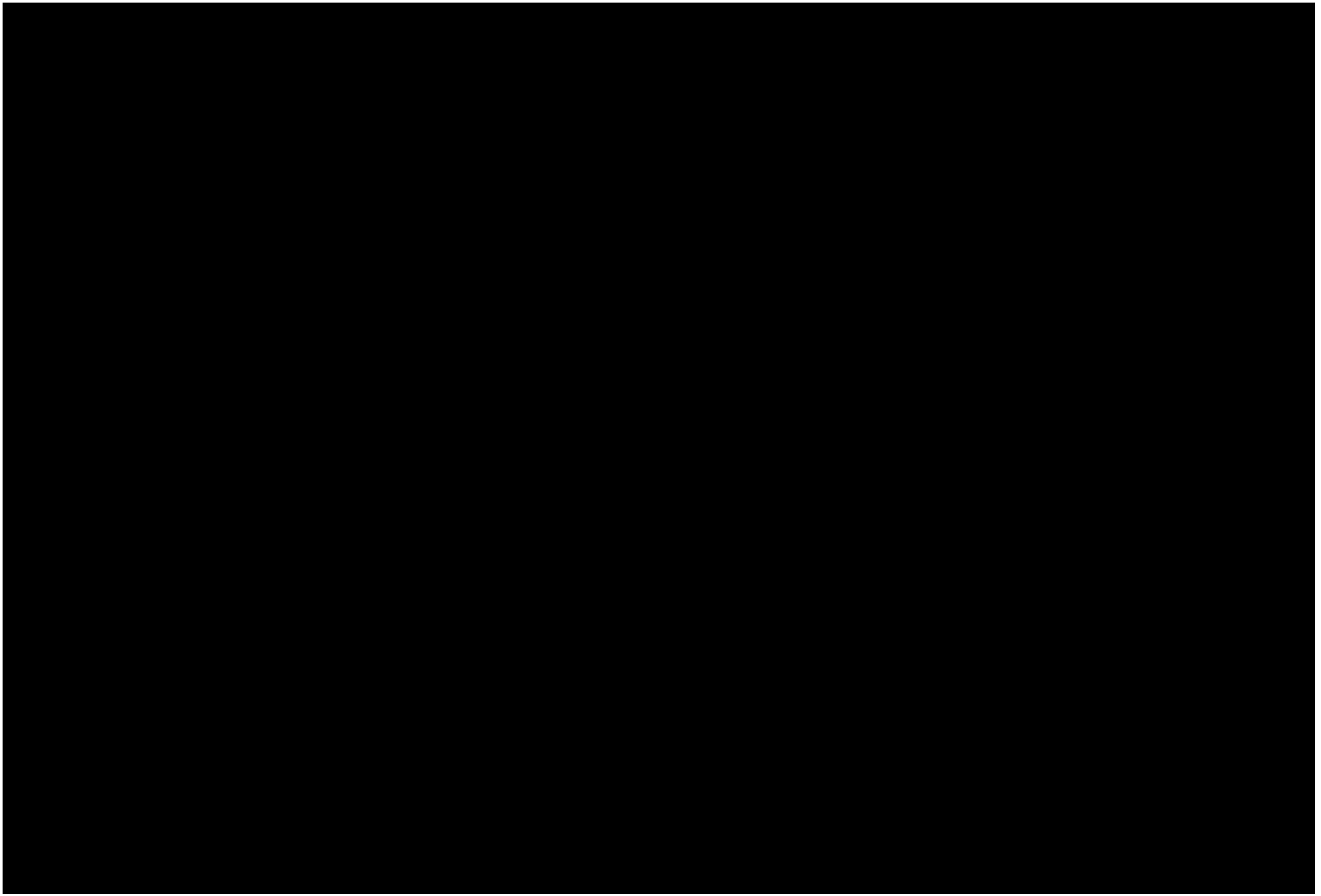
Date of On Peak Day - 03/17/2021



Member Forecasted On Peak Demand Day for April 2021

Southwestern Electric Cooperative, Inc.

Date of On Peak Day - 04/20/2021



Member Forecasted On Peak Demand Day for May 2021

Southwestern Electric Cooperative, Inc.

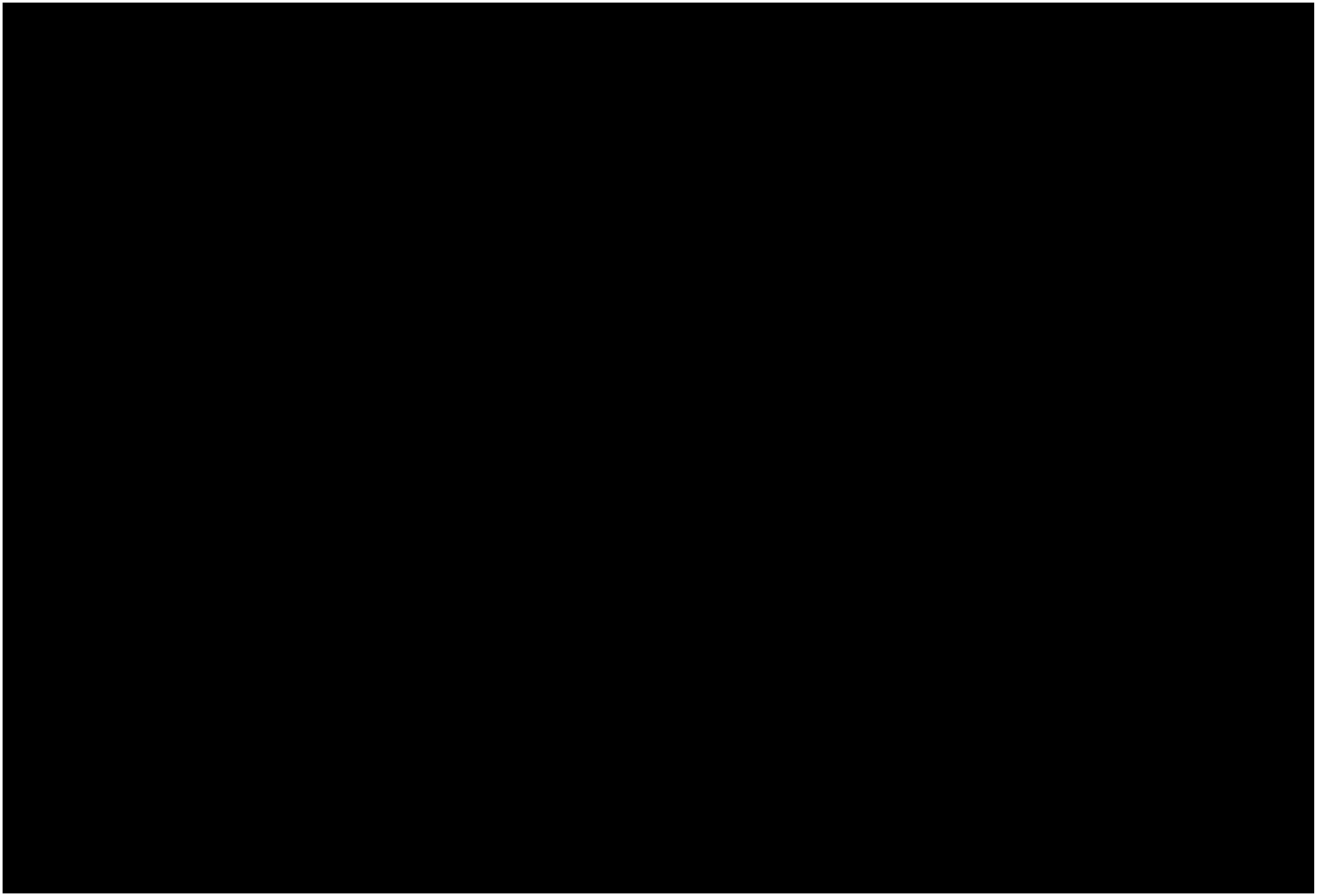
Date of On Peak Day - 05/26/2021

[redacted]

Member Forecasted On Peak Demand Day for June 2021

Southwestern Electric Cooperative, Inc.

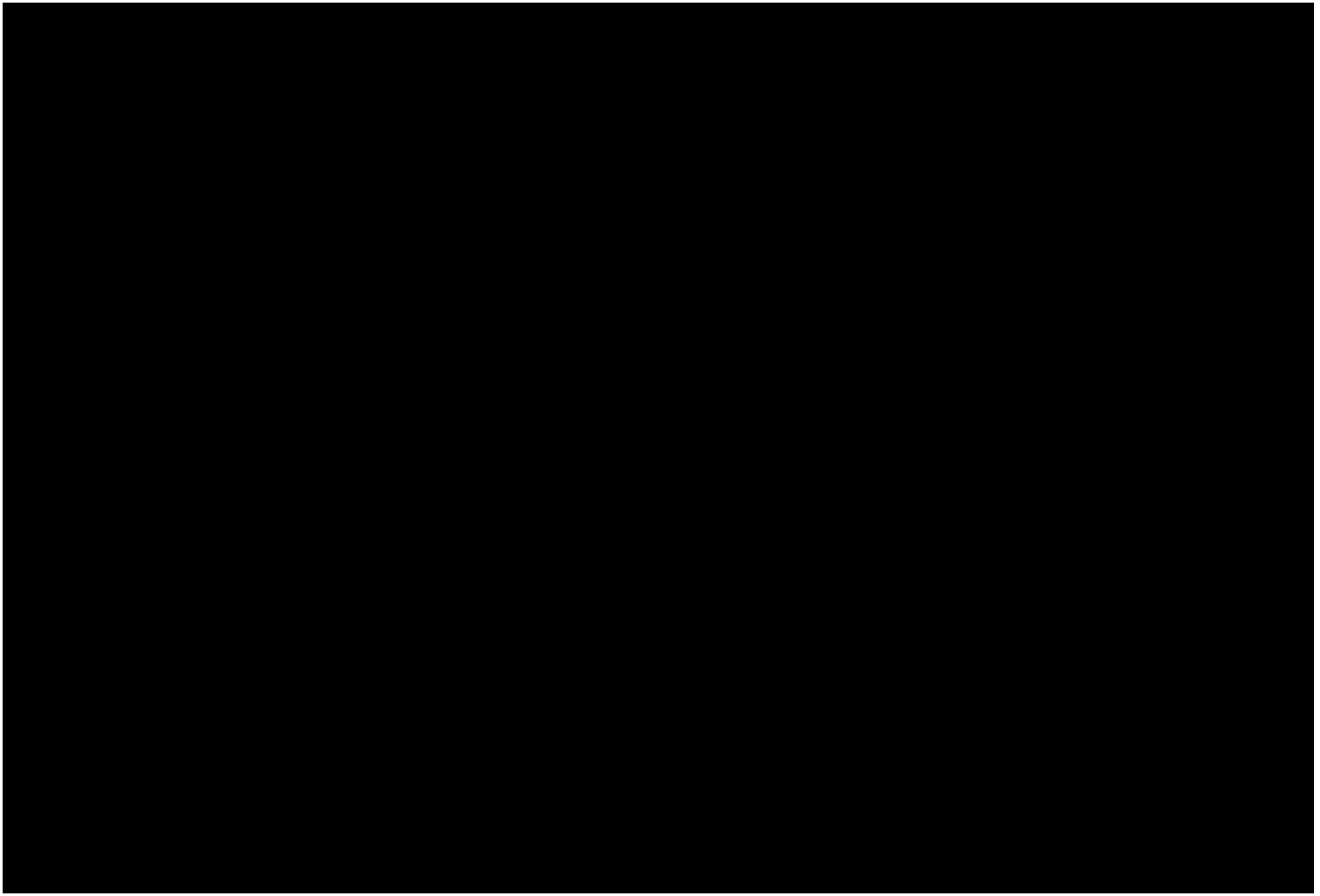
Date of On Peak Day - 06/30/2021



Member Forecasted On Peak Demand Day for July 2021

Southwestern Electric Cooperative, Inc.

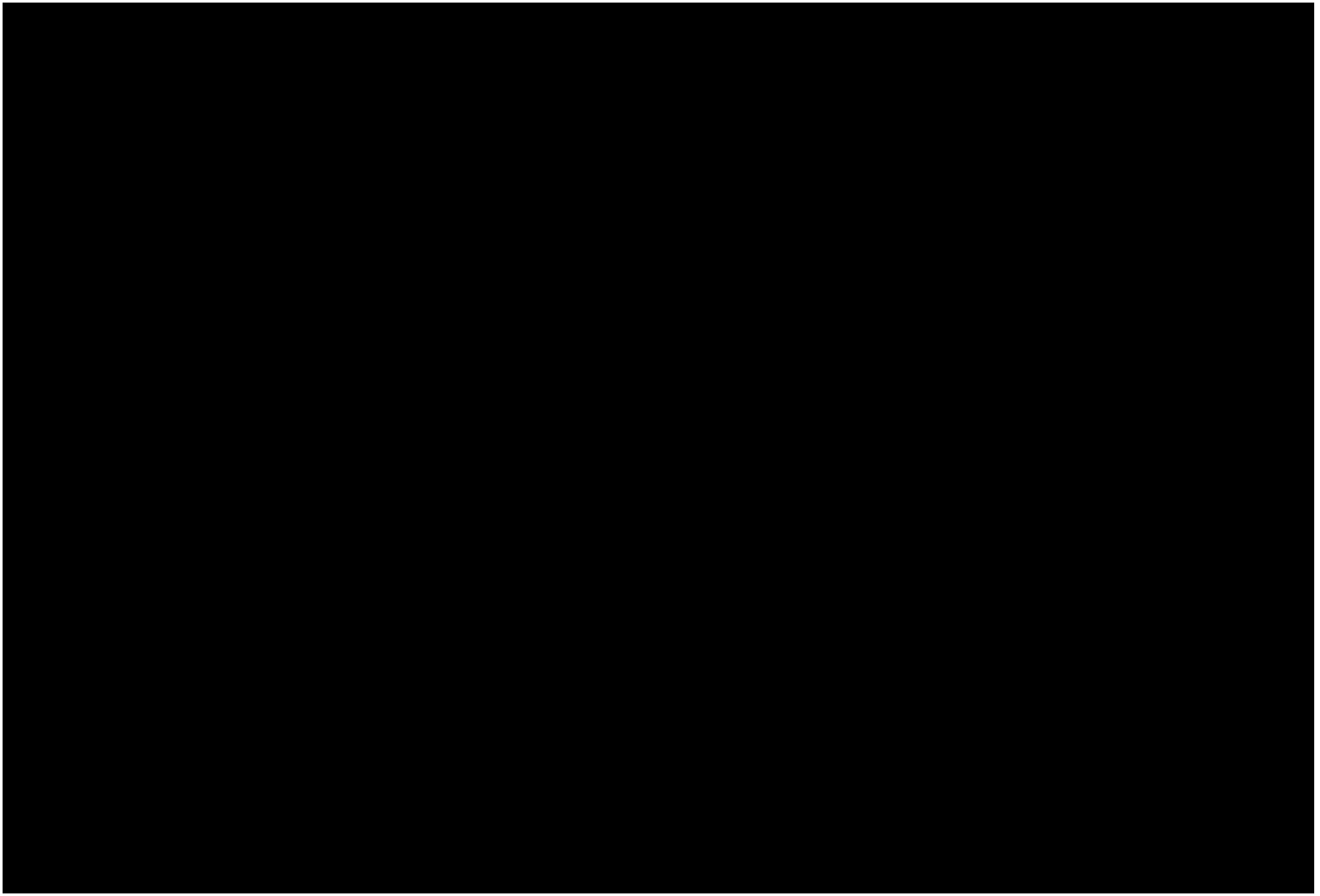
Date of On Peak Day - 07/23/2021



Member Forecasted On Peak Demand Day for August 2021

Southwestern Electric Cooperative, Inc.

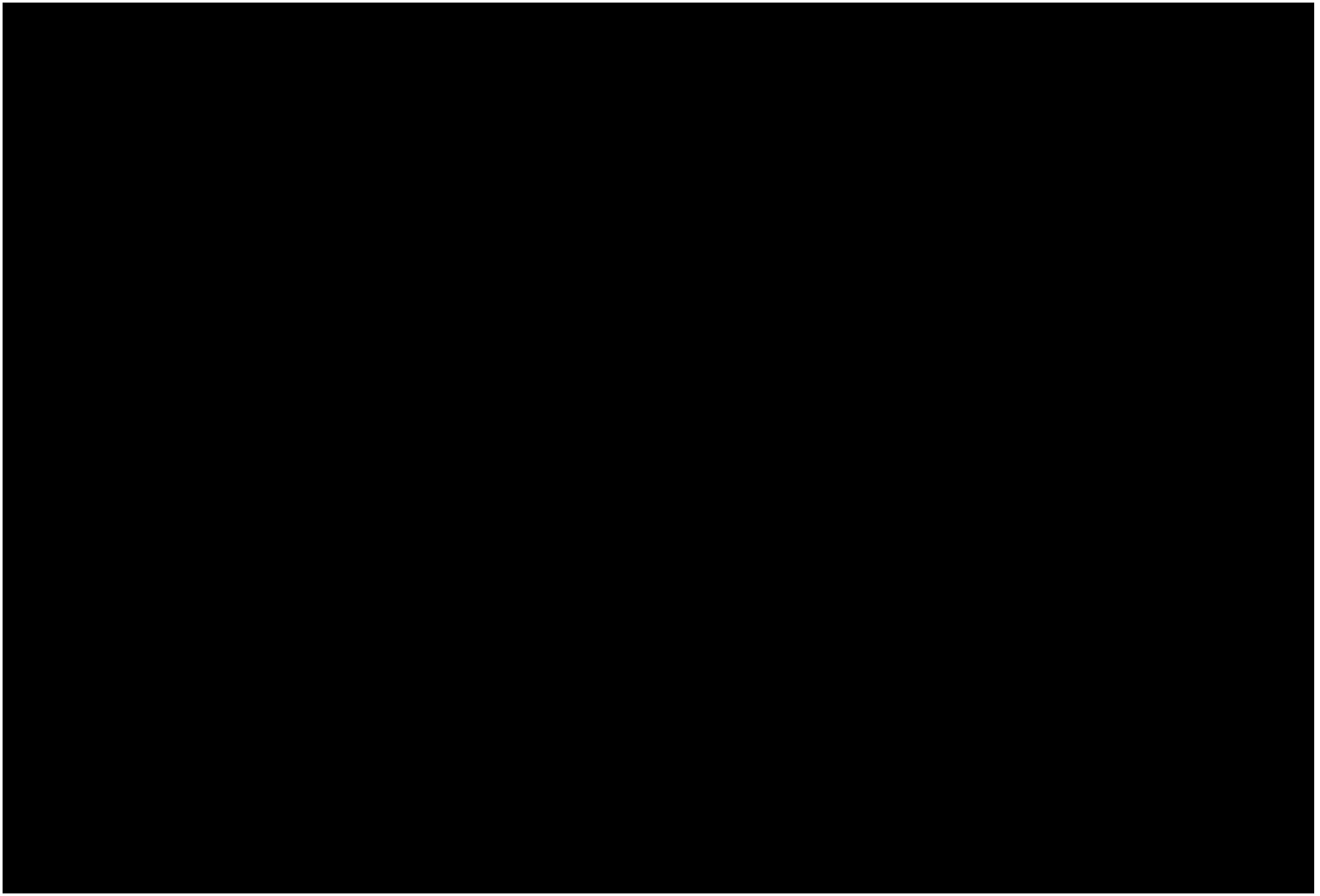
Date of On Peak Day - 08/01/2021



Member Forecasted On Peak Demand Day for September 2021

Southwestern Electric Cooperative, Inc.

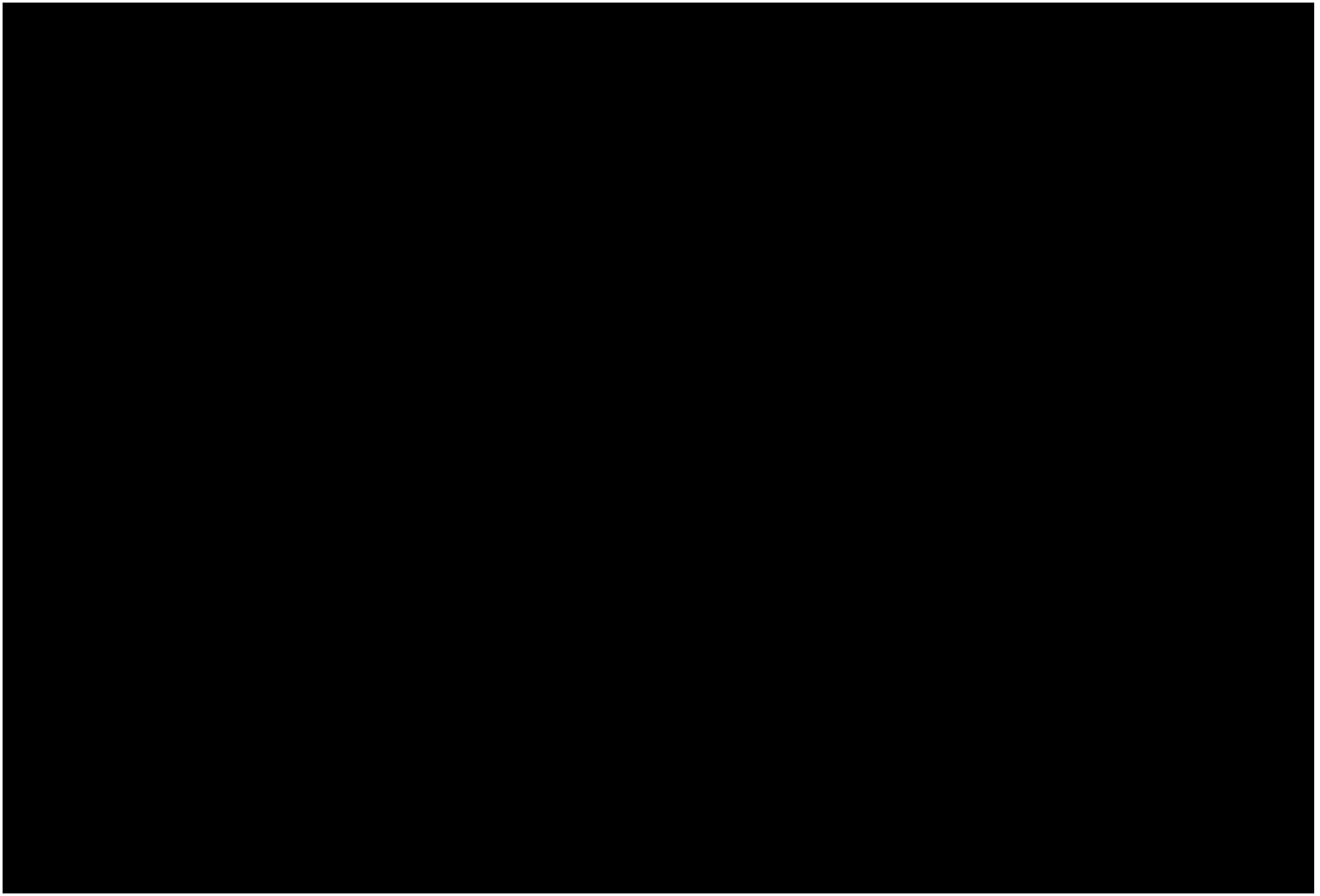
Date of On Peak Day - 09/08/2021



Member Forecasted On Peak Demand Day for October 2021

Southwestern Electric Cooperative, Inc.

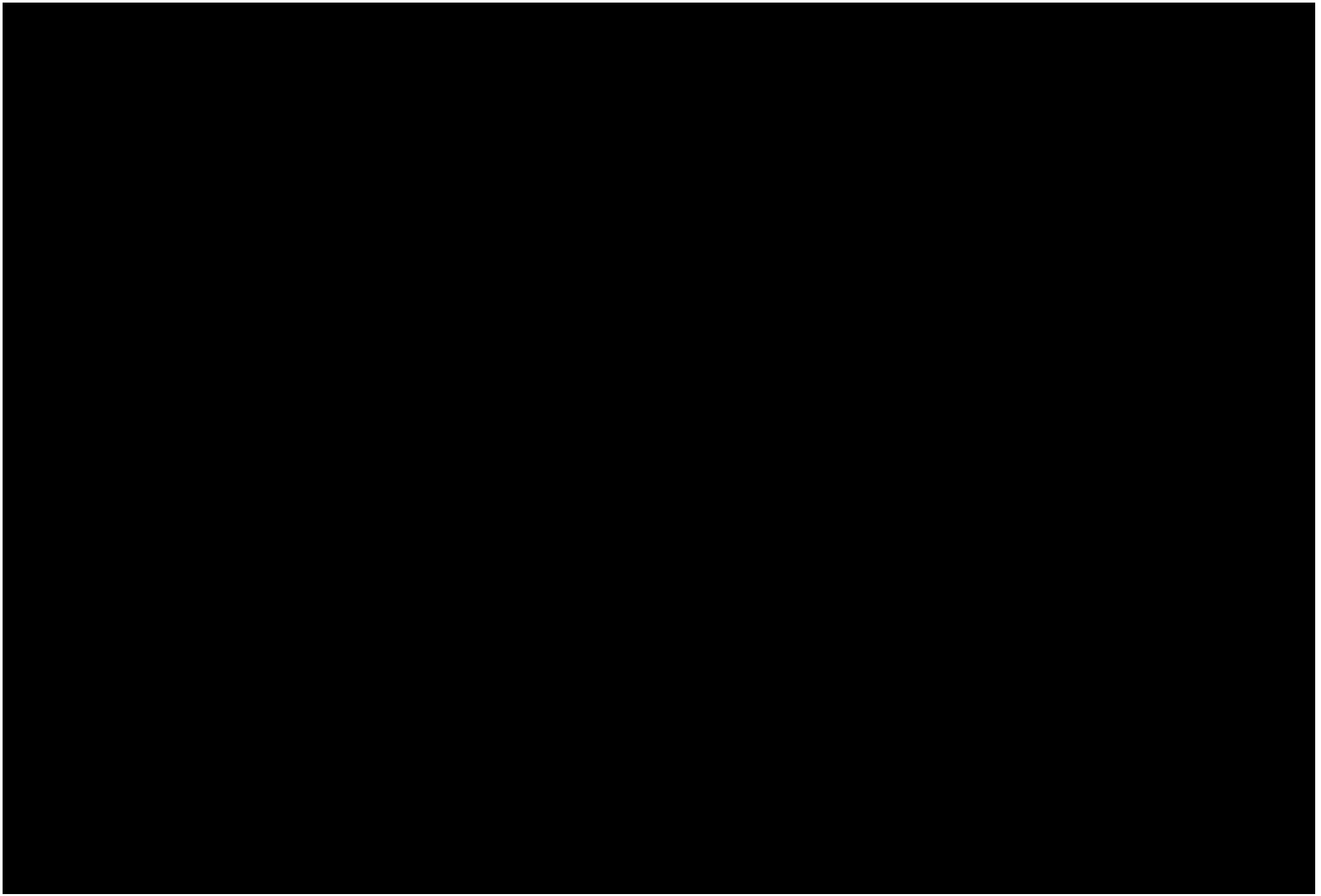
Date of On Peak Day - 10/15/2021



Member Forecasted On Peak Demand Day for November 2021

Southwestern Electric Cooperative, Inc.

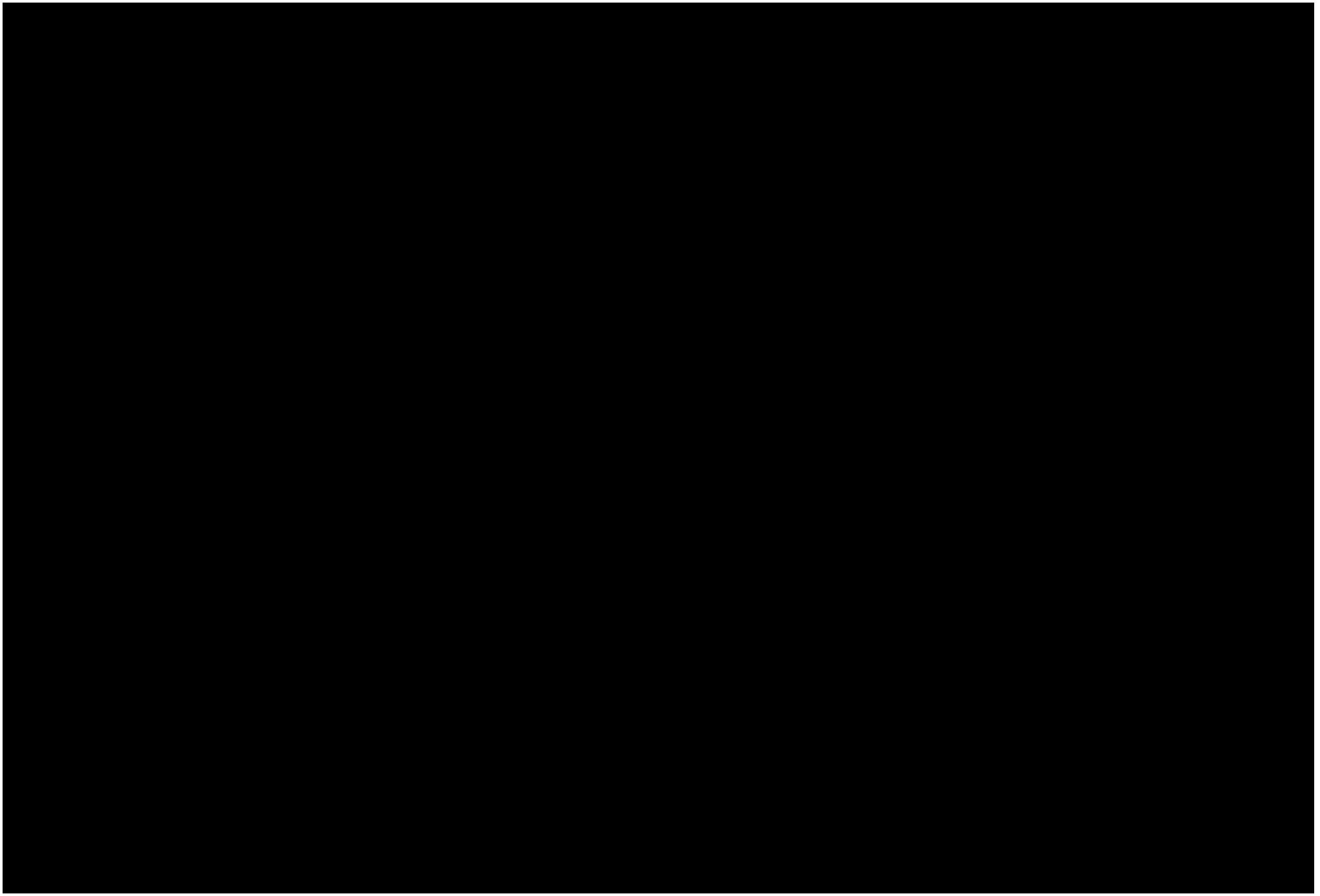
Date of On Peak Day - 11/28/2021



Member Forecasted On Peak Demand Day for December 2021

Southwestern Electric Cooperative, Inc.

Date of On Peak Day - 12/06/2021



Member Forecasted On Peak Demand Day for January 2021

United Power, Inc.

Date of On Peak Day - 01/06/2021

[redacted]

Member Forecasted On Peak Demand Day for February 2021

United Power, Inc.

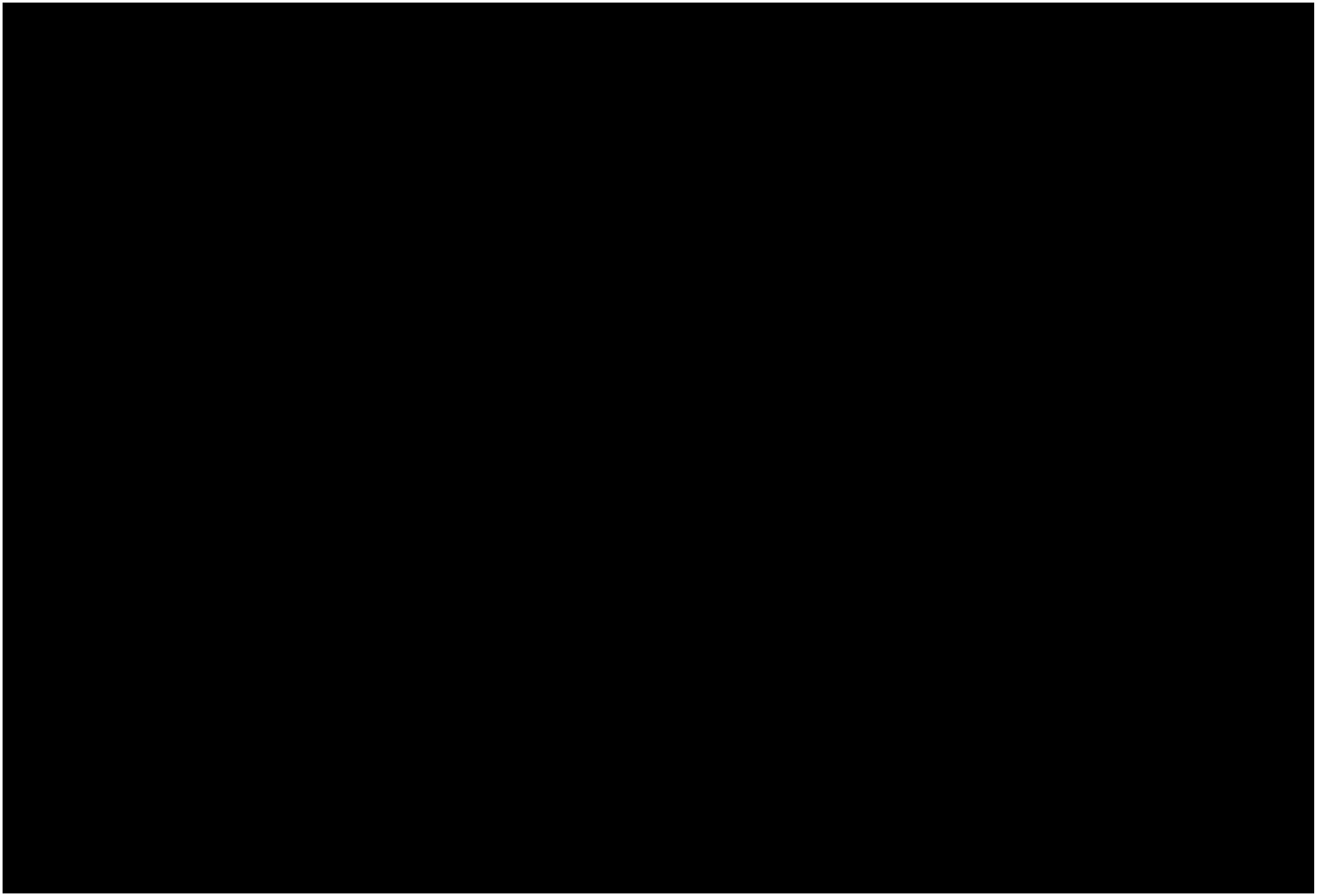
Date of On Peak Day - 02/01/2021

[redacted]

Member Forecasted On Peak Demand Day for March 2021

United Power, Inc.

Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

United Power, Inc.

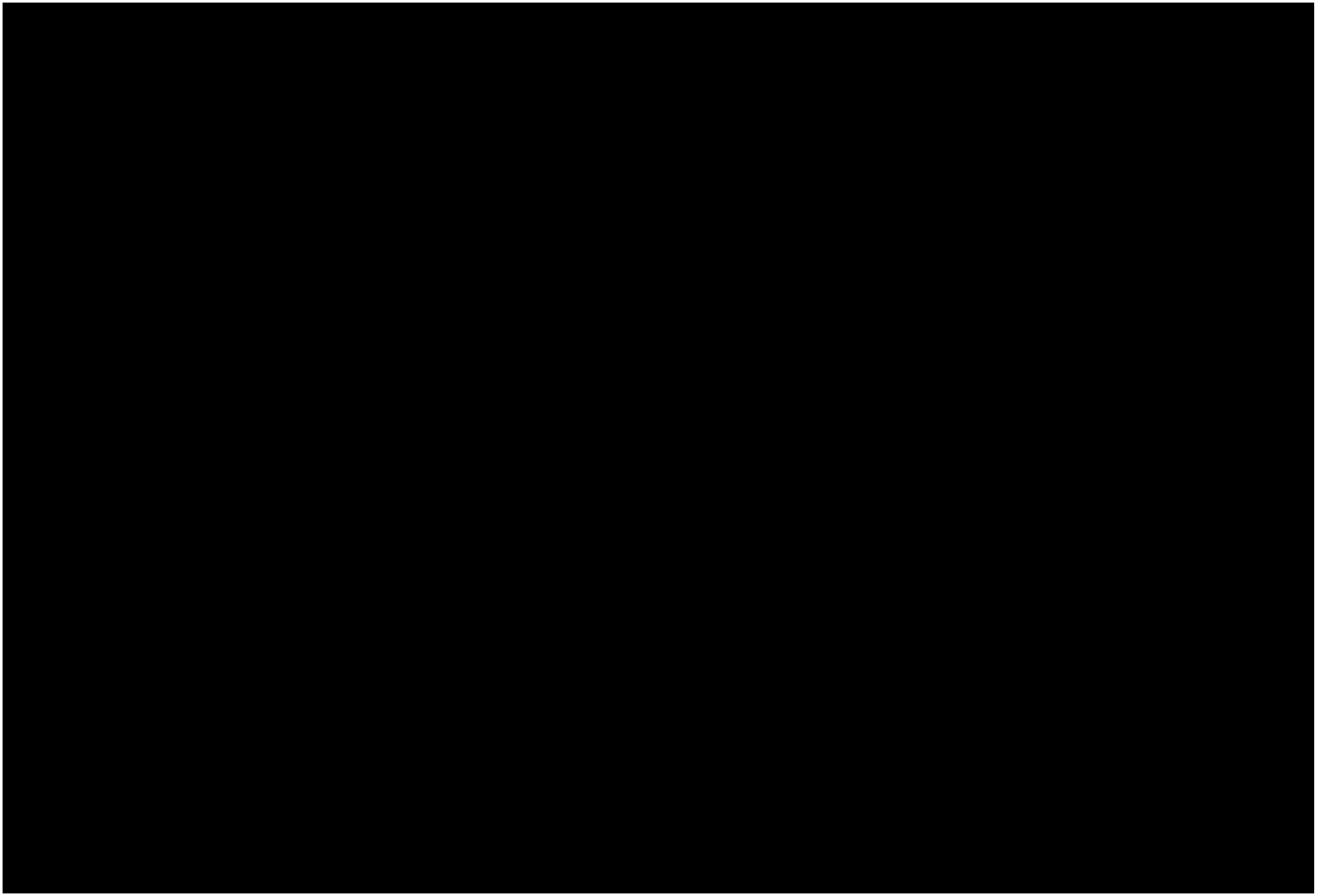
Date of On Peak Day - 04/26/2021

[redacted]

Member Forecasted On Peak Demand Day for May 2021

United Power, Inc.

Date of On Peak Day - 05/31/2021



Member Forecasted On Peak Demand Day for June 2021

United Power, Inc.

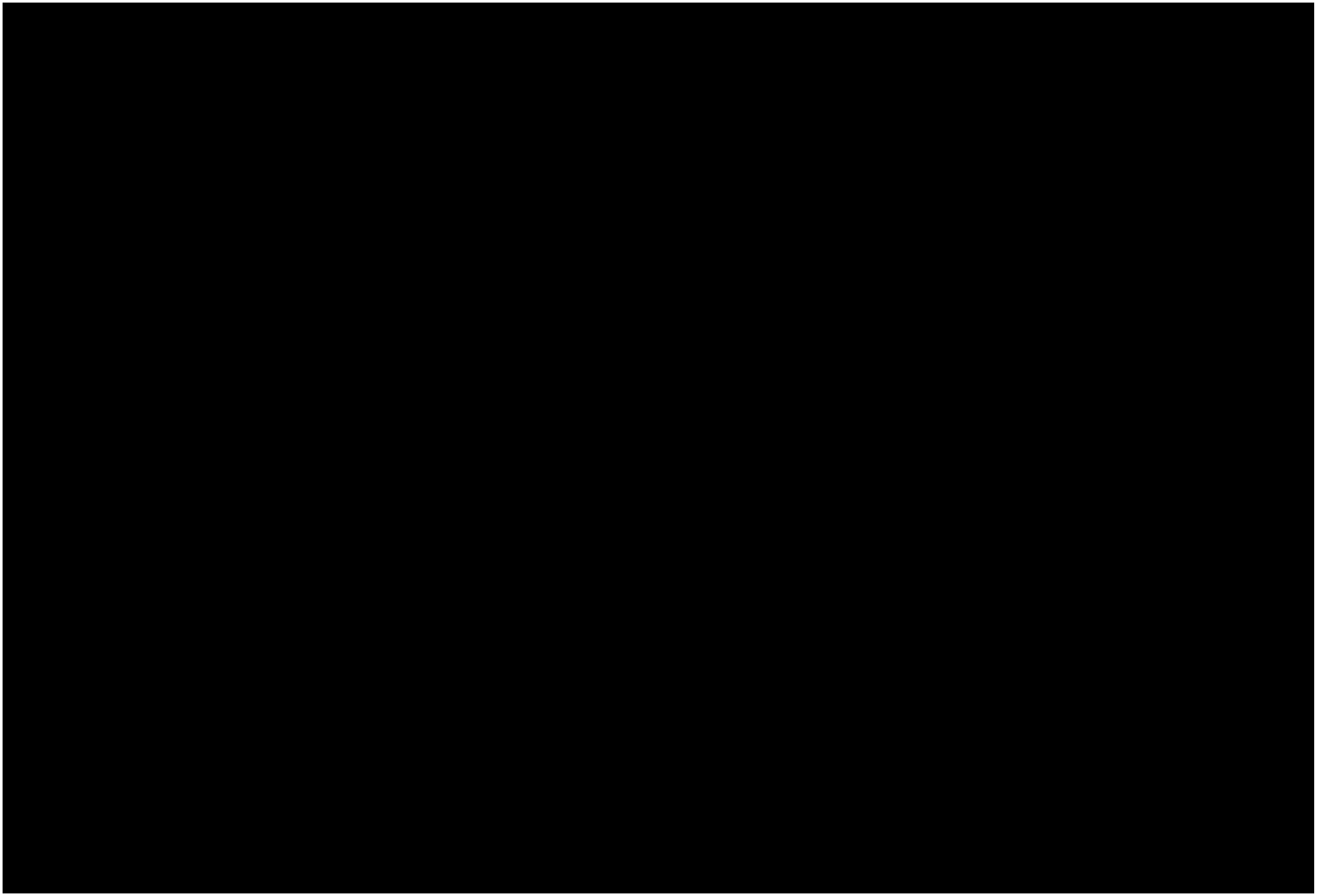
Date of On Peak Day - 06/10/2021

[redacted]

Member Forecasted On Peak Demand Day for July 2021

United Power, Inc.

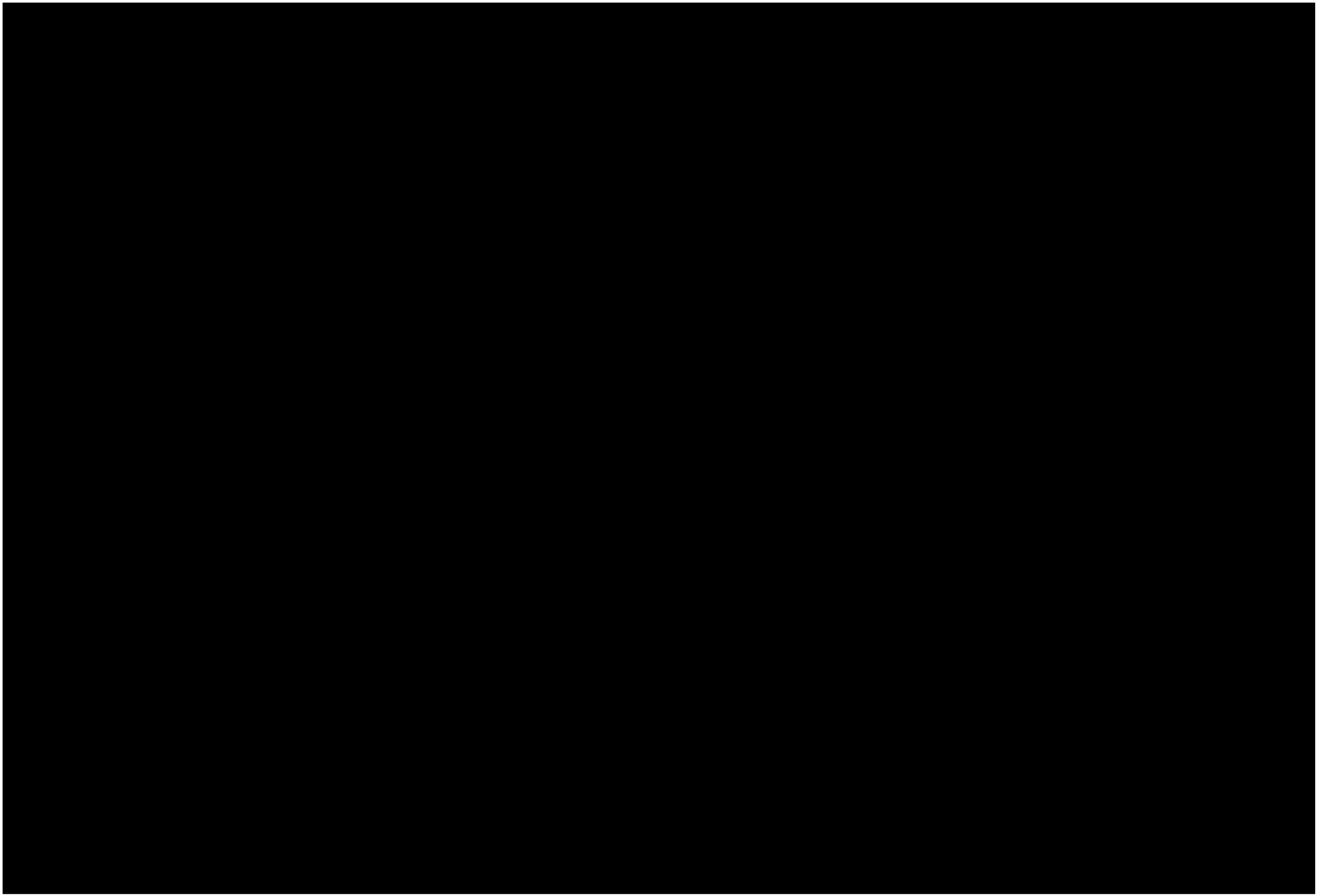
Date of On Peak Day - 07/22/2021



Member Forecasted On Peak Demand Day for August 2021

United Power, Inc.

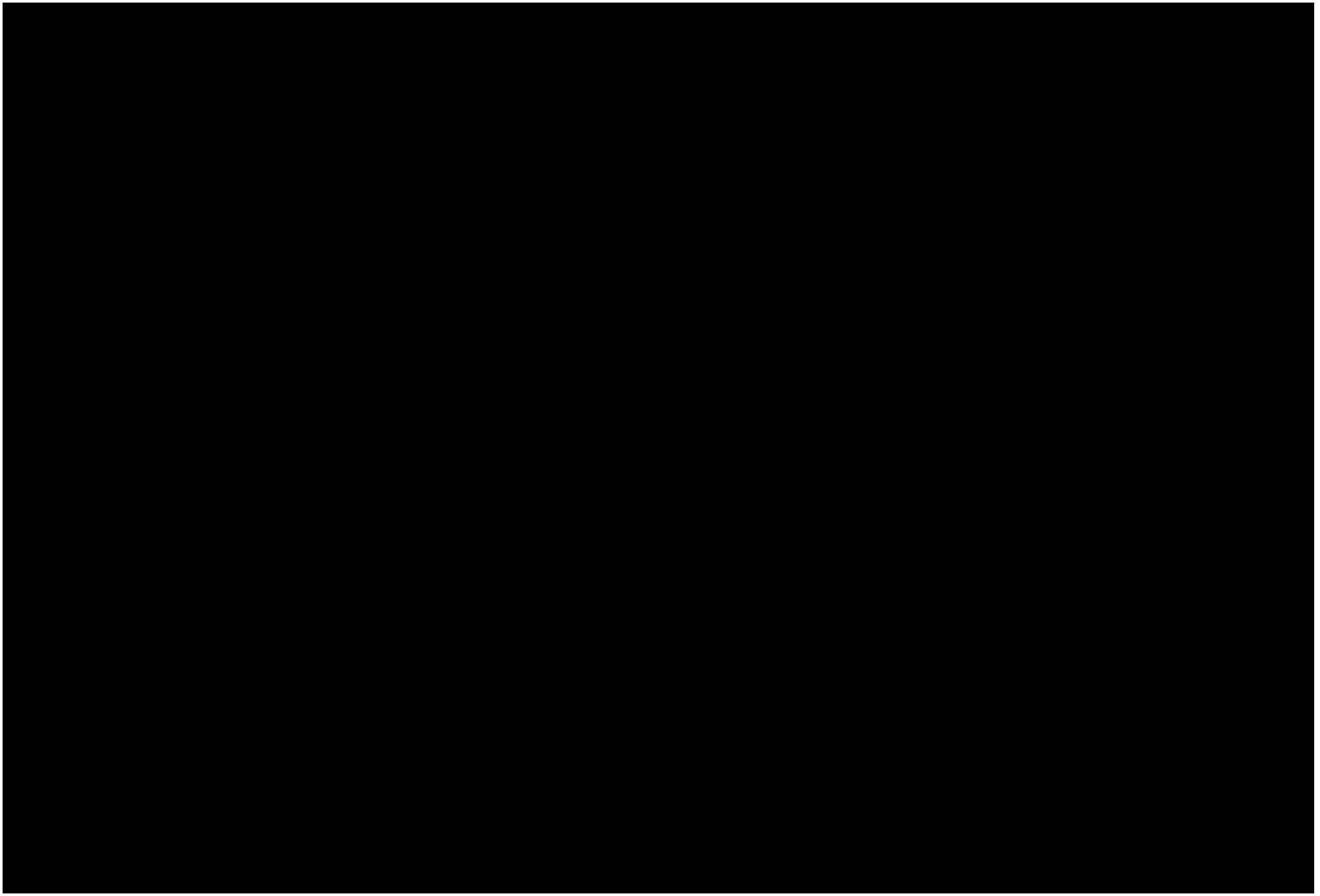
Date of On Peak Day - 08/28/2021



Member Forecasted On Peak Demand Day for September 2021

United Power, Inc.

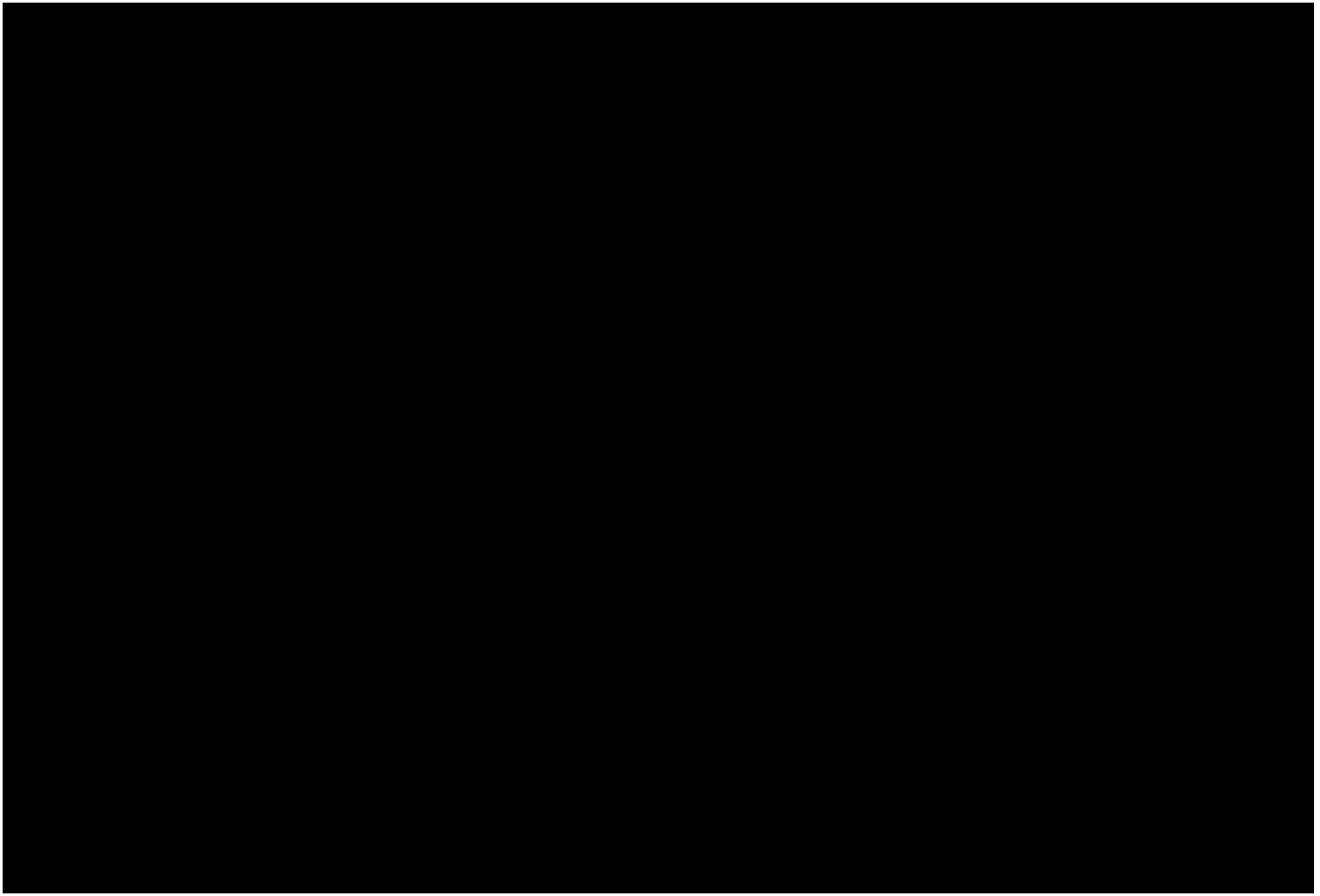
Date of On Peak Day - 09/01/2021



Member Forecasted On Peak Demand Day for October 2021

United Power, Inc.

Date of On Peak Day - 10/13/2021



Member Forecasted On Peak Demand Day for November 2021

United Power, Inc.

Date of On Peak Day - 11/29/2021

[redacted]

Member Forecasted On Peak Demand Day for December 2021

United Power, Inc.

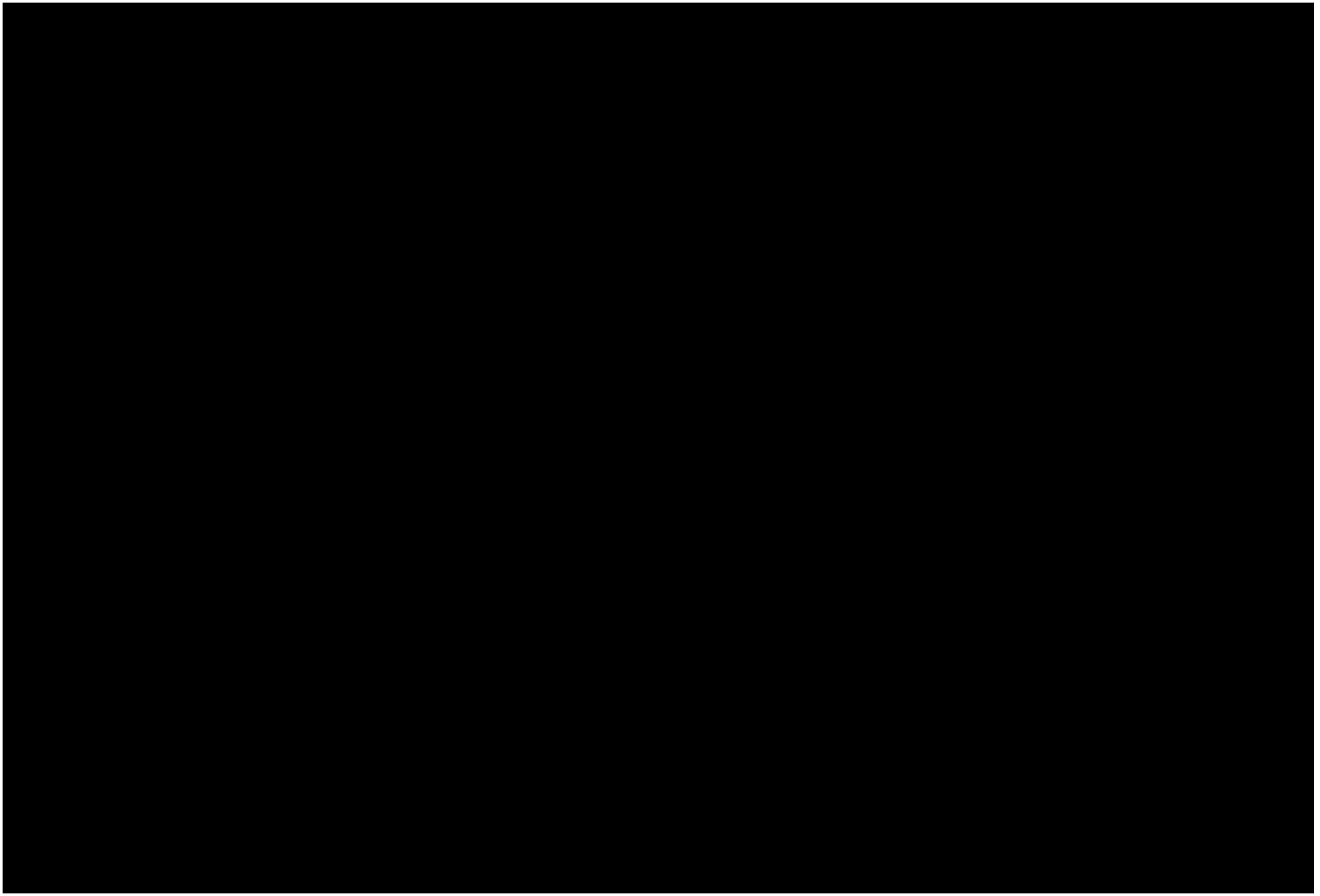
Date of On Peak Day - 12/29/2021

[redacted]

Member Forecasted On Peak Demand Day for January 2021

Wheat Belt Public Power District

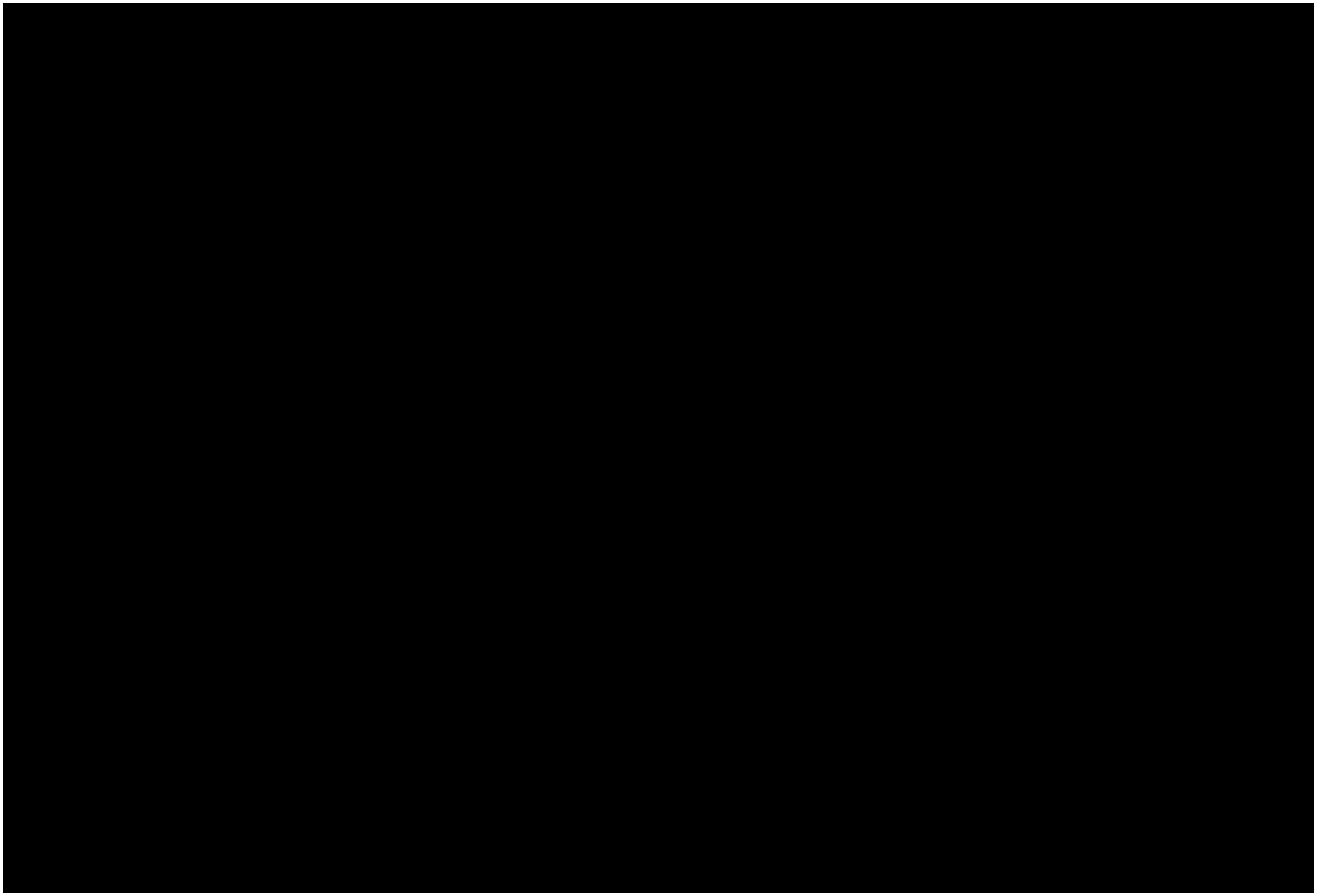
Date of On Peak Day - 01/06/2021



Member Forecasted On Peak Demand Day for February 2021

Wheat Belt Public Power District

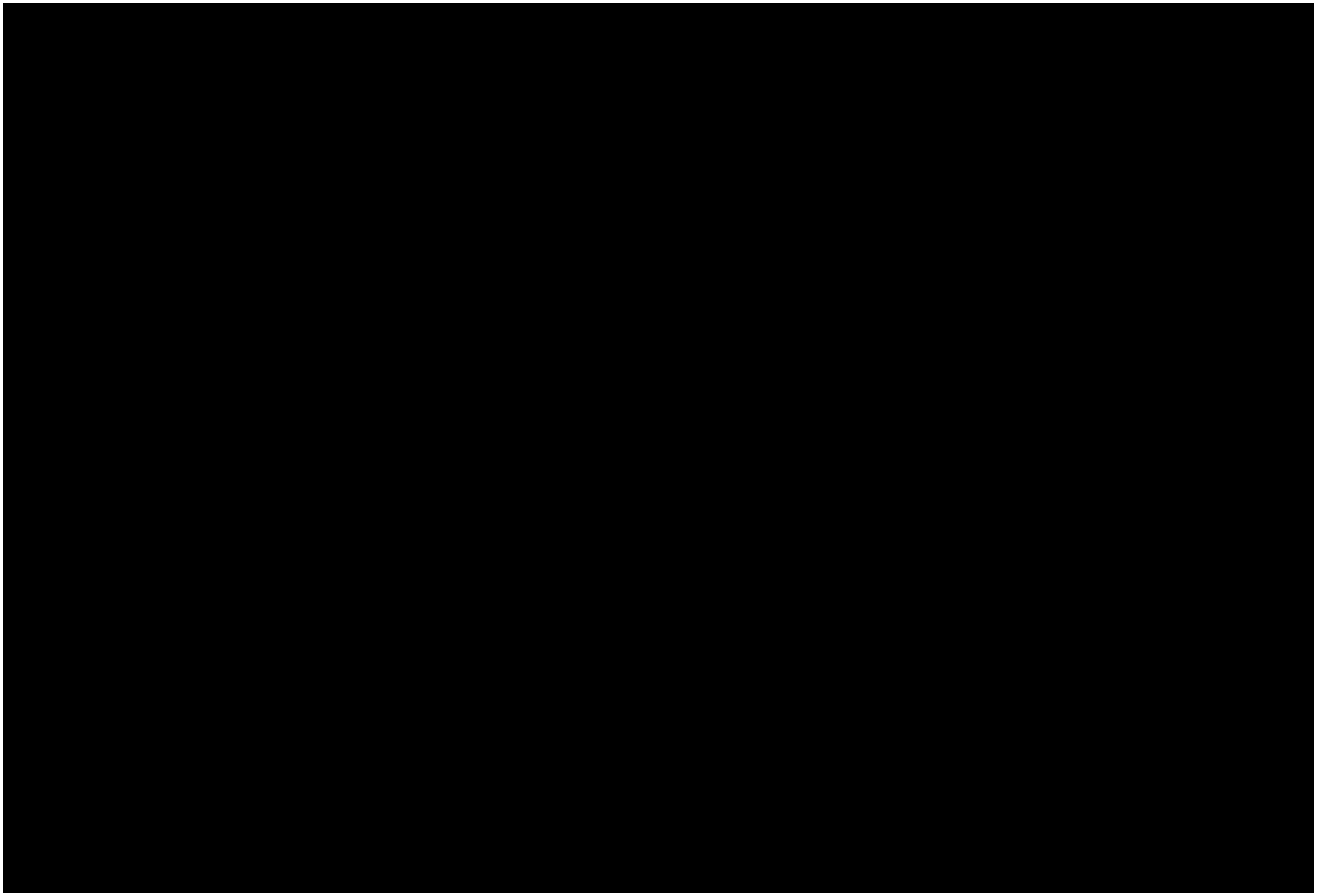
Date of On Peak Day - 02/25/2021



Member Forecasted On Peak Demand Day for March 2021

Wheat Belt Public Power District

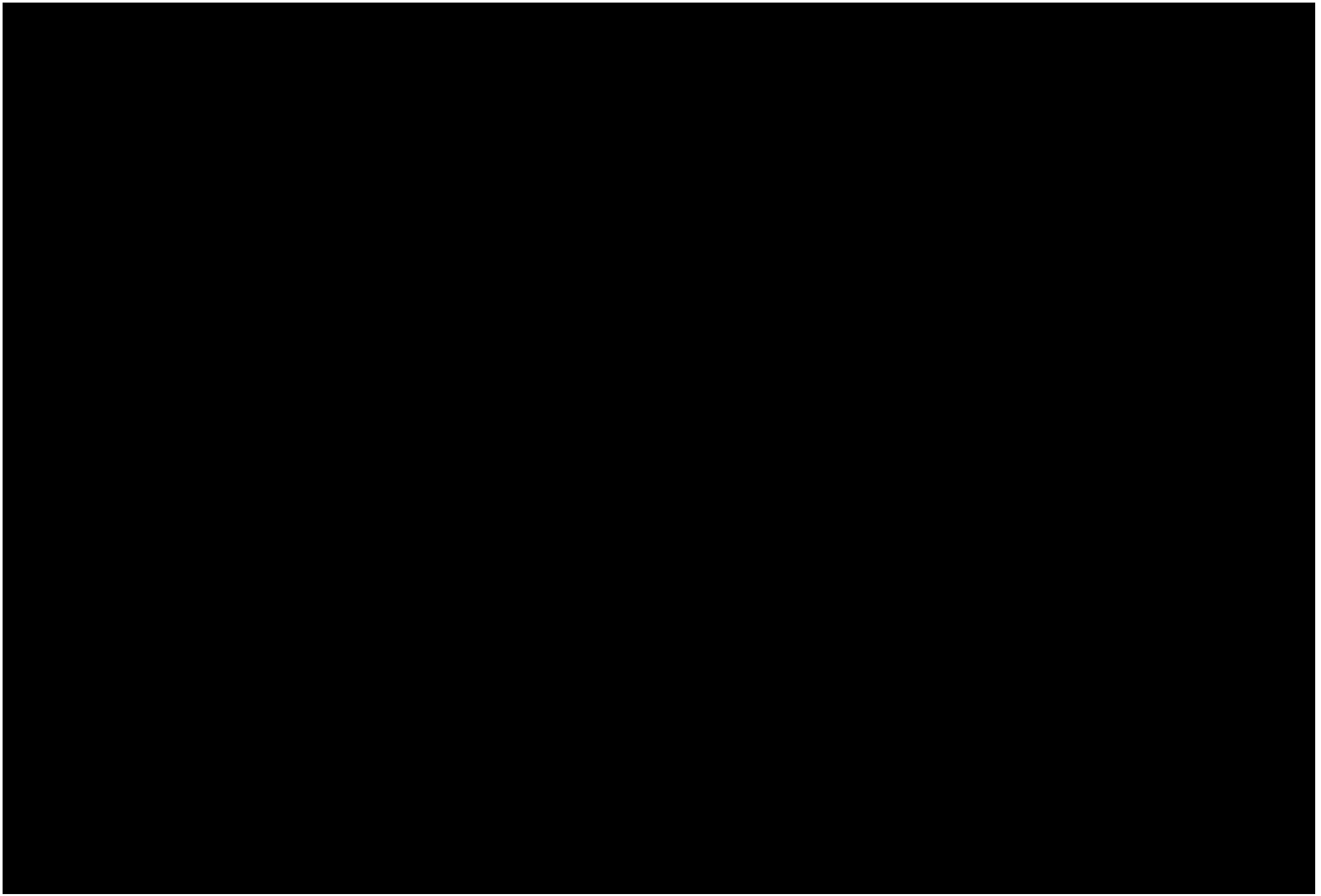
Date of On Peak Day - 03/03/2021



Member Forecasted On Peak Demand Day for April 2021

Wheat Belt Public Power District

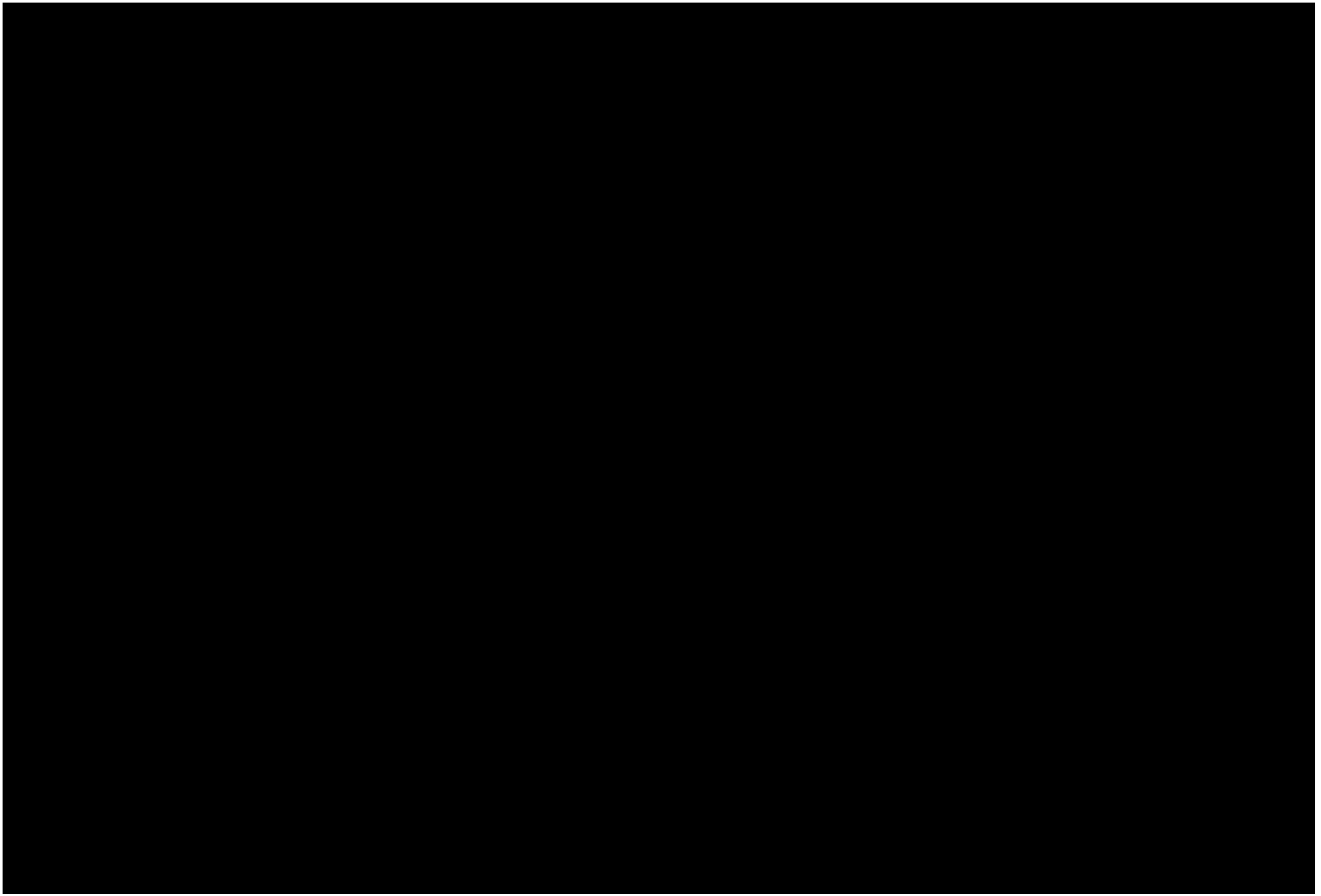
Date of On Peak Day - 04/01/2021



Member Forecasted On Peak Demand Day for May 2021

Wheat Belt Public Power District

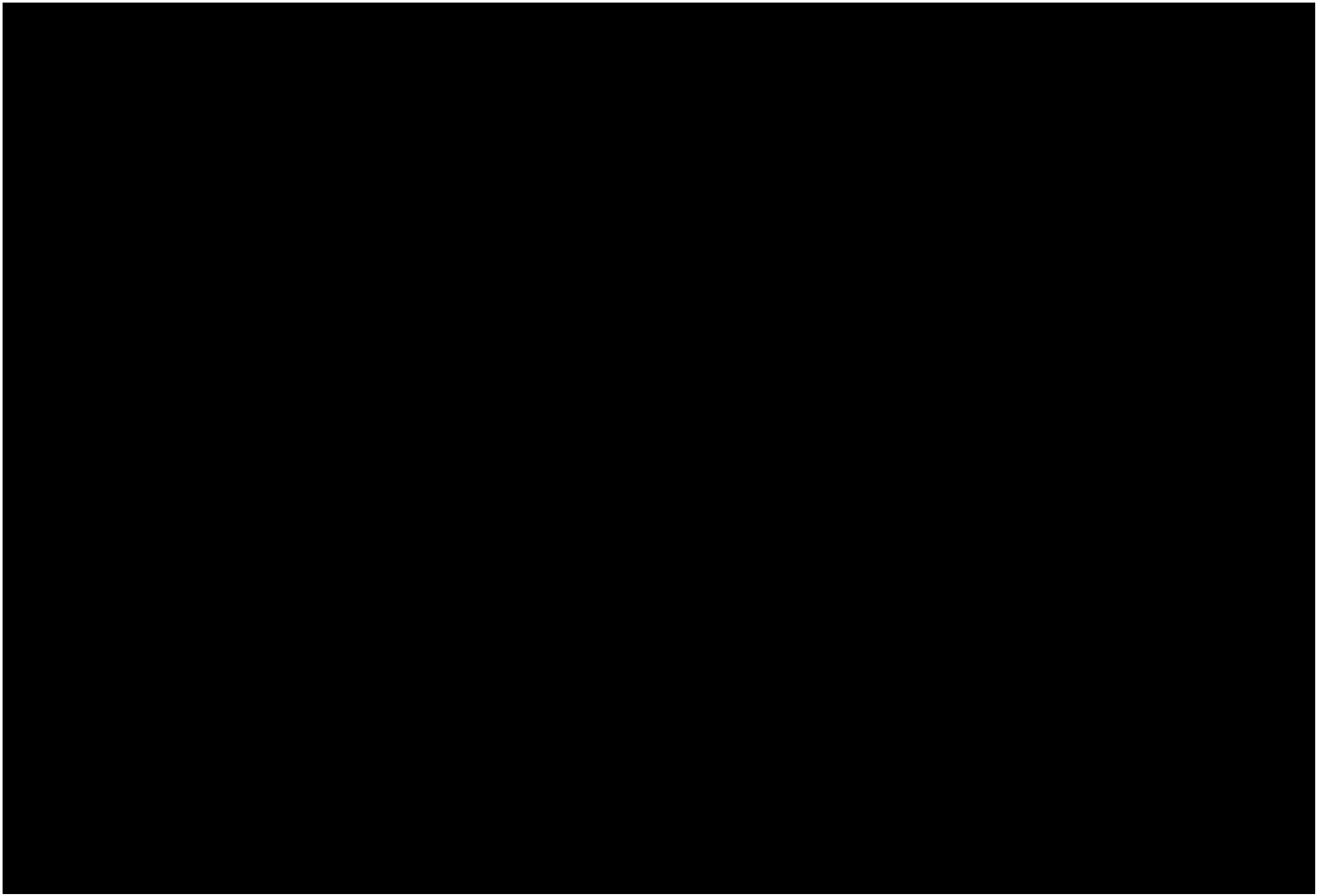
Date of On Peak Day - 05/16/2021



Member Forecasted On Peak Demand Day for June 2021

Wheat Belt Public Power District

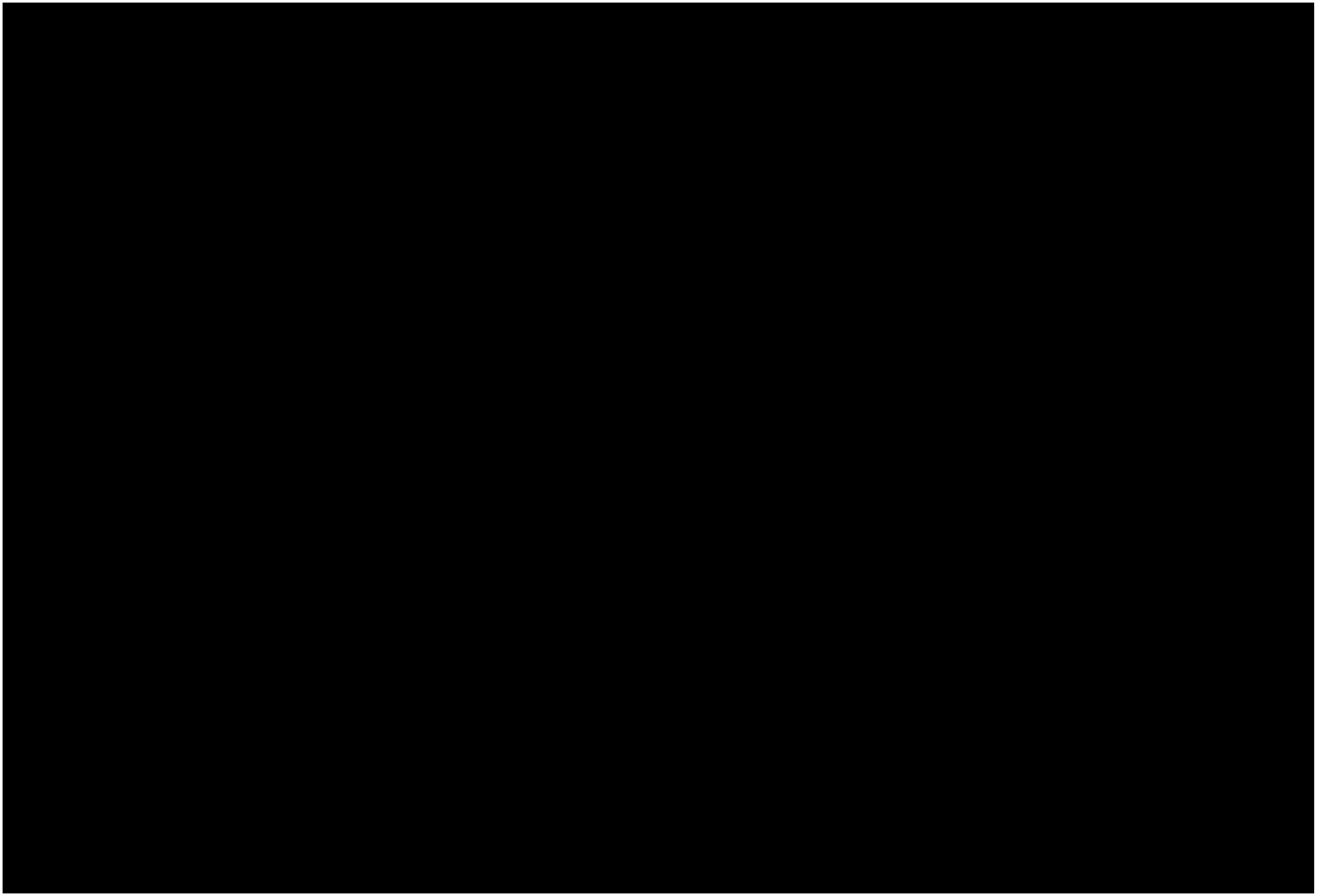
Date of On Peak Day - 06/28/2021



Member Forecasted On Peak Demand Day for July 2021

Wheat Belt Public Power District

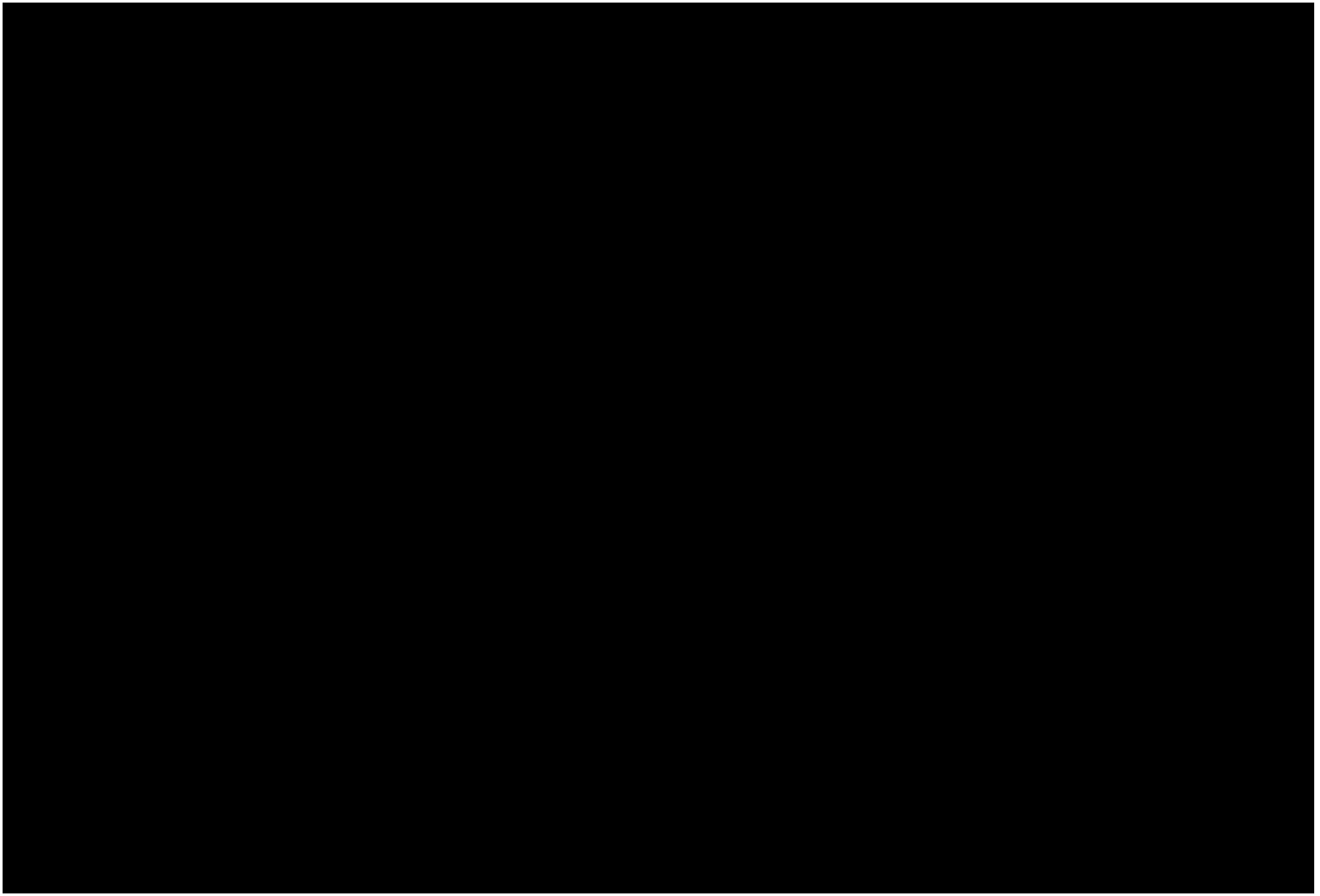
Date of On Peak Day - 07/09/2021



Member Forecasted On Peak Demand Day for August 2021

Wheat Belt Public Power District

Date of On Peak Day - 08/24/2021



Hearing Exhibit 101
PUBLIC Attachment BN-2
Proceeding No. 20A-0528E
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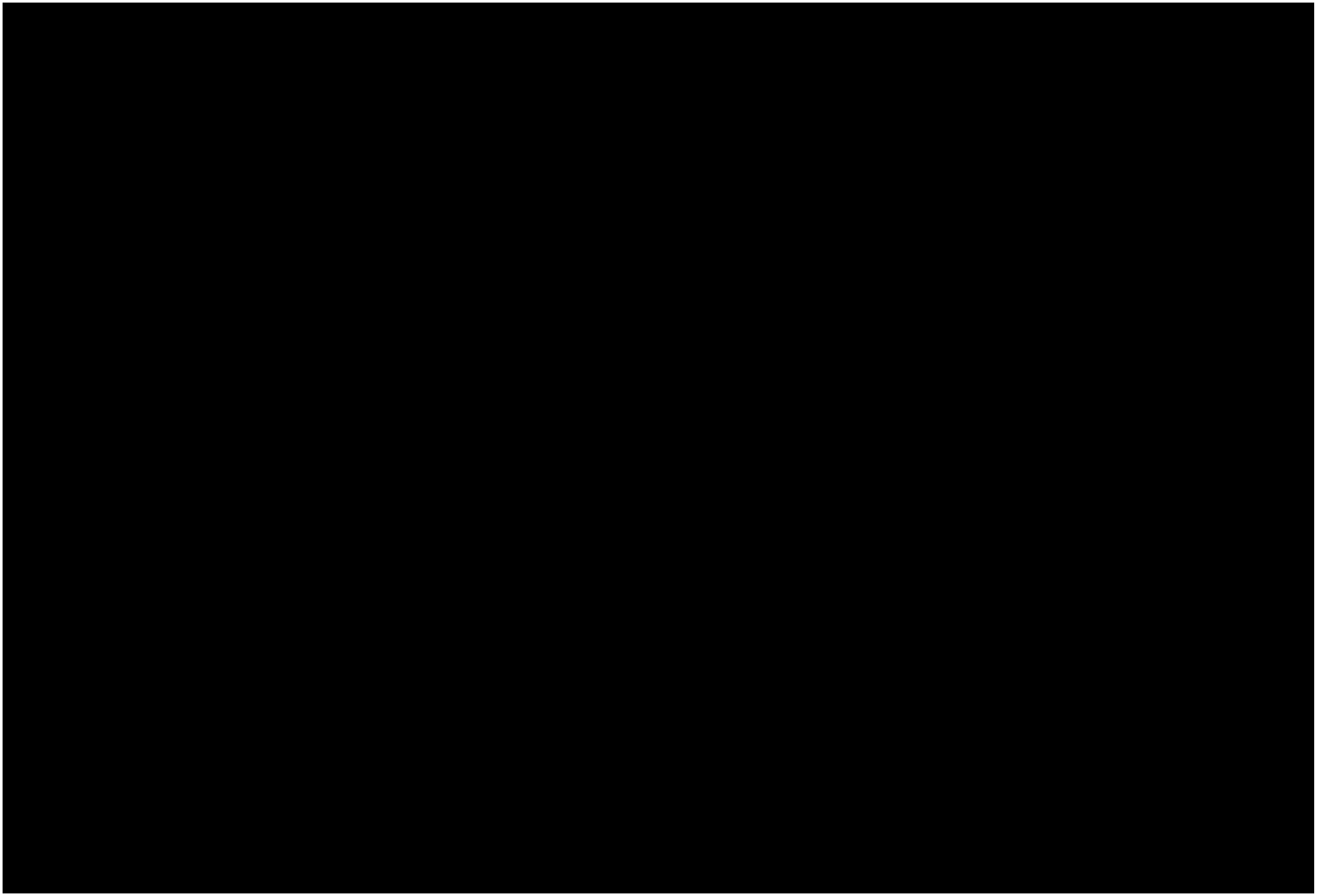
Member Forecasted On Peak Demand Day for September 2021

Wheat Belt Public Power District

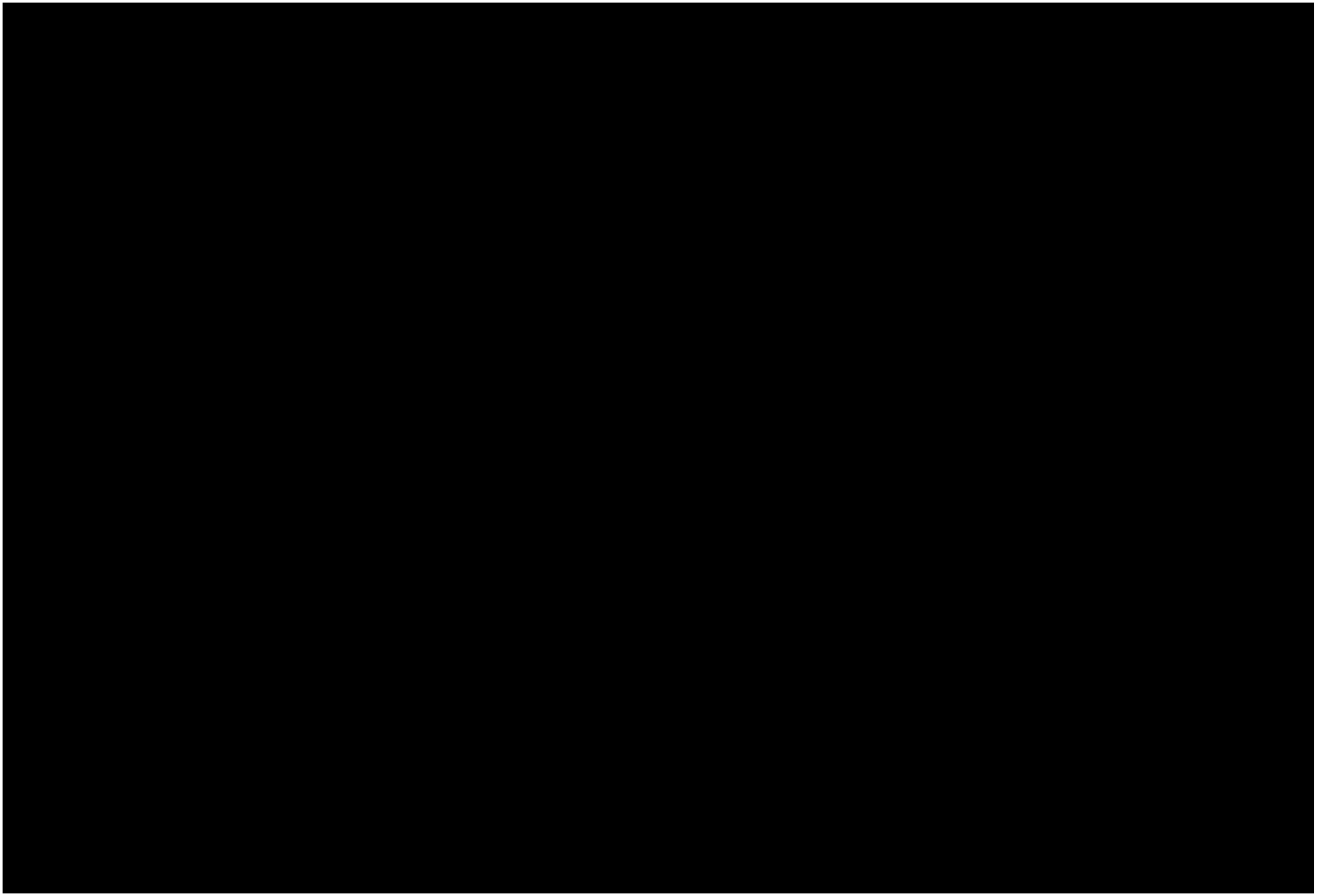
Date of On Peak Day - 09/02/2021



Member Forecasted On Peak Demand Day for October 2021

Wheat Belt Public Power District

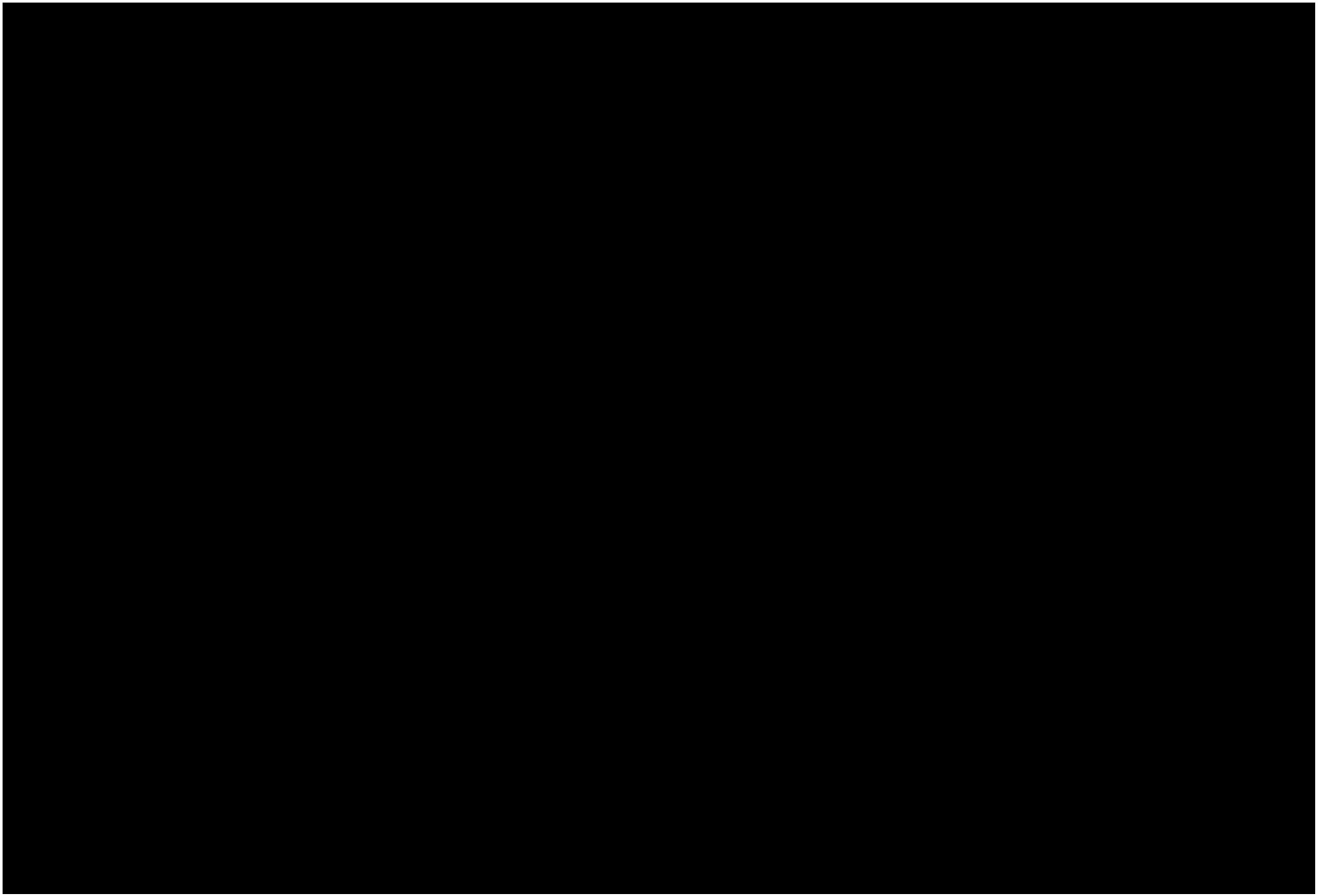
Date of On Peak Day - 10/04/2021



Member Forecasted On Peak Demand Day for November 2021

Wheat Belt Public Power District

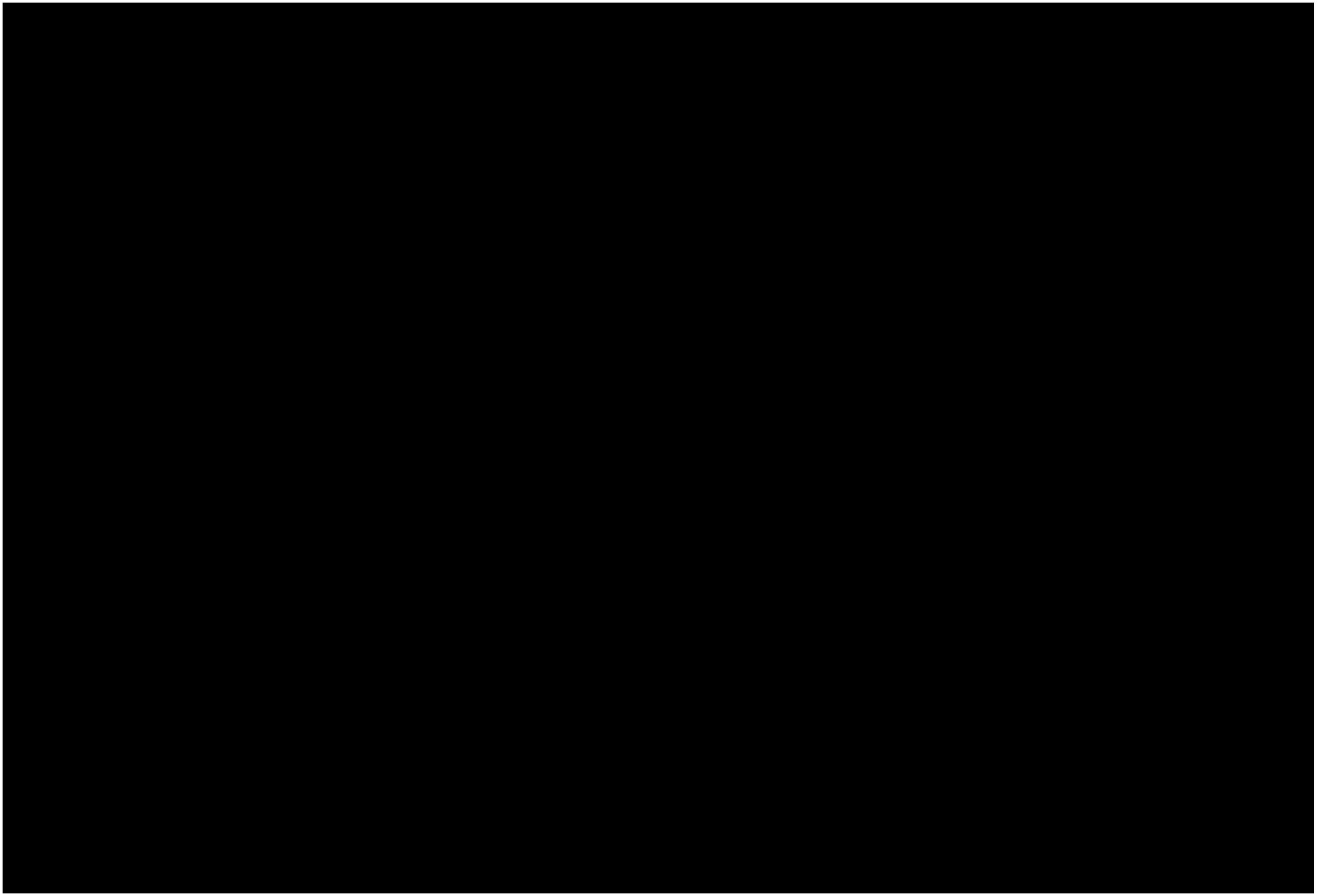
Date of On Peak Day - 11/09/2021



Member Forecasted On Peak Demand Day for December 2021

Wheat Belt Public Power District

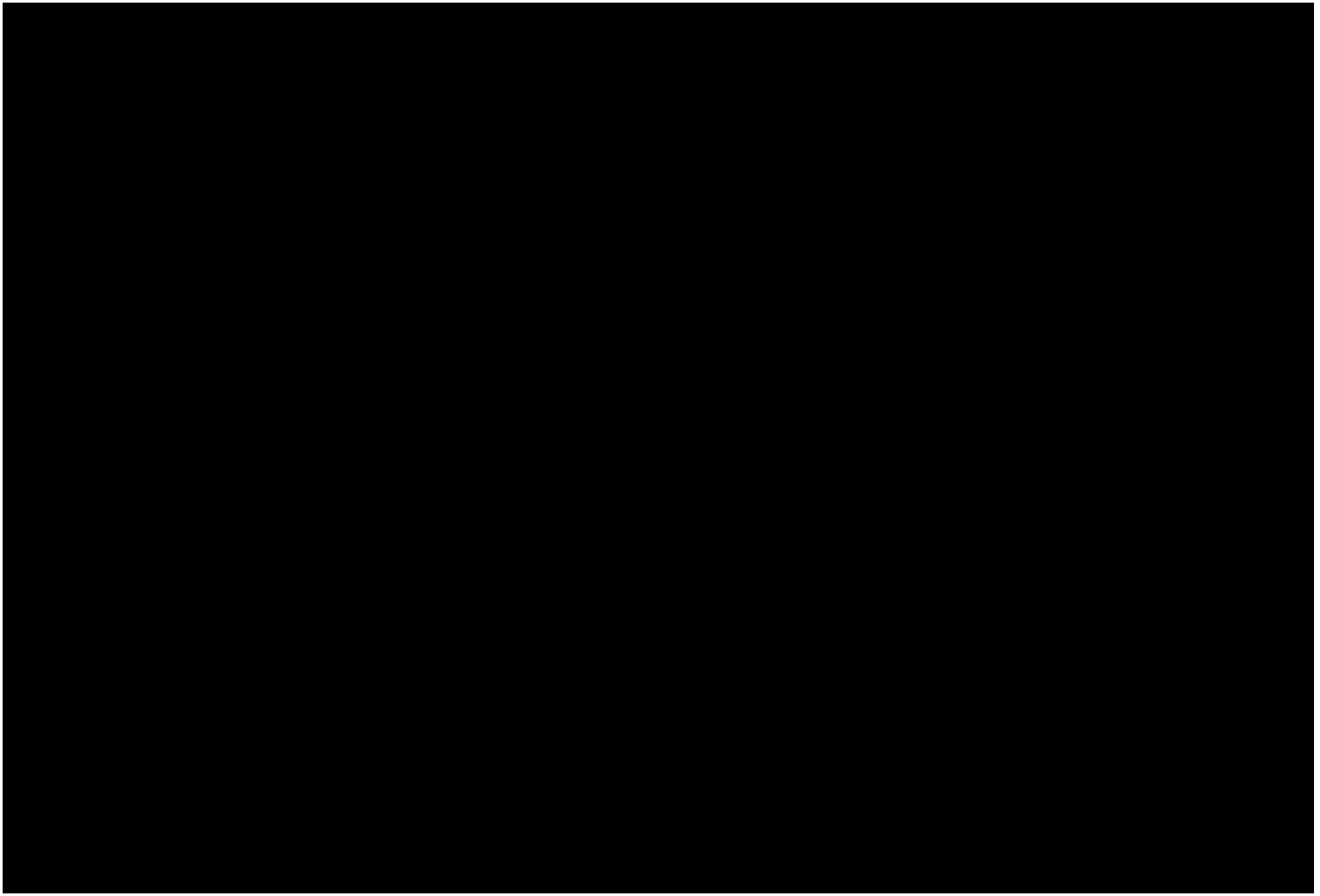
Date of On Peak Day - 12/27/2021



Member Forecasted On Peak Demand Day for January 2021

Wheatland Rural Electric Association, Inc.

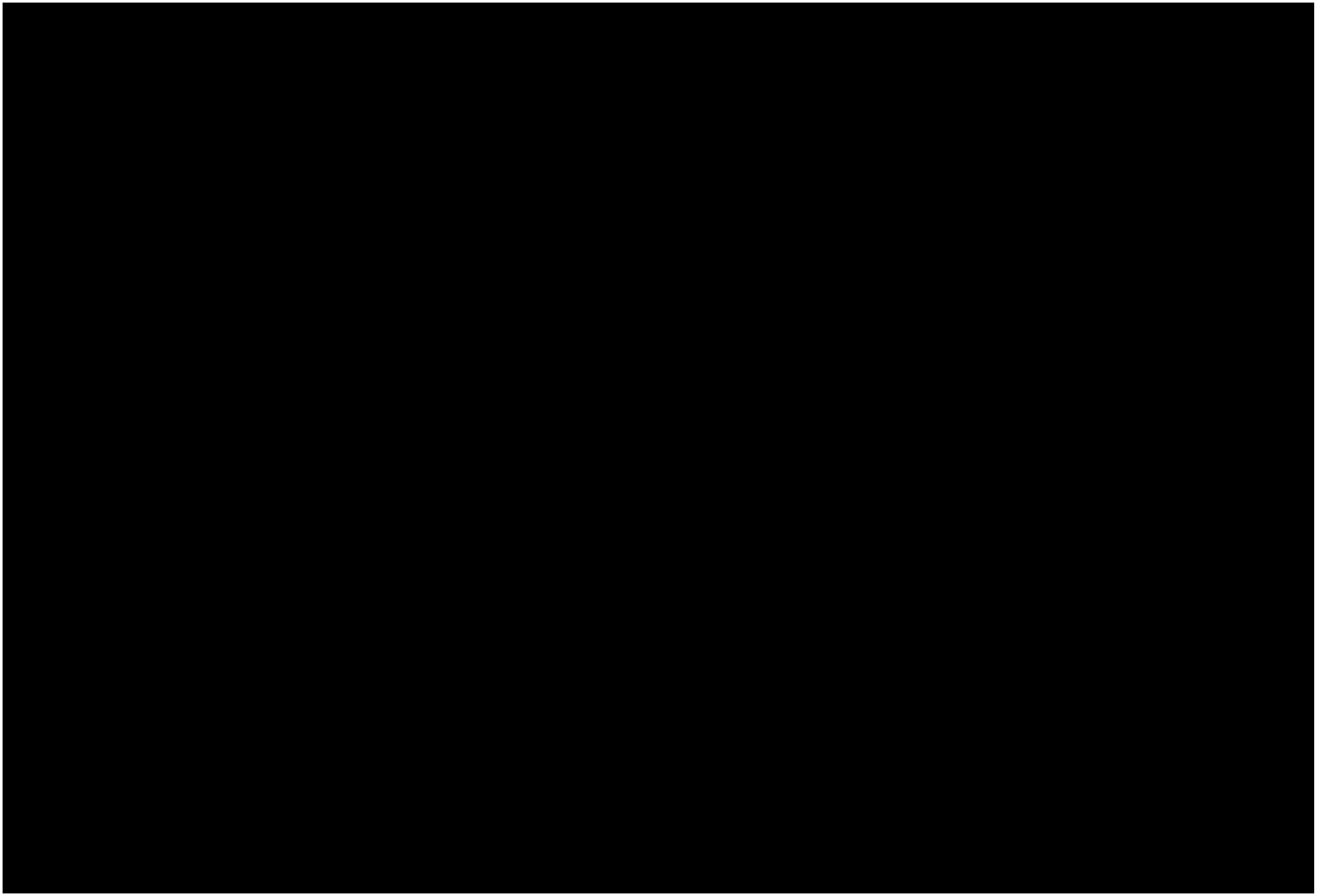
Date of On Peak Day - 01/05/2021



Member Forecasted On Peak Demand Day for February 2021

Wheatland Rural Electric Association, Inc.

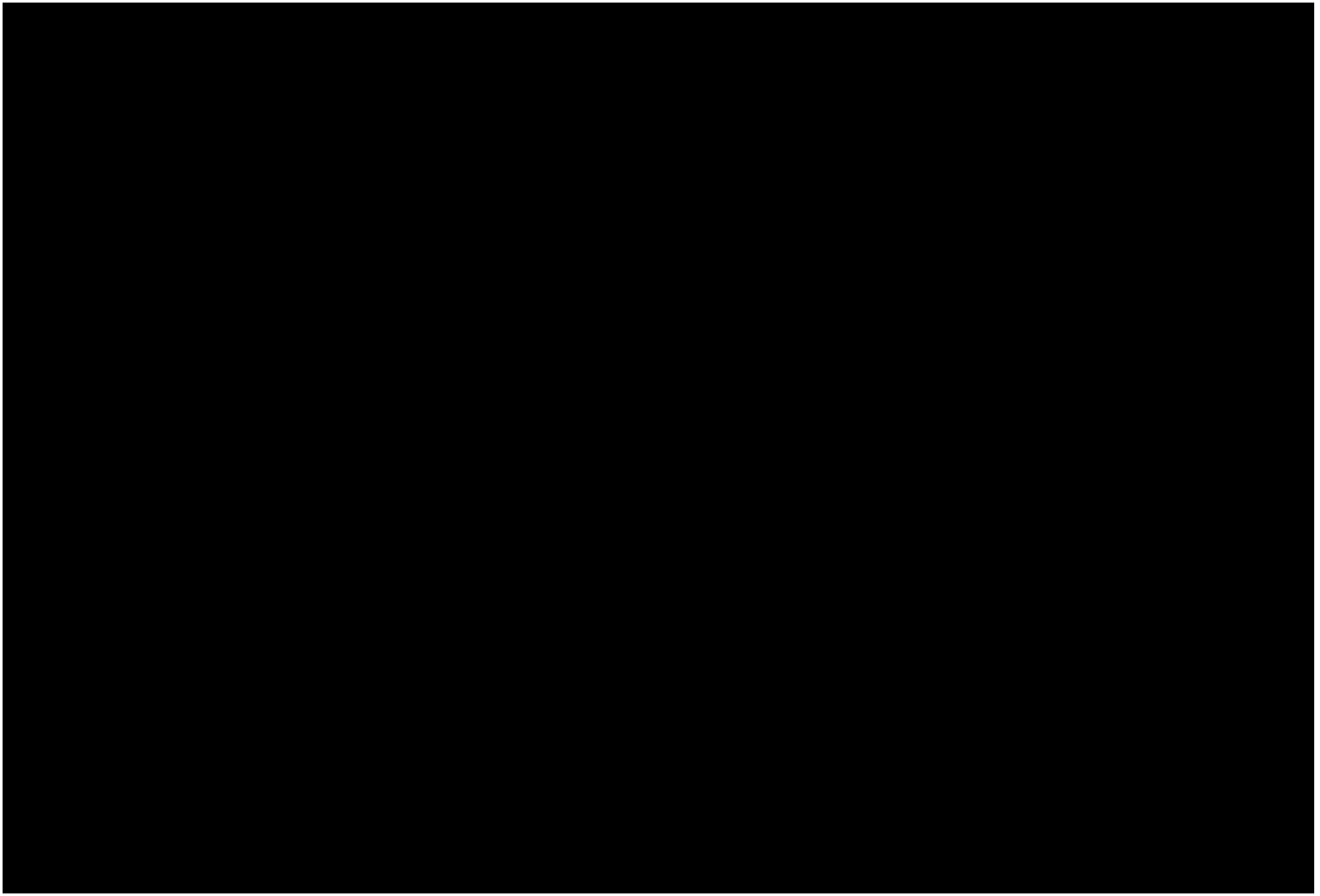
Date of On Peak Day - 02/03/2021



Member Forecasted On Peak Demand Day for March 2021

Wheatland Rural Electric Association, Inc.

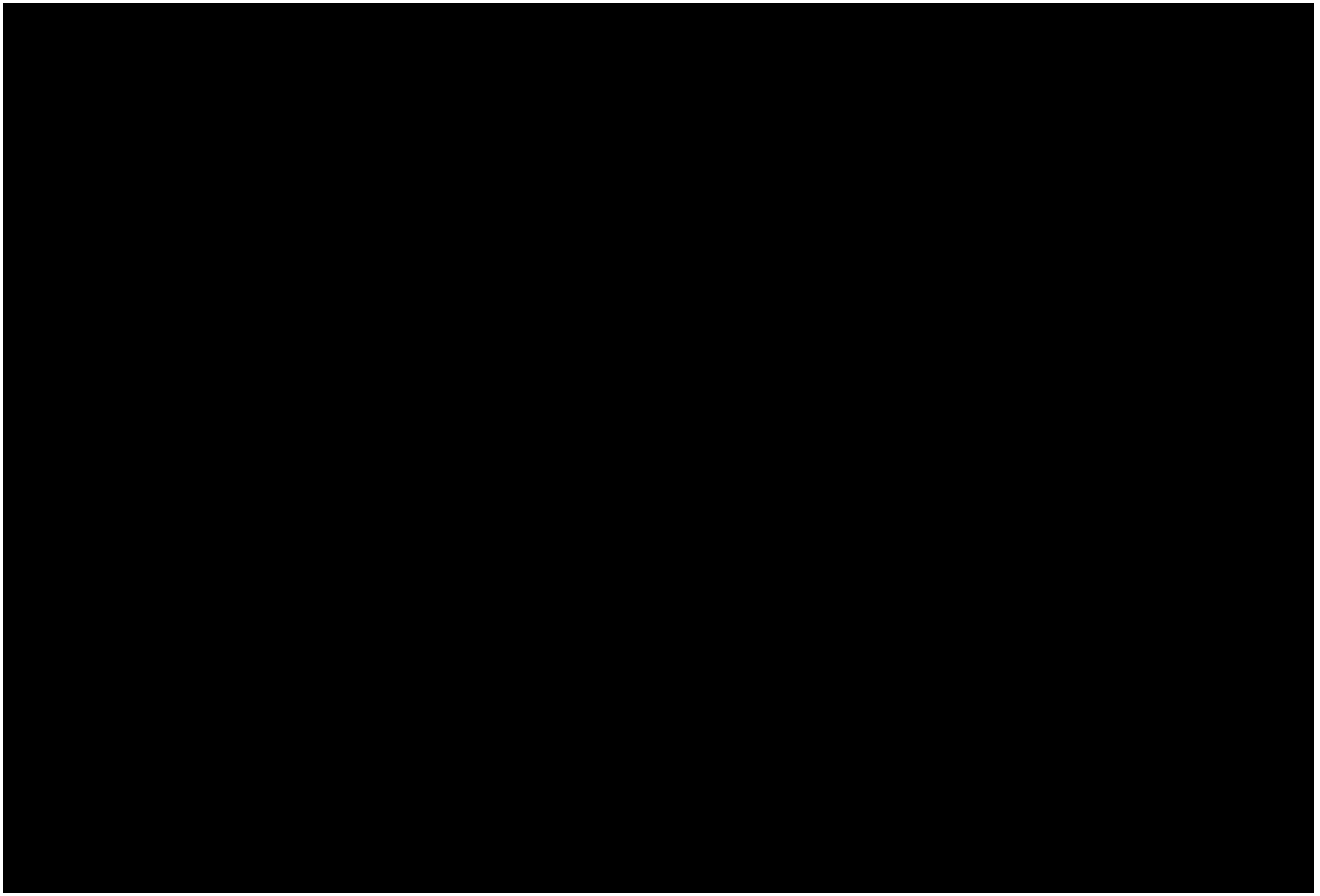
Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

Wheatland Rural Electric Association, Inc.

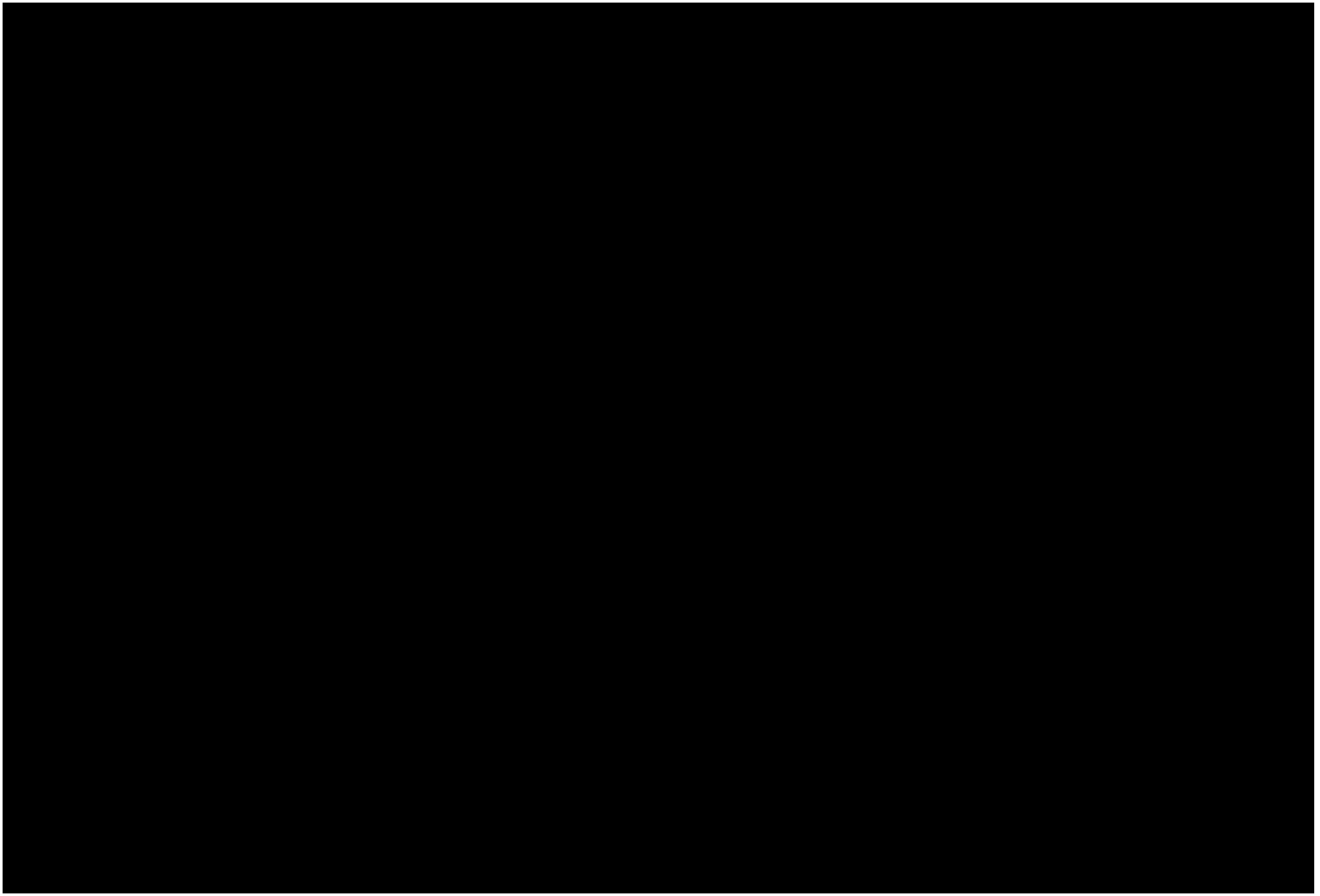
Date of On Peak Day - 04/04/2021



Member Forecasted On Peak Demand Day for May 2021

Wheatland Rural Electric Association, Inc.

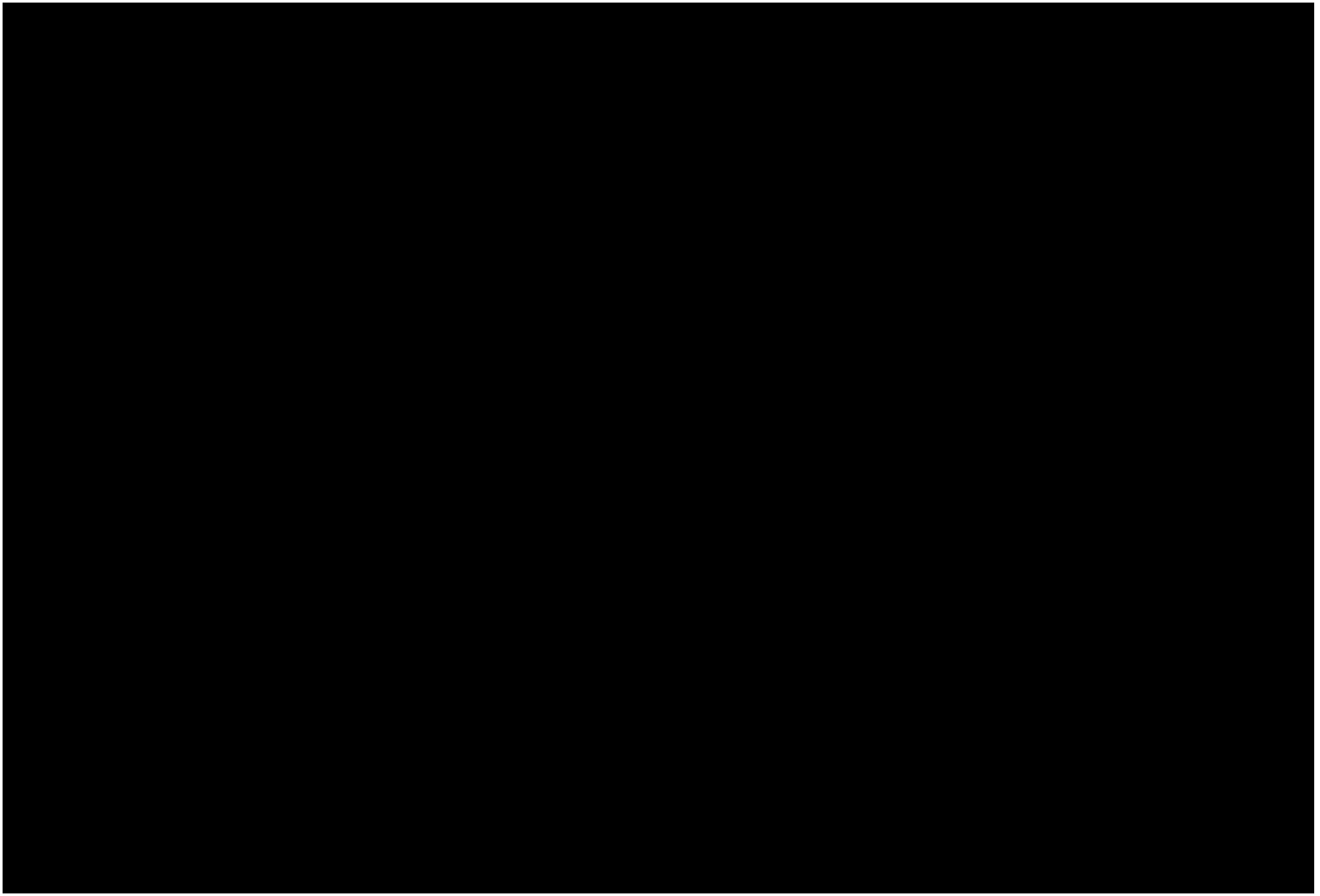
Date of On Peak Day - 05/13/2021



Member Forecasted On Peak Demand Day for June 2021

Wheatland Rural Electric Association, Inc.

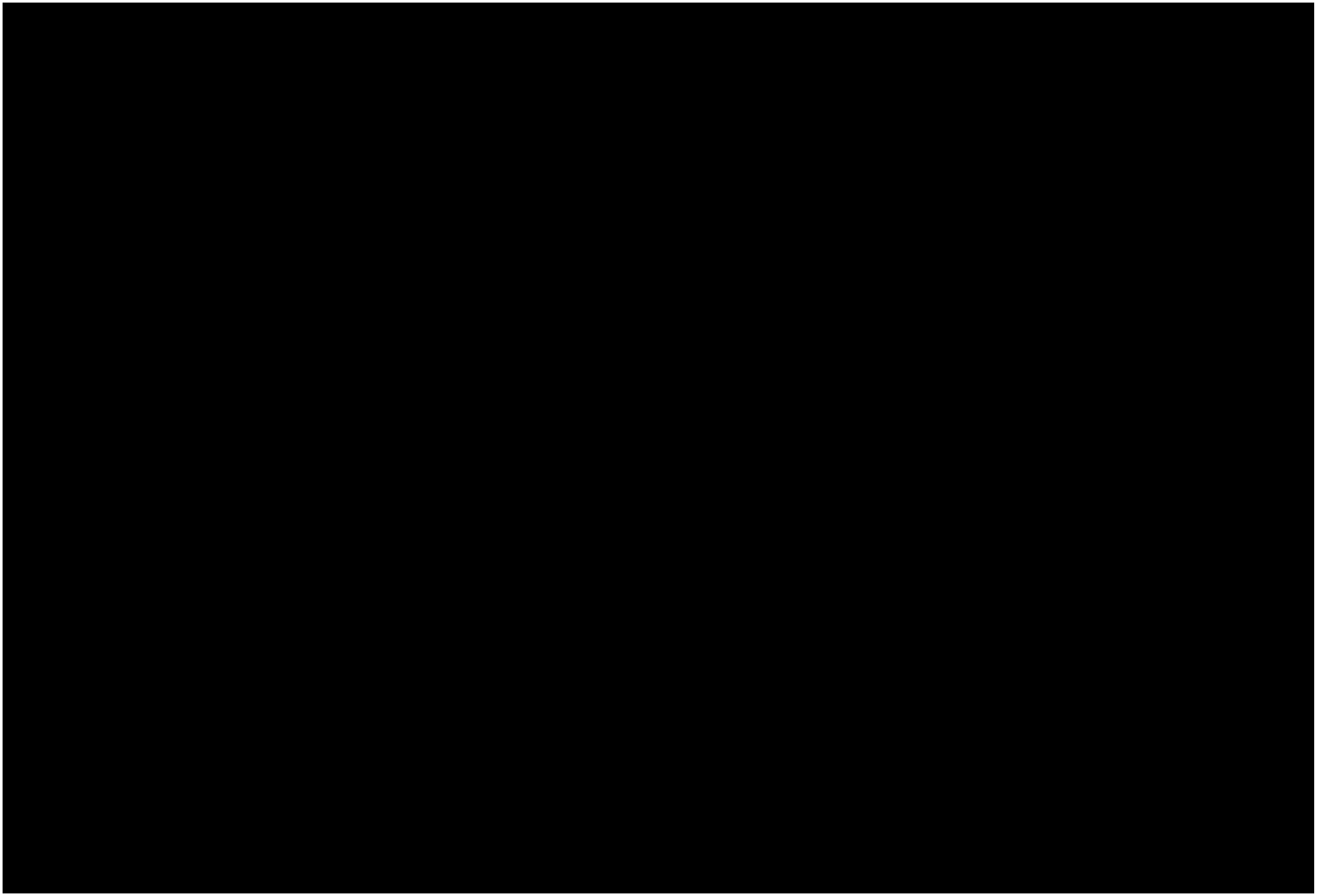
Date of On Peak Day - 06/11/2021



Member Forecasted On Peak Demand Day for July 2021

Wheatland Rural Electric Association, Inc.

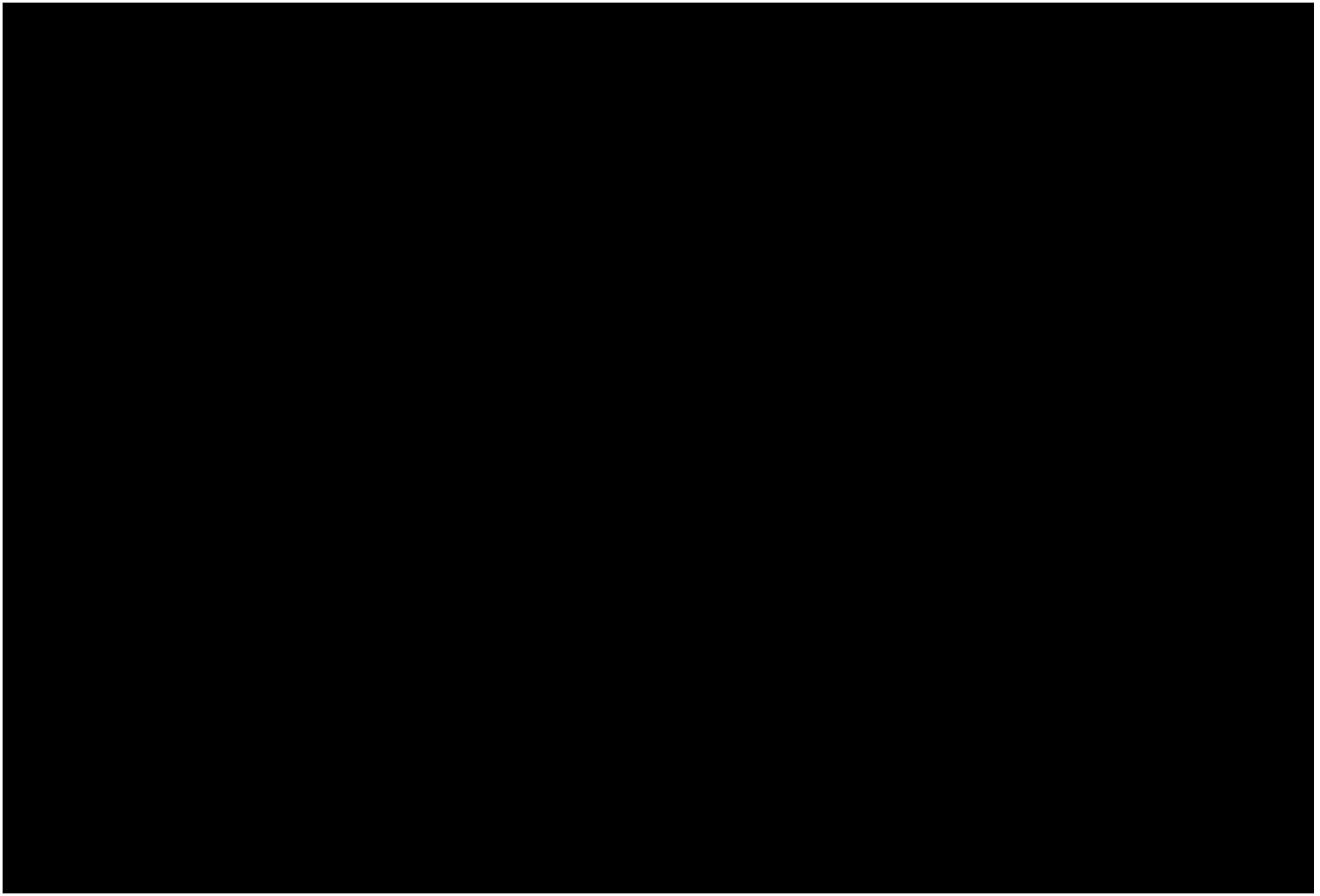
Date of On Peak Day - 07/25/2021



Member Forecasted On Peak Demand Day for August 2021

Wheatland Rural Electric Association, Inc.

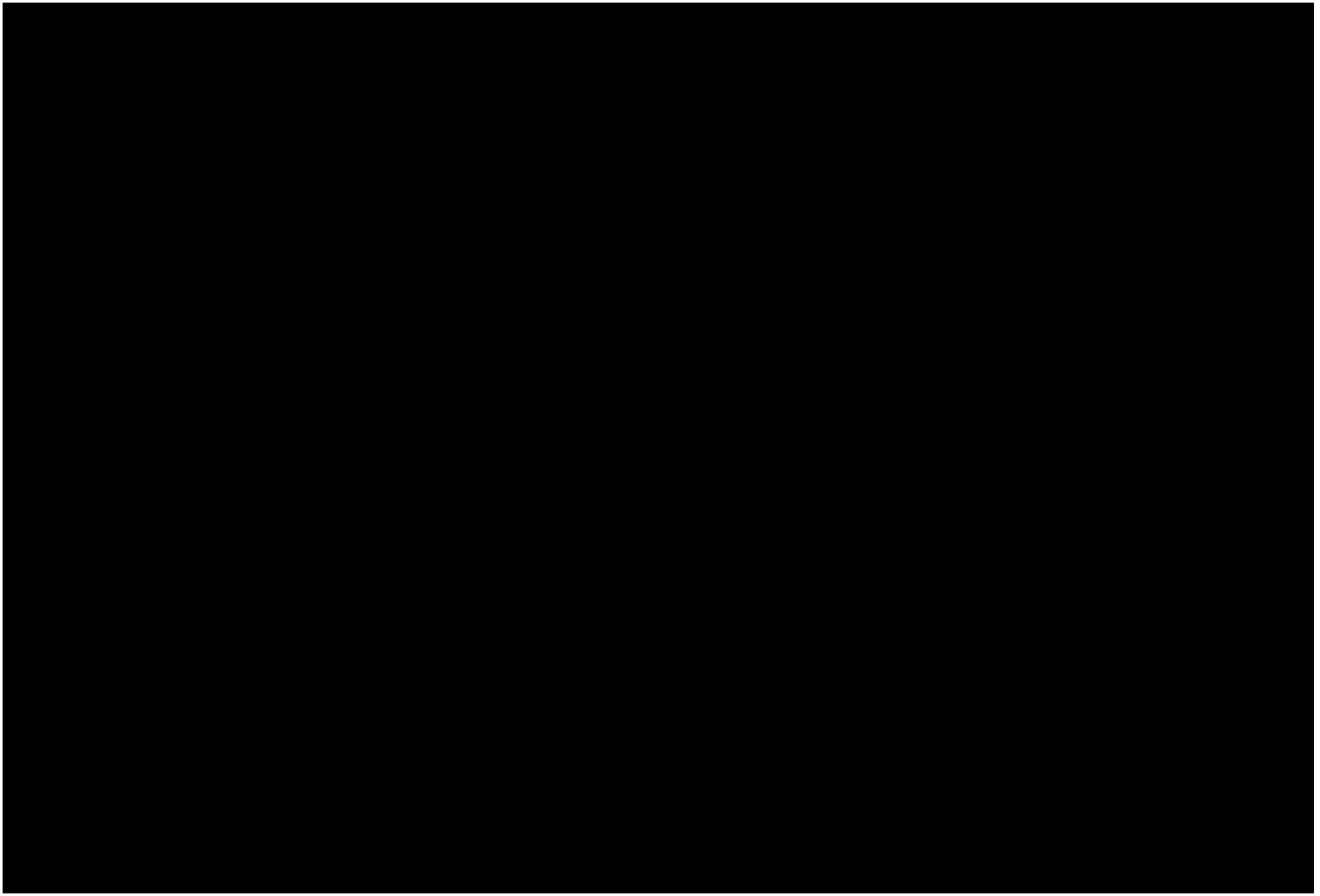
Date of On Peak Day - 08/31/2021



Member Forecasted On Peak Demand Day for September 2021

Wheatland Rural Electric Association, Inc.

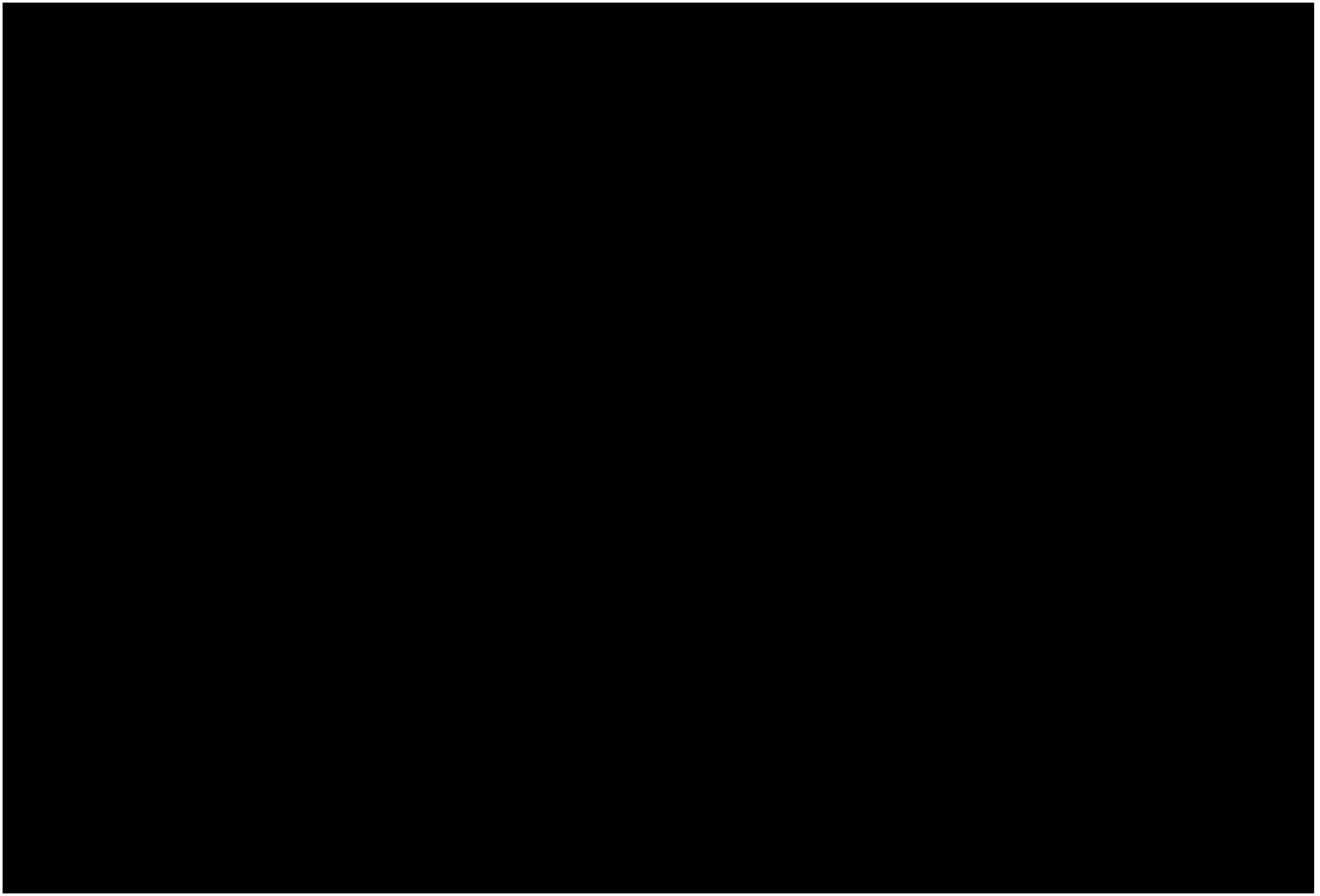
Date of On Peak Day - 09/03/2021



Member Forecasted On Peak Demand Day for October 2021

Wheatland Rural Electric Association, Inc.

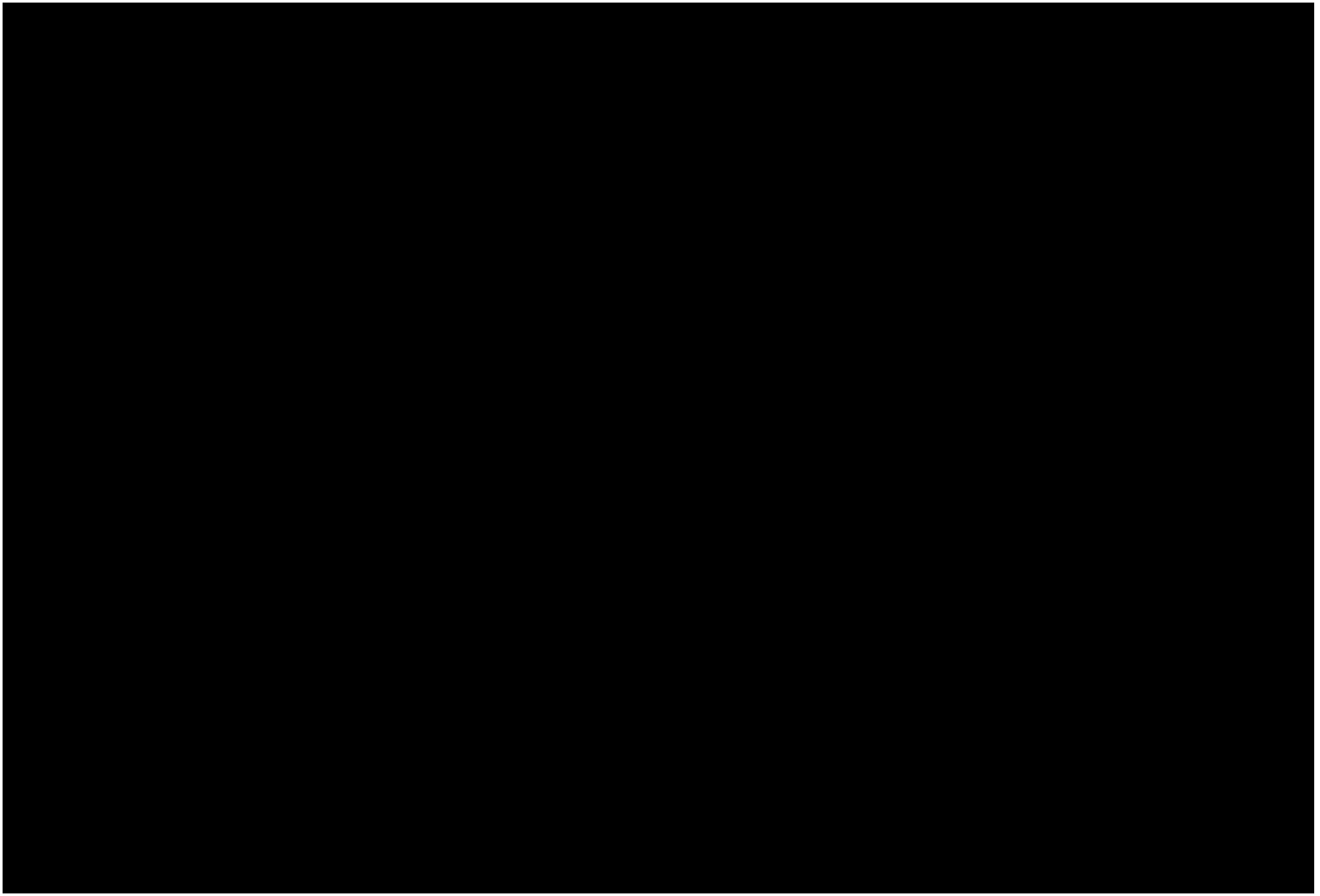
Date of On Peak Day - 10/14/2021



Member Forecasted On Peak Demand Day for November 2021

Wheatland Rural Electric Association, Inc.

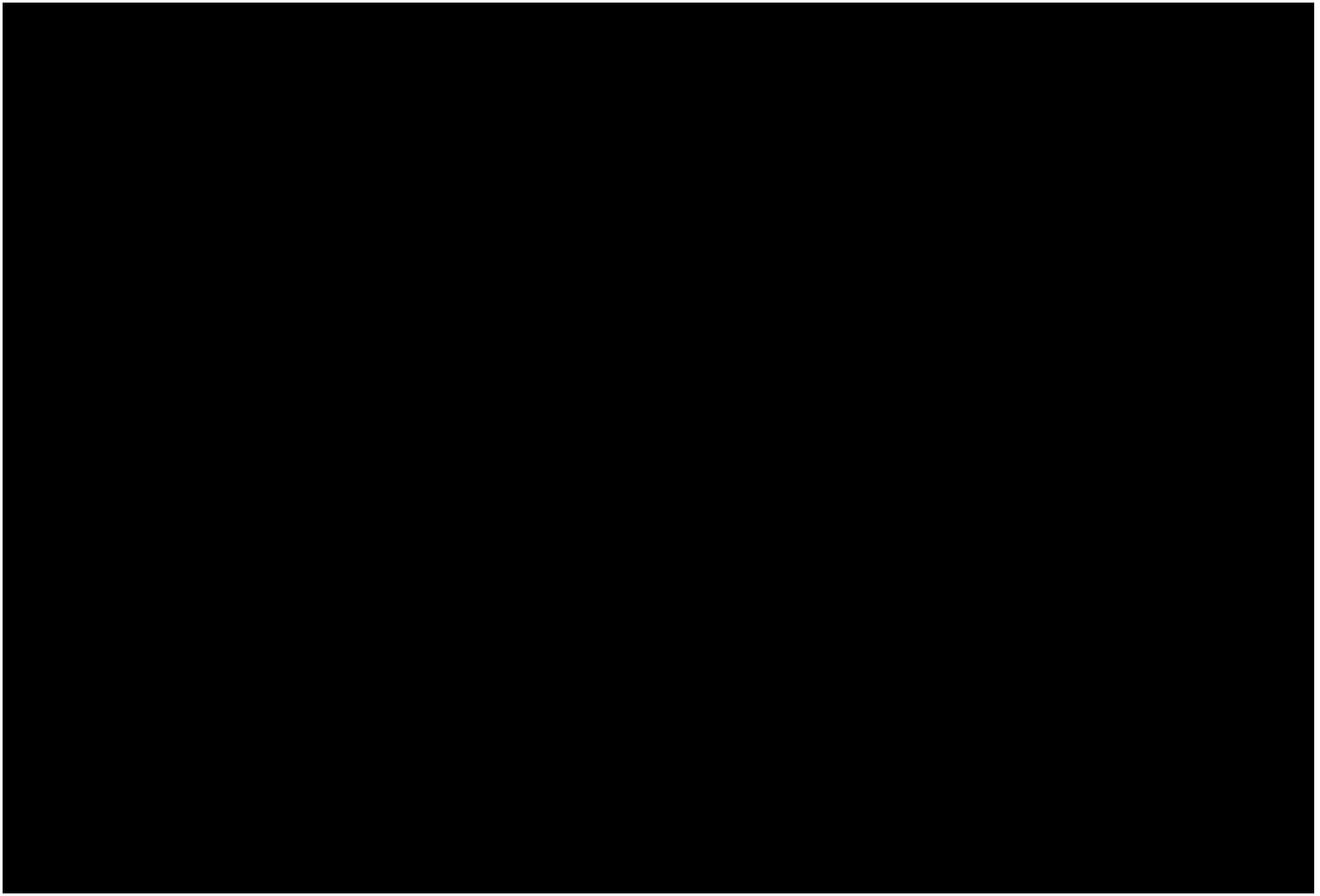
Date of On Peak Day - 11/28/2021



Member Forecasted On Peak Demand Day for December 2021

Wheatland Rural Electric Association, Inc.

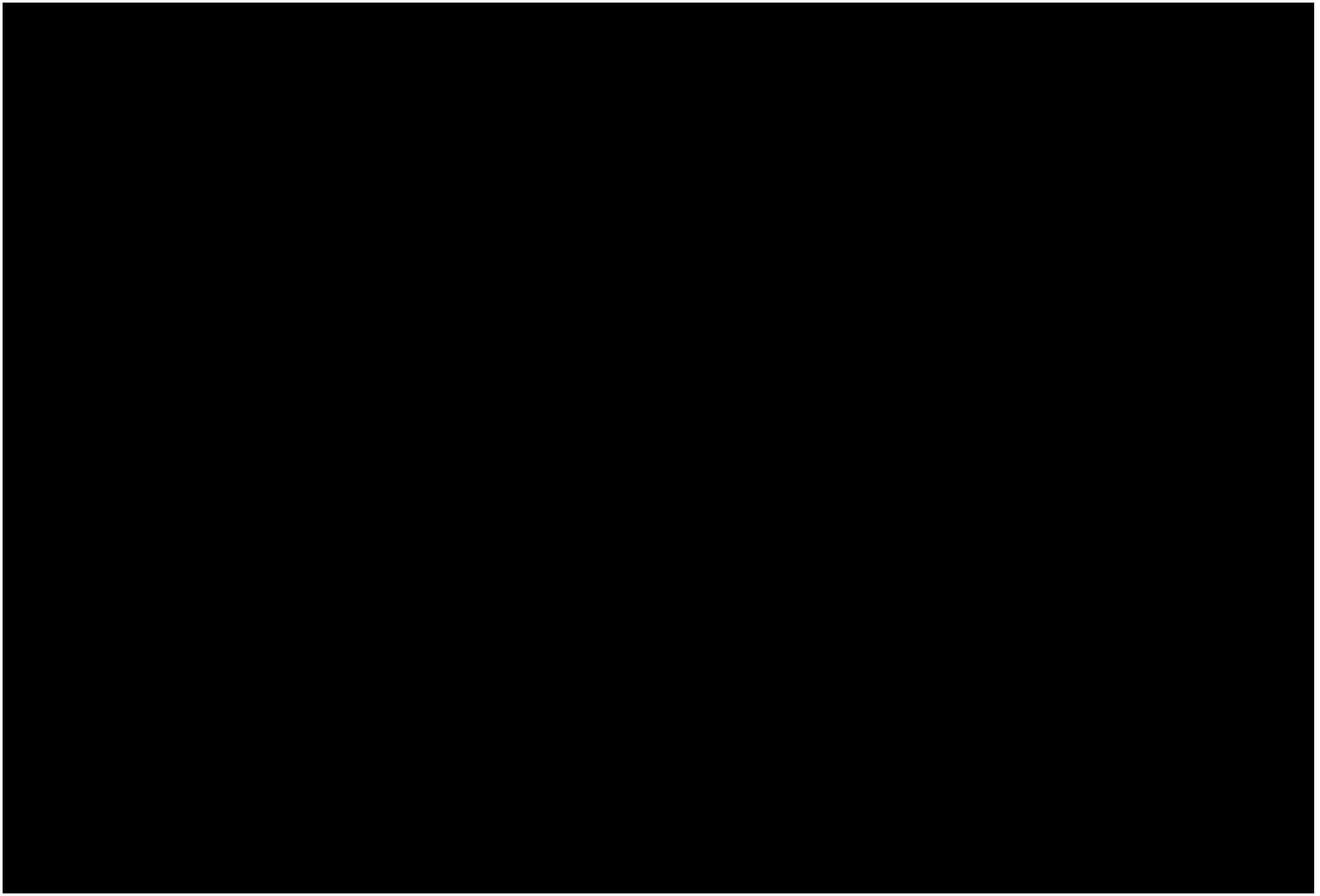
Date of On Peak Day - 12/02/2021



Member Forecasted On Peak Demand Day for January 2021

White River Electric Association, Inc.

Date of On Peak Day - 01/28/2021



Member Forecasted On Peak Demand Day for February 2021

White River Electric Association, Inc.

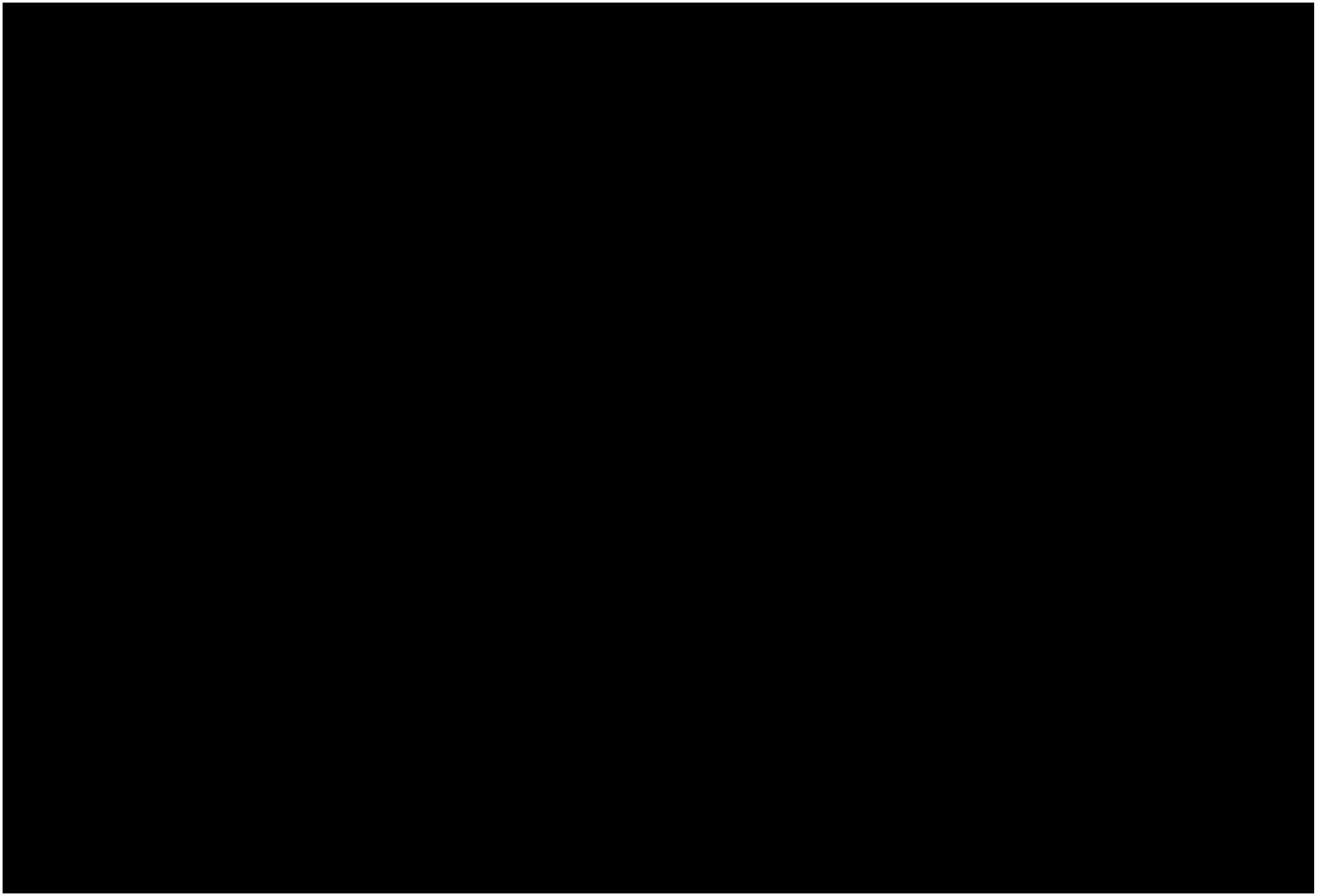
Date of On Peak Day - 02/02/2021

[redacted]

Member Forecasted On Peak Demand Day for March 2021

White River Electric Association, Inc.

Date of On Peak Day - 03/30/2021



Member Forecasted On Peak Demand Day for April 2021

White River Electric Association, Inc.

Date of On Peak Day - 04/01/2021

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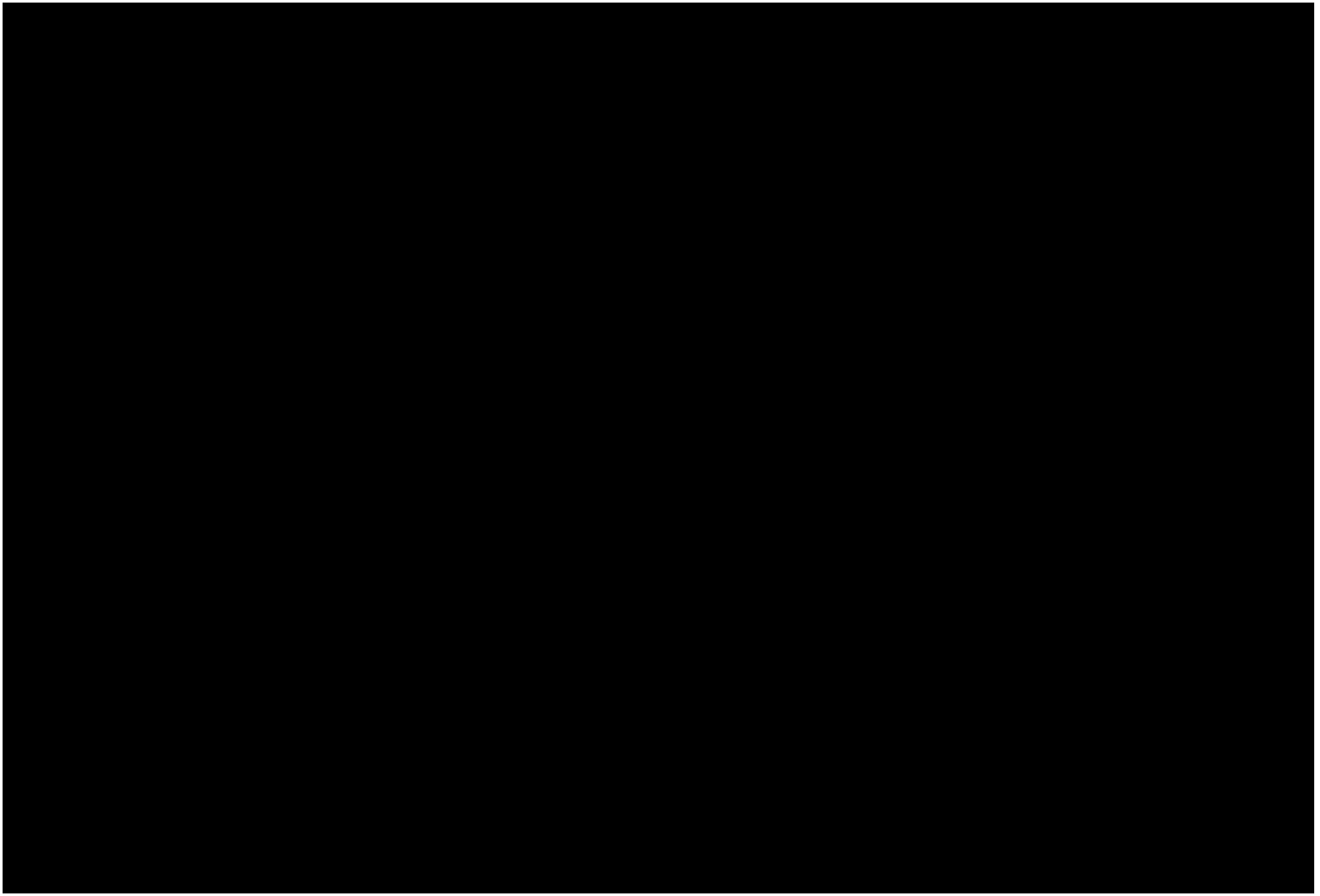
Member Forecasted On Peak Demand Day for May 2021

White River Electric Association, Inc.

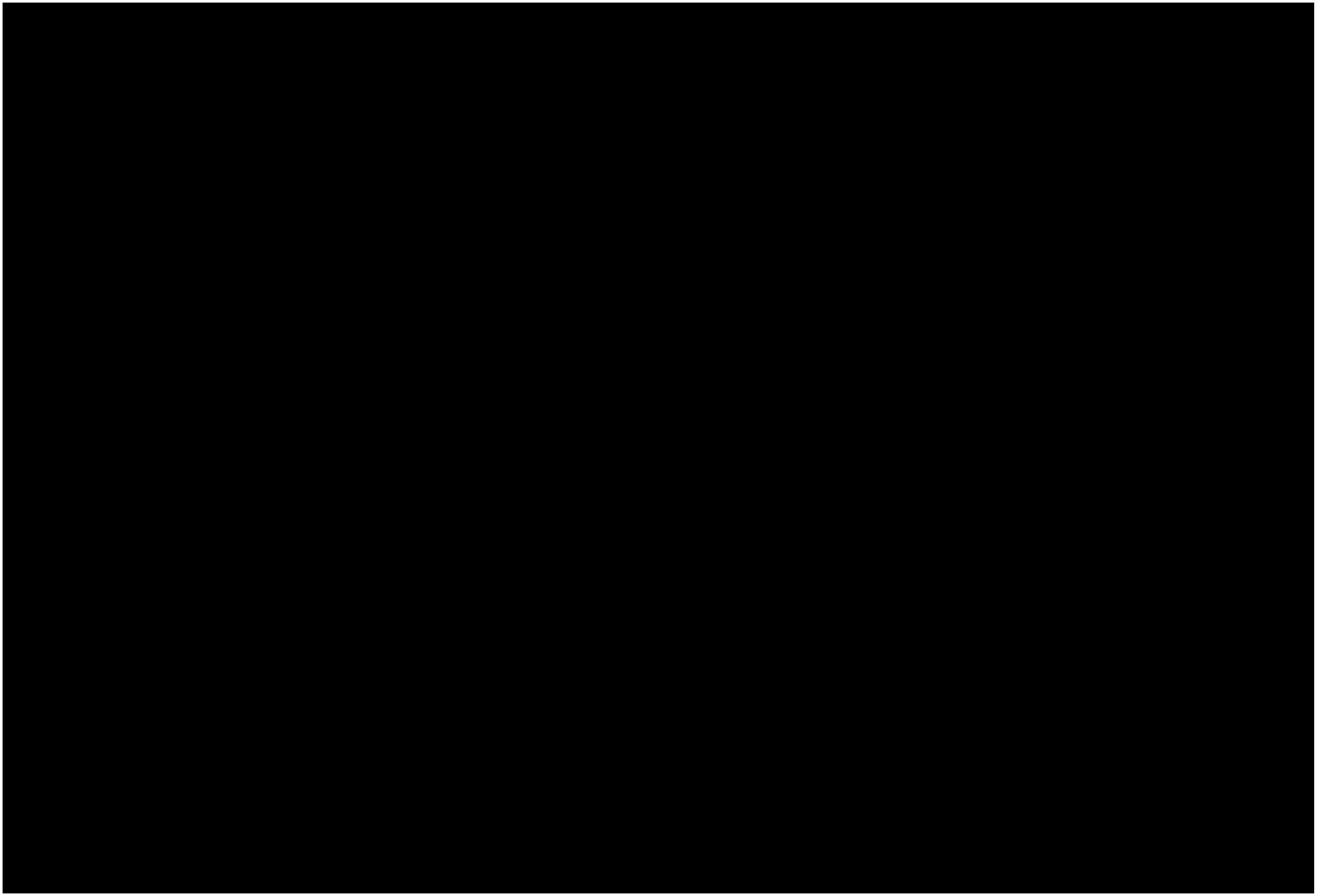
Date of On Peak Day - 05/03/2021



Member Forecasted On Peak Demand Day for June 2021

White River Electric Association, Inc.

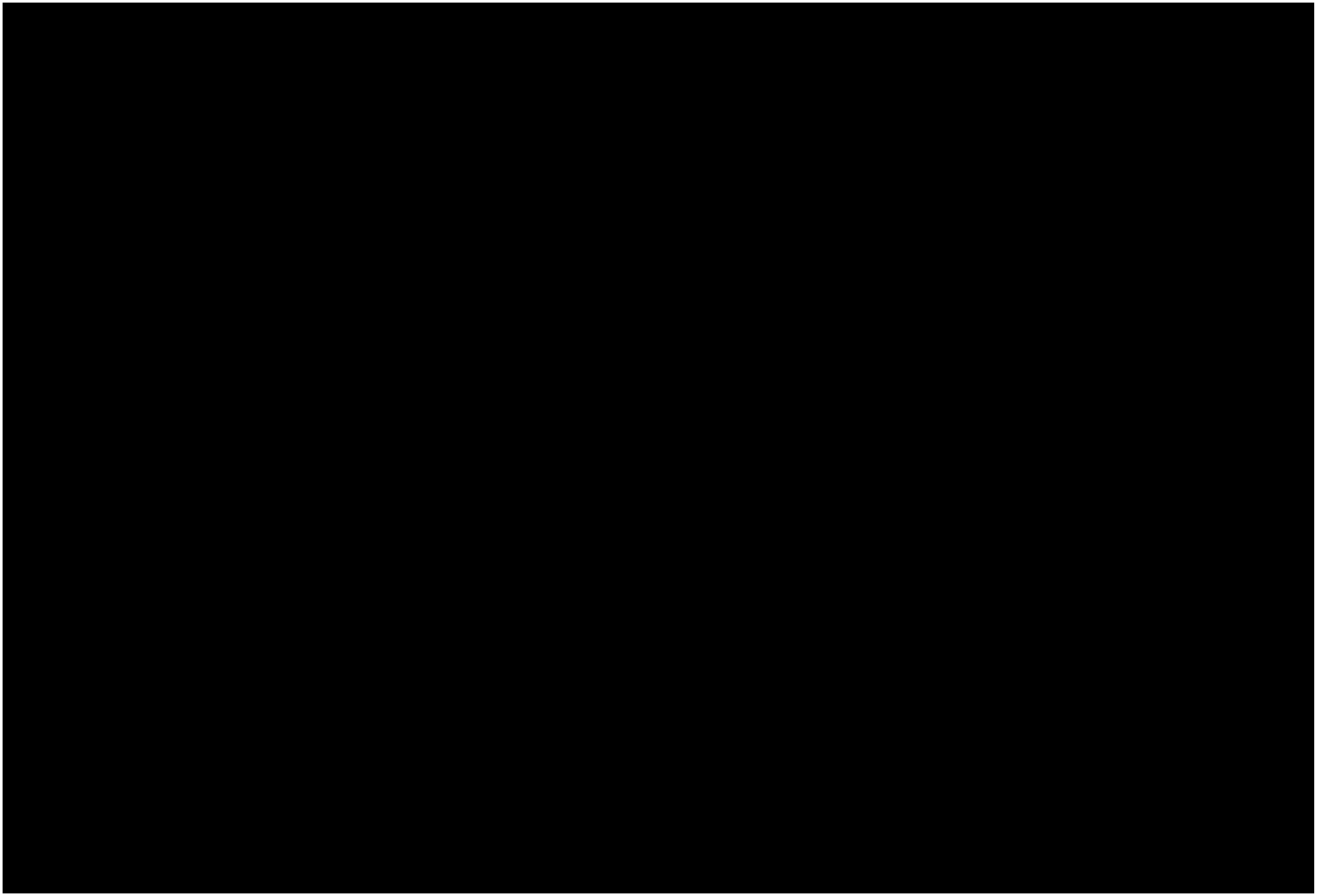
Date of On Peak Day - 06/03/2021



Member Forecasted On Peak Demand Day for July 2021

White River Electric Association, Inc.

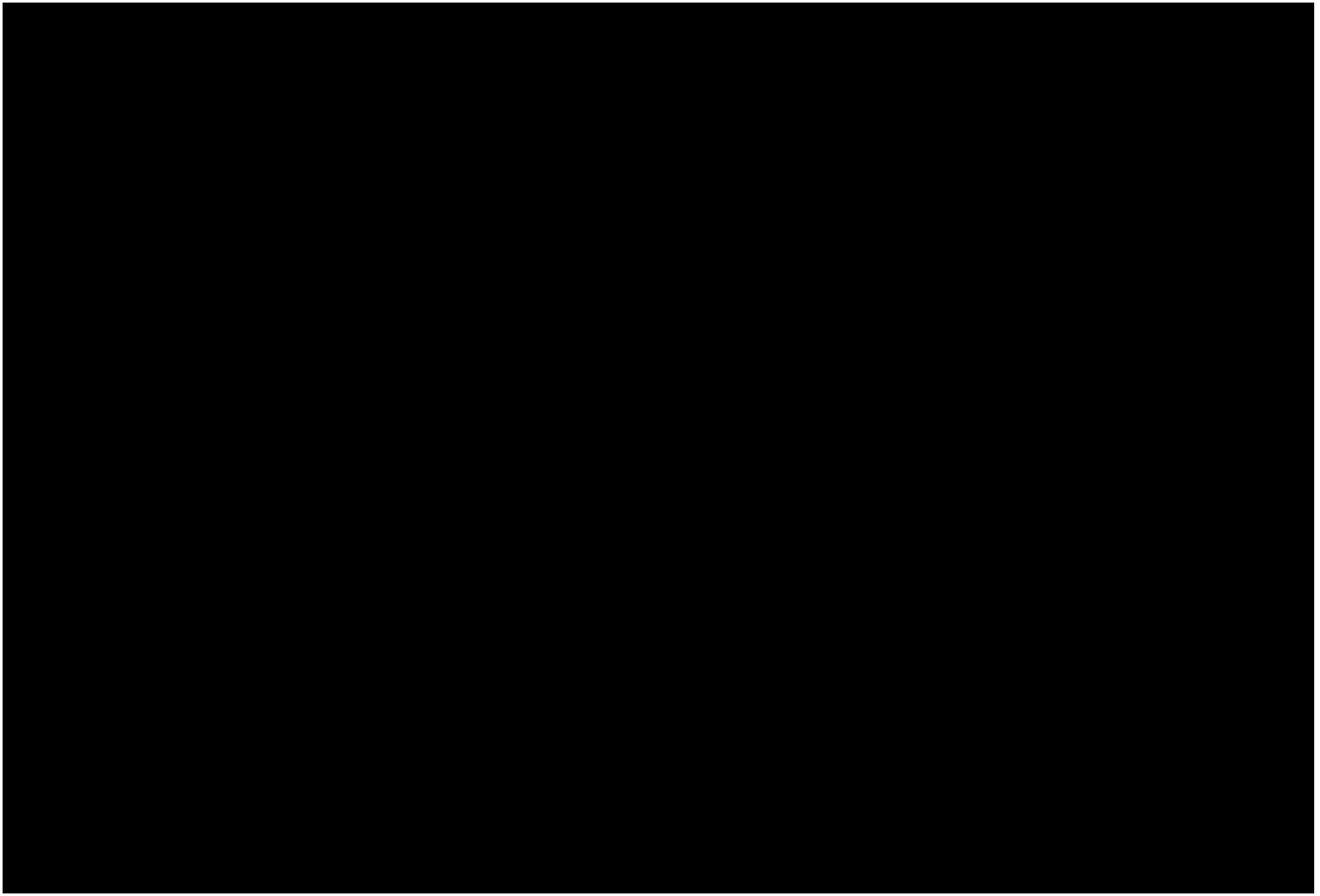
Date of On Peak Day - 07/06/2021



Member Forecasted On Peak Demand Day for August 2021

White River Electric Association, Inc.

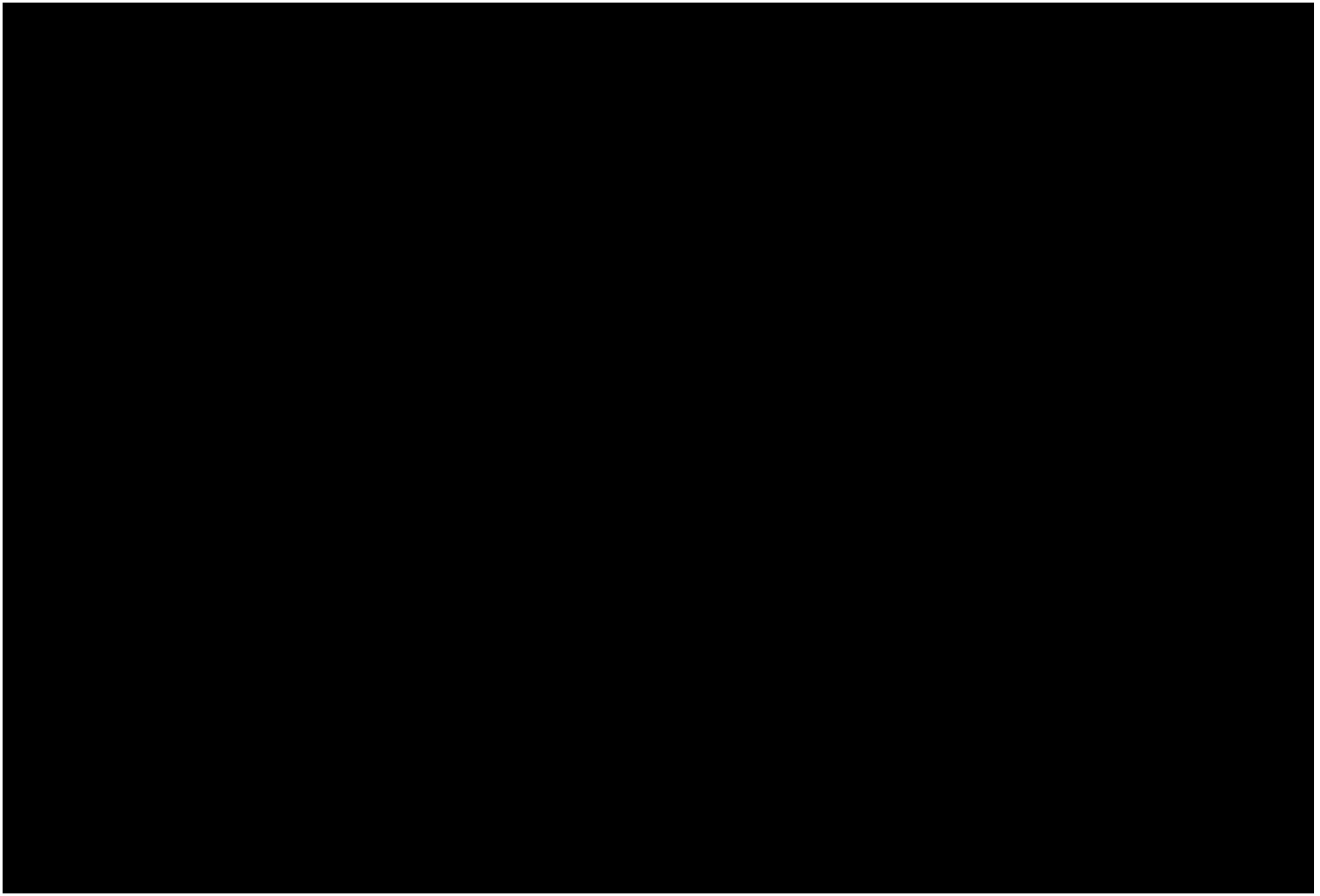
Date of On Peak Day - 08/30/2021



Member Forecasted On Peak Demand Day for September 2021

White River Electric Association, Inc.

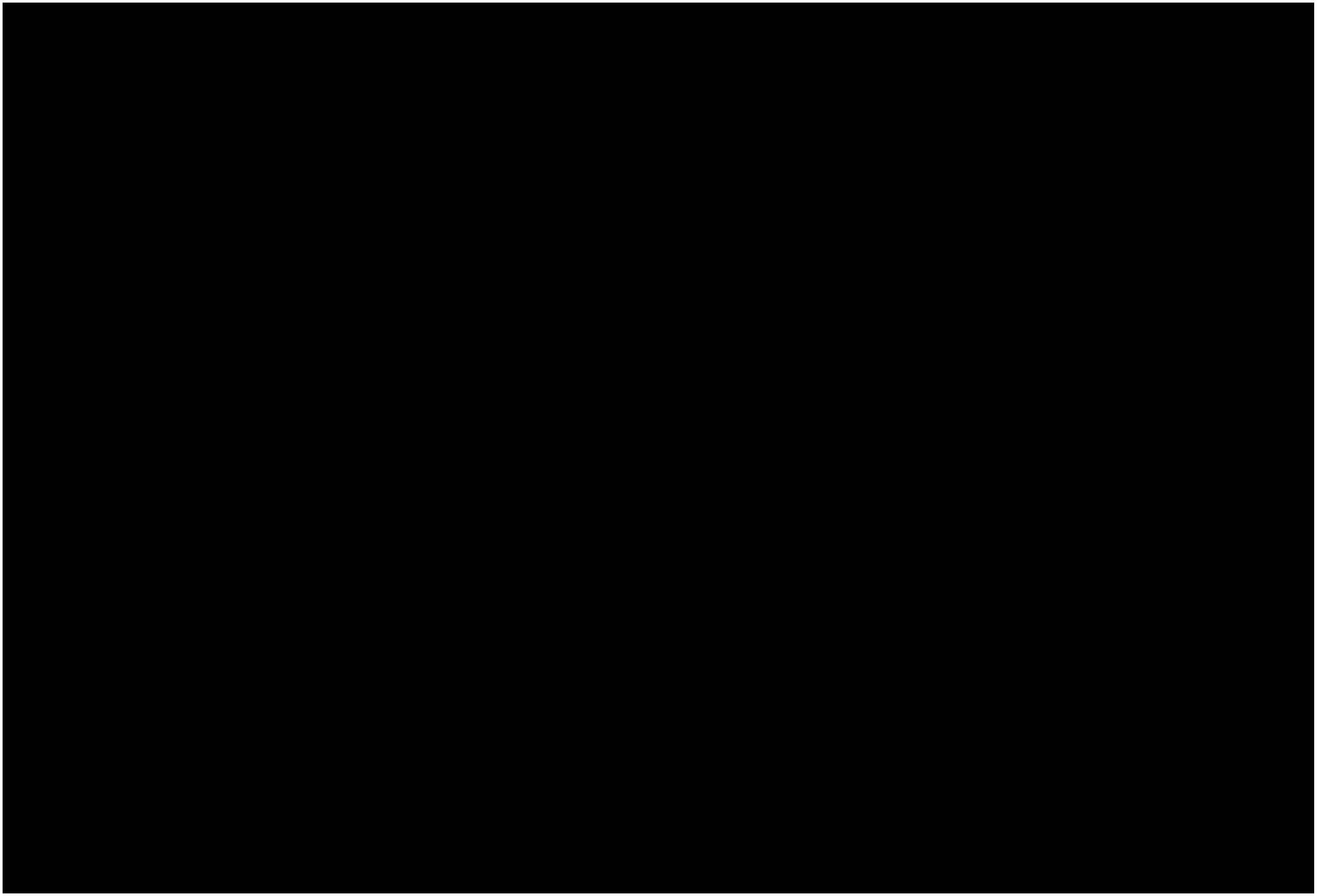
Date of On Peak Day - 09/03/2021



Member Forecasted On Peak Demand Day for October 2021

White River Electric Association, Inc.

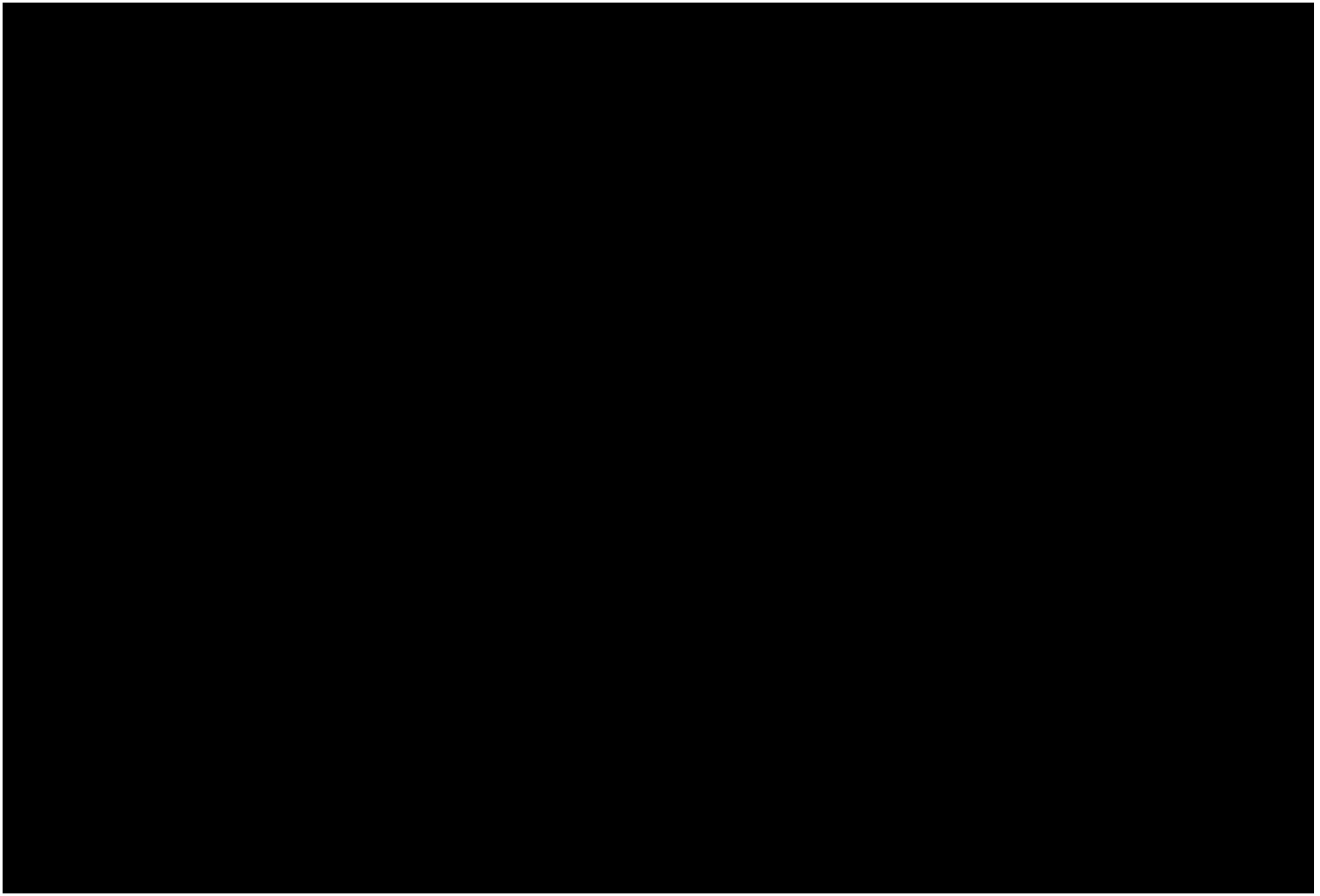
Date of On Peak Day - 10/28/2021



Member Forecasted On Peak Demand Day for November 2021

White River Electric Association, Inc.

Date of On Peak Day - 11/04/2021



Member Forecasted On Peak Demand Day for December 2021

White River Electric Association, Inc.

Date of On Peak Day - 12/30/2021

[redacted]

Member Forecasted On Peak Demand Day for January 2021

Wyrulec Company

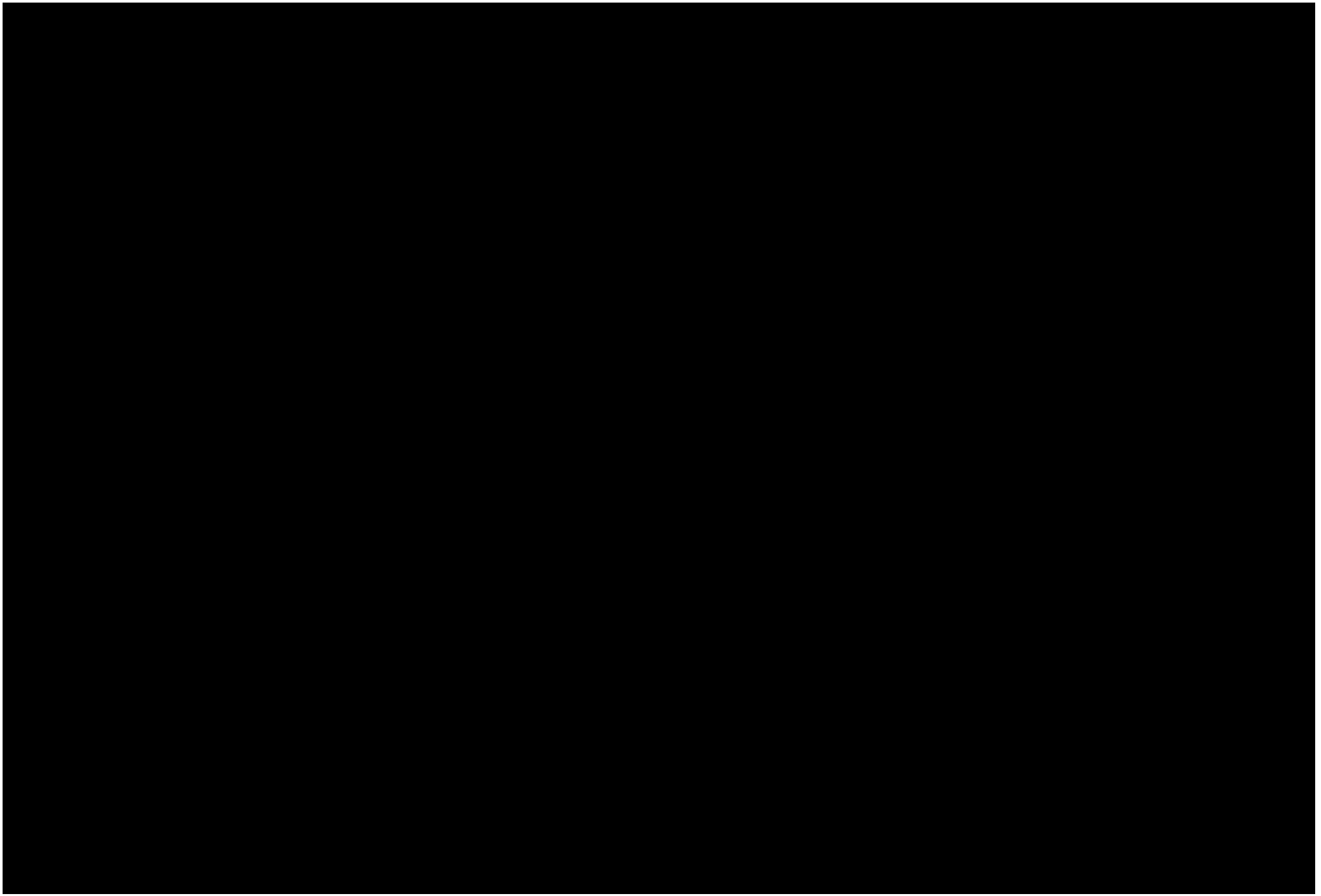
Date of On Peak Day - 01/25/2021

[redacted]

Member Forecasted On Peak Demand Day for February 2021

Wyrulec Company

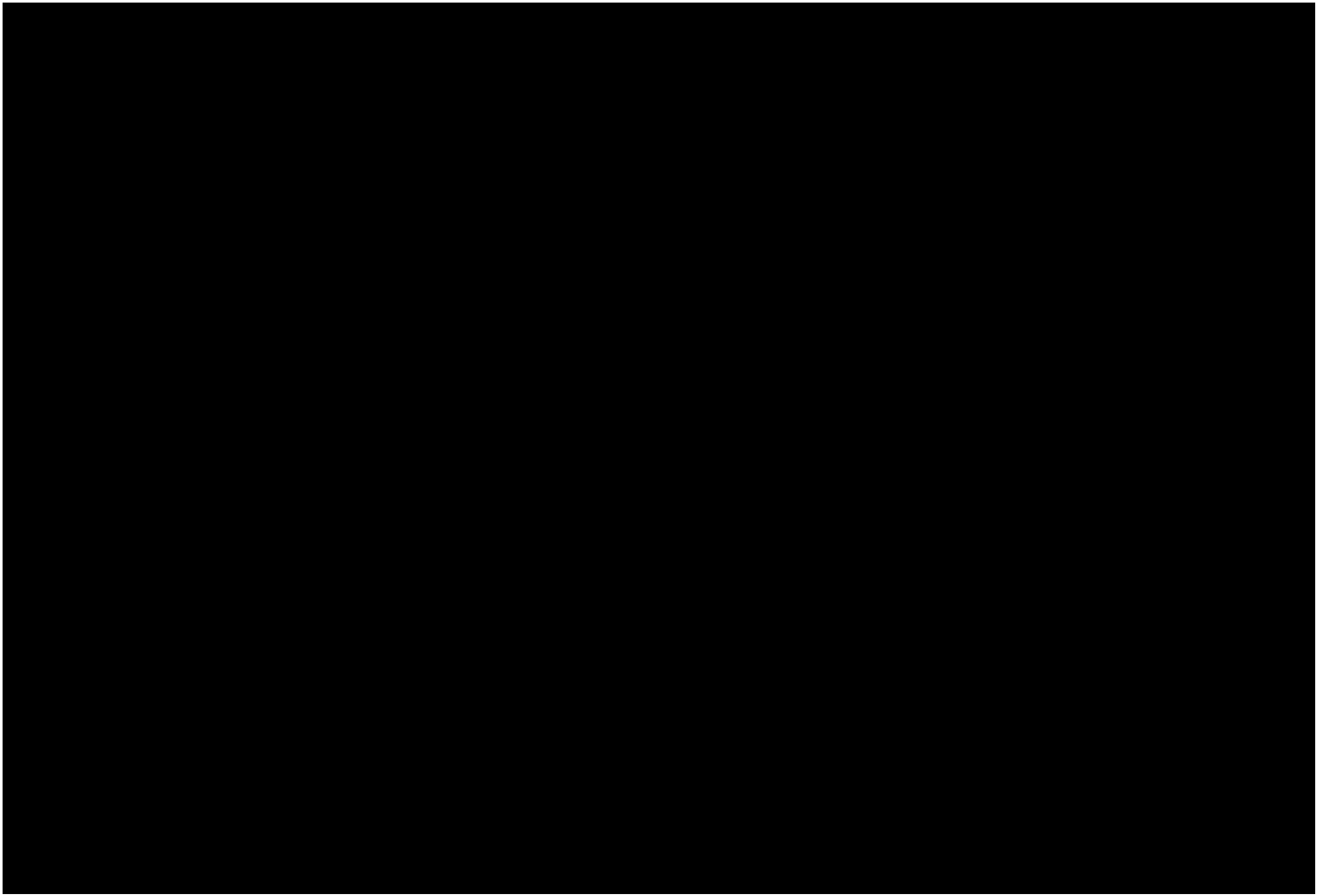
Date of On Peak Day - 02/24/2021



Member Forecasted On Peak Demand Day for March 2021

Wyrulec Company

Date of On Peak Day - 03/04/2021



Member Forecasted On Peak Demand Day for April 2021

Wyrulec Company

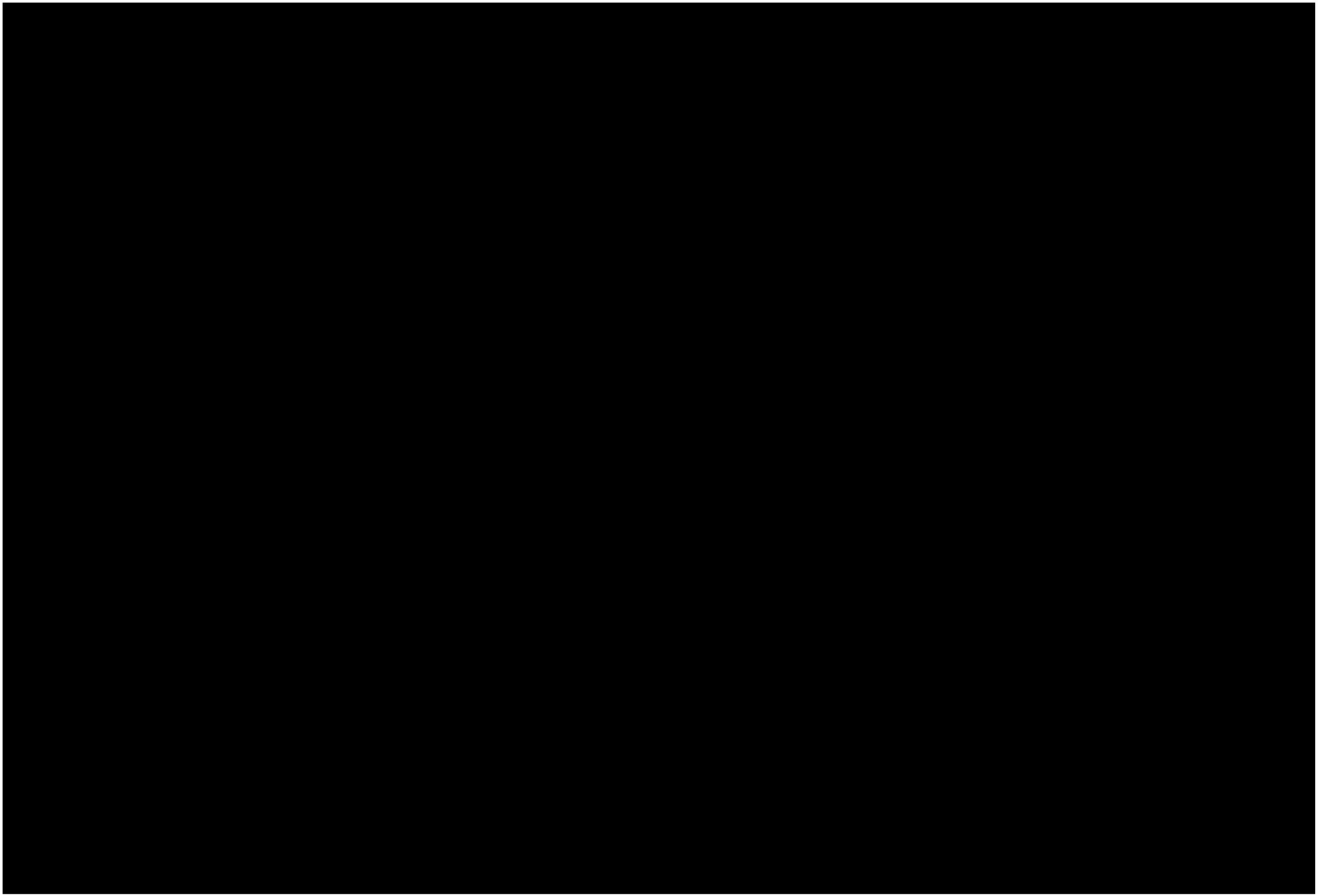
Date of On Peak Day - 04/04/2021

[redacted]

Member Forecasted On Peak Demand Day for May 2021

Wyrulec Company

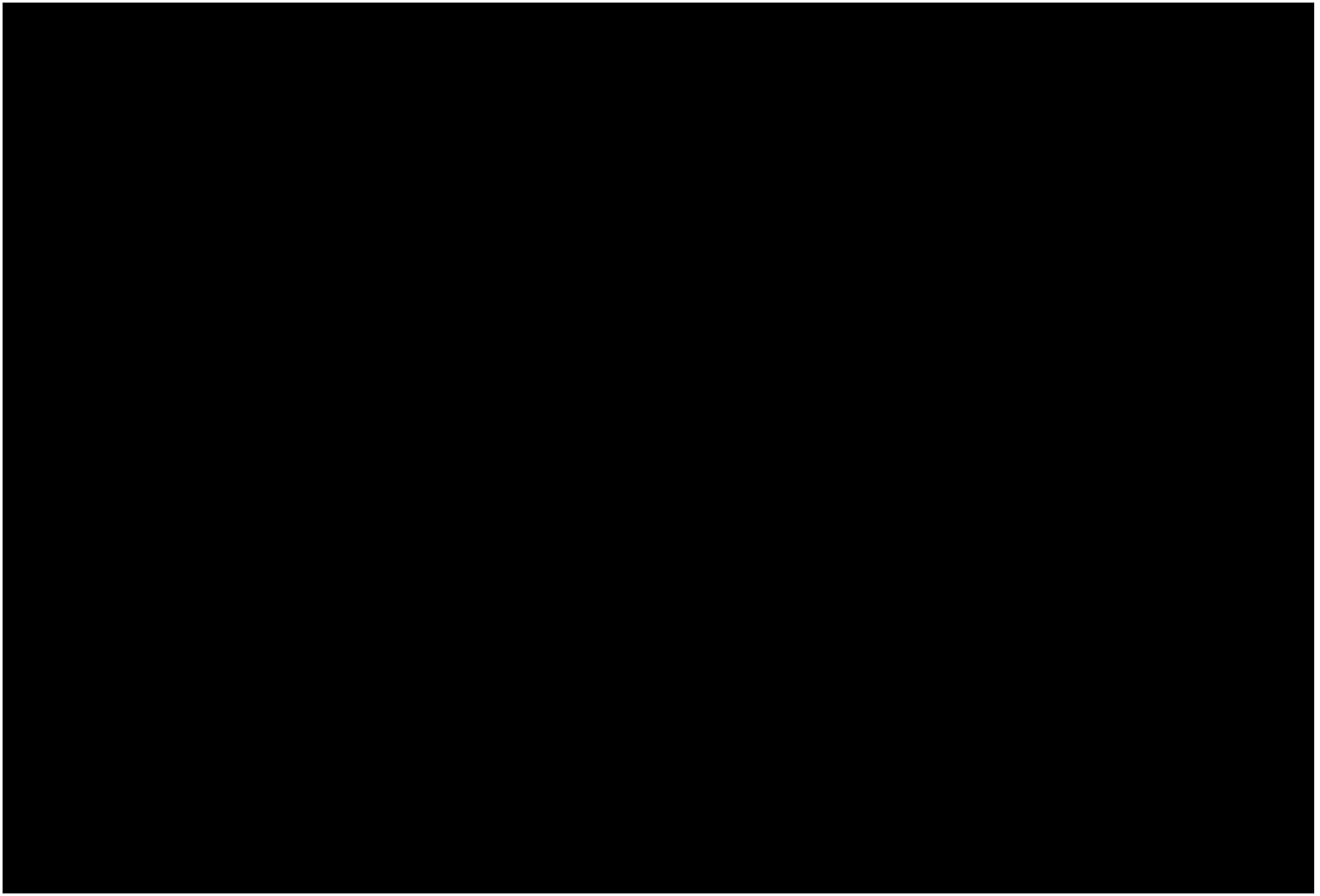
Date of On Peak Day - 05/13/2021



Member Forecasted On Peak Demand Day for June 2021

Wyrulec Company

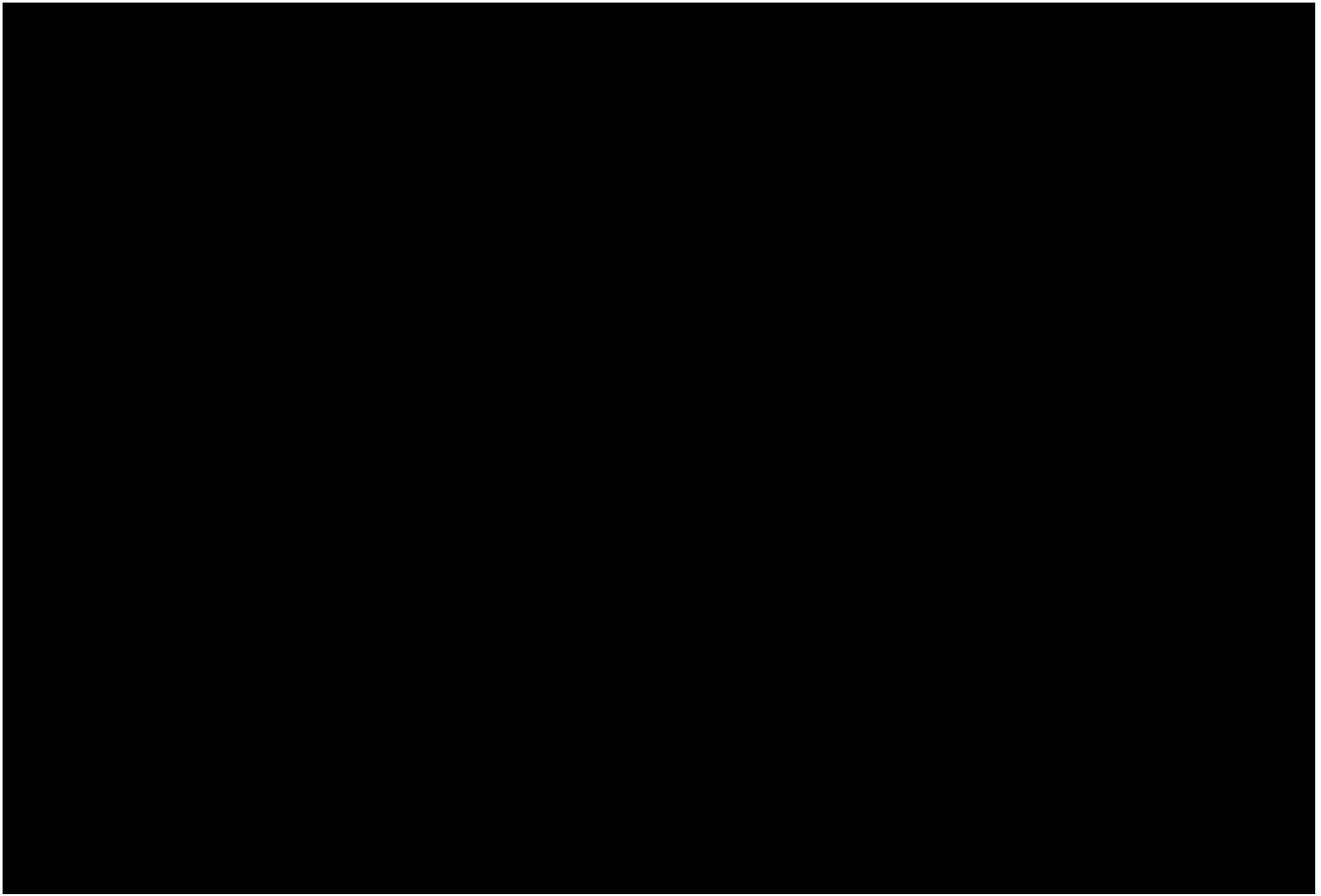
Date of On Peak Day - 06/28/2021



Member Forecasted On Peak Demand Day for July 2021

Wyrulec Company

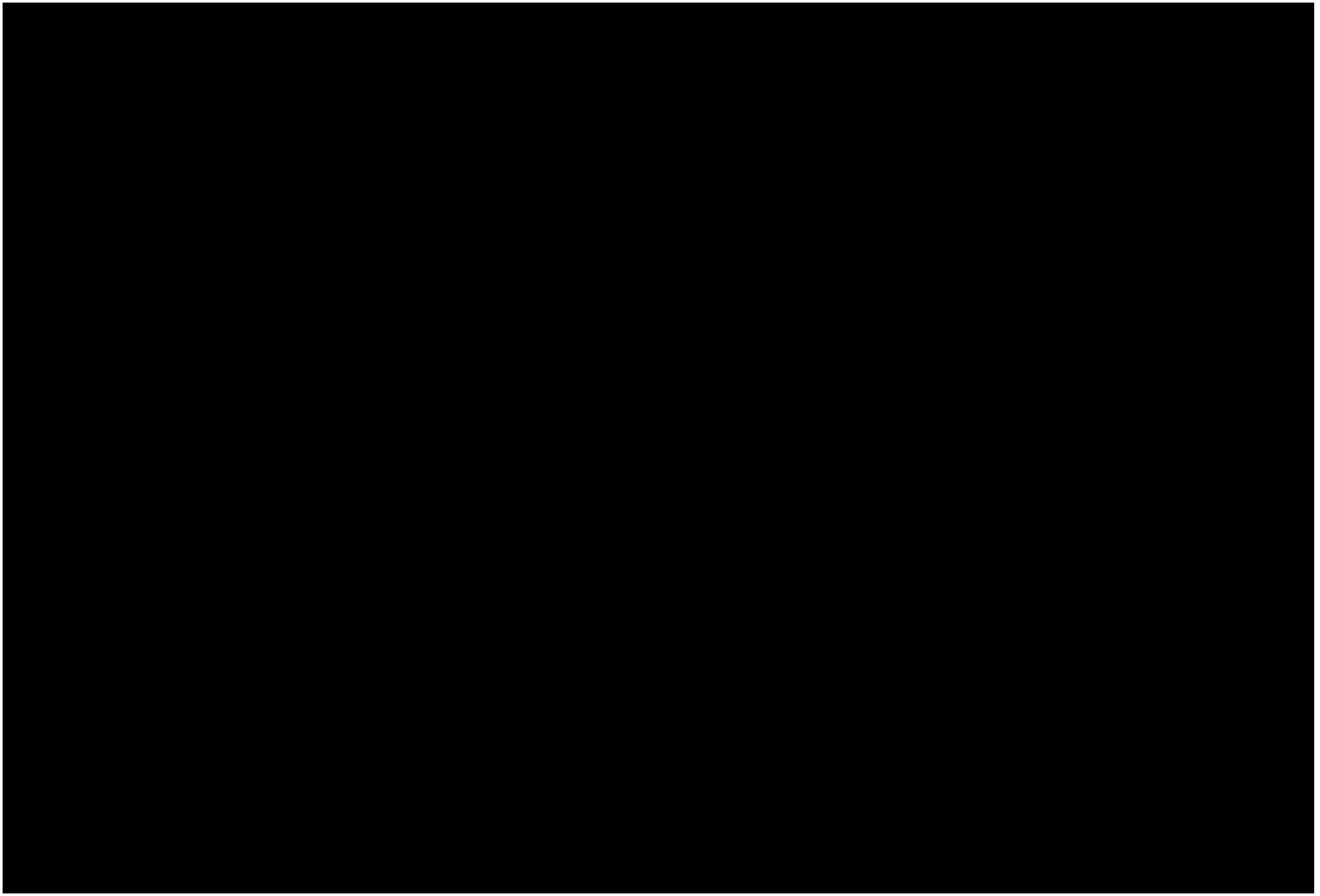
Date of On Peak Day - 07/22/2021



Member Forecasted On Peak Demand Day for August 2021

Wyrulec Company

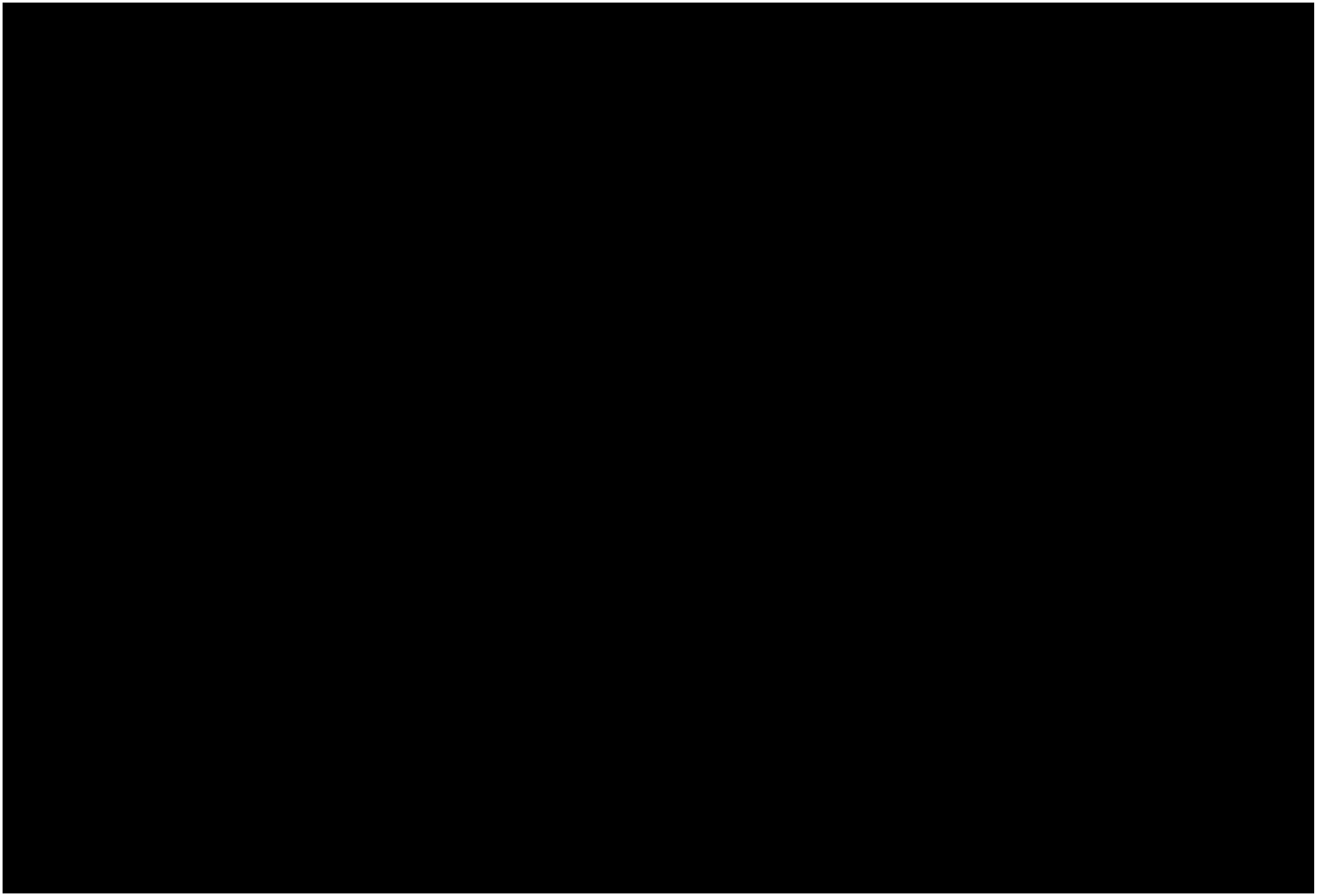
Date of On Peak Day - 08/01/2021



Member Forecasted On Peak Demand Day for September 2021

Wyrulec Company

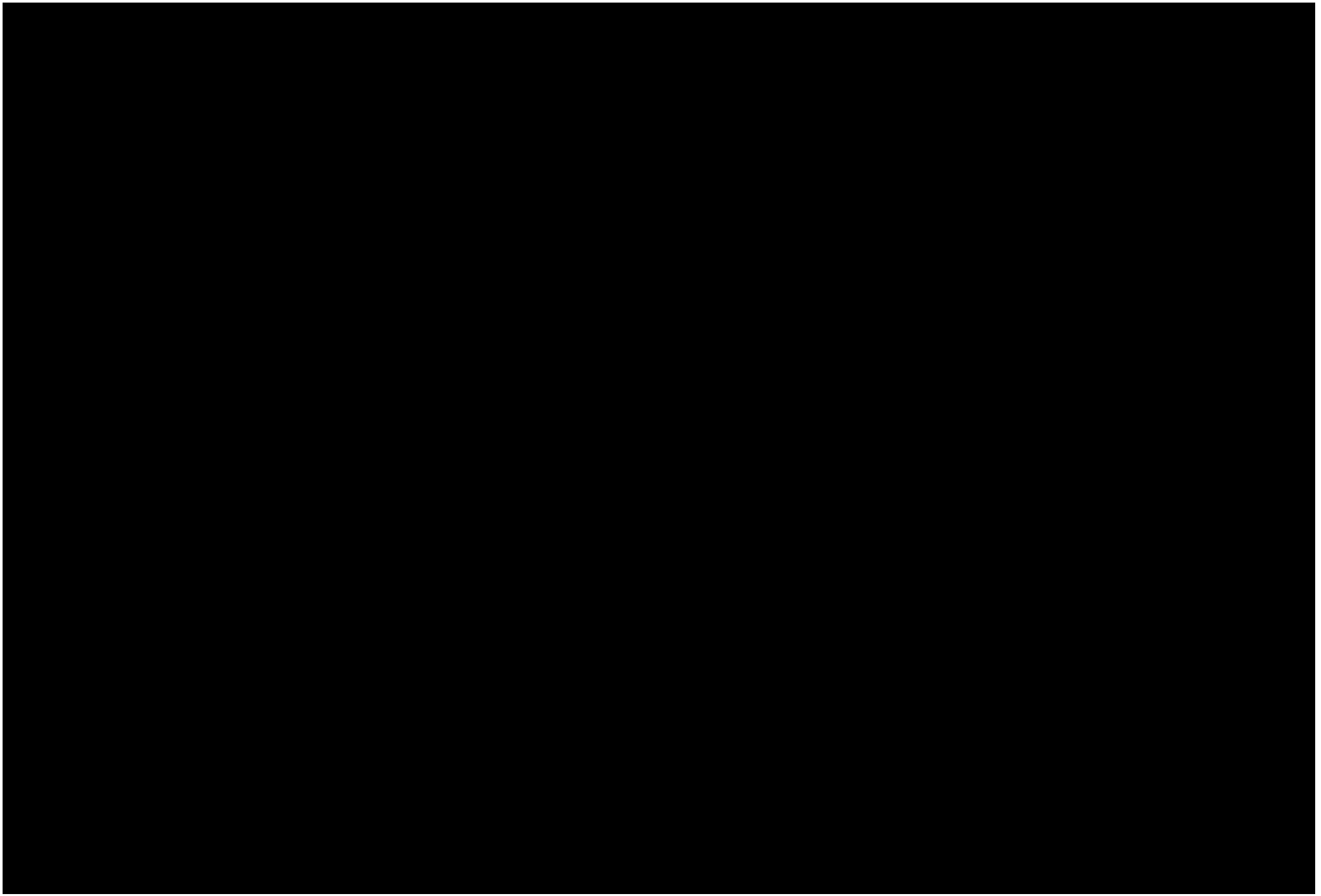
Date of On Peak Day - 09/02/2021



Member Forecasted On Peak Demand Day for October 2021

Wyrulec Company

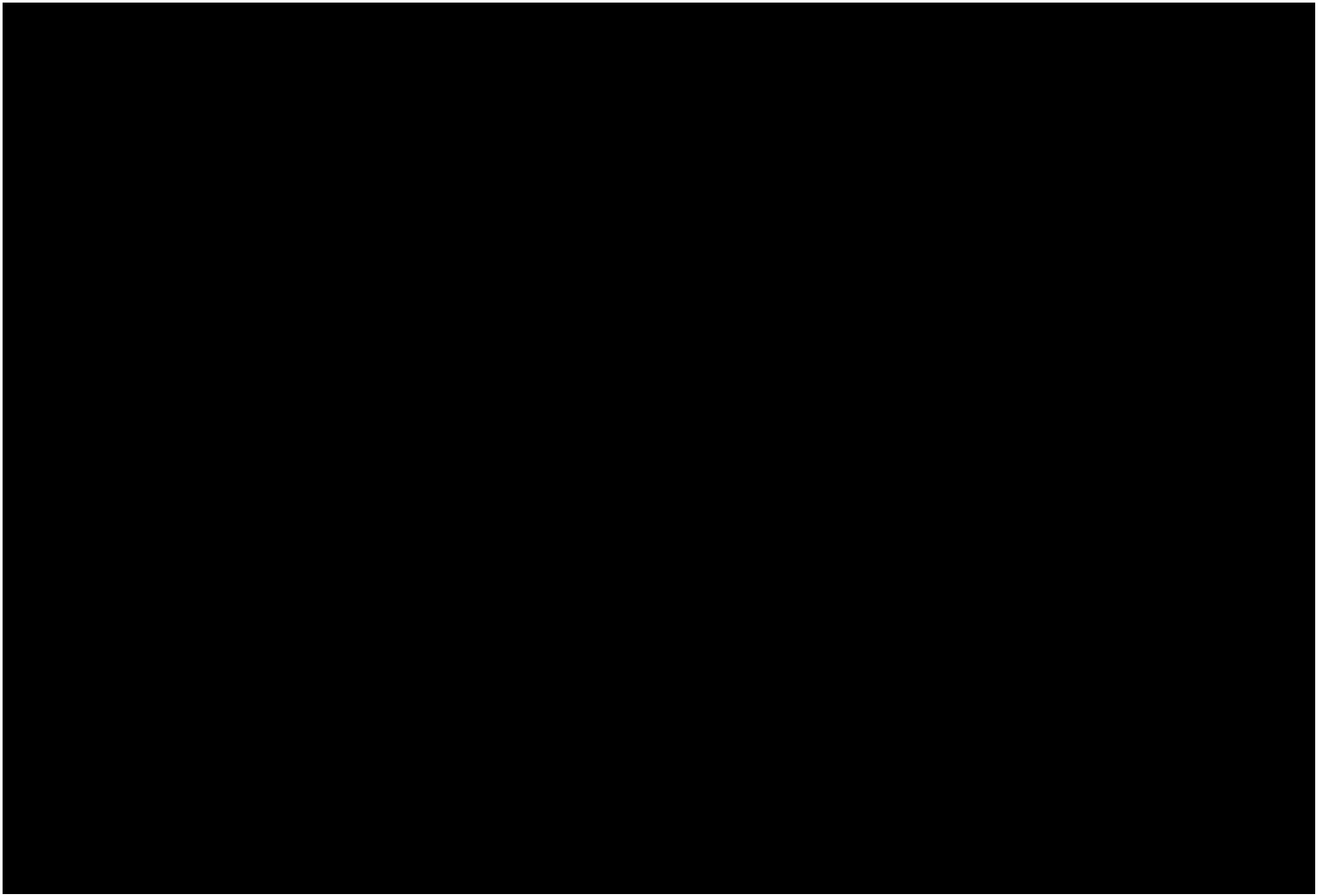
Date of On Peak Day - 10/27/2021



Member Forecasted On Peak Demand Day for November 2021

Wyrulec Company

Date of On Peak Day - 11/22/2021



Member Forecasted On Peak Demand Day for December 2021

Wyrulec Company

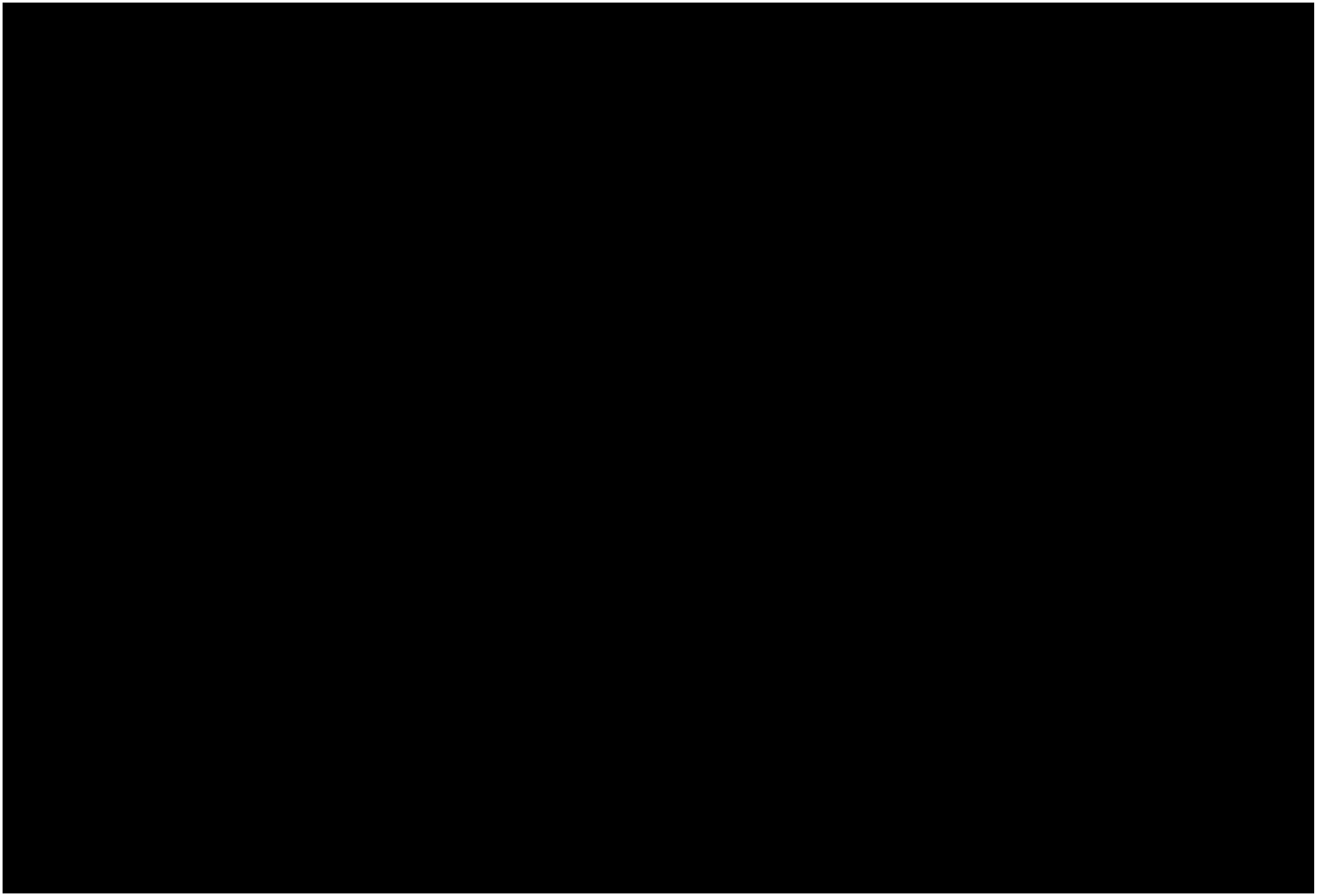
Date of On Peak Day - 12/27/2021

[redacted]

Member Forecasted On Peak Demand Day for January 2021

Y-W Electric Association, Inc.

Date of On Peak Day - 01/07/2021



Member Forecasted On Peak Demand Day for February 2021

Y-W Electric Association, Inc.

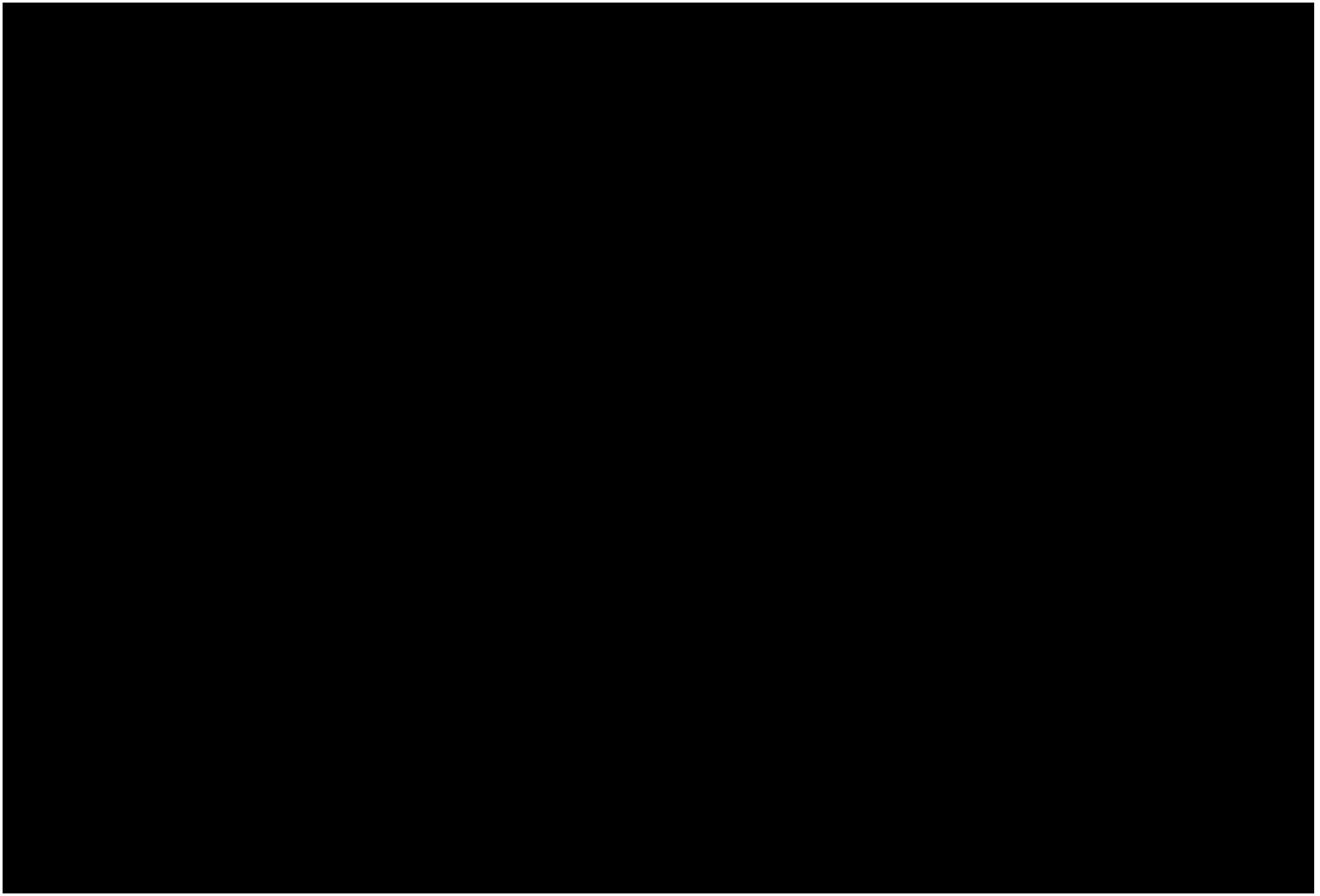
Date of On Peak Day - 02/25/2021

[redacted]

Member Forecasted On Peak Demand Day for March 2021

Y-W Electric Association, Inc.

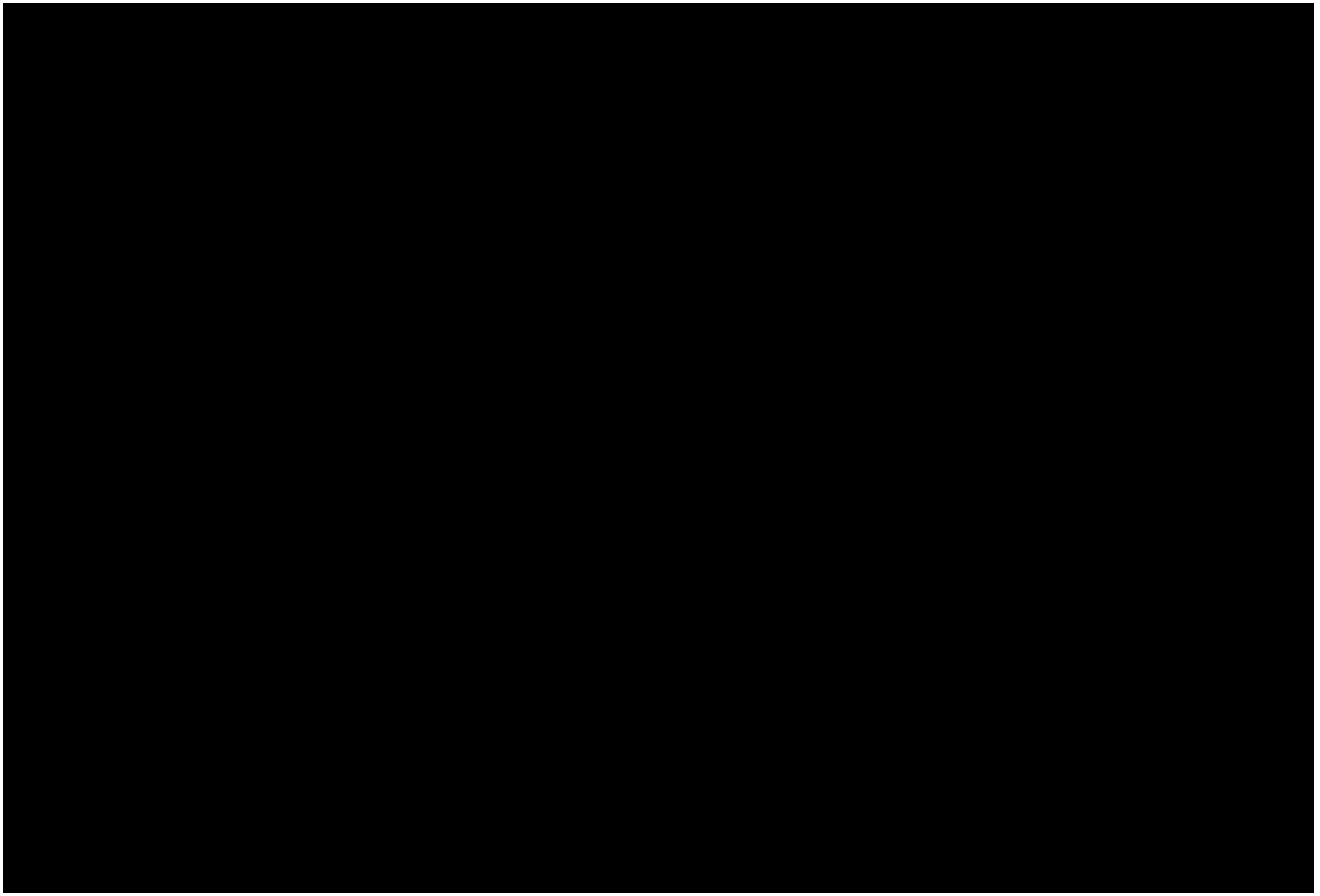
Date of On Peak Day - 03/18/2021



Member Forecasted On Peak Demand Day for April 2021

Y-W Electric Association, Inc.

Date of On Peak Day - 04/12/2021



Member Forecasted On Peak Demand Day for May 2021

Y-W Electric Association, Inc.

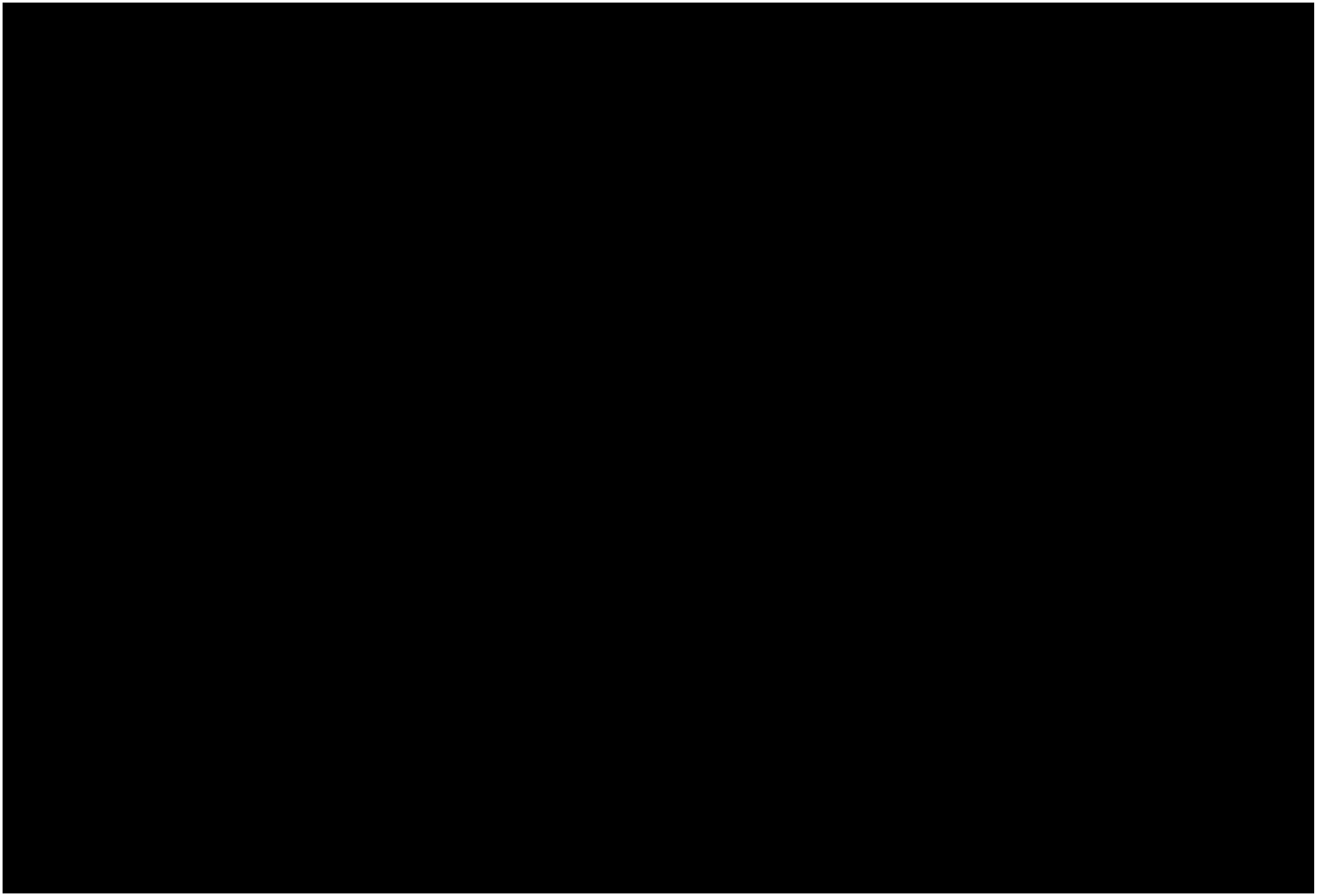
Date of On Peak Day - 05/31/2021

[redacted]

Member Forecasted On Peak Demand Day for June 2021

Y-W Electric Association, Inc.

Date of On Peak Day - 06/11/2021



Member Forecasted On Peak Demand Day for July 2021

Y-W Electric Association, Inc.

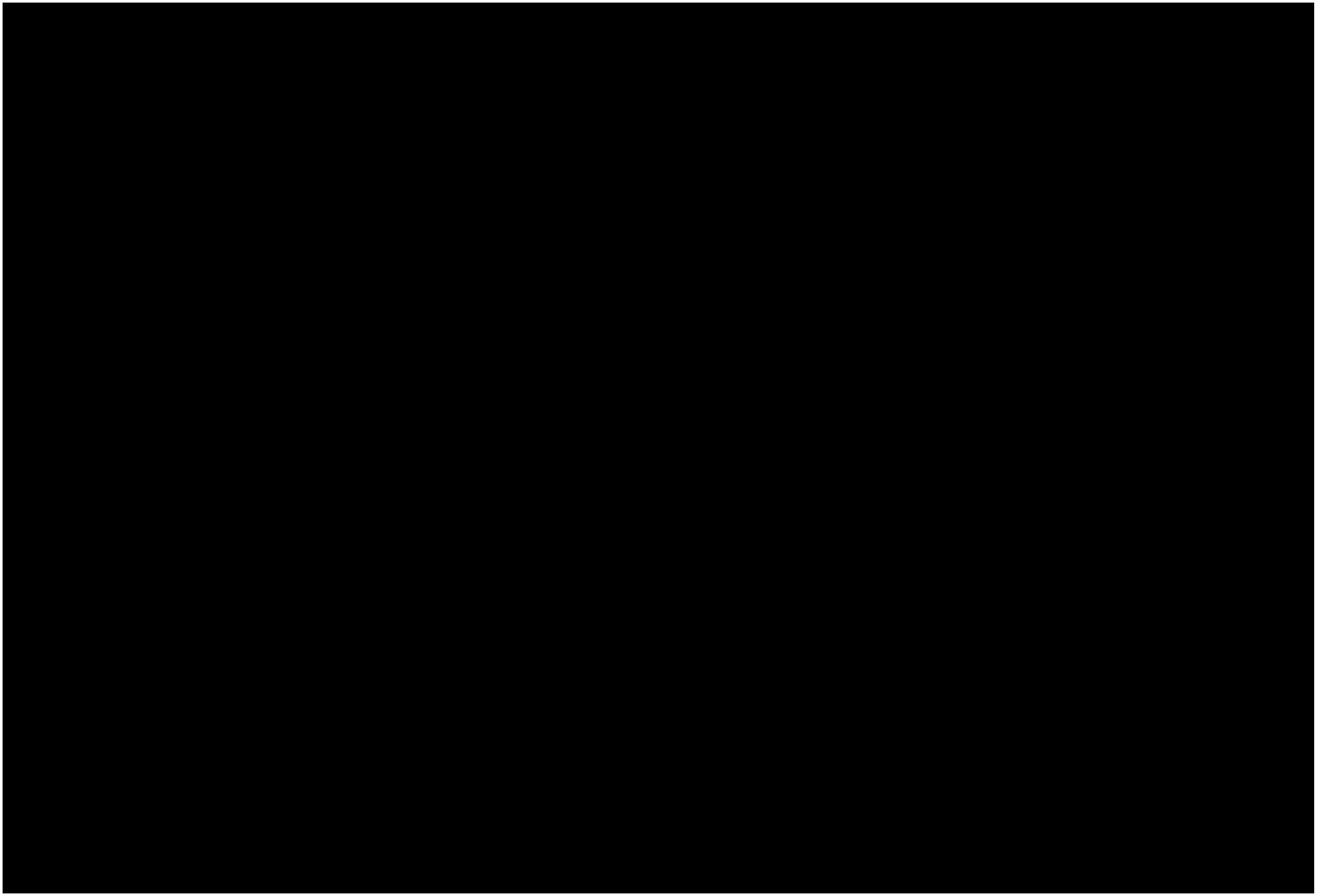
Date of On Peak Day - 07/21/2021

[redacted]

Member Forecasted On Peak Demand Day for August 2021

Y-W Electric Association, Inc.

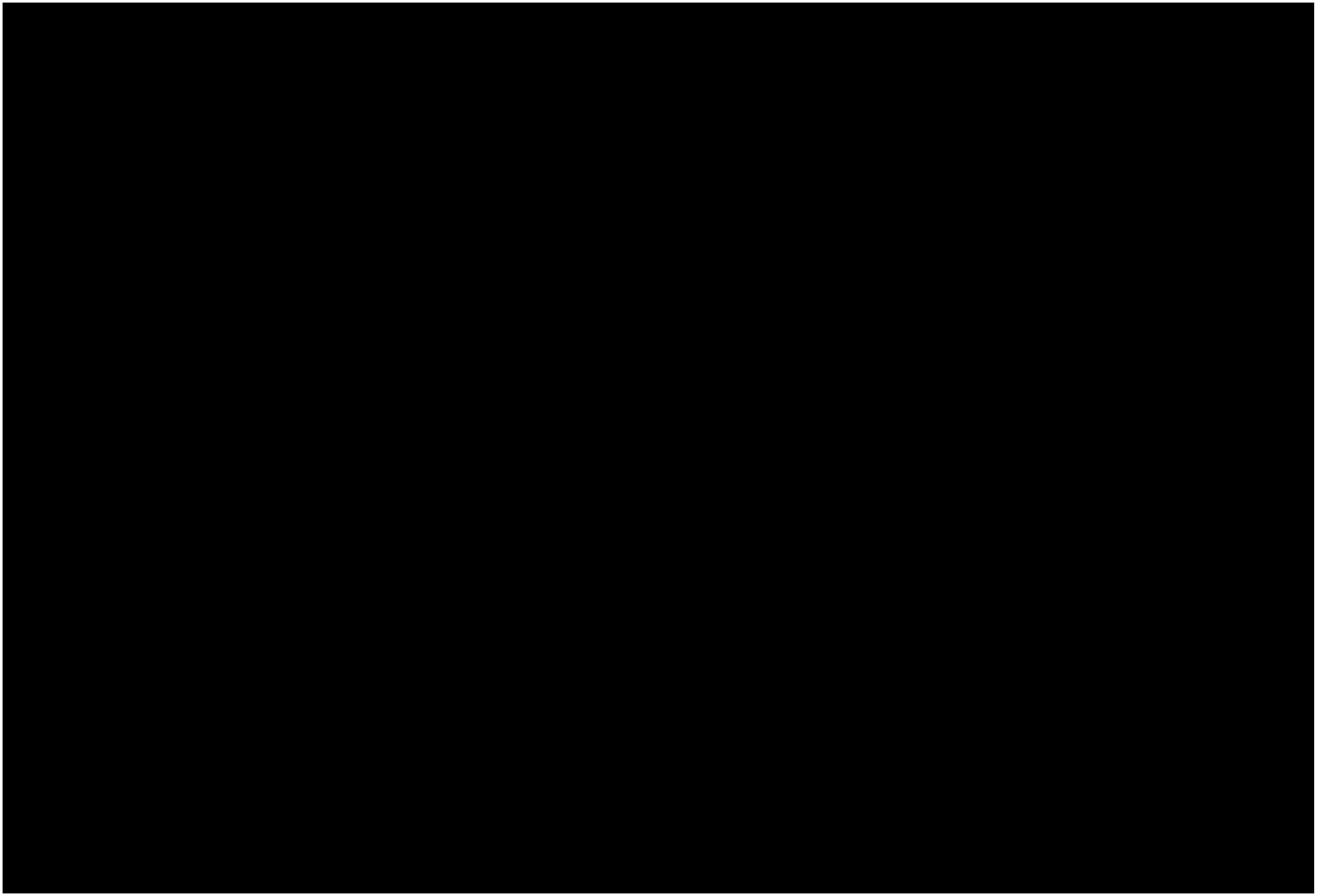
Date of On Peak Day - 08/28/2021



Member Forecasted On Peak Demand Day for September 2021

Y-W Electric Association, Inc.

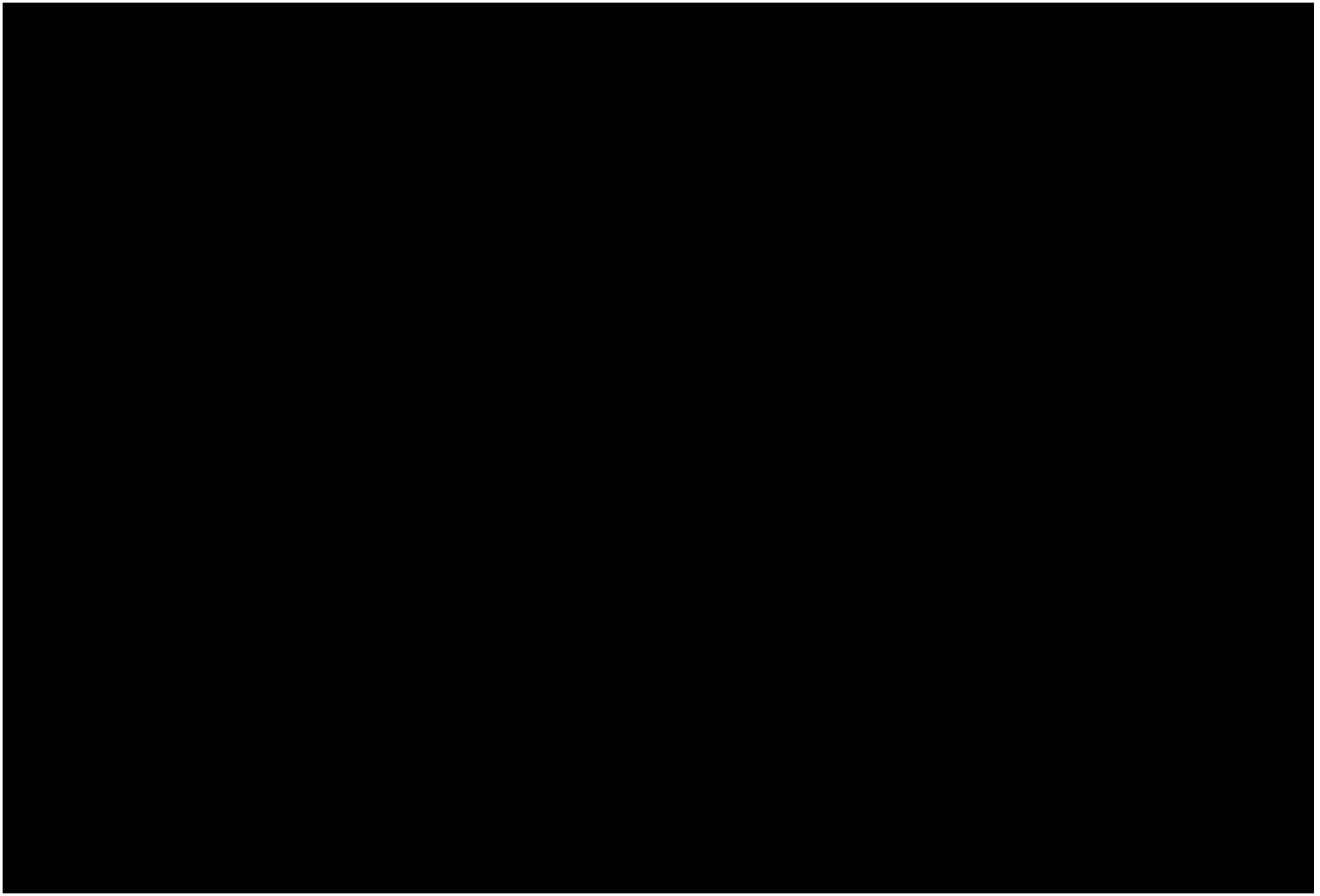
Date of On Peak Day - 09/03/2021



Member Forecasted On Peak Demand Day for October 2021

Y-W Electric Association, Inc.

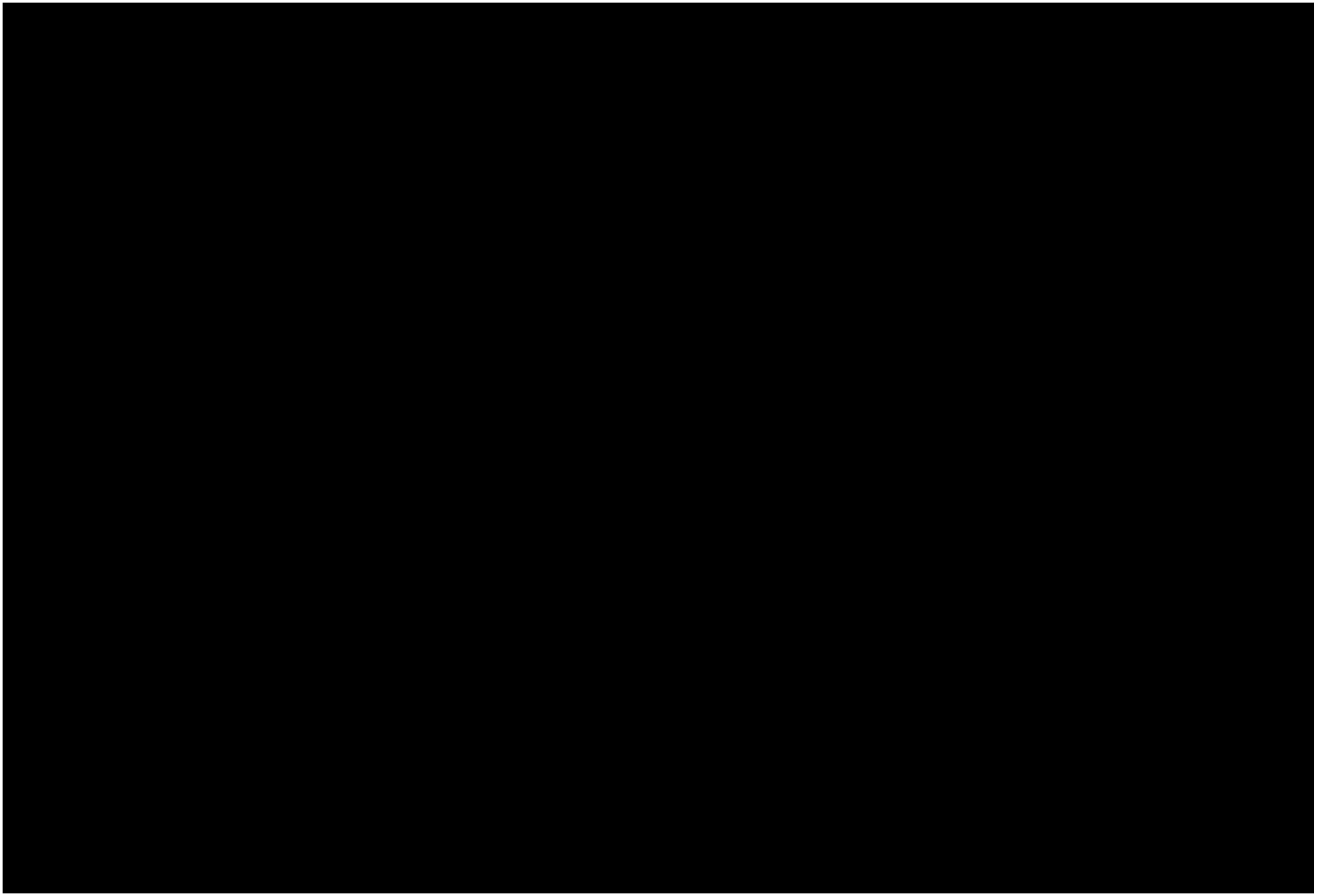
Date of On Peak Day - 10/11/2021



Member Forecasted On Peak Demand Day for November 2021

Y-W Electric Association, Inc.

Date of On Peak Day - 11/17/2021



Member Forecasted On Peak Demand Day for December 2021

Y-W Electric Association, Inc.

Date of On Peak Day - 12/29/2021

[redacted]

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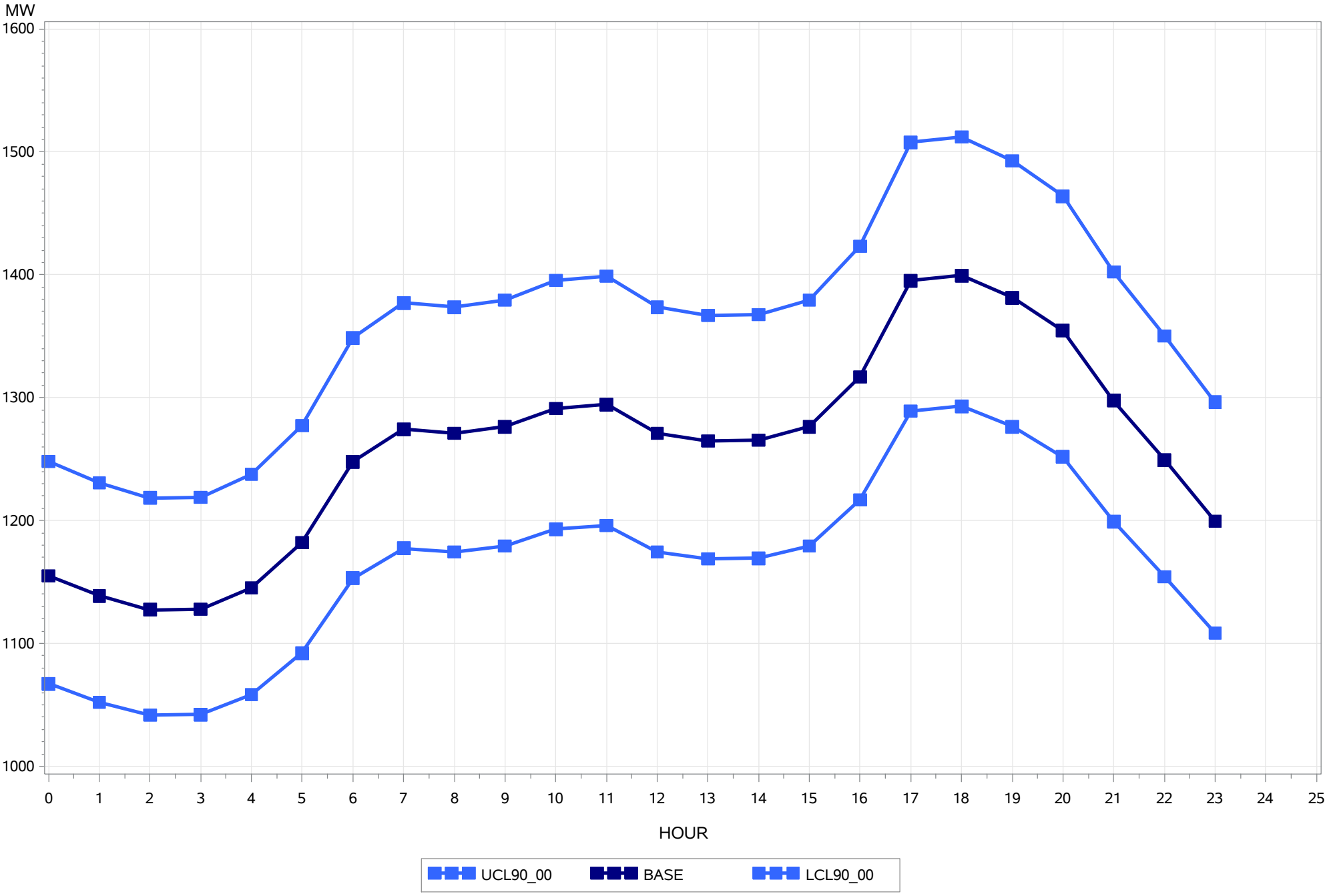
Member Forecasted Off Peak Demand Day for January 2021

STATE OF COLORADO

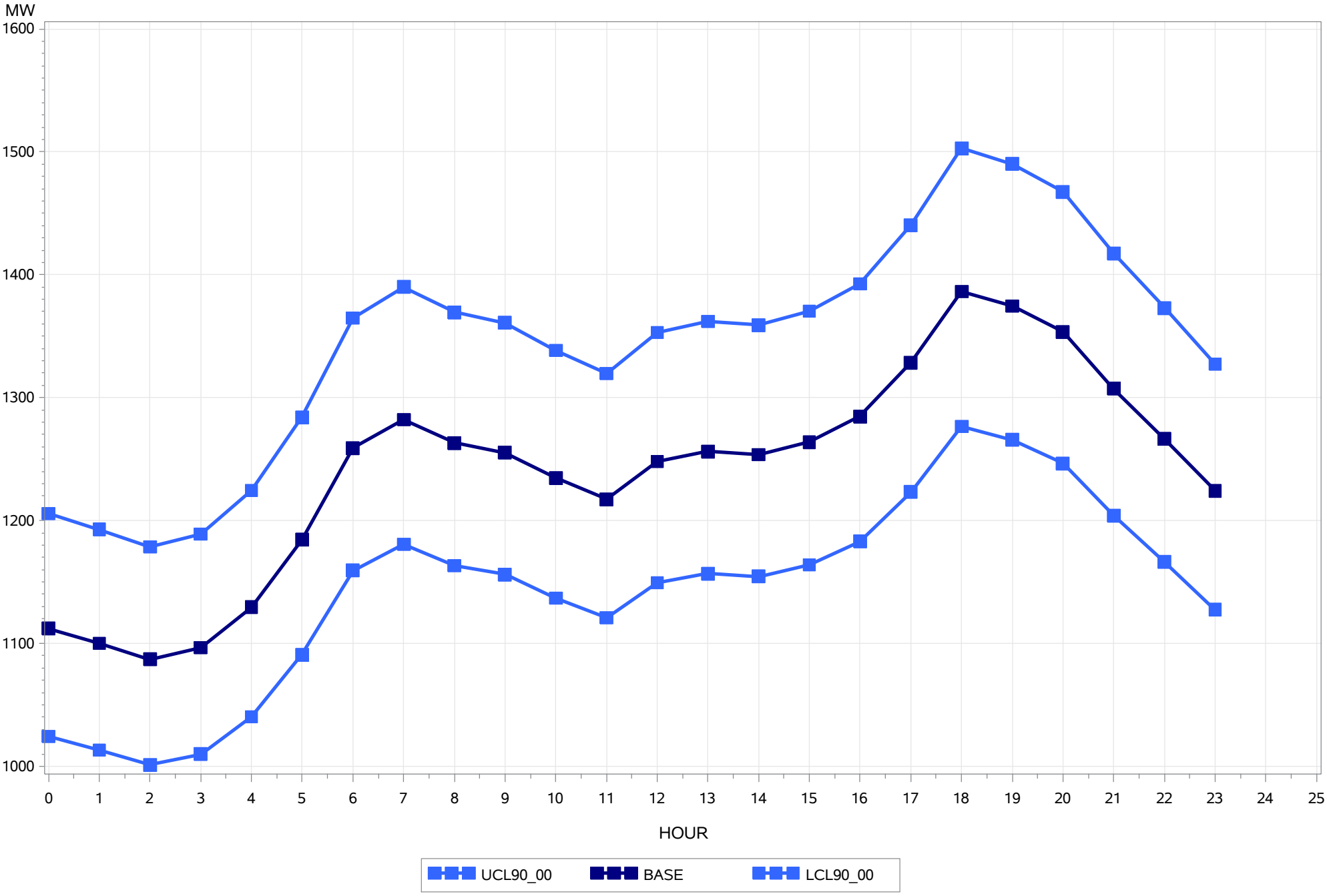
Date of Off Peak Day - 01/11/2021



Member Forecasted Off Peak Demand Day for February 2021

STATE OF COLORADO

Date of Off Peak Day - 02/11/2021



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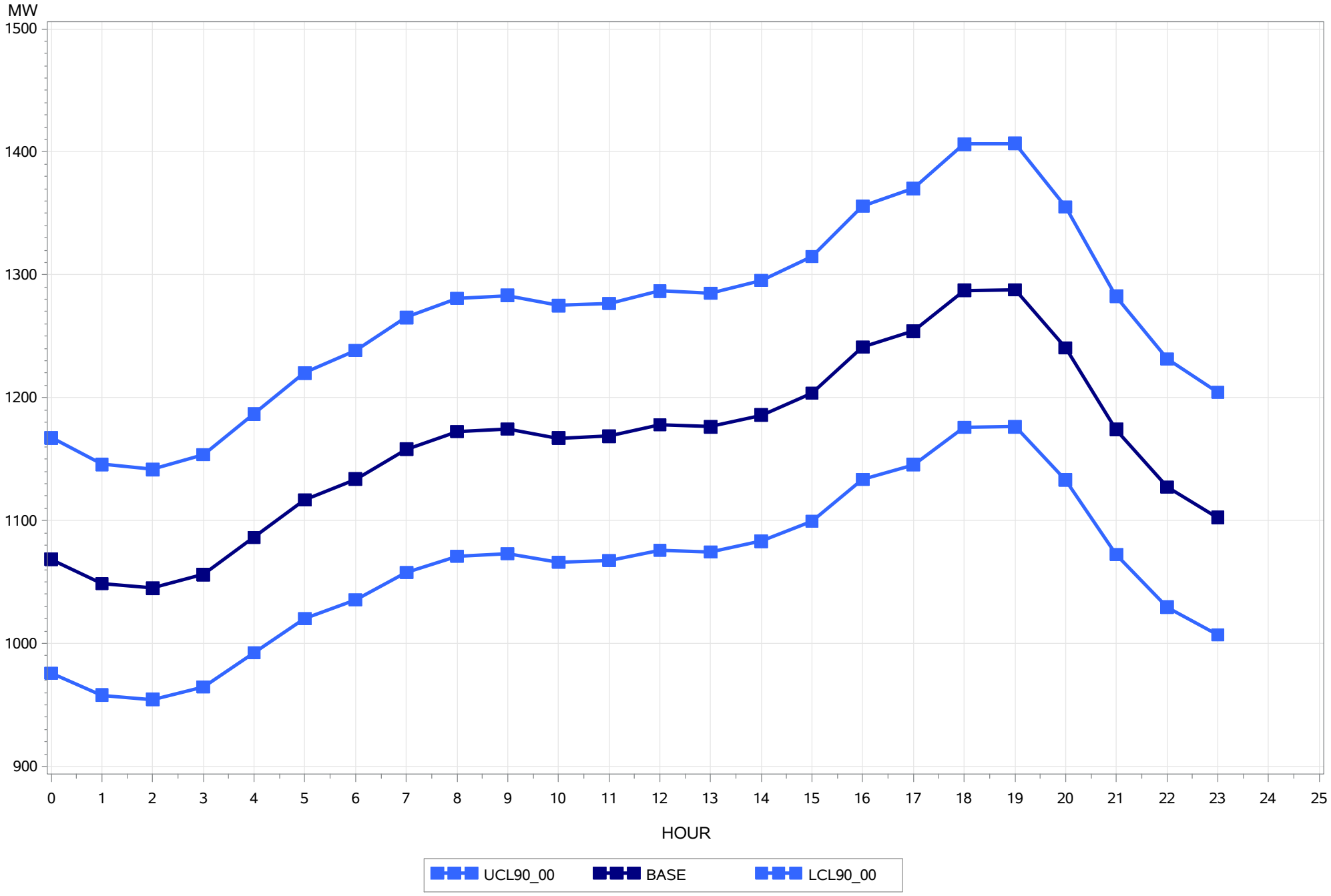
Member Forecasted Off Peak Demand Day for March 2021

STATE OF COLORADO

Date of Off Peak Day - 03/21/2021



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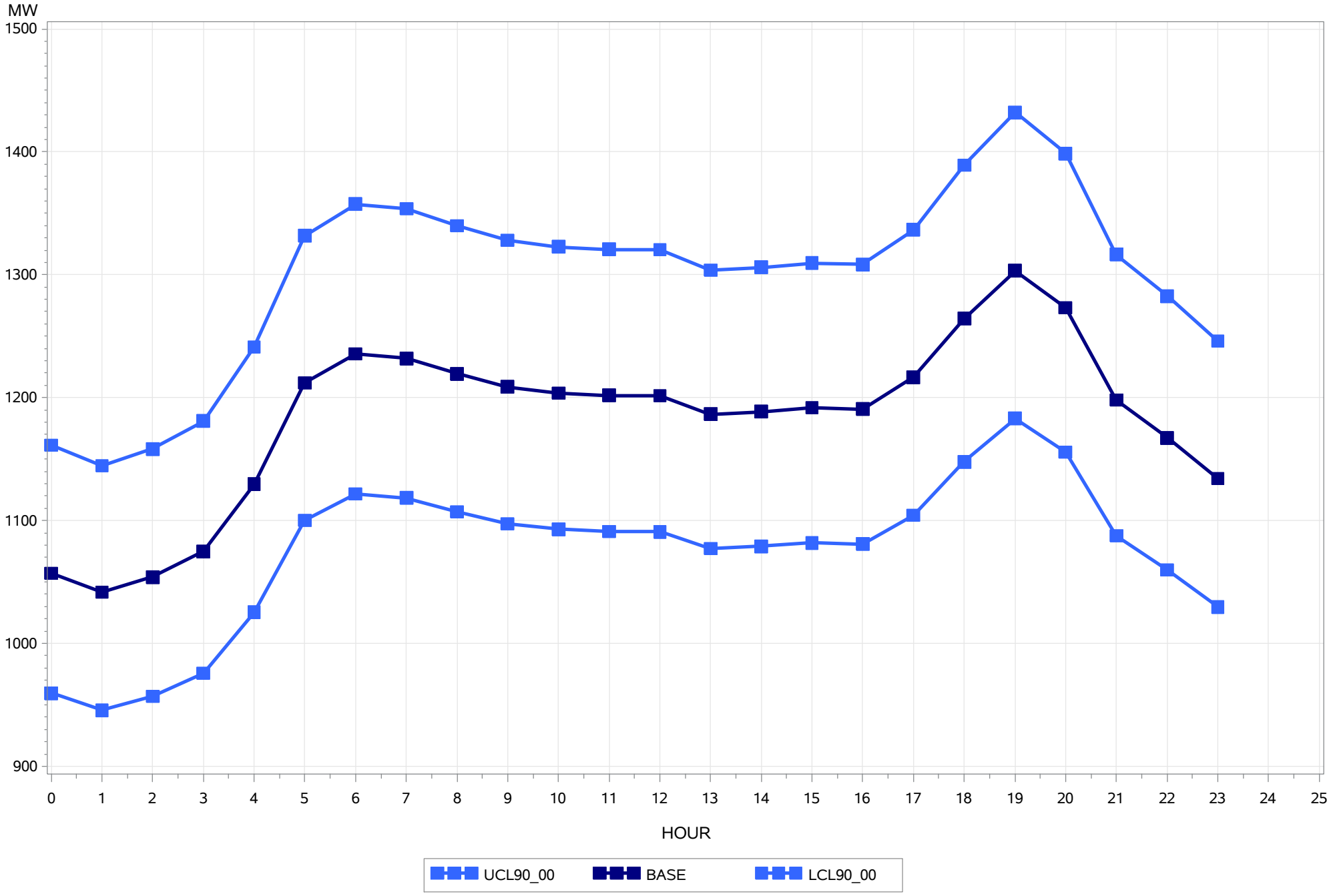
Member Forecasted Off Peak Demand Day for April 2021

STATE OF COLORADO

Date of Off Peak Day - 04/07/2021



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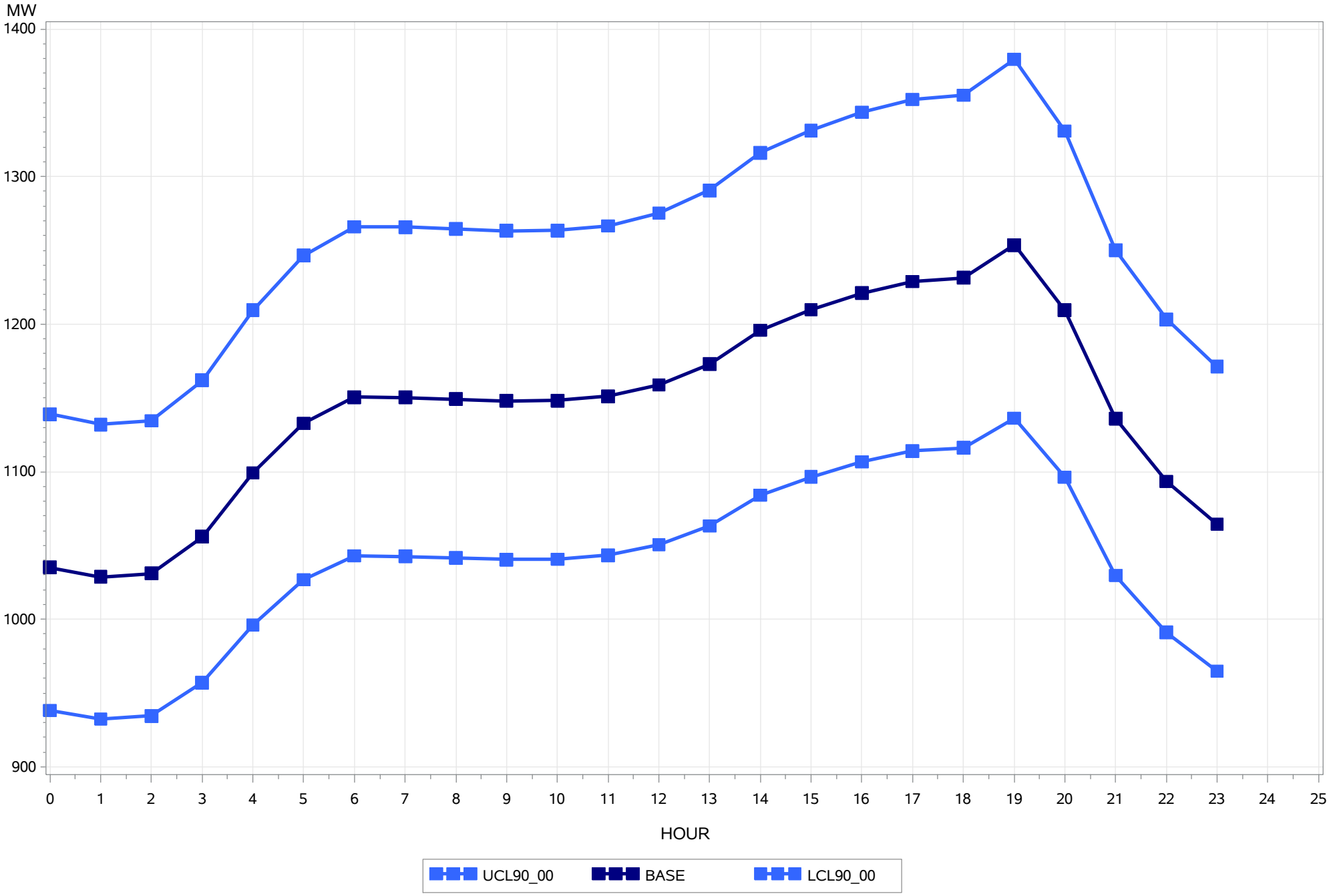
Member Forecasted Off Peak Demand Day for May 2021

STATE OF COLORADO

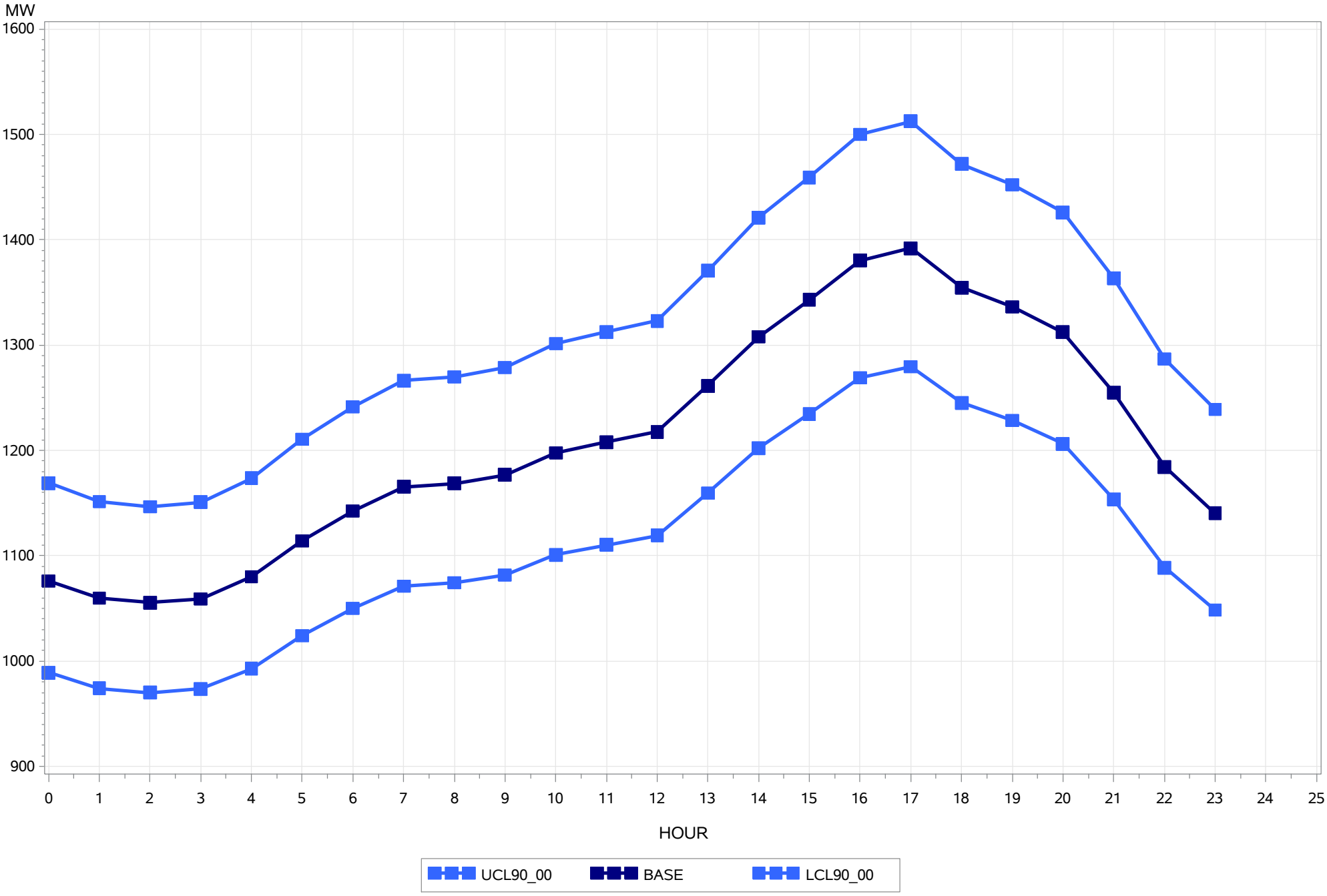
Date of Off Peak Day - 05/12/2021



Member Forecasted Off Peak Demand Day for June 2021

STATE OF COLORADO

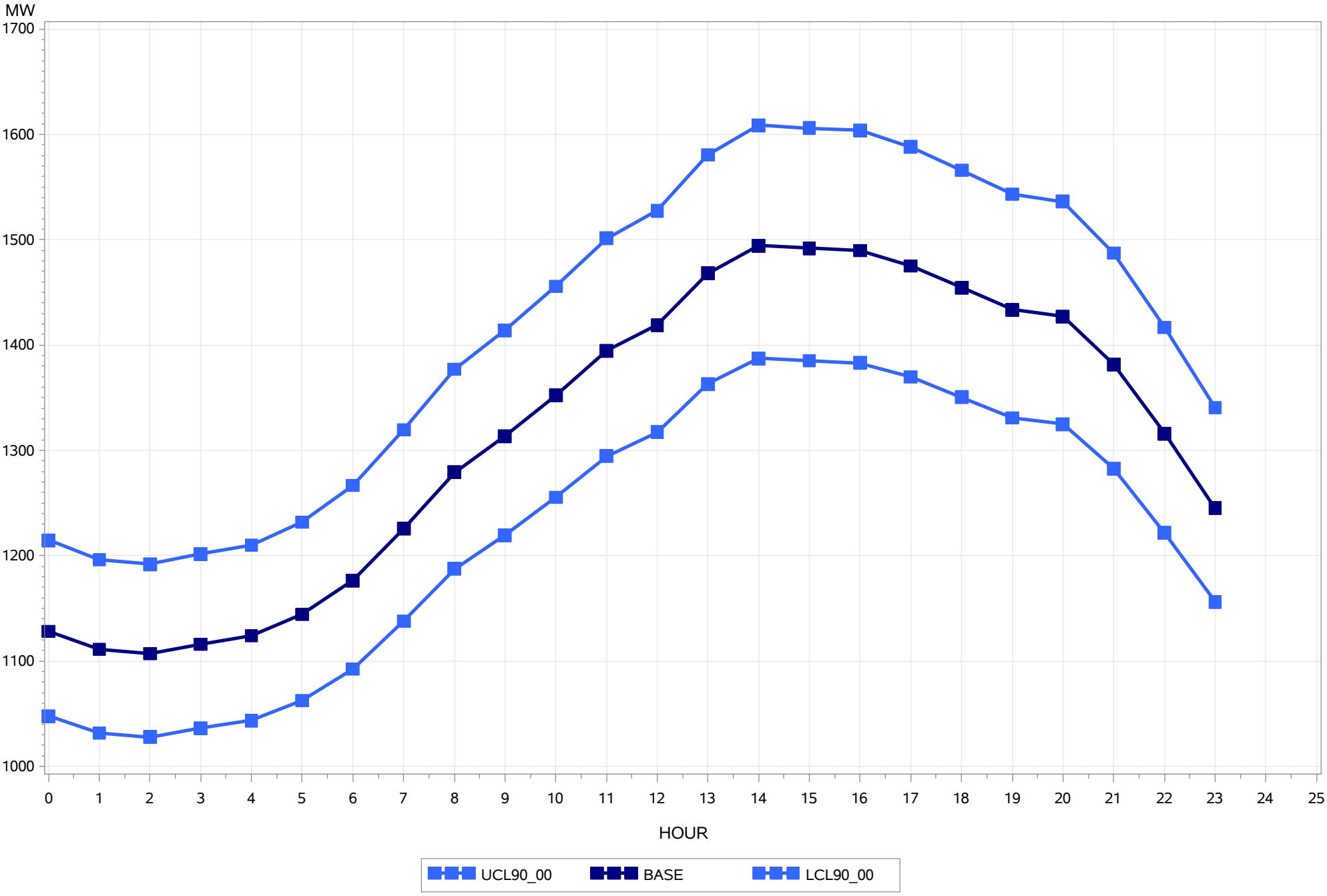
Date of Off Peak Day - 06/02/2021



Member Forecasted Off Peak Demand Day for July 2021

STATE OF COLORADO

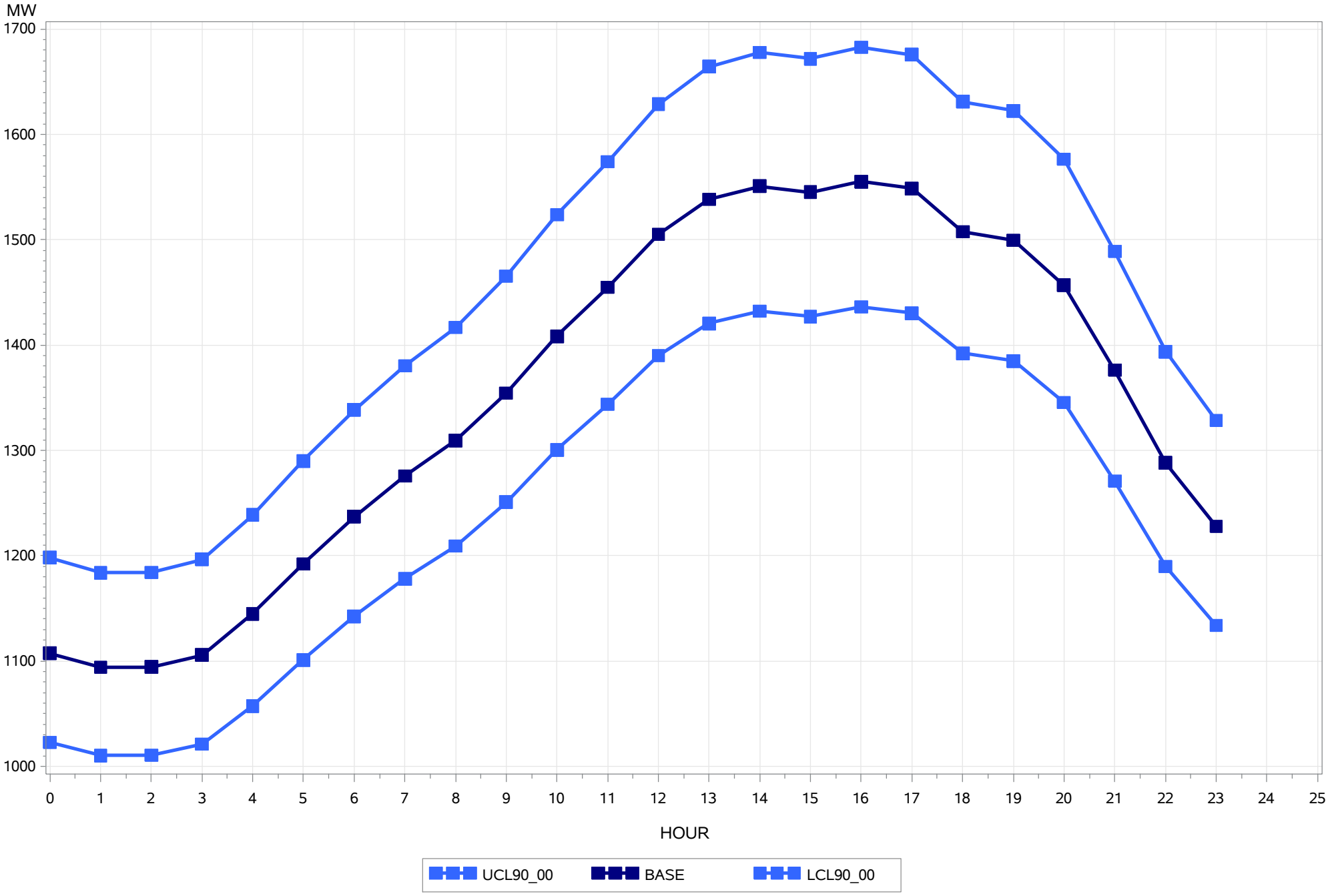
Date of Off Peak Day - 07/03/2021



Member Forecasted Off Peak Demand Day for August 2021

STATE OF COLORADO

Date of Off Peak Day - 08/13/2021



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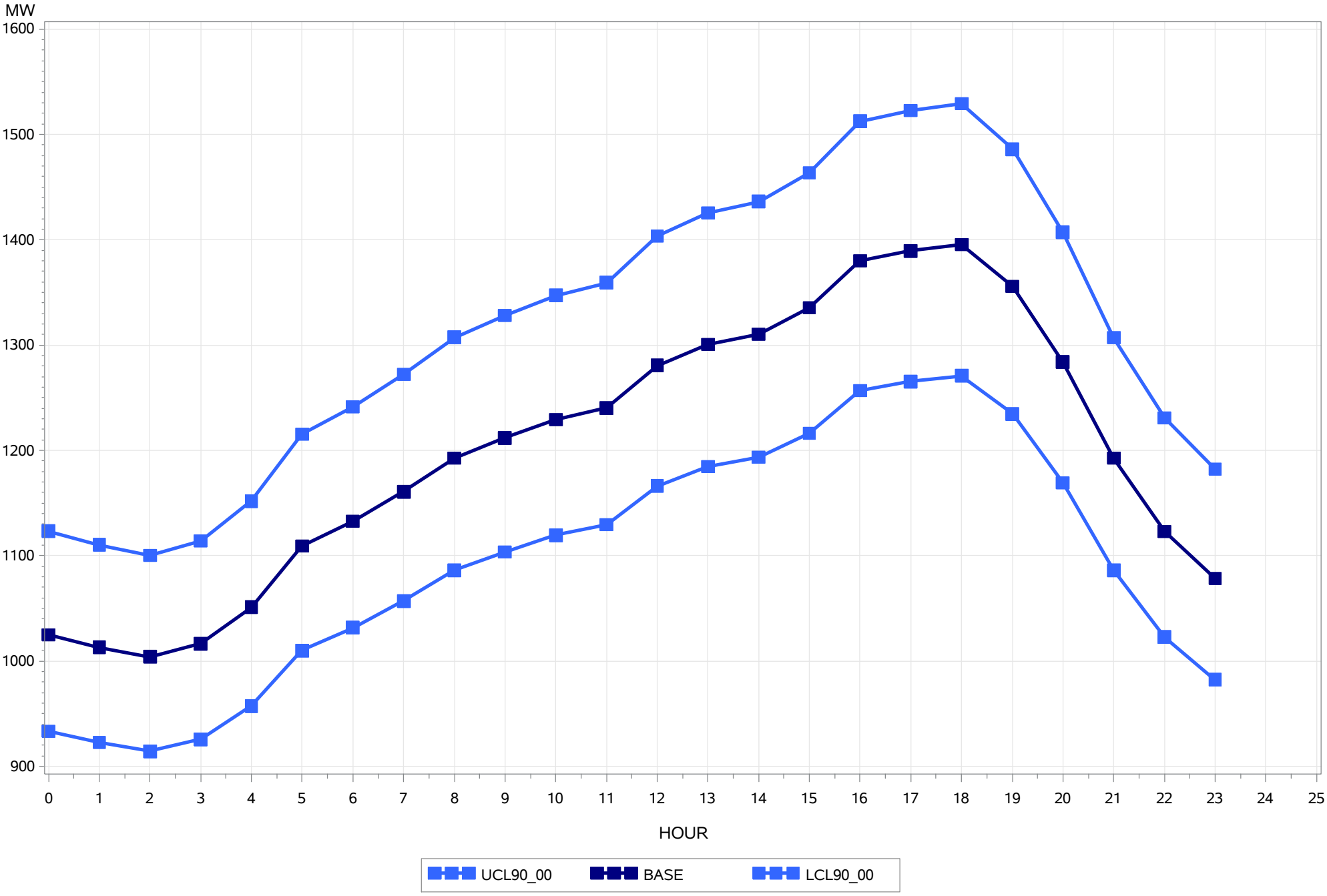
Member Forecasted Off Peak Demand Day for September 2021

STATE OF COLORADO

Date of Off Peak Day - 09/20/2021



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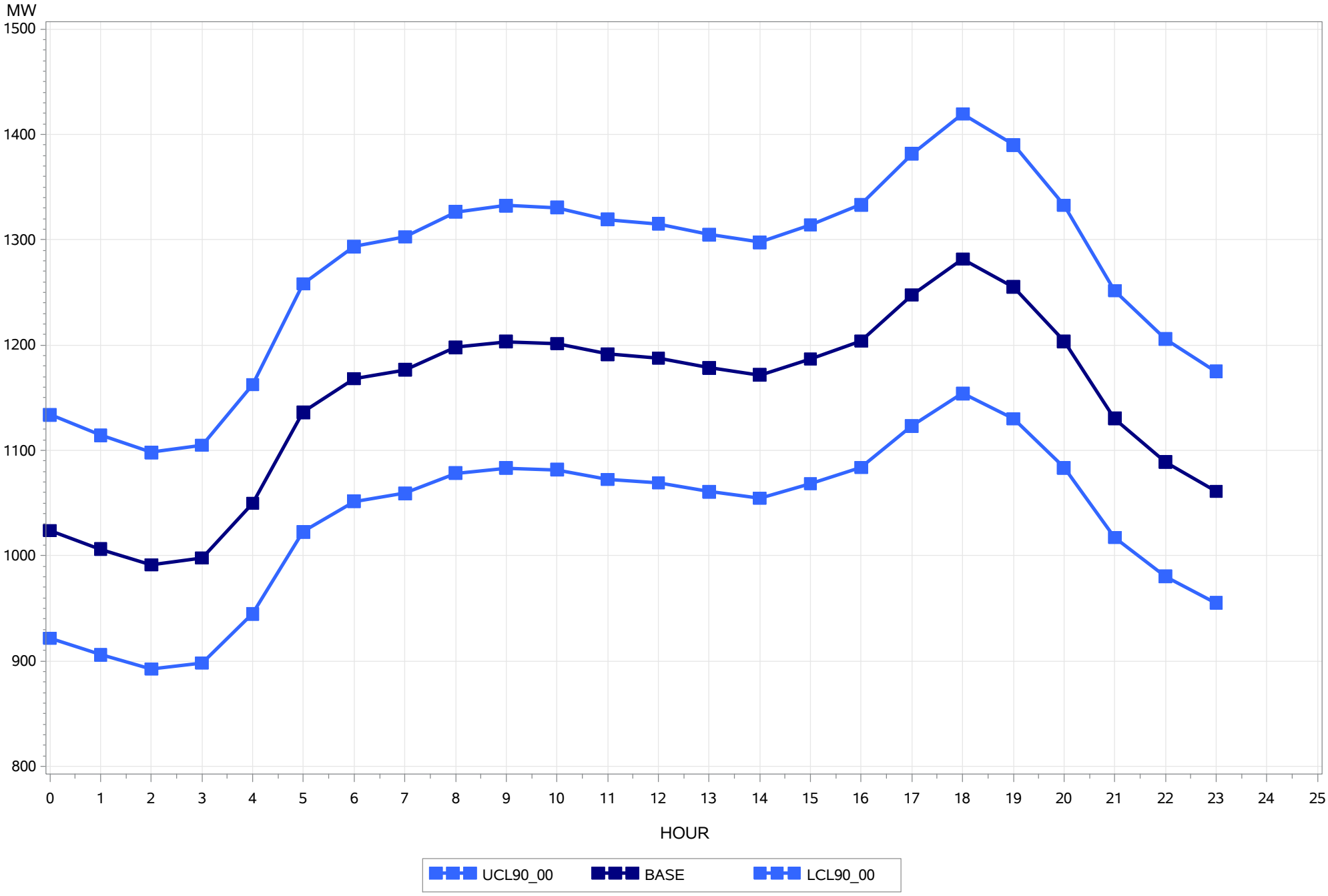
Member Forecasted Off Peak Demand Day for October 2021

STATE OF COLORADO

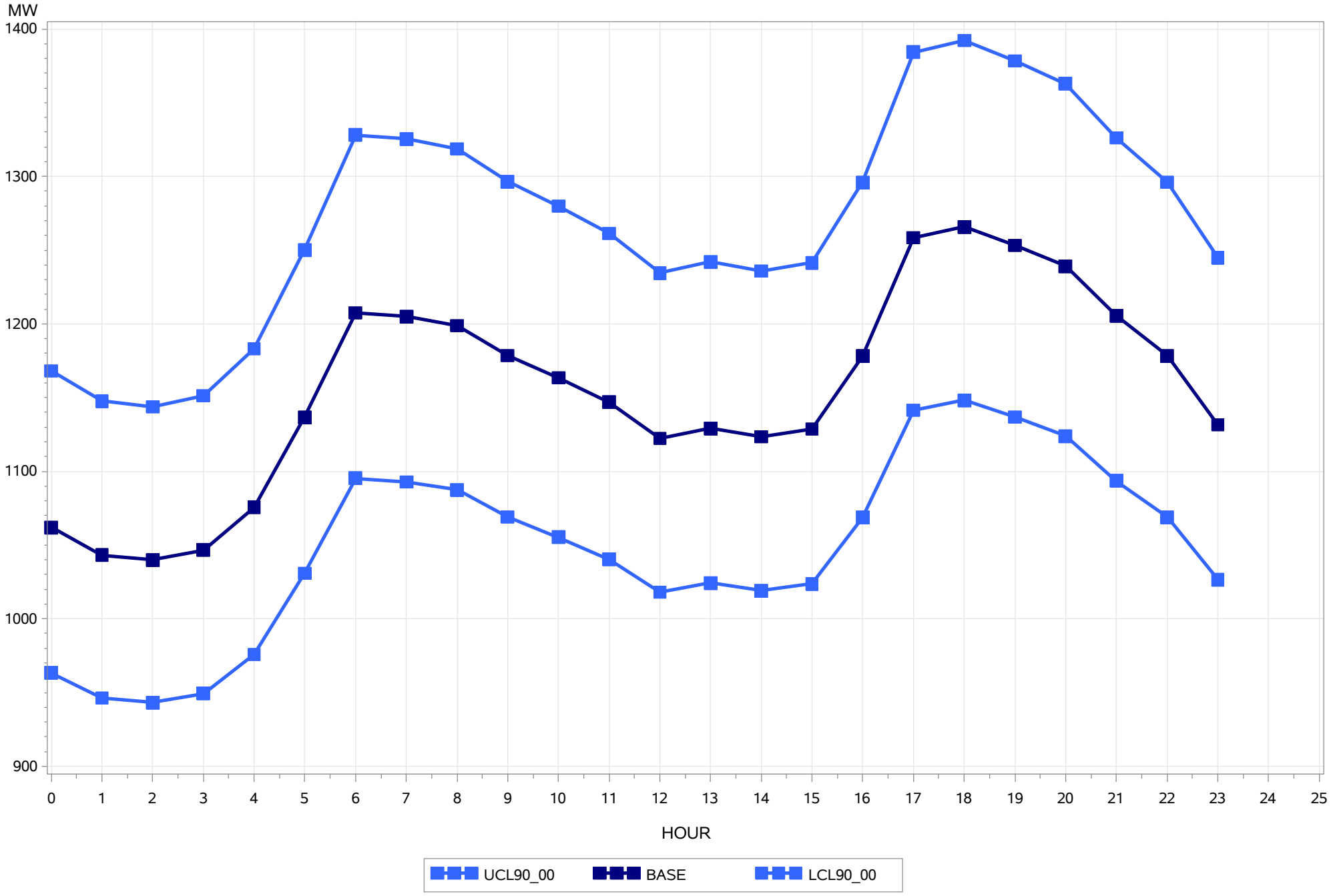
Date of Off Peak Day - 10/04/2021



Member Forecasted Off Peak Demand Day for November 2021

STATE OF COLORADO

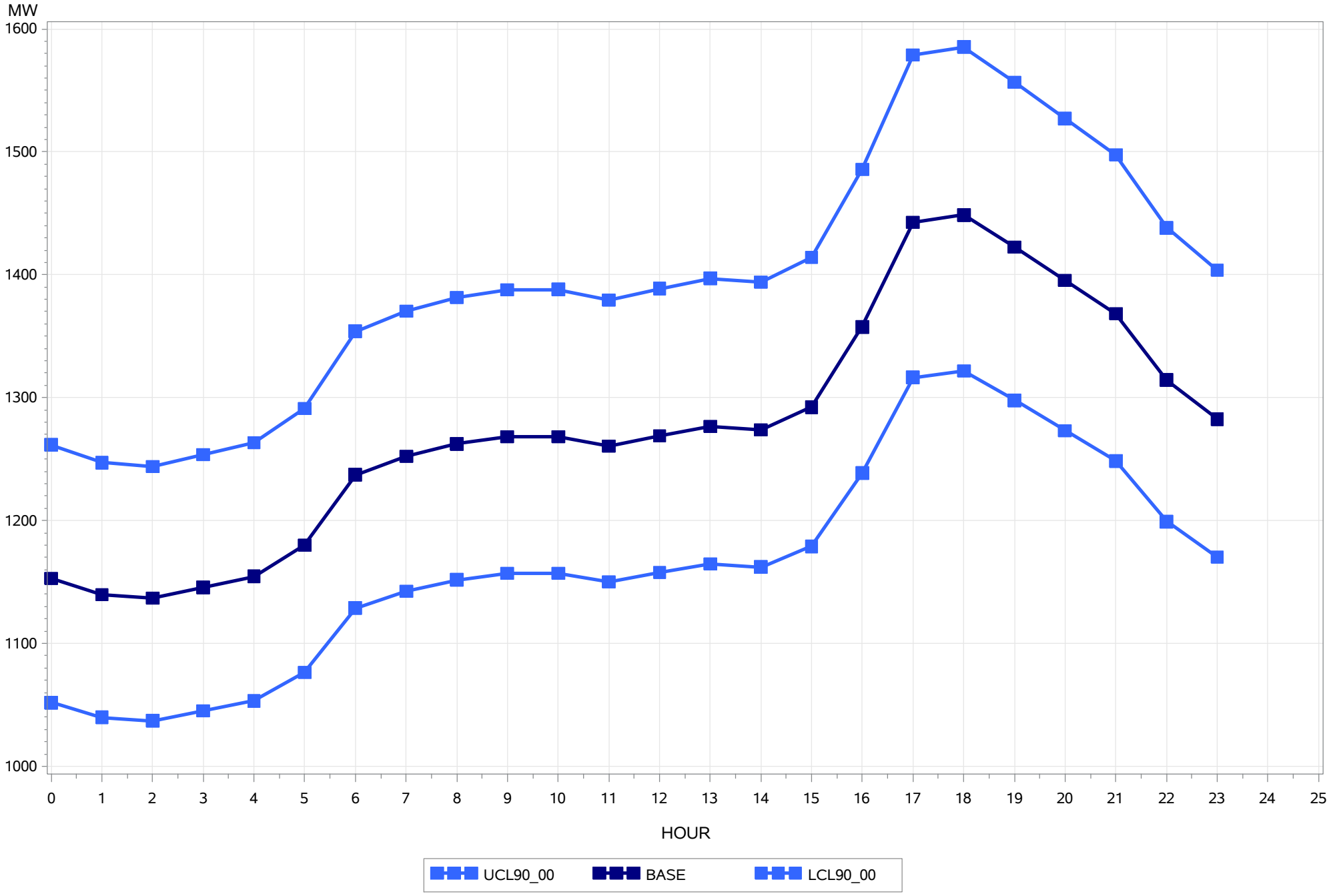
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

STATE OF COLORADO

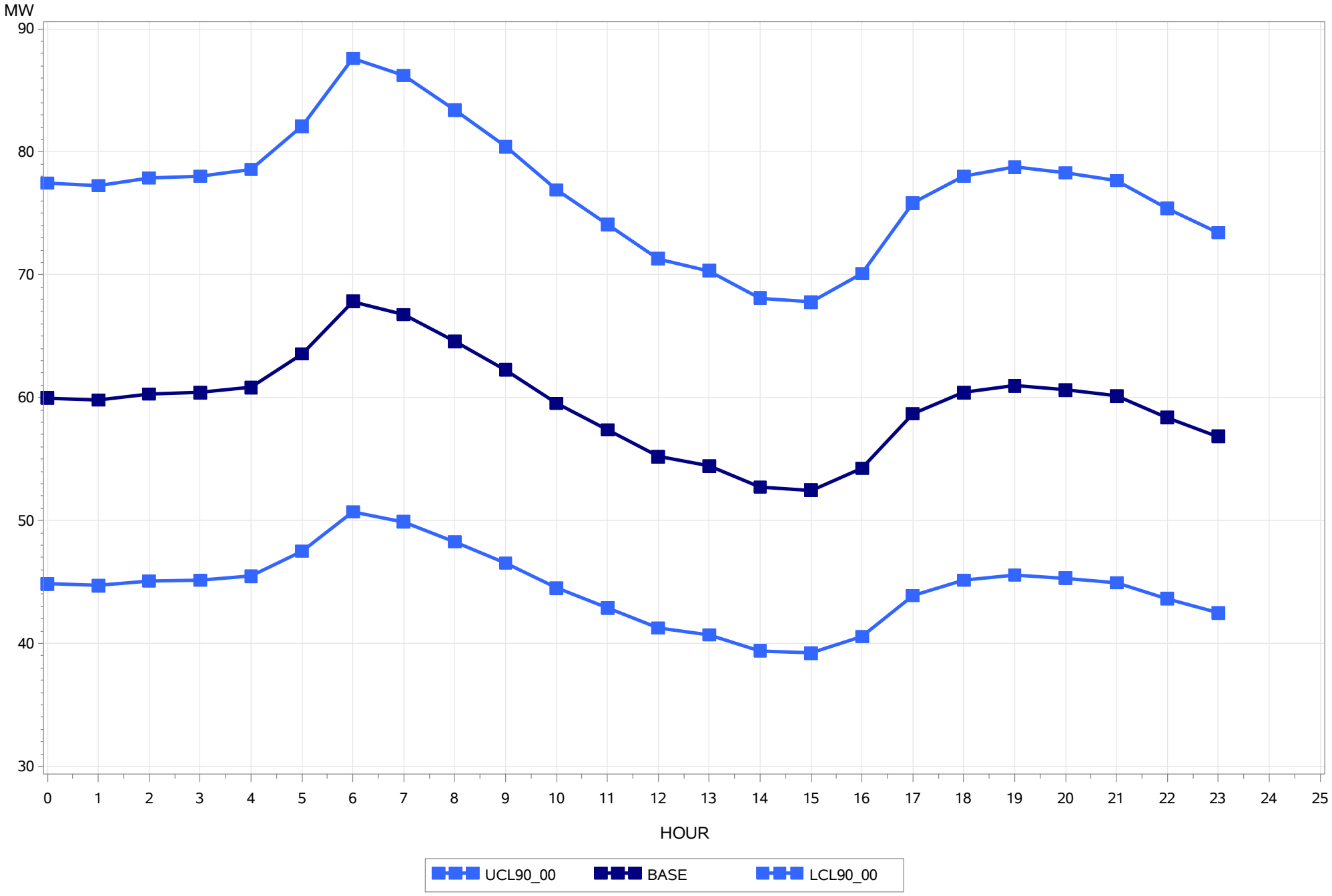
Date of Off Peak Day - 12/11/2021



Member Forecasted Off Peak Demand Day for January 2021

STATE OF NEBRASKA

Date of Off Peak Day - 01/18/2021



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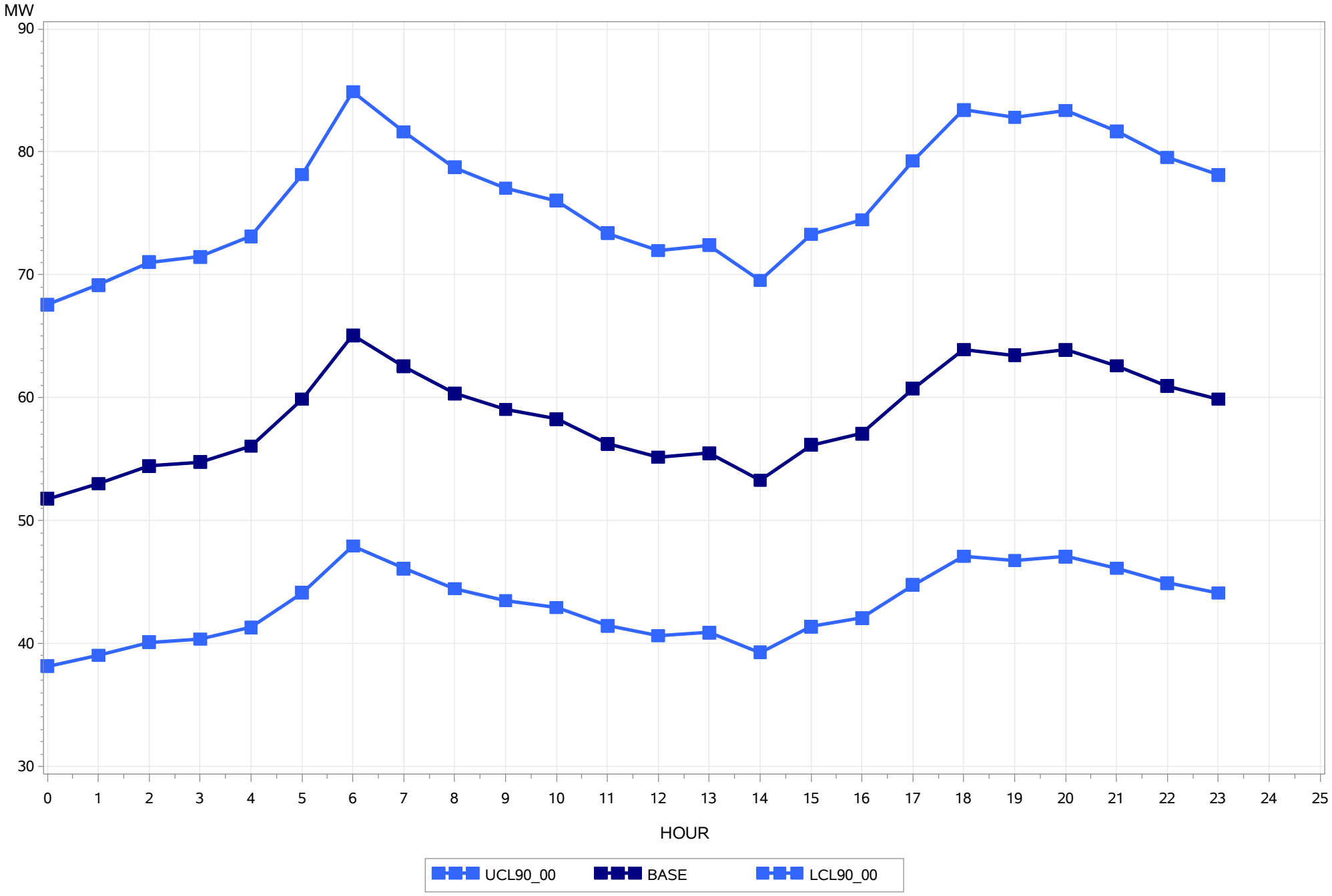
Member Forecasted Off Peak Demand Day for February 2021

STATE OF NEBRASKA

Date of Off Peak Day - 02/22/2021



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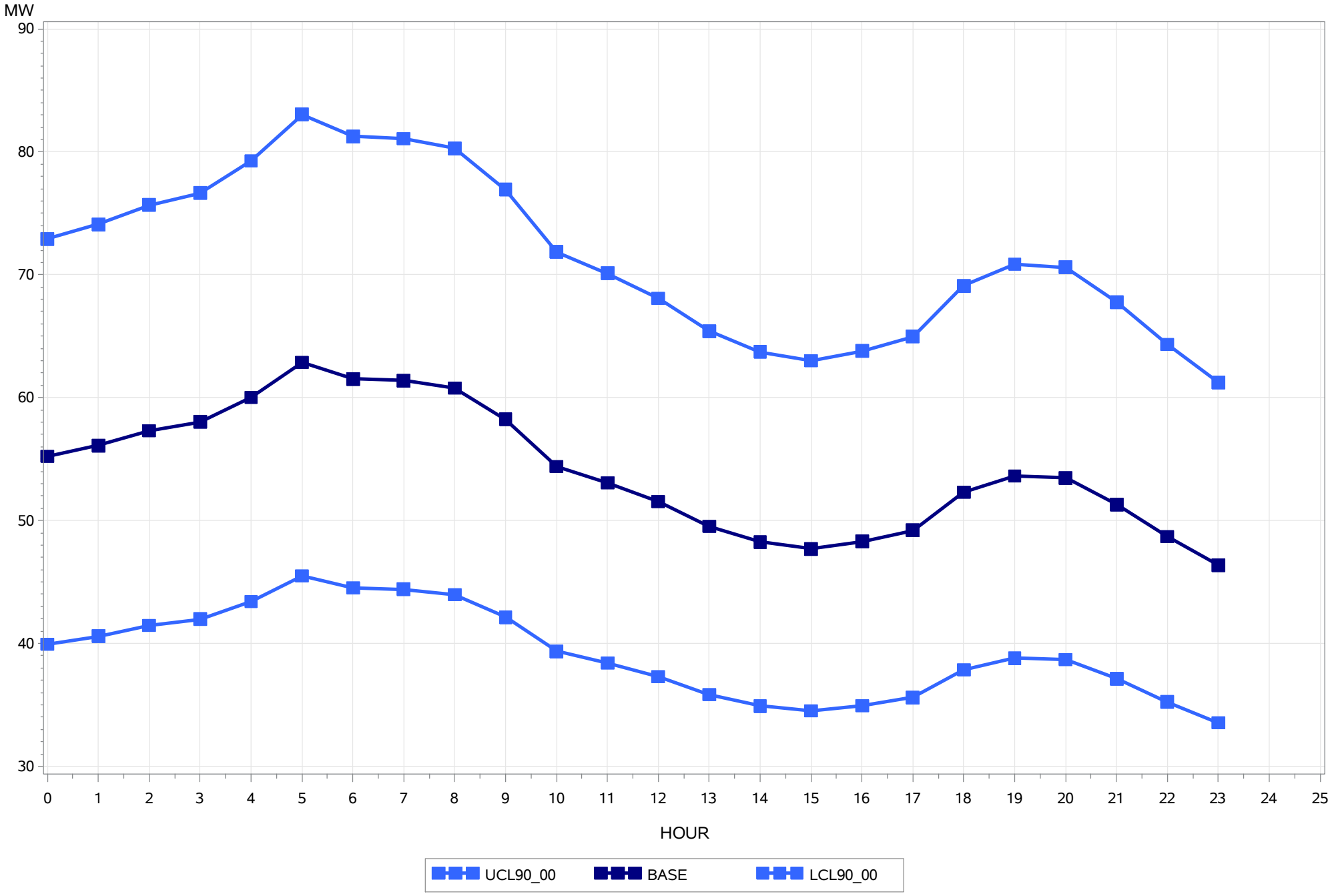
Member Forecasted Off Peak Demand Day for March 2021

STATE OF NEBRASKA

Date of Off Peak Day - 03/27/2021



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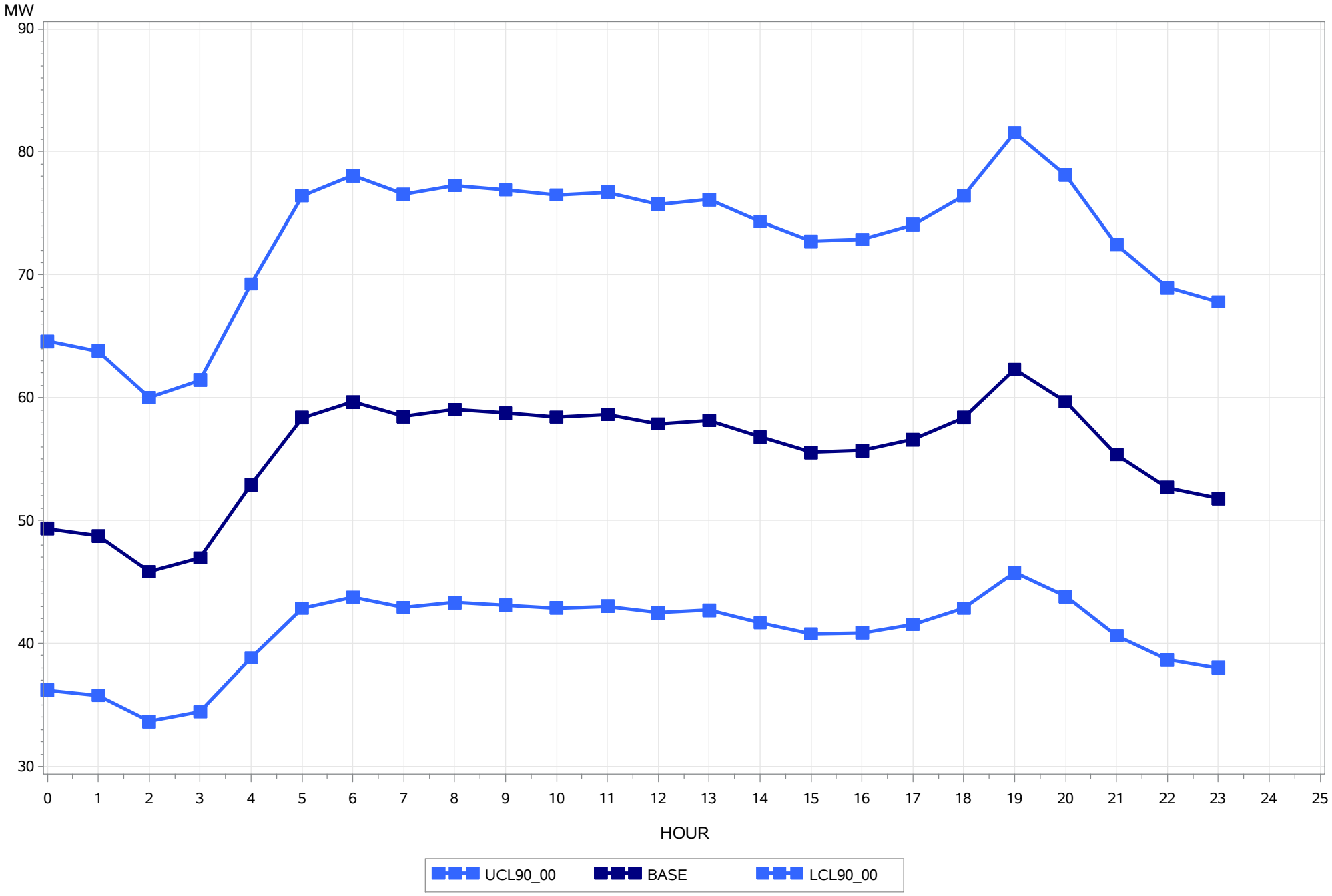
Member Forecasted Off Peak Demand Day for April 2021

STATE OF NEBRASKA

Date of Off Peak Day - 04/29/2021



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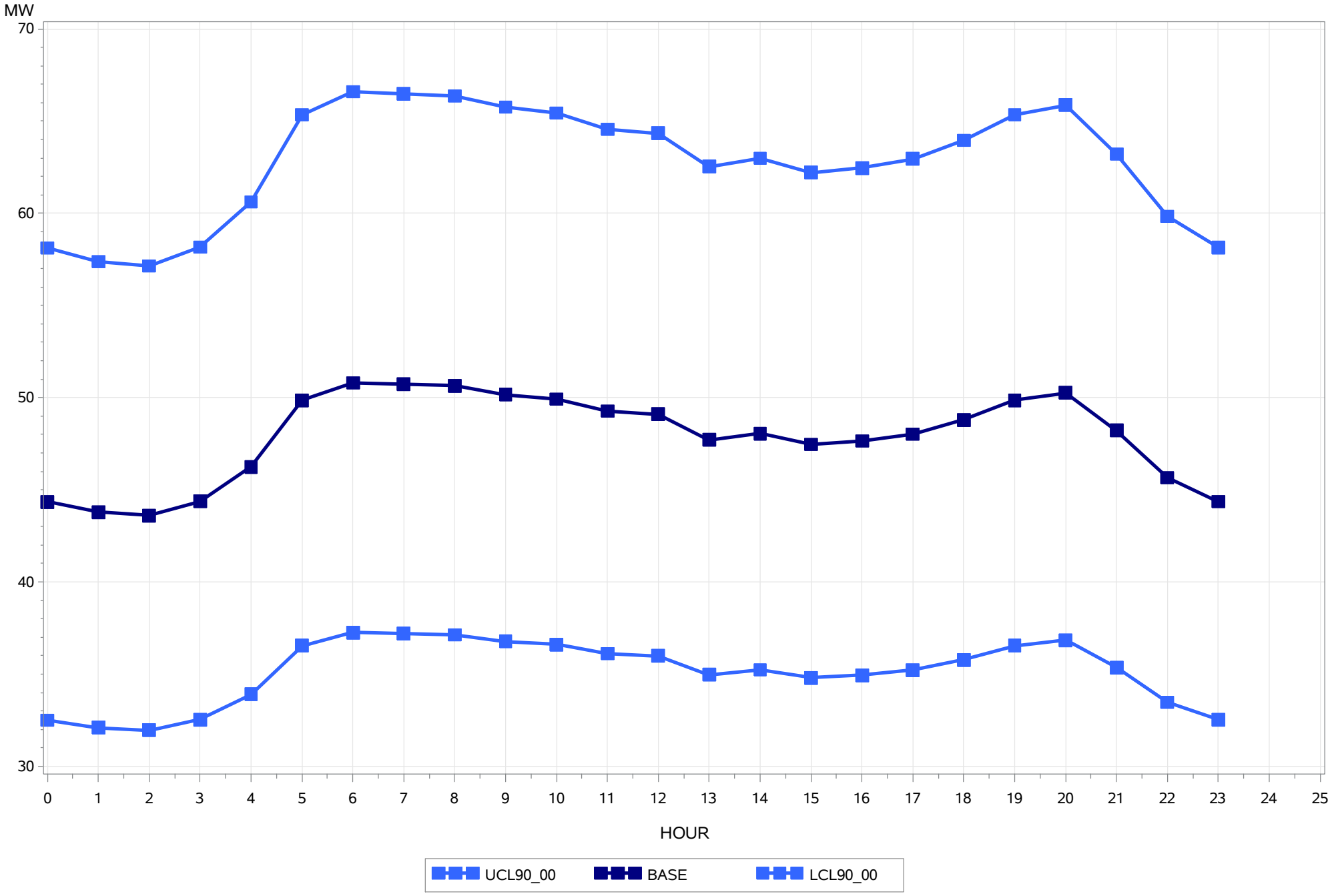
Member Forecasted Off Peak Demand Day for May 2021

STATE OF NEBRASKA

Date of Off Peak Day - 05/27/2021



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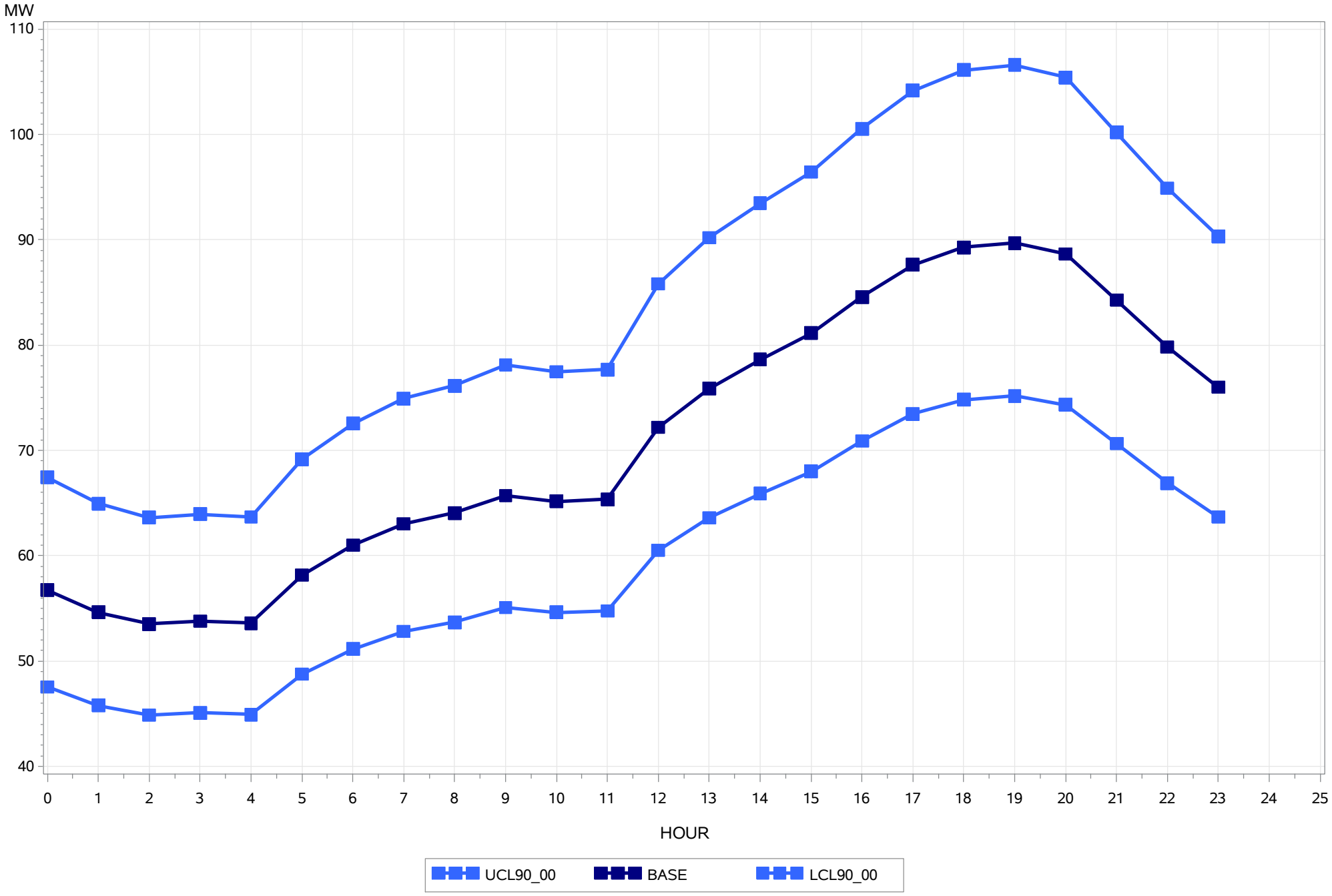
Member Forecasted Off Peak Demand Day for June 2021

STATE OF NEBRASKA

Date of Off Peak Day - 06/21/2021



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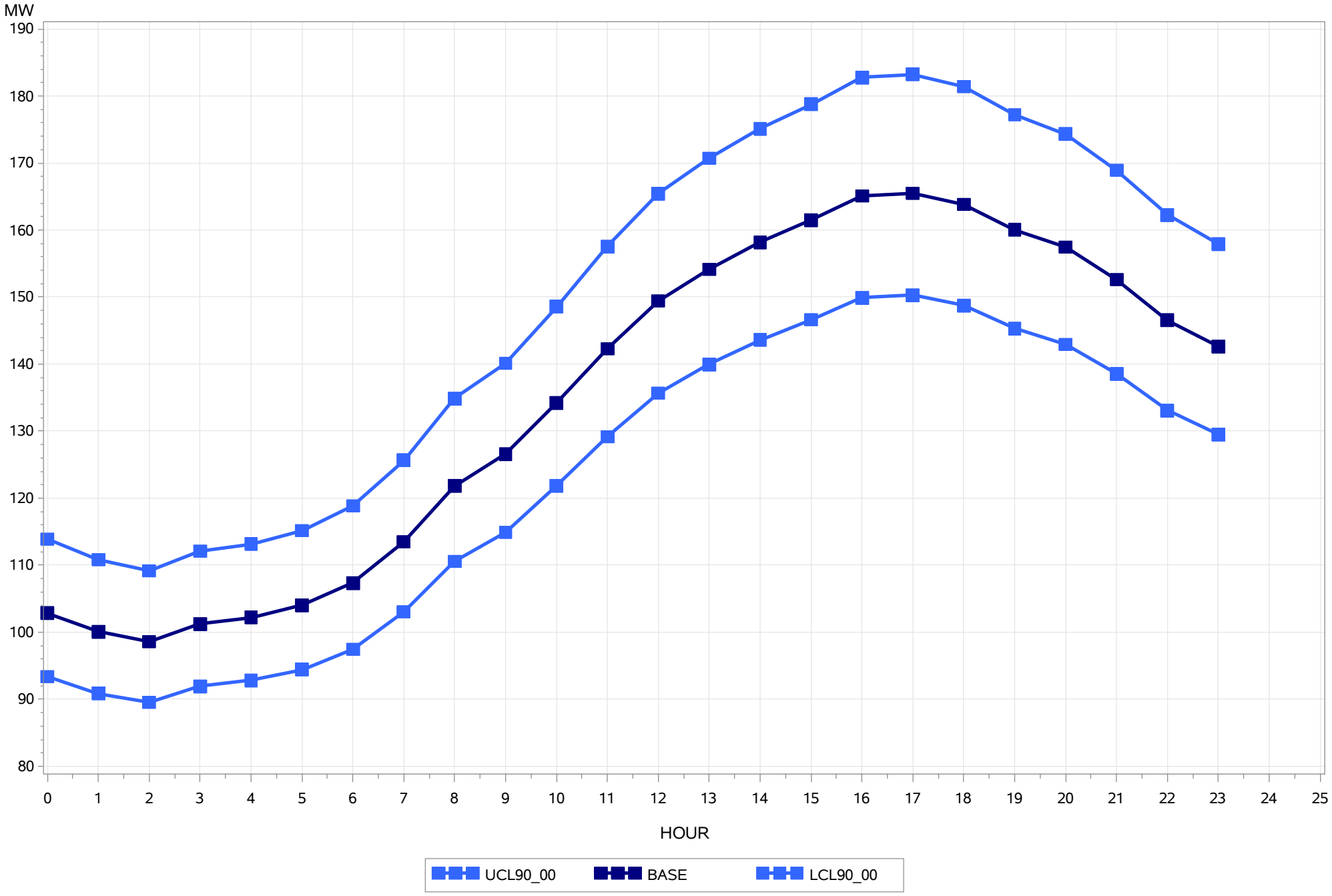
Member Forecasted Off Peak Demand Day for July 2021

STATE OF NEBRASKA

Date of Off Peak Day - 07/03/2021



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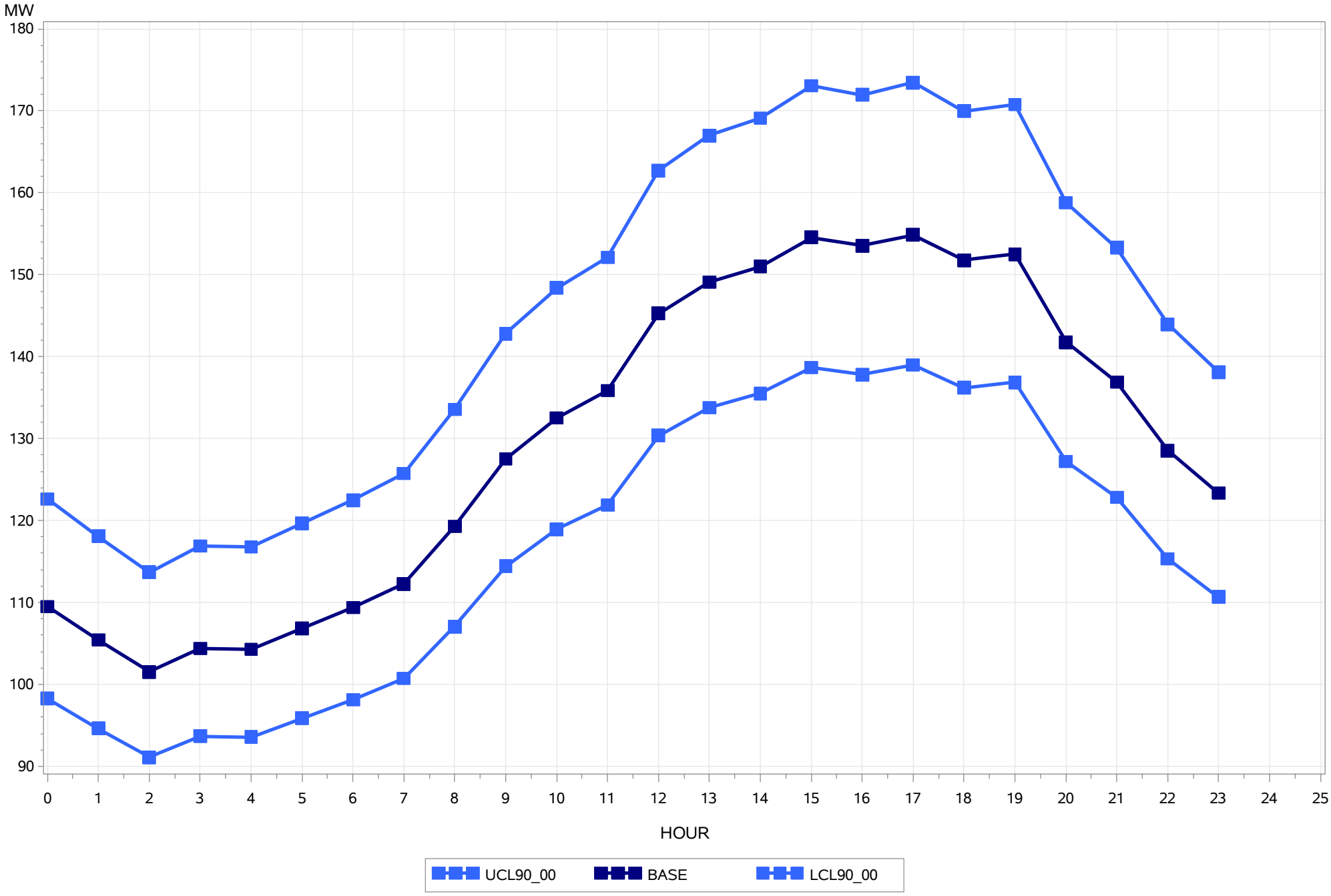
Member Forecasted Off Peak Demand Day for August 2021

STATE OF NEBRASKA

Date of Off Peak Day - 08/13/2021



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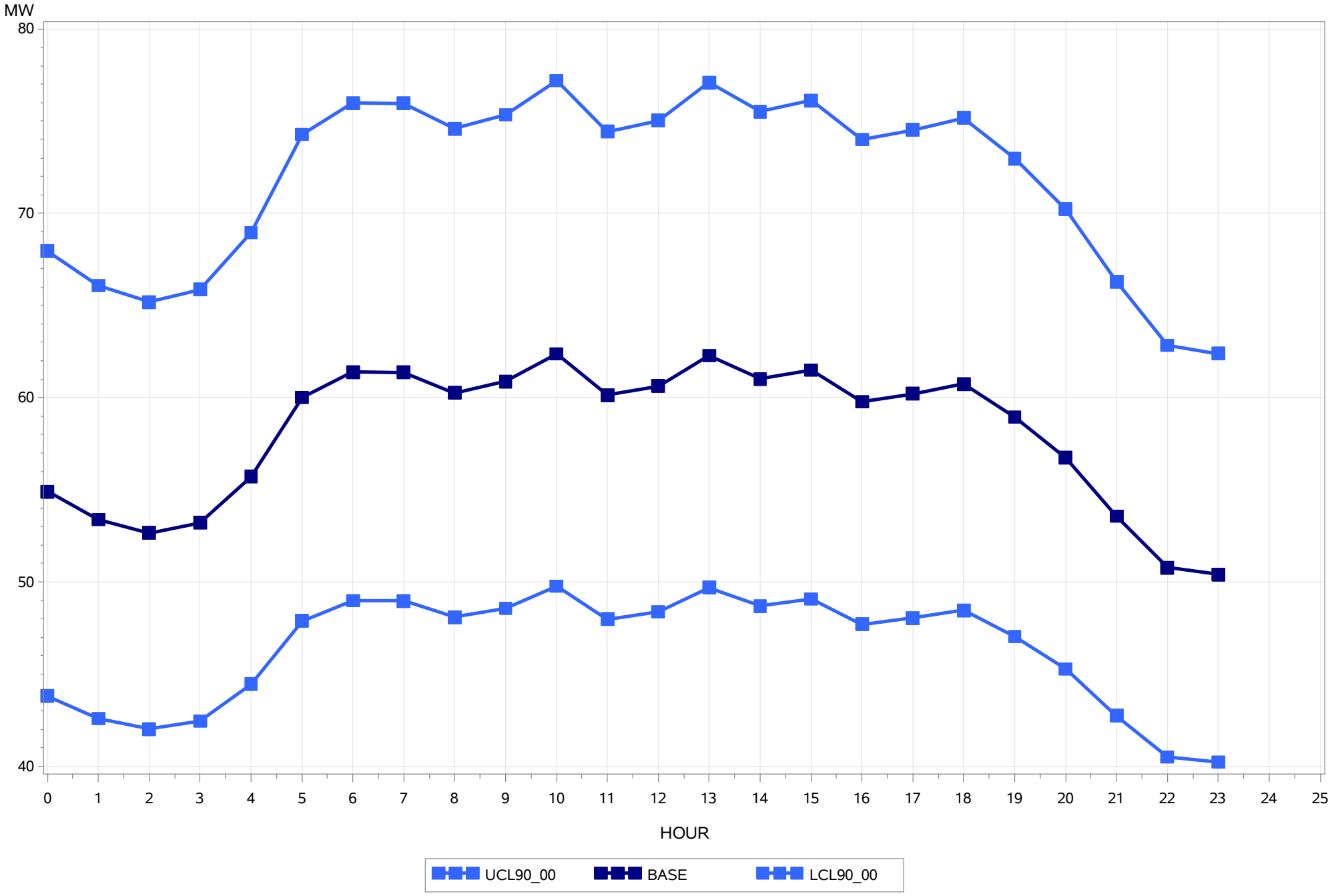
Member Forecasted Off Peak Demand Day for September 2021

STATE OF NEBRASKA

Date of Off Peak Day - 09/30/2021



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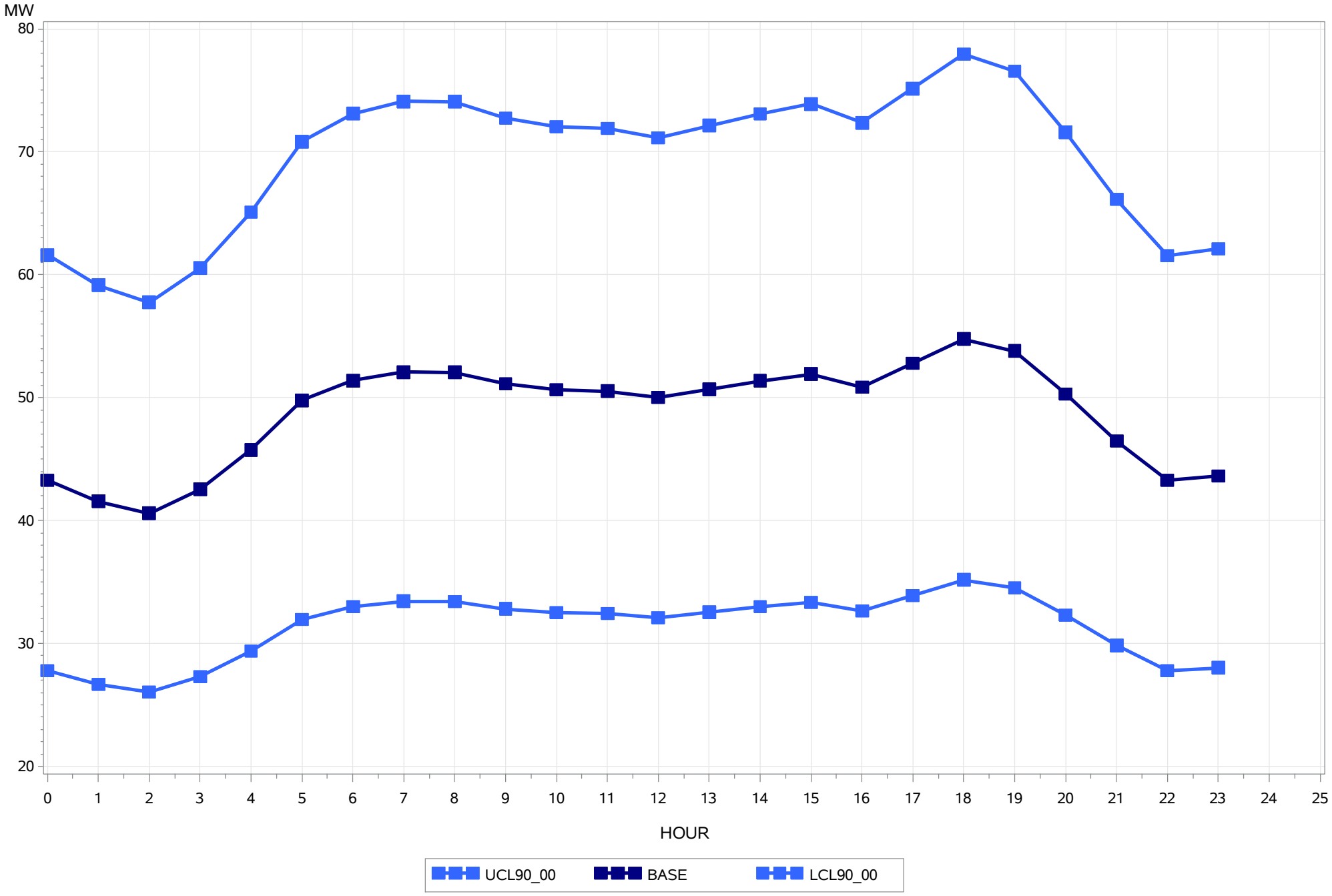
Member Forecasted Off Peak Demand Day for October 2021

STATE OF NEBRASKA

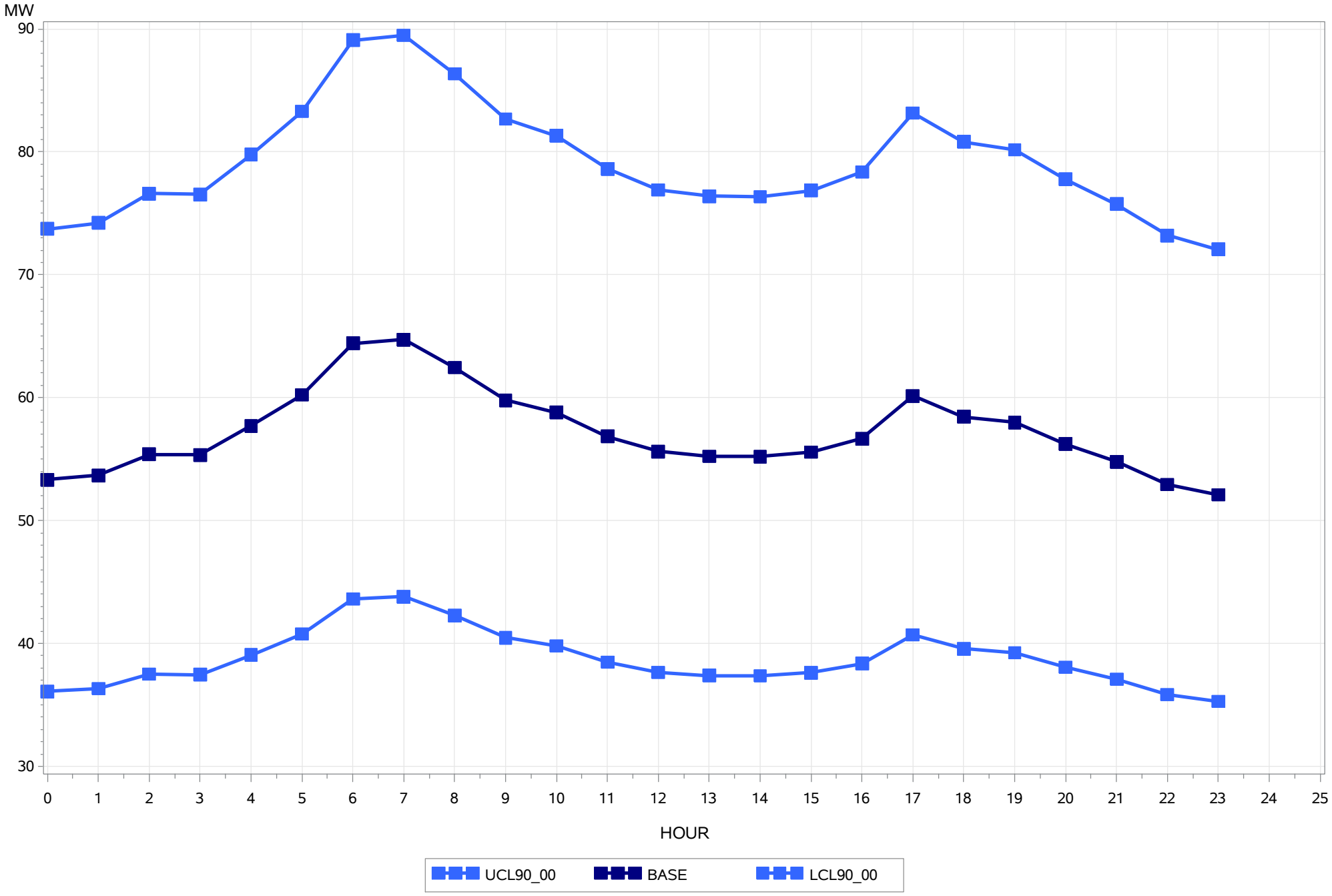
Date of Off Peak Day - 10/07/2021



Member Forecasted Off Peak Demand Day for November 2021

STATE OF NEBRASKA

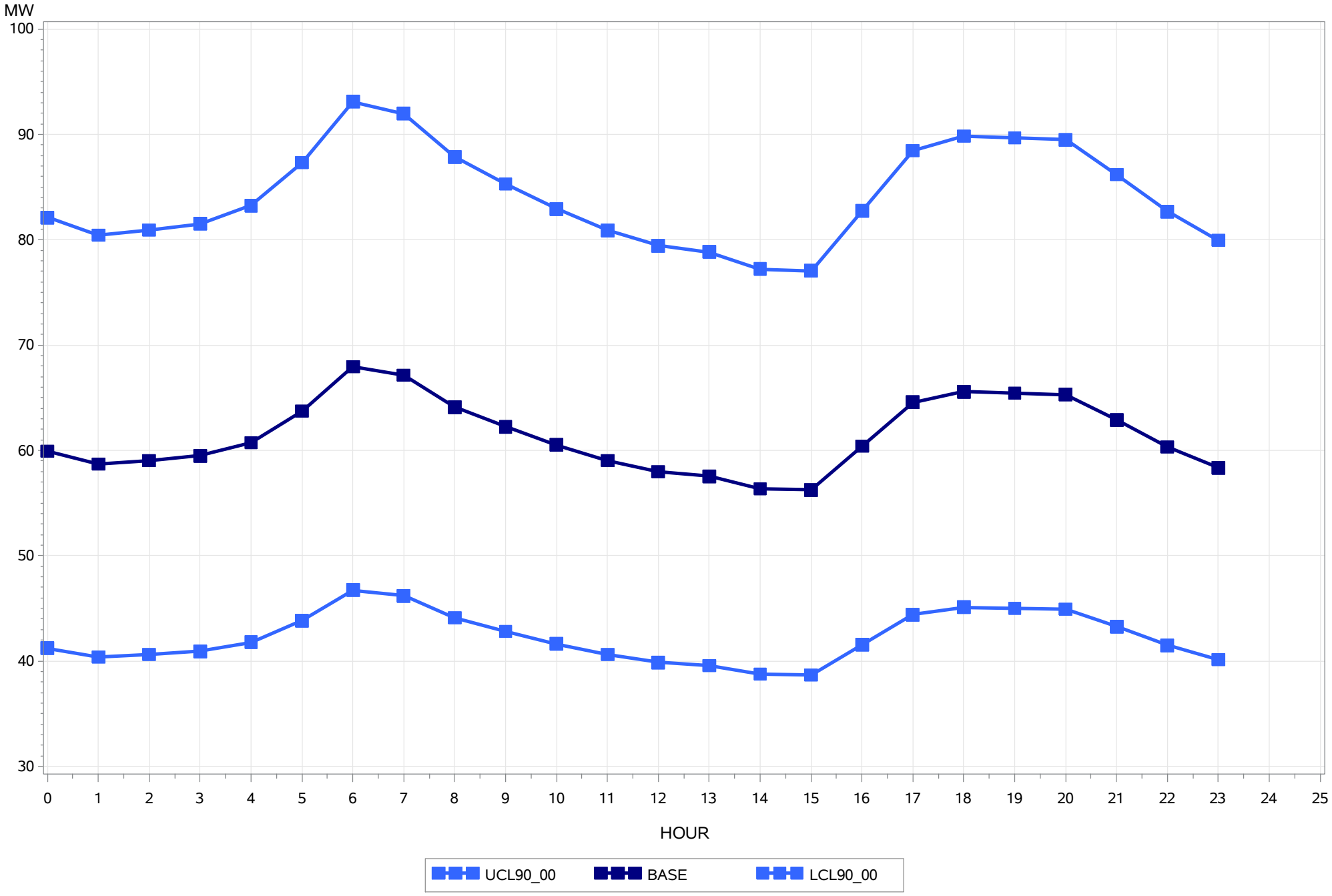
Date of Off Peak Day - 11/03/2021



Member Forecasted Off Peak Demand Day for December 2021

STATE OF NEBRASKA

Date of Off Peak Day - 12/08/2021



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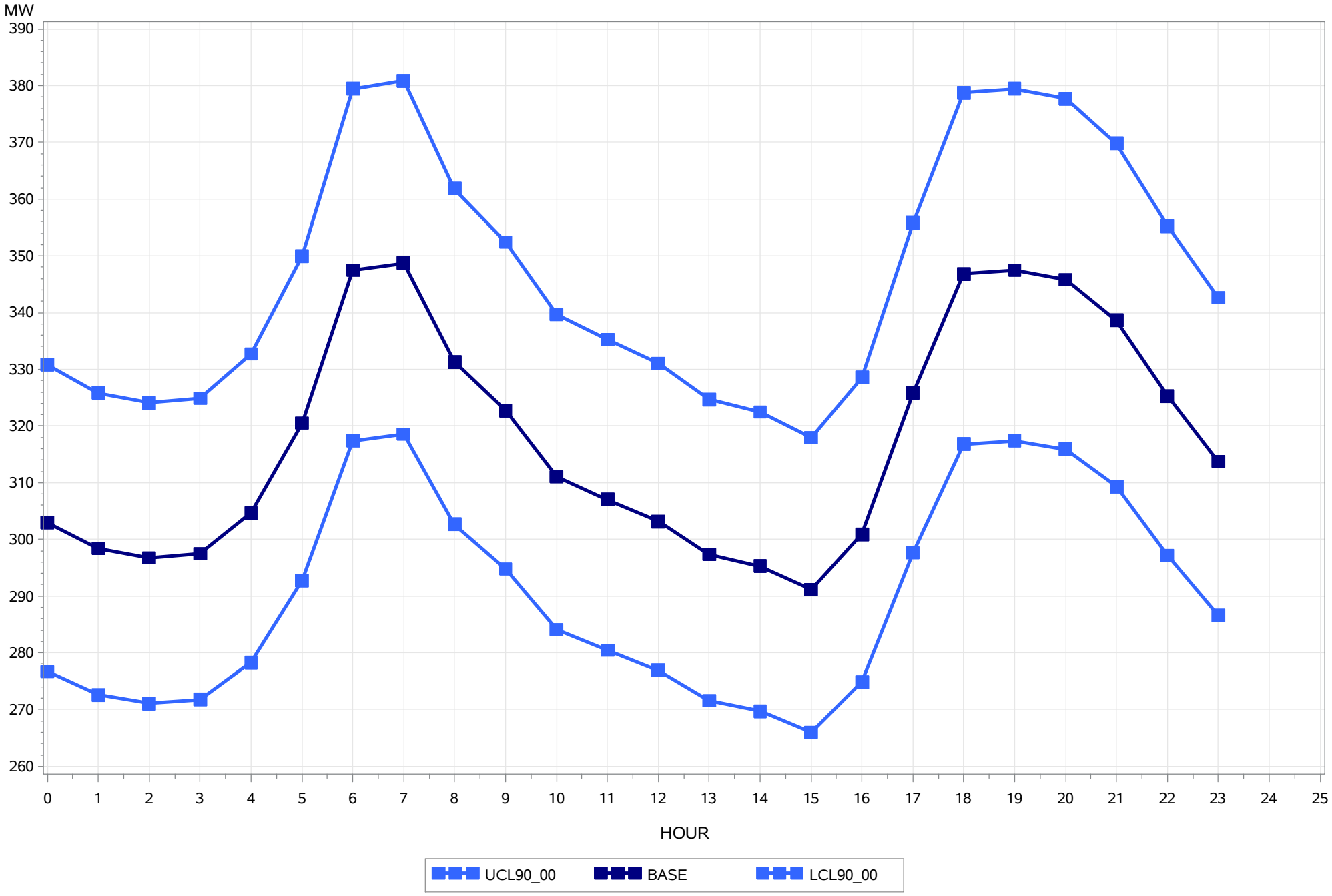
Member Forecasted Off Peak Demand Day for January 2021

STATE OF NEW MEXICO

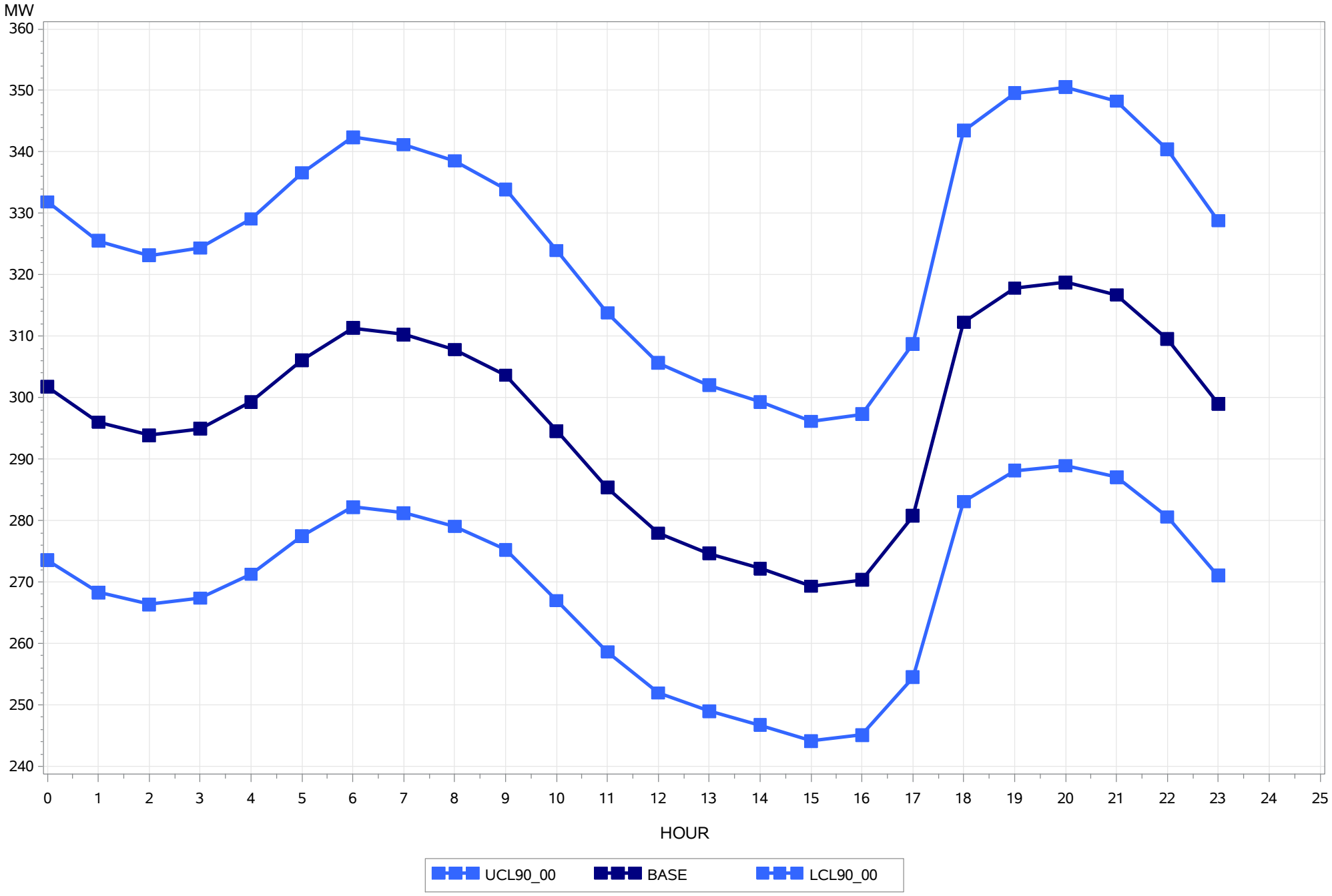
Date of Off Peak Day - 01/12/2021



Member Forecasted Off Peak Demand Day for February 2021

STATE OF NEW MEXICO

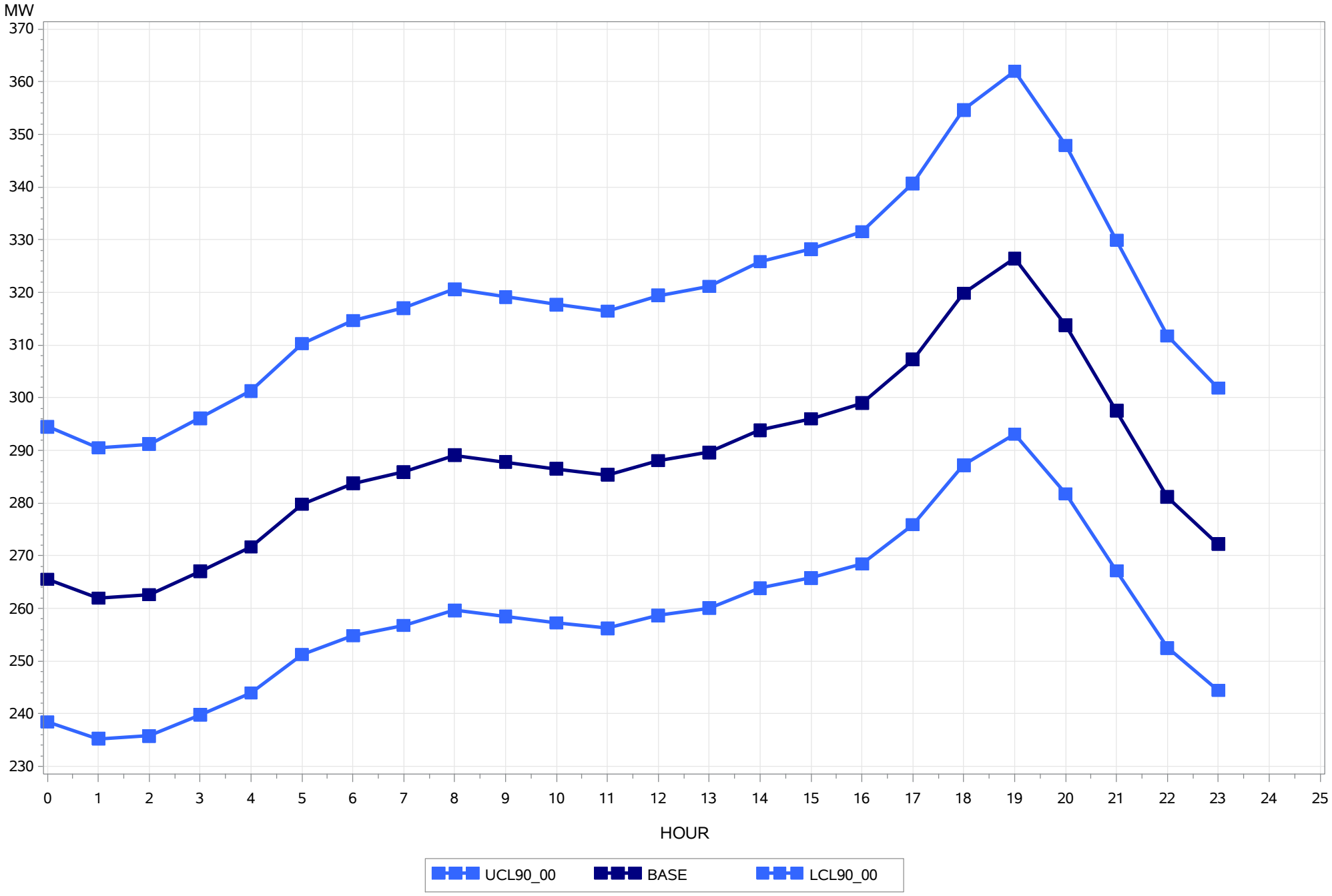
Date of Off Peak Day - 02/20/2021



Member Forecasted Off Peak Demand Day for March 2021

STATE OF NEW MEXICO

Date of Off Peak Day - 03/21/2021



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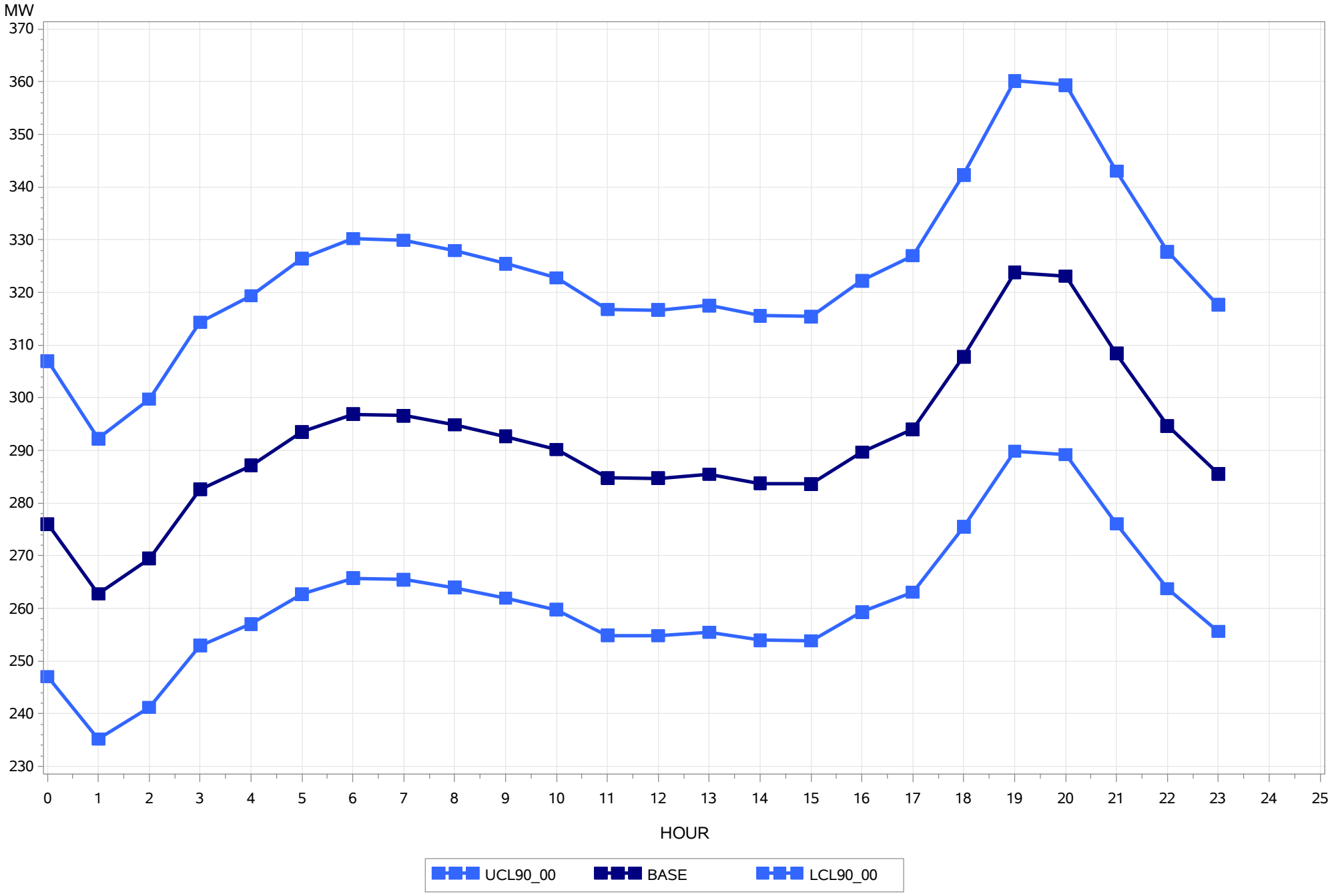
Member Forecasted Off Peak Demand Day for April 2021

STATE OF NEW MEXICO

Date of Off Peak Day - 04/03/2021



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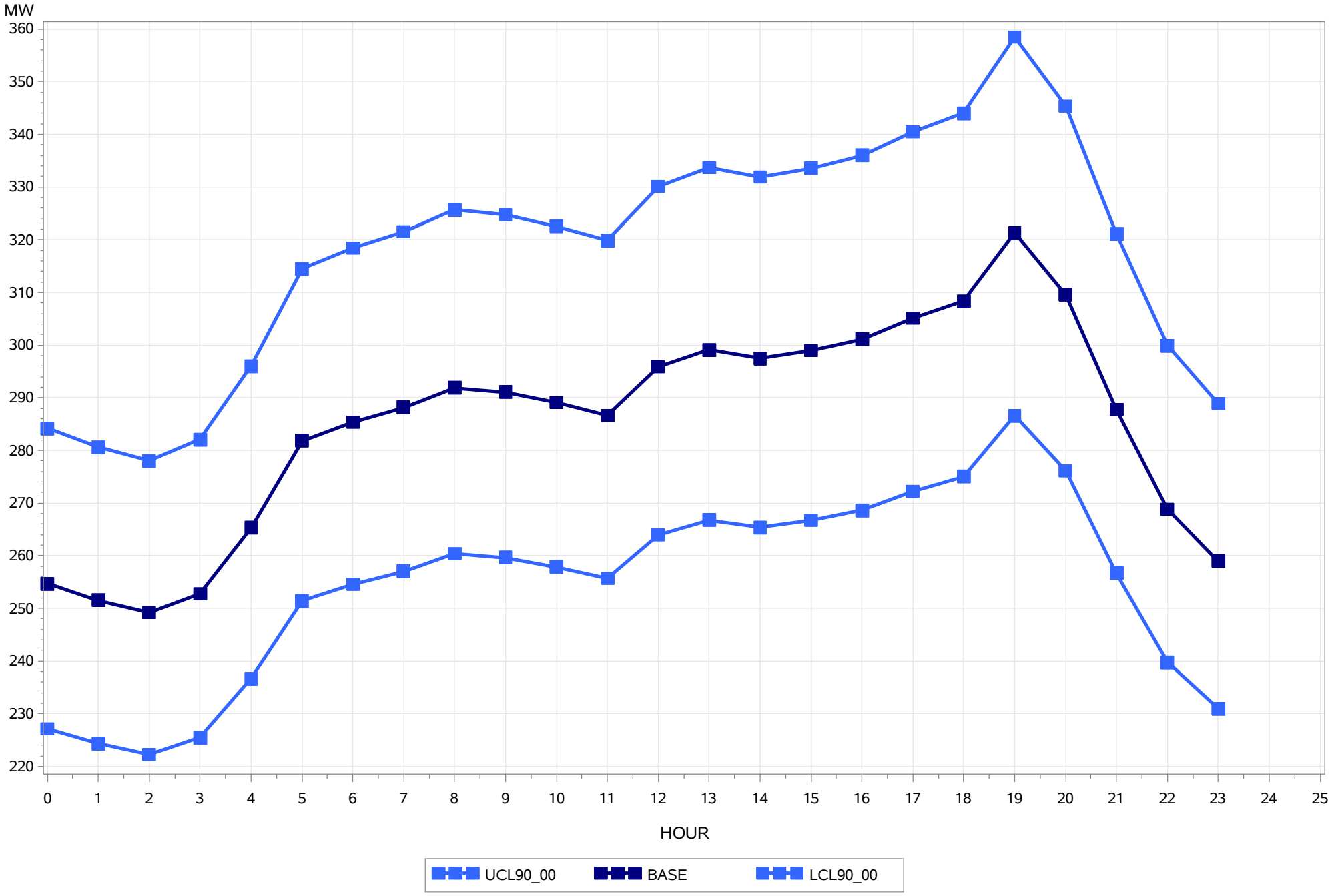
Member Forecasted Off Peak Demand Day for May 2021

STATE OF NEW MEXICO

Date of Off Peak Day - 05/03/2021



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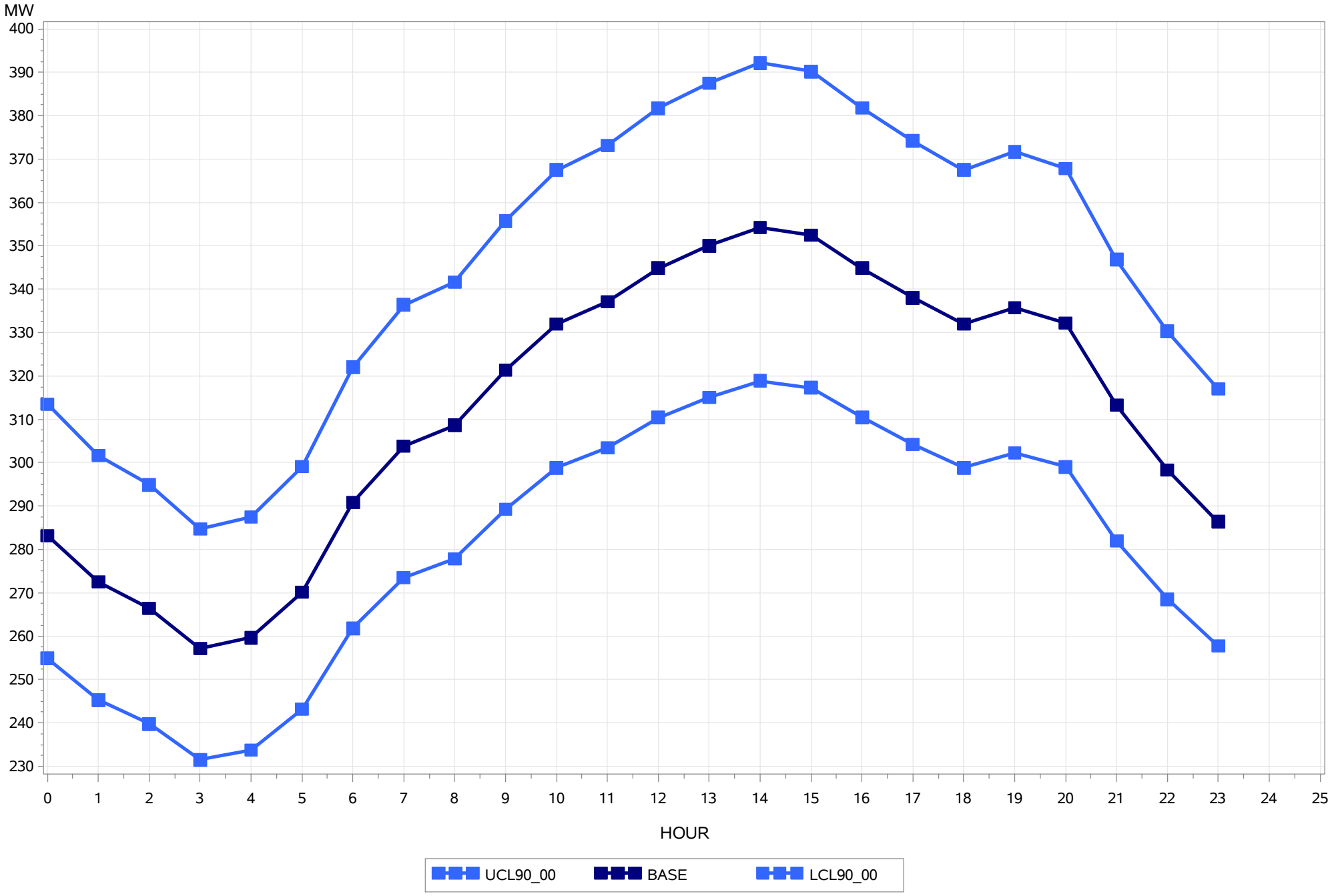
Member Forecasted Off Peak Demand Day for June 2021

STATE OF NEW MEXICO

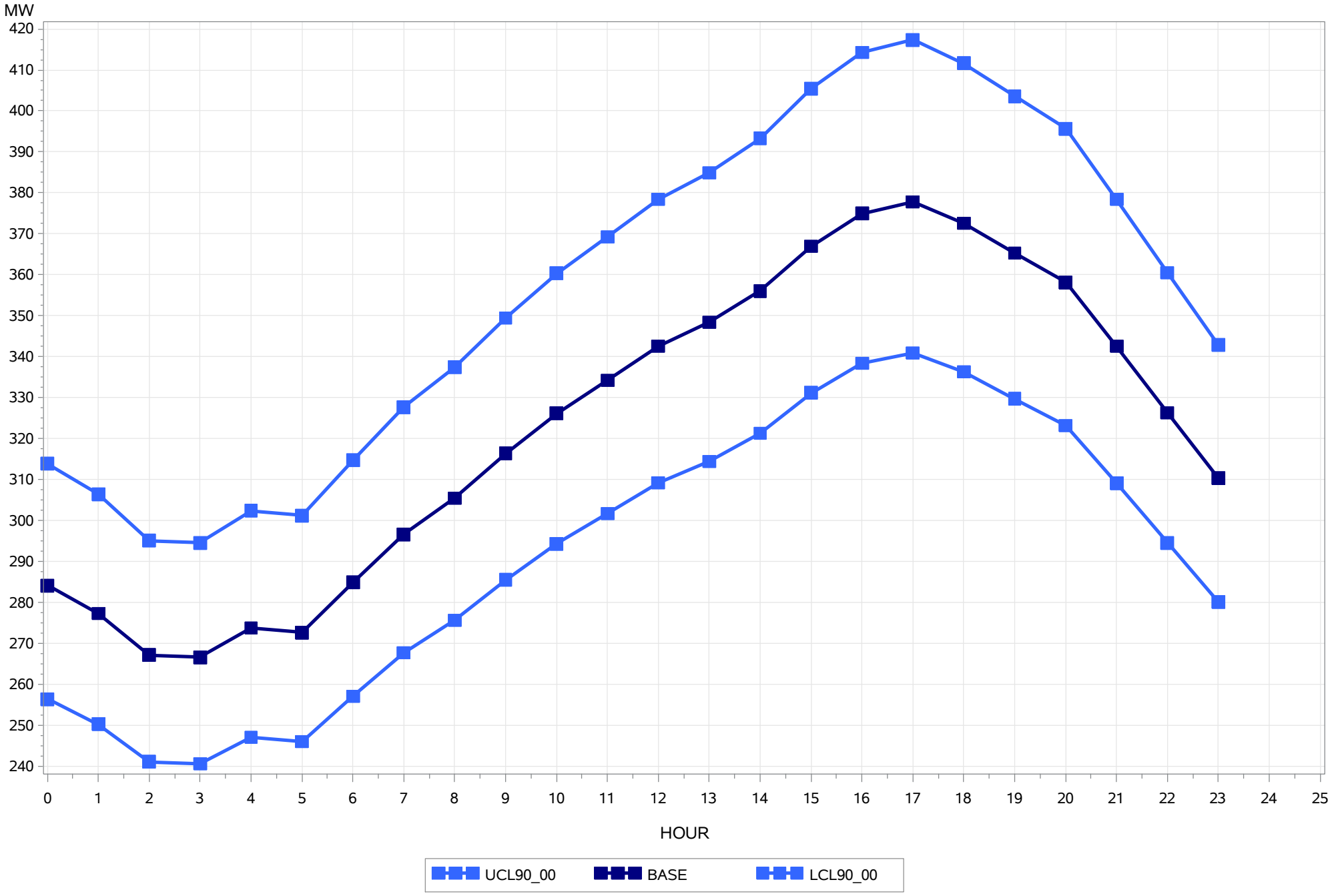
Date of Off Peak Day - 06/03/2021



Member Forecasted Off Peak Demand Day for July 2021

STATE OF NEW MEXICO

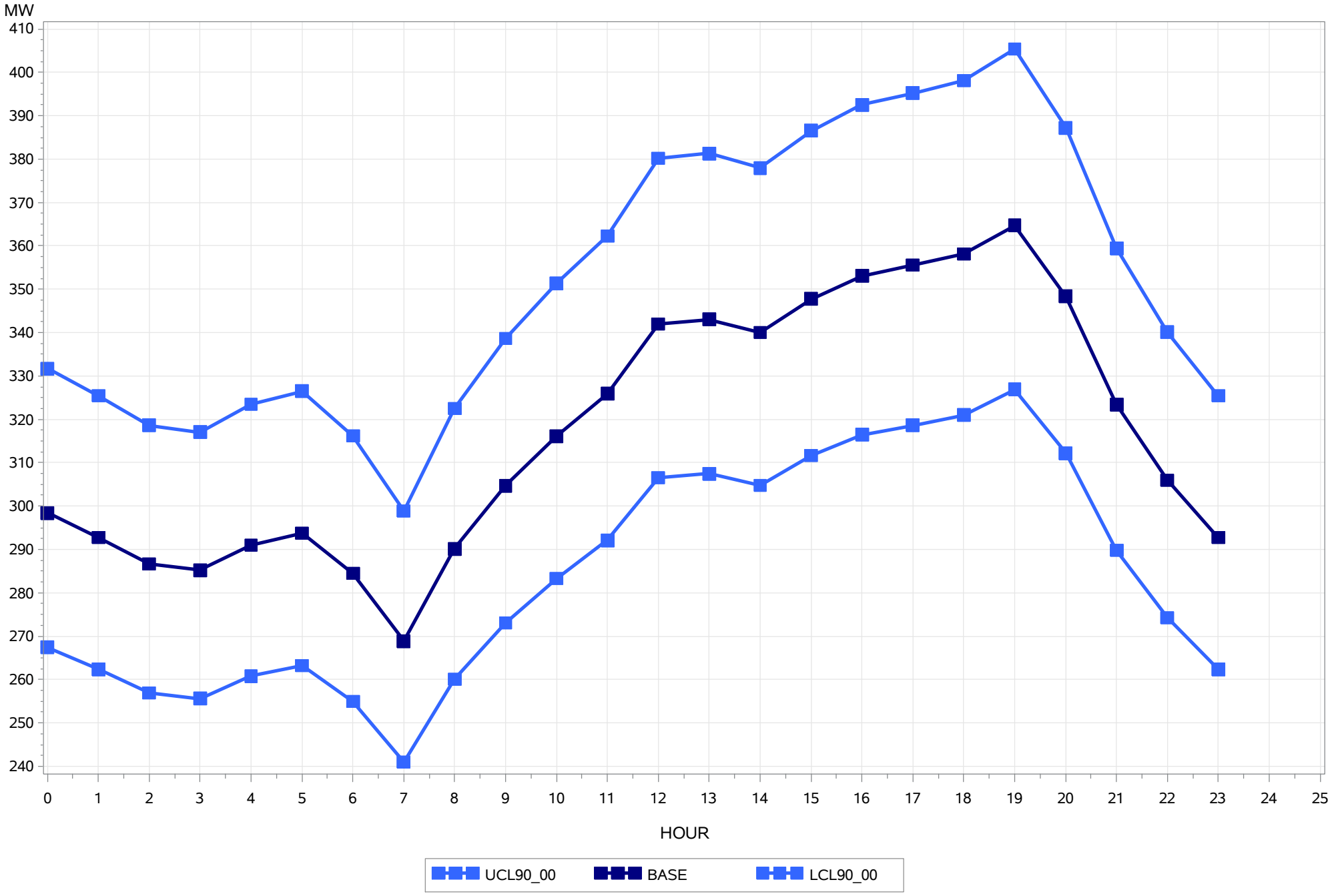
Date of Off Peak Day - 07/03/2021



Member Forecasted Off Peak Demand Day for August 2021

STATE OF NEW MEXICO

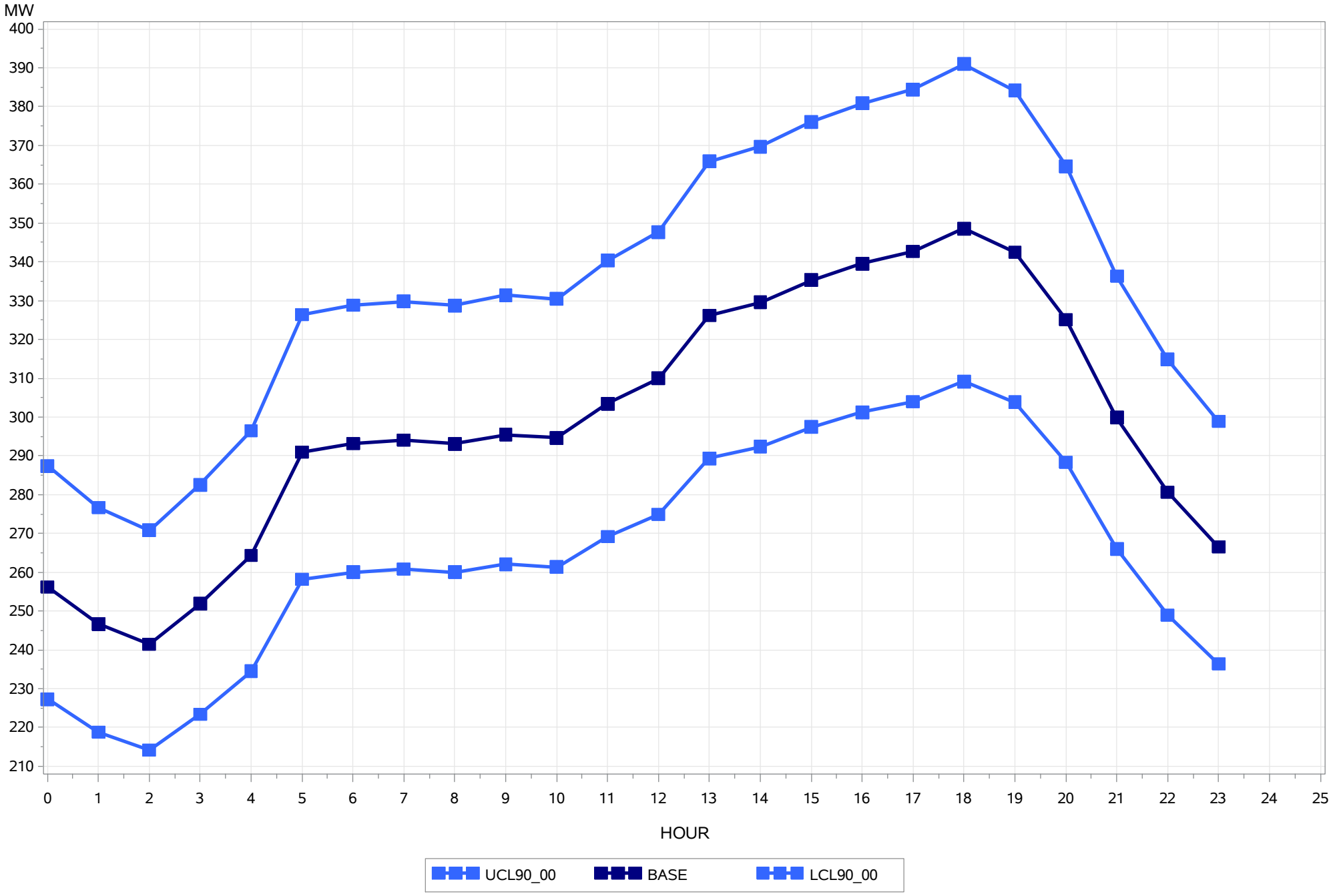
Date of Off Peak Day - 08/29/2021



Member Forecasted Off Peak Demand Day for September 2021

STATE OF NEW MEXICO

Date of Off Peak Day - 09/28/2021



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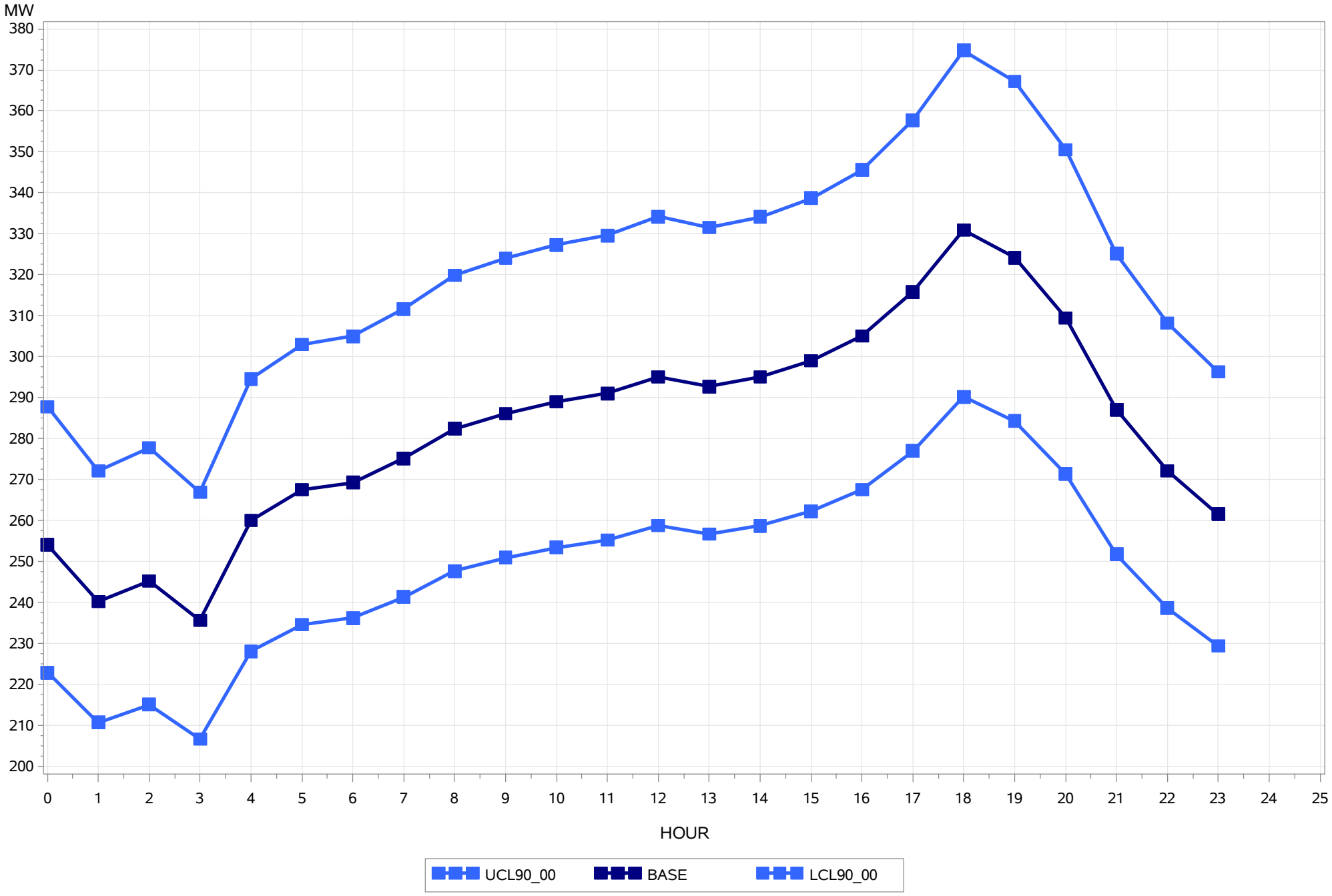
Member Forecasted Off Peak Demand Day for October 2021

STATE OF NEW MEXICO

Date of Off Peak Day - 10/03/2021



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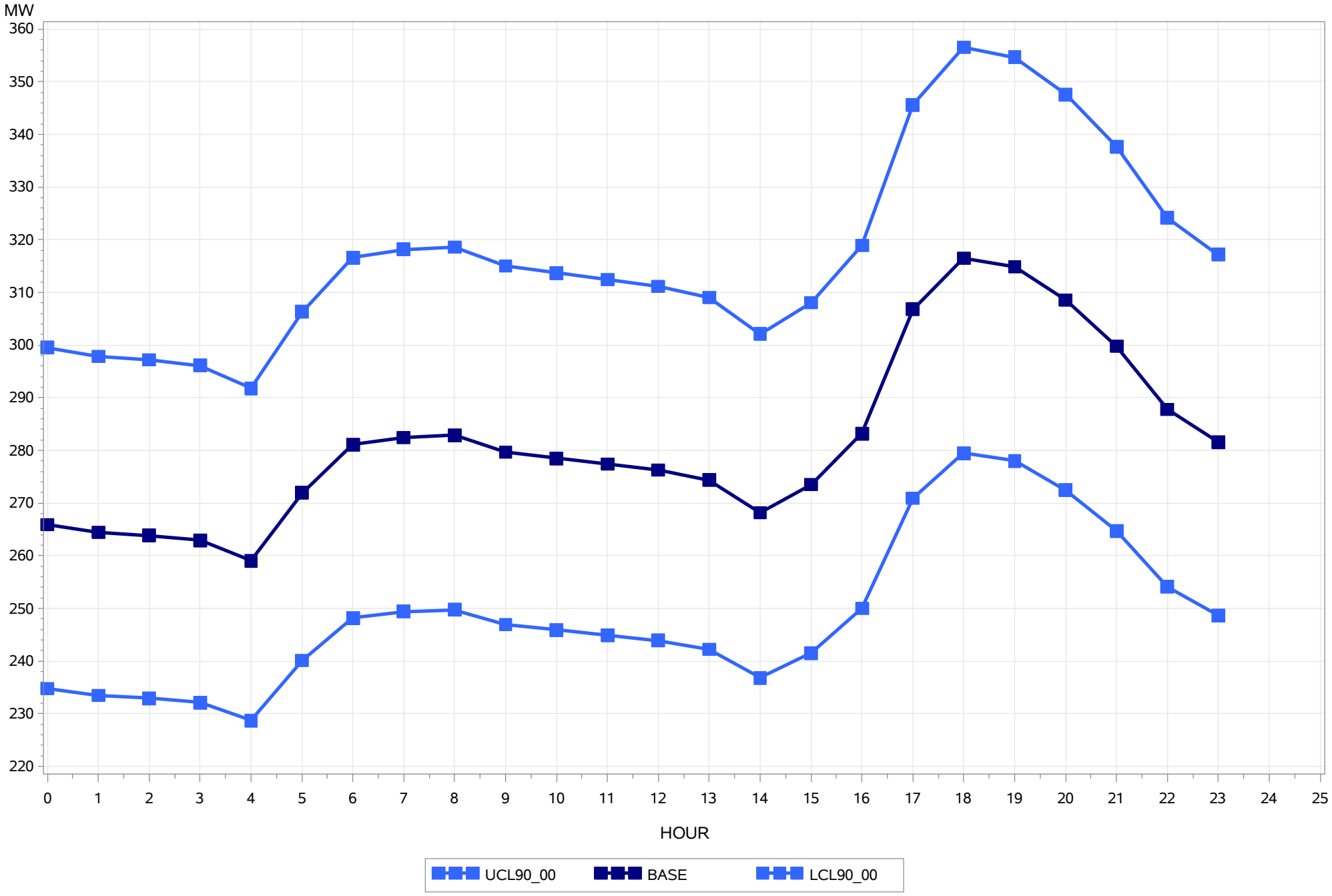
Member Forecasted Off Peak Demand Day for November 2021

STATE OF NEW MEXICO

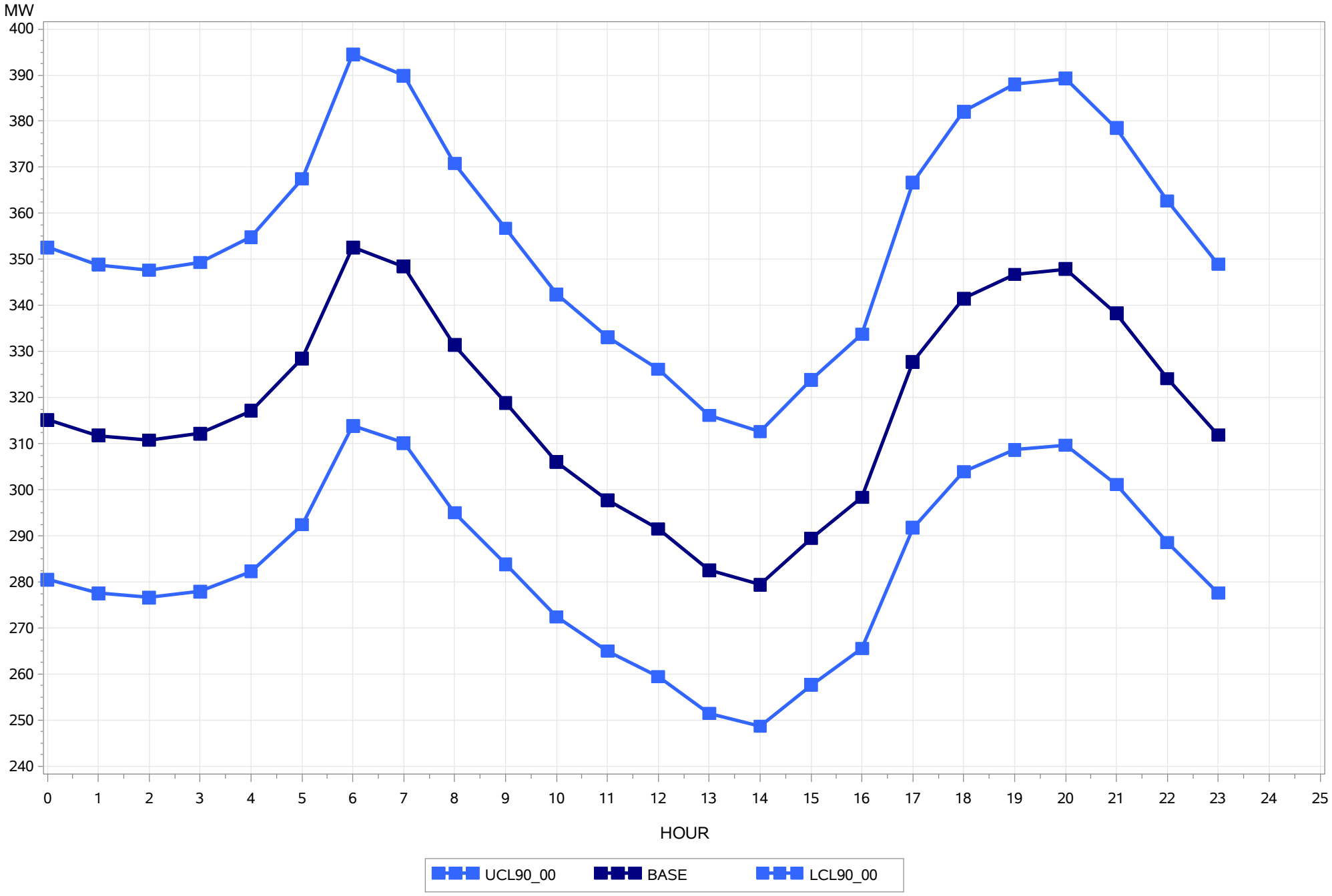
Date of Off Peak Day - 11/07/2021



Member Forecasted Off Peak Demand Day for December 2021

STATE OF NEW MEXICO

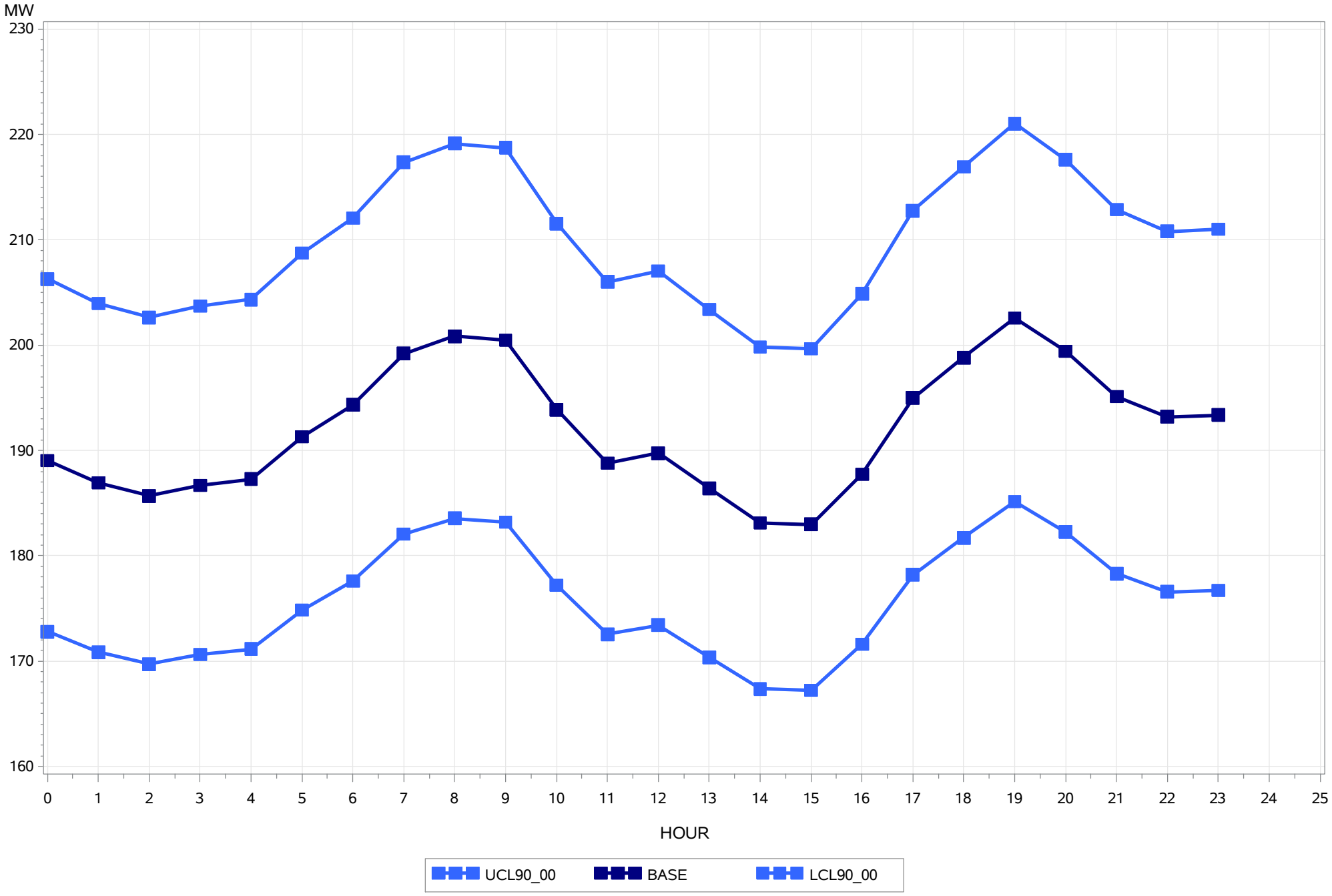
Date of Off Peak Day - 12/08/2021



Member Forecasted Off Peak Demand Day for January 2021

STATE OF WYOMING

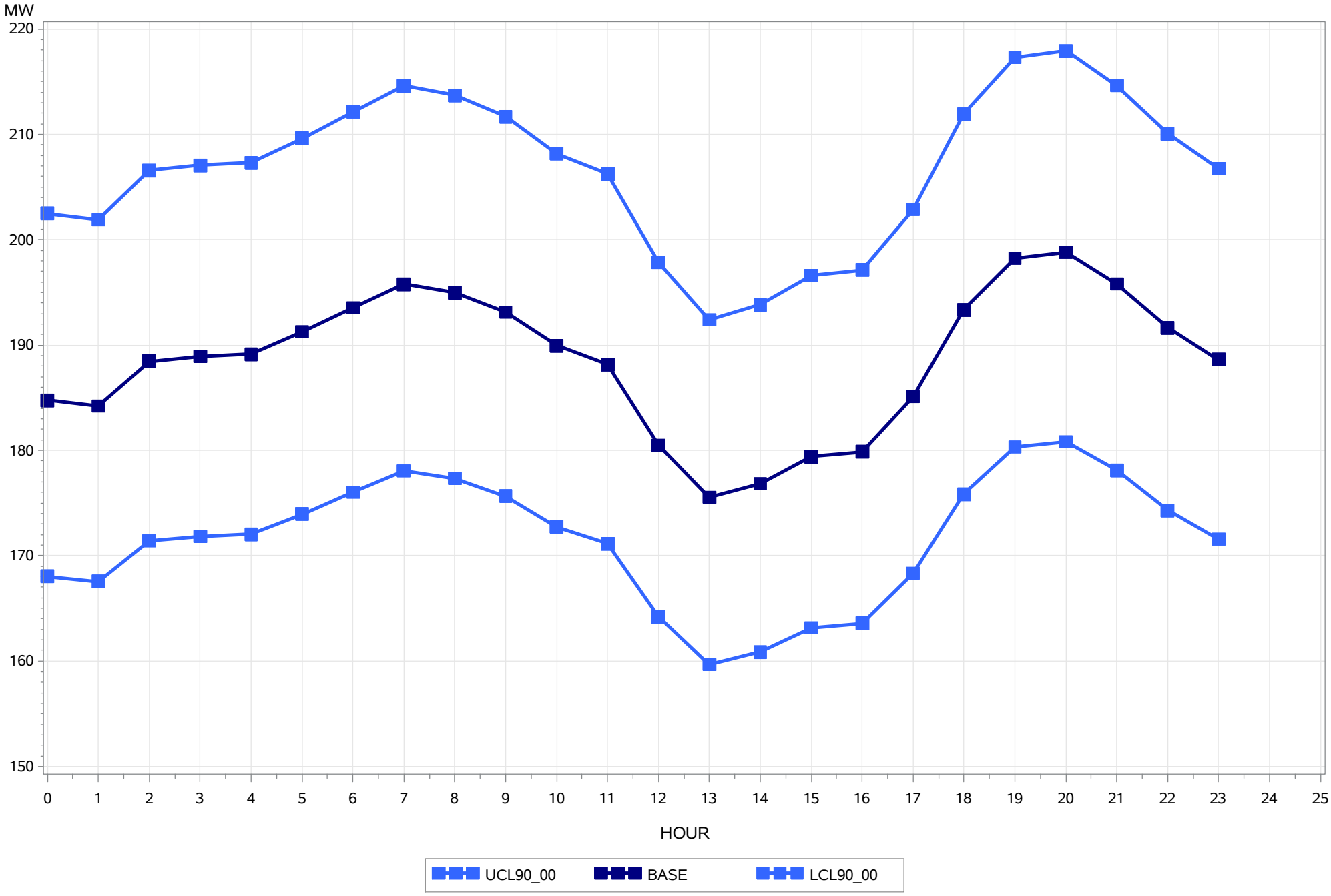
Date of Off Peak Day - 01/31/2021



Member Forecasted Off Peak Demand Day for February 2021

STATE OF WYOMING

Date of Off Peak Day - 02/21/2021



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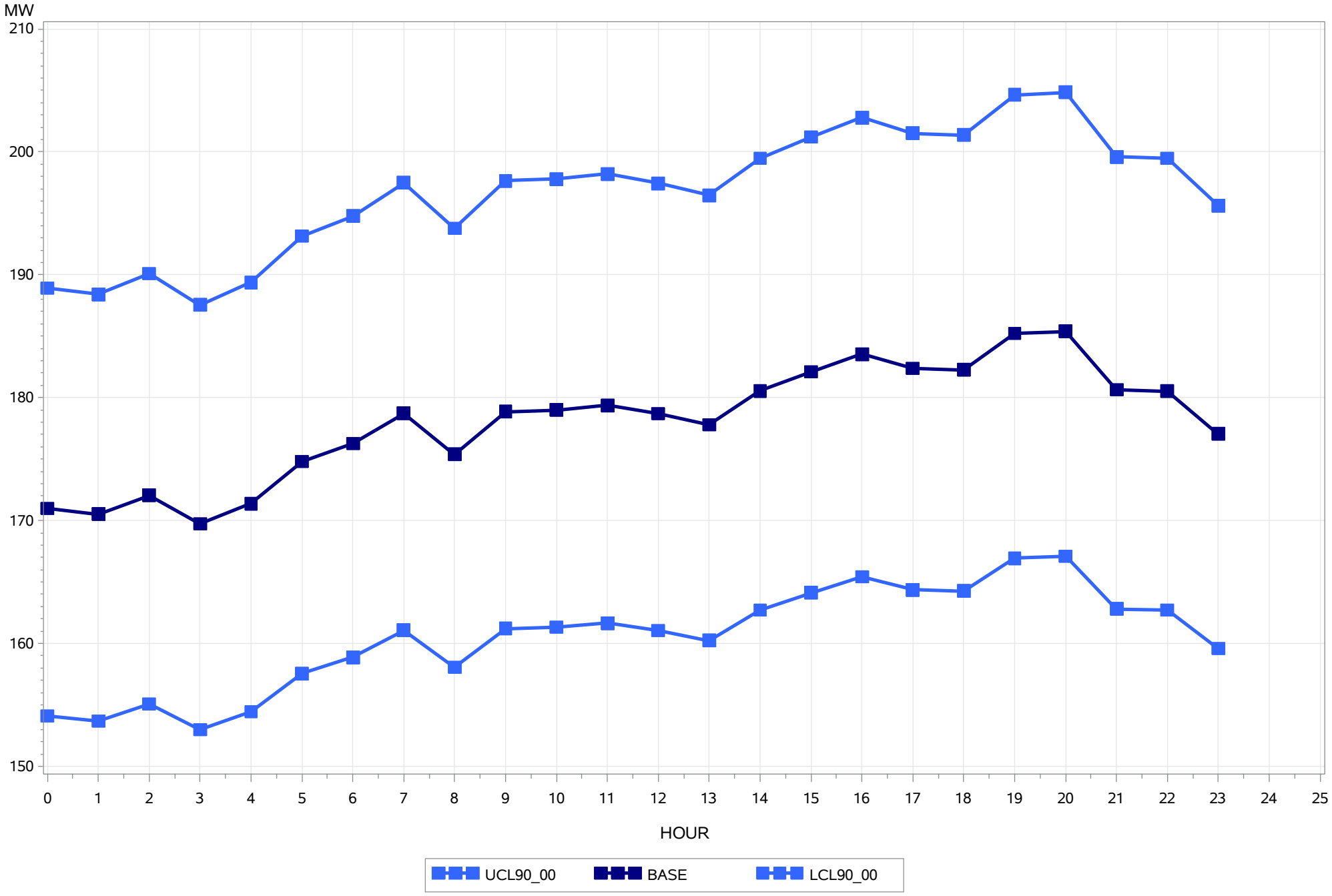
Member Forecasted Off Peak Demand Day for March 2021

STATE OF WYOMING

Date of Off Peak Day - 03/21/2021



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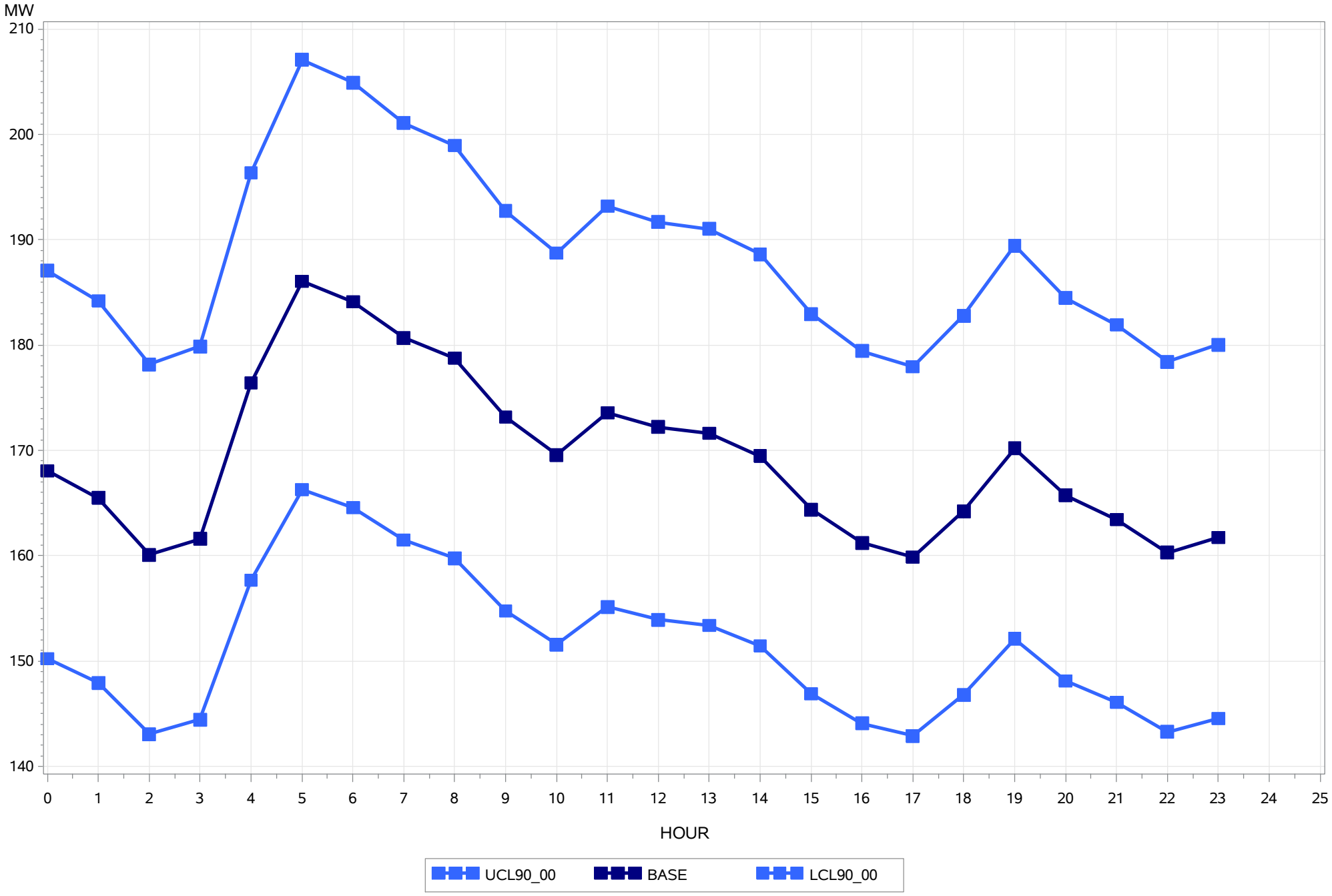
Member Forecasted Off Peak Demand Day for April 2021

STATE OF WYOMING

Date of Off Peak Day - 04/29/2021



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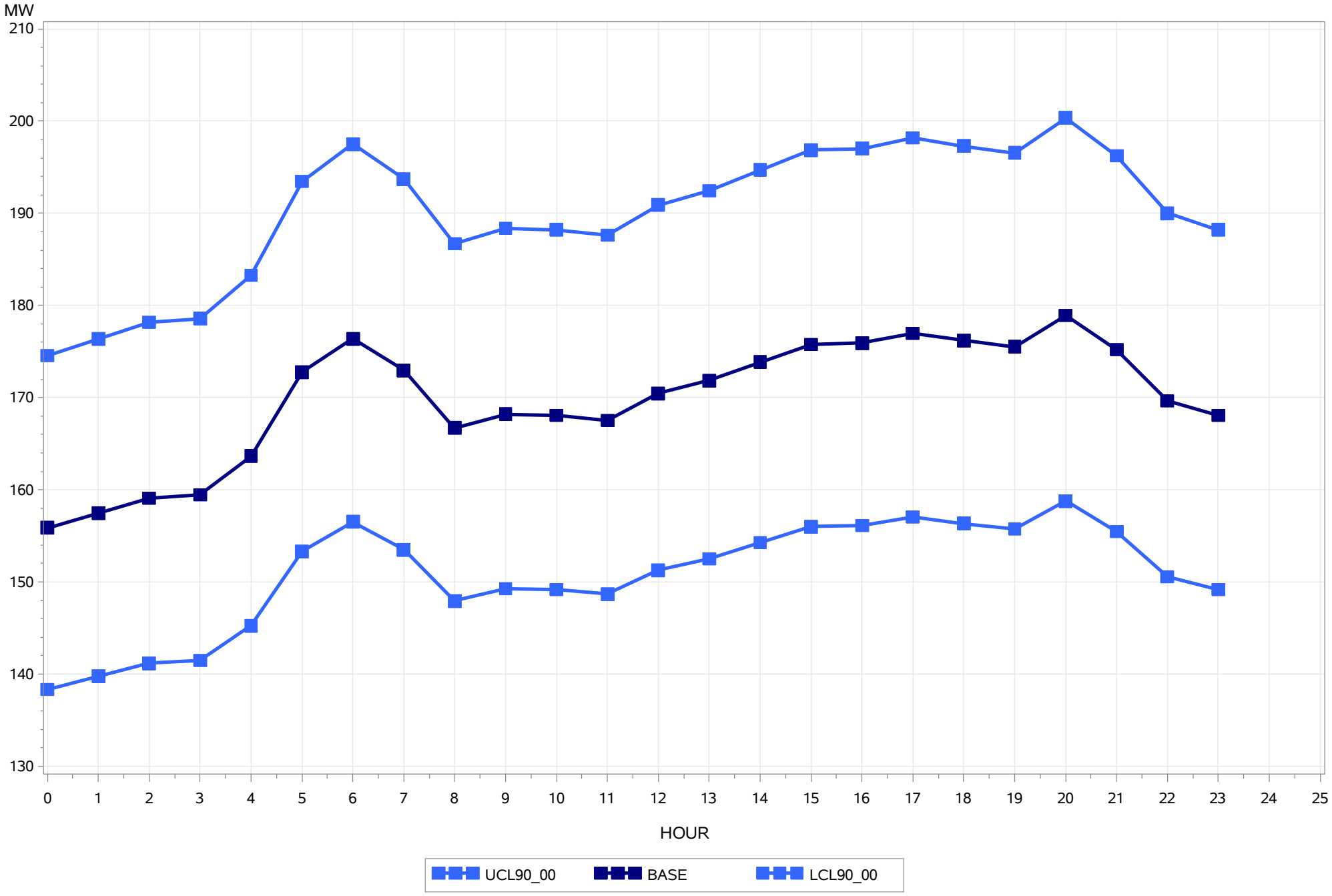
Member Forecasted Off Peak Demand Day for May 2021

STATE OF WYOMING

Date of Off Peak Day - 05/12/2021



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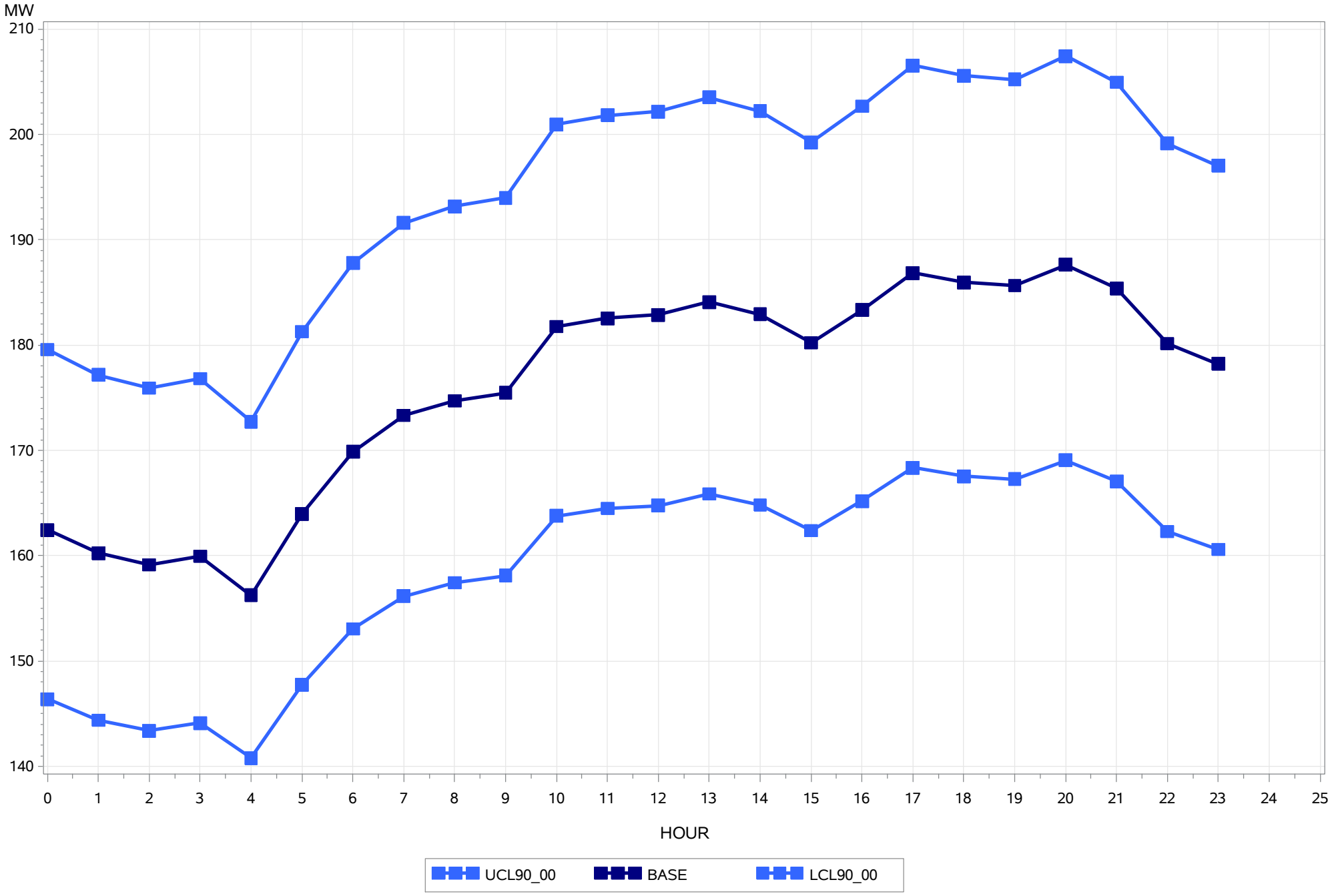
Member Forecasted Off Peak Demand Day for June 2021

STATE OF WYOMING

Date of Off Peak Day - 06/01/2021



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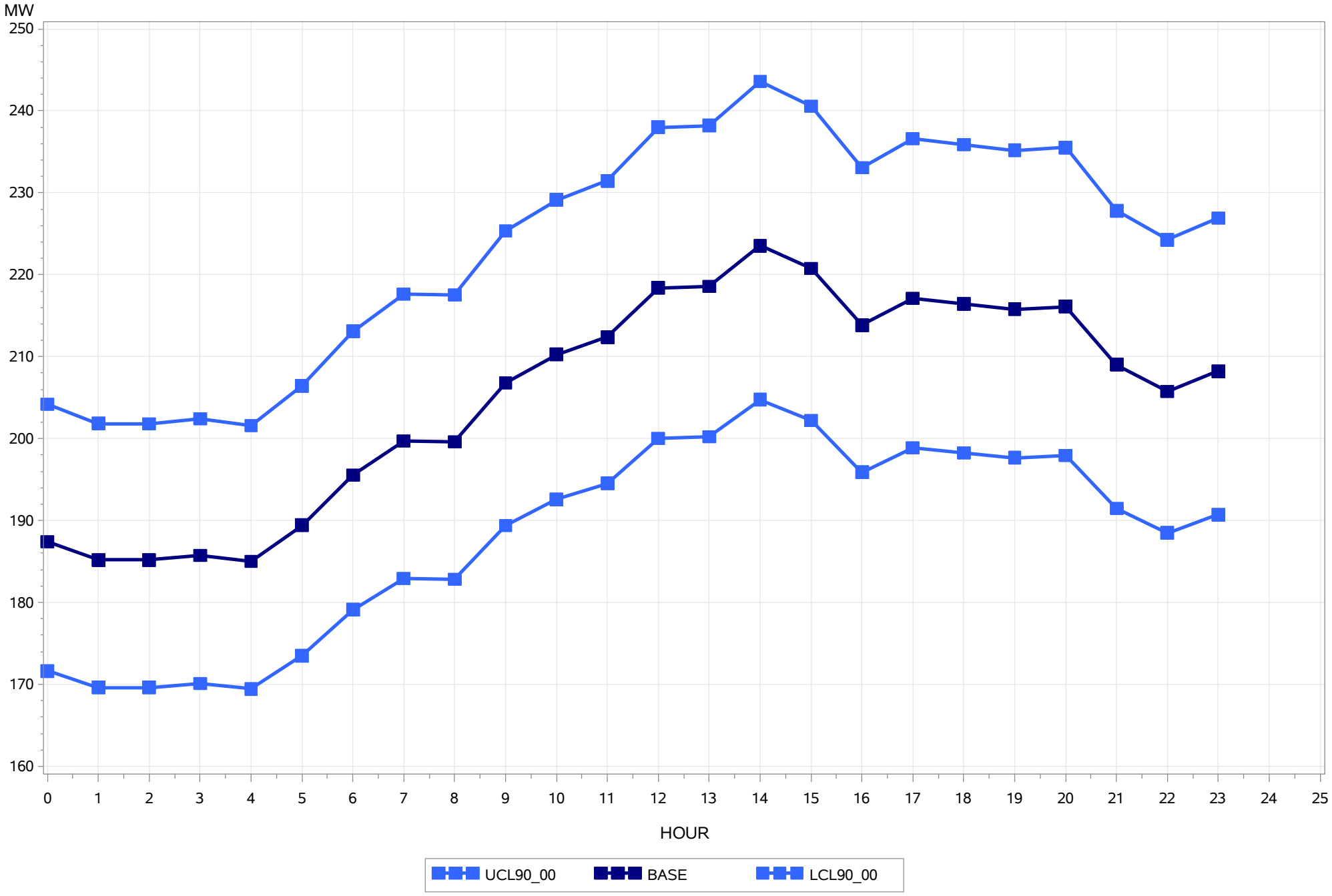
Member Forecasted Off Peak Demand Day for July 2021

STATE OF WYOMING

Date of Off Peak Day - 07/01/2021



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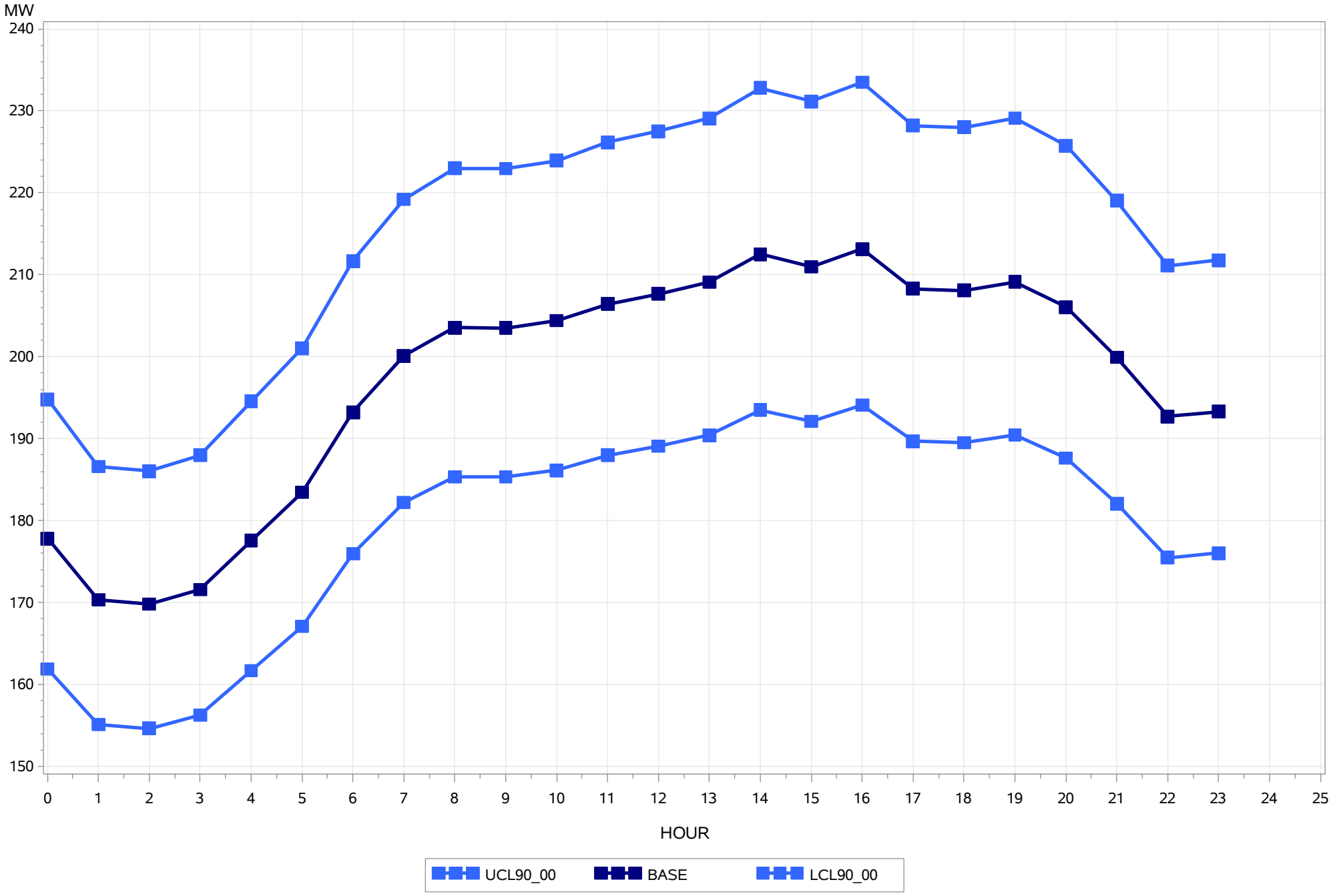
Member Forecasted Off Peak Demand Day for August 2021

STATE OF WYOMING

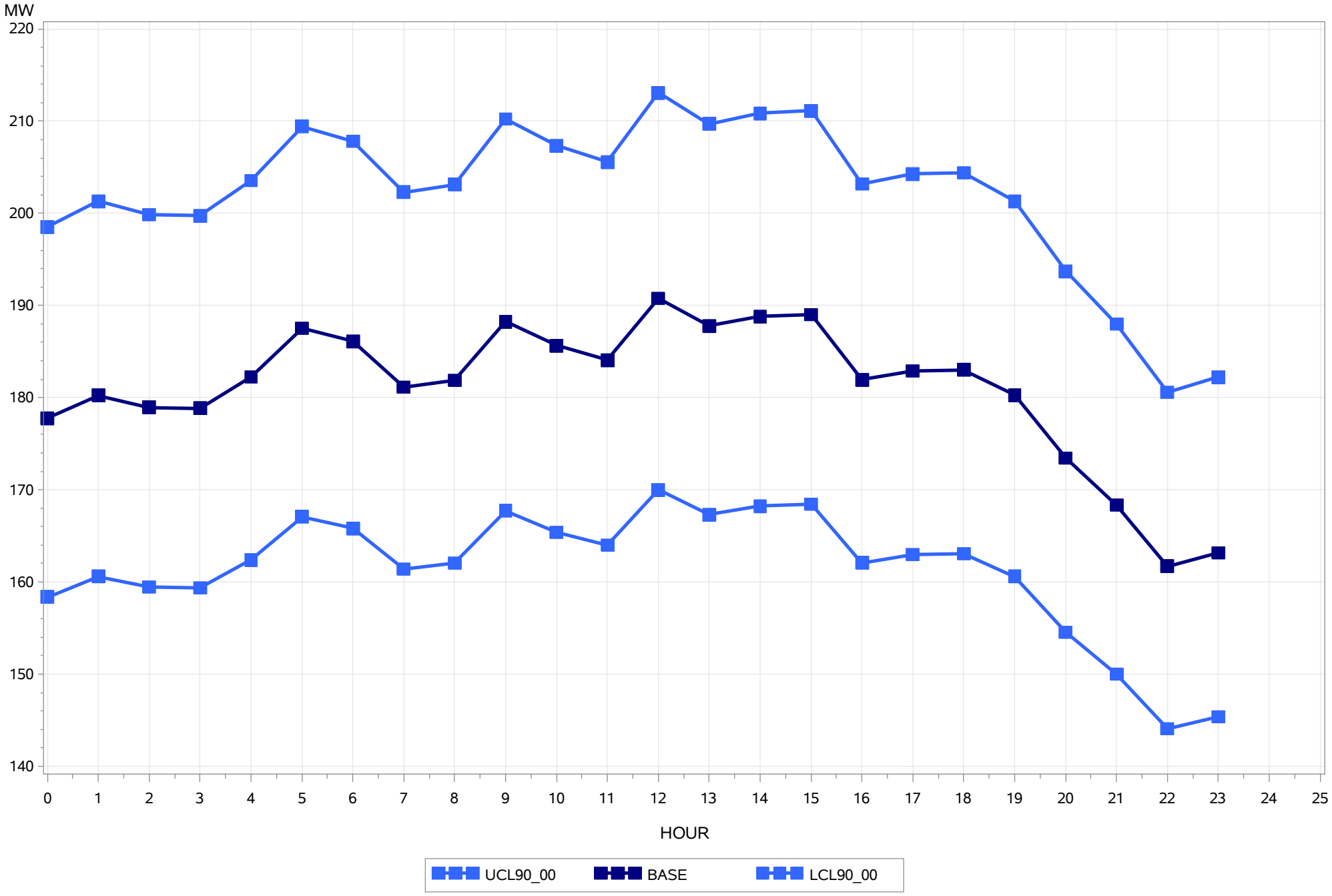
Date of Off Peak Day - 08/16/2021



Member Forecasted Off Peak Demand Day for September 2021

STATE OF WYOMING

Date of Off Peak Day - 09/30/2021



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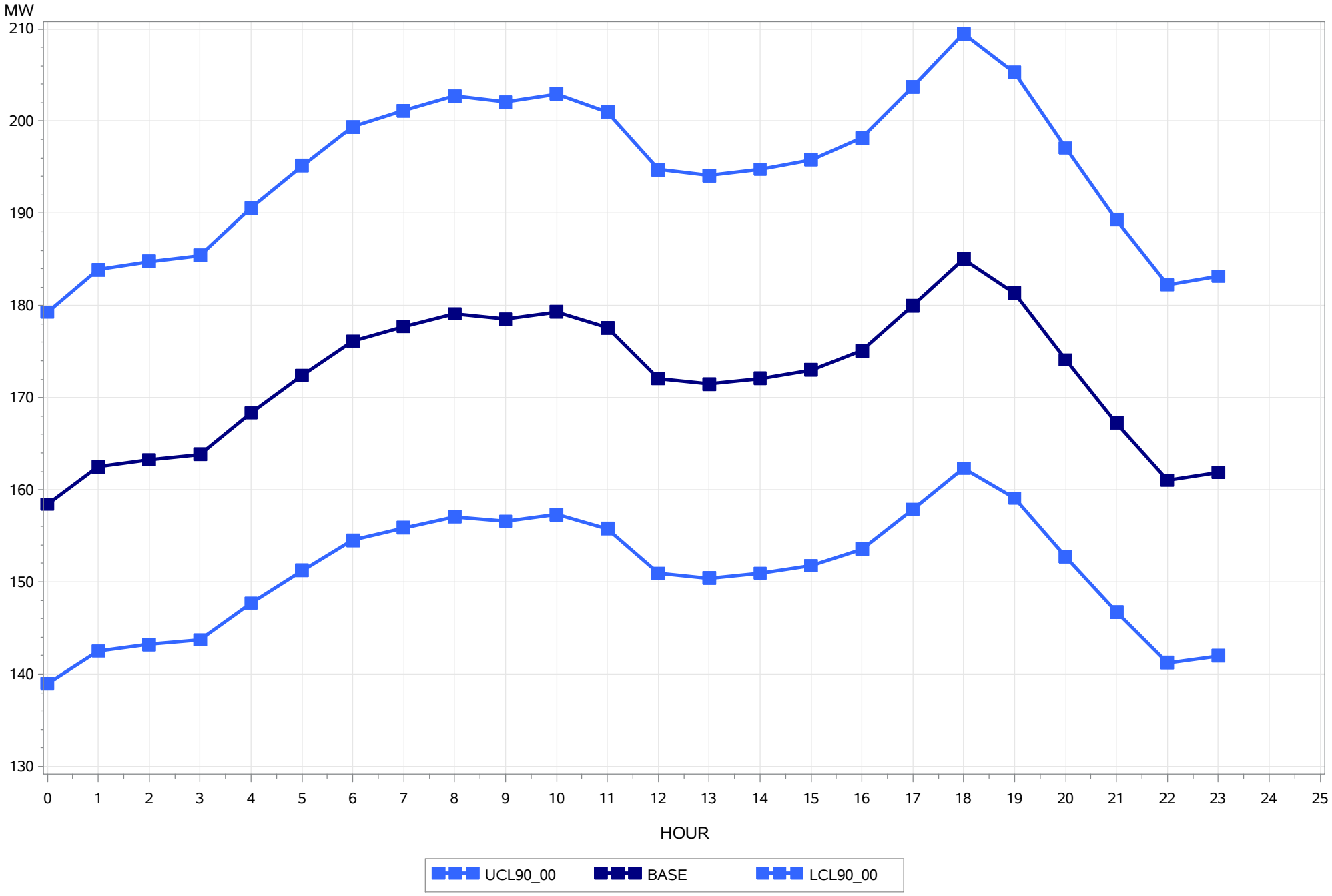
Member Forecasted Off Peak Demand Day for October 2021

STATE OF WYOMING

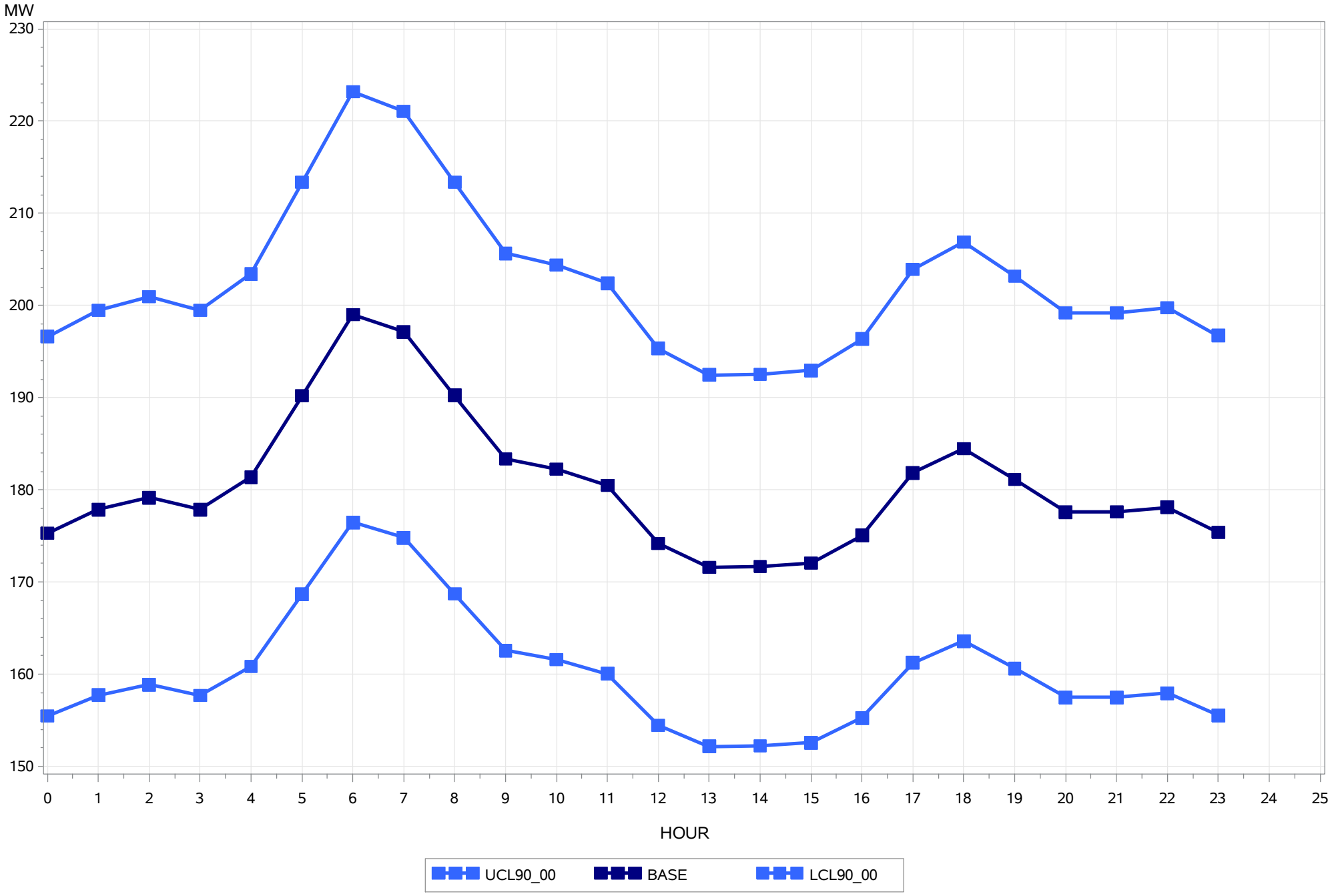
Date of Off Peak Day - 10/10/2021



Member Forecasted Off Peak Demand Day for November 2021

STATE OF WYOMING

Date of Off Peak Day - 11/03/2021



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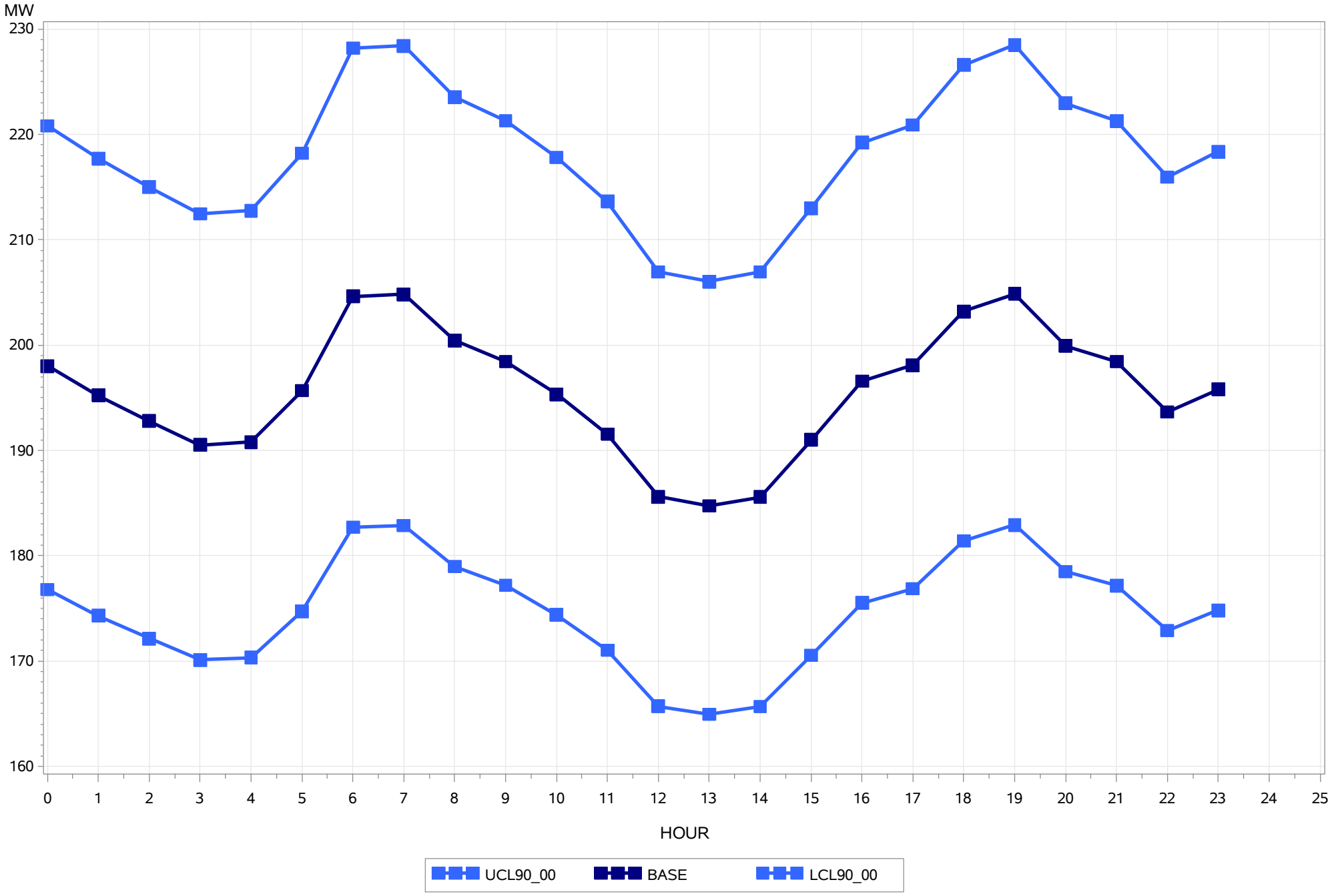
Member Forecasted Off Peak Demand Day for December 2021

STATE OF WYOMING

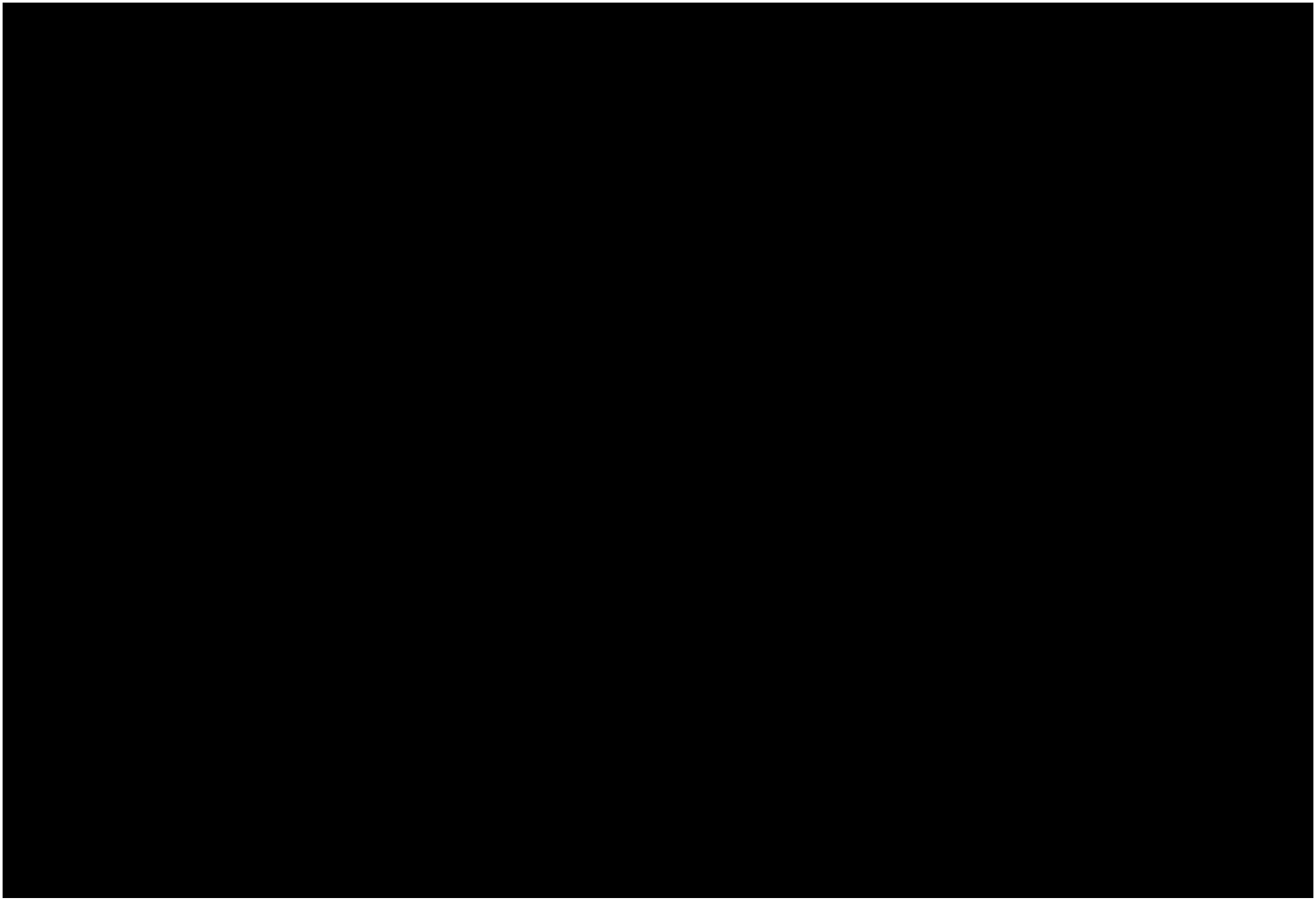
Date of Off Peak Day - 12/09/2021



Member Forecasted Off Peak Demand Day for January 2021

Big Horn Rural Electric Company

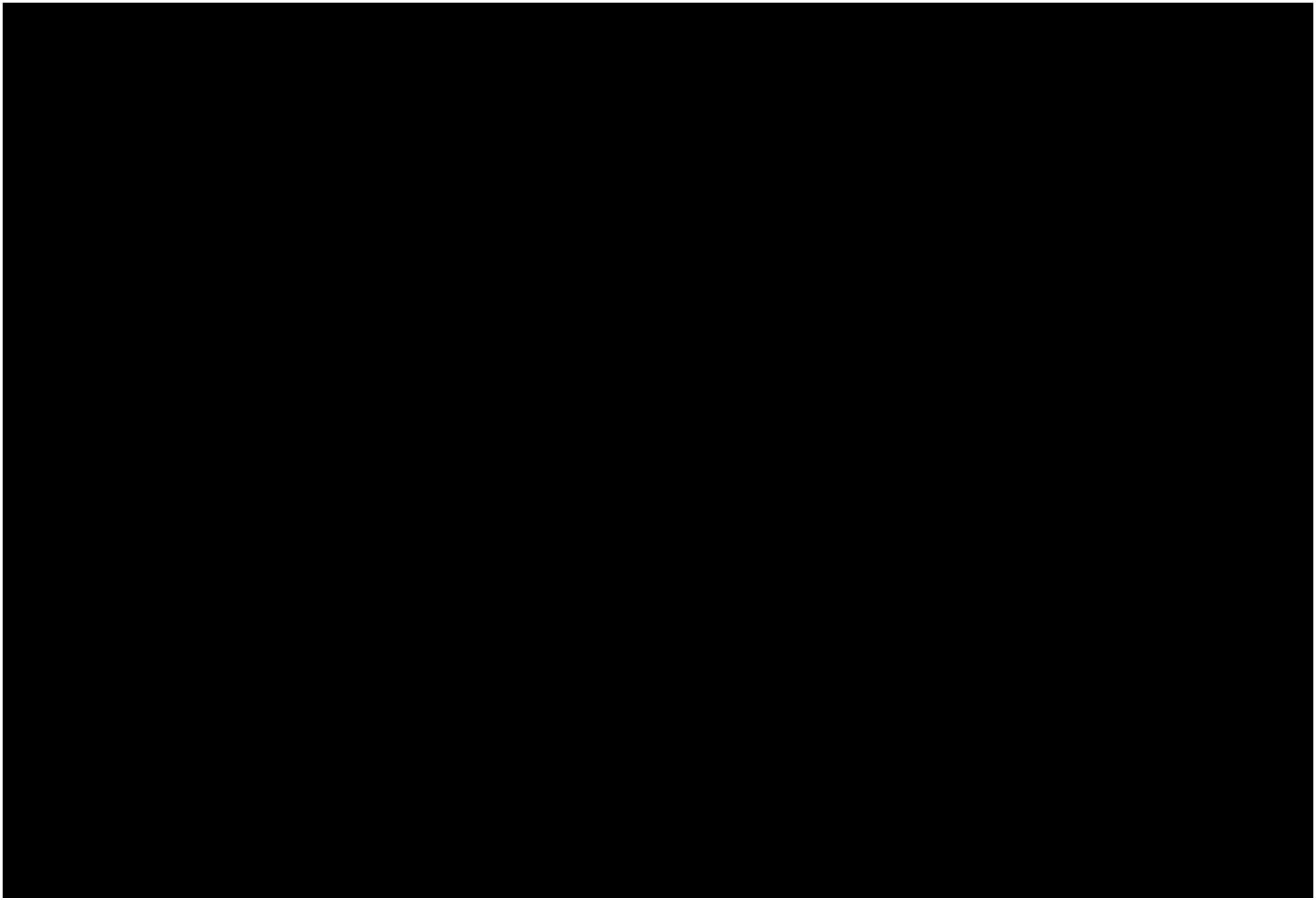
Date of Off Peak Day - 01/31/2021



Member Forecasted Off Peak Demand Day for February 2021

Big Horn Rural Electric Company

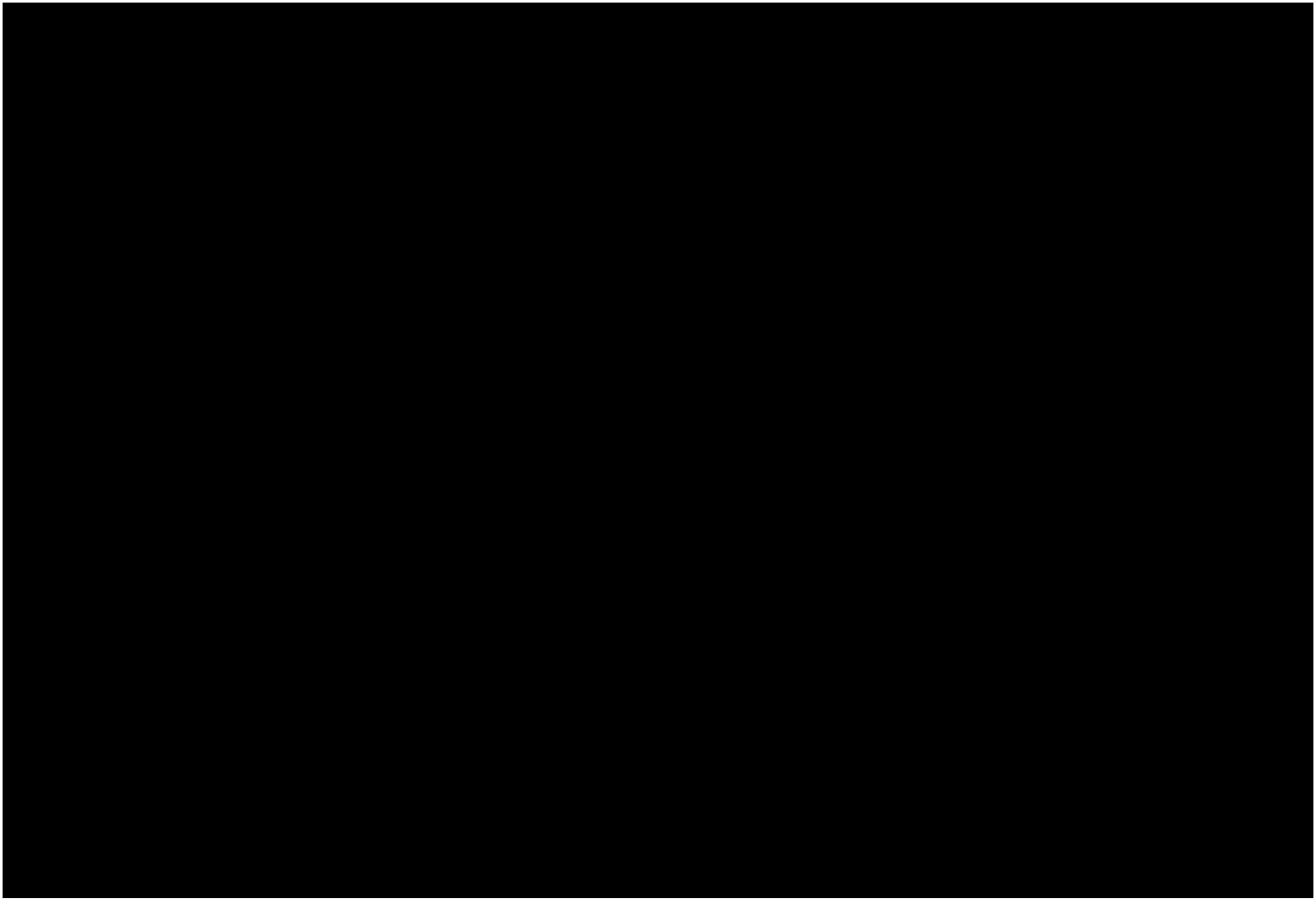
Date of Off Peak Day - 02/27/2021



Member Forecasted Off Peak Demand Day for March 2021

Big Horn Rural Electric Company

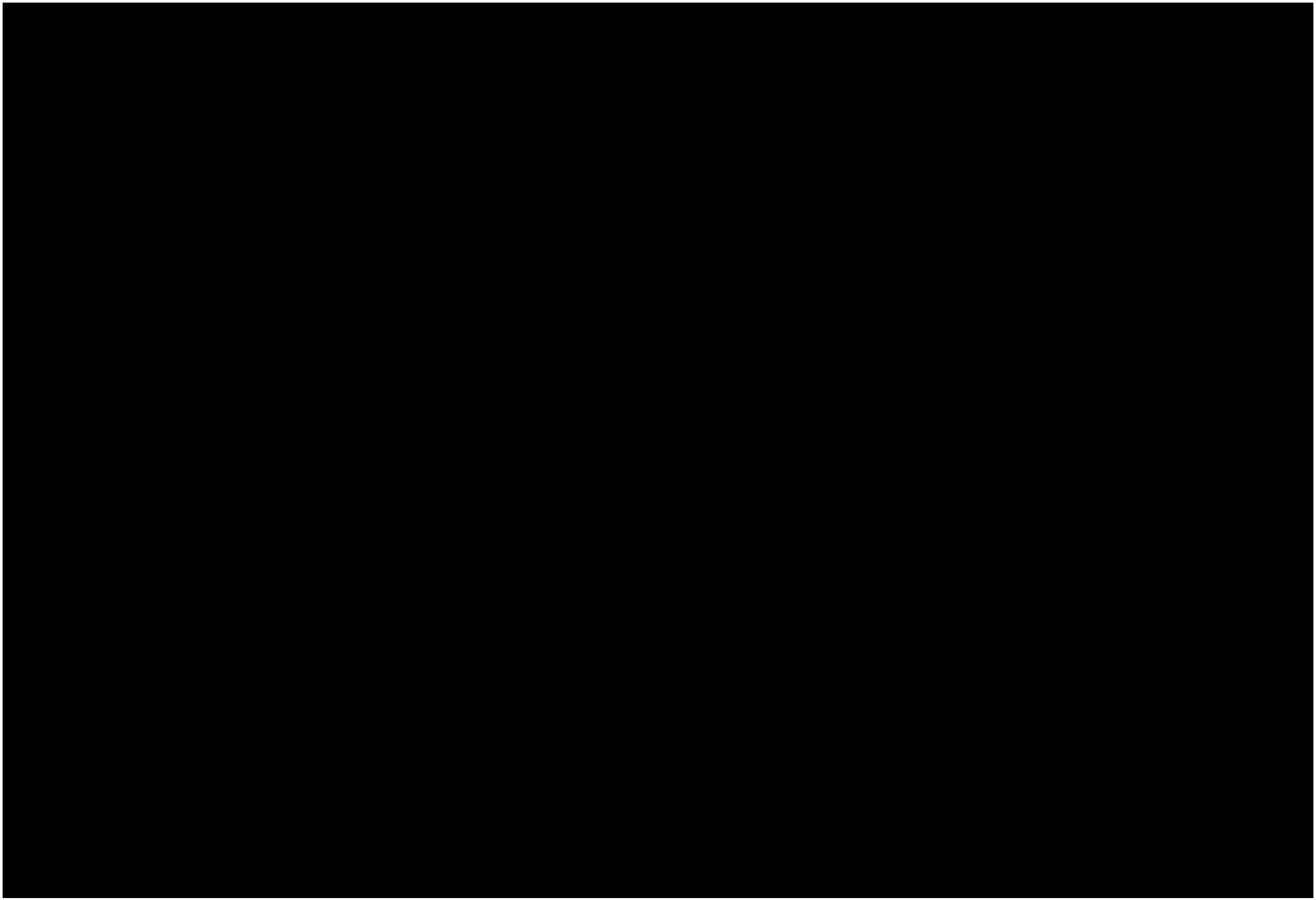
Date of Off Peak Day - 03/27/2021



Member Forecasted Off Peak Demand Day for April 2021

Big Horn Rural Electric Company

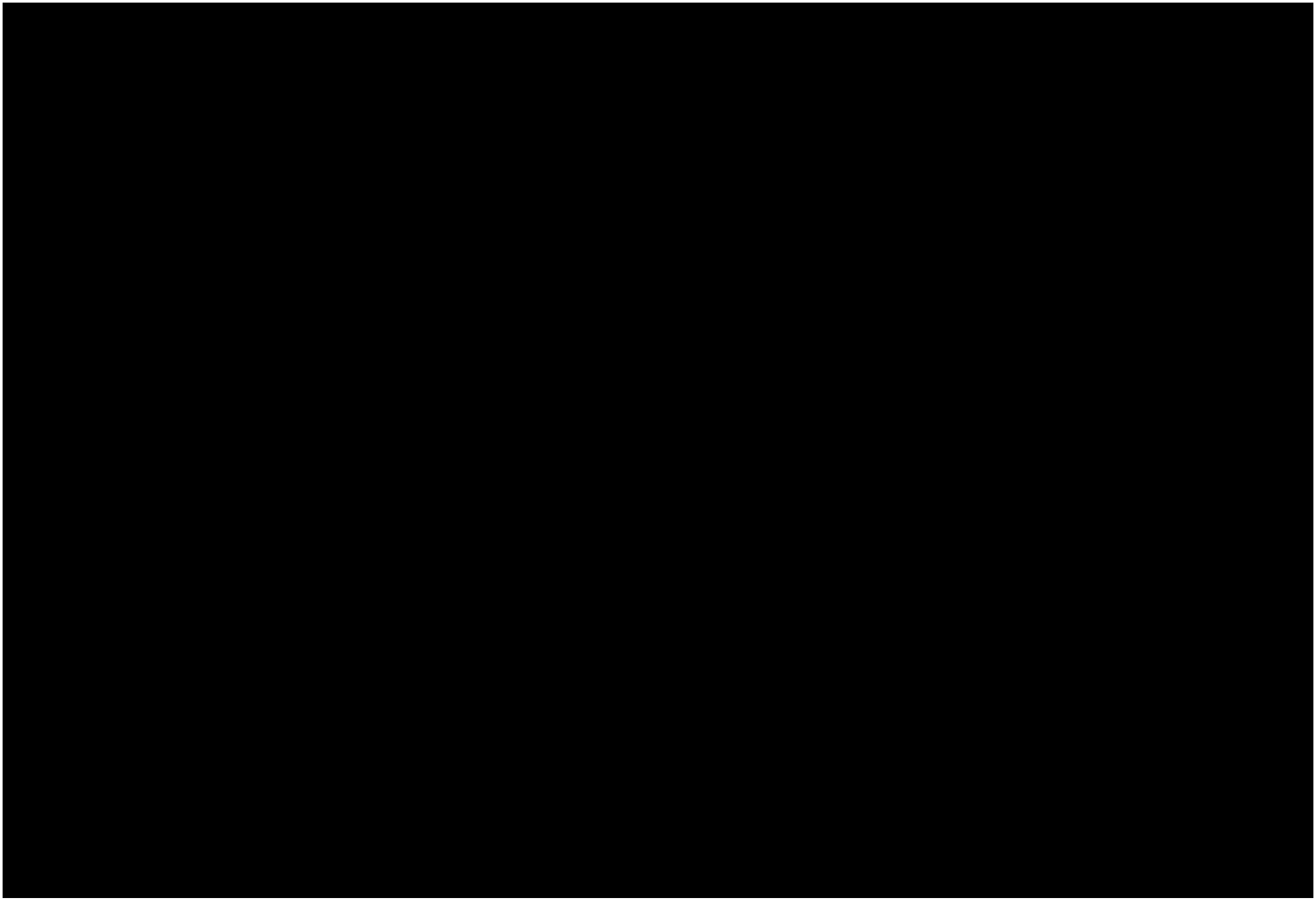
Date of Off Peak Day - 04/01/2021



Member Forecasted Off Peak Demand Day for May 2021

Big Horn Rural Electric Company

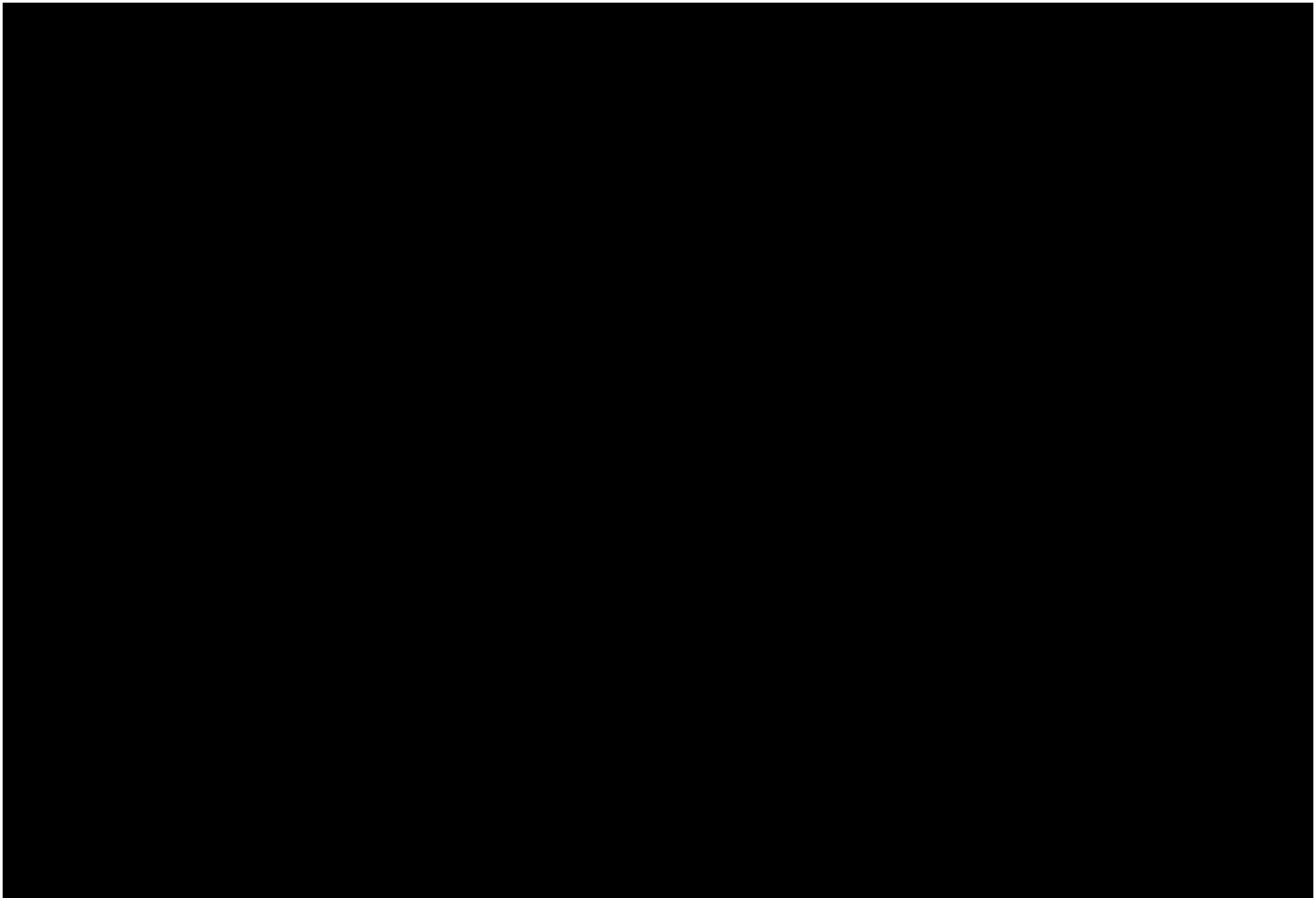
Date of Off Peak Day - 05/23/2021



Member Forecasted Off Peak Demand Day for June 2021

Big Horn Rural Electric Company

Date of Off Peak Day - 06/02/2021



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Member Forecasted Off Peak Demand Day for July 2021

Big Horn Rural Electric Company

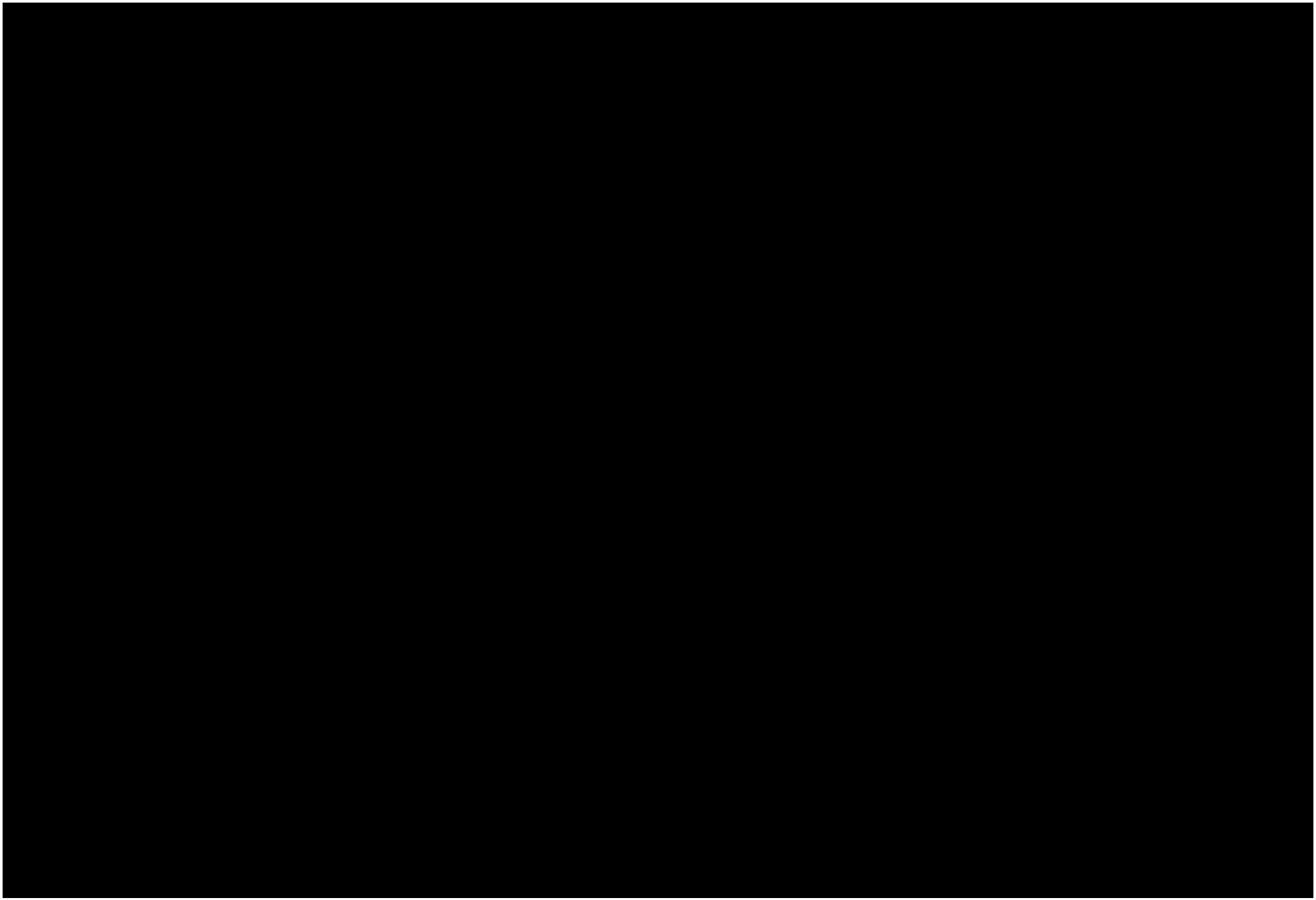
Date of Off Peak Day - 07/14/2021

[redacted]

Member Forecasted Off Peak Demand Day for August 2021

Big Horn Rural Electric Company

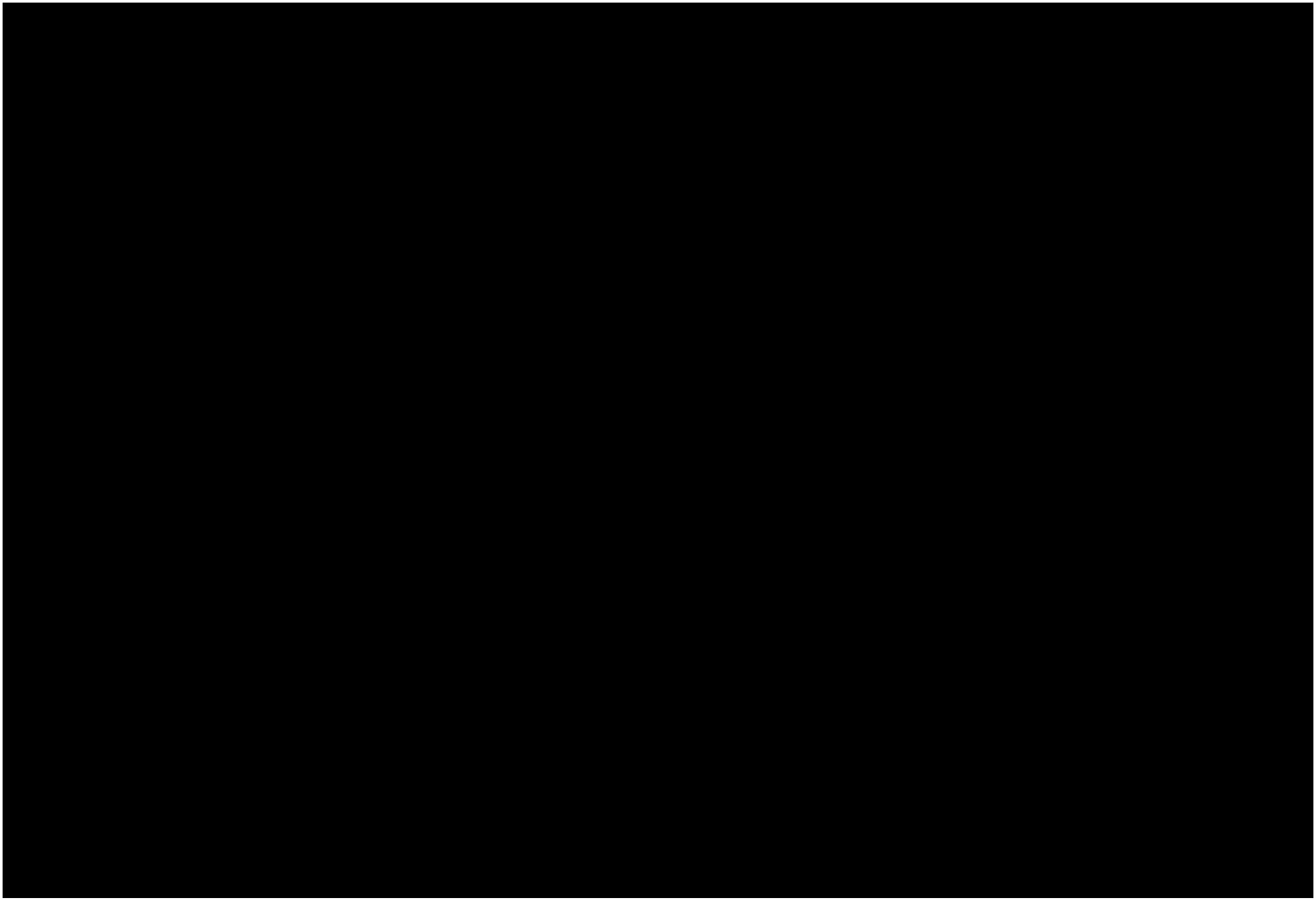
Date of Off Peak Day - 08/18/2021



Member Forecasted Off Peak Demand Day for September 2021

Big Horn Rural Electric Company

Date of Off Peak Day - 09/17/2021



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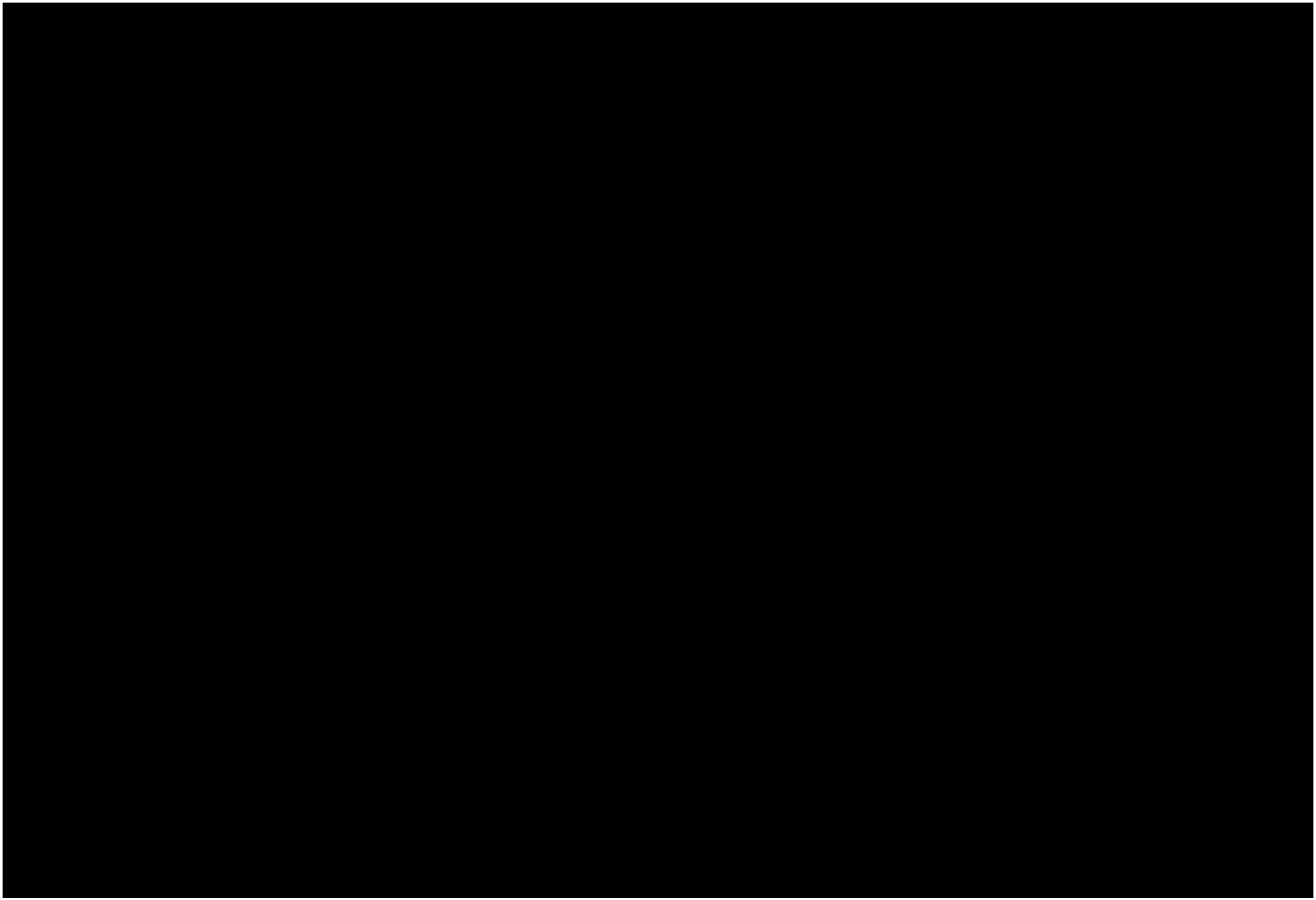
Member Forecasted Off Peak Demand Day for October 2021

Big Horn Rural Electric Company

Date of Off Peak Day - 10/07/2021



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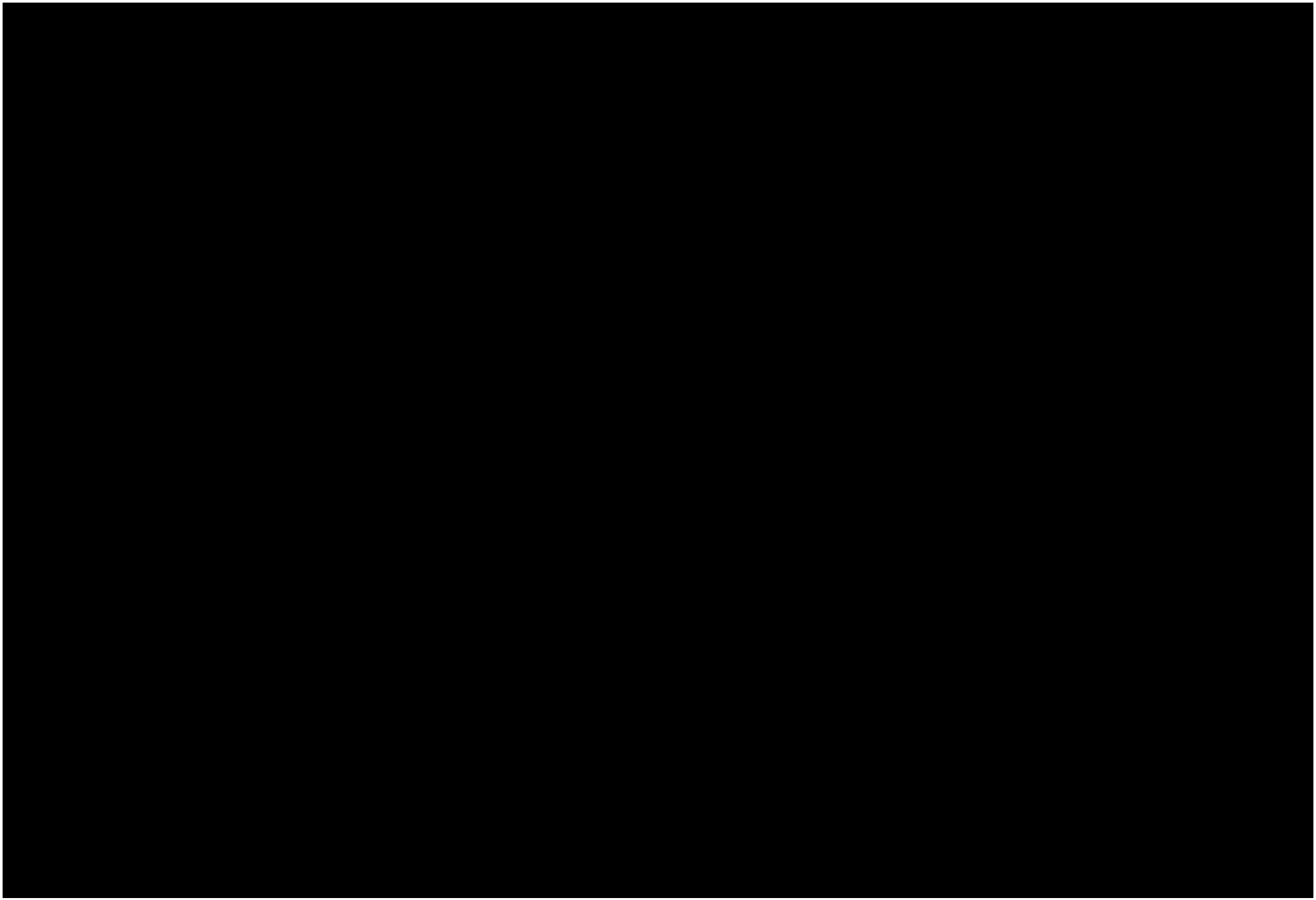
Member Forecasted Off Peak Demand Day for November 2021

Big Horn Rural Electric Company

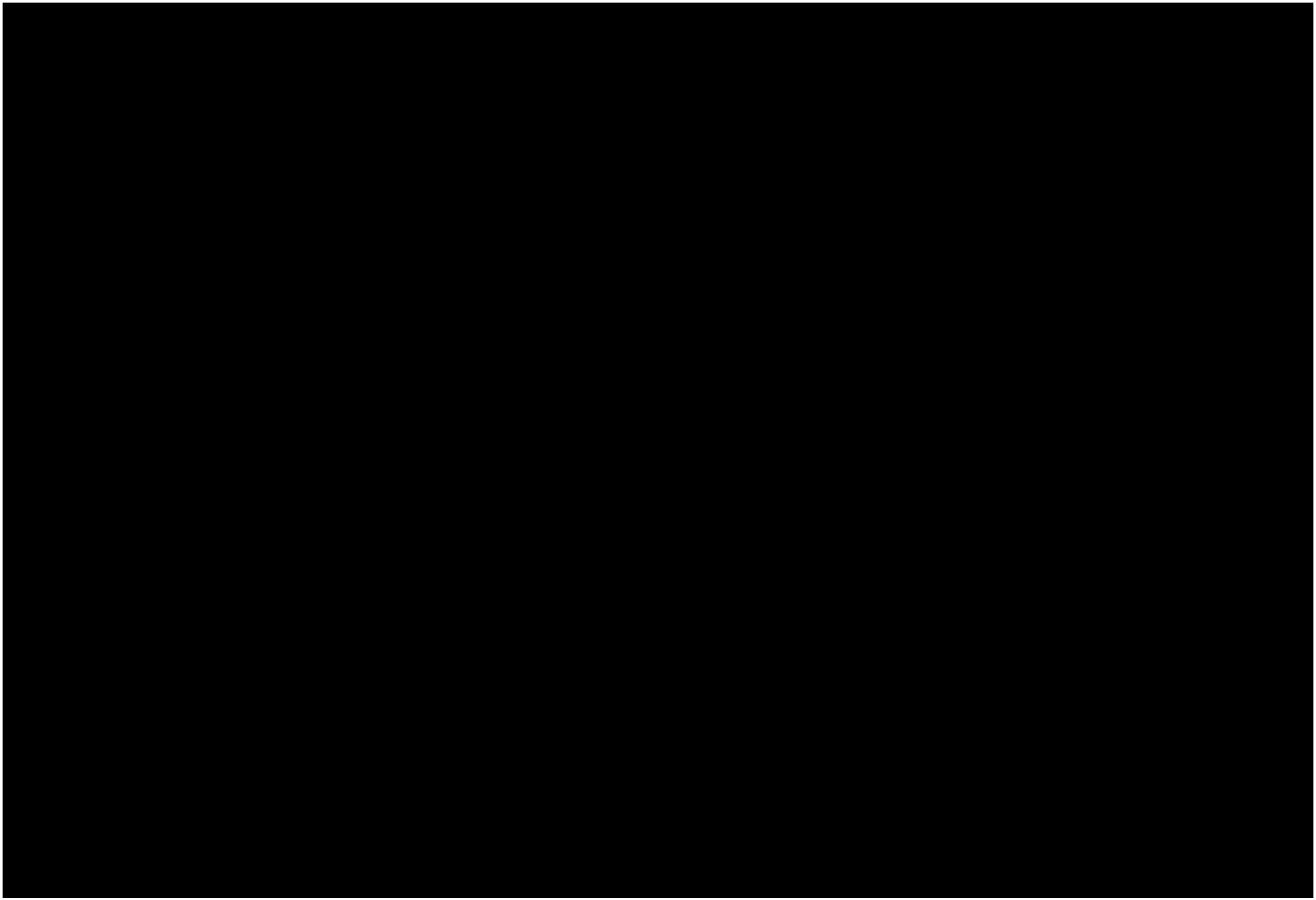
Date of Off Peak Day - 11/18/2021



Member Forecasted Off Peak Demand Day for December 2021

Big Horn Rural Electric Company

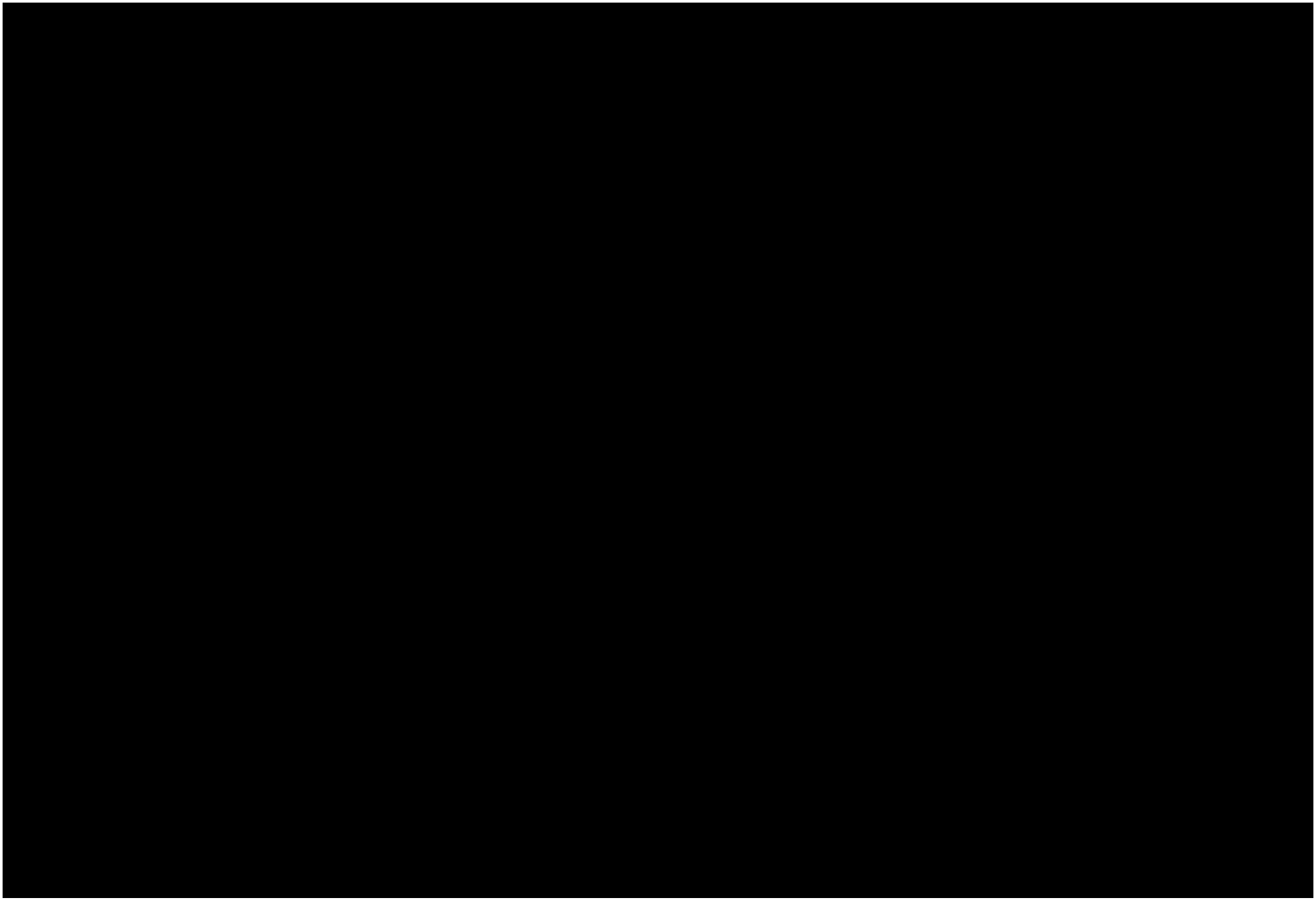
Date of Off Peak Day - 12/04/2021



Member Forecasted Off Peak Demand Day for January 2021

Carbon Power and Light, Inc.

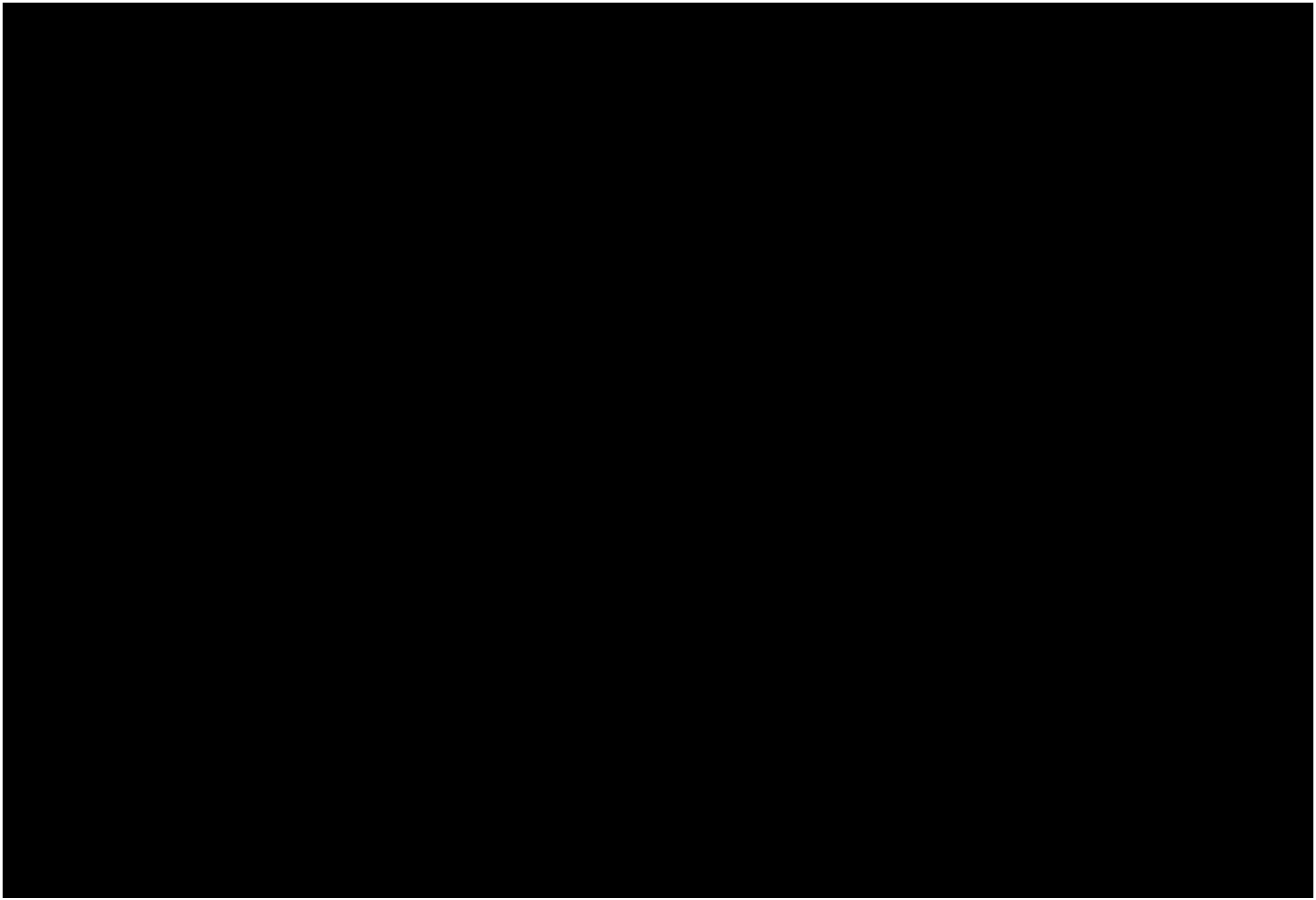
Date of Off Peak Day - 01/31/2021



Member Forecasted Off Peak Demand Day for February 2021

Carbon Power and Light, Inc.

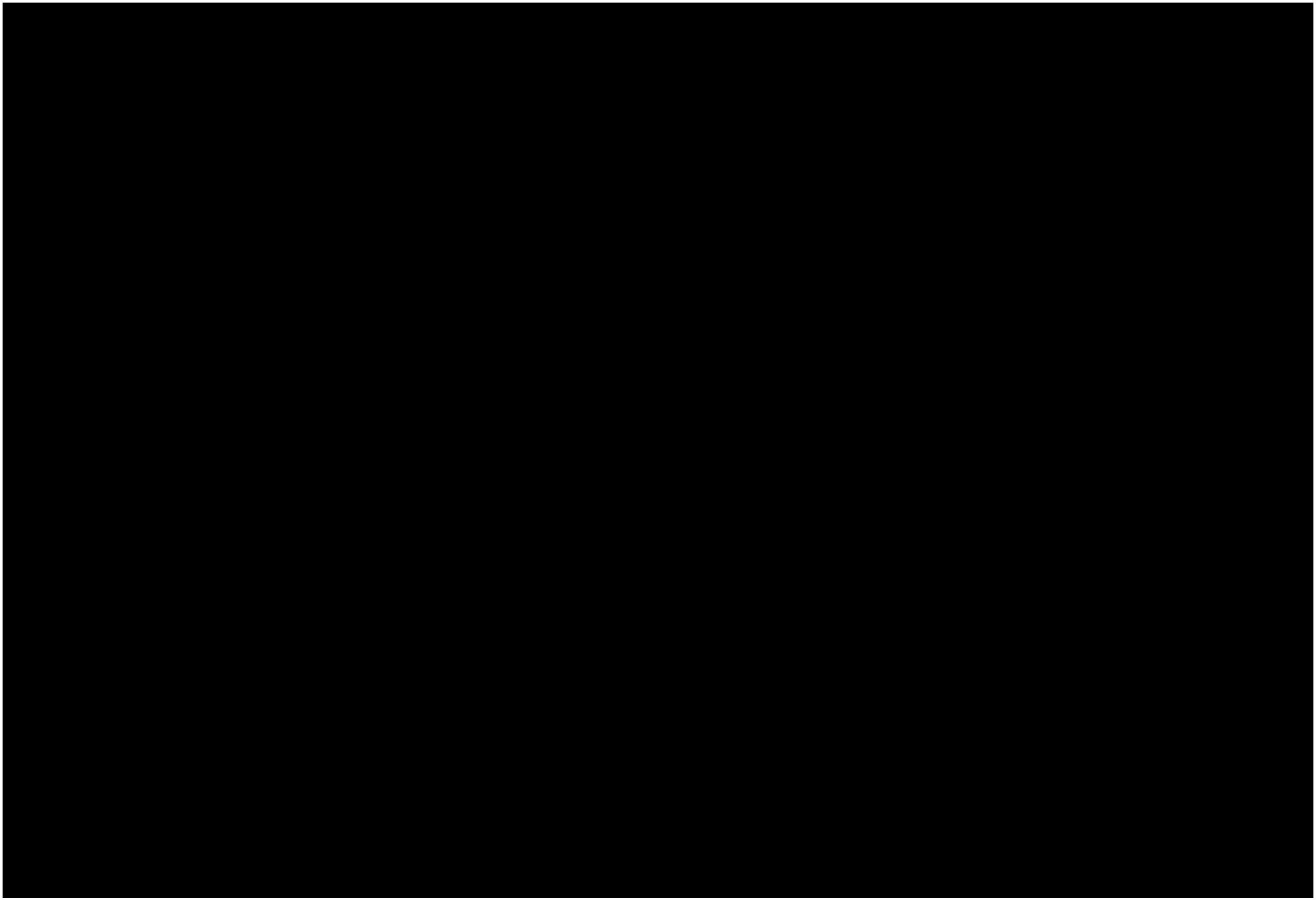
Date of Off Peak Day - 02/21/2021



Member Forecasted Off Peak Demand Day for March 2021

Carbon Power and Light, Inc.

Date of Off Peak Day - 03/21/2021



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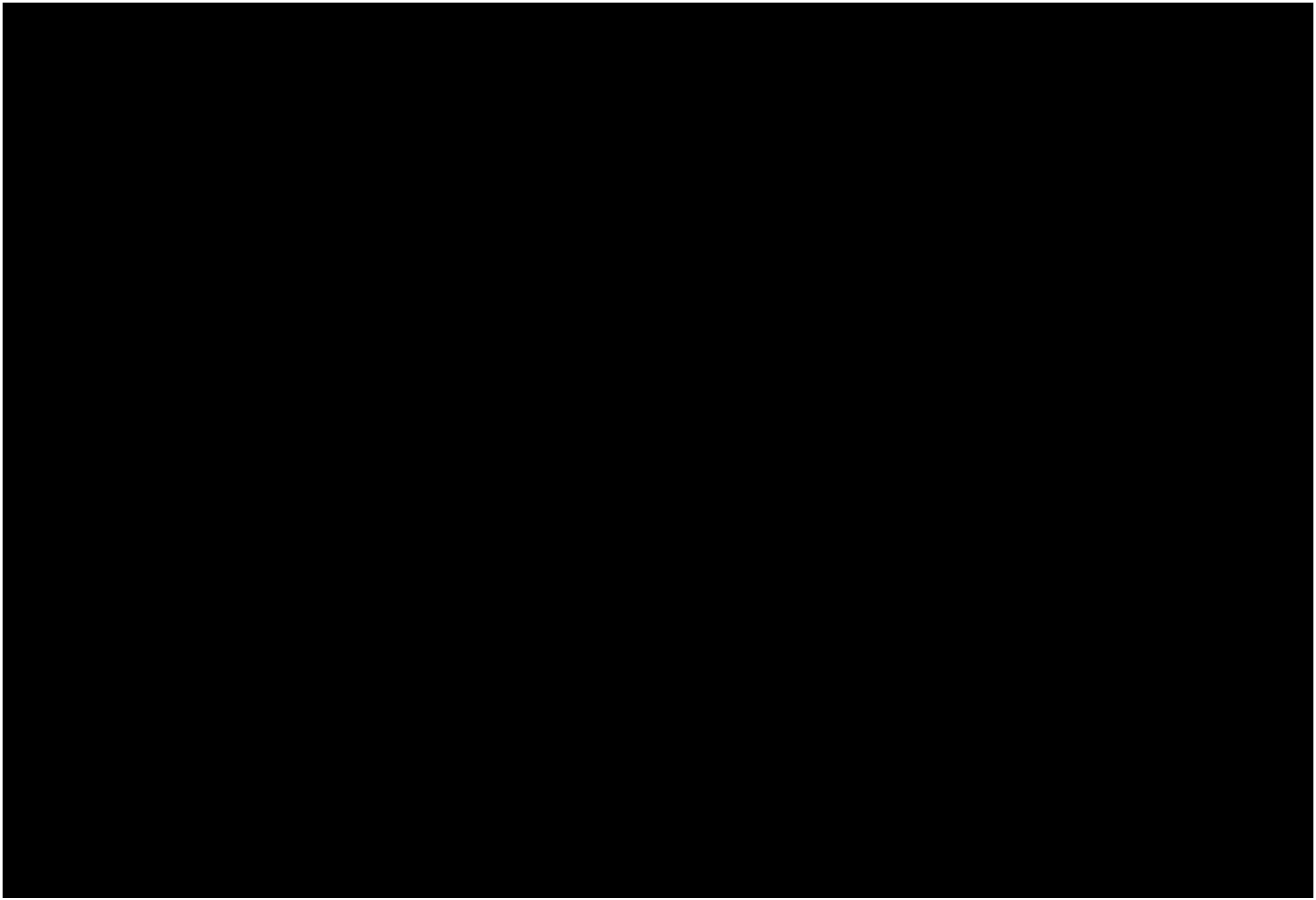
Member Forecasted Off Peak Demand Day for April 2021

Carbon Power and Light, Inc.

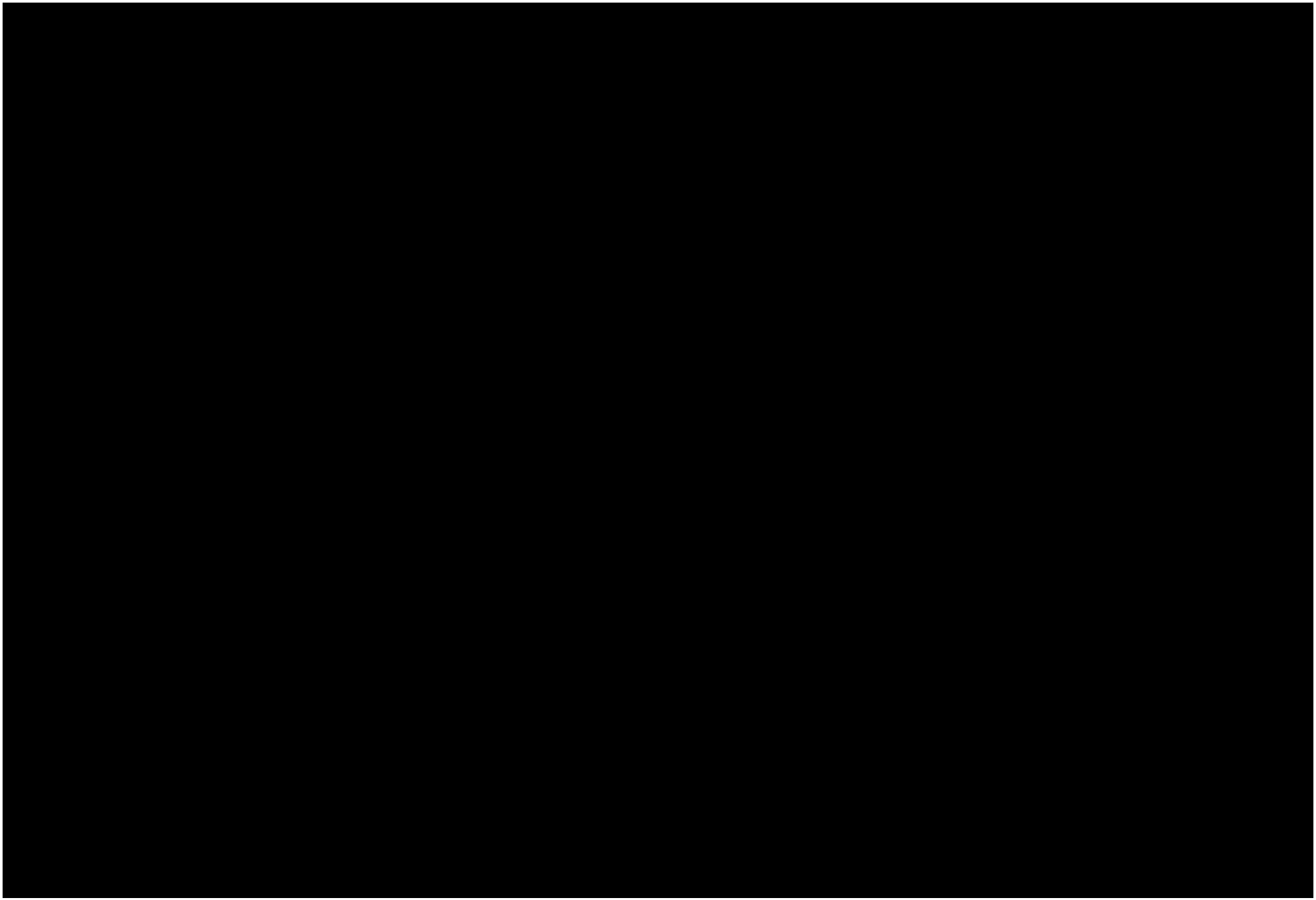
Date of Off Peak Day - 04/28/2021



Member Forecasted Off Peak Demand Day for May 2021

Carbon Power and Light, Inc.

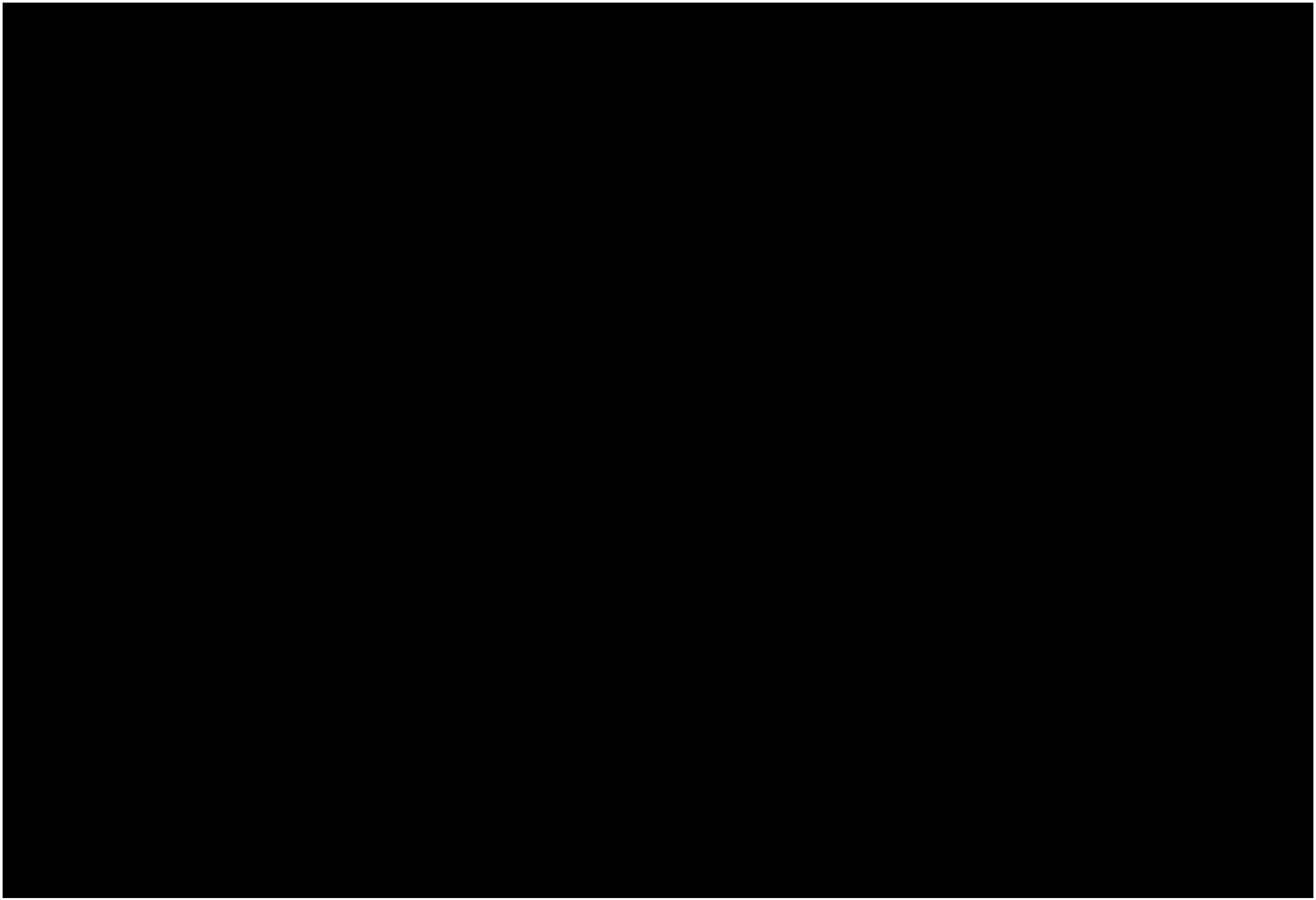
Date of Off Peak Day - 05/04/2021



Member Forecasted Off Peak Demand Day for June 2021

Carbon Power and Light, Inc.

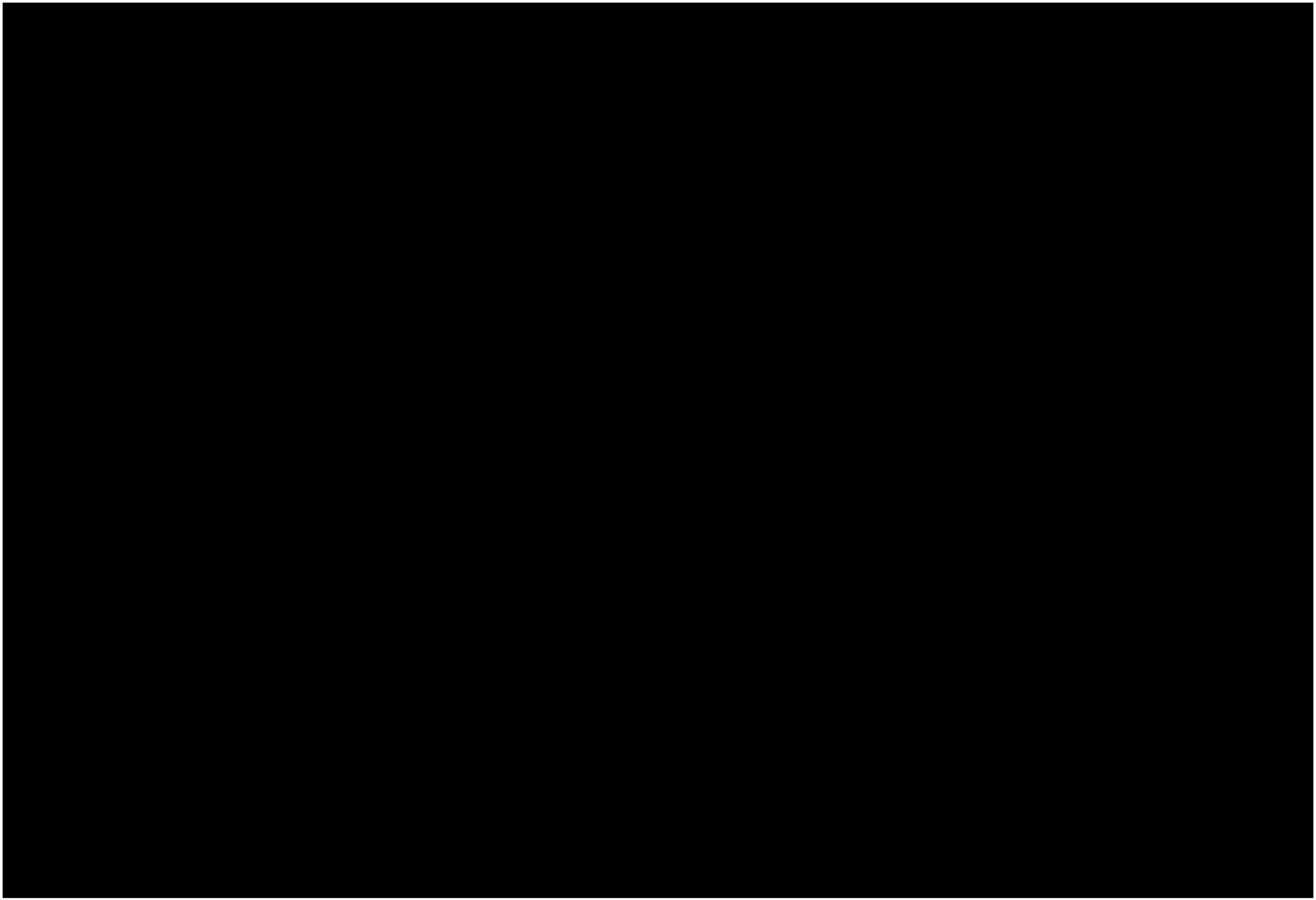
Date of Off Peak Day - 06/07/2021



Member Forecasted Off Peak Demand Day for July 2021

Carbon Power and Light, Inc.

Date of Off Peak Day - 07/04/2021



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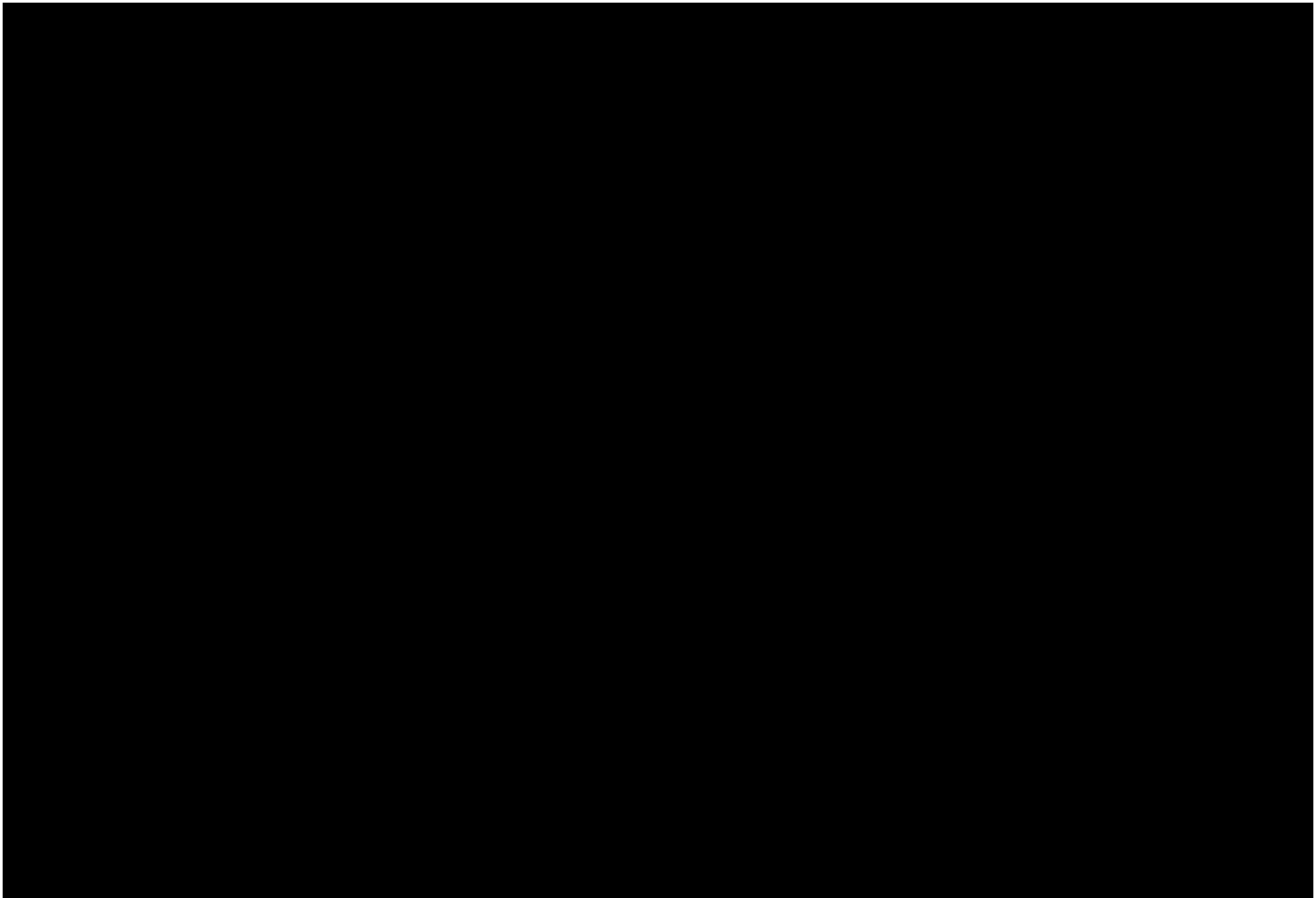
Member Forecasted Off Peak Demand Day for August 2021

Carbon Power and Light, Inc.

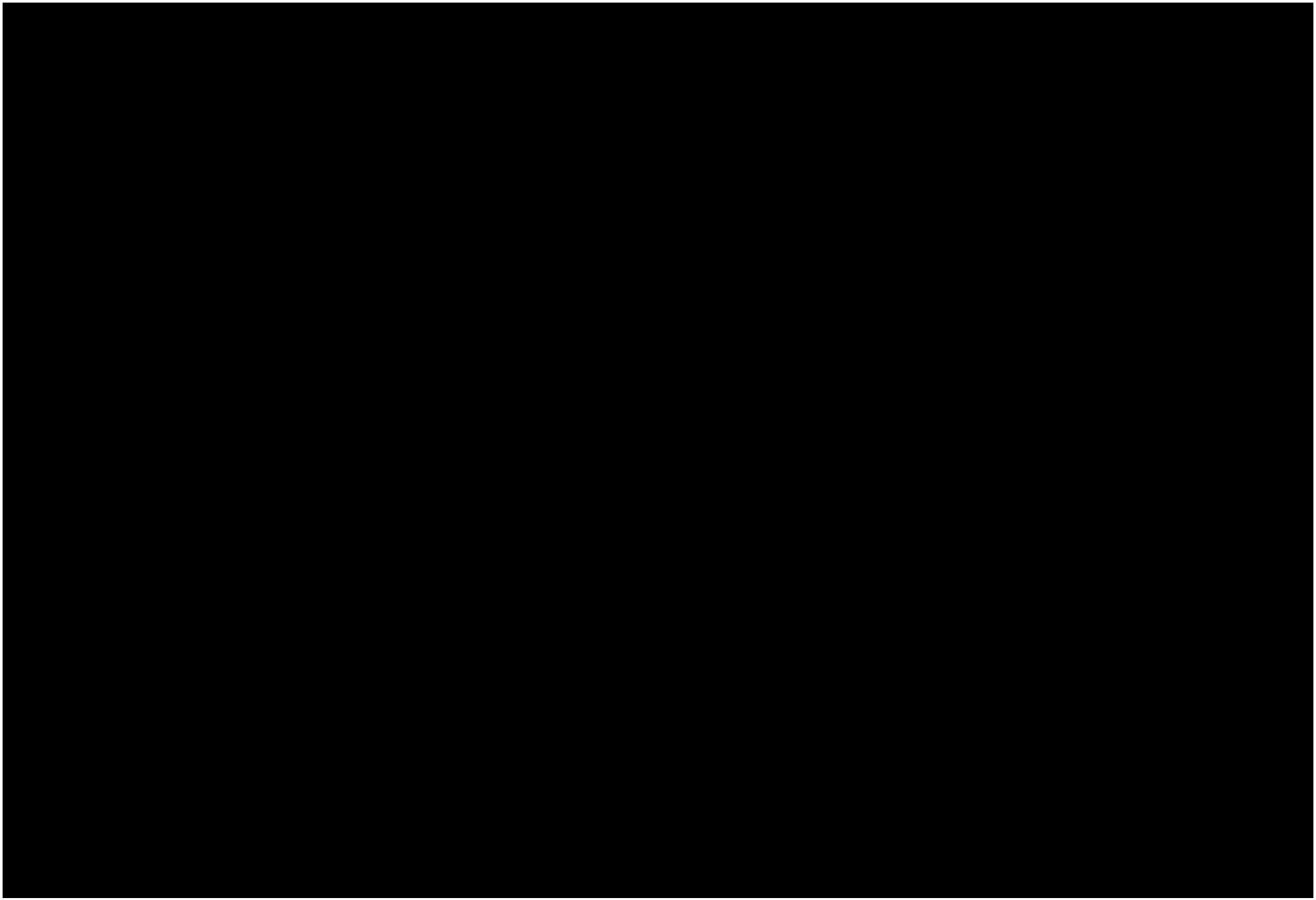
Date of Off Peak Day - 08/30/2021



Member Forecasted Off Peak Demand Day for September 2021

Carbon Power and Light, Inc.

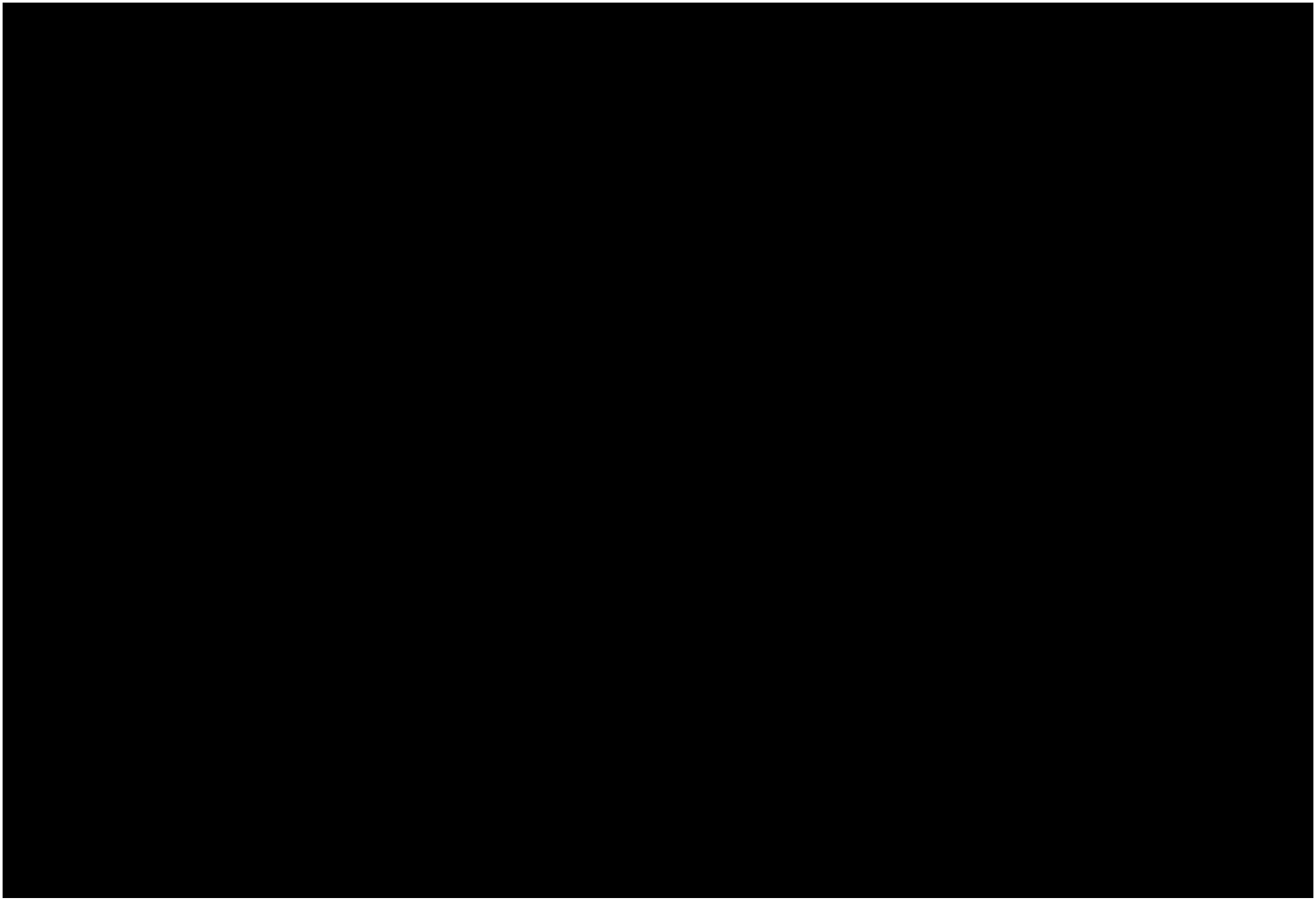
Date of Off Peak Day - 09/30/2021



Member Forecasted Off Peak Demand Day for October 2021

Carbon Power and Light, Inc.

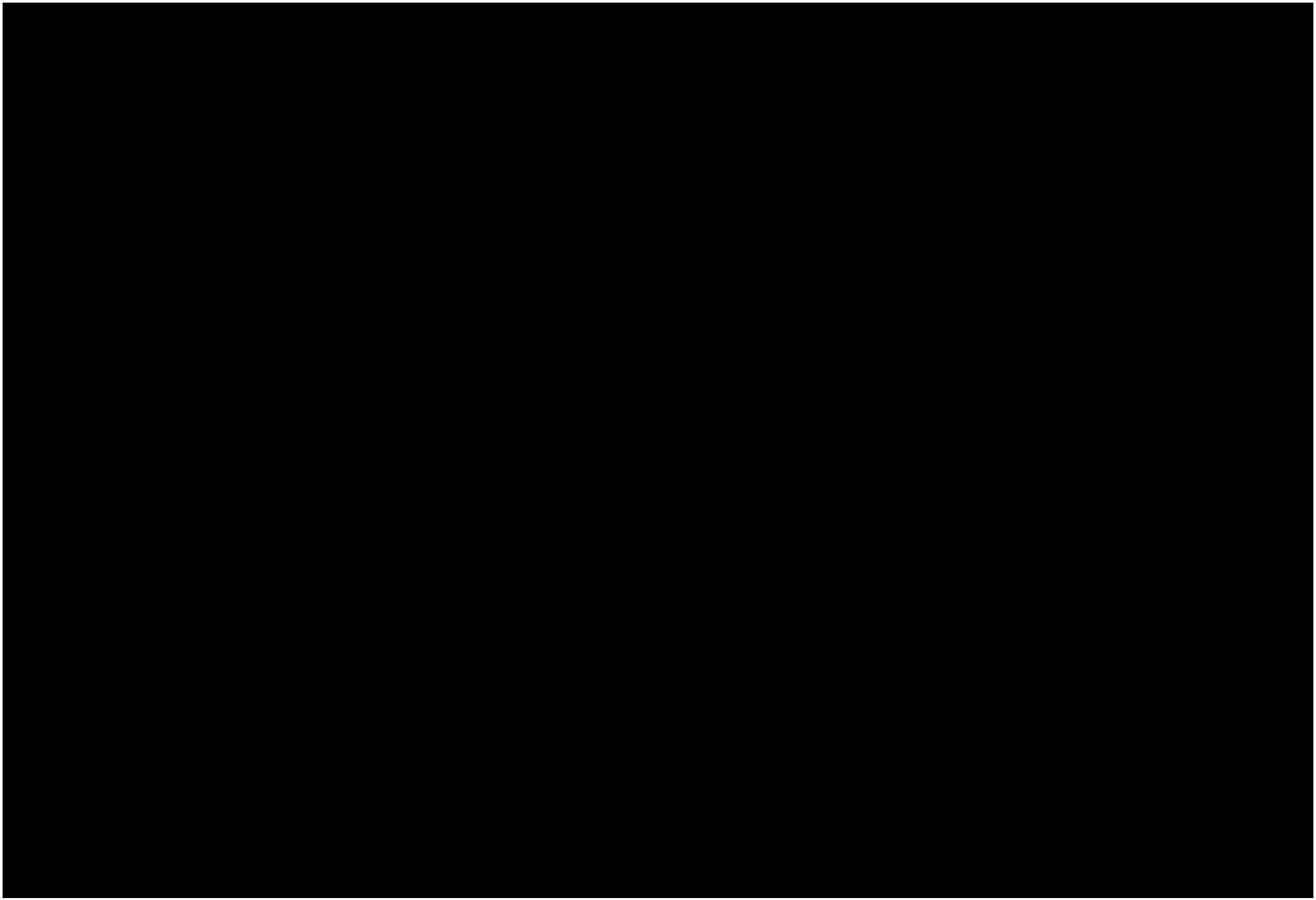
Date of Off Peak Day - 10/10/2021



Member Forecasted Off Peak Demand Day for November 2021

Carbon Power and Light, Inc.

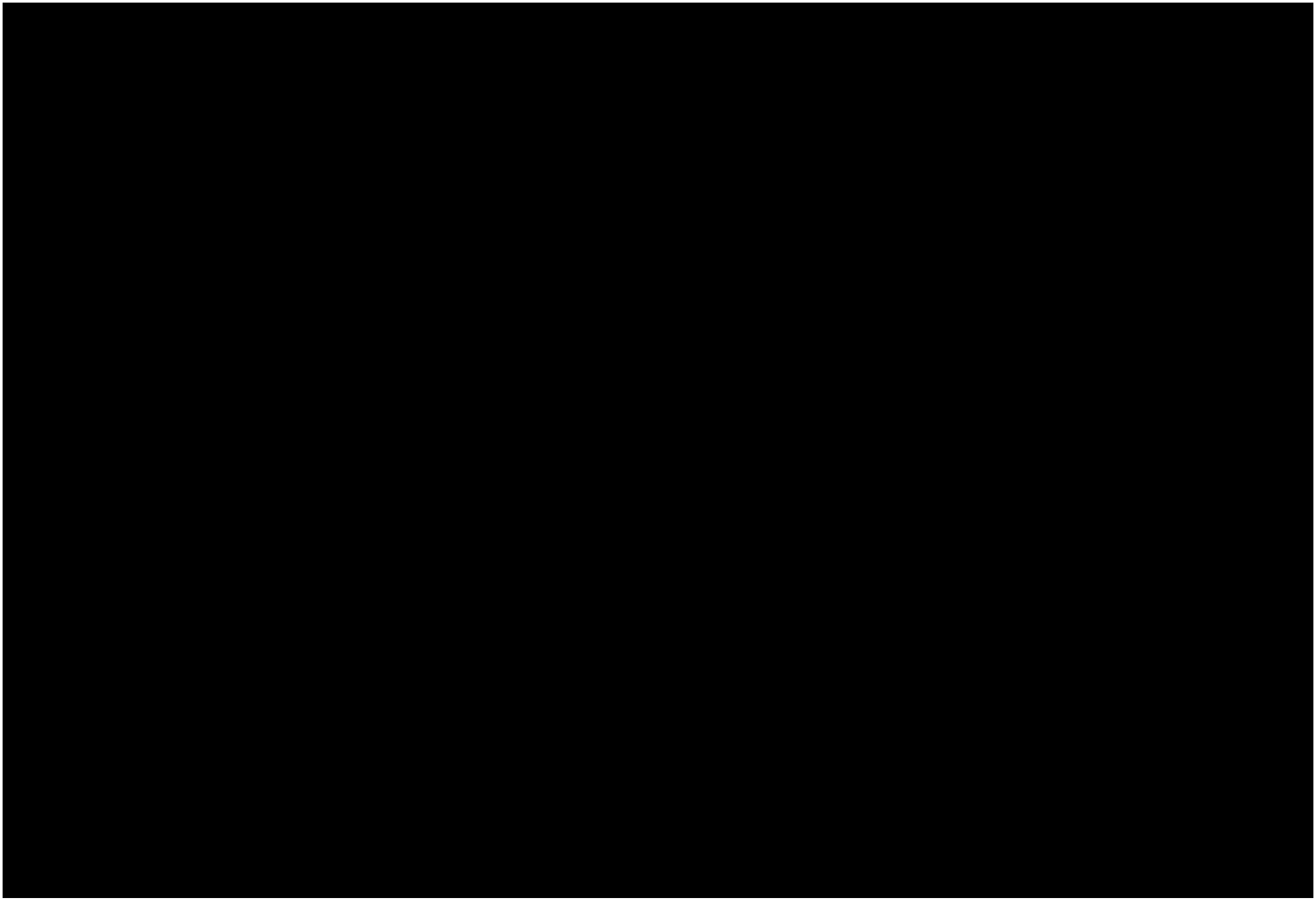
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

Carbon Power and Light, Inc.

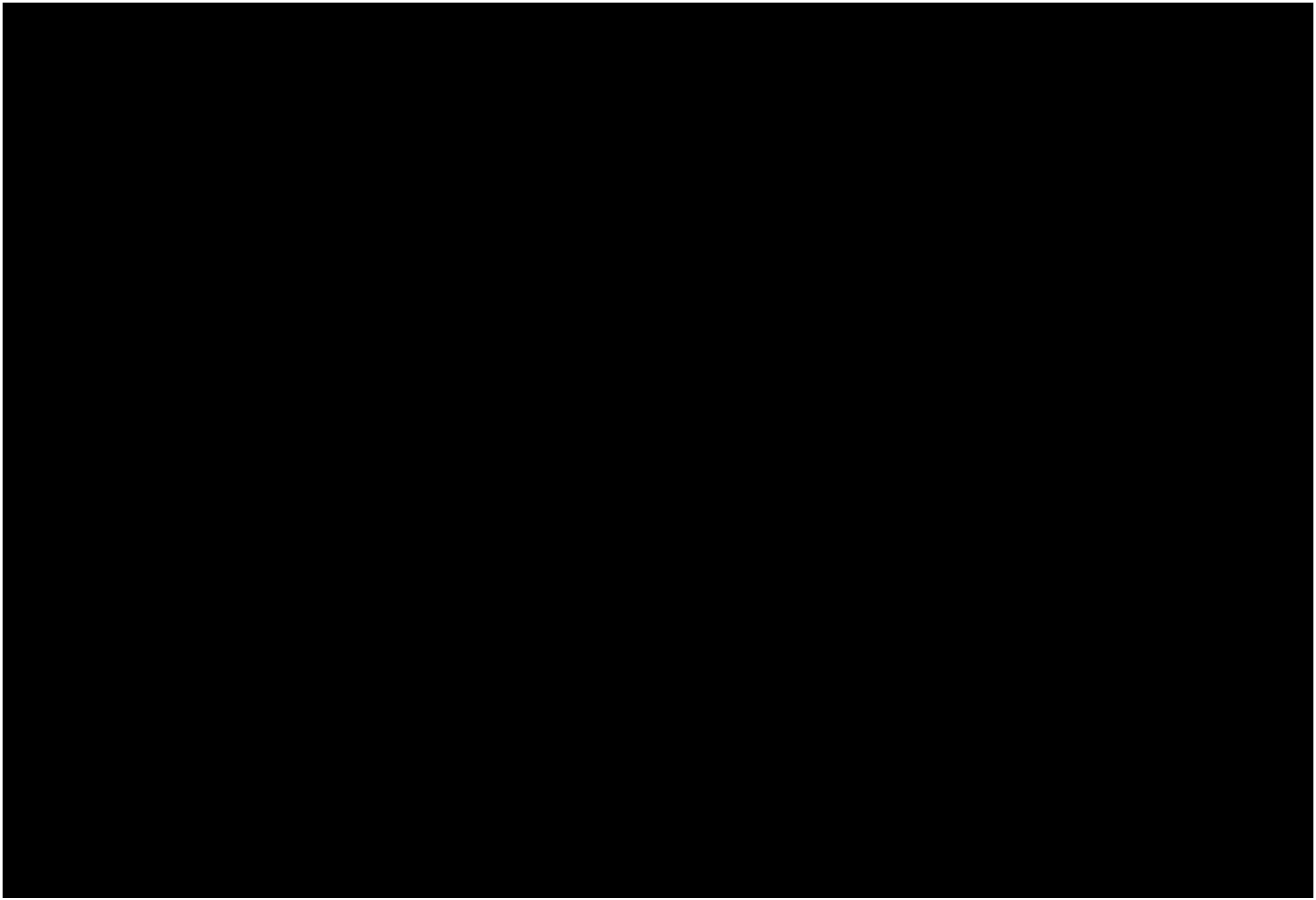
Date of Off Peak Day - 12/09/2021



Member Forecasted Off Peak Demand Day for January 2021

Continental Divide Electric Cooperative, Inc.

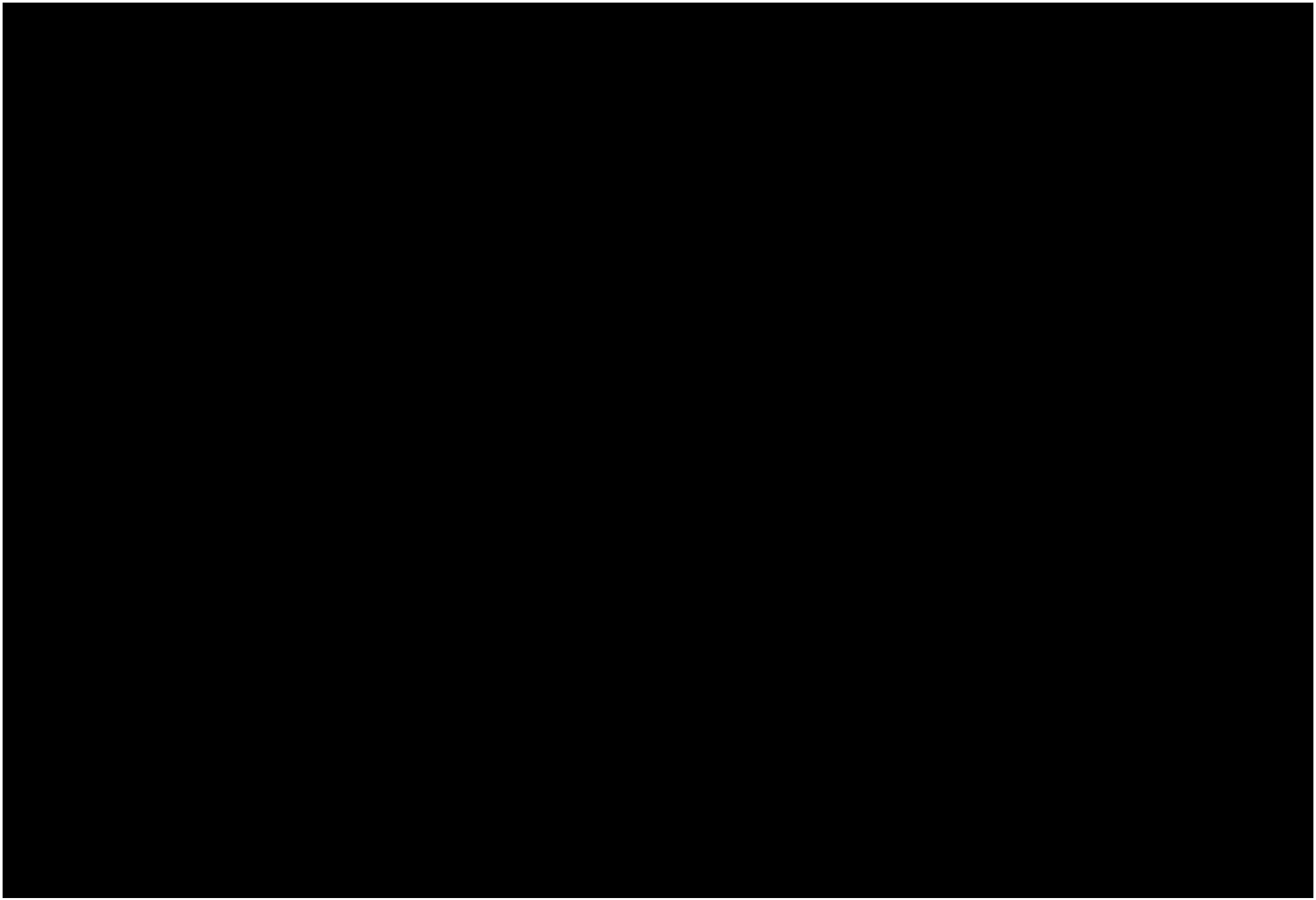
Date of Off Peak Day - 01/18/2021



Member Forecasted Off Peak Demand Day for February 2021

Continental Divide Electric Cooperative, Inc.

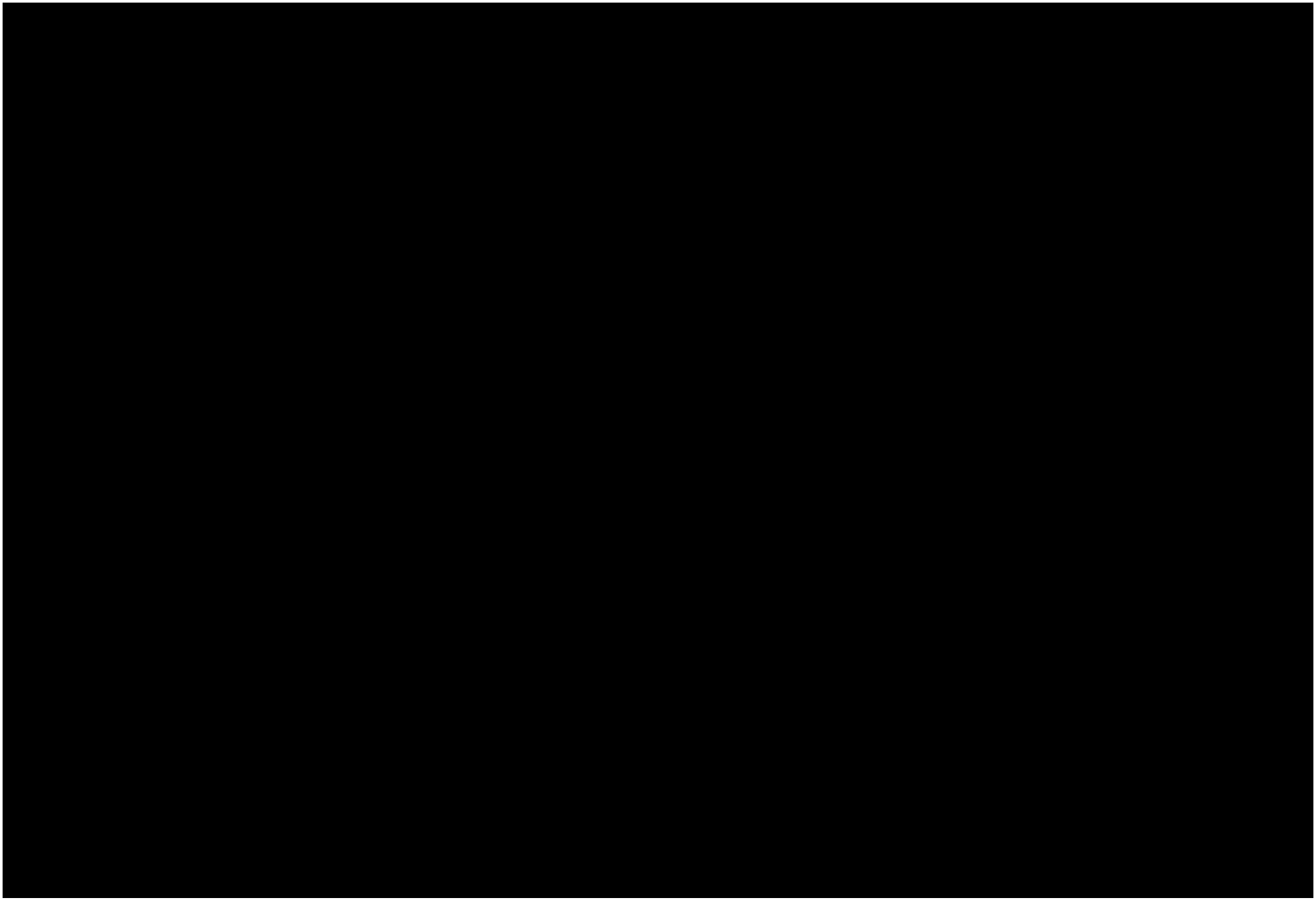
Date of Off Peak Day - 02/20/2021



Member Forecasted Off Peak Demand Day for March 2021

Continental Divide Electric Cooperative, Inc.

Date of Off Peak Day - 03/31/2021



Member Forecasted Off Peak Demand Day for April 2021

Continental Divide Electric Cooperative, Inc.

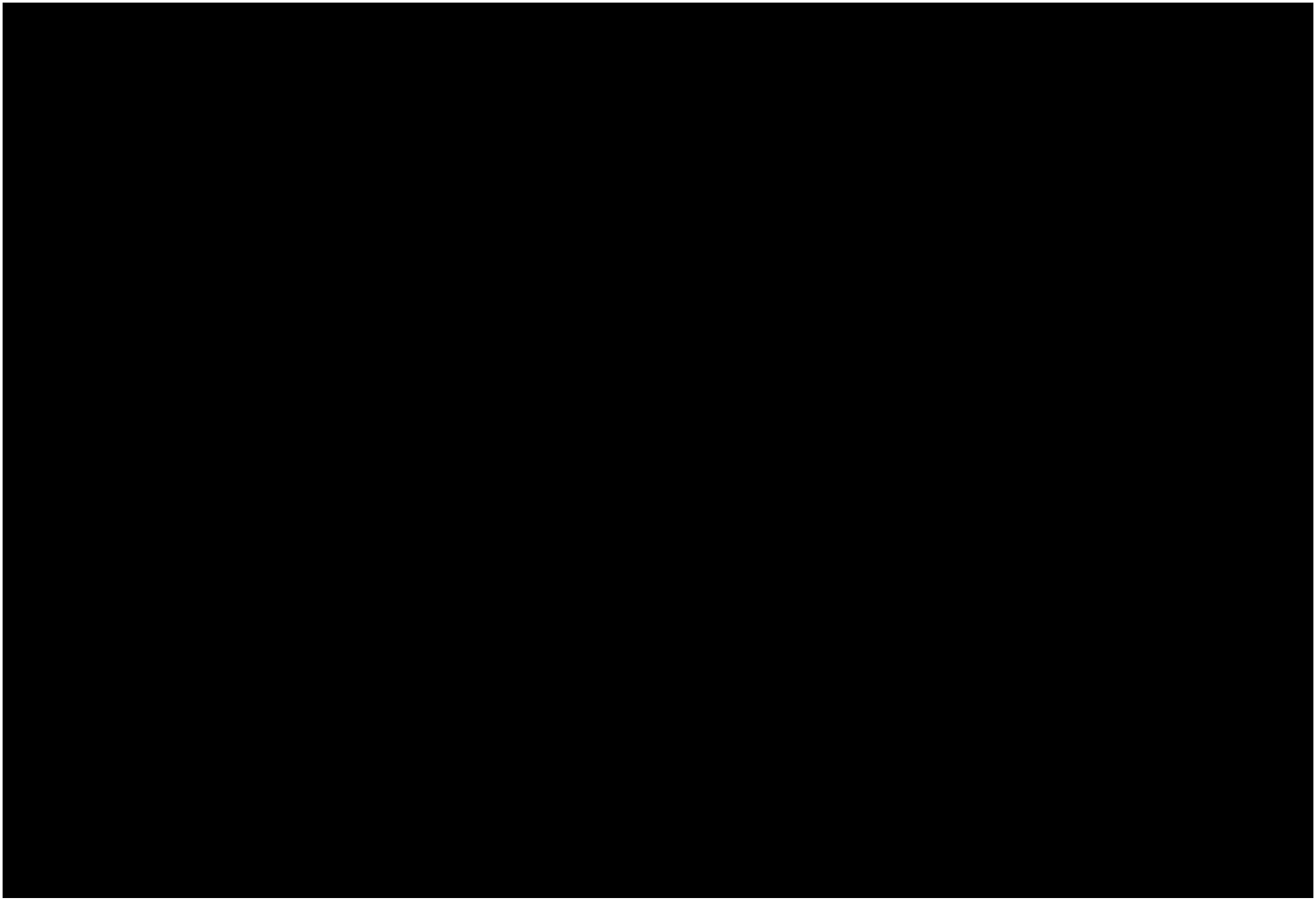
Date of Off Peak Day - 04/10/2021

[redacted]

Member Forecasted Off Peak Demand Day for May 2021

Continental Divide Electric Cooperative, Inc.

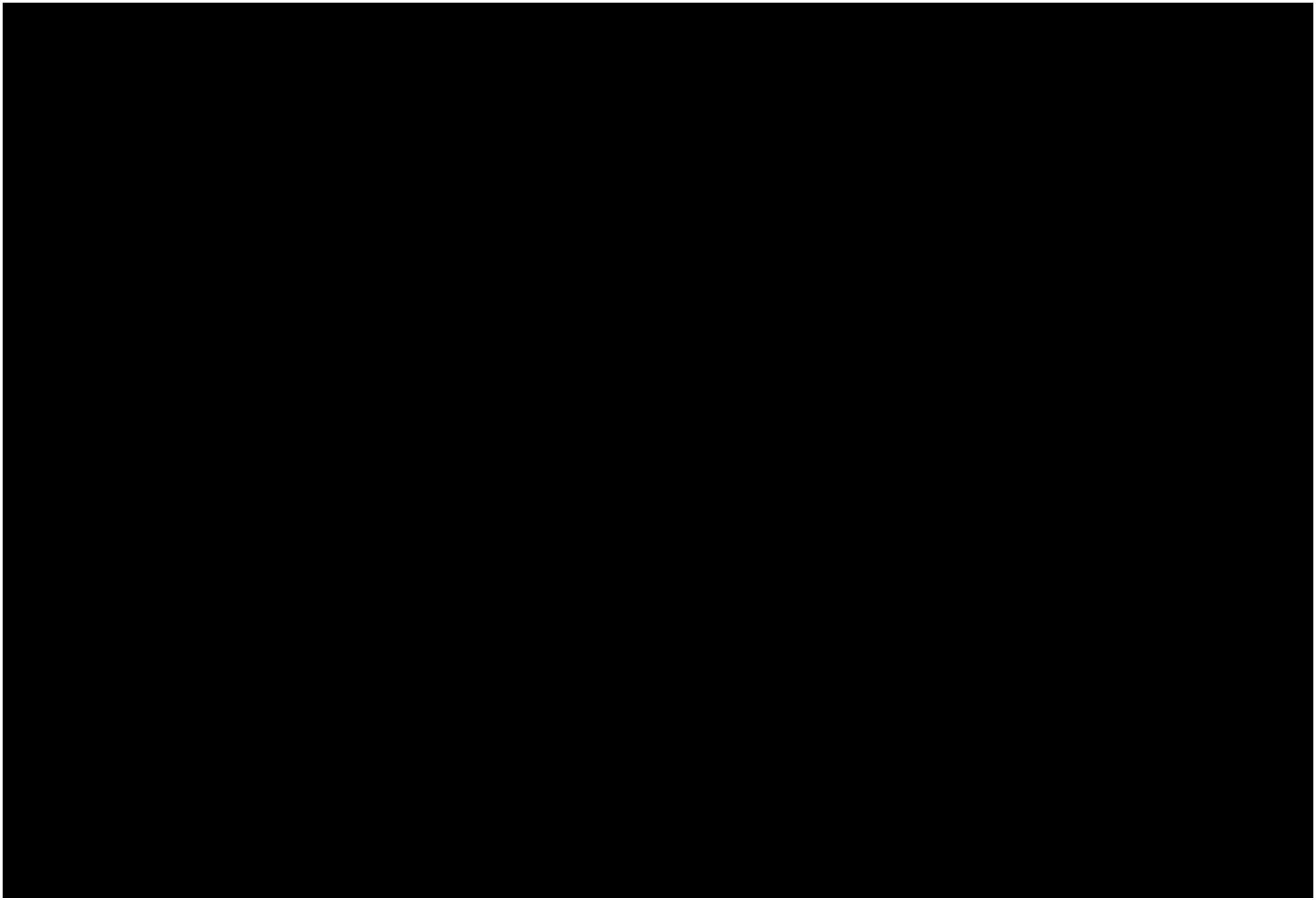
Date of Off Peak Day - 05/23/2021



Member Forecasted Off Peak Demand Day for June 2021

Continental Divide Electric Cooperative, Inc.

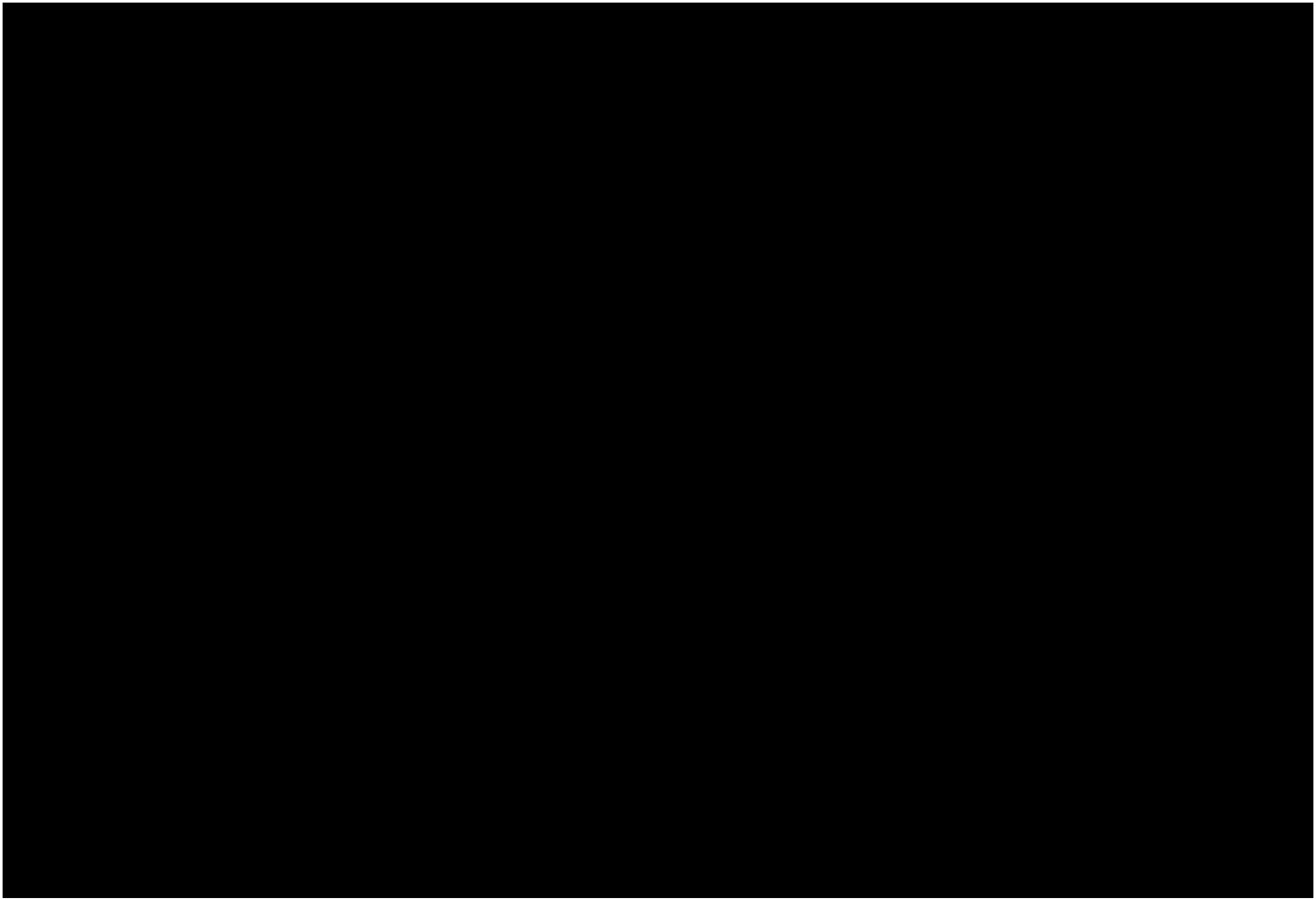
Date of Off Peak Day - 06/13/2021



Member Forecasted Off Peak Demand Day for July 2021

Continental Divide Electric Cooperative, Inc.

Date of Off Peak Day - 07/31/2021



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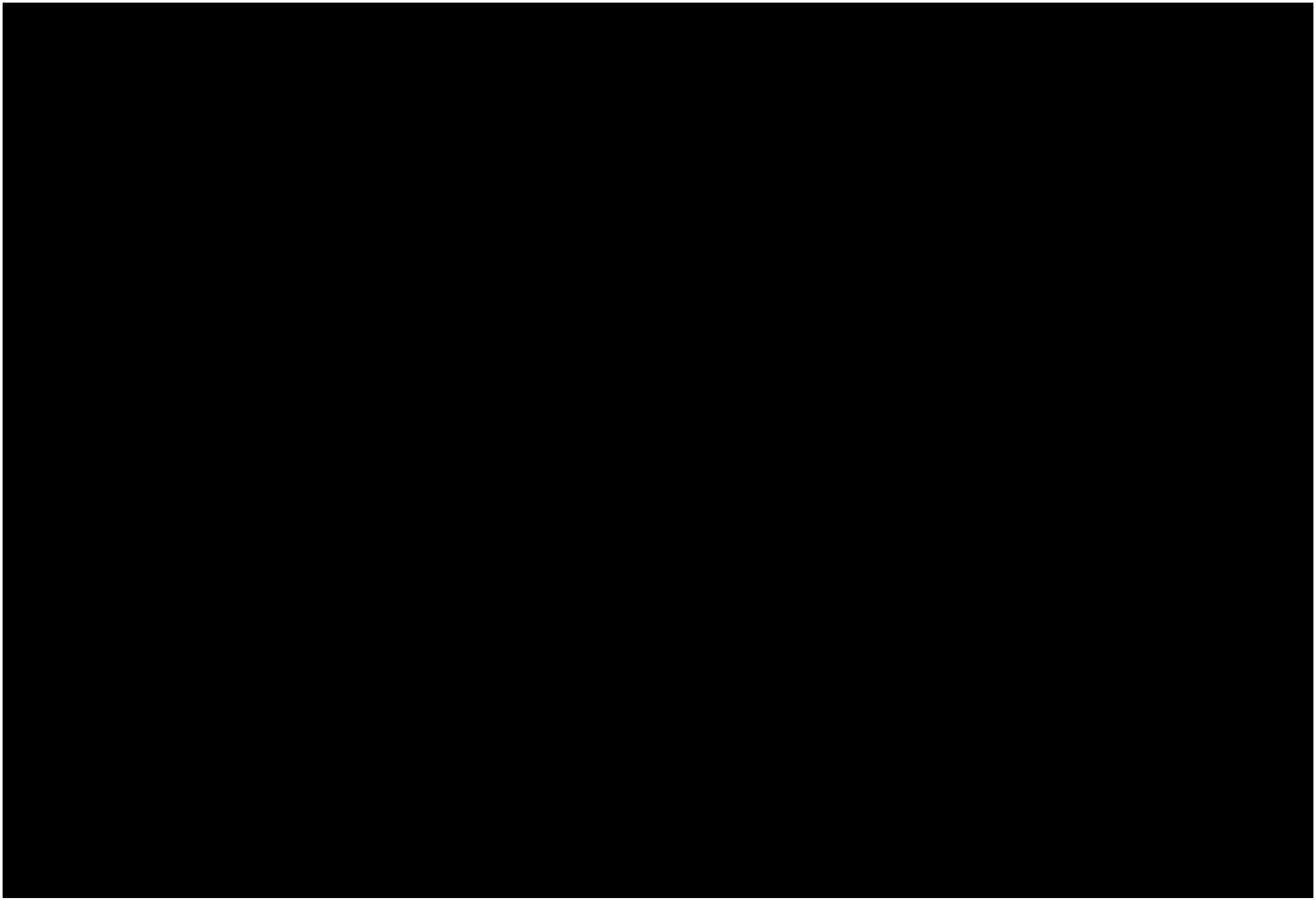
Member Forecasted Off Peak Demand Day for August 2021

Continental Divide Electric Cooperative, Inc.

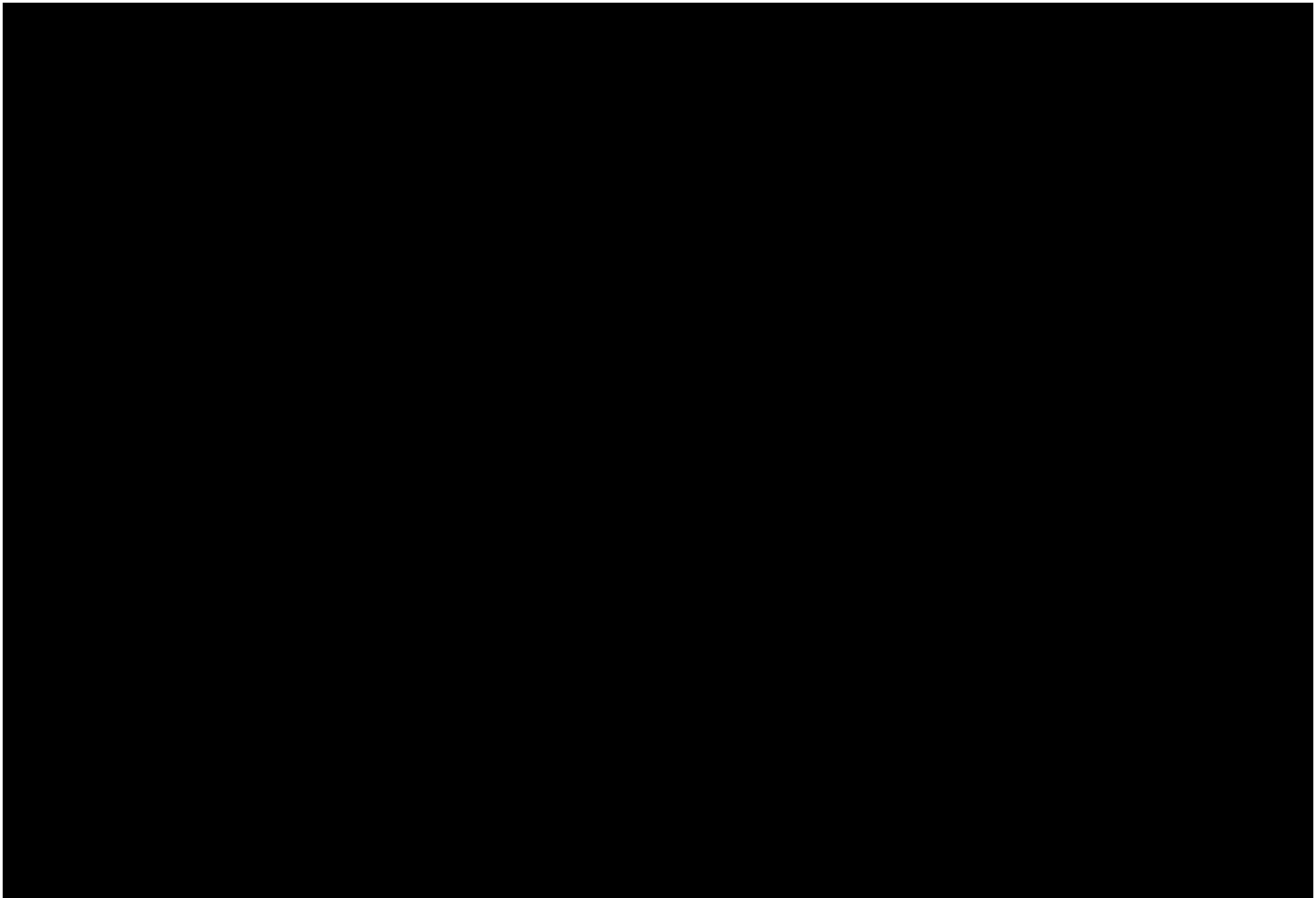
Date of Off Peak Day - 08/01/2021



Member Forecasted Off Peak Demand Day for September 2021

Continental Divide Electric Cooperative, Inc.

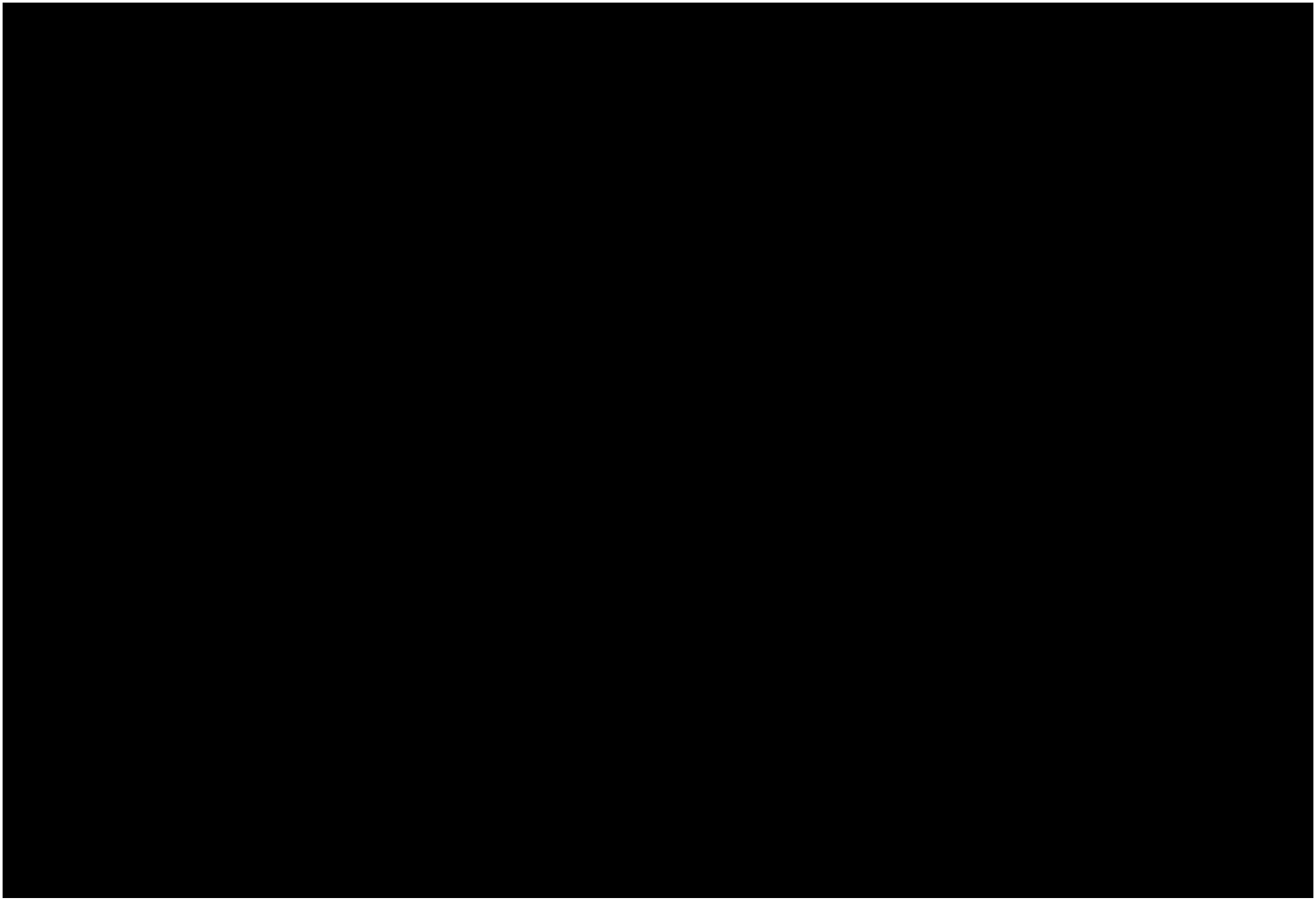
Date of Off Peak Day - 09/22/2021



Member Forecasted Off Peak Demand Day for October 2021

Continental Divide Electric Cooperative, Inc.

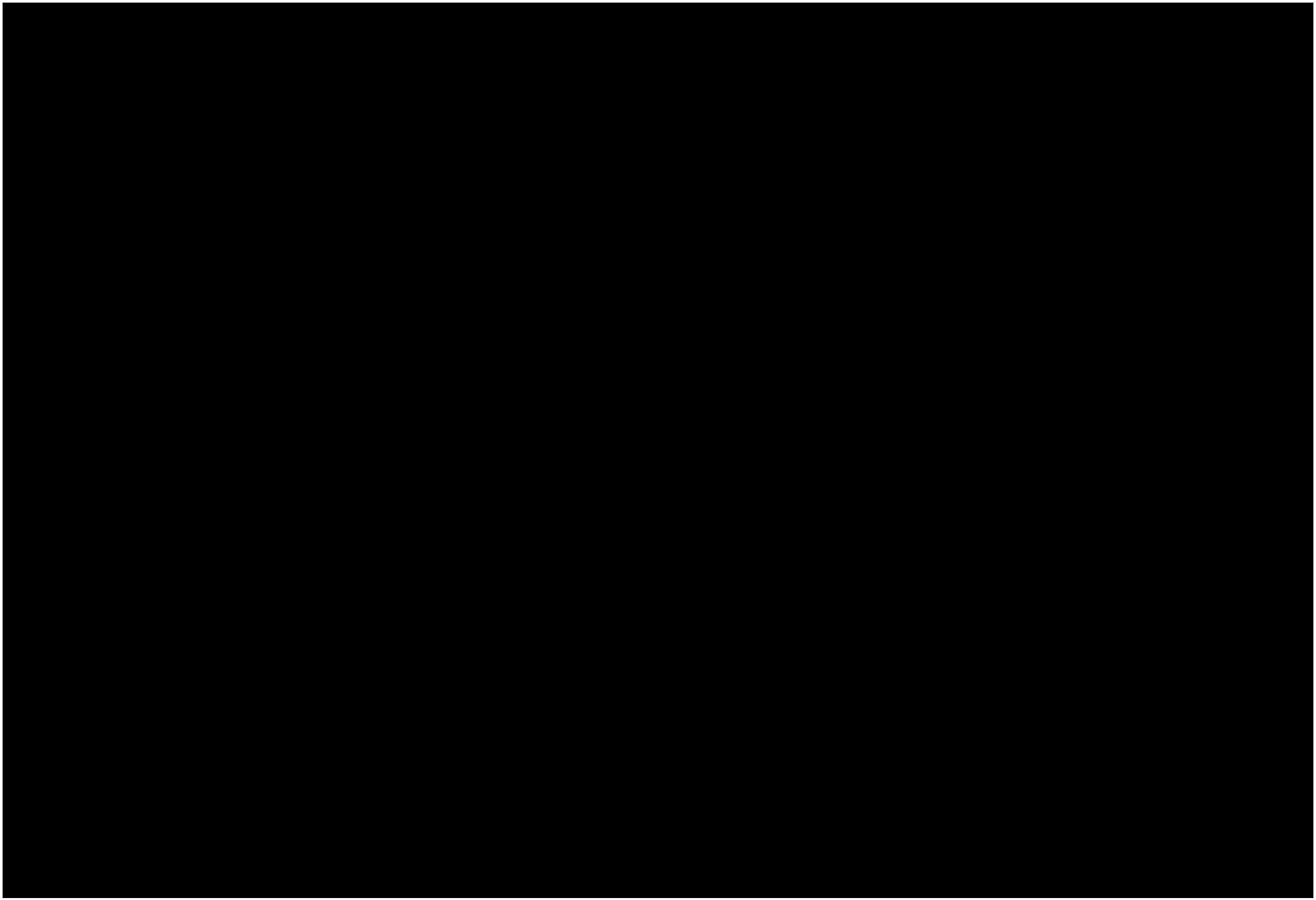
Date of Off Peak Day - 10/21/2021



Member Forecasted Off Peak Demand Day for November 2021

Continental Divide Electric Cooperative, Inc.

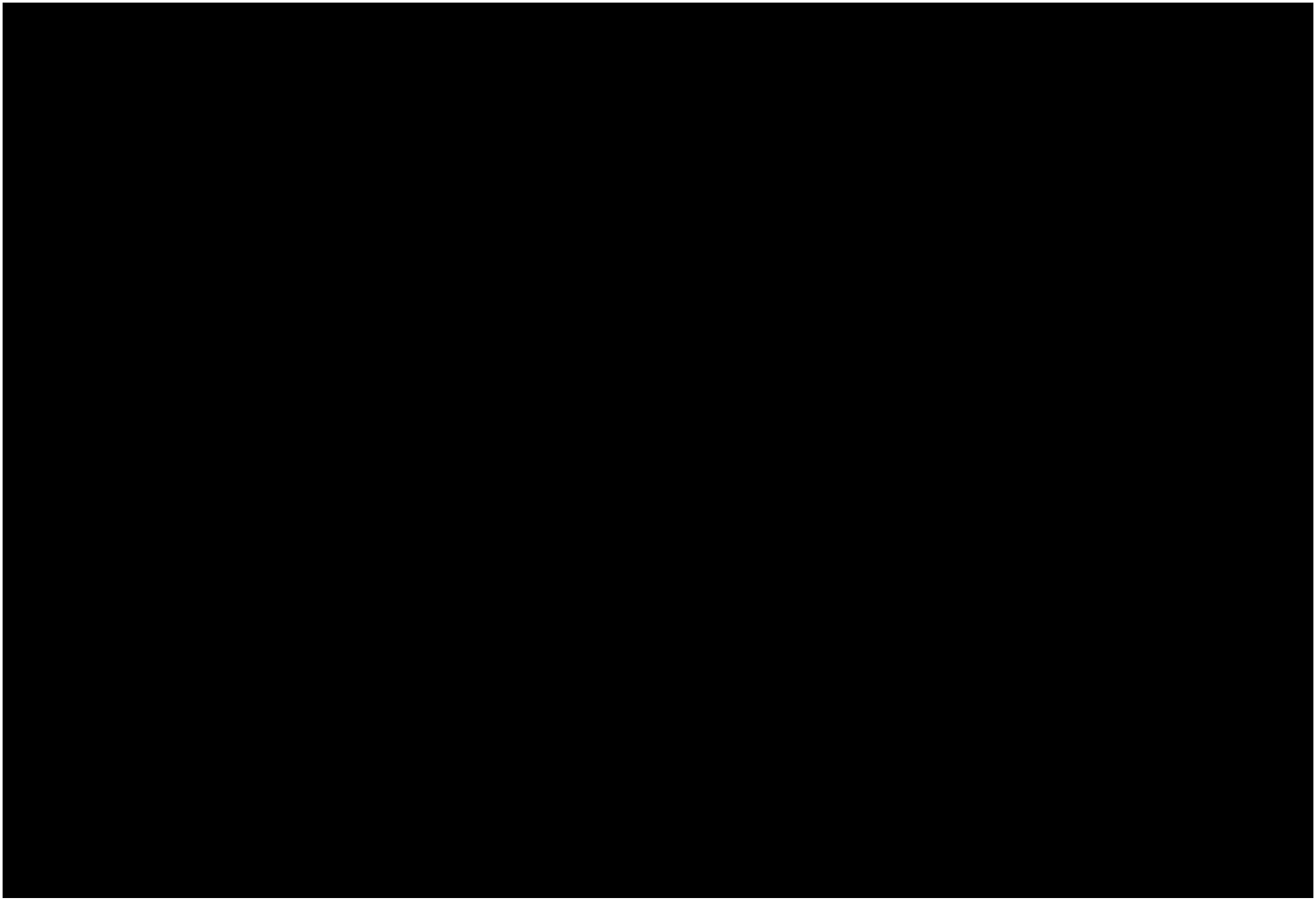
Date of Off Peak Day - 11/07/2021



Member Forecasted Off Peak Demand Day for December 2021

Continental Divide Electric Cooperative, Inc.

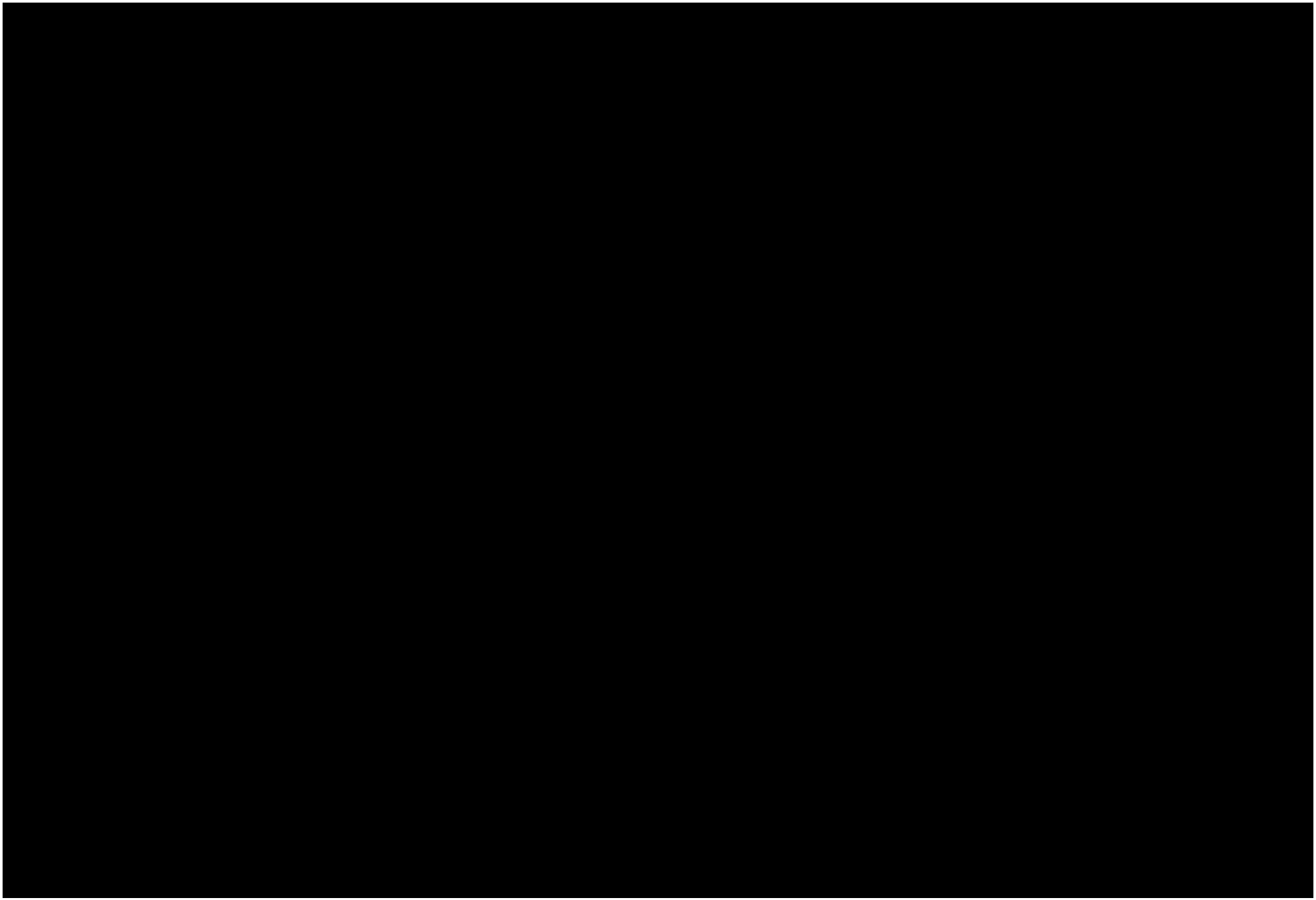
Date of Off Peak Day - 12/09/2021



Member Forecasted Off Peak Demand Day for January 2021

Columbus Electric Cooperative, Inc.

Date of Off Peak Day - 01/04/2021



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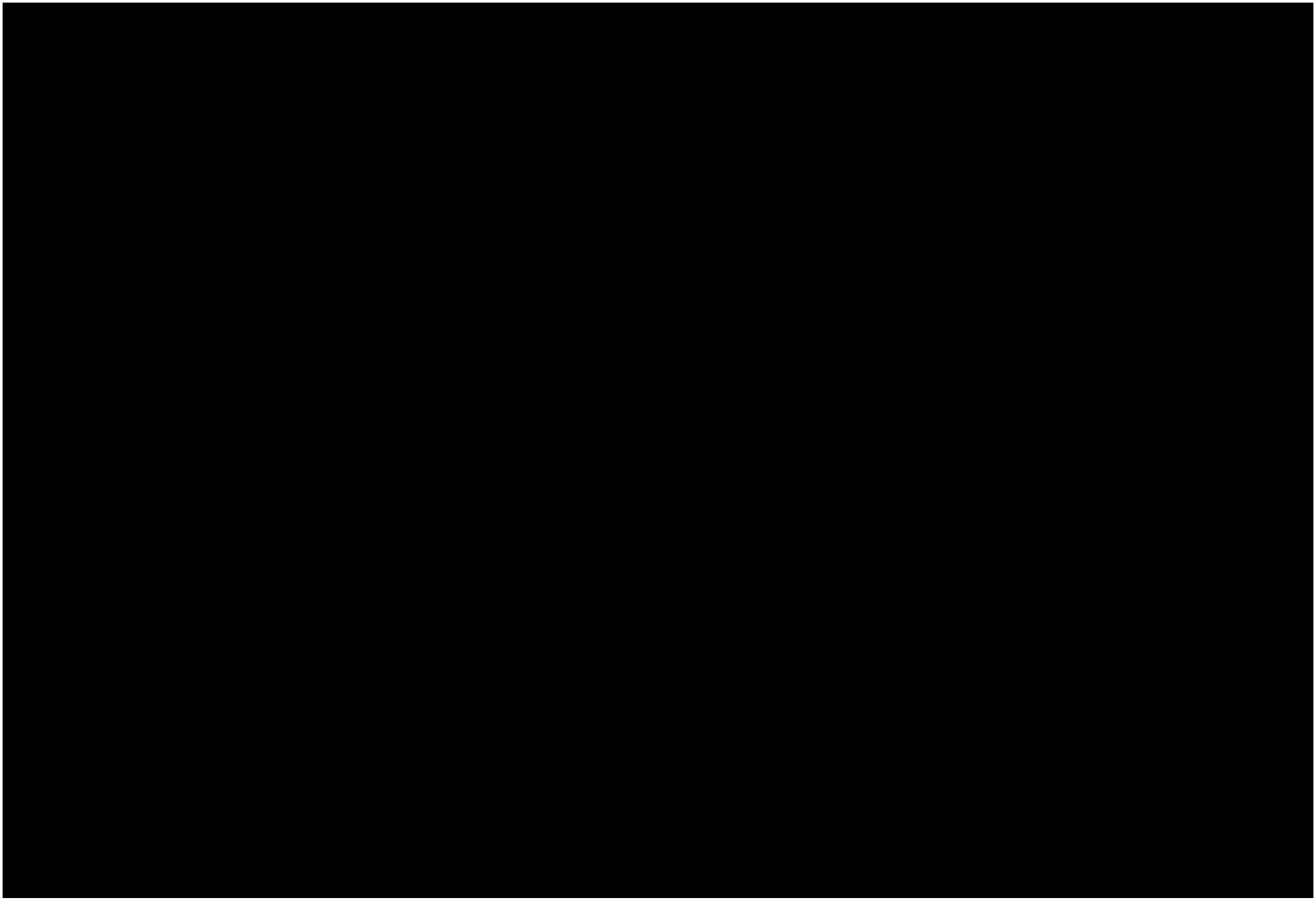
Member Forecasted Off Peak Demand Day for February 2021

Columbus Electric Cooperative, Inc.

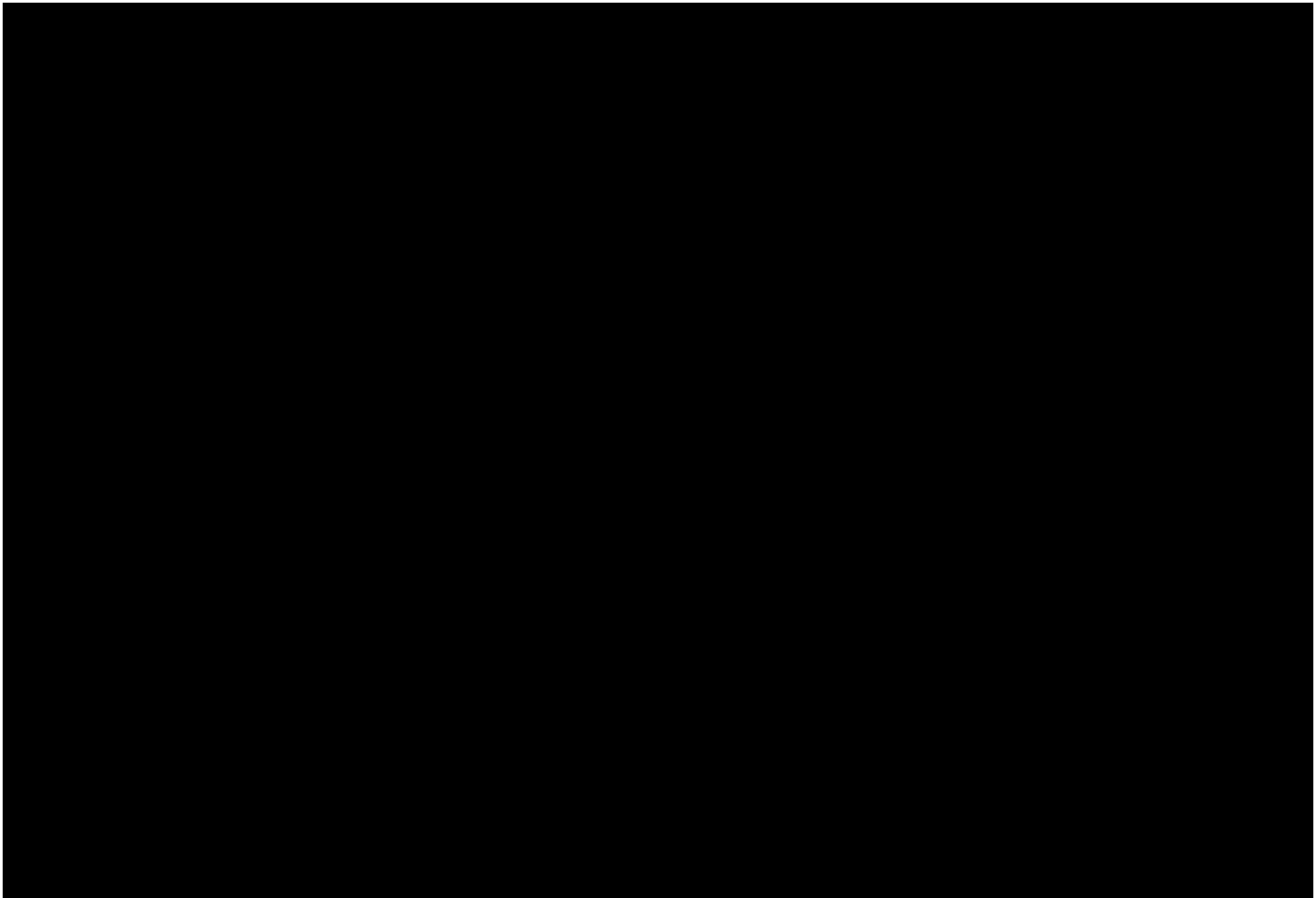
Date of Off Peak Day - 02/16/2021



Member Forecasted Off Peak Demand Day for March 2021

Columbus Electric Cooperative, Inc.

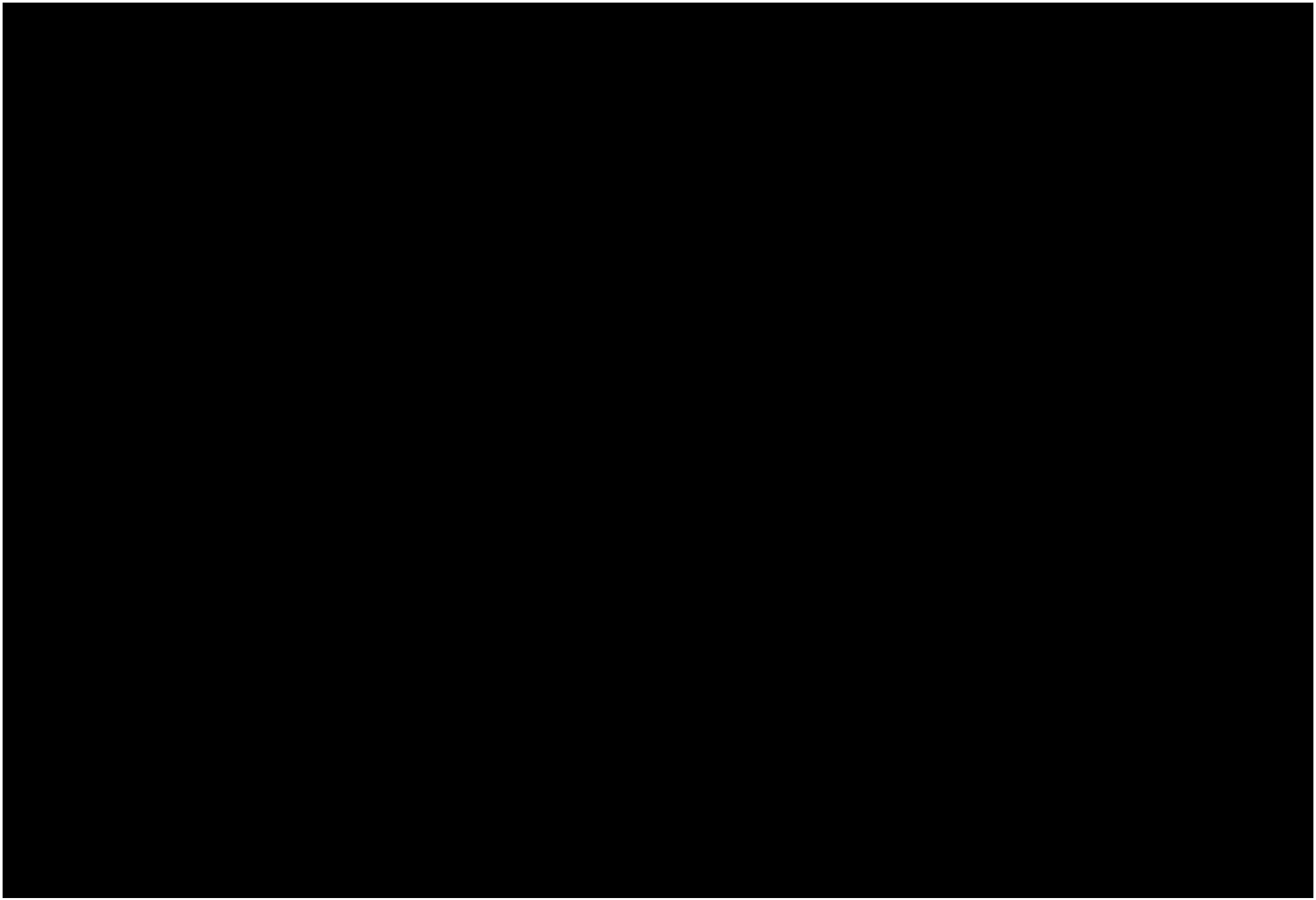
Date of Off Peak Day - 03/01/2021



Member Forecasted Off Peak Demand Day for April 2021

Columbus Electric Cooperative, Inc.

Date of Off Peak Day - 04/19/2021



Member Forecasted Off Peak Demand Day for May 2021

Columbus Electric Cooperative, Inc.

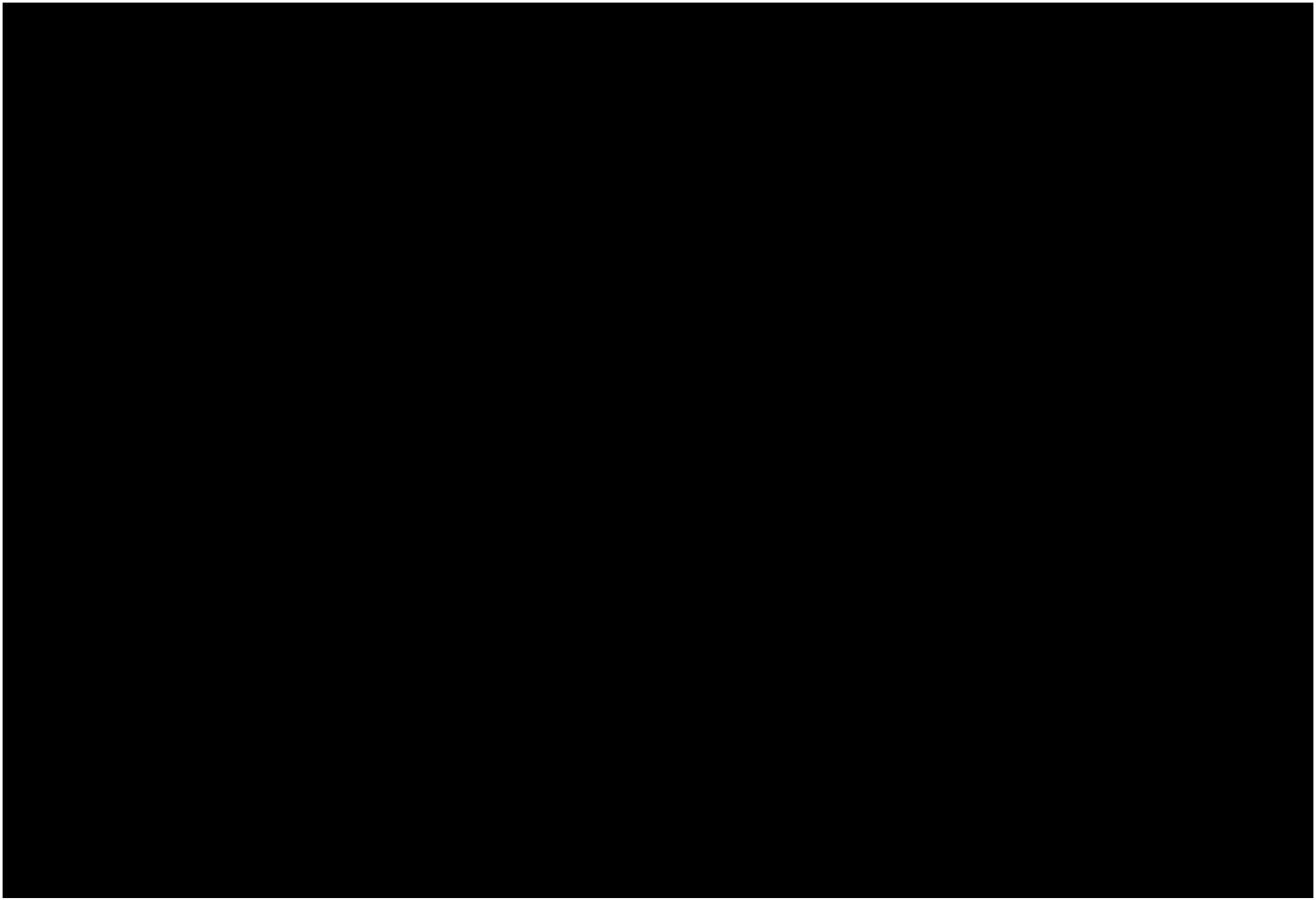
Date of Off Peak Day - 05/31/2021

[redacted]

Member Forecasted Off Peak Demand Day for June 2021

Columbus Electric Cooperative, Inc.

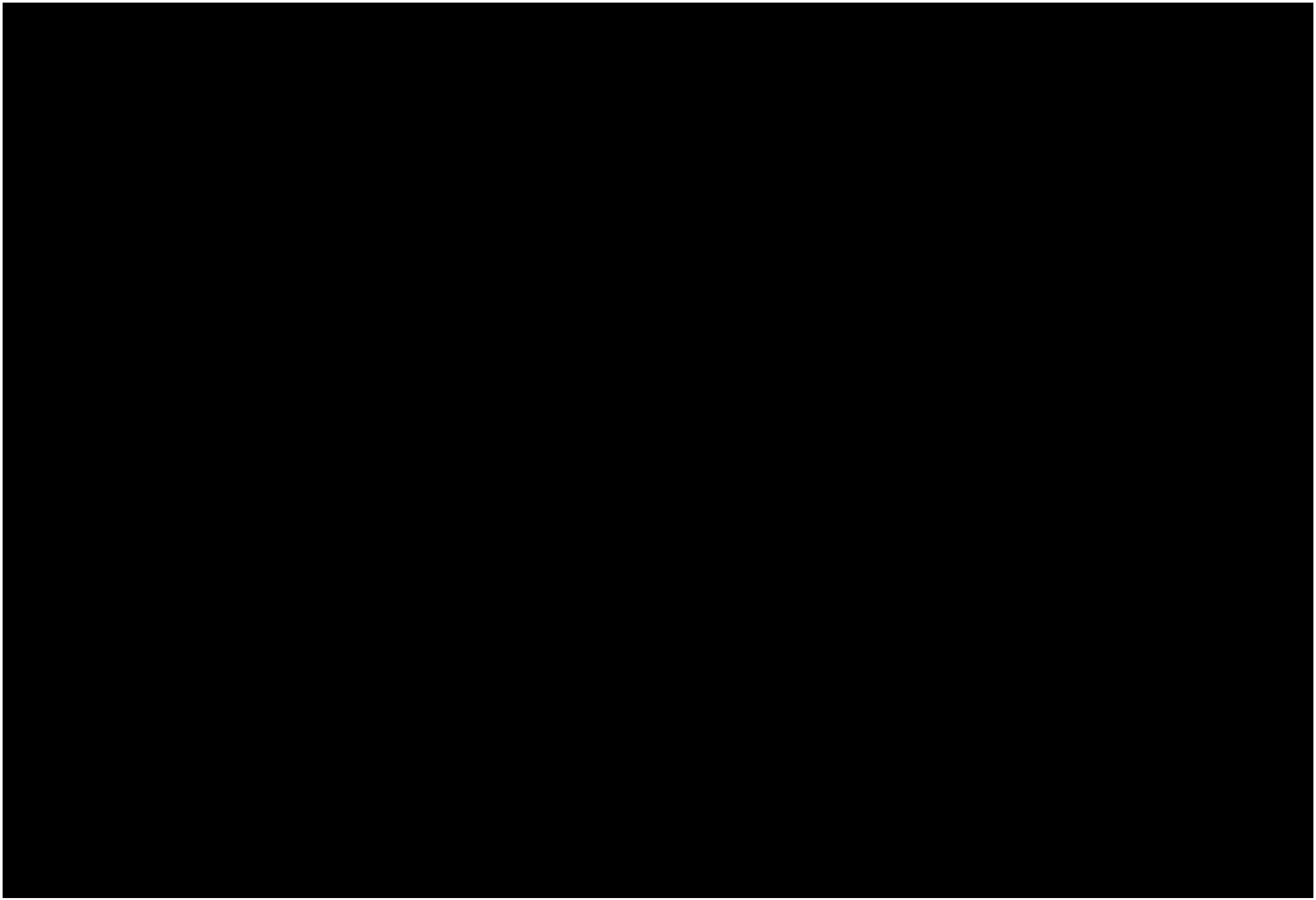
Date of Off Peak Day - 06/16/2021



Member Forecasted Off Peak Demand Day for July 2021

Columbus Electric Cooperative, Inc.

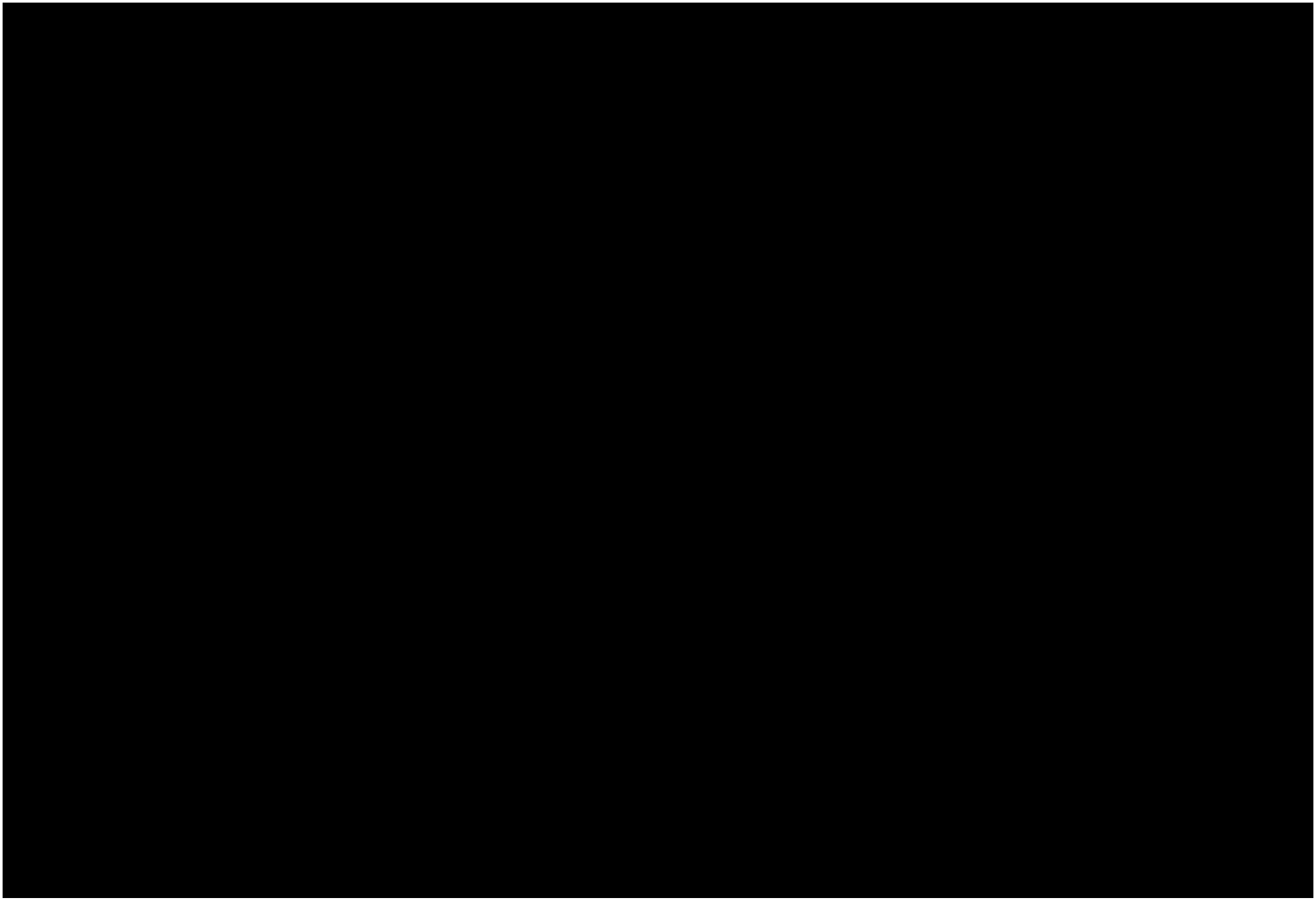
Date of Off Peak Day - 07/02/2021



Member Forecasted Off Peak Demand Day for August 2021

Columbus Electric Cooperative, Inc.

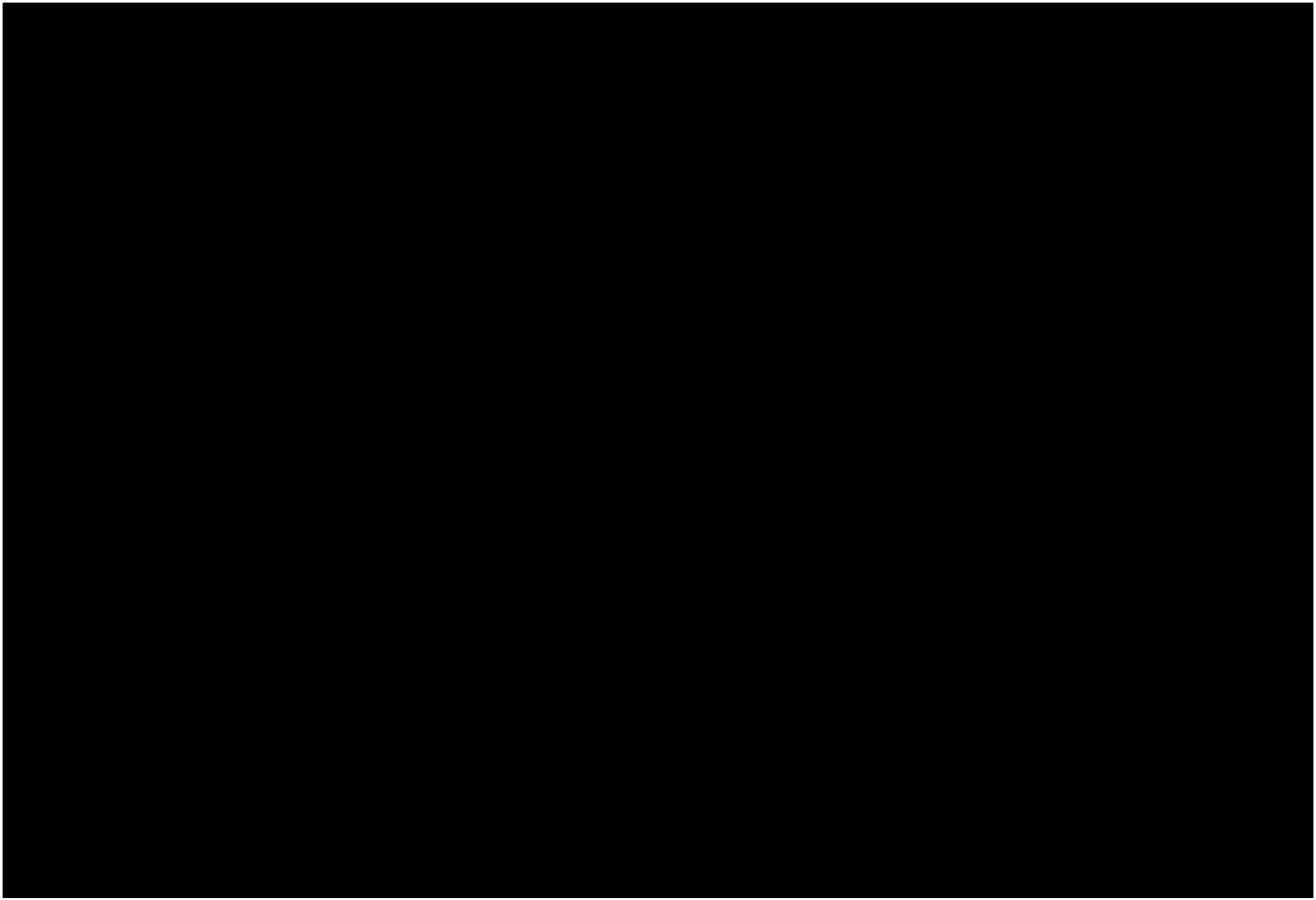
Date of Off Peak Day - 08/02/2021



Member Forecasted Off Peak Demand Day for September 2021

Columbus Electric Cooperative, Inc.

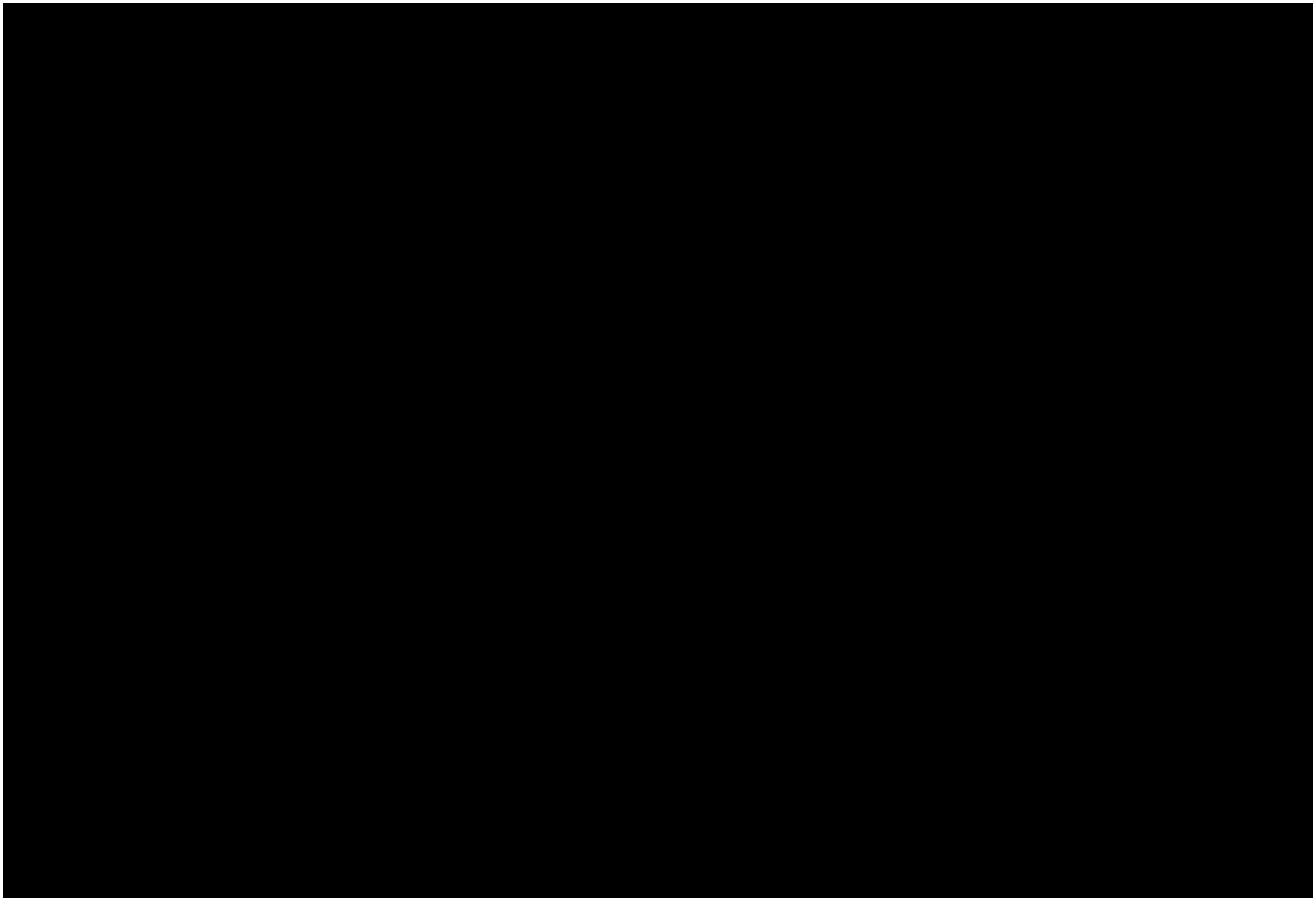
Date of Off Peak Day - 09/23/2021



Member Forecasted Off Peak Demand Day for October 2021

Columbus Electric Cooperative, Inc.

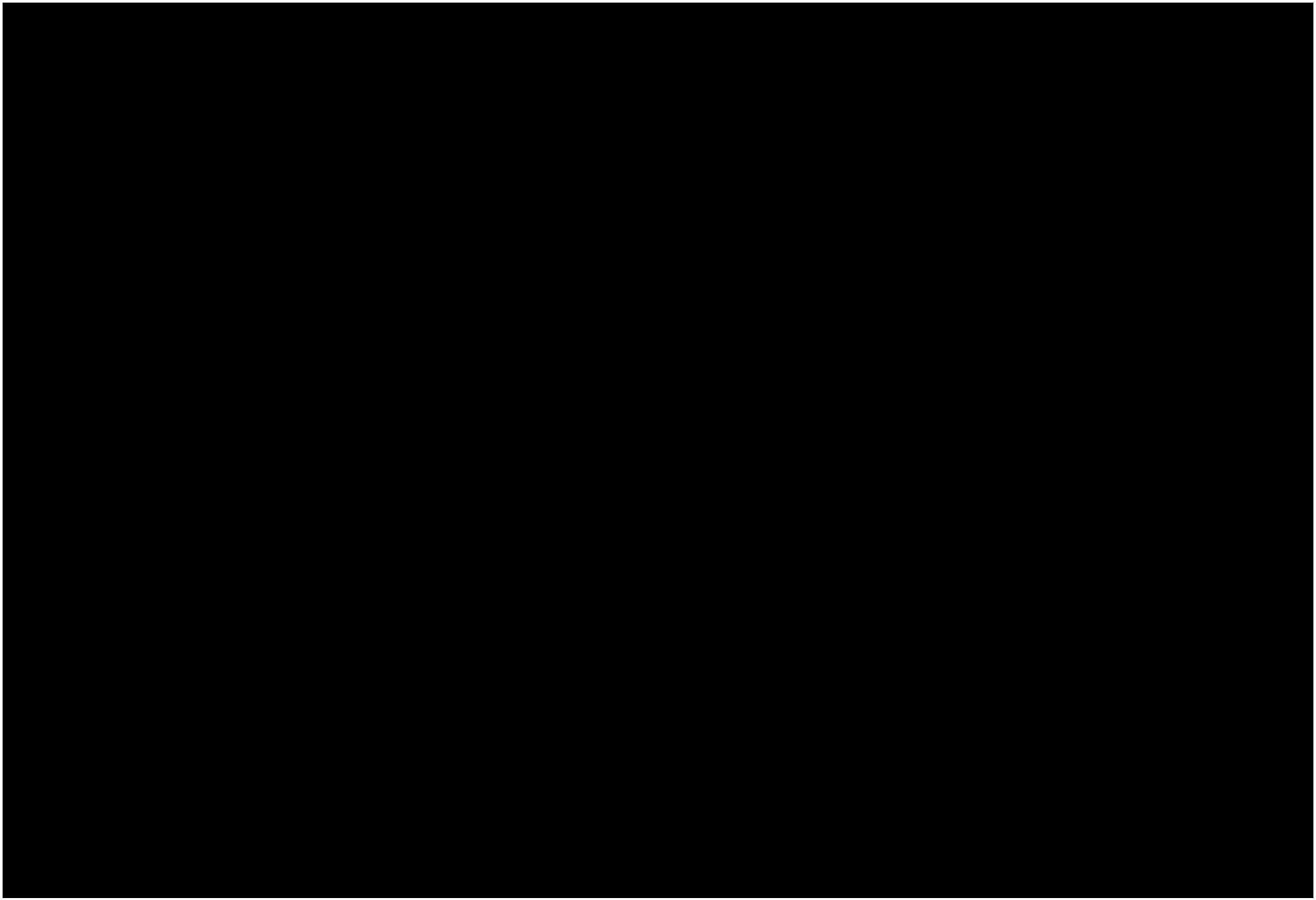
Date of Off Peak Day - 10/23/2021



Member Forecasted Off Peak Demand Day for November 2021

Columbus Electric Cooperative, Inc.

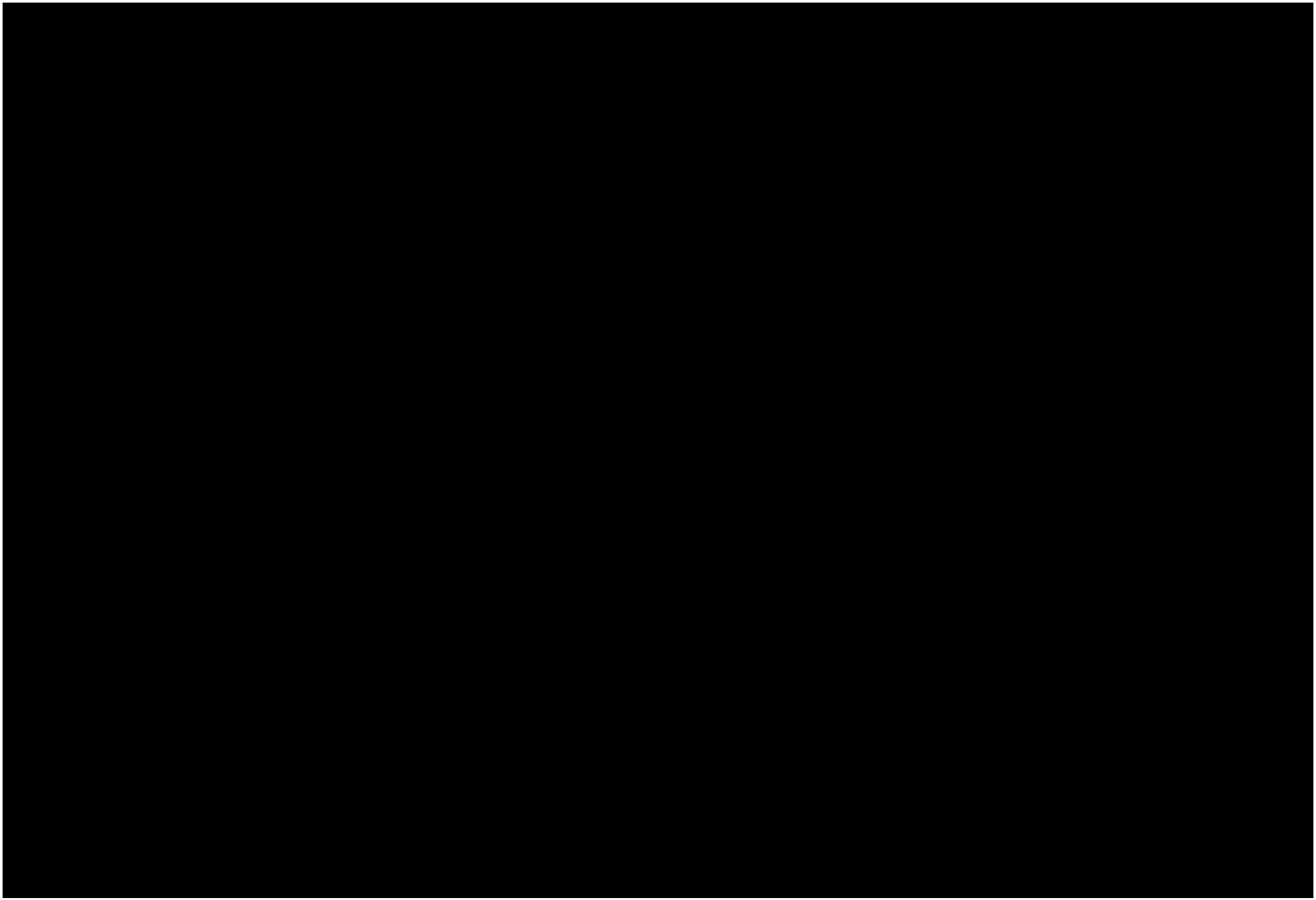
Date of Off Peak Day - 11/07/2021



Member Forecasted Off Peak Demand Day for December 2021

Columbus Electric Cooperative, Inc.

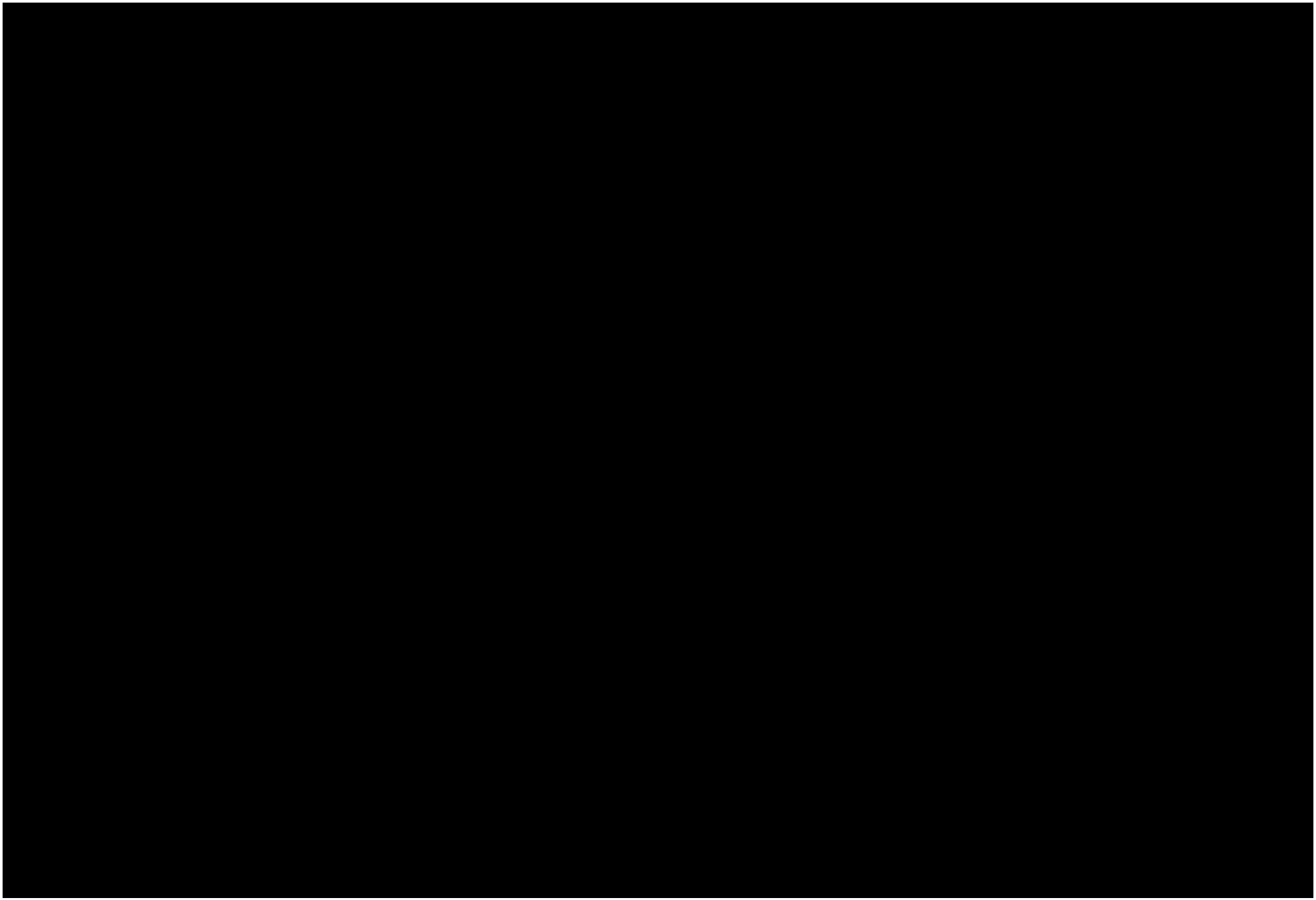
Date of Off Peak Day - 12/30/2021



Member Forecasted Off Peak Demand Day for January 2021

Central New Mexico Electric Cooperative, Inc.

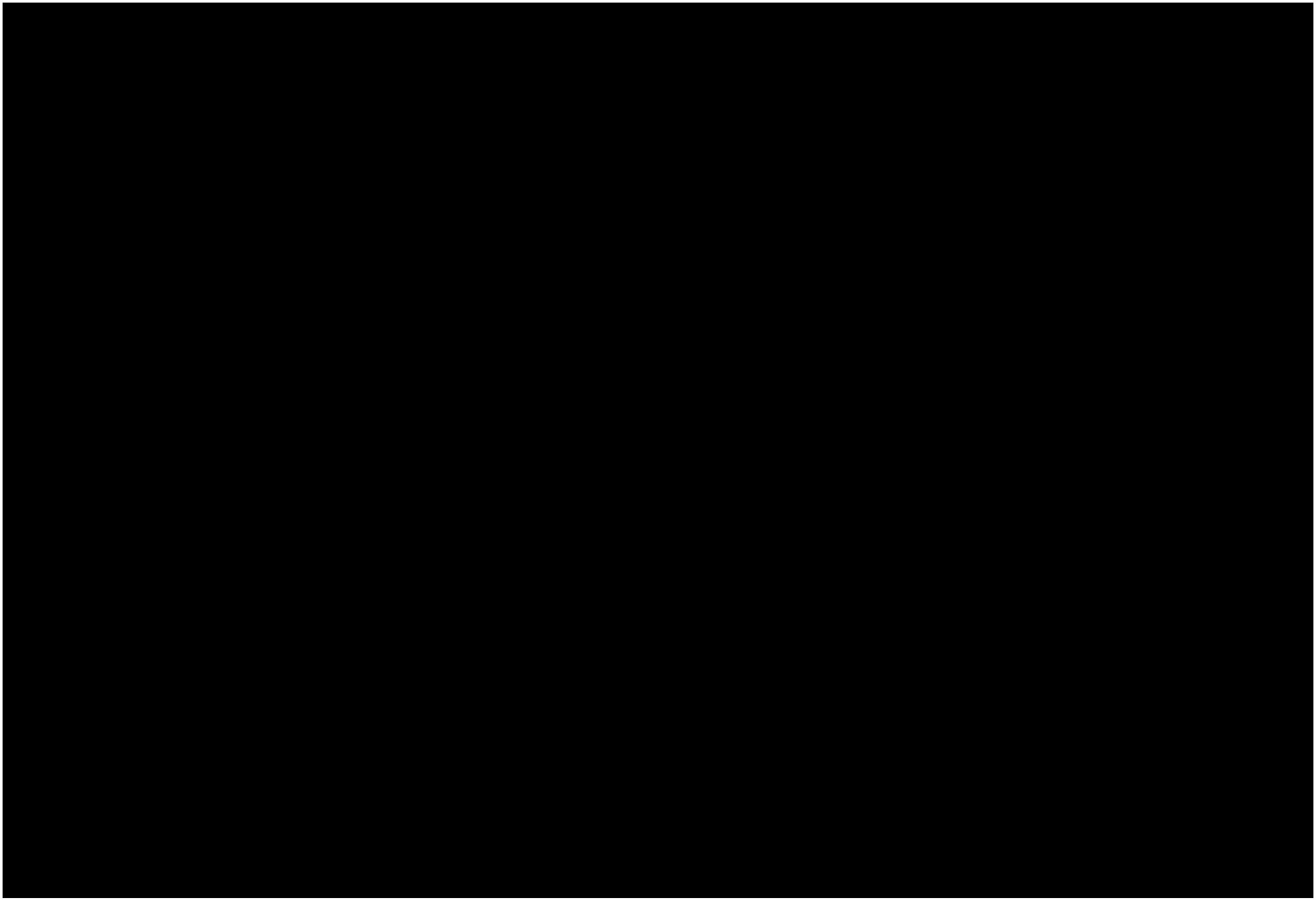
Date of Off Peak Day - 01/12/2021



Member Forecasted Off Peak Demand Day for February 2021

Central New Mexico Electric Cooperative, Inc.

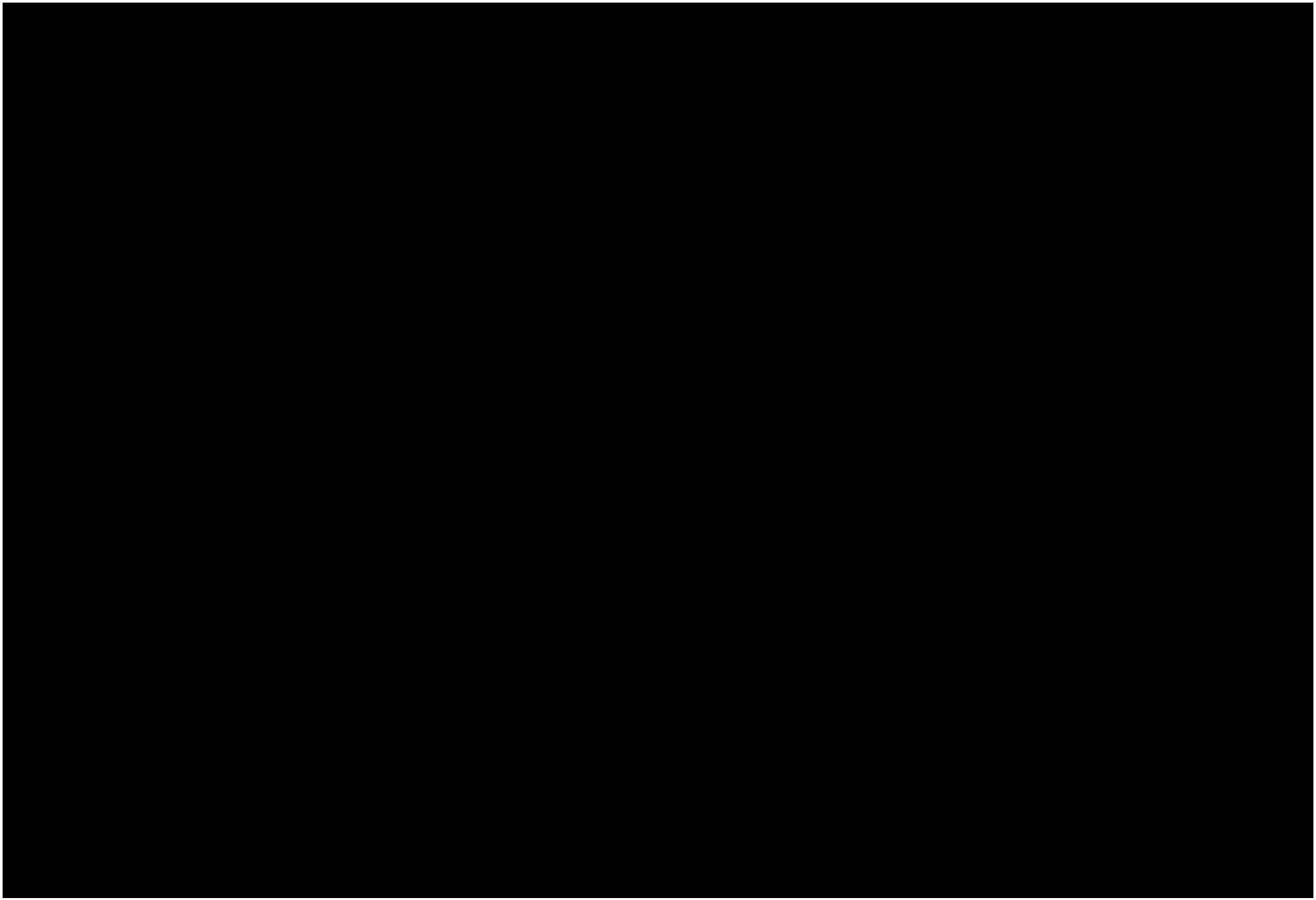
Date of Off Peak Day - 02/20/2021



Member Forecasted Off Peak Demand Day for March 2021

Central New Mexico Electric Cooperative, Inc.

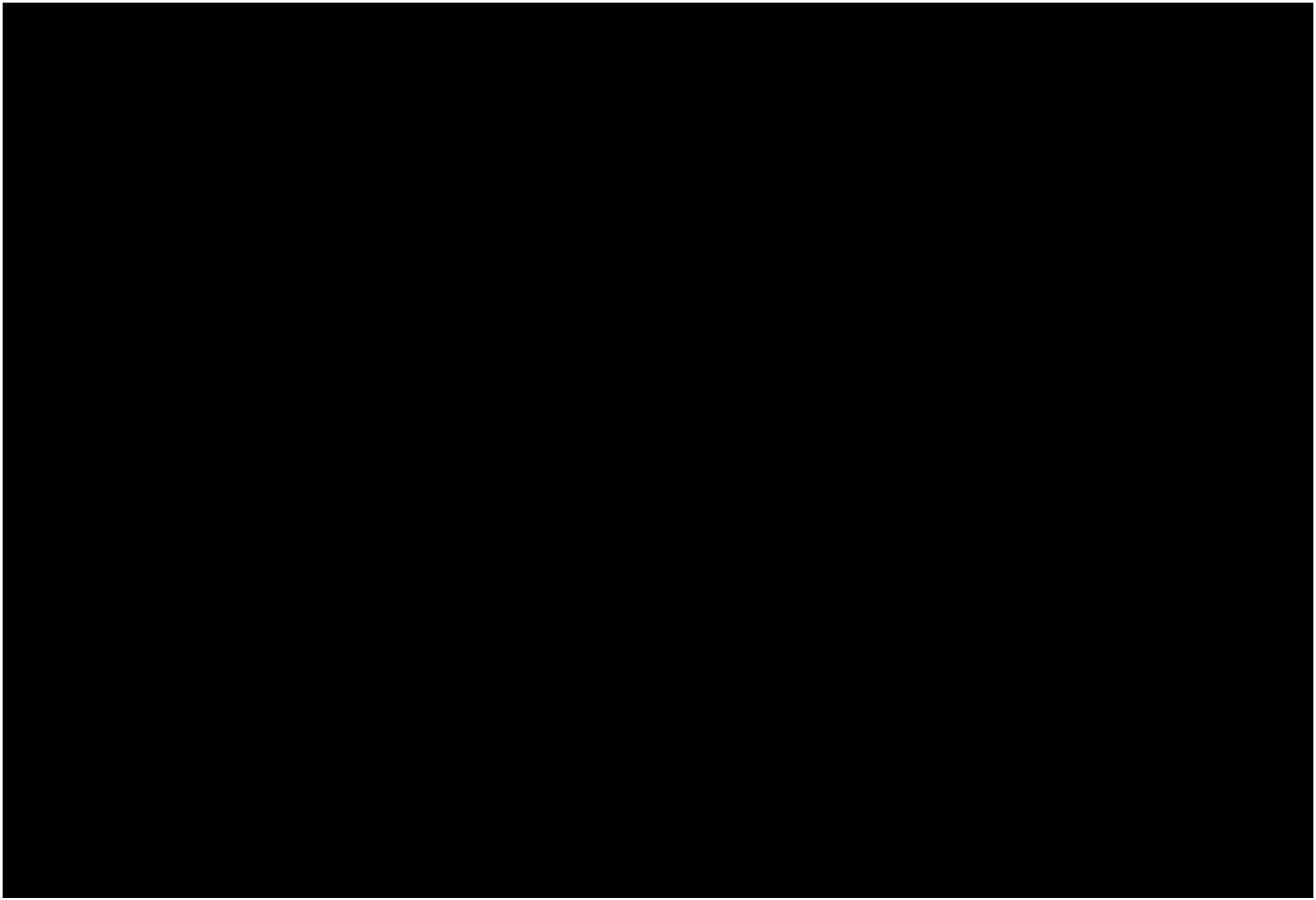
Date of Off Peak Day - 03/22/2021



Member Forecasted Off Peak Demand Day for April 2021

Central New Mexico Electric Cooperative, Inc.

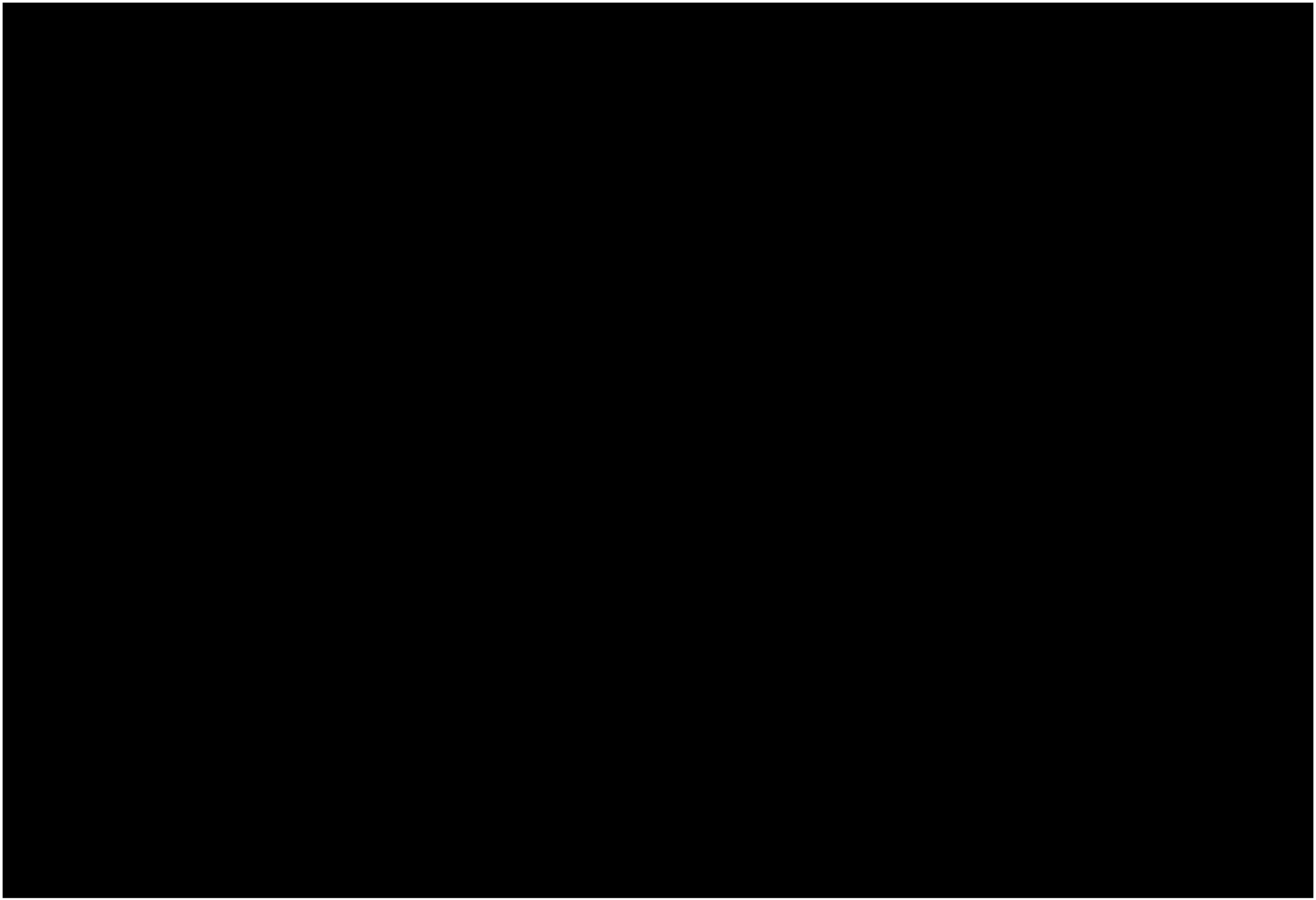
Date of Off Peak Day - 04/30/2021



Member Forecasted Off Peak Demand Day for May 2021

Central New Mexico Electric Cooperative, Inc.

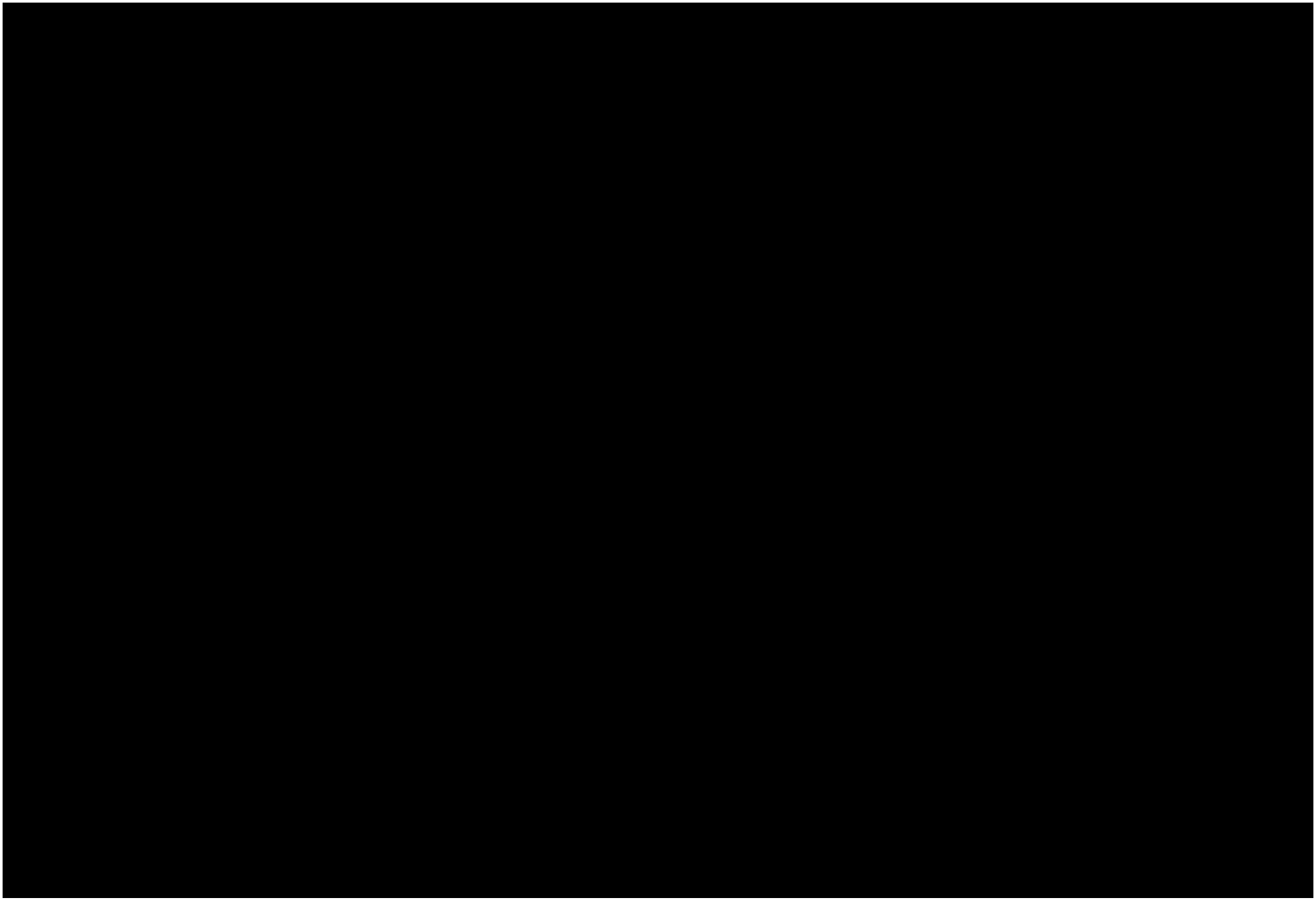
Date of Off Peak Day - 05/03/2021



Member Forecasted Off Peak Demand Day for June 2021

Central New Mexico Electric Cooperative, Inc.

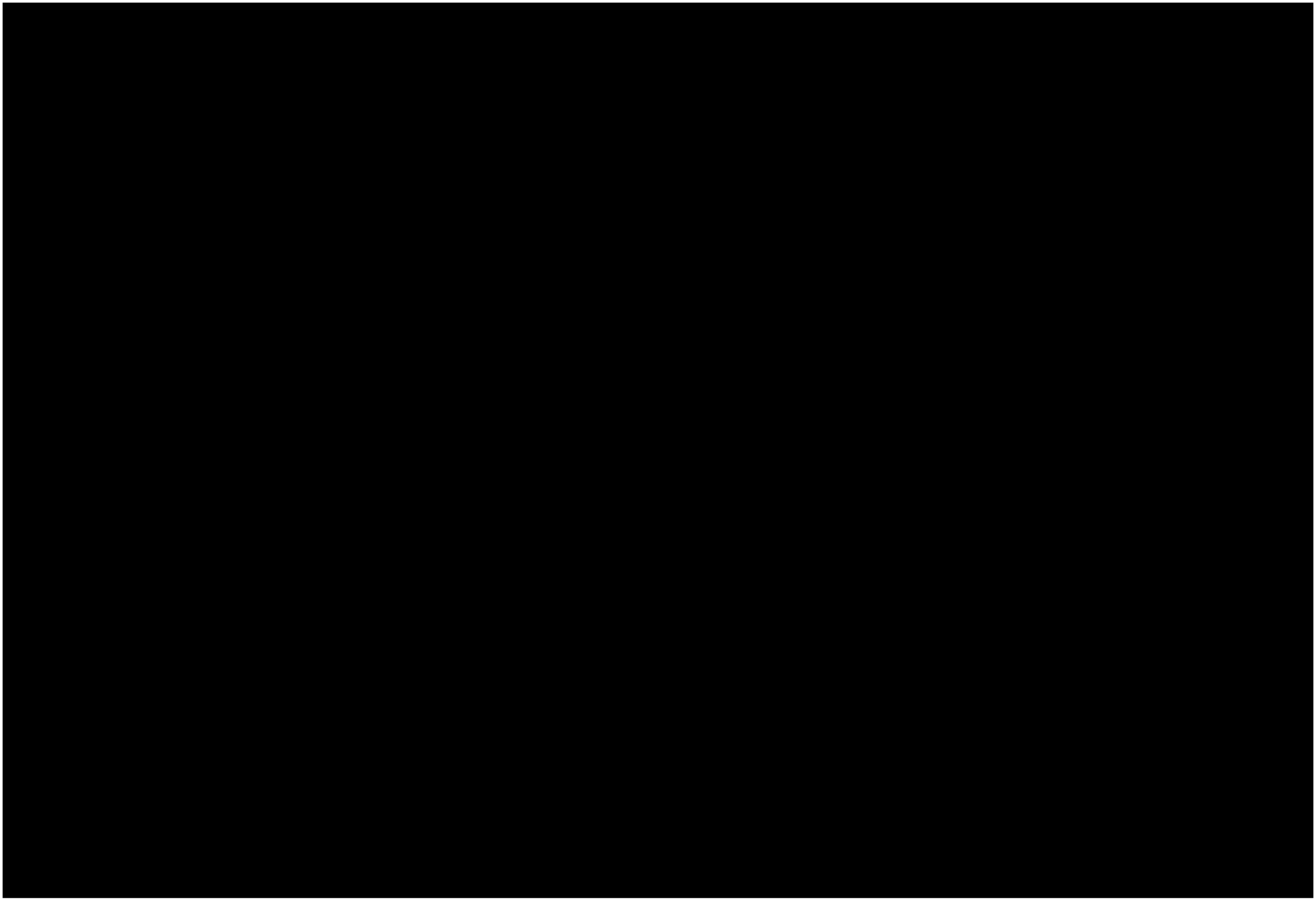
Date of Off Peak Day - 06/05/2021



Member Forecasted Off Peak Demand Day for July 2021

Central New Mexico Electric Cooperative, Inc.

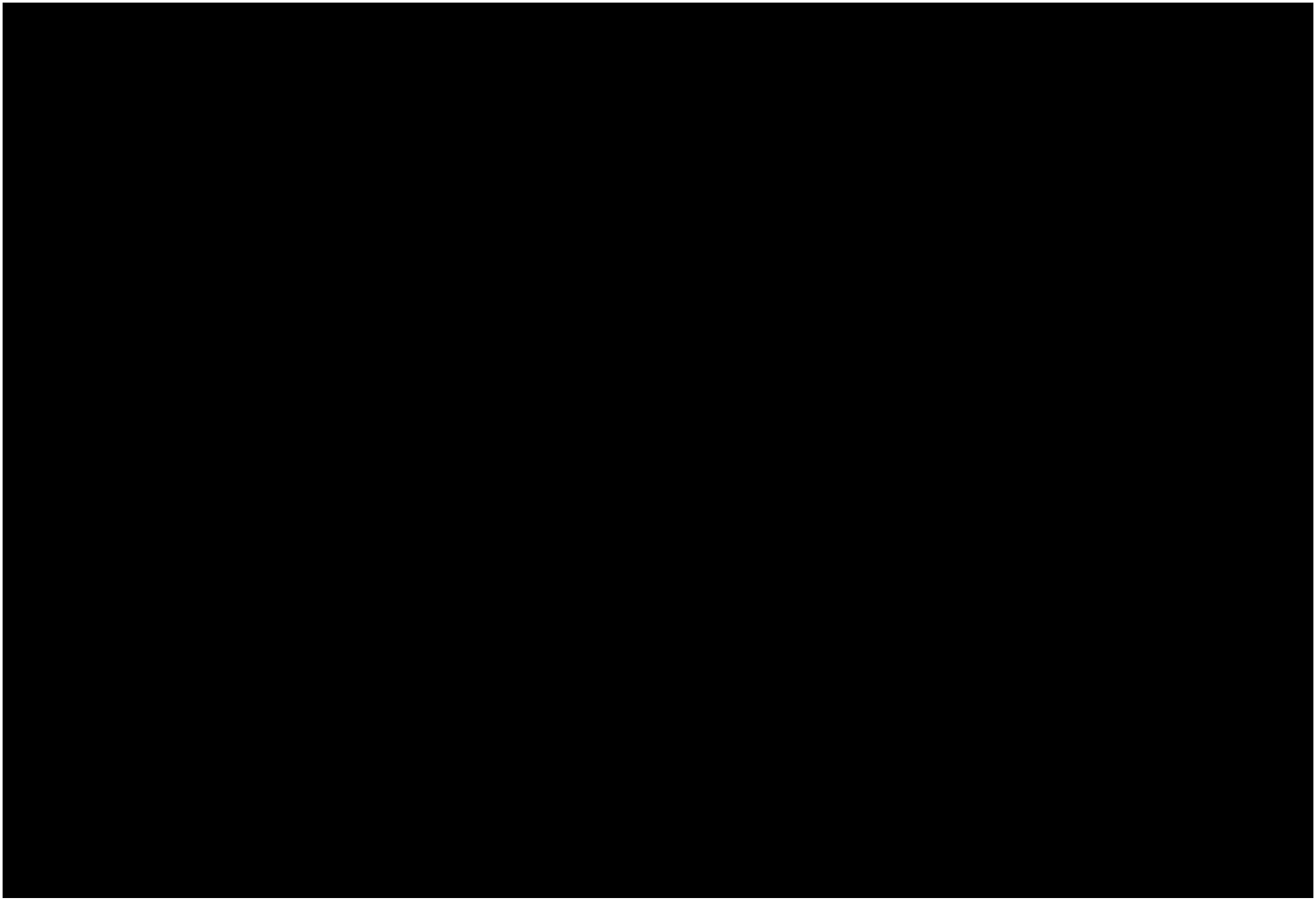
Date of Off Peak Day - 07/03/2021



Member Forecasted Off Peak Demand Day for August 2021

Central New Mexico Electric Cooperative, Inc.

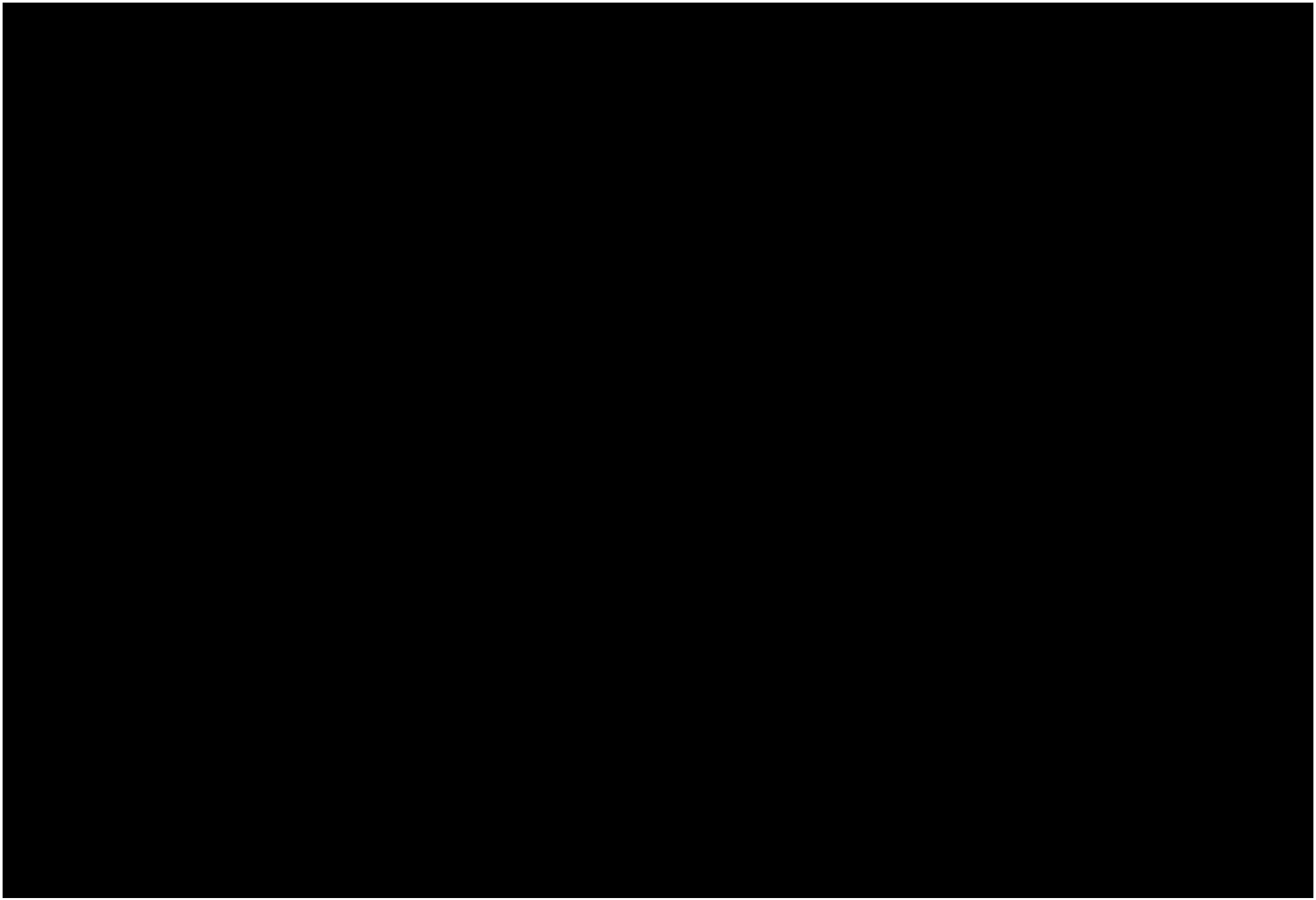
Date of Off Peak Day - 08/12/2021



Member Forecasted Off Peak Demand Day for September 2021

Central New Mexico Electric Cooperative, Inc.

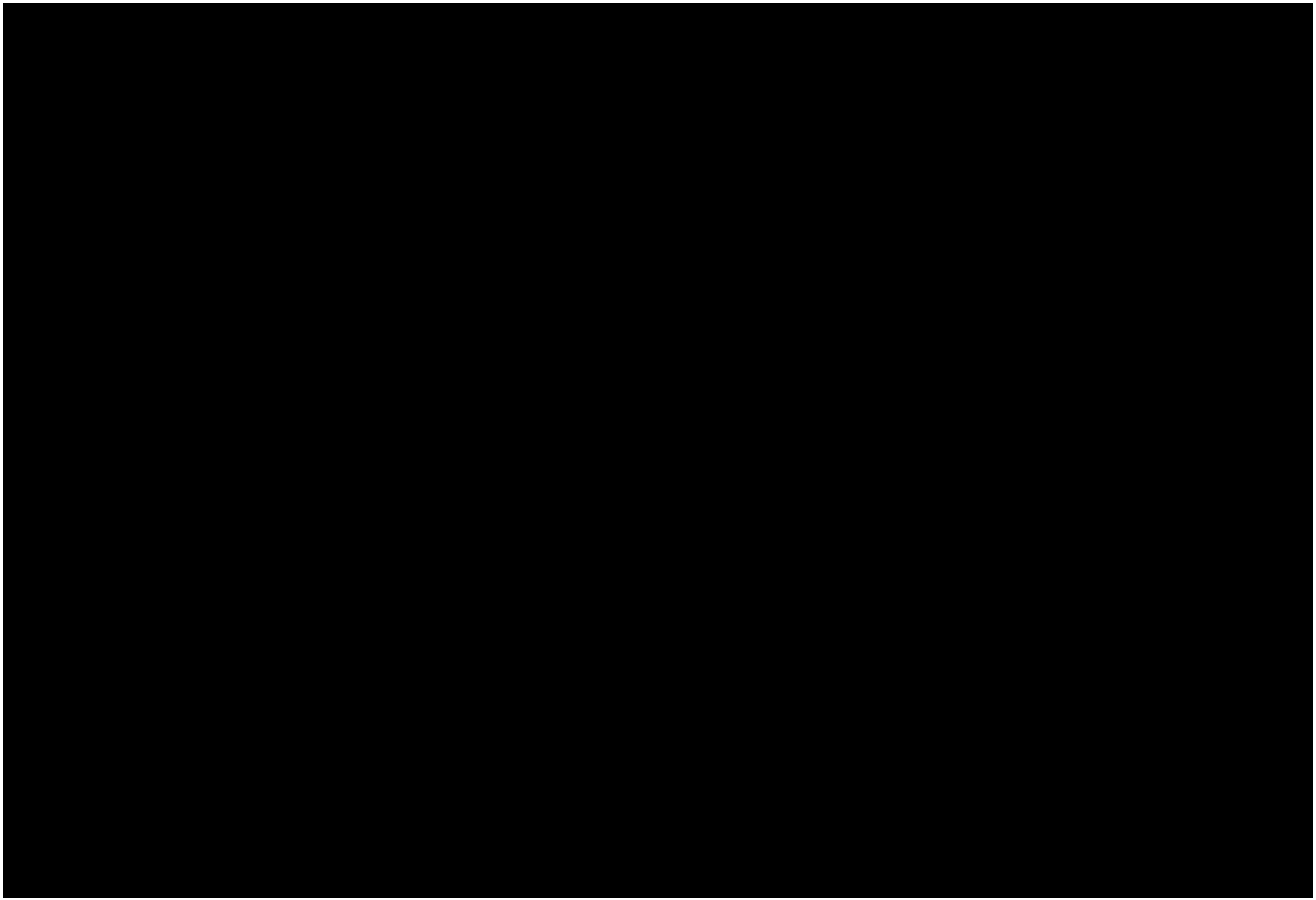
Date of Off Peak Day - 09/29/2021



Member Forecasted Off Peak Demand Day for October 2021

Central New Mexico Electric Cooperative, Inc.

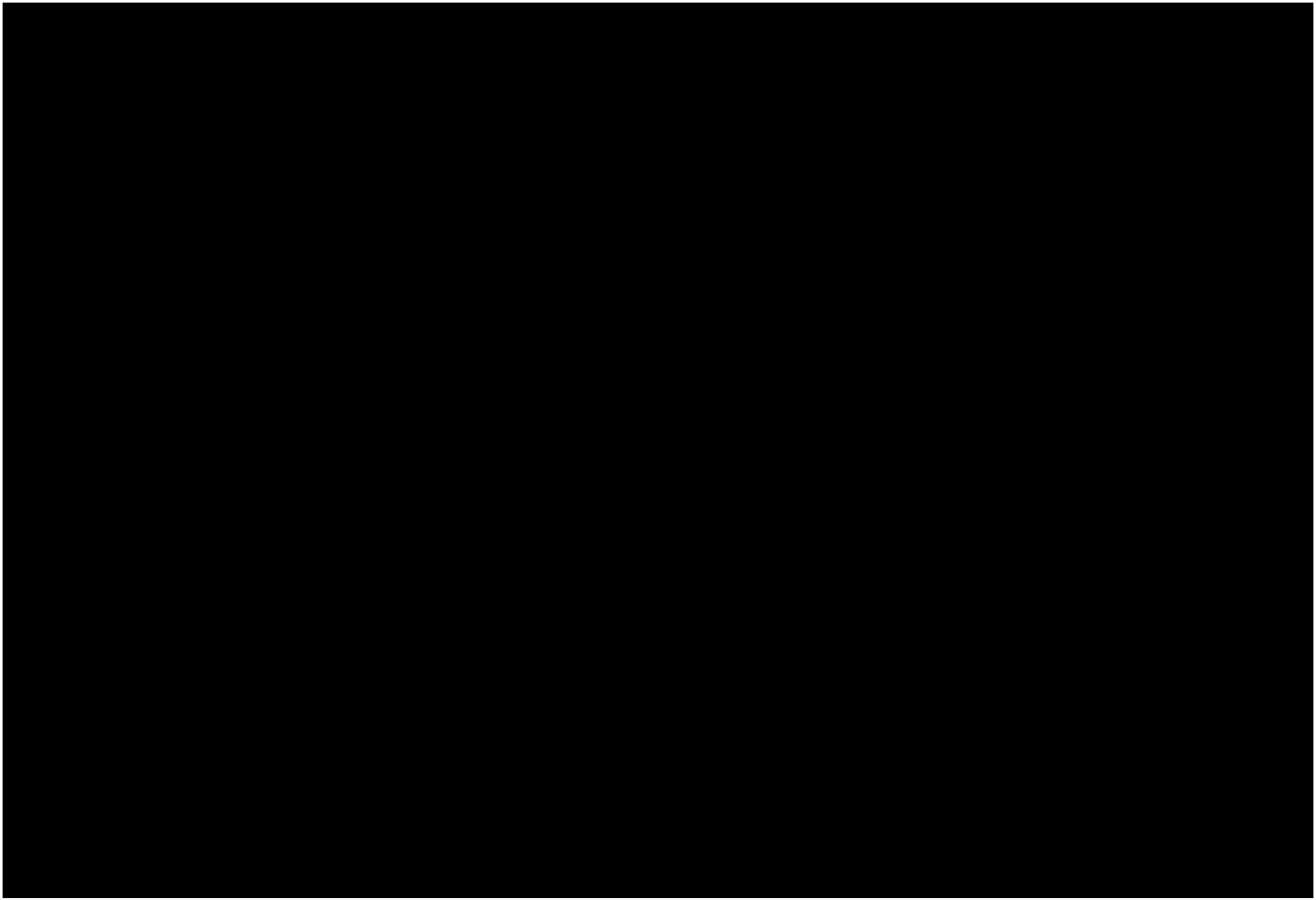
Date of Off Peak Day - 10/15/2021



Member Forecasted Off Peak Demand Day for November 2021

Central New Mexico Electric Cooperative, Inc.

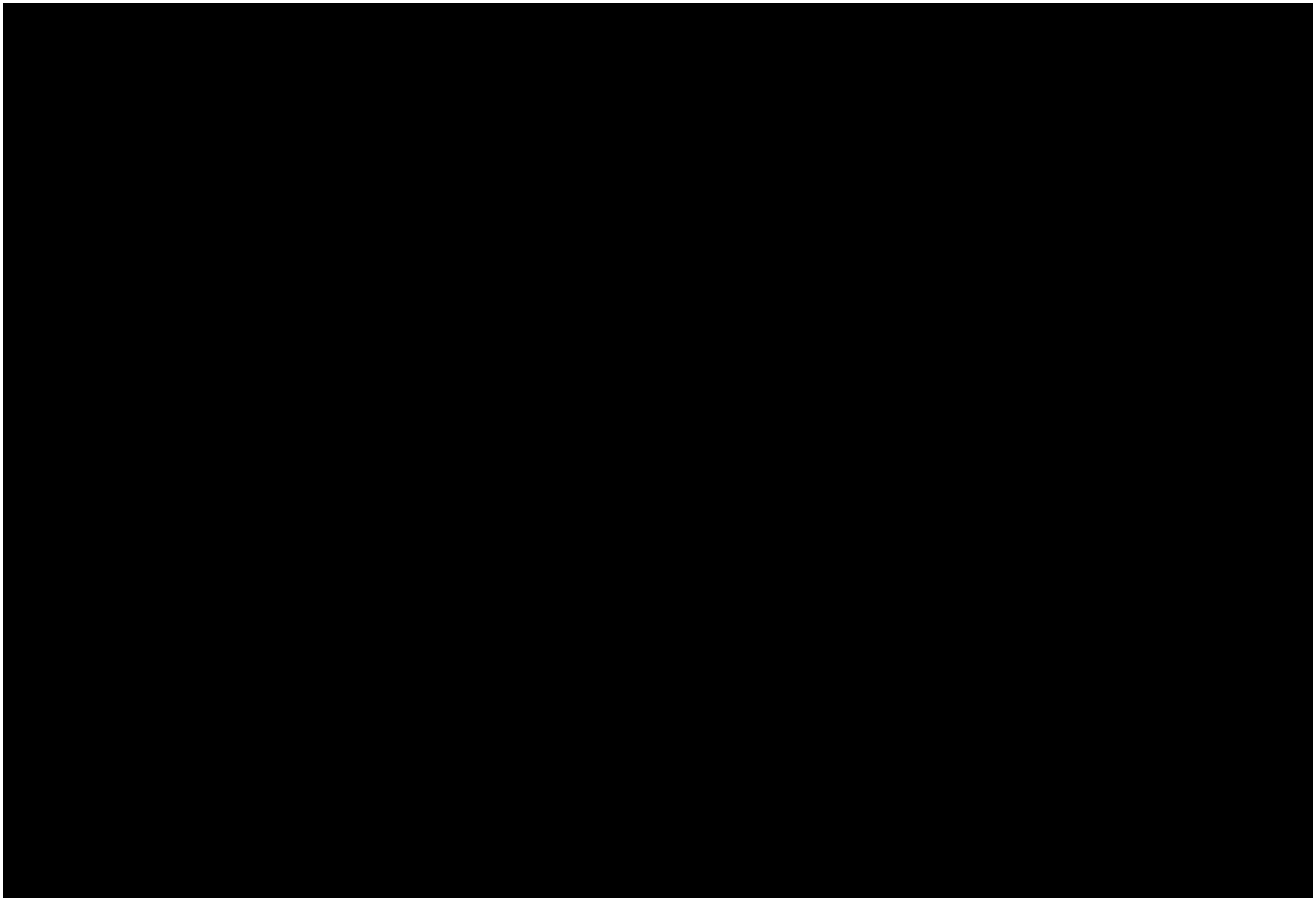
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

Central New Mexico Electric Cooperative, Inc.

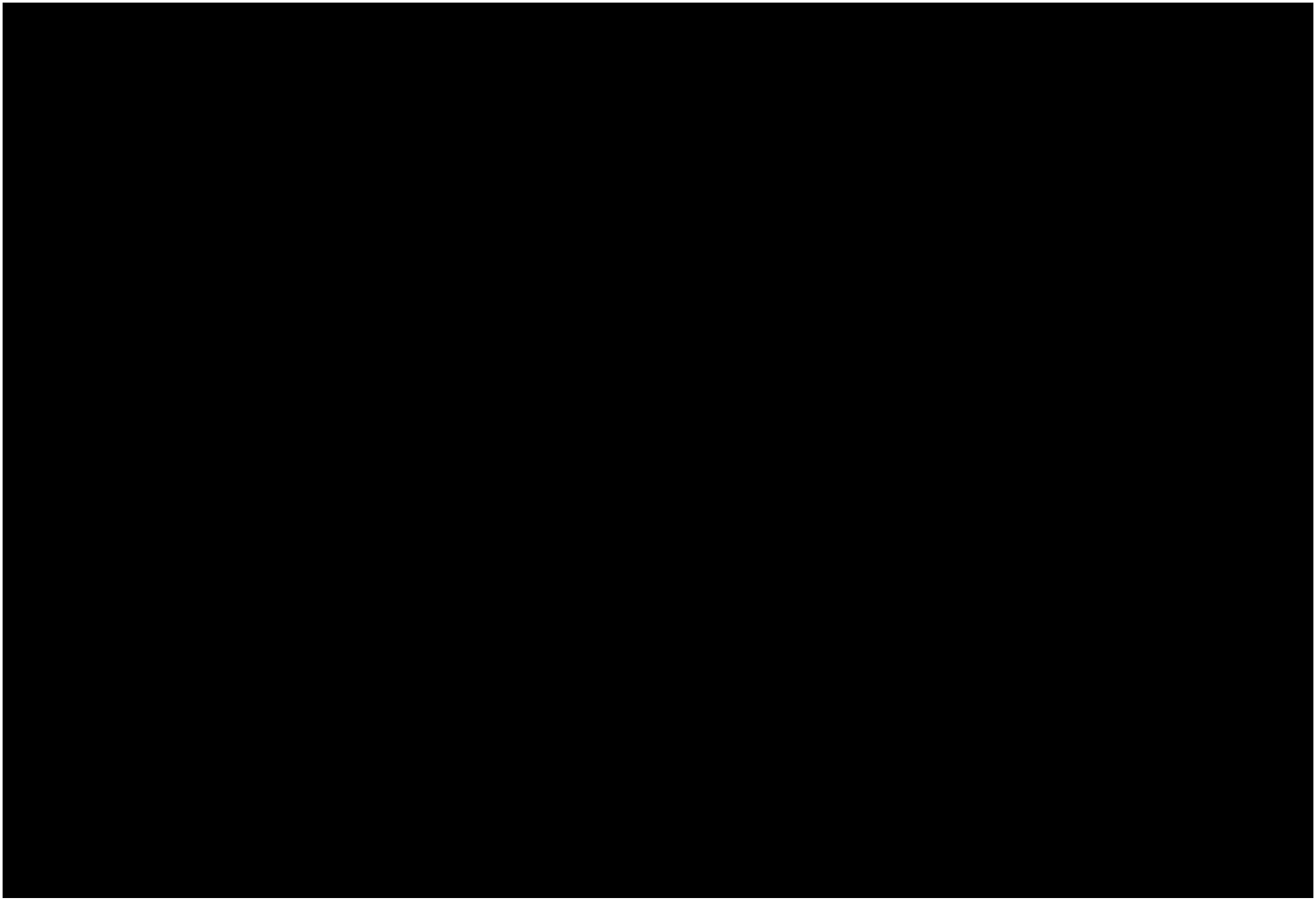
Date of Off Peak Day - 12/03/2021



Member Forecasted Off Peak Demand Day for January 2021

Chimney Rock Public Power District

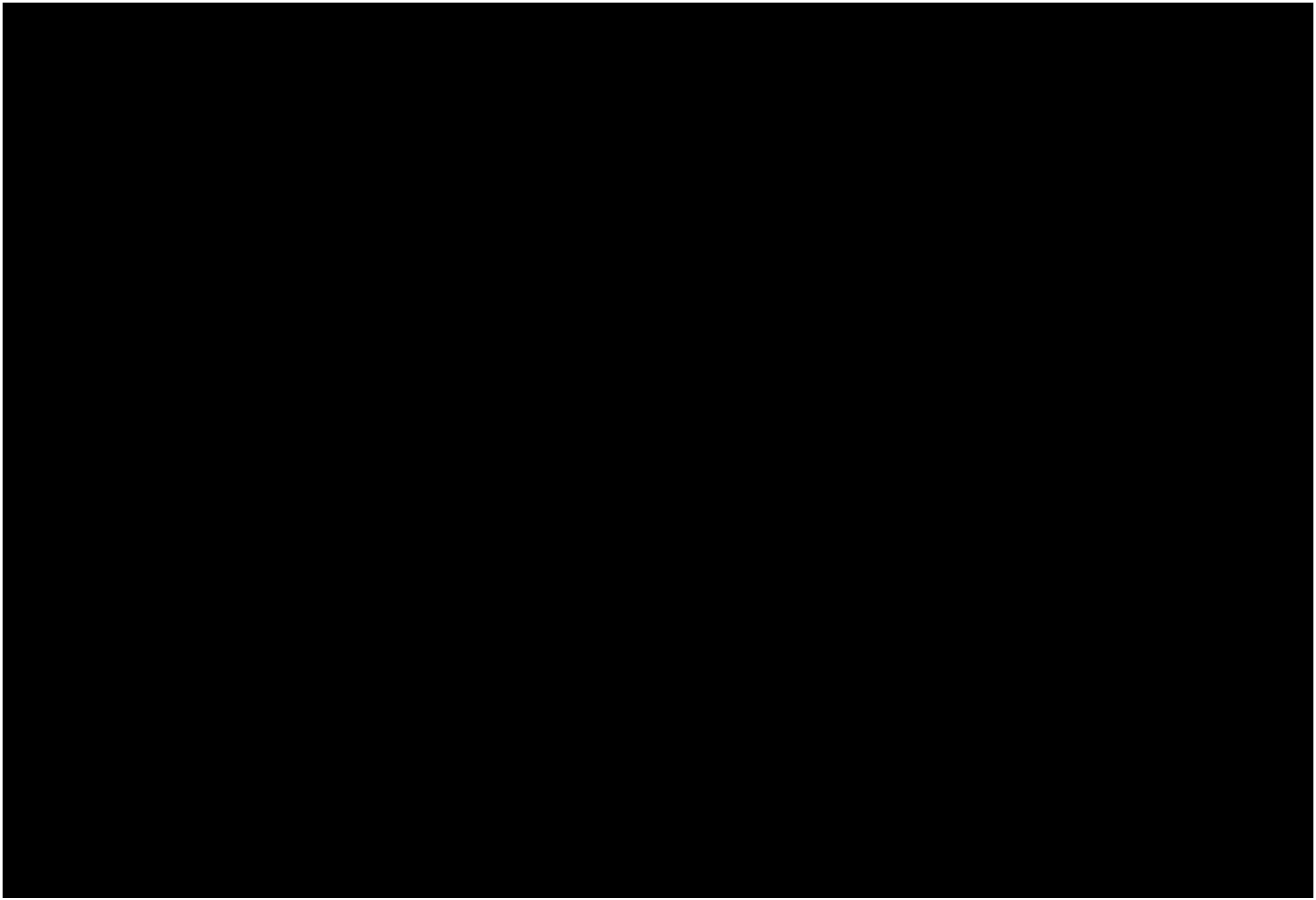
Date of Off Peak Day - 01/18/2021



Member Forecasted Off Peak Demand Day for February 2021

Chimney Rock Public Power District

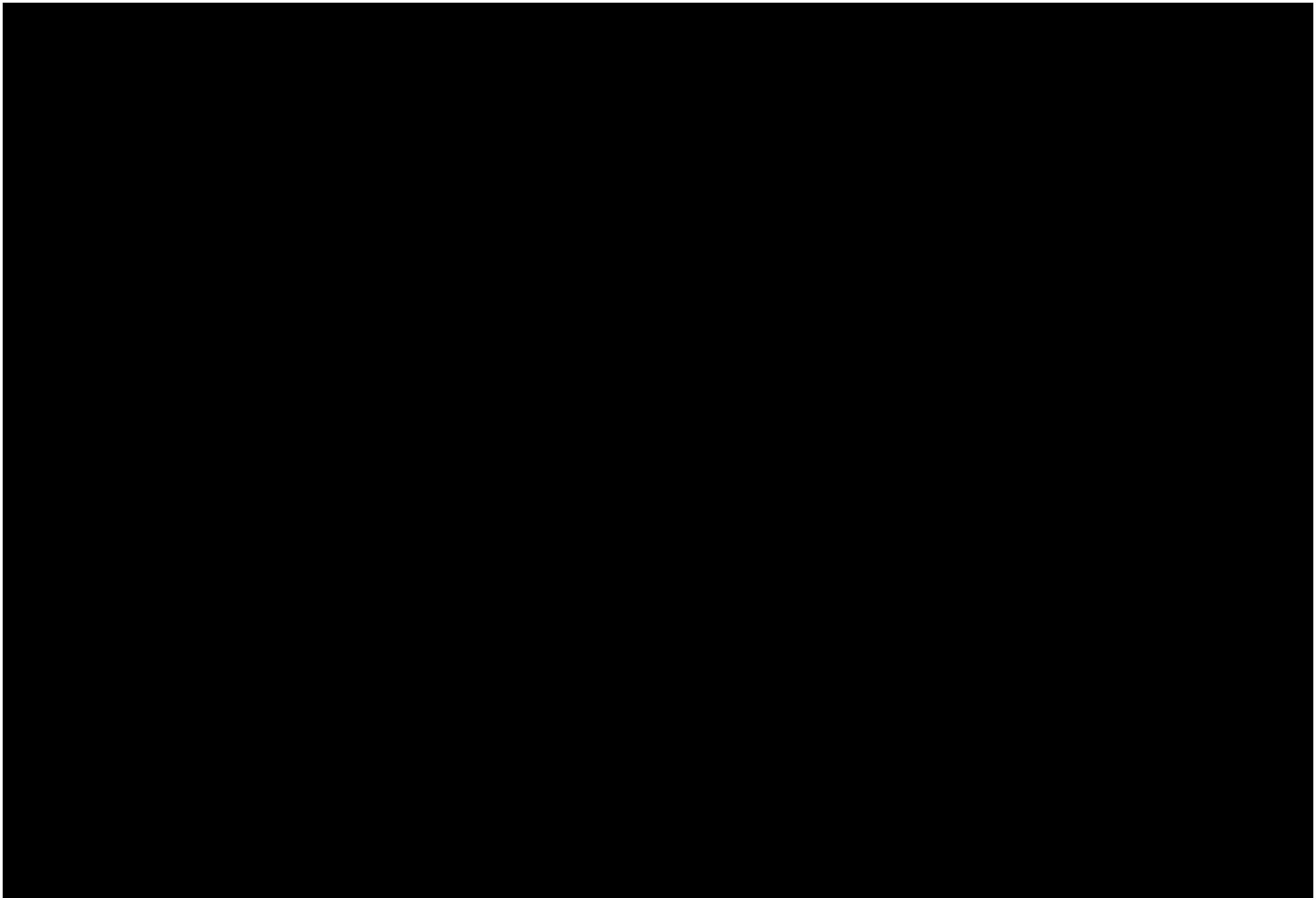
Date of Off Peak Day - 02/22/2021



Member Forecasted Off Peak Demand Day for March 2021

Chimney Rock Public Power District

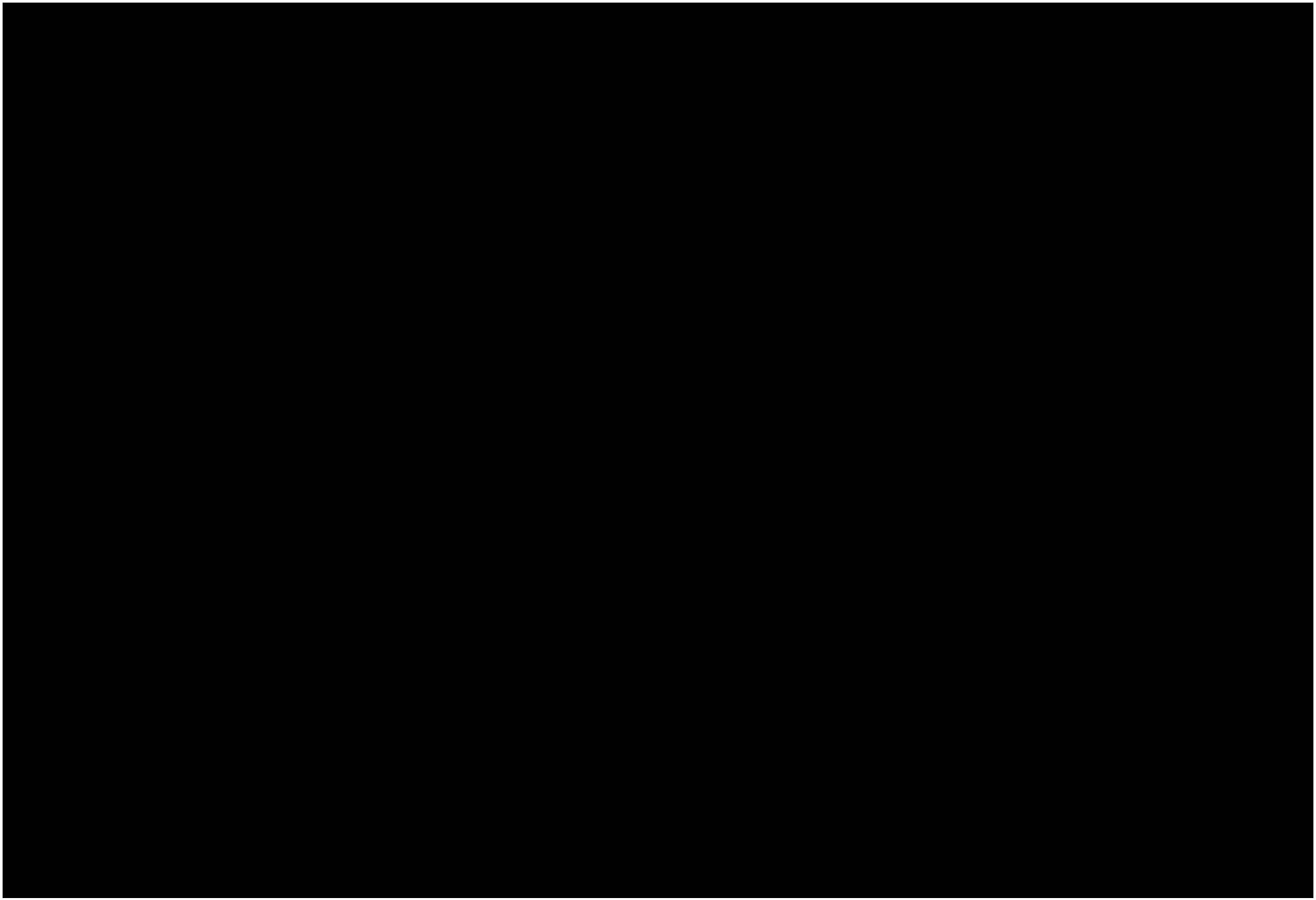
Date of Off Peak Day - 03/28/2021



Member Forecasted Off Peak Demand Day for April 2021

Chimney Rock Public Power District

Date of Off Peak Day - 04/30/2021



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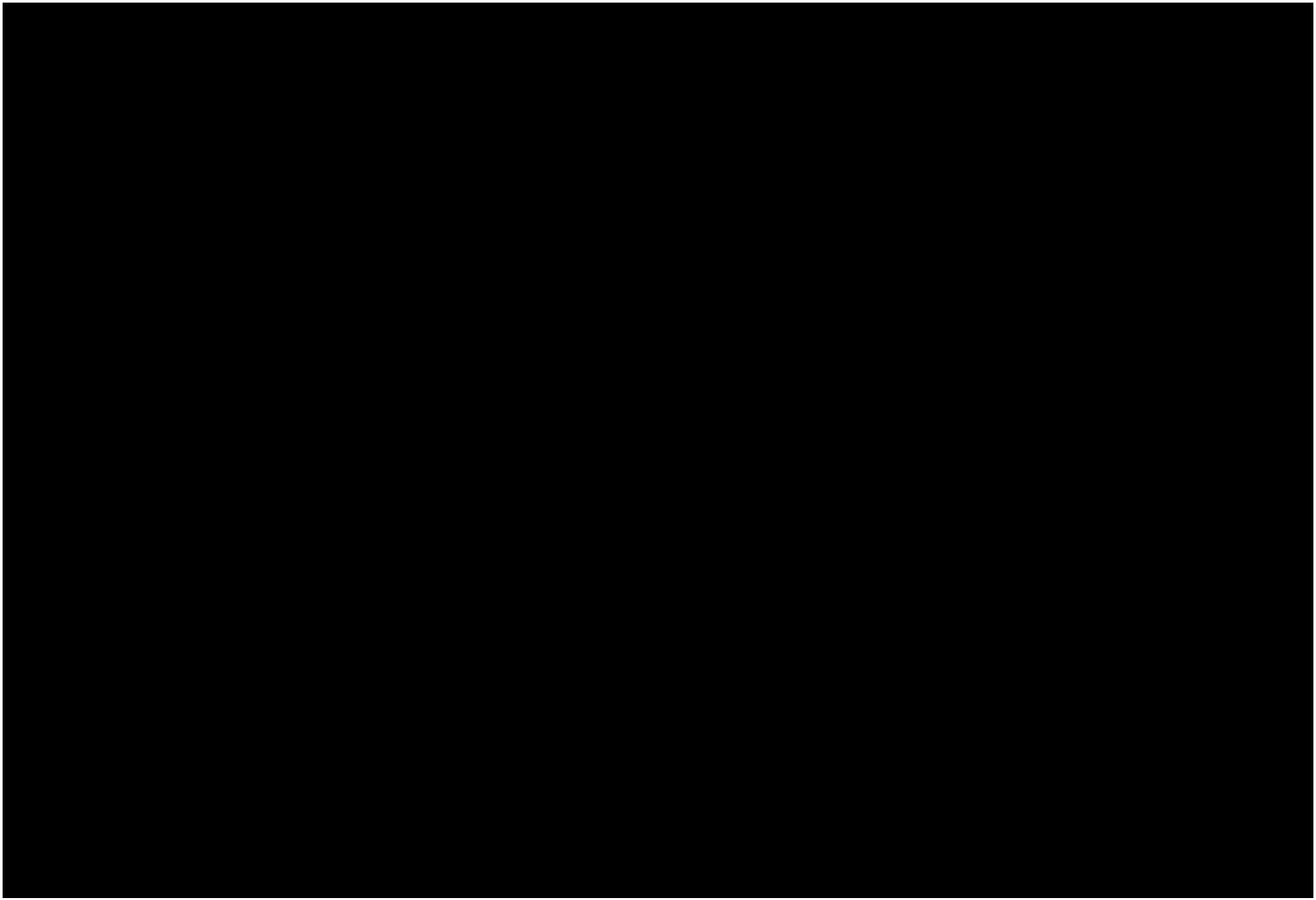
Member Forecasted Off Peak Demand Day for May 2021

Chimney Rock Public Power District

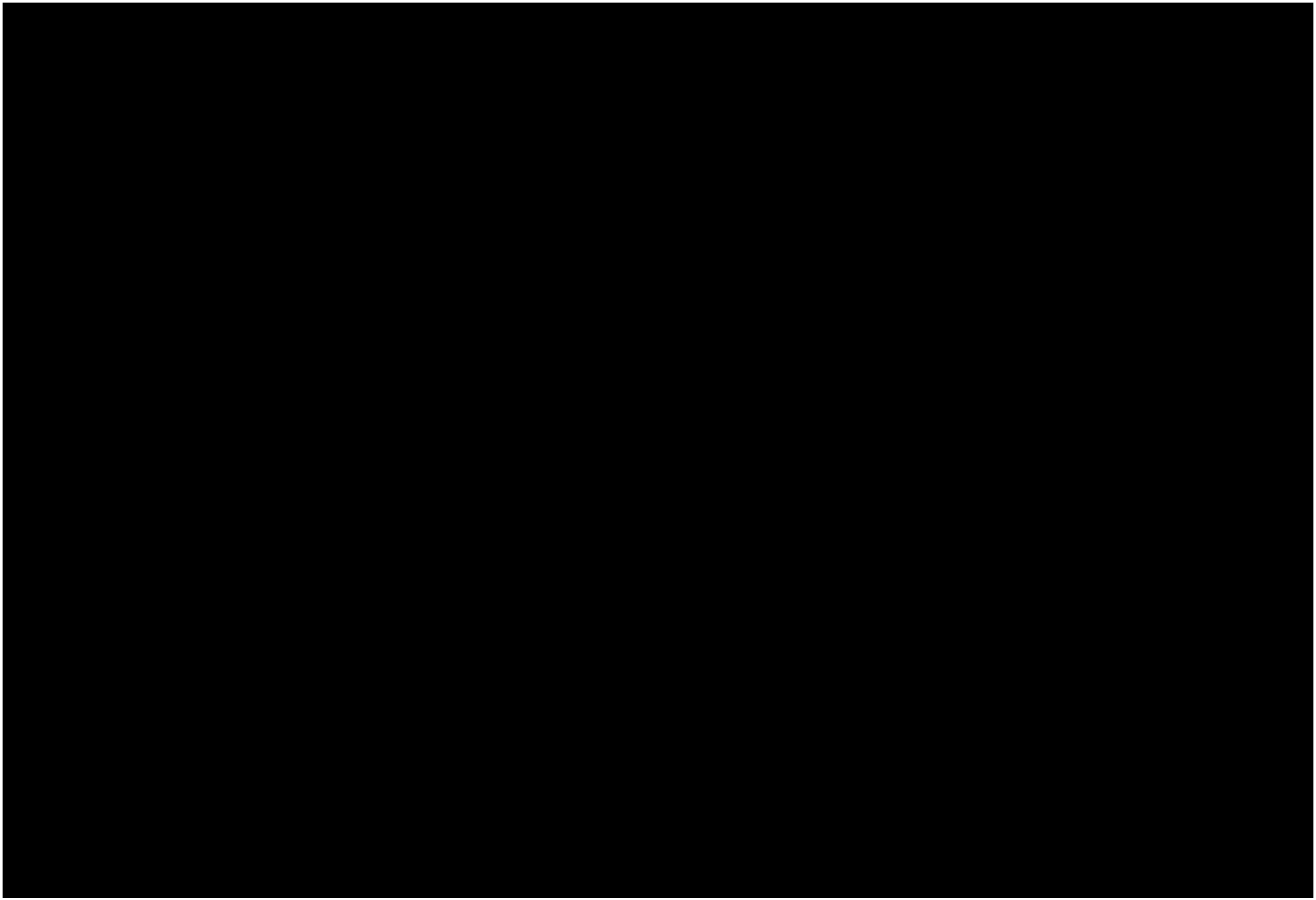
Date of Off Peak Day - 05/30/2021



Member Forecasted Off Peak Demand Day for June 2021

Chimney Rock Public Power District

Date of Off Peak Day - 06/01/2021



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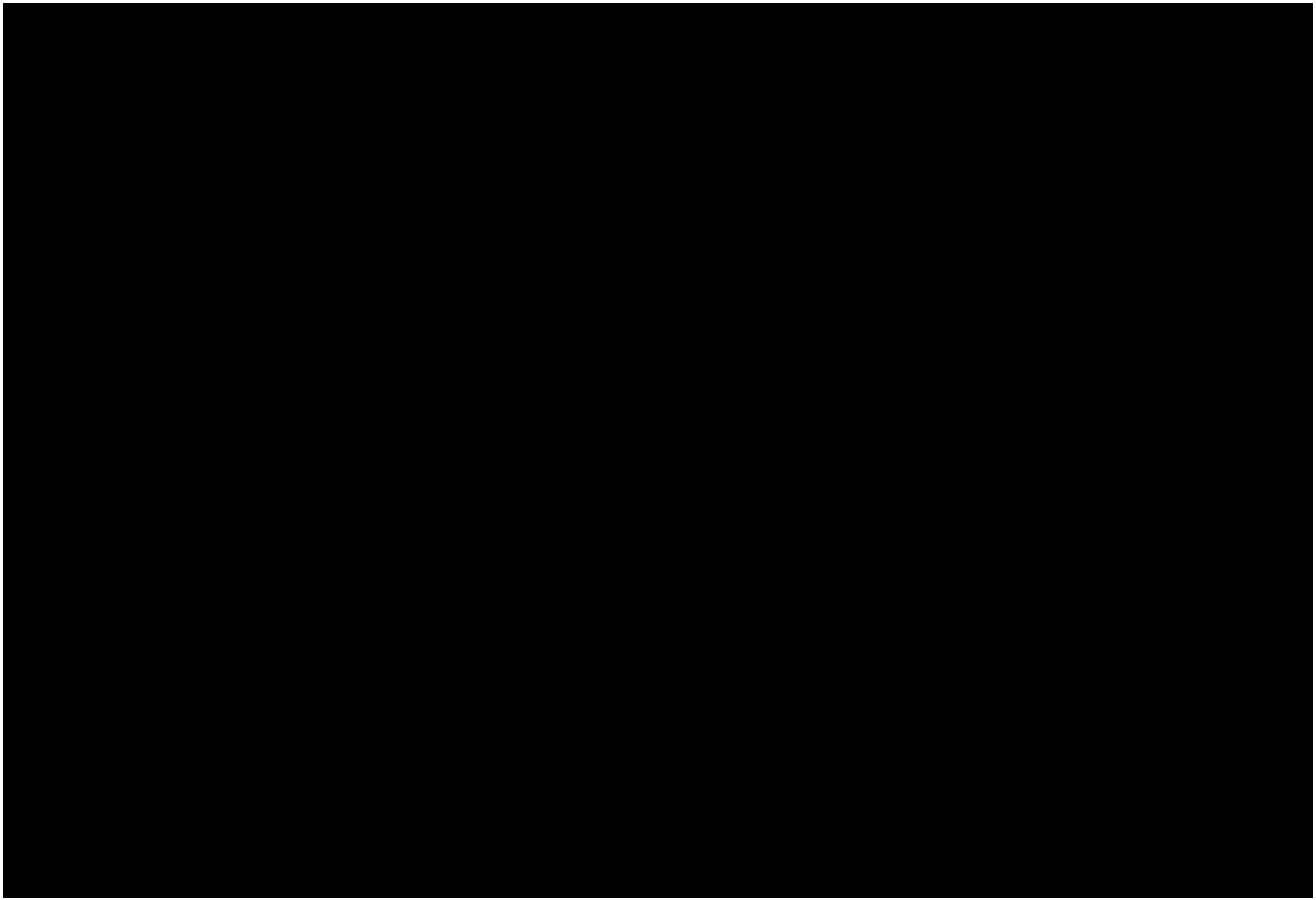
Member Forecasted Off Peak Demand Day for July 2021

Chimney Rock Public Power District

Date of Off Peak Day - 07/31/2021



Member Forecasted Off Peak Demand Day for August 2021

Chimney Rock Public Power District

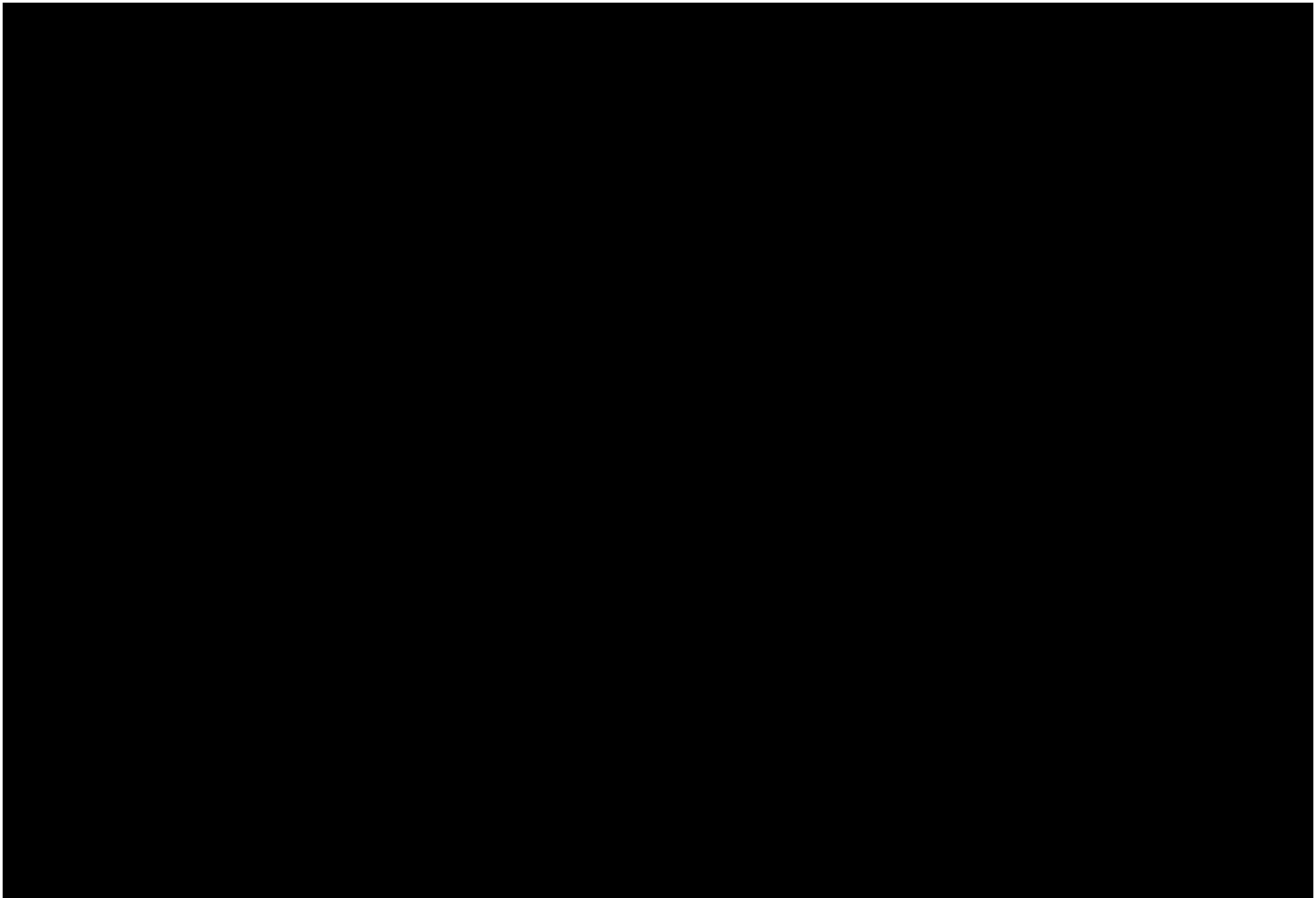
Date of Off Peak Day - 08/11/2021

[redacted]

Member Forecasted Off Peak Demand Day for September 2021

Chimney Rock Public Power District

Date of Off Peak Day - 09/20/2021



Member Forecasted Off Peak Demand Day for October 2021

Chimney Rock Public Power District

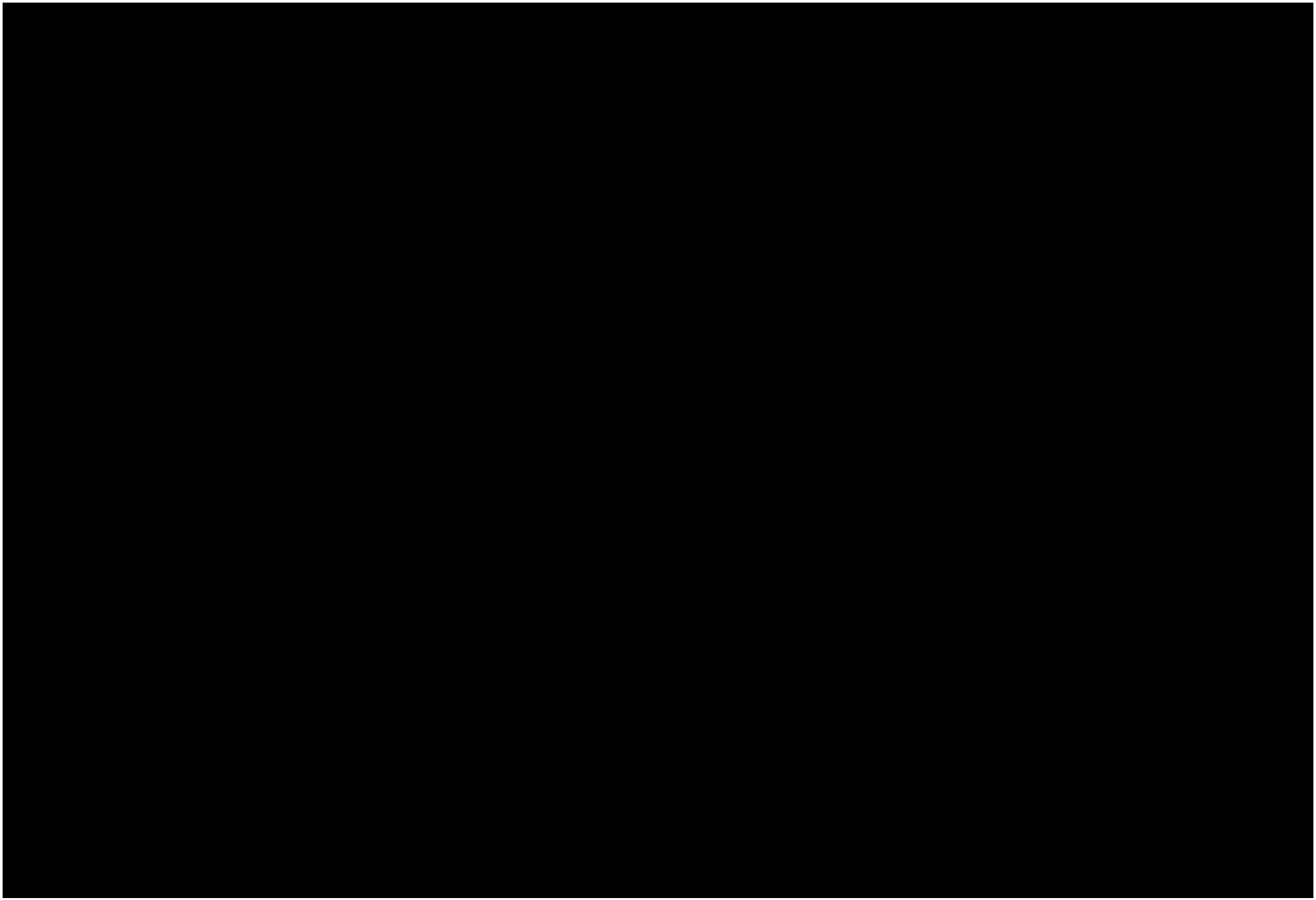
Date of Off Peak Day - 10/07/2021

[redacted]

Member Forecasted Off Peak Demand Day for November 2021

Chimney Rock Public Power District

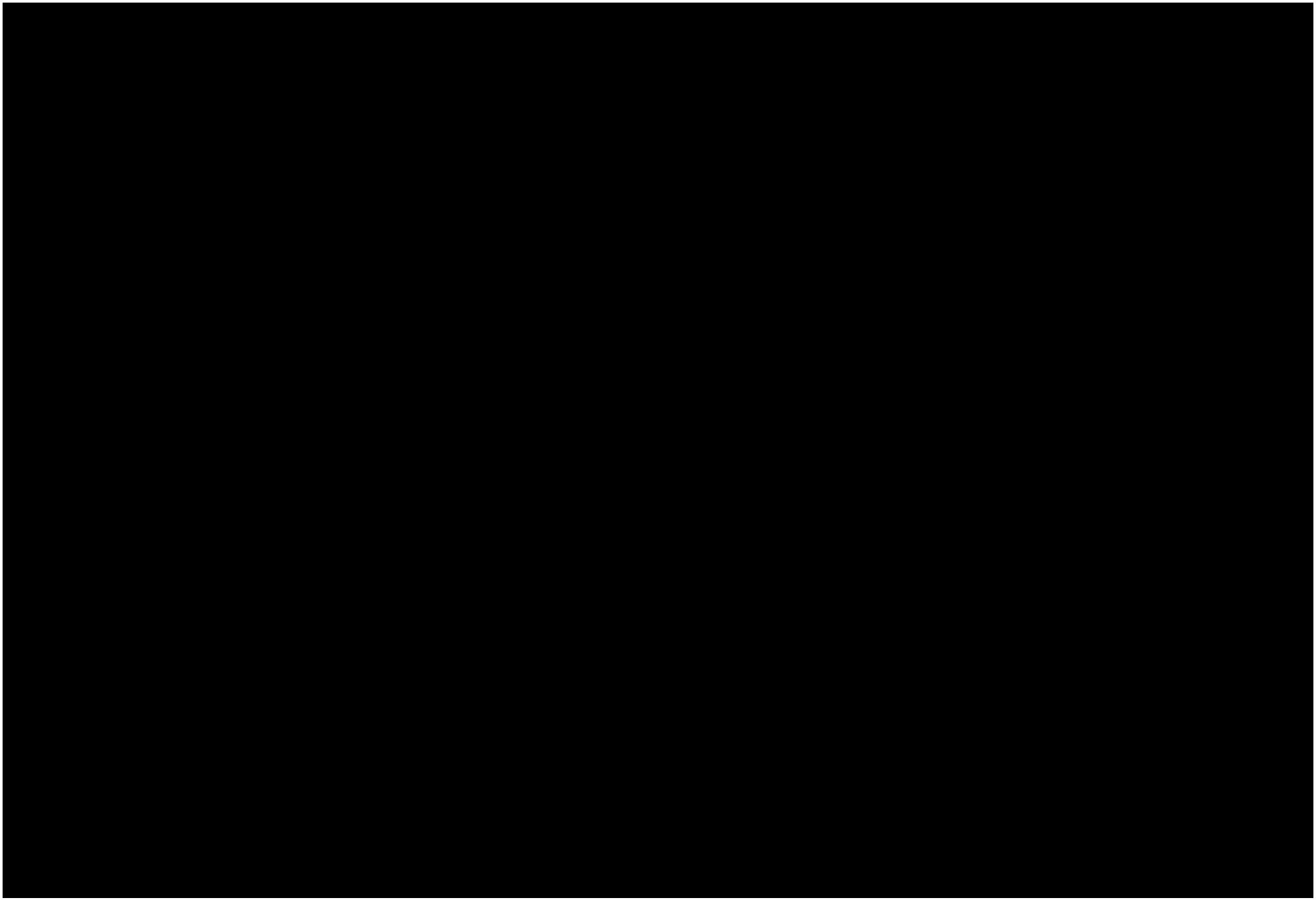
Date of Off Peak Day - 11/03/2021



Member Forecasted Off Peak Demand Day for December 2021

Chimney Rock Public Power District

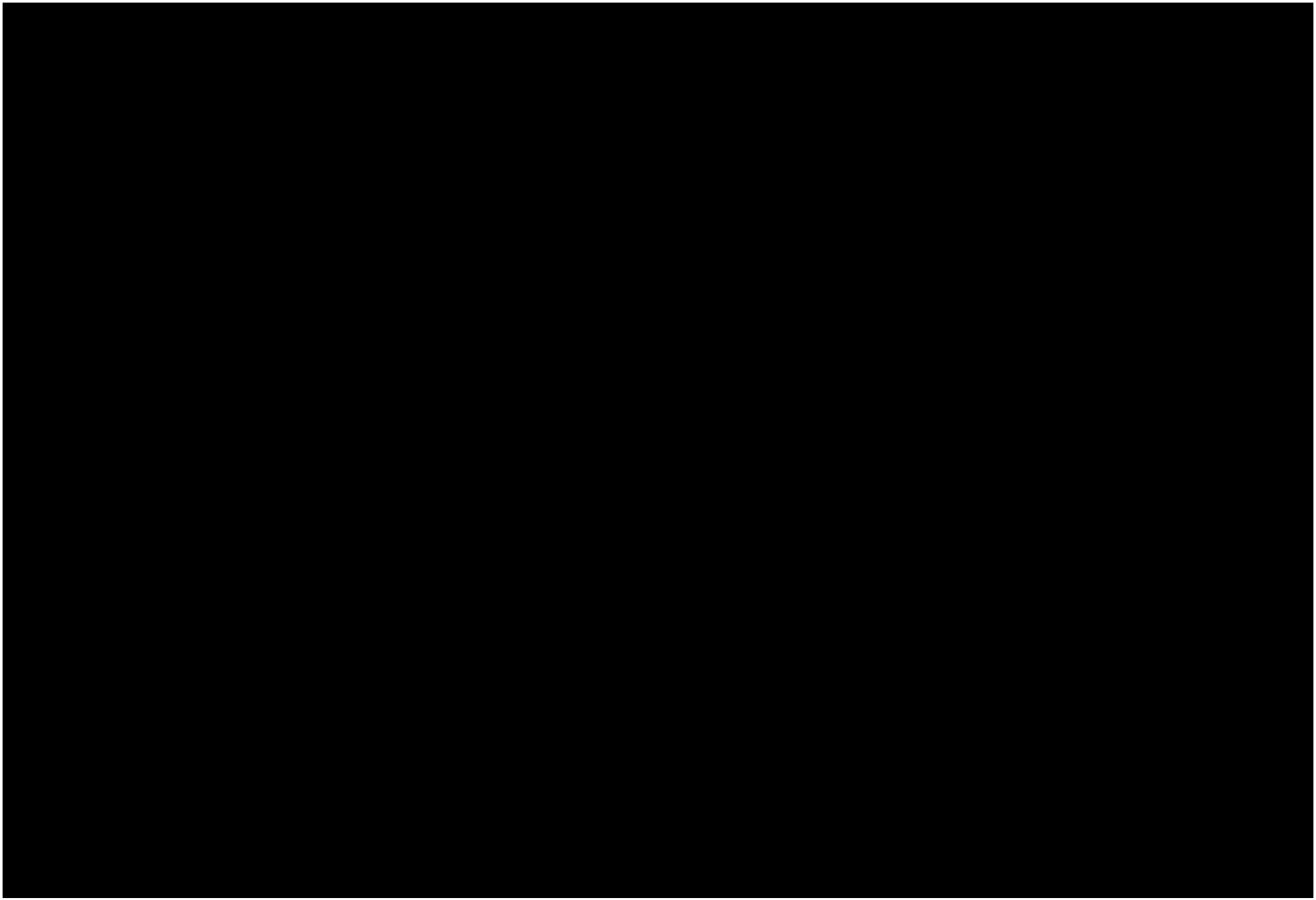
Date of Off Peak Day - 12/08/2021



Member Forecasted Off Peak Demand Day for January 2021

Empire Electric Association, Inc.

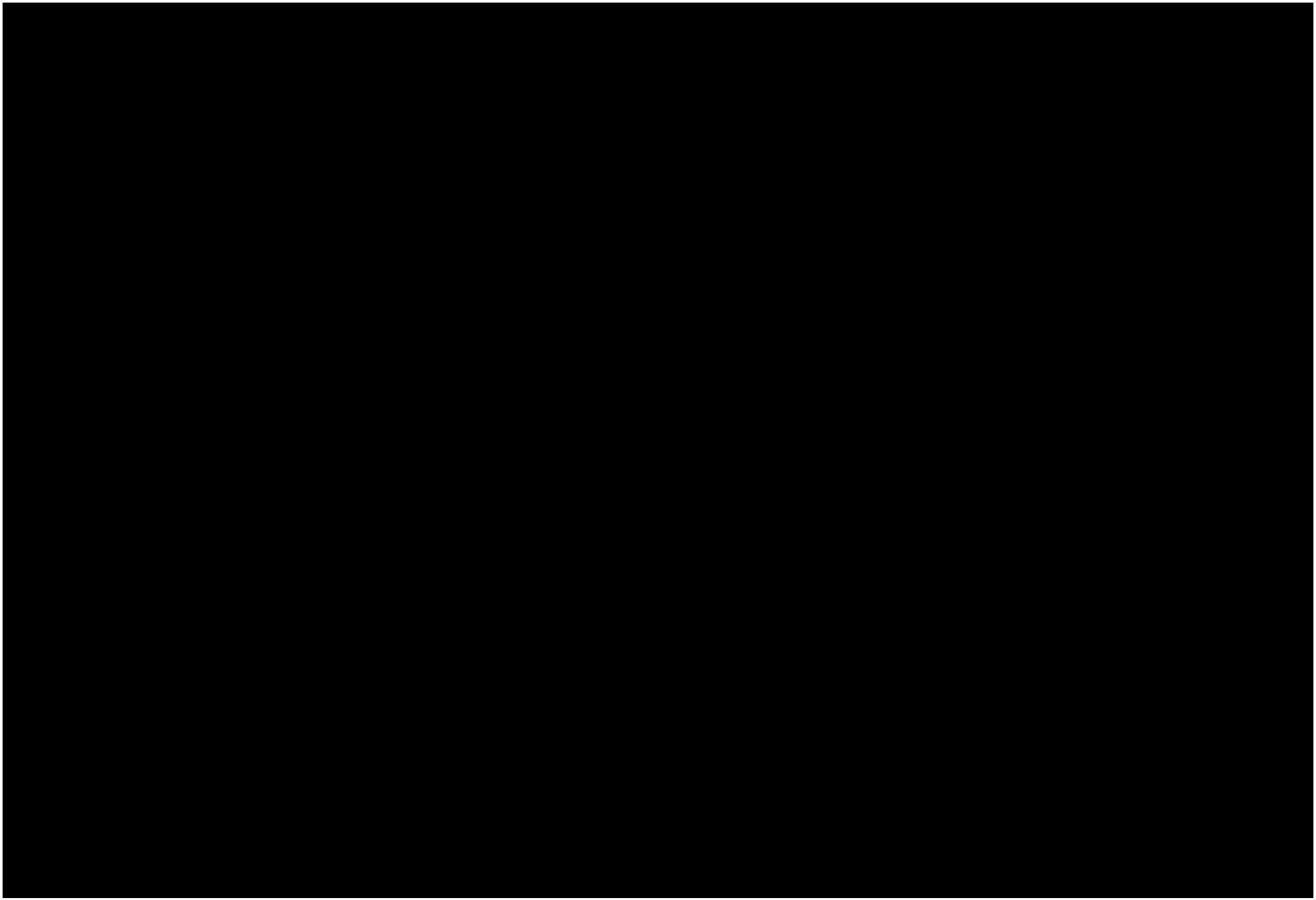
Date of Off Peak Day - 01/13/2021



Member Forecasted Off Peak Demand Day for February 2021

Empire Electric Association, Inc.

Date of Off Peak Day - 02/05/2021



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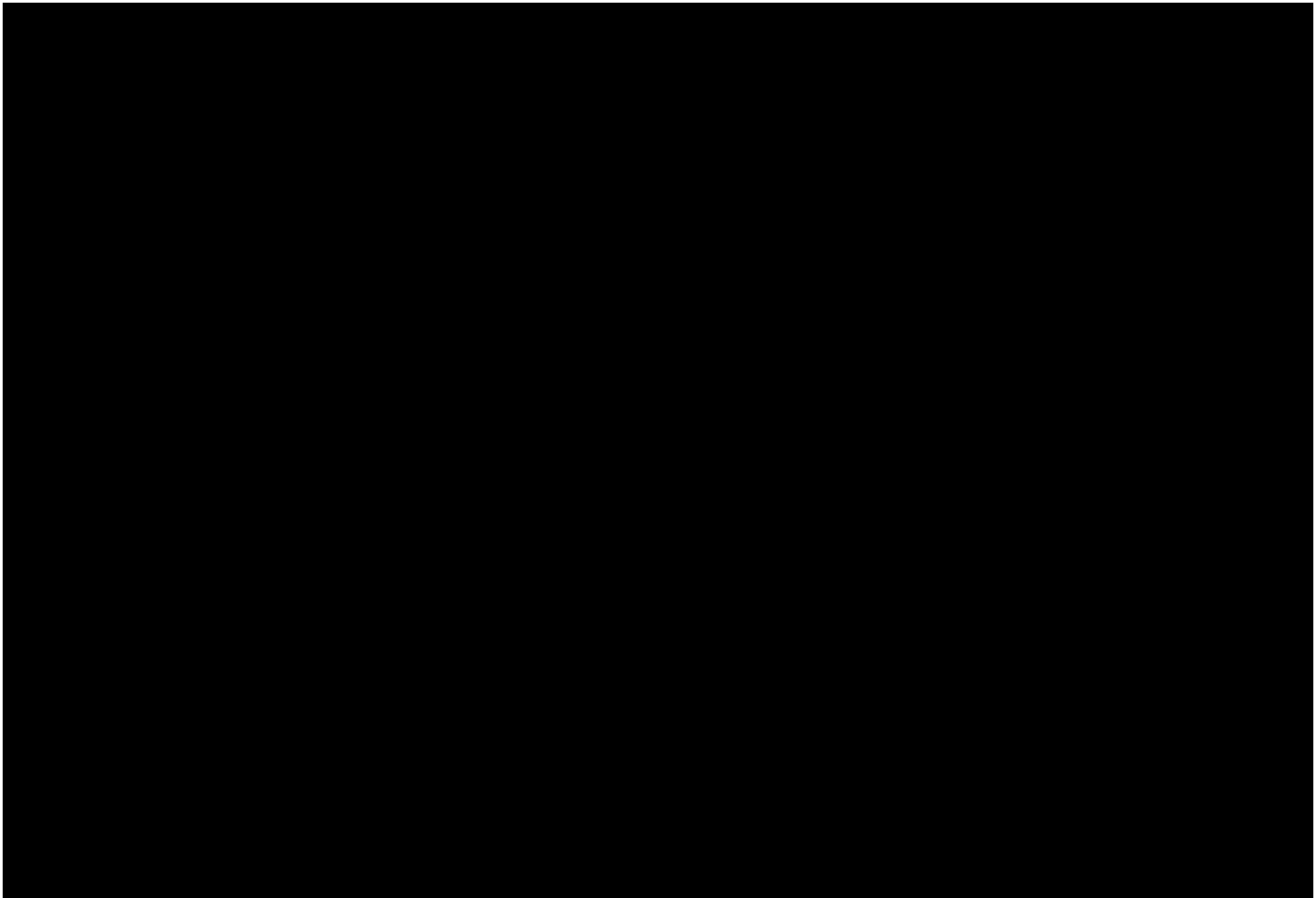
Member Forecasted Off Peak Demand Day for March 2021

Empire Electric Association, Inc.

Date of Off Peak Day - 03/20/2021



Member Forecasted Off Peak Demand Day for April 2021

Empire Electric Association, Inc.

Date of Off Peak Day - 04/11/2021

[redacted]

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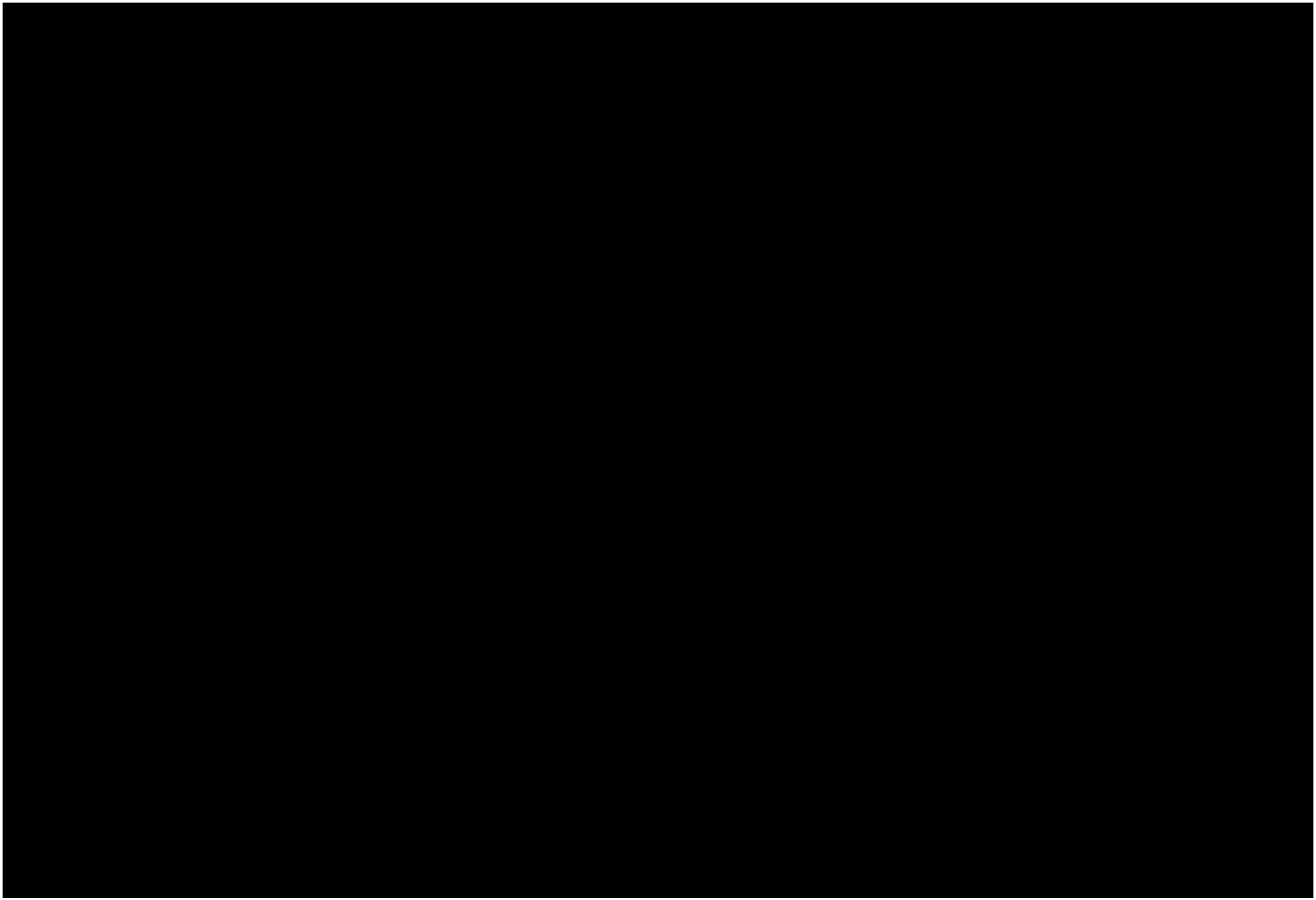
Member Forecasted Off Peak Demand Day for May 2021

Empire Electric Association, Inc.

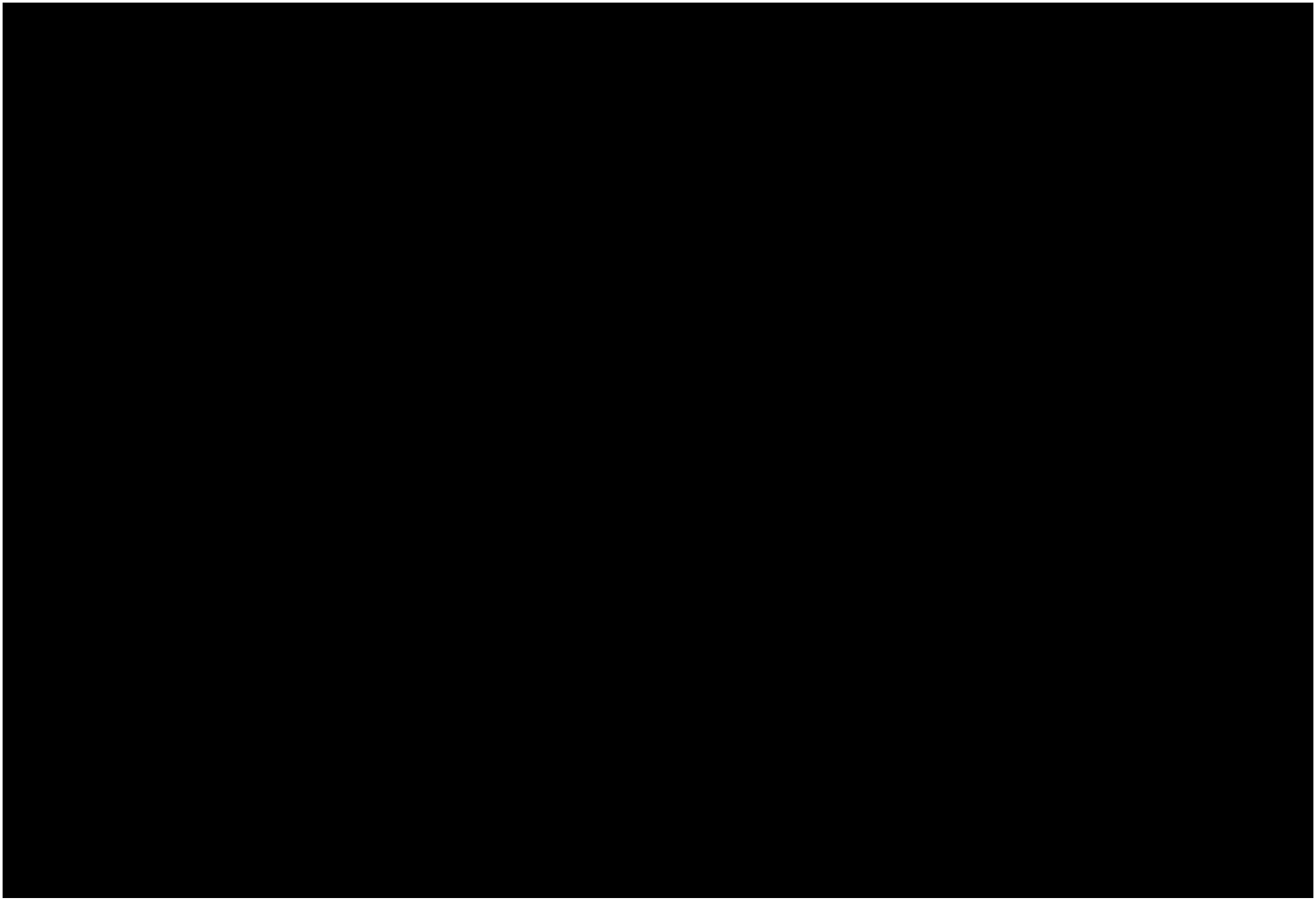
Date of Off Peak Day - 05/02/2021



Member Forecasted Off Peak Demand Day for June 2021

Empire Electric Association, Inc.

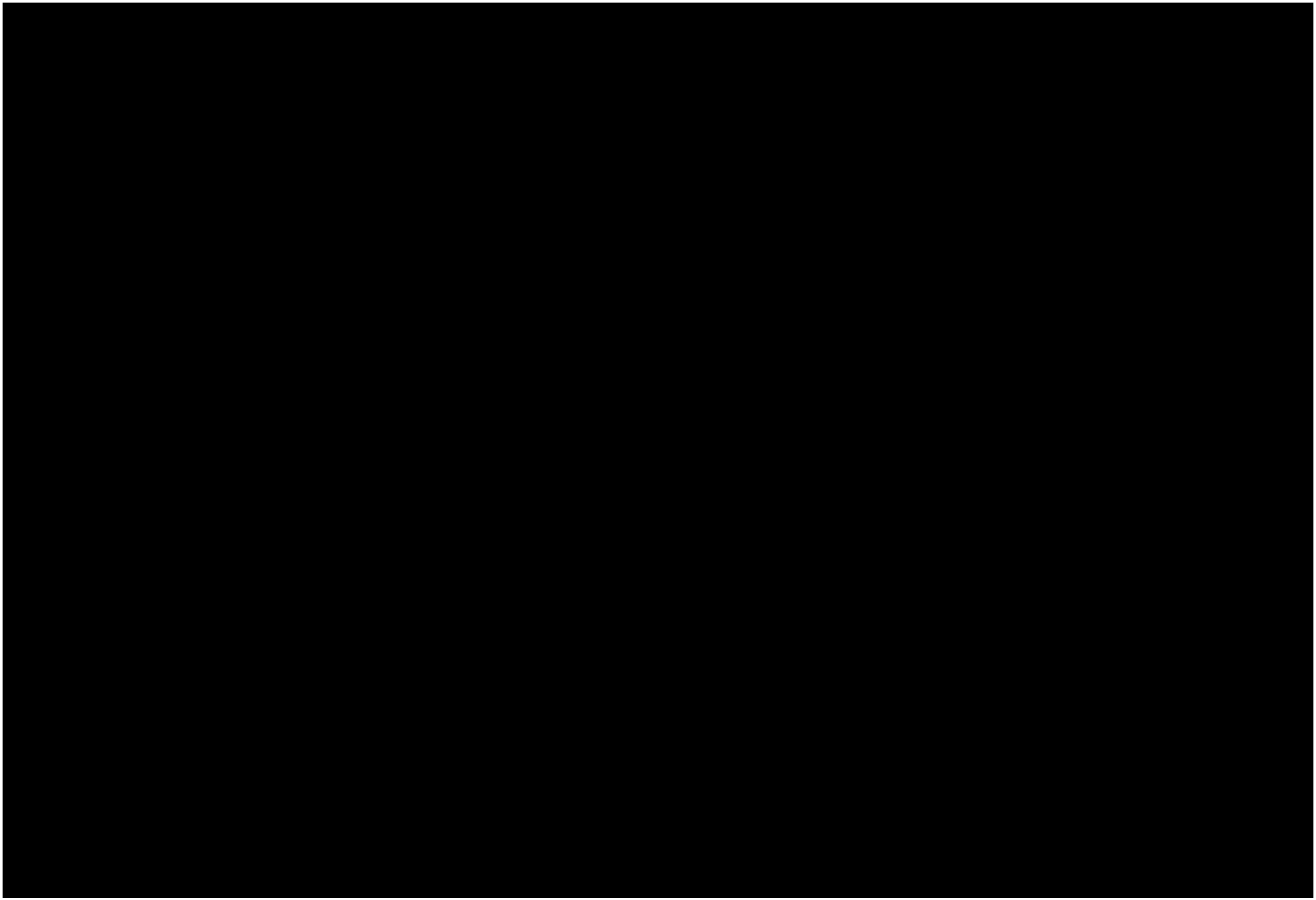
Date of Off Peak Day - 06/28/2021



Member Forecasted Off Peak Demand Day for July 2021

Empire Electric Association, Inc.

Date of Off Peak Day - 07/18/2021



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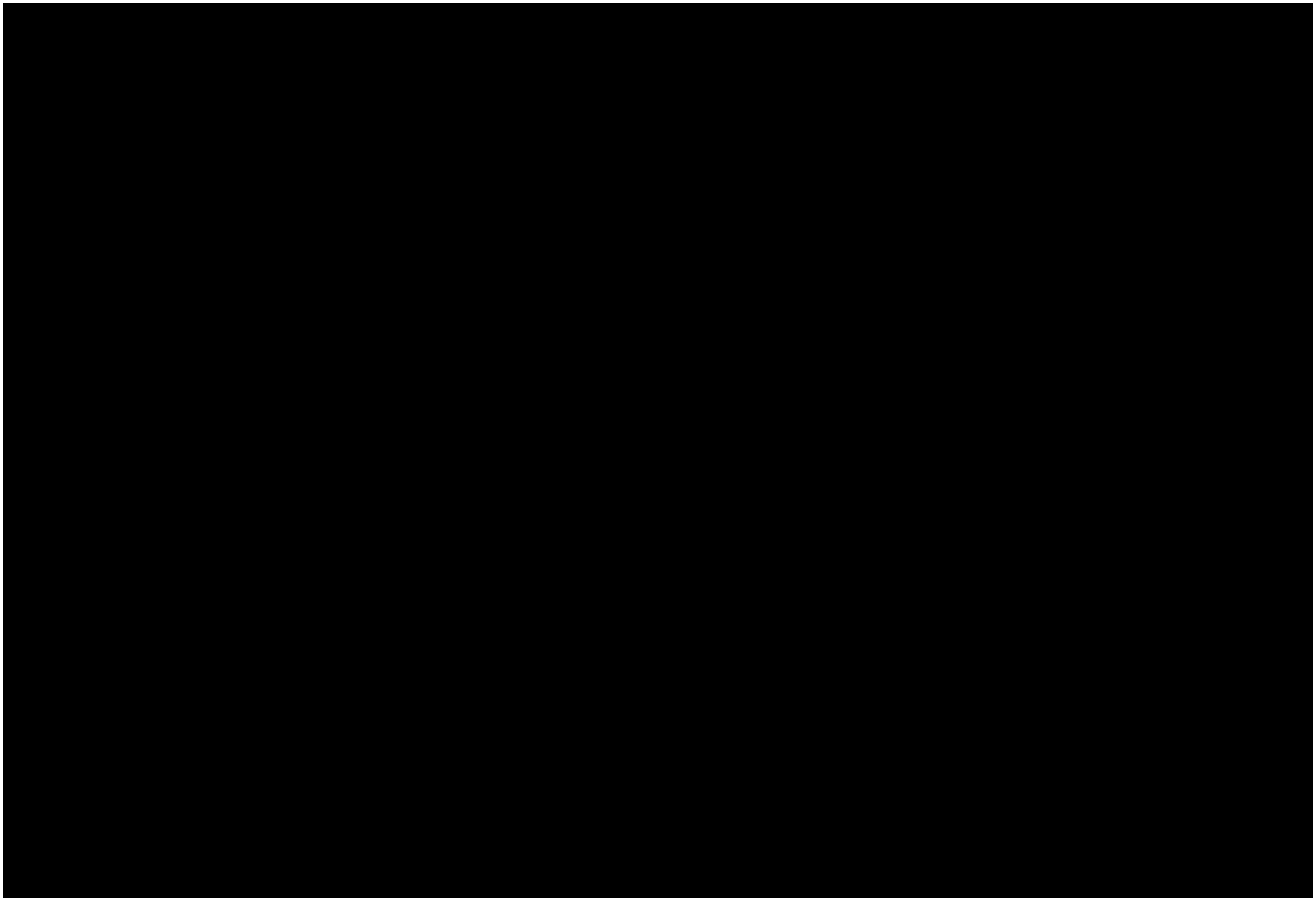
Member Forecasted Off Peak Demand Day for August 2021

Empire Electric Association, Inc.

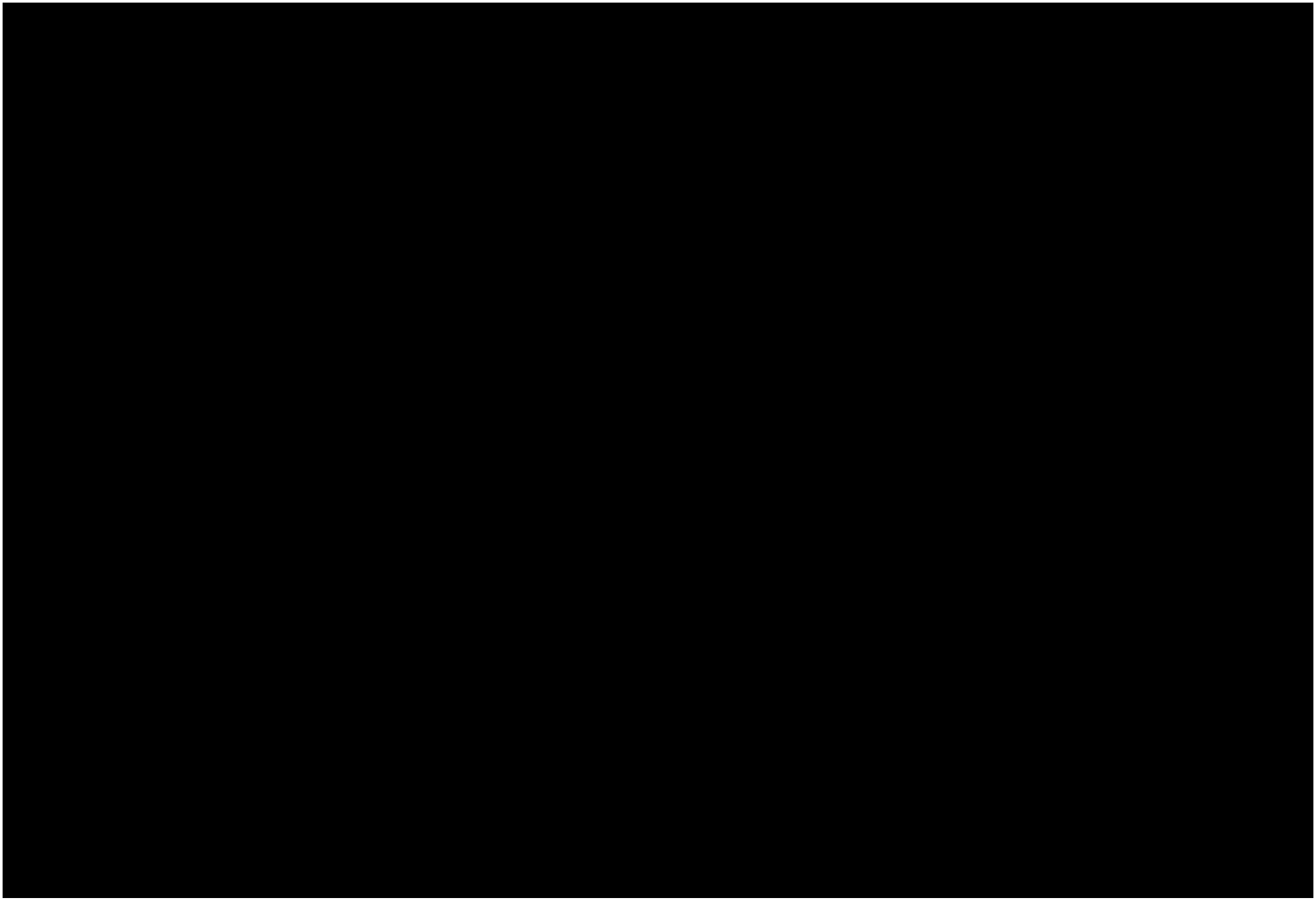
Date of Off Peak Day - 08/12/2021



Member Forecasted Off Peak Demand Day for September 2021

Empire Electric Association, Inc.

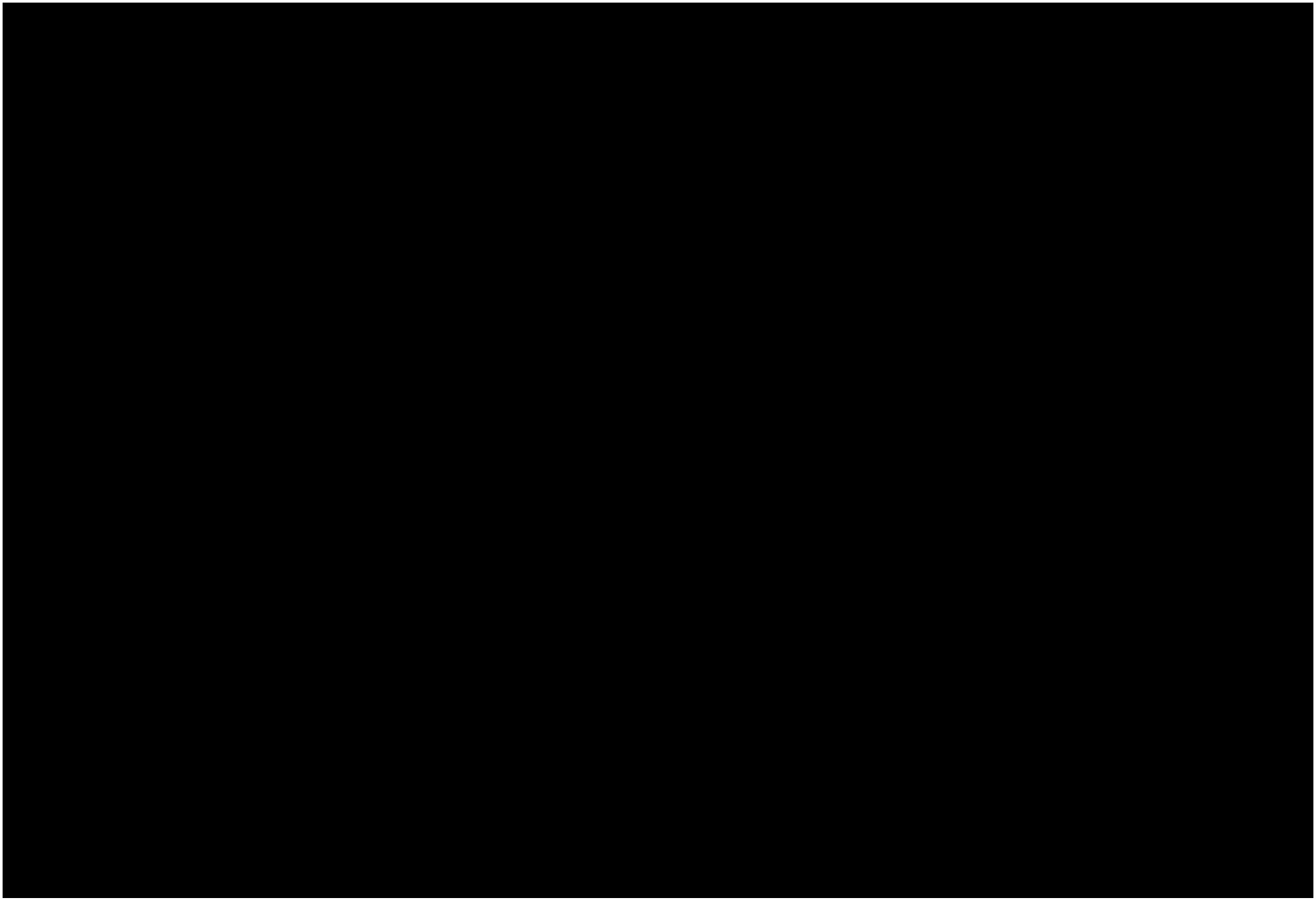
Date of Off Peak Day - 09/19/2021



Member Forecasted Off Peak Demand Day for October 2021

Empire Electric Association, Inc.

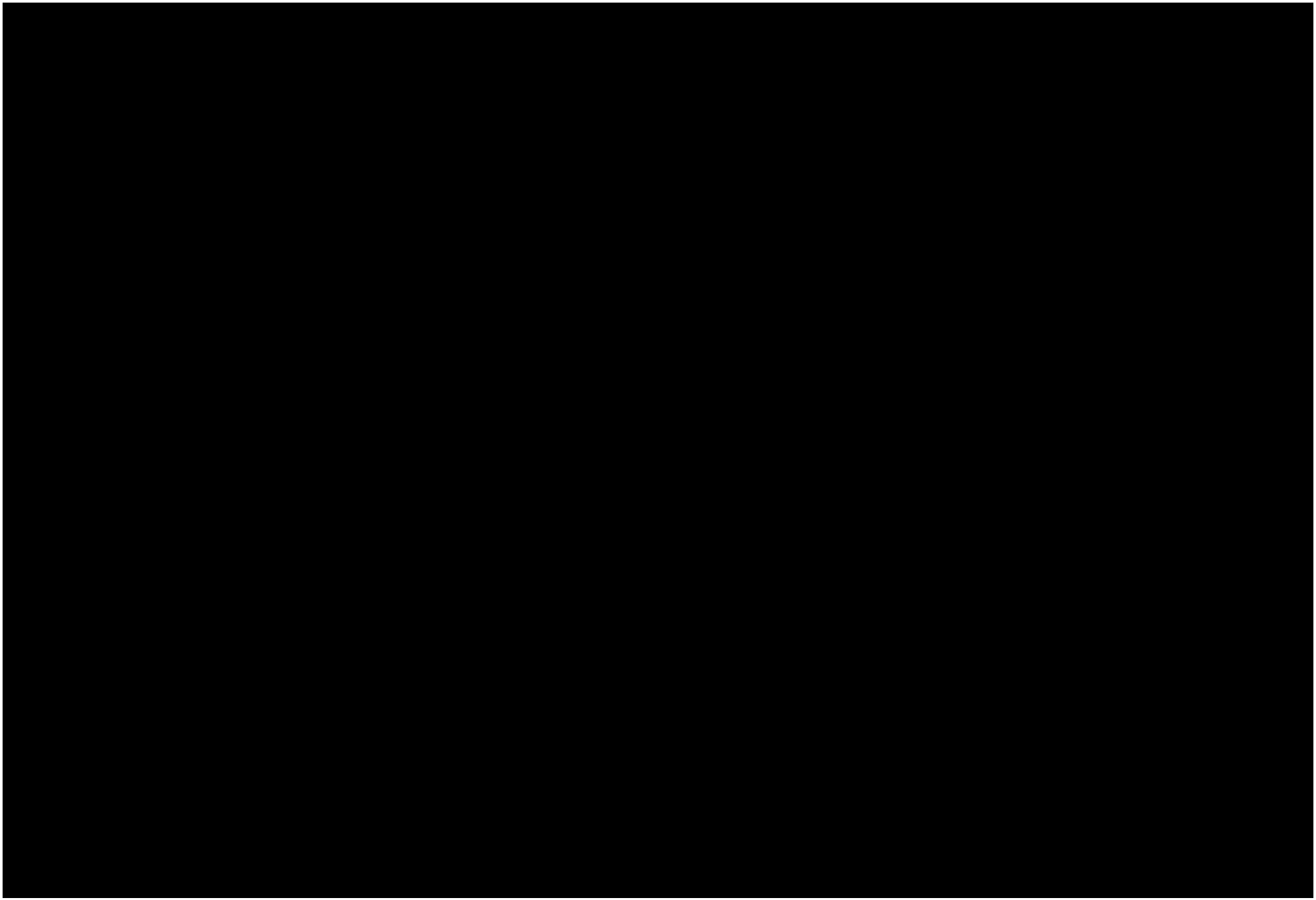
Date of Off Peak Day - 10/07/2021



Member Forecasted Off Peak Demand Day for November 2021

Empire Electric Association, Inc.

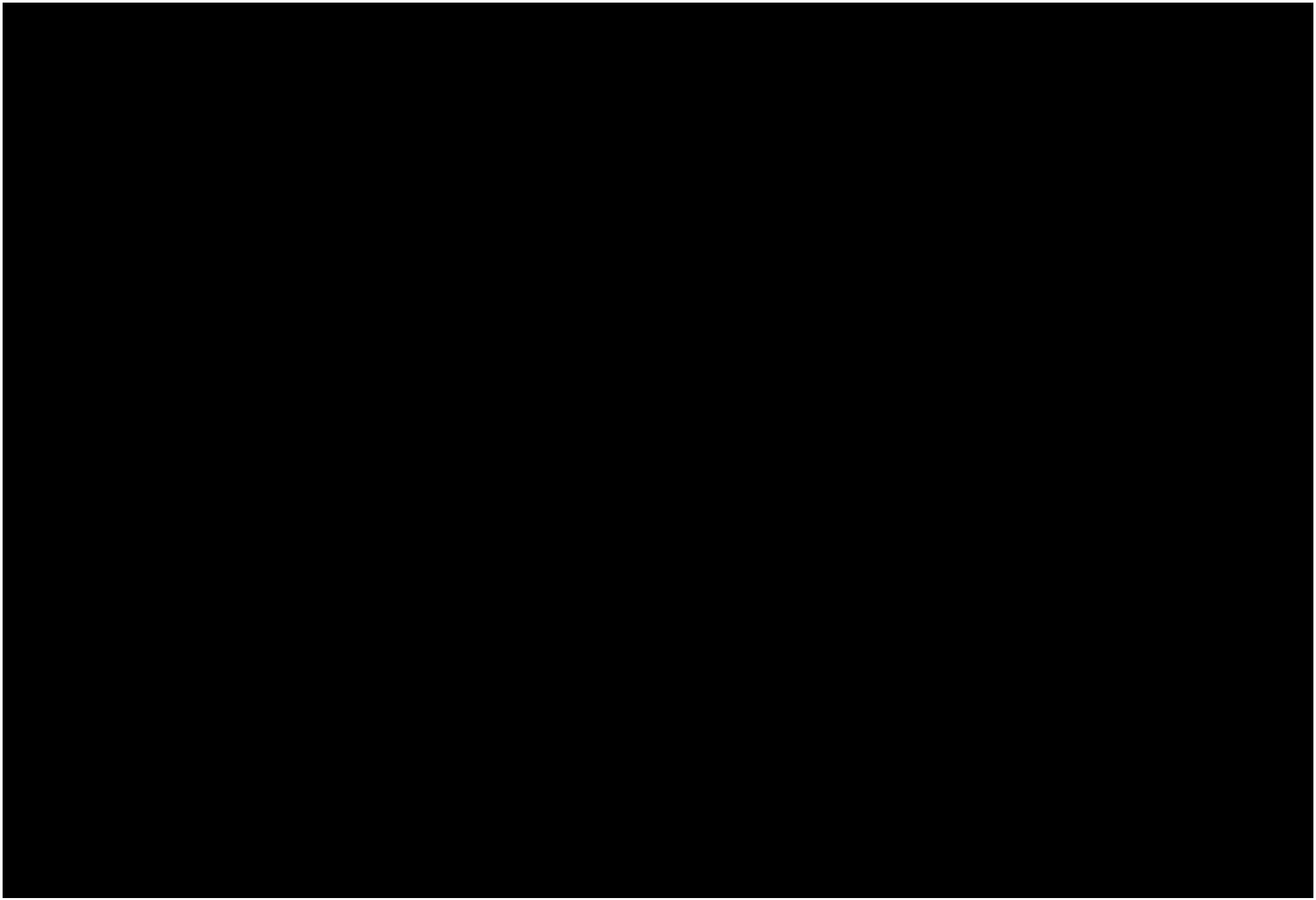
Date of Off Peak Day - 11/03/2021



Member Forecasted Off Peak Demand Day for December 2021

Empire Electric Association, Inc.

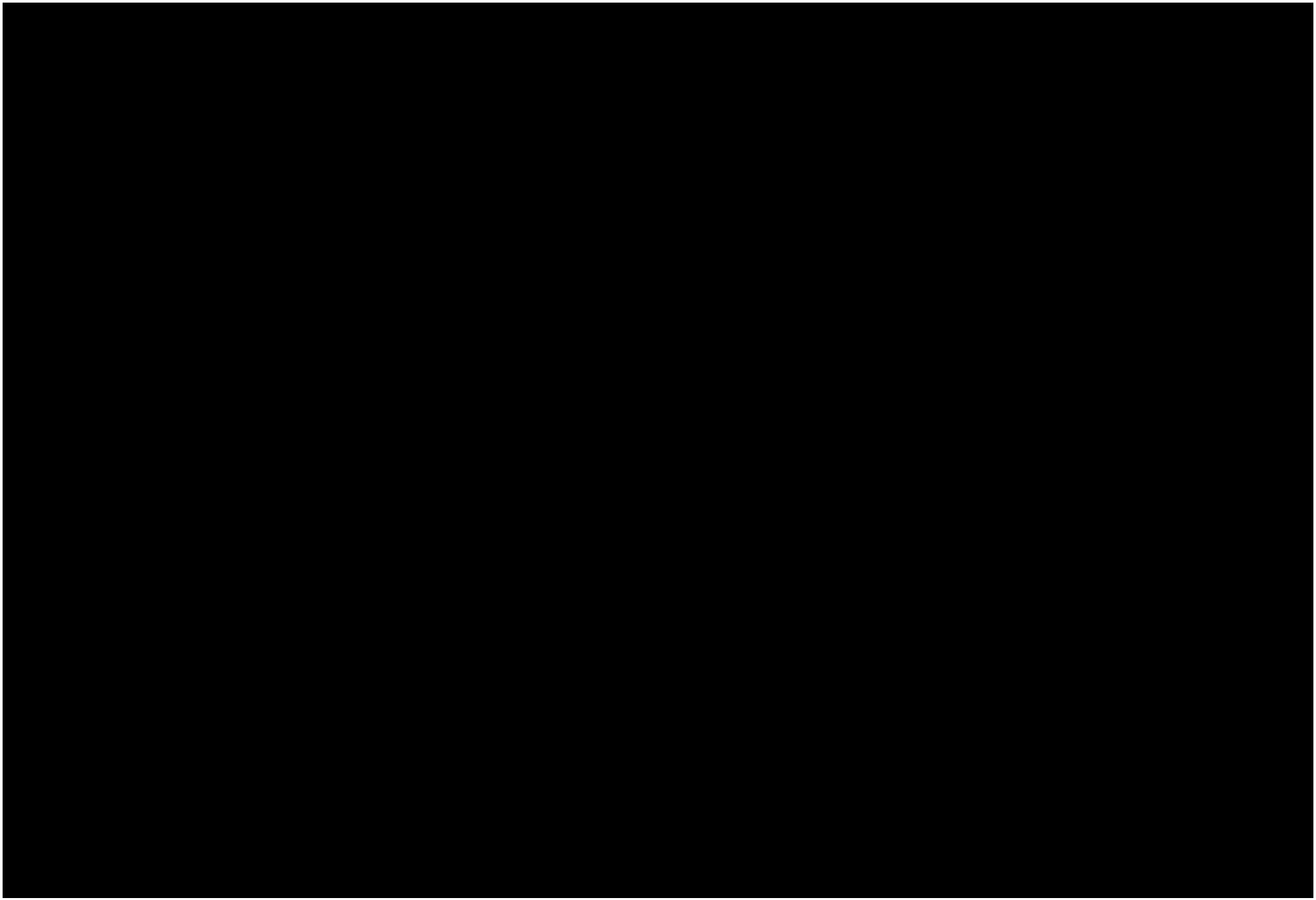
Date of Off Peak Day - 12/10/2021



Member Forecasted Off Peak Demand Day for January 2021

Gunnison County Electric Association, Inc.

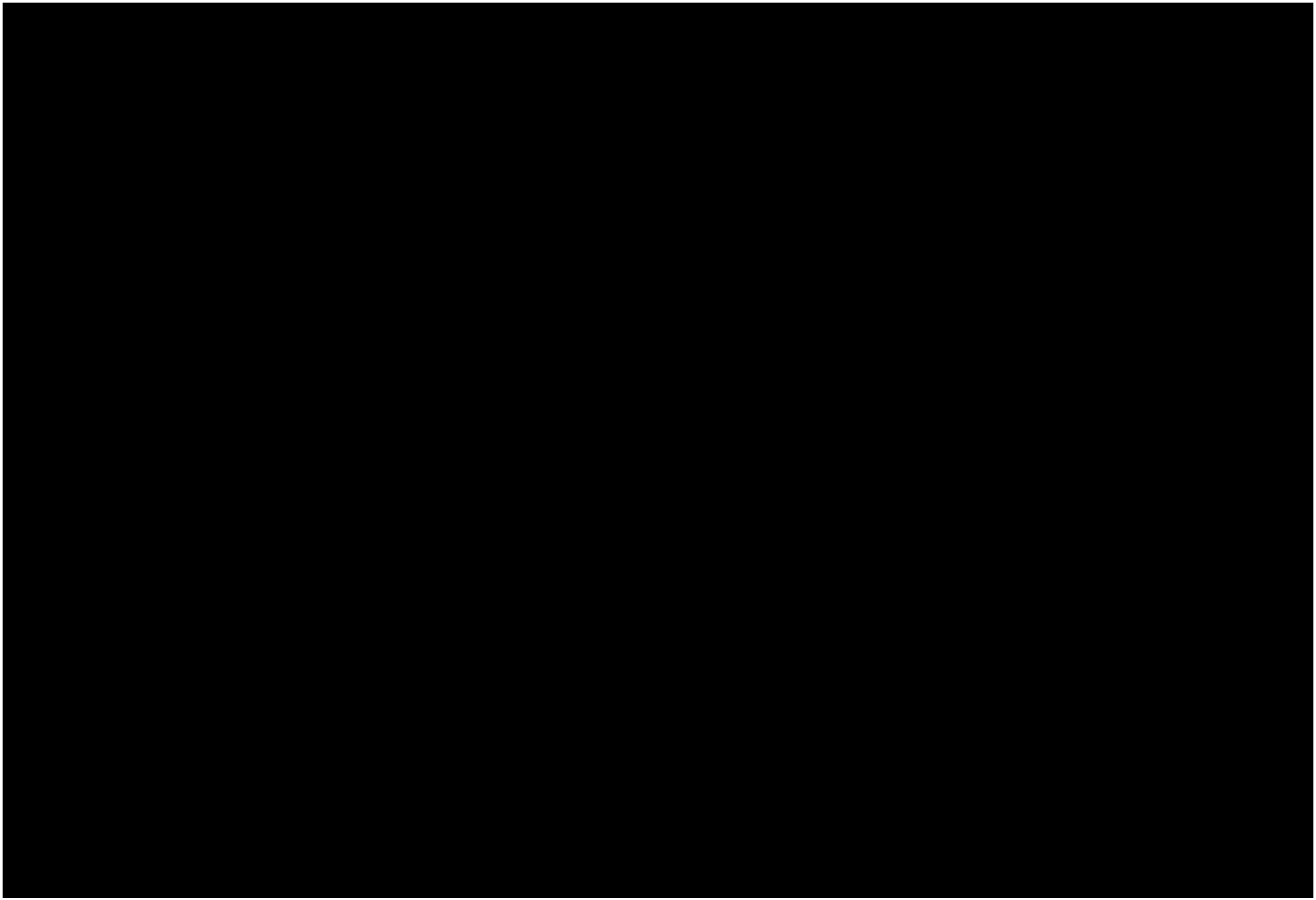
Date of Off Peak Day - 01/14/2021



Member Forecasted Off Peak Demand Day for February 2021

Gunnison County Electric Association, Inc.

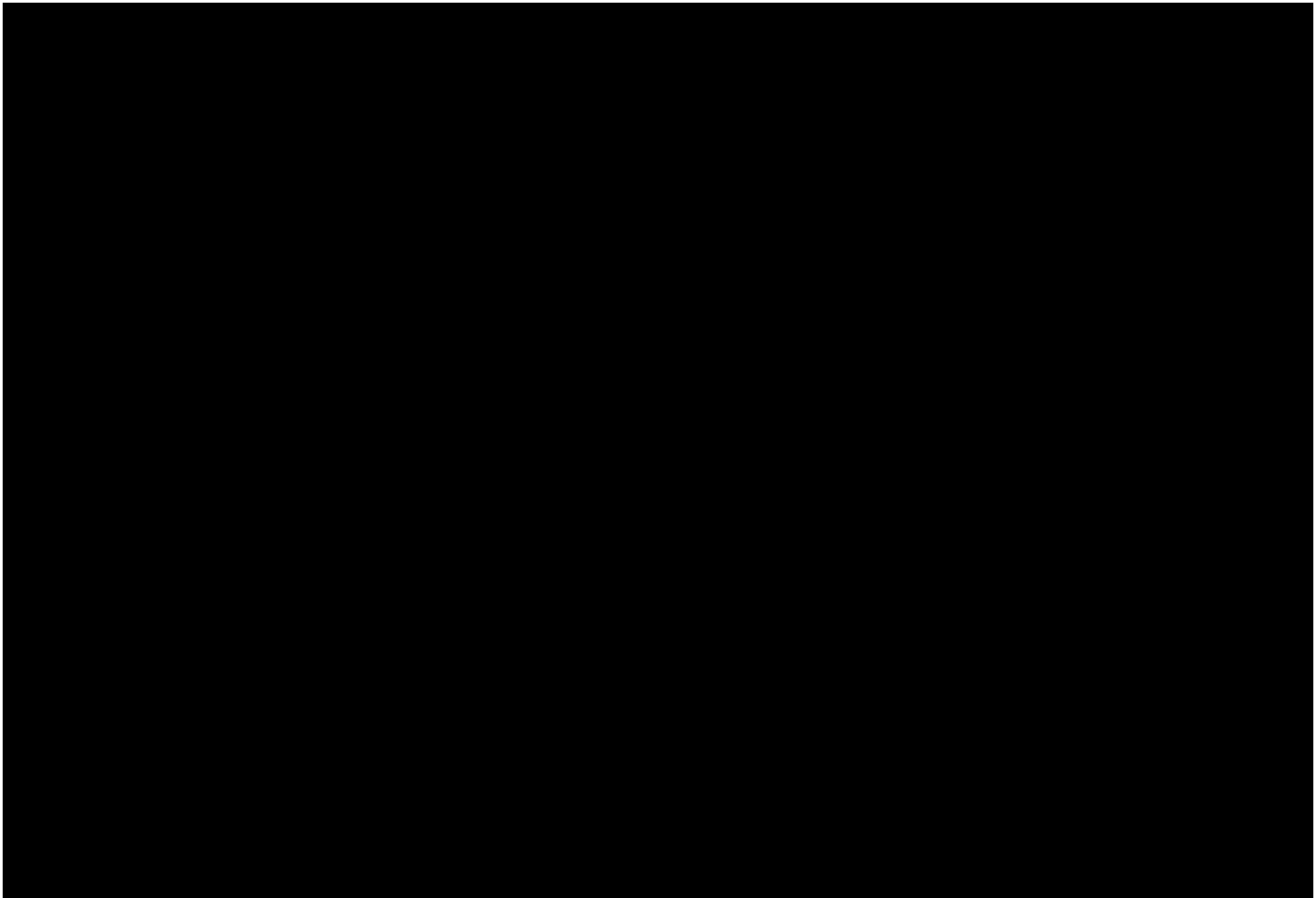
Date of Off Peak Day - 02/11/2021



Member Forecasted Off Peak Demand Day for March 2021

Gunnison County Electric Association, Inc.

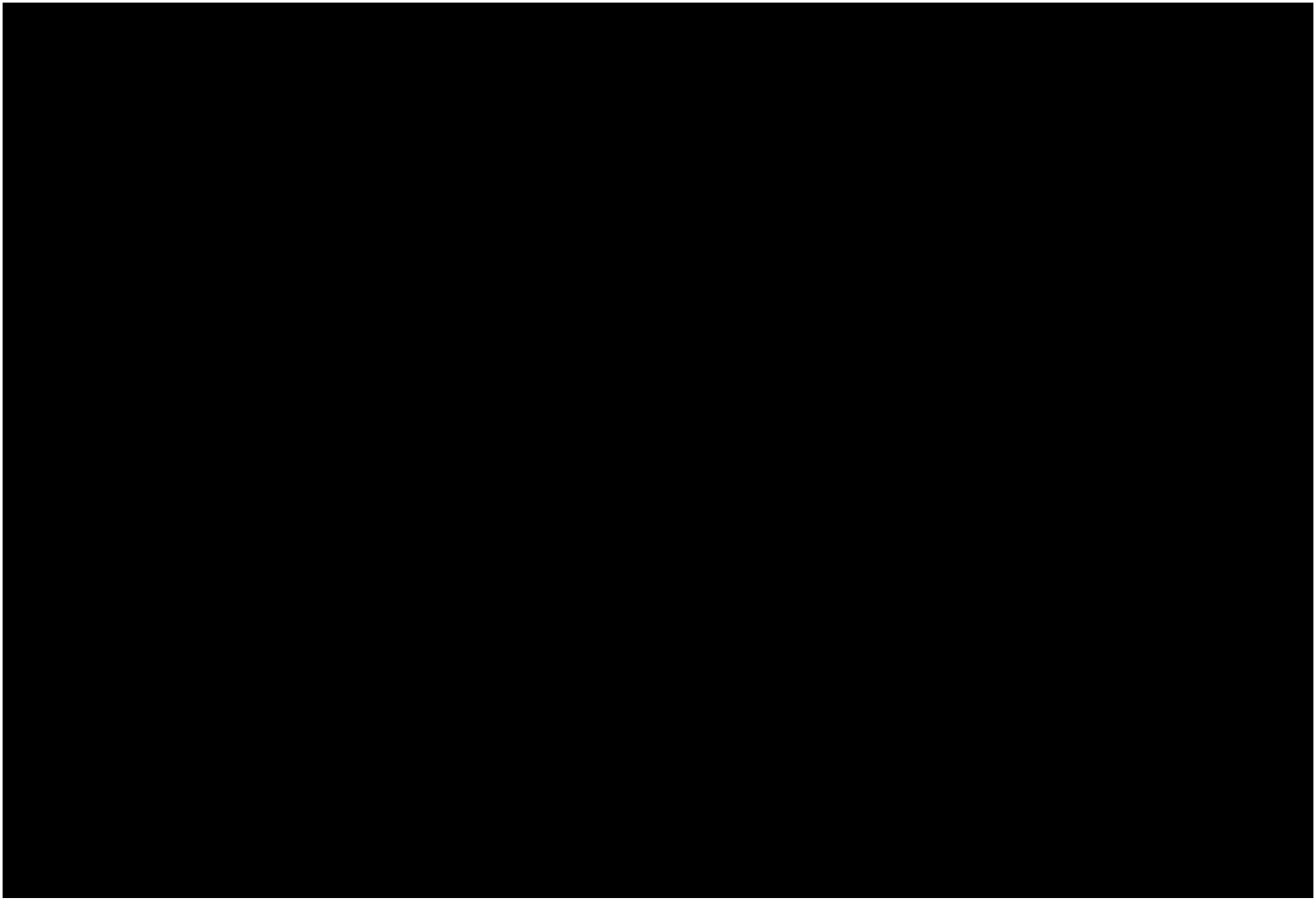
Date of Off Peak Day - 03/21/2021



Member Forecasted Off Peak Demand Day for April 2021

Gunnison County Electric Association, Inc.

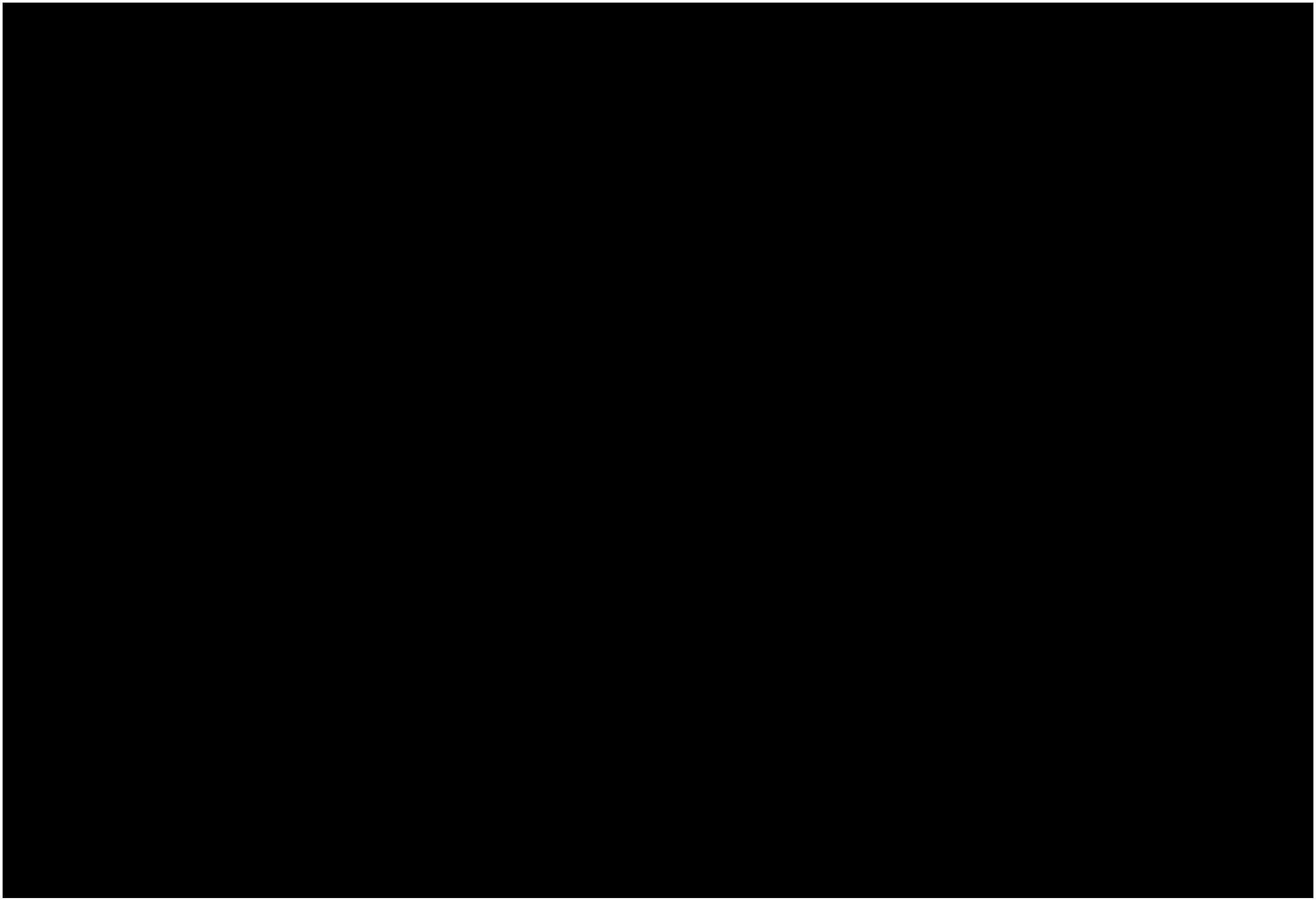
Date of Off Peak Day - 04/12/2021



Member Forecasted Off Peak Demand Day for May 2021

Gunnison County Electric Association, Inc.

Date of Off Peak Day - 05/31/2021



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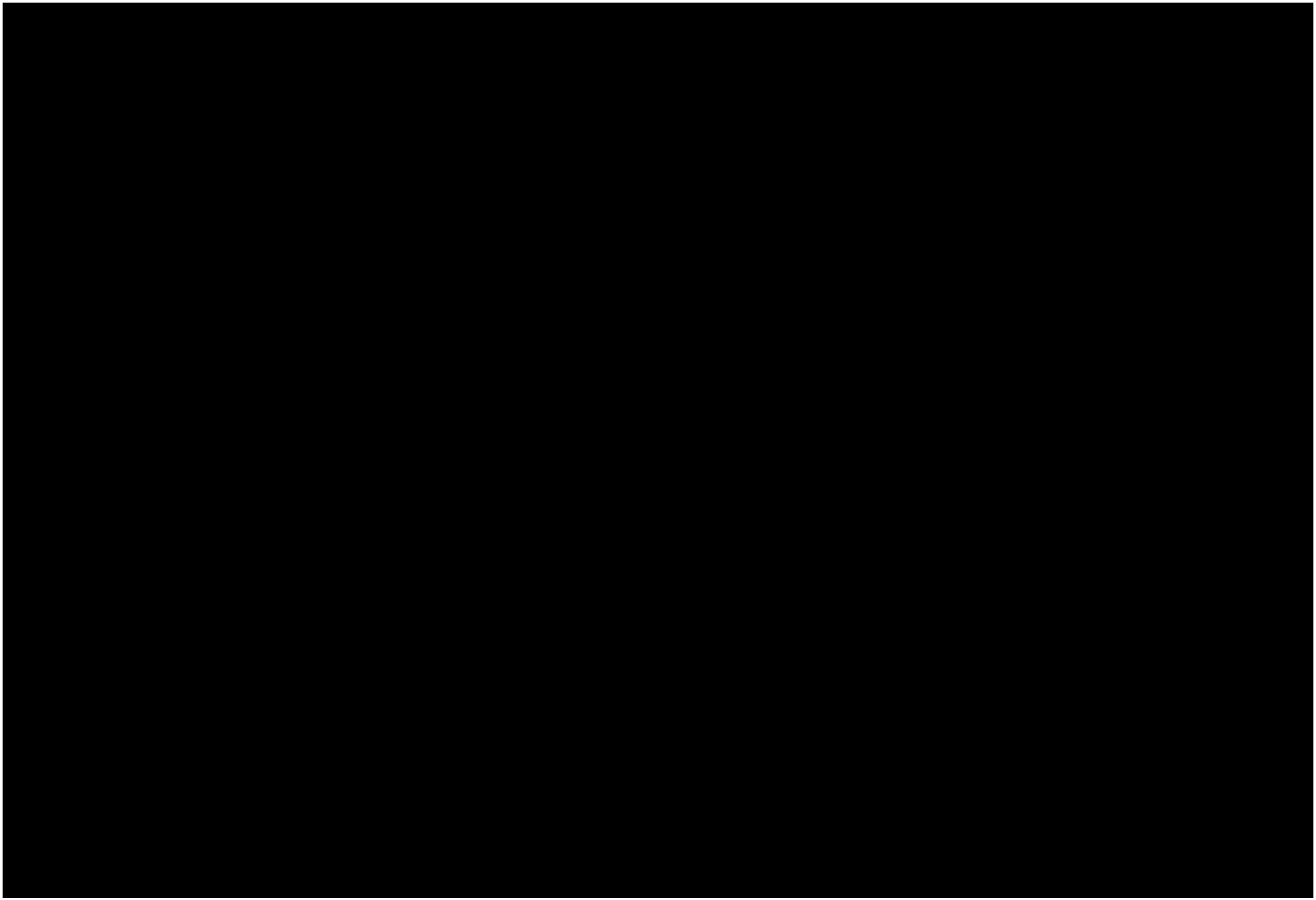
Member Forecasted Off Peak Demand Day for June 2021

Gunnison County Electric Association, Inc.

Date of Off Peak Day - 06/16/2021



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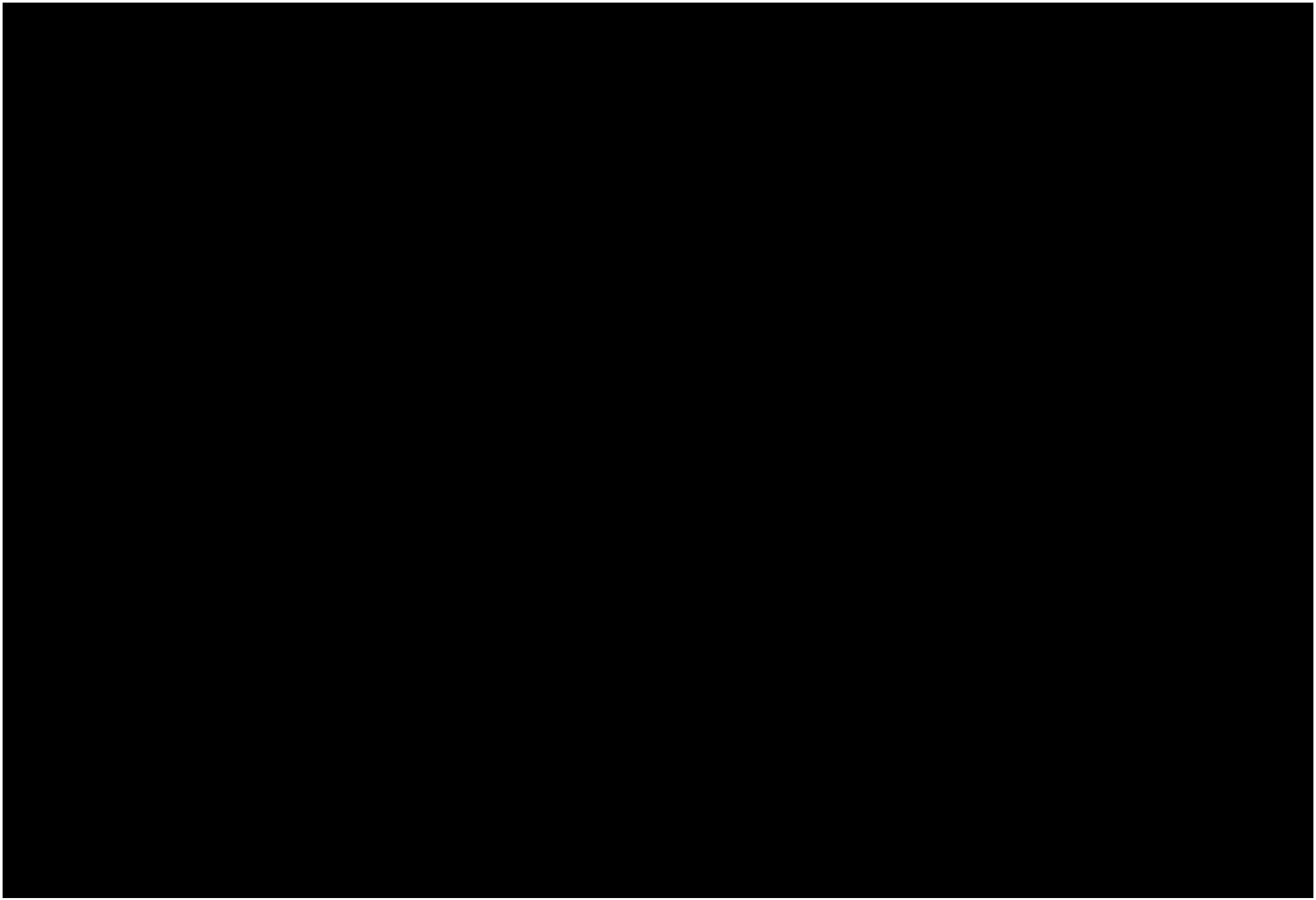
Member Forecasted Off Peak Demand Day for July 2021

Gunnison County Electric Association, Inc.

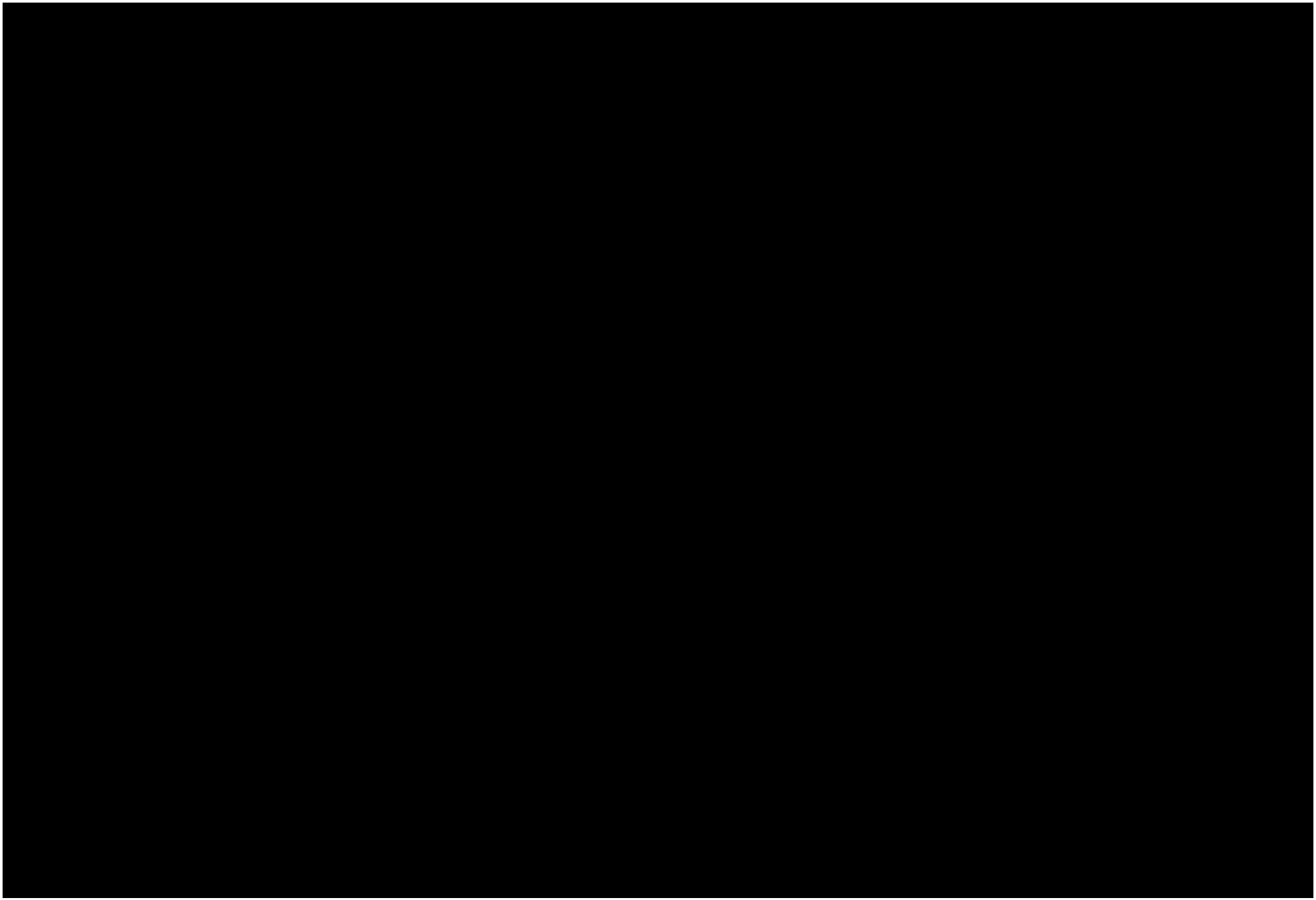
Date of Off Peak Day - 07/01/2021



Member Forecasted Off Peak Demand Day for August 2021

Gunnison County Electric Association, Inc.

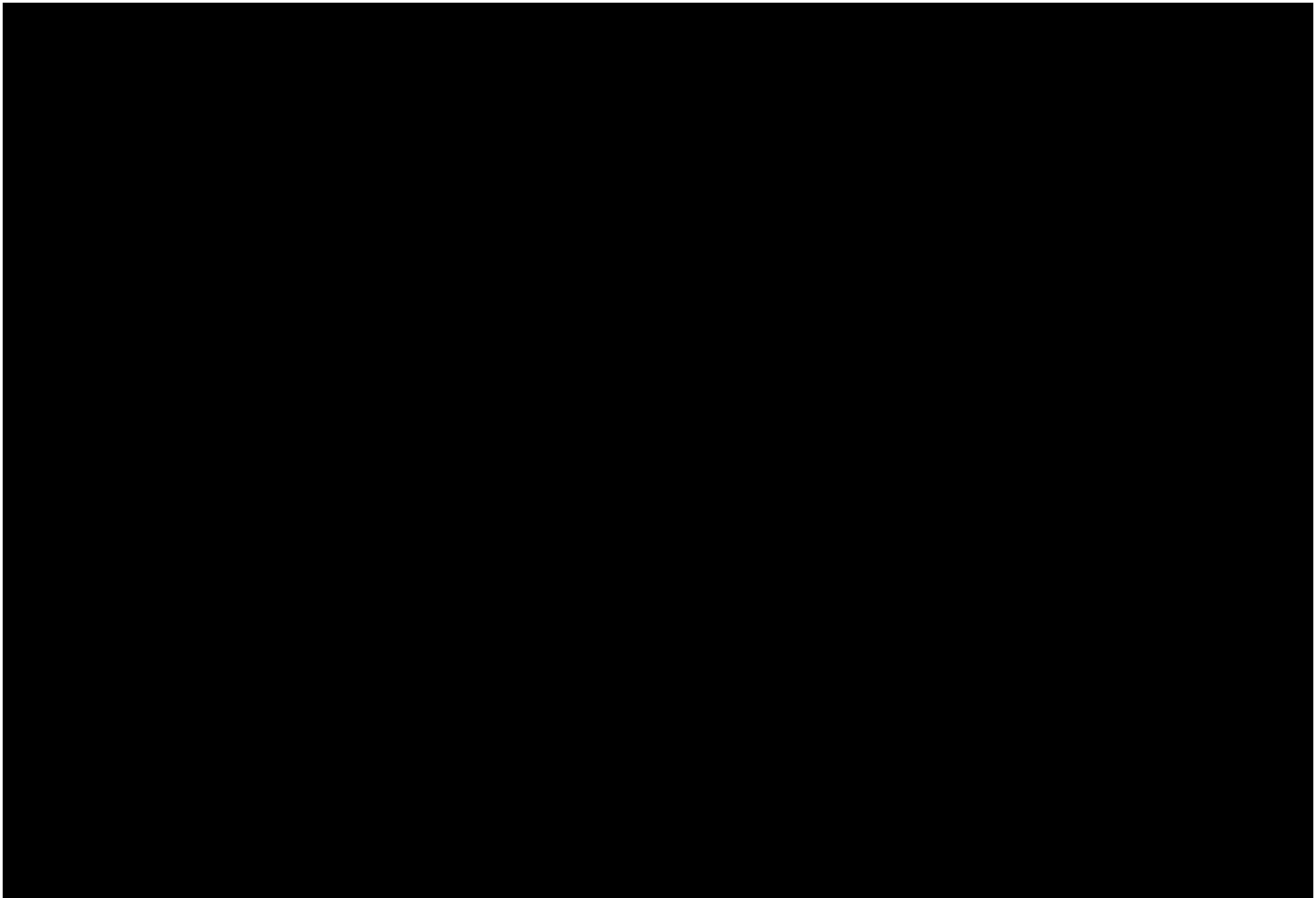
Date of Off Peak Day - 08/31/2021



Member Forecasted Off Peak Demand Day for September 2021

Gunnison County Electric Association, Inc.

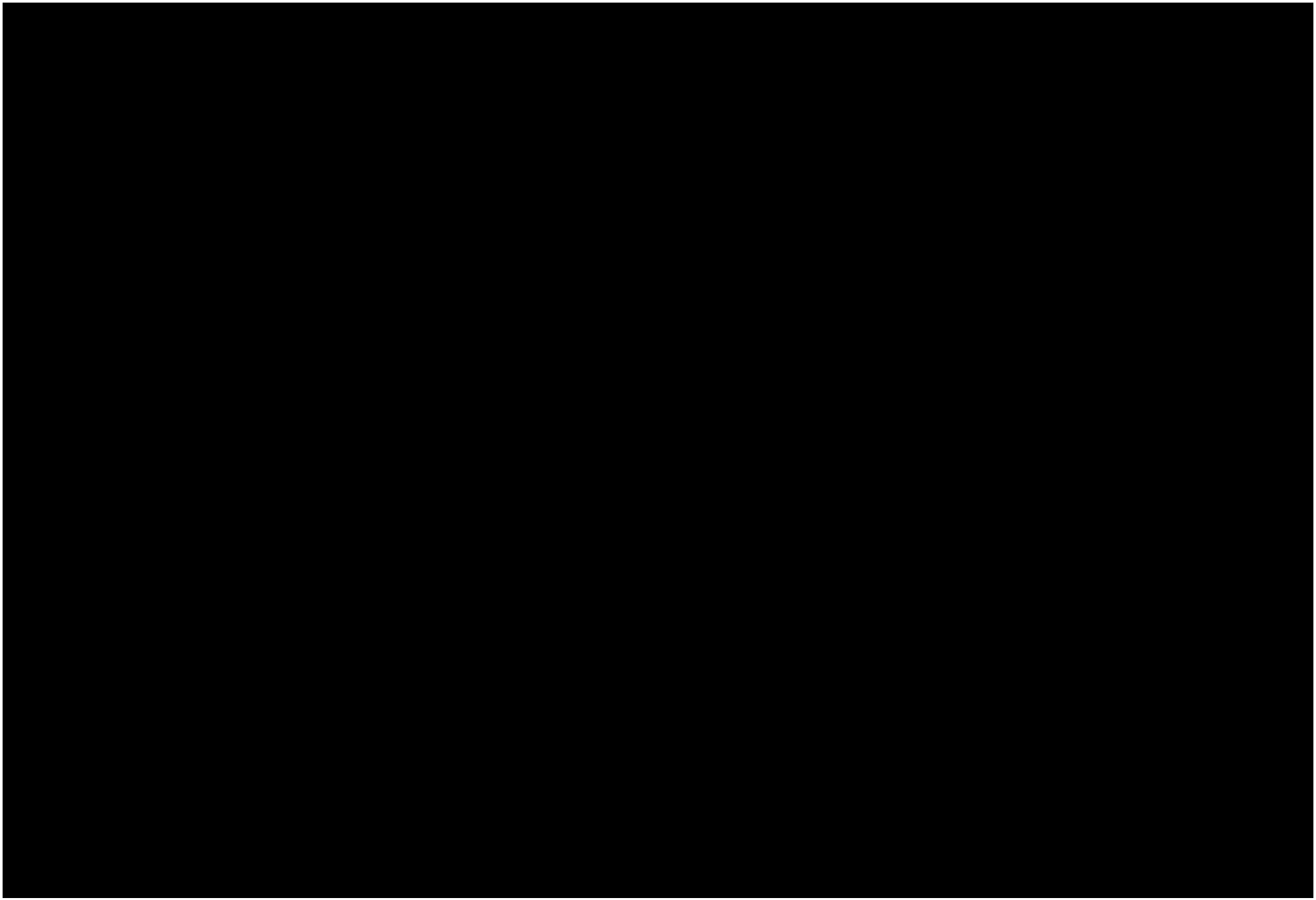
Date of Off Peak Day - 09/28/2021



Member Forecasted Off Peak Demand Day for October 2021

Gunnison County Electric Association, Inc.

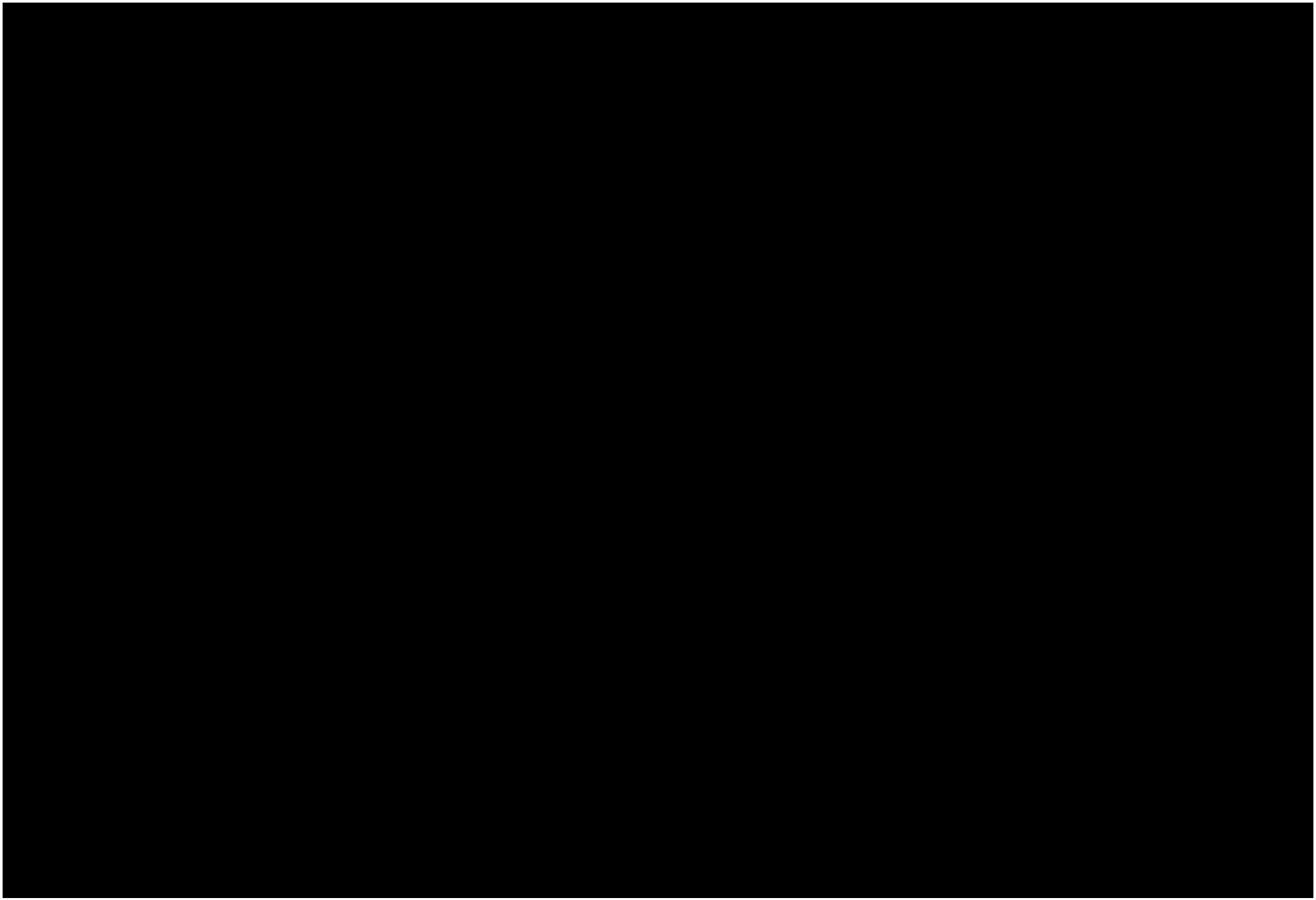
Date of Off Peak Day - 10/11/2021



Member Forecasted Off Peak Demand Day for November 2021

Gunnison County Electric Association, Inc.

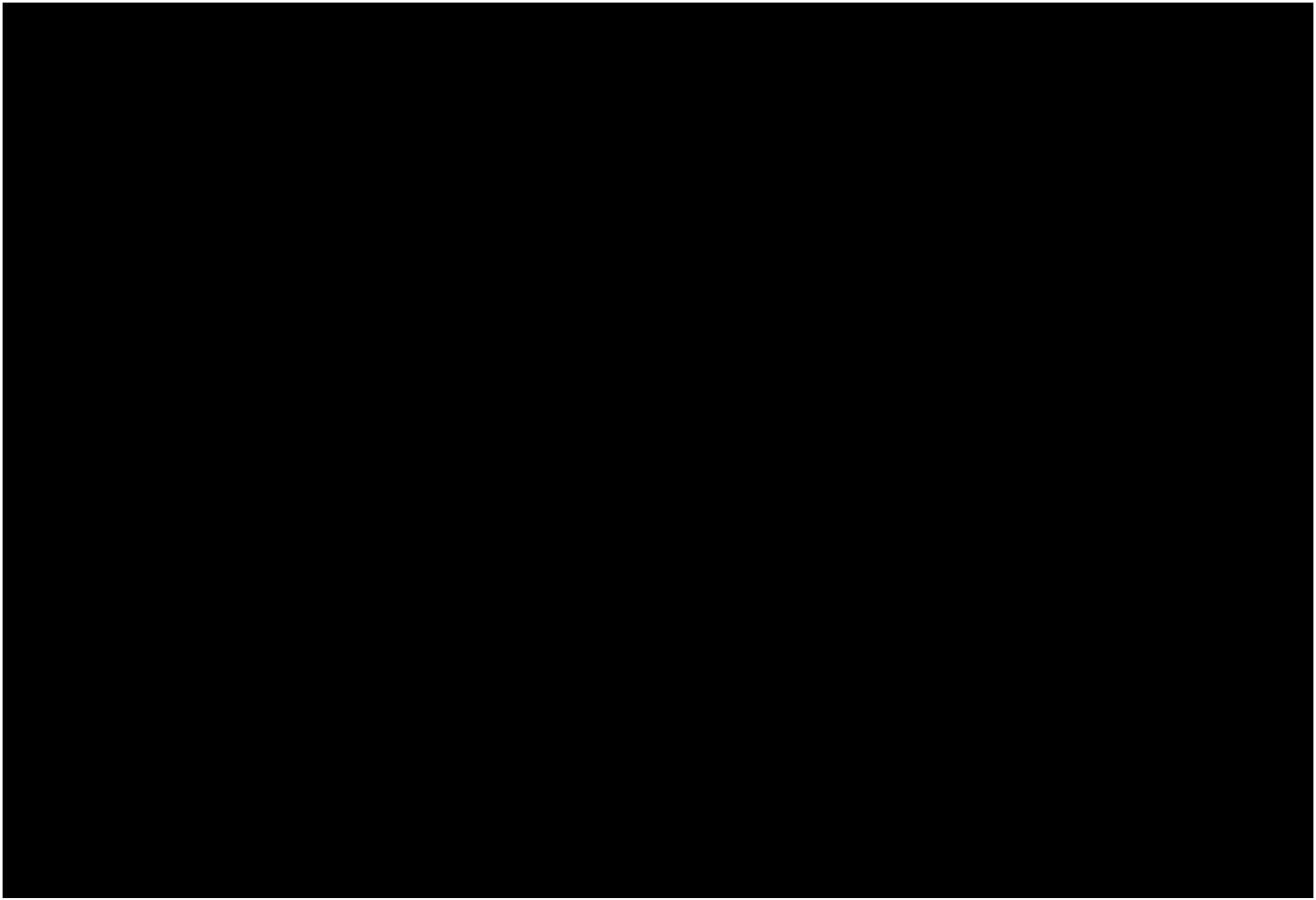
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

Gunnison County Electric Association, Inc.

Date of Off Peak Day - 12/11/2021



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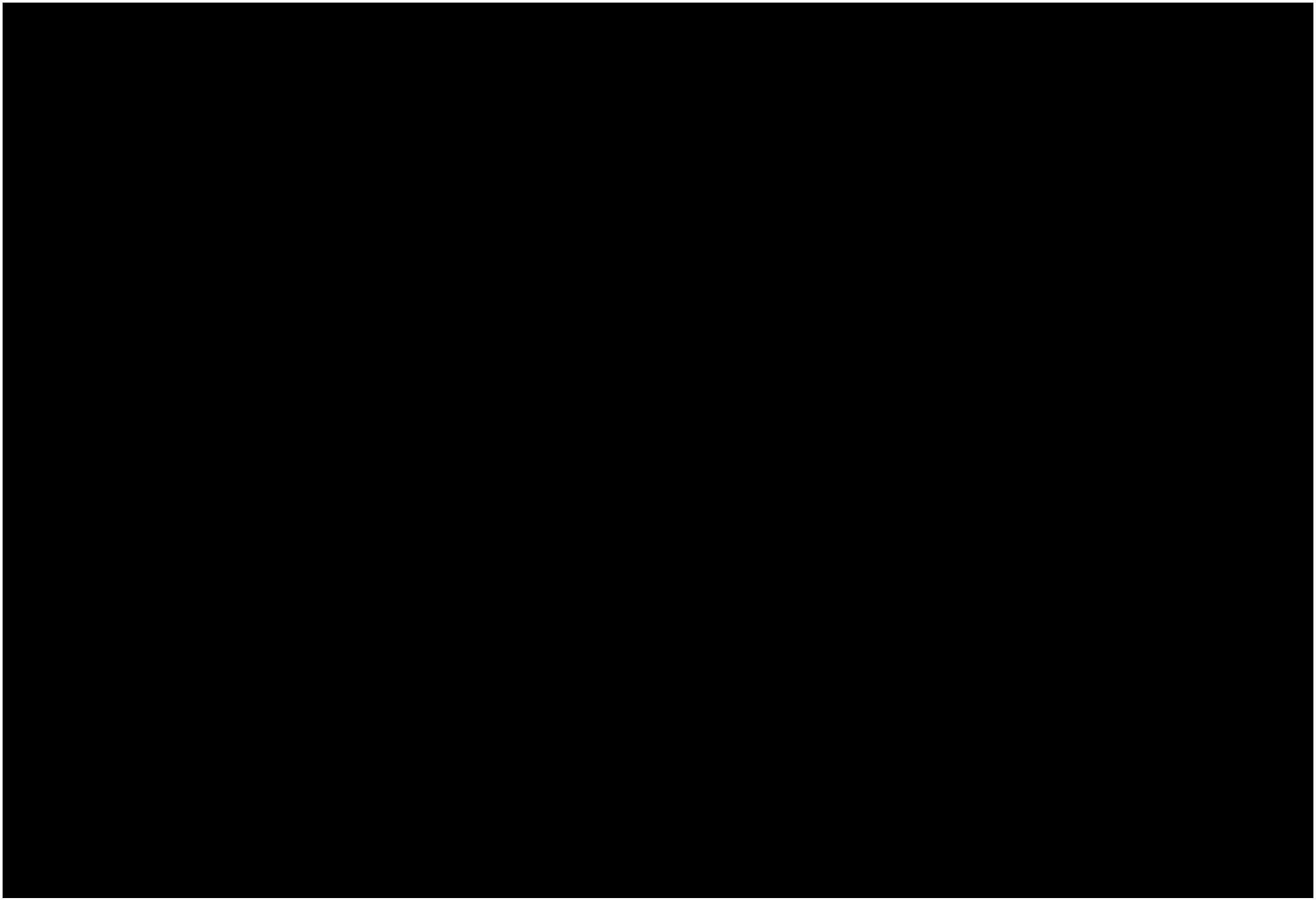
Member Forecasted Off Peak Demand Day for January 2021

Garland Light and Power Company

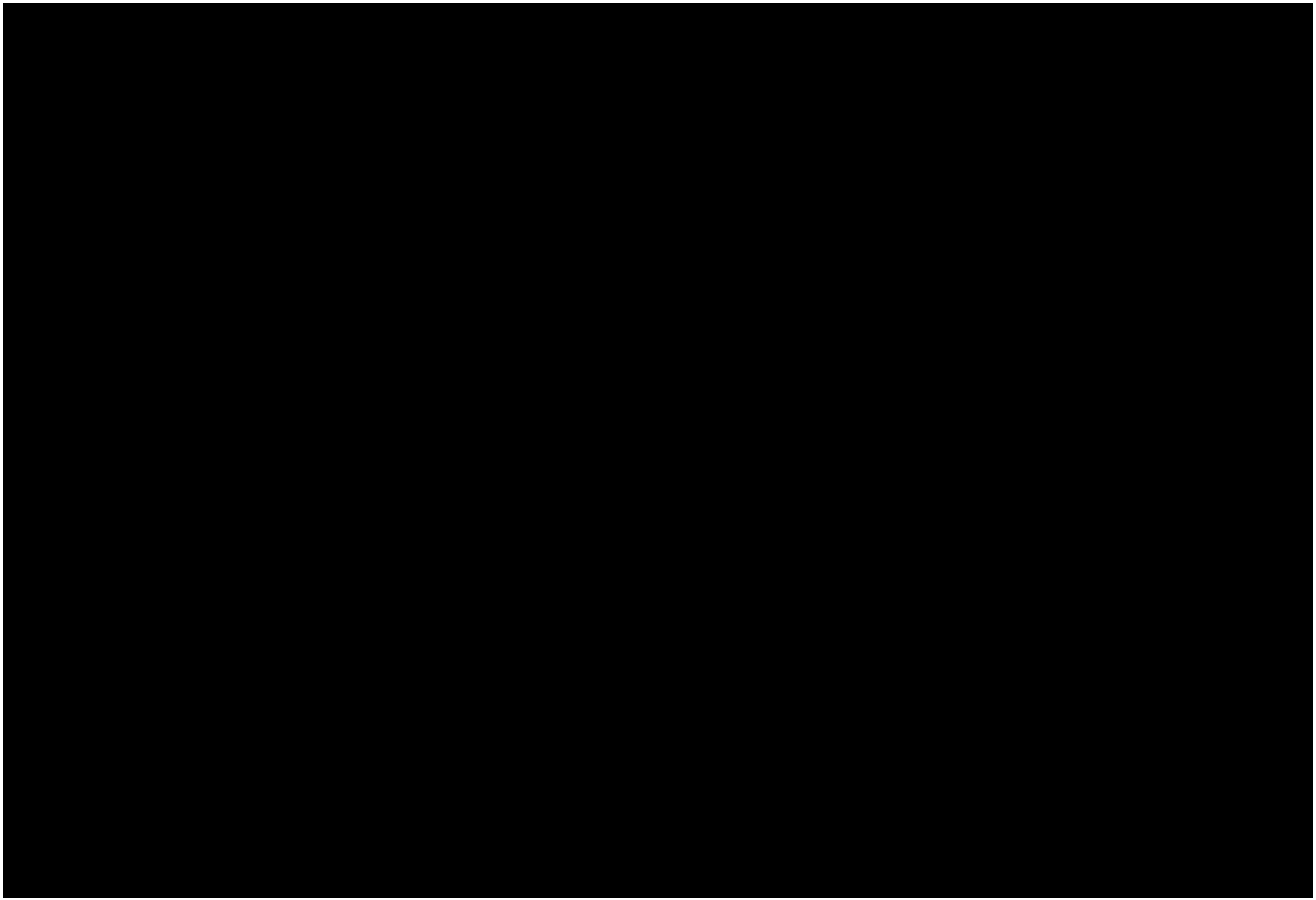
Date of Off Peak Day - 01/31/2021



Member Forecasted Off Peak Demand Day for February 2021

Garland Light and Power Company

Date of Off Peak Day - 02/22/2021



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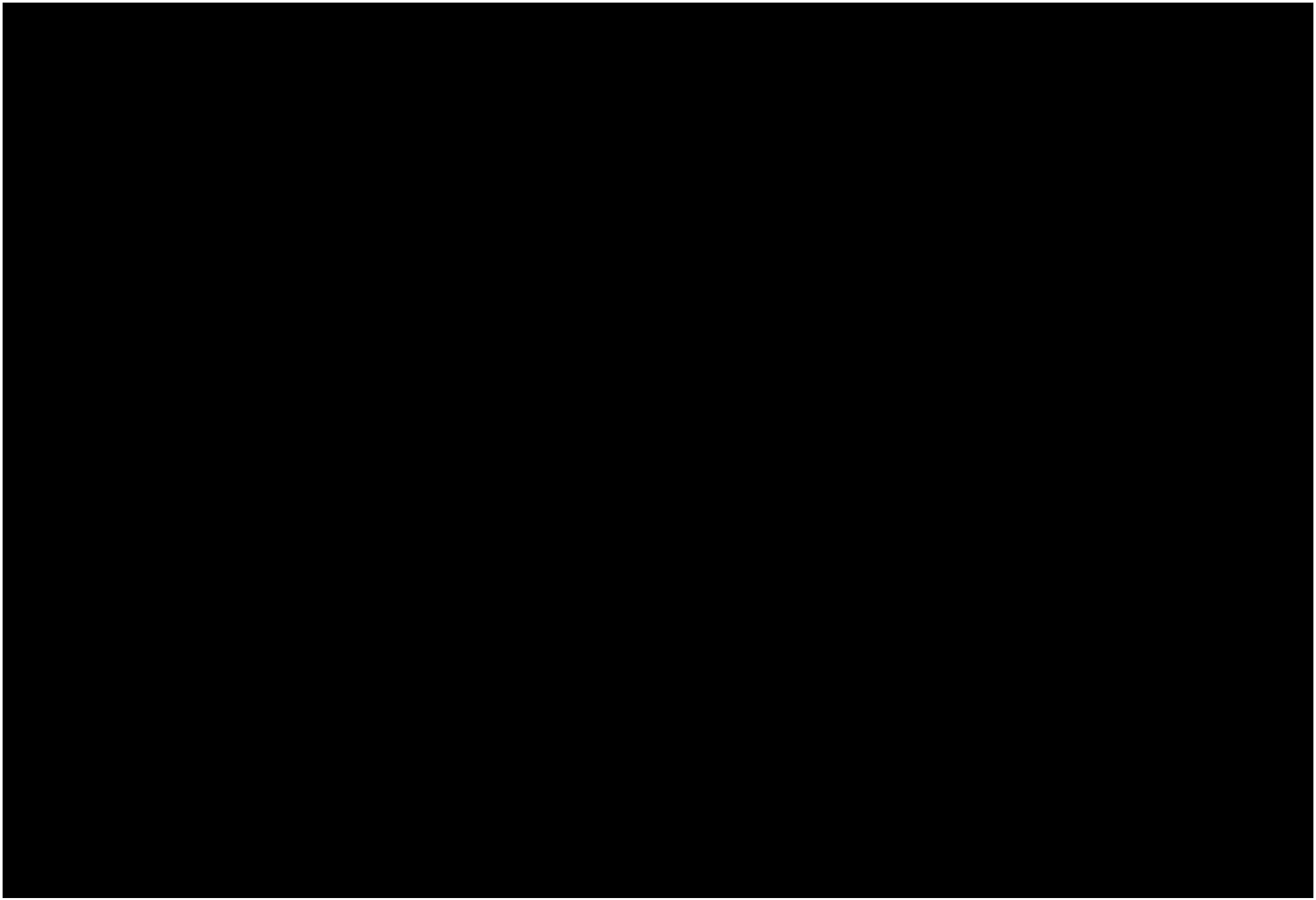
Member Forecasted Off Peak Demand Day for March 2021

Garland Light and Power Company

Date of Off Peak Day - 03/28/2021



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Member Forecasted Off Peak Demand Day for April 2021

Garland Light and Power Company

Date of Off Peak Day - 04/14/2021

[redacted]

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Member Forecasted Off Peak Demand Day for May 2021

Garland Light and Power Company

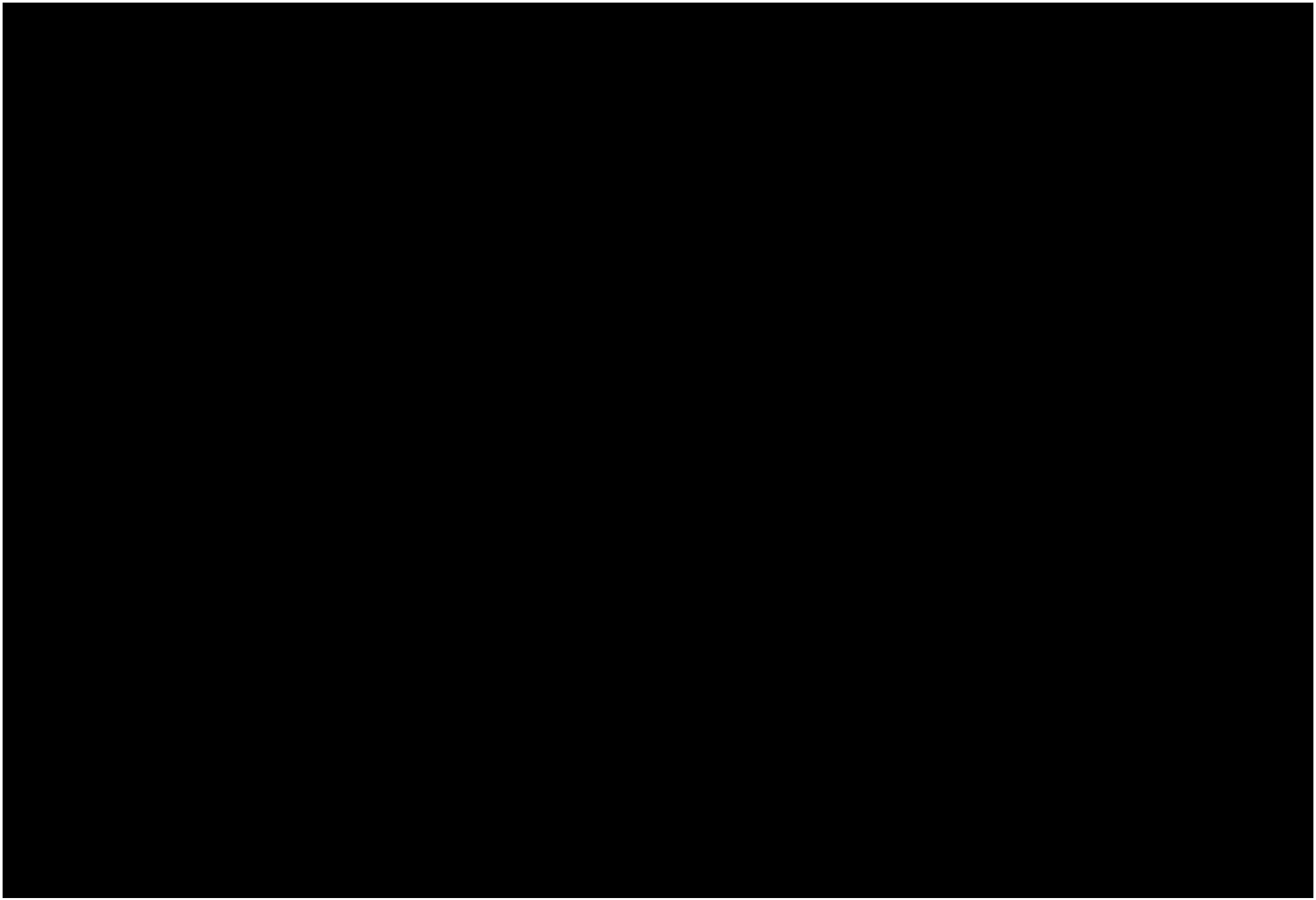
Date of Off Peak Day - 05/05/2021

[redacted]

Member Forecasted Off Peak Demand Day for June 2021

Garland Light and Power Company

Date of Off Peak Day - 06/21/2021



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Member Forecasted Off Peak Demand Day for July 2021

Garland Light and Power Company

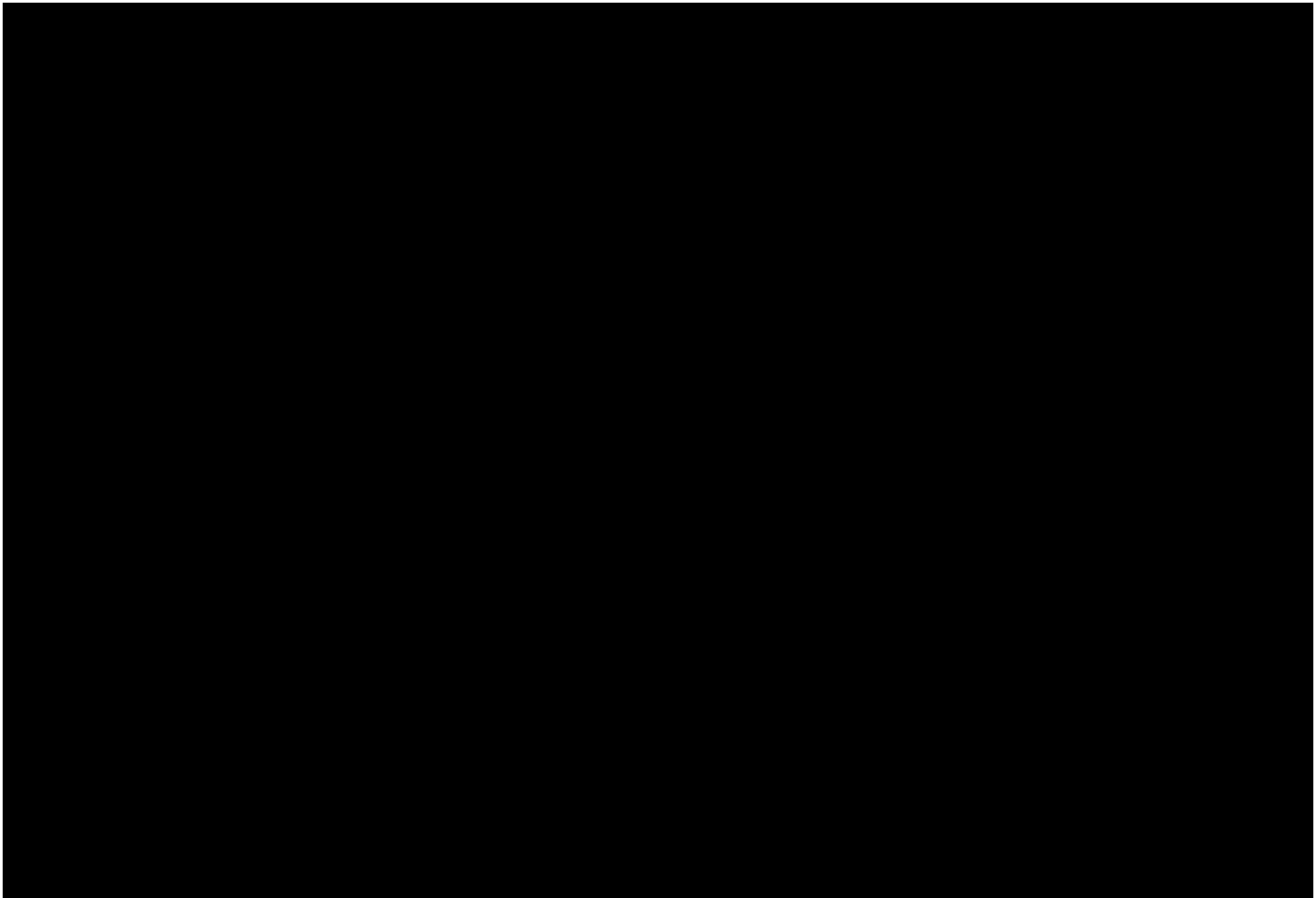
Date of Off Peak Day - 07/12/2021

[redacted]

Member Forecasted Off Peak Demand Day for August 2021

Garland Light and Power Company

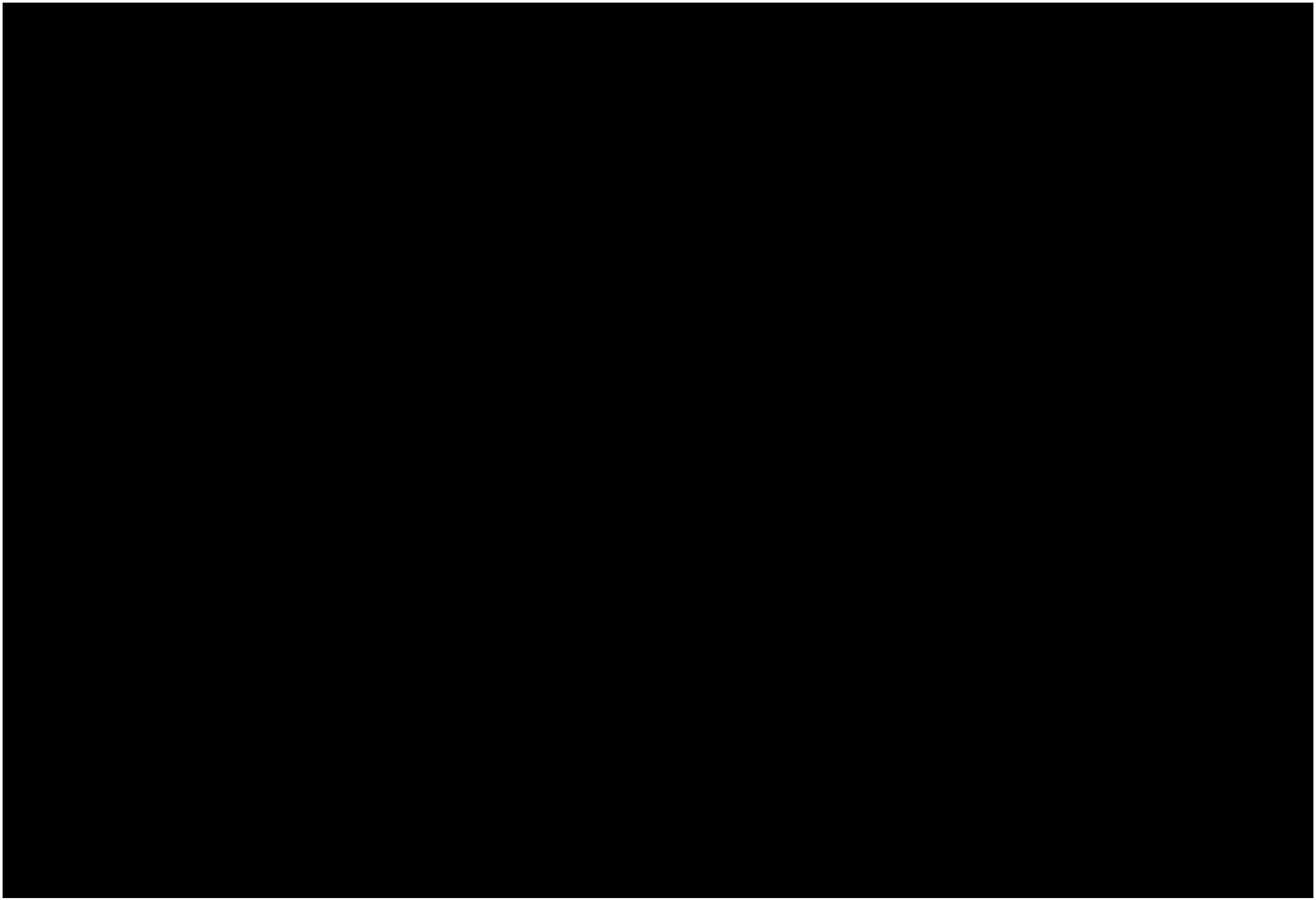
Date of Off Peak Day - 08/17/2021



Member Forecasted Off Peak Demand Day for September 2021

Garland Light and Power Company

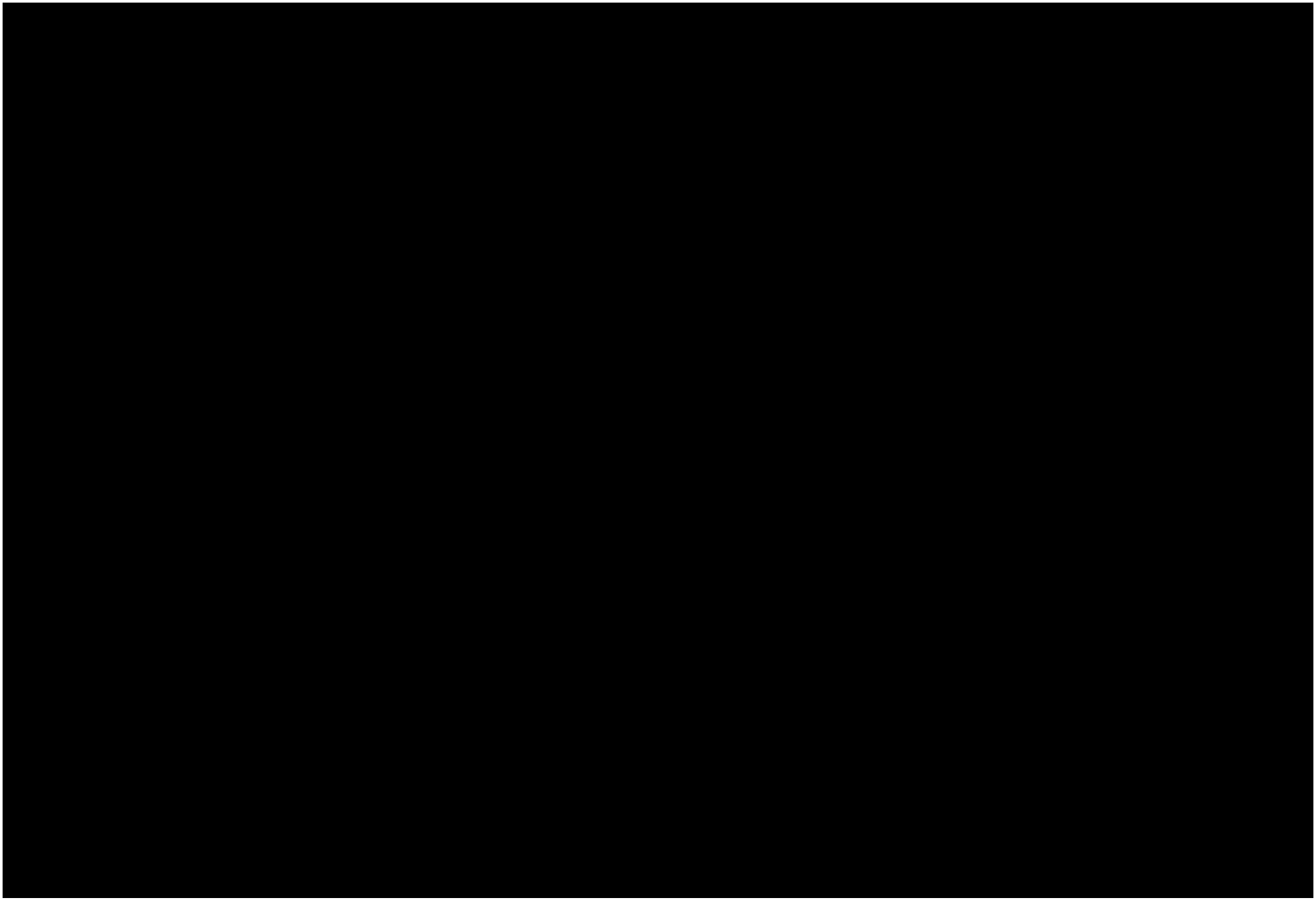
Date of Off Peak Day - 09/29/2021



Member Forecasted Off Peak Demand Day for October 2021

Garland Light and Power Company

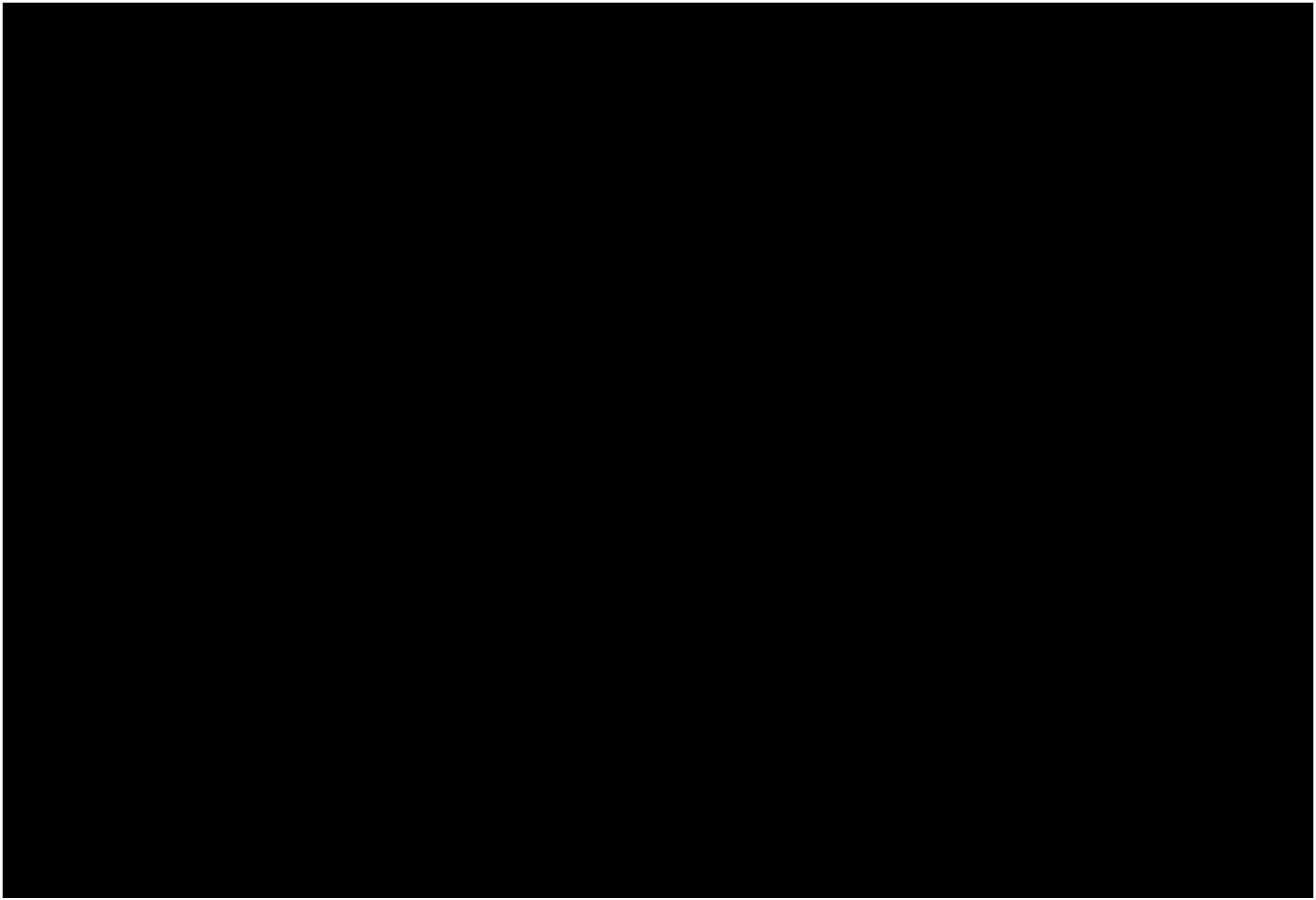
Date of Off Peak Day - 10/08/2021



Member Forecasted Off Peak Demand Day for November 2021

Garland Light and Power Company

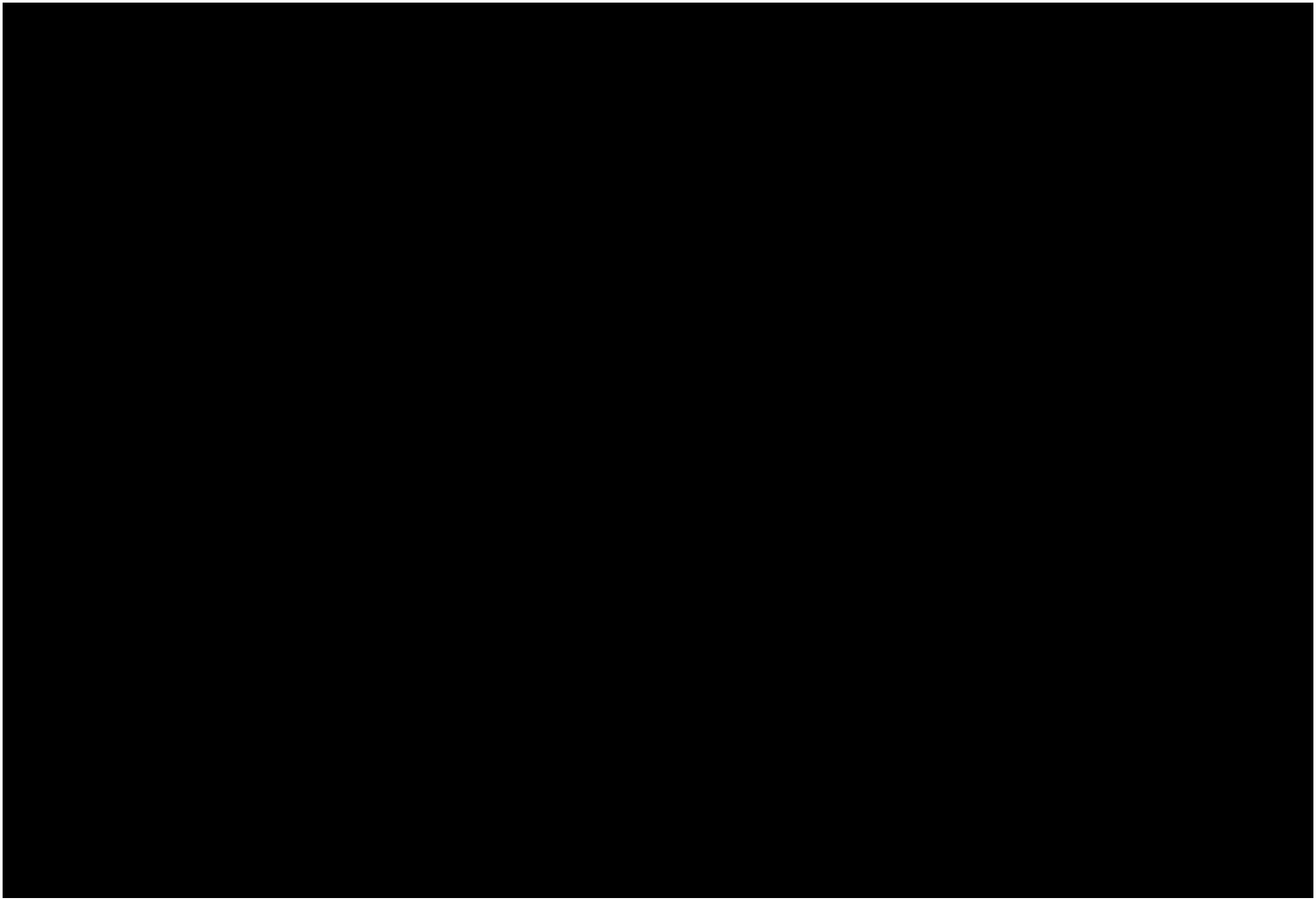
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

Garland Light and Power Company

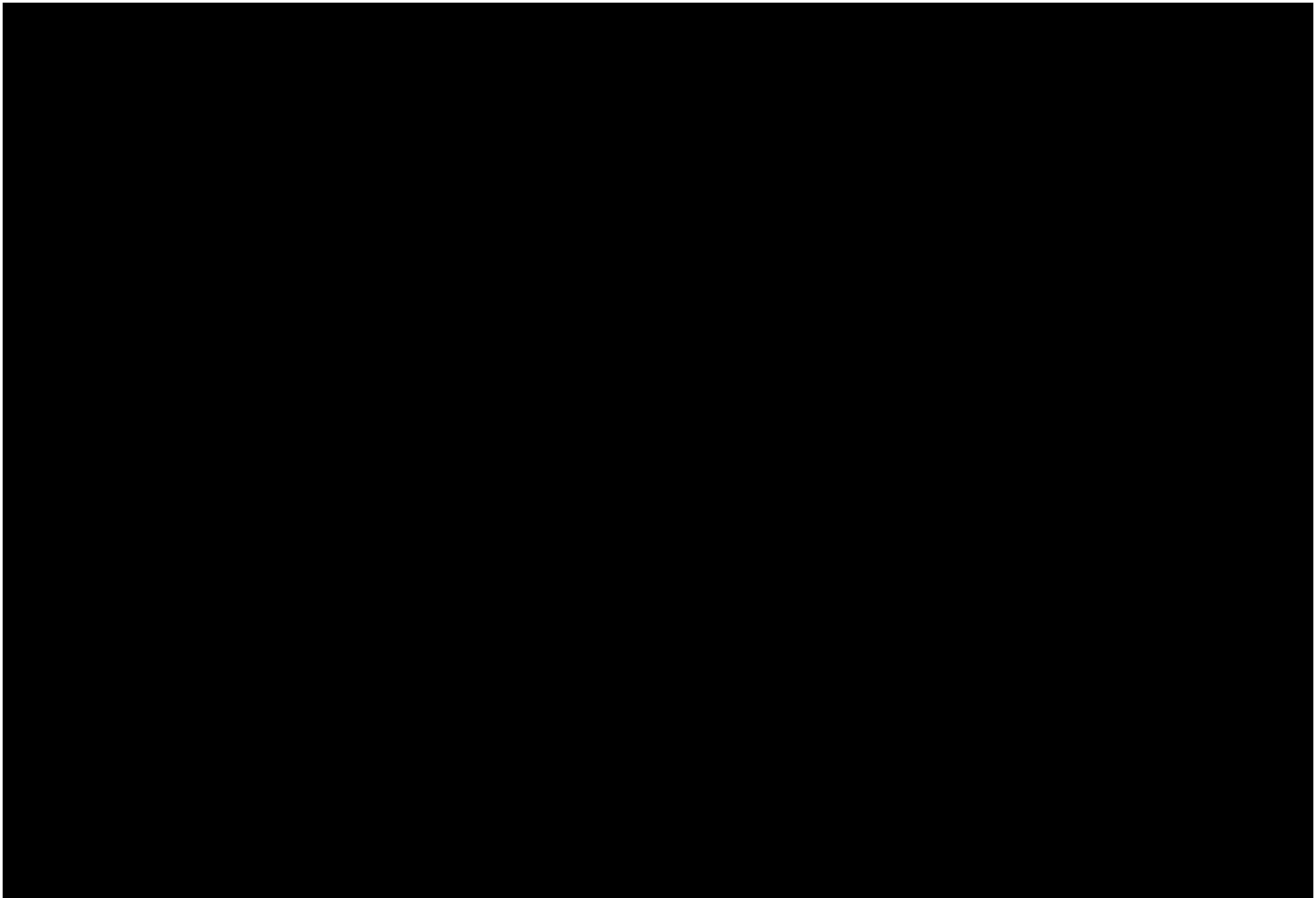
Date of Off Peak Day - 12/09/2021



Member Forecasted Off Peak Demand Day for January 2021

Highline Electric Association

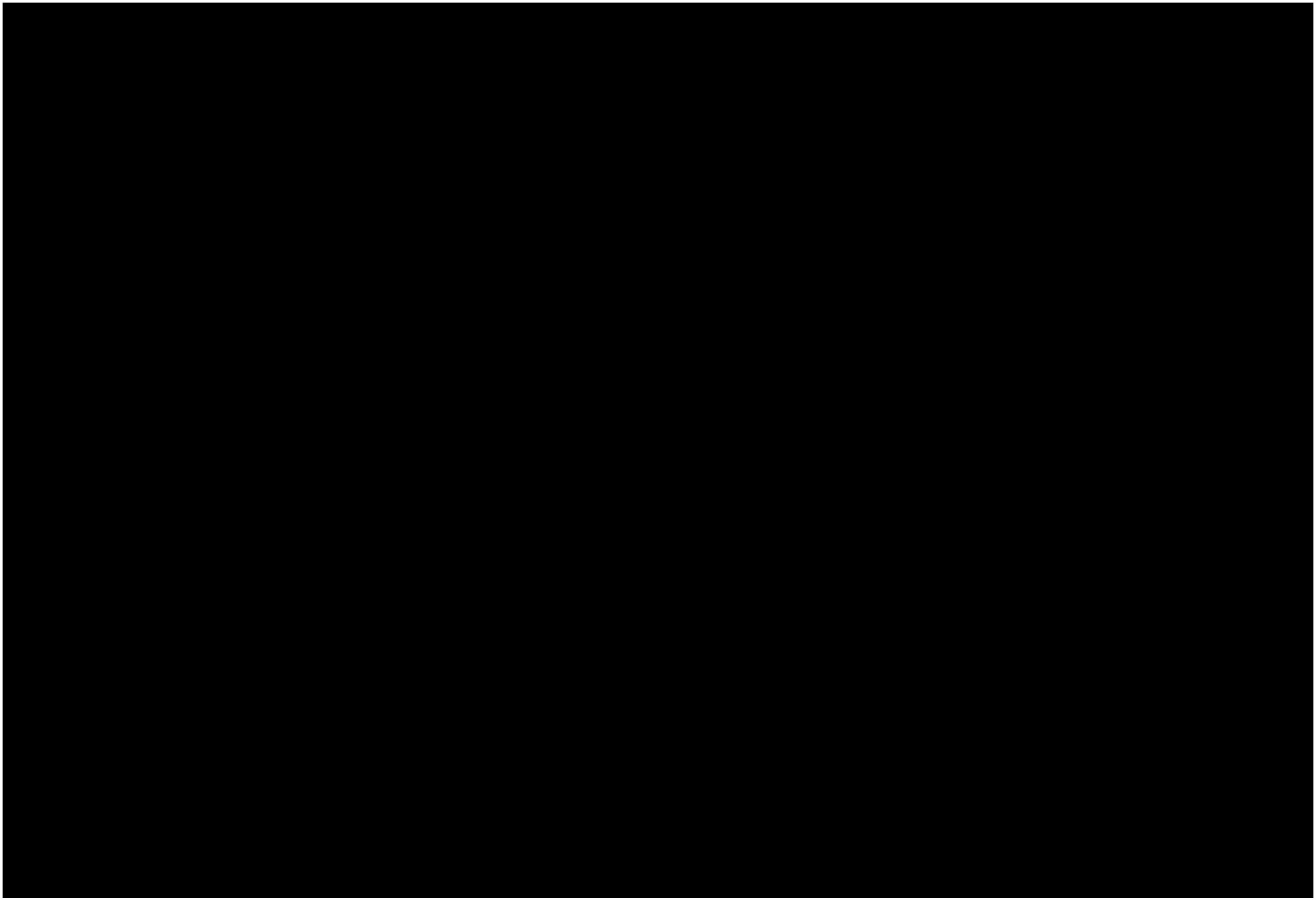
Date of Off Peak Day - 01/11/2021



Member Forecasted Off Peak Demand Day for February 2021

Highline Electric Association

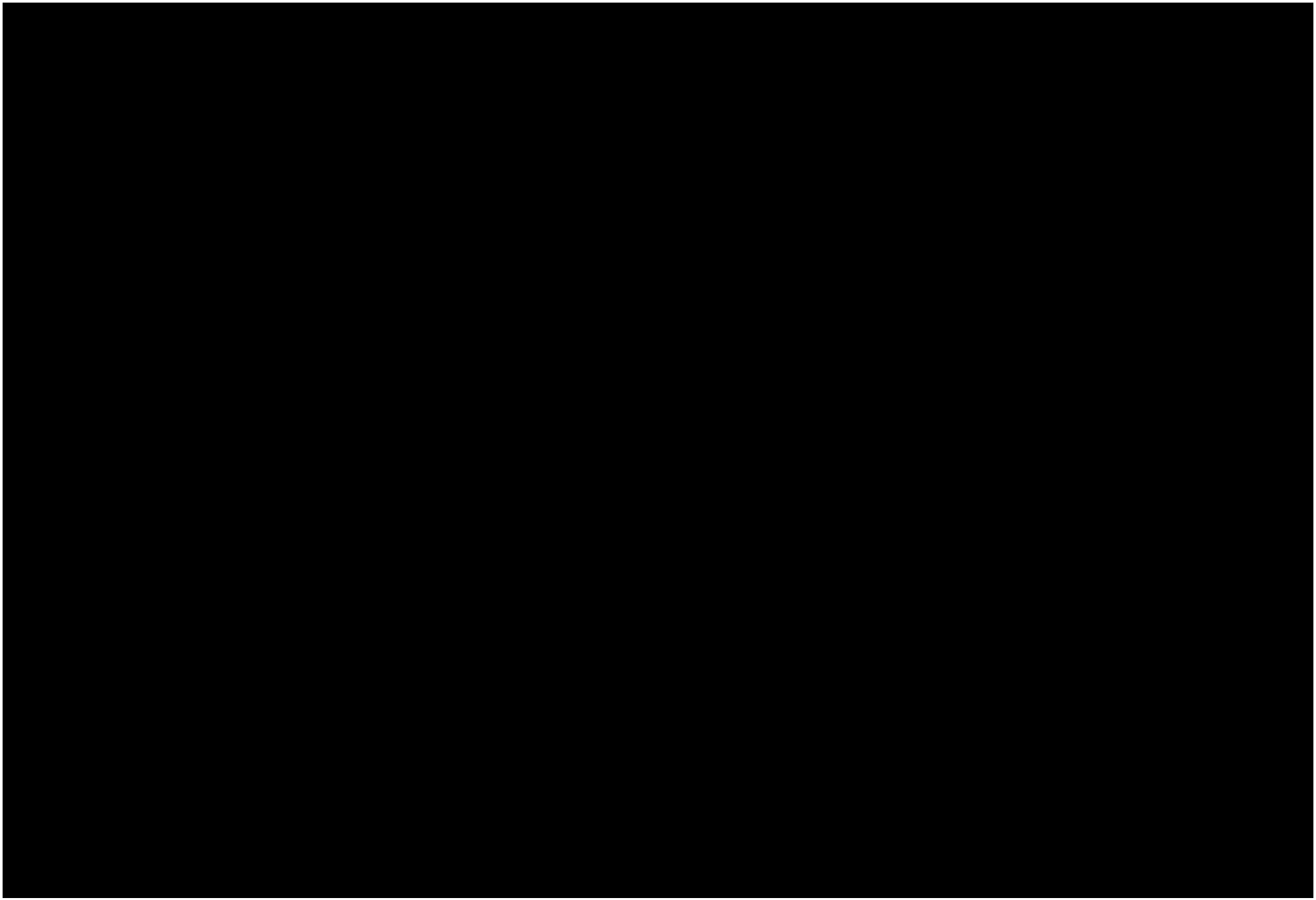
Date of Off Peak Day - 02/21/2021



Member Forecasted Off Peak Demand Day for March 2021

Highline Electric Association

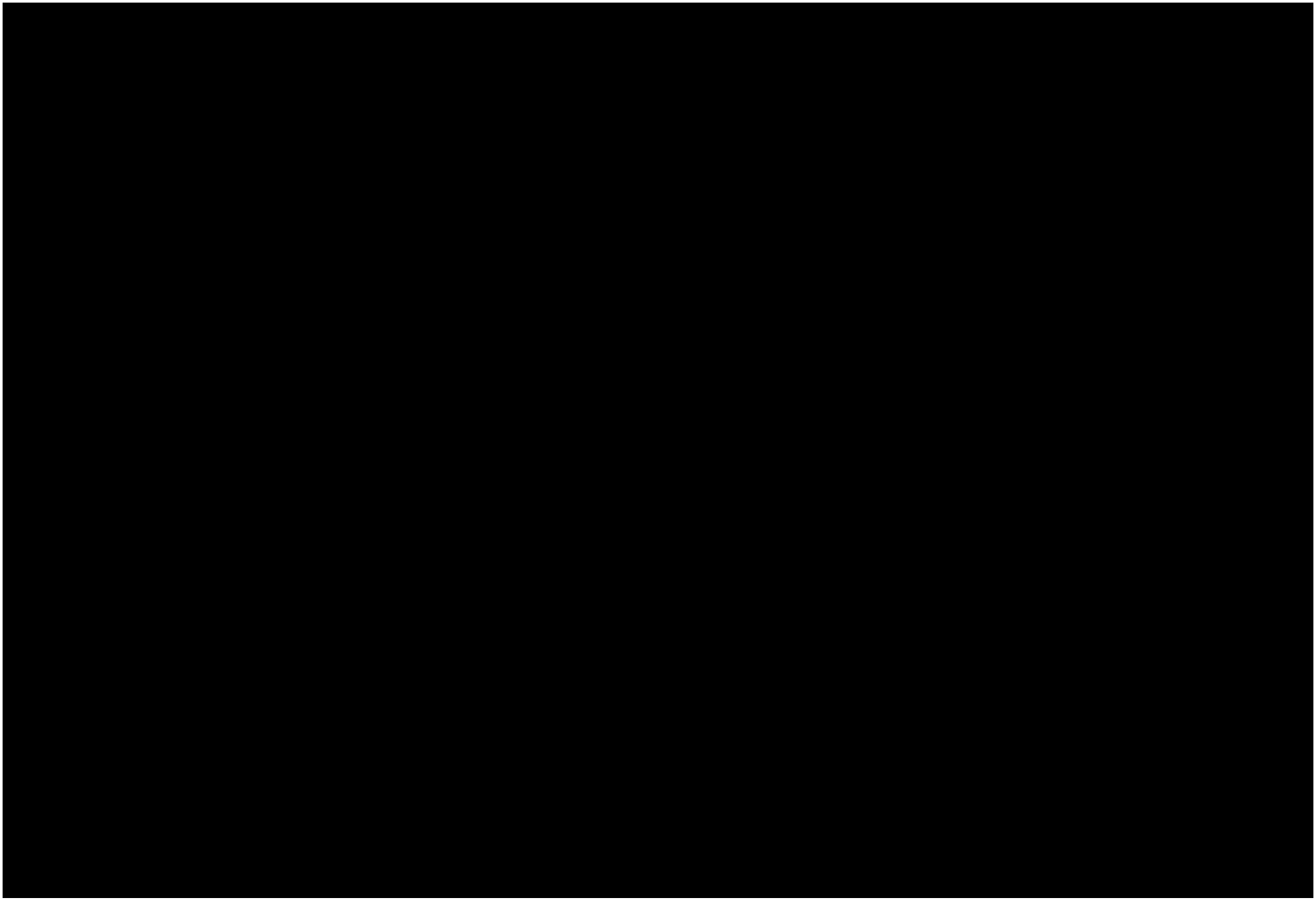
Date of Off Peak Day - 03/14/2021



Member Forecasted Off Peak Demand Day for April 2021

Highline Electric Association

Date of Off Peak Day - 04/09/2021



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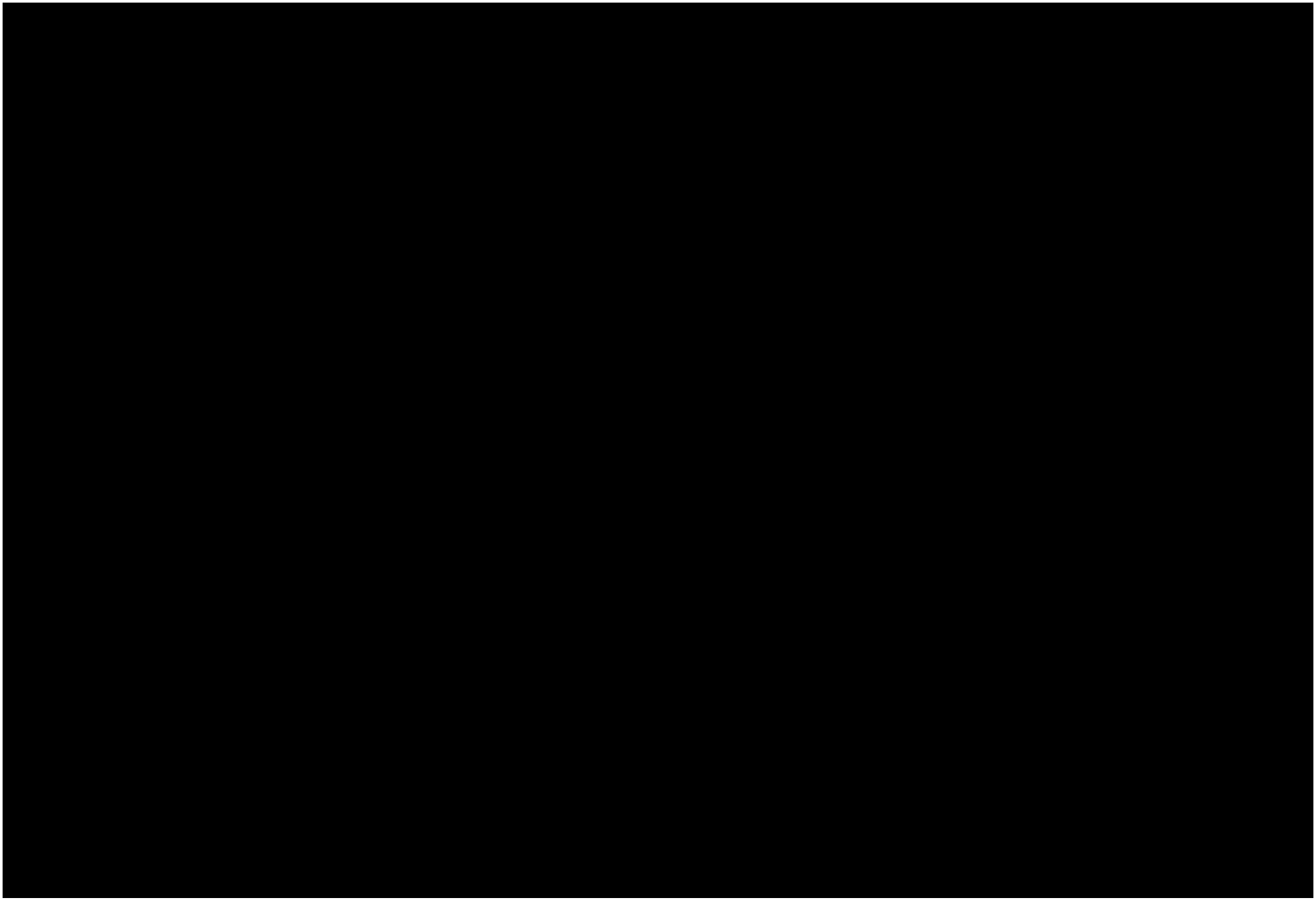
Member Forecasted Off Peak Demand Day for May 2021

Highline Electric Association

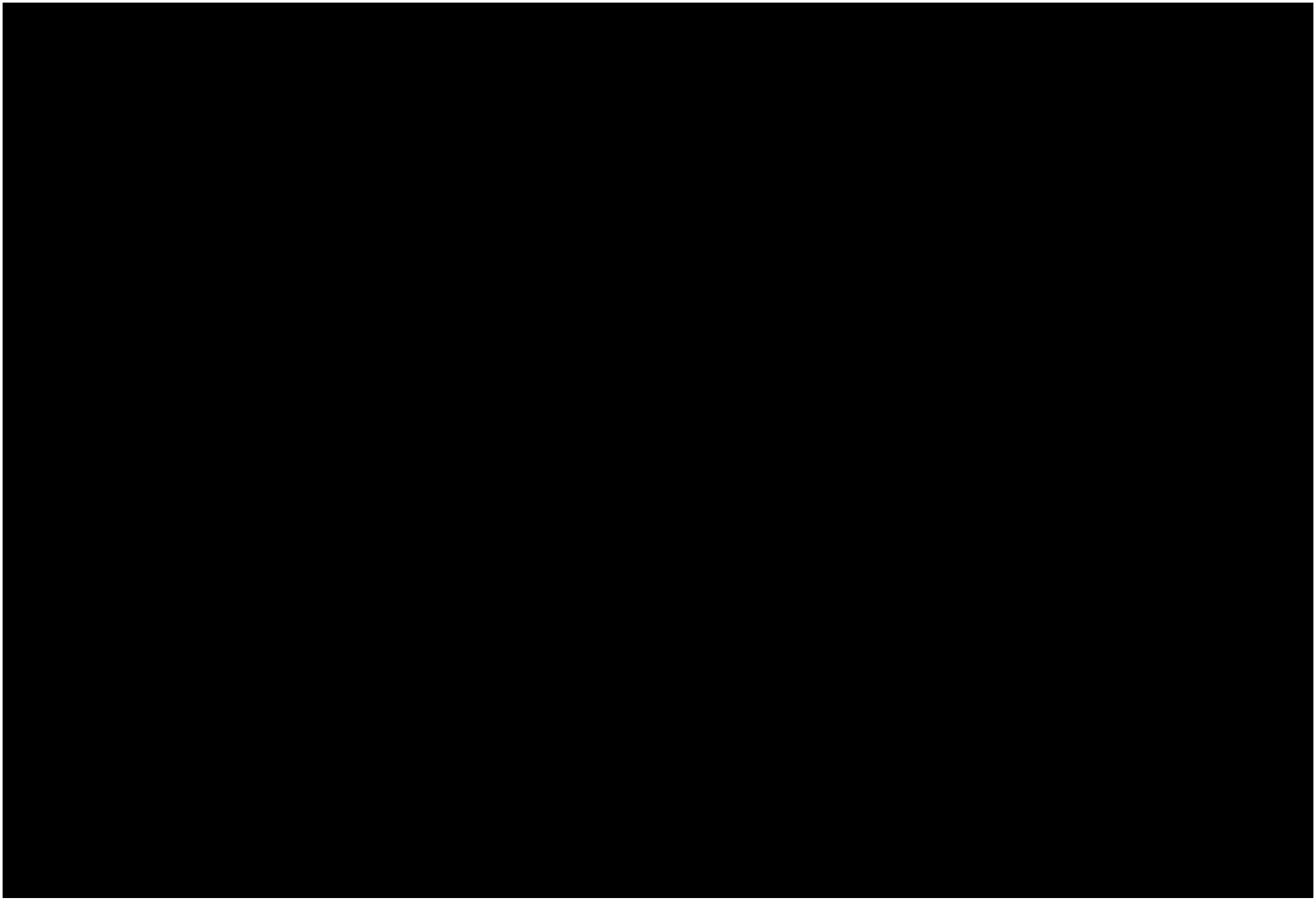
Date of Off Peak Day - 05/09/2021



Member Forecasted Off Peak Demand Day for June 2021

Highline Electric Association

Date of Off Peak Day - 06/01/2021



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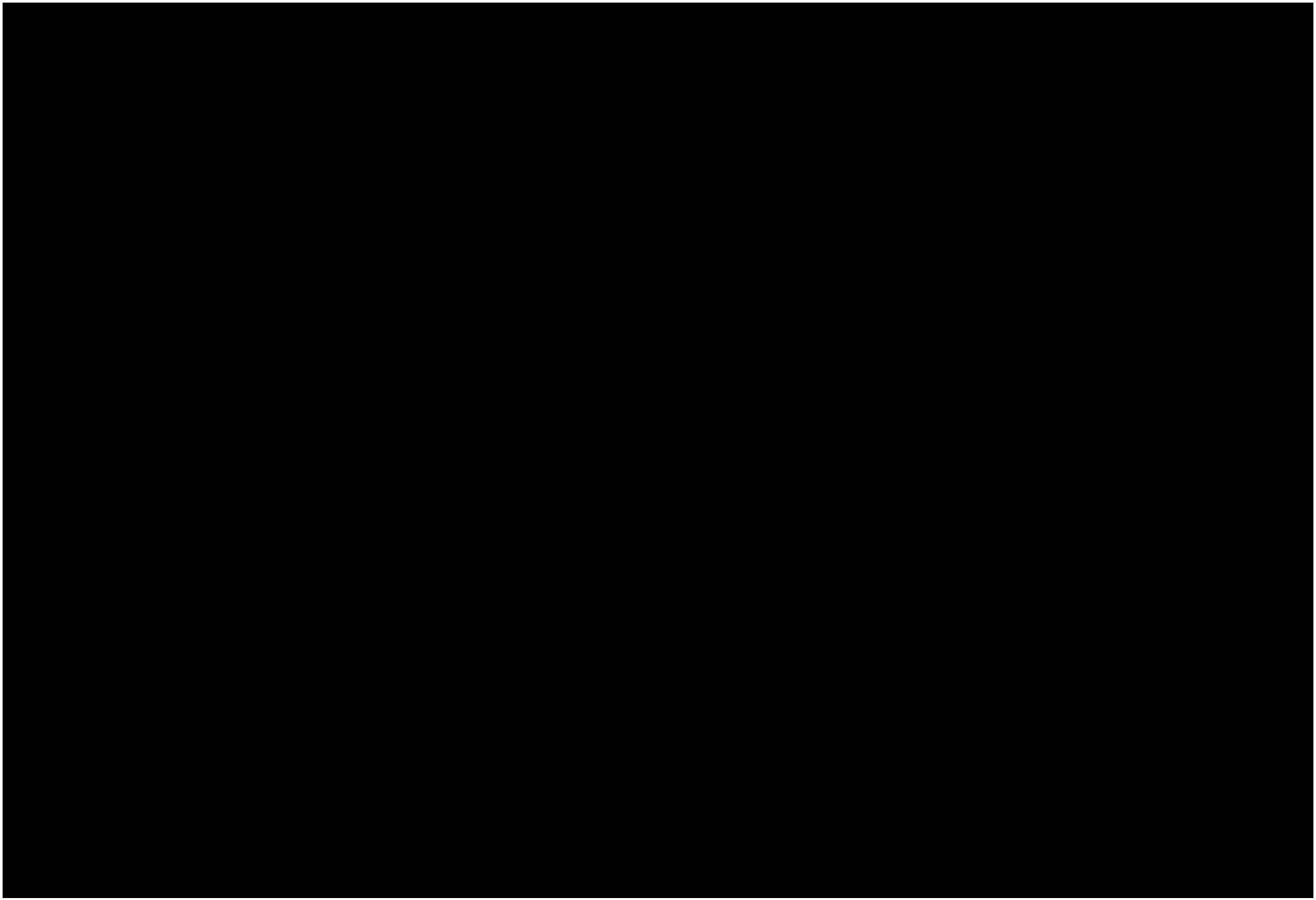
Member Forecasted Off Peak Demand Day for July 2021

Highline Electric Association

Date of Off Peak Day - 07/03/2021



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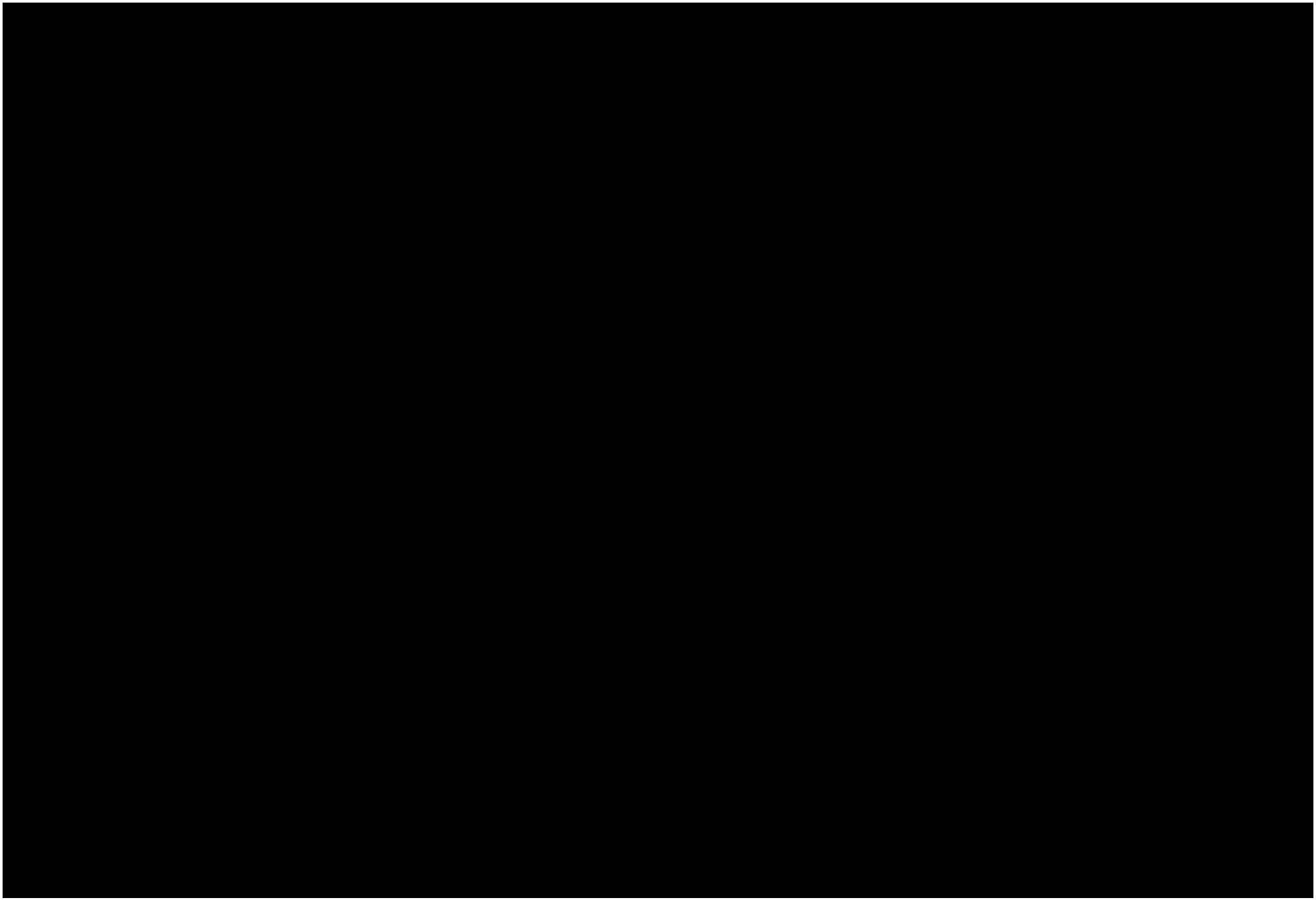
Member Forecasted Off Peak Demand Day for August 2021

Highline Electric Association

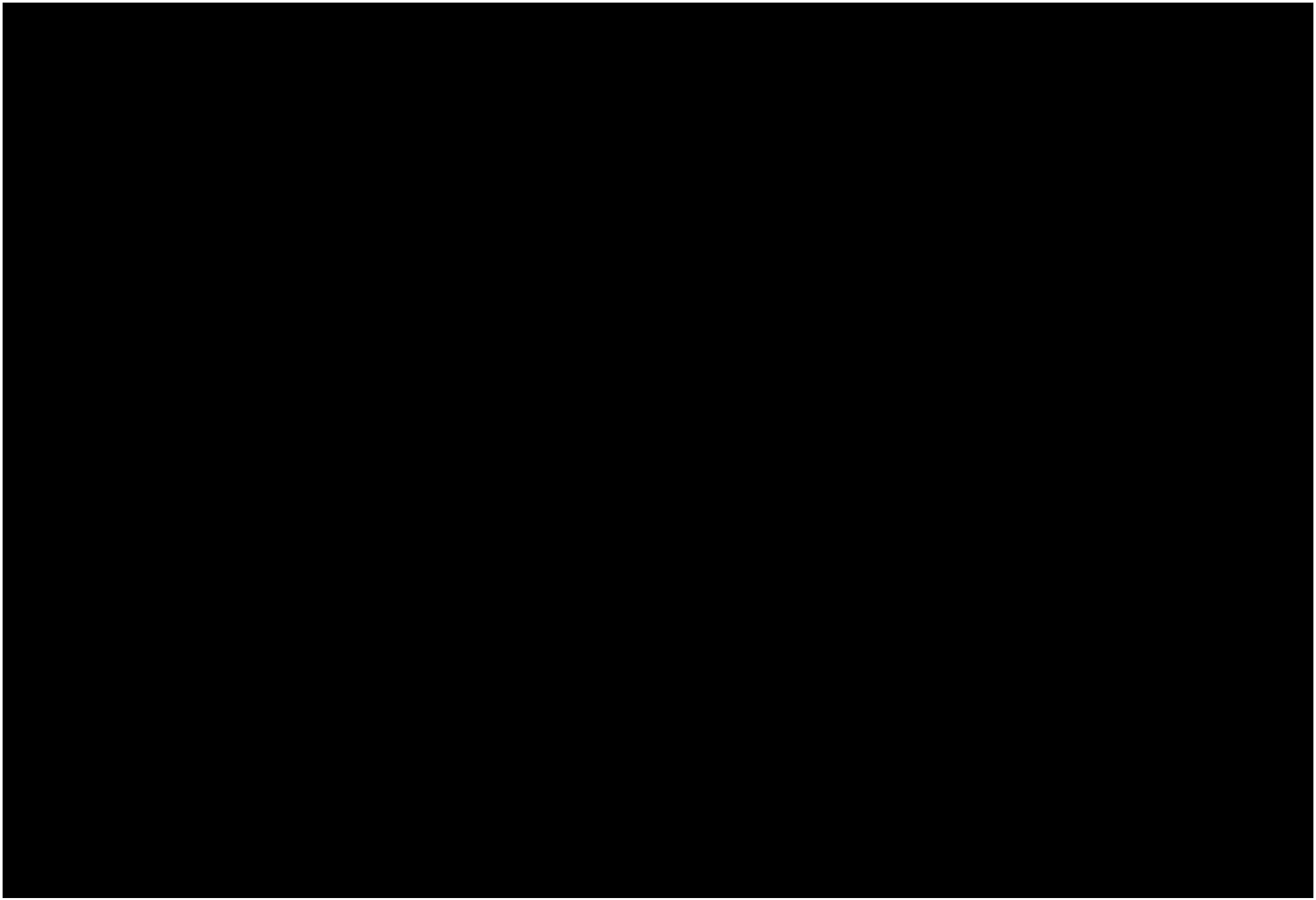
Date of Off Peak Day - 08/13/2021



Member Forecasted Off Peak Demand Day for September 2021

Highline Electric Association

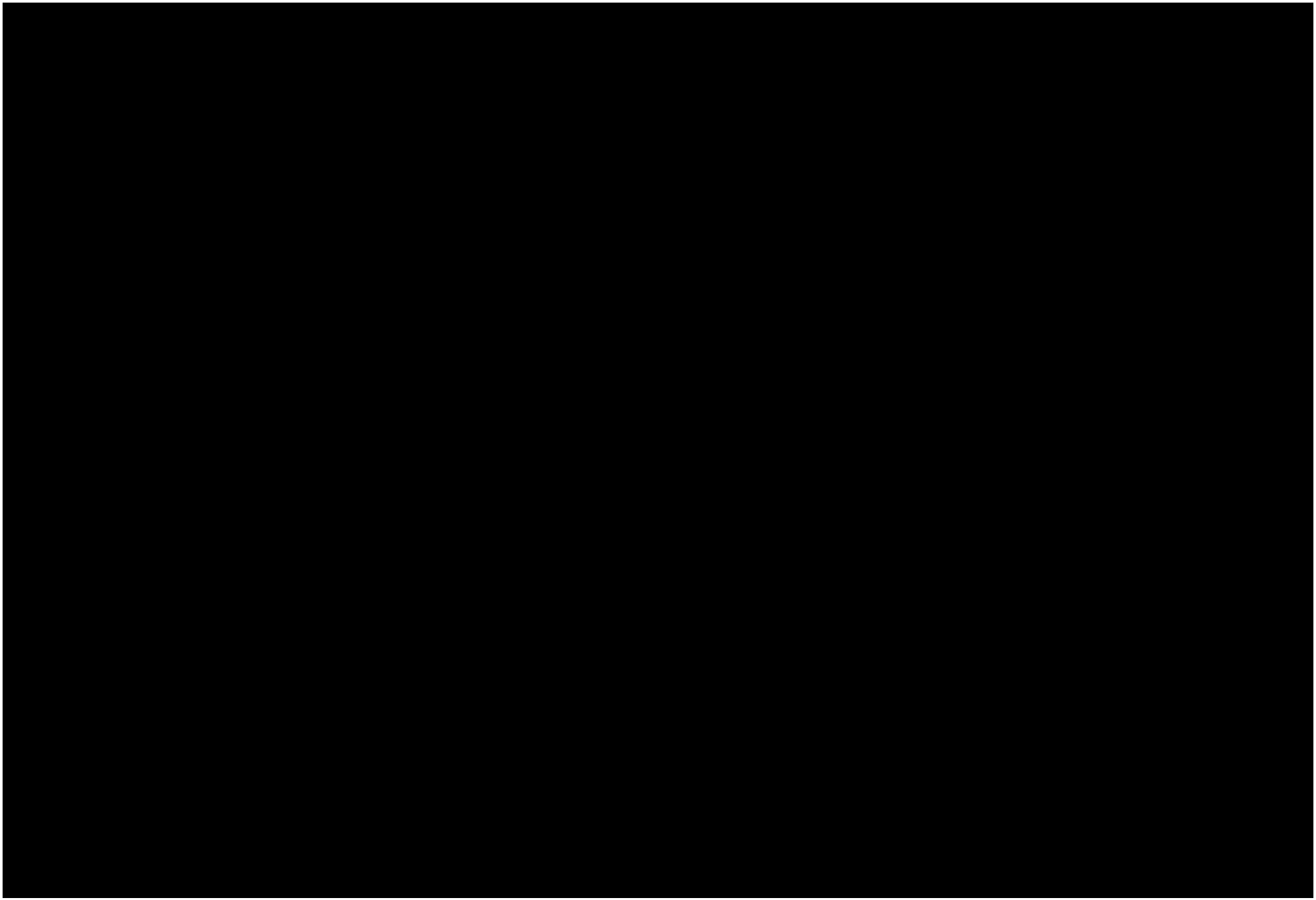
Date of Off Peak Day - 09/30/2021



Member Forecasted Off Peak Demand Day for October 2021

Highline Electric Association

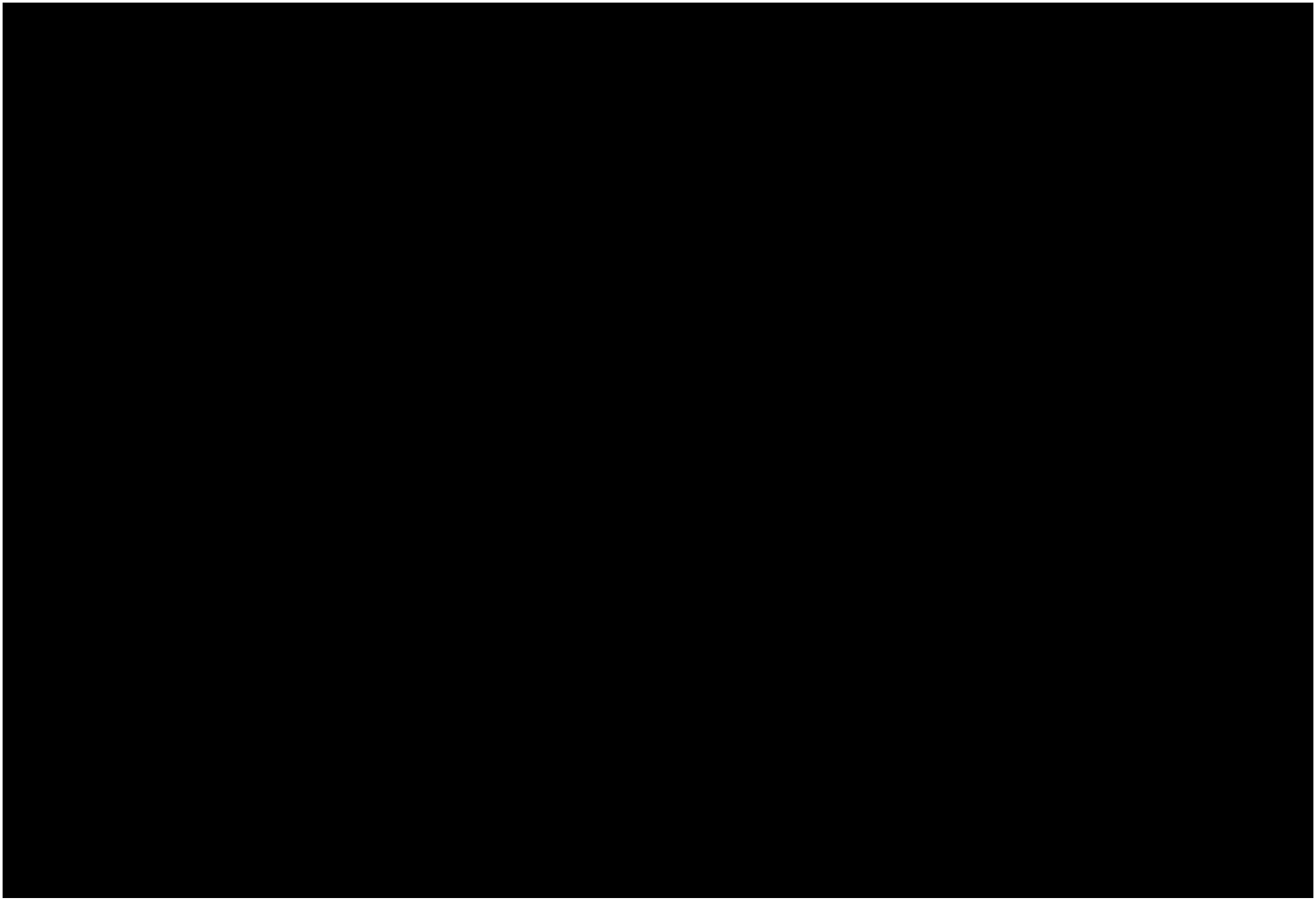
Date of Off Peak Day - 10/07/2021



Member Forecasted Off Peak Demand Day for November 2021

Highline Electric Association

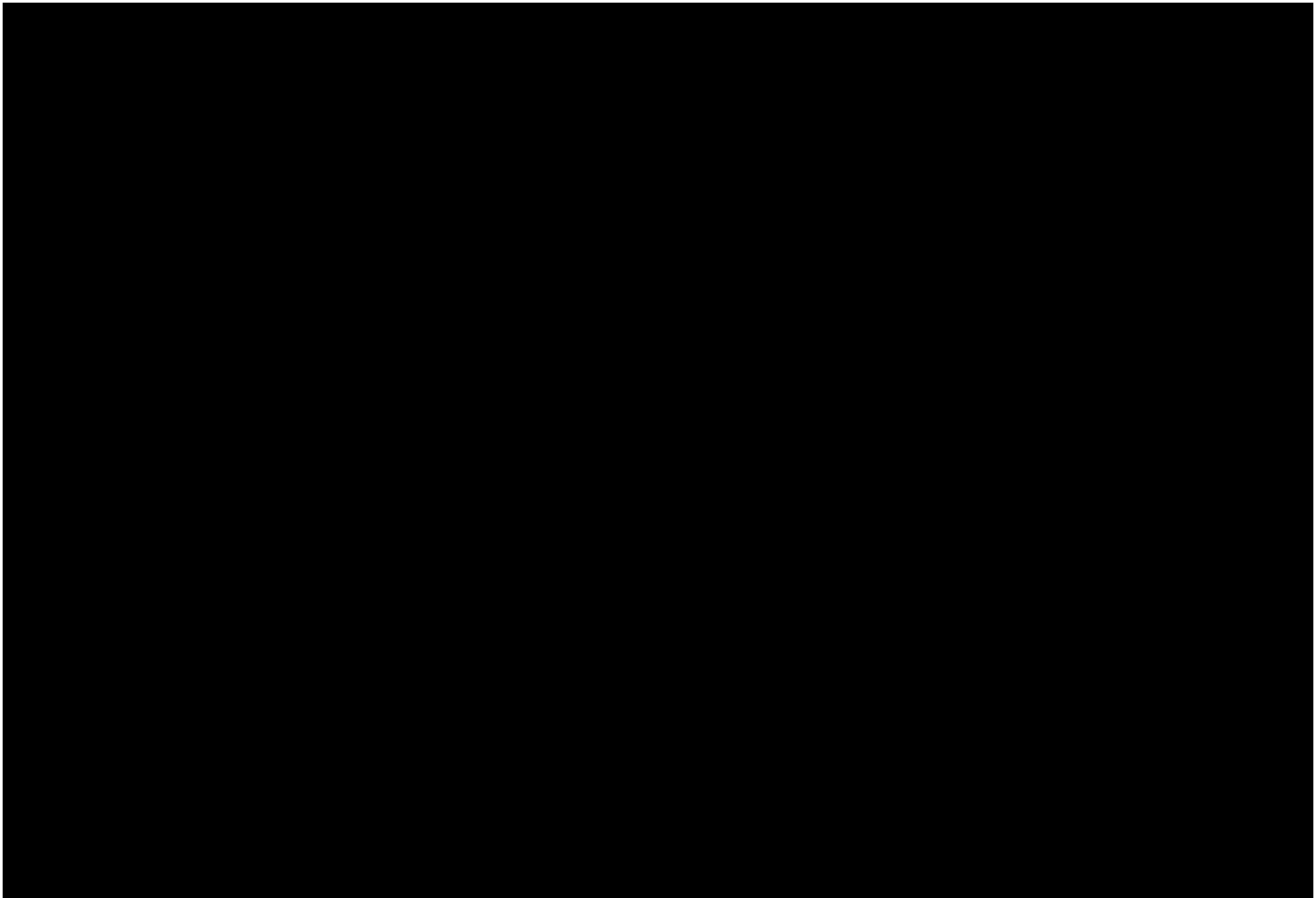
Date of Off Peak Day - 11/07/2021



Member Forecasted Off Peak Demand Day for December 2021

Highline Electric Association

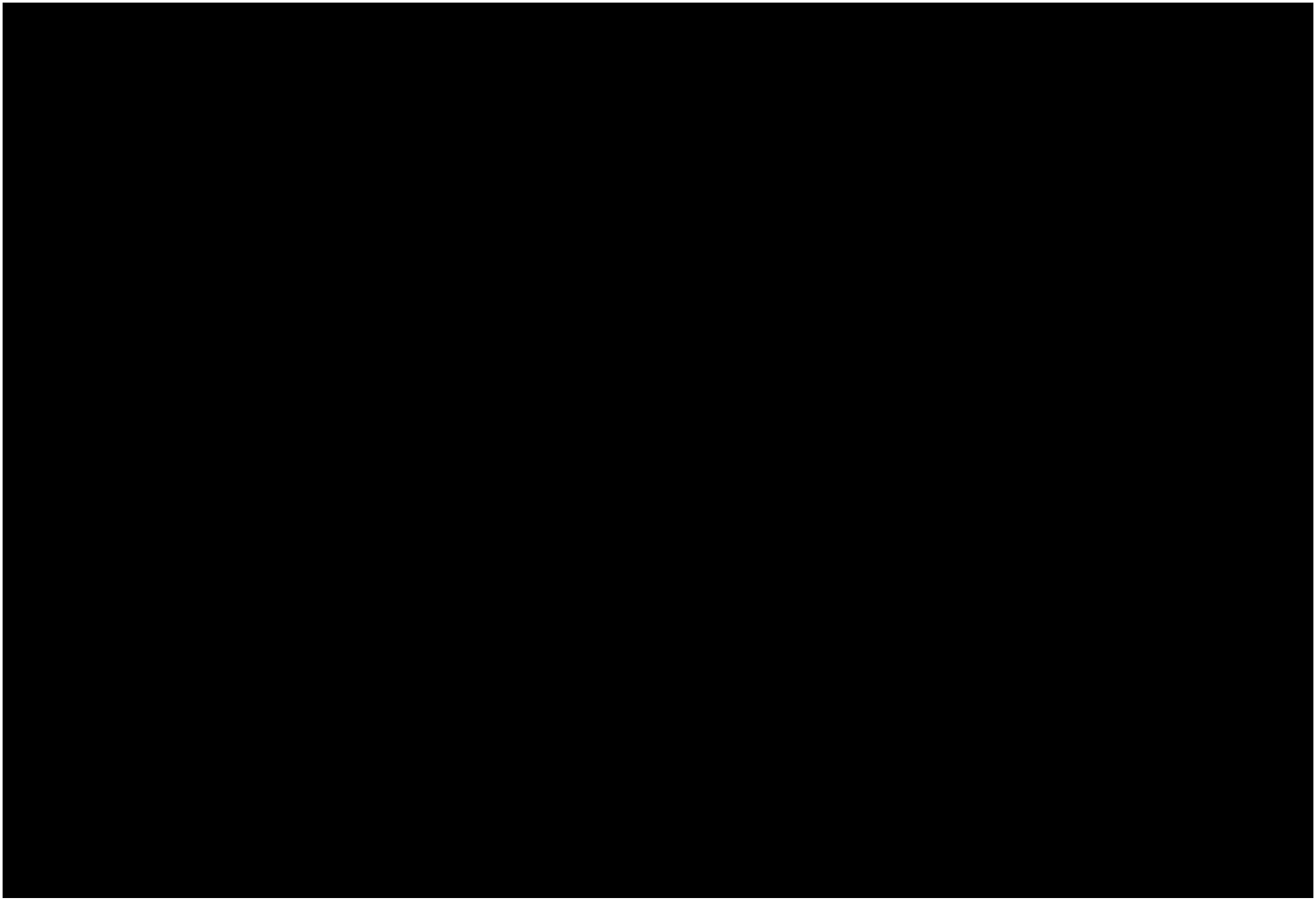
Date of Off Peak Day - 12/09/2021



Member Forecasted Off Peak Demand Day for January 2021

High Plains Power, Inc.

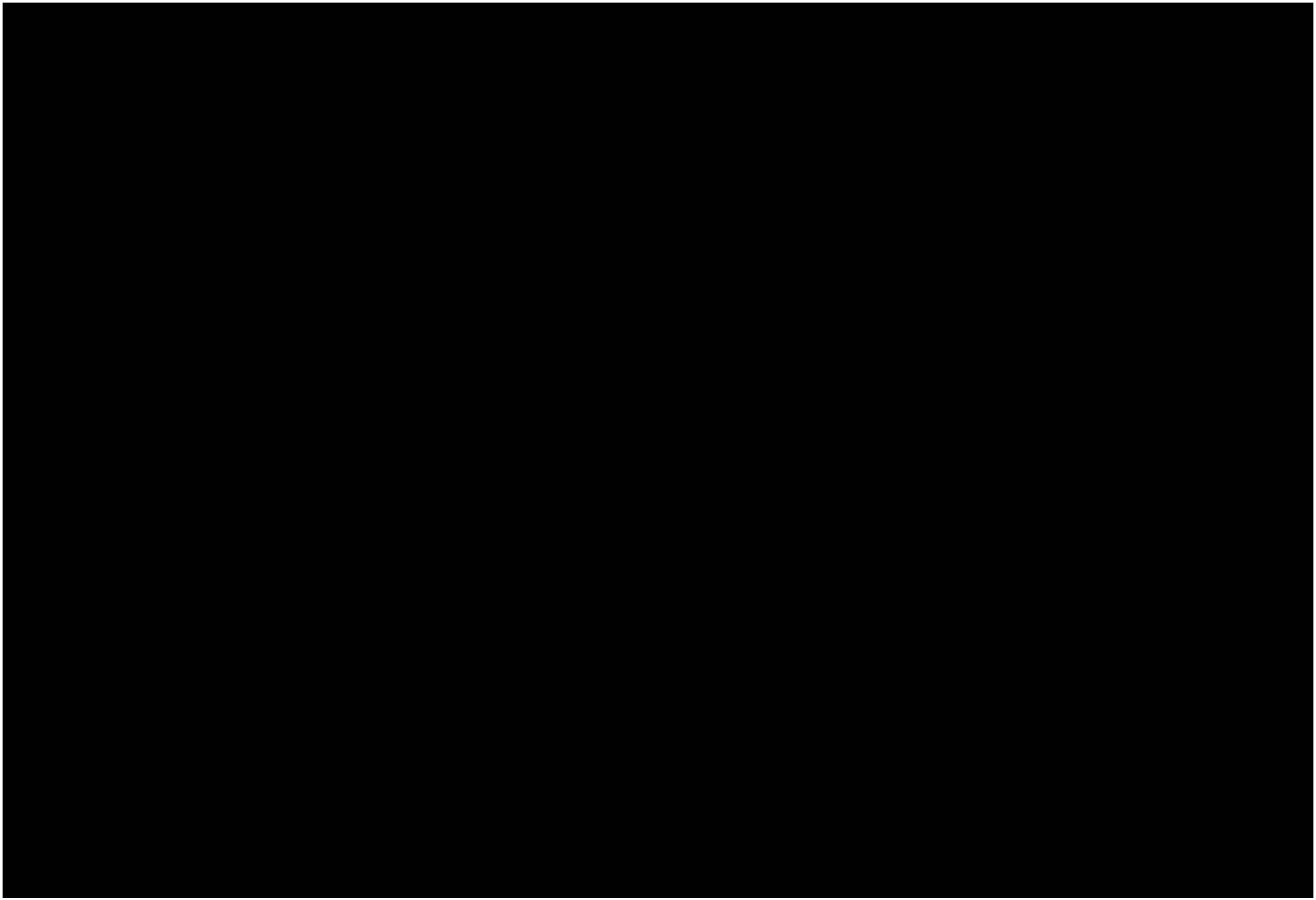
Date of Off Peak Day - 01/20/2021



Member Forecasted Off Peak Demand Day for February 2021

High Plains Power, Inc.

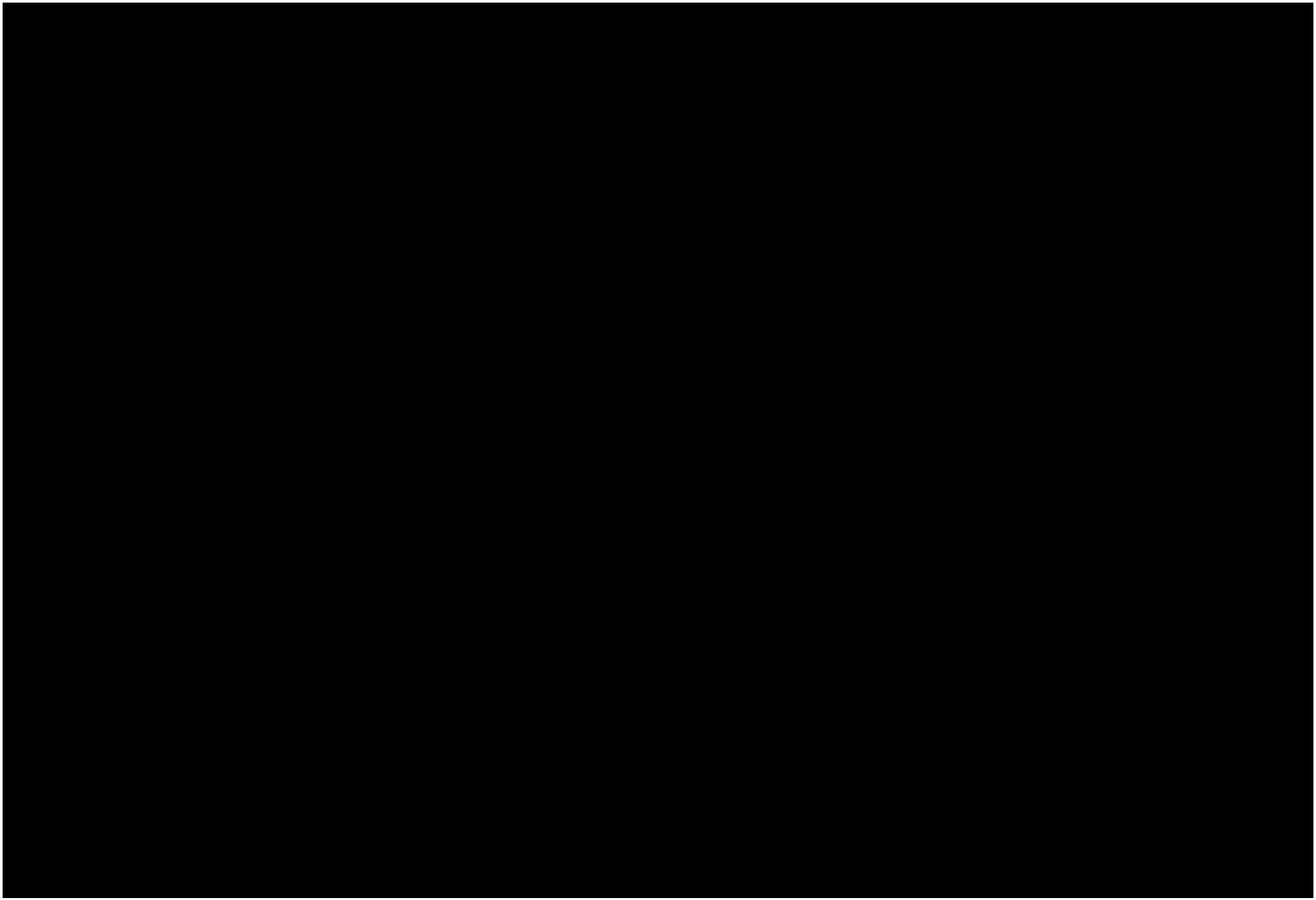
Date of Off Peak Day - 02/11/2021



Member Forecasted Off Peak Demand Day for March 2021

High Plains Power, Inc.

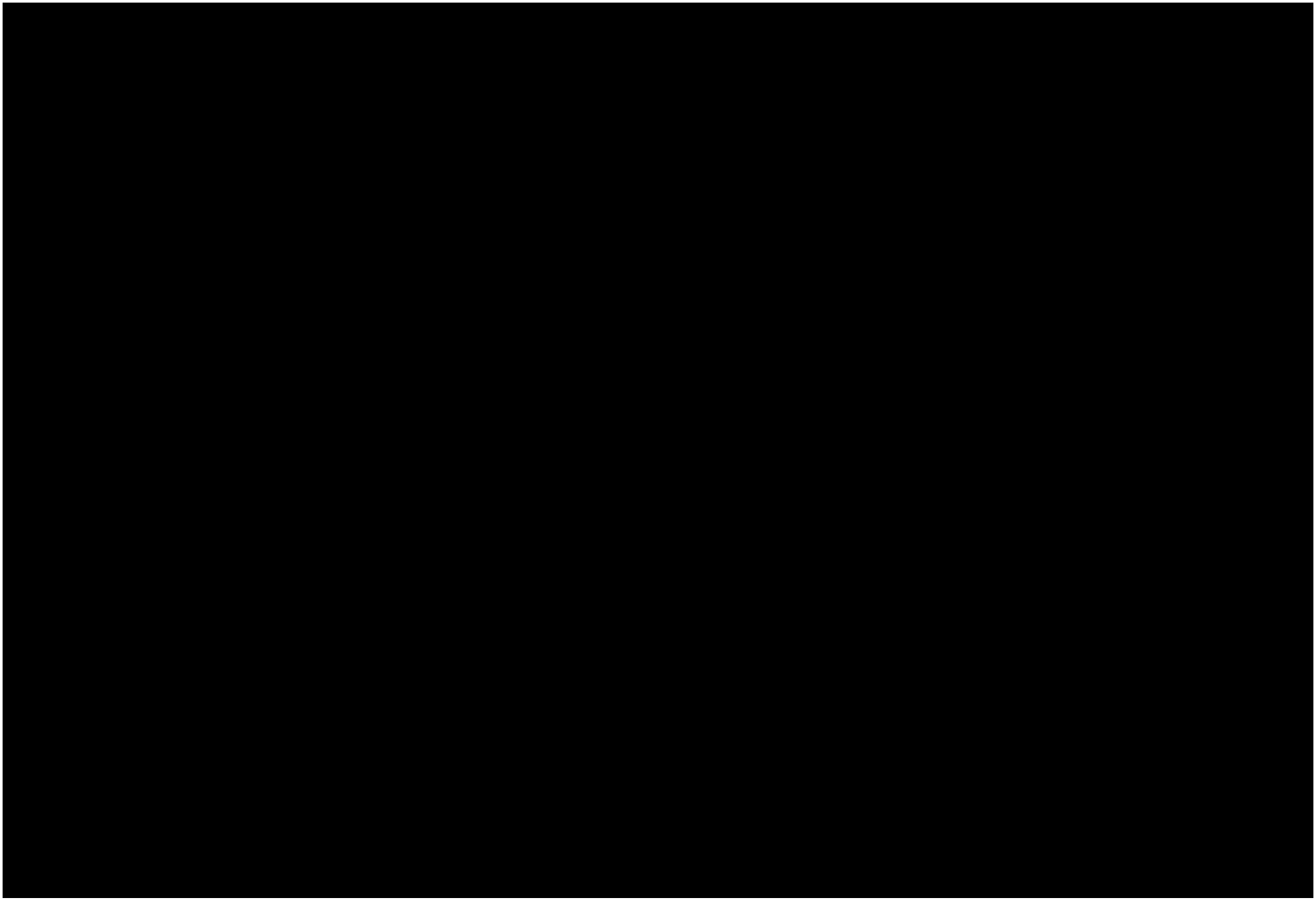
Date of Off Peak Day - 03/31/2021



Member Forecasted Off Peak Demand Day for April 2021

High Plains Power, Inc.

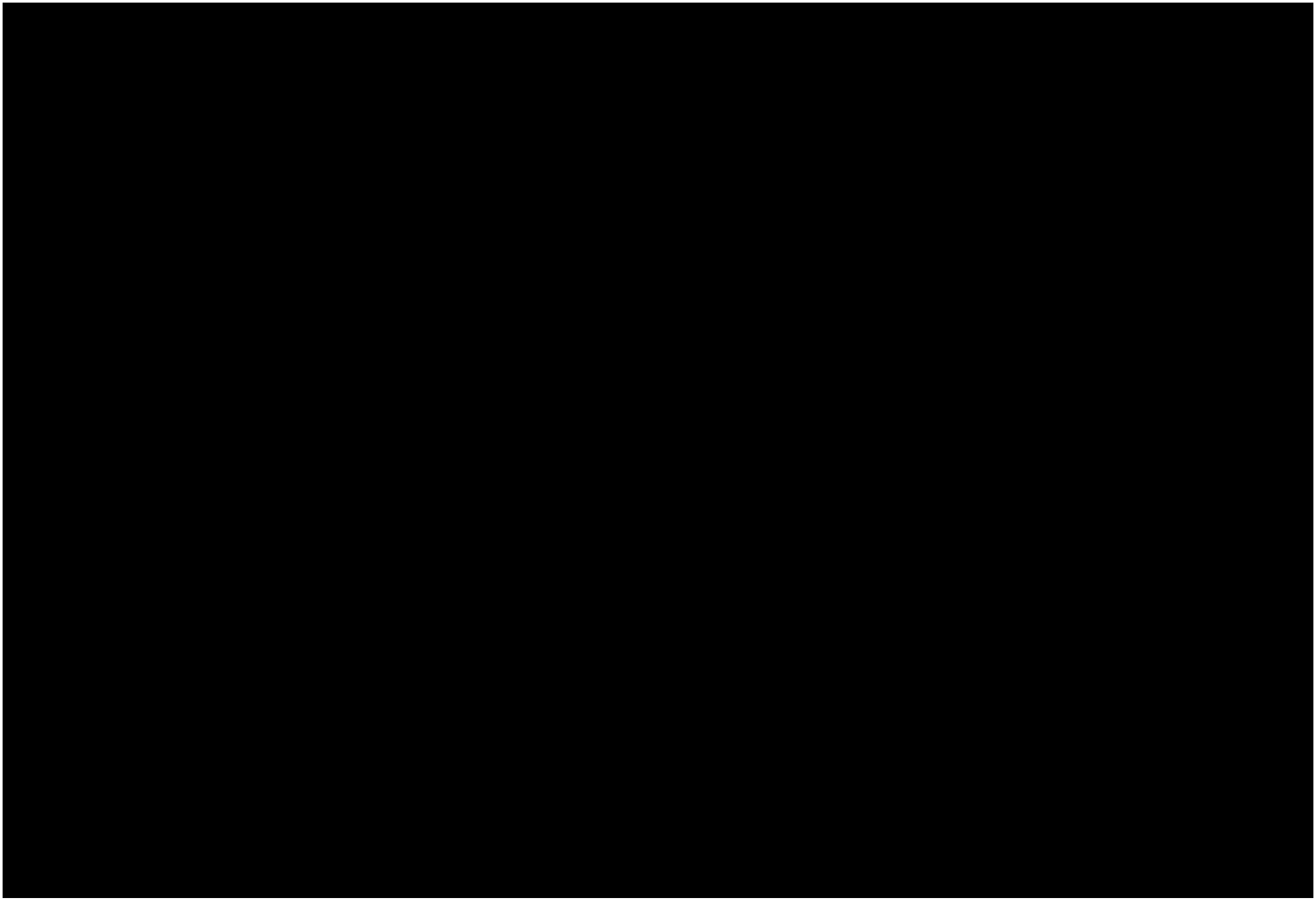
Date of Off Peak Day - 04/30/2021



Member Forecasted Off Peak Demand Day for May 2021

High Plains Power, Inc.

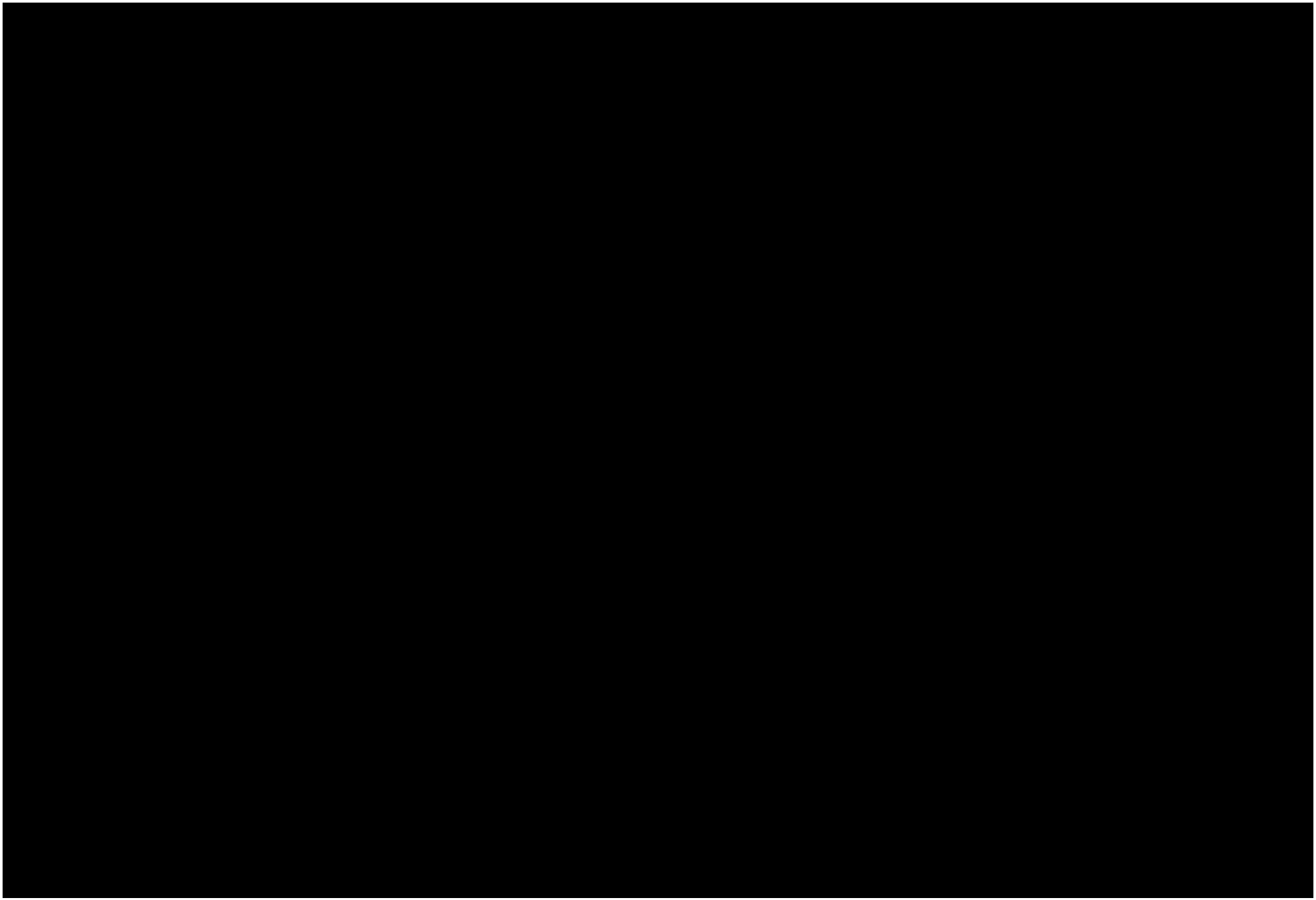
Date of Off Peak Day - 05/12/2021



Member Forecasted Off Peak Demand Day for June 2021

High Plains Power, Inc.

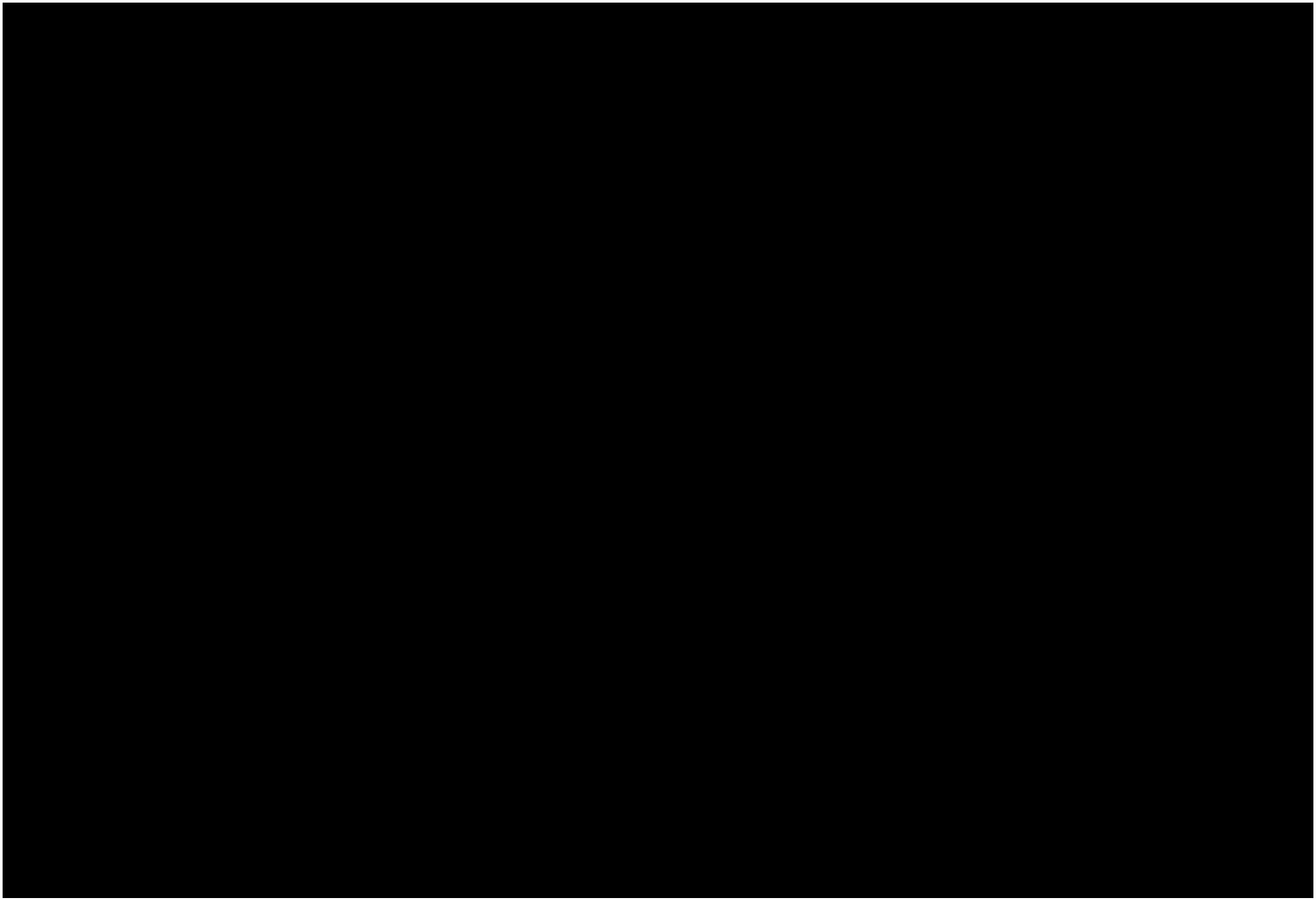
Date of Off Peak Day - 06/02/2021



Member Forecasted Off Peak Demand Day for July 2021

High Plains Power, Inc.

Date of Off Peak Day - 07/31/2021



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Member Forecasted Off Peak Demand Day for August 2021

High Plains Power, Inc.

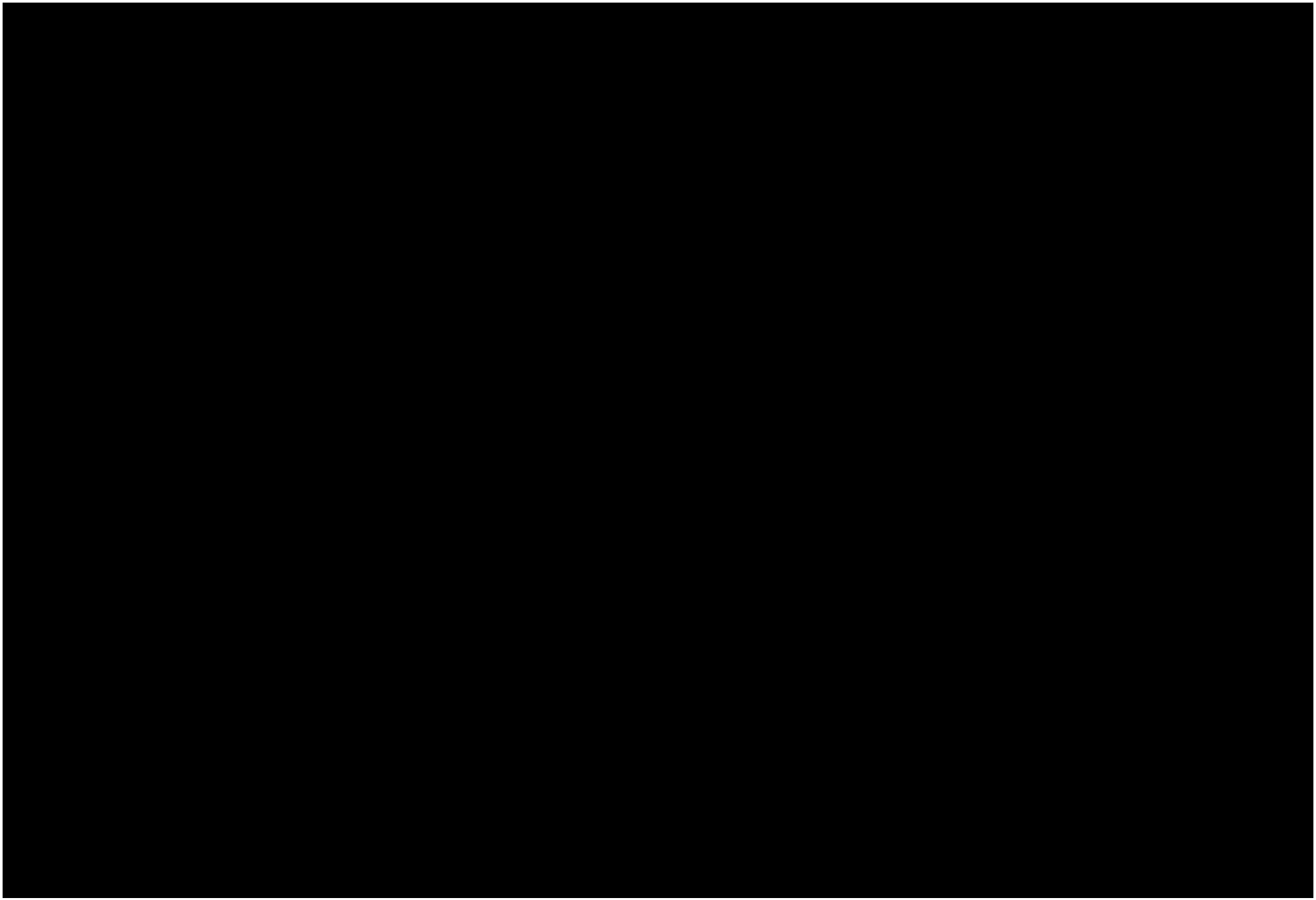
Date of Off Peak Day - 08/14/2021

[redacted]

Member Forecasted Off Peak Demand Day for September 2021

High Plains Power, Inc.

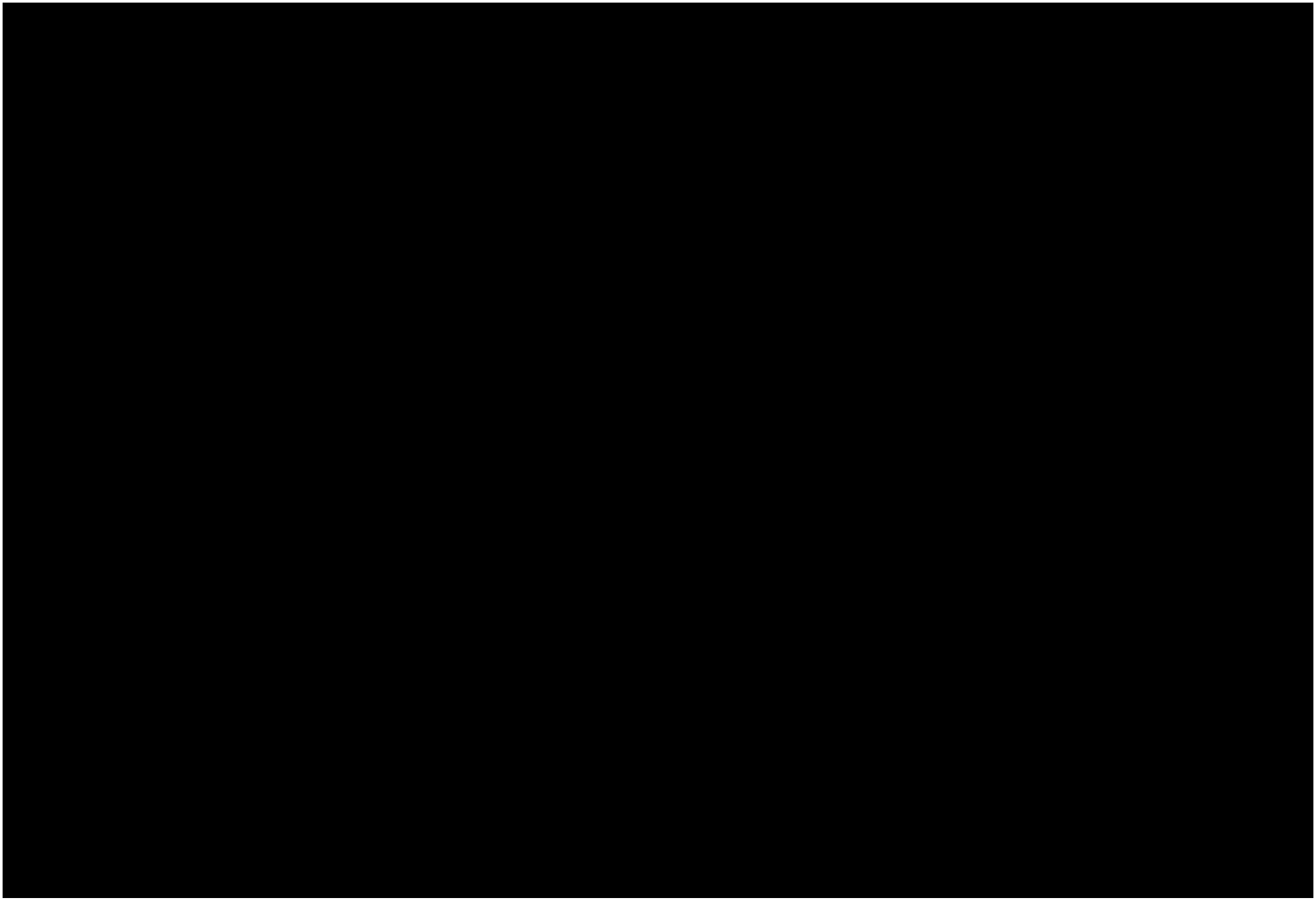
Date of Off Peak Day - 09/29/2021



Member Forecasted Off Peak Demand Day for October 2021

High Plains Power, Inc.

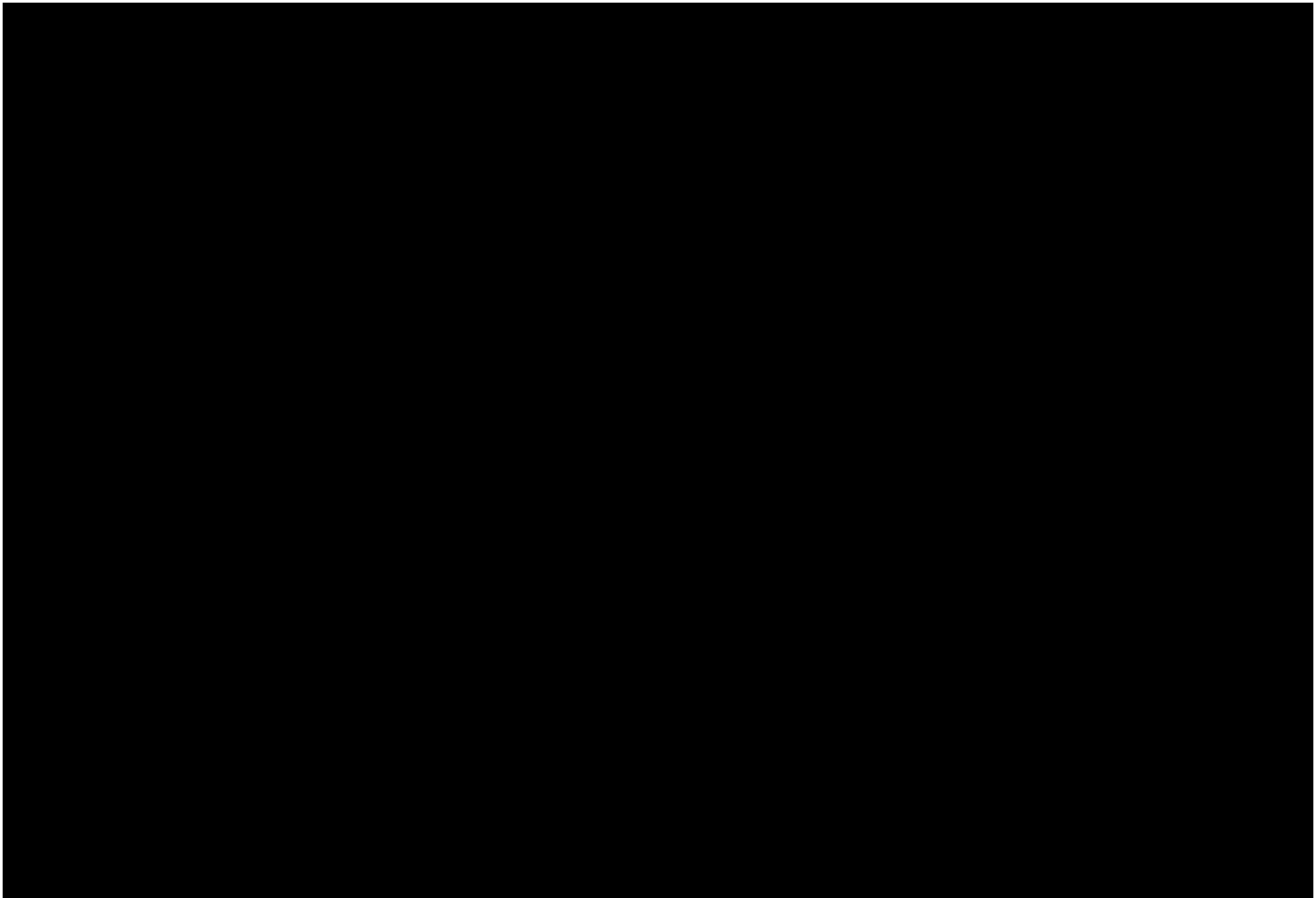
Date of Off Peak Day - 10/02/2021



Member Forecasted Off Peak Demand Day for November 2021

High Plains Power, Inc.

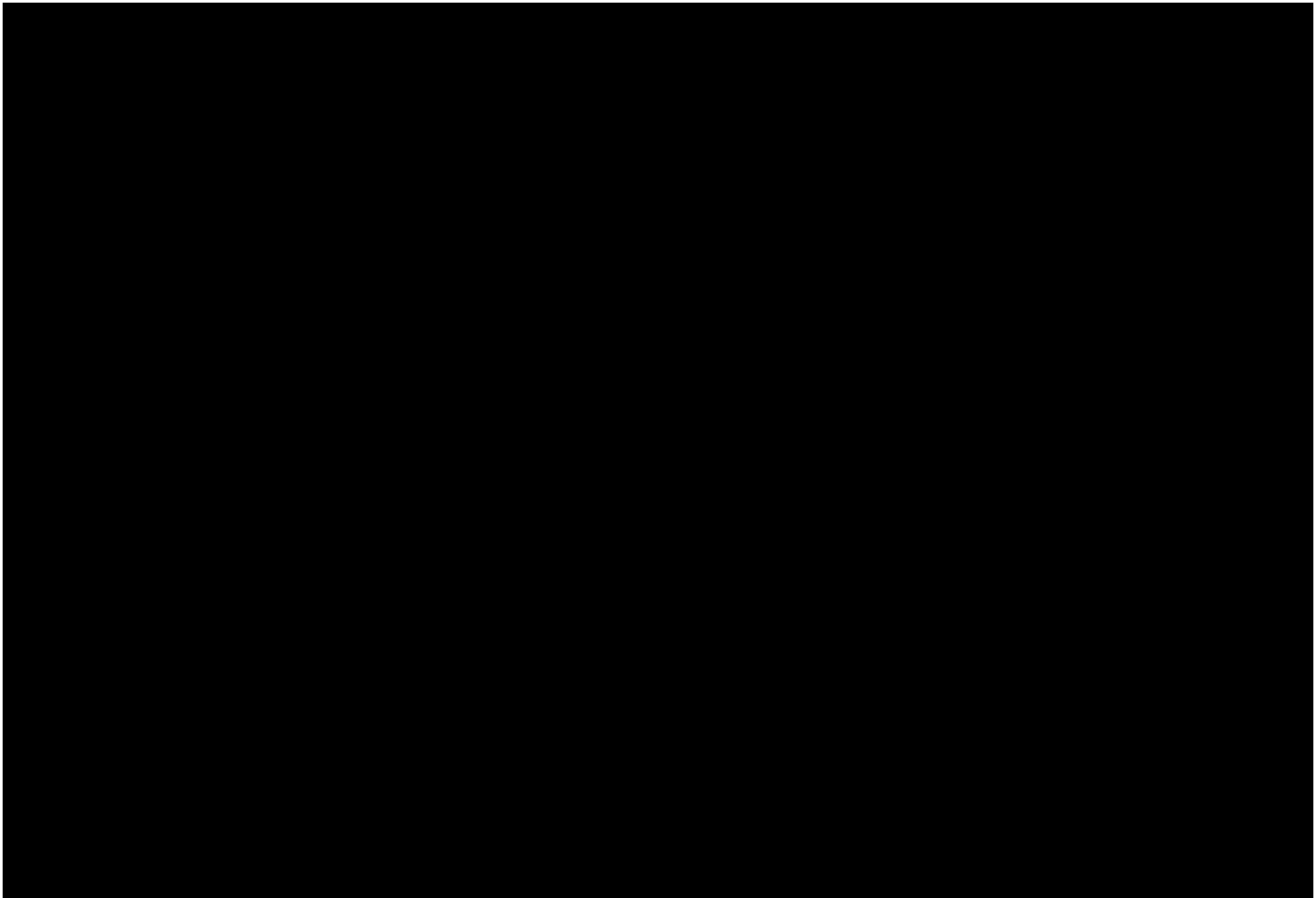
Date of Off Peak Day - 11/03/2021



Member Forecasted Off Peak Demand Day for December 2021

High Plains Power, Inc.

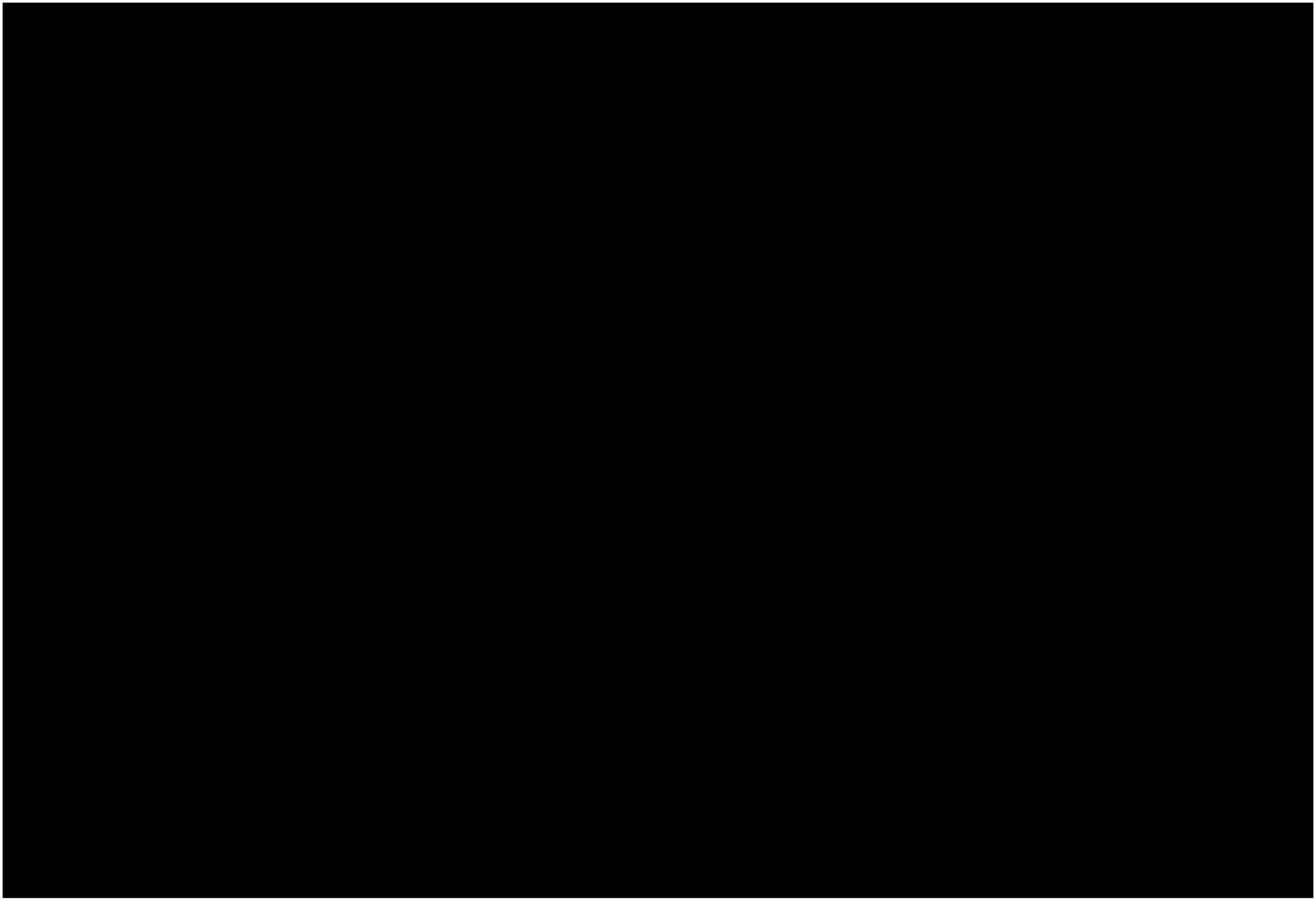
Date of Off Peak Day - 12/09/2021



Member Forecasted Off Peak Demand Day for January 2021

High West Energy, Inc.

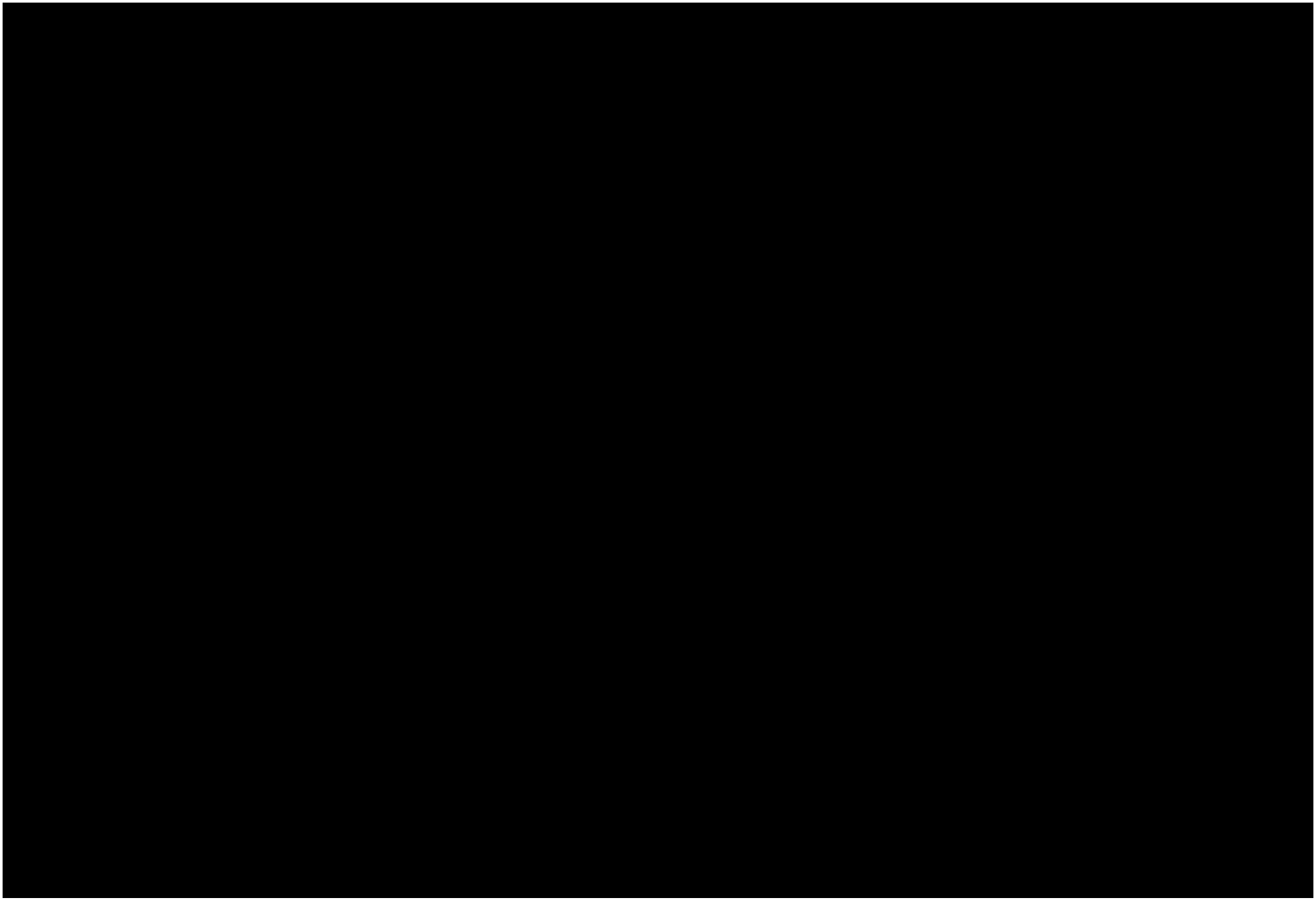
Date of Off Peak Day - 01/18/2021



Member Forecasted Off Peak Demand Day for February 2021

High West Energy, Inc.

Date of Off Peak Day - 02/10/2021



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Member Forecasted Off Peak Demand Day for March 2021

High West Energy, Inc.

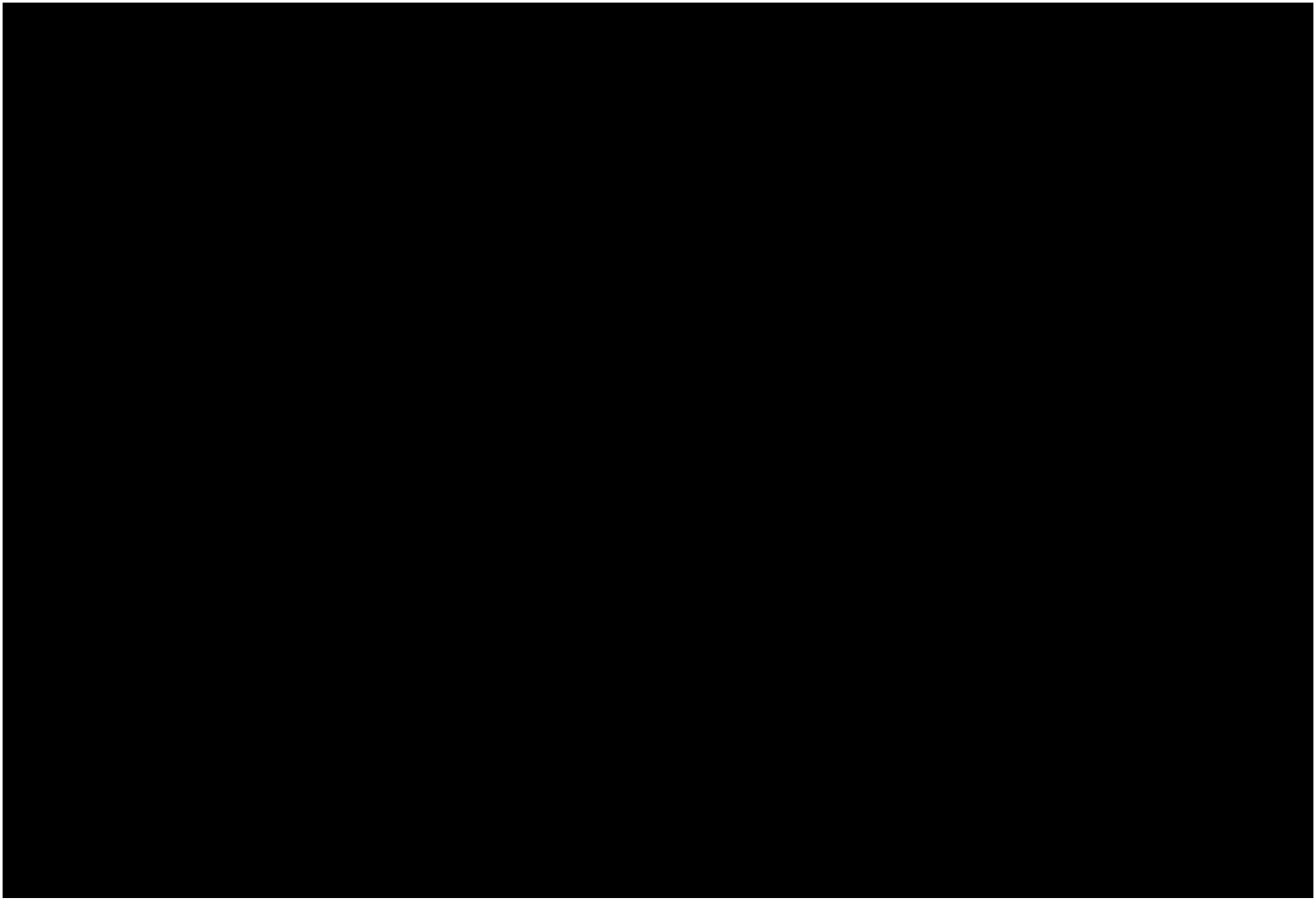
Date of Off Peak Day - 03/28/2021

[redacted]

Member Forecasted Off Peak Demand Day for April 2021

High West Energy, Inc.

Date of Off Peak Day - 04/29/2021



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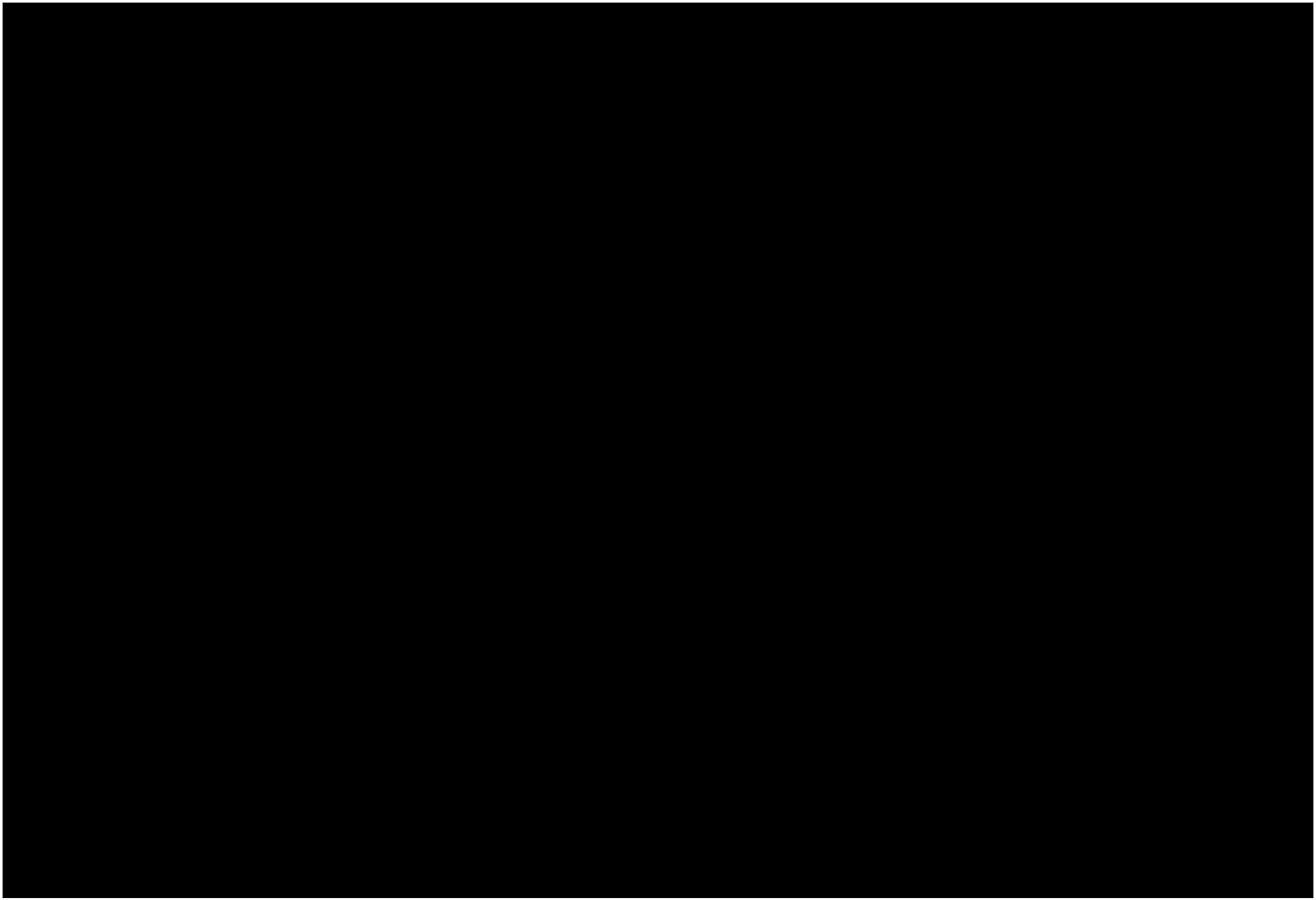
Member Forecasted Off Peak Demand Day for May 2021

High West Energy, Inc.

Date of Off Peak Day - 05/12/2021



Member Forecasted Off Peak Demand Day for June 2021

High West Energy, Inc.

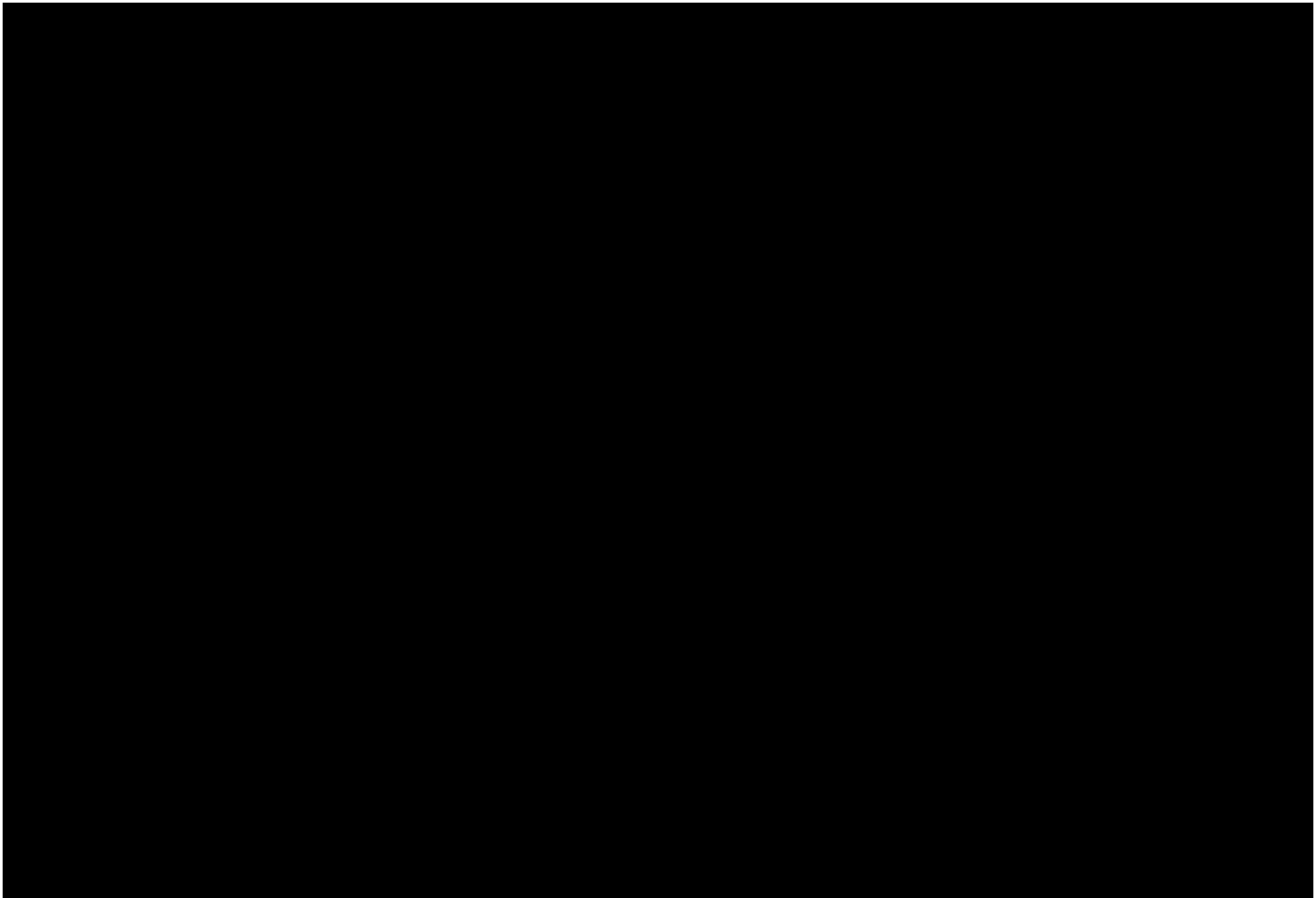
Date of Off Peak Day - 06/21/2021

[redacted]

Member Forecasted Off Peak Demand Day for July 2021

High West Energy, Inc.

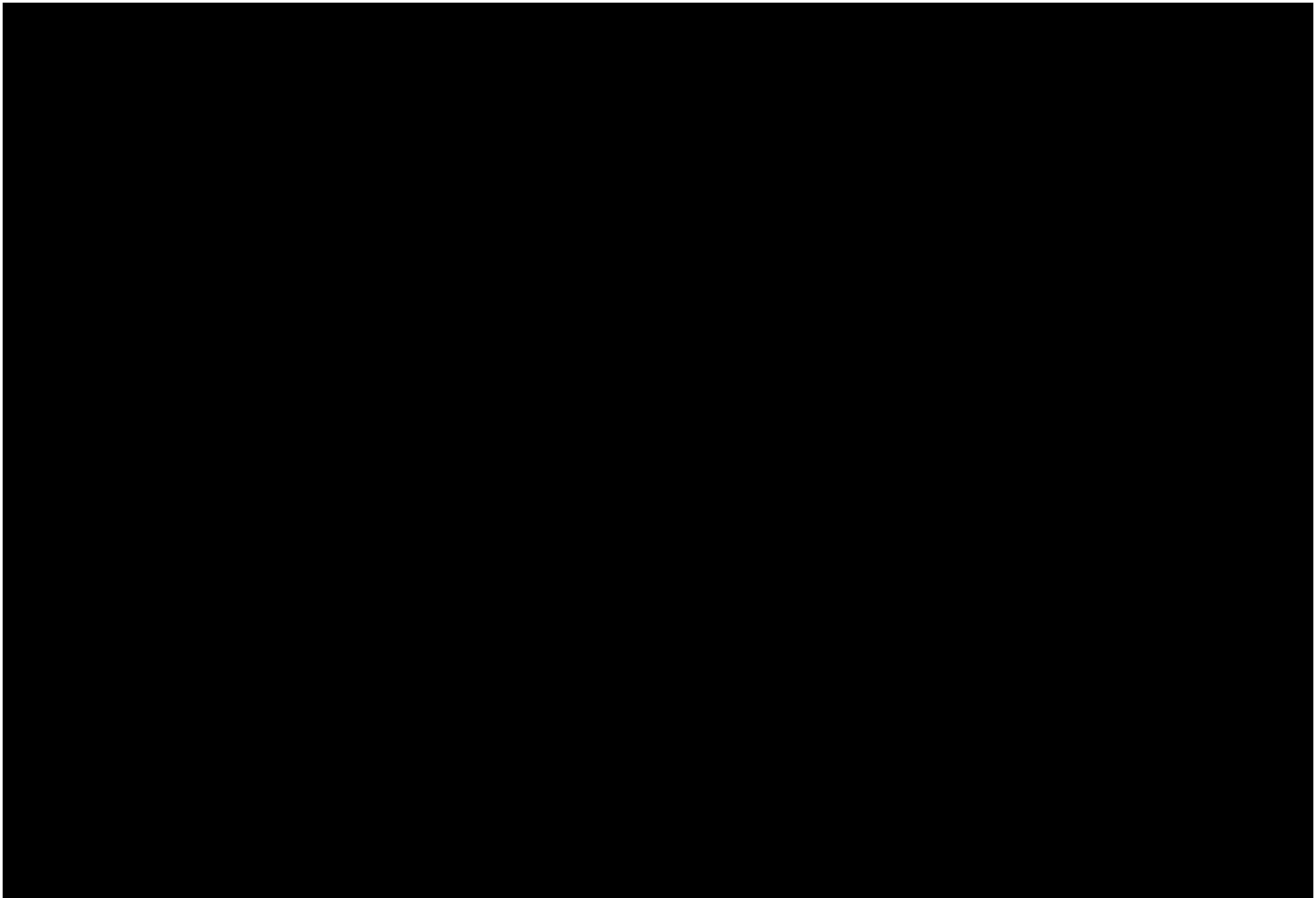
Date of Off Peak Day - 07/01/2021



Member Forecasted Off Peak Demand Day for August 2021

High West Energy, Inc.

Date of Off Peak Day - 08/16/2021



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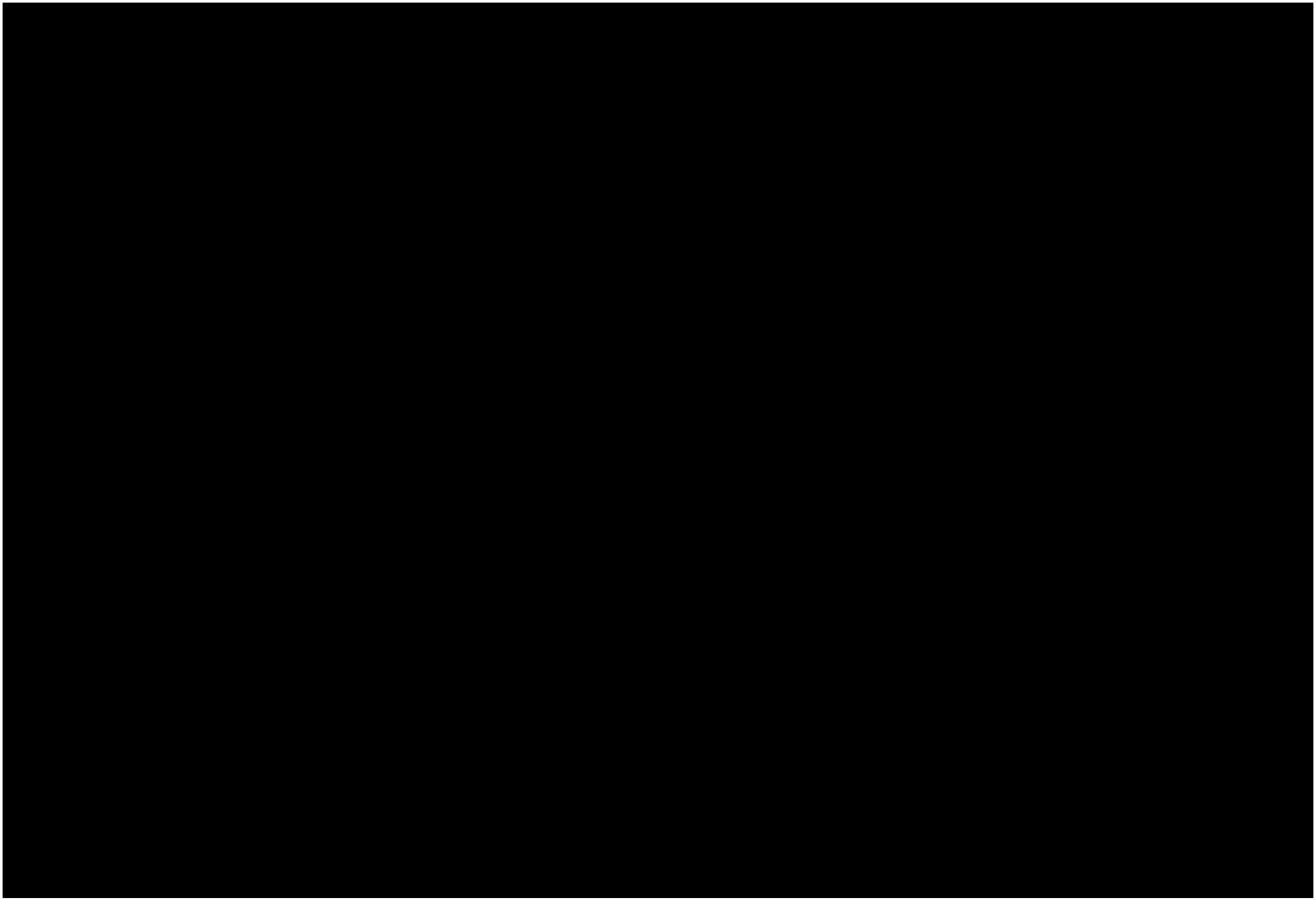
Member Forecasted Off Peak Demand Day for September 2021

High West Energy, Inc.

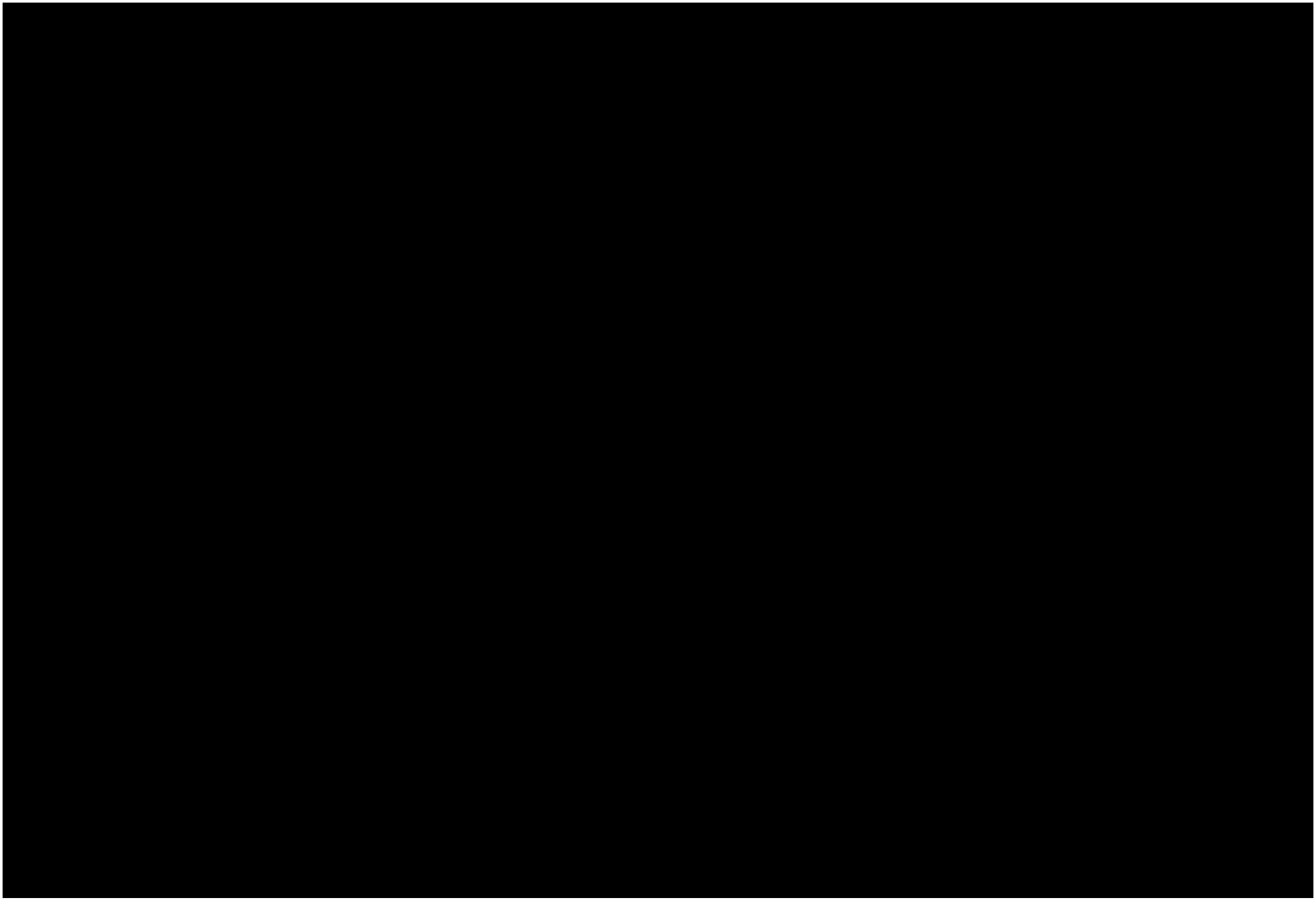
Date of Off Peak Day - 09/19/2021



Member Forecasted Off Peak Demand Day for October 2021

High West Energy, Inc.

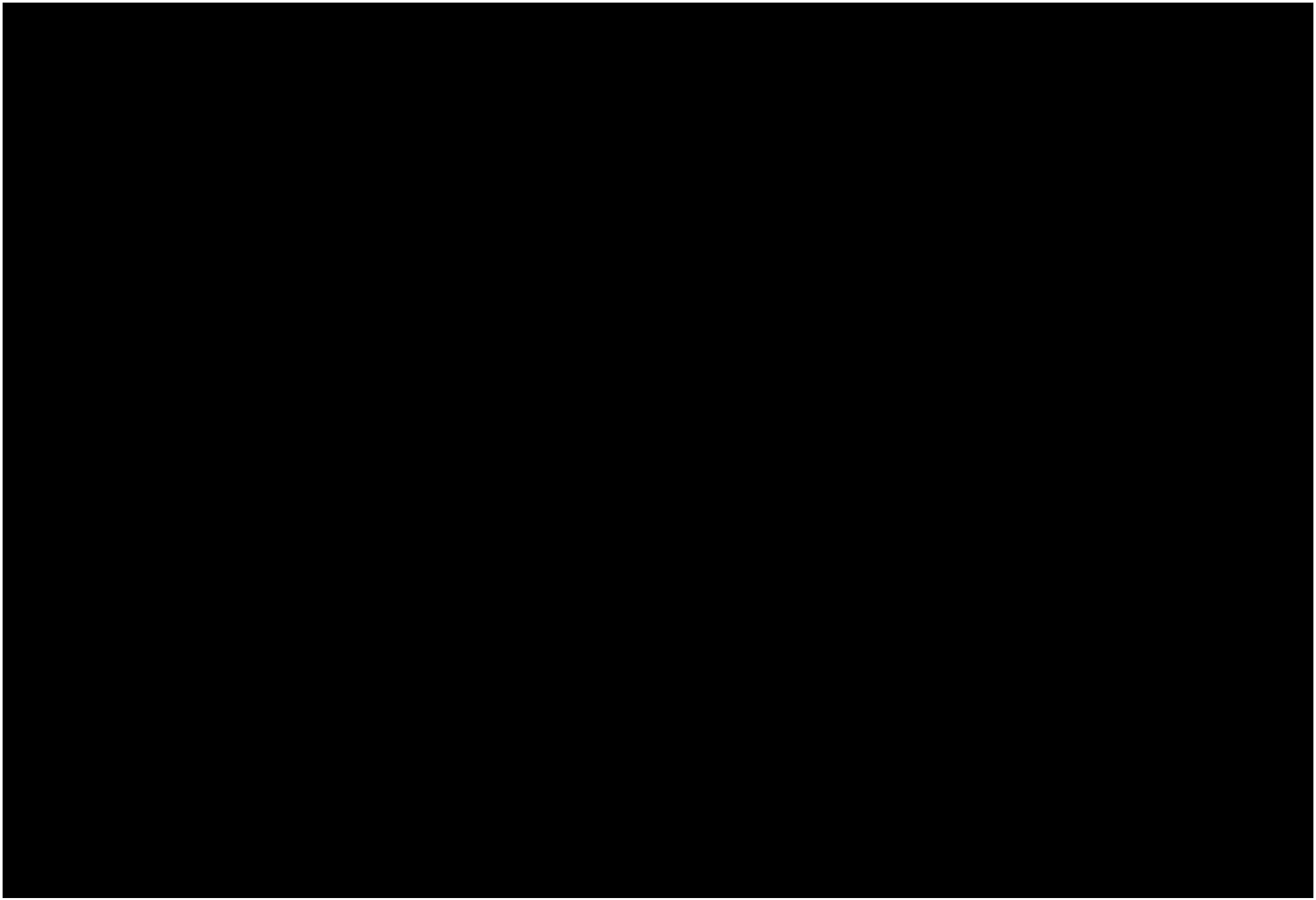
Date of Off Peak Day - 10/17/2021



Member Forecasted Off Peak Demand Day for November 2021

High West Energy, Inc.

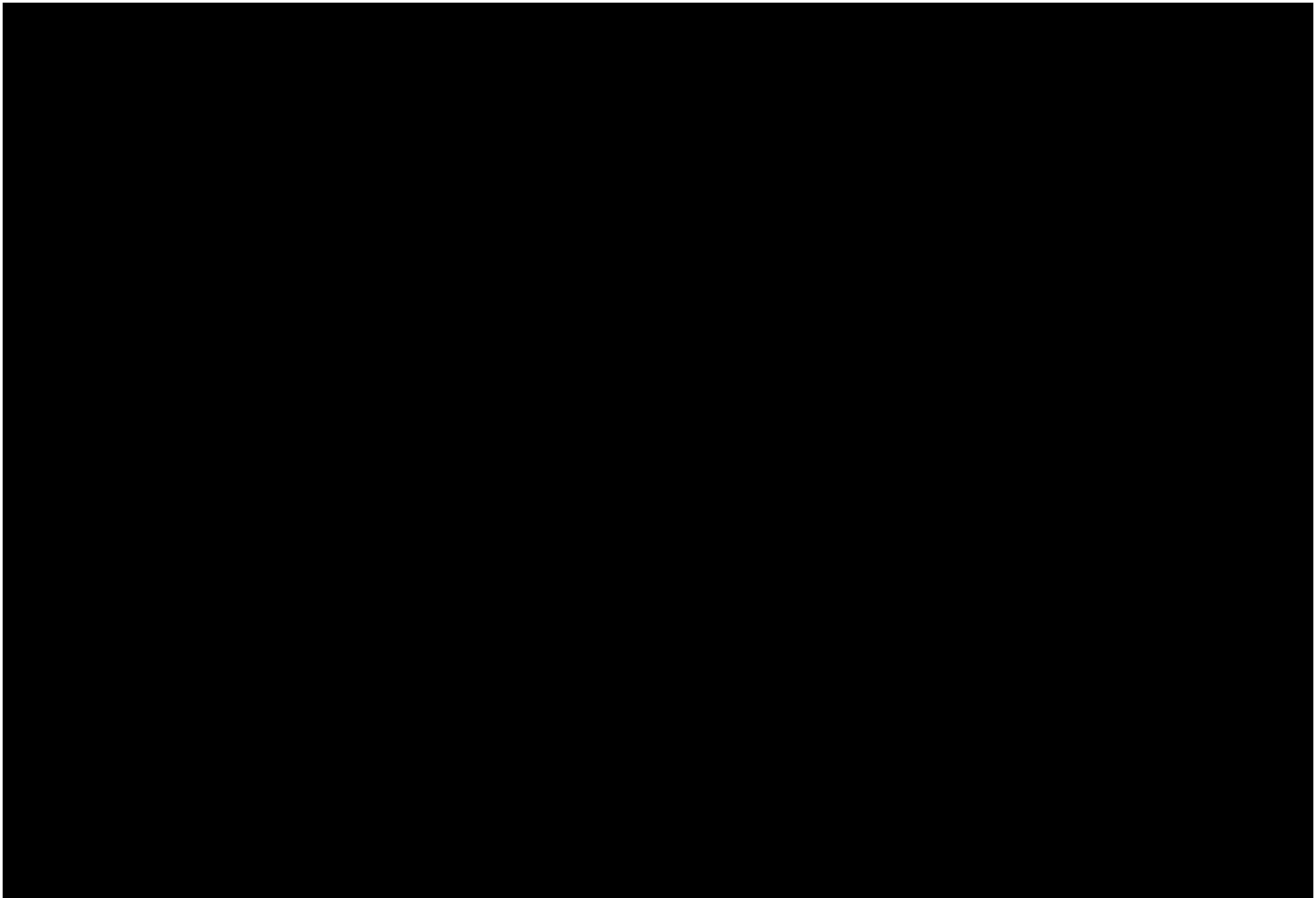
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

High West Energy, Inc.

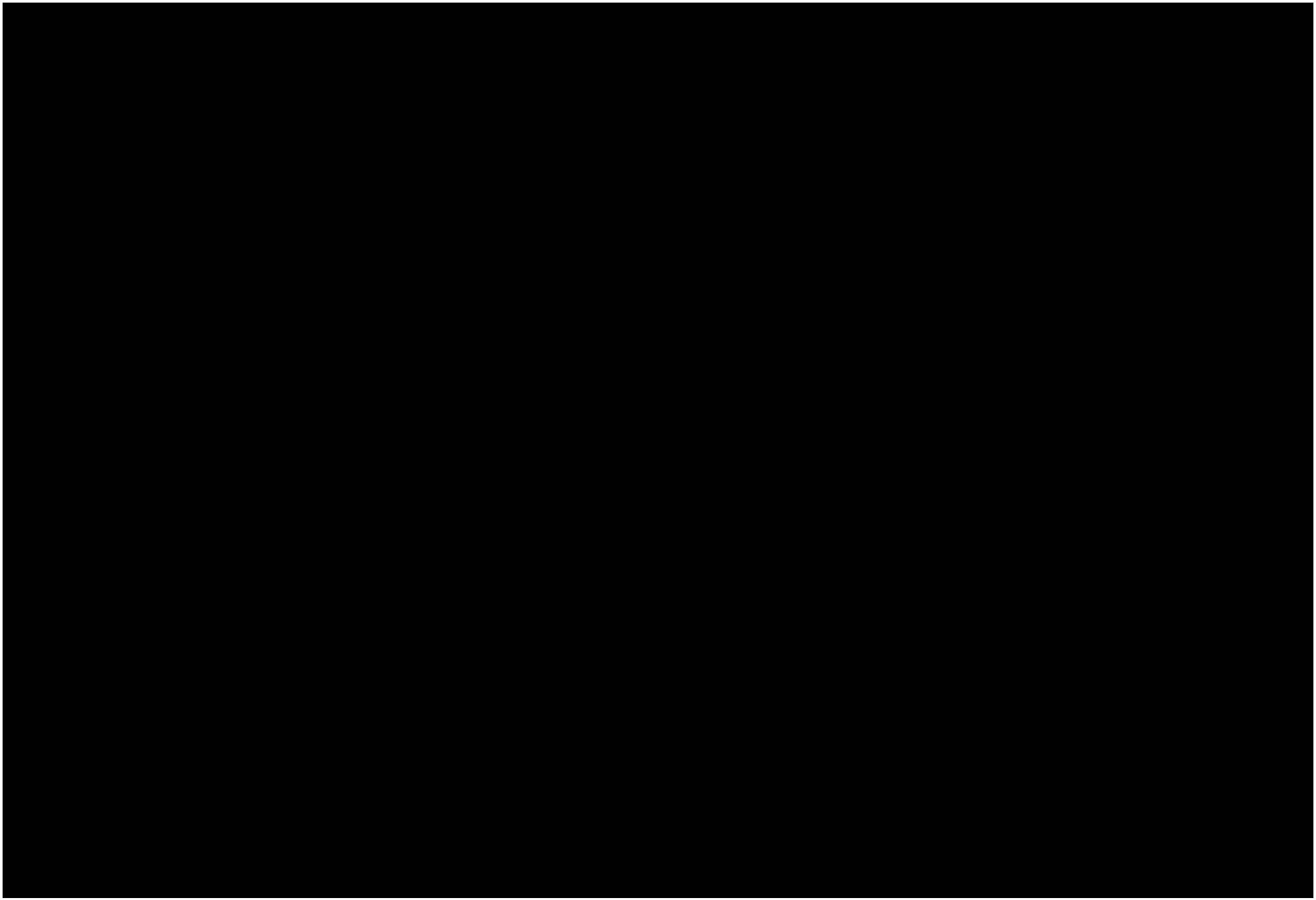
Date of Off Peak Day - 12/10/2021



Member Forecasted Off Peak Demand Day for January 2021

Jemez Mountains Electric Cooperative, Inc.

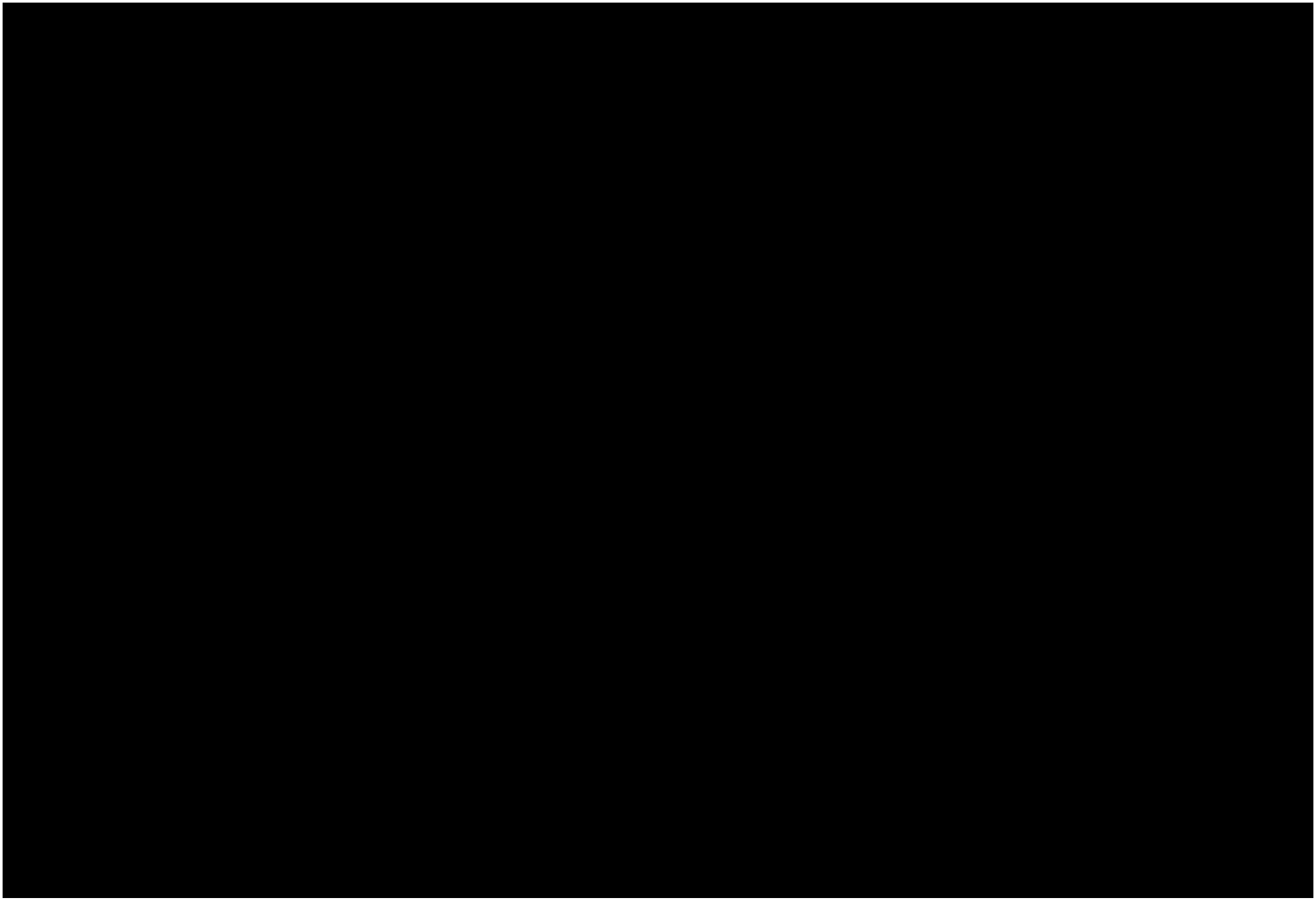
Date of Off Peak Day - 01/13/2021



Member Forecasted Off Peak Demand Day for February 2021

Jemez Mountains Electric Cooperative, Inc.

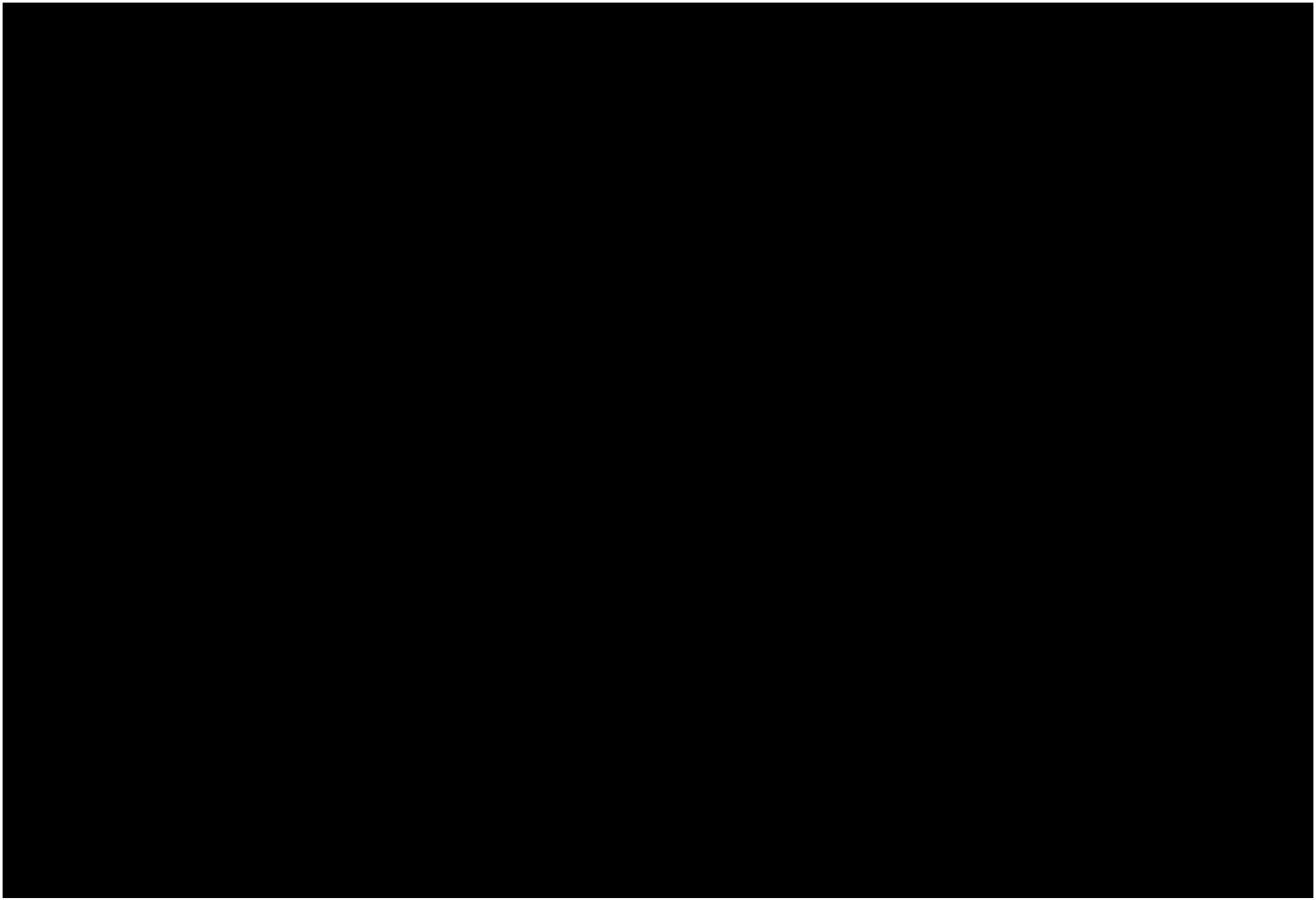
Date of Off Peak Day - 02/11/2021



Member Forecasted Off Peak Demand Day for March 2021

Jemez Mountains Electric Cooperative, Inc.

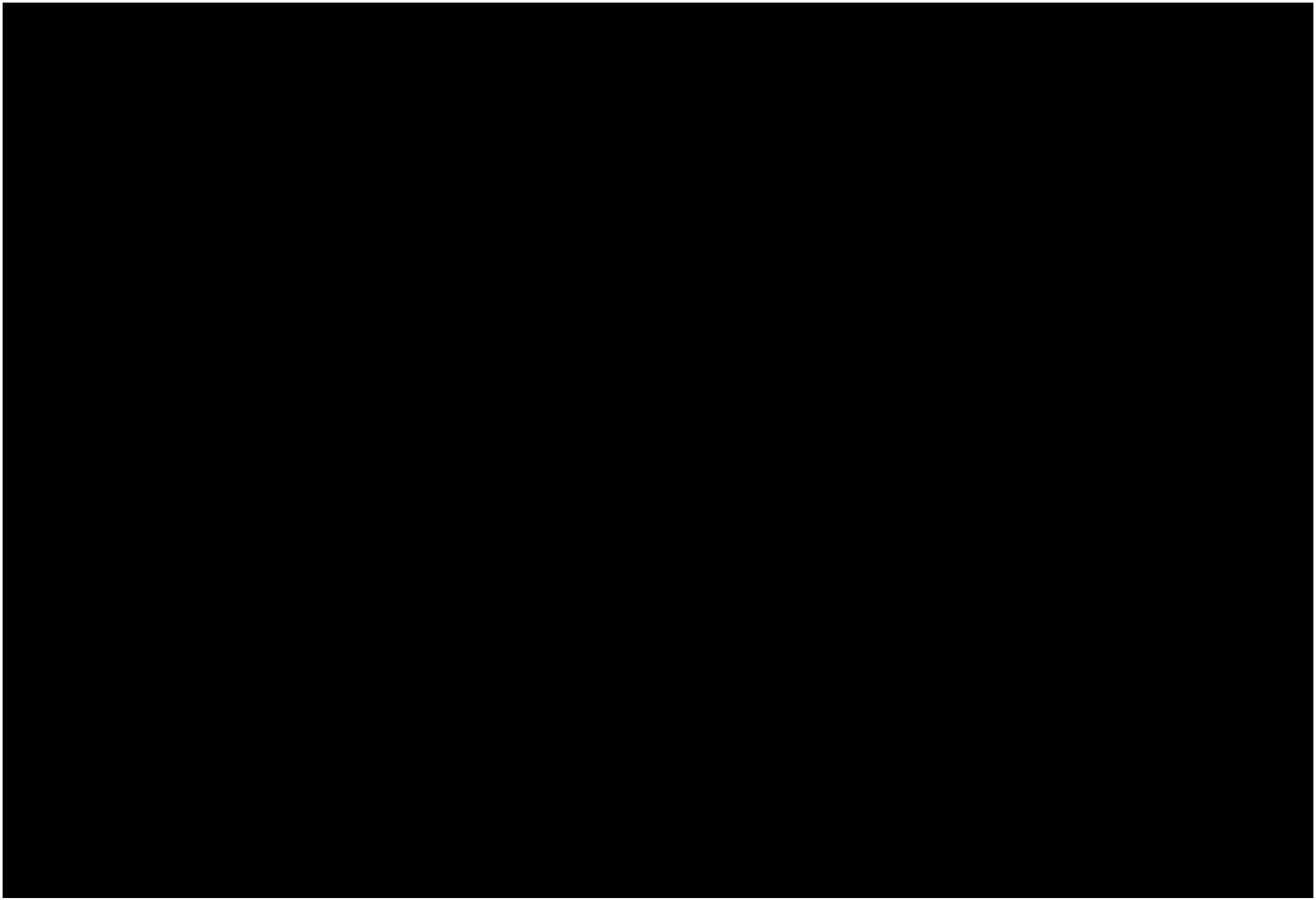
Date of Off Peak Day - 03/21/2021



Member Forecasted Off Peak Demand Day for April 2021

Jemez Mountains Electric Cooperative, Inc.

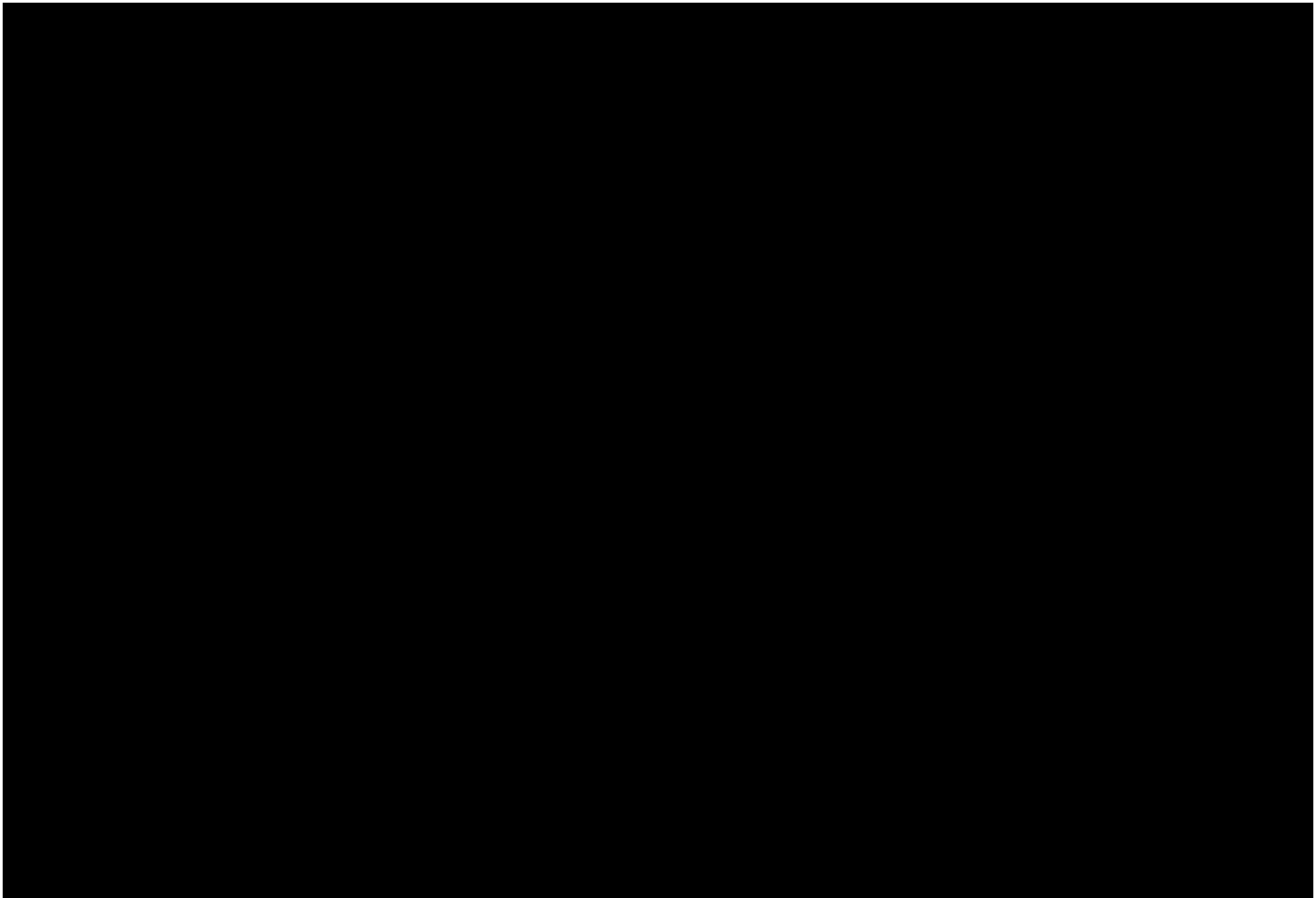
Date of Off Peak Day - 04/07/2021



Member Forecasted Off Peak Demand Day for May 2021

Jemez Mountains Electric Cooperative, Inc.

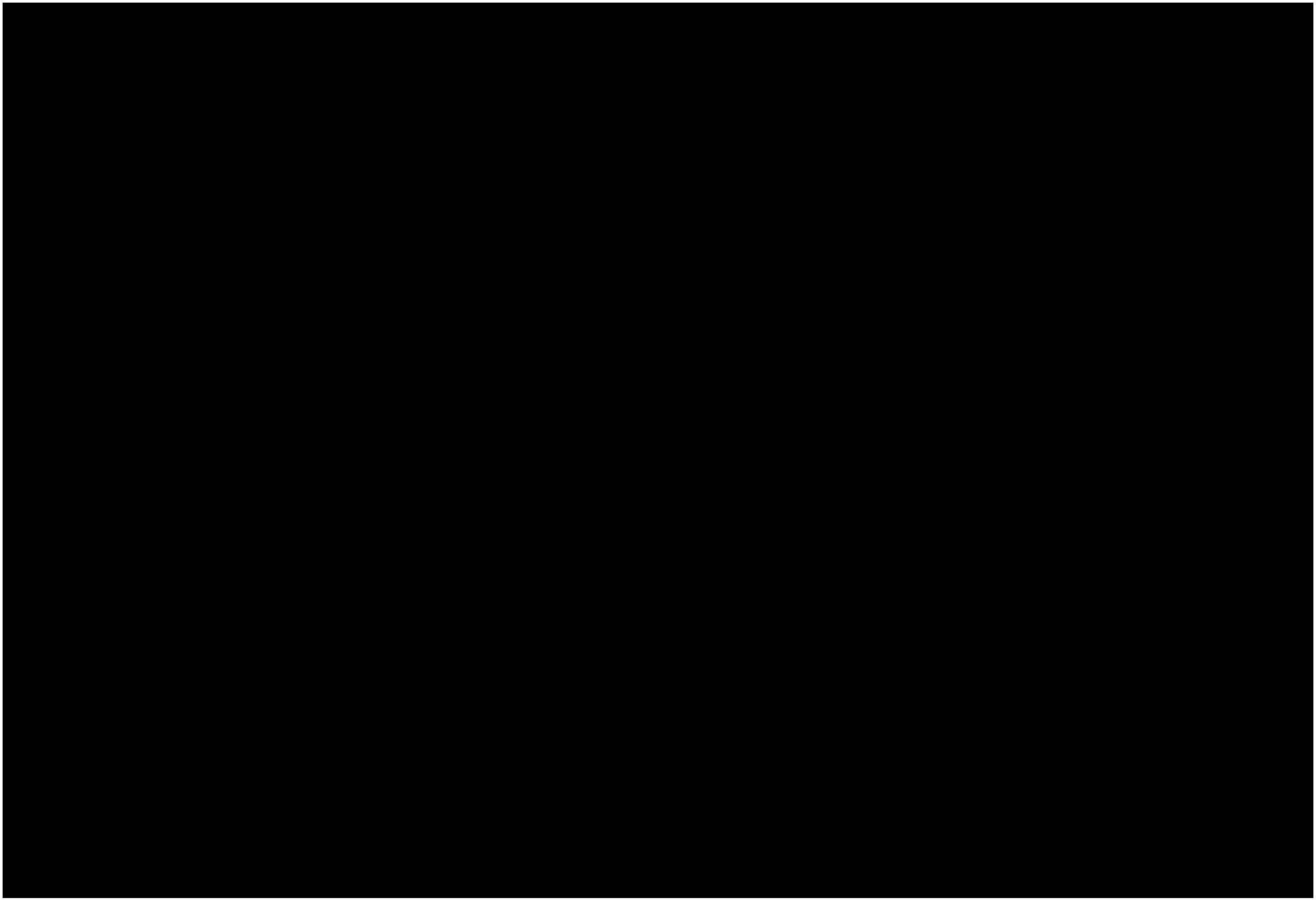
Date of Off Peak Day - 05/03/2021



Member Forecasted Off Peak Demand Day for June 2021

Jemez Mountains Electric Cooperative, Inc.

Date of Off Peak Day - 06/01/2021



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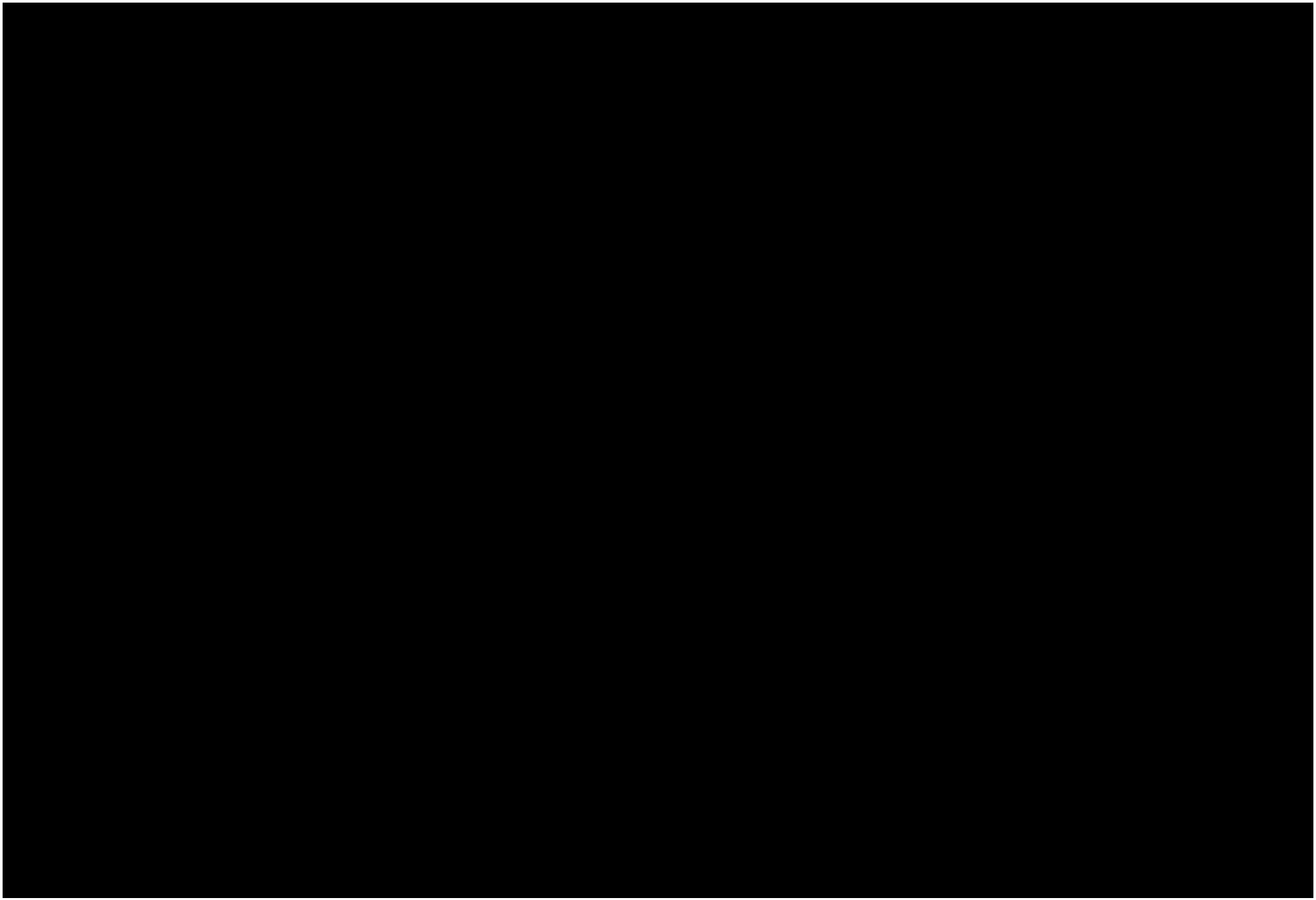
Member Forecasted Off Peak Demand Day for July 2021

Jemez Mountains Electric Cooperative, Inc.

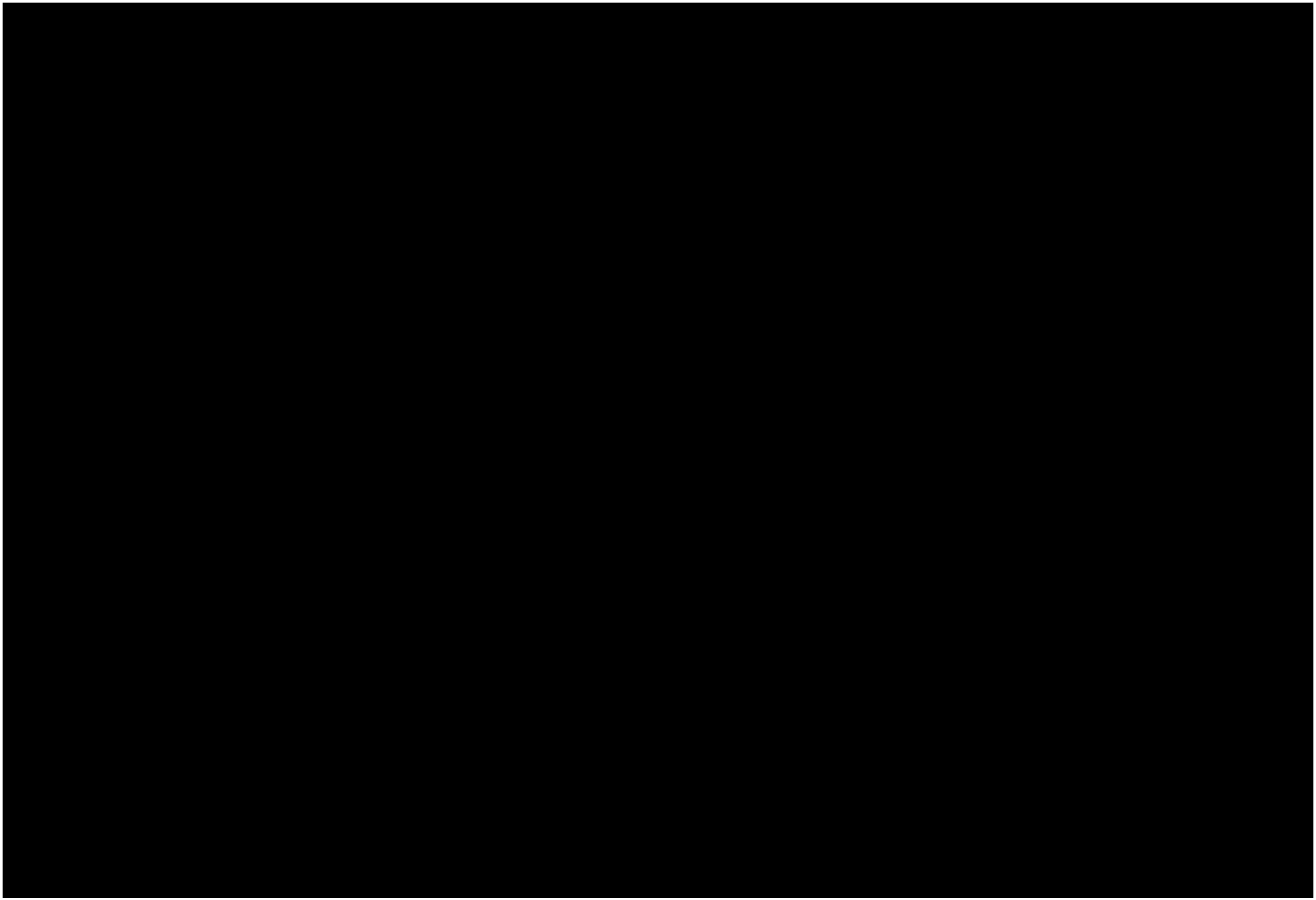
Date of Off Peak Day - 07/04/2021



Member Forecasted Off Peak Demand Day for August 2021

Jemez Mountains Electric Cooperative, Inc.

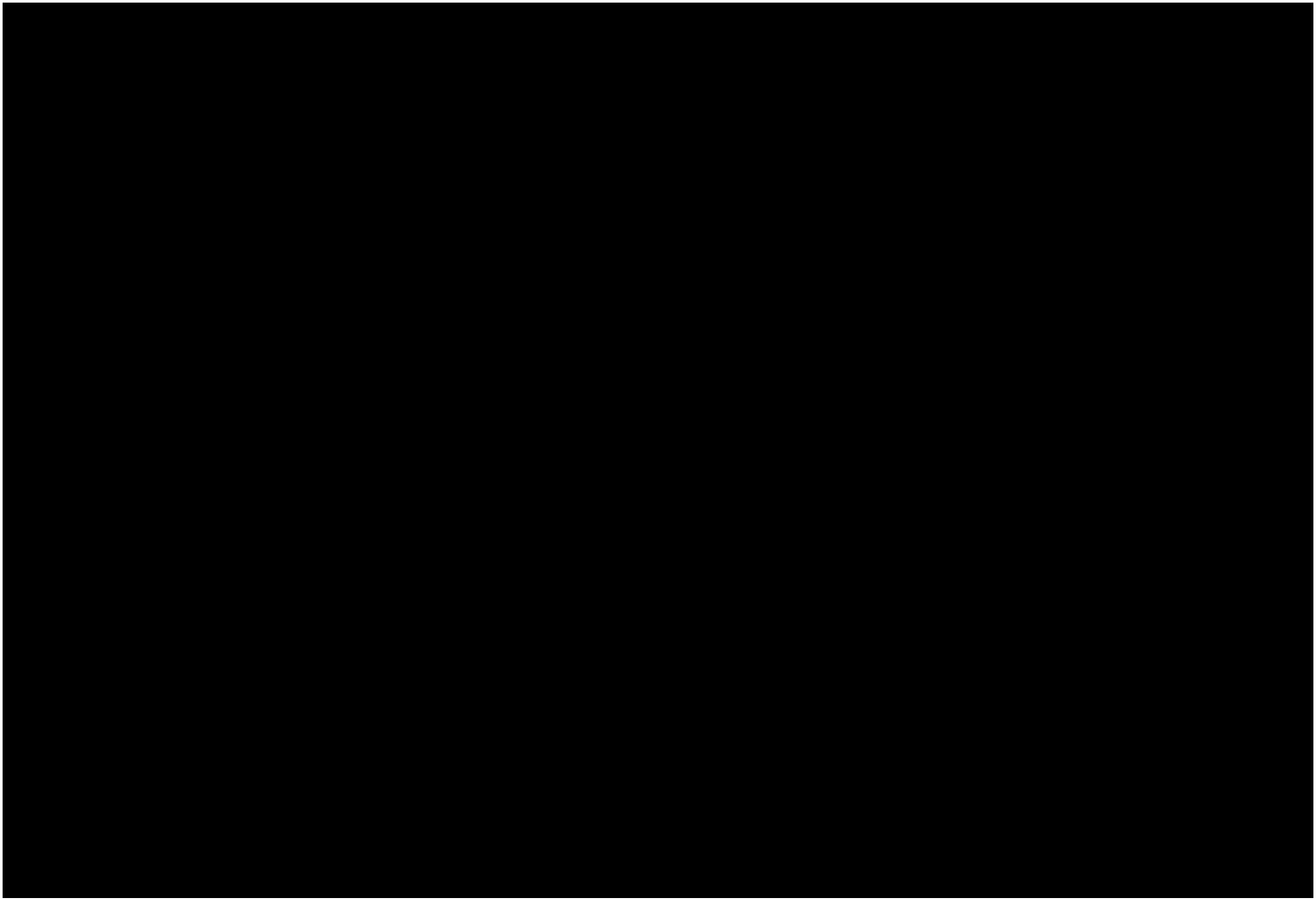
Date of Off Peak Day - 08/14/2021



Member Forecasted Off Peak Demand Day for September 2021

Jemez Mountains Electric Cooperative, Inc.

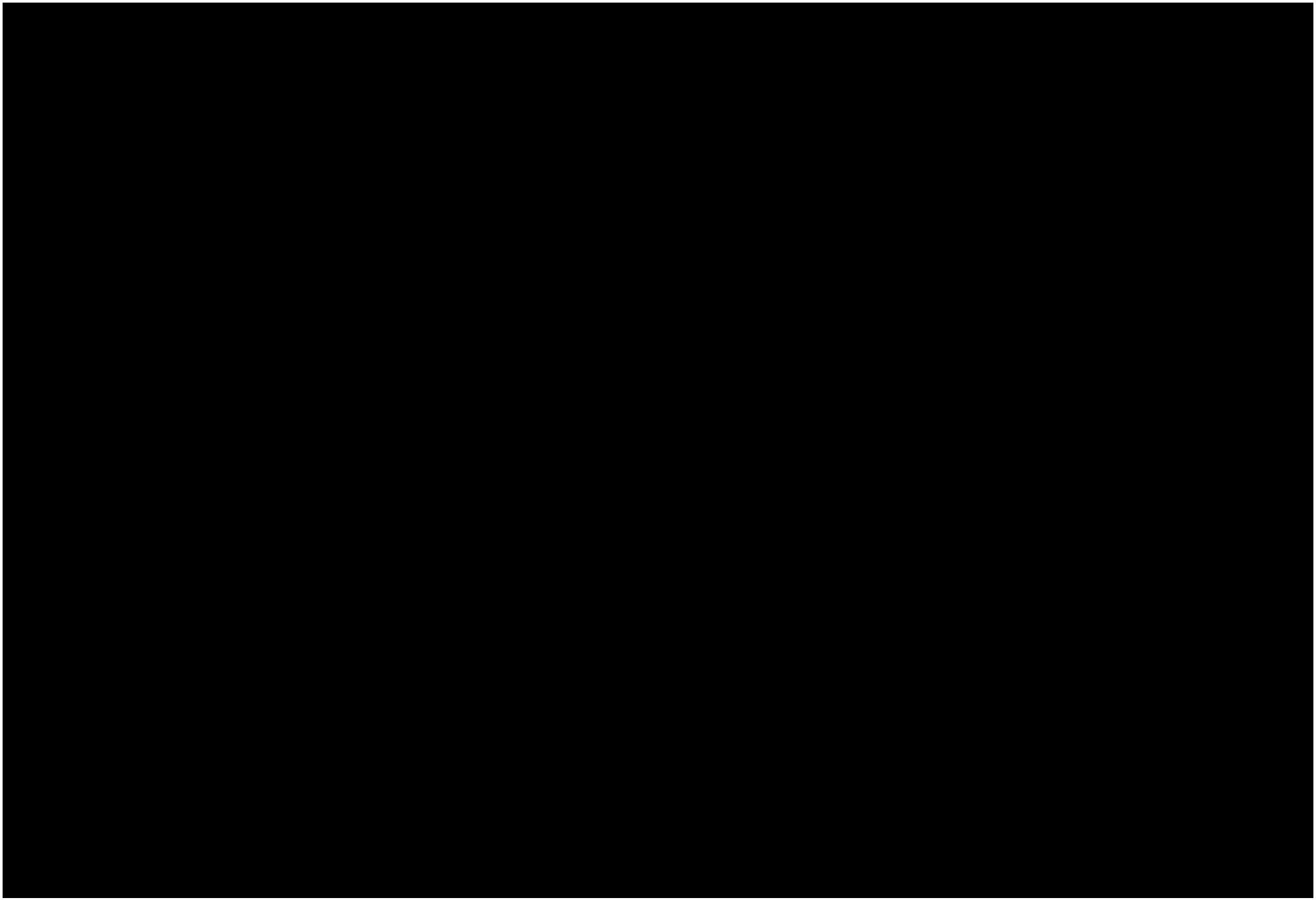
Date of Off Peak Day - 09/28/2021



Member Forecasted Off Peak Demand Day for October 2021

Jemez Mountains Electric Cooperative, Inc.

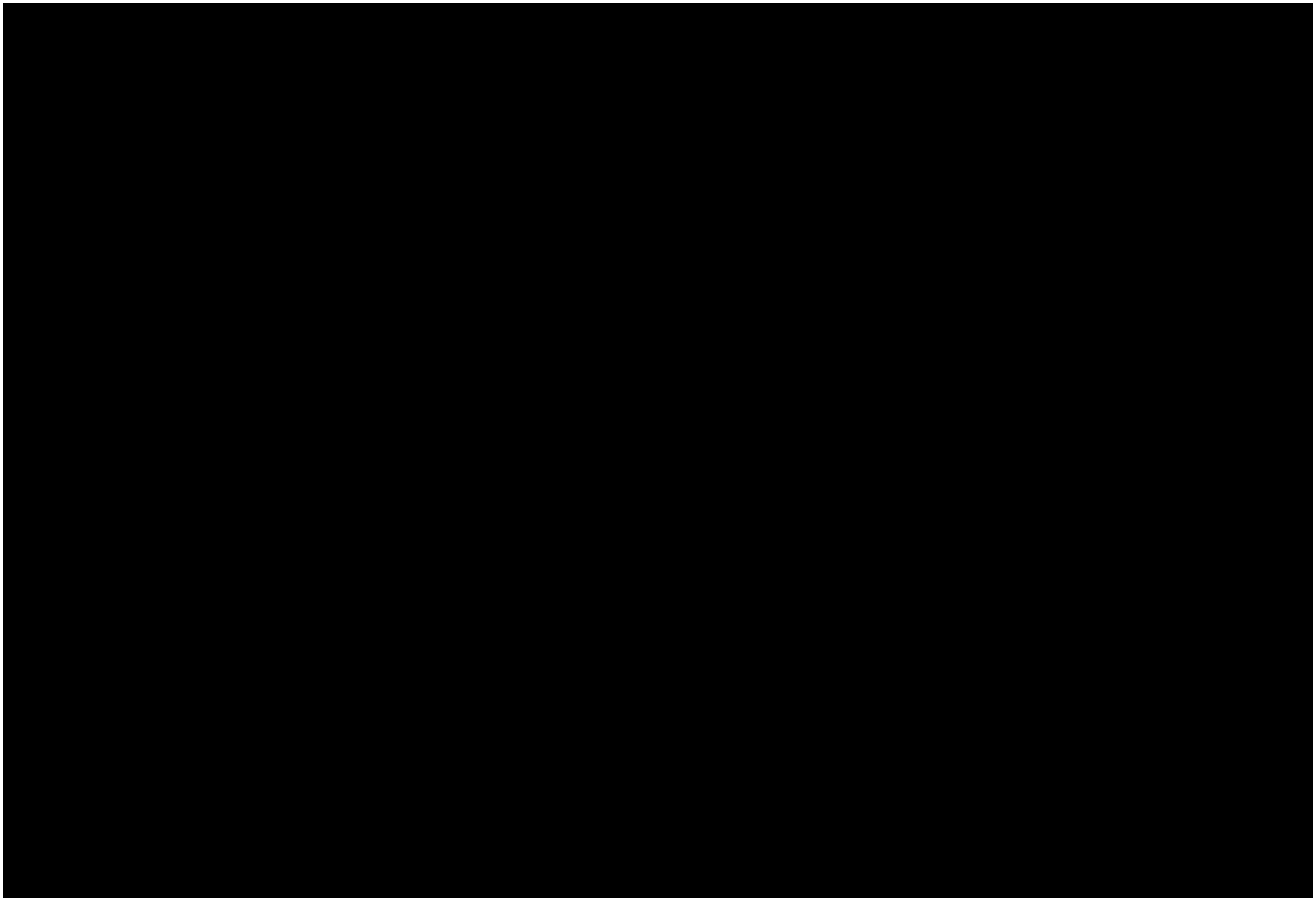
Date of Off Peak Day - 10/04/2021



Member Forecasted Off Peak Demand Day for November 2021

Jemez Mountains Electric Cooperative, Inc.

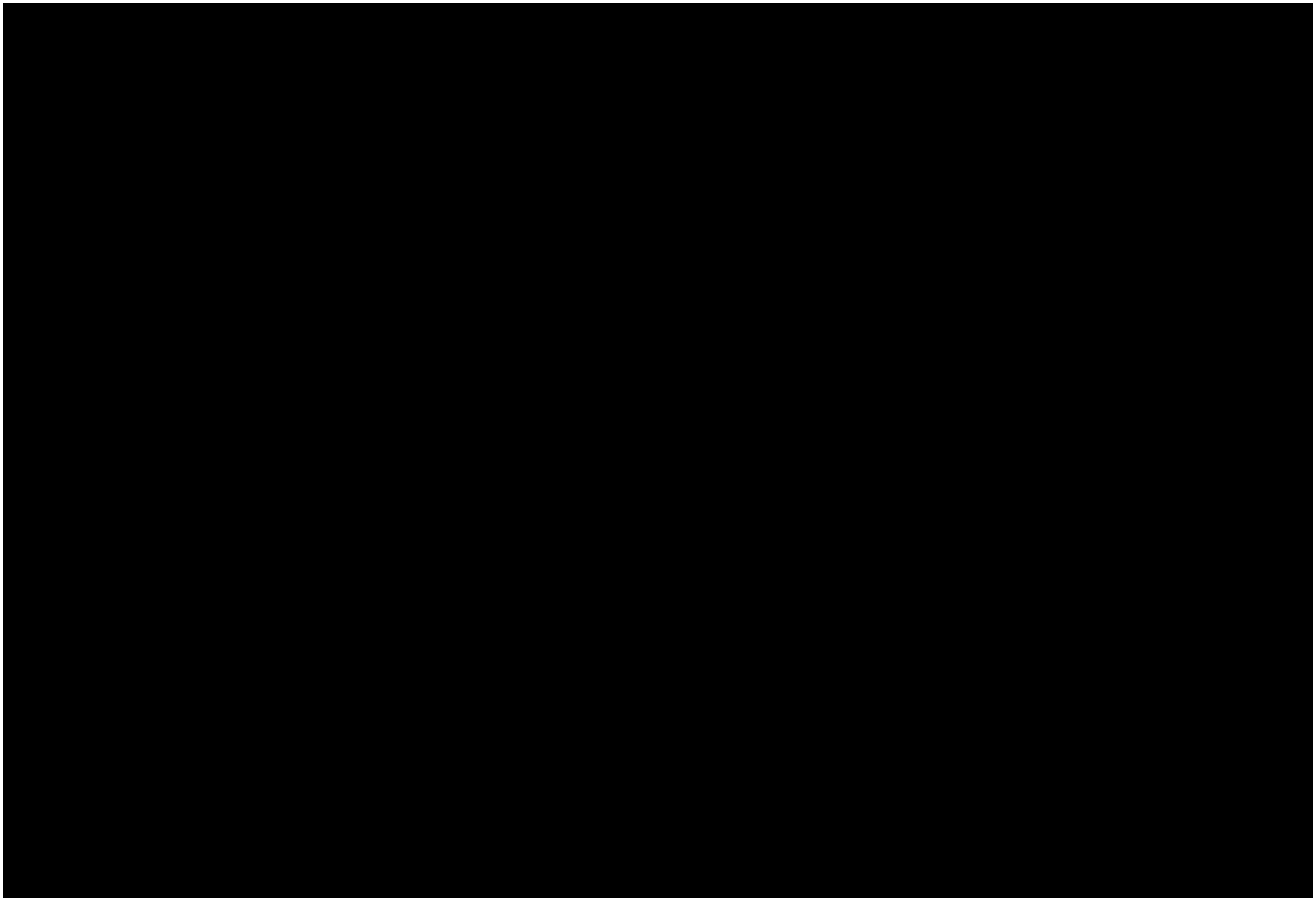
Date of Off Peak Day - 11/01/2021



Member Forecasted Off Peak Demand Day for December 2021

Jemez Mountains Electric Cooperative, Inc.

Date of Off Peak Day - 12/12/2021



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Member Forecasted Off Peak Demand Day for January 2021

K.C. Electric Association, Inc.

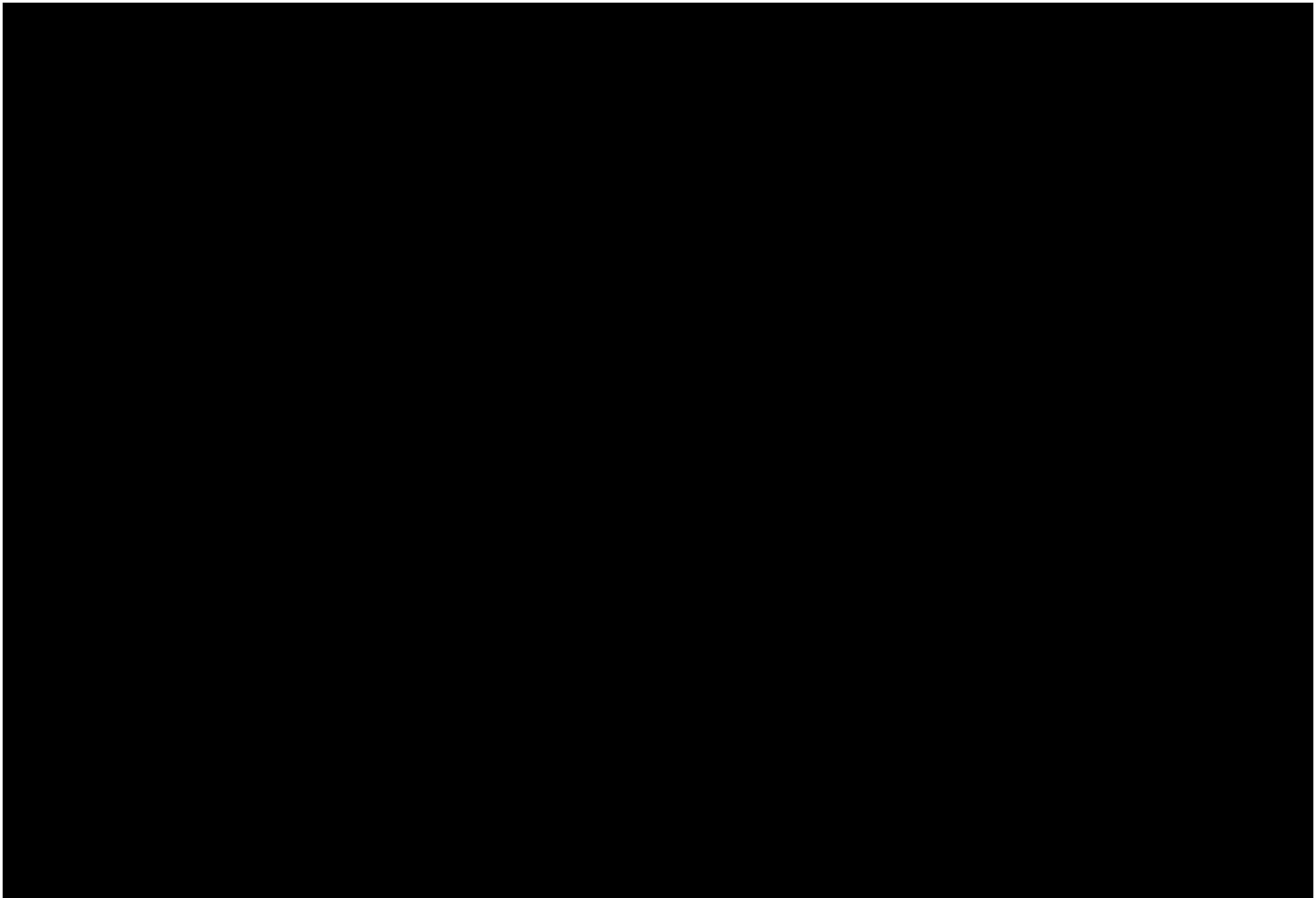
Date of Off Peak Day - 01/19/2021

[redacted]

Member Forecasted Off Peak Demand Day for February 2021

K.C. Electric Association, Inc.

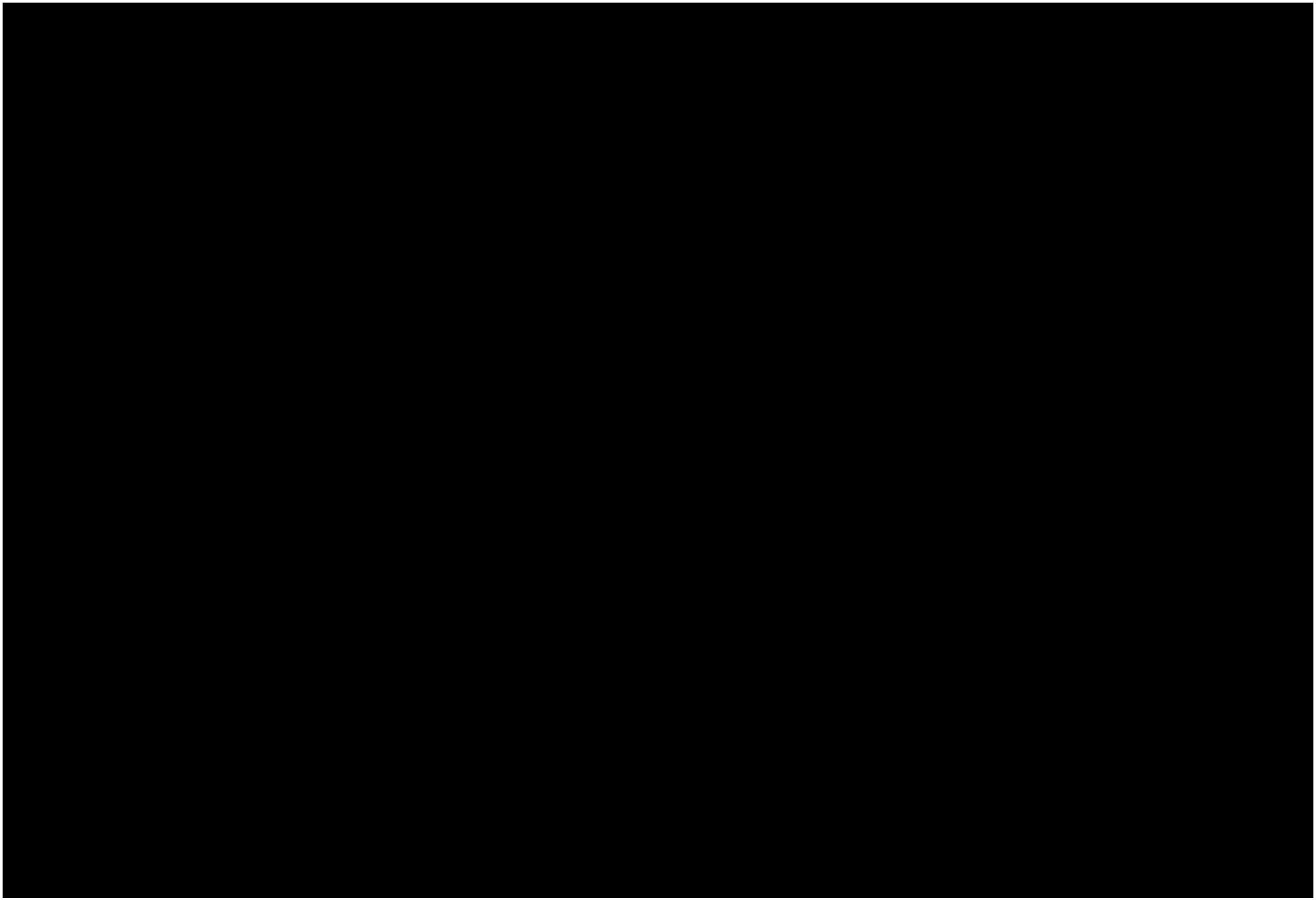
Date of Off Peak Day - 02/22/2021



Member Forecasted Off Peak Demand Day for March 2021

K.C. Electric Association, Inc.

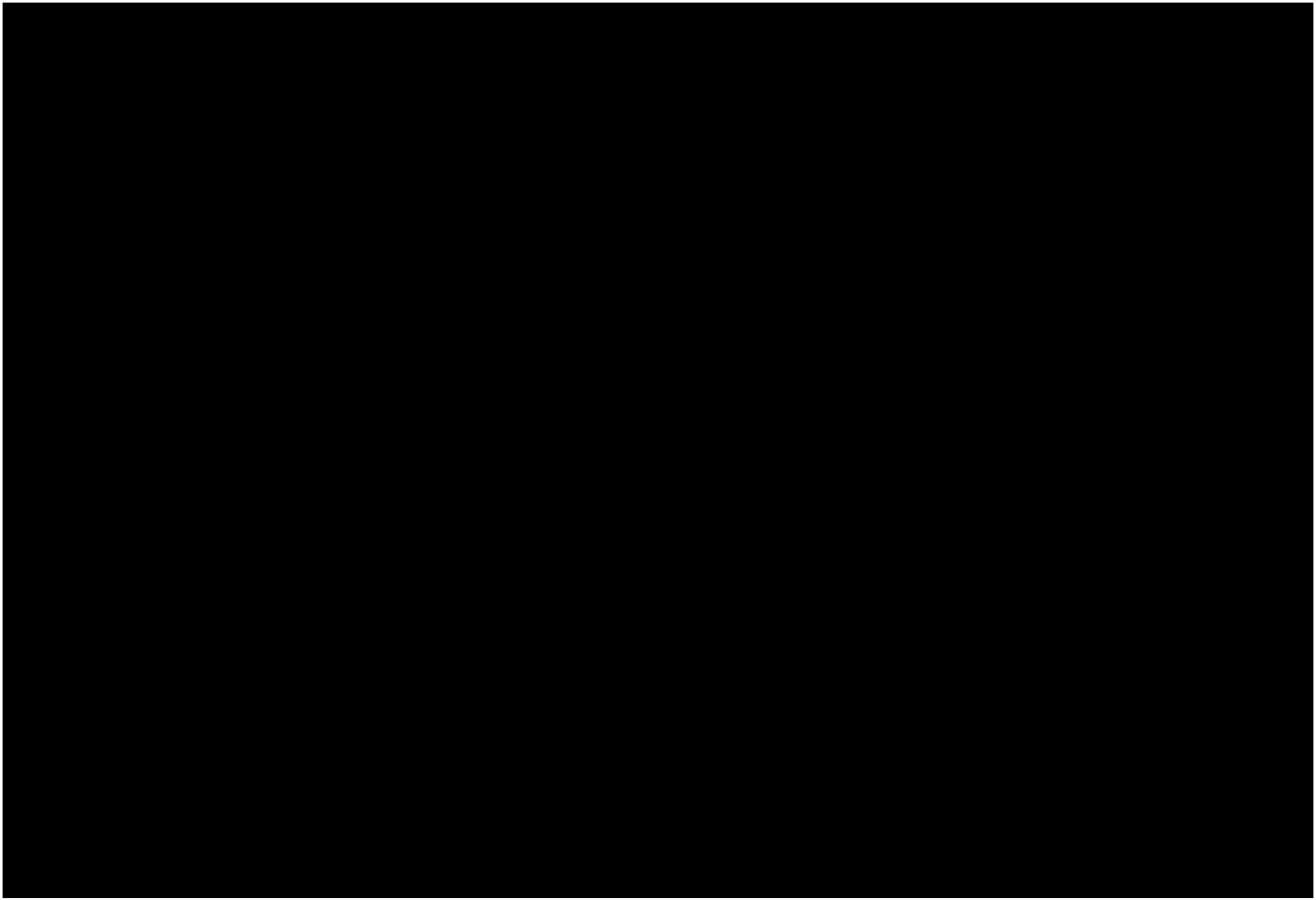
Date of Off Peak Day - 03/08/2021



Member Forecasted Off Peak Demand Day for April 2021

K.C. Electric Association, Inc.

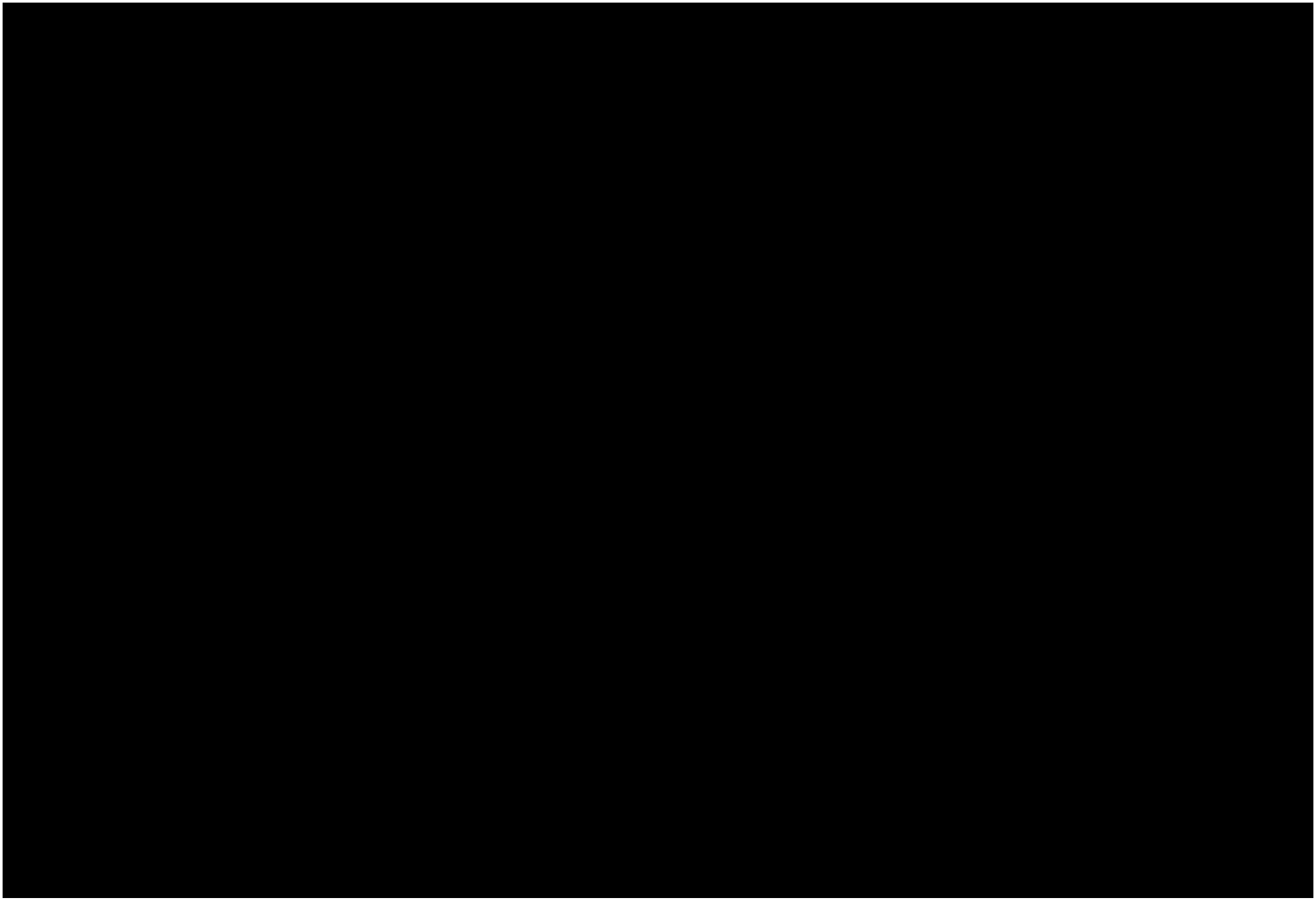
Date of Off Peak Day - 04/23/2021



Member Forecasted Off Peak Demand Day for May 2021

K.C. Electric Association, Inc.

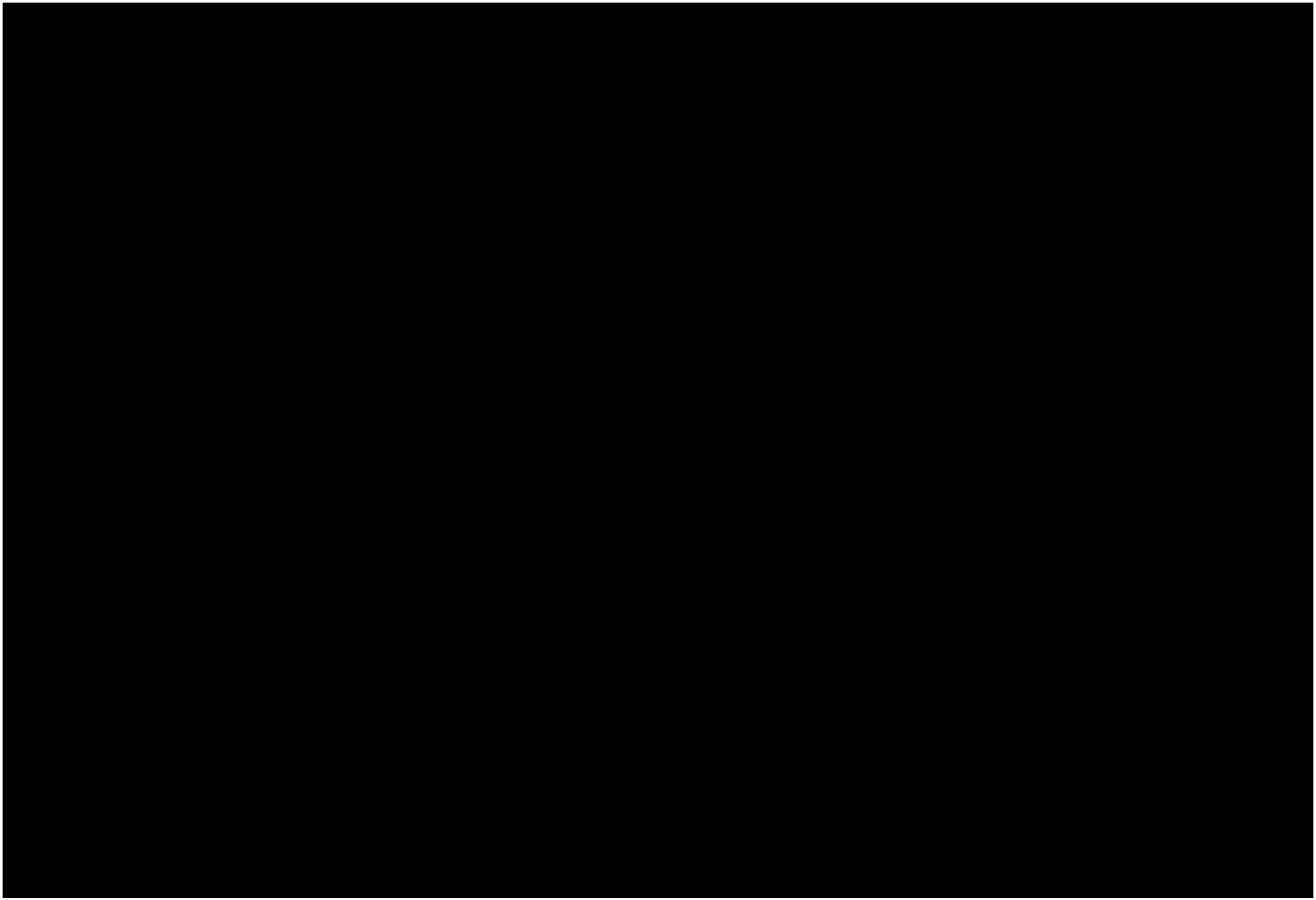
Date of Off Peak Day - 05/01/2021



Member Forecasted Off Peak Demand Day for June 2021

K.C. Electric Association, Inc.

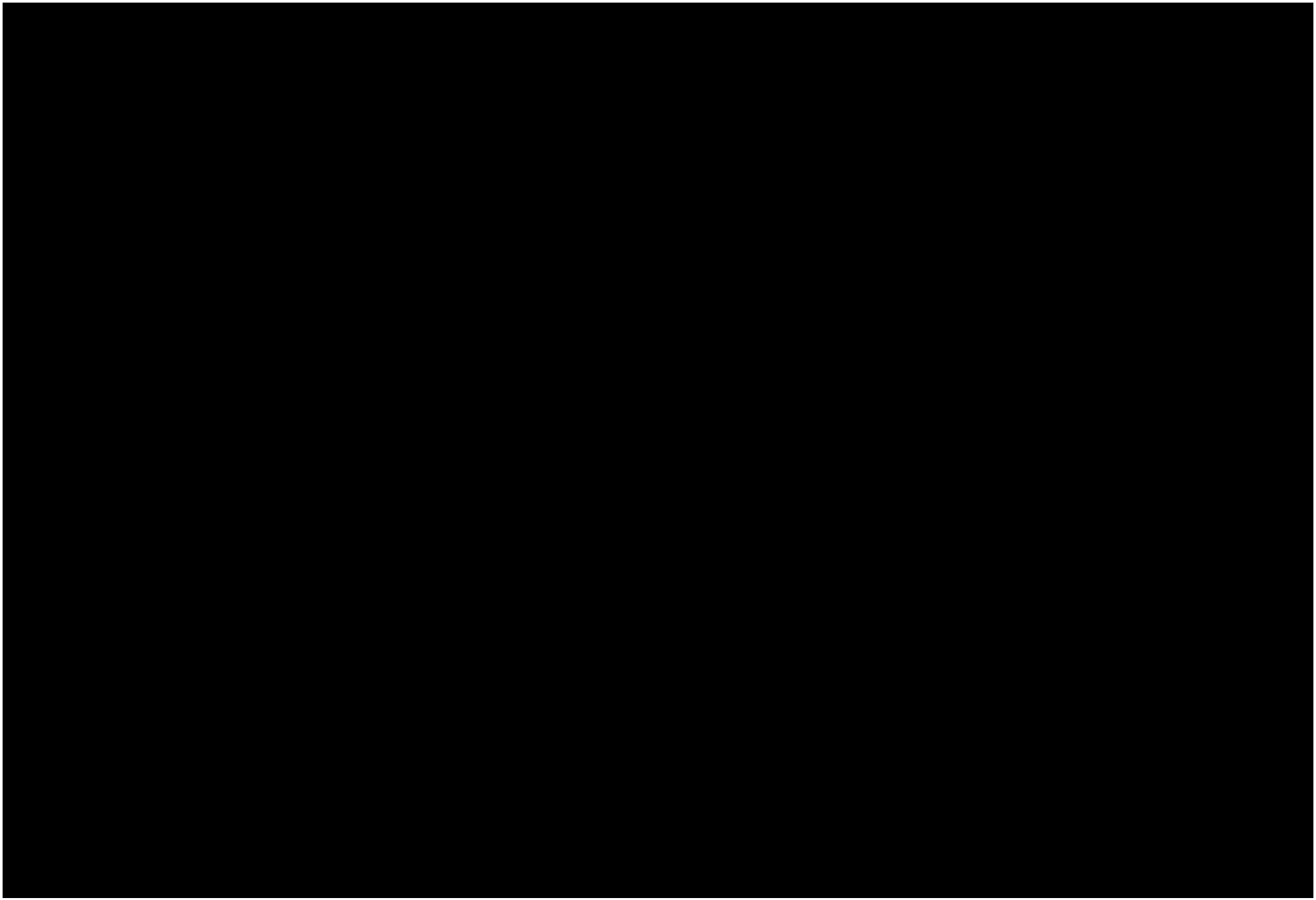
Date of Off Peak Day - 06/01/2021



Member Forecasted Off Peak Demand Day for July 2021

K.C. Electric Association, Inc.

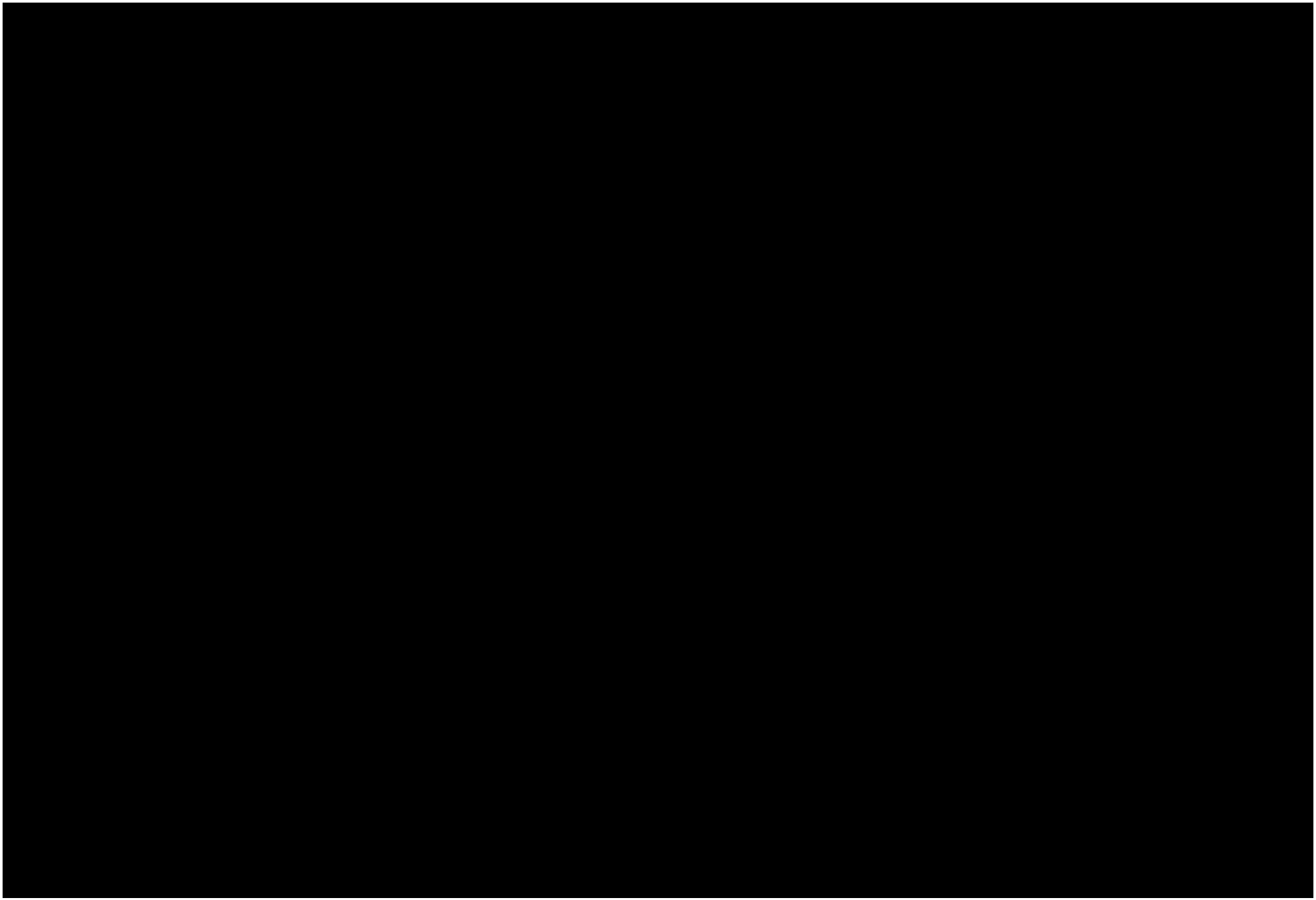
Date of Off Peak Day - 07/02/2021



Member Forecasted Off Peak Demand Day for August 2021

K.C. Electric Association, Inc.

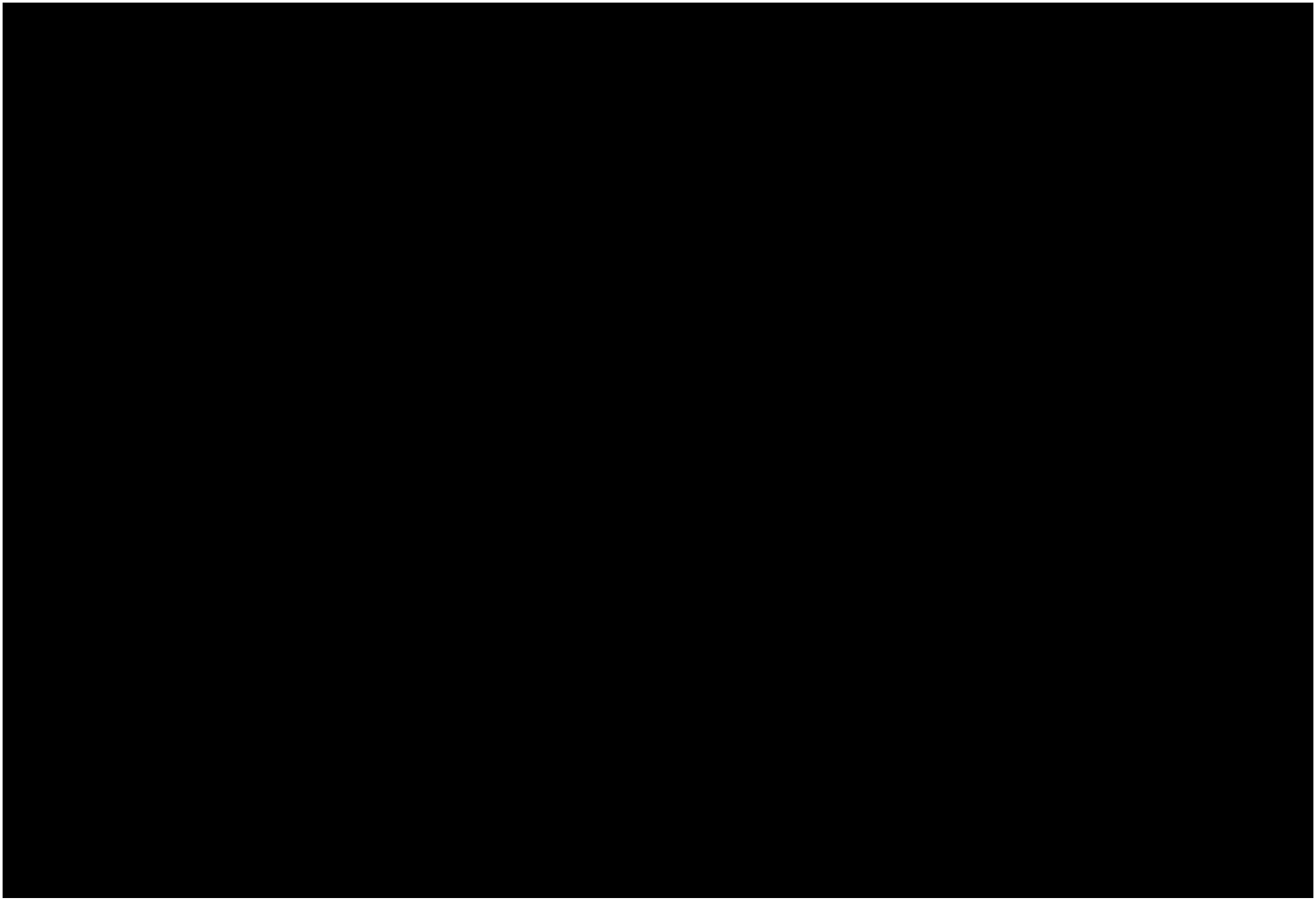
Date of Off Peak Day - 08/10/2021



Member Forecasted Off Peak Demand Day for September 2021

K.C. Electric Association, Inc.

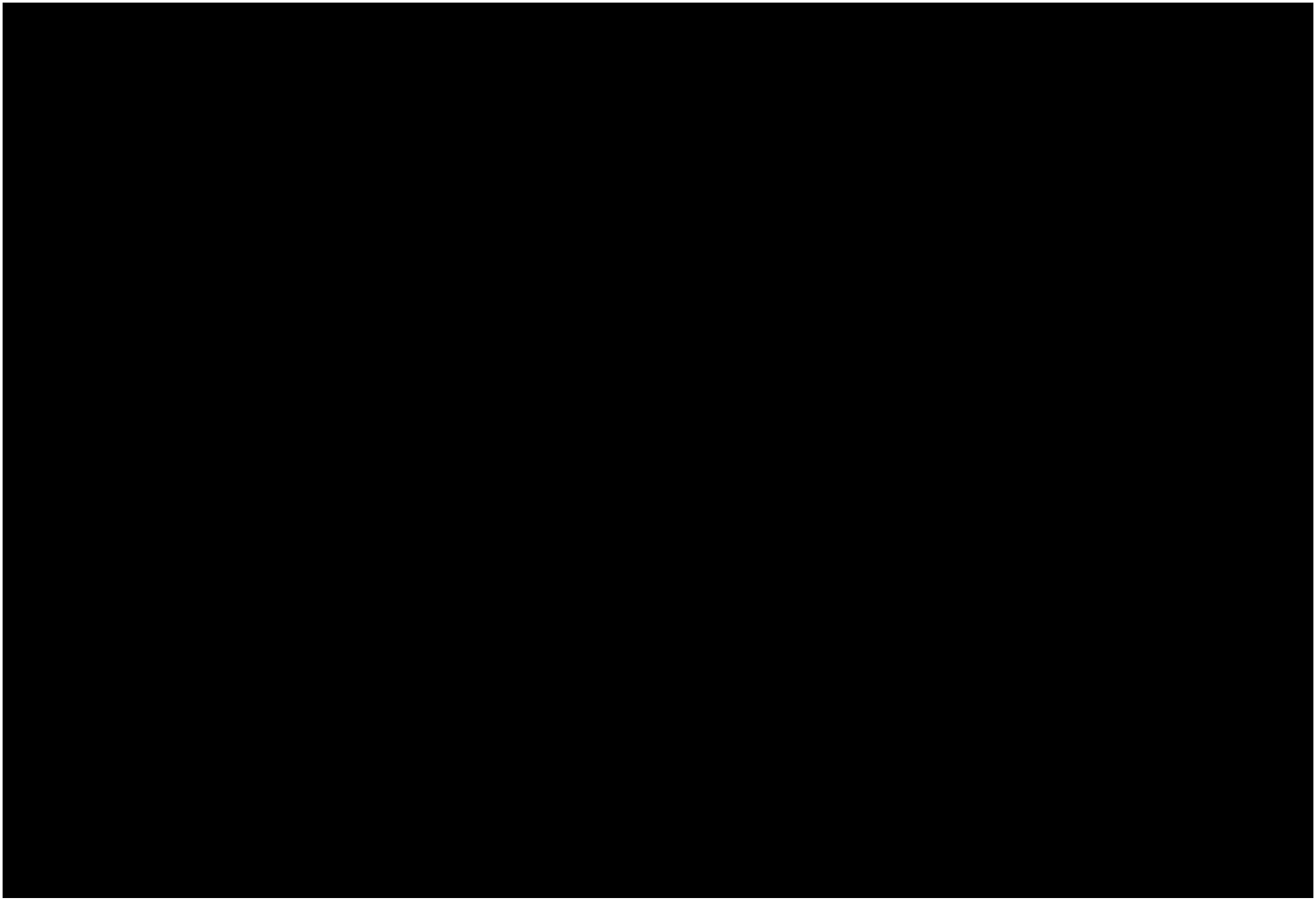
Date of Off Peak Day - 09/30/2021



Member Forecasted Off Peak Demand Day for October 2021

K.C. Electric Association, Inc.

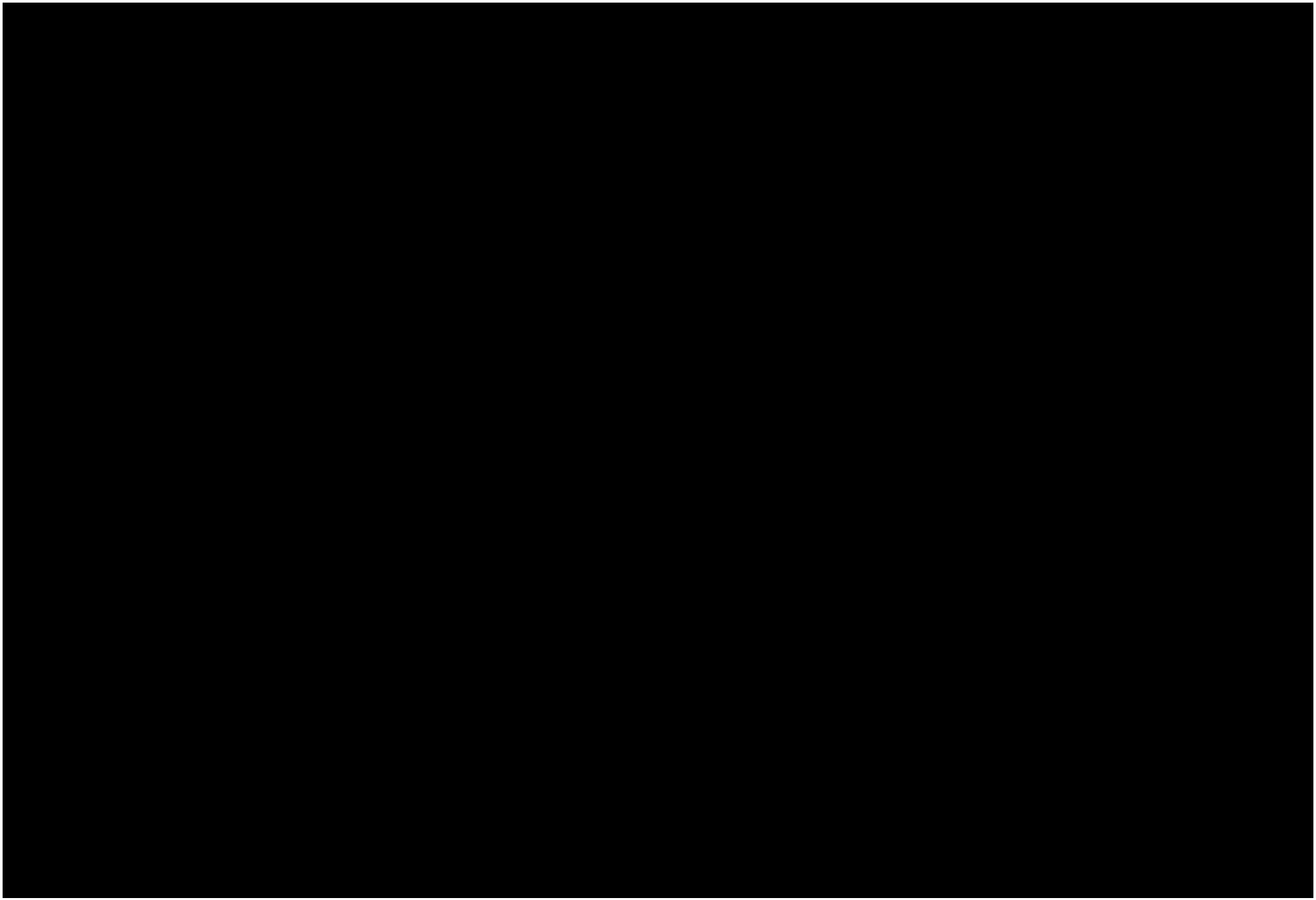
Date of Off Peak Day - 10/02/2021



Member Forecasted Off Peak Demand Day for November 2021

K.C. Electric Association, Inc.

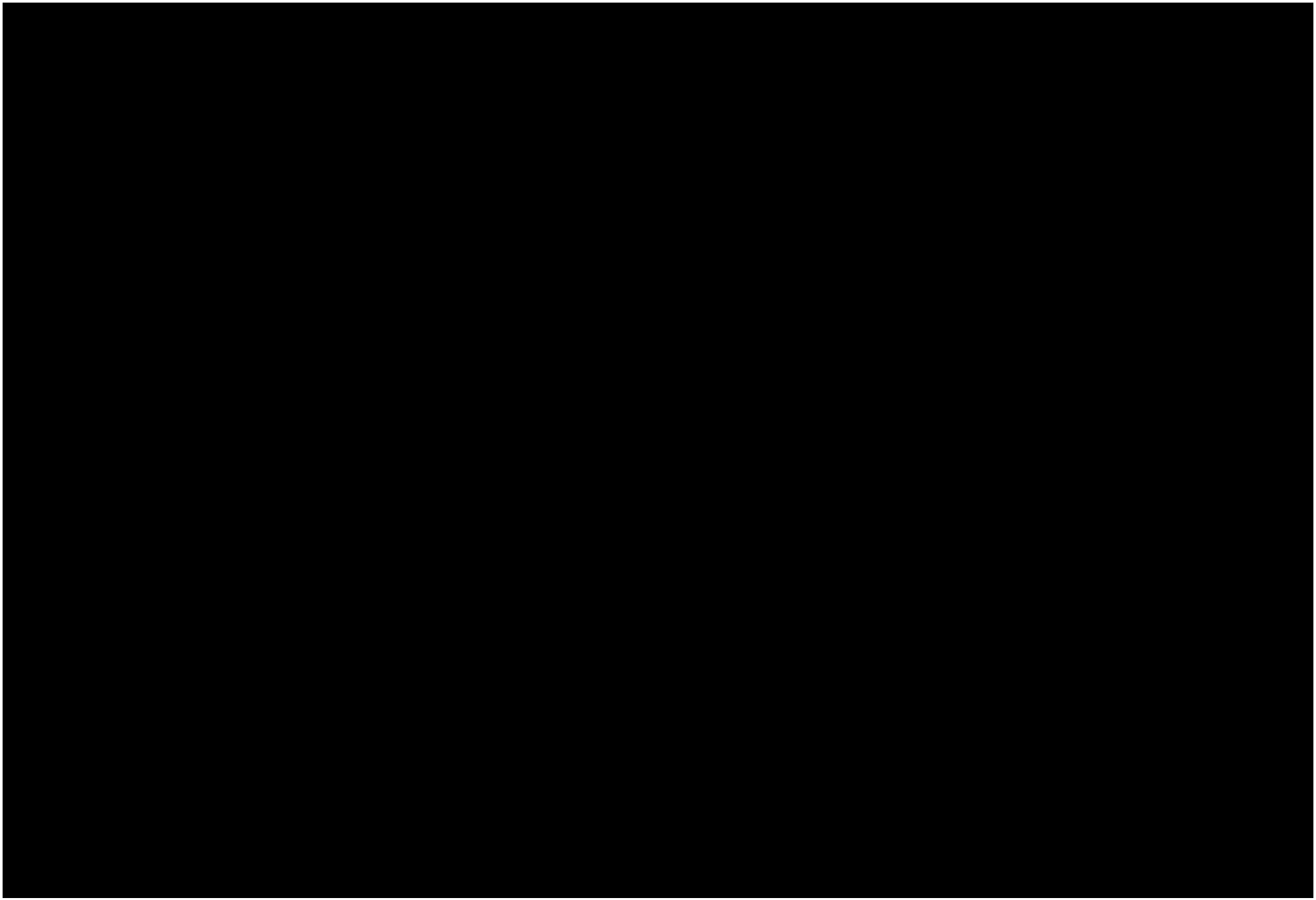
Date of Off Peak Day - 11/04/2021



Member Forecasted Off Peak Demand Day for December 2021

K.C. Electric Association, Inc.

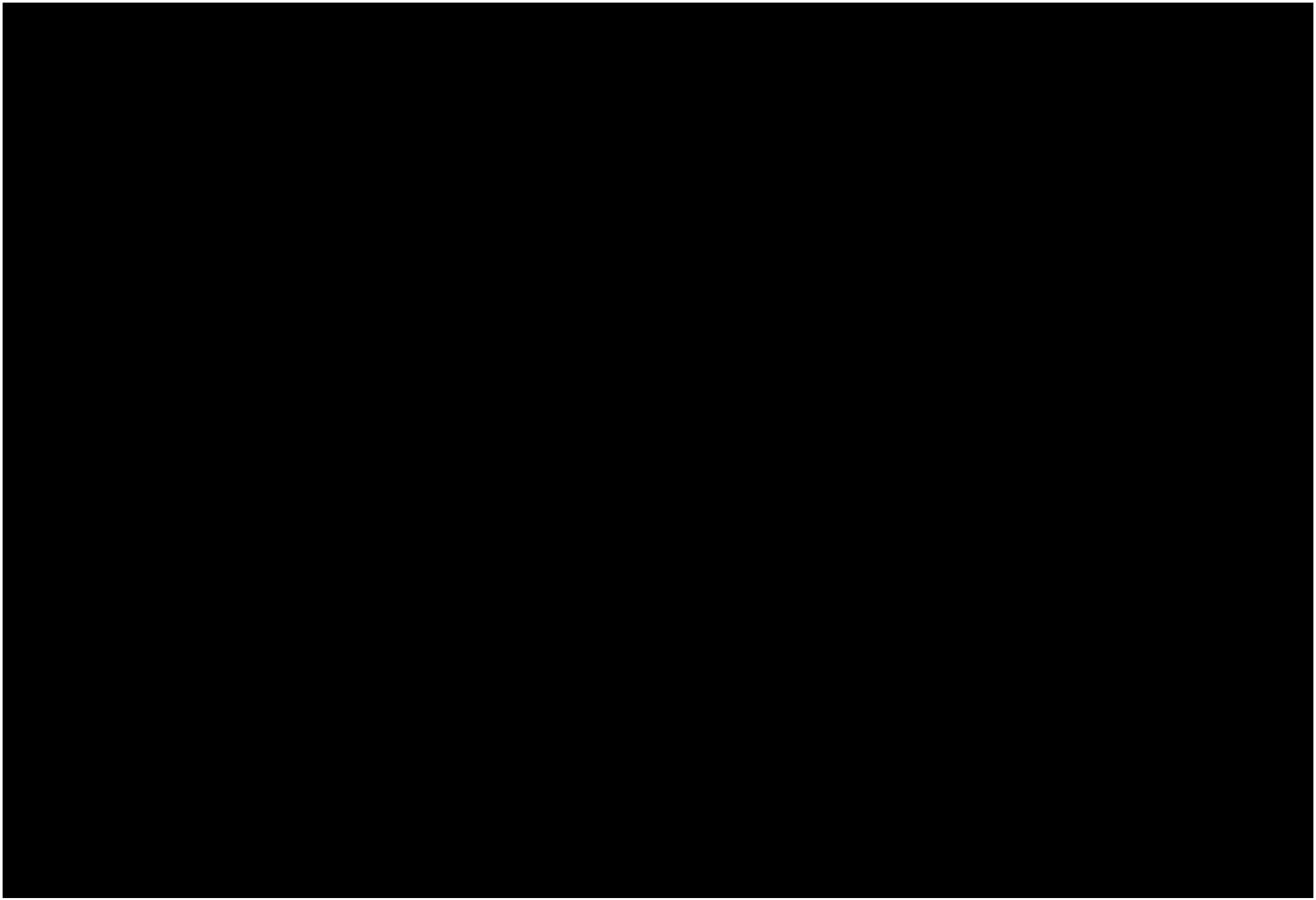
Date of Off Peak Day - 12/21/2021



Member Forecasted Off Peak Demand Day for January 2021

La Plata Electric Association, Inc.

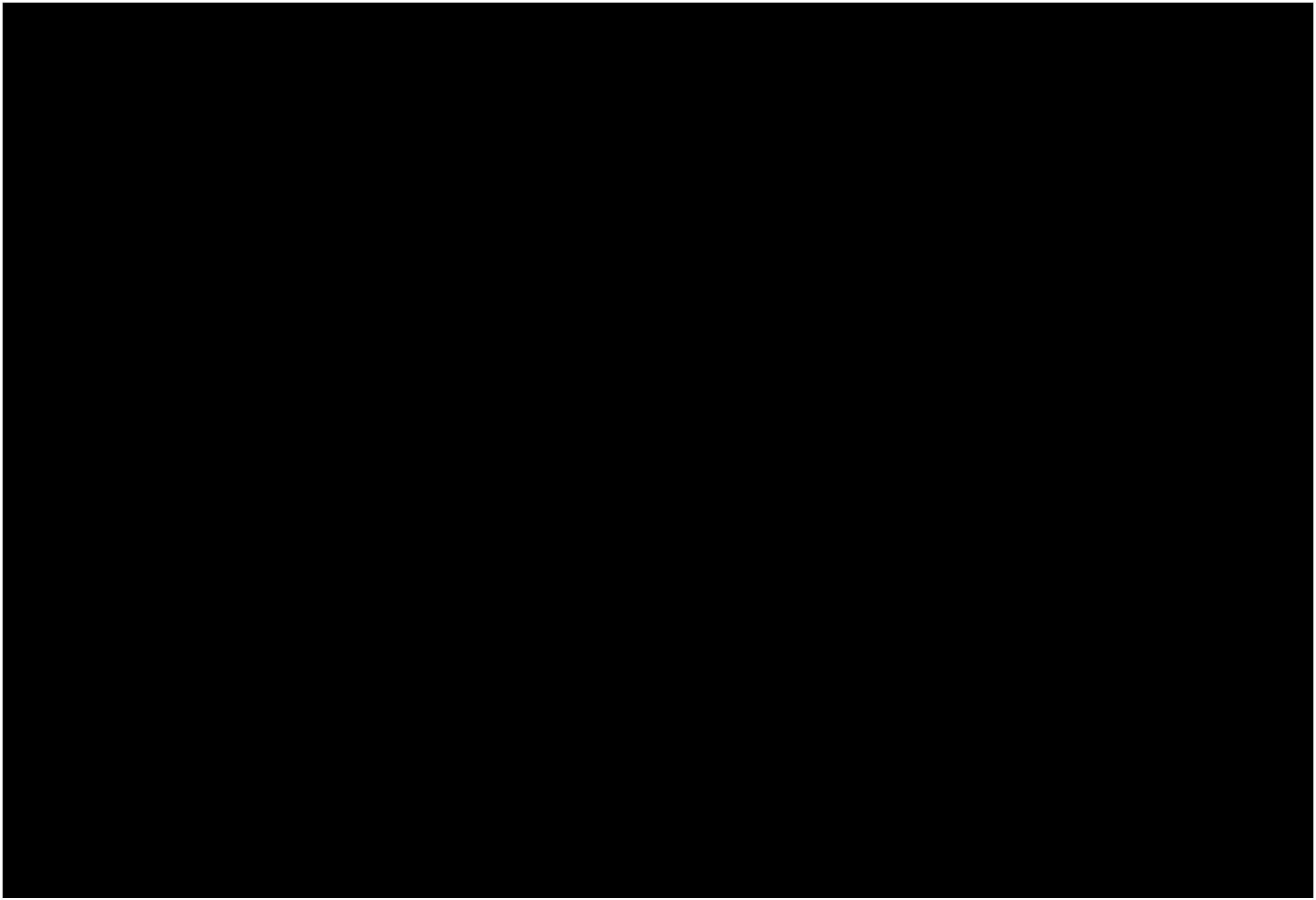
Date of Off Peak Day - 01/14/2021



Member Forecasted Off Peak Demand Day for February 2021

La Plata Electric Association, Inc.

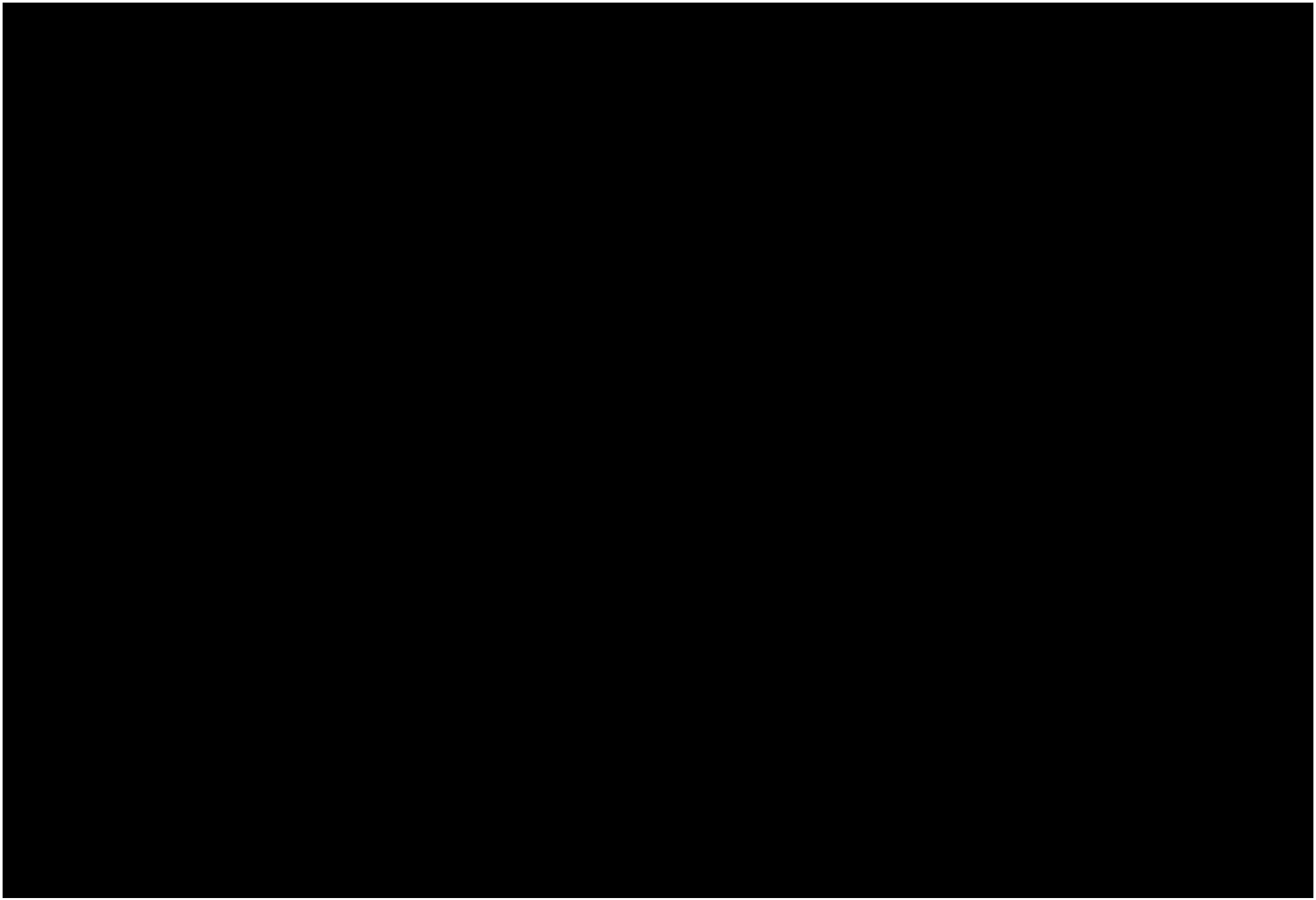
Date of Off Peak Day - 02/11/2021



Member Forecasted Off Peak Demand Day for March 2021

La Plata Electric Association, Inc.

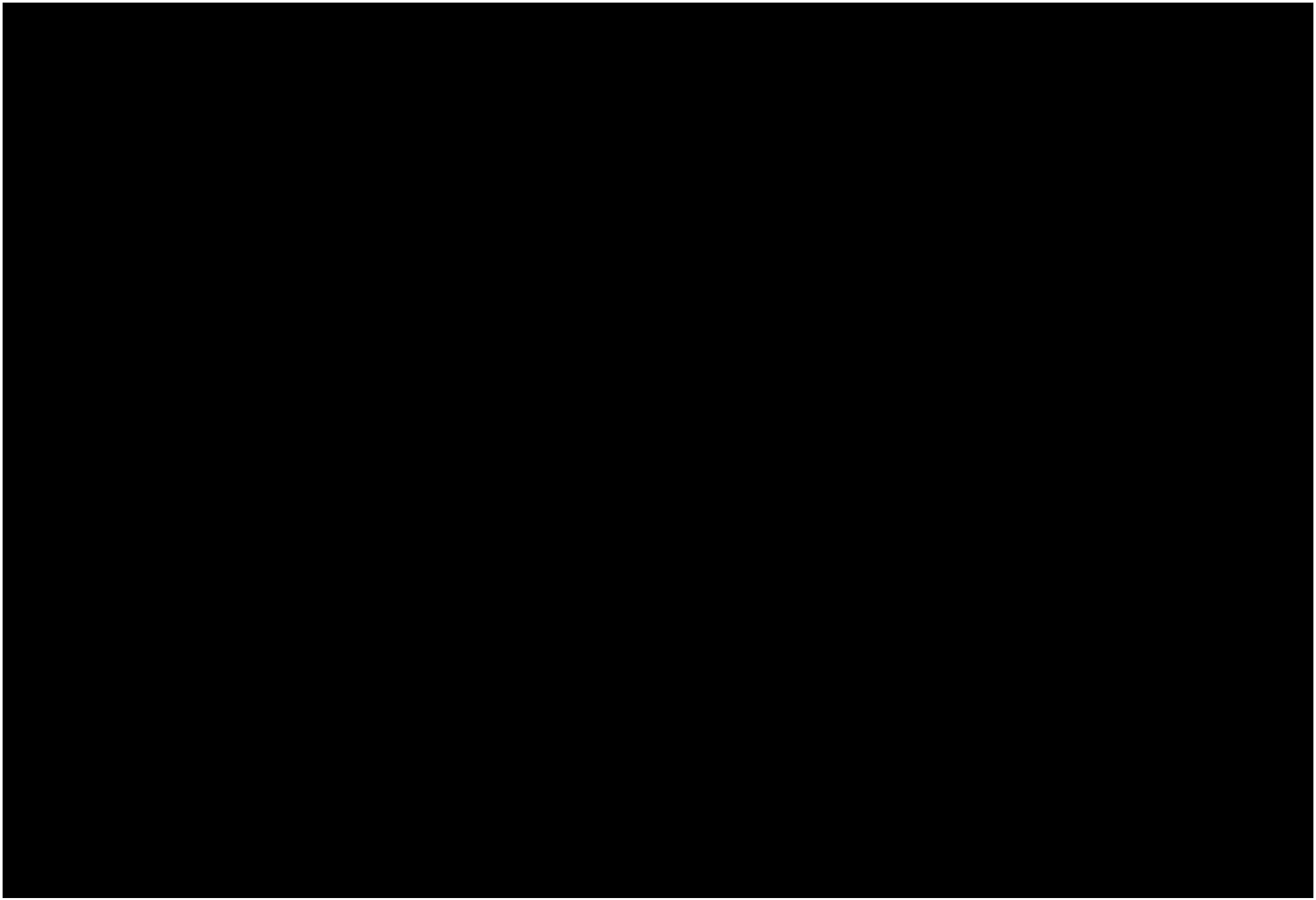
Date of Off Peak Day - 03/21/2021



Member Forecasted Off Peak Demand Day for April 2021

La Plata Electric Association, Inc.

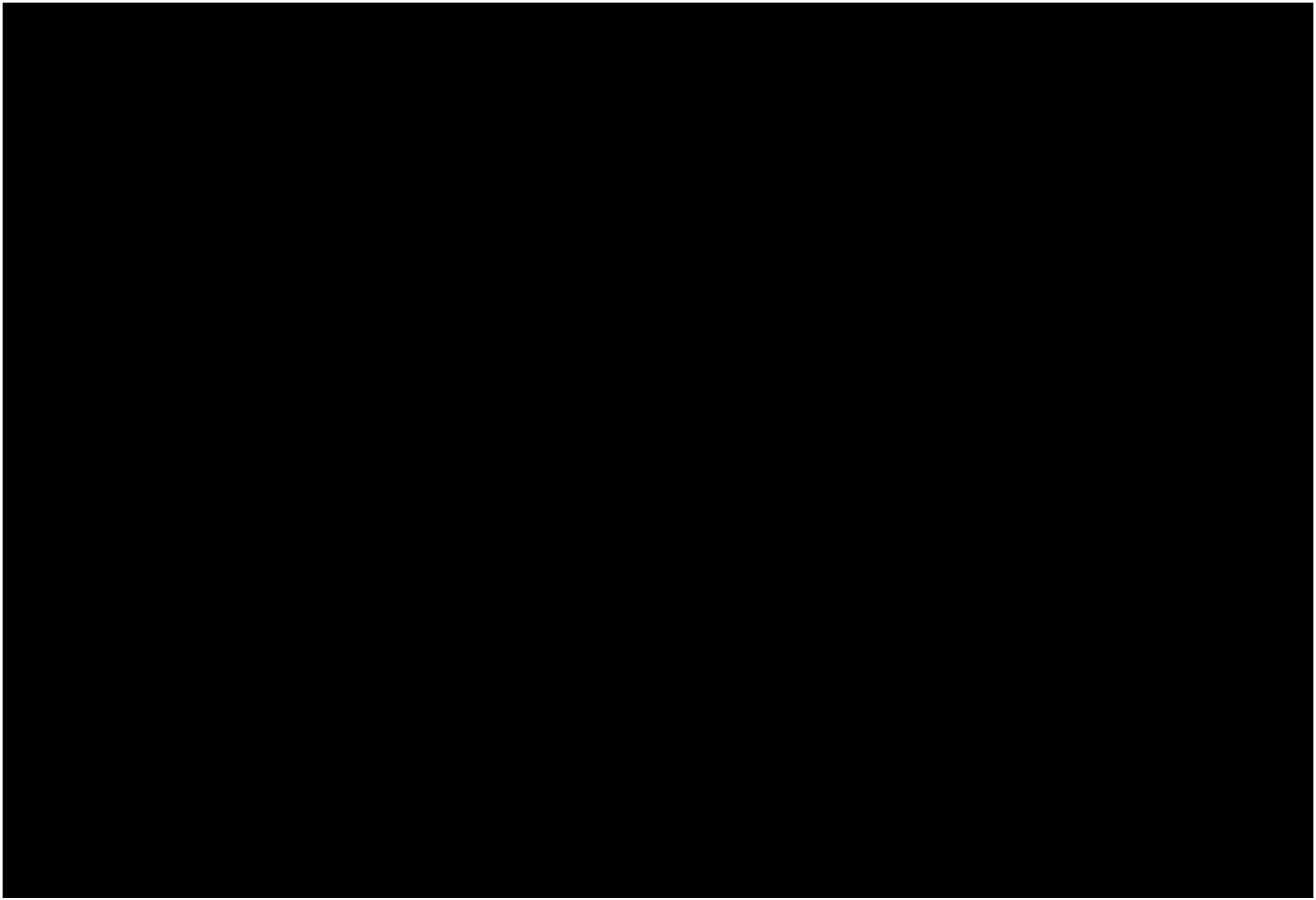
Date of Off Peak Day - 04/30/2021



Member Forecasted Off Peak Demand Day for May 2021

La Plata Electric Association, Inc.

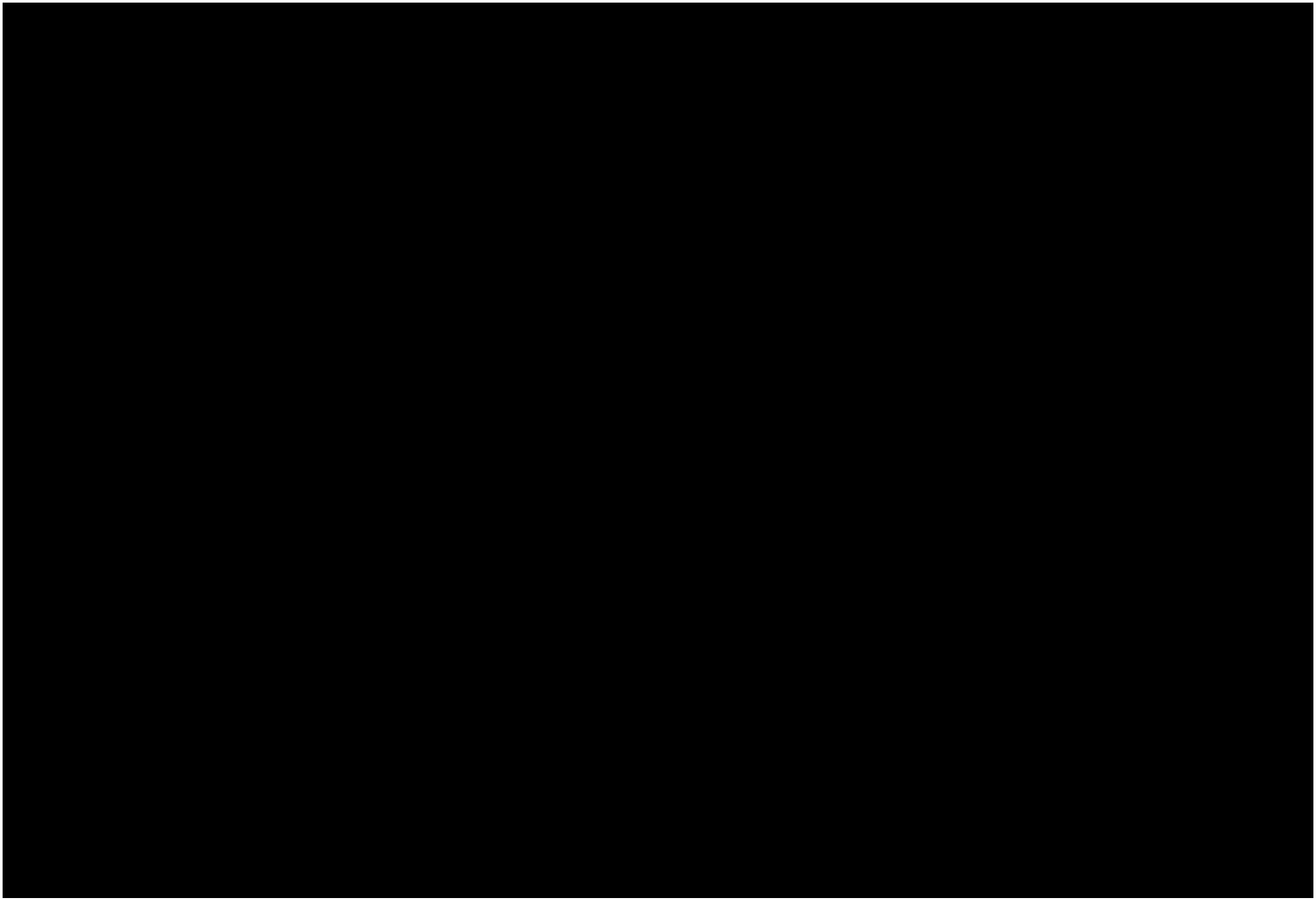
Date of Off Peak Day - 05/26/2021



Member Forecasted Off Peak Demand Day for June 2021

La Plata Electric Association, Inc.

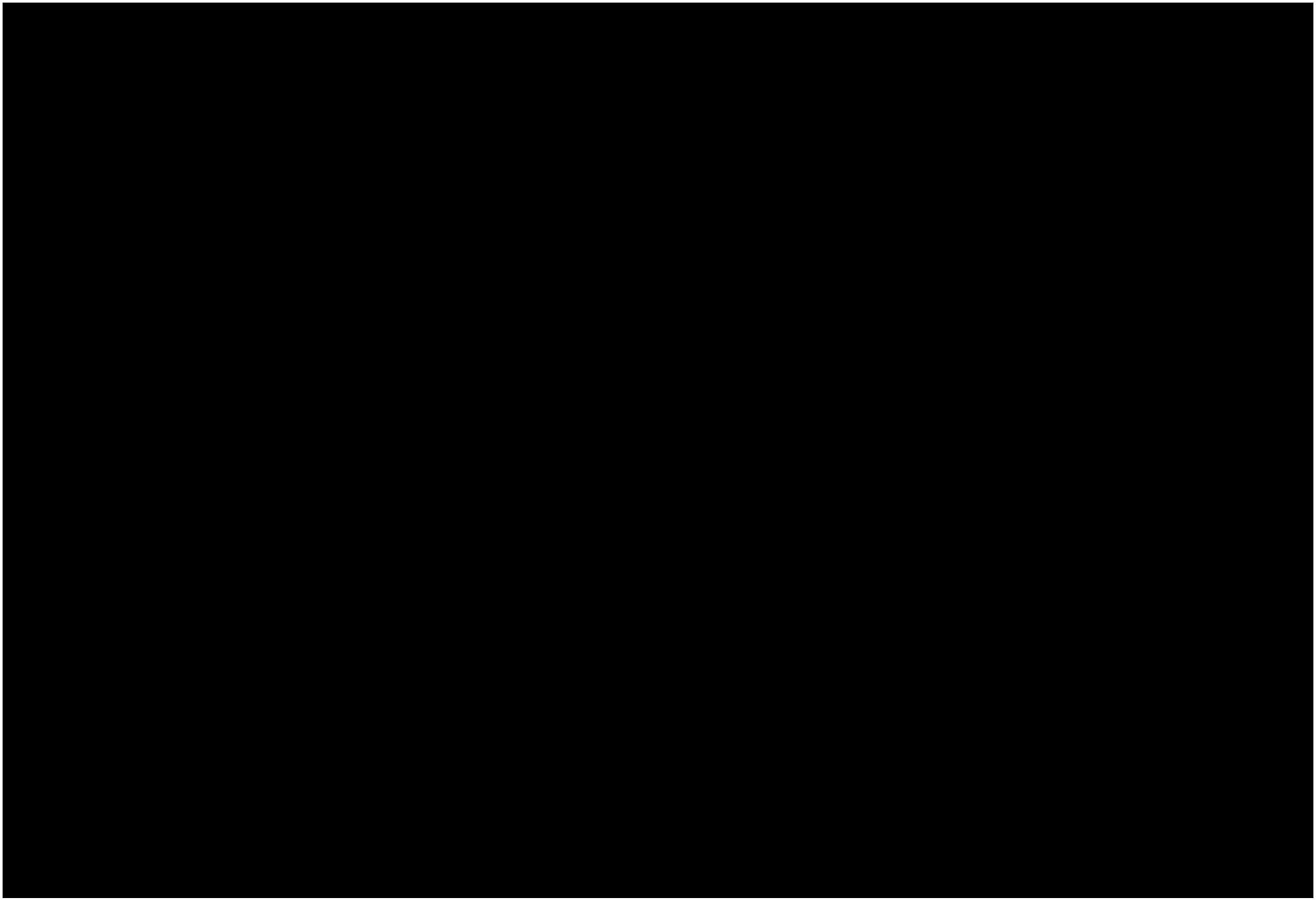
Date of Off Peak Day - 06/06/2021



Member Forecasted Off Peak Demand Day for July 2021

La Plata Electric Association, Inc.

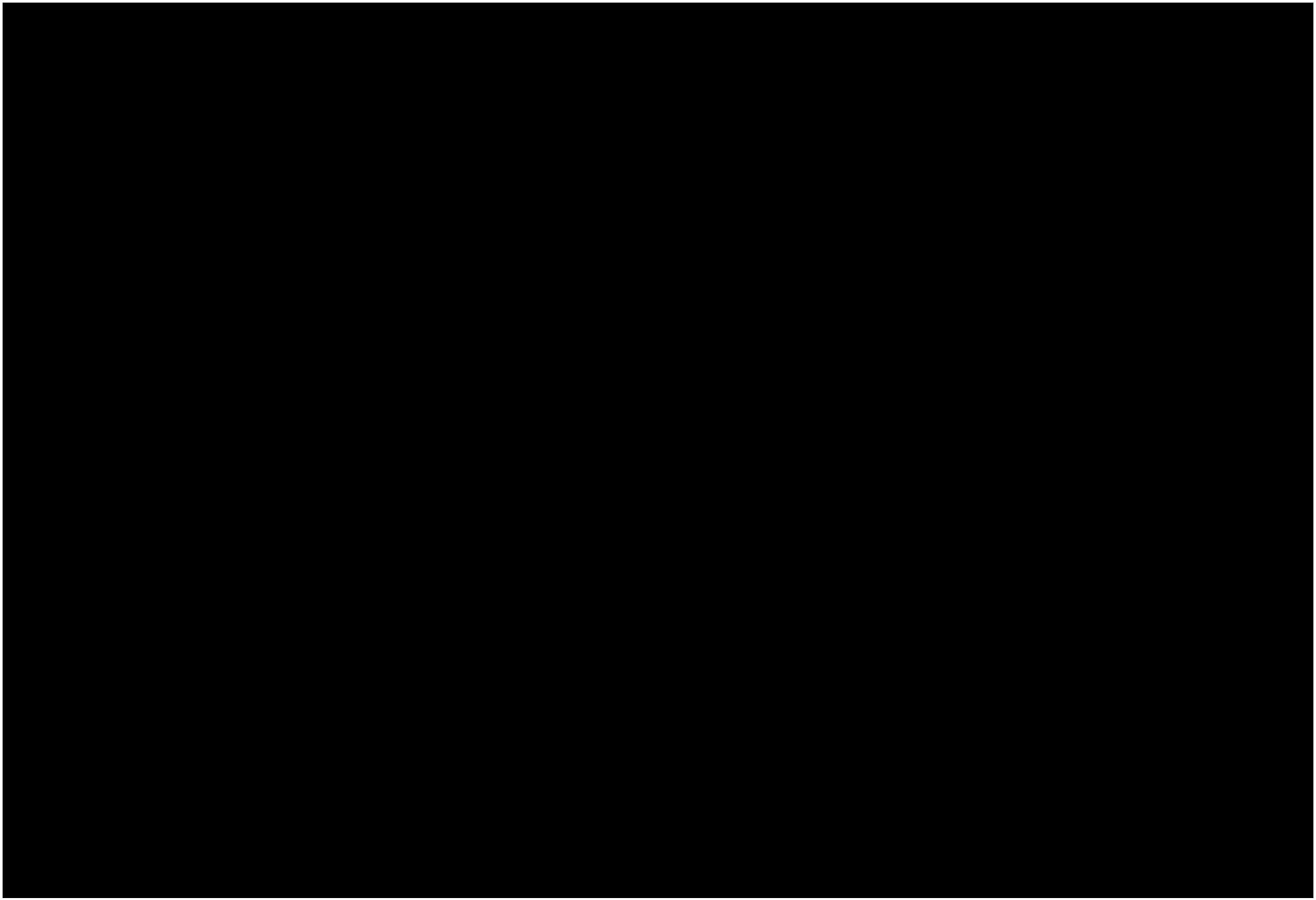
Date of Off Peak Day - 07/04/2021



Member Forecasted Off Peak Demand Day for August 2021

La Plata Electric Association, Inc.

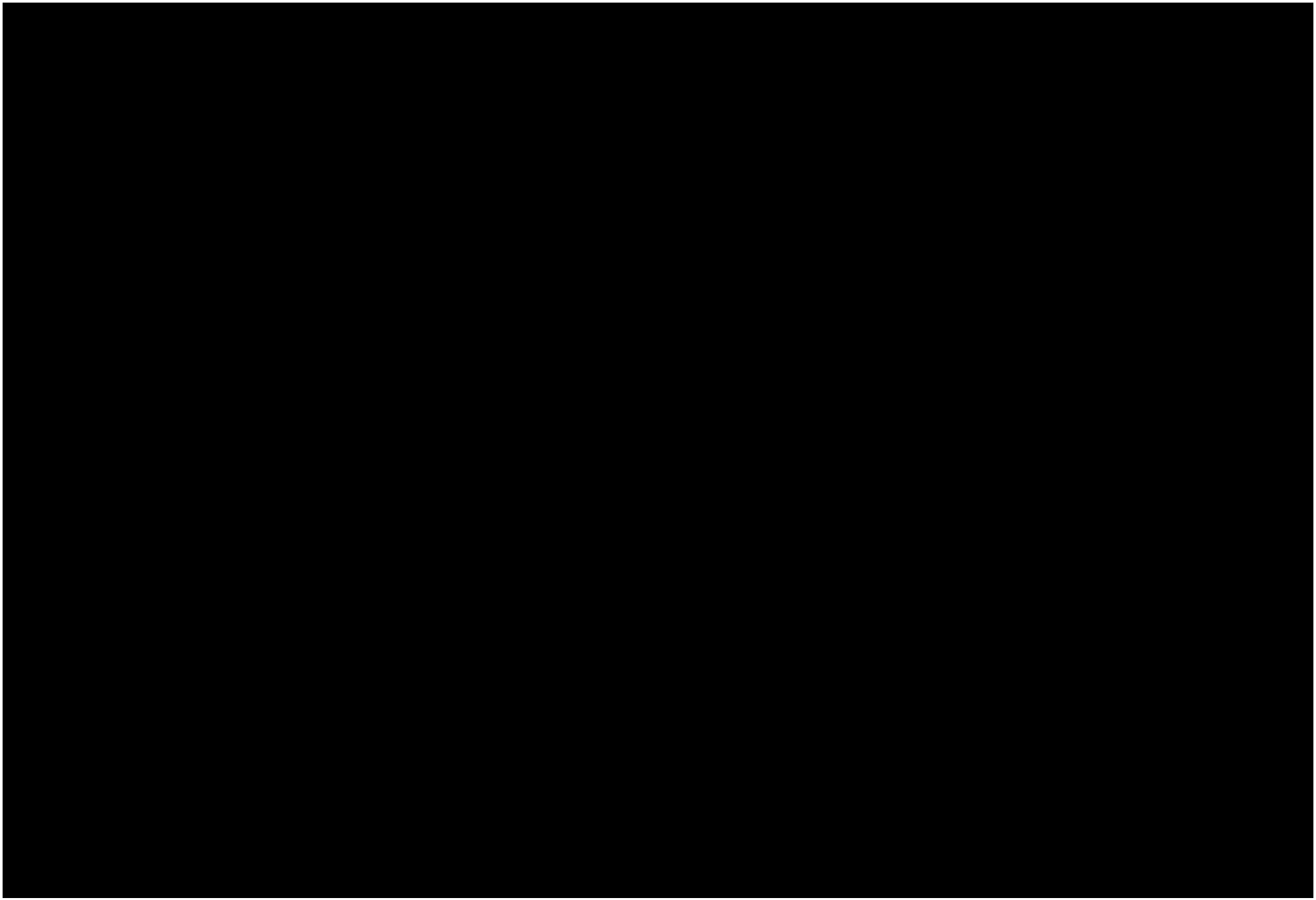
Date of Off Peak Day - 08/01/2021



Member Forecasted Off Peak Demand Day for September 2021

La Plata Electric Association, Inc.

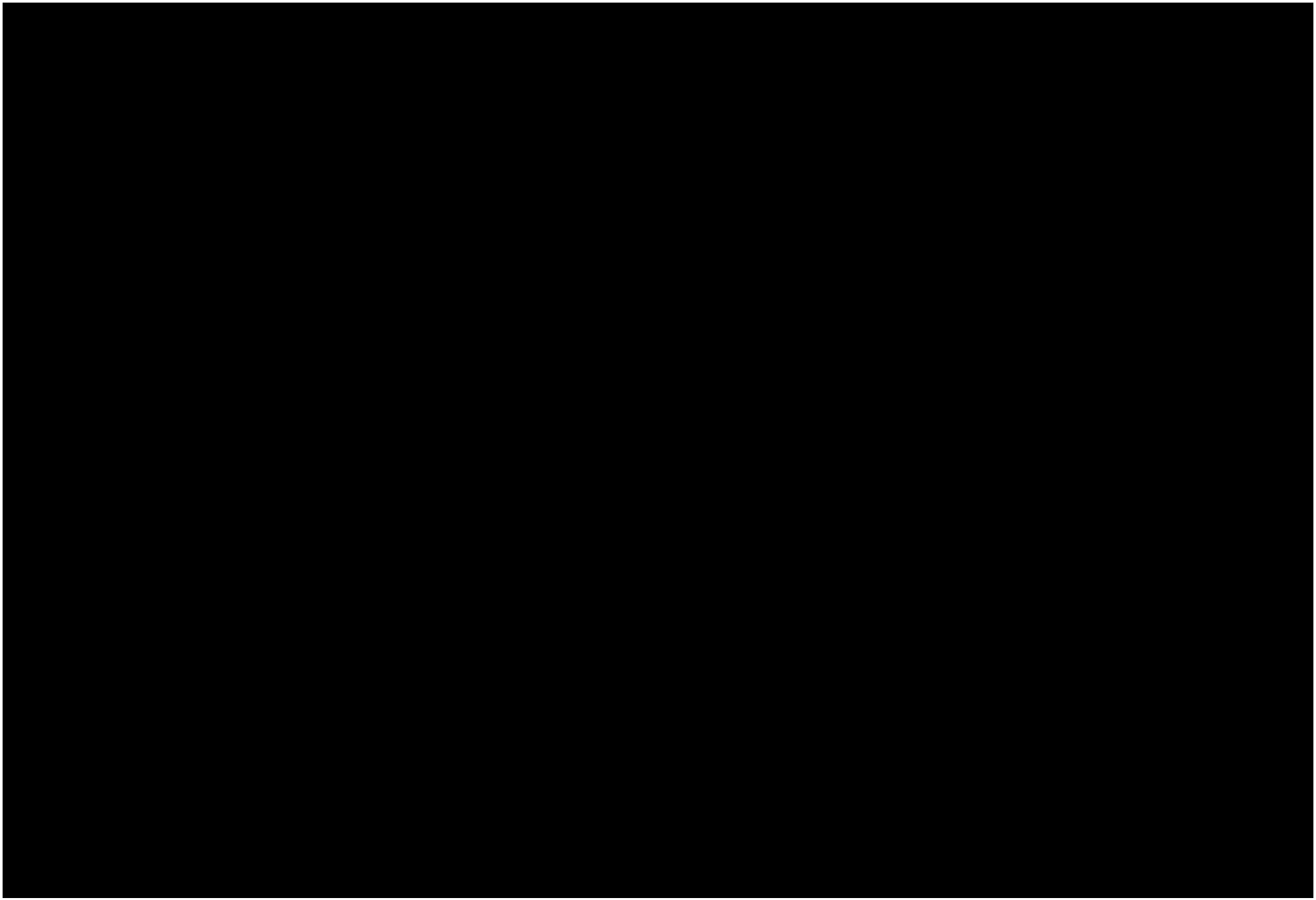
Date of Off Peak Day - 09/21/2021



Member Forecasted Off Peak Demand Day for October 2021

La Plata Electric Association, Inc.

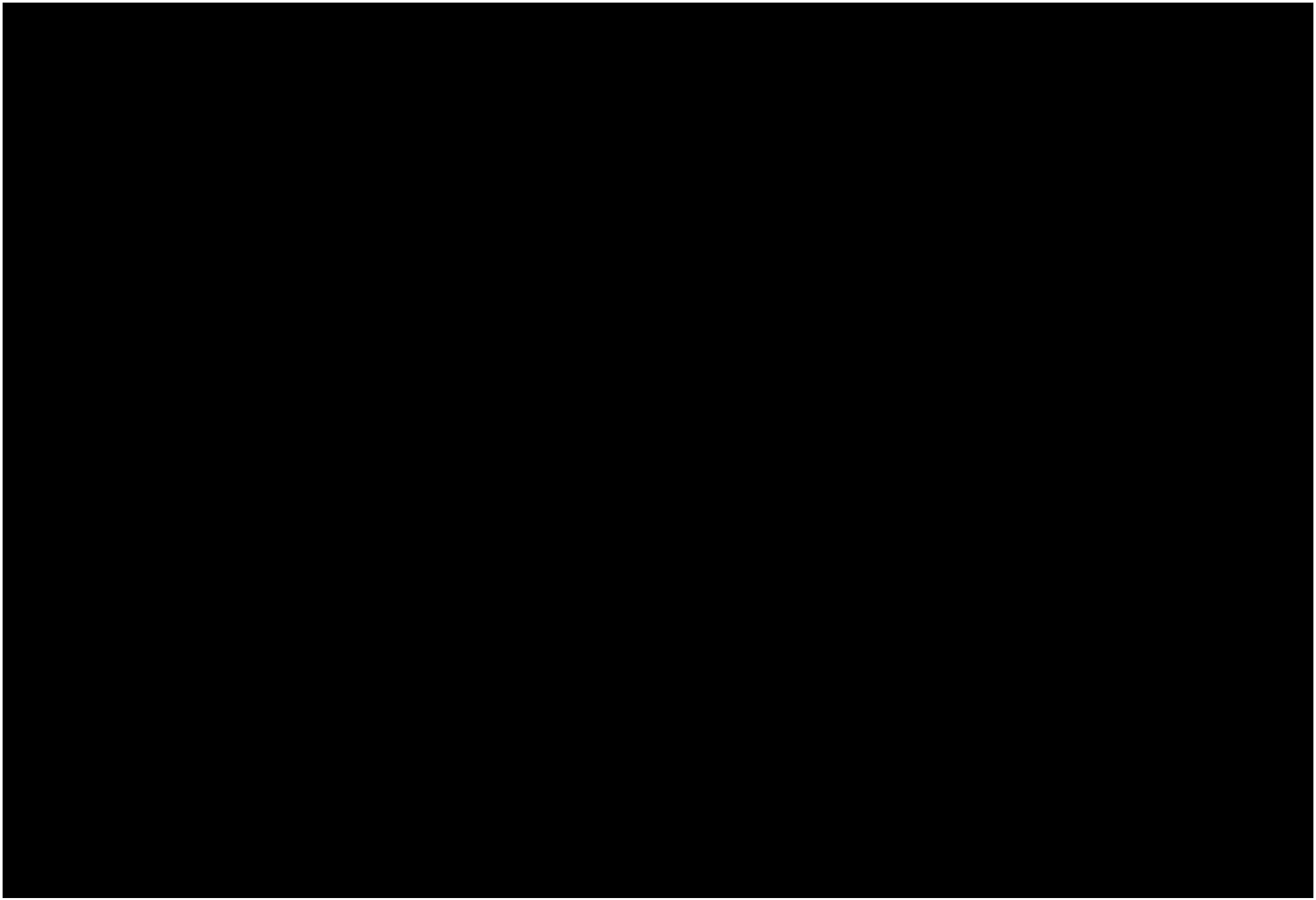
Date of Off Peak Day - 10/04/2021



Member Forecasted Off Peak Demand Day for November 2021

La Plata Electric Association, Inc.

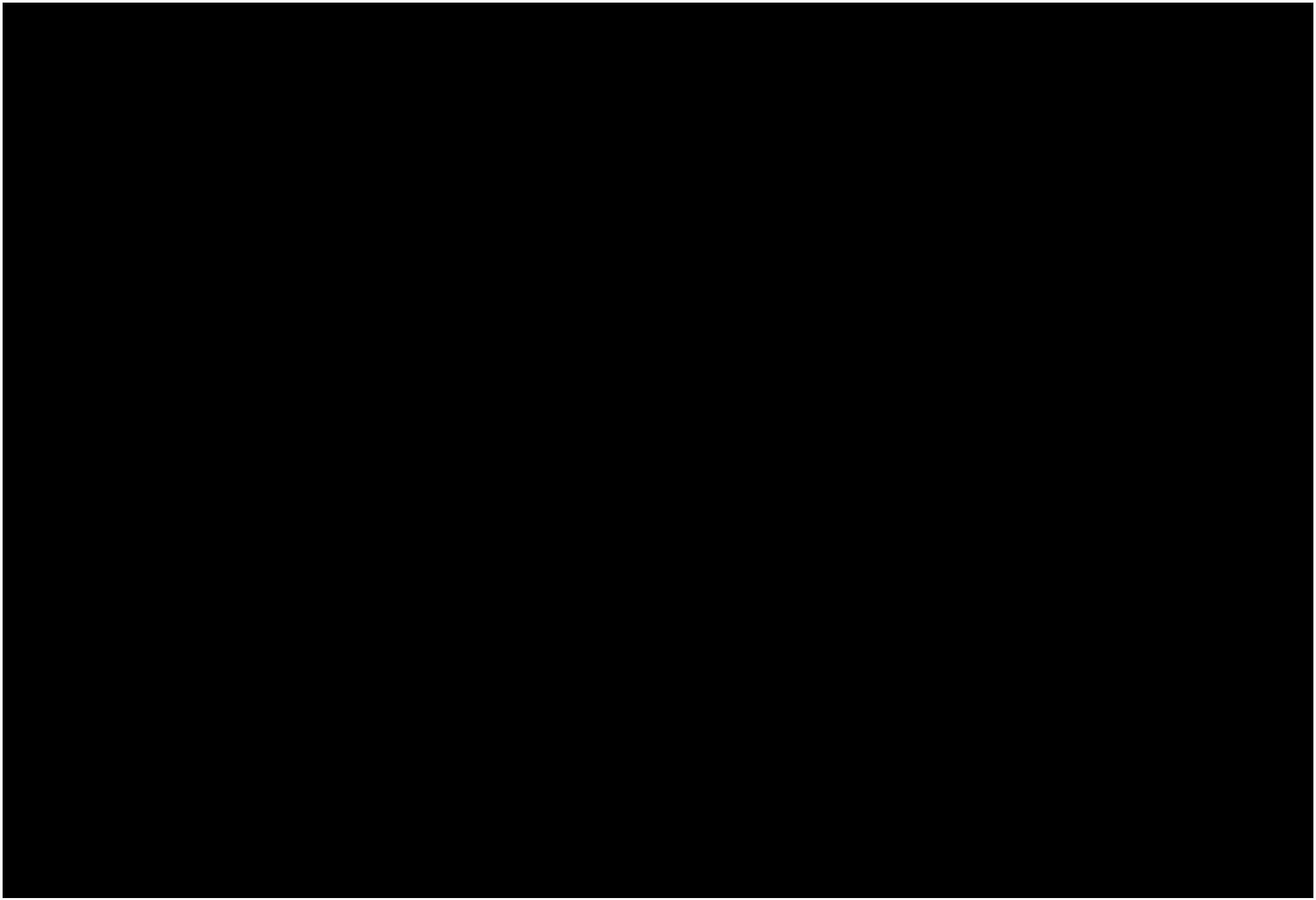
Date of Off Peak Day - 11/03/2021



Member Forecasted Off Peak Demand Day for December 2021

La Plata Electric Association, Inc.

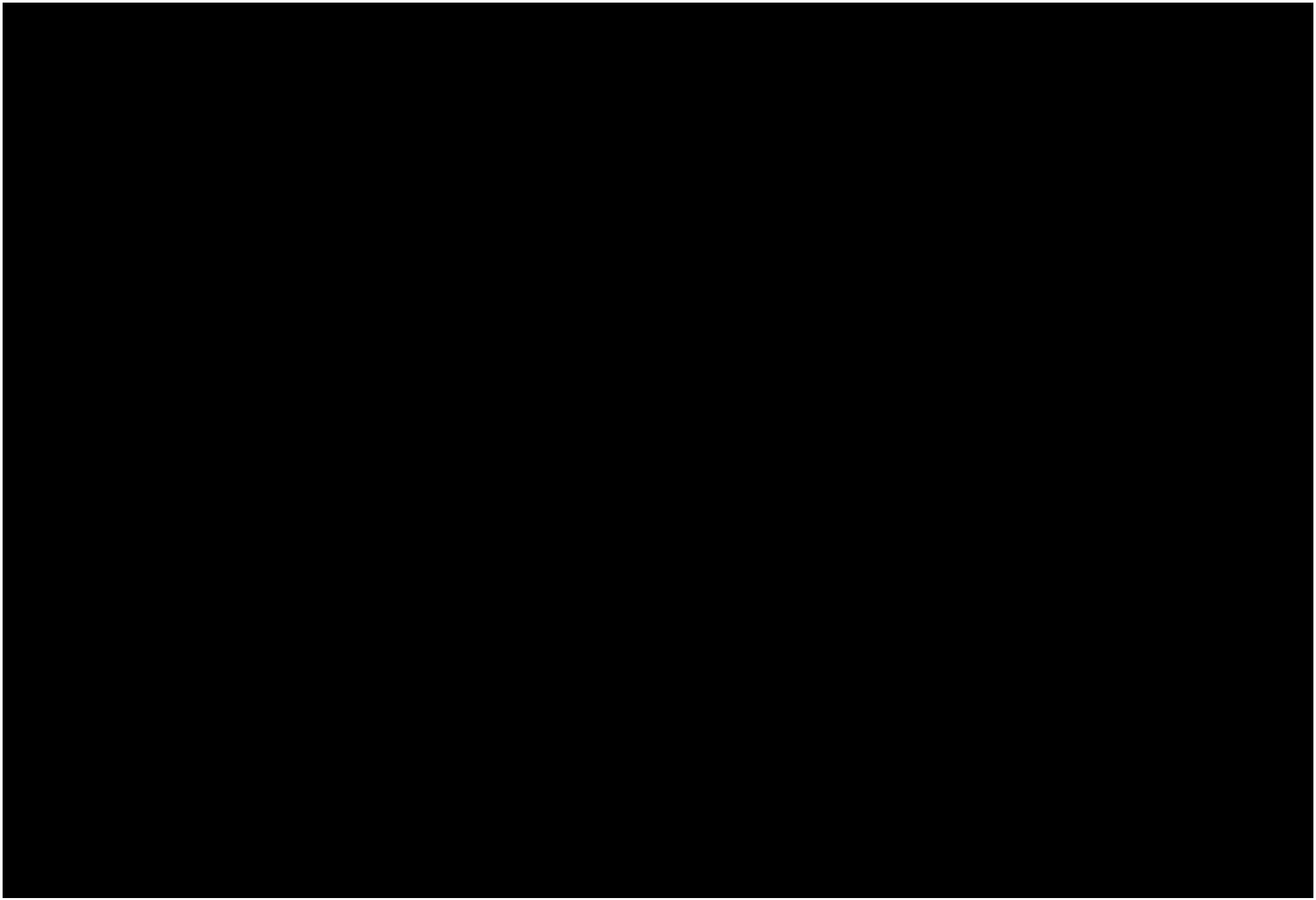
Date of Off Peak Day - 12/11/2021



Member Forecasted Off Peak Demand Day for January 2021

Morgan County Rural Electric Association

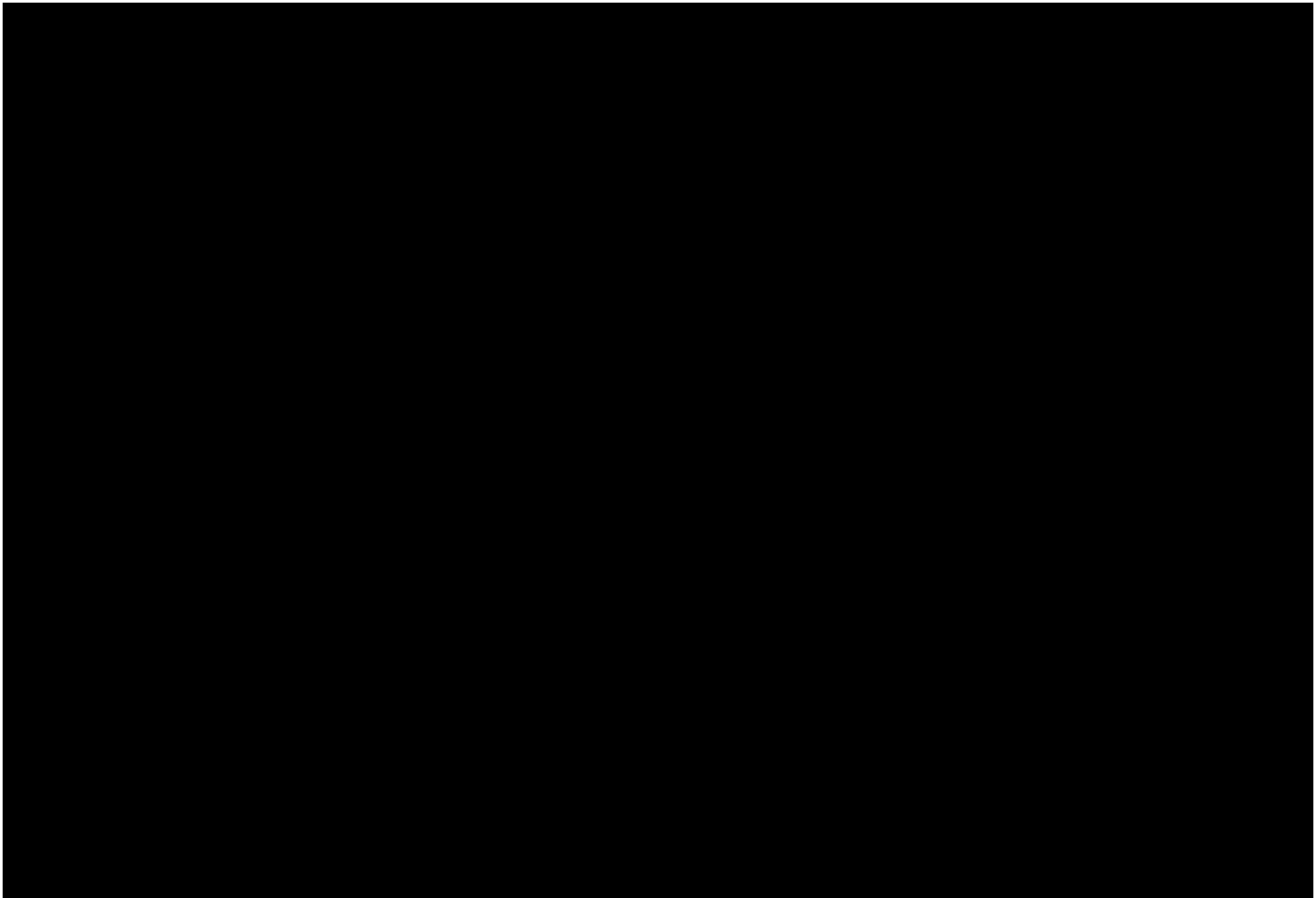
Date of Off Peak Day - 01/10/2021



Member Forecasted Off Peak Demand Day for February 2021

Morgan County Rural Electric Association

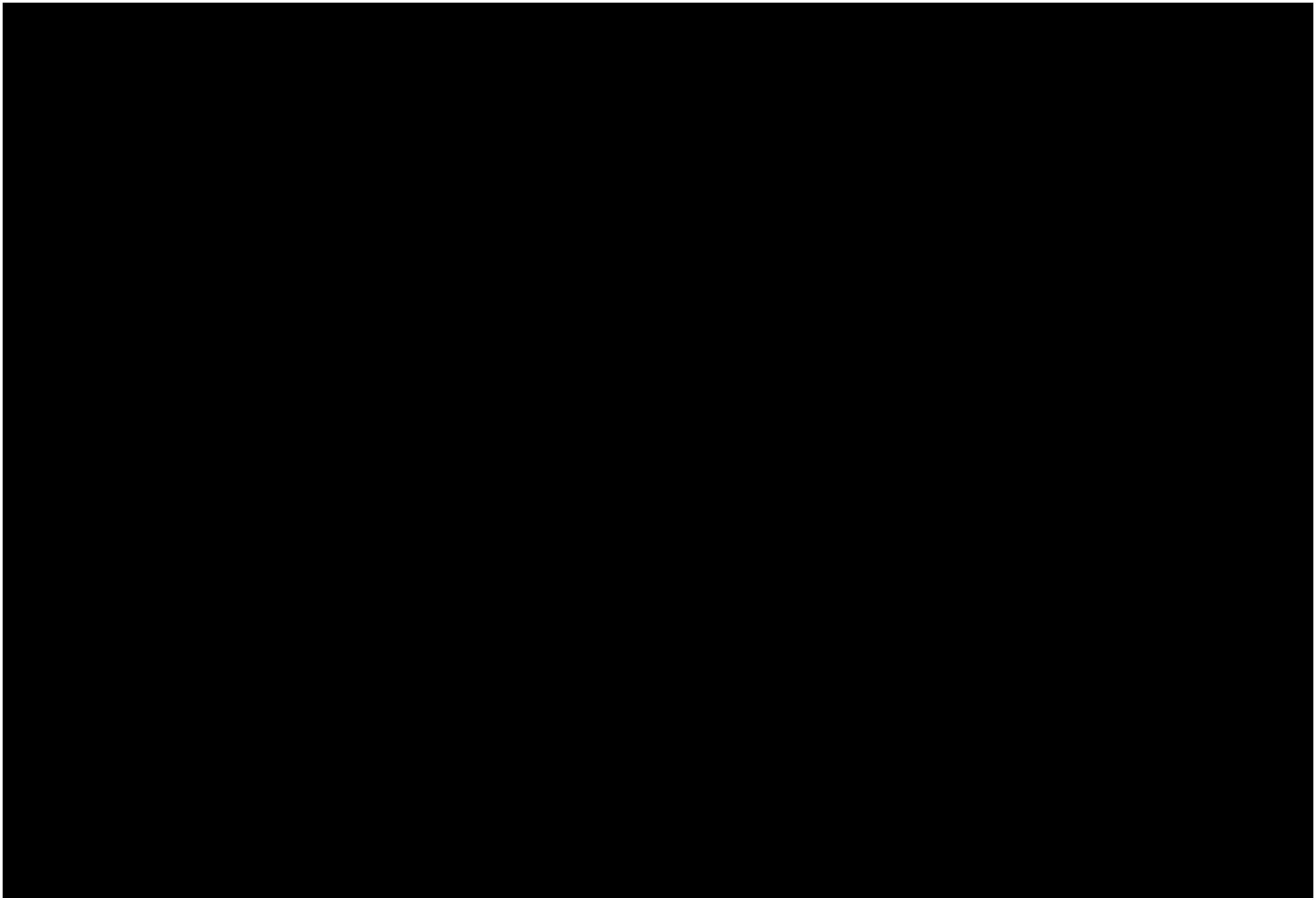
Date of Off Peak Day - 02/11/2021



Member Forecasted Off Peak Demand Day for March 2021

Morgan County Rural Electric Association

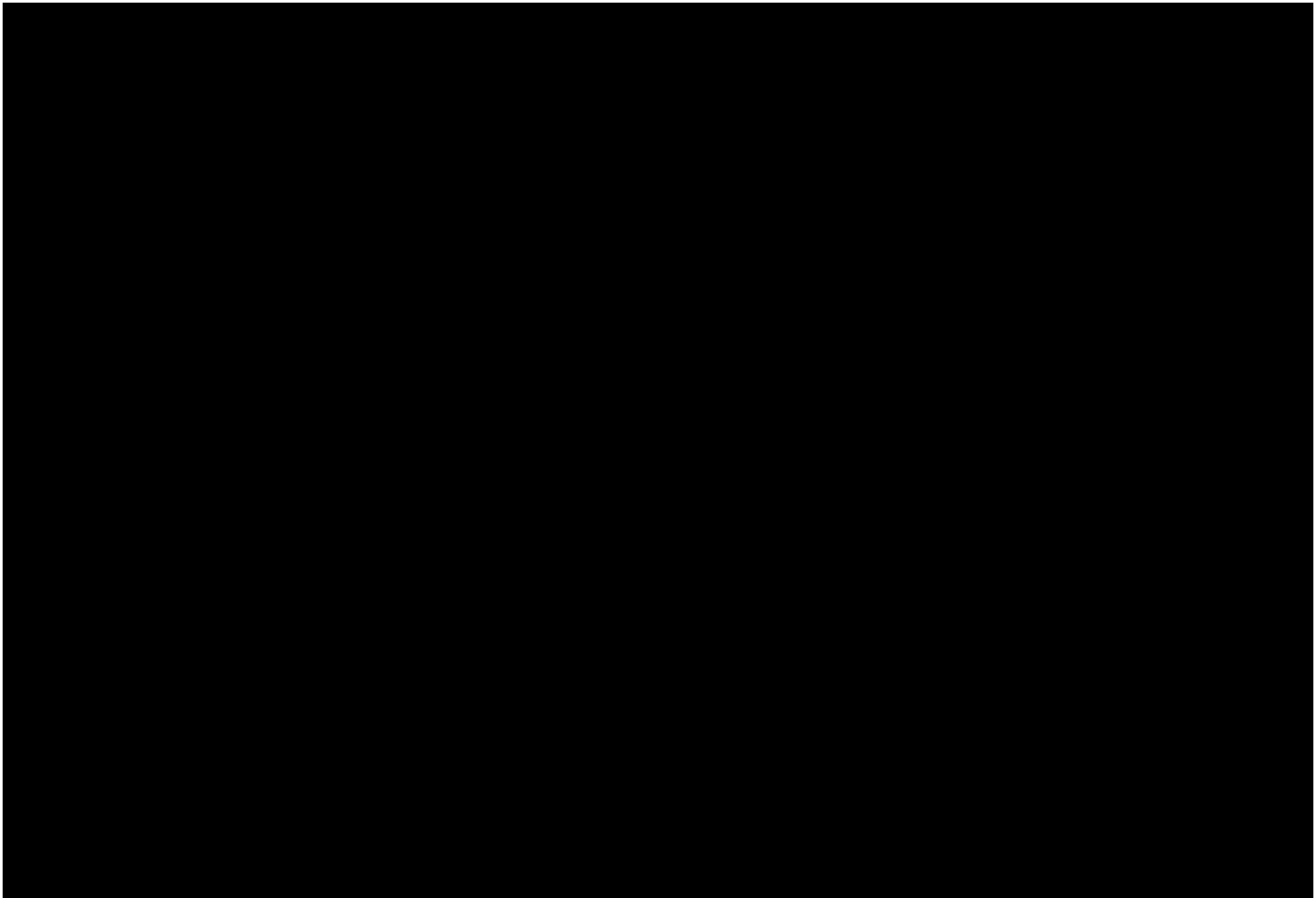
Date of Off Peak Day - 03/25/2021



Member Forecasted Off Peak Demand Day for April 2021

Morgan County Rural Electric Association

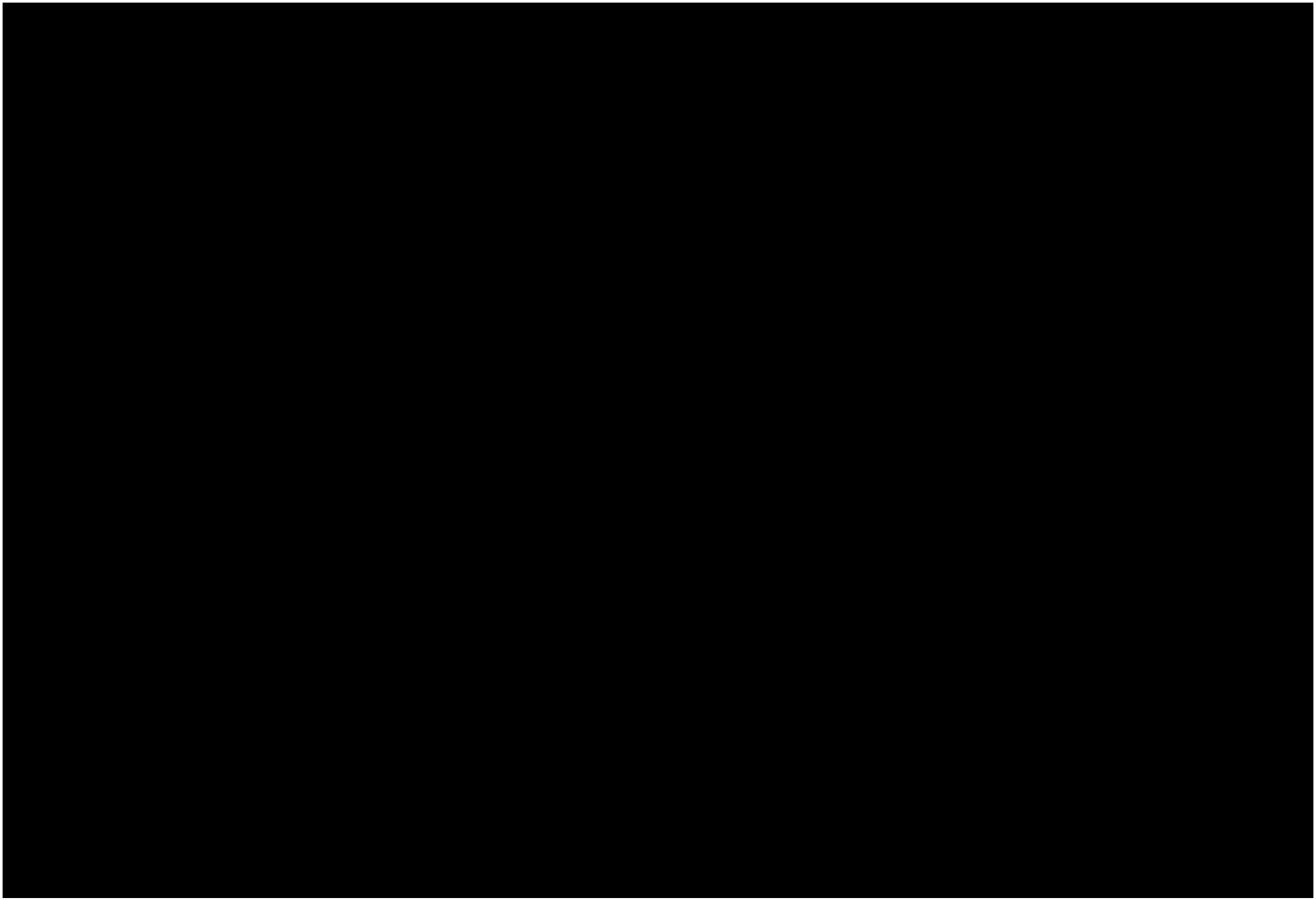
Date of Off Peak Day - 04/30/2021



Member Forecasted Off Peak Demand Day for May 2021

Morgan County Rural Electric Association

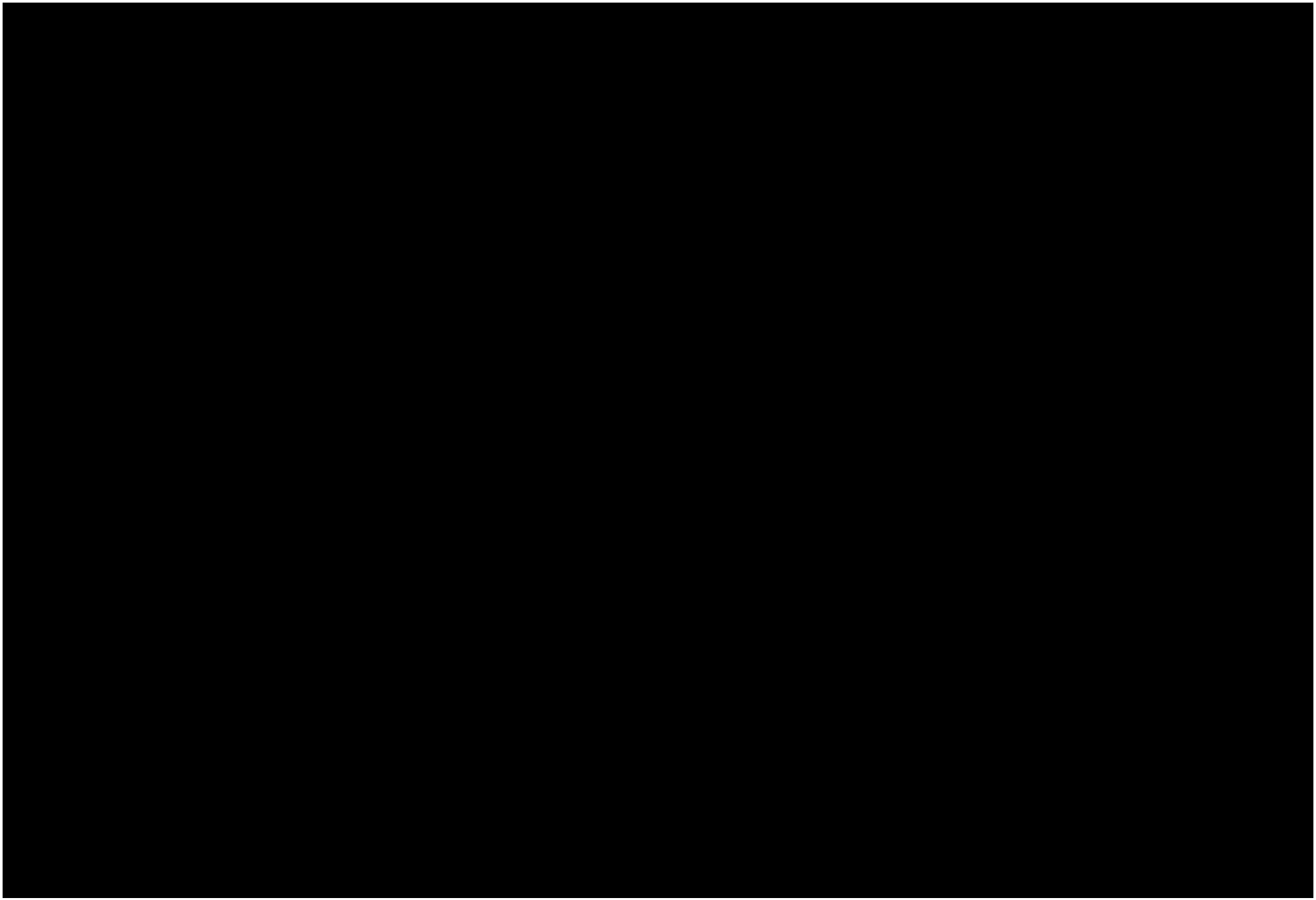
Date of Off Peak Day - 05/01/2021



Member Forecasted Off Peak Demand Day for June 2021

Morgan County Rural Electric Association

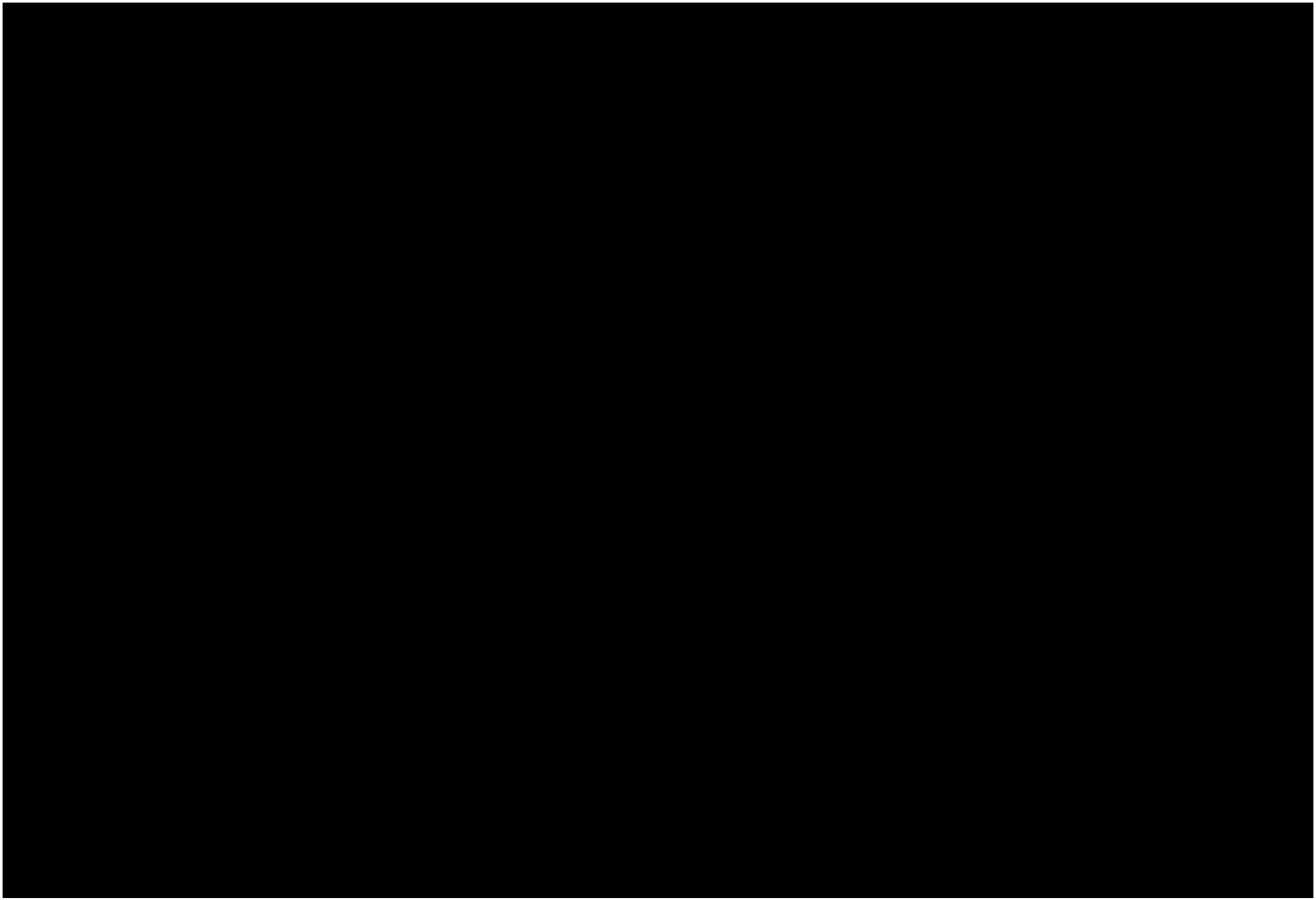
Date of Off Peak Day - 06/01/2021



Member Forecasted Off Peak Demand Day for July 2021

Morgan County Rural Electric Association

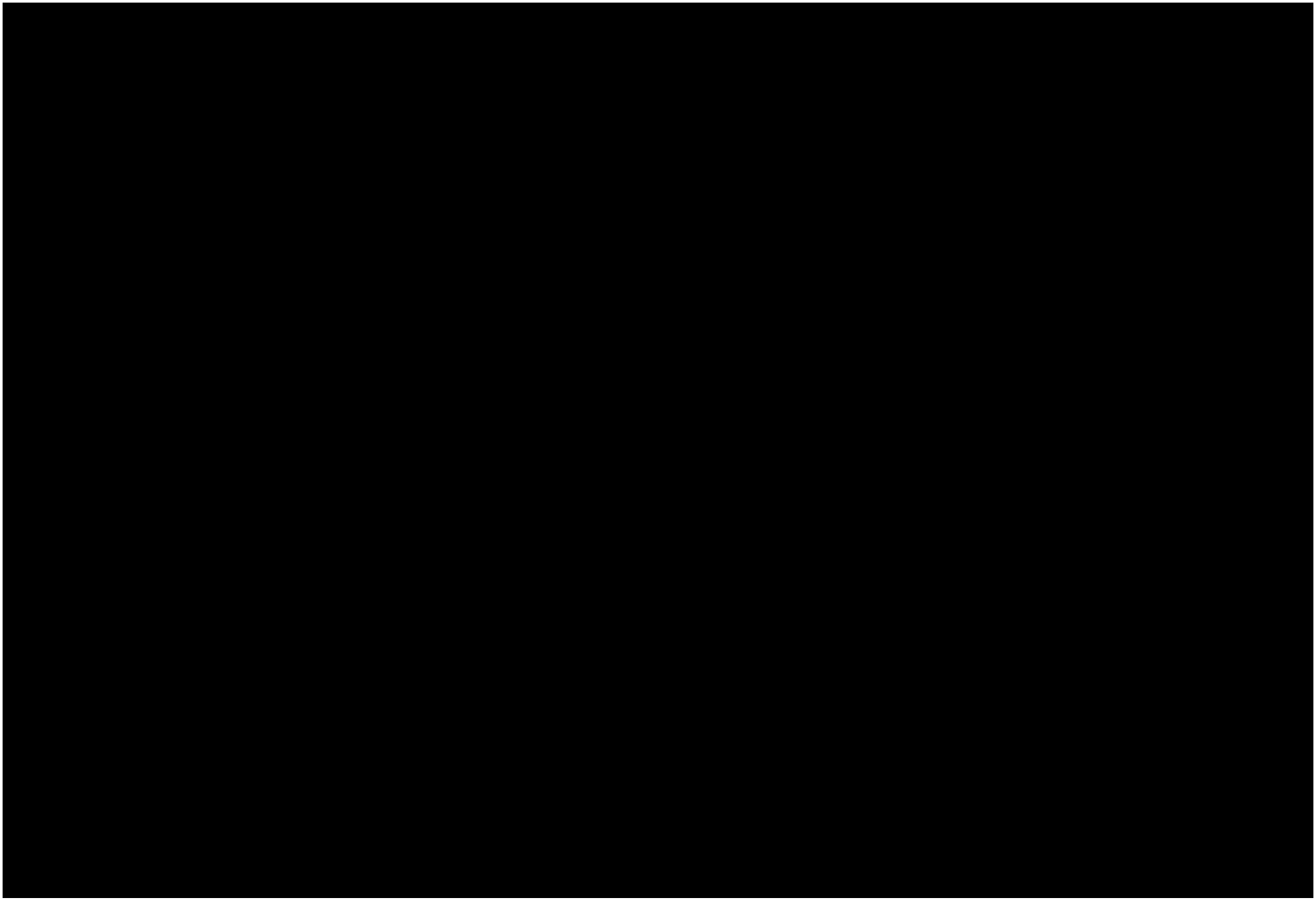
Date of Off Peak Day - 07/03/2021



Member Forecasted Off Peak Demand Day for August 2021

Morgan County Rural Electric Association

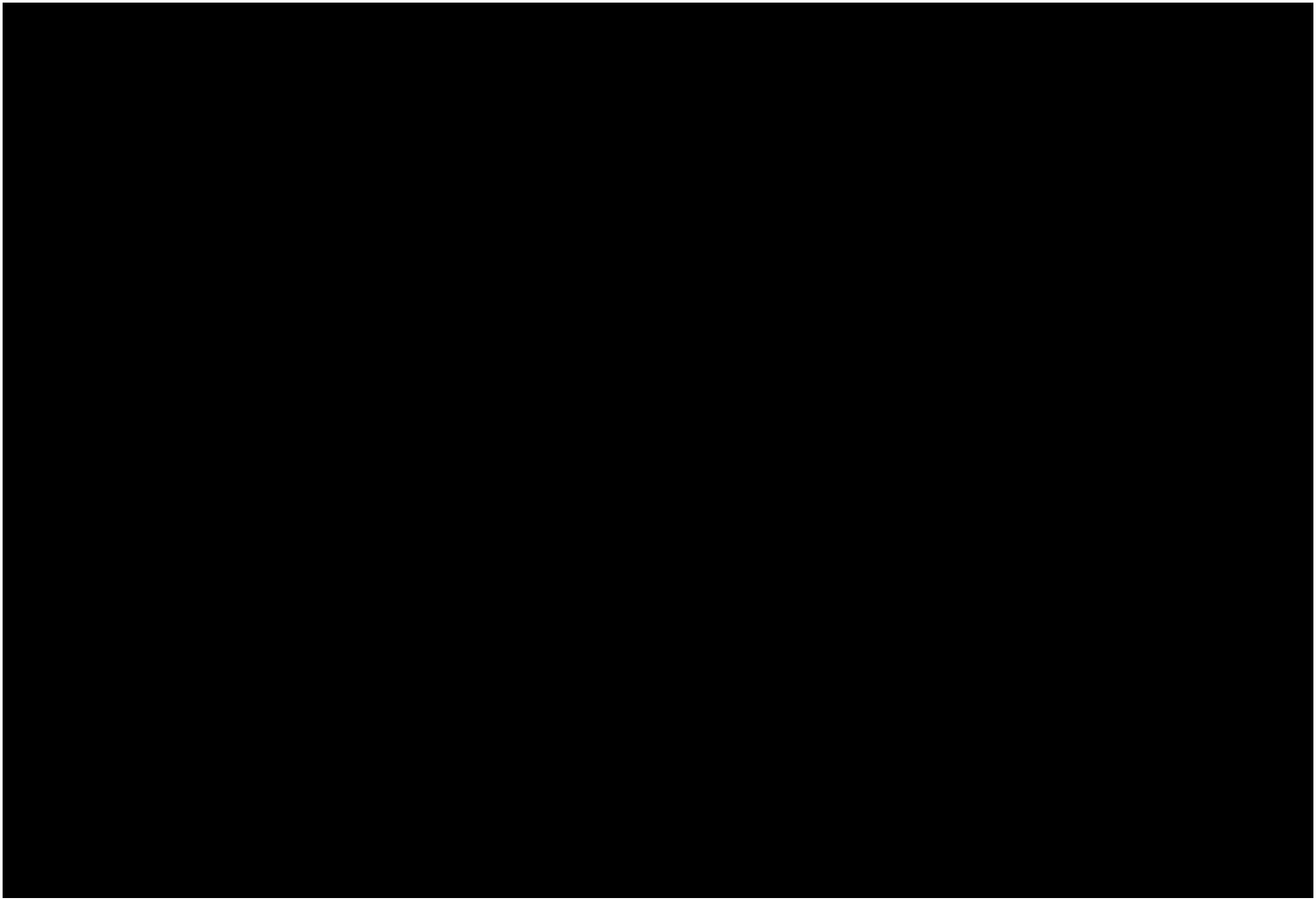
Date of Off Peak Day - 08/08/2021



Member Forecasted Off Peak Demand Day for September 2021

Morgan County Rural Electric Association

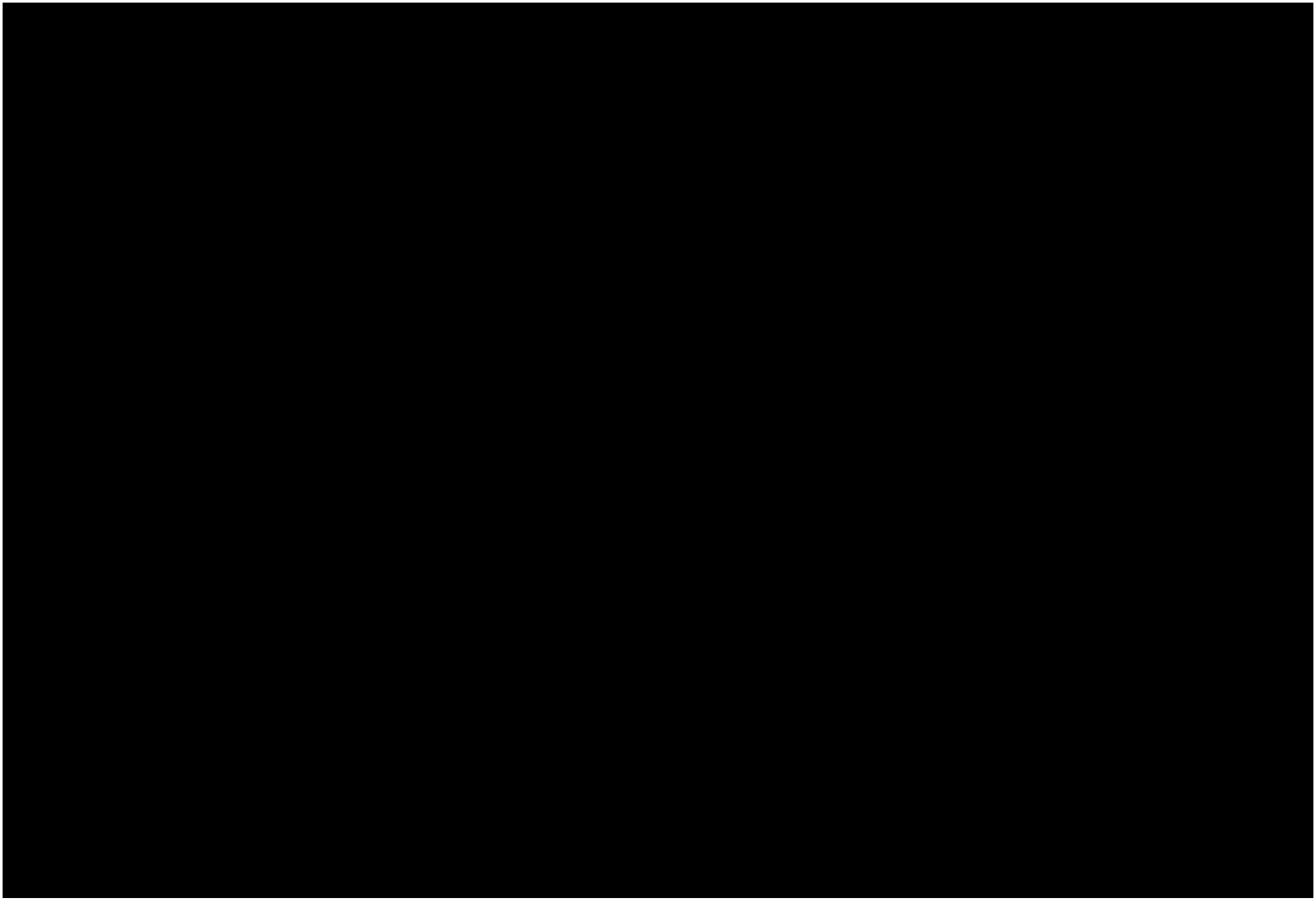
Date of Off Peak Day - 09/30/2021



Member Forecasted Off Peak Demand Day for October 2021

Morgan County Rural Electric Association

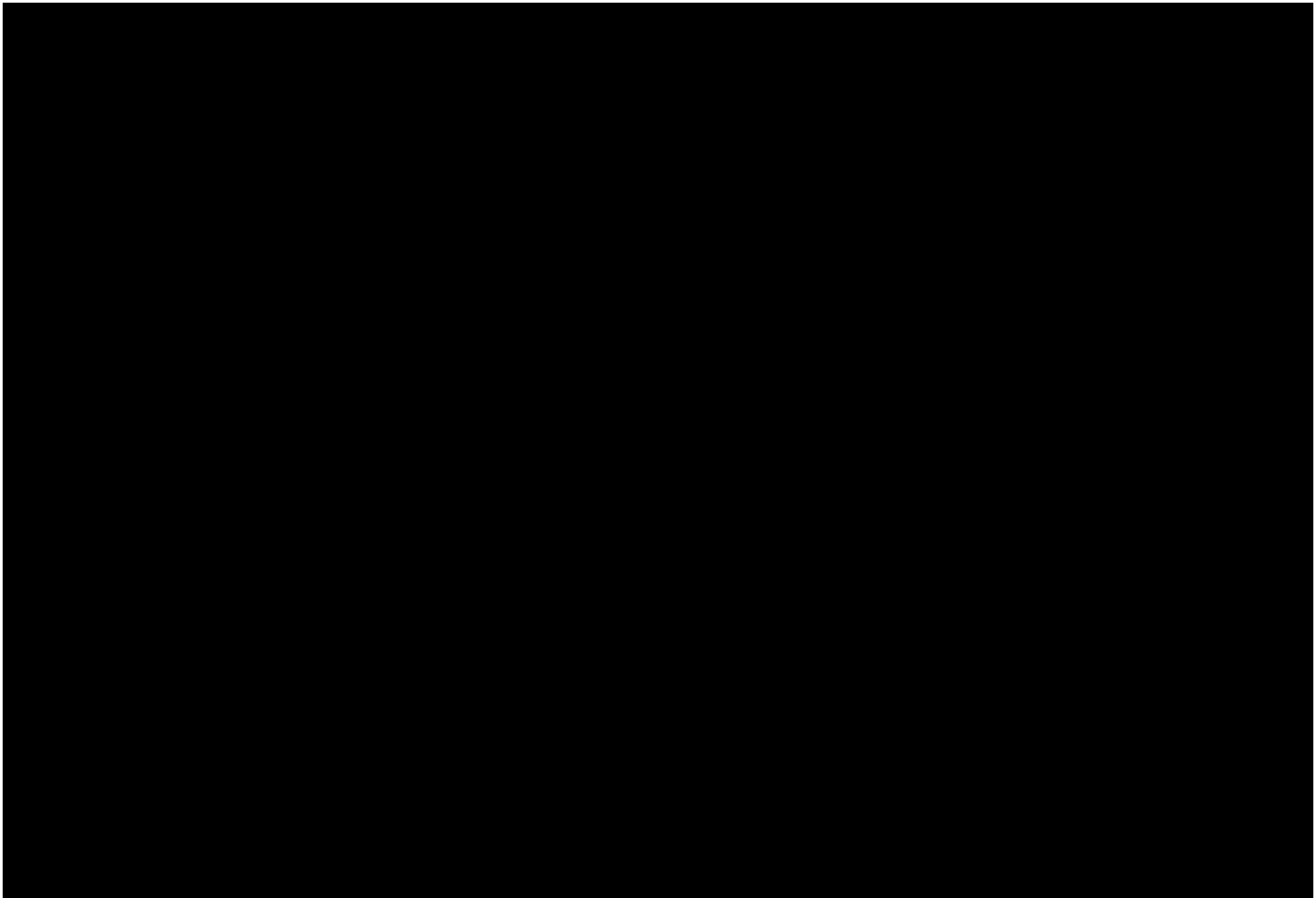
Date of Off Peak Day - 10/10/2021



Member Forecasted Off Peak Demand Day for November 2021

Morgan County Rural Electric Association

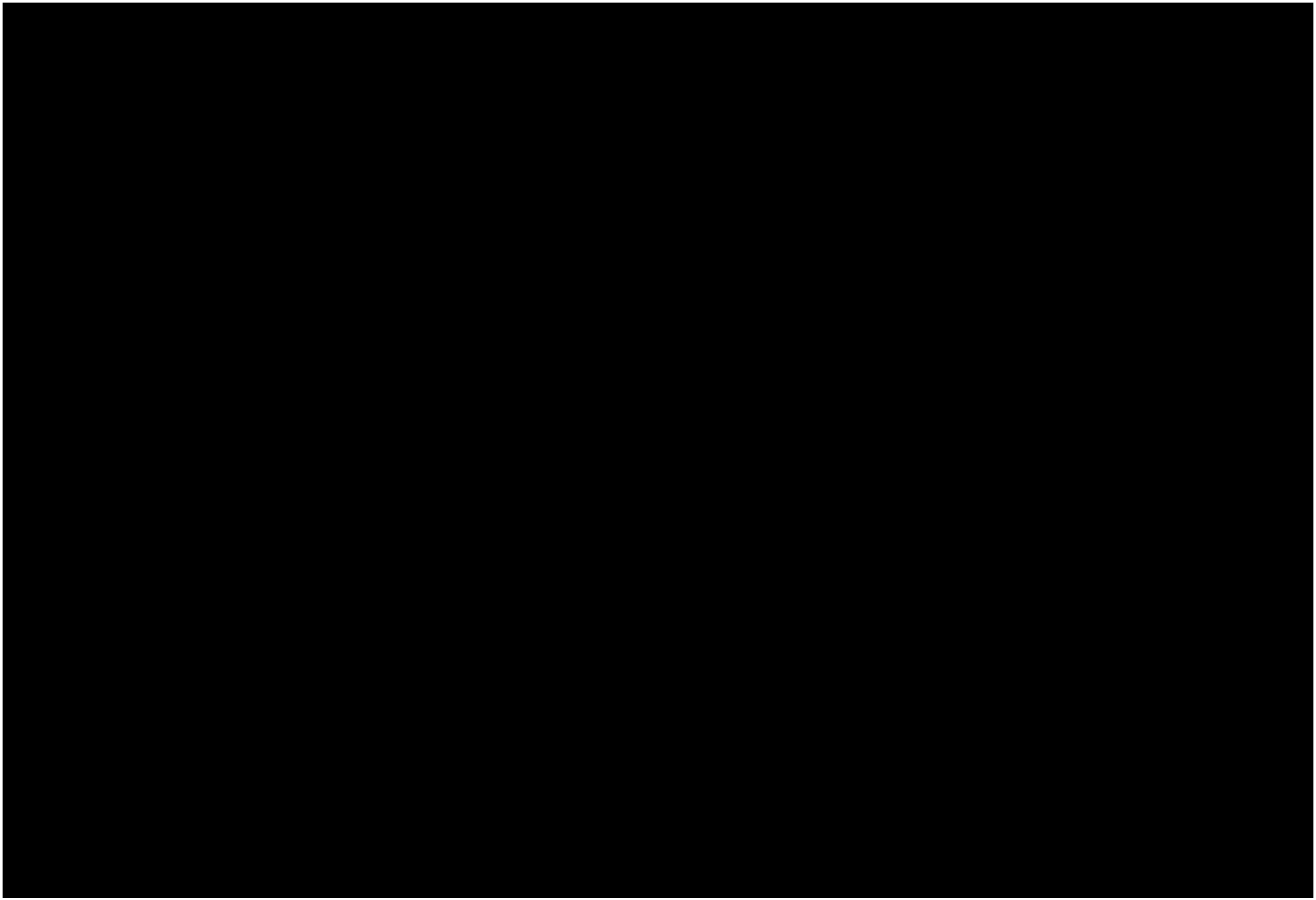
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

Morgan County Rural Electric Association

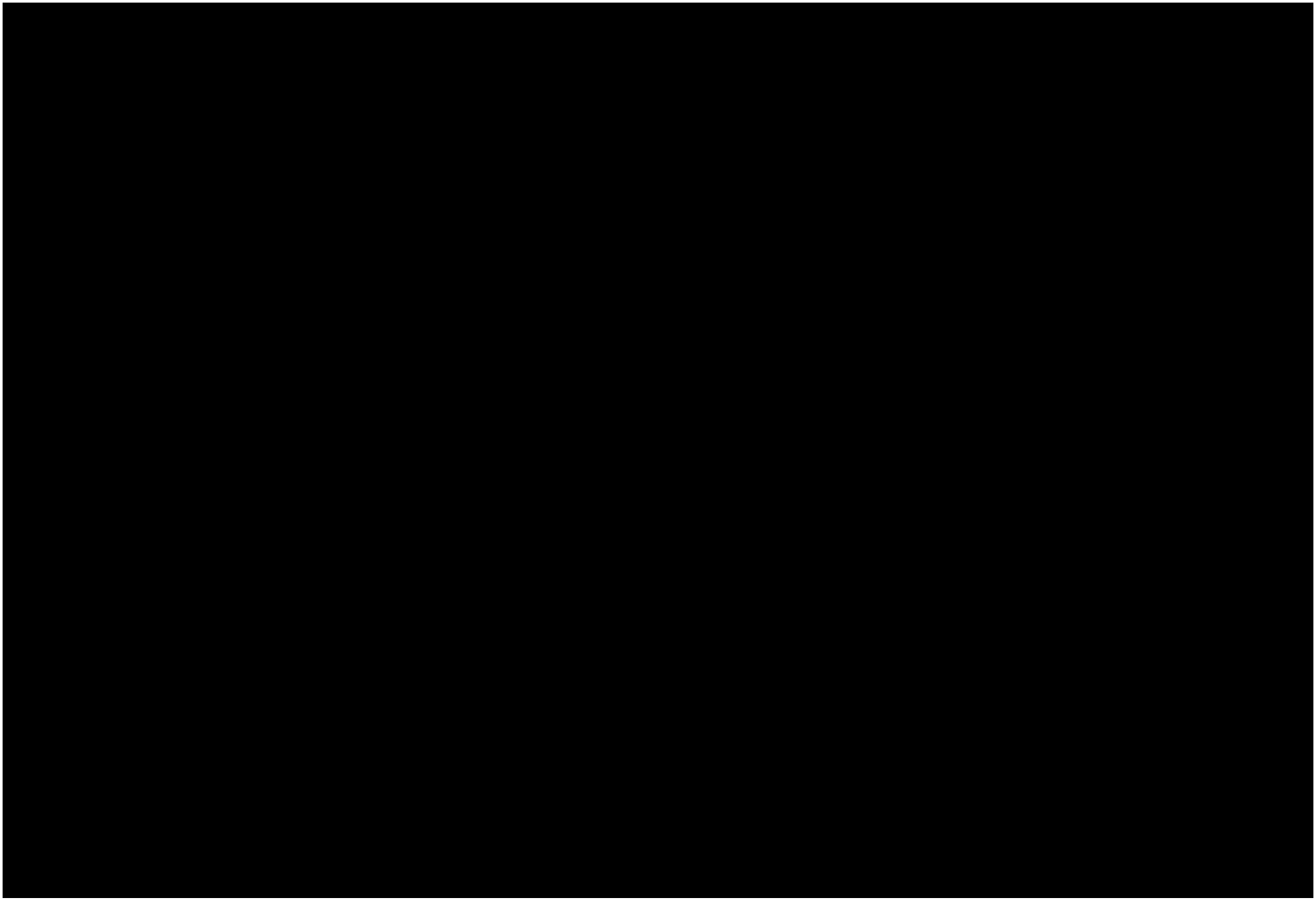
Date of Off Peak Day - 12/08/2021



Member Forecasted Off Peak Demand Day for January 2021

Mountain Parks Electric, Inc.

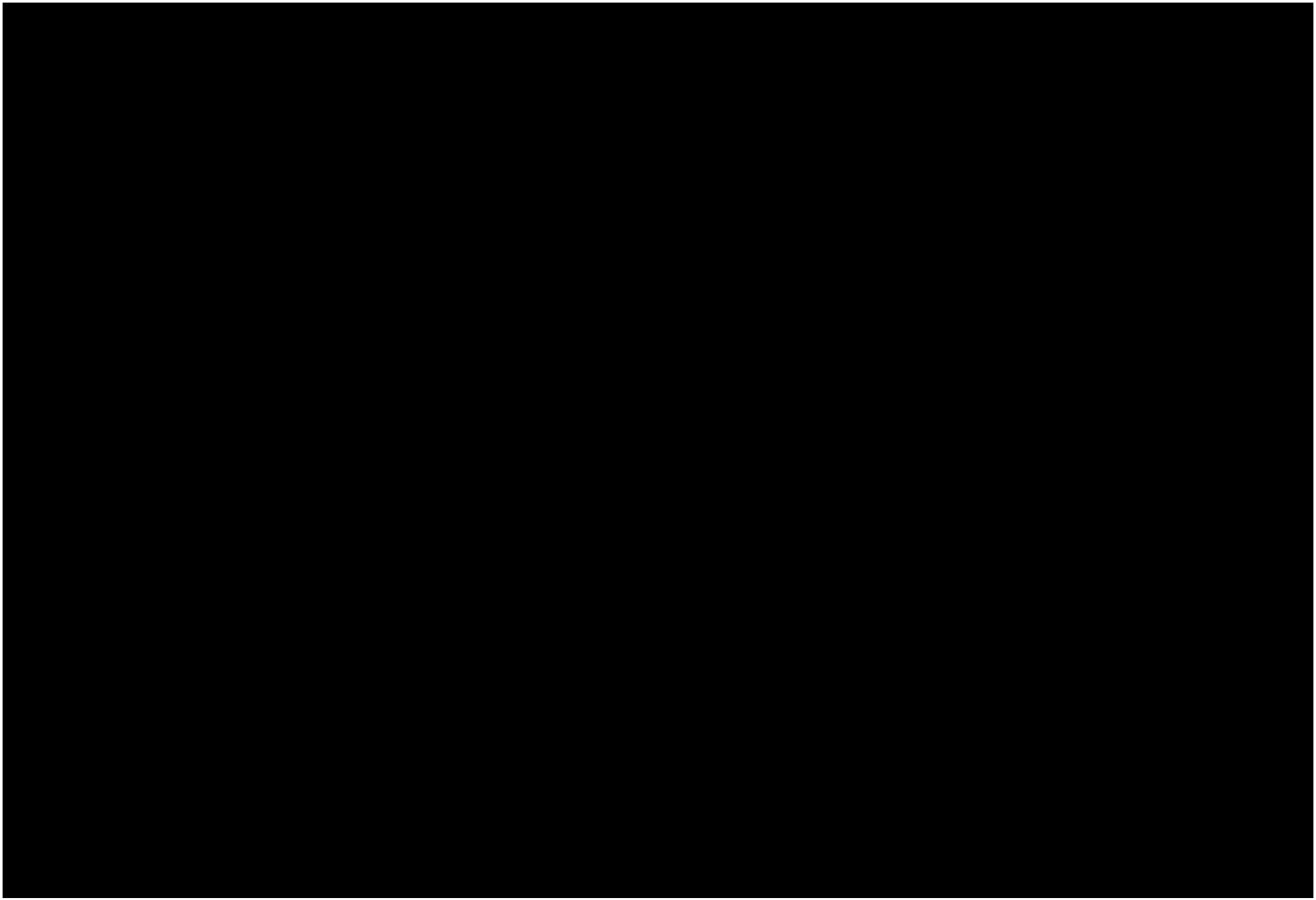
Date of Off Peak Day - 01/31/2021



Member Forecasted Off Peak Demand Day for February 2021

Mountain Parks Electric, Inc.

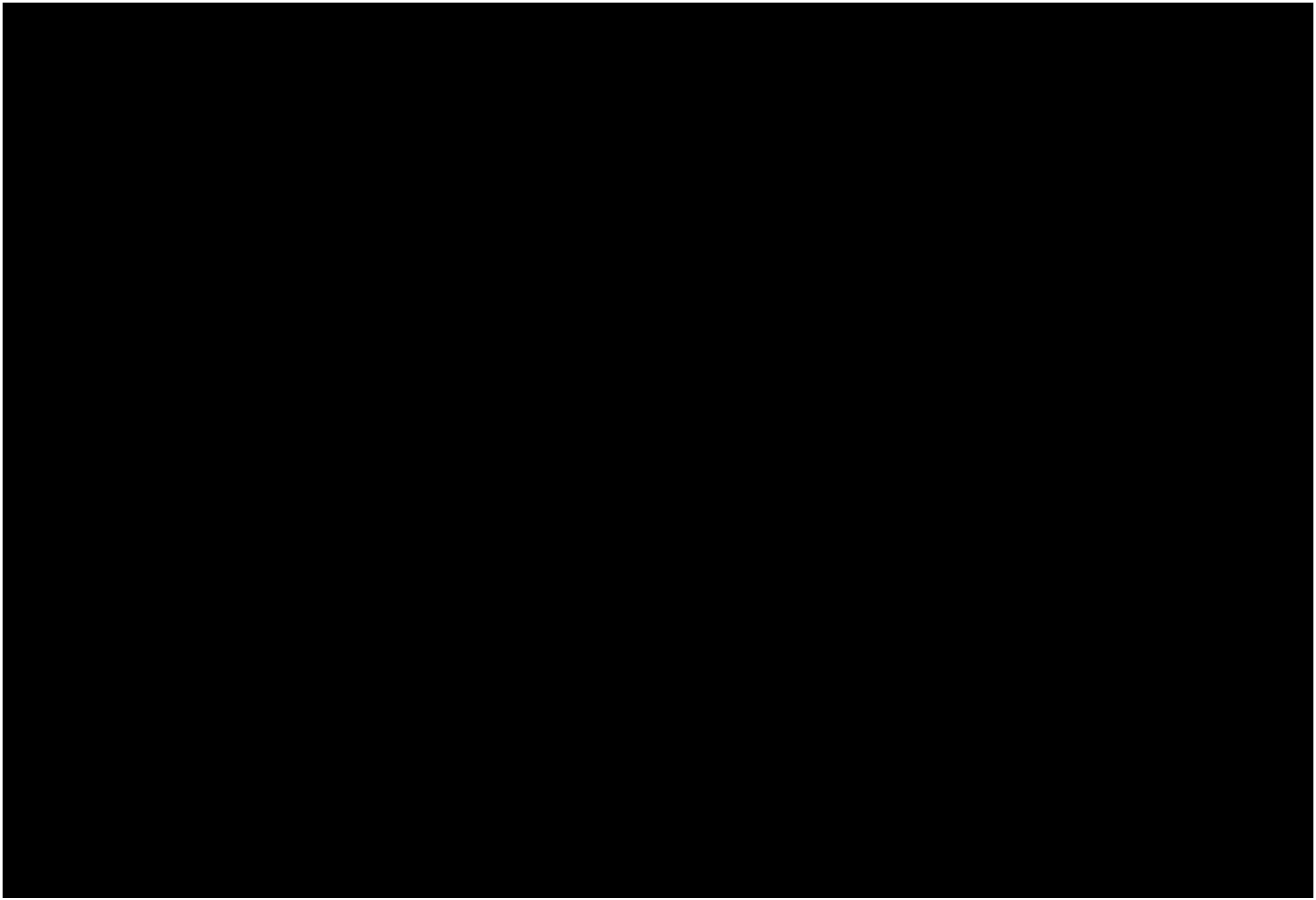
Date of Off Peak Day - 02/22/2021



Member Forecasted Off Peak Demand Day for March 2021

Mountain Parks Electric, Inc.

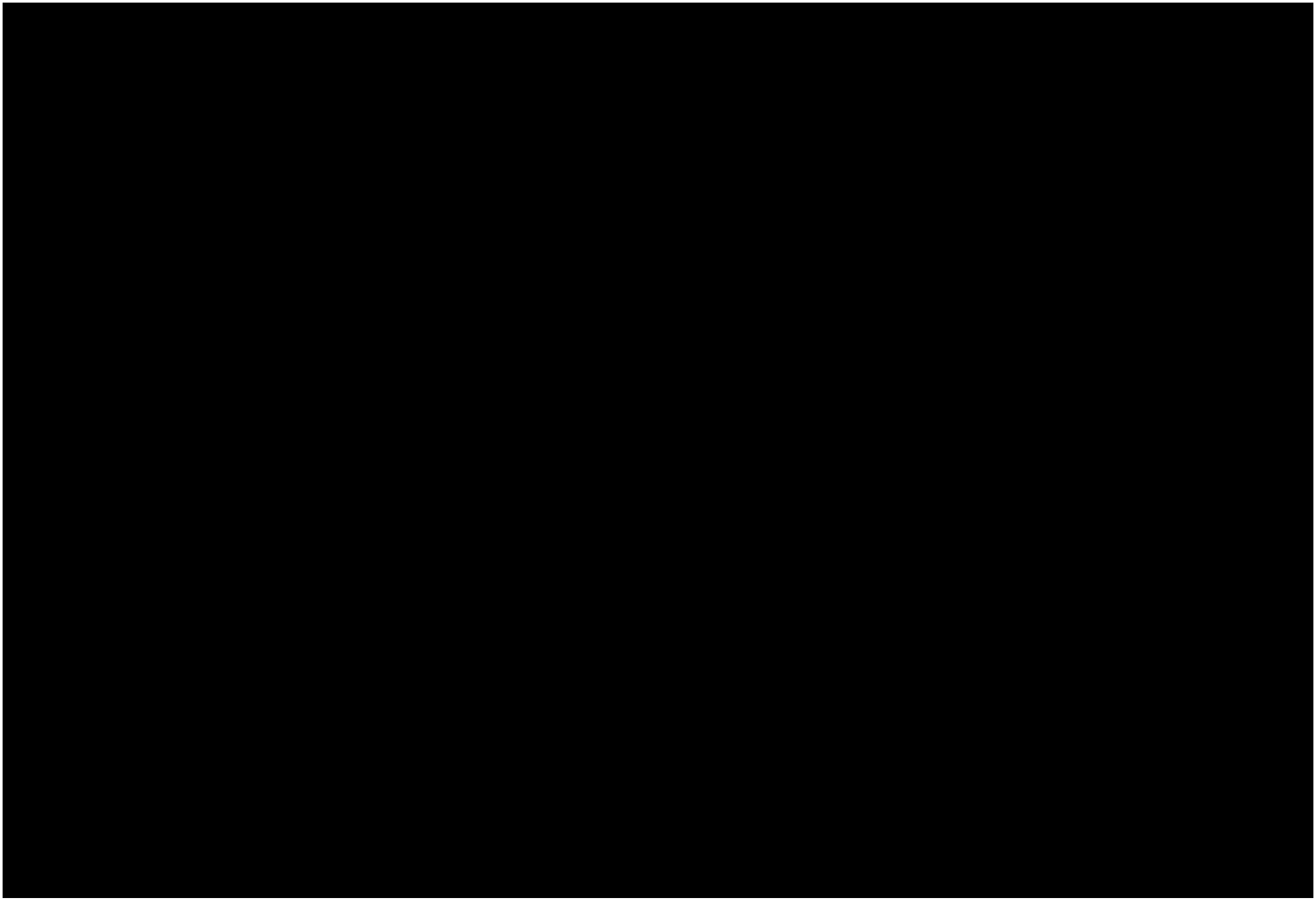
Date of Off Peak Day - 03/21/2021



Member Forecasted Off Peak Demand Day for April 2021

Mountain Parks Electric, Inc.

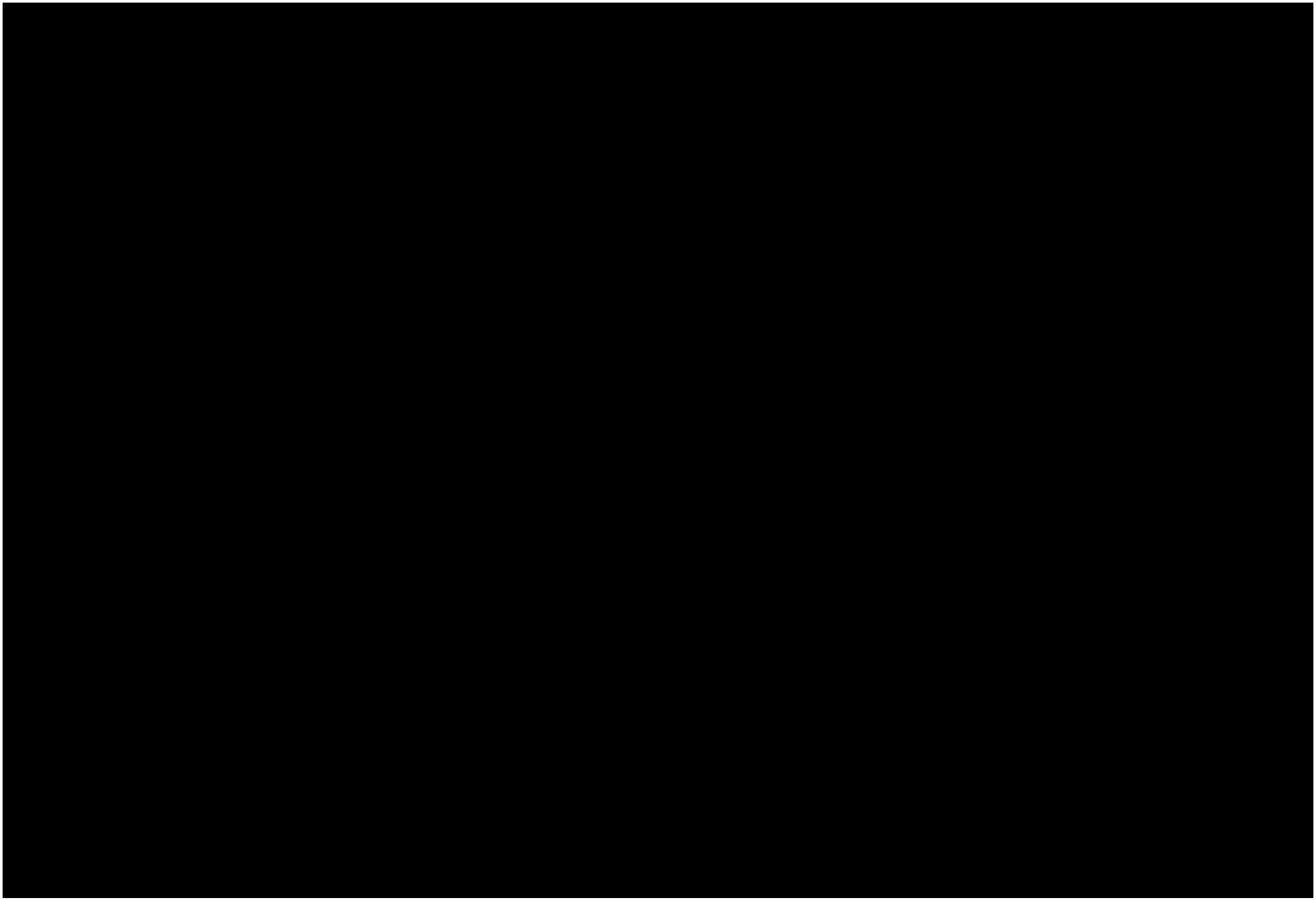
Date of Off Peak Day - 04/29/2021



Member Forecasted Off Peak Demand Day for May 2021

Mountain Parks Electric, Inc.

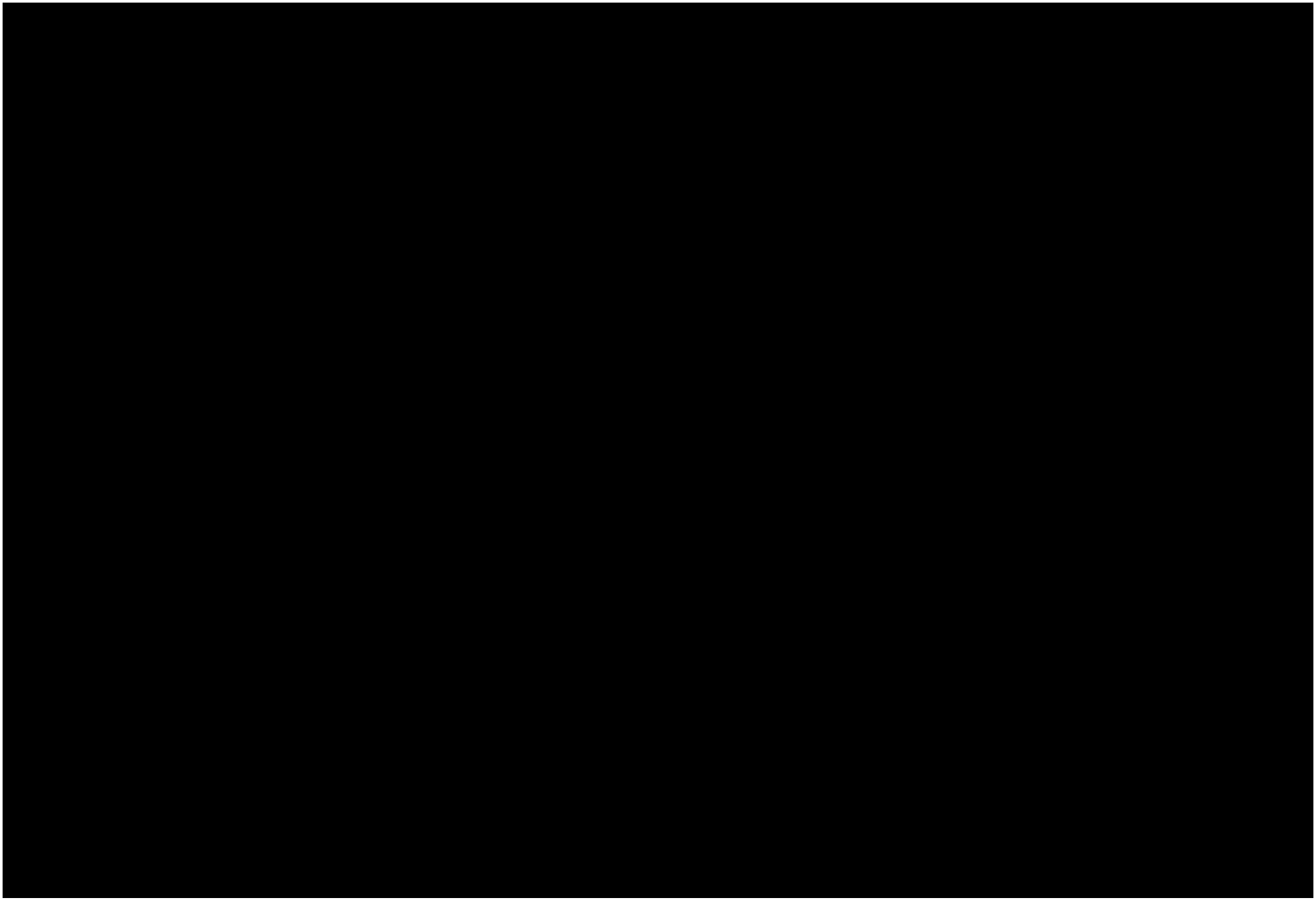
Date of Off Peak Day - 05/25/2021



Member Forecasted Off Peak Demand Day for June 2021

Mountain Parks Electric, Inc.

Date of Off Peak Day - 06/20/2021



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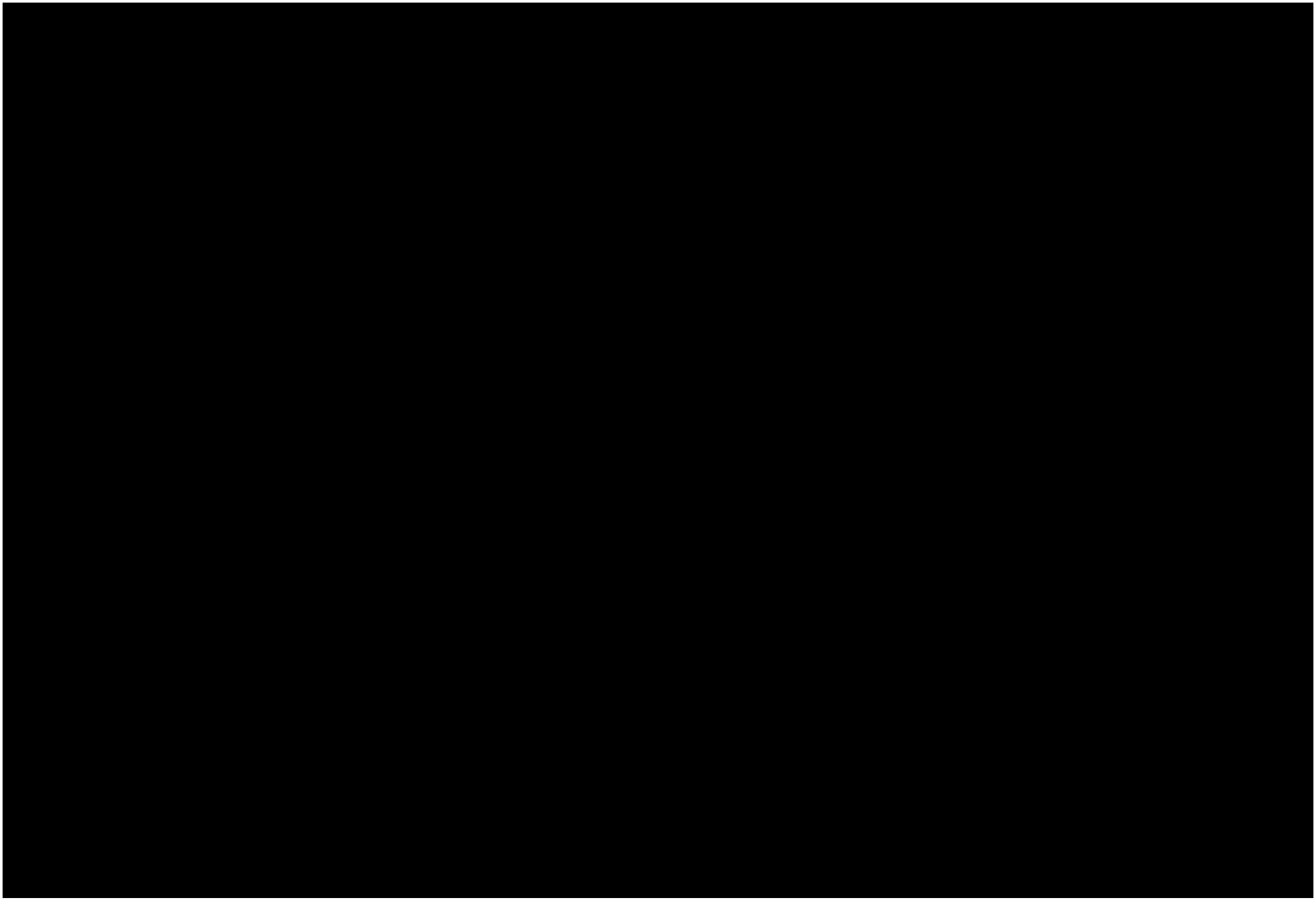
Member Forecasted Off Peak Demand Day for July 2021

Mountain Parks Electric, Inc.

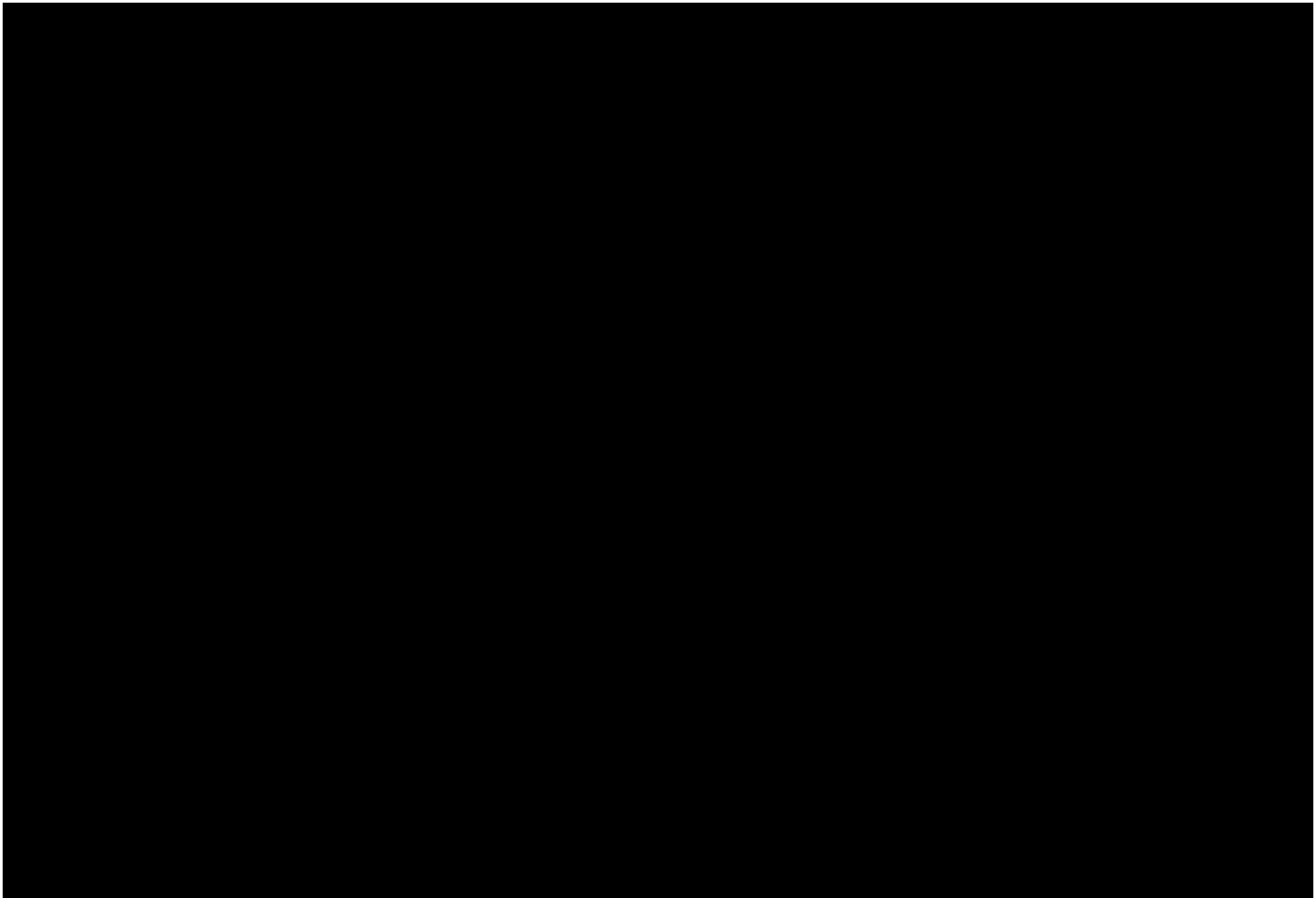
Date of Off Peak Day - 07/19/2021



Member Forecasted Off Peak Demand Day for August 2021

Mountain Parks Electric, Inc.

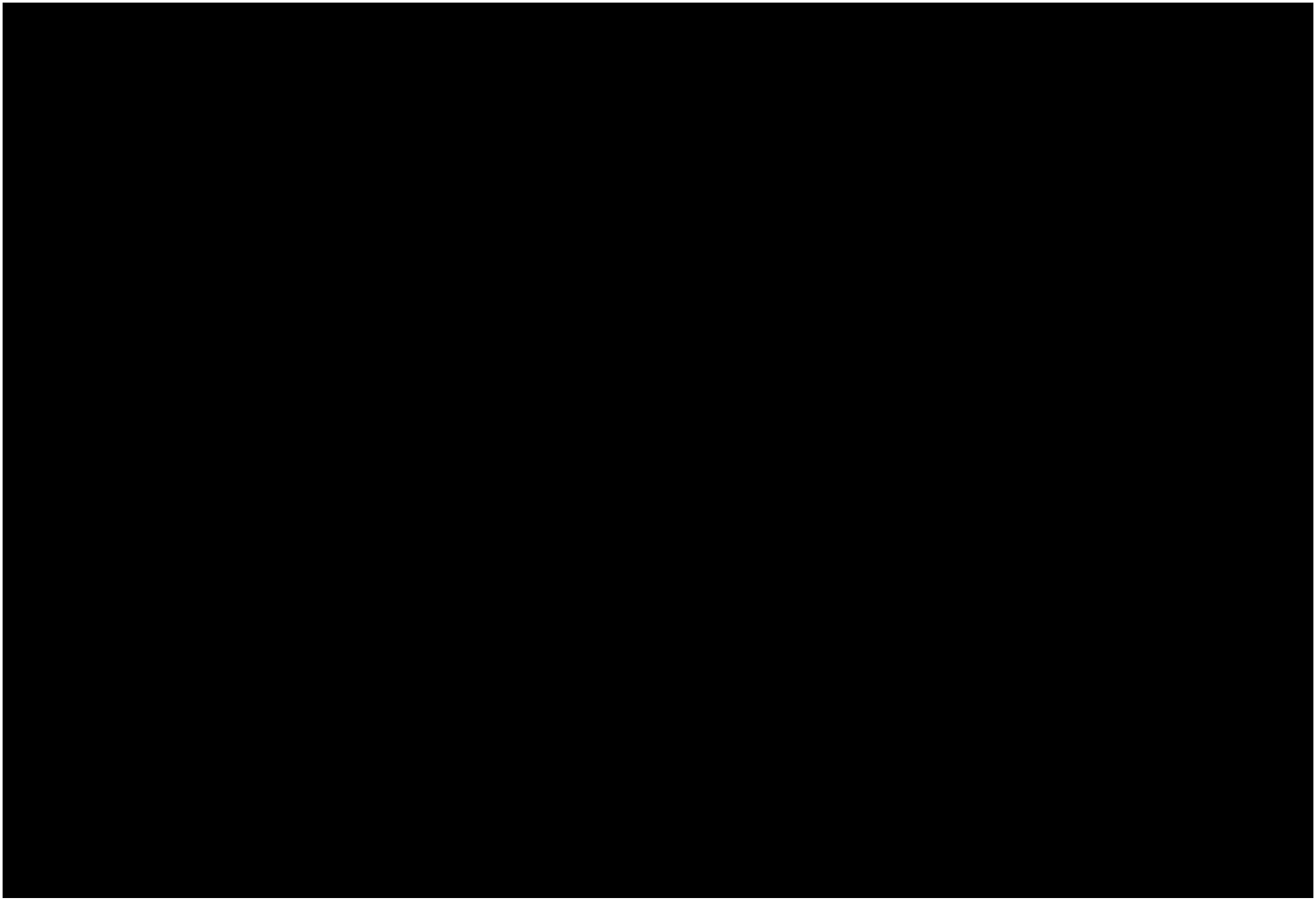
Date of Off Peak Day - 08/23/2021



Member Forecasted Off Peak Demand Day for September 2021

Mountain Parks Electric, Inc.

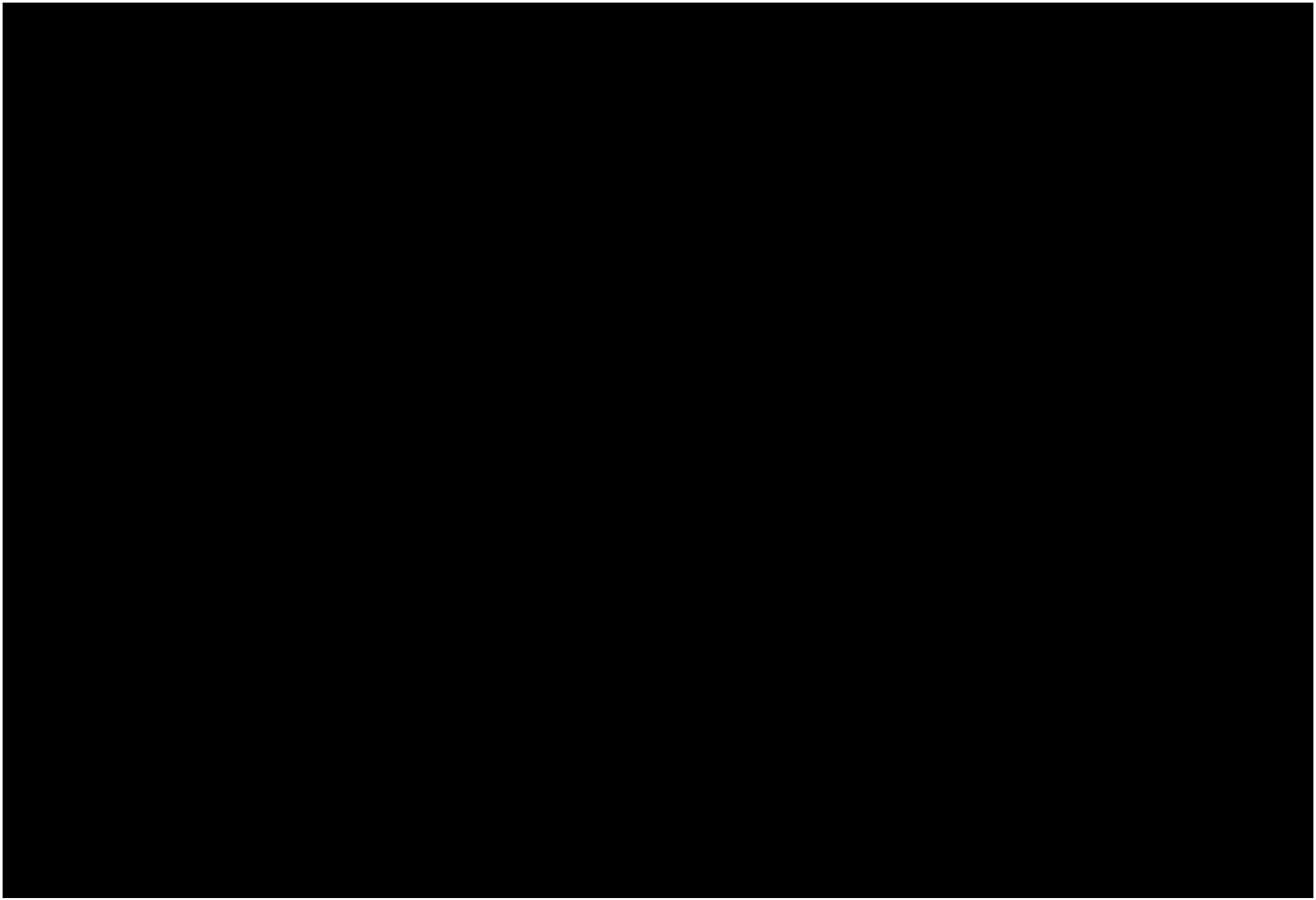
Date of Off Peak Day - 09/27/2021



Member Forecasted Off Peak Demand Day for October 2021

Mountain Parks Electric, Inc.

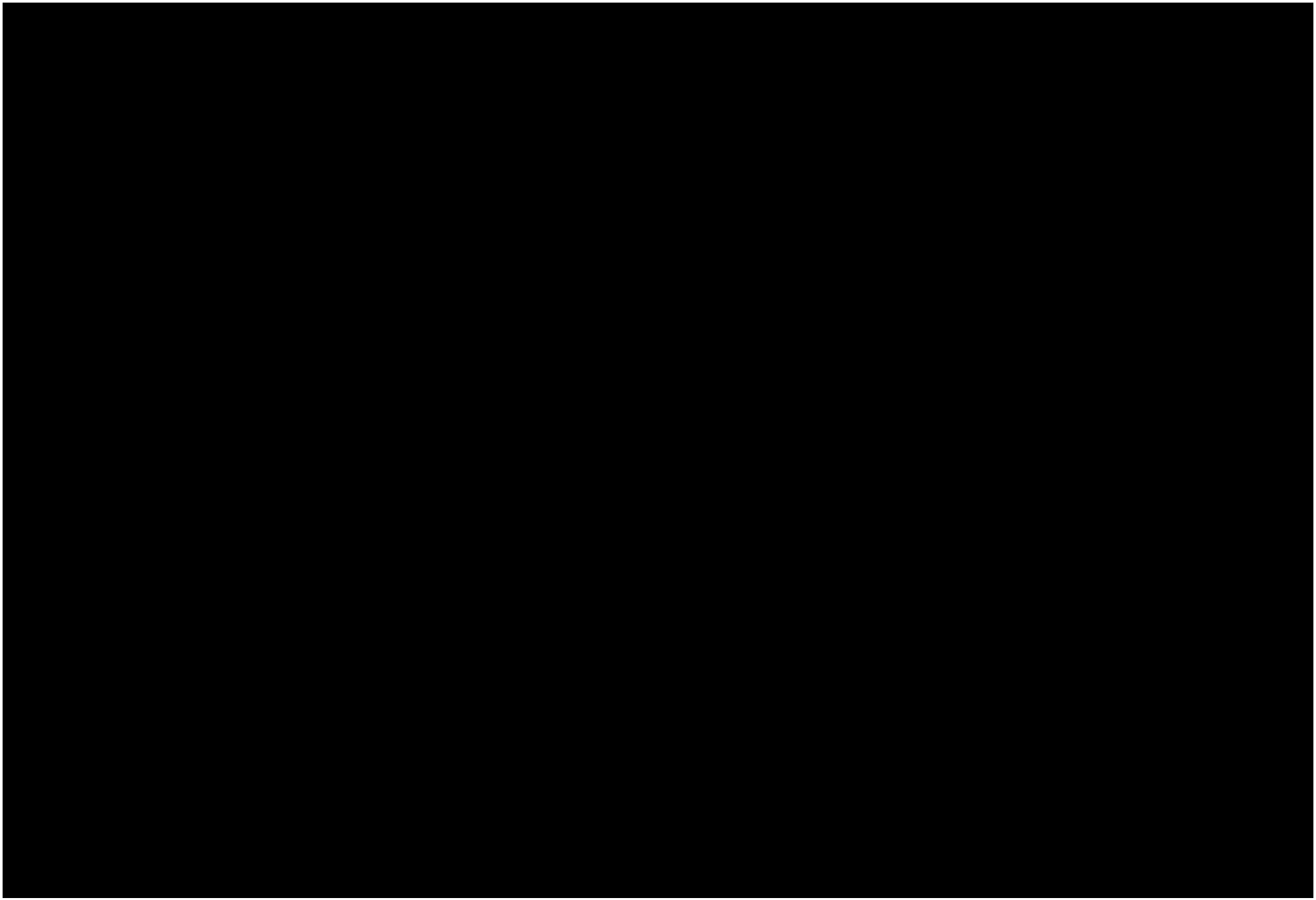
Date of Off Peak Day - 10/01/2021



Member Forecasted Off Peak Demand Day for November 2021

Mountain Parks Electric, Inc.

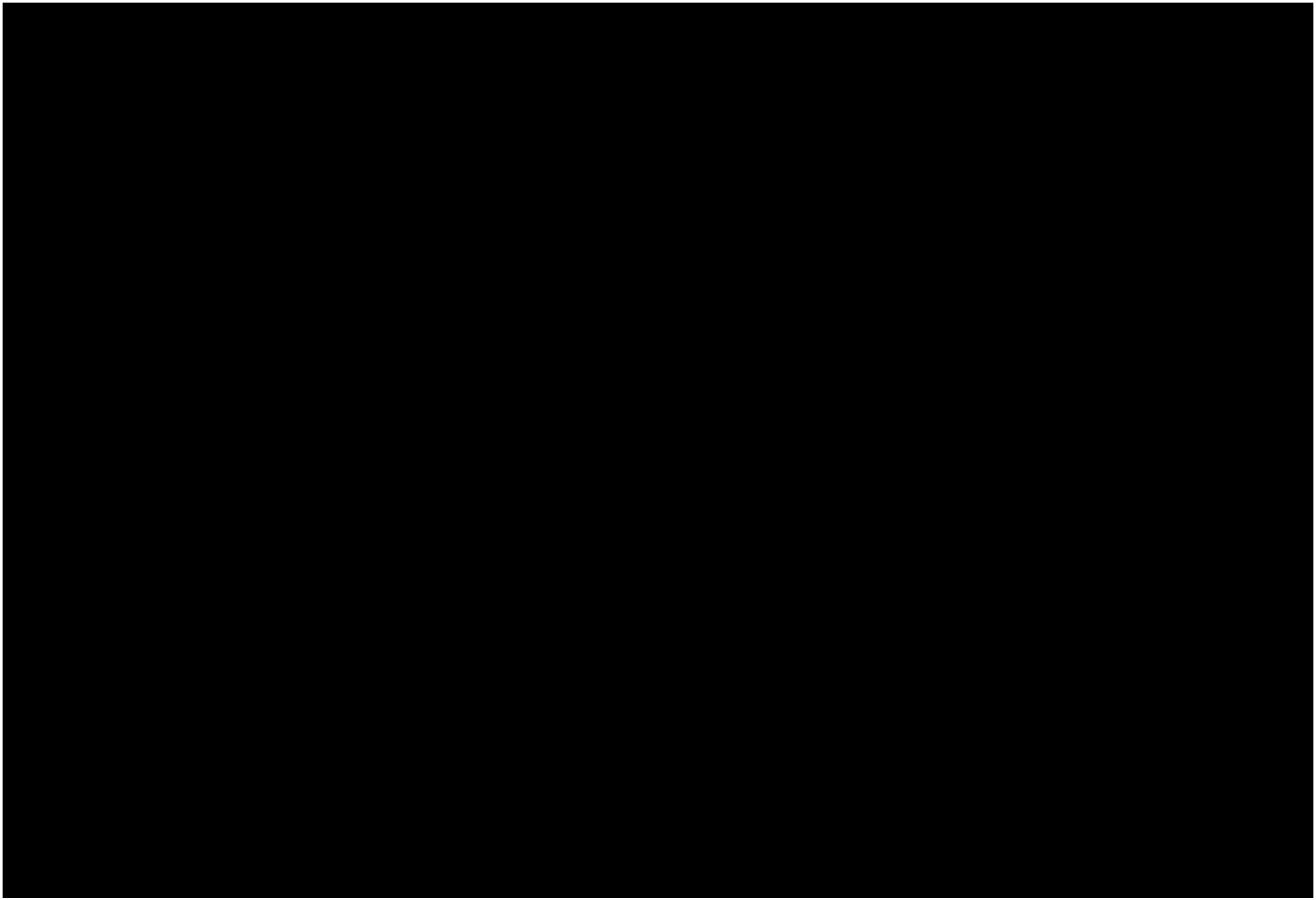
Date of Off Peak Day - 11/03/2021



Member Forecasted Off Peak Demand Day for December 2021

Mountain Parks Electric, Inc.

Date of Off Peak Day - 12/11/2021



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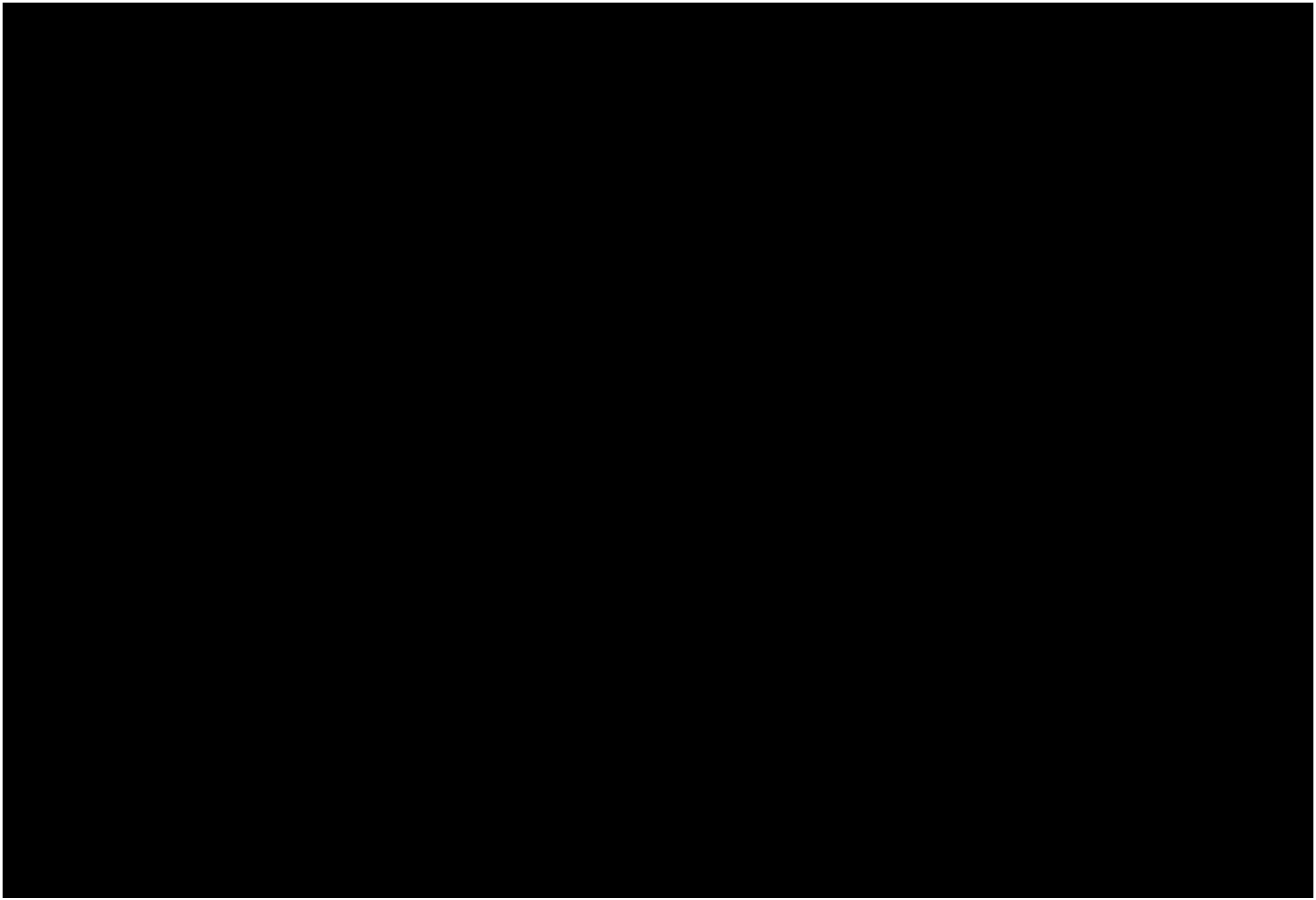
Member Forecasted Off Peak Demand Day for January 2021

Mora-San Miguel Electric Cooperative, Inc.

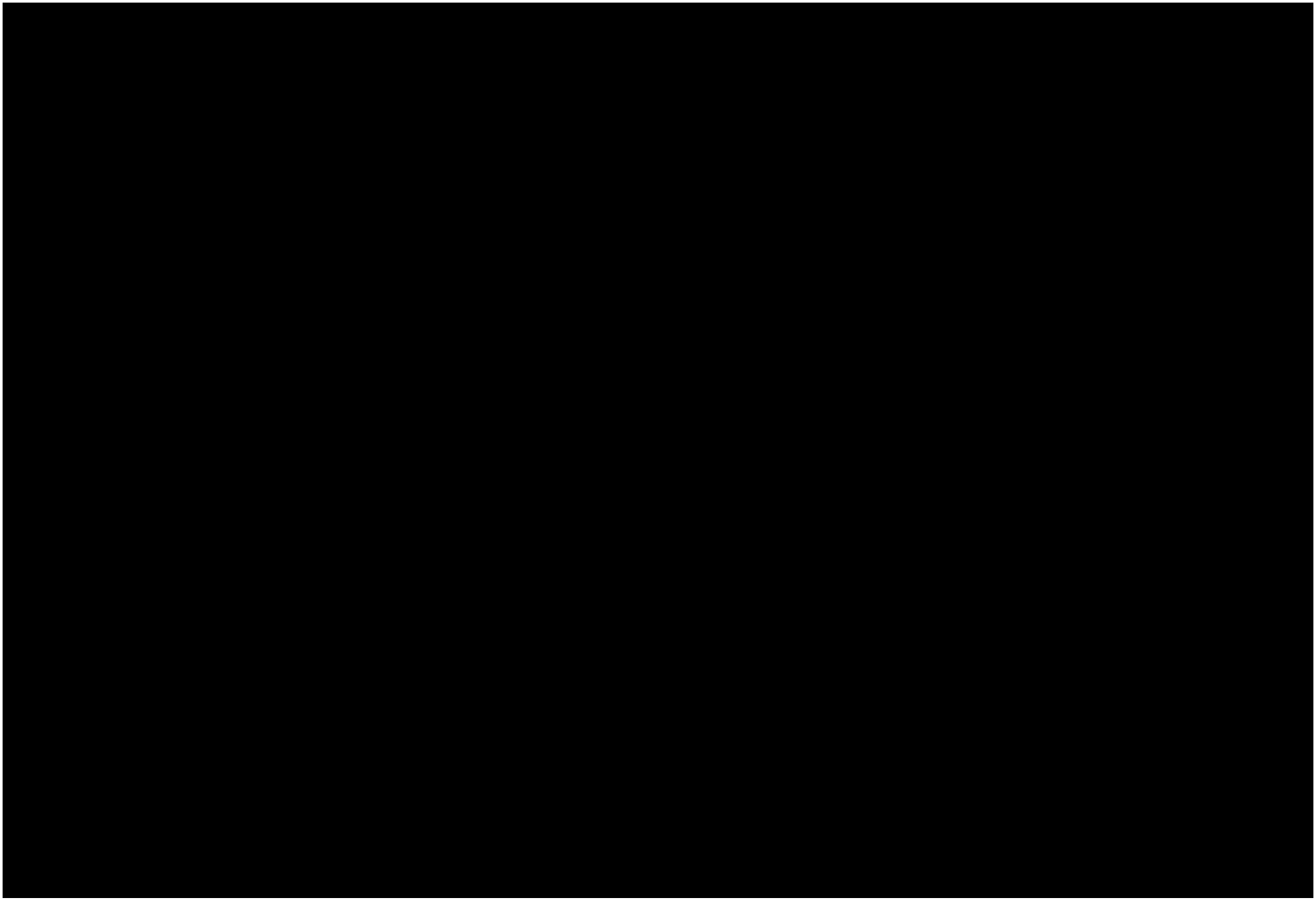
Date of Off Peak Day - 01/14/2021



Member Forecasted Off Peak Demand Day for February 2021

Mora-San Miguel Electric Cooperative, Inc.

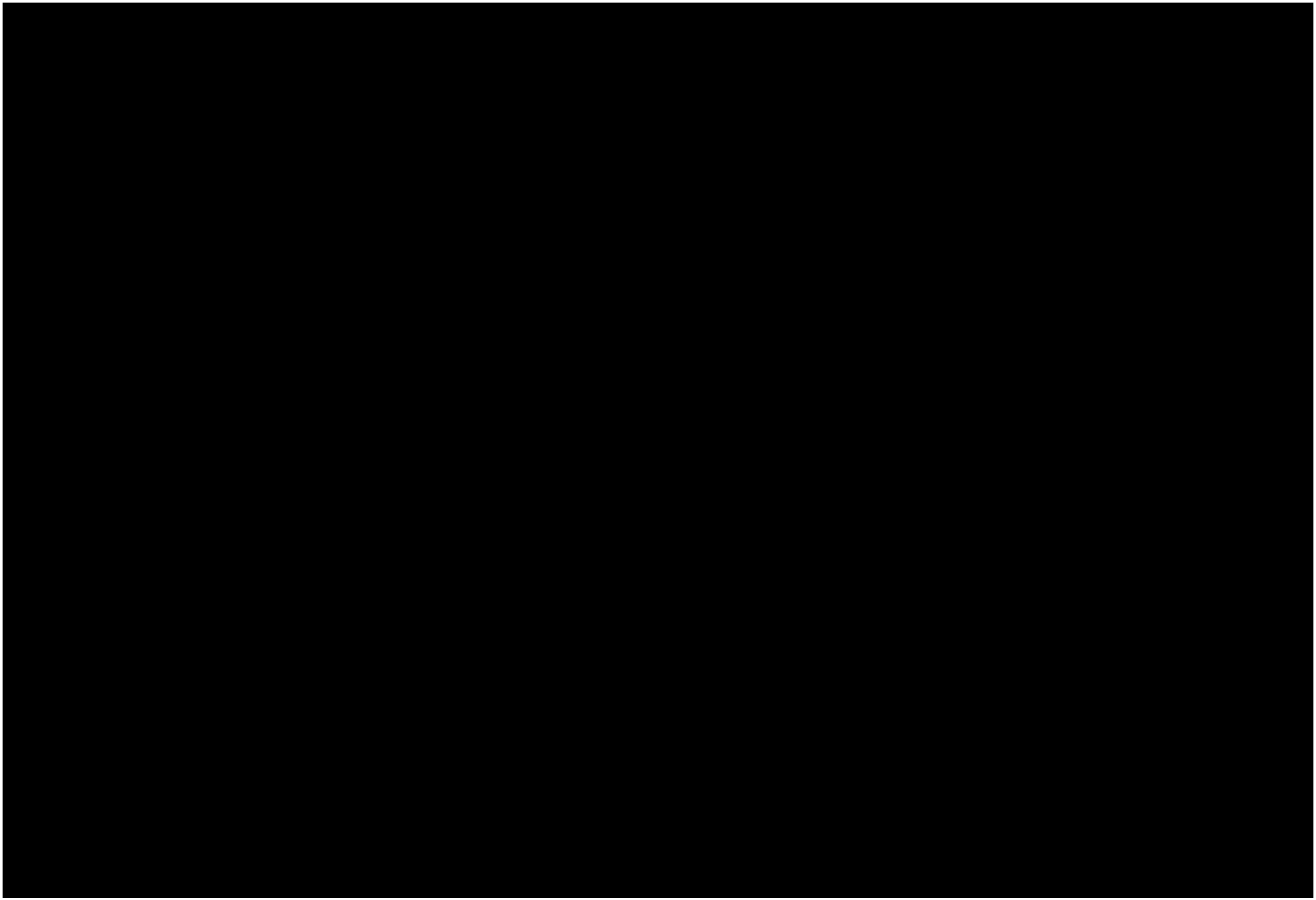
Date of Off Peak Day - 02/11/2021



Member Forecasted Off Peak Demand Day for March 2021

Mora-San Miguel Electric Cooperative, Inc.

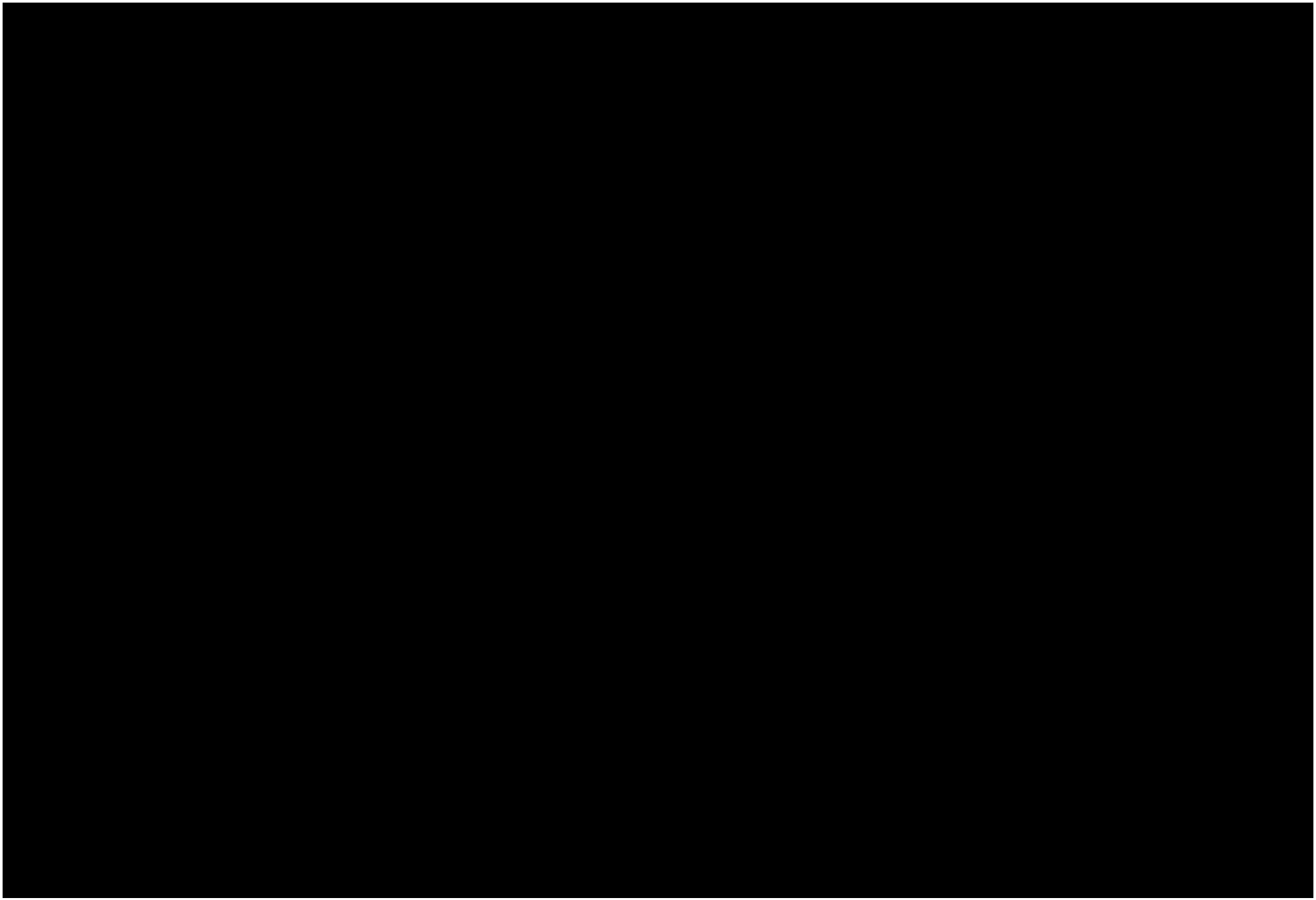
Date of Off Peak Day - 03/22/2021



Member Forecasted Off Peak Demand Day for April 2021

Mora-San Miguel Electric Cooperative, Inc.

Date of Off Peak Day - 04/07/2021



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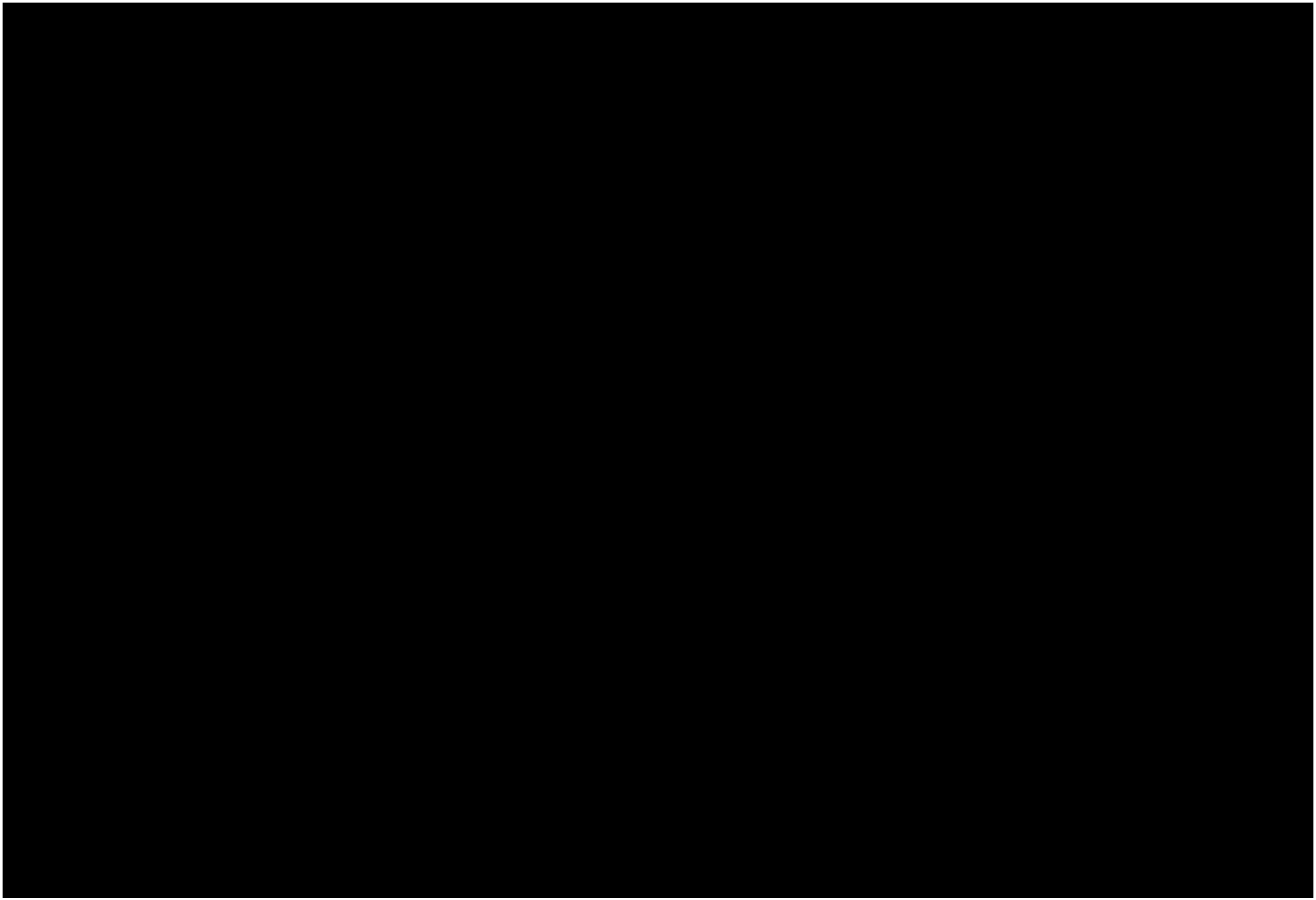
Member Forecasted Off Peak Demand Day for May 2021

Mora-San Miguel Electric Cooperative, Inc.

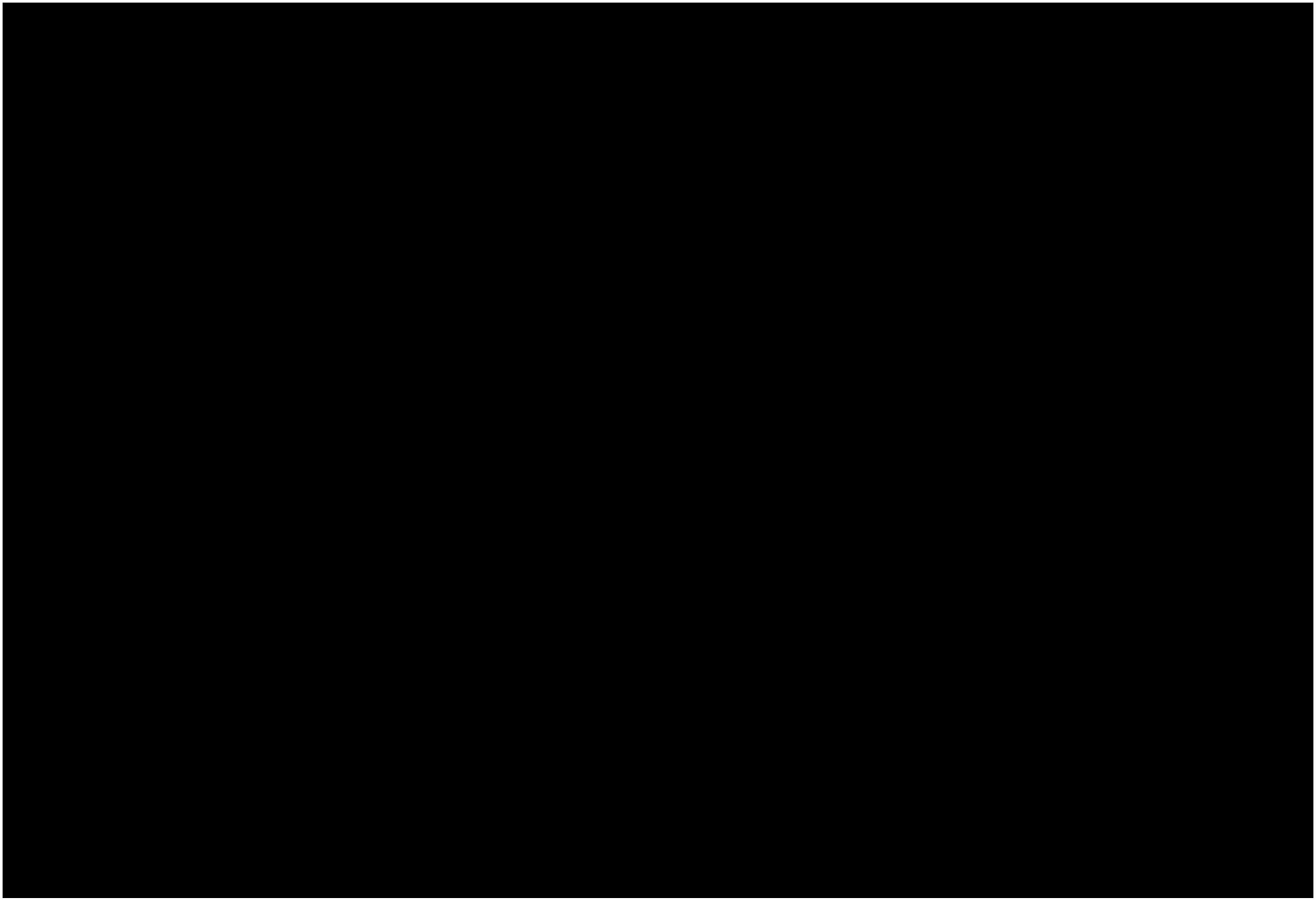
Date of Off Peak Day - 05/31/2021



Member Forecasted Off Peak Demand Day for June 2021

Mora-San Miguel Electric Cooperative, Inc.

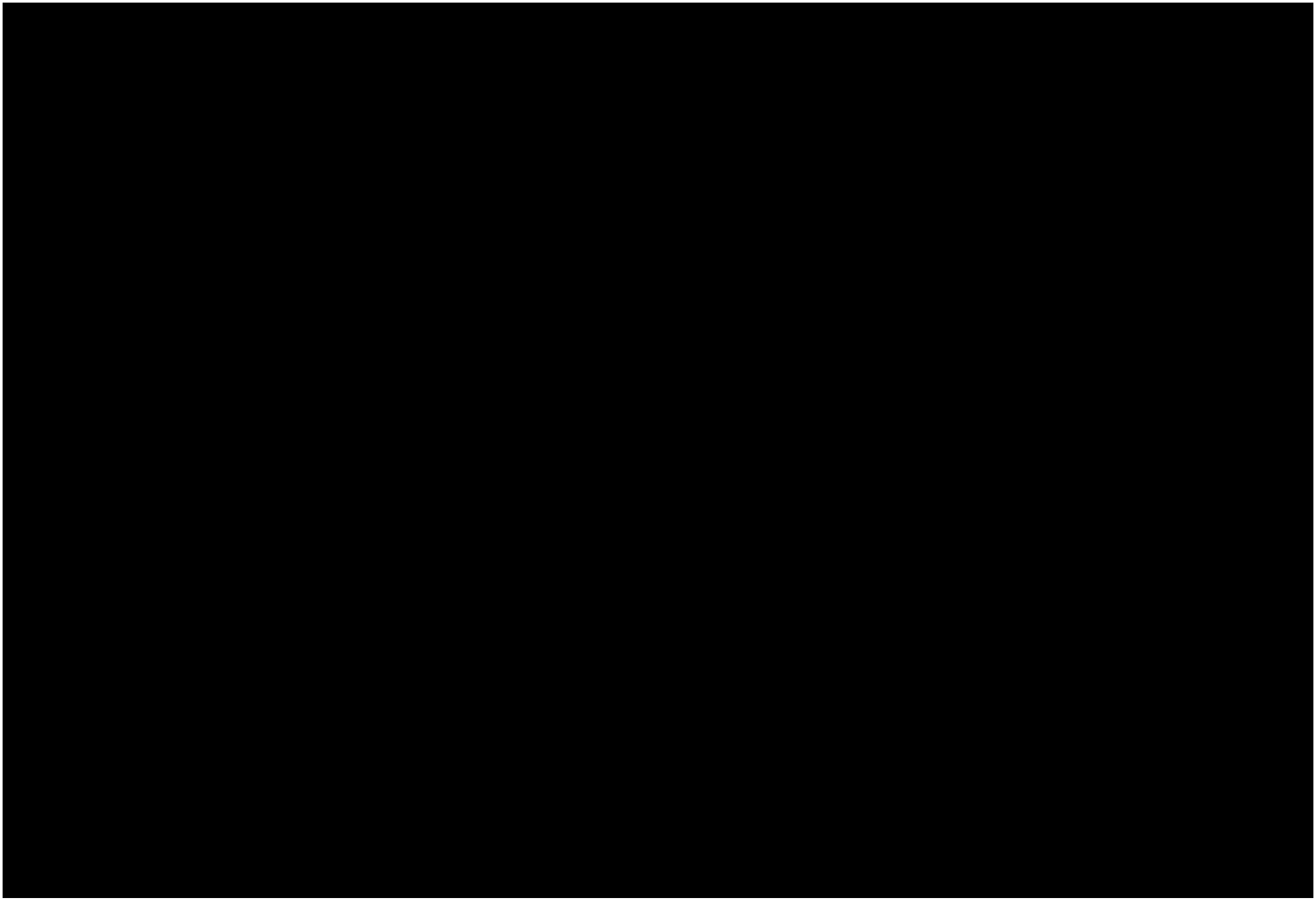
Date of Off Peak Day - 06/01/2021



Member Forecasted Off Peak Demand Day for July 2021

Mora-San Miguel Electric Cooperative, Inc.

Date of Off Peak Day - 07/30/2021



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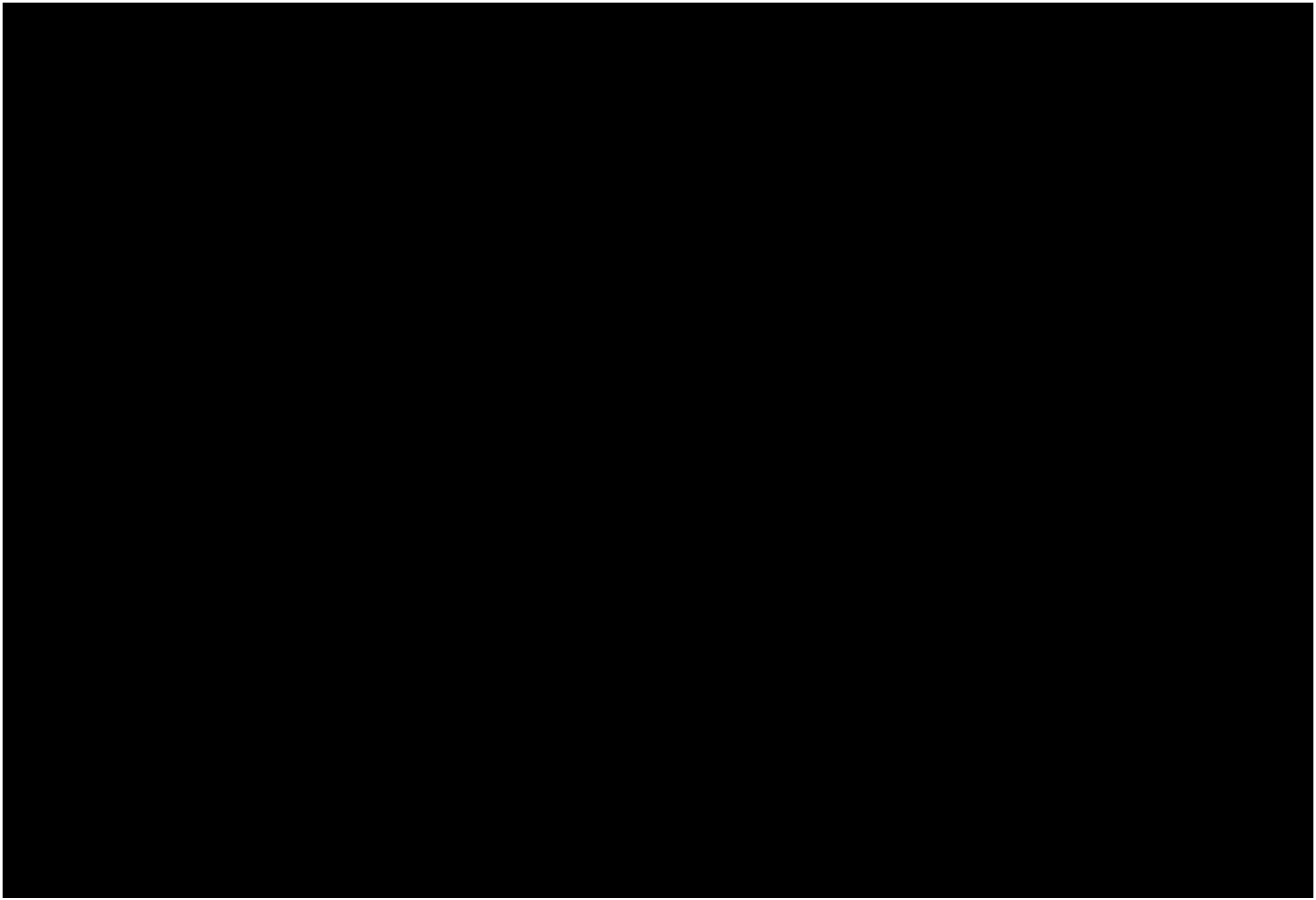
Member Forecasted Off Peak Demand Day for August 2021

Mora-San Miguel Electric Cooperative, Inc.

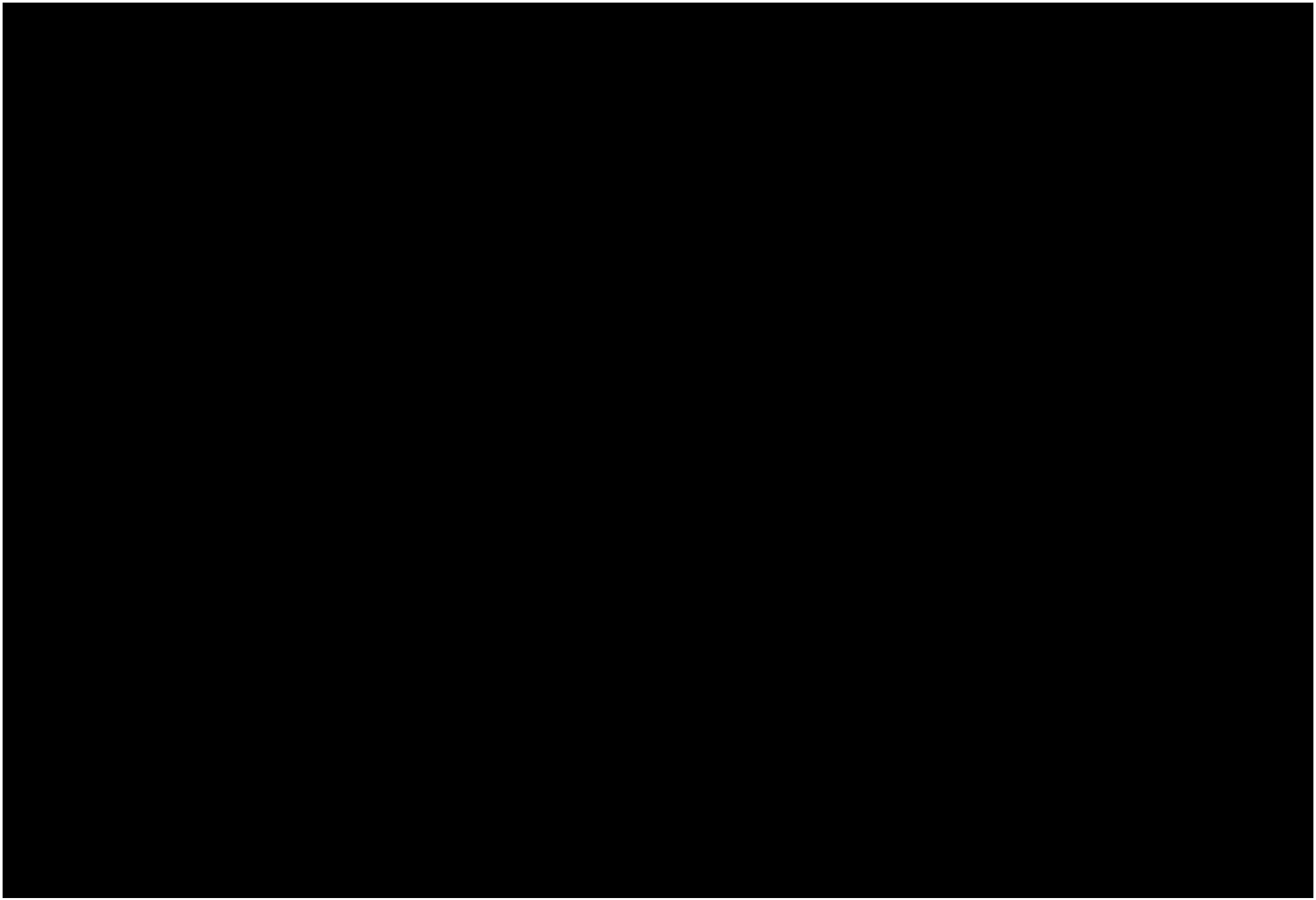
Date of Off Peak Day - 08/25/2021



Member Forecasted Off Peak Demand Day for September 2021

Mora-San Miguel Electric Cooperative, Inc.

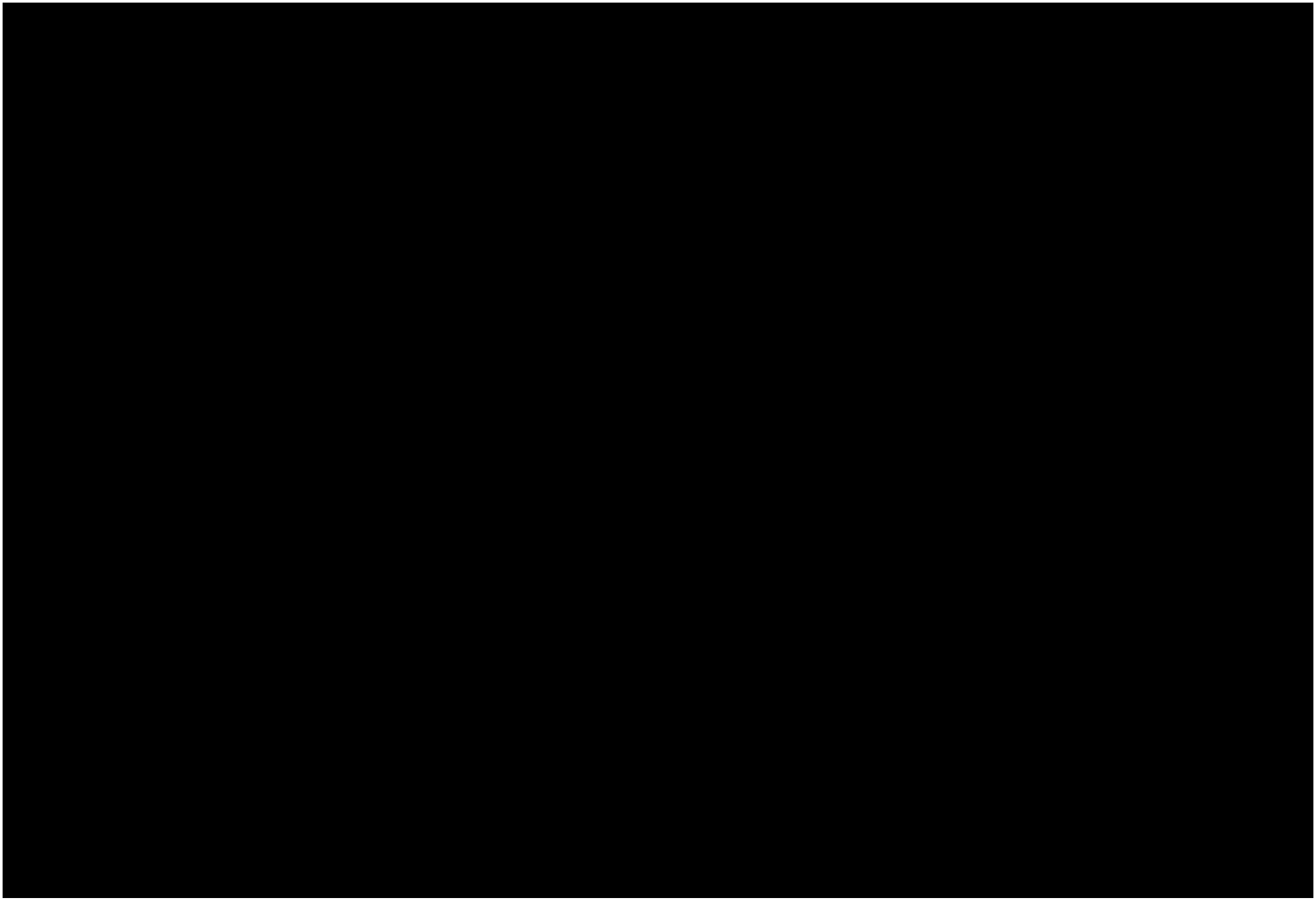
Date of Off Peak Day - 09/23/2021



Member Forecasted Off Peak Demand Day for October 2021

Mora-San Miguel Electric Cooperative, Inc.

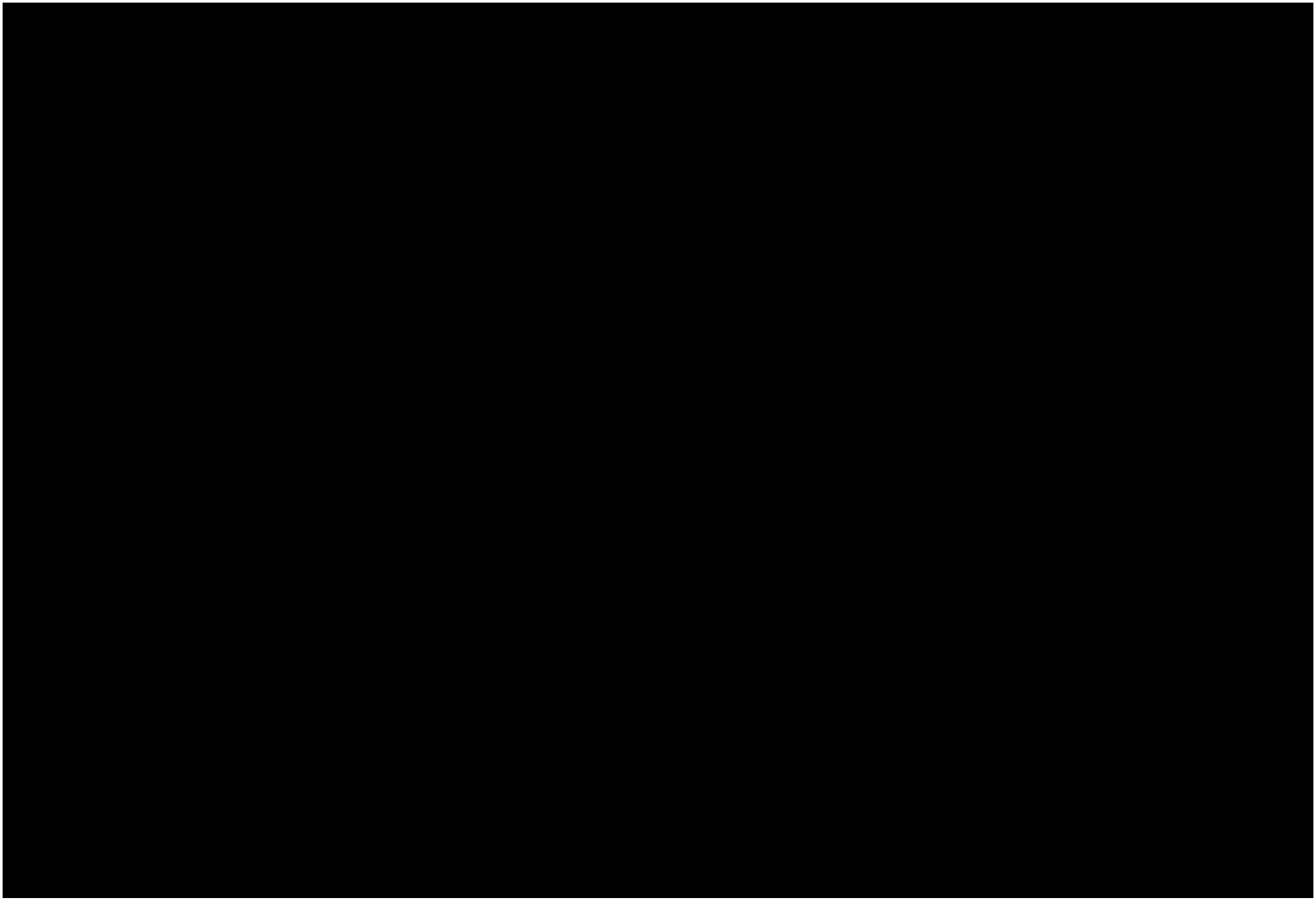
Date of Off Peak Day - 10/04/2021



Member Forecasted Off Peak Demand Day for November 2021

Mora-San Miguel Electric Cooperative, Inc.

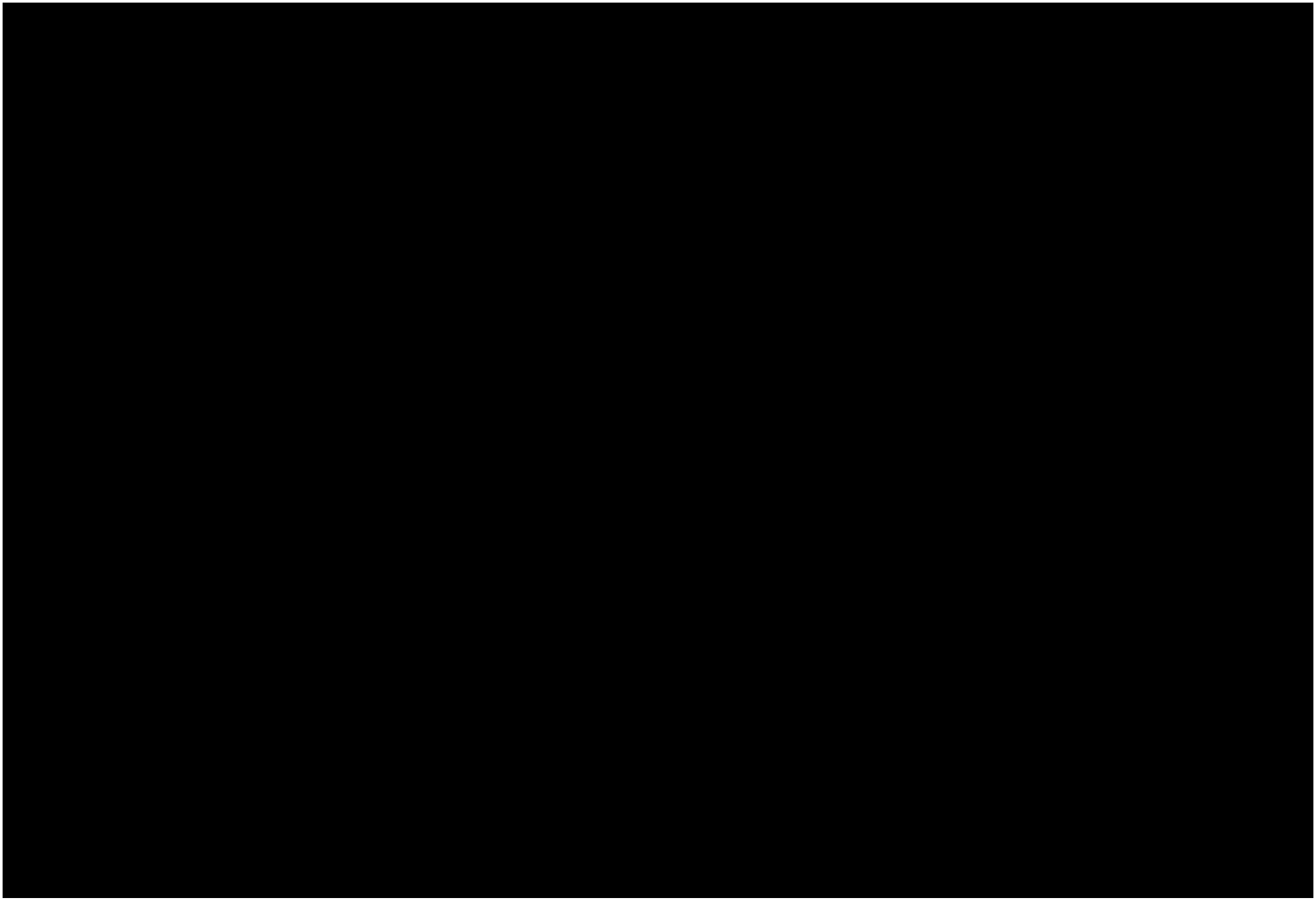
Date of Off Peak Day - 11/06/2021



Member Forecasted Off Peak Demand Day for December 2021

Mora-San Miguel Electric Cooperative, Inc.

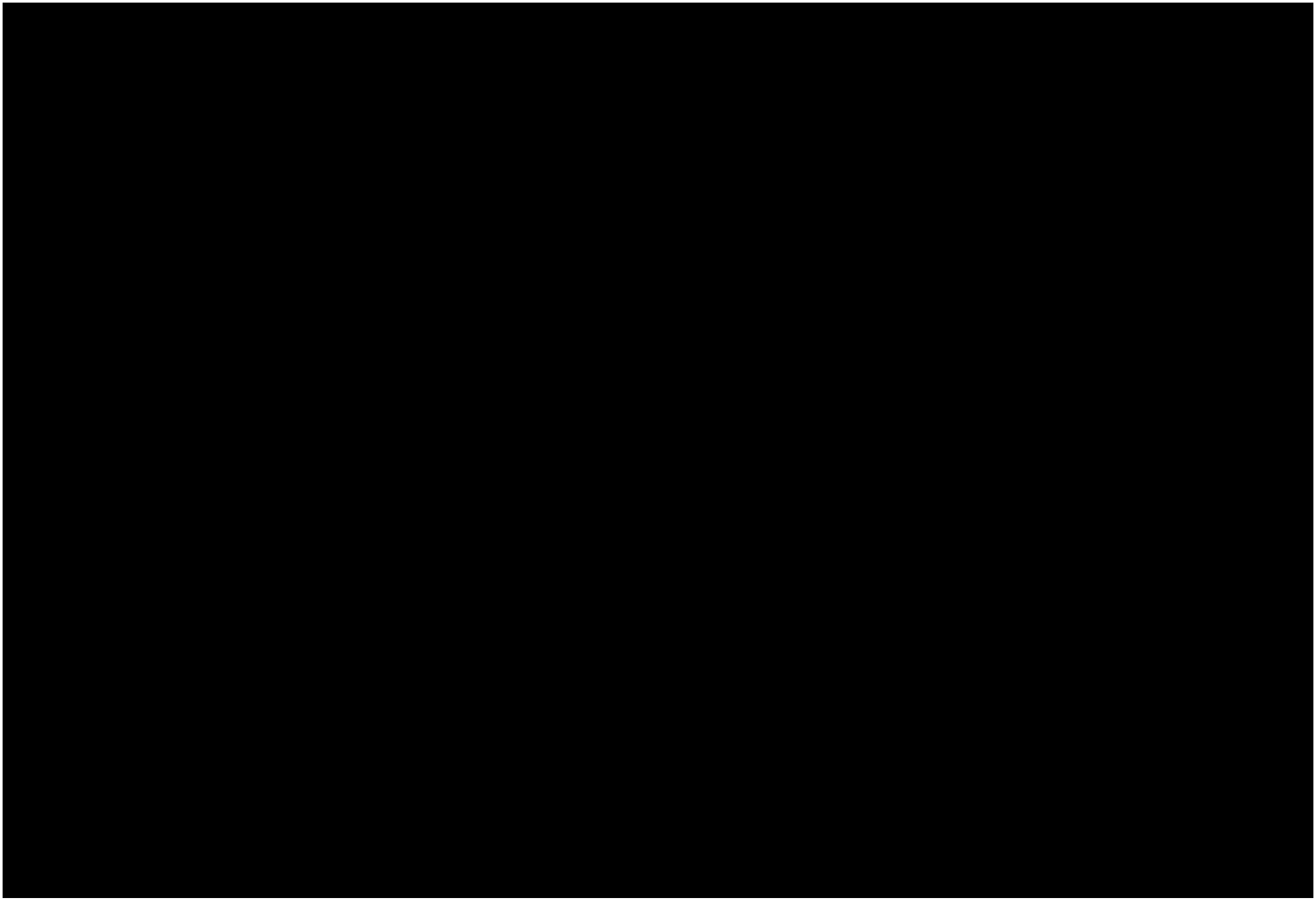
Date of Off Peak Day - 12/11/2021



Member Forecasted Off Peak Demand Day for January 2021

Mountain View Electric Association, Inc.

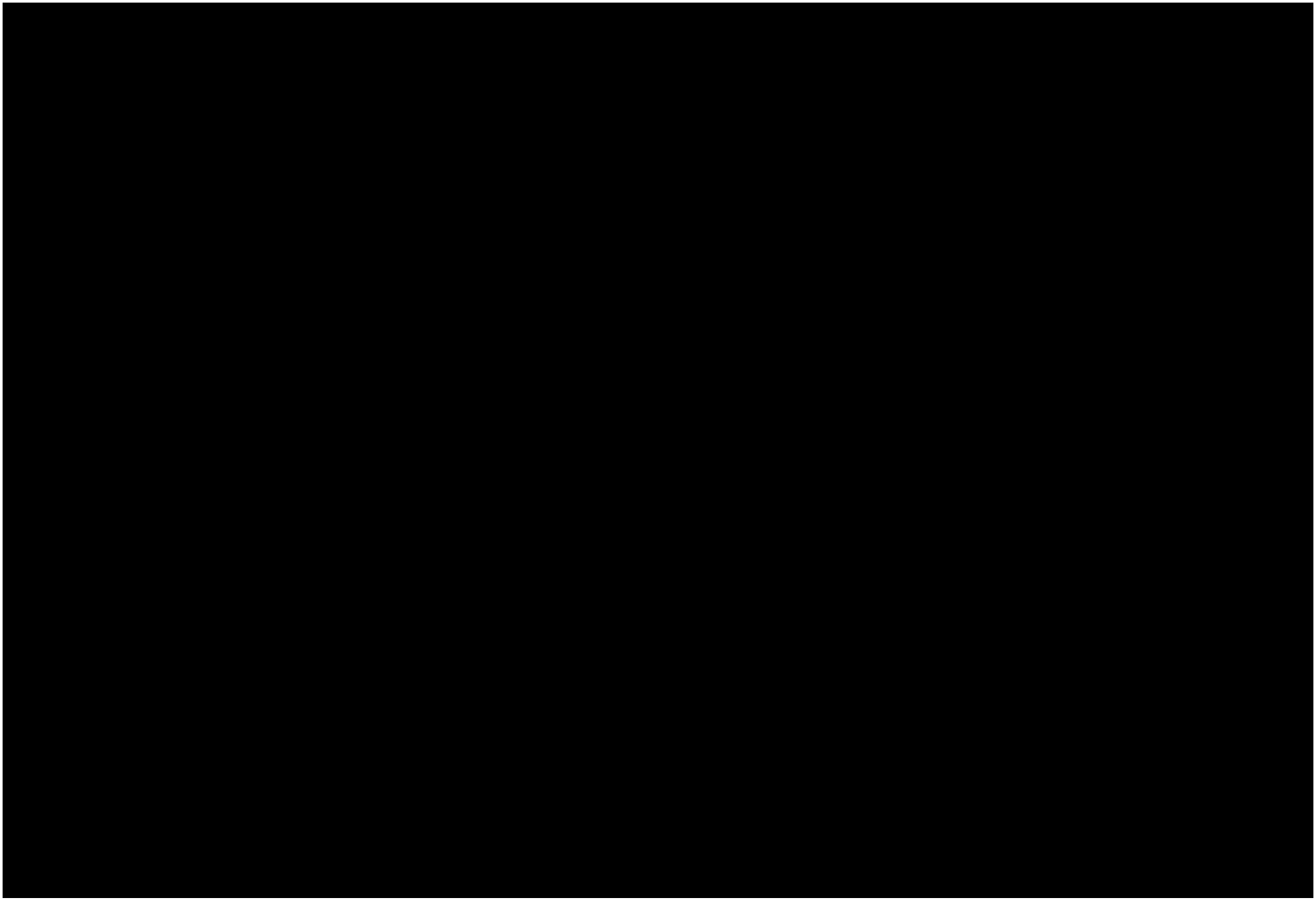
Date of Off Peak Day - 01/20/2021



Member Forecasted Off Peak Demand Day for February 2021

Mountain View Electric Association, Inc.

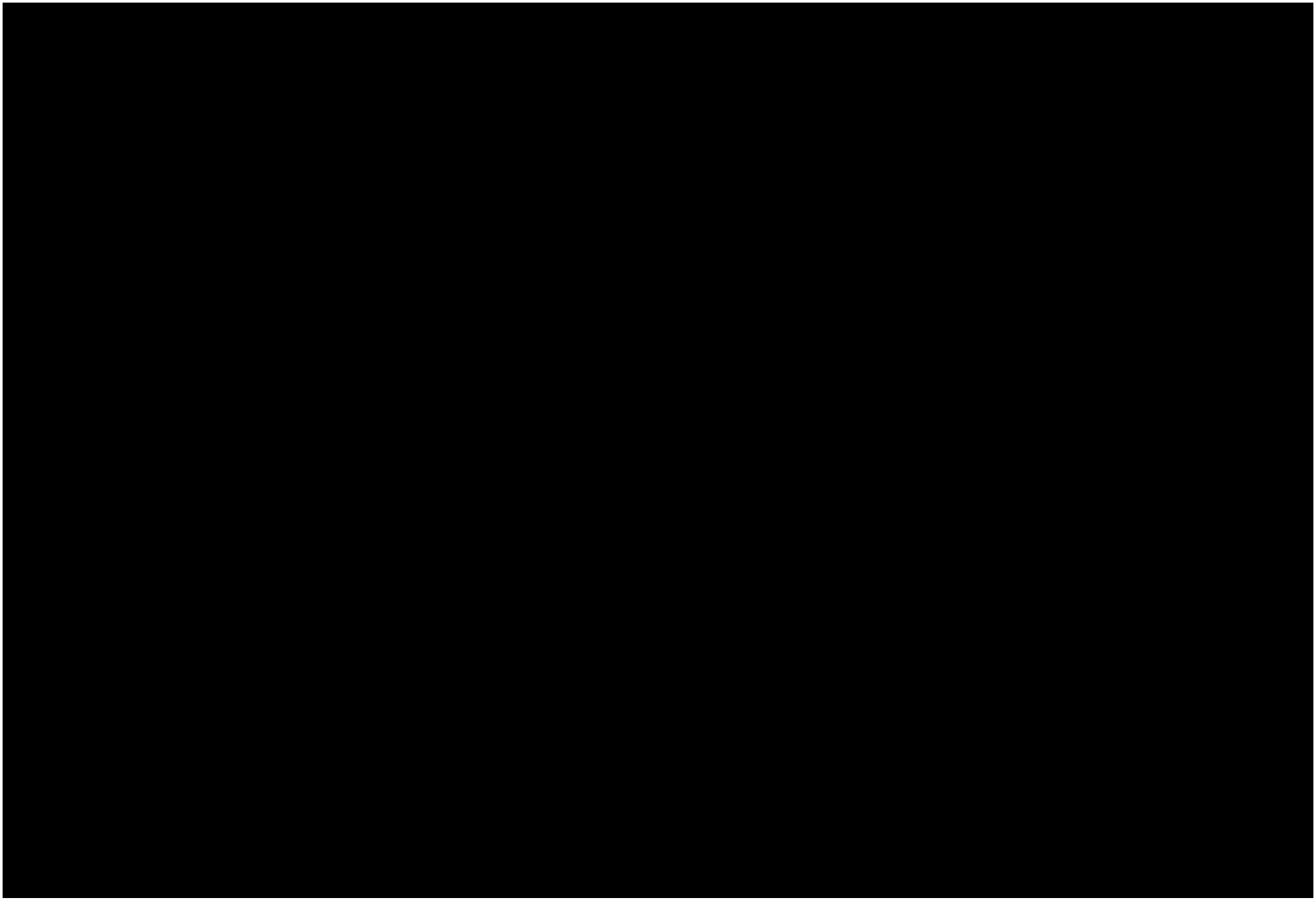
Date of Off Peak Day - 02/11/2021



Member Forecasted Off Peak Demand Day for March 2021

Mountain View Electric Association, Inc.

Date of Off Peak Day - 03/21/2021



Member Forecasted Off Peak Demand Day for April 2021

Mountain View Electric Association, Inc.

Date of Off Peak Day - 04/07/2021

[redacted]

Member Forecasted Off Peak Demand Day for May 2021

Mountain View Electric Association, Inc.

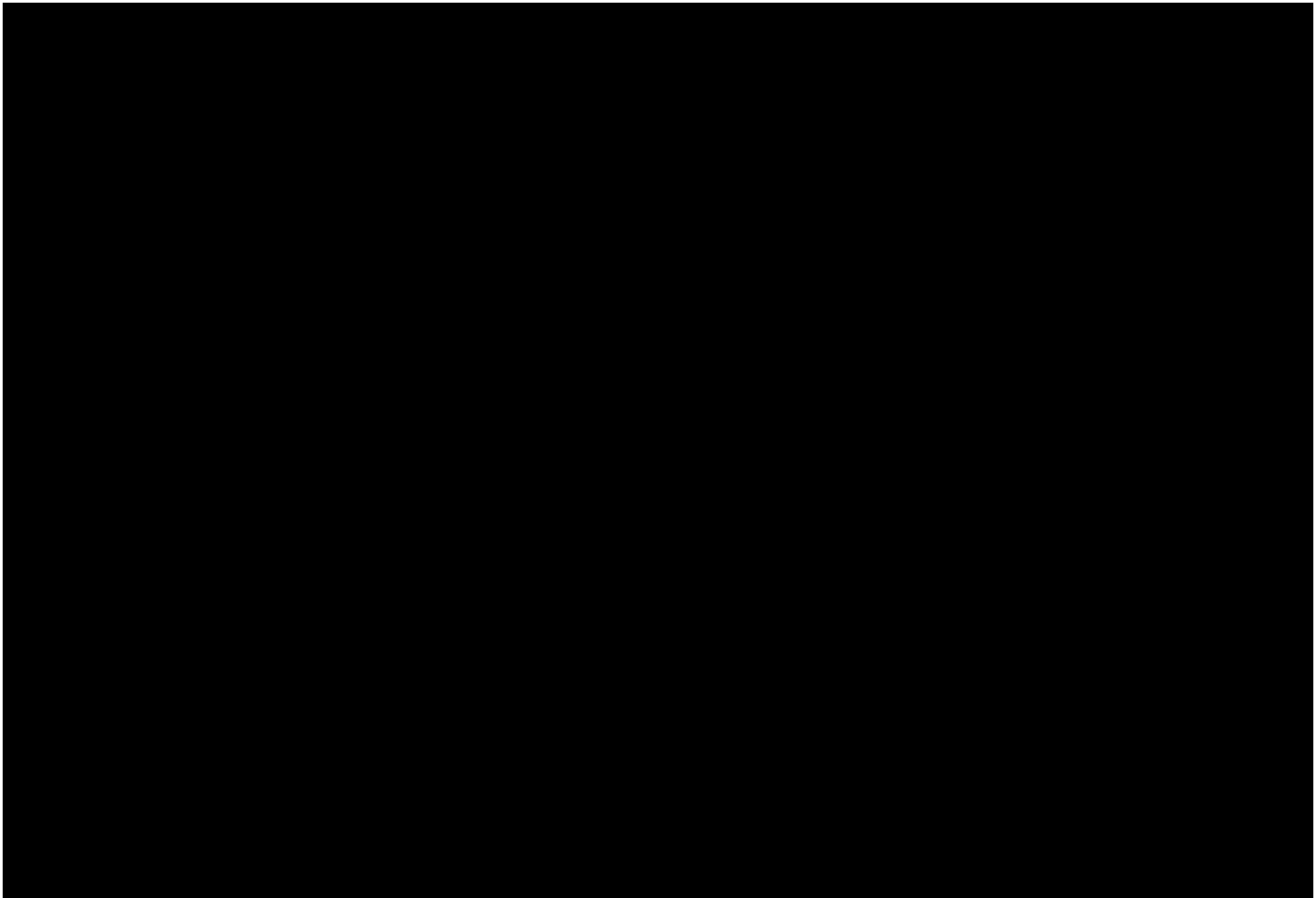
Date of Off Peak Day - 05/29/2021

[redacted]

Member Forecasted Off Peak Demand Day for June 2021

Mountain View Electric Association, Inc.

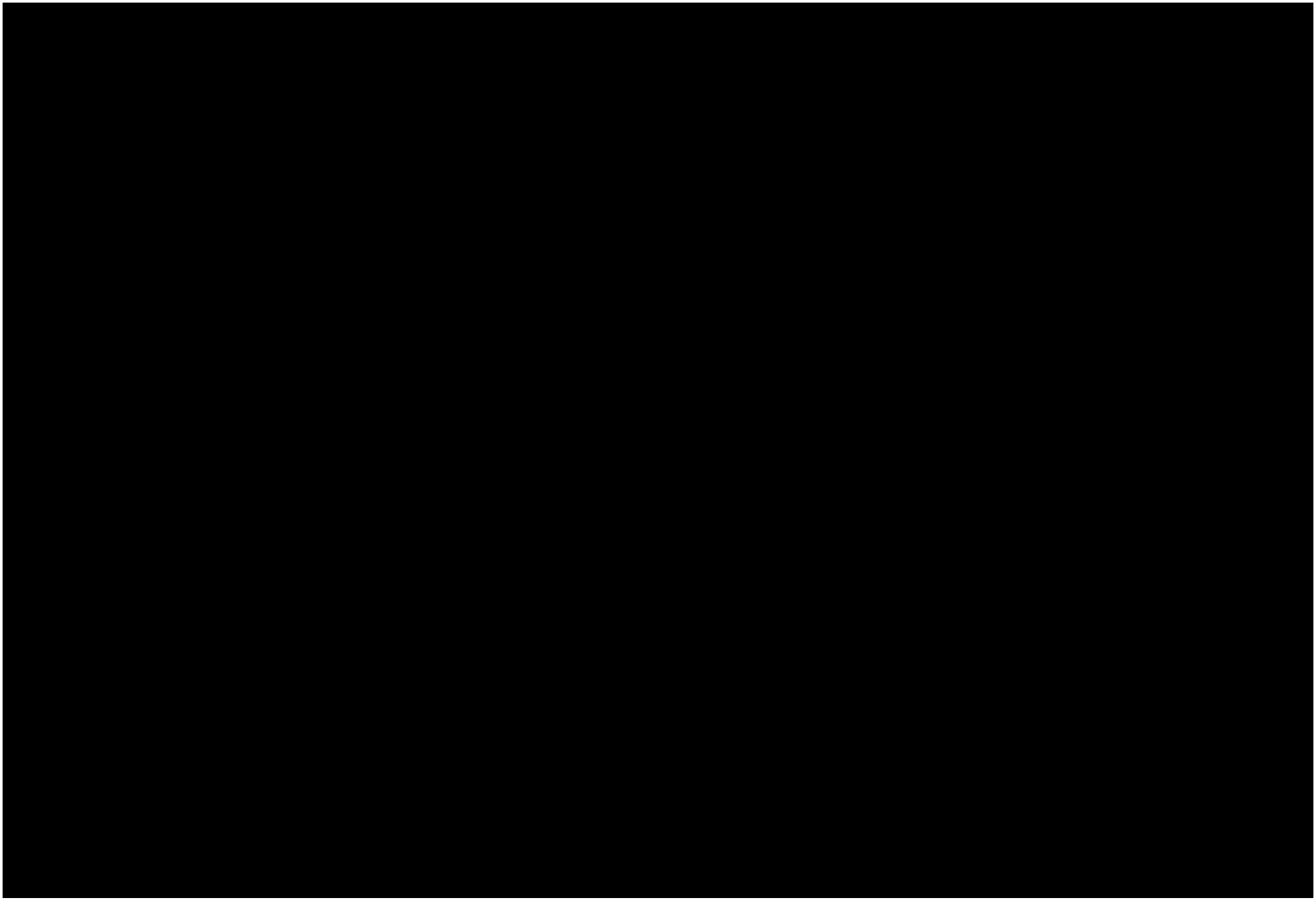
Date of Off Peak Day - 06/01/2021



Member Forecasted Off Peak Demand Day for July 2021

Mountain View Electric Association, Inc.

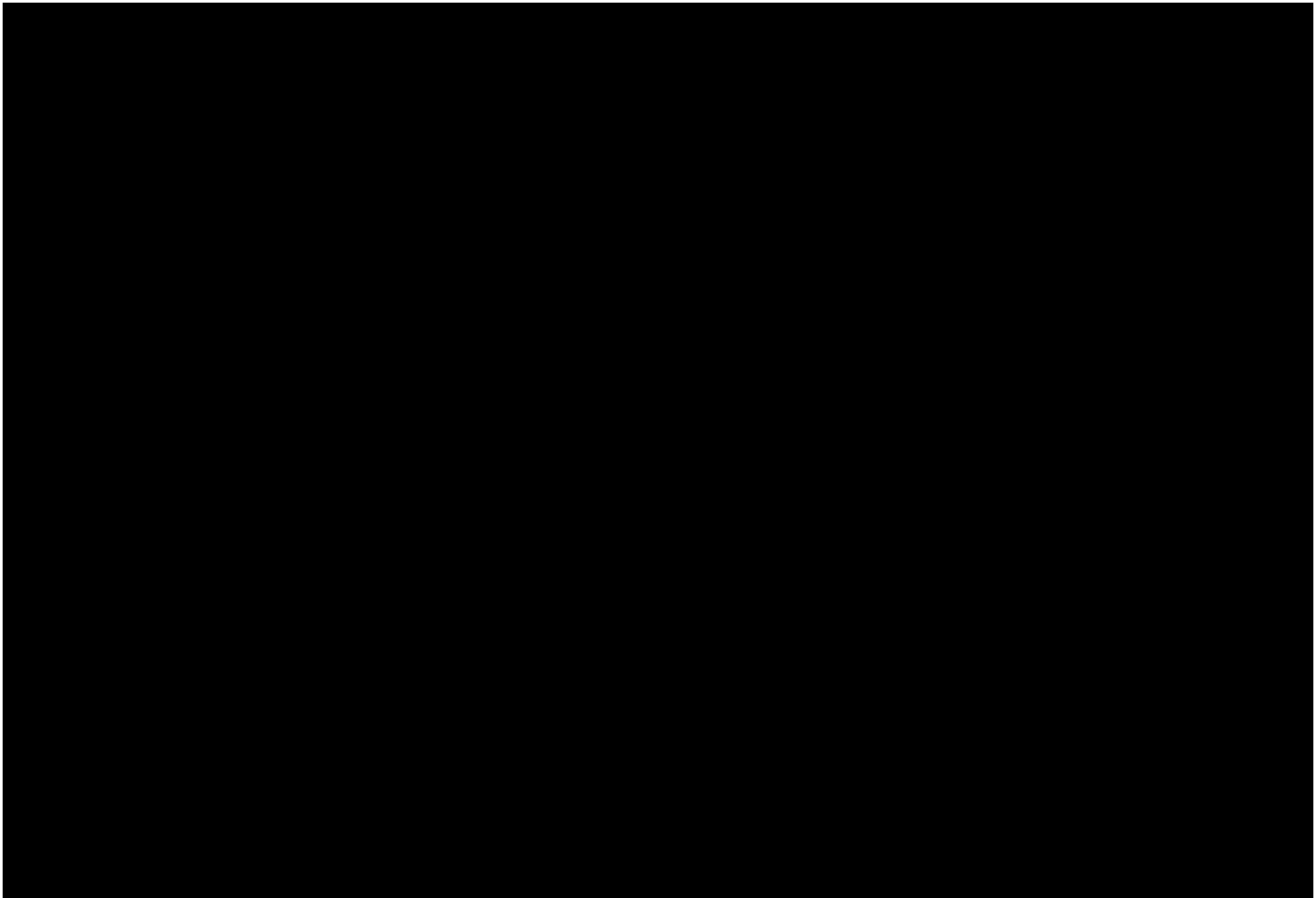
Date of Off Peak Day - 07/04/2021



Member Forecasted Off Peak Demand Day for August 2021

Mountain View Electric Association, Inc.

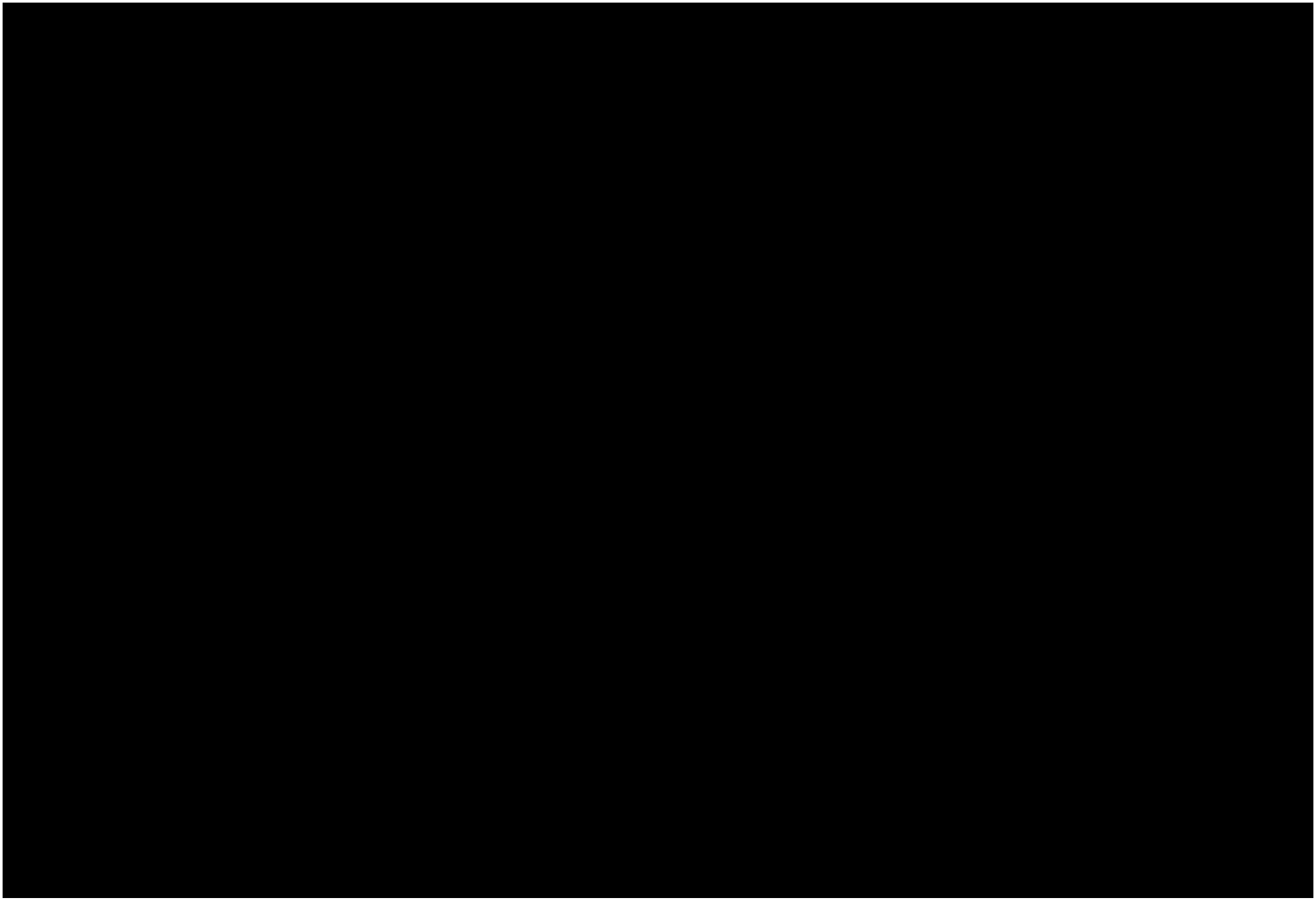
Date of Off Peak Day - 08/17/2021



Member Forecasted Off Peak Demand Day for September 2021

Mountain View Electric Association, Inc.

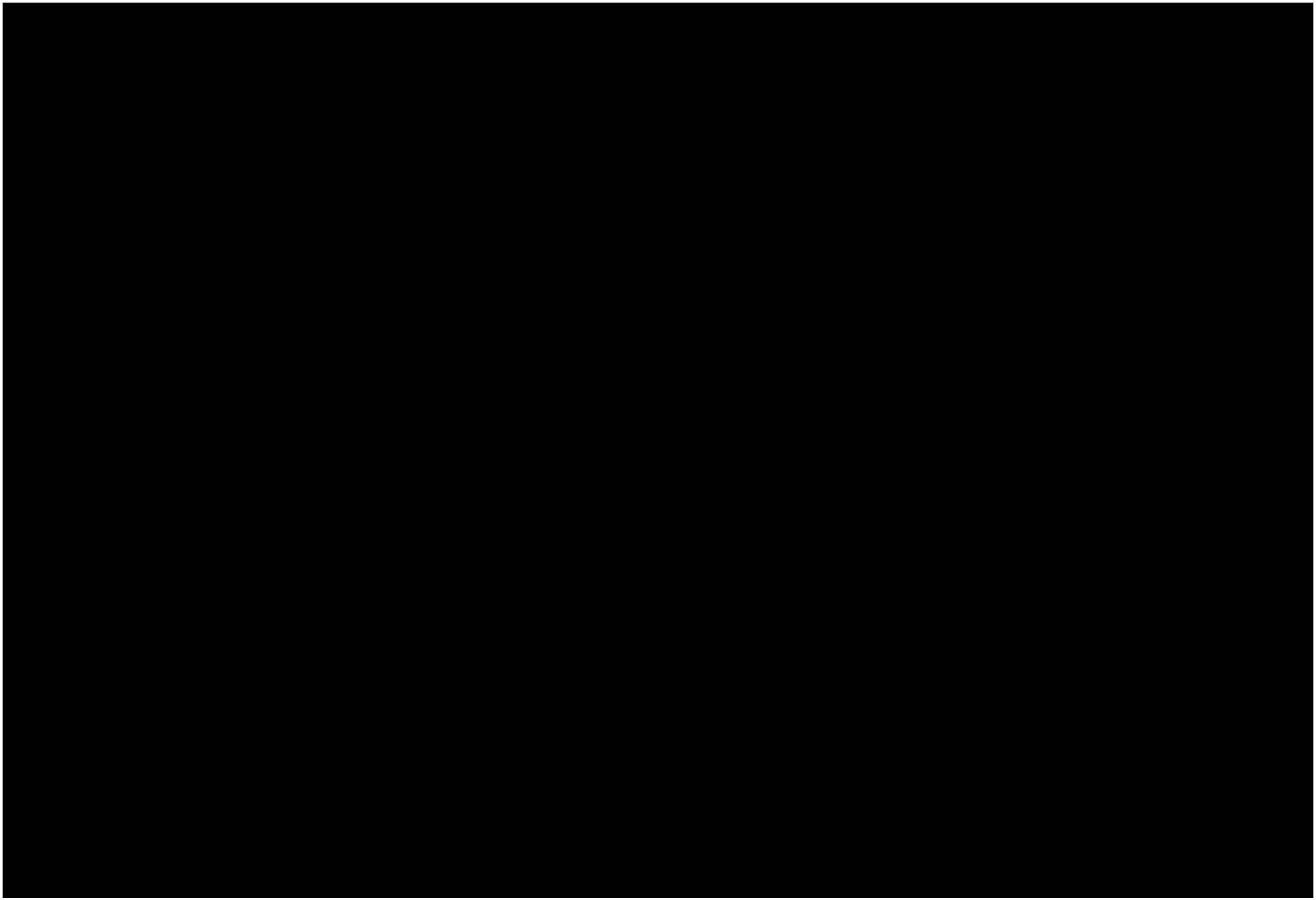
Date of Off Peak Day - 09/18/2021



Member Forecasted Off Peak Demand Day for October 2021

Mountain View Electric Association, Inc.

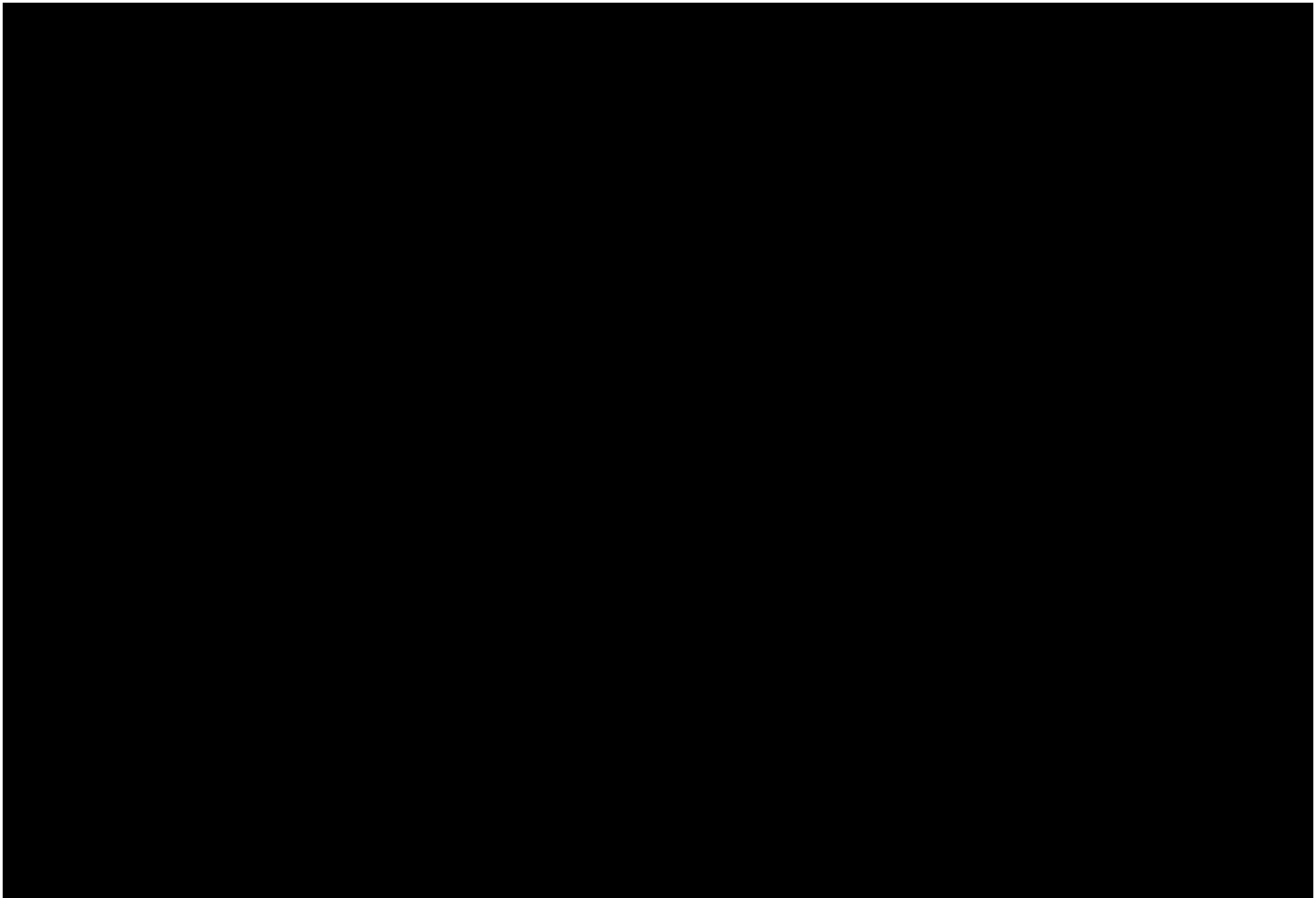
Date of Off Peak Day - 10/10/2021



Member Forecasted Off Peak Demand Day for November 2021

Mountain View Electric Association, Inc.

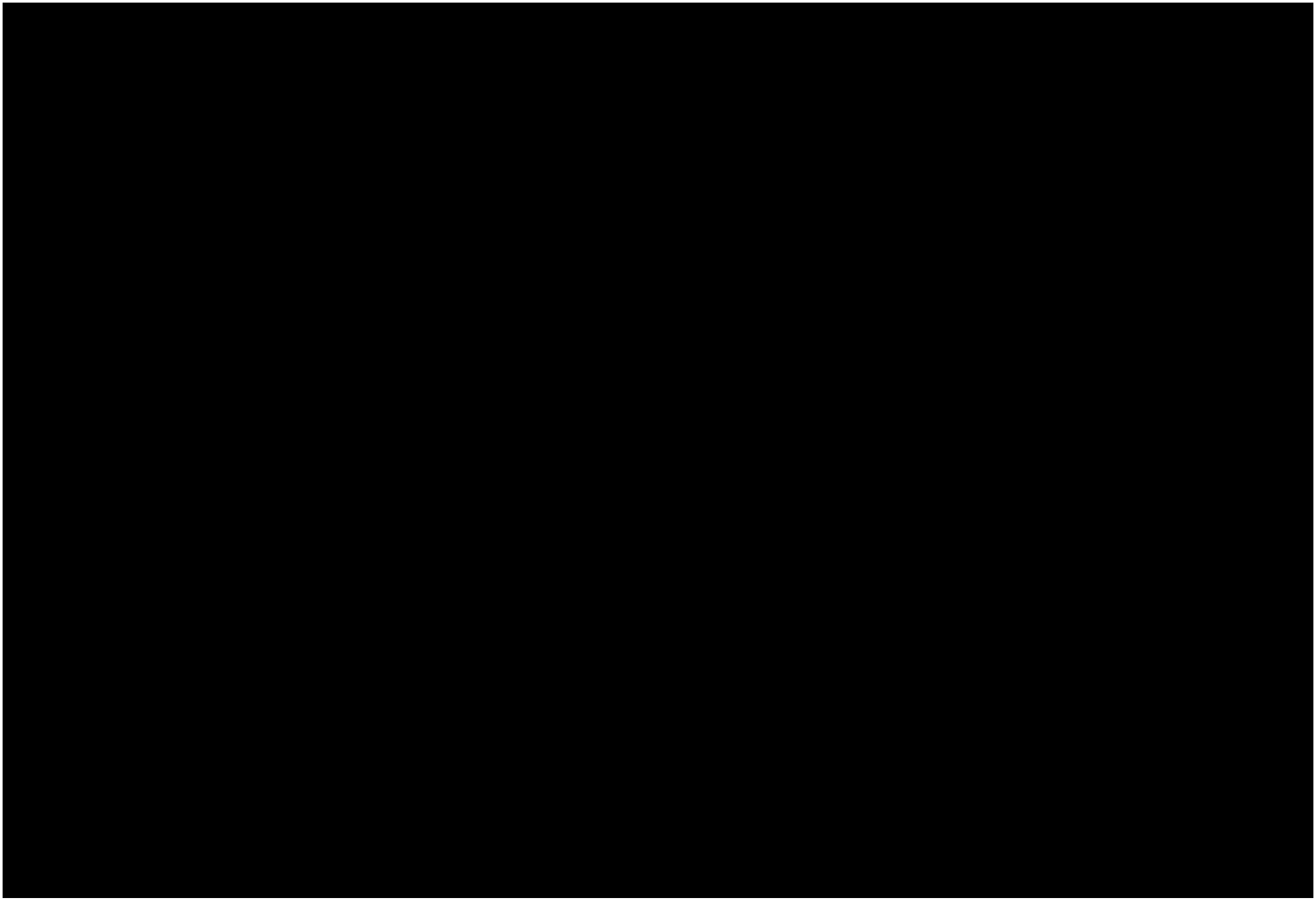
Date of Off Peak Day - 11/04/2021



Member Forecasted Off Peak Demand Day for December 2021

Mountain View Electric Association, Inc.

Date of Off Peak Day - 12/11/2021



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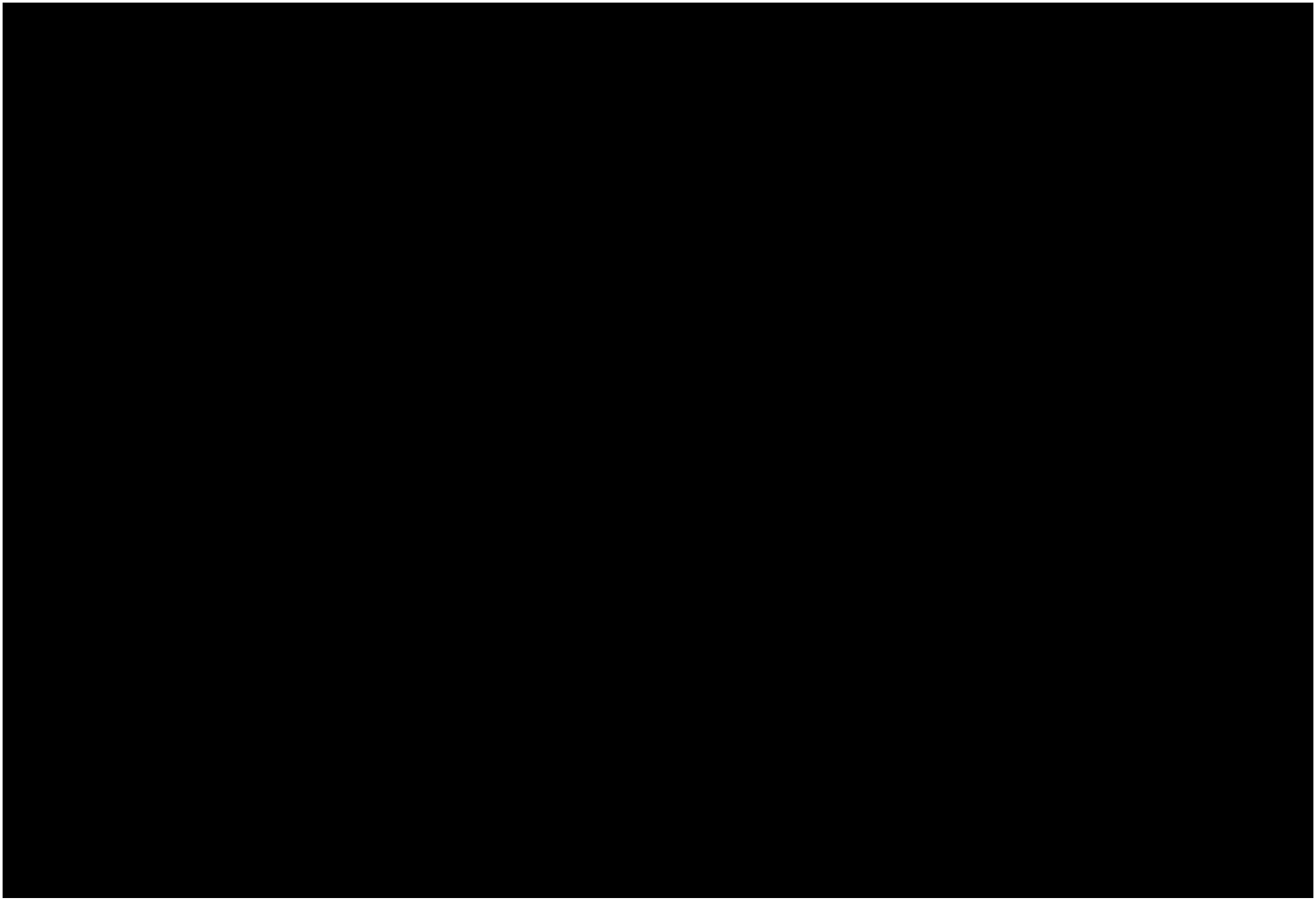
Member Forecasted Off Peak Demand Day for January 2021

Midwest Electric Cooperative Corporation

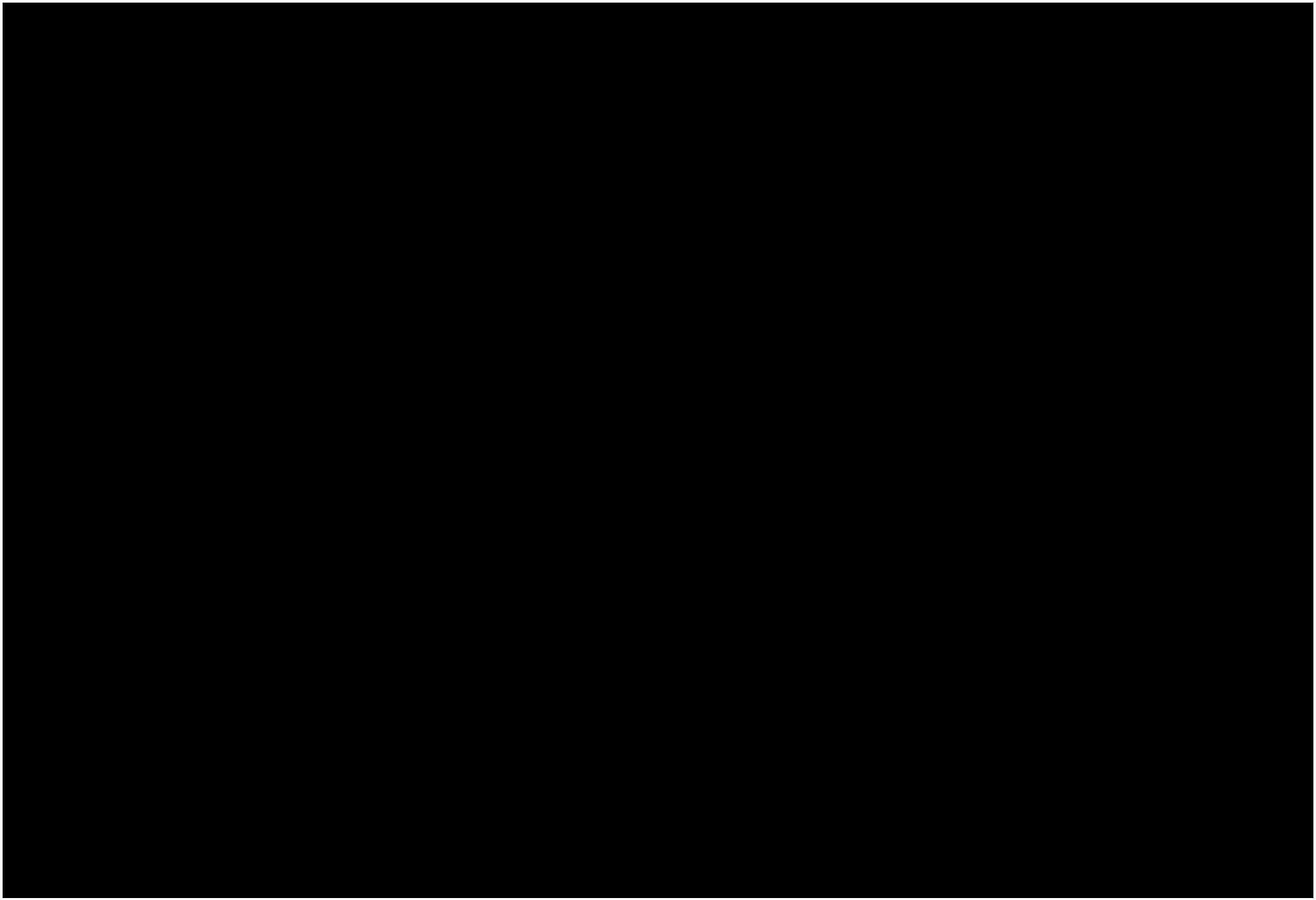
Date of Off Peak Day - 01/30/2021



Member Forecasted Off Peak Demand Day for February 2021

Midwest Electric Cooperative Corporation

Date of Off Peak Day - 02/16/2021



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Member Forecasted Off Peak Demand Day for March 2021

Midwest Electric Cooperative Corporation

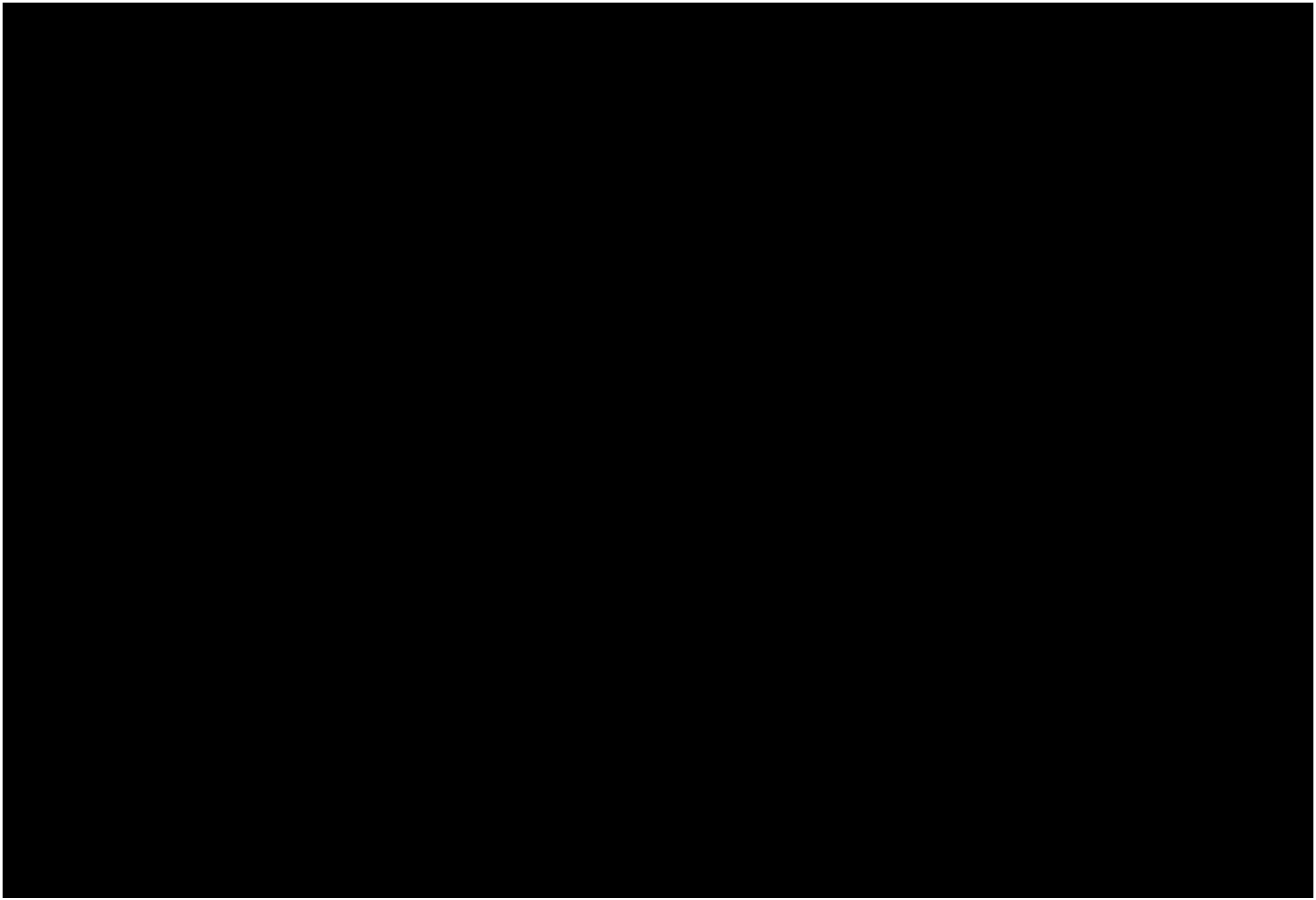
Date of Off Peak Day - 03/29/2021

[redacted]

Member Forecasted Off Peak Demand Day for April 2021

Midwest Electric Cooperative Corporation

Date of Off Peak Day - 04/23/2021



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Member Forecasted Off Peak Demand Day for May 2021

Midwest Electric Cooperative Corporation

Date of Off Peak Day - 05/02/2021

[redacted]

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Member Forecasted Off Peak Demand Day for June 2021

Midwest Electric Cooperative Corporation

Date of Off Peak Day - 06/08/2021

[redacted]

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Member Forecasted Off Peak Demand Day for July 2021

Midwest Electric Cooperative Corporation

Date of Off Peak Day - 07/03/2021

[redacted]

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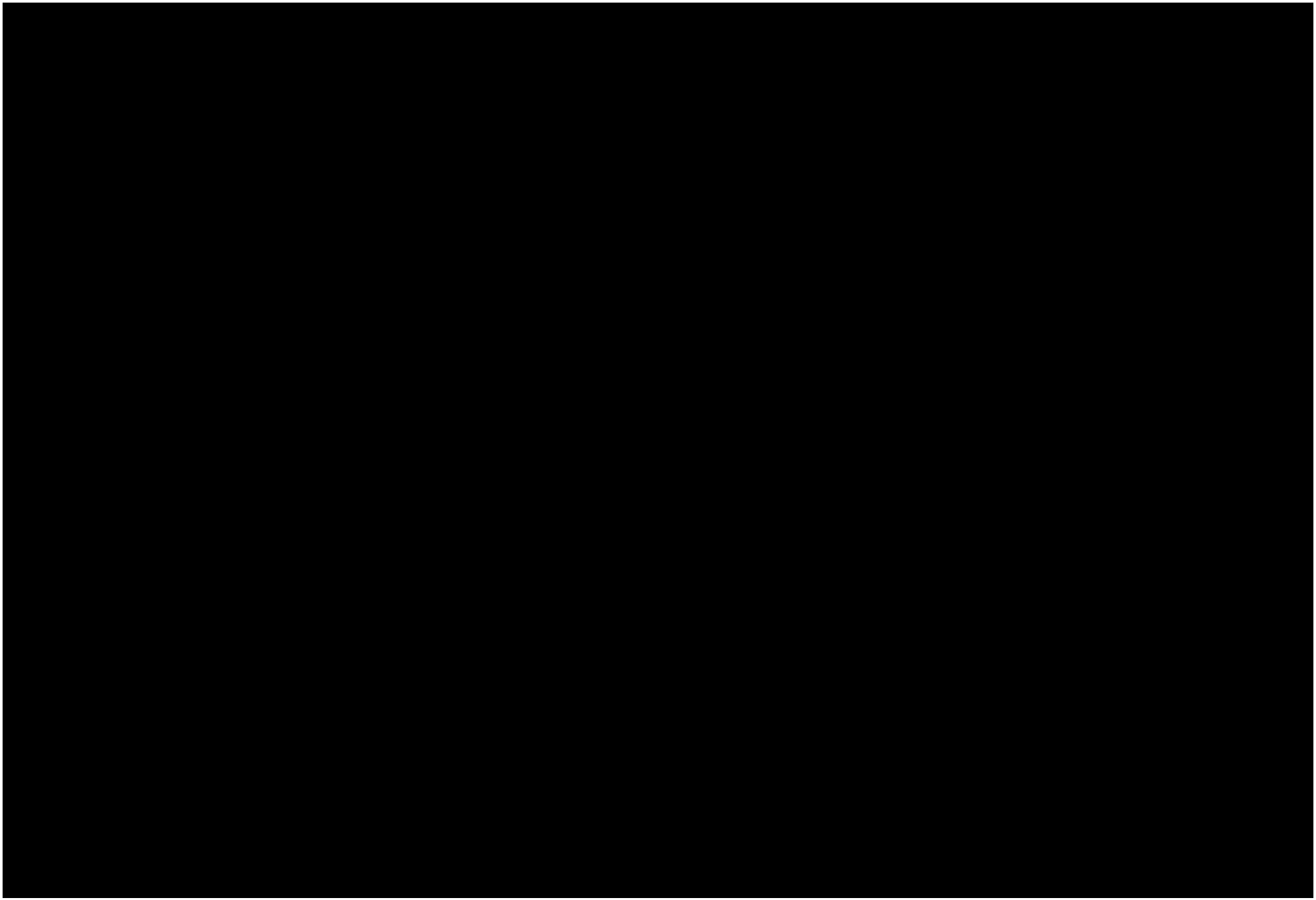
Member Forecasted Off Peak Demand Day for August 2021

Midwest Electric Cooperative Corporation

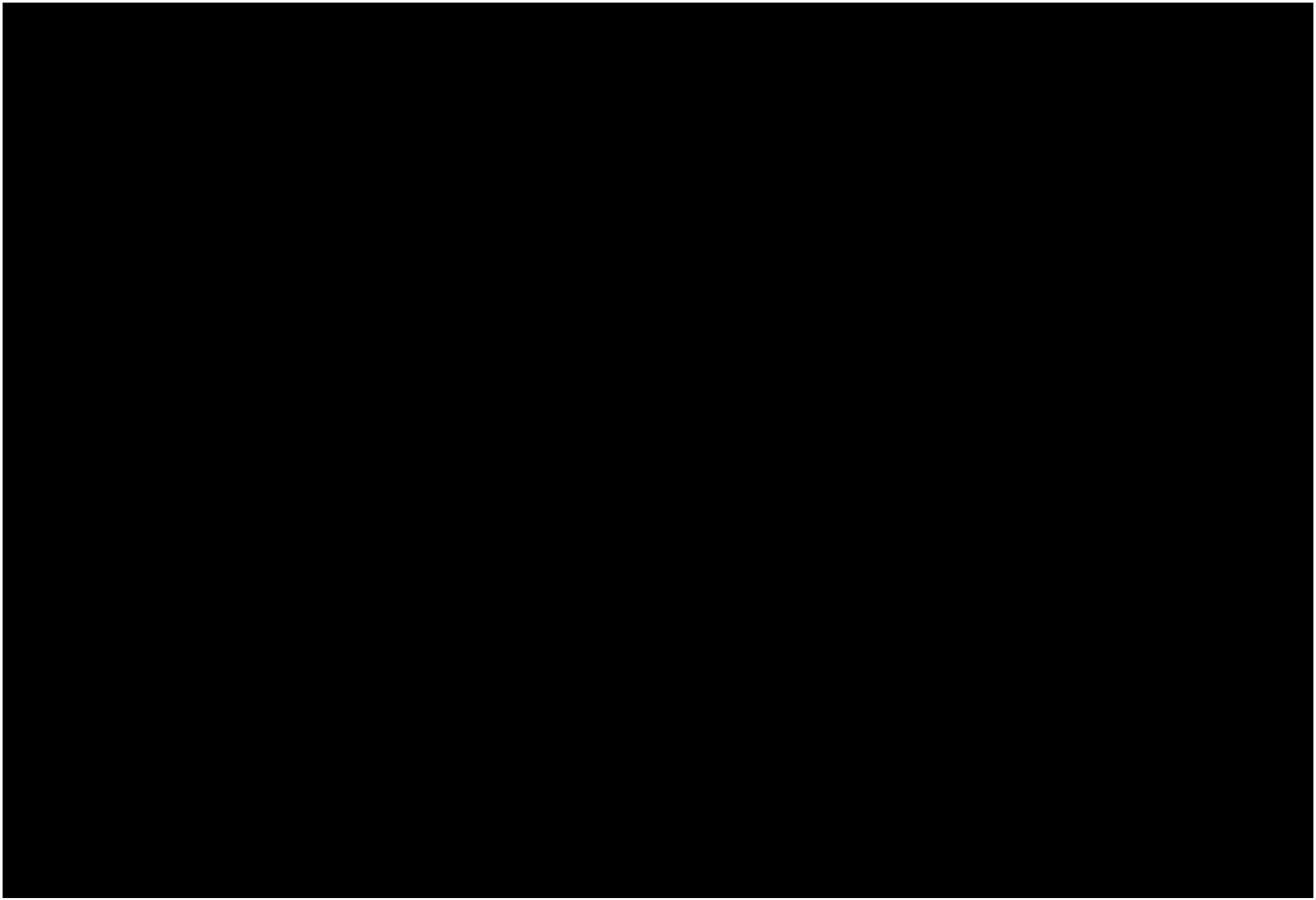
Date of Off Peak Day - 08/17/2021



Member Forecasted Off Peak Demand Day for September 2021

Midwest Electric Cooperative Corporation

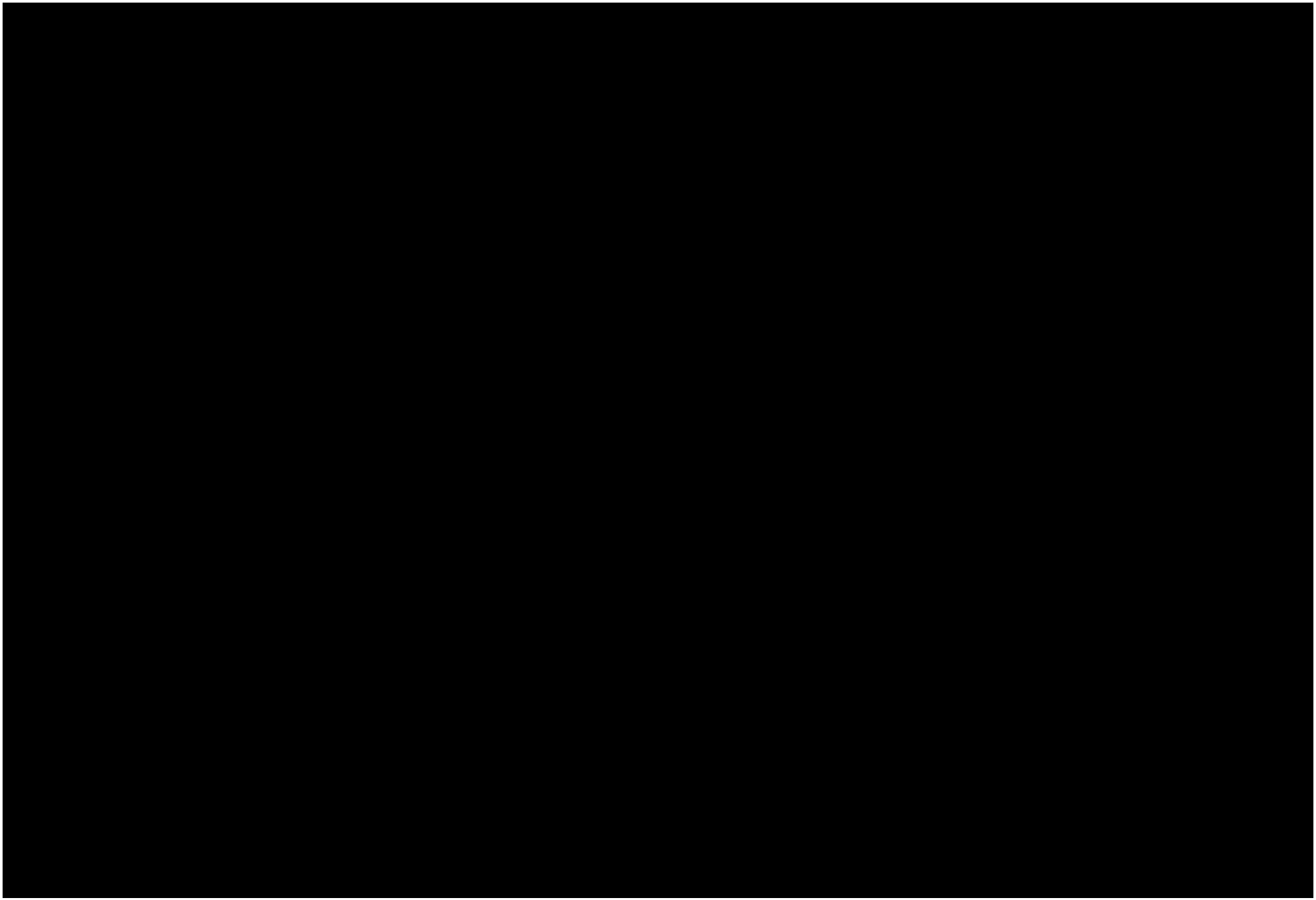
Date of Off Peak Day - 09/30/2021



Member Forecasted Off Peak Demand Day for October 2021

Midwest Electric Cooperative Corporation

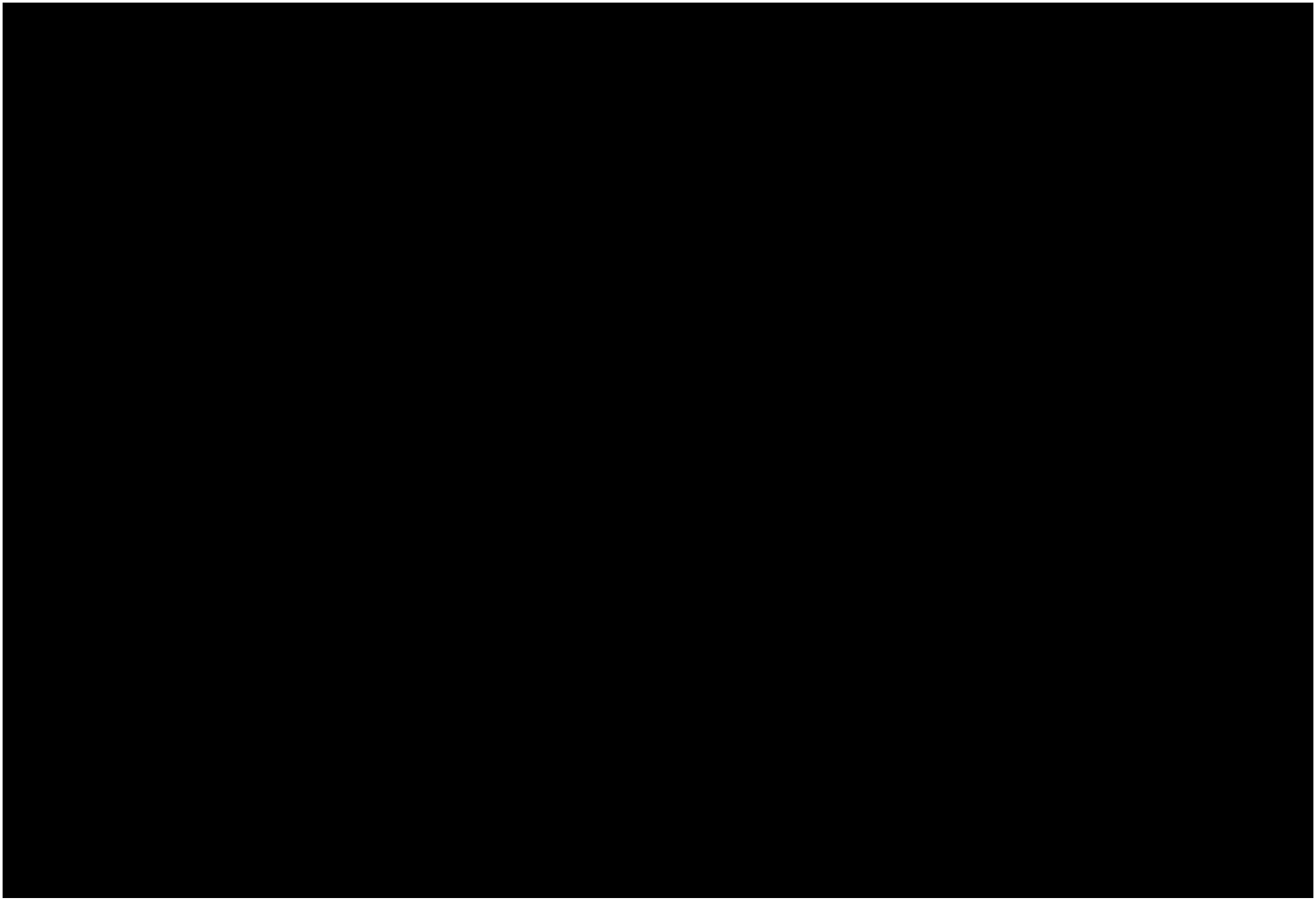
Date of Off Peak Day - 10/07/2021



Member Forecasted Off Peak Demand Day for November 2021

Midwest Electric Cooperative Corporation

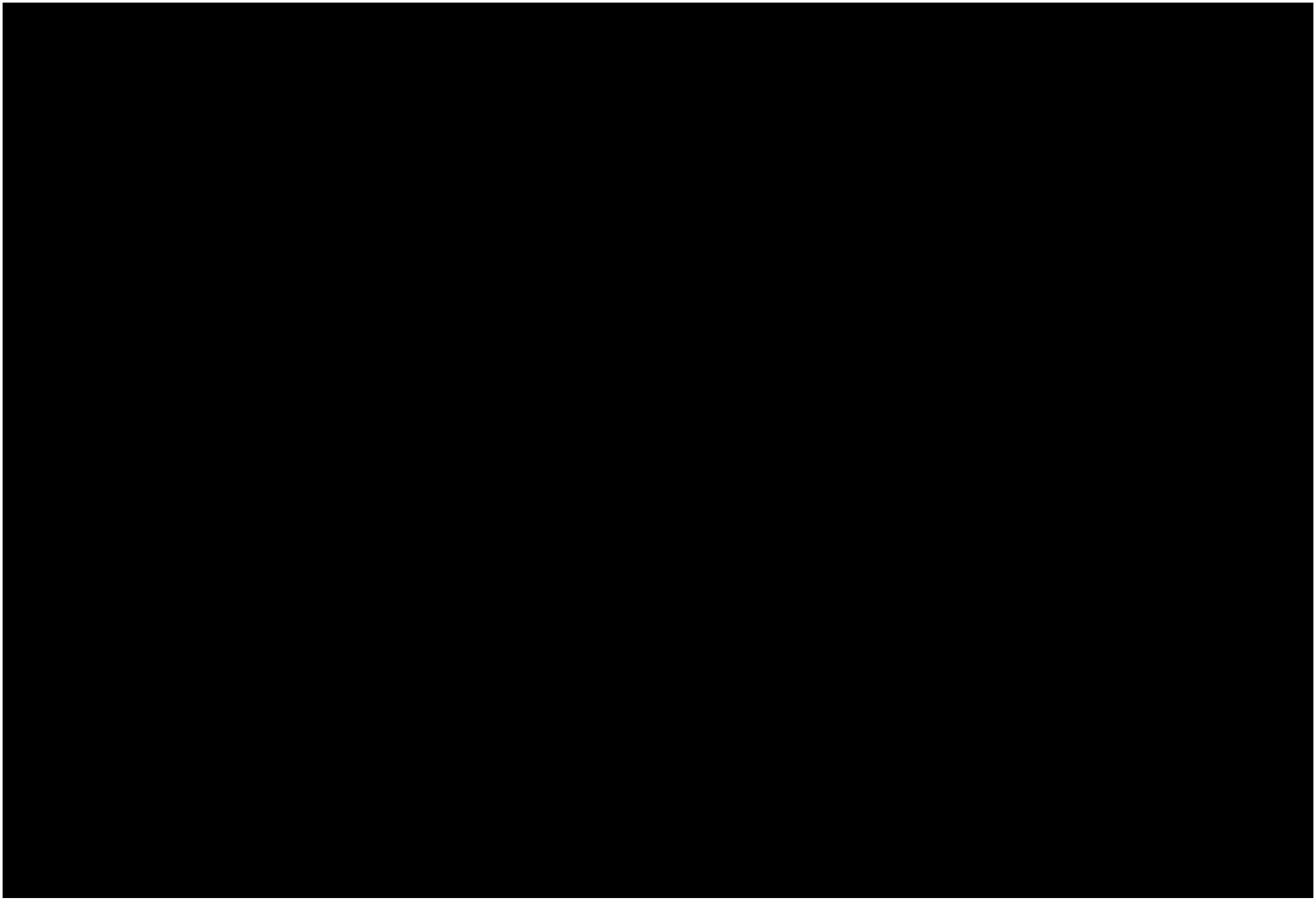
Date of Off Peak Day - 11/30/2021



Member Forecasted Off Peak Demand Day for December 2021

Midwest Electric Cooperative Corporation

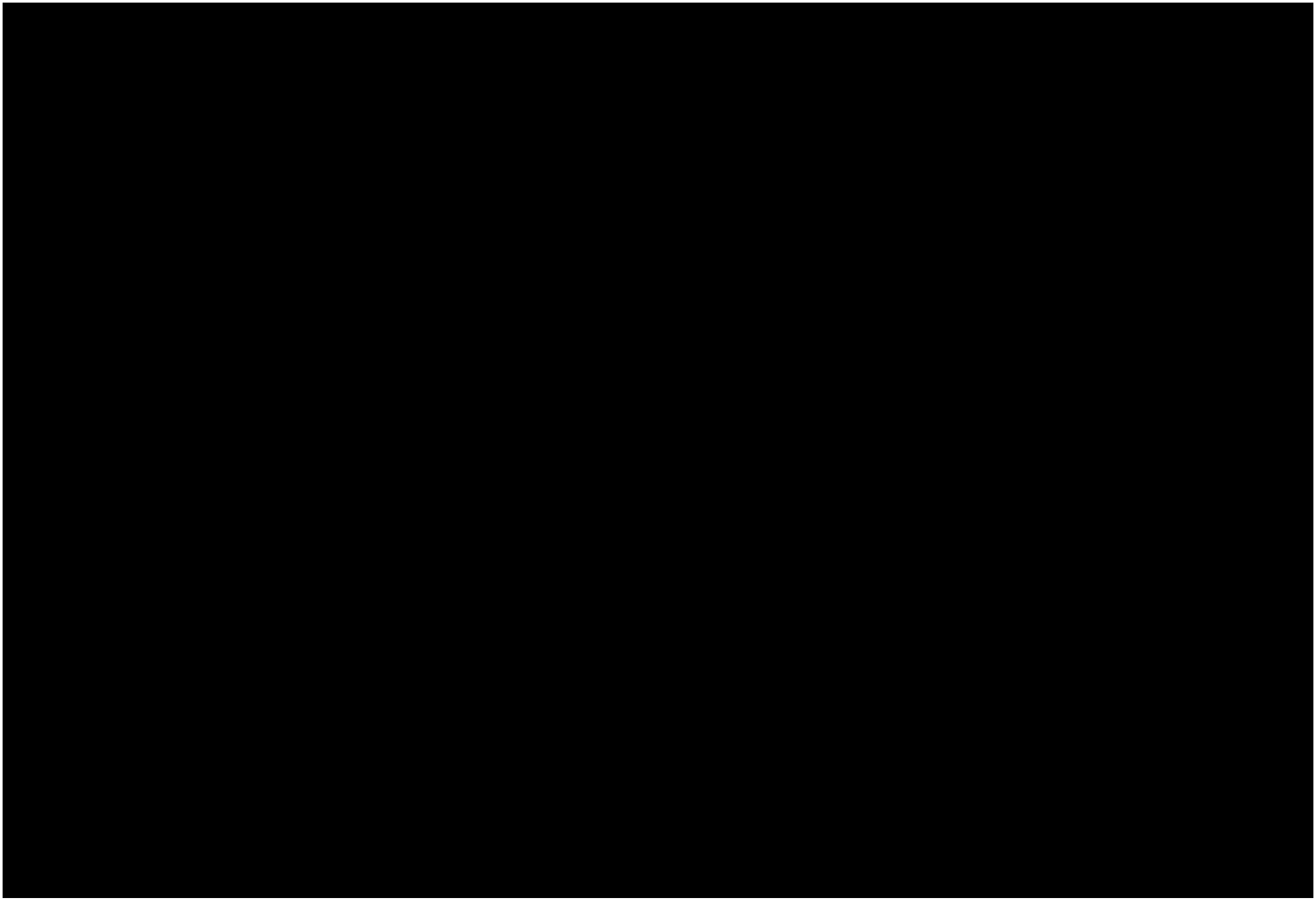
Date of Off Peak Day - 12/06/2021



Member Forecasted Off Peak Demand Day for January 2021

Niobrara Electric Association, Inc.

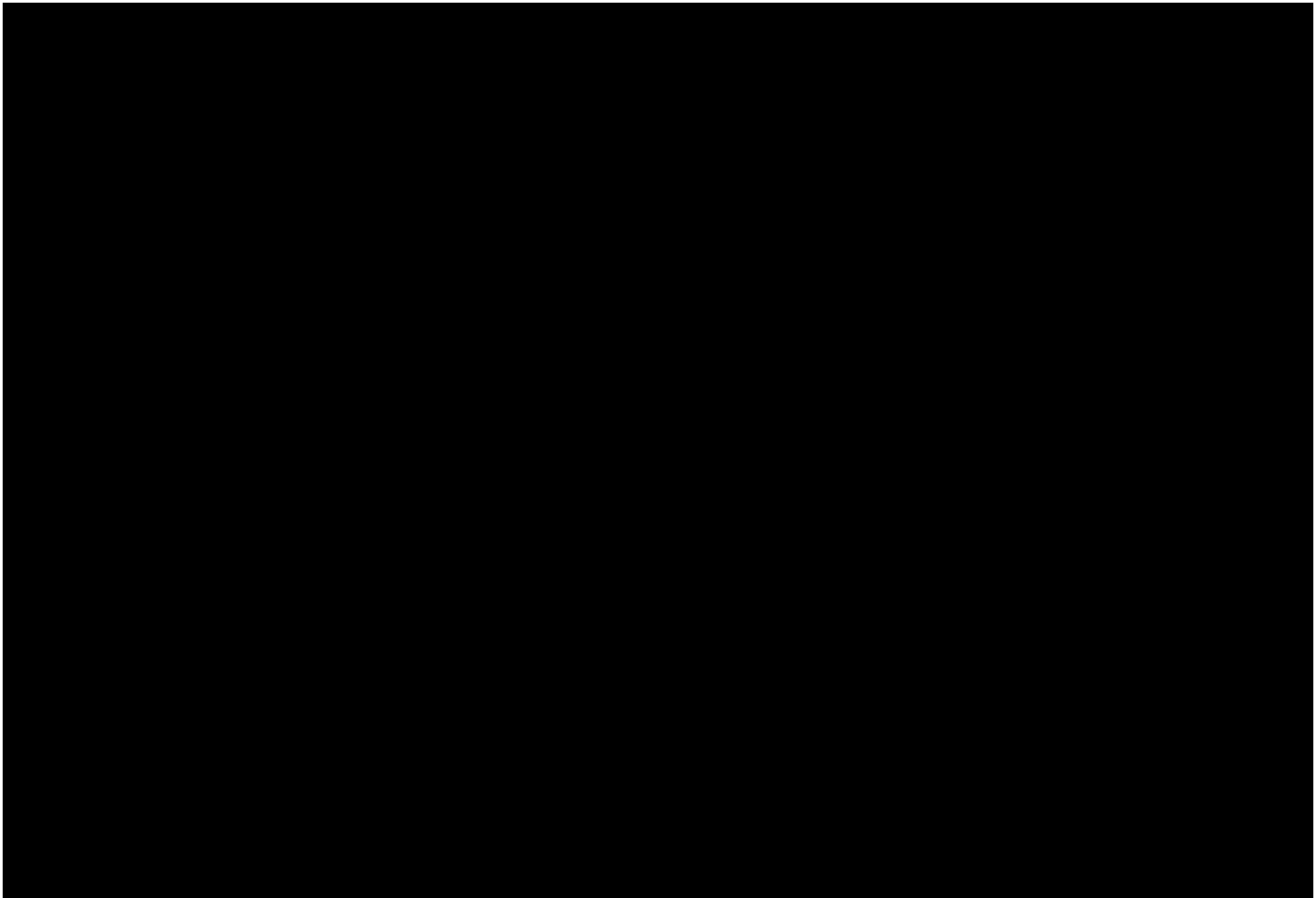
Date of Off Peak Day - 01/10/2021



Member Forecasted Off Peak Demand Day for February 2021

Niobrara Electric Association, Inc.

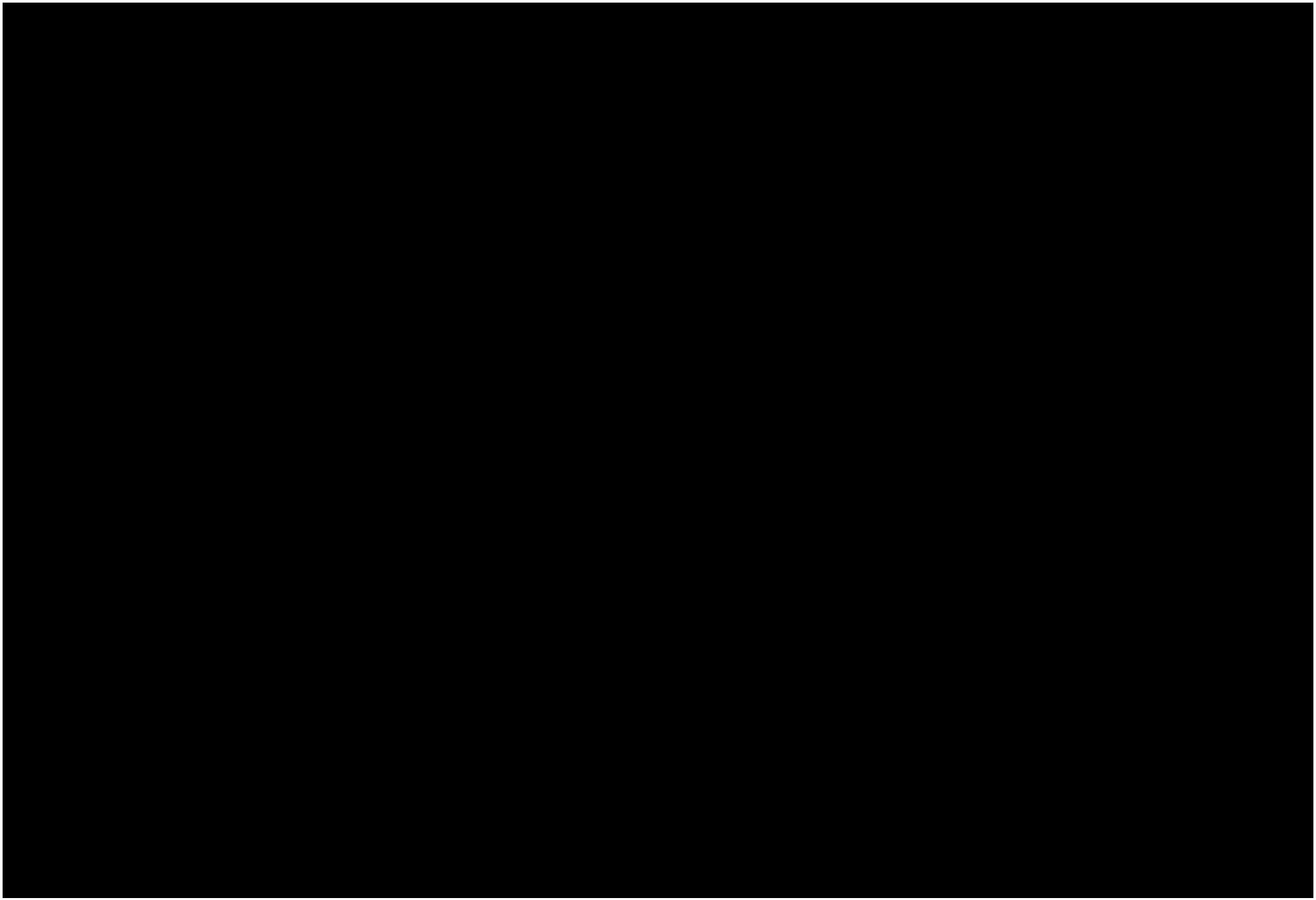
Date of Off Peak Day - 02/21/2021



Member Forecasted Off Peak Demand Day for March 2021

Niobrara Electric Association, Inc.

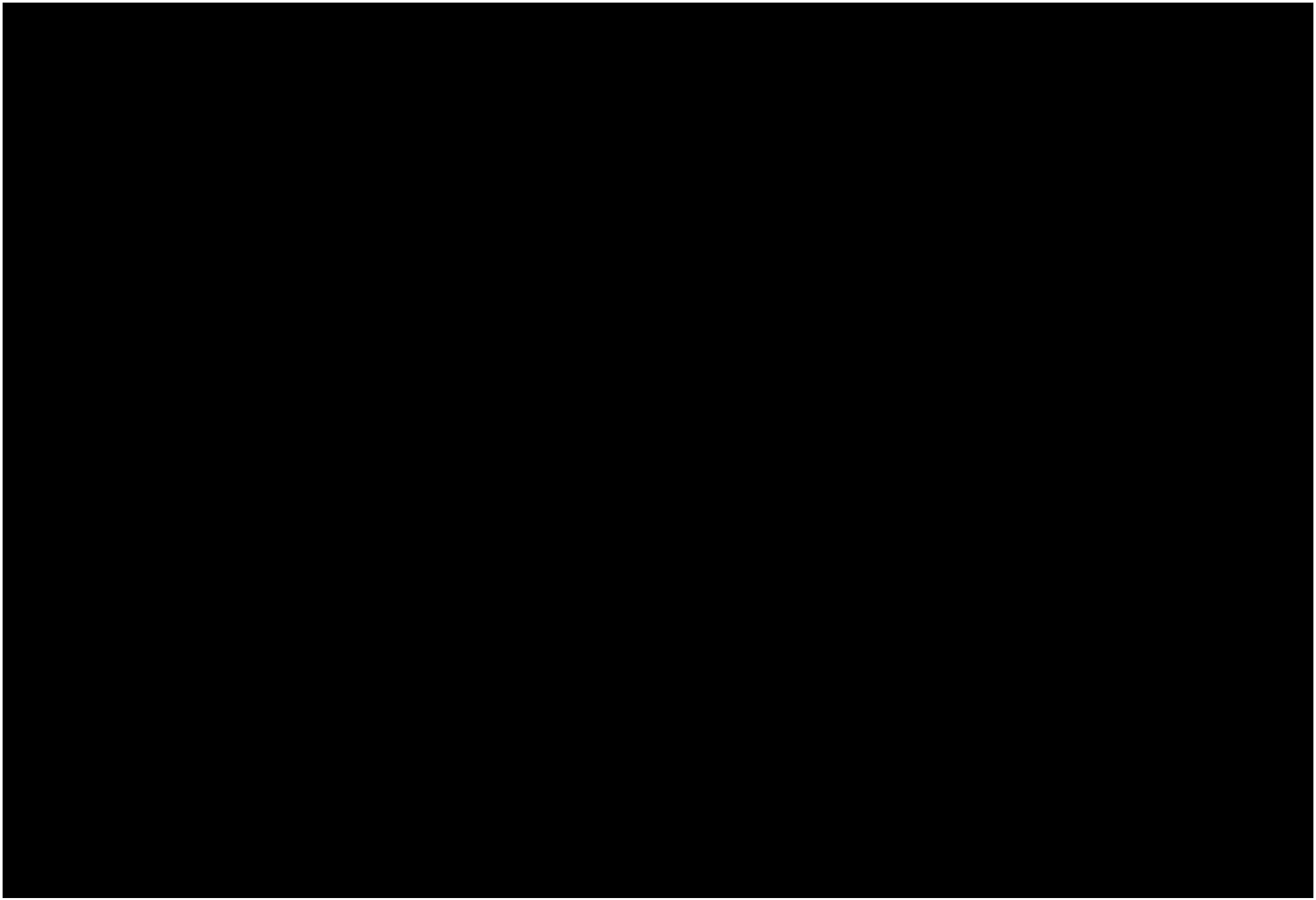
Date of Off Peak Day - 03/15/2021



Member Forecasted Off Peak Demand Day for April 2021

Niobrara Electric Association, Inc.

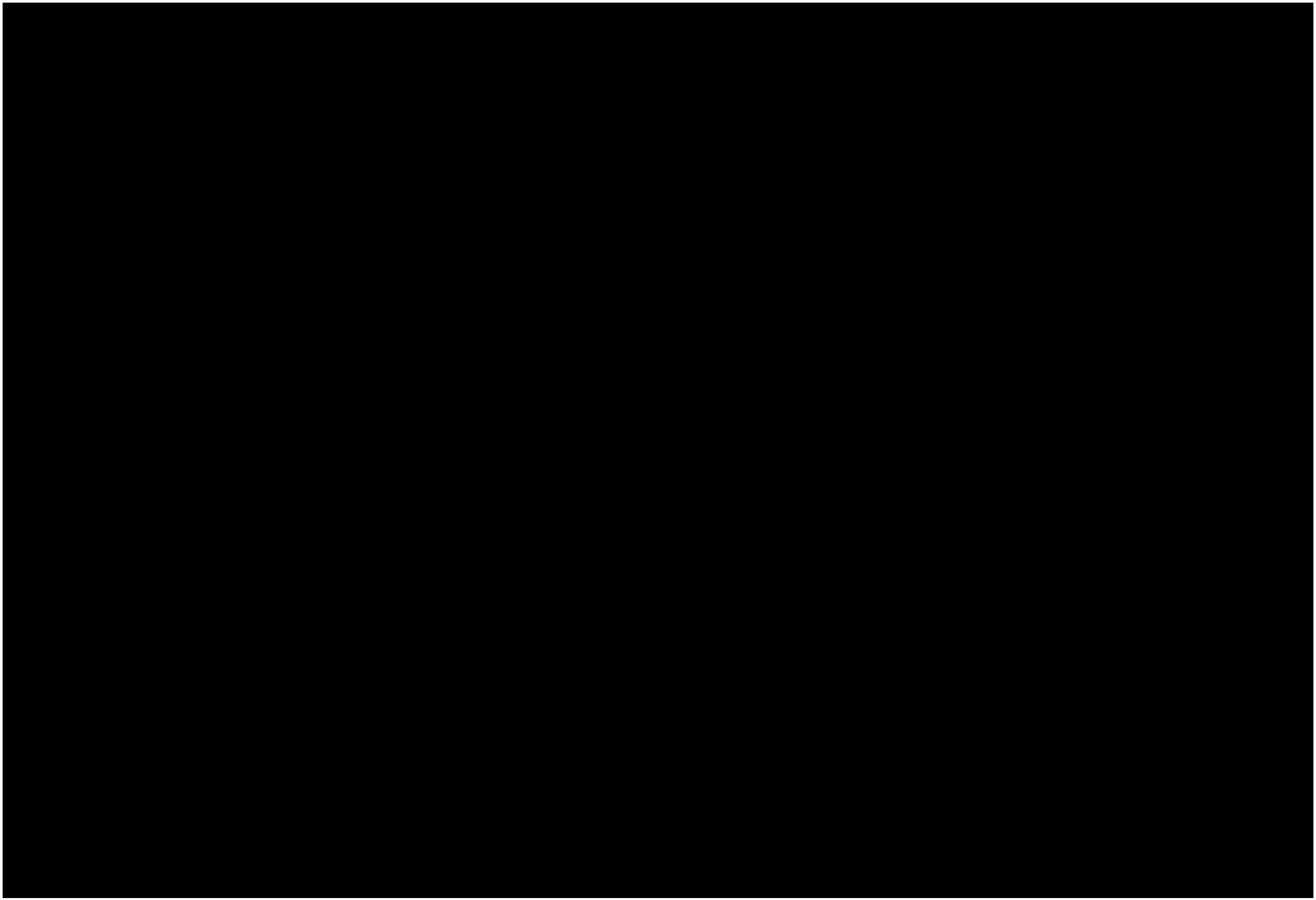
Date of Off Peak Day - 04/01/2021



Member Forecasted Off Peak Demand Day for May 2021

Niobrara Electric Association, Inc.

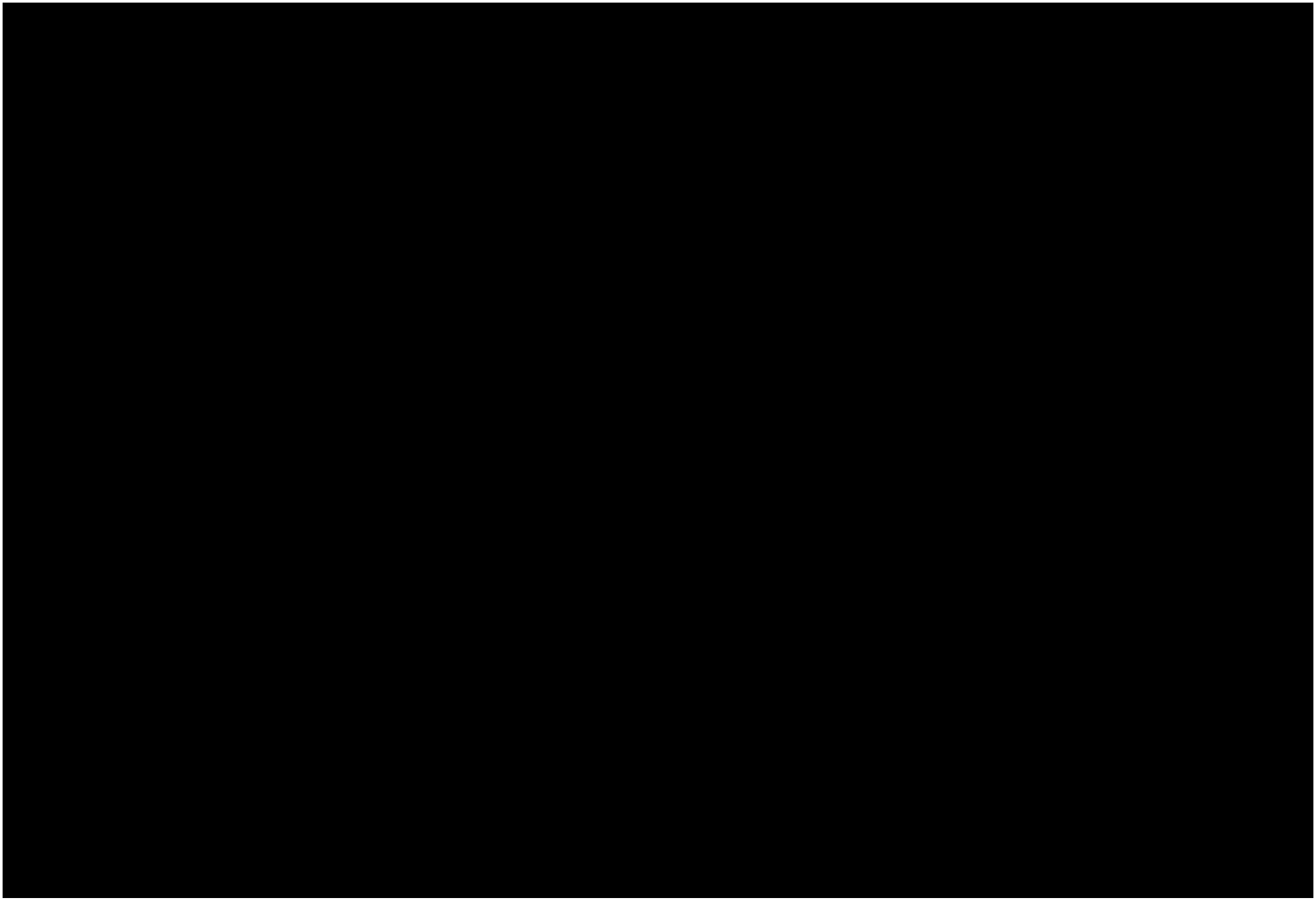
Date of Off Peak Day - 05/01/2021



Member Forecasted Off Peak Demand Day for June 2021

Niobrara Electric Association, Inc.

Date of Off Peak Day - 06/19/2021



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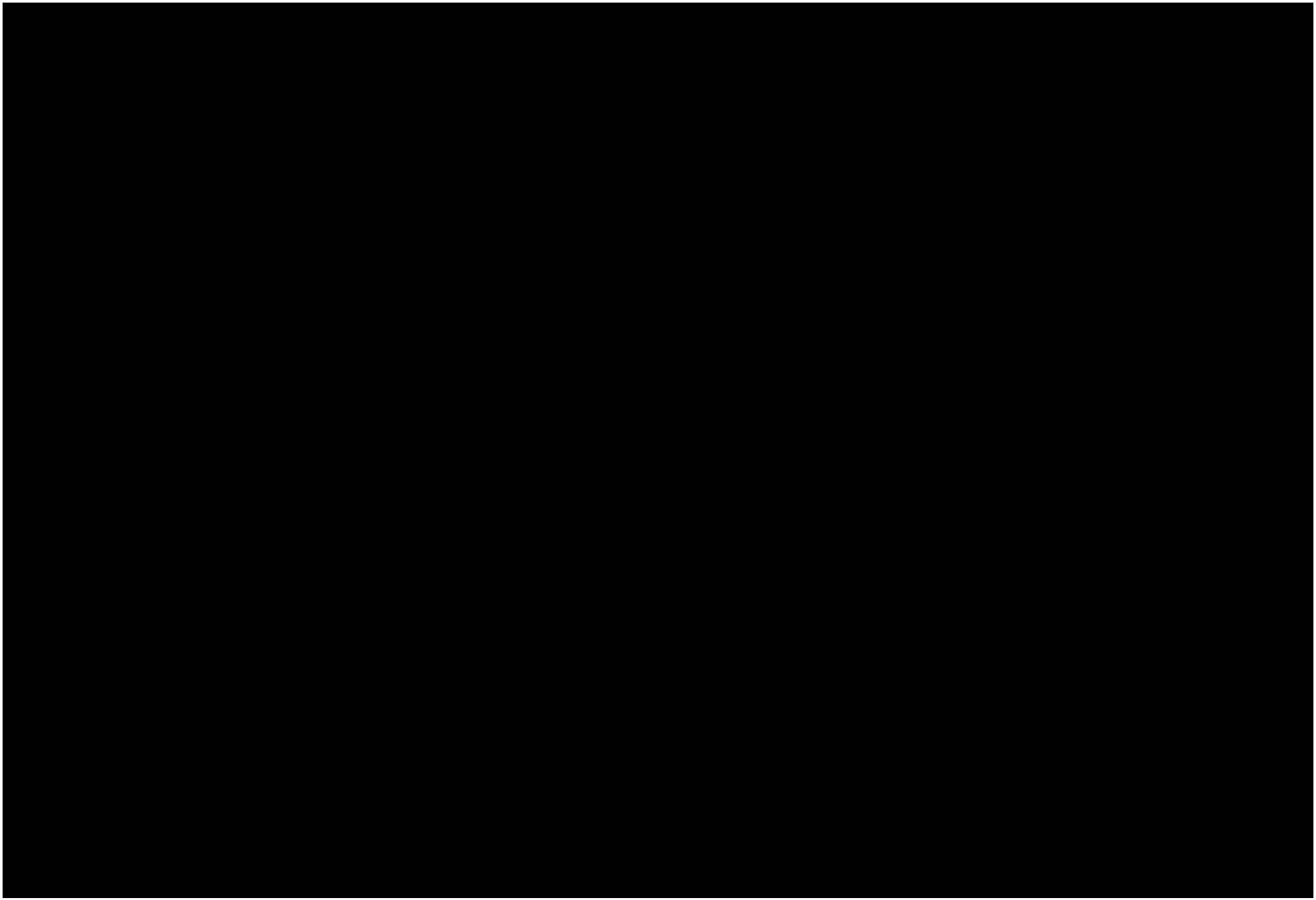
Member Forecasted Off Peak Demand Day for July 2021

Niobrara Electric Association, Inc.

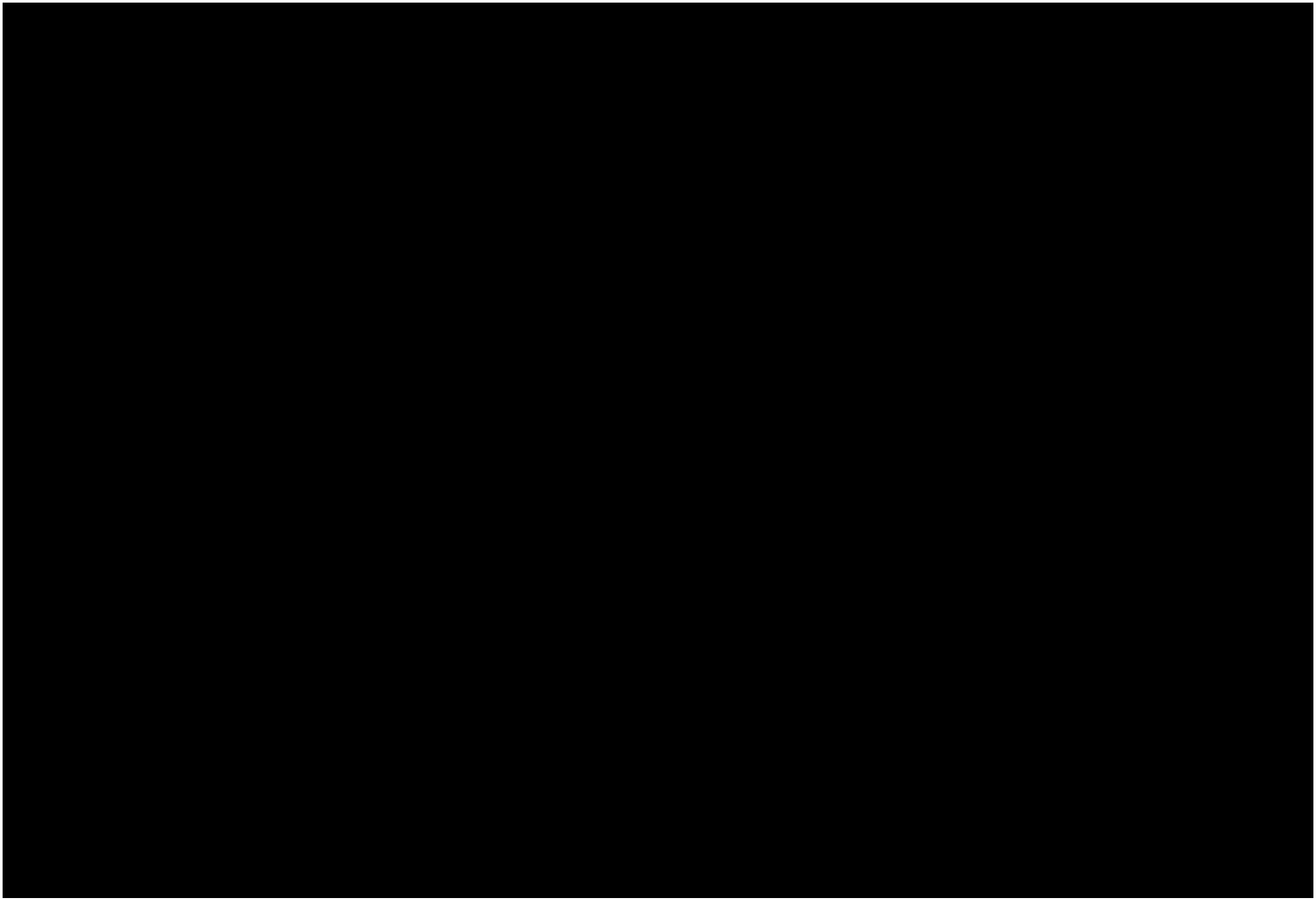
Date of Off Peak Day - 07/29/2021



Member Forecasted Off Peak Demand Day for August 2021

Niobrara Electric Association, Inc.

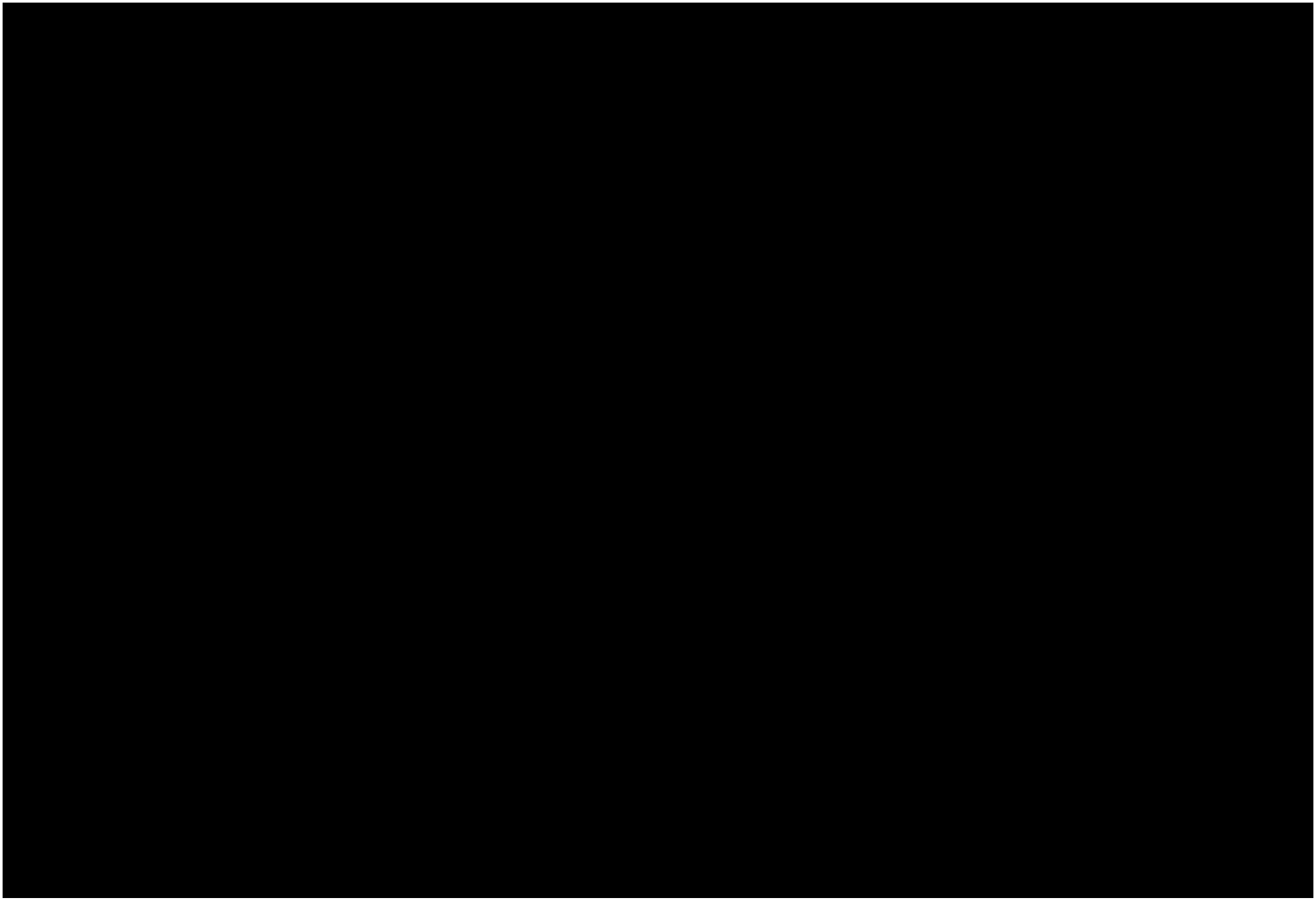
Date of Off Peak Day - 08/13/2021



Member Forecasted Off Peak Demand Day for September 2021

Niobrara Electric Association, Inc.

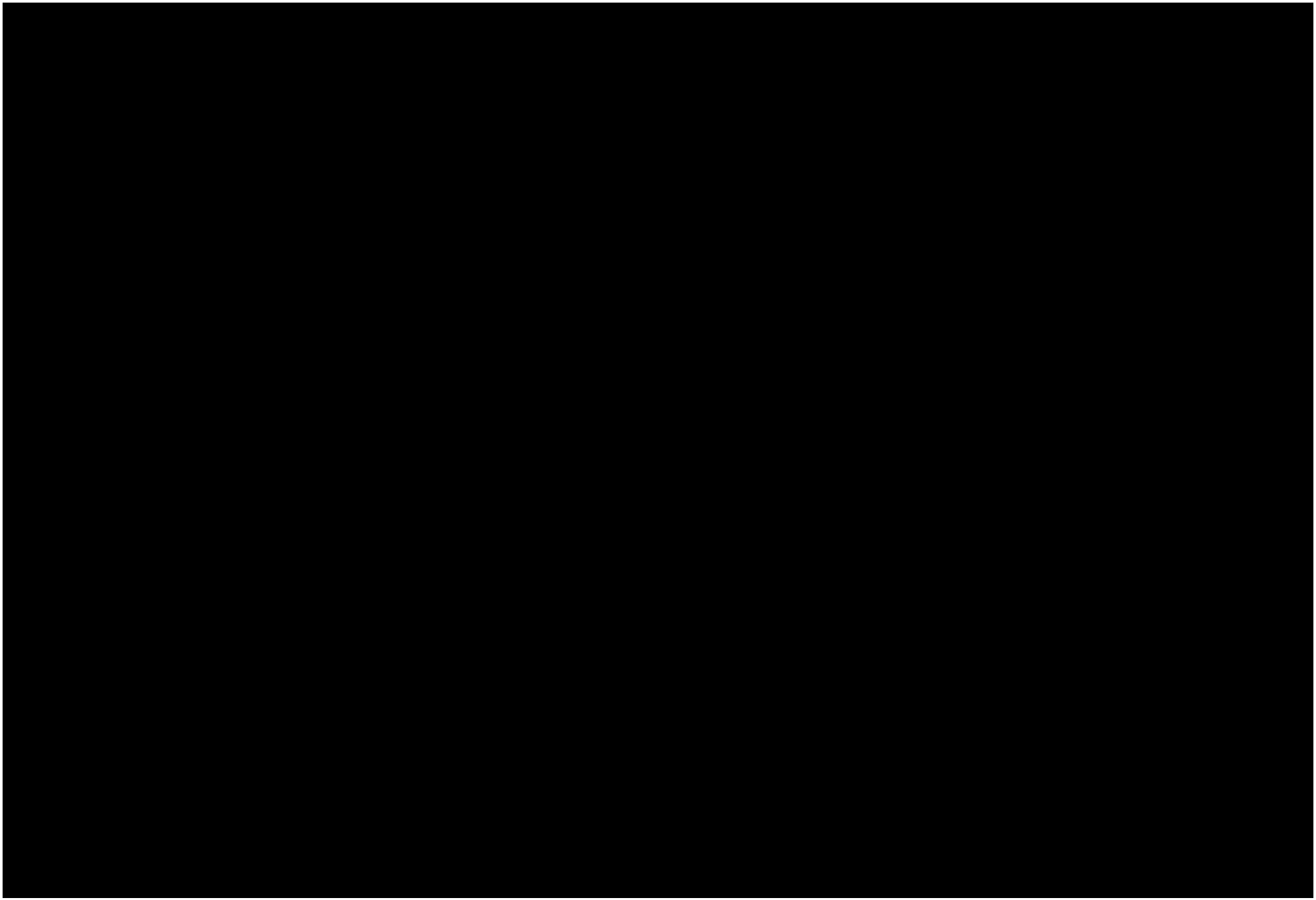
Date of Off Peak Day - 09/01/2021



Member Forecasted Off Peak Demand Day for October 2021

Niobrara Electric Association, Inc.

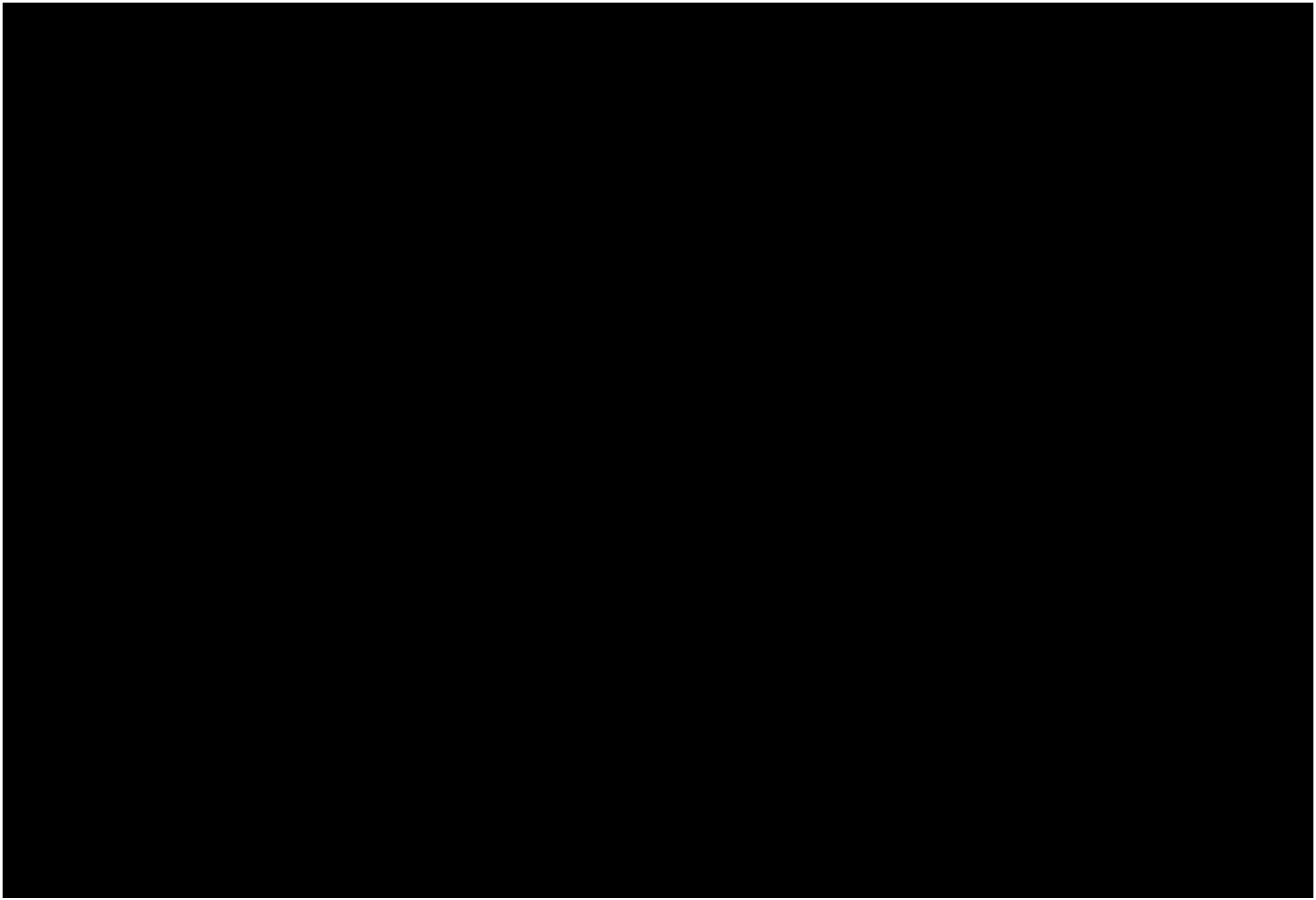
Date of Off Peak Day - 10/04/2021



Member Forecasted Off Peak Demand Day for November 2021

Niobrara Electric Association, Inc.

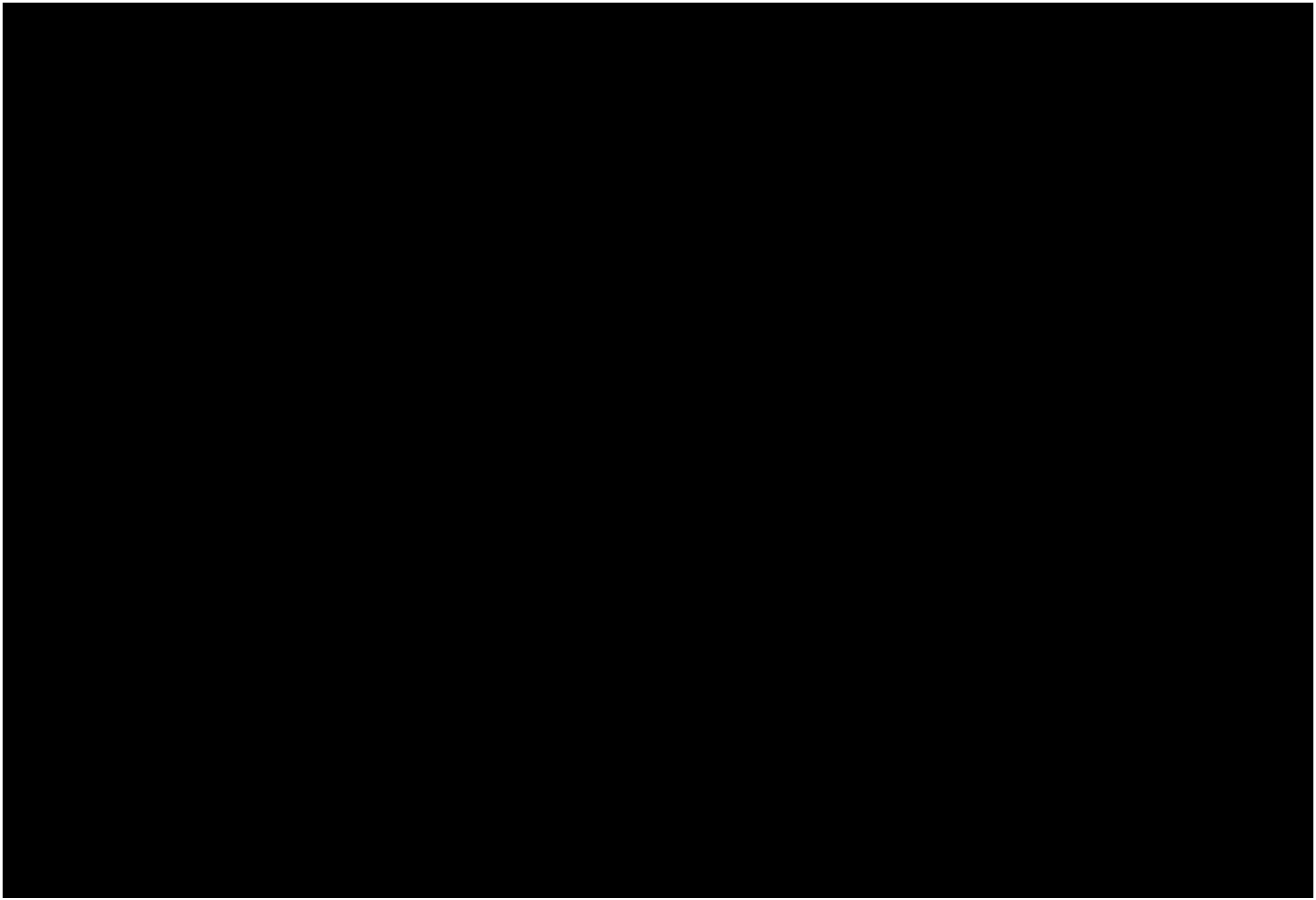
Date of Off Peak Day - 11/15/2021



Member Forecasted Off Peak Demand Day for December 2021

Niobrara Electric Association, Inc.

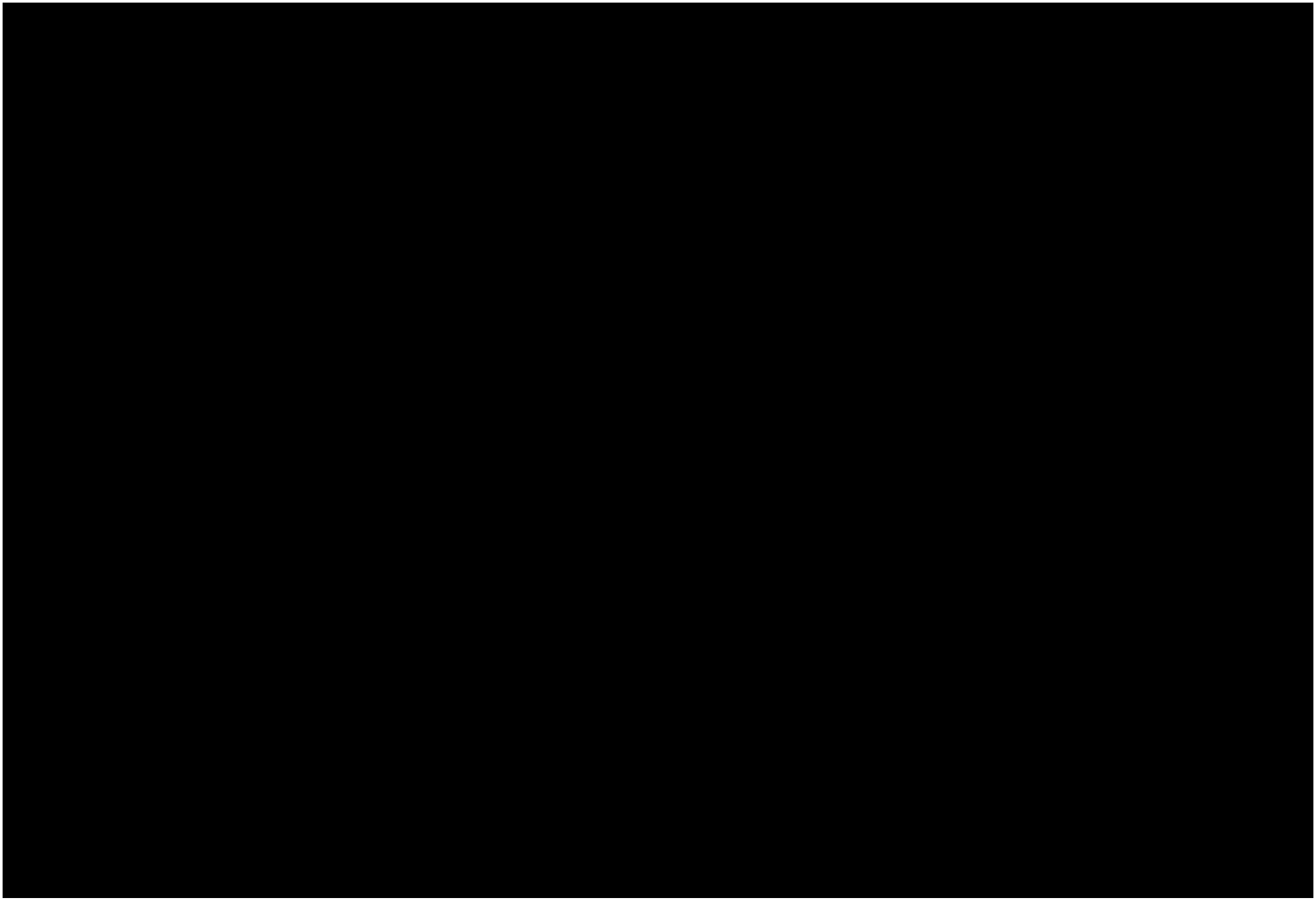
Date of Off Peak Day - 12/03/2021



Member Forecasted Off Peak Demand Day for January 2021

Northwest Rural Public Power District

Date of Off Peak Day - 01/18/2021



Member Forecasted Off Peak Demand Day for February 2021

Northwest Rural Public Power District

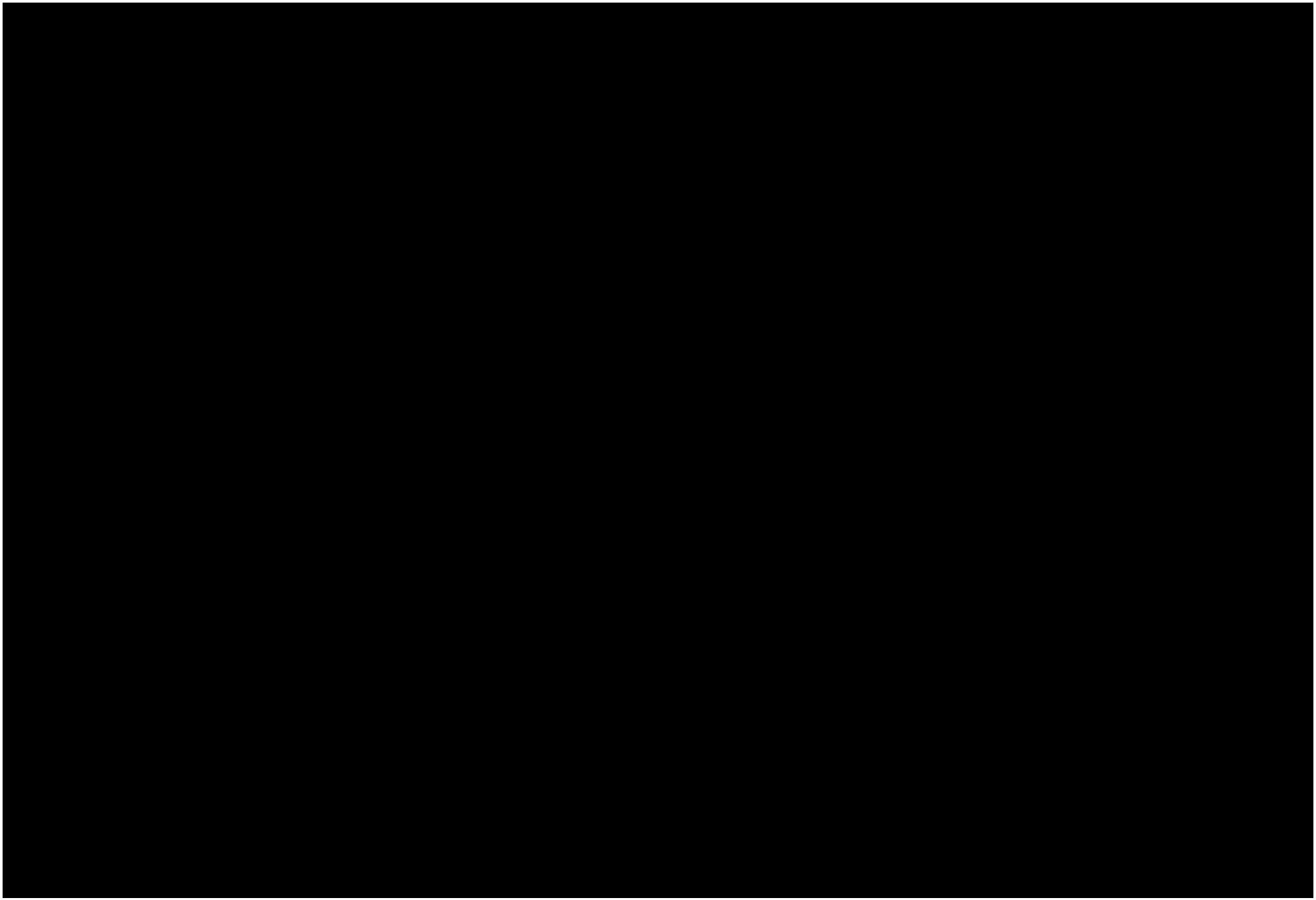
Date of Off Peak Day - 02/22/2021

[redacted]

Member Forecasted Off Peak Demand Day for March 2021

Northwest Rural Public Power District

Date of Off Peak Day - 03/27/2021



Member Forecasted Off Peak Demand Day for April 2021

Northwest Rural Public Power District

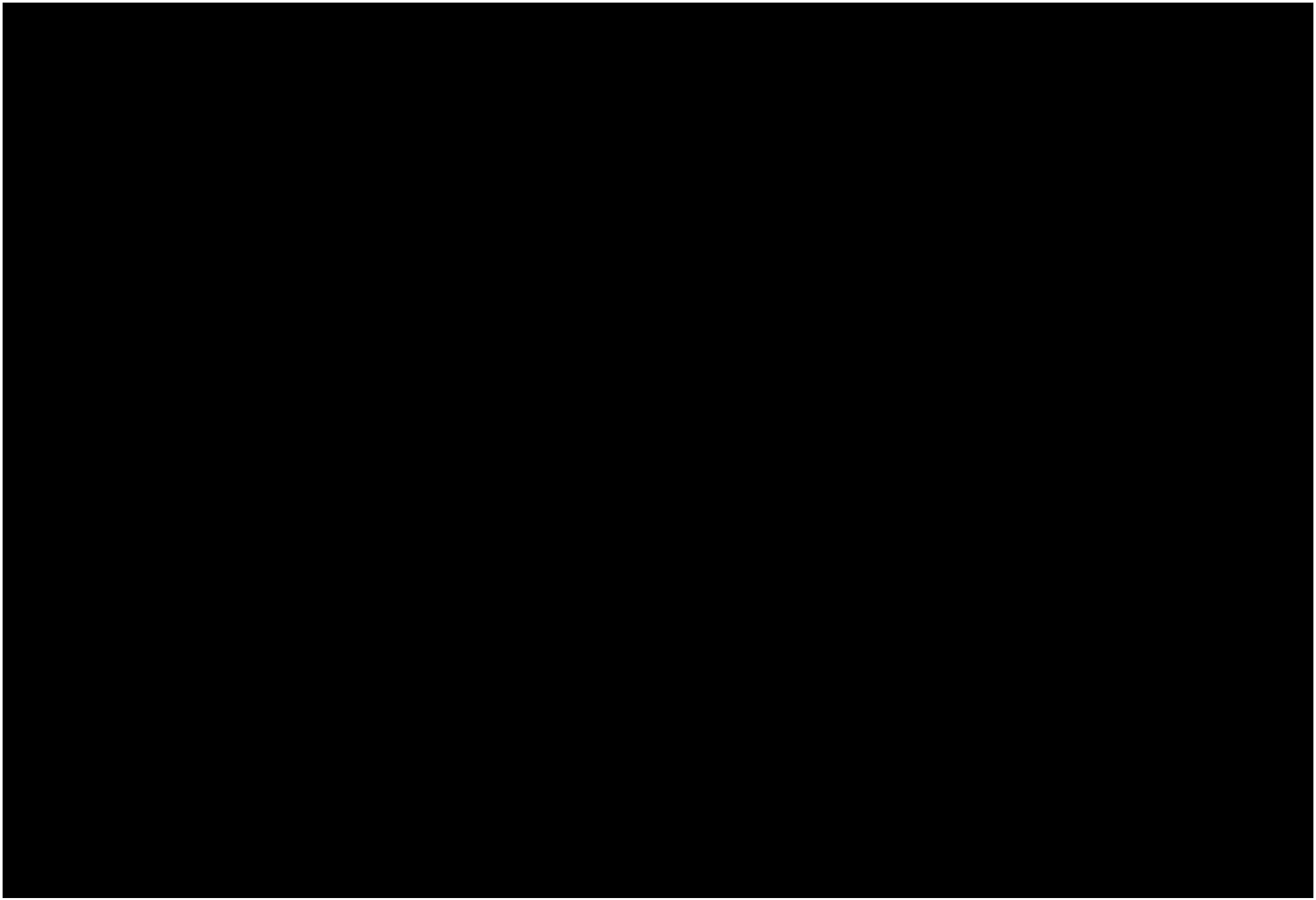
Date of Off Peak Day - 04/23/2021

[redacted]

Member Forecasted Off Peak Demand Day for May 2021

Northwest Rural Public Power District

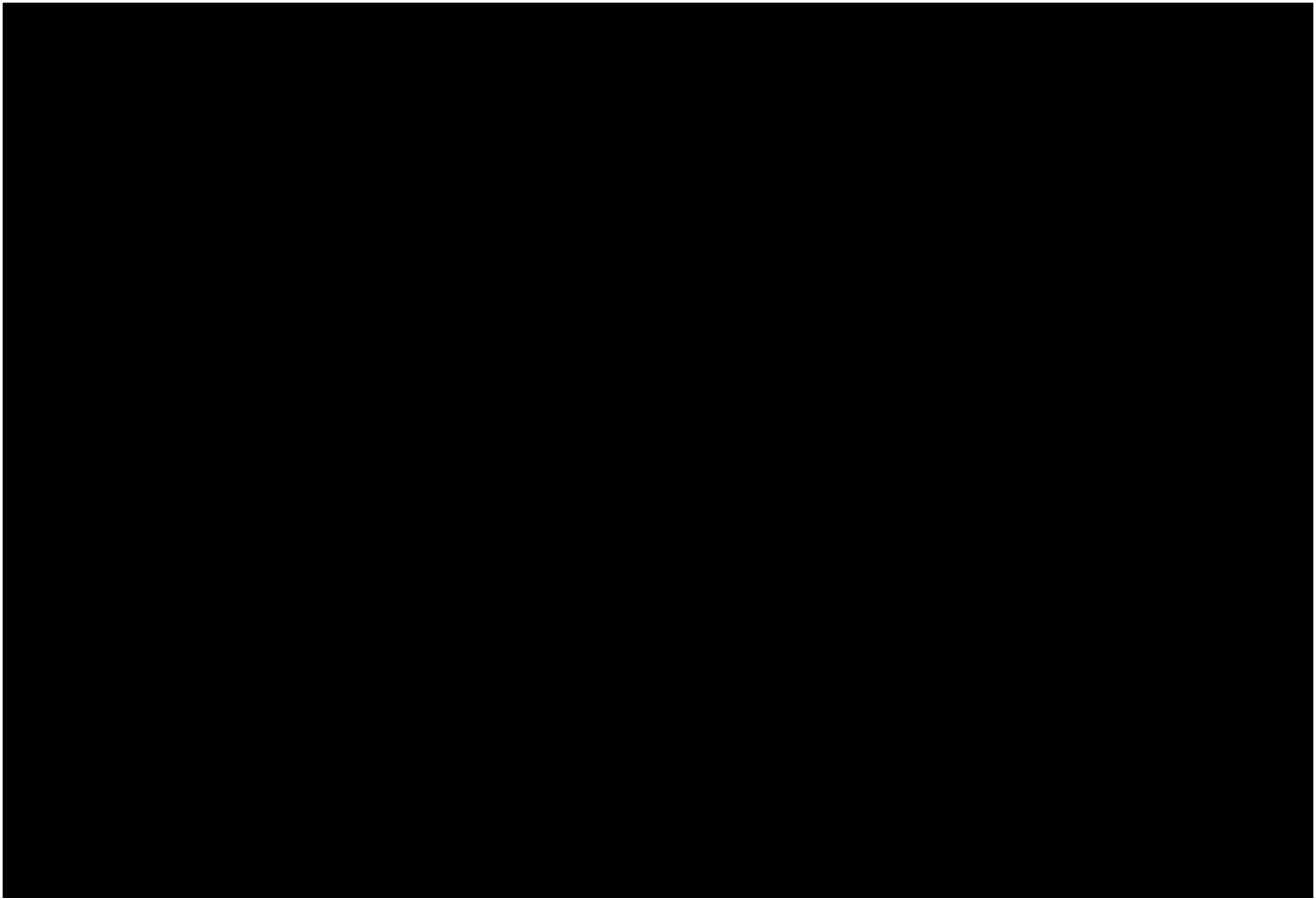
Date of Off Peak Day - 05/22/2021



Member Forecasted Off Peak Demand Day for June 2021

Northwest Rural Public Power District

Date of Off Peak Day - 06/21/2021



Member Forecasted Off Peak Demand Day for July 2021

Northwest Rural Public Power District

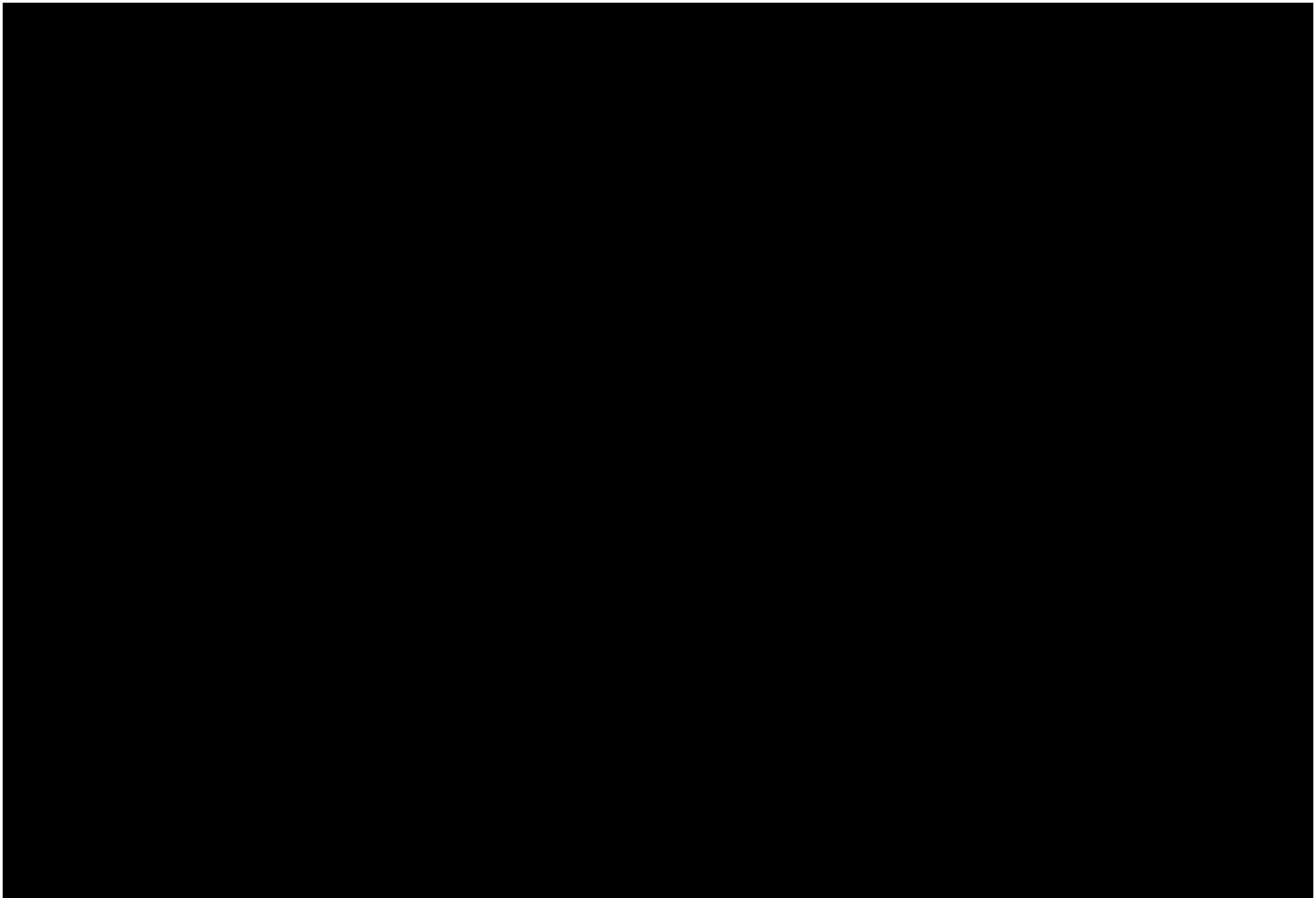
Date of Off Peak Day - 07/03/2021

[redacted]

Member Forecasted Off Peak Demand Day for August 2021

Northwest Rural Public Power District

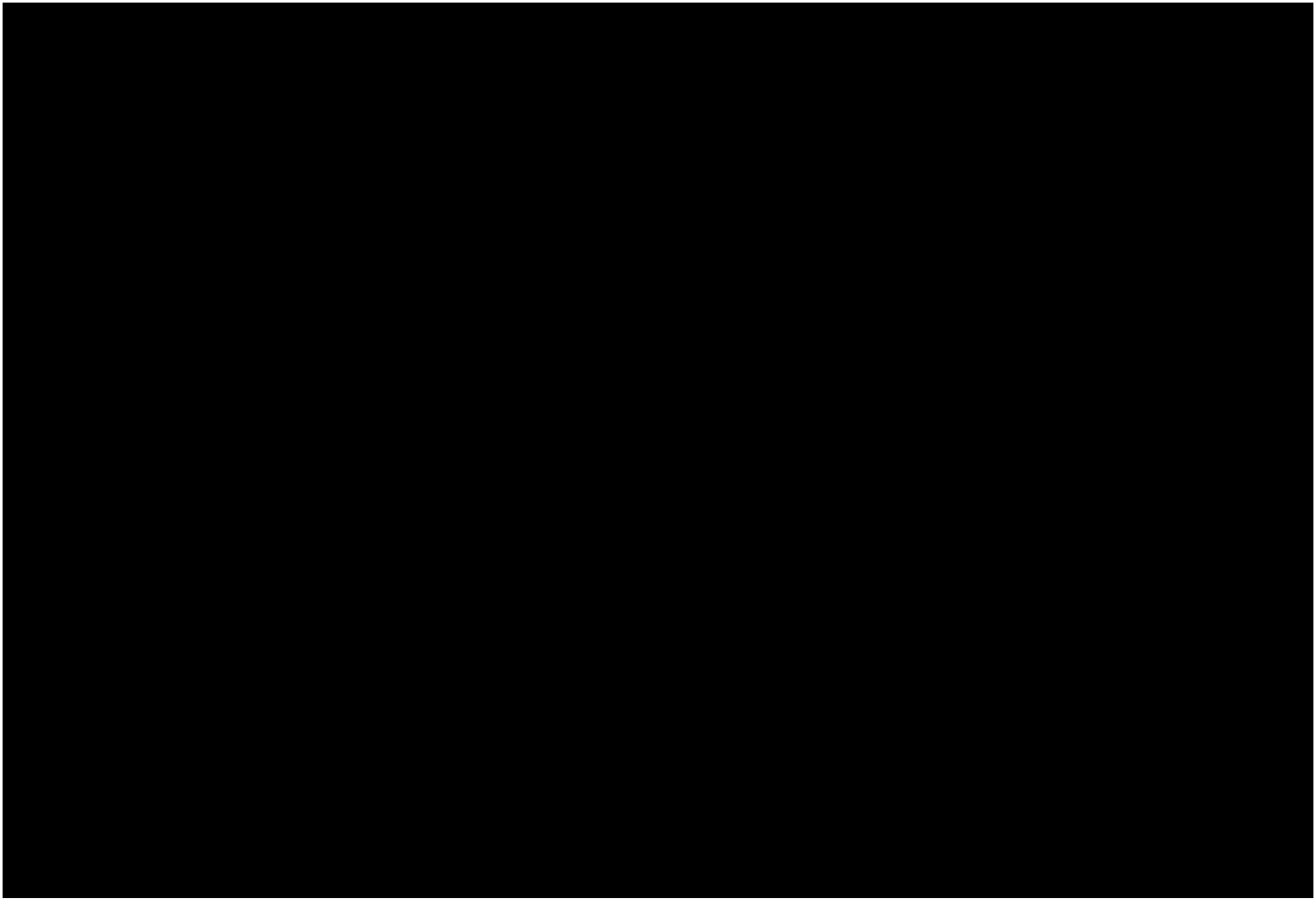
Date of Off Peak Day - 08/09/2021



Member Forecasted Off Peak Demand Day for September 2021

Northwest Rural Public Power District

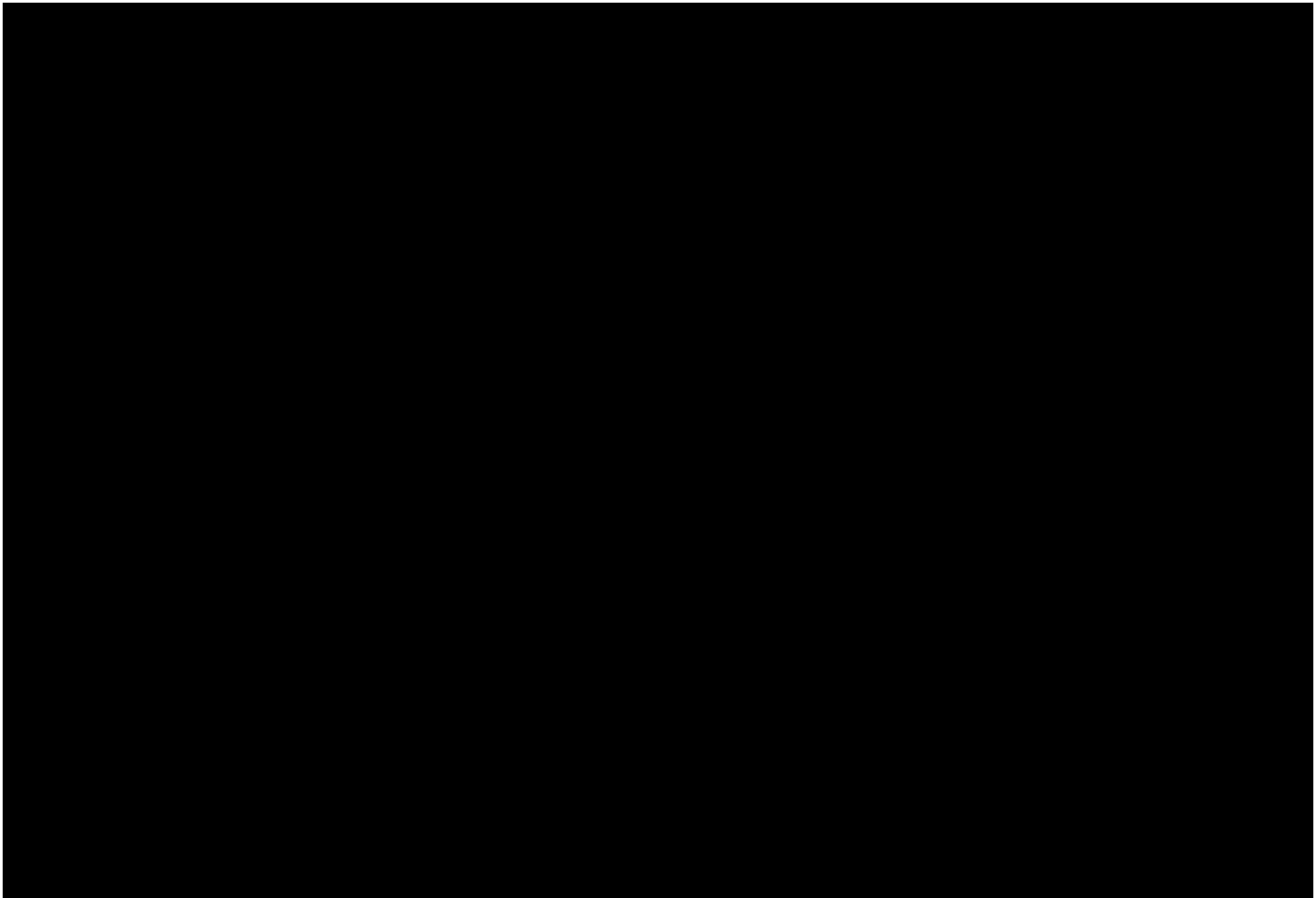
Date of Off Peak Day - 09/19/2021



Member Forecasted Off Peak Demand Day for October 2021

Northwest Rural Public Power District

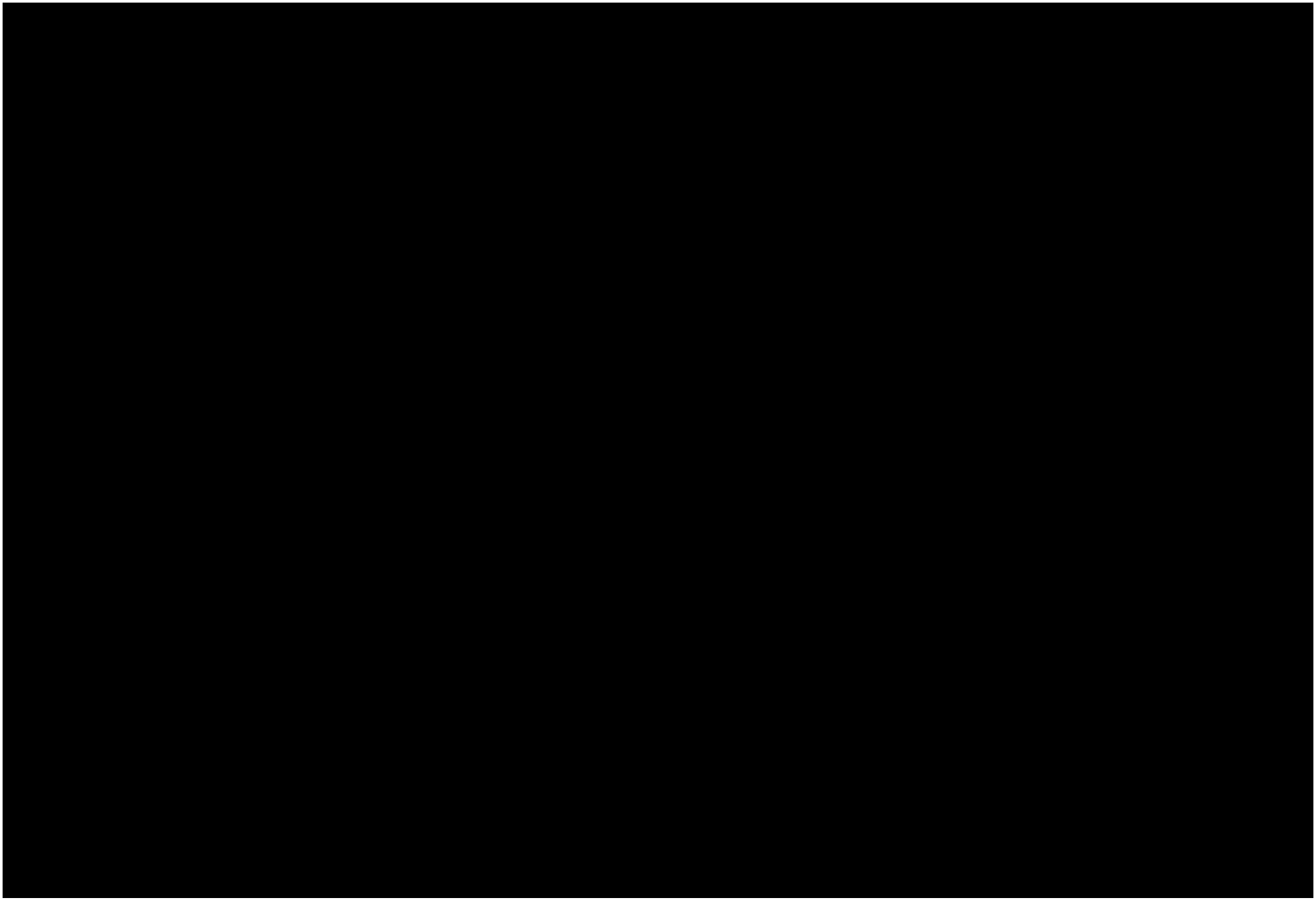
Date of Off Peak Day - 10/22/2021



Member Forecasted Off Peak Demand Day for November 2021

Northwest Rural Public Power District

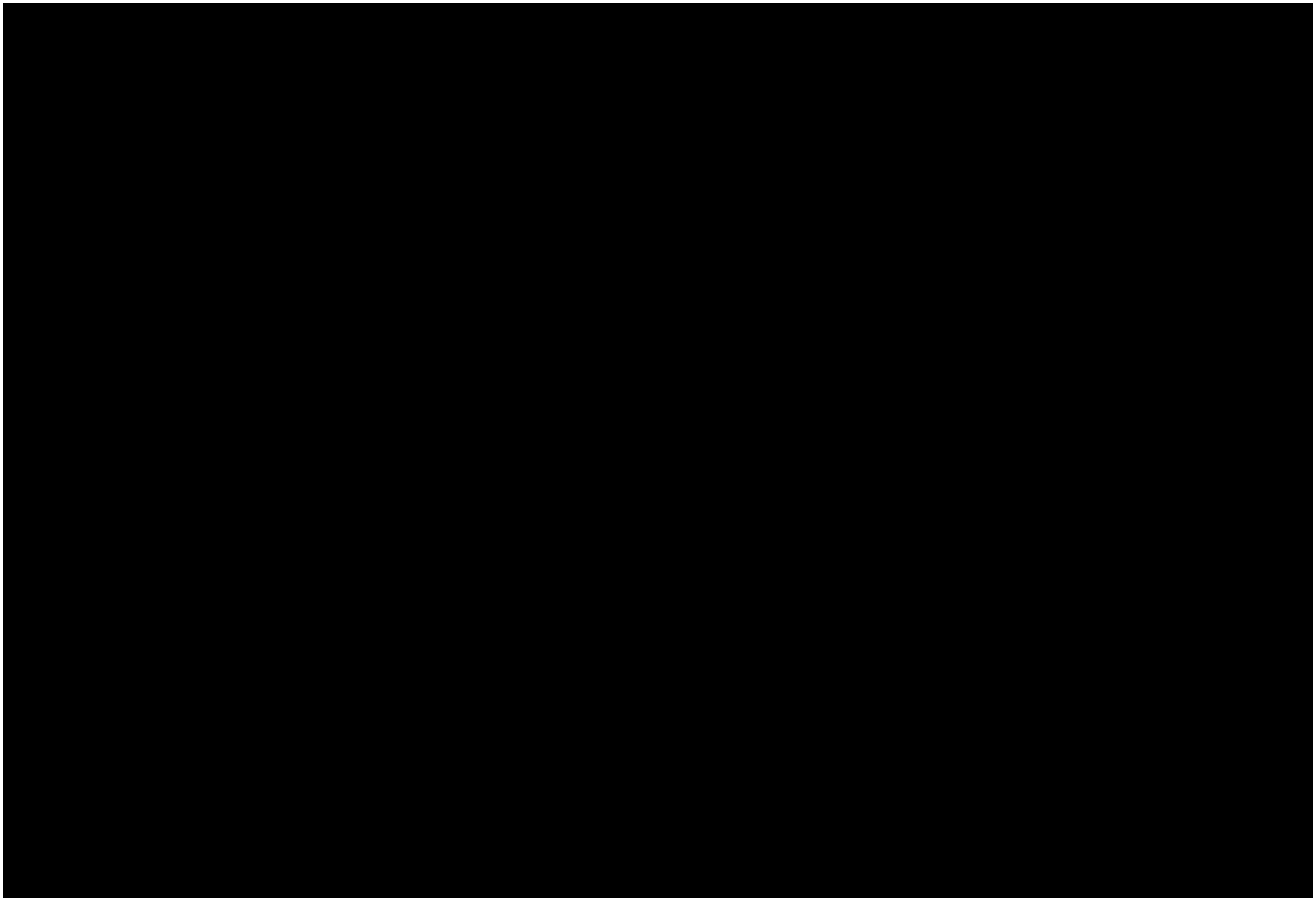
Date of Off Peak Day - 11/04/2021



Member Forecasted Off Peak Demand Day for December 2021

Northwest Rural Public Power District

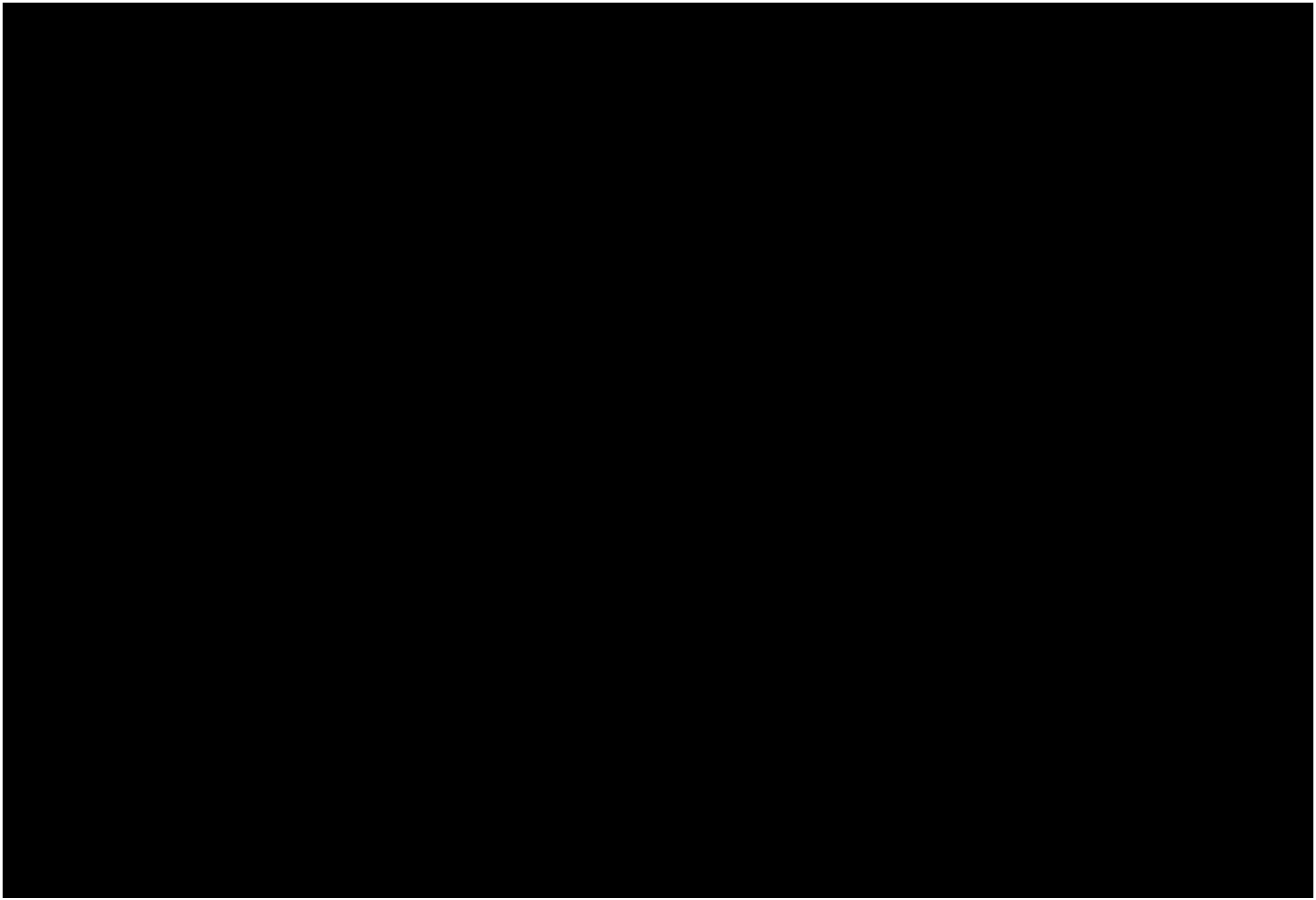
Date of Off Peak Day - 12/08/2021



Member Forecasted Off Peak Demand Day for January 2021

Otero County Electric Cooperative, Inc.

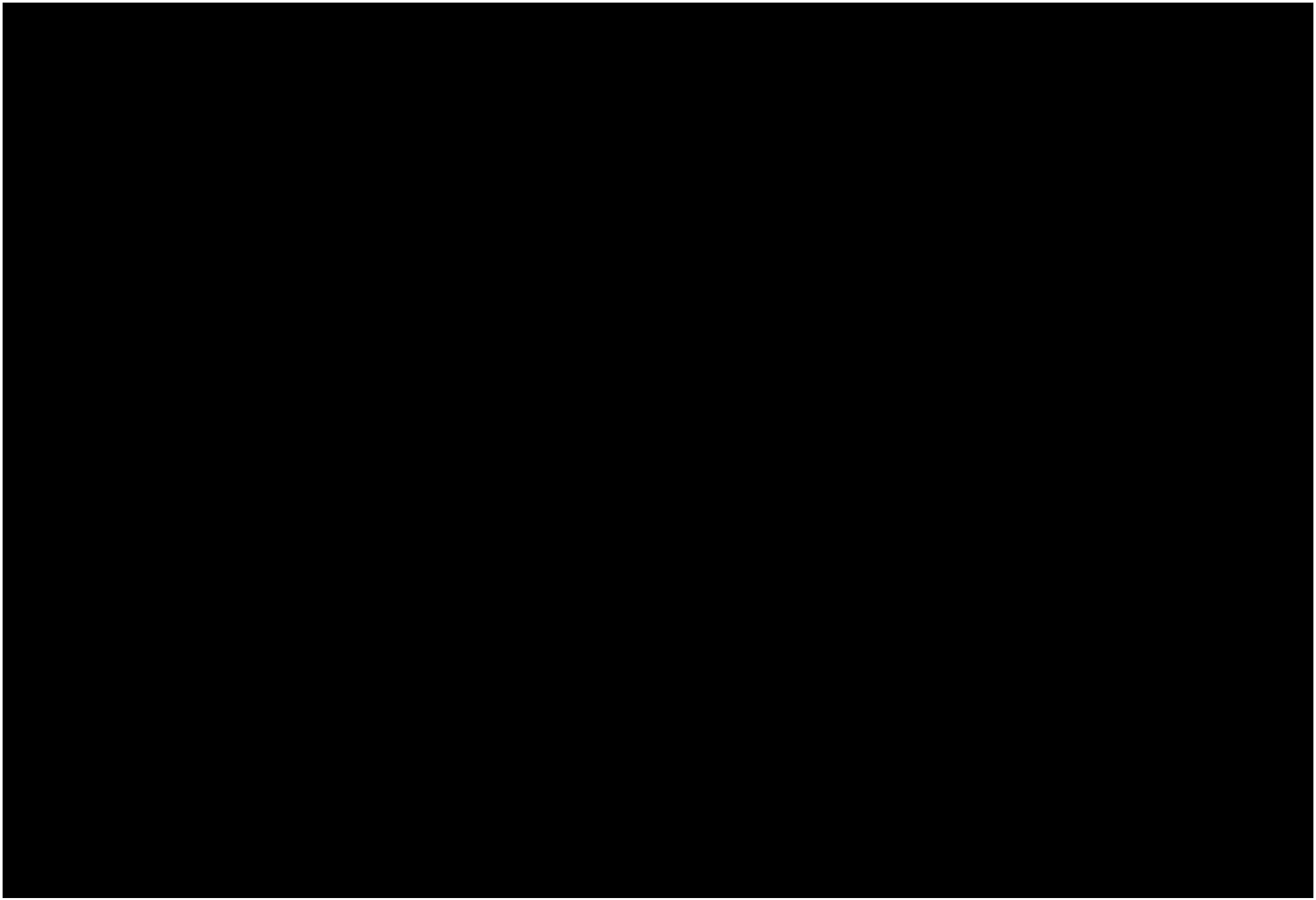
Date of Off Peak Day - 01/12/2021



Member Forecasted Off Peak Demand Day for February 2021

Otero County Electric Cooperative, Inc.

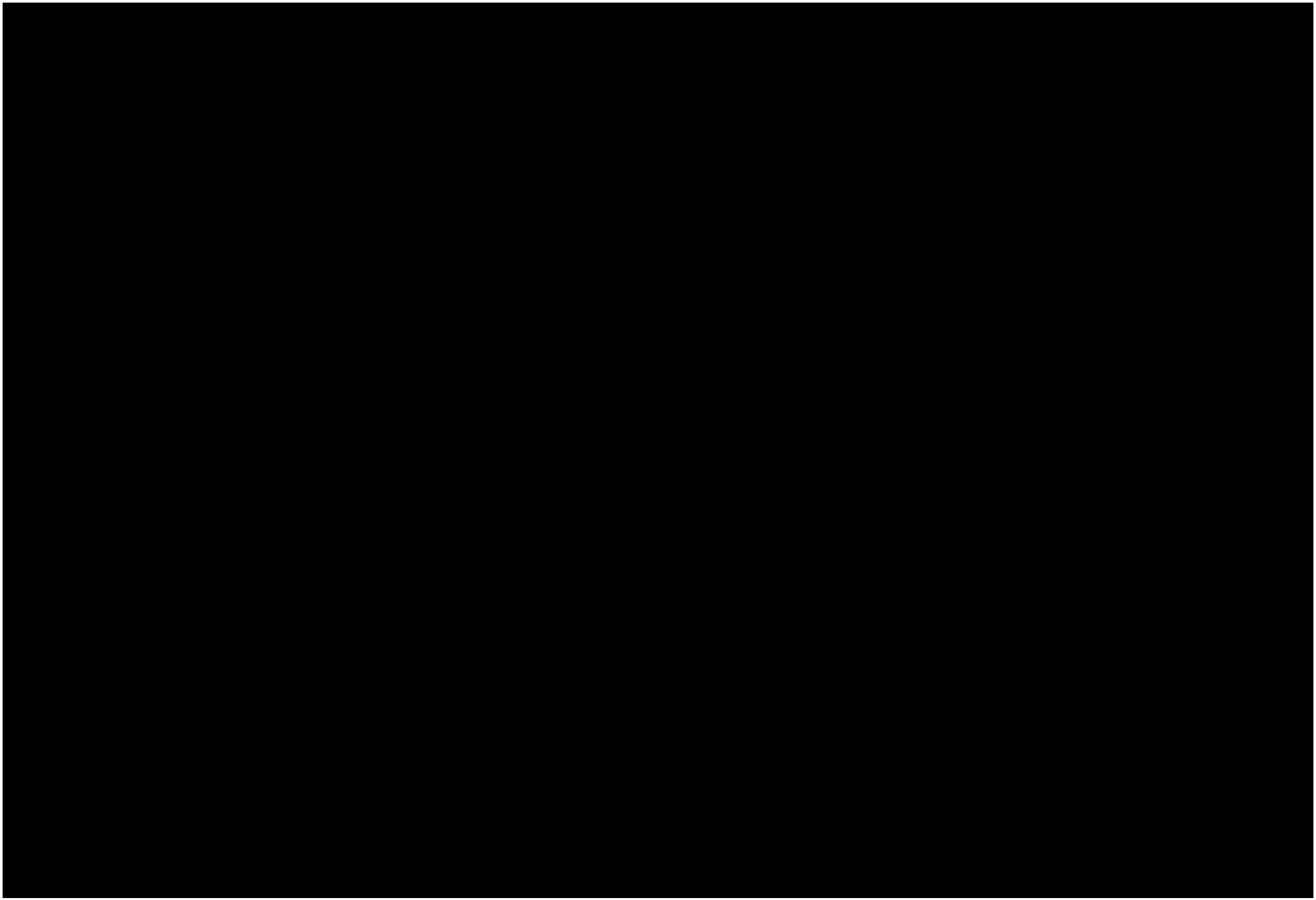
Date of Off Peak Day - 02/27/2021



Member Forecasted Off Peak Demand Day for March 2021

Otero County Electric Cooperative, Inc.

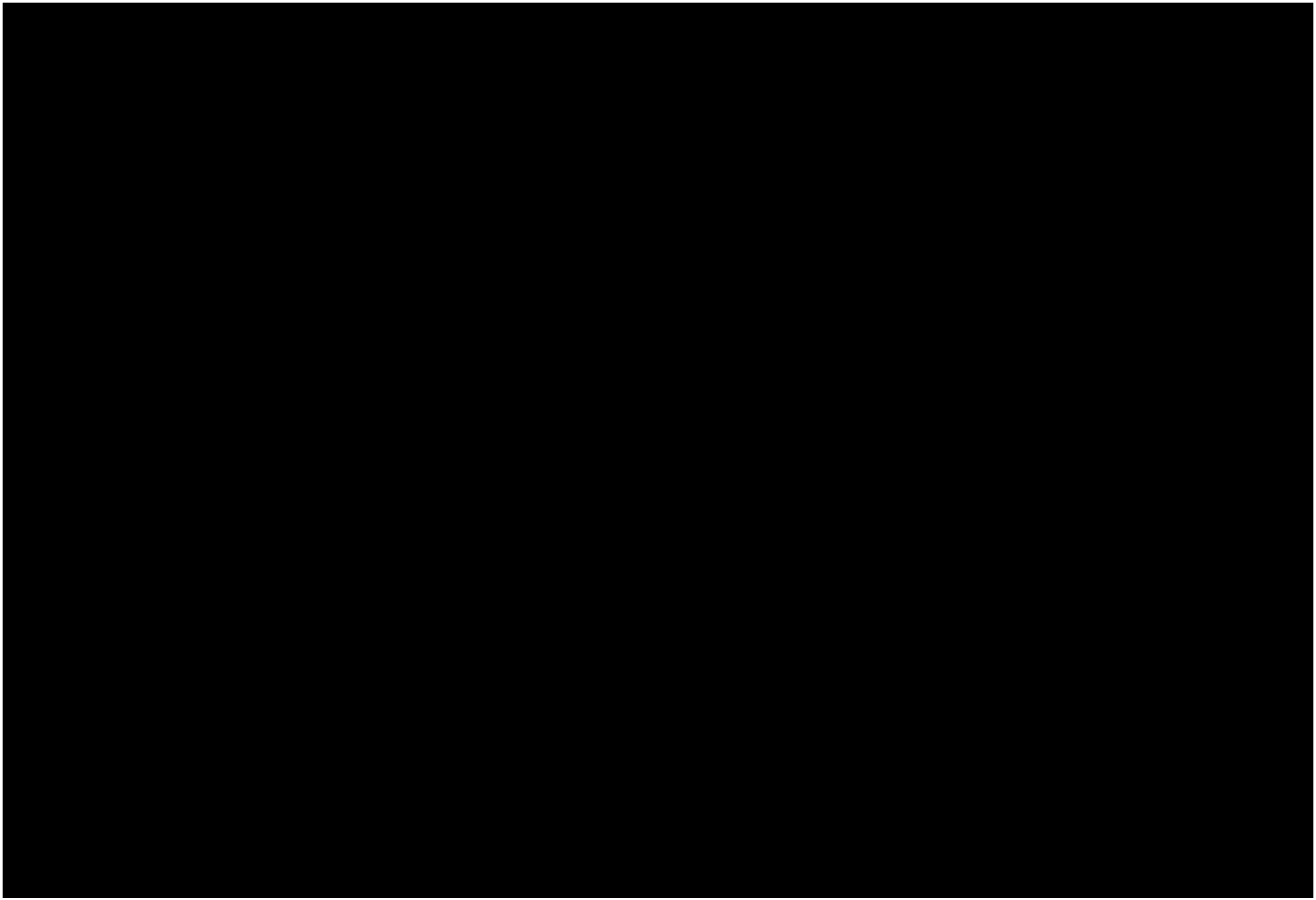
Date of Off Peak Day - 03/22/2021



Member Forecasted Off Peak Demand Day for April 2021

Otero County Electric Cooperative, Inc.

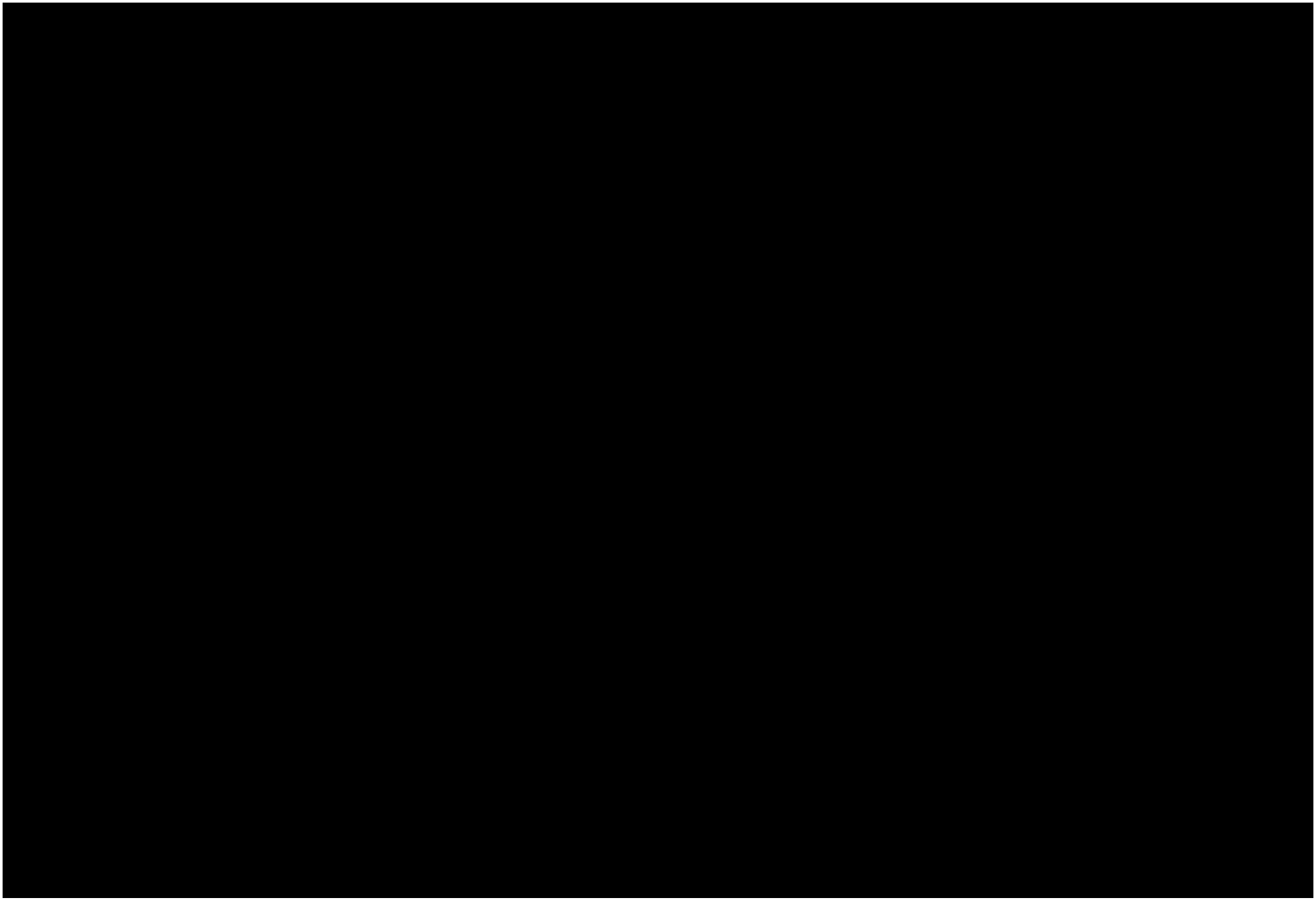
Date of Off Peak Day - 04/21/2021



Member Forecasted Off Peak Demand Day for May 2021

Otero County Electric Cooperative, Inc.

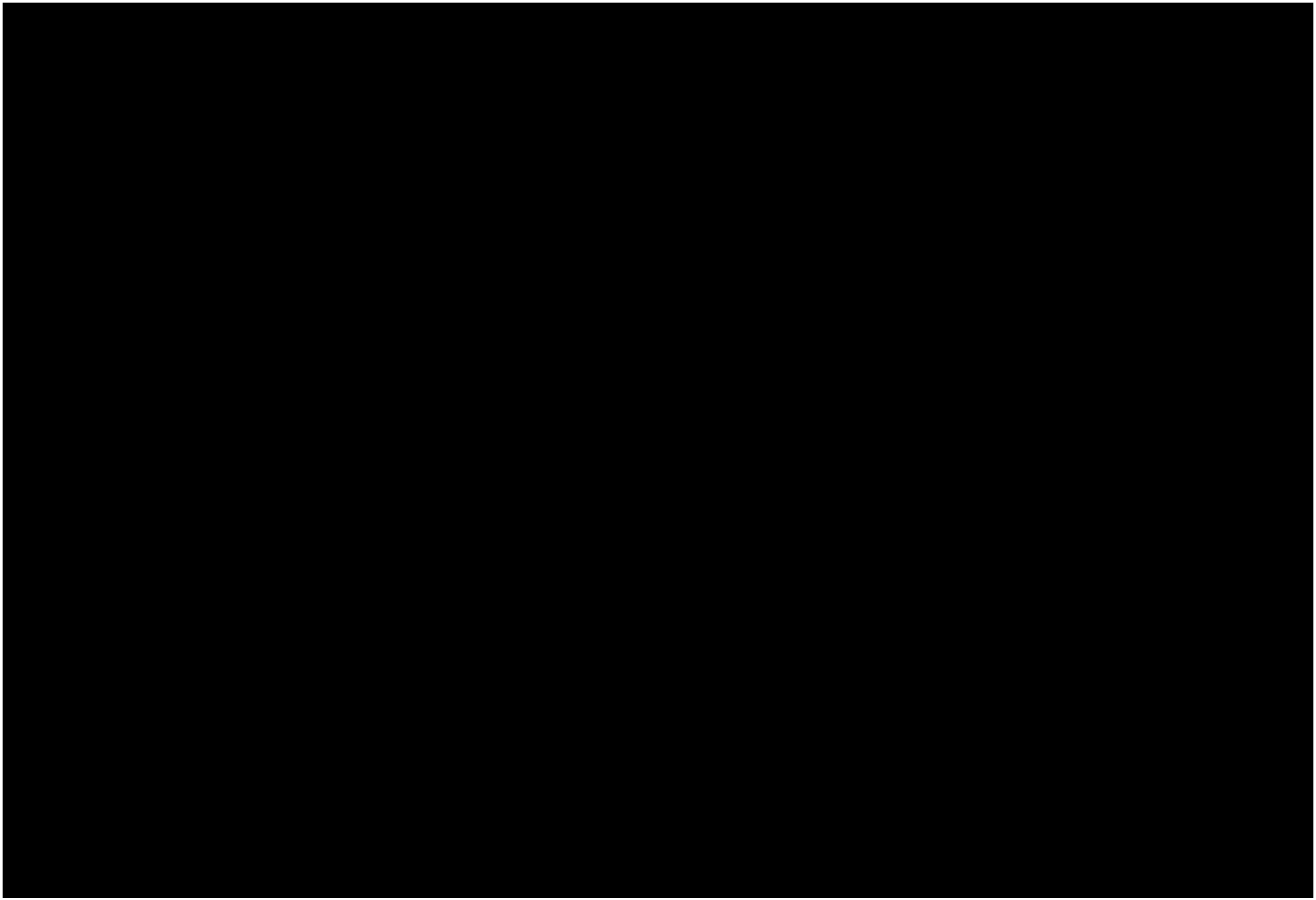
Date of Off Peak Day - 05/03/2021



Member Forecasted Off Peak Demand Day for June 2021

Otero County Electric Cooperative, Inc.

Date of Off Peak Day - 06/20/2021



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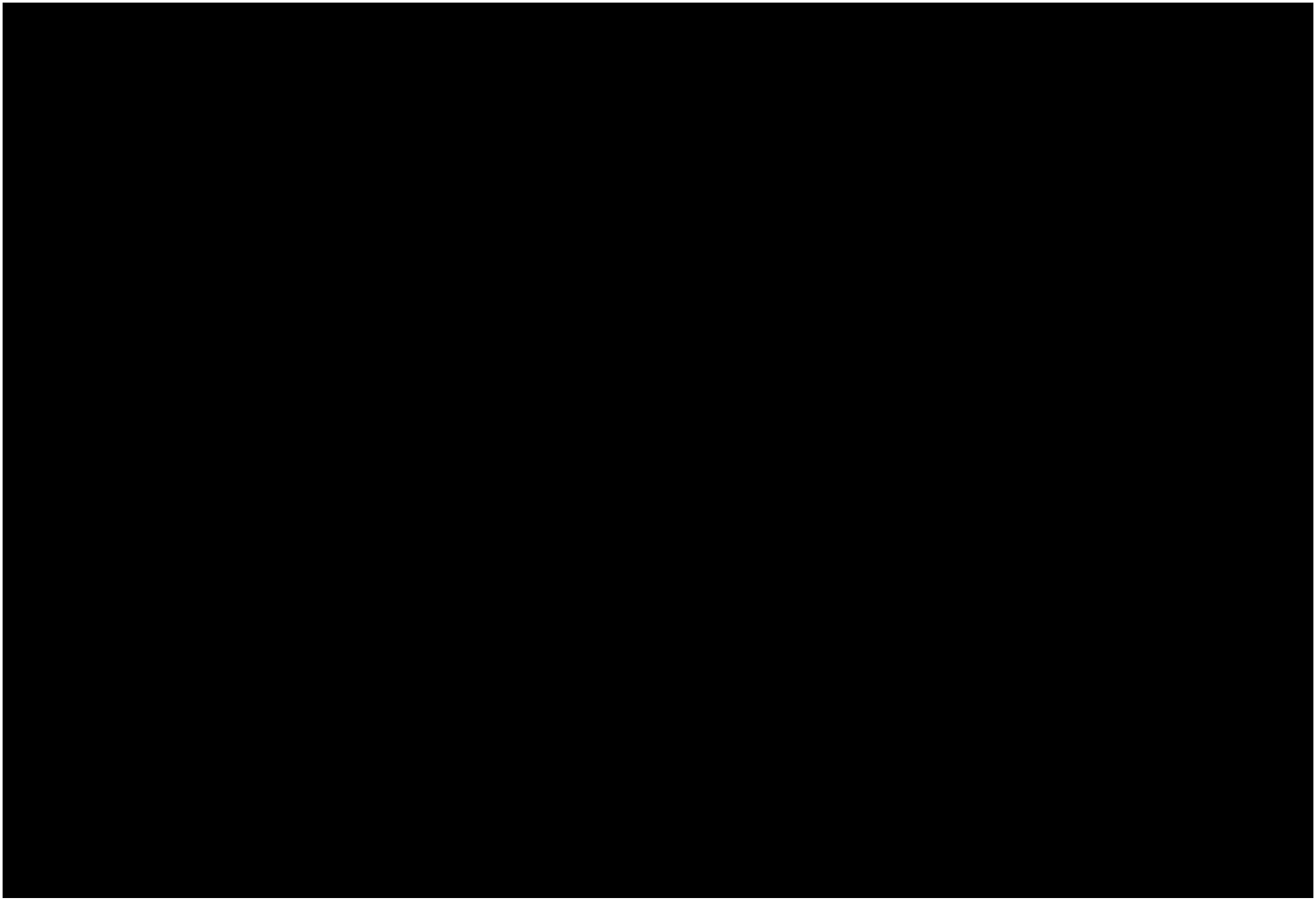
Member Forecasted Off Peak Demand Day for July 2021

Otero County Electric Cooperative, Inc.

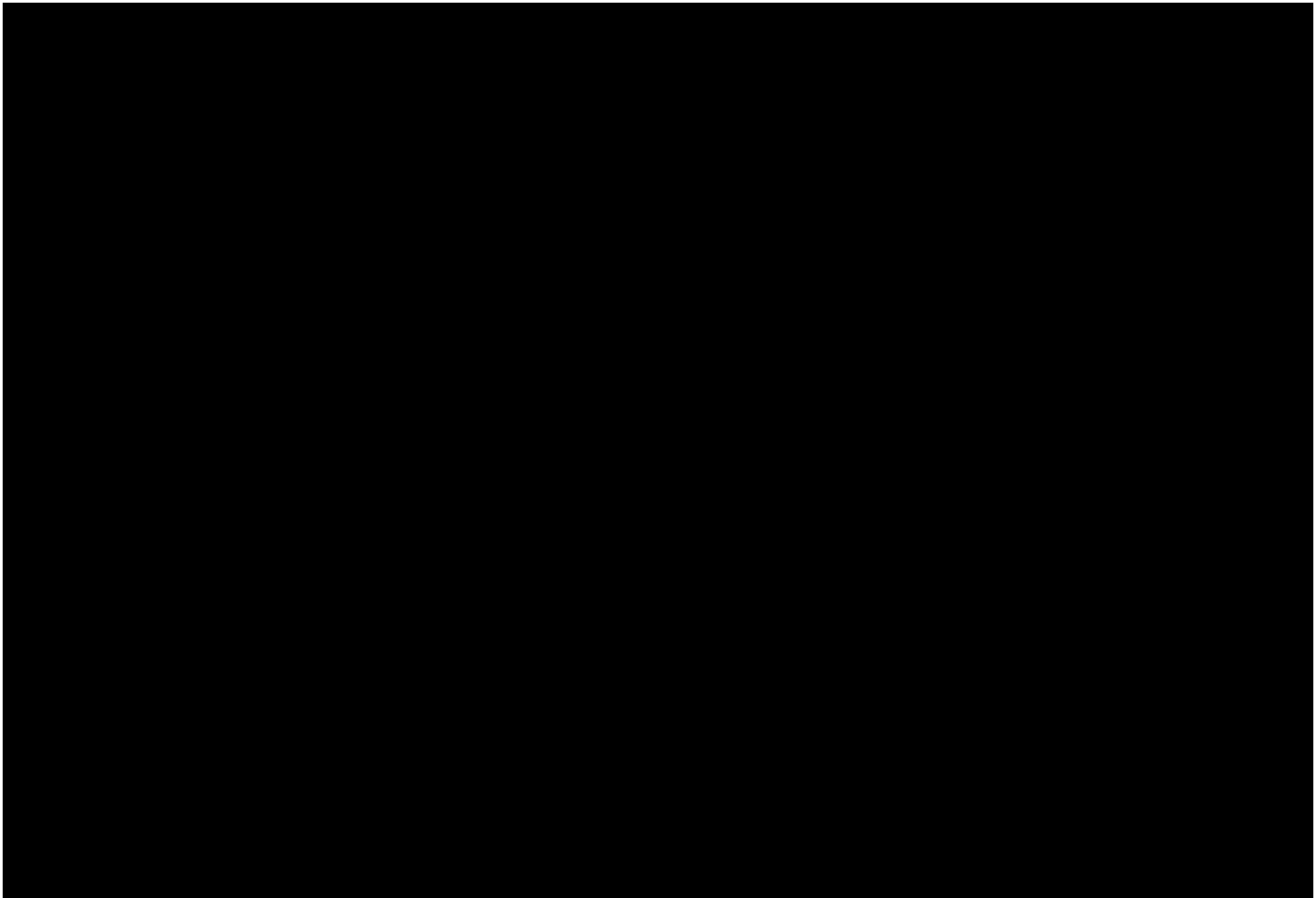
Date of Off Peak Day - 07/02/2021



Member Forecasted Off Peak Demand Day for August 2021

Otero County Electric Cooperative, Inc.

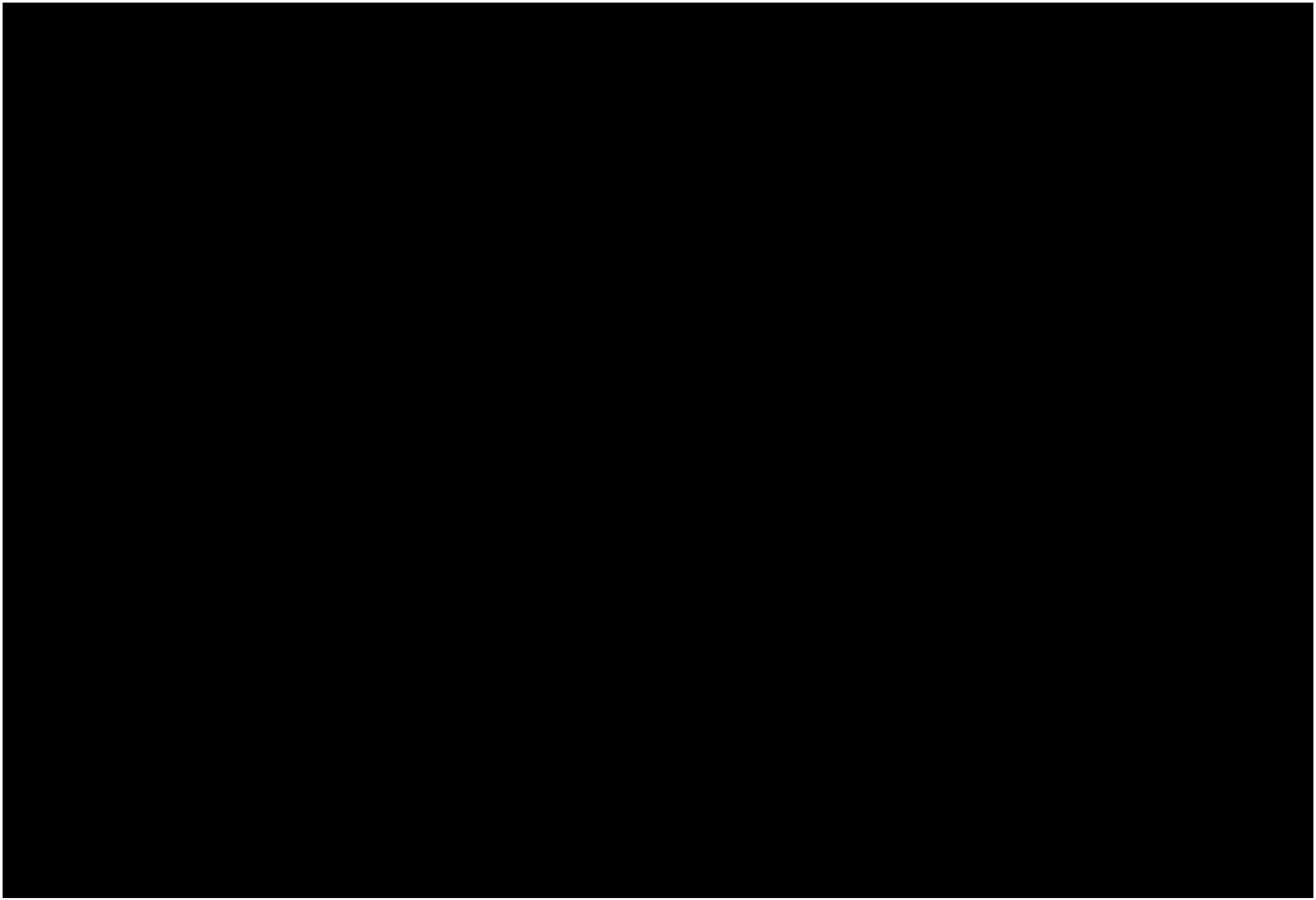
Date of Off Peak Day - 08/30/2021



Member Forecasted Off Peak Demand Day for September 2021

Otero County Electric Cooperative, Inc.

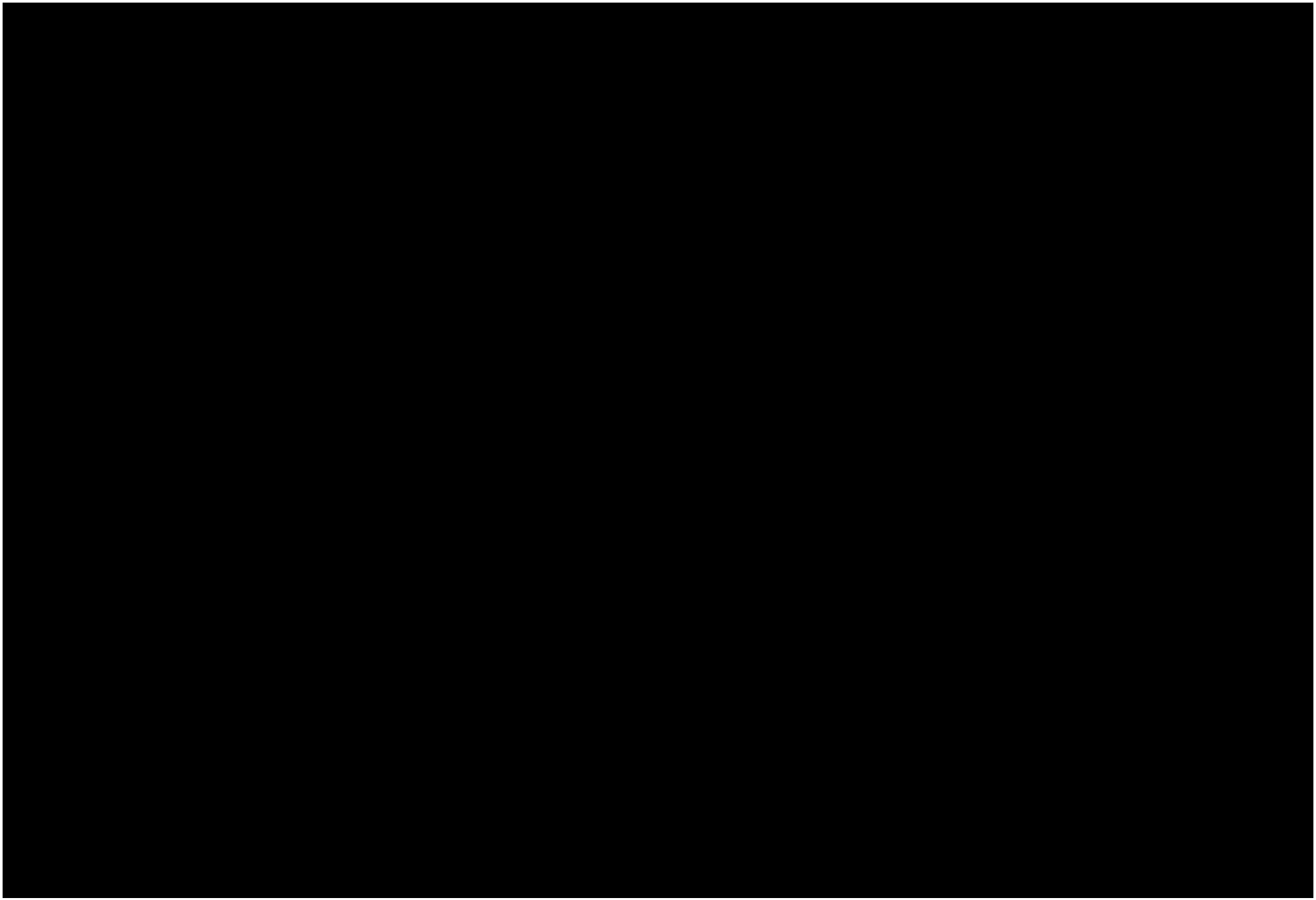
Date of Off Peak Day - 09/28/2021



Member Forecasted Off Peak Demand Day for October 2021

Otero County Electric Cooperative, Inc.

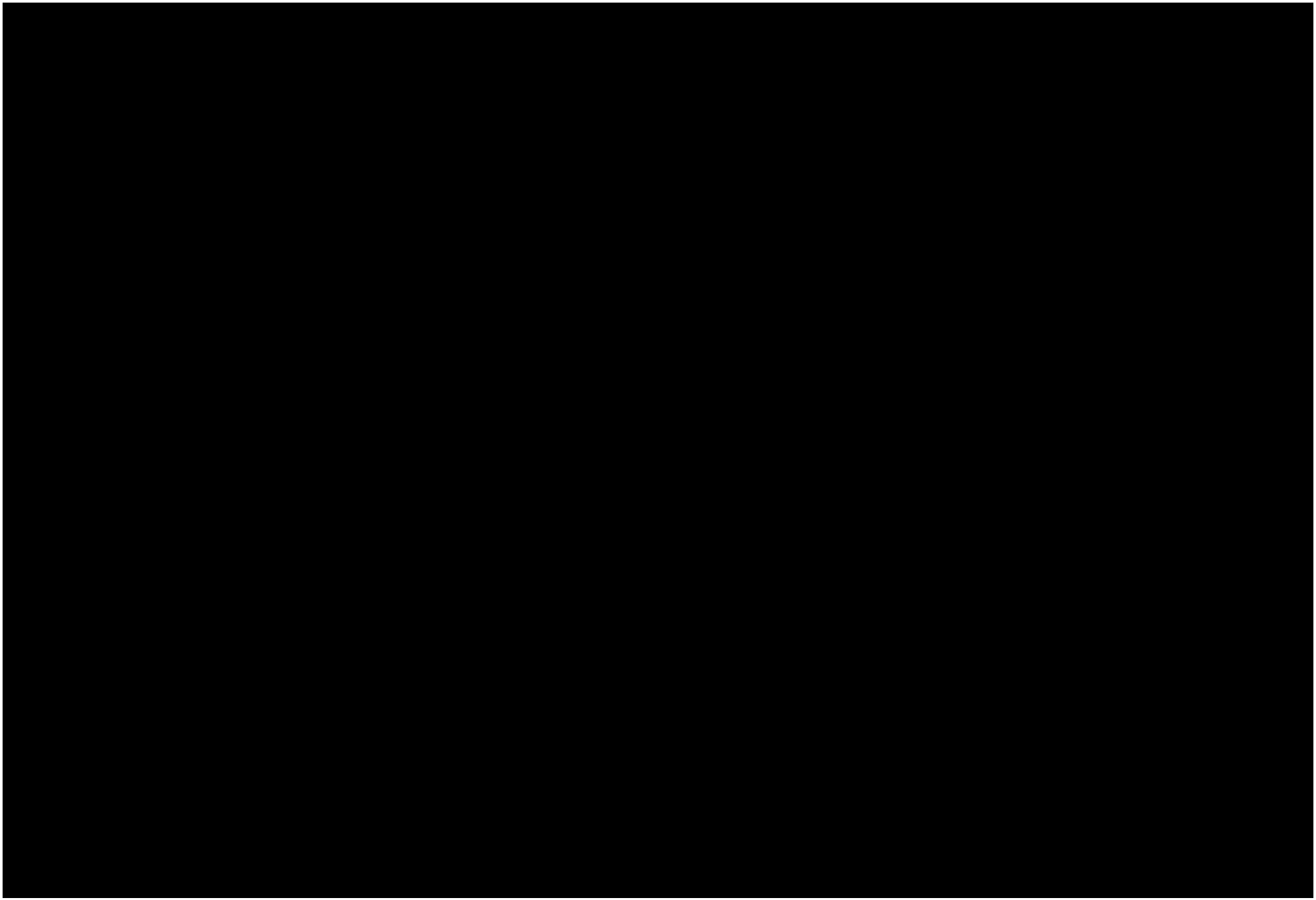
Date of Off Peak Day - 10/04/2021



Member Forecasted Off Peak Demand Day for November 2021

Otero County Electric Cooperative, Inc.

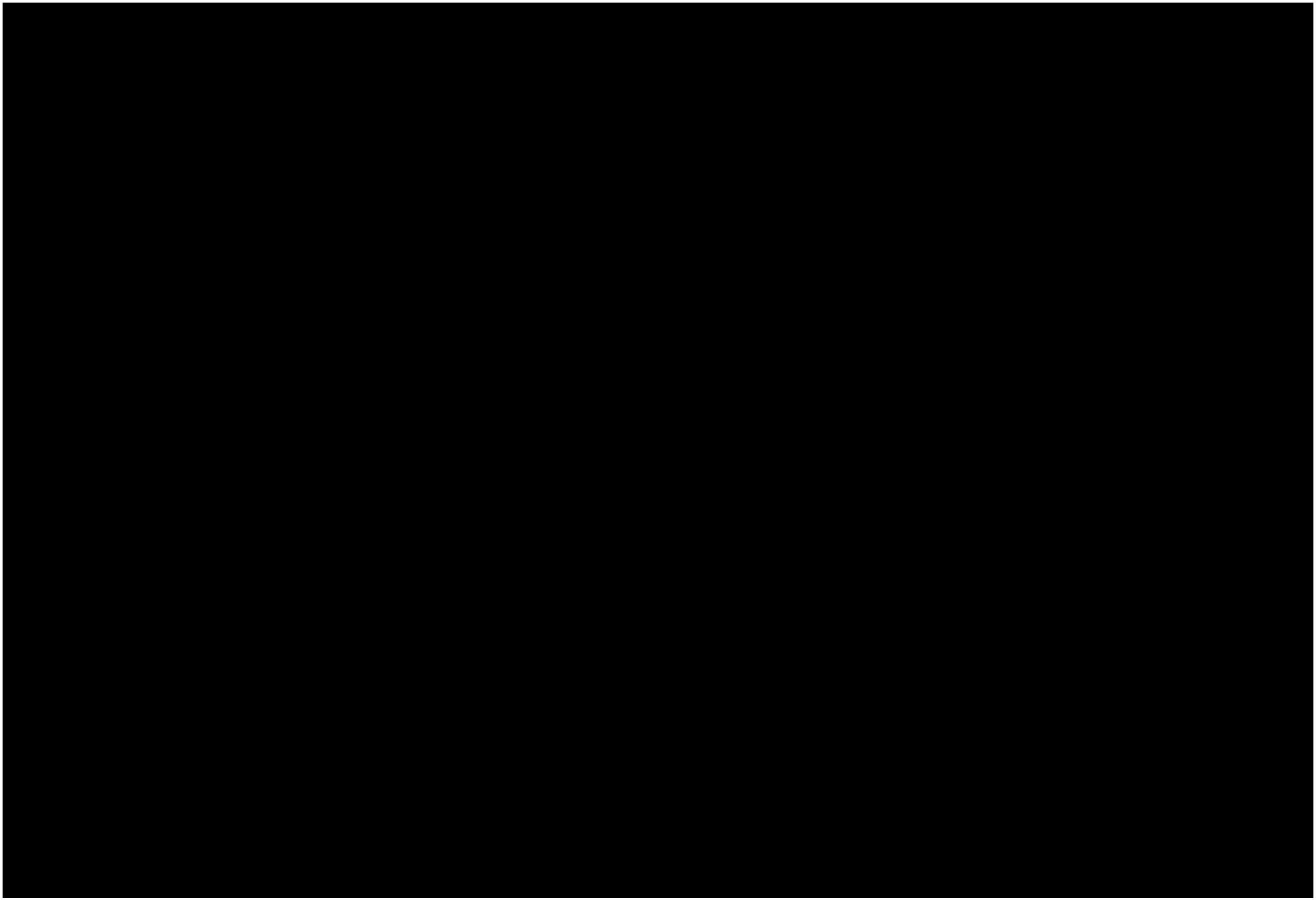
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

Otero County Electric Cooperative, Inc.

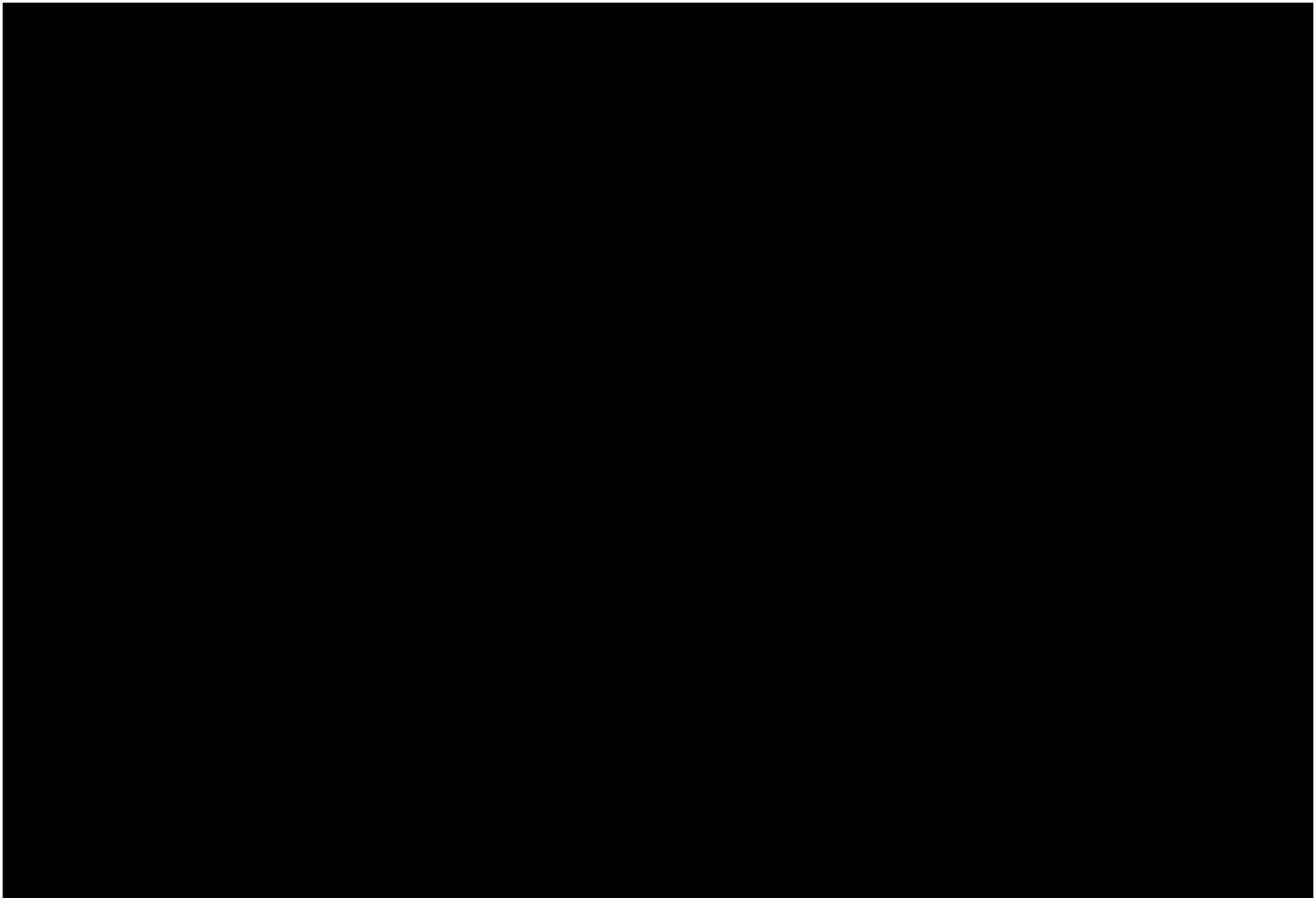
Date of Off Peak Day - 12/10/2021



Member Forecasted Off Peak Demand Day for January 2021

Panhandle Rural Electric Membership Association

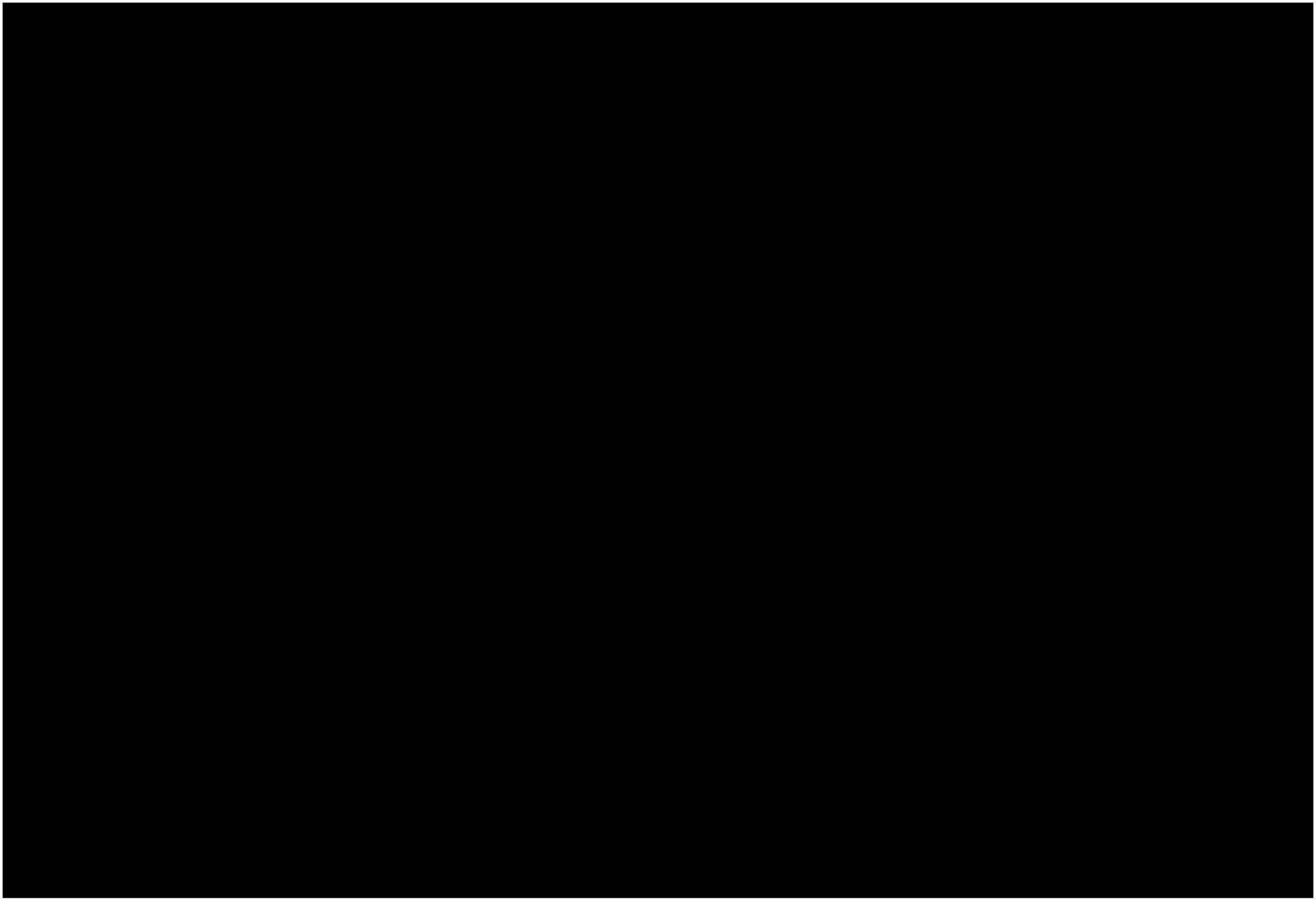
Date of Off Peak Day - 01/18/2021



Member Forecasted Off Peak Demand Day for February 2021

Panhandle Rural Electric Membership Association

Date of Off Peak Day - 02/22/2021



Member Forecasted Off Peak Demand Day for March 2021

Panhandle Rural Electric Membership Association

Date of Off Peak Day - 03/27/2021

[redacted]

Member Forecasted Off Peak Demand Day for April 2021

Panhandle Rural Electric Membership Association

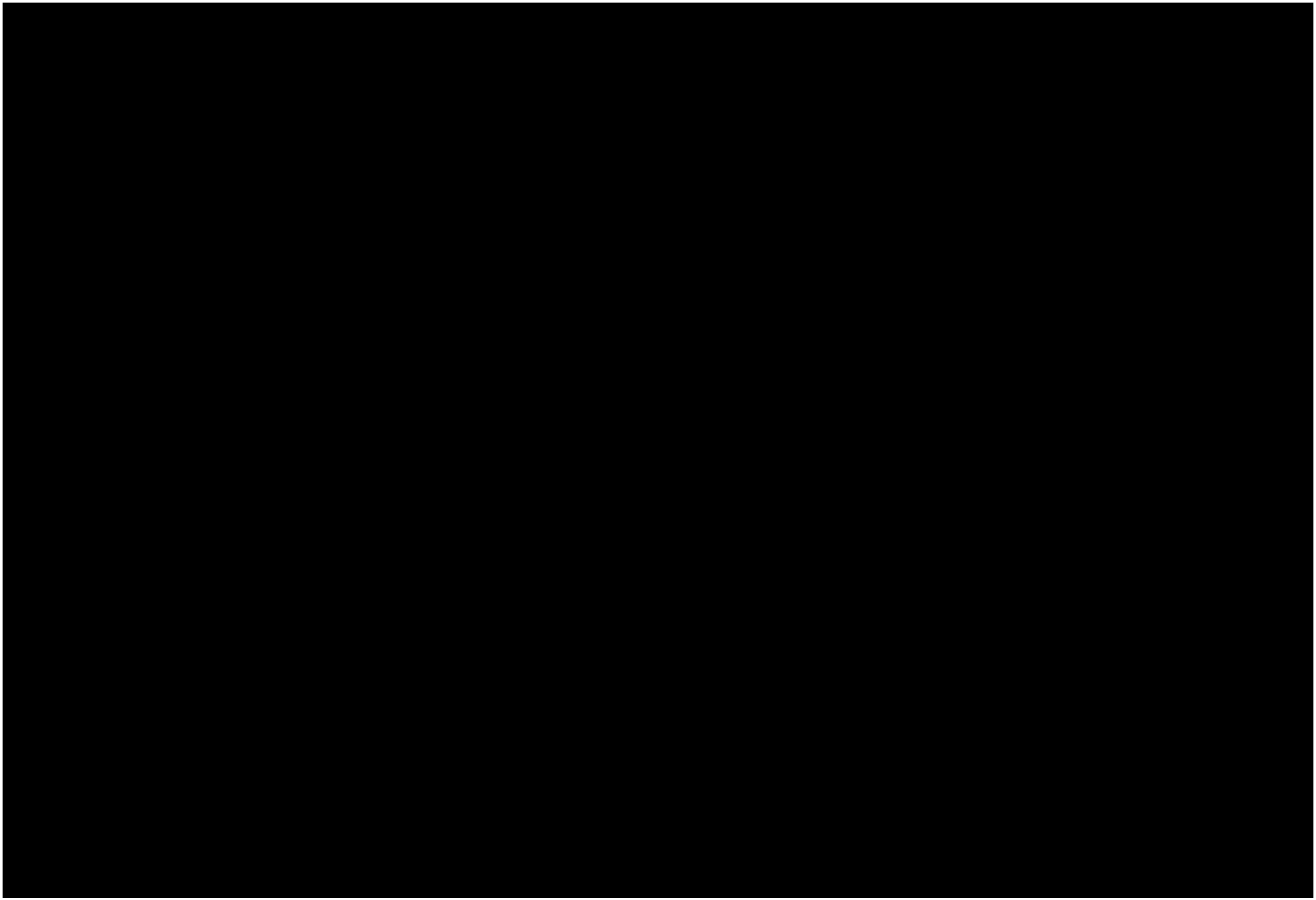
Date of Off Peak Day - 04/18/2021

[redacted]

Member Forecasted Off Peak Demand Day for May 2021

Panhandle Rural Electric Membership Association

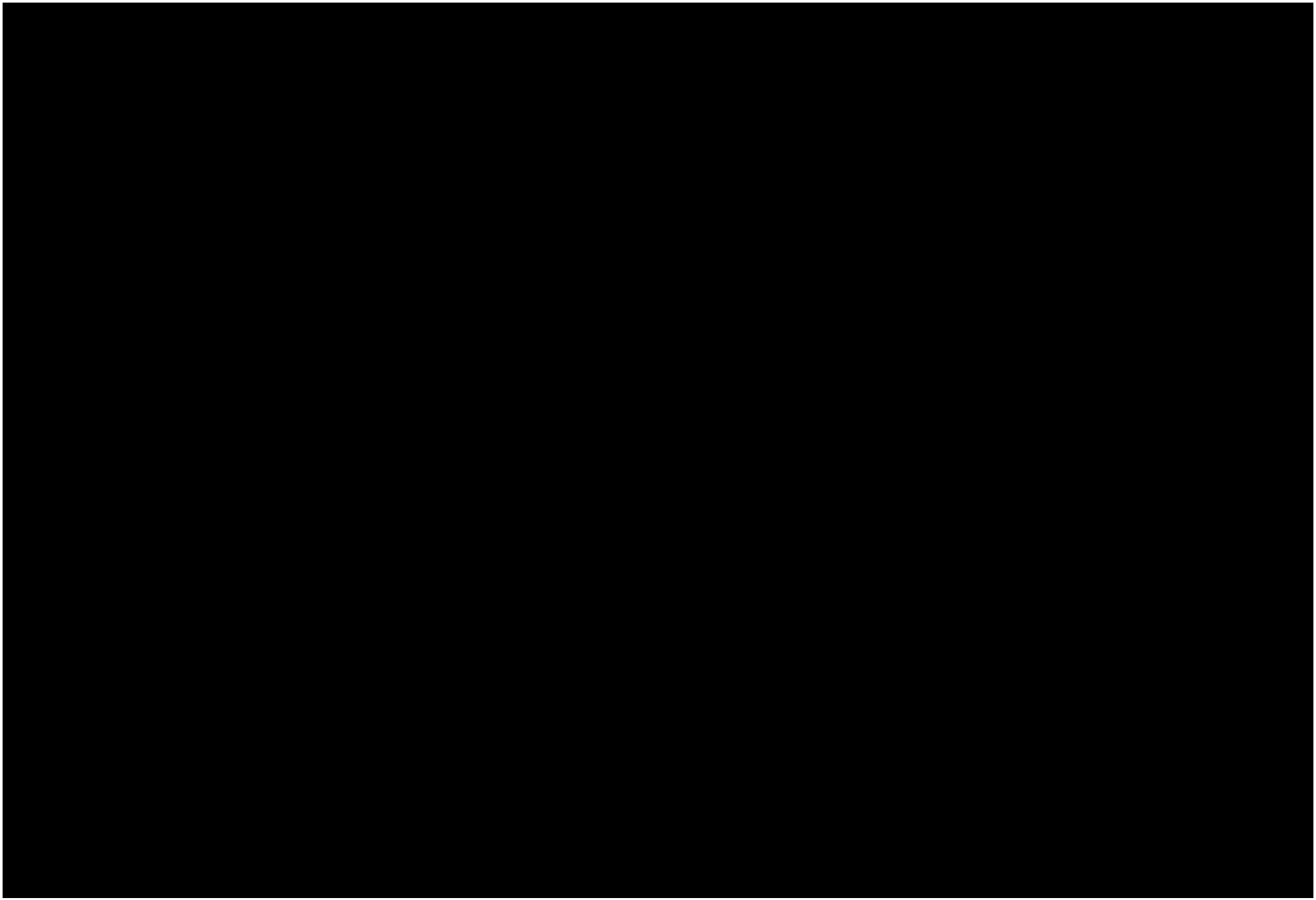
Date of Off Peak Day - 05/28/2021



Member Forecasted Off Peak Demand Day for June 2021

Panhandle Rural Electric Membership Association

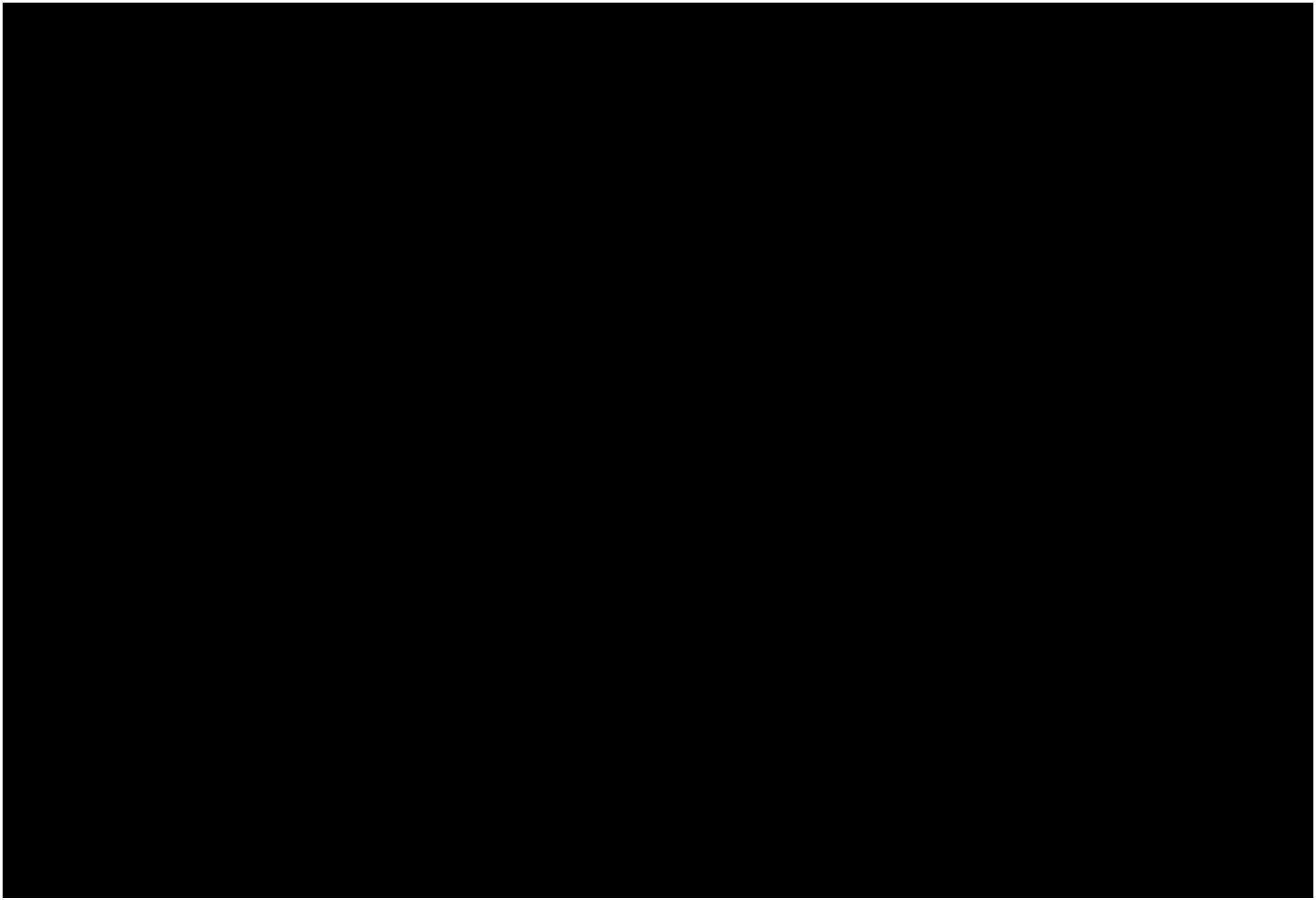
Date of Off Peak Day - 06/21/2021



Member Forecasted Off Peak Demand Day for July 2021

Panhandle Rural Electric Membership Association

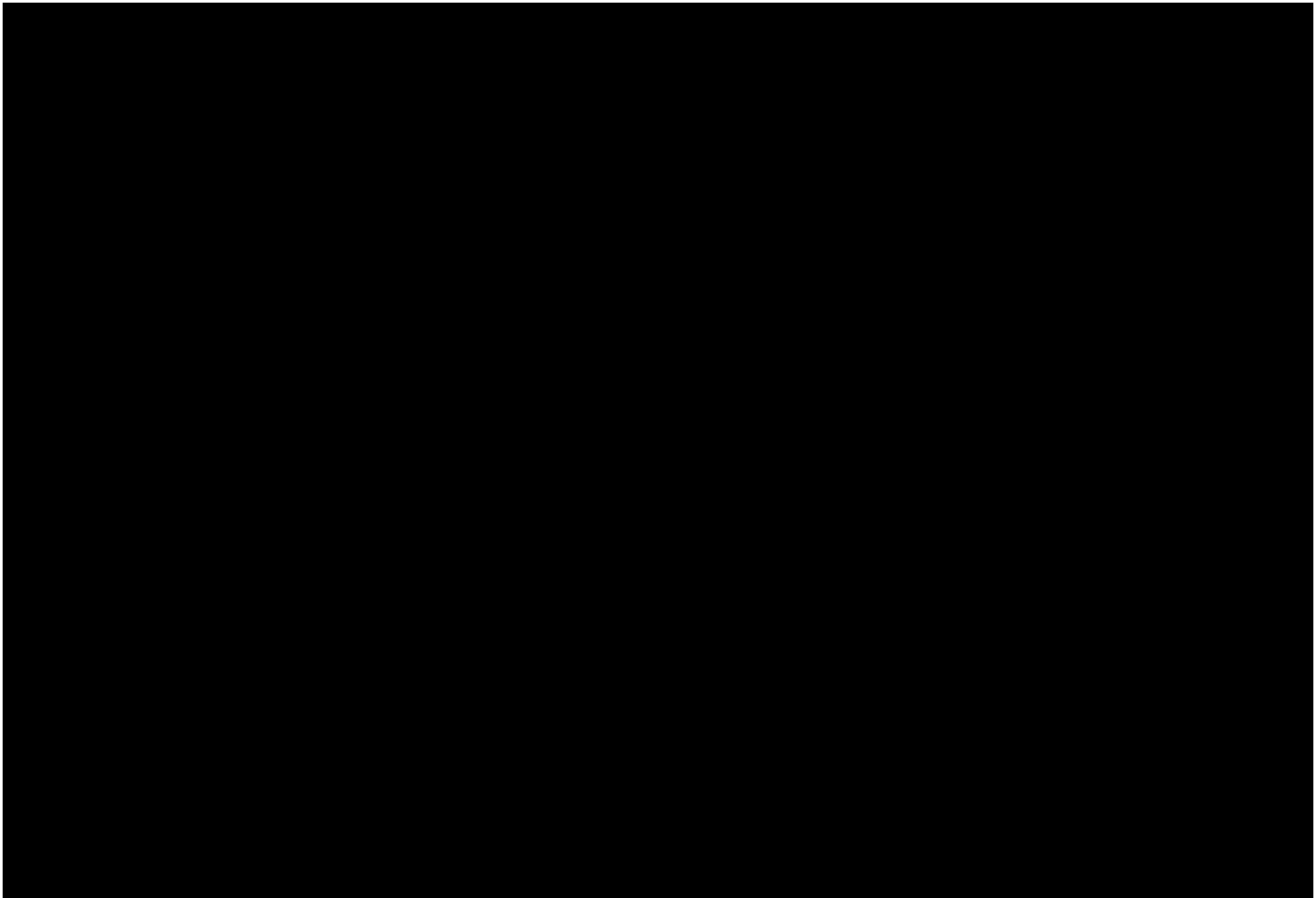
Date of Off Peak Day - 07/03/2021



Member Forecasted Off Peak Demand Day for August 2021

Panhandle Rural Electric Membership Association

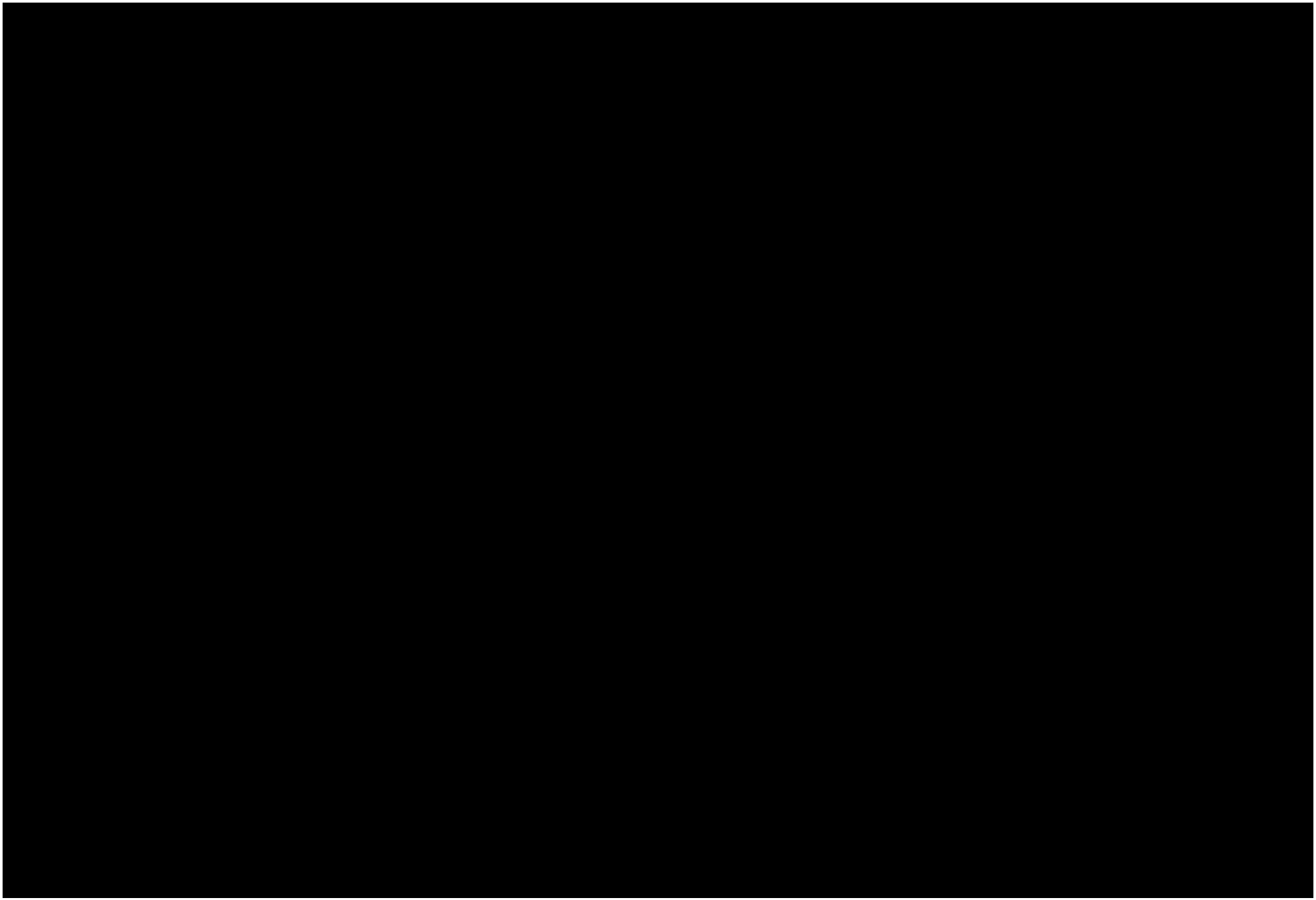
Date of Off Peak Day - 08/13/2021



Member Forecasted Off Peak Demand Day for September 2021

Panhandle Rural Electric Membership Association

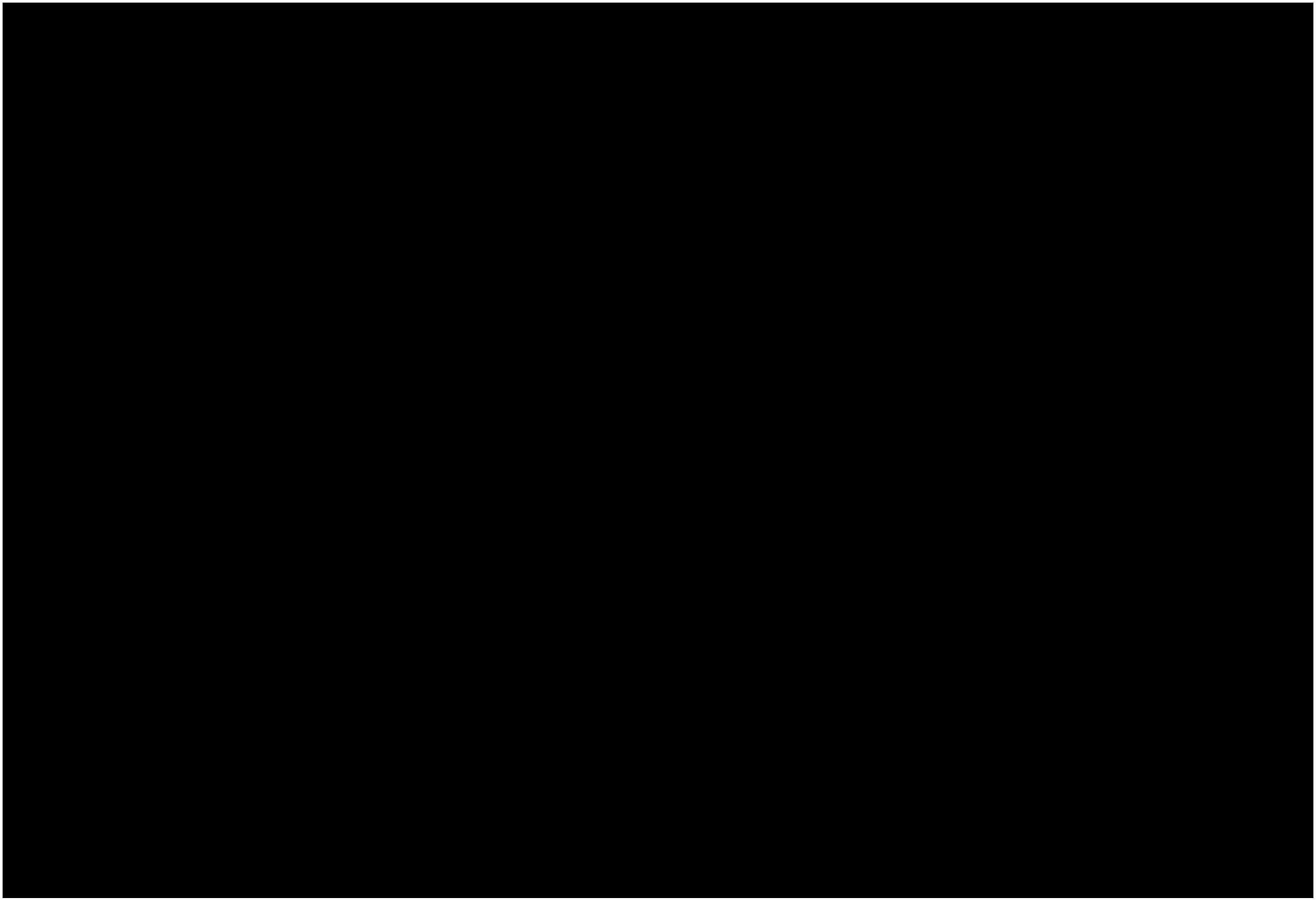
Date of Off Peak Day - 09/19/2021



Member Forecasted Off Peak Demand Day for October 2021

Panhandle Rural Electric Membership Association

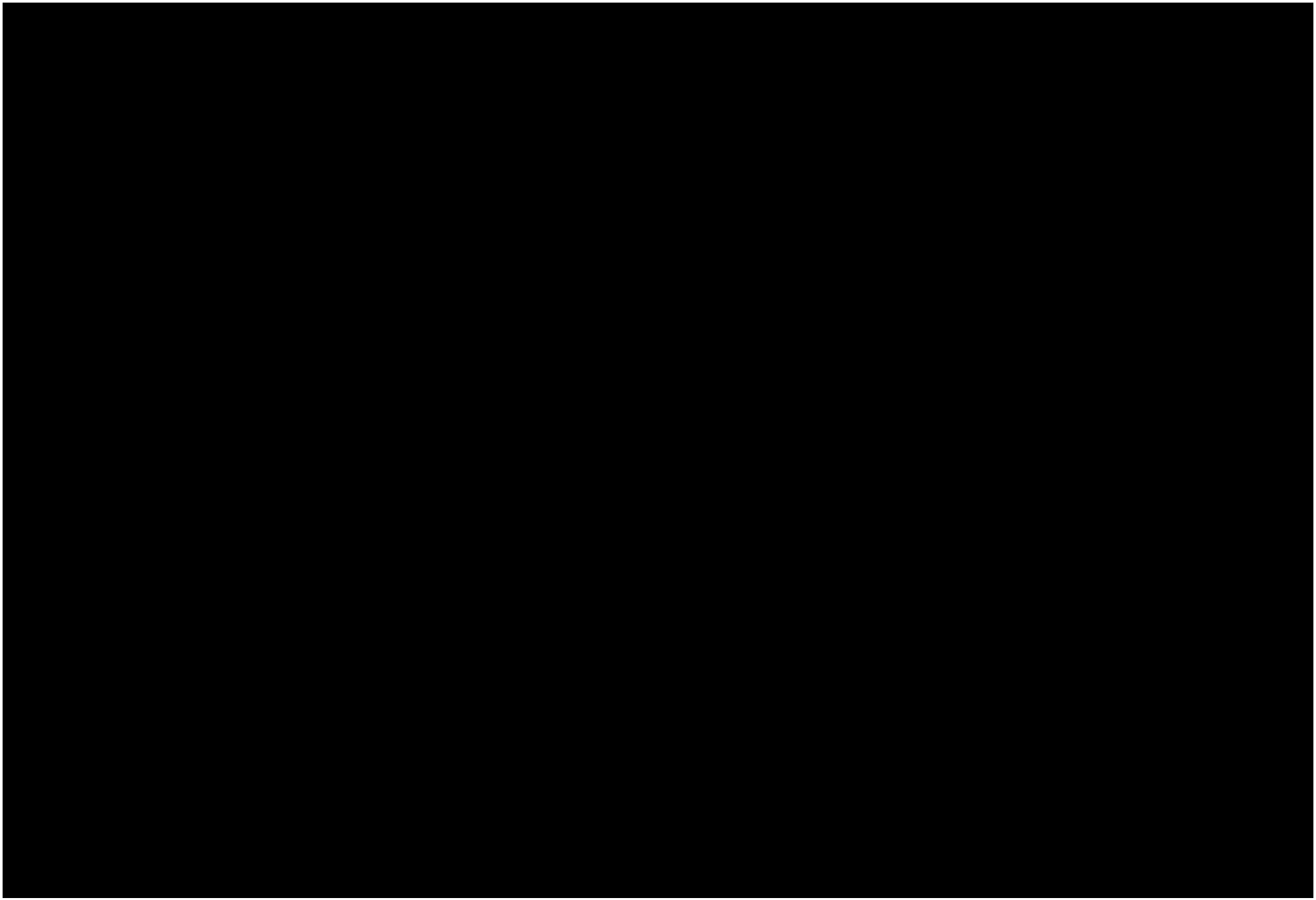
Date of Off Peak Day - 10/11/2021



Member Forecasted Off Peak Demand Day for November 2021

Panhandle Rural Electric Membership Association

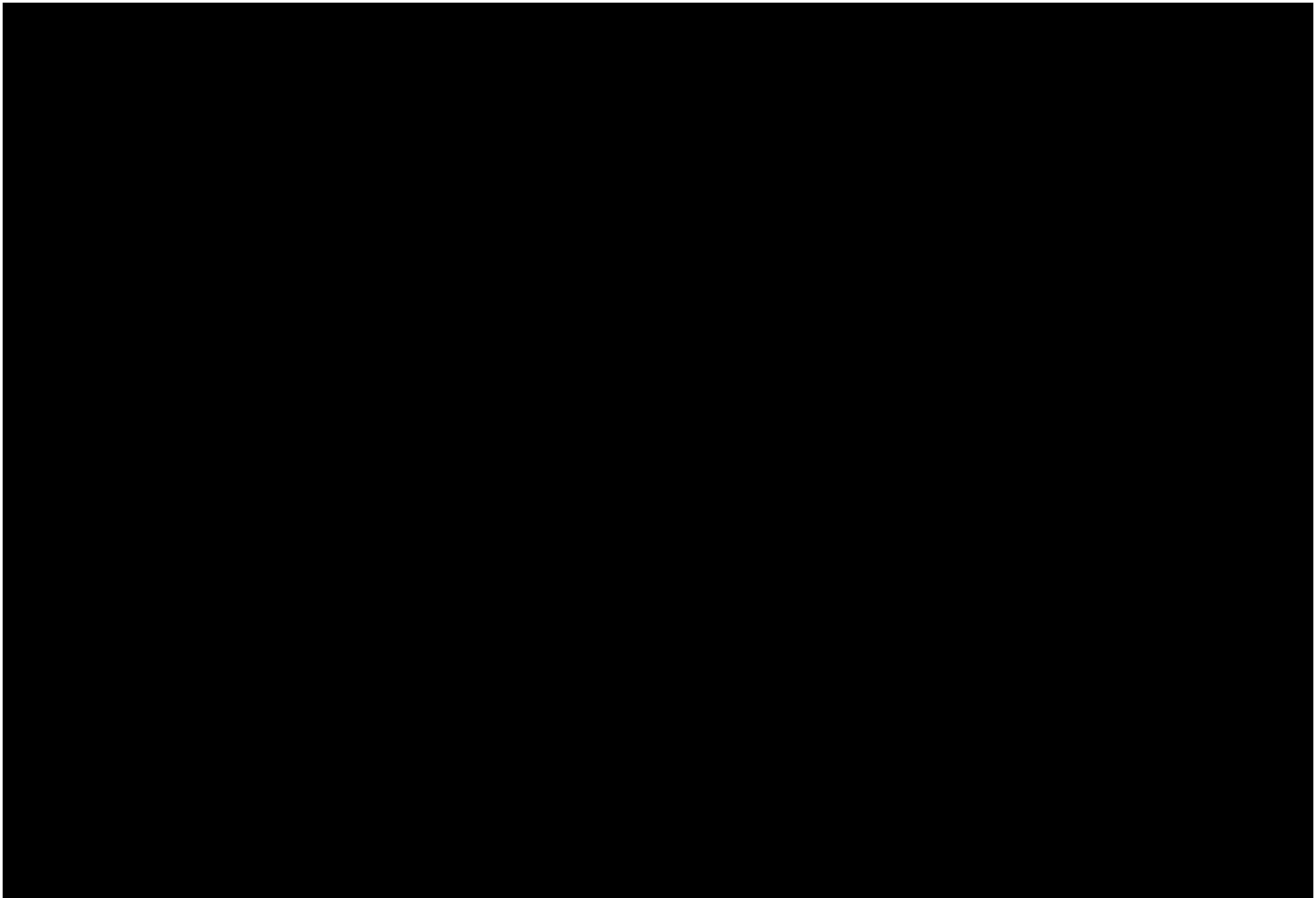
Date of Off Peak Day - 11/04/2021



Member Forecasted Off Peak Demand Day for December 2021

Panhandle Rural Electric Membership Association

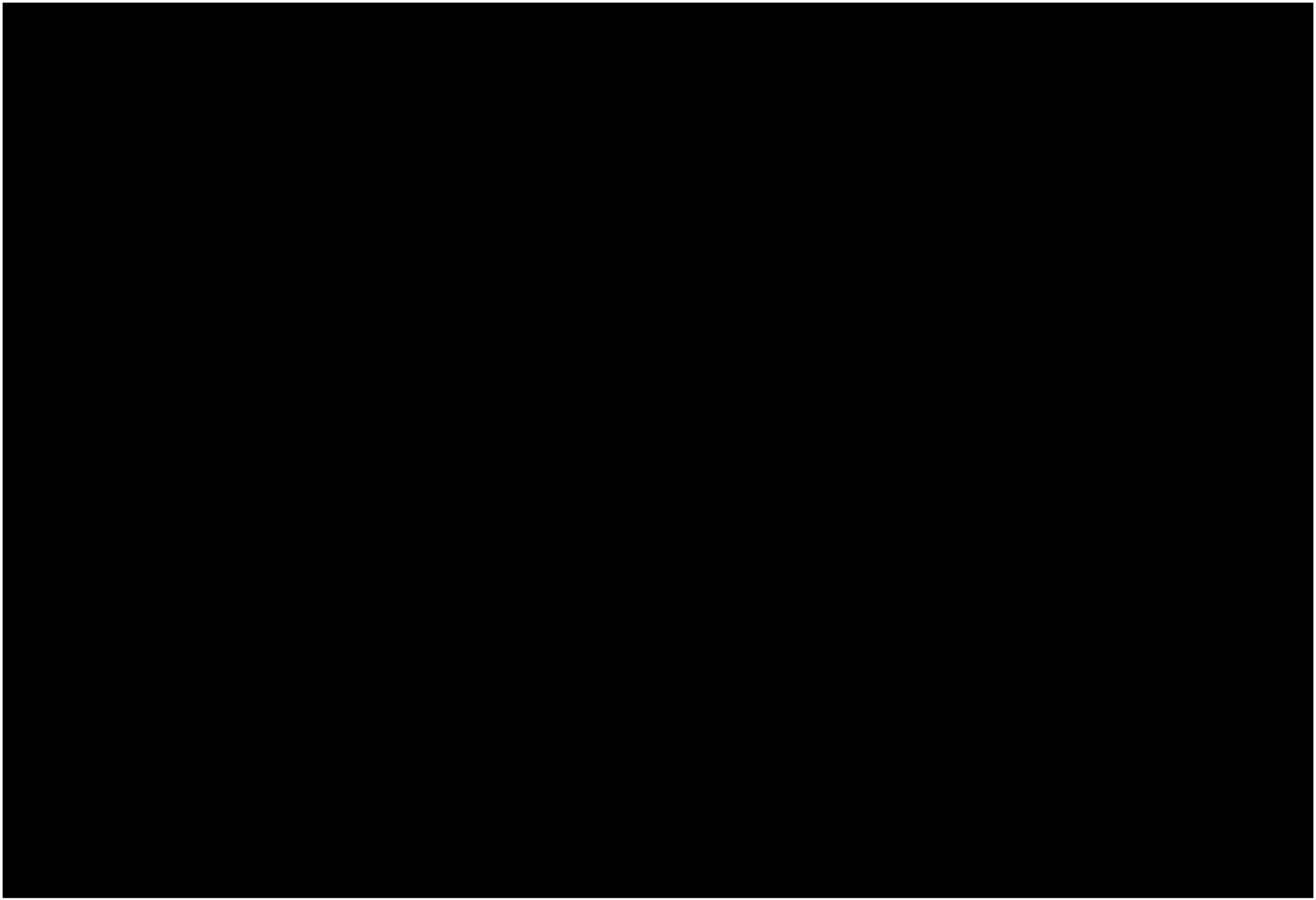
Date of Off Peak Day - 12/08/2021



Member Forecasted Off Peak Demand Day for January 2021

Poudre Valley Electric Association, Inc.

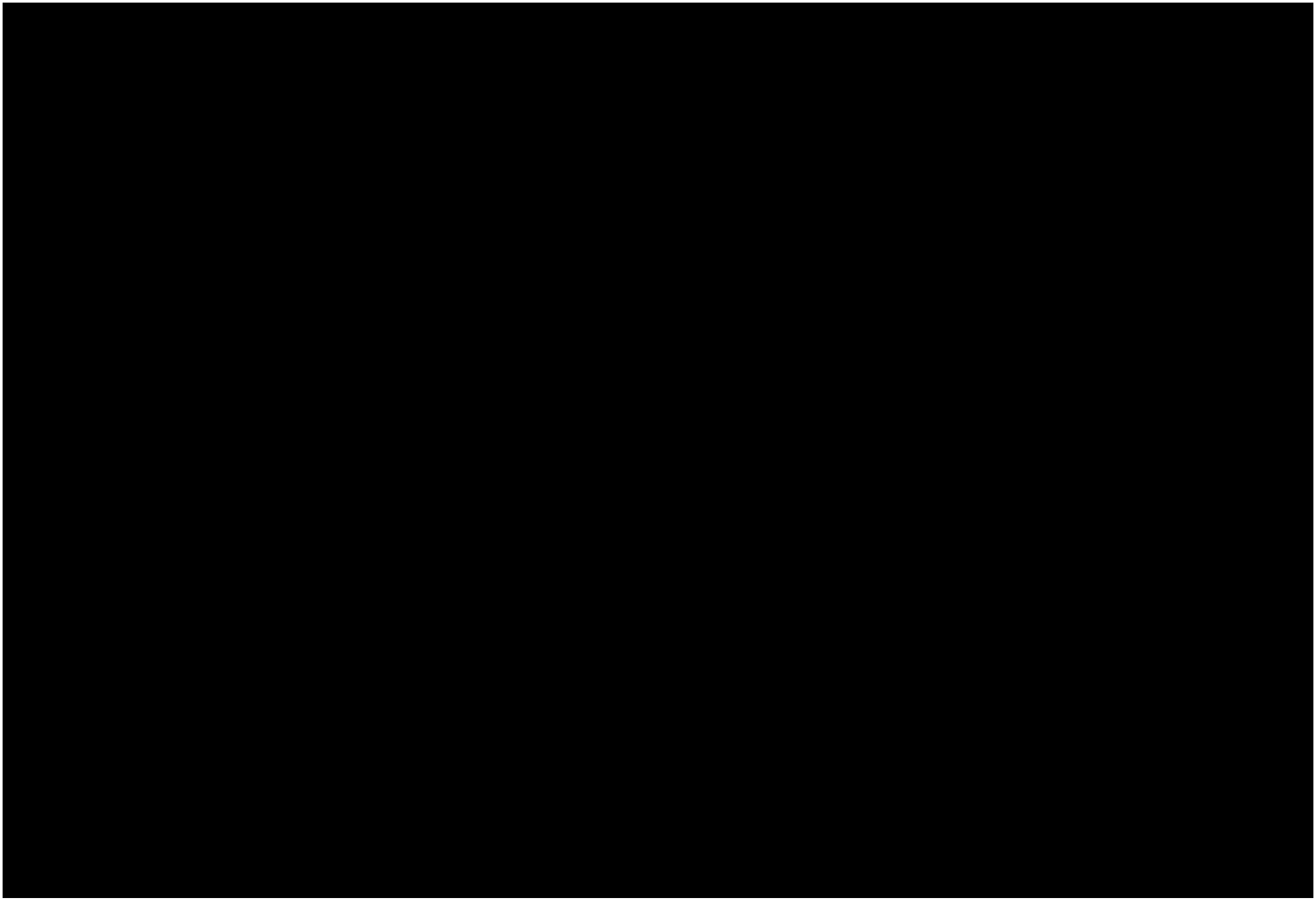
Date of Off Peak Day - 01/19/2021



Member Forecasted Off Peak Demand Day for February 2021

Poudre Valley Electric Association, Inc.

Date of Off Peak Day - 02/17/2021



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Member Forecasted Off Peak Demand Day for March 2021

Poudre Valley Electric Association, Inc.

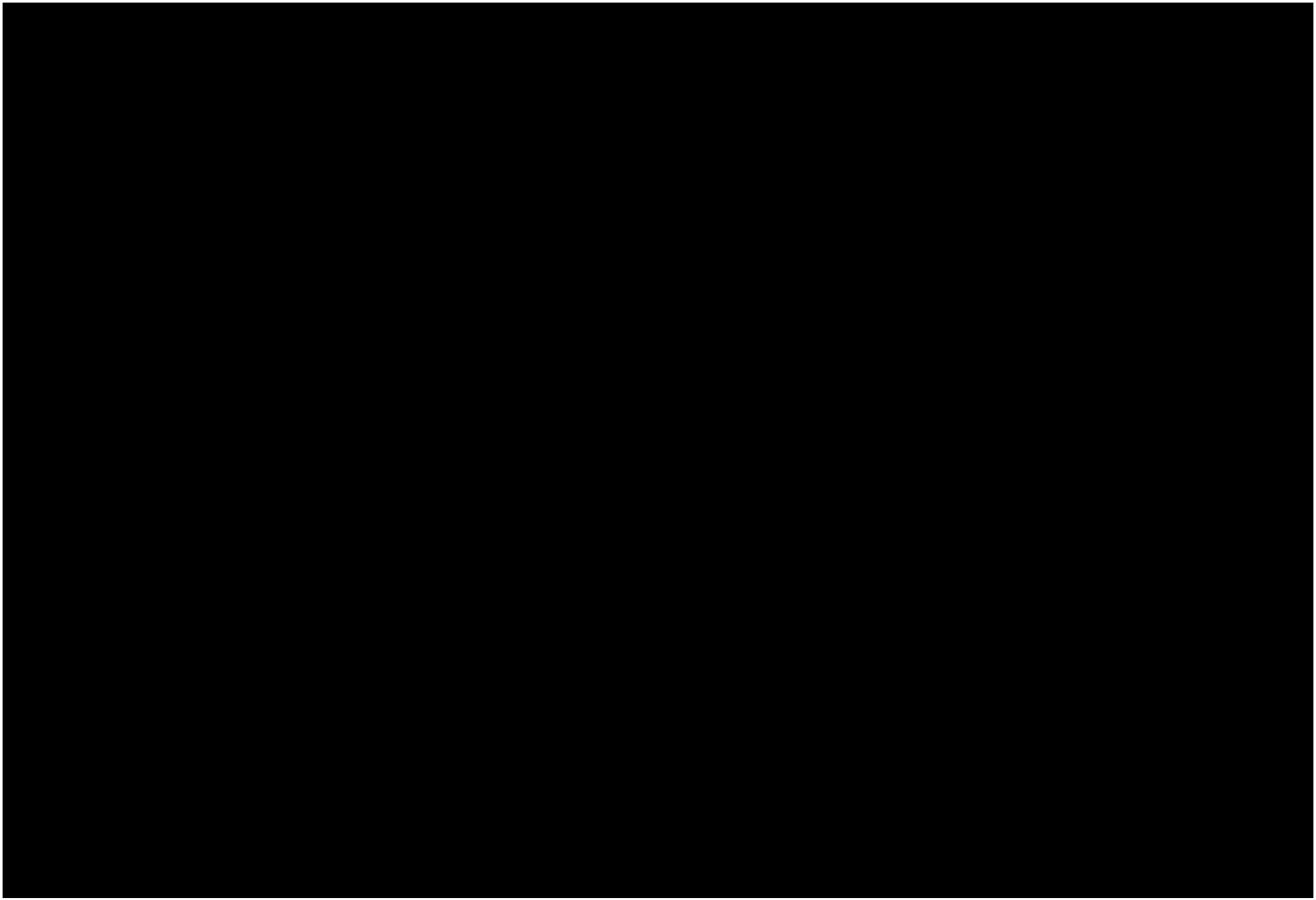
Date of Off Peak Day - 03/21/2021

[redacted]

Member Forecasted Off Peak Demand Day for April 2021

Poudre Valley Electric Association, Inc.

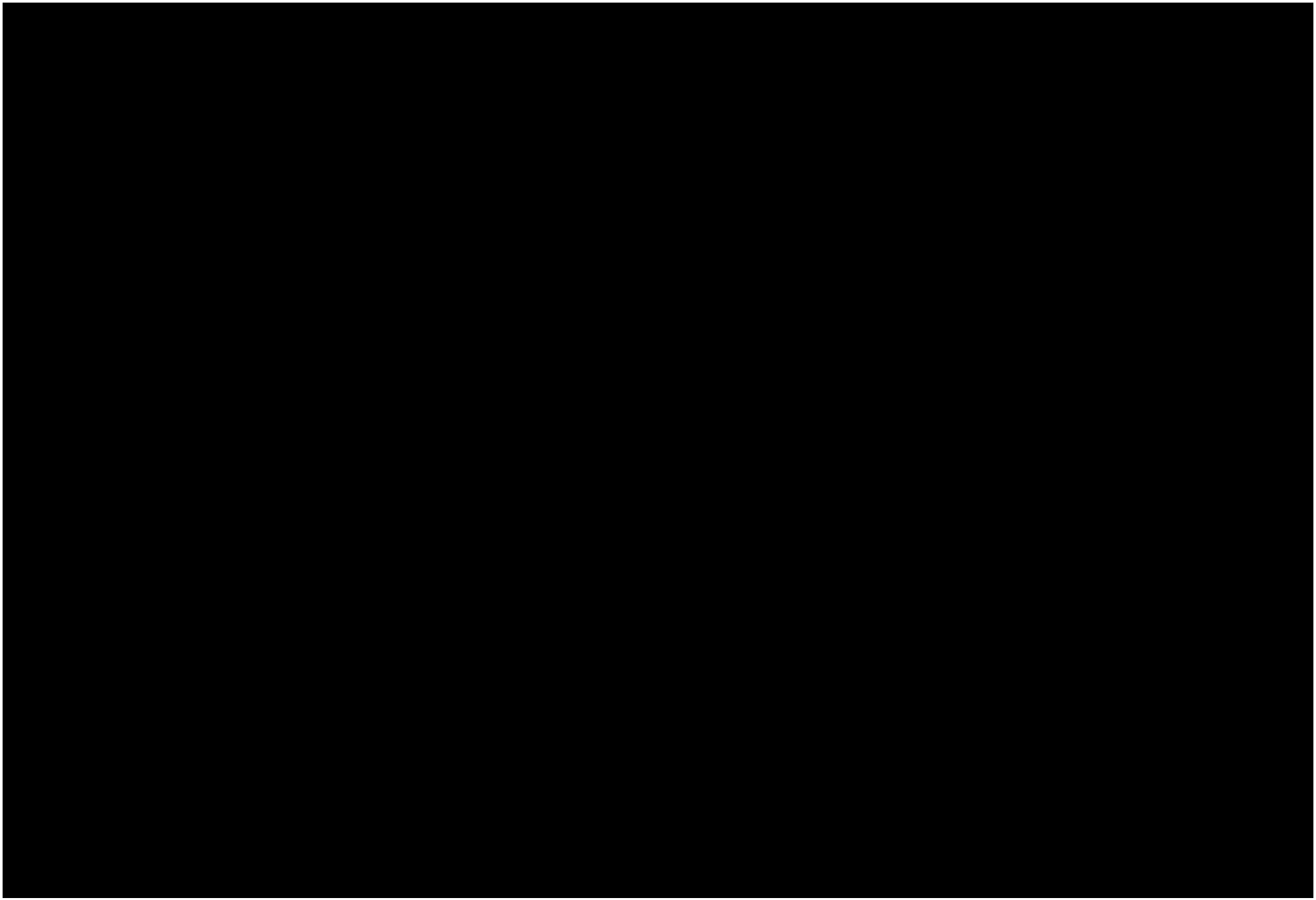
Date of Off Peak Day - 04/19/2021



Member Forecasted Off Peak Demand Day for May 2021

Poudre Valley Electric Association, Inc.

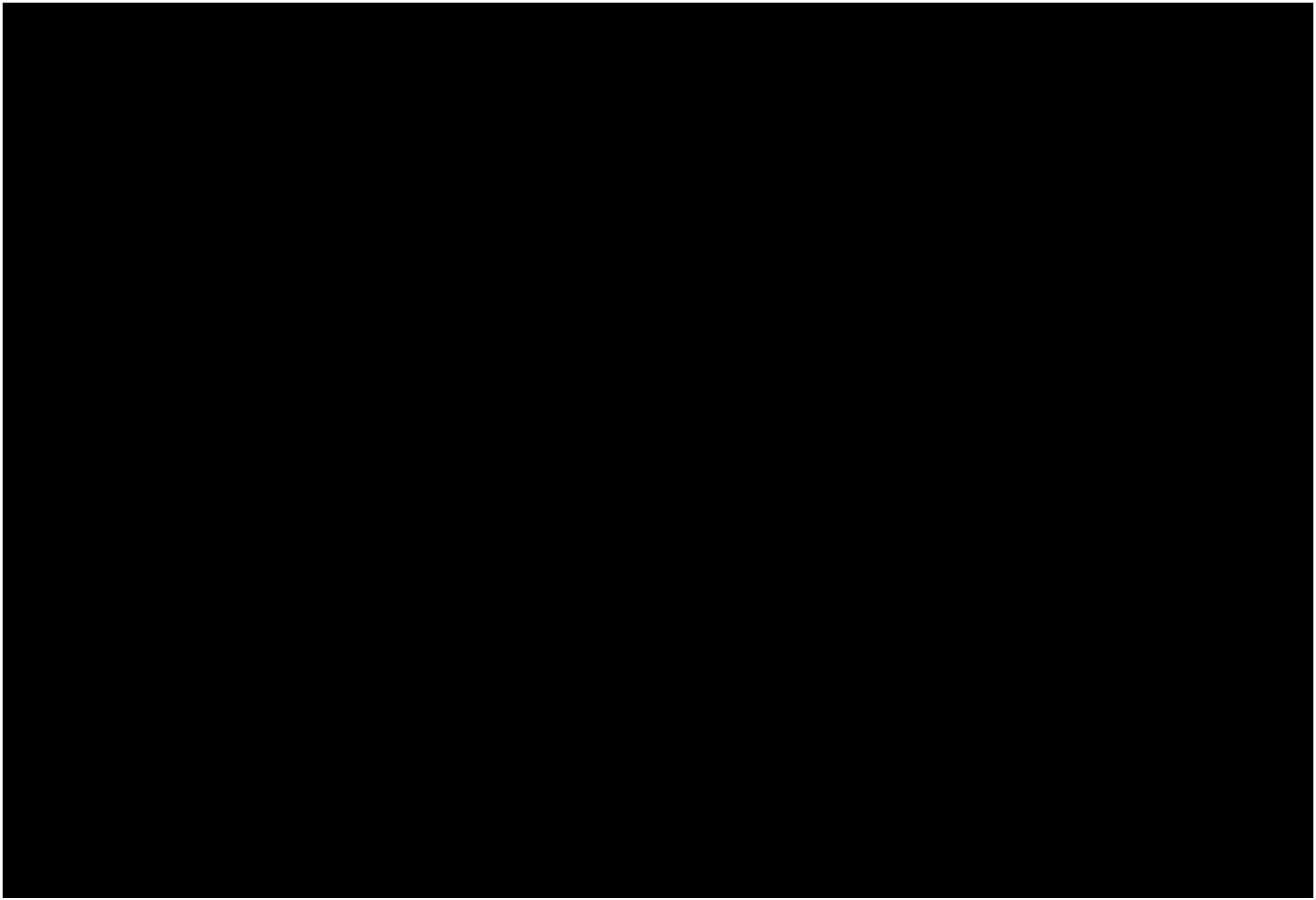
Date of Off Peak Day - 05/31/2021



Member Forecasted Off Peak Demand Day for June 2021

Poudre Valley Electric Association, Inc.

Date of Off Peak Day - 06/21/2021



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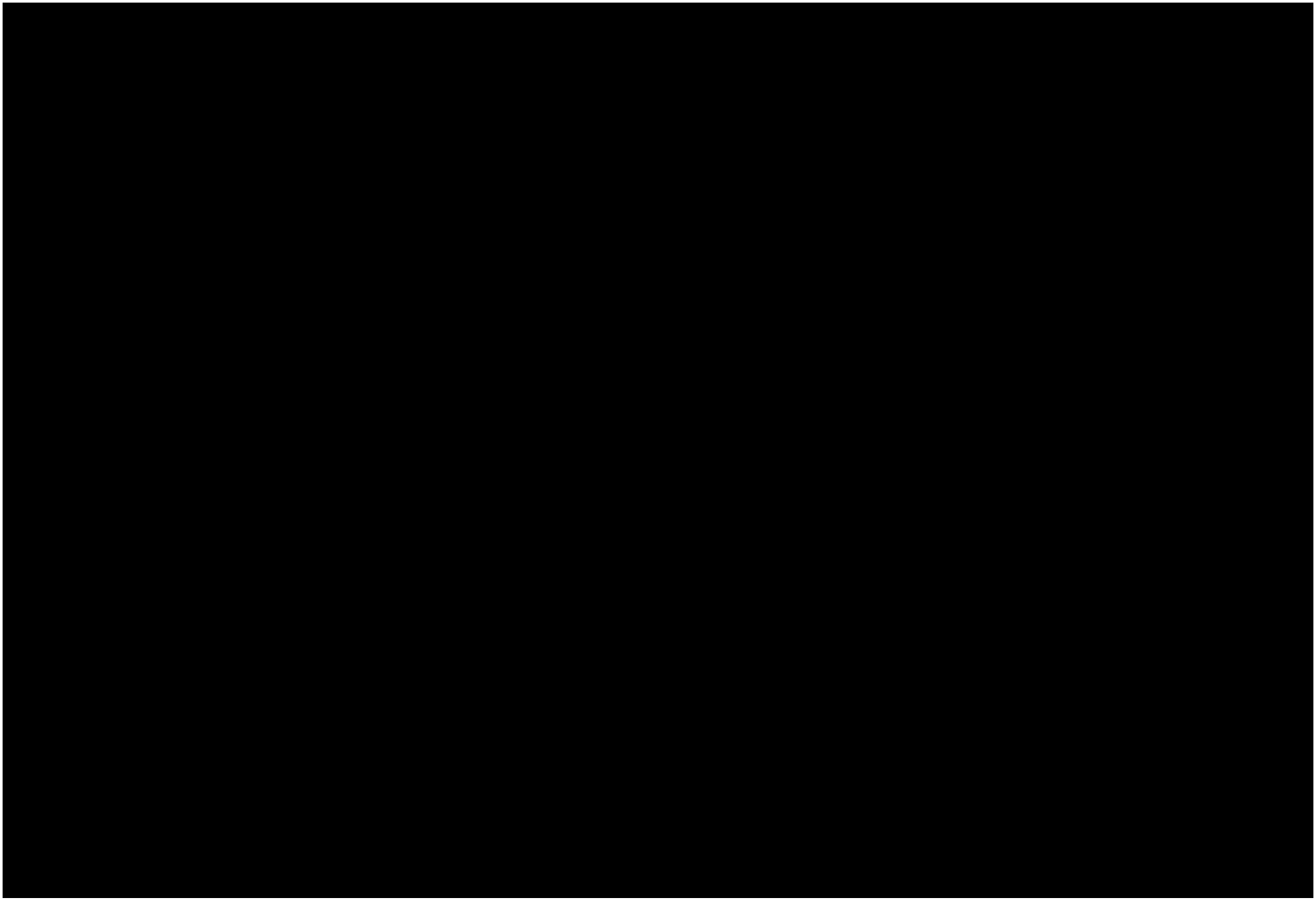
Member Forecasted Off Peak Demand Day for July 2021

Poudre Valley Electric Association, Inc.

Date of Off Peak Day - 07/04/2021



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Member Forecasted Off Peak Demand Day for August 2021

Poudre Valley Electric Association, Inc.

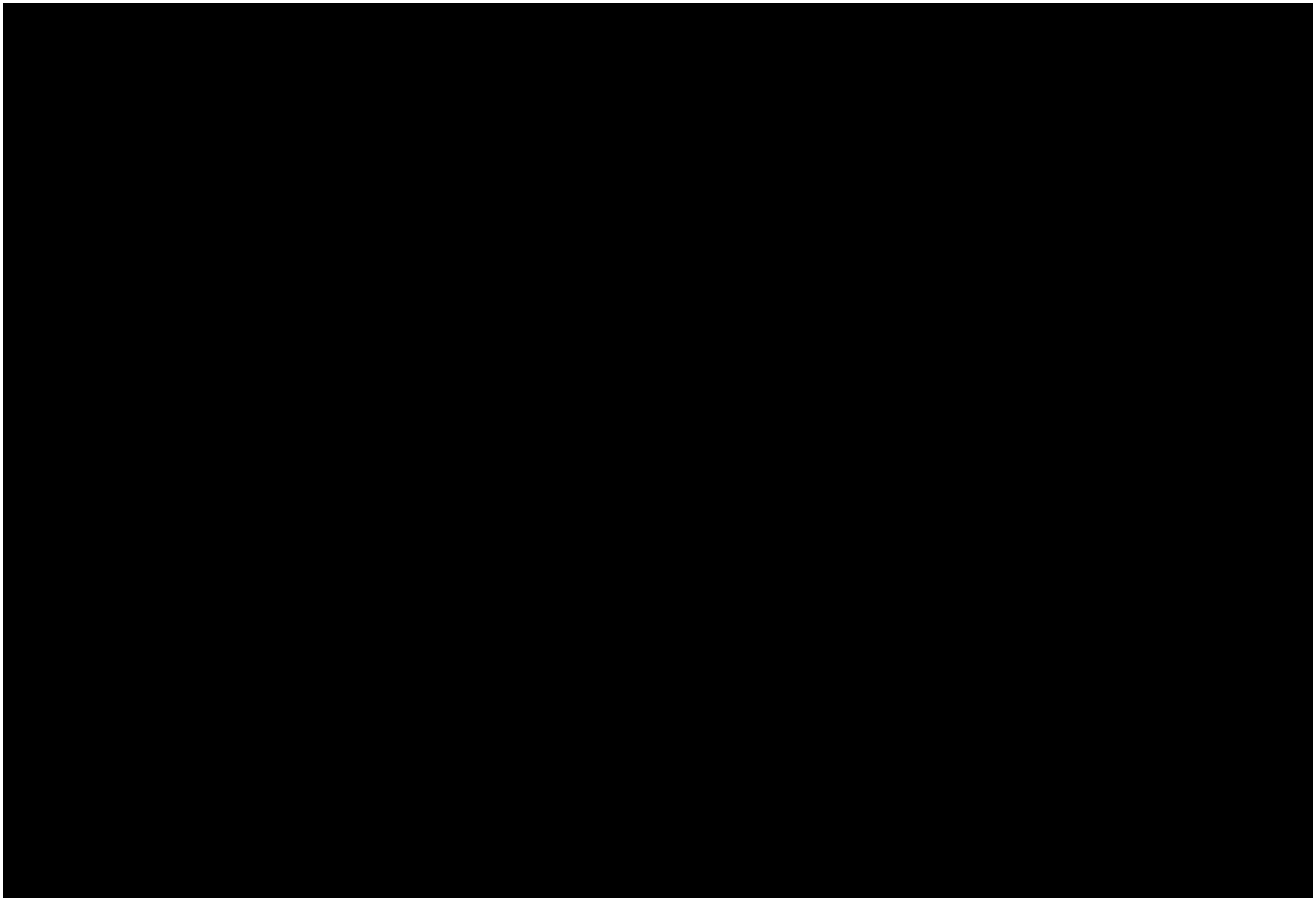
Date of Off Peak Day - 08/30/2021

[redacted]

Member Forecasted Off Peak Demand Day for September 2021

Poudre Valley Electric Association, Inc.

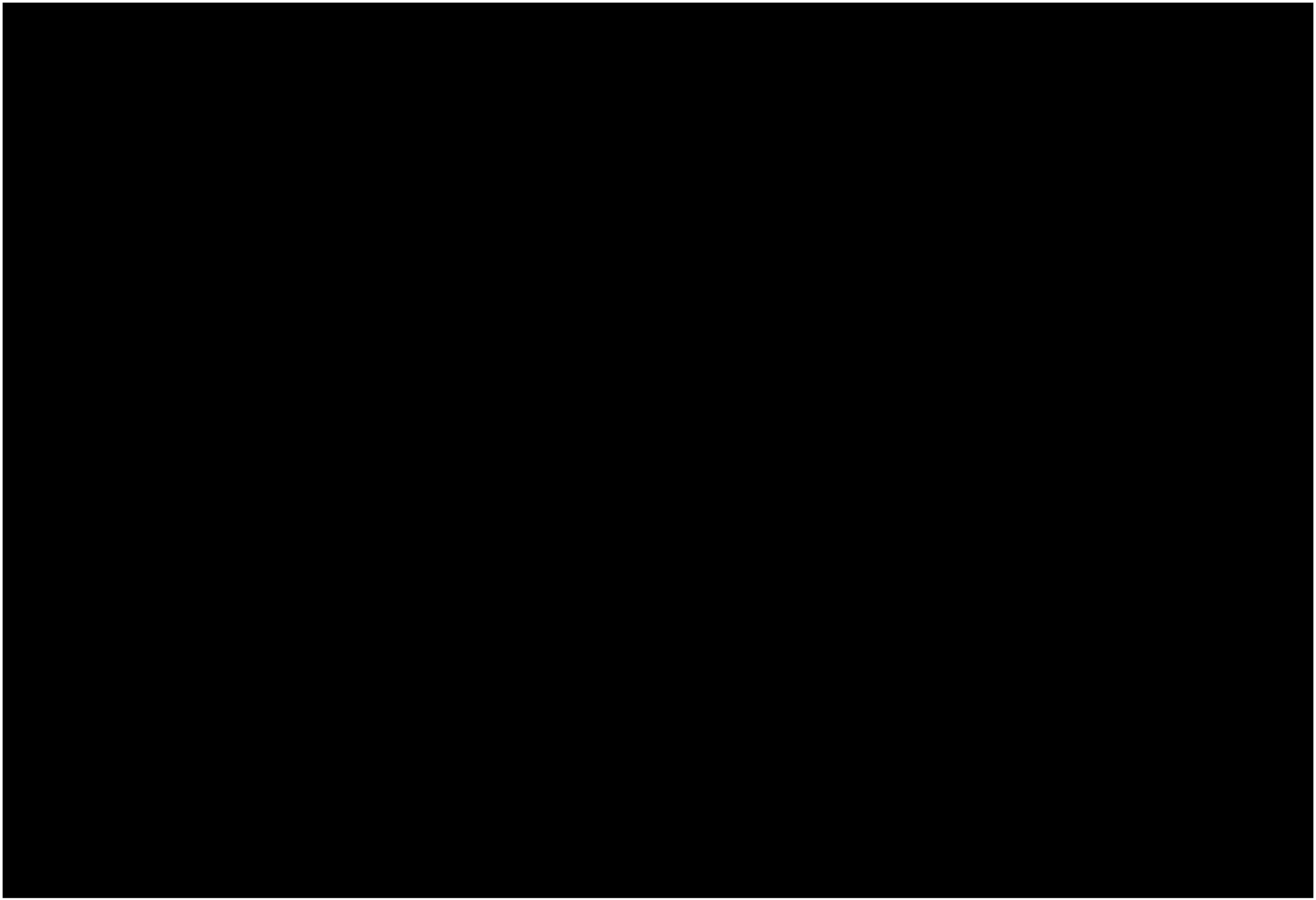
Date of Off Peak Day - 09/13/2021



Member Forecasted Off Peak Demand Day for October 2021

Poudre Valley Electric Association, Inc.

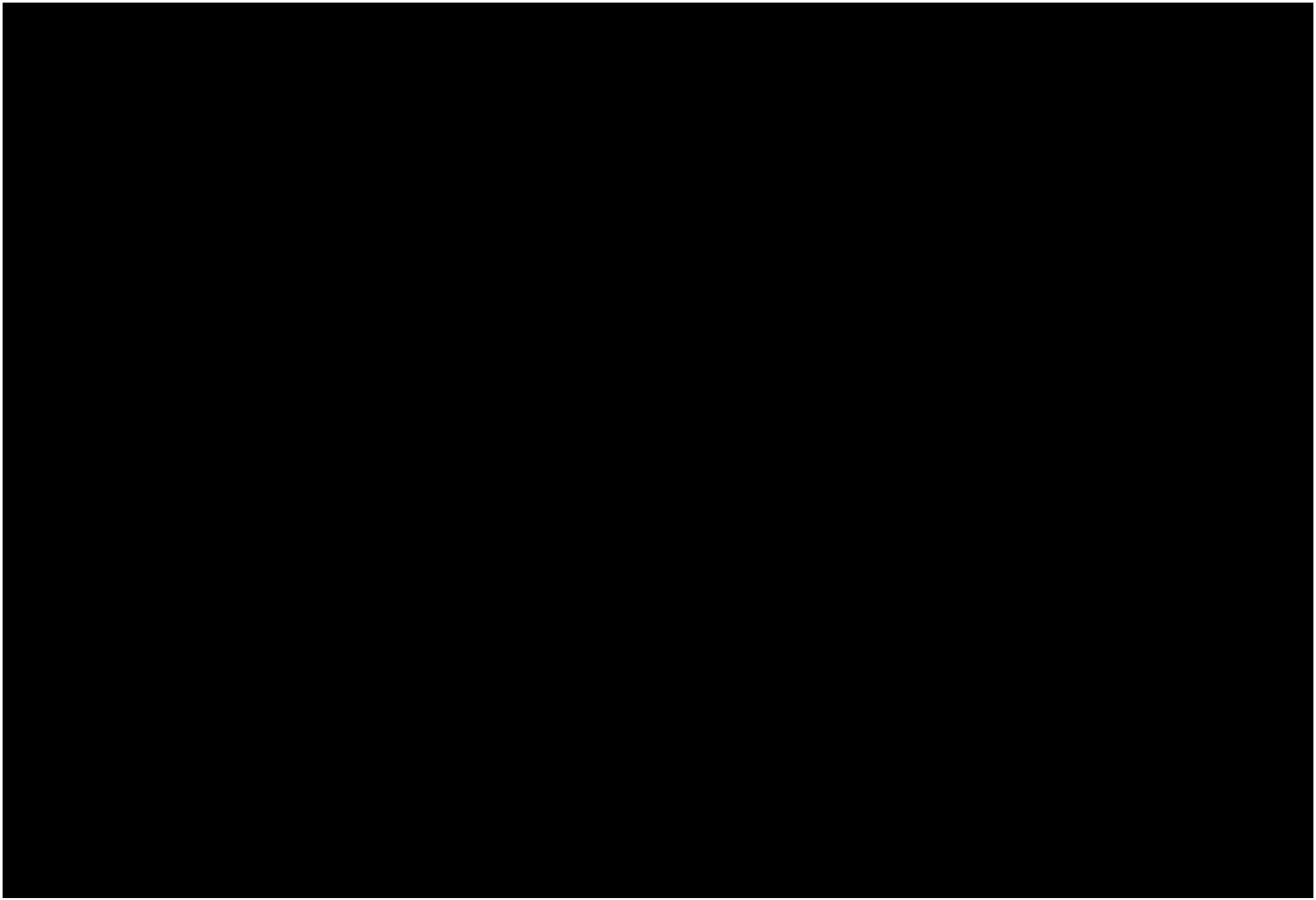
Date of Off Peak Day - 10/01/2021



Member Forecasted Off Peak Demand Day for November 2021

Poudre Valley Electric Association, Inc.

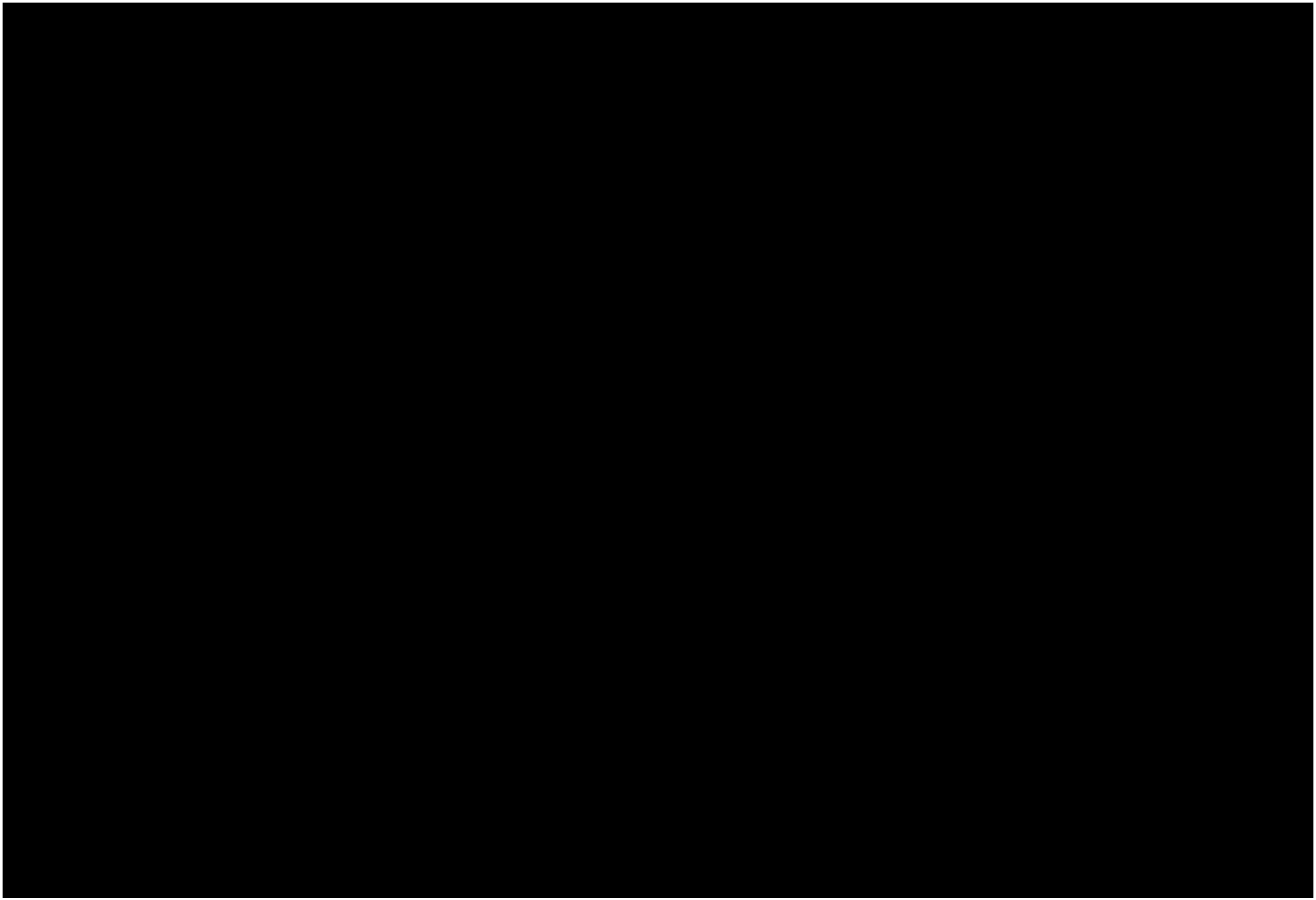
Date of Off Peak Day - 11/19/2021



Member Forecasted Off Peak Demand Day for December 2021

Poudre Valley Electric Association, Inc.

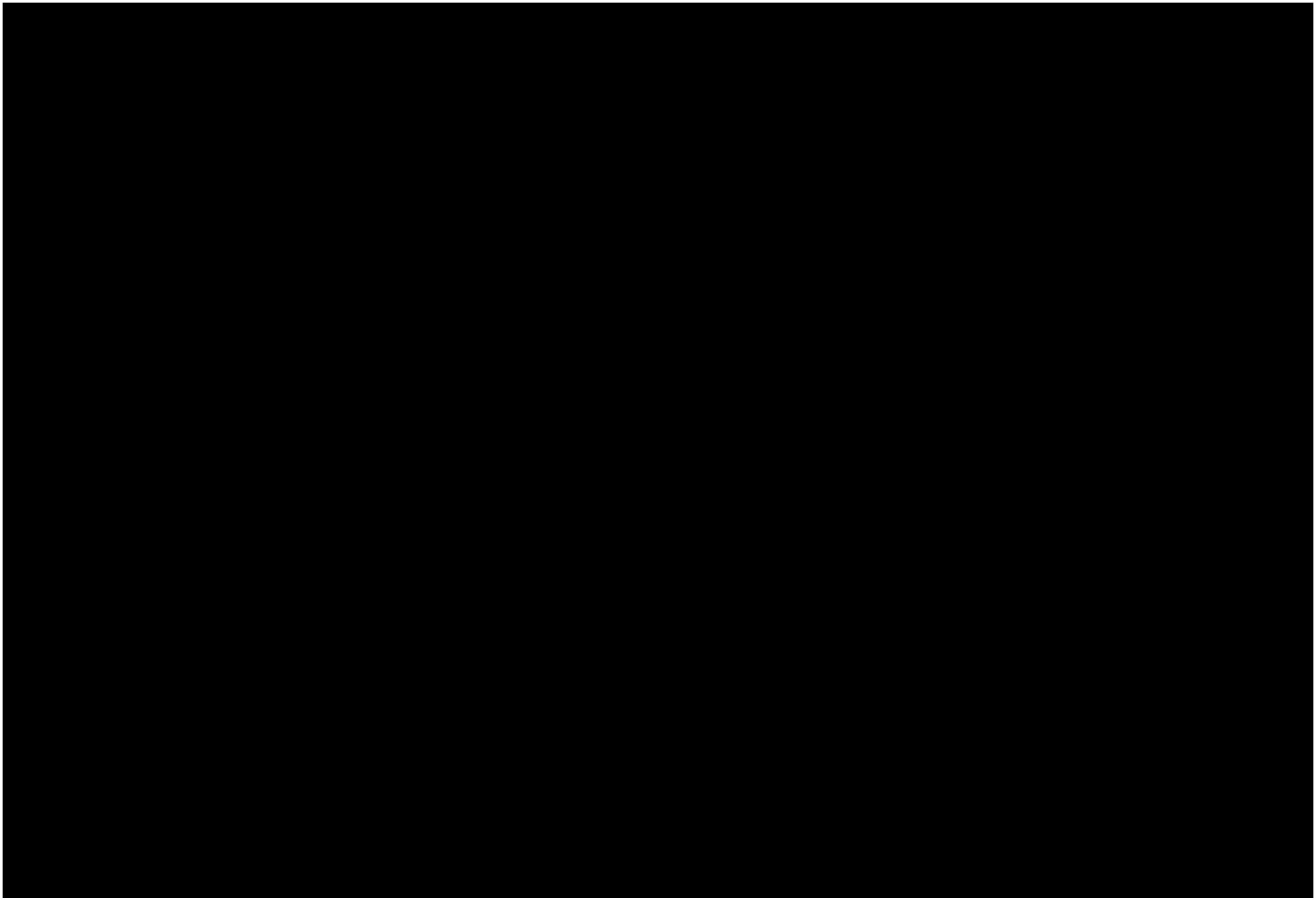
Date of Off Peak Day - 12/03/2021



Member Forecasted Off Peak Demand Day for January 2021

Northern Rio Arriba Electric Cooperative, Inc.

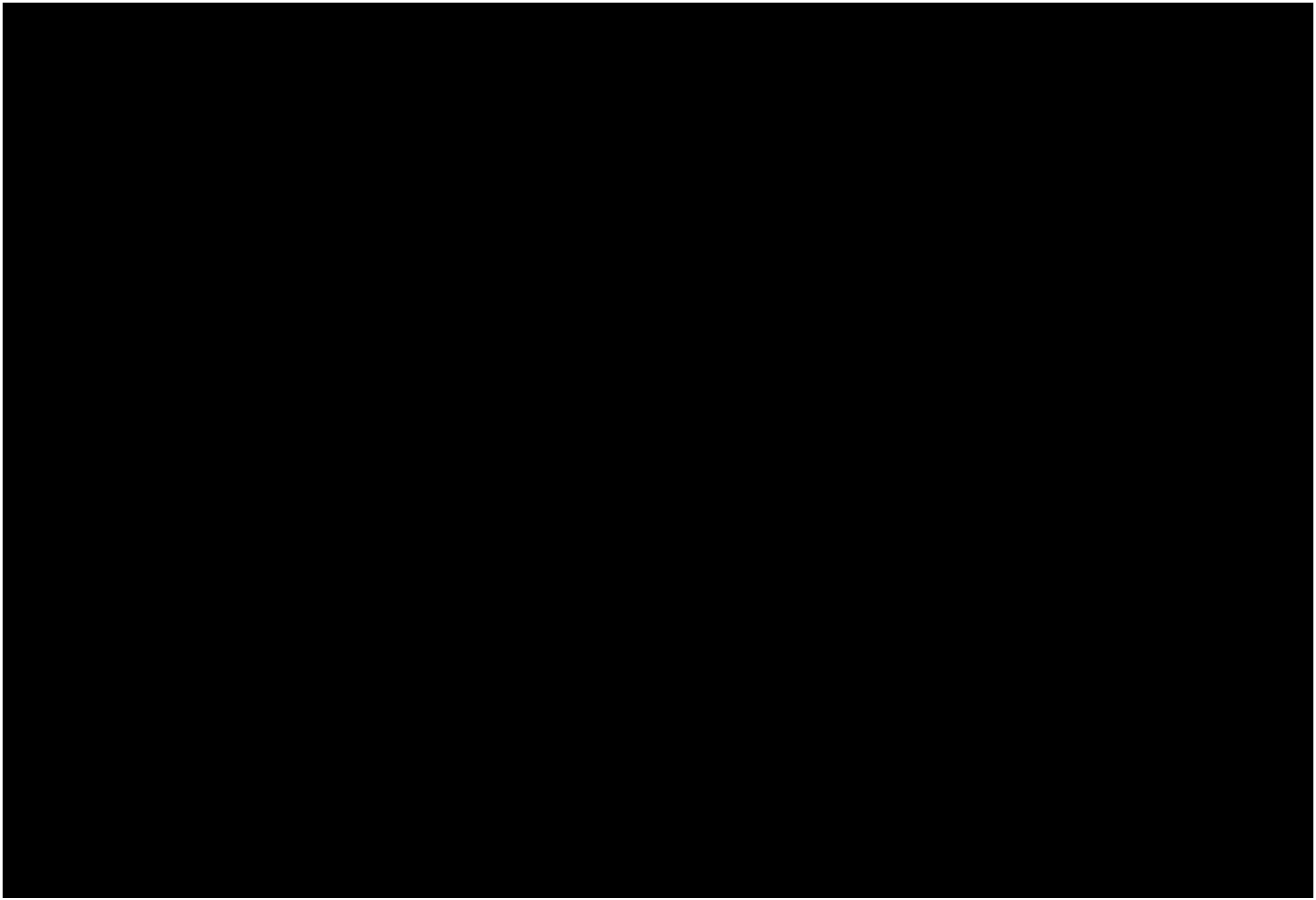
Date of Off Peak Day - 01/14/2021



Member Forecasted Off Peak Demand Day for February 2021

Northern Rio Arriba Electric Cooperative, Inc.

Date of Off Peak Day - 02/02/2021



Member Forecasted Off Peak Demand Day for March 2021

Northern Rio Arriba Electric Cooperative, Inc.

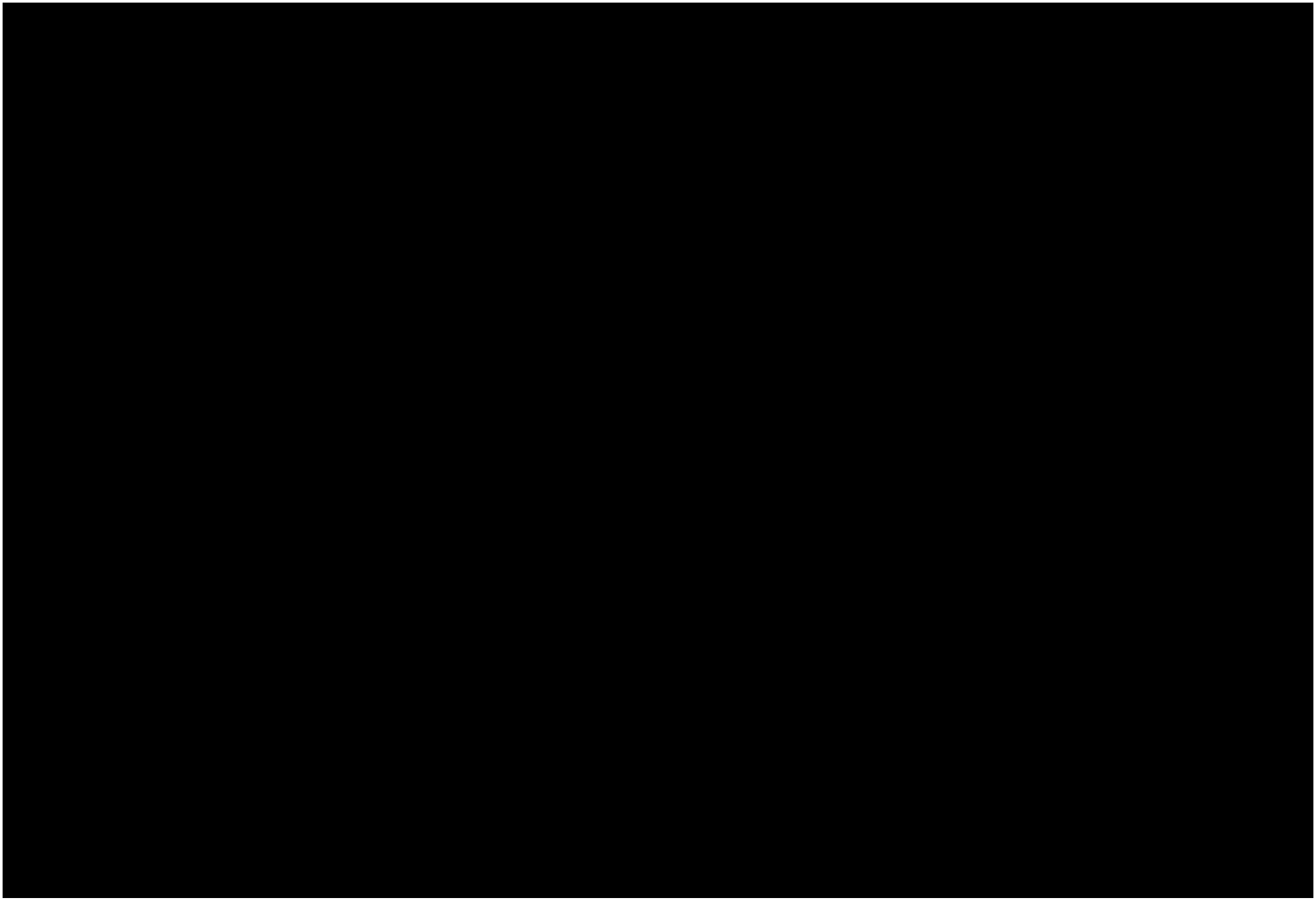
Date of Off Peak Day - 03/28/2021

[redacted]

Member Forecasted Off Peak Demand Day for April 2021

Northern Rio Arriba Electric Cooperative, Inc.

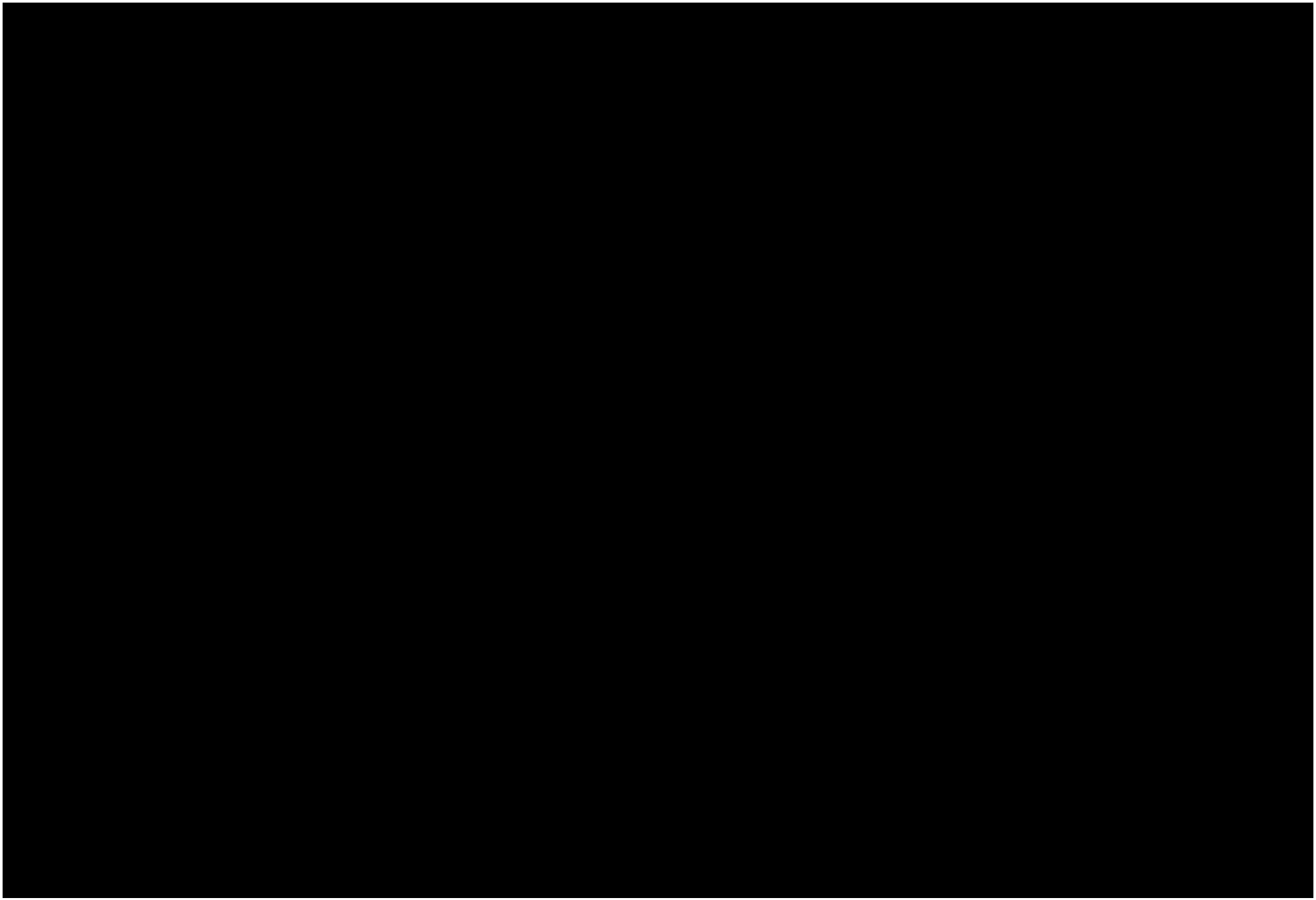
Date of Off Peak Day - 04/18/2021



Member Forecasted Off Peak Demand Day for May 2021

Northern Rio Arriba Electric Cooperative, Inc.

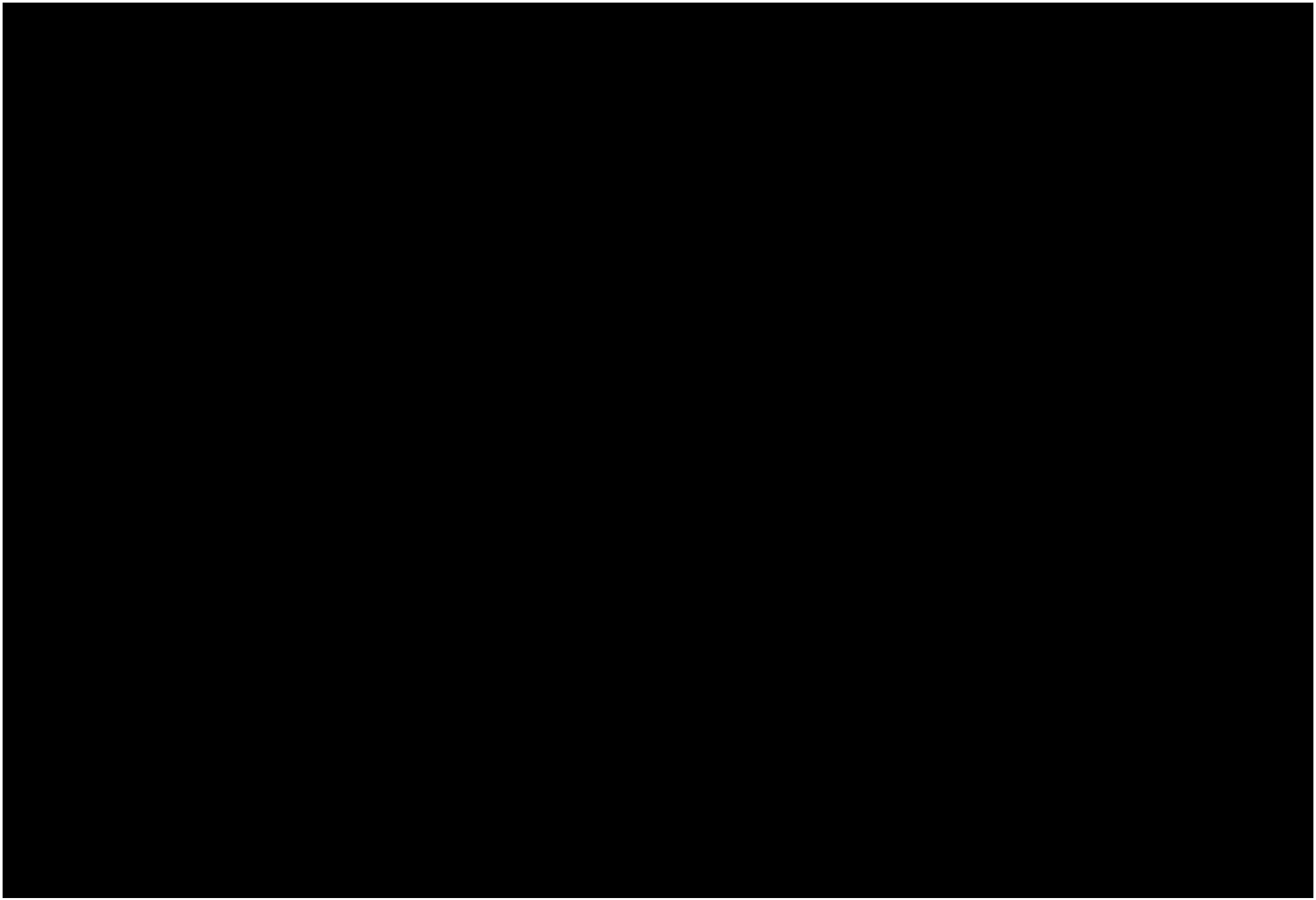
Date of Off Peak Day - 05/01/2021



Member Forecasted Off Peak Demand Day for June 2021

Northern Rio Arriba Electric Cooperative, Inc.

Date of Off Peak Day - 06/19/2021



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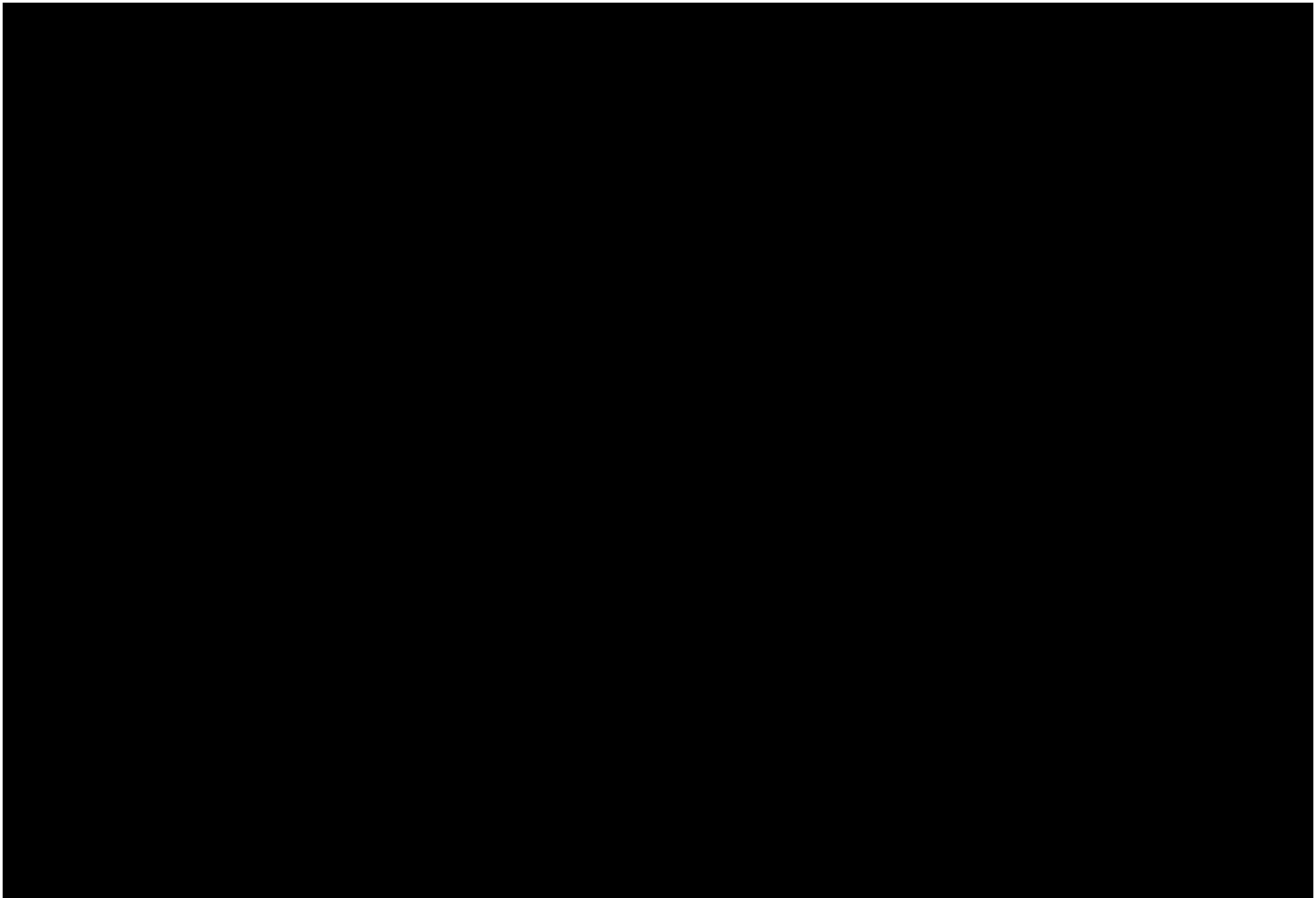
Member Forecasted Off Peak Demand Day for July 2021

Northern Rio Arriba Electric Cooperative, Inc.

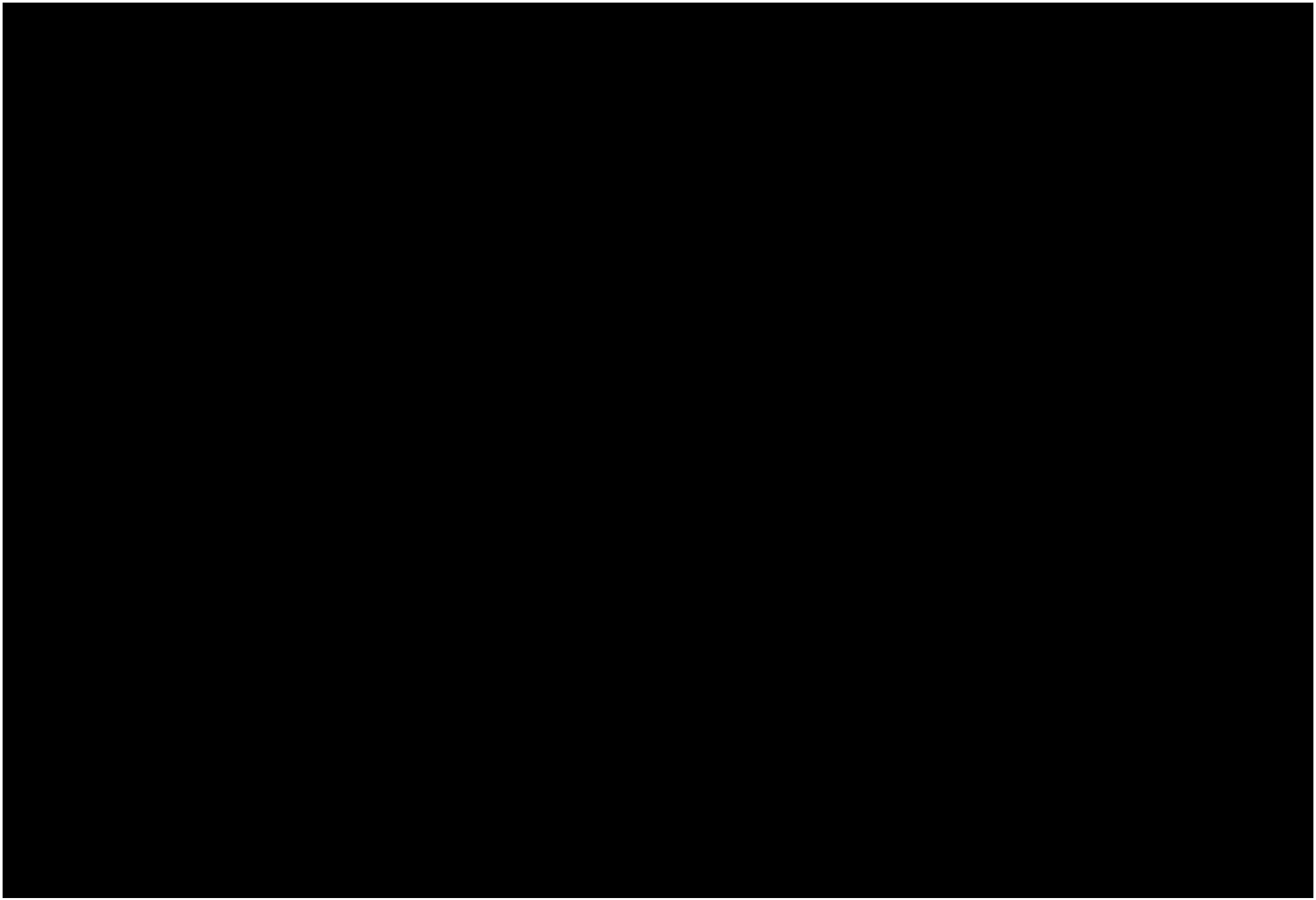
Date of Off Peak Day - 07/06/2021



Member Forecasted Off Peak Demand Day for August 2021

Northern Rio Arriba Electric Cooperative, Inc.

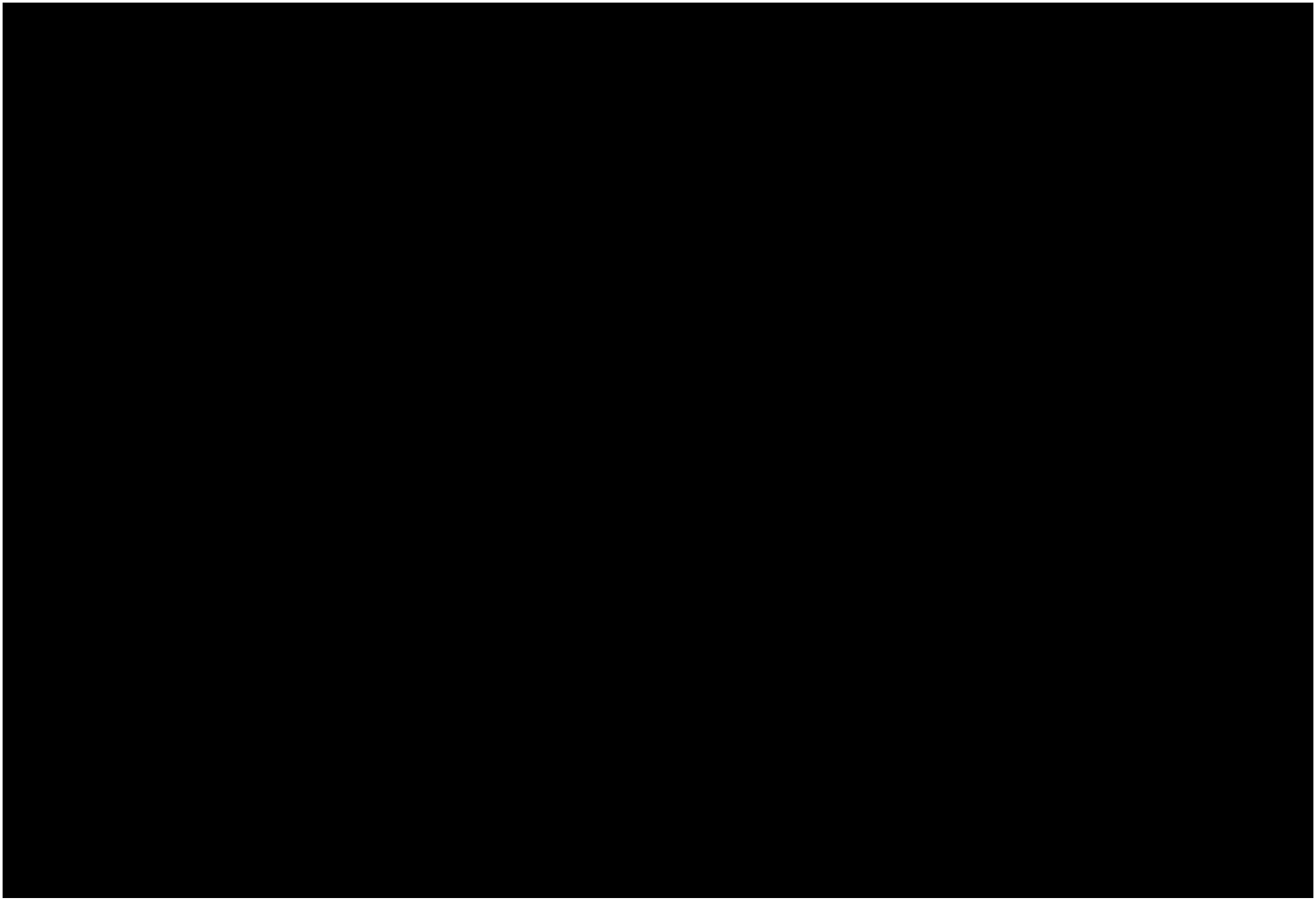
Date of Off Peak Day - 08/24/2021



Member Forecasted Off Peak Demand Day for September 2021

Northern Rio Arriba Electric Cooperative, Inc.

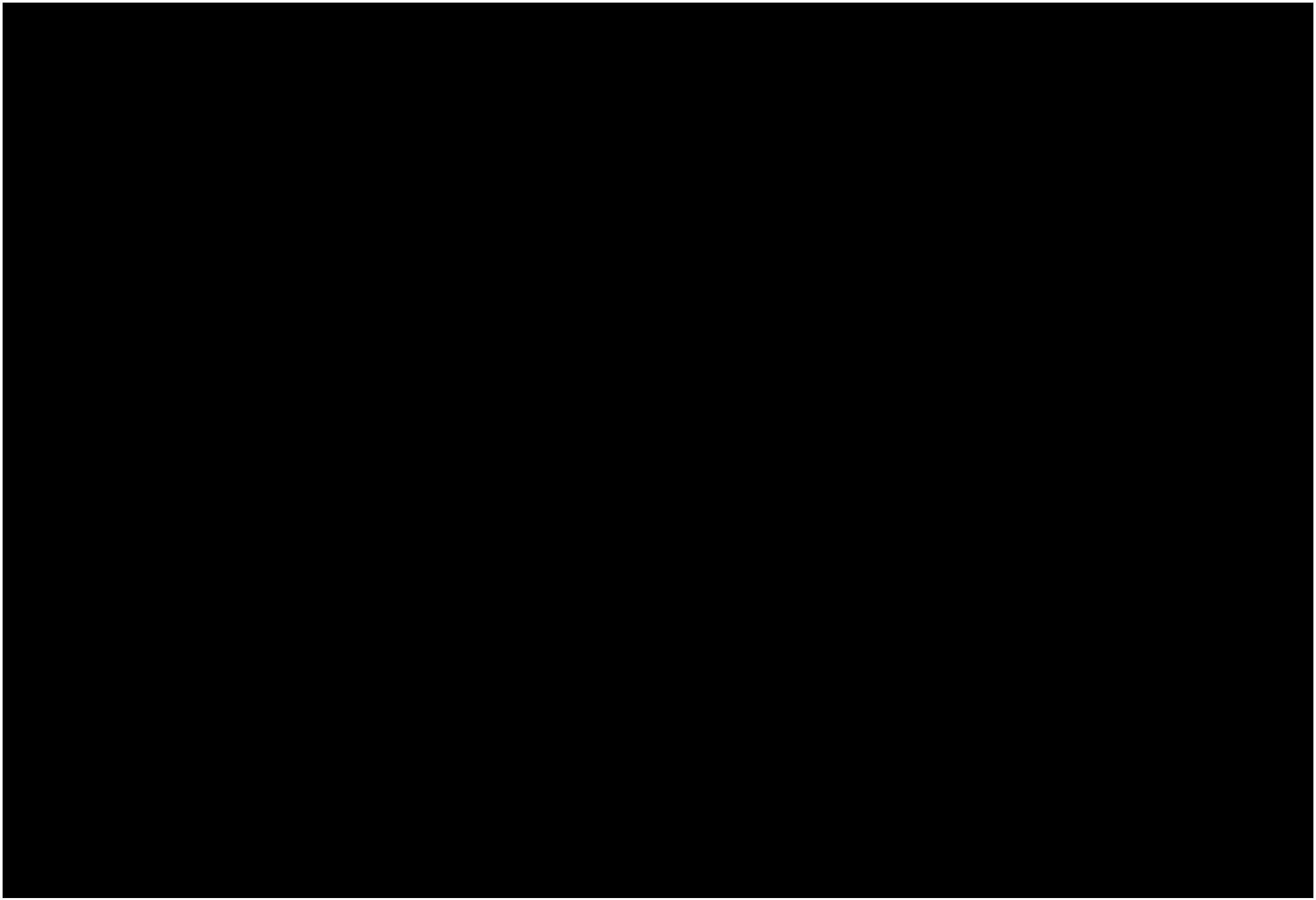
Date of Off Peak Day - 09/14/2021



Member Forecasted Off Peak Demand Day for October 2021

Northern Rio Arriba Electric Cooperative, Inc.

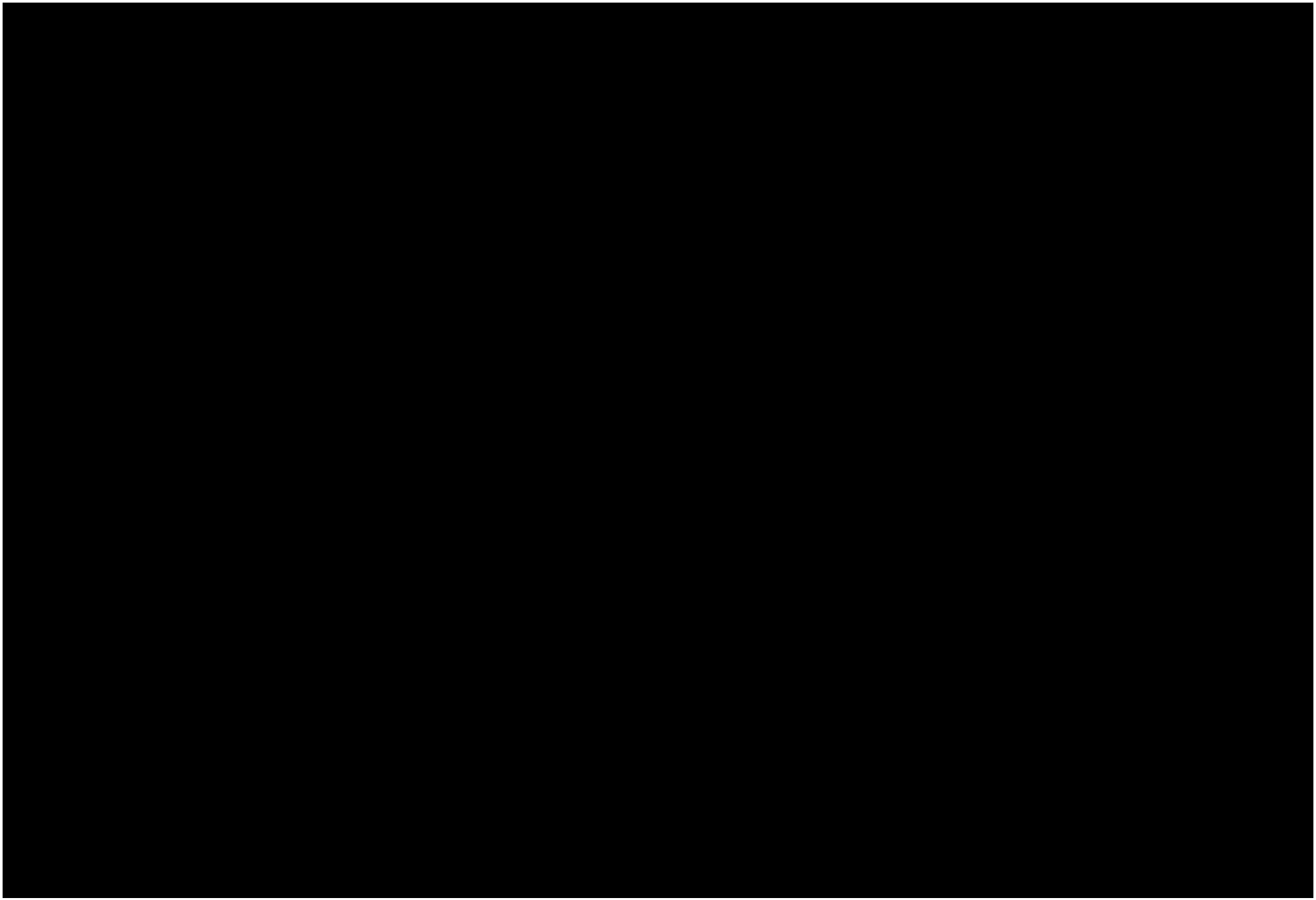
Date of Off Peak Day - 10/14/2021



Member Forecasted Off Peak Demand Day for November 2021

Northern Rio Arriba Electric Cooperative, Inc.

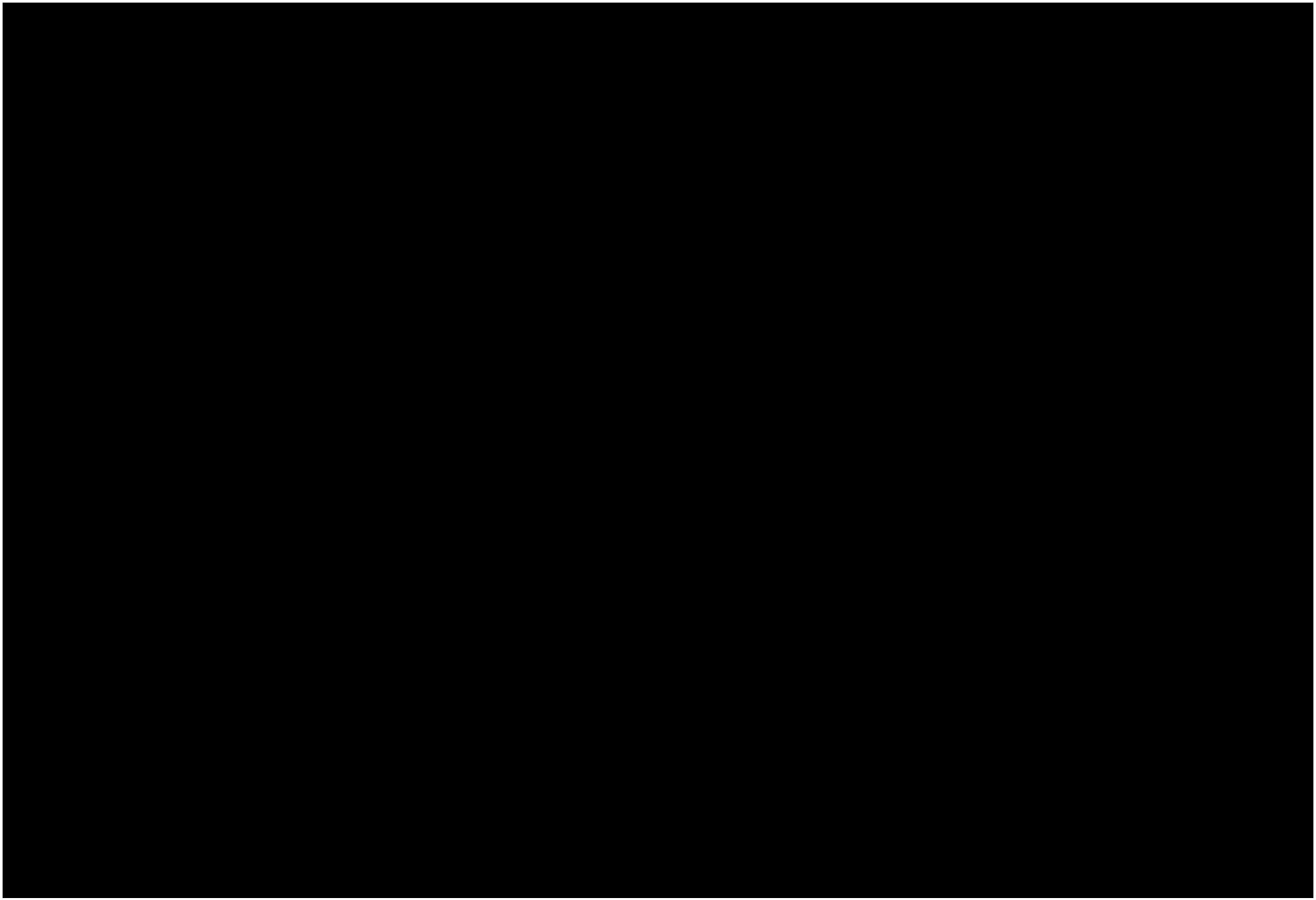
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

Northern Rio Arriba Electric Cooperative, Inc.

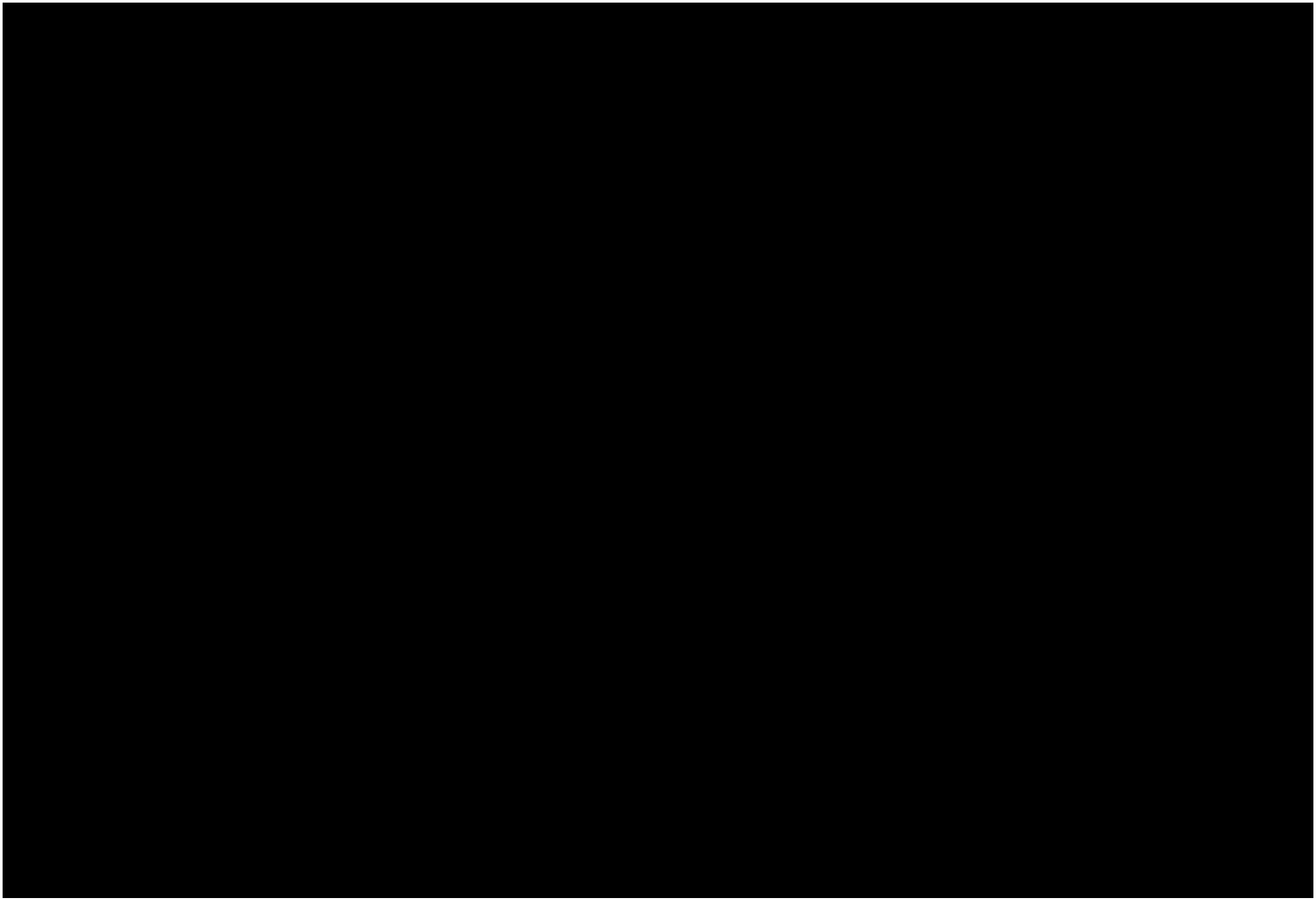
Date of Off Peak Day - 12/10/2021



Member Forecasted Off Peak Demand Day for January 2021

Roosevelt Public Power District

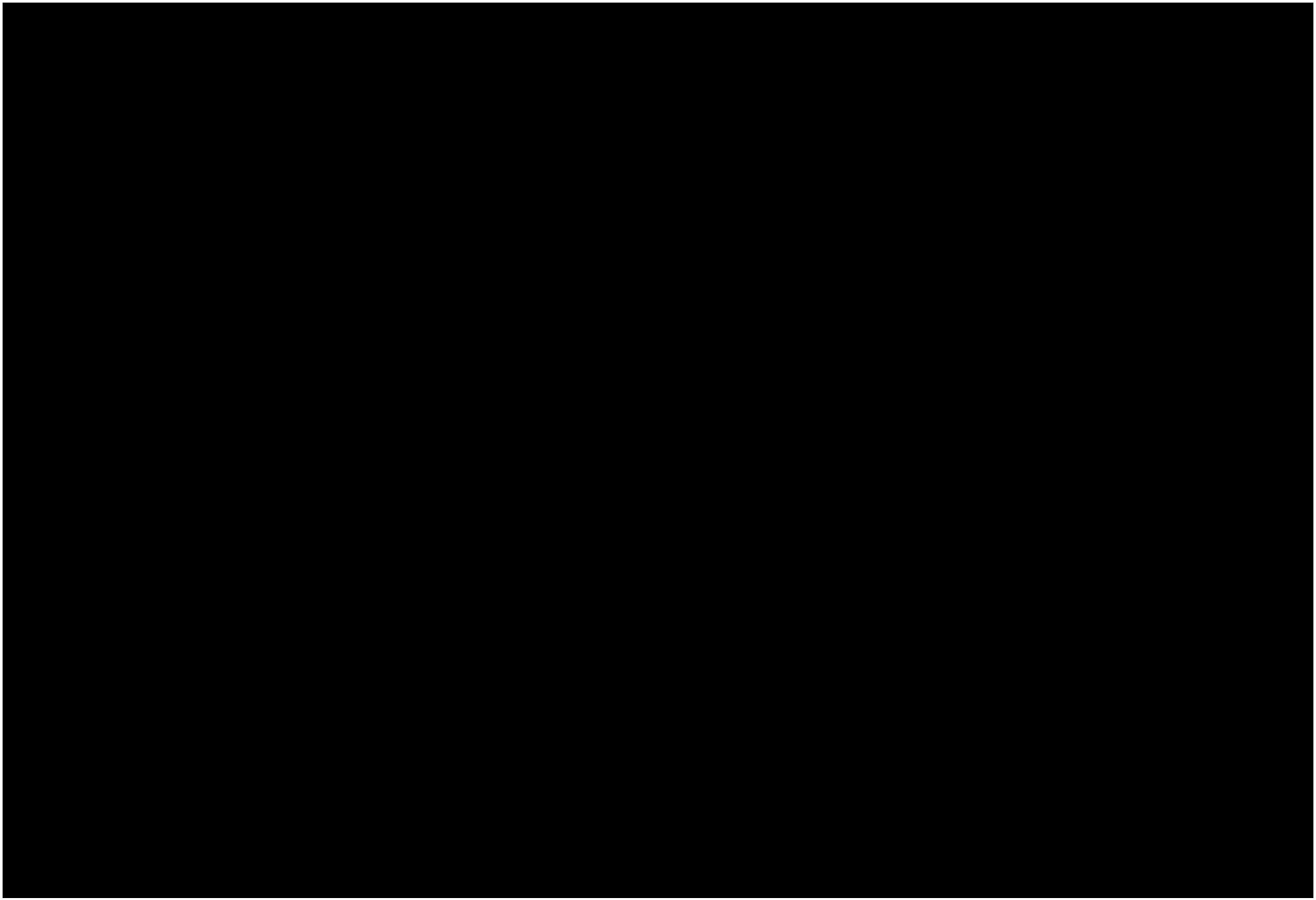
Date of Off Peak Day - 01/18/2021



Member Forecasted Off Peak Demand Day for February 2021

Roosevelt Public Power District

Date of Off Peak Day - 02/16/2021



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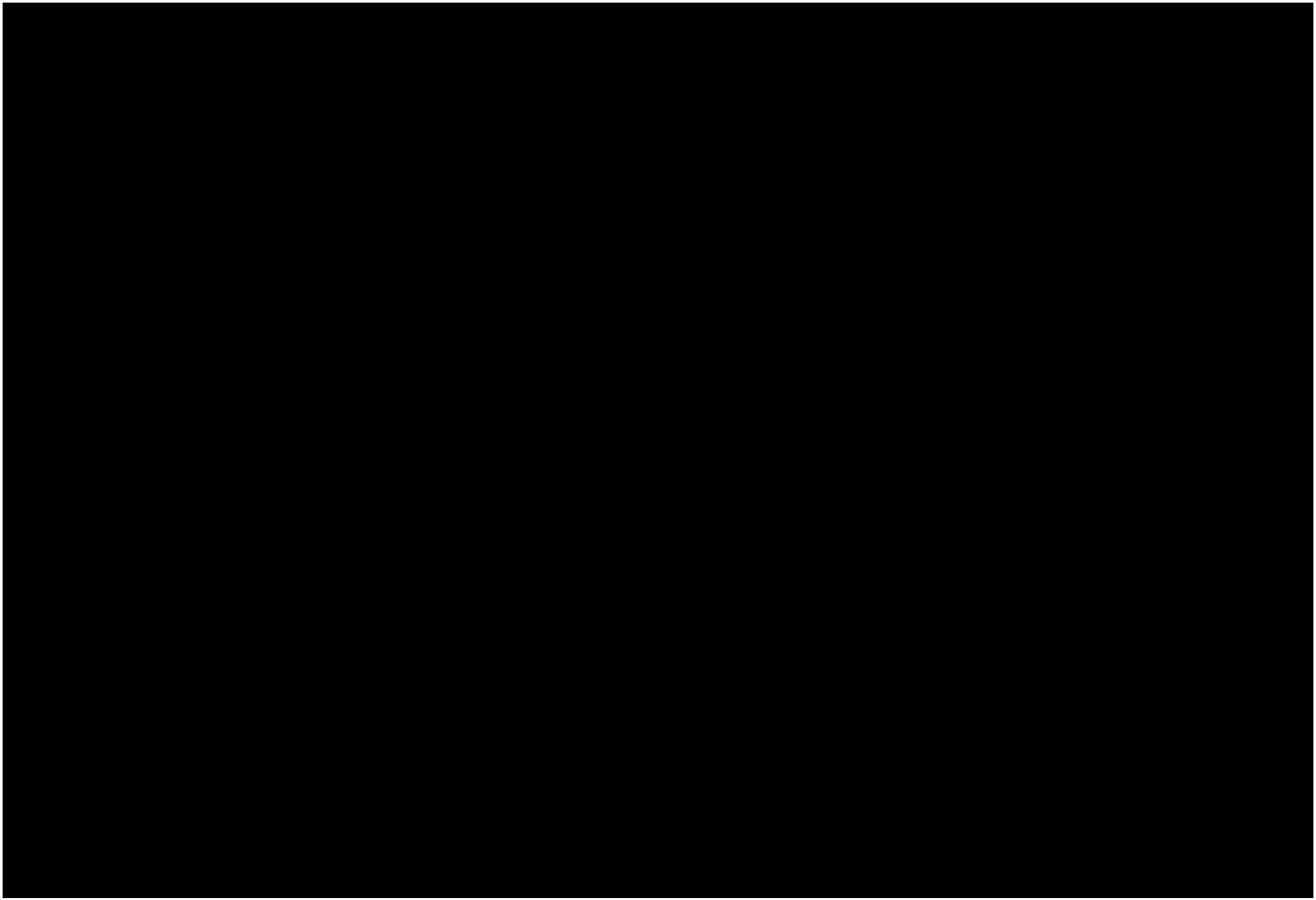
Member Forecasted Off Peak Demand Day for March 2021

Roosevelt Public Power District

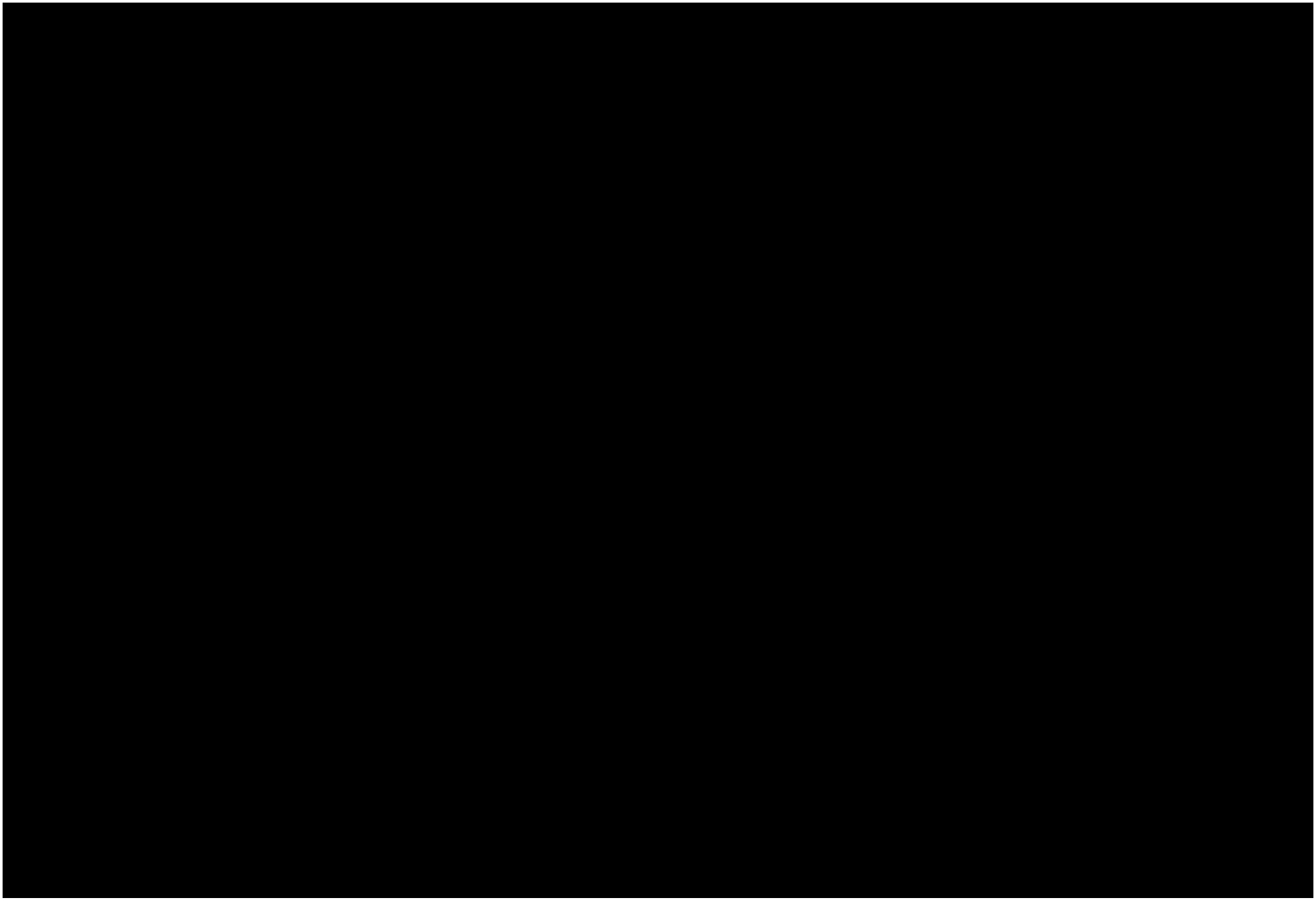
Date of Off Peak Day - 03/28/2021



Member Forecasted Off Peak Demand Day for April 2021

Roosevelt Public Power District

Date of Off Peak Day - 04/30/2021



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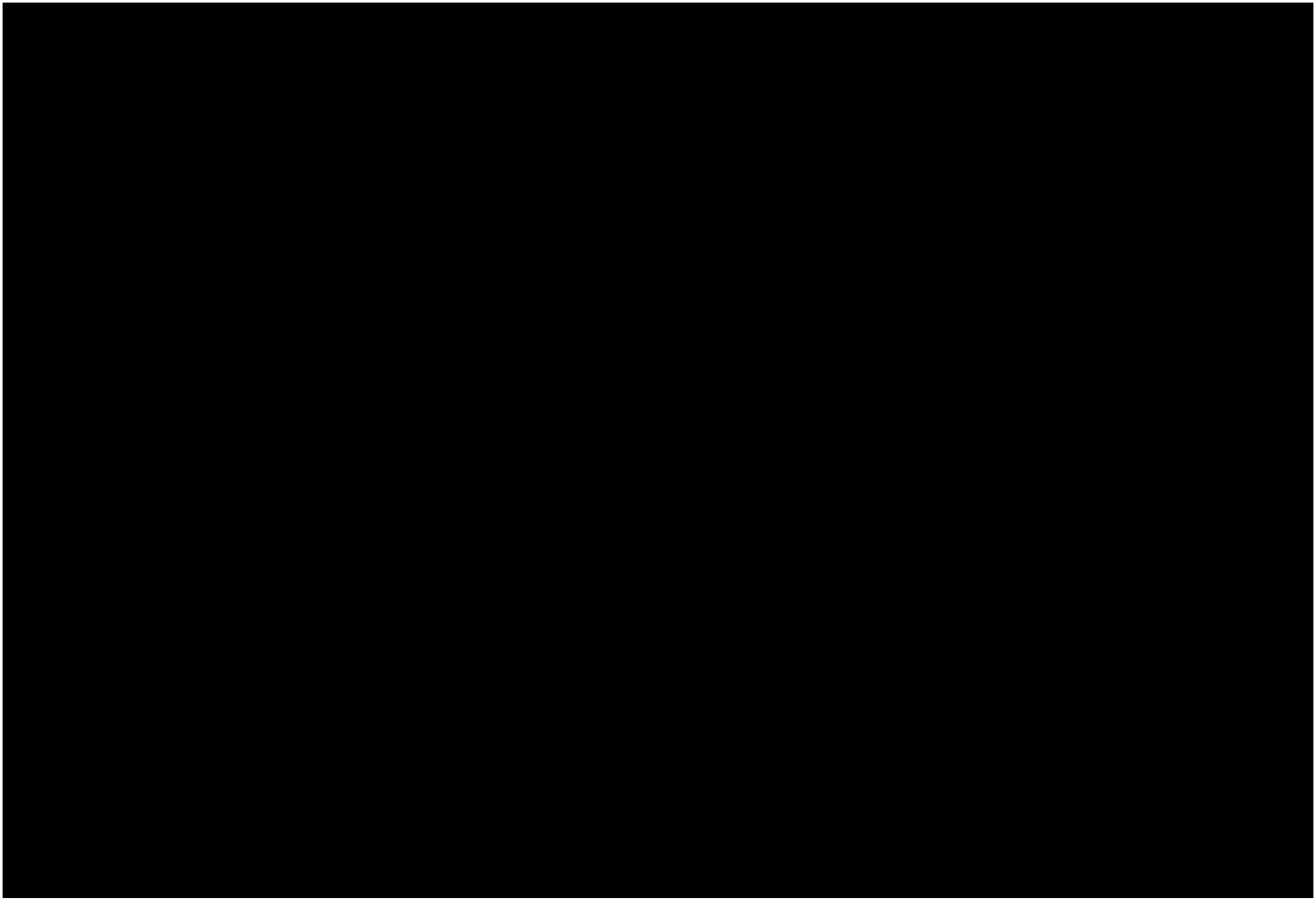
Member Forecasted Off Peak Demand Day for May 2021

Roosevelt Public Power District

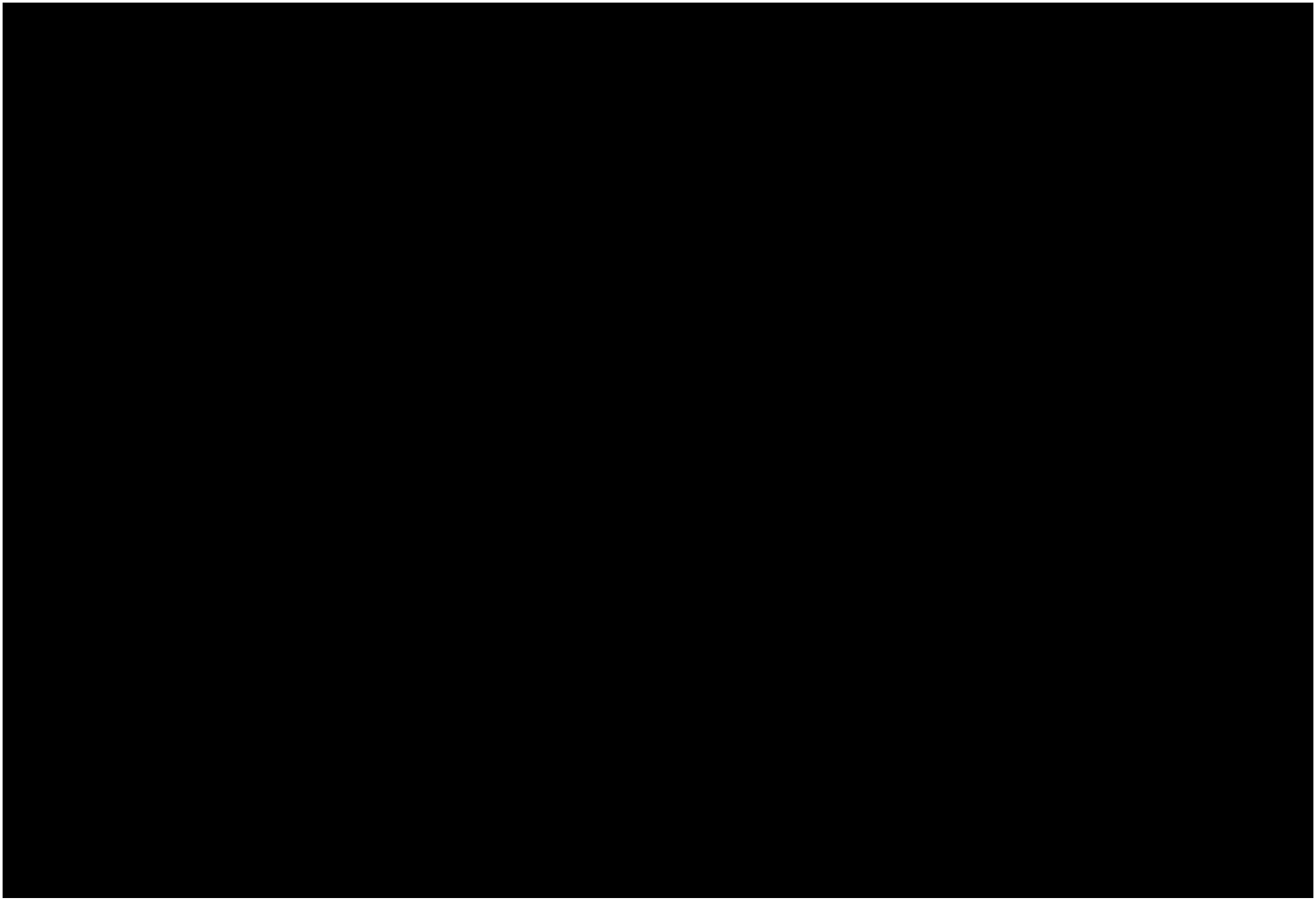
Date of Off Peak Day - 05/06/2021



Member Forecasted Off Peak Demand Day for June 2021

Roosevelt Public Power District

Date of Off Peak Day - 06/01/2021



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Member Forecasted Off Peak Demand Day for July 2021

Roosevelt Public Power District

Date of Off Peak Day - 07/31/2021

[redacted]

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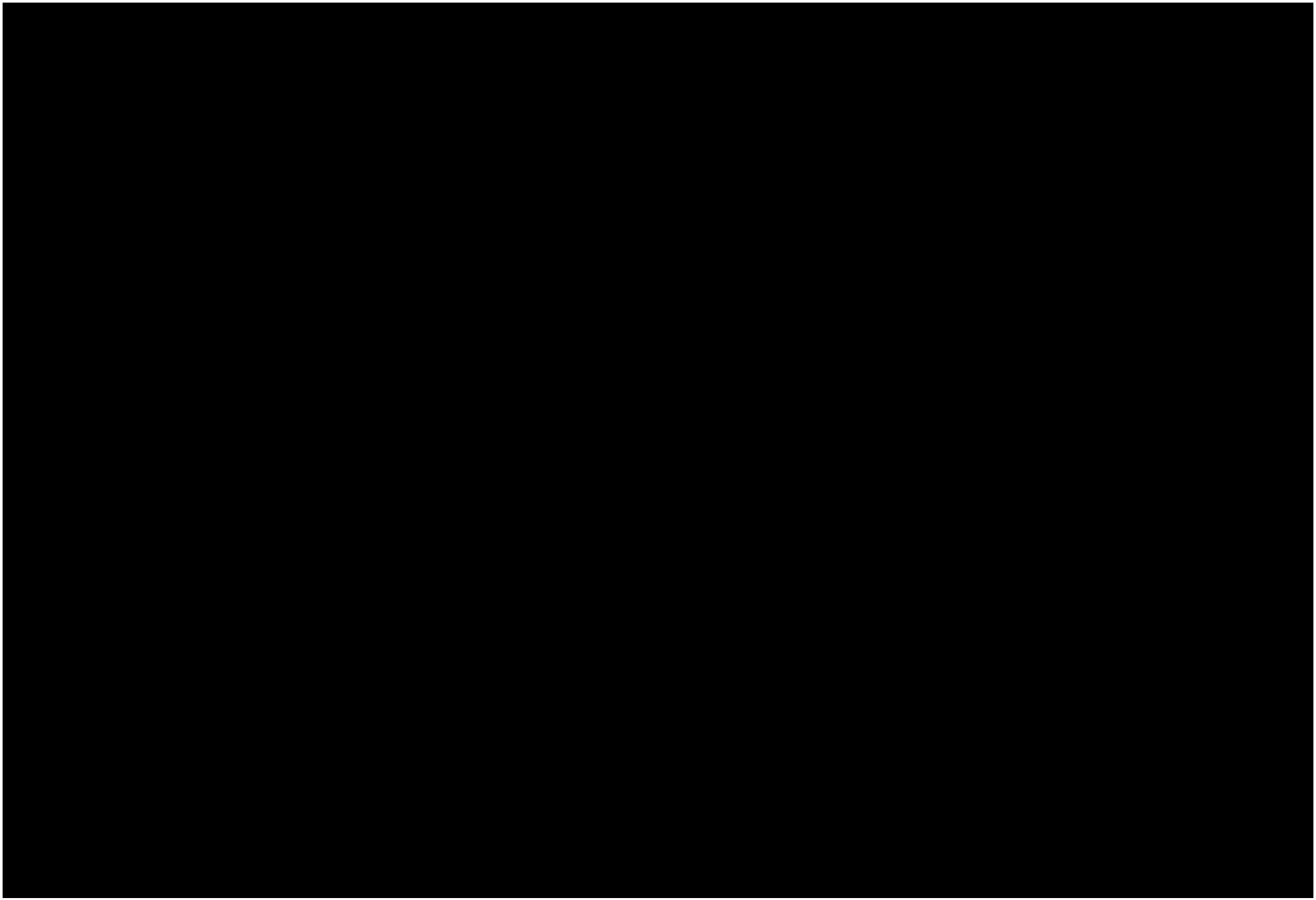
Member Forecasted Off Peak Demand Day for August 2021

Roosevelt Public Power District

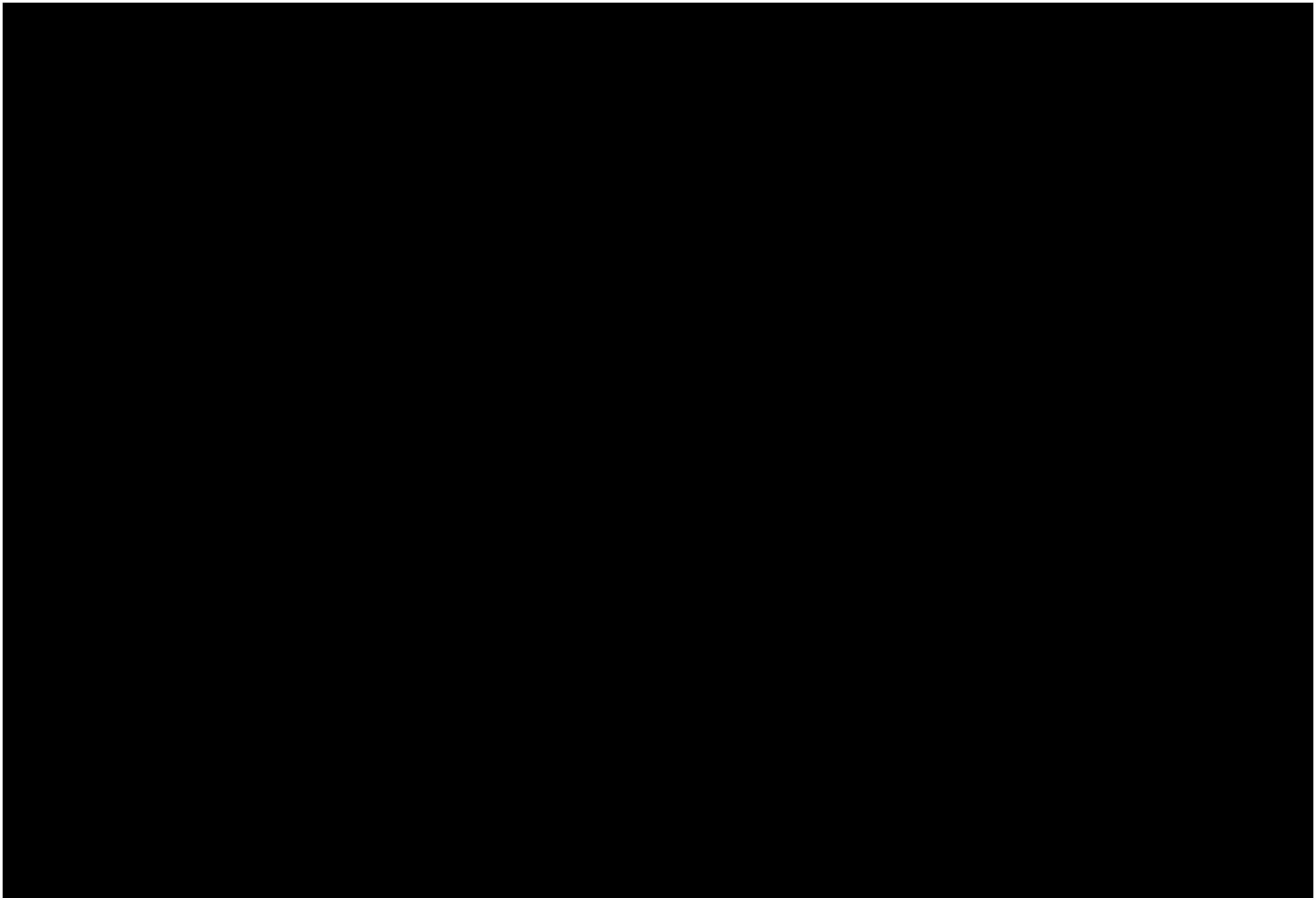
Date of Off Peak Day - 08/11/2021



Member Forecasted Off Peak Demand Day for September 2021

Roosevelt Public Power District

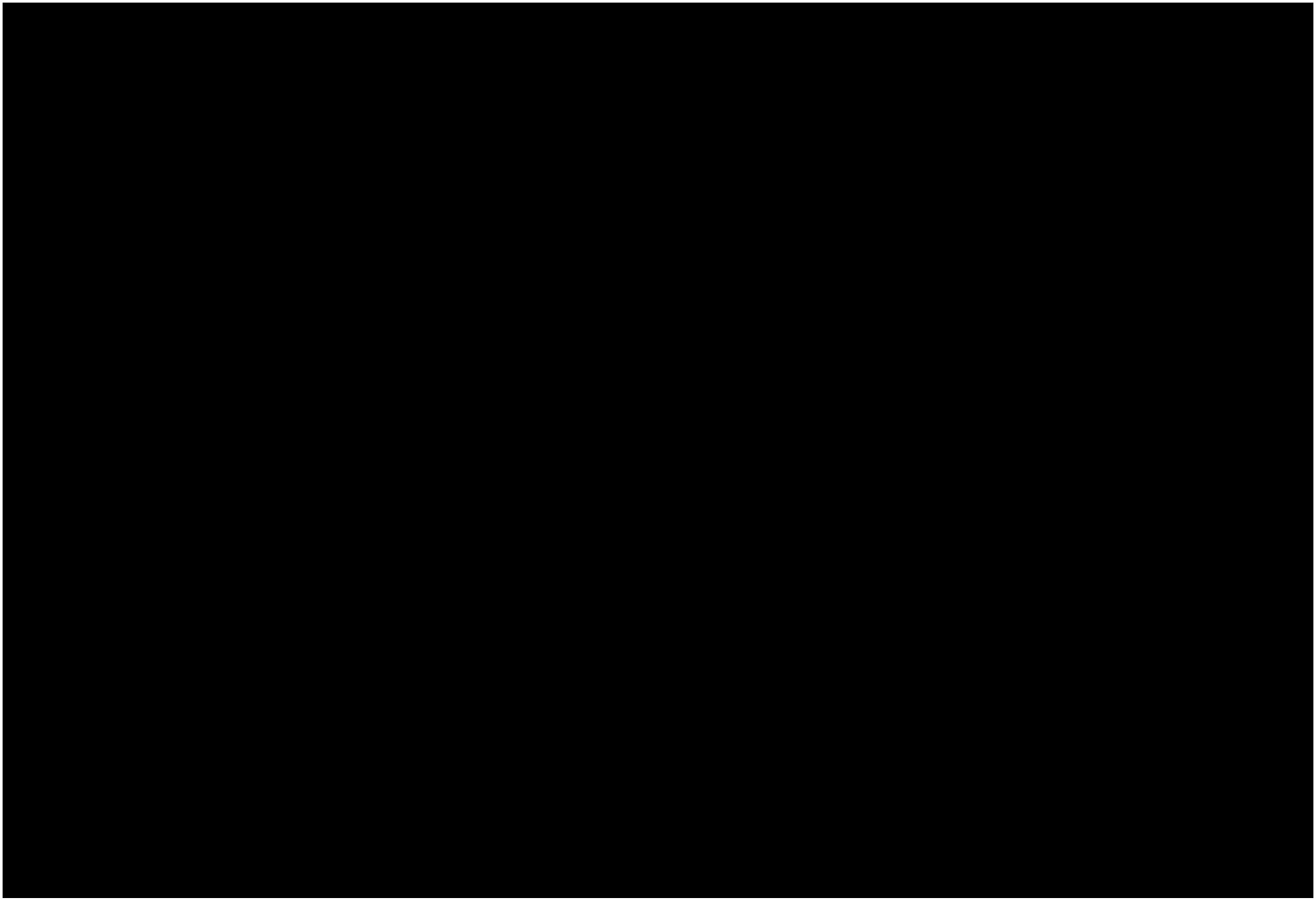
Date of Off Peak Day - 09/30/2021



Member Forecasted Off Peak Demand Day for October 2021

Roosevelt Public Power District

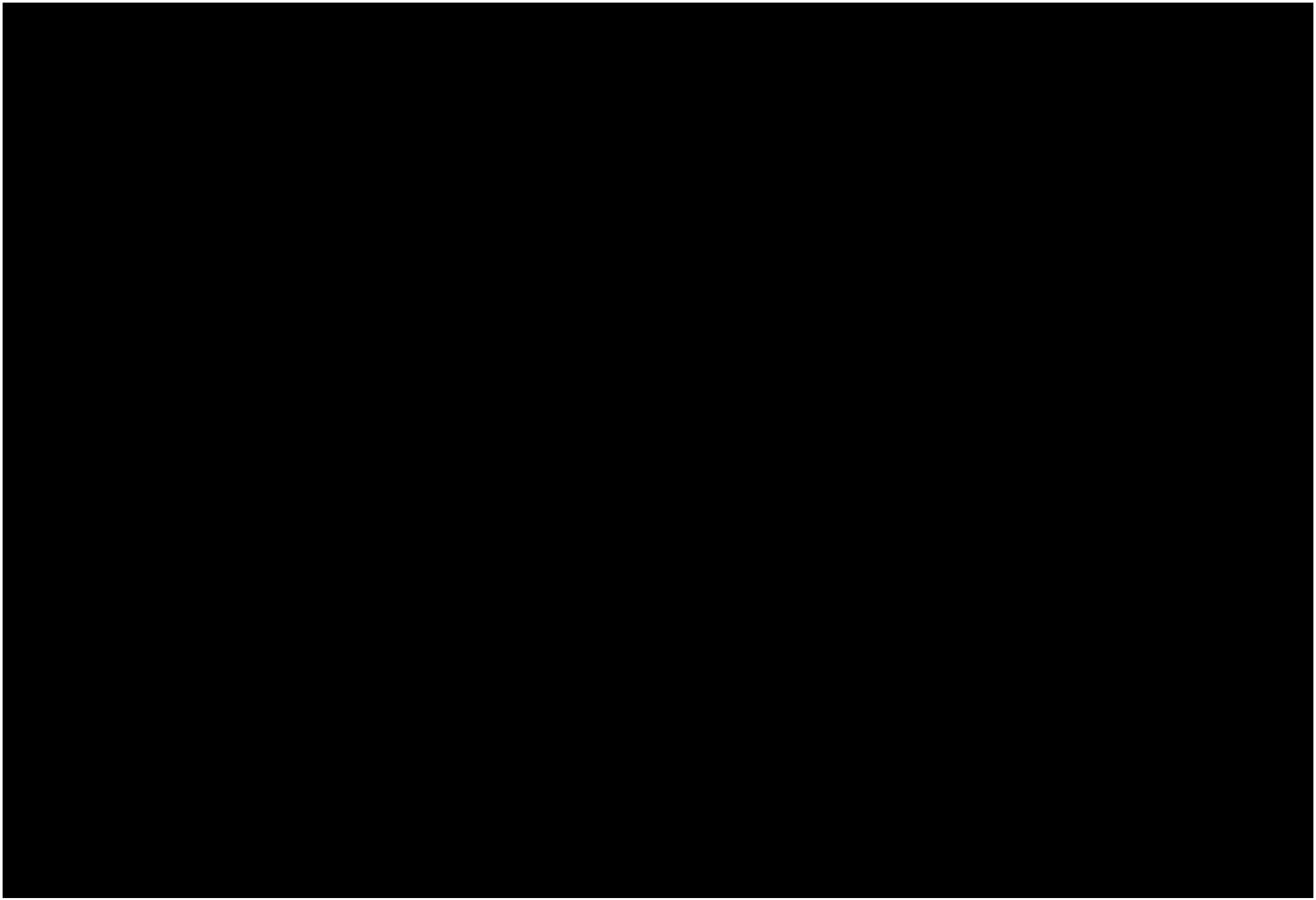
Date of Off Peak Day - 10/10/2021



Member Forecasted Off Peak Demand Day for November 2021

Roosevelt Public Power District

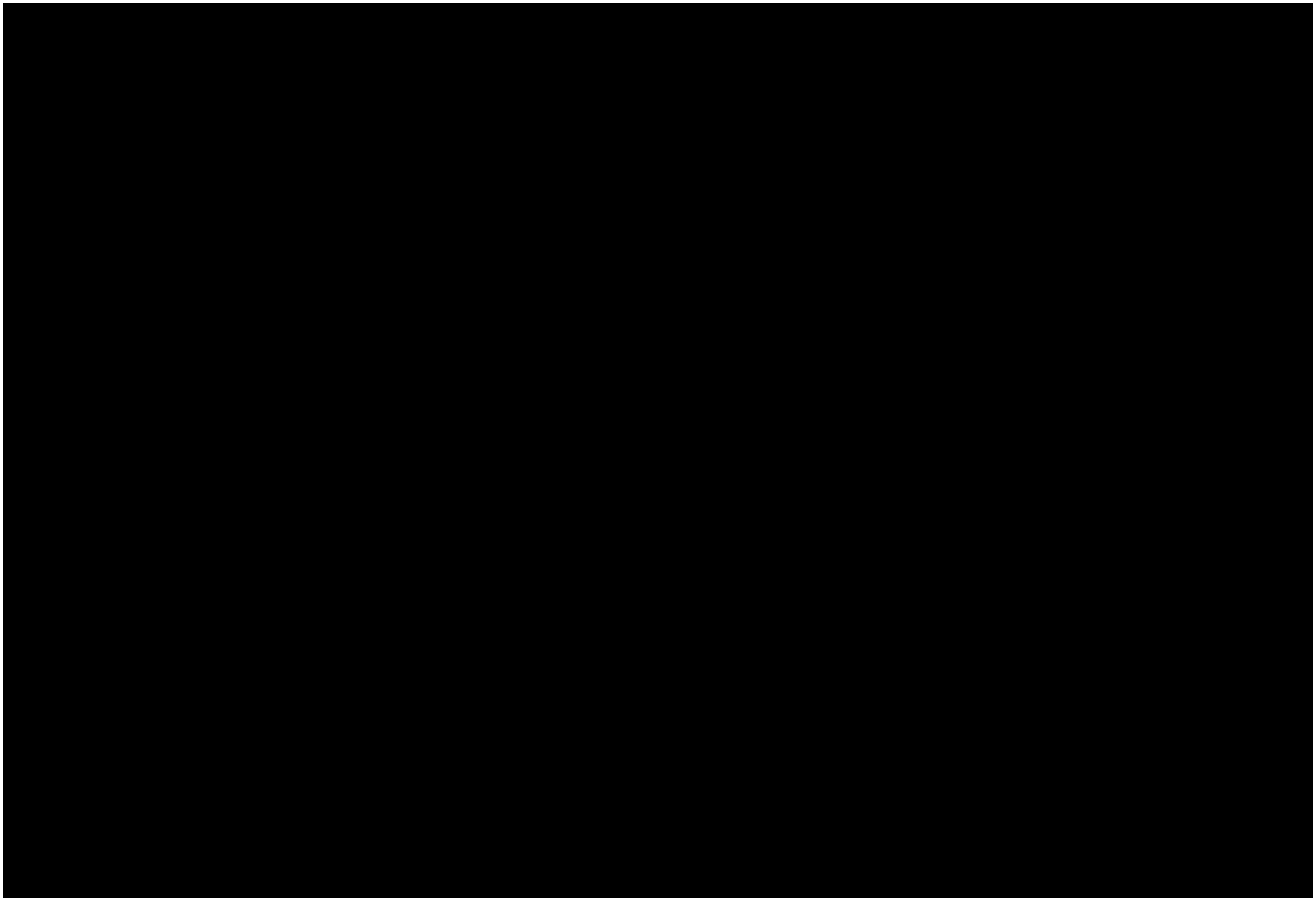
Date of Off Peak Day - 11/03/2021



Member Forecasted Off Peak Demand Day for December 2021

Roosevelt Public Power District

Date of Off Peak Day - 12/08/2021



Member Forecasted Off Peak Demand Day for January 2021

Sierra Electric Cooperative, Inc.

Date of Off Peak Day - 01/12/2021

[redacted]

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Member Forecasted Off Peak Demand Day for February 2021

Sierra Electric Cooperative, Inc.

Date of Off Peak Day - 02/20/2021

[redacted]

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Member Forecasted Off Peak Demand Day for March 2021

Sierra Electric Cooperative, Inc.

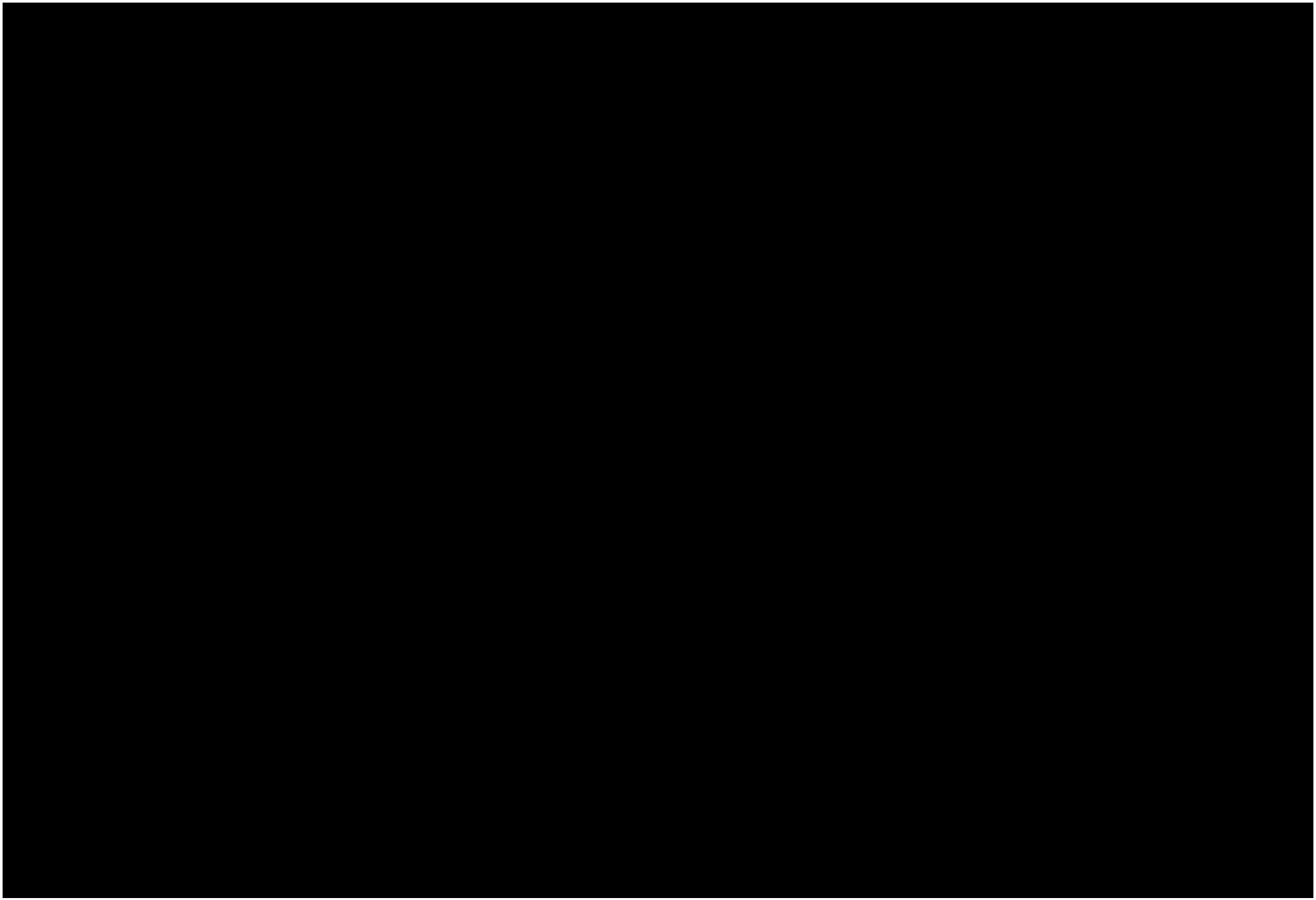
Date of Off Peak Day - 03/14/2021

[redacted]

Member Forecasted Off Peak Demand Day for April 2021

Sierra Electric Cooperative, Inc.

Date of Off Peak Day - 04/10/2021



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Member Forecasted Off Peak Demand Day for May 2021

Sierra Electric Cooperative, Inc.

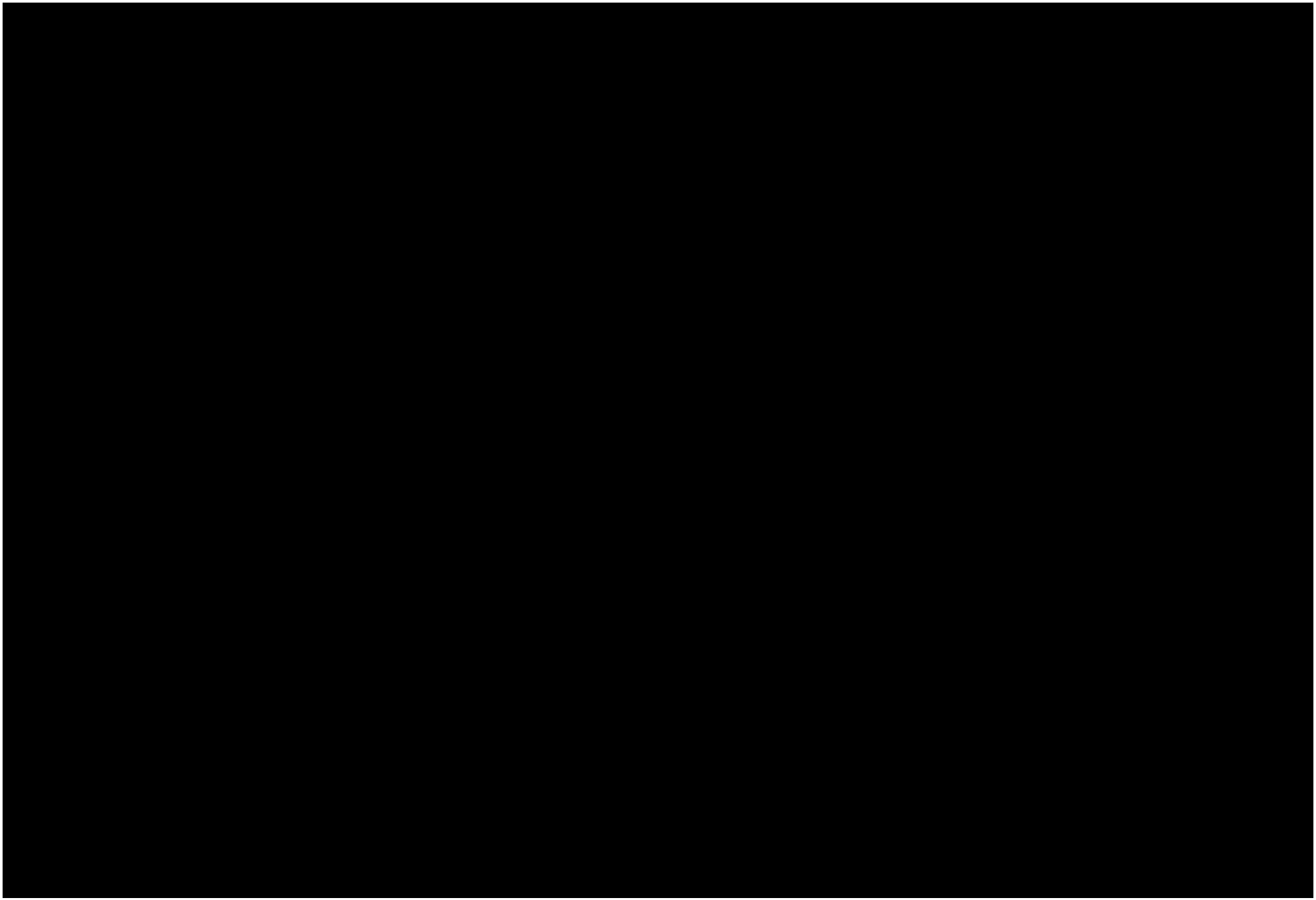
Date of Off Peak Day - 05/02/2021

[redacted]

Member Forecasted Off Peak Demand Day for June 2021

Sierra Electric Cooperative, Inc.

Date of Off Peak Day - 06/01/2021



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Member Forecasted Off Peak Demand Day for July 2021

Sierra Electric Cooperative, Inc.

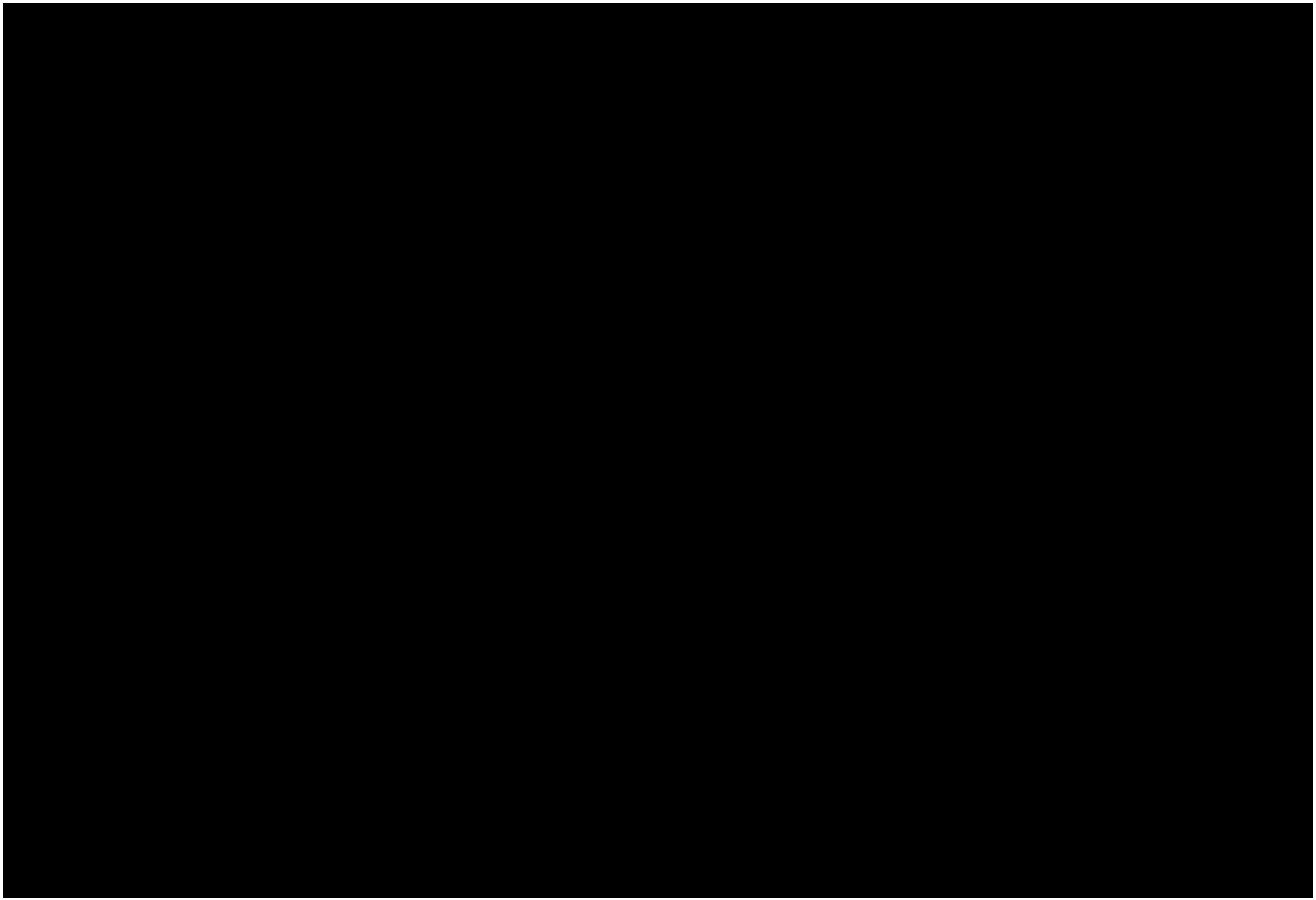
Date of Off Peak Day - 07/02/2021

[redacted]

Member Forecasted Off Peak Demand Day for August 2021

Sierra Electric Cooperative, Inc.

Date of Off Peak Day - 08/30/2021



Member Forecasted Off Peak Demand Day for September 2021

Sierra Electric Cooperative, Inc.

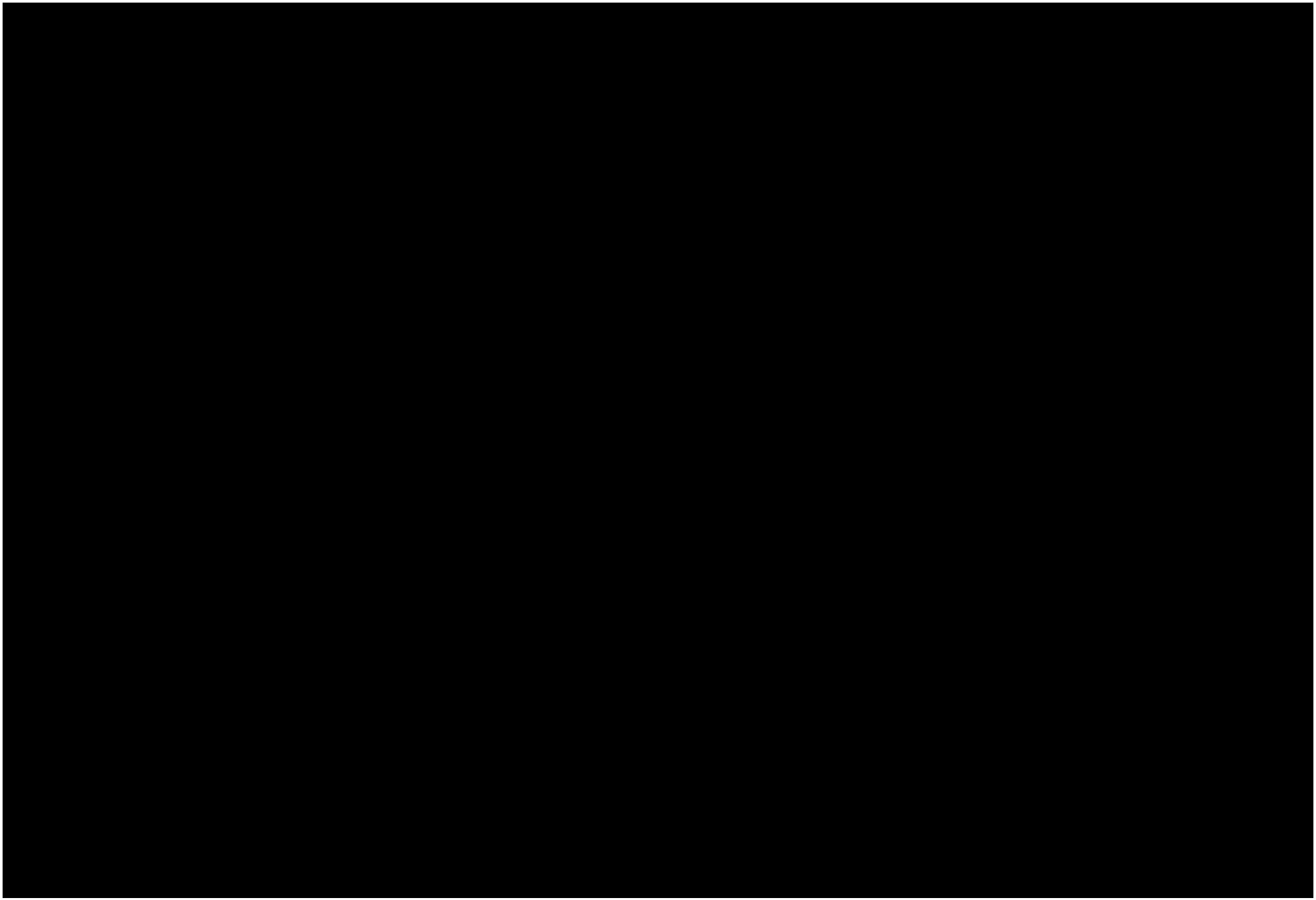
Date of Off Peak Day - 09/11/2021

[redacted]

Member Forecasted Off Peak Demand Day for October 2021

Sierra Electric Cooperative, Inc.

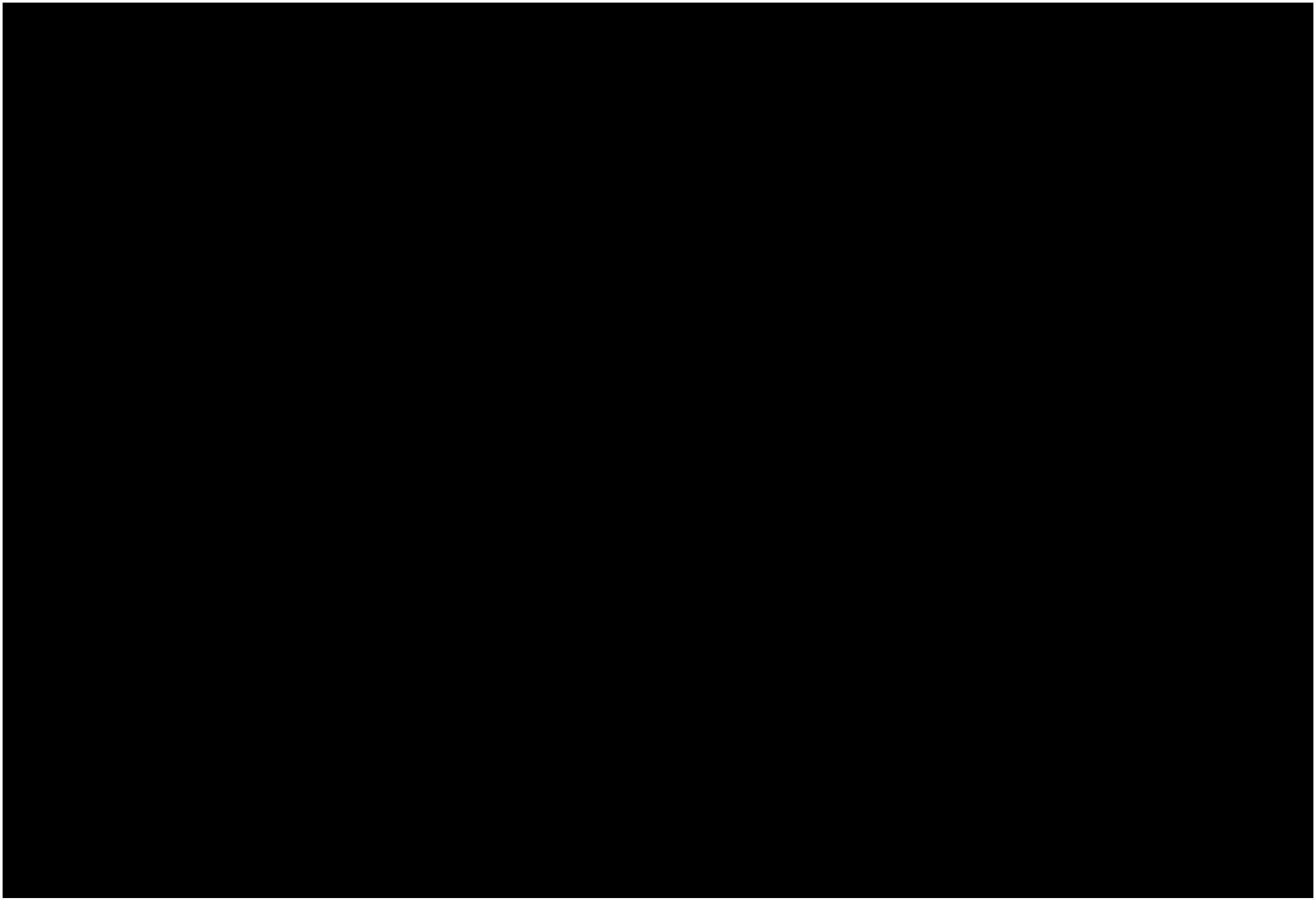
Date of Off Peak Day - 10/24/2021



Member Forecasted Off Peak Demand Day for November 2021

Sierra Electric Cooperative, Inc.

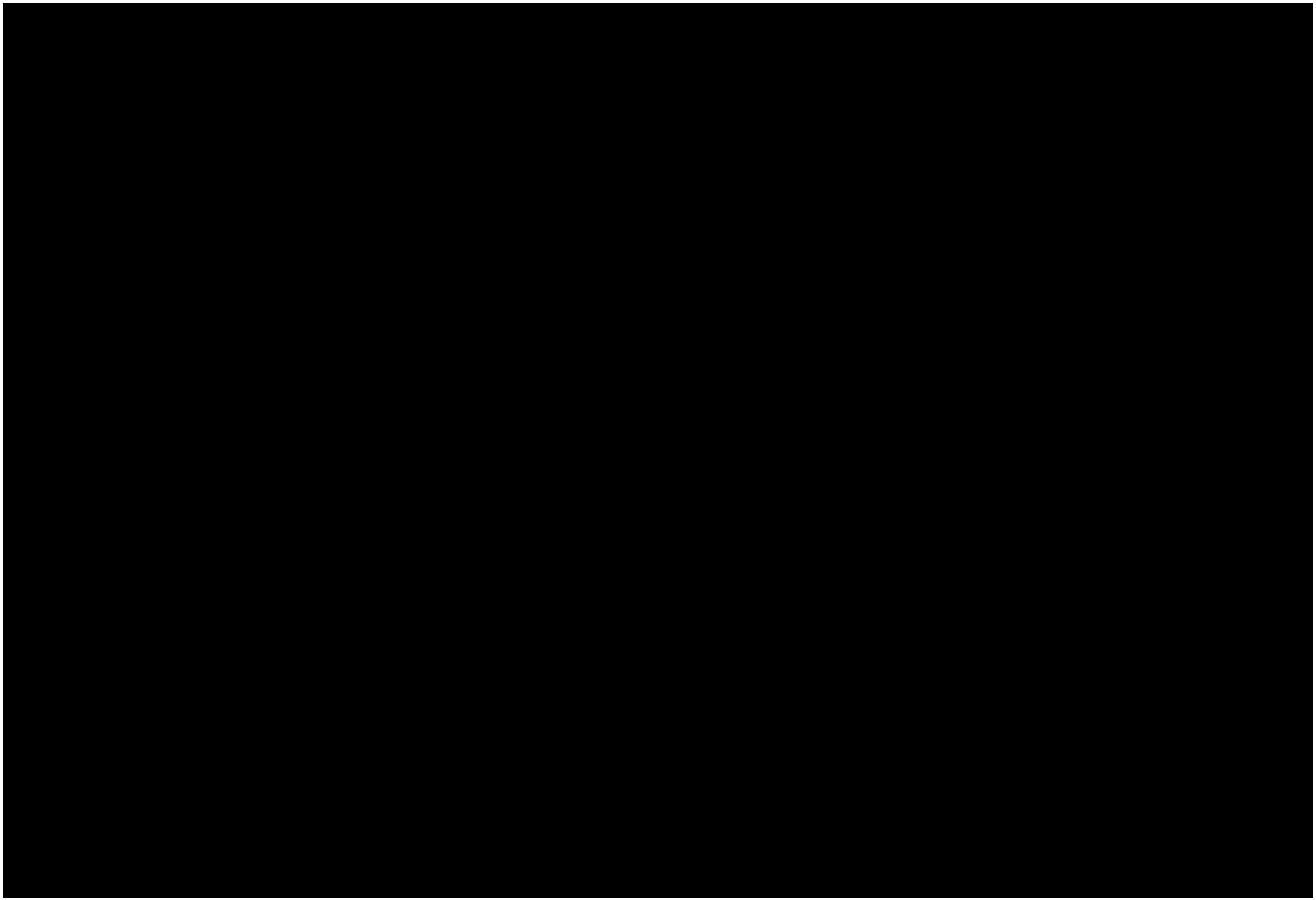
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

Sierra Electric Cooperative, Inc.

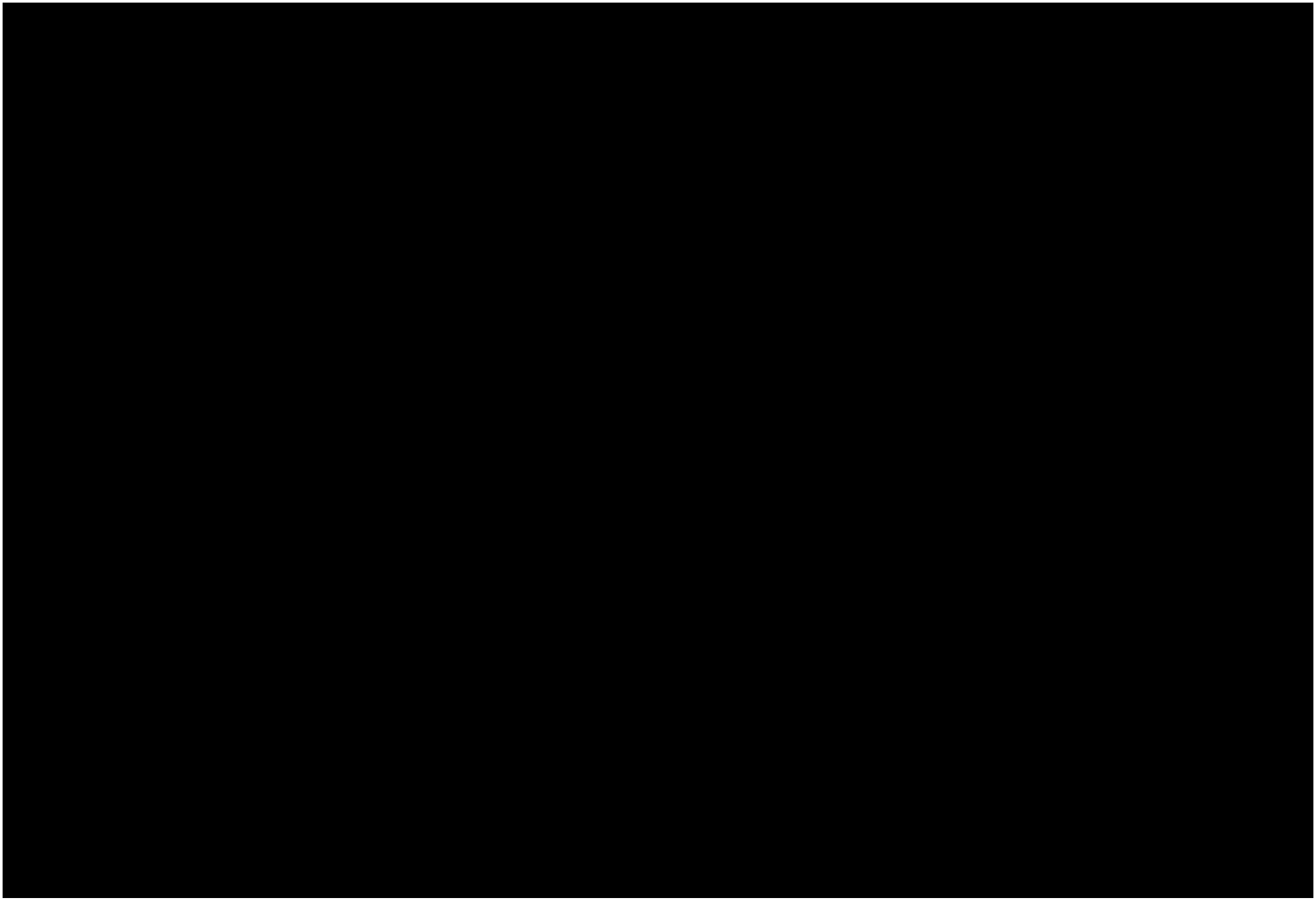
Date of Off Peak Day - 12/05/2021



Member Forecasted Off Peak Demand Day for January 2021

Sangre de Cristo Electric Association, Inc.

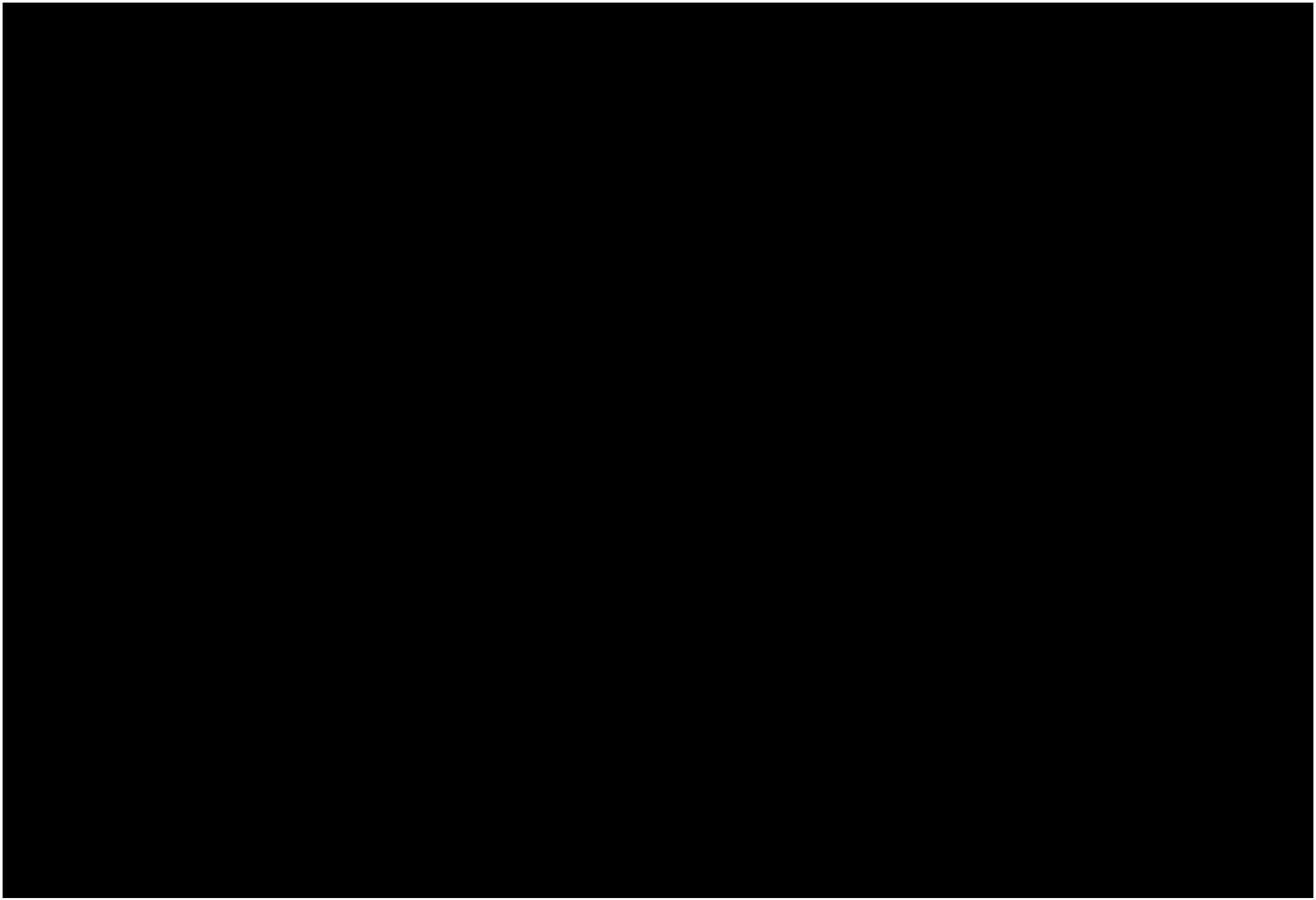
Date of Off Peak Day - 01/19/2021



Member Forecasted Off Peak Demand Day for February 2021

Sangre de Cristo Electric Association, Inc.

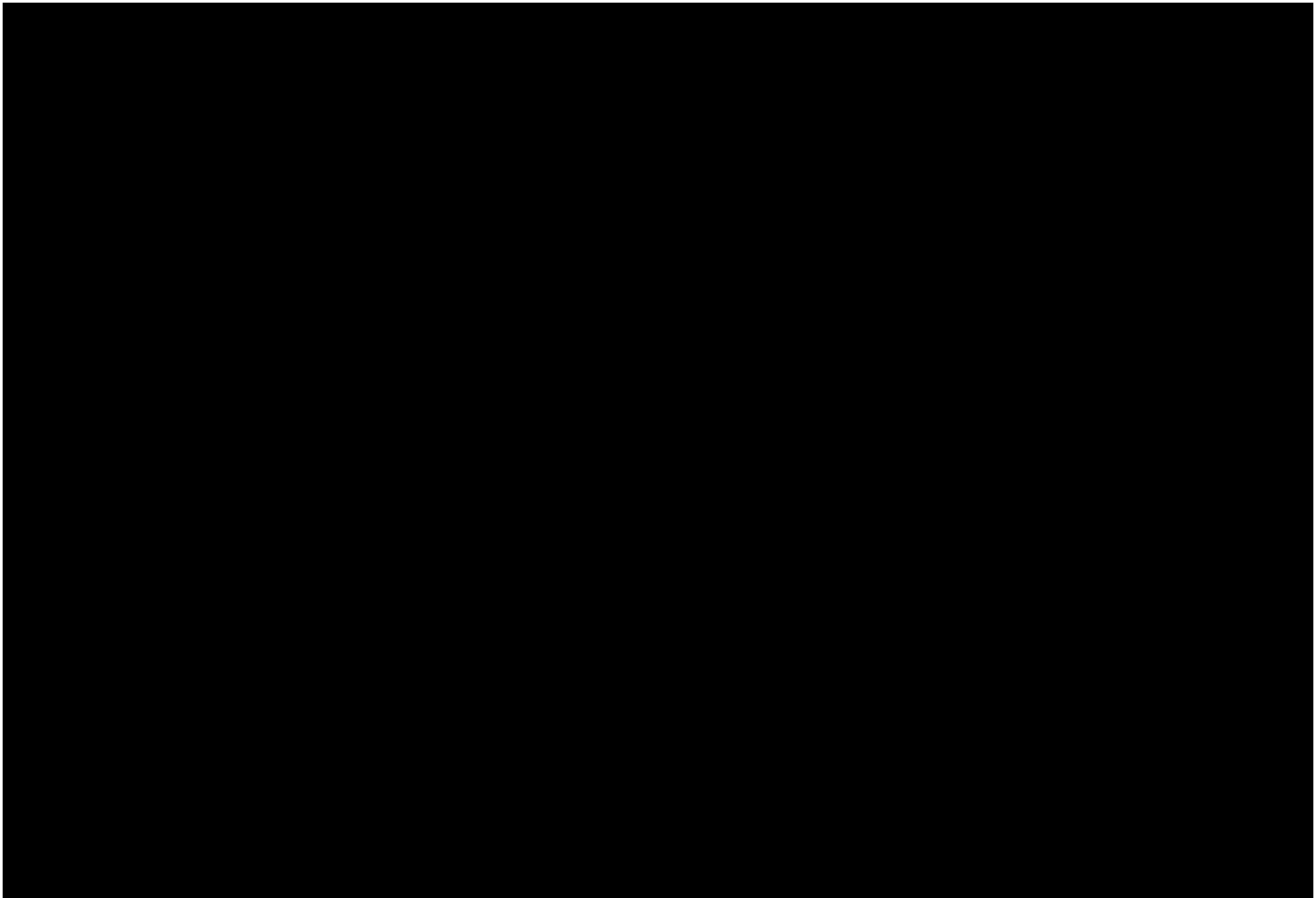
Date of Off Peak Day - 02/10/2021



Member Forecasted Off Peak Demand Day for March 2021

Sangre de Cristo Electric Association, Inc.

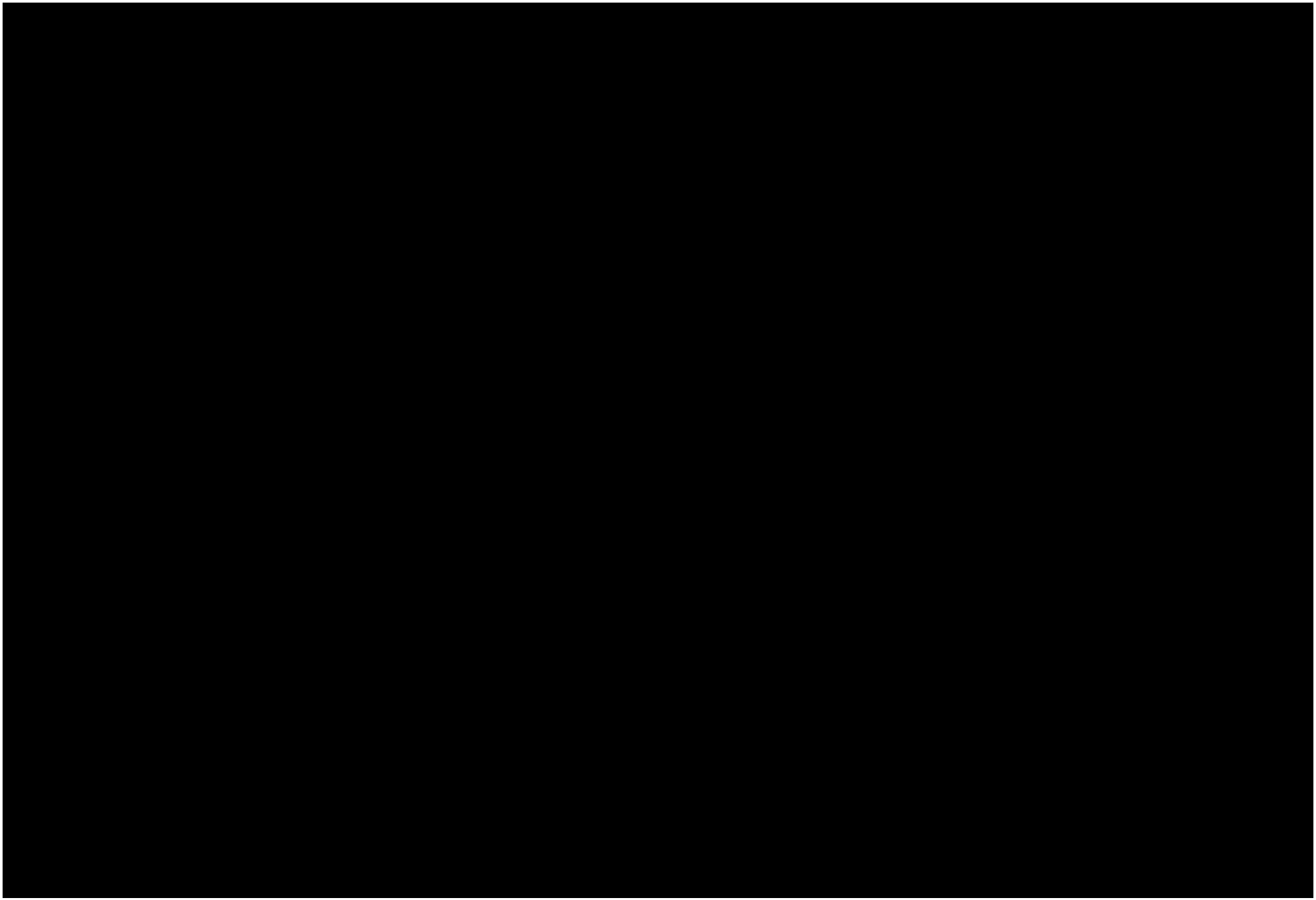
Date of Off Peak Day - 03/20/2021



Member Forecasted Off Peak Demand Day for April 2021

Sangre de Cristo Electric Association, Inc.

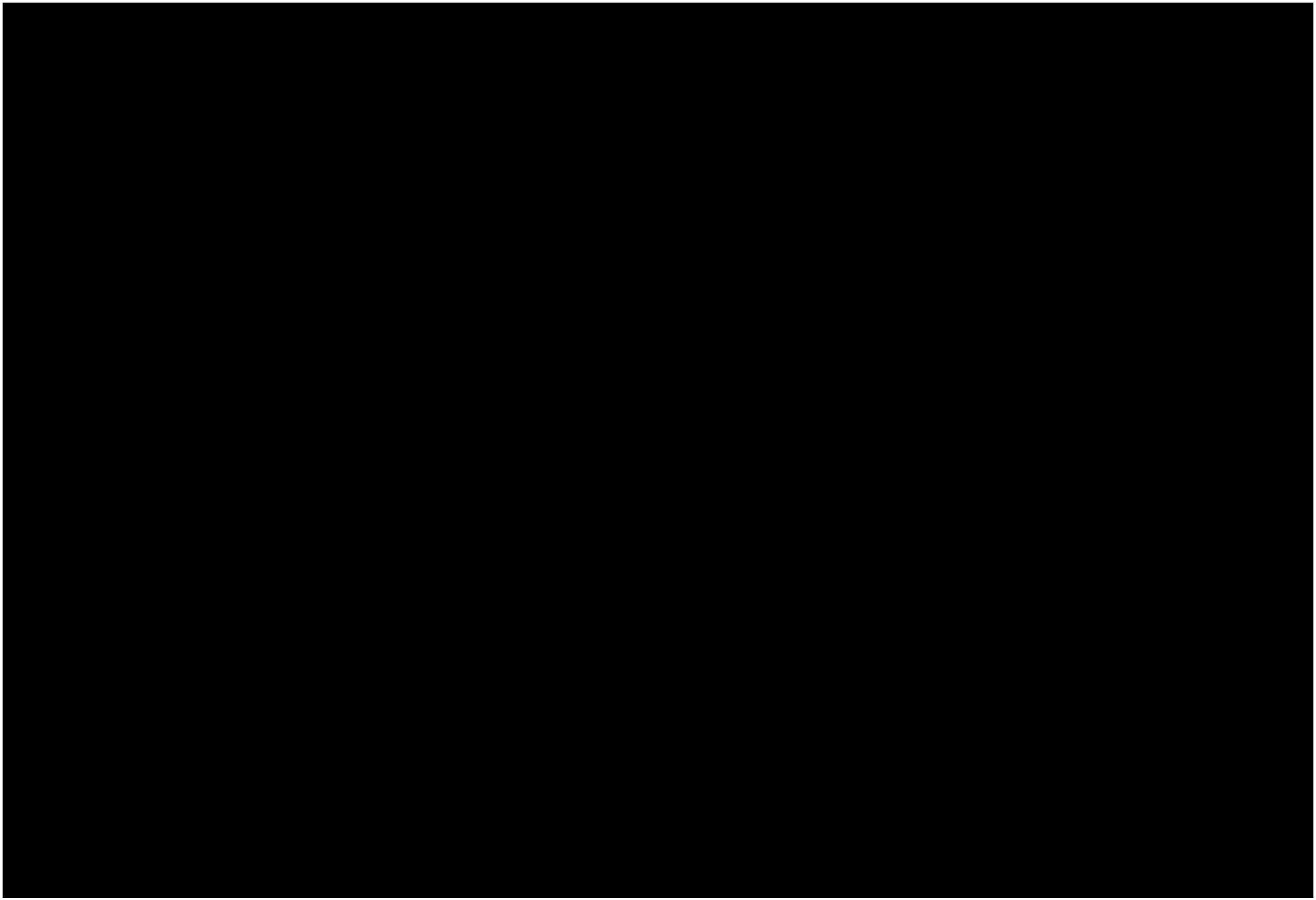
Date of Off Peak Day - 04/30/2021



Member Forecasted Off Peak Demand Day for May 2021

Sangre de Cristo Electric Association, Inc.

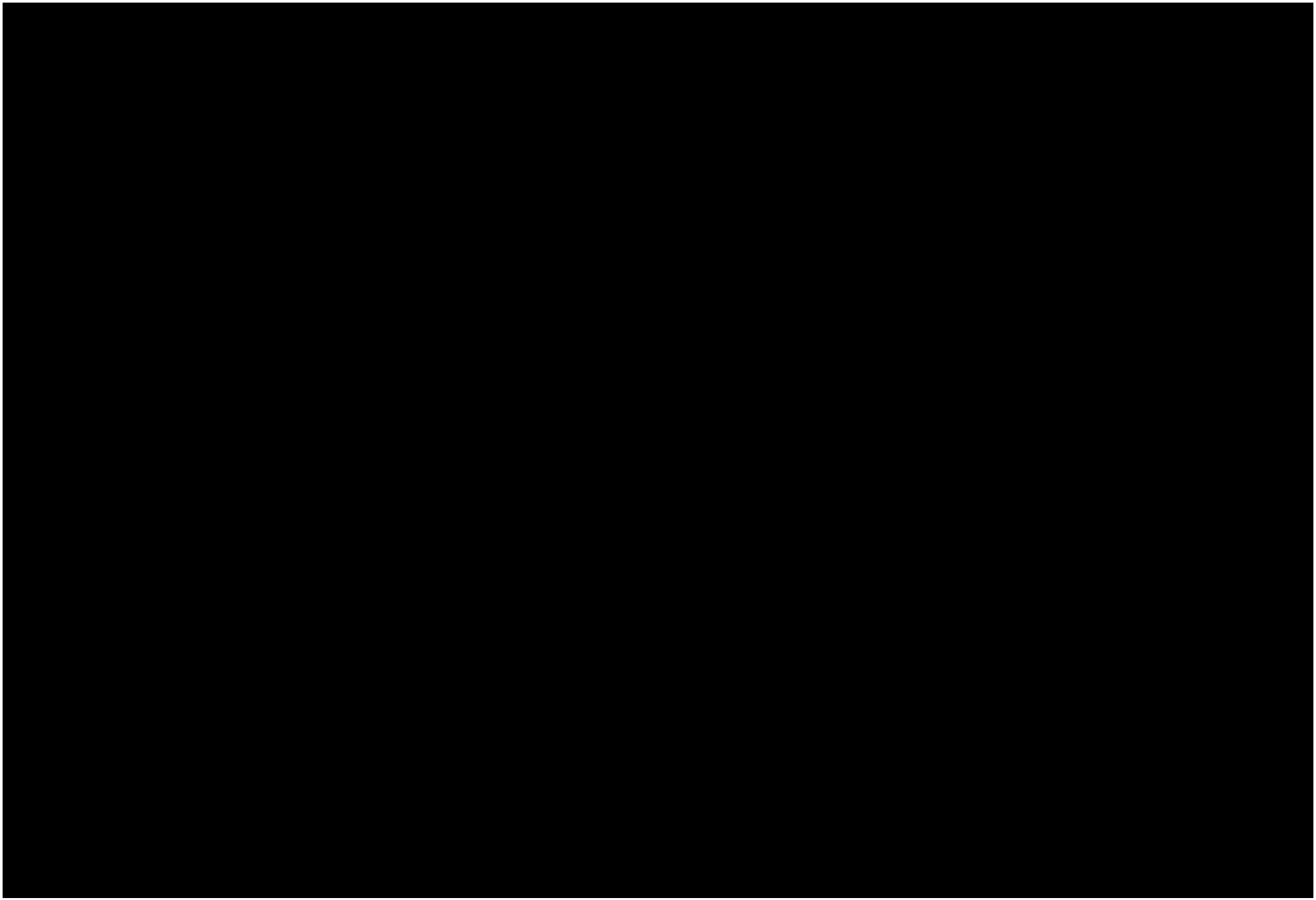
Date of Off Peak Day - 05/13/2021



Member Forecasted Off Peak Demand Day for June 2021

Sangre de Cristo Electric Association, Inc.

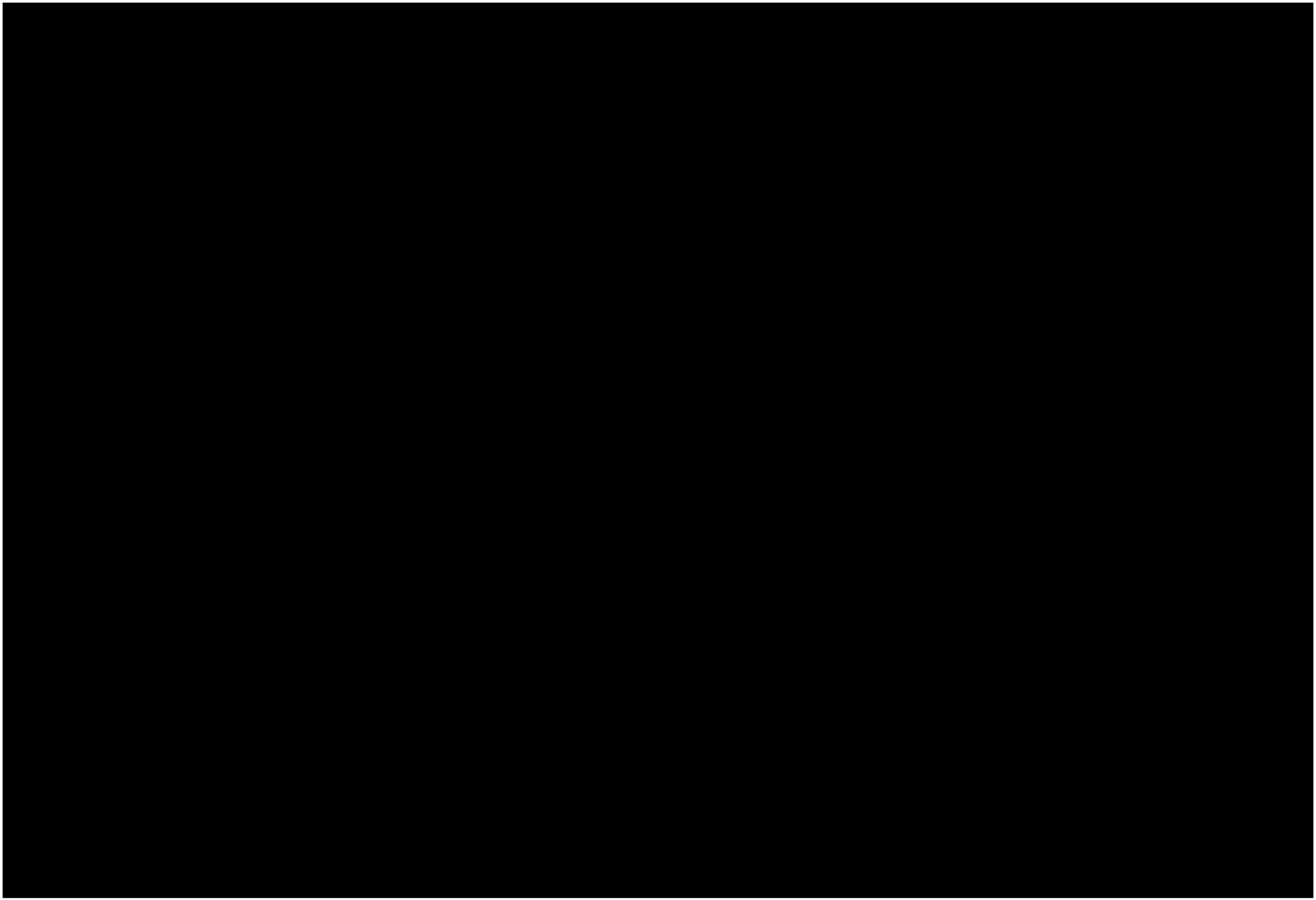
Date of Off Peak Day - 06/01/2021



Member Forecasted Off Peak Demand Day for July 2021

Sangre de Cristo Electric Association, Inc.

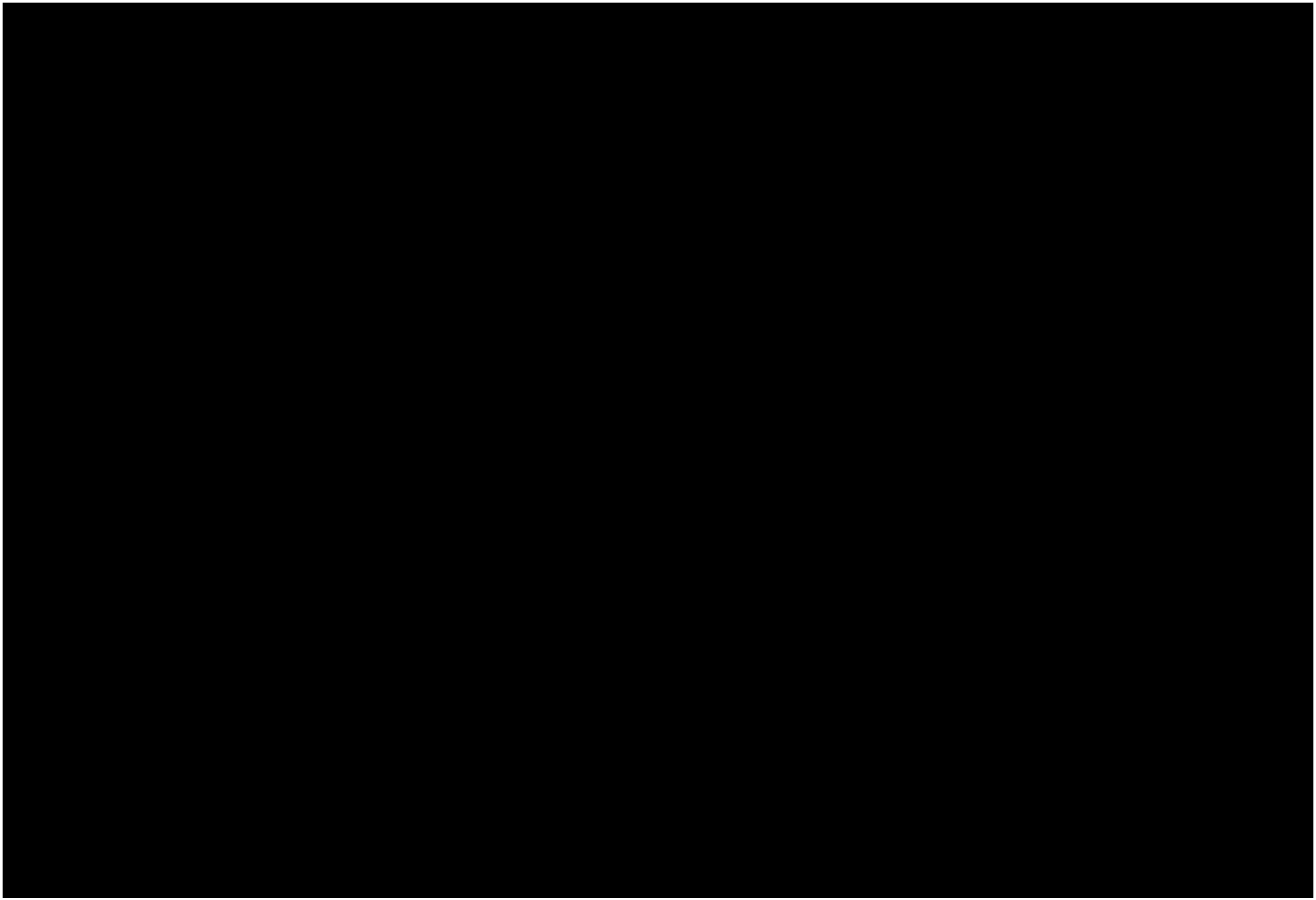
Date of Off Peak Day - 07/31/2021



Member Forecasted Off Peak Demand Day for August 2021

Sangre de Cristo Electric Association, Inc.

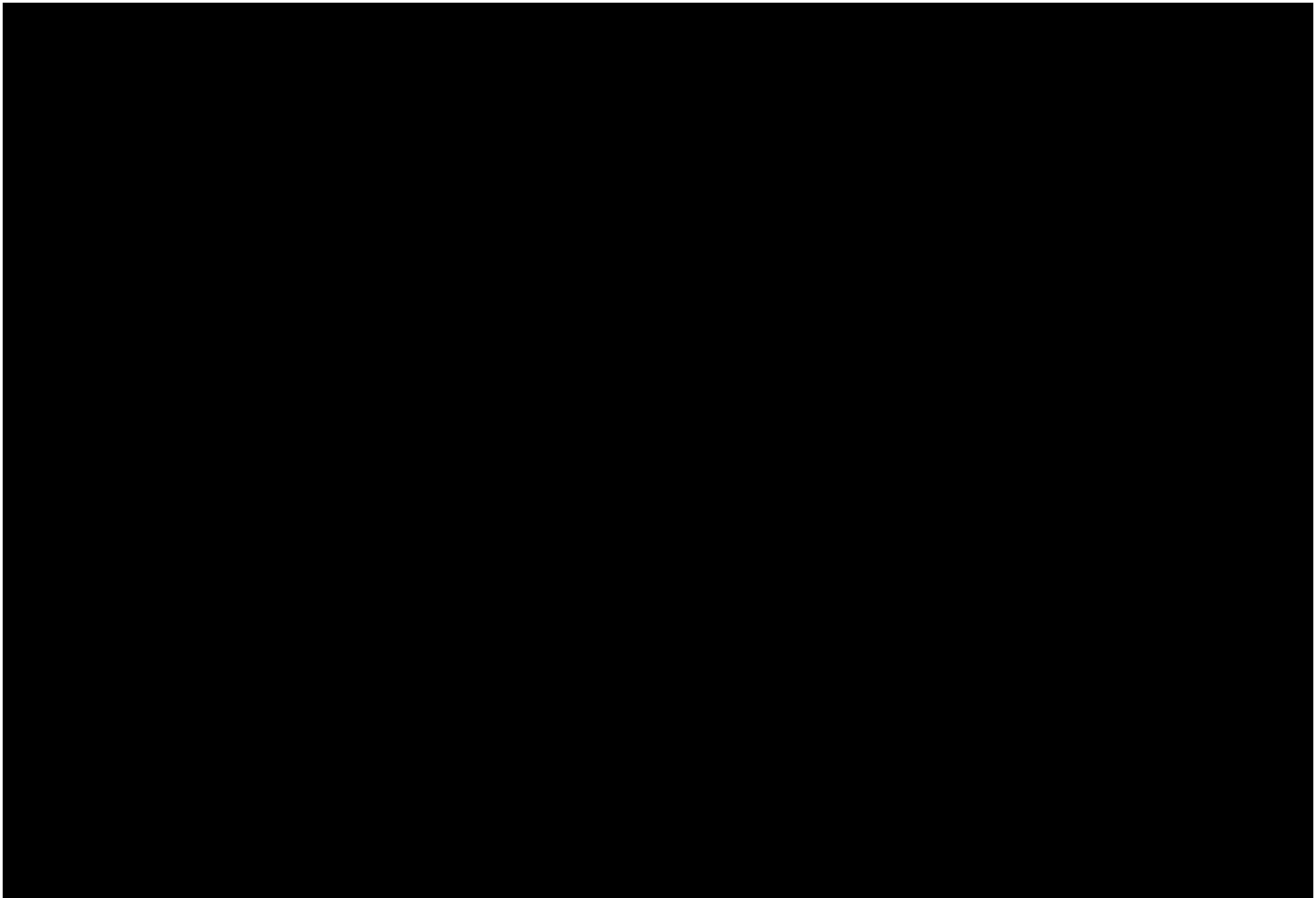
Date of Off Peak Day - 08/26/2021



Member Forecasted Off Peak Demand Day for September 2021

Sangre de Cristo Electric Association, Inc.

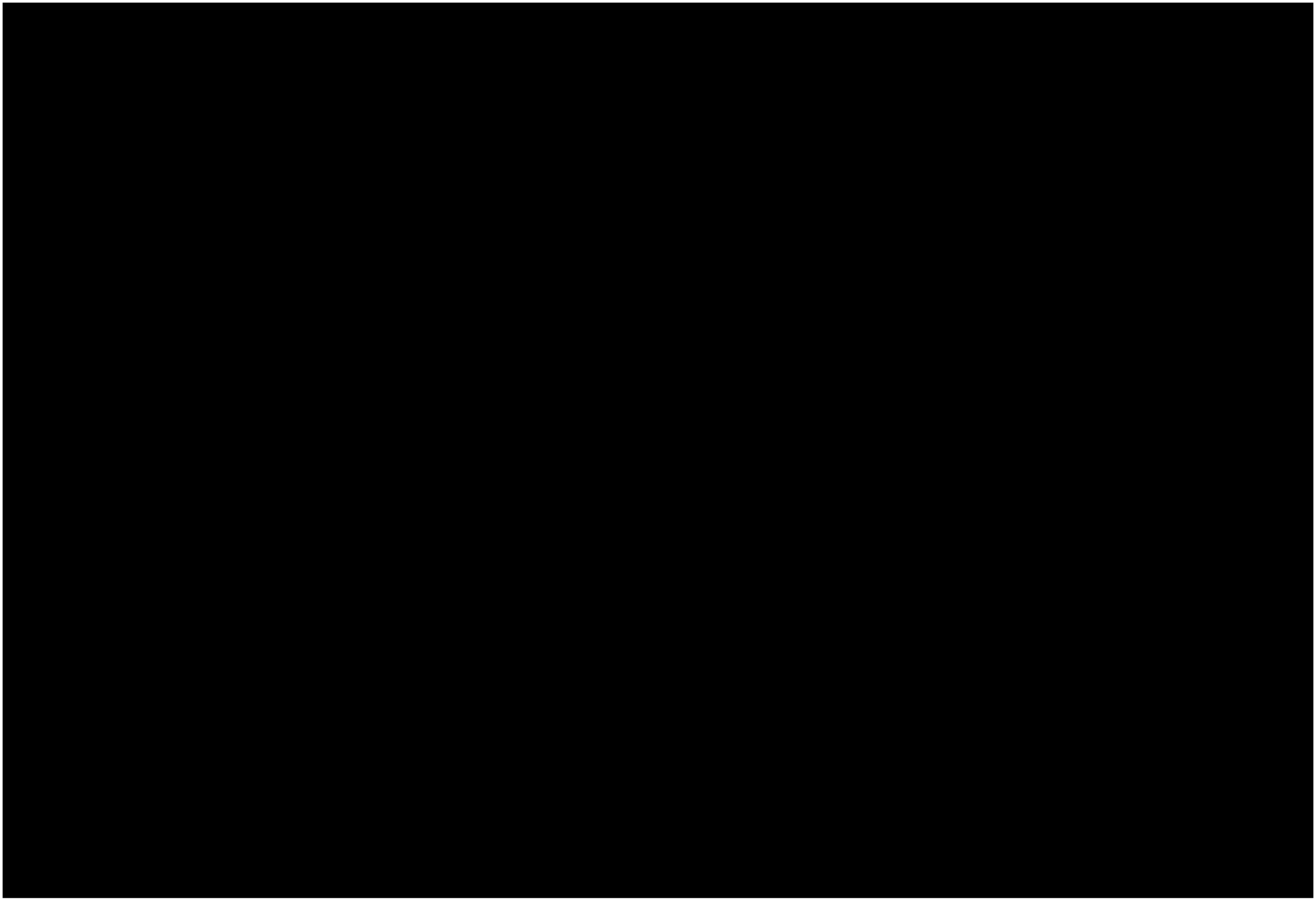
Date of Off Peak Day - 09/28/2021



Member Forecasted Off Peak Demand Day for October 2021

Sangre de Cristo Electric Association, Inc.

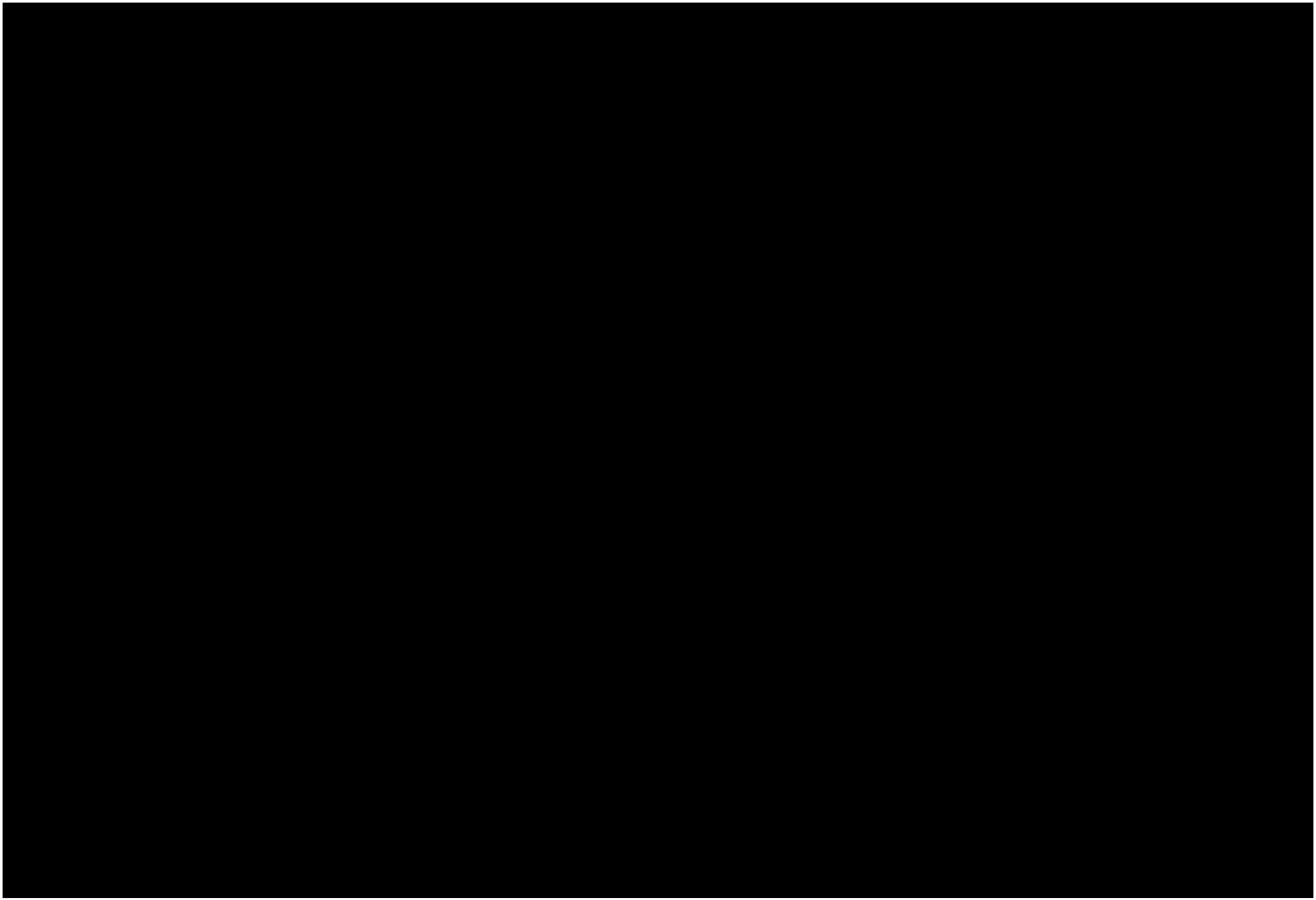
Date of Off Peak Day - 10/01/2021



Member Forecasted Off Peak Demand Day for November 2021

Sangre de Cristo Electric Association, Inc.

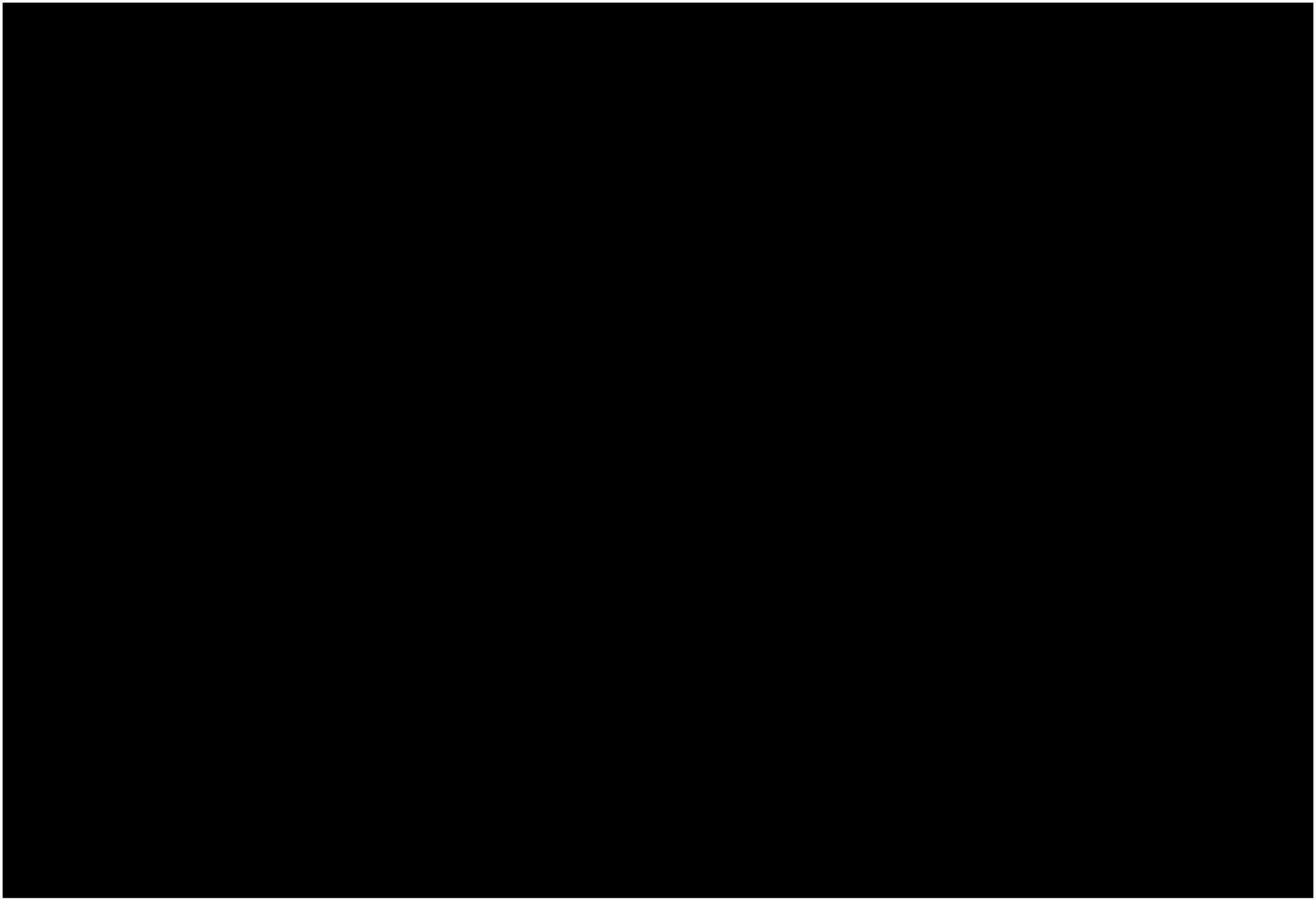
Date of Off Peak Day - 11/18/2021



Member Forecasted Off Peak Demand Day for December 2021

Sangre de Cristo Electric Association, Inc.

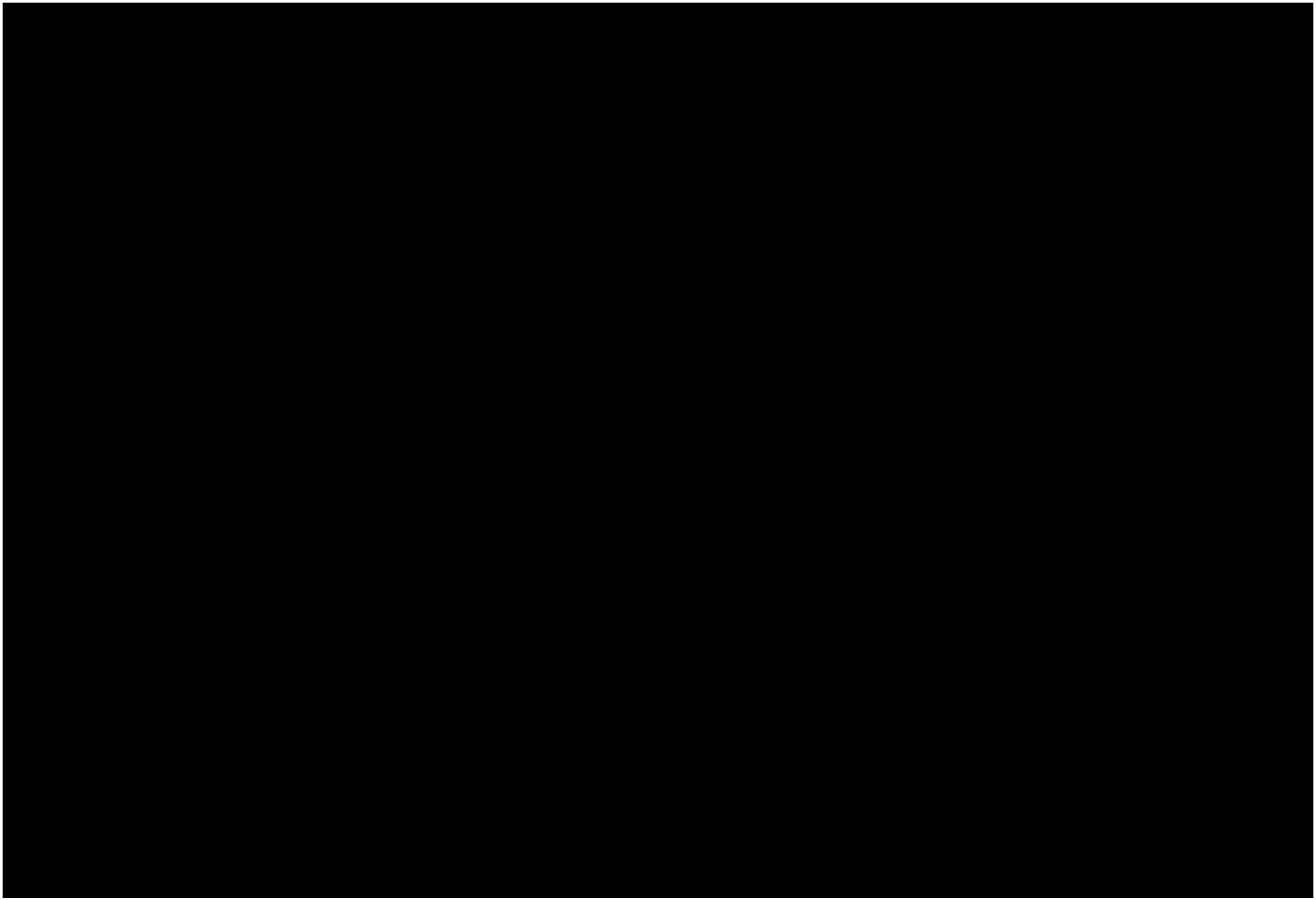
Date of Off Peak Day - 12/10/2021



Member Forecasted Off Peak Demand Day for January 2021

Southeast Colorado Power Association

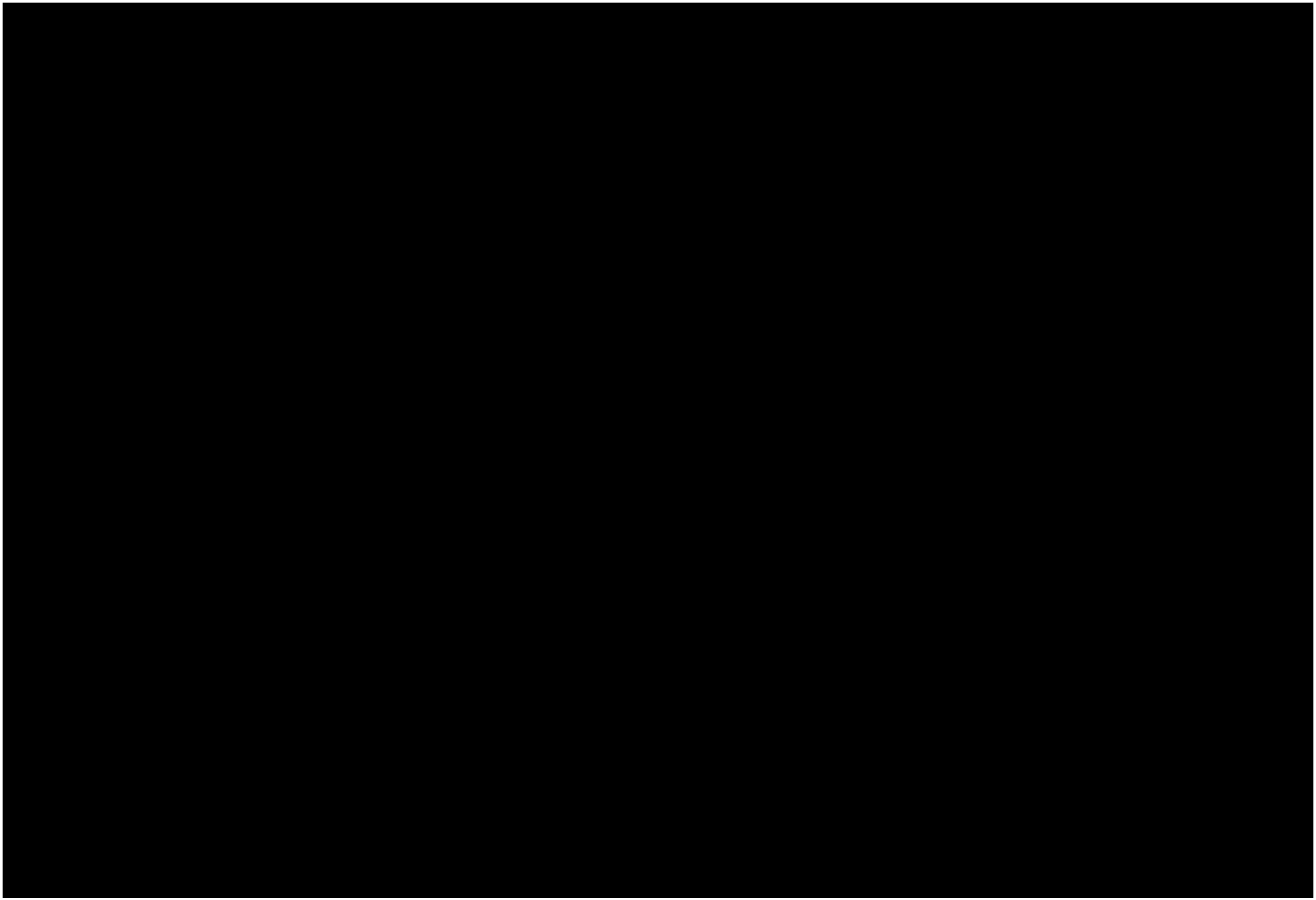
Date of Off Peak Day - 01/19/2021



Member Forecasted Off Peak Demand Day for February 2021

Southeast Colorado Power Association

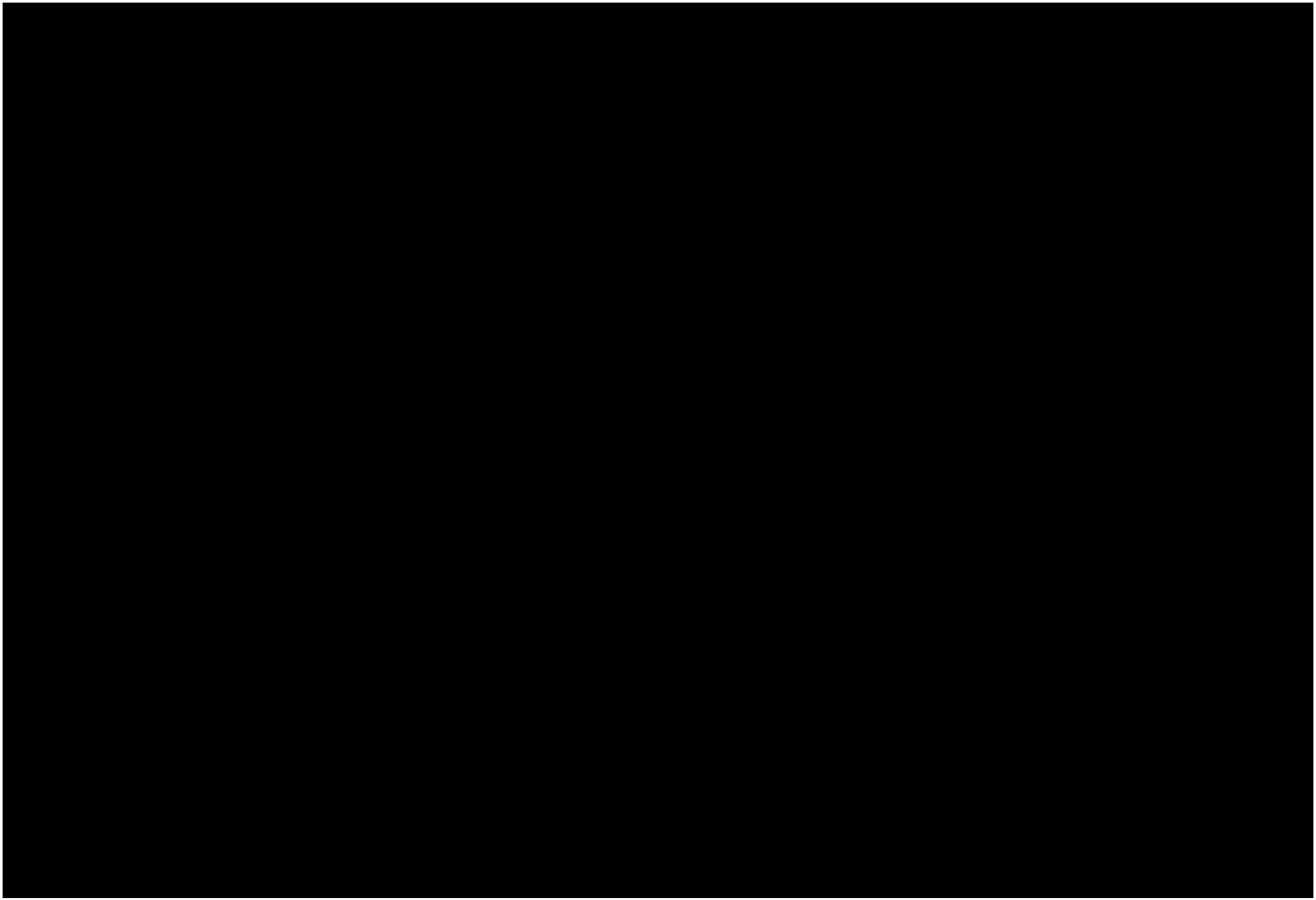
Date of Off Peak Day - 02/27/2021



Member Forecasted Off Peak Demand Day for March 2021

Southeast Colorado Power Association

Date of Off Peak Day - 03/05/2021



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Member Forecasted Off Peak Demand Day for April 2021

Southeast Colorado Power Association

Date of Off Peak Day - 04/03/2021

[redacted]

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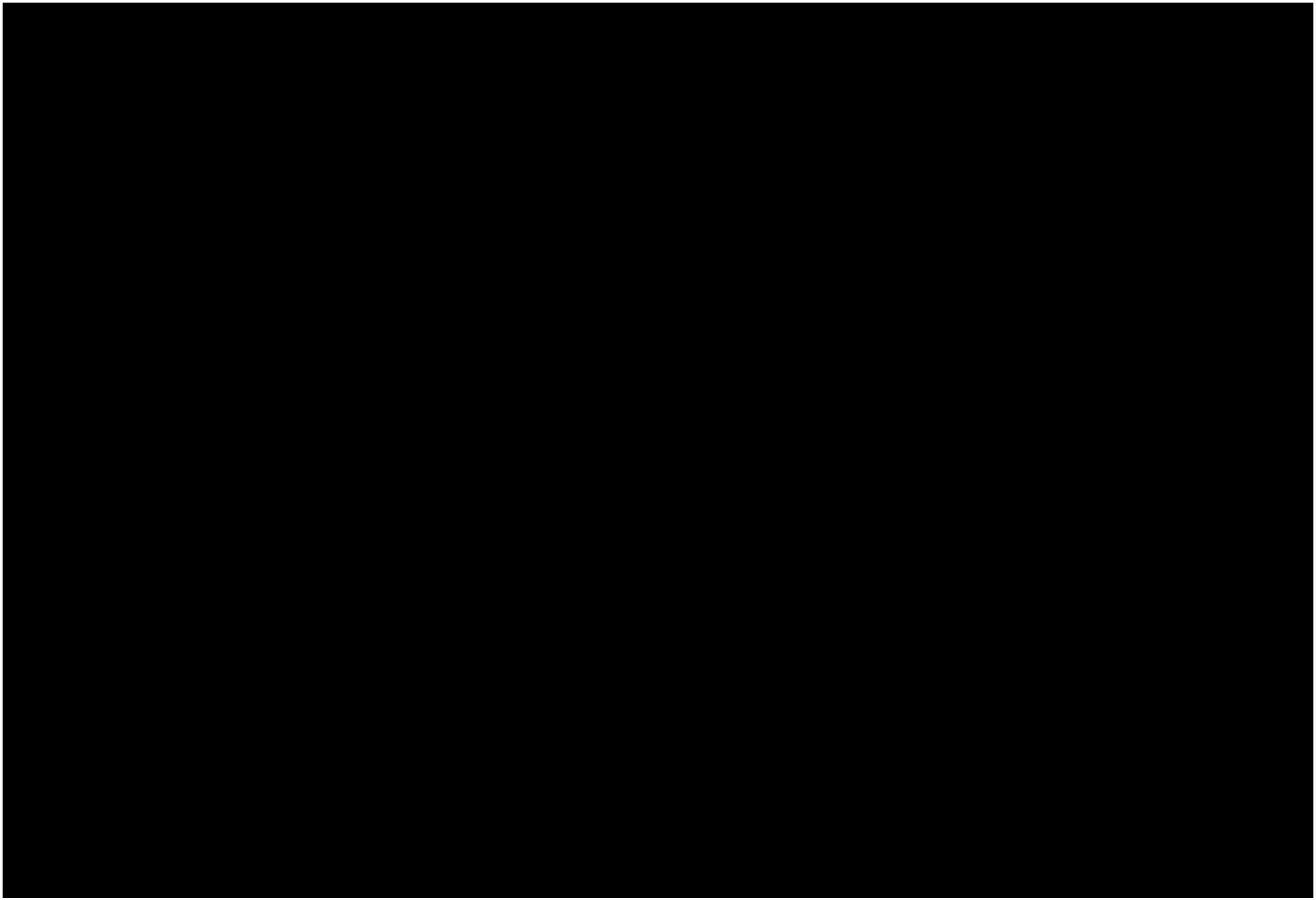
Member Forecasted Off Peak Demand Day for May 2021

Southeast Colorado Power Association

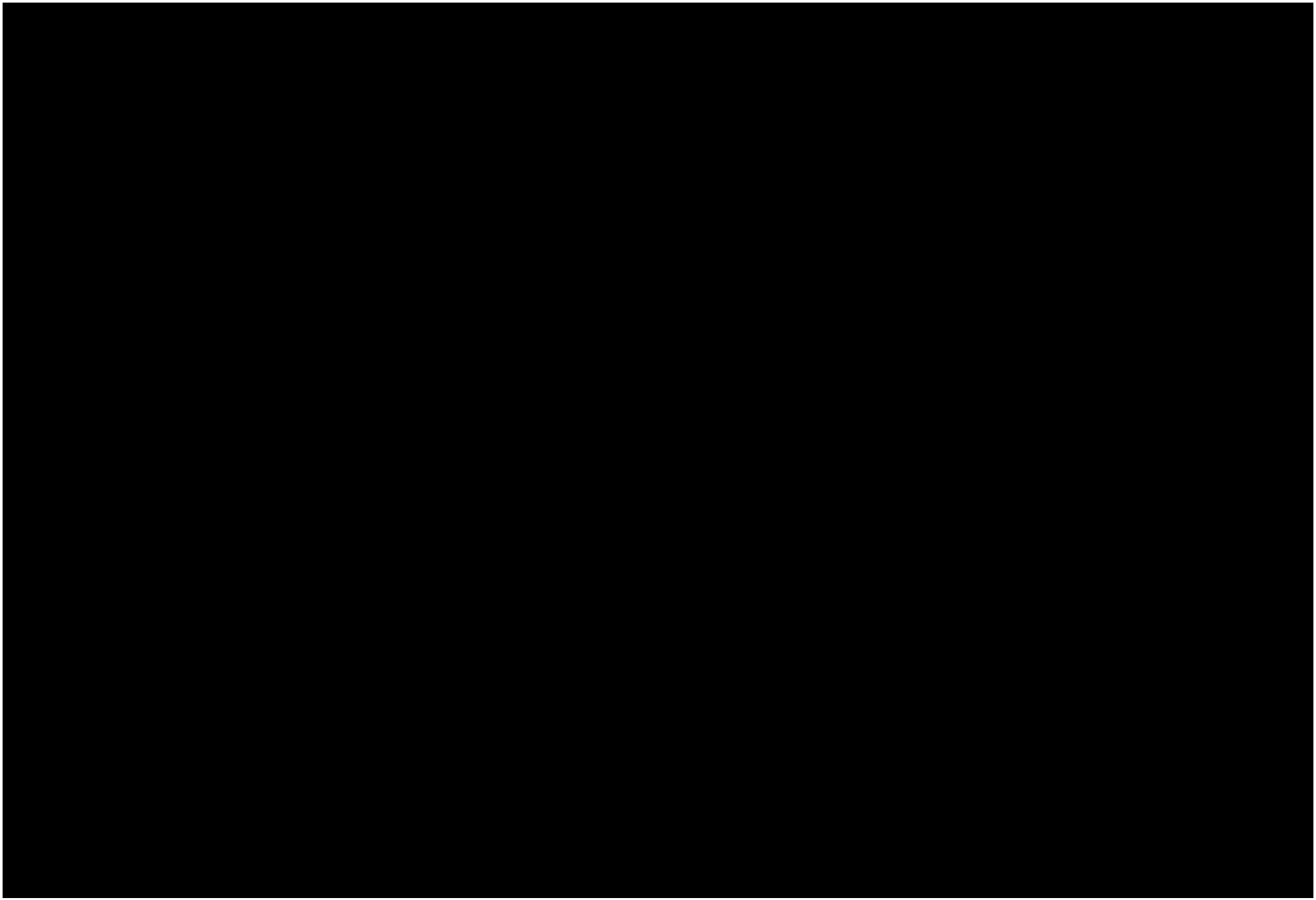
Date of Off Peak Day - 05/02/2021



Member Forecasted Off Peak Demand Day for June 2021

Southeast Colorado Power Association

Date of Off Peak Day - 06/25/2021



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Member Forecasted Off Peak Demand Day for July 2021

Southeast Colorado Power Association

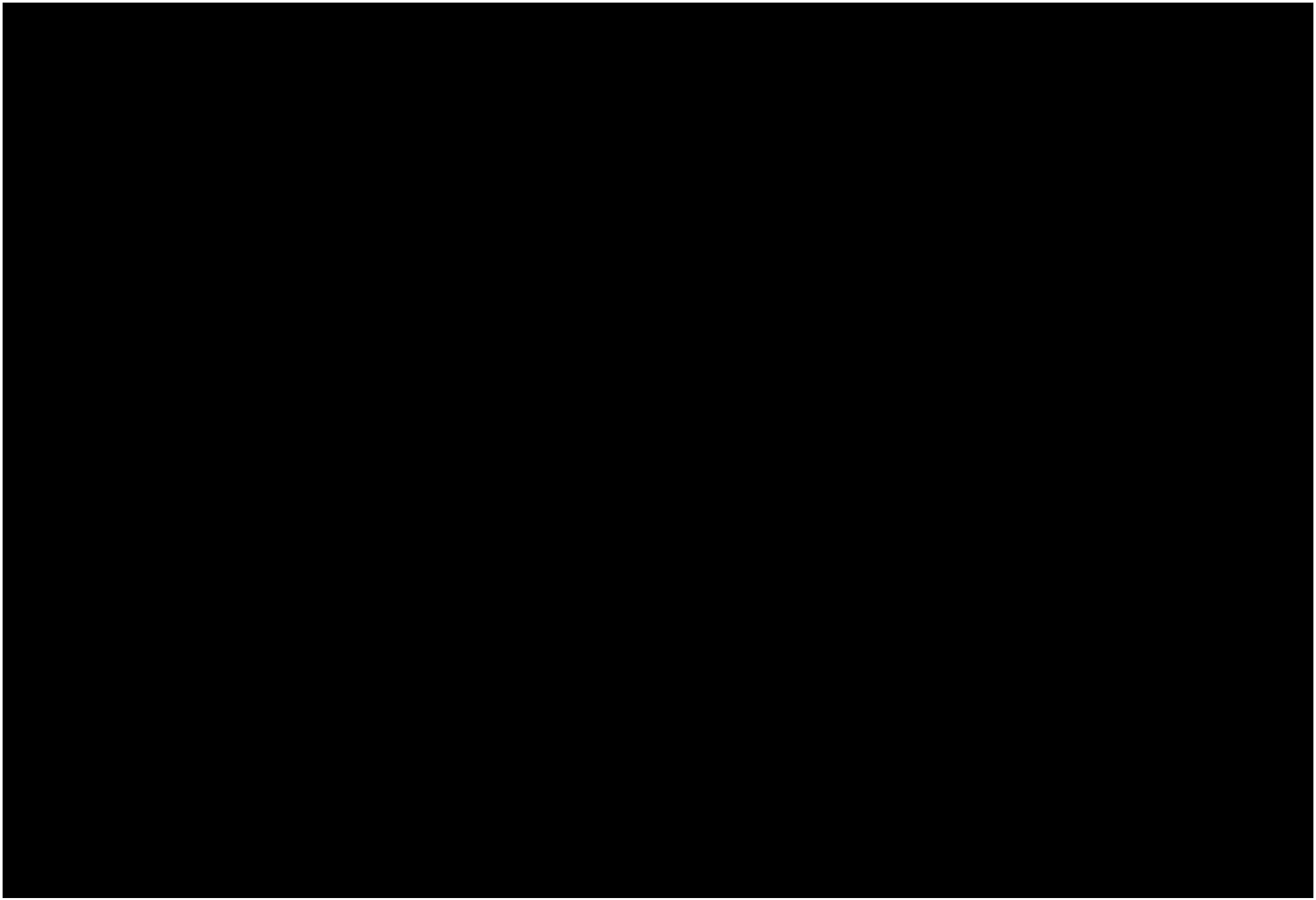
Date of Off Peak Day - 07/04/2021

[redacted]

Member Forecasted Off Peak Demand Day for August 2021

Southeast Colorado Power Association

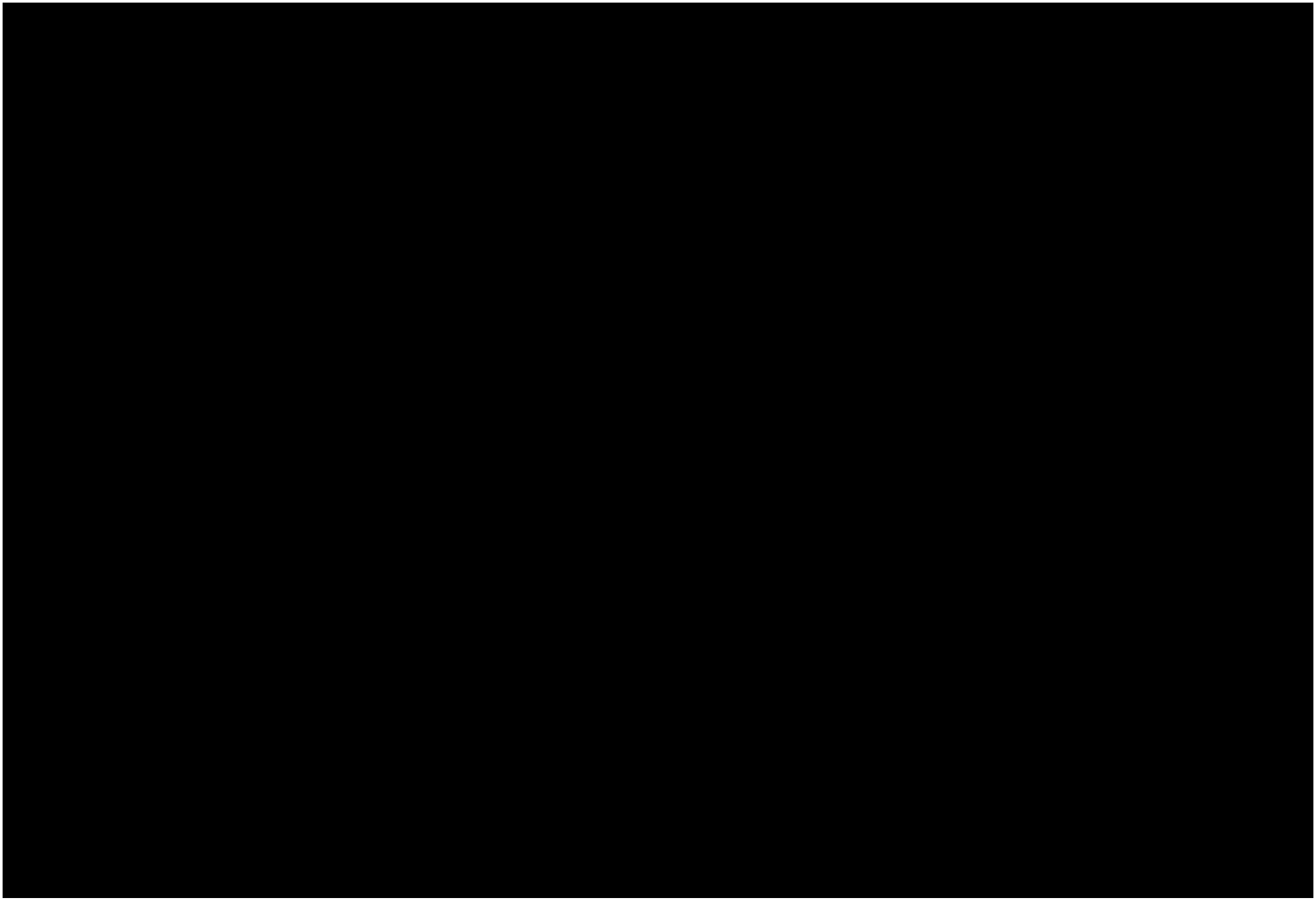
Date of Off Peak Day - 08/13/2021



Member Forecasted Off Peak Demand Day for September 2021

Southeast Colorado Power Association

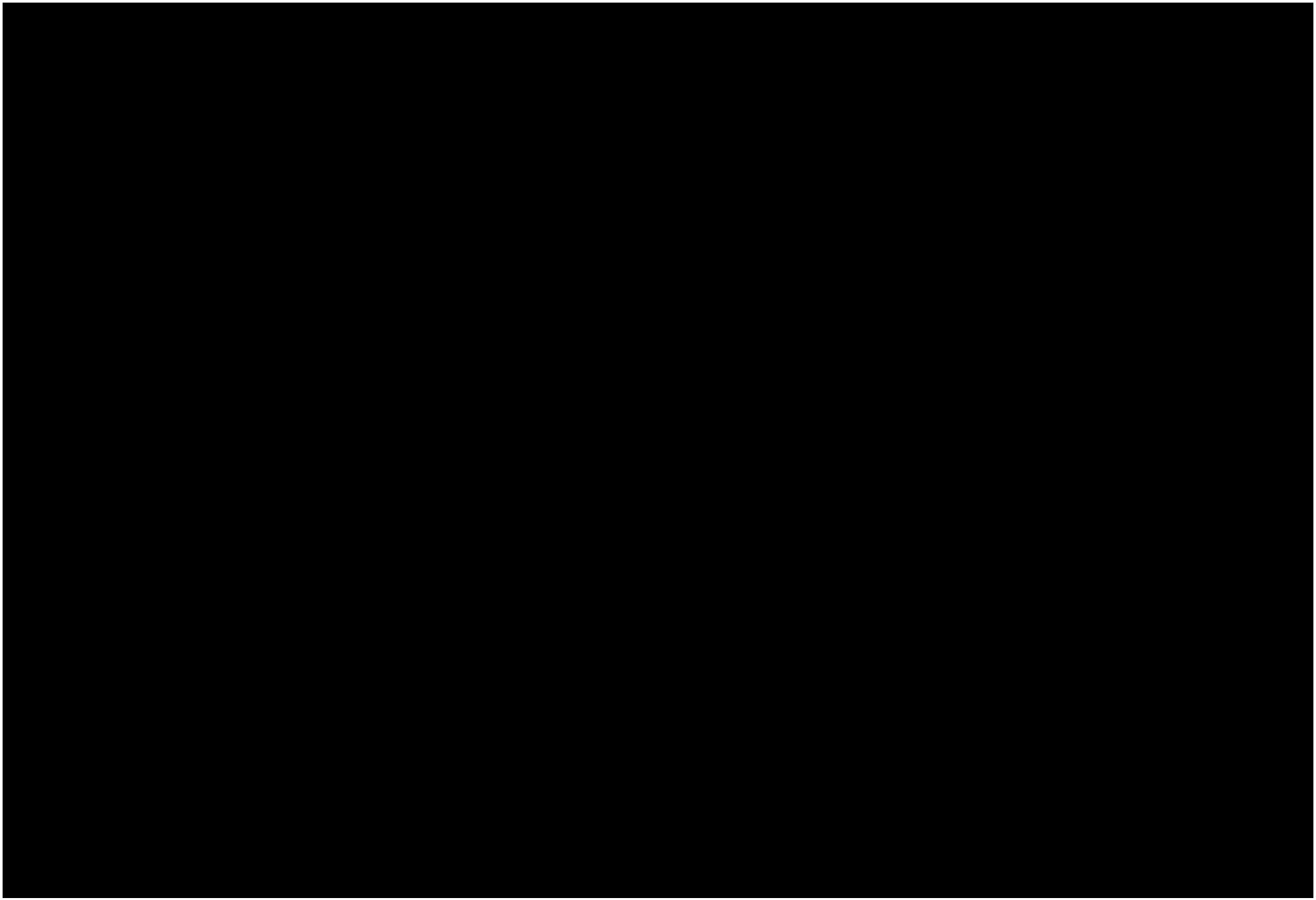
Date of Off Peak Day - 09/30/2021



Member Forecasted Off Peak Demand Day for October 2021

Southeast Colorado Power Association

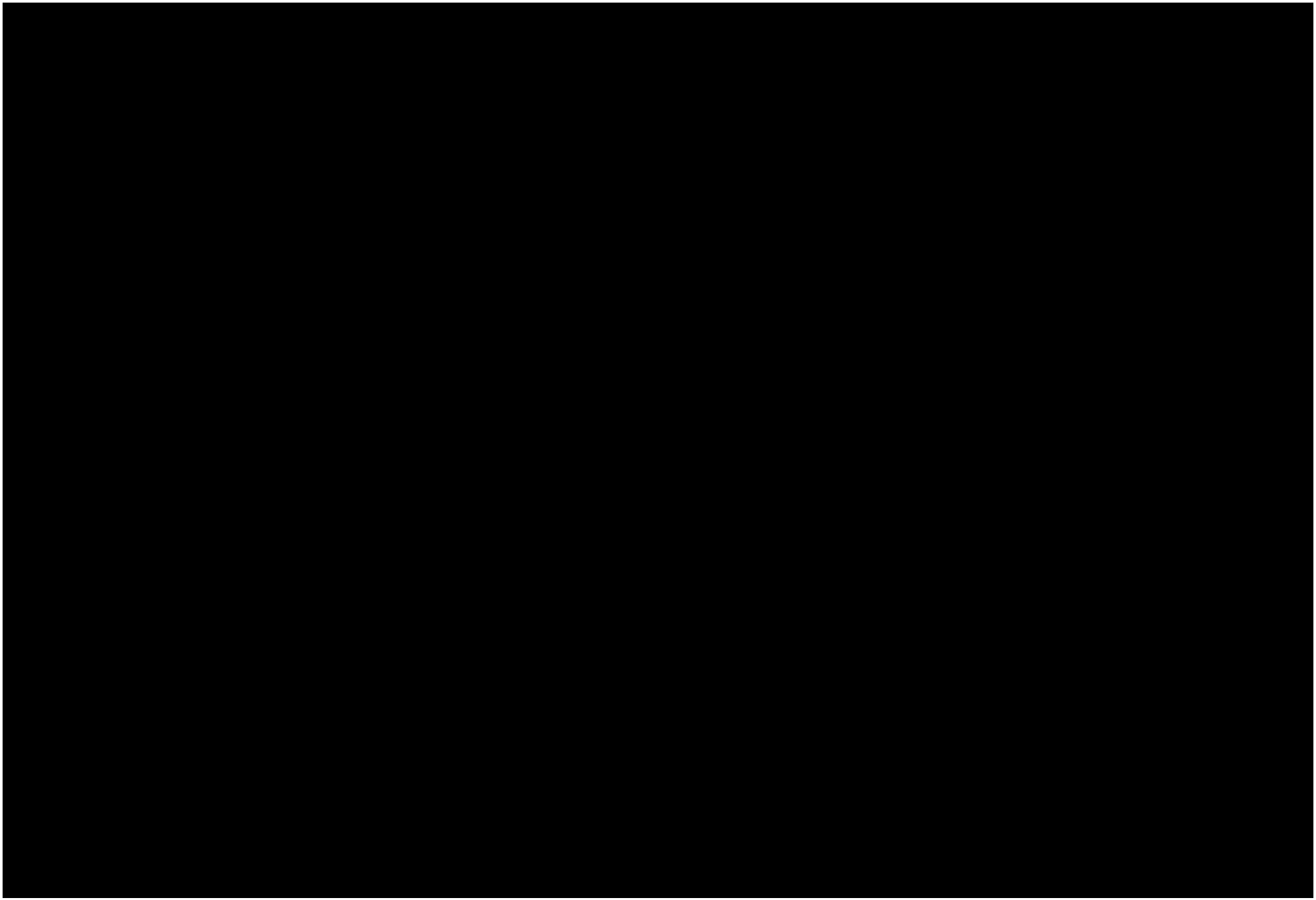
Date of Off Peak Day - 10/31/2021



Member Forecasted Off Peak Demand Day for November 2021

Southeast Colorado Power Association

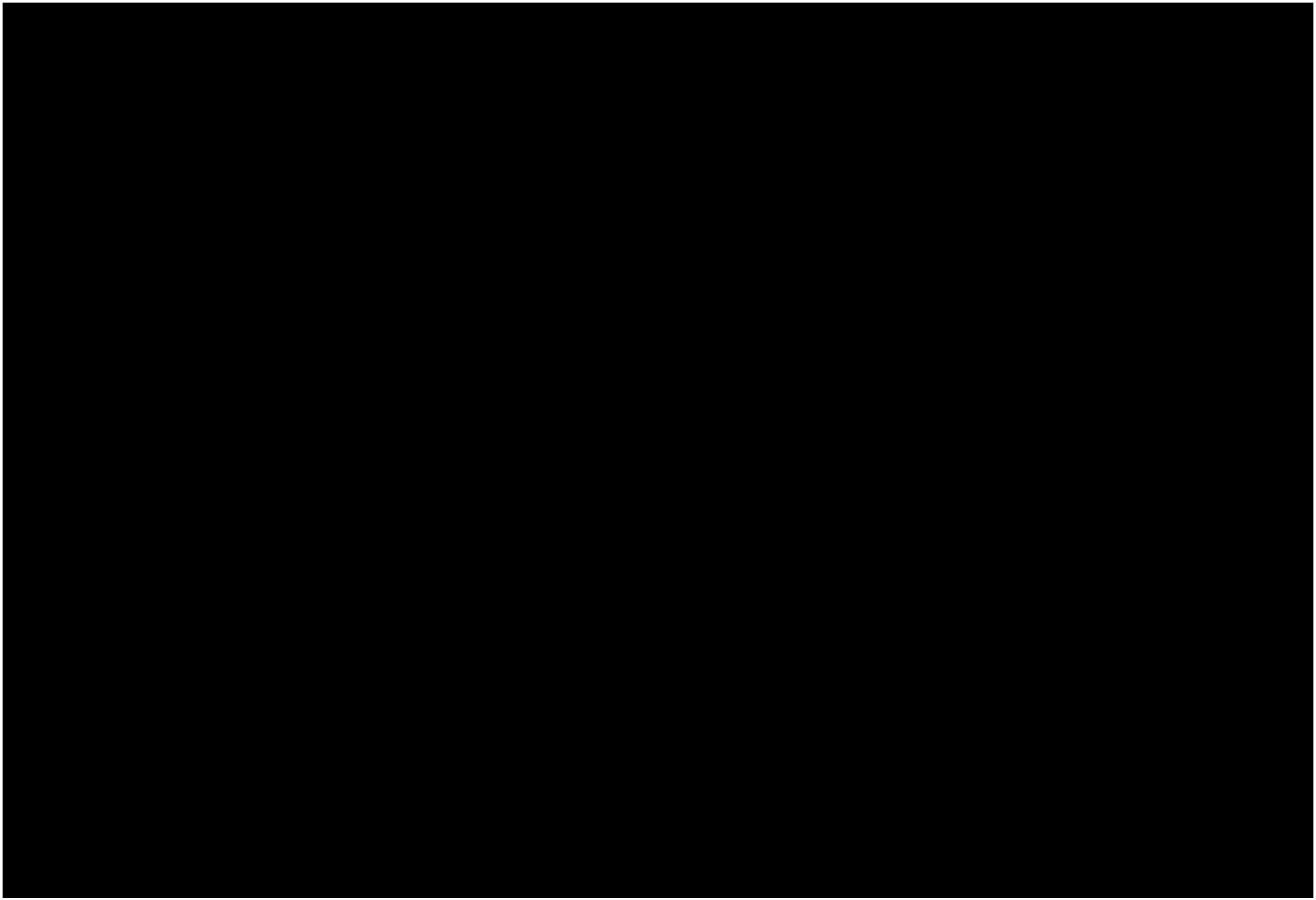
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

Southeast Colorado Power Association

Date of Off Peak Day - 12/11/2021



Member Forecasted Off Peak Demand Day for January 2021

San Isabel Electric Association, Inc.

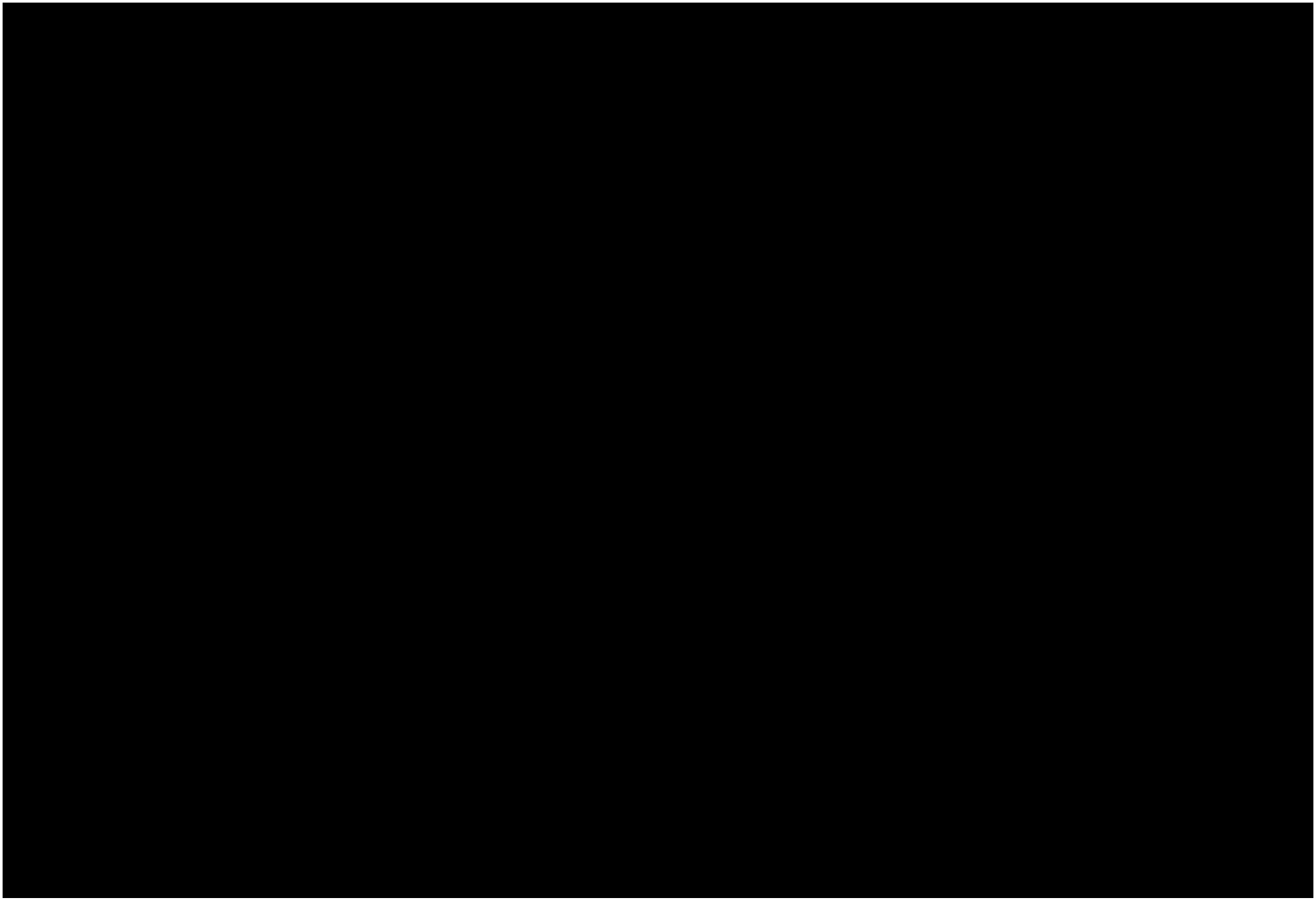
Date of Off Peak Day - 01/12/2021

[redacted]

Member Forecasted Off Peak Demand Day for February 2021

San Isabel Electric Association, Inc.

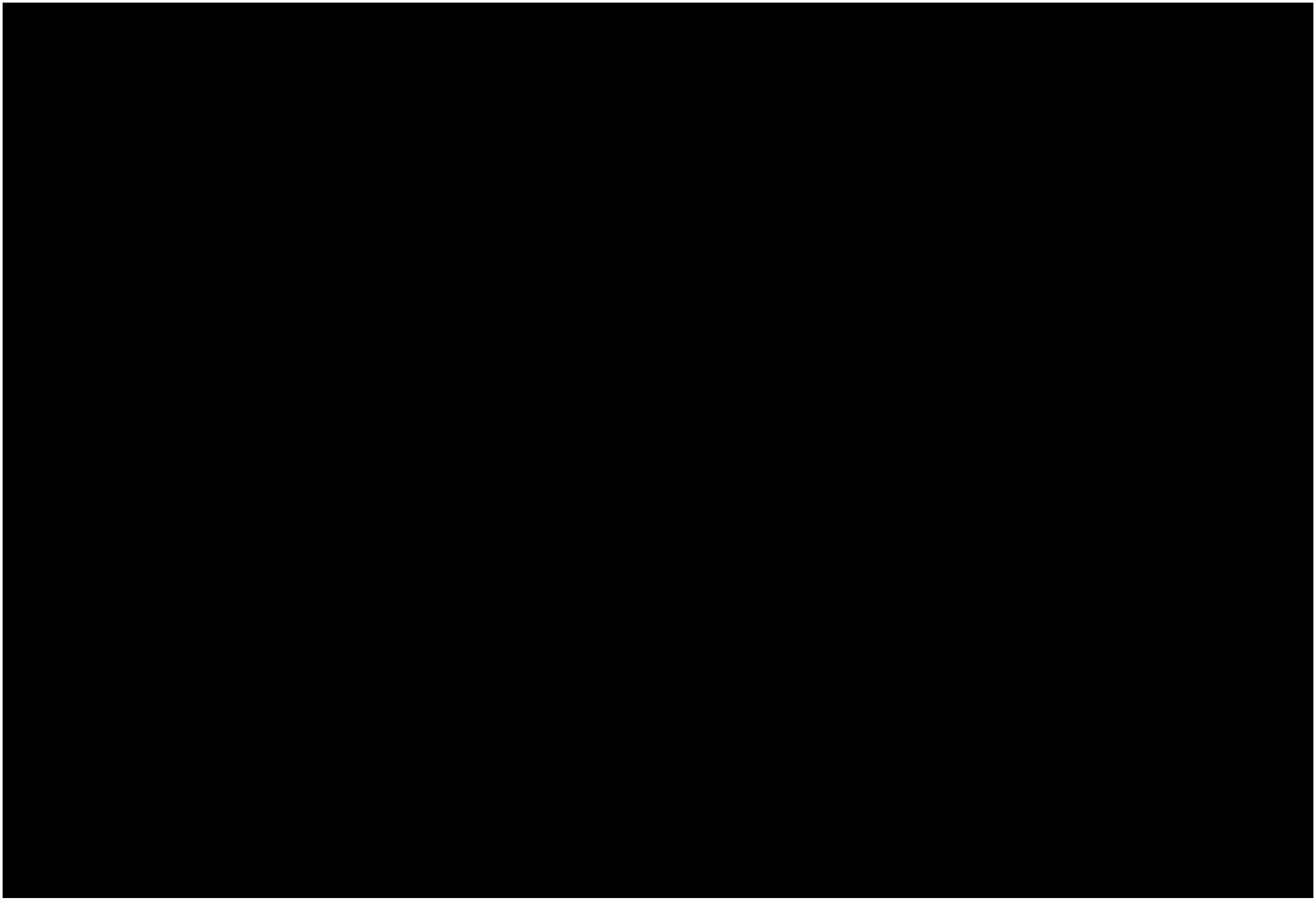
Date of Off Peak Day - 02/11/2021



Member Forecasted Off Peak Demand Day for March 2021

San Isabel Electric Association, Inc.

Date of Off Peak Day - 03/24/2021



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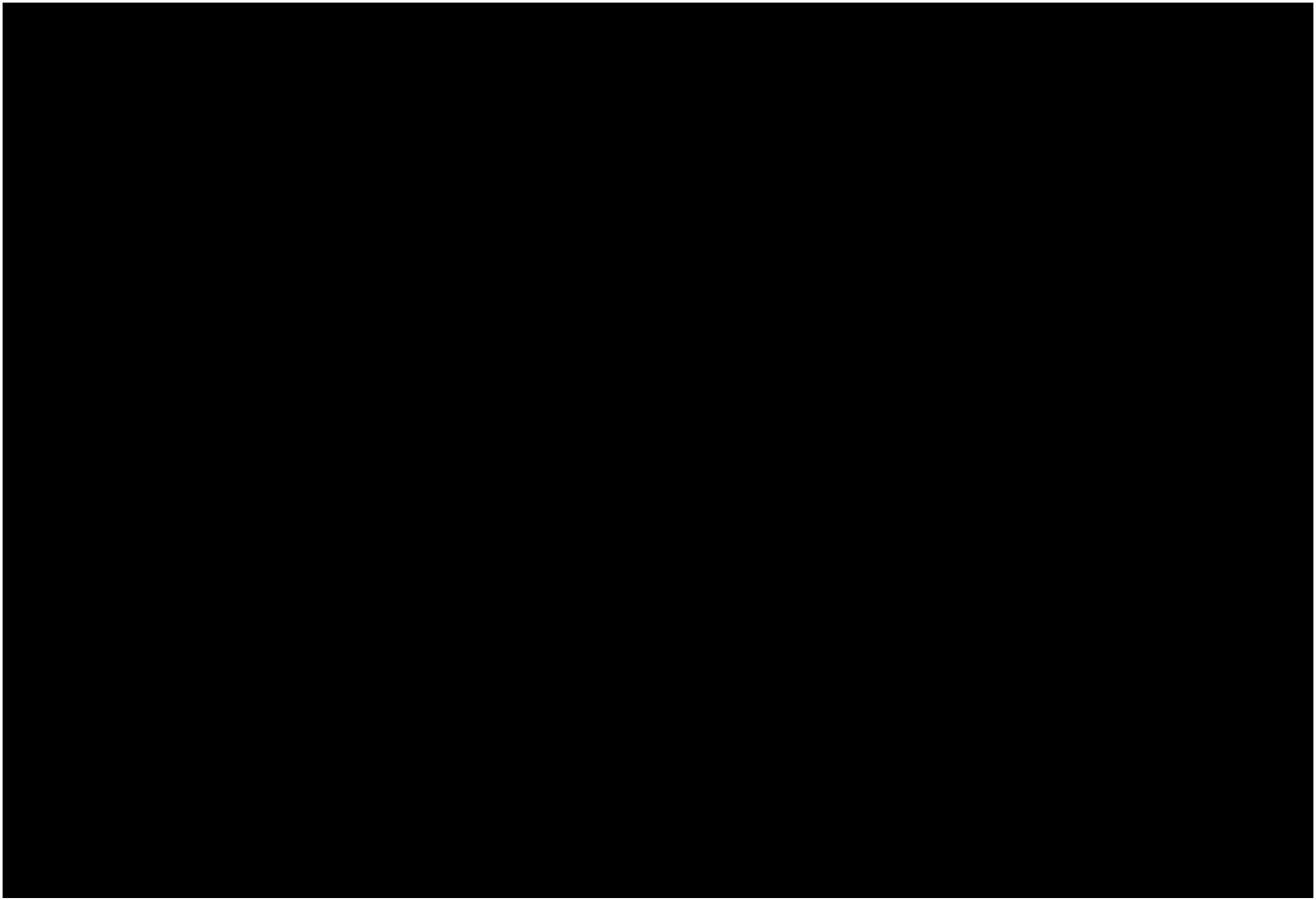
Member Forecasted Off Peak Demand Day for April 2021

San Isabel Electric Association, Inc.

Date of Off Peak Day - 04/01/2021



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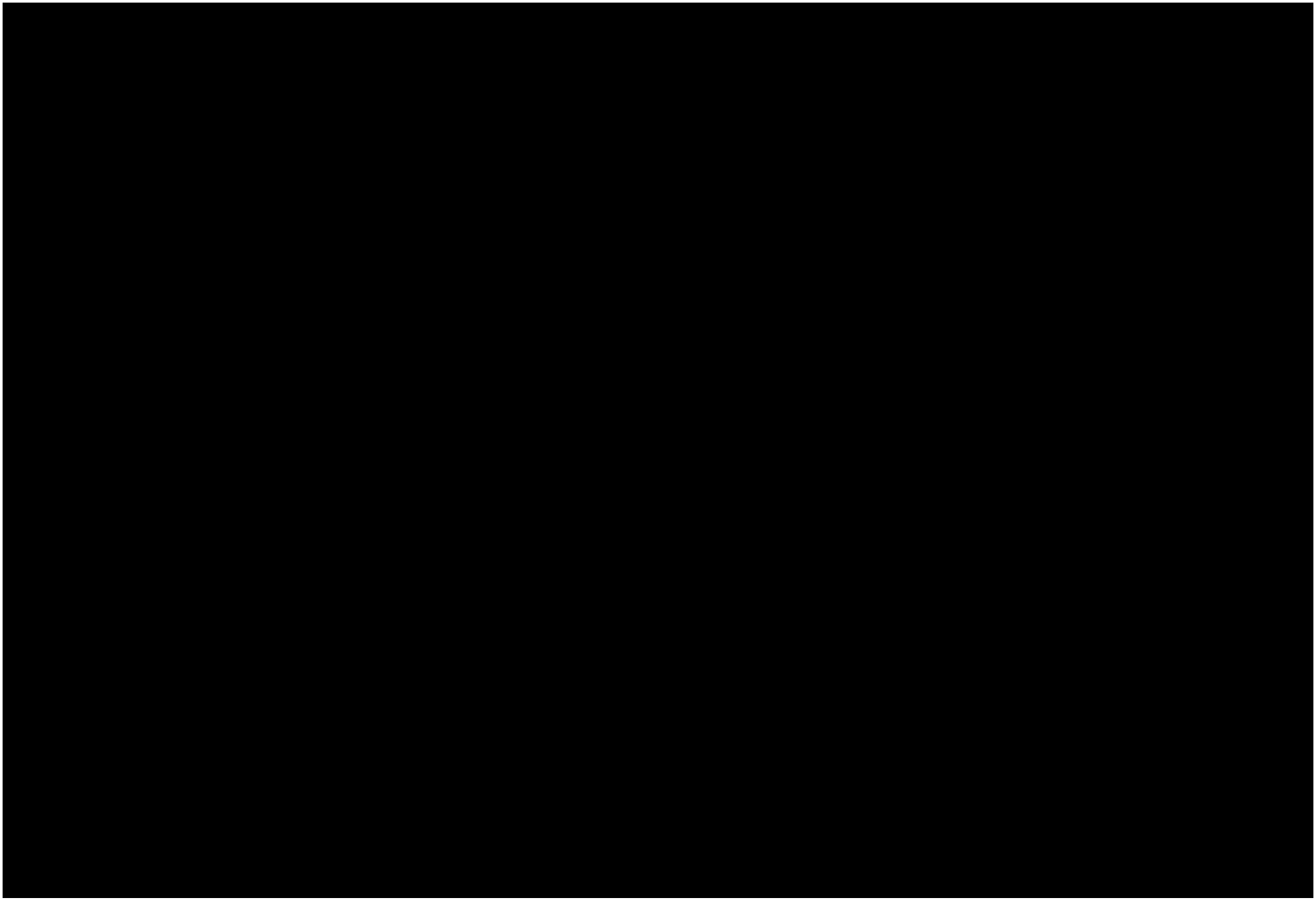
Member Forecasted Off Peak Demand Day for May 2021

San Isabel Electric Association, Inc.

Date of Off Peak Day - 05/30/2021



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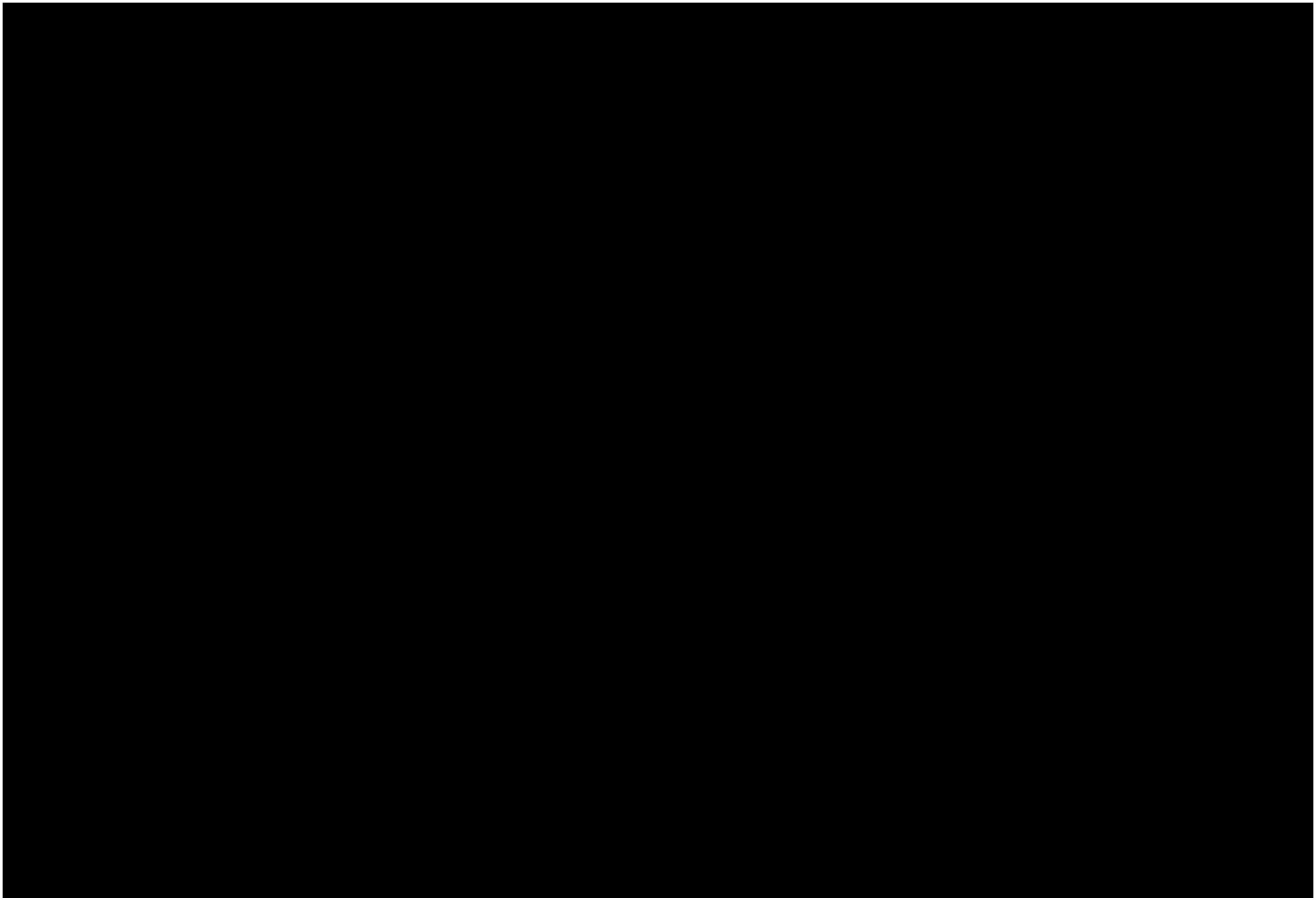
Member Forecasted Off Peak Demand Day for June 2021

San Isabel Electric Association, Inc.

Date of Off Peak Day - 06/30/2021



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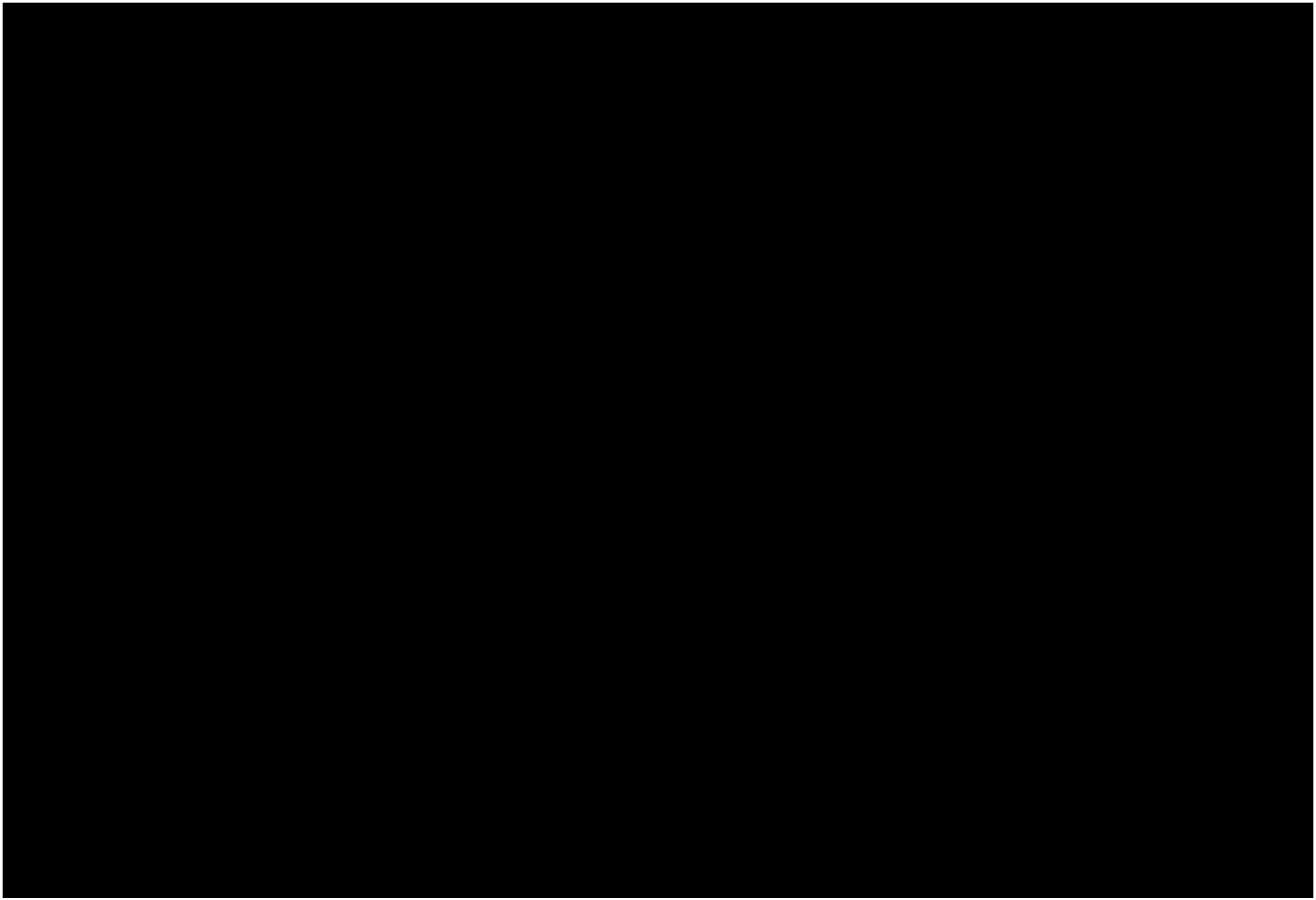
Member Forecasted Off Peak Demand Day for July 2021

San Isabel Electric Association, Inc.

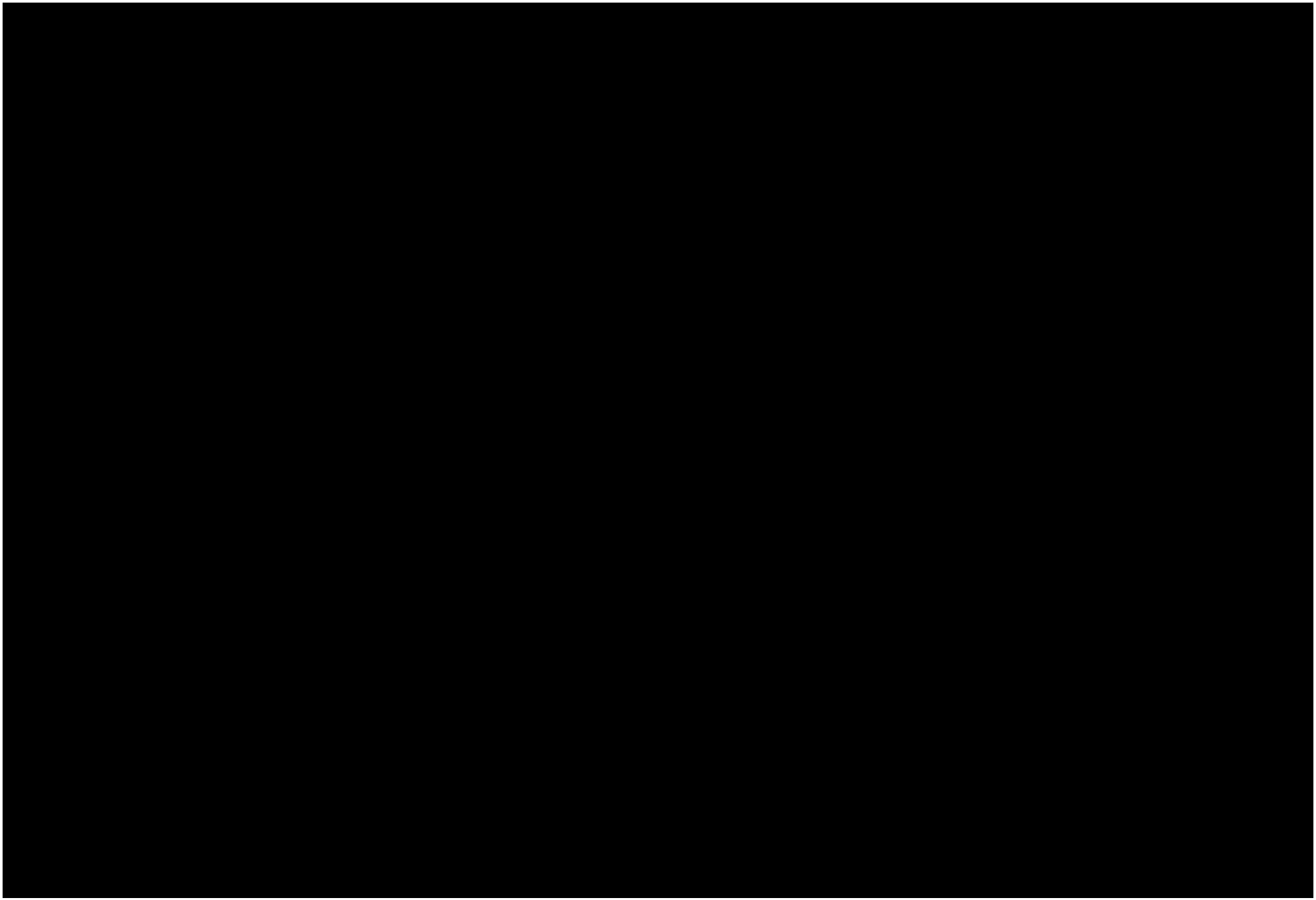
Date of Off Peak Day - 07/04/2021



Member Forecasted Off Peak Demand Day for August 2021

San Isabel Electric Association, Inc.

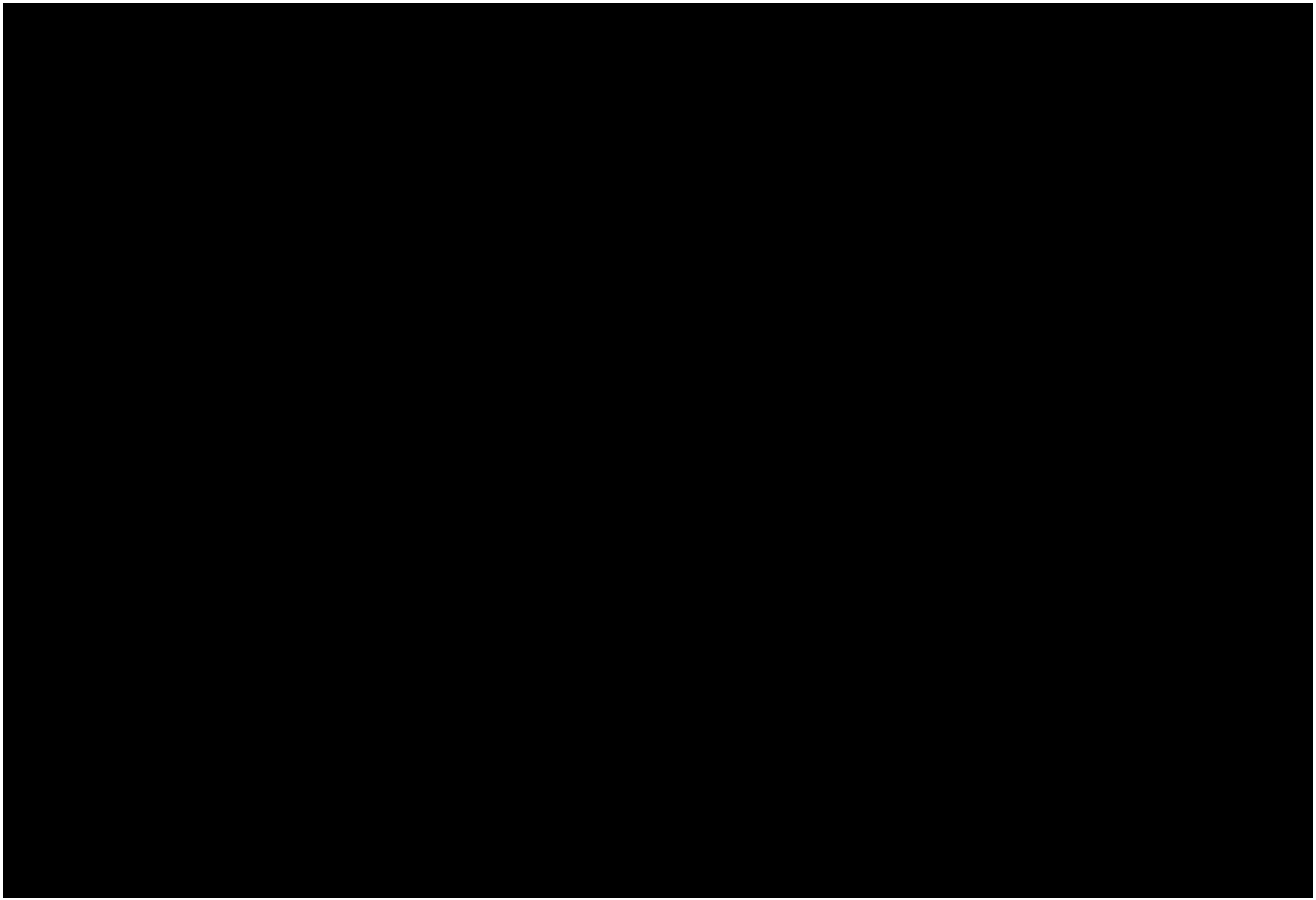
Date of Off Peak Day - 08/17/2021



Member Forecasted Off Peak Demand Day for September 2021

San Isabel Electric Association, Inc.

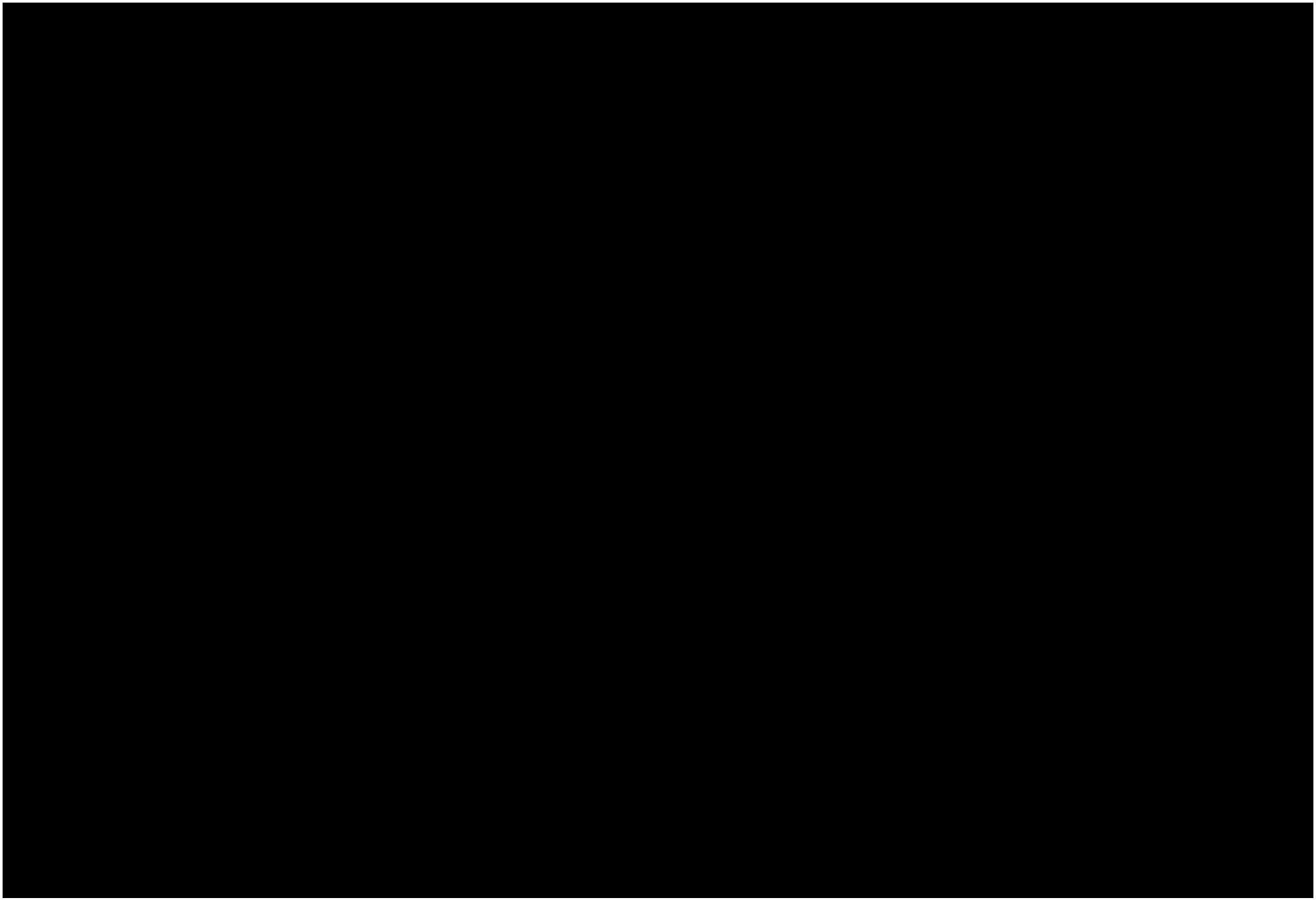
Date of Off Peak Day - 09/02/2021



Member Forecasted Off Peak Demand Day for October 2021

San Isabel Electric Association, Inc.

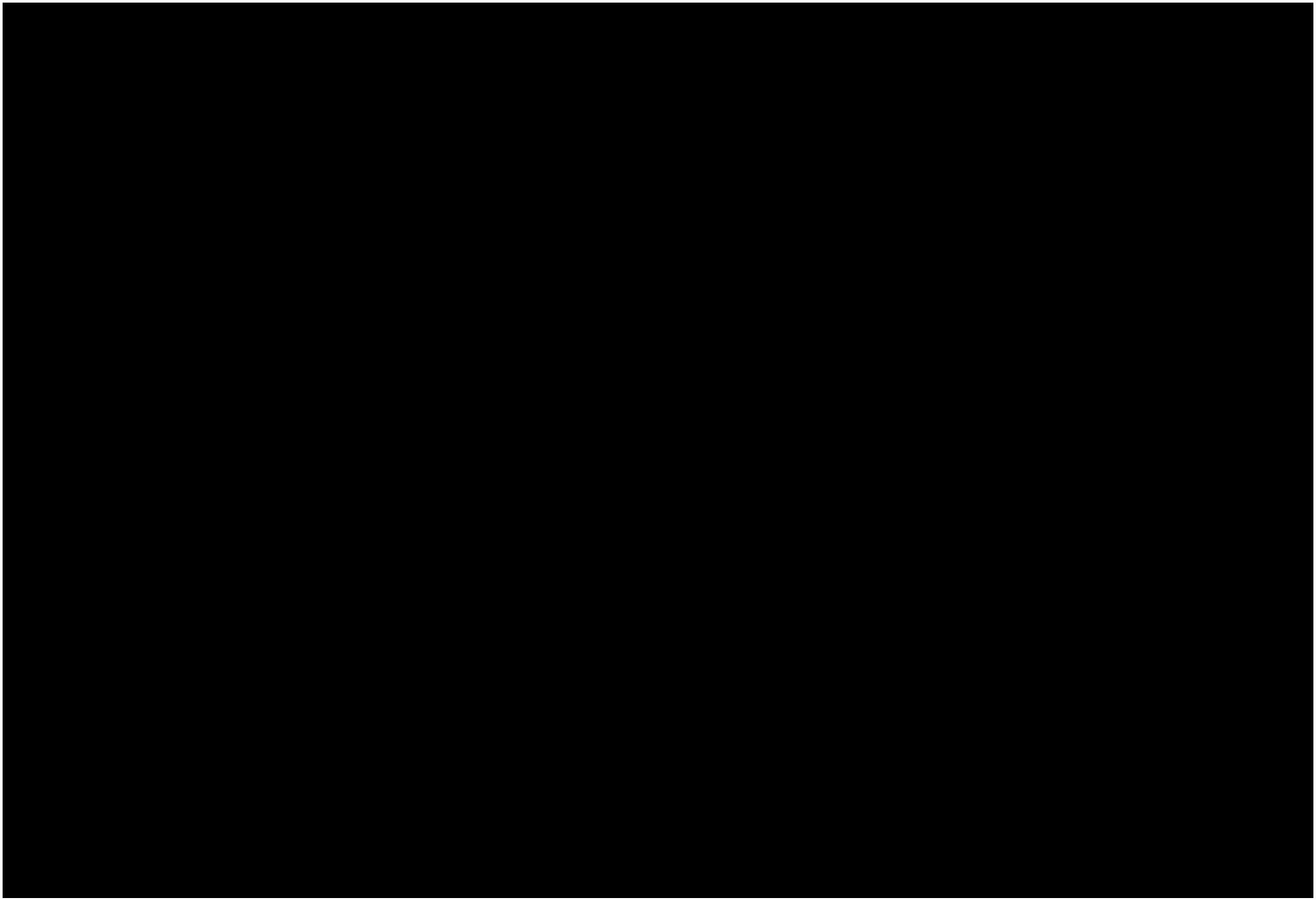
Date of Off Peak Day - 10/26/2021



Member Forecasted Off Peak Demand Day for November 2021

San Isabel Electric Association, Inc.

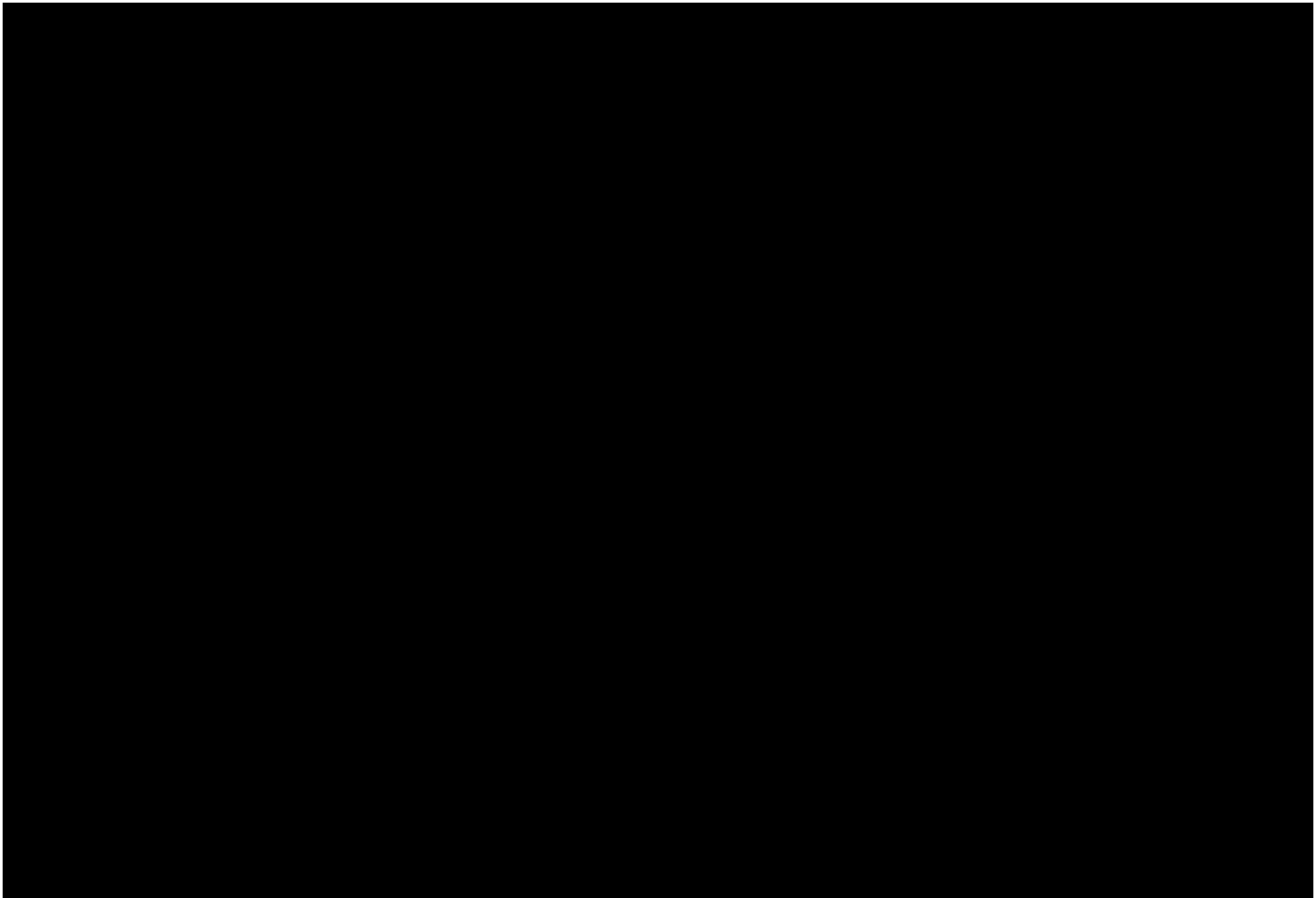
Date of Off Peak Day - 11/10/2021



Member Forecasted Off Peak Demand Day for December 2021

San Isabel Electric Association, Inc.

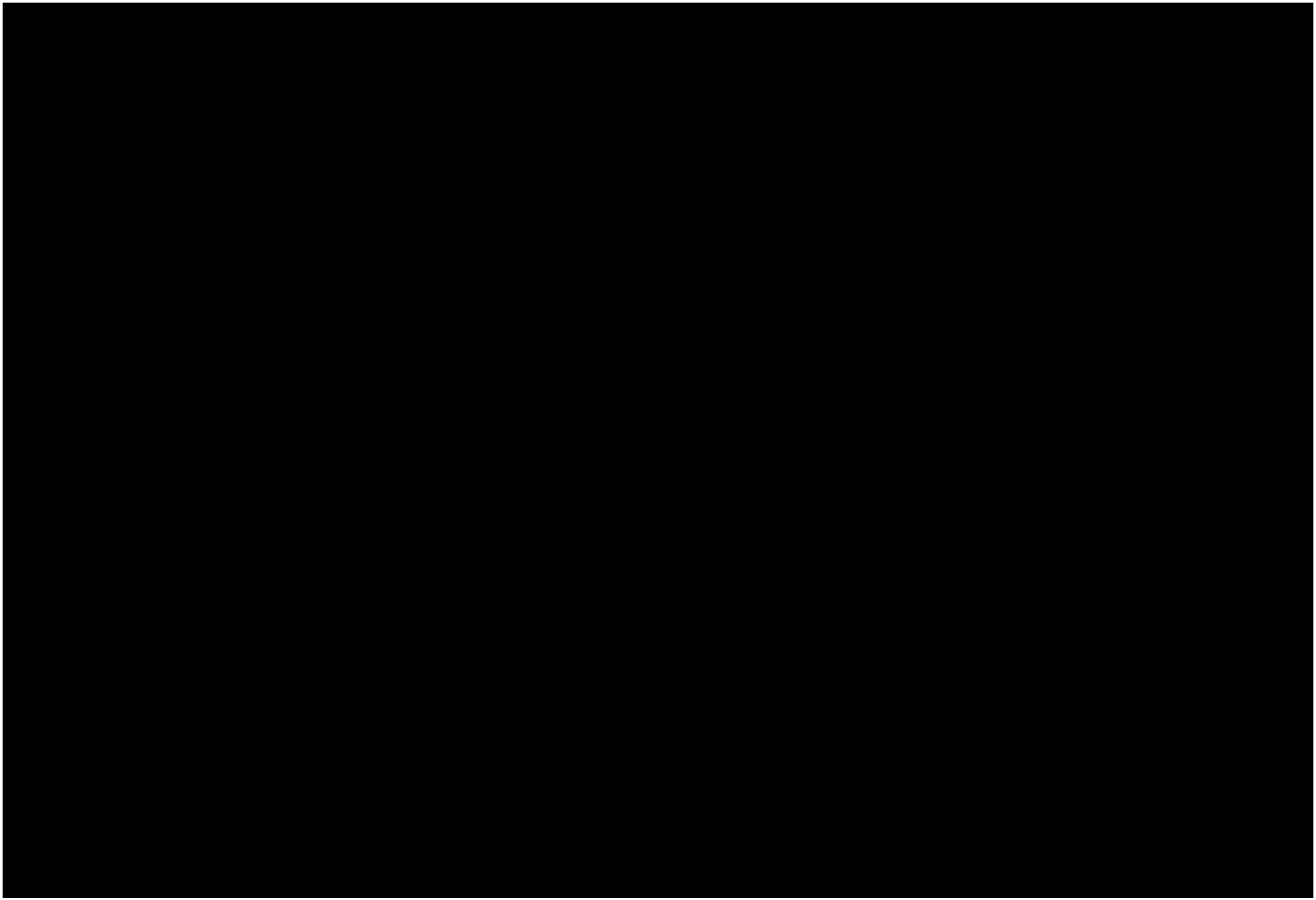
Date of Off Peak Day - 12/03/2021



Member Forecasted Off Peak Demand Day for January 2021

San Luis Valley Rural Electric Cooperative, Inc.

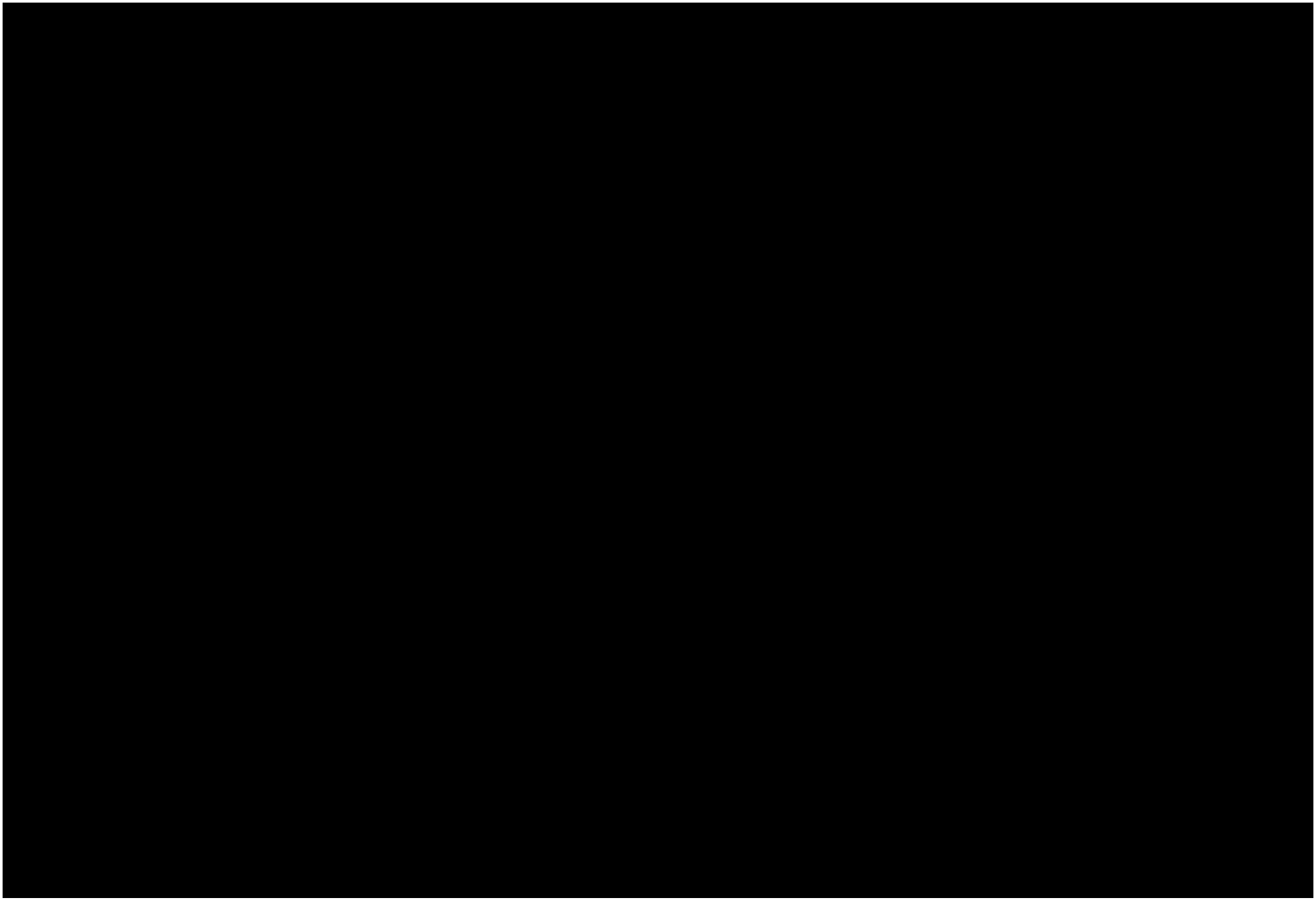
Date of Off Peak Day - 01/14/2021



Member Forecasted Off Peak Demand Day for February 2021

San Luis Valley Rural Electric Cooperative, Inc.

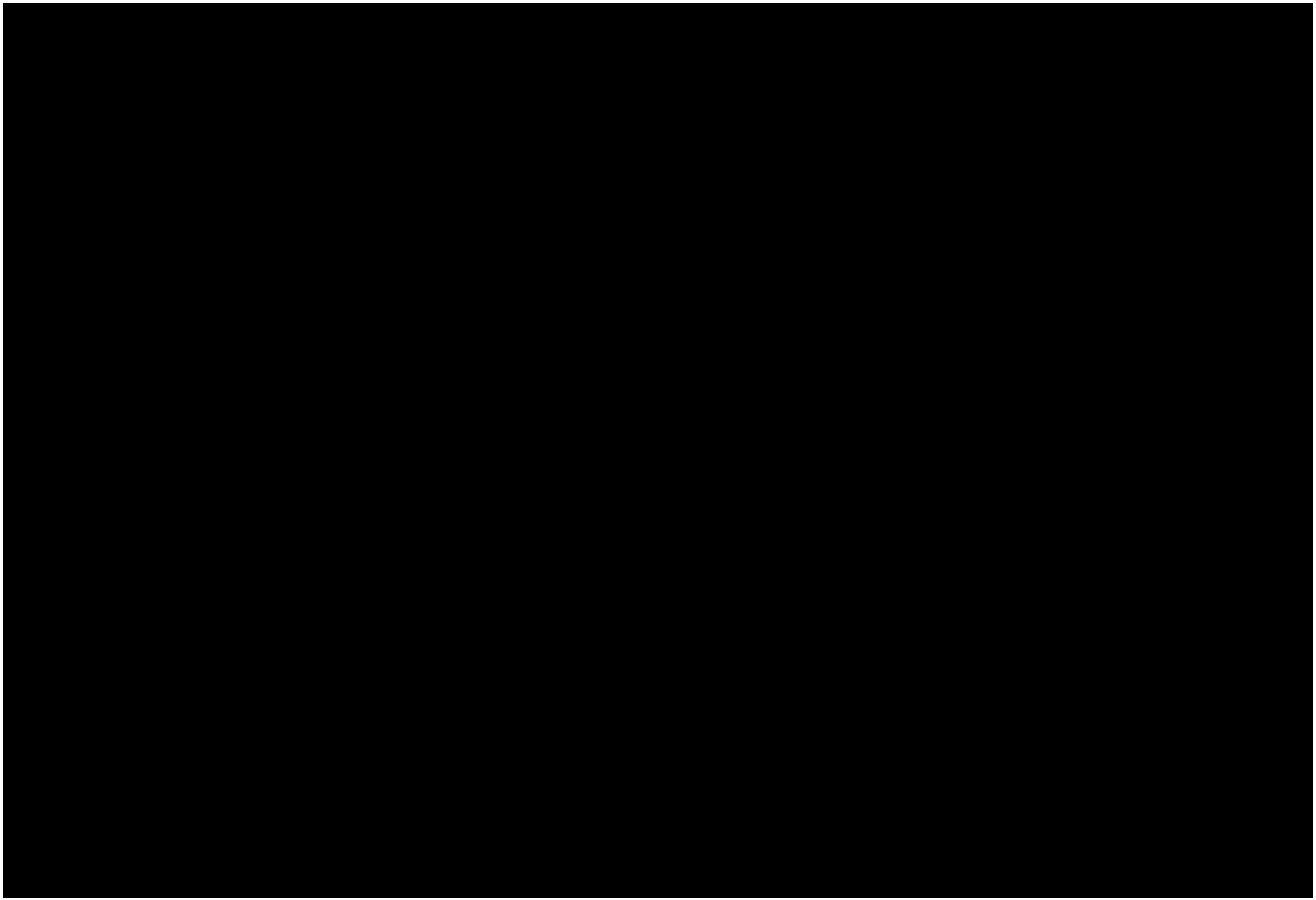
Date of Off Peak Day - 02/20/2021



Member Forecasted Off Peak Demand Day for March 2021

San Luis Valley Rural Electric Cooperative, Inc.

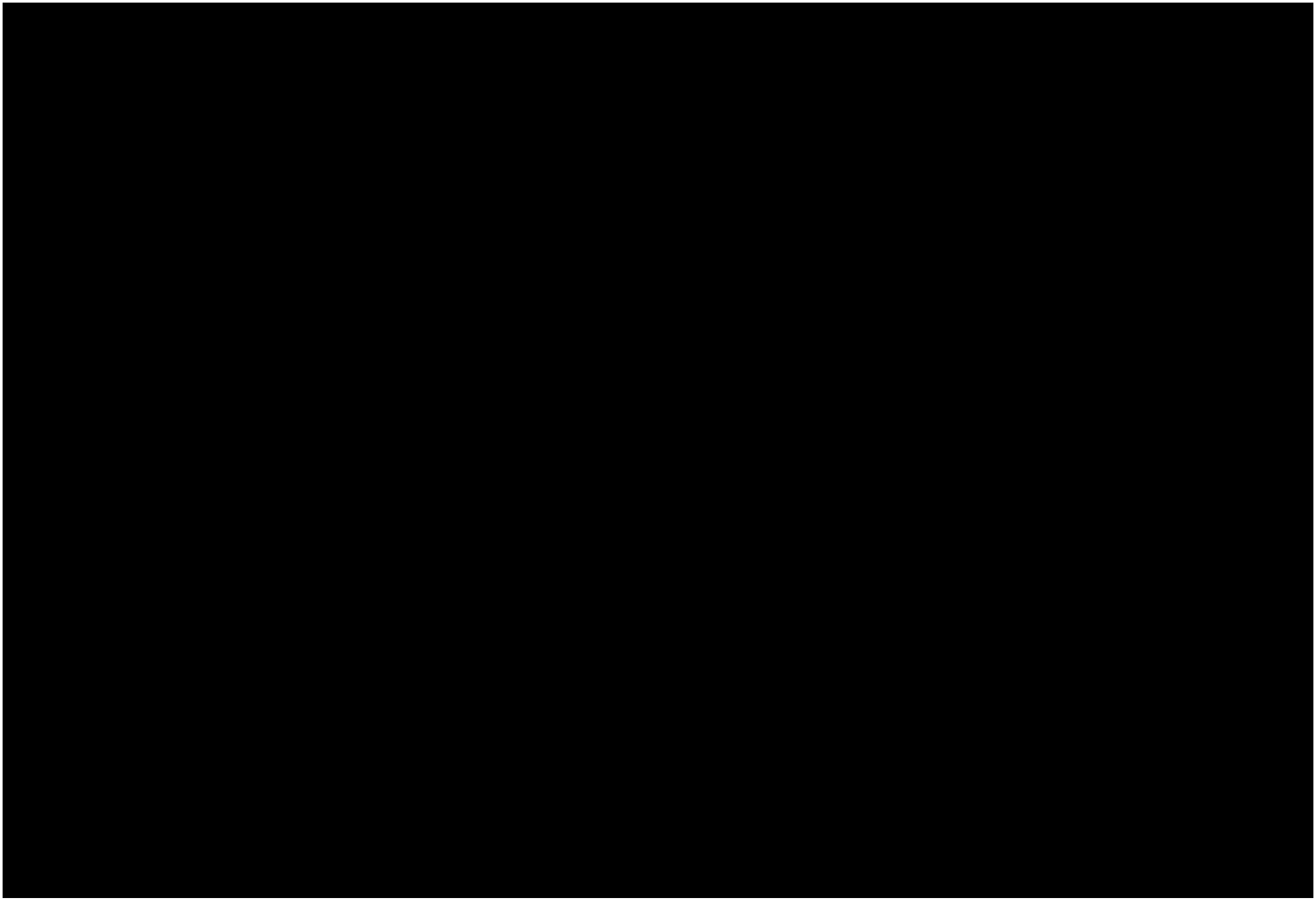
Date of Off Peak Day - 03/20/2021



Member Forecasted Off Peak Demand Day for April 2021

San Luis Valley Rural Electric Cooperative, Inc.

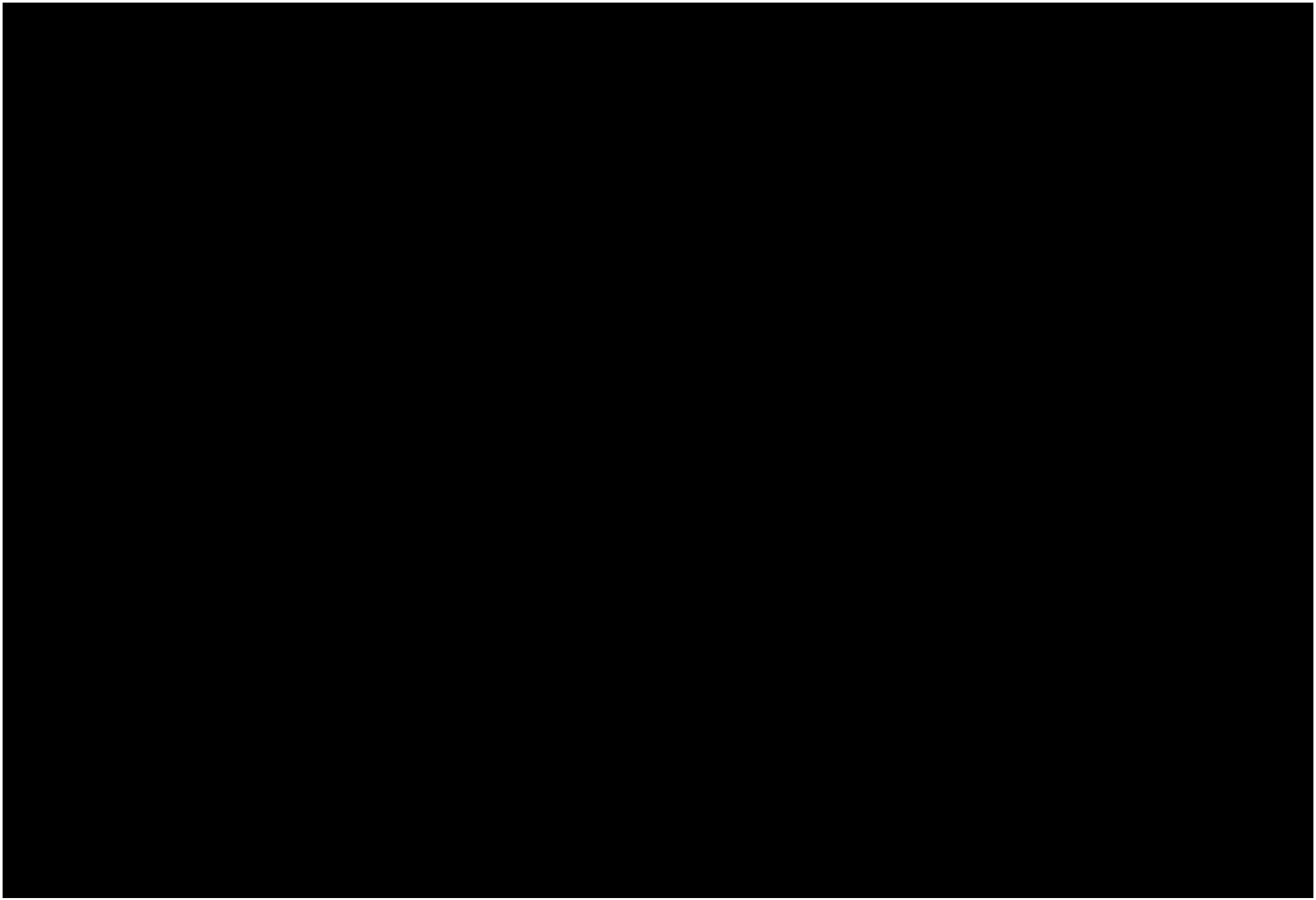
Date of Off Peak Day - 04/02/2021



Member Forecasted Off Peak Demand Day for May 2021

San Luis Valley Rural Electric Cooperative, Inc.

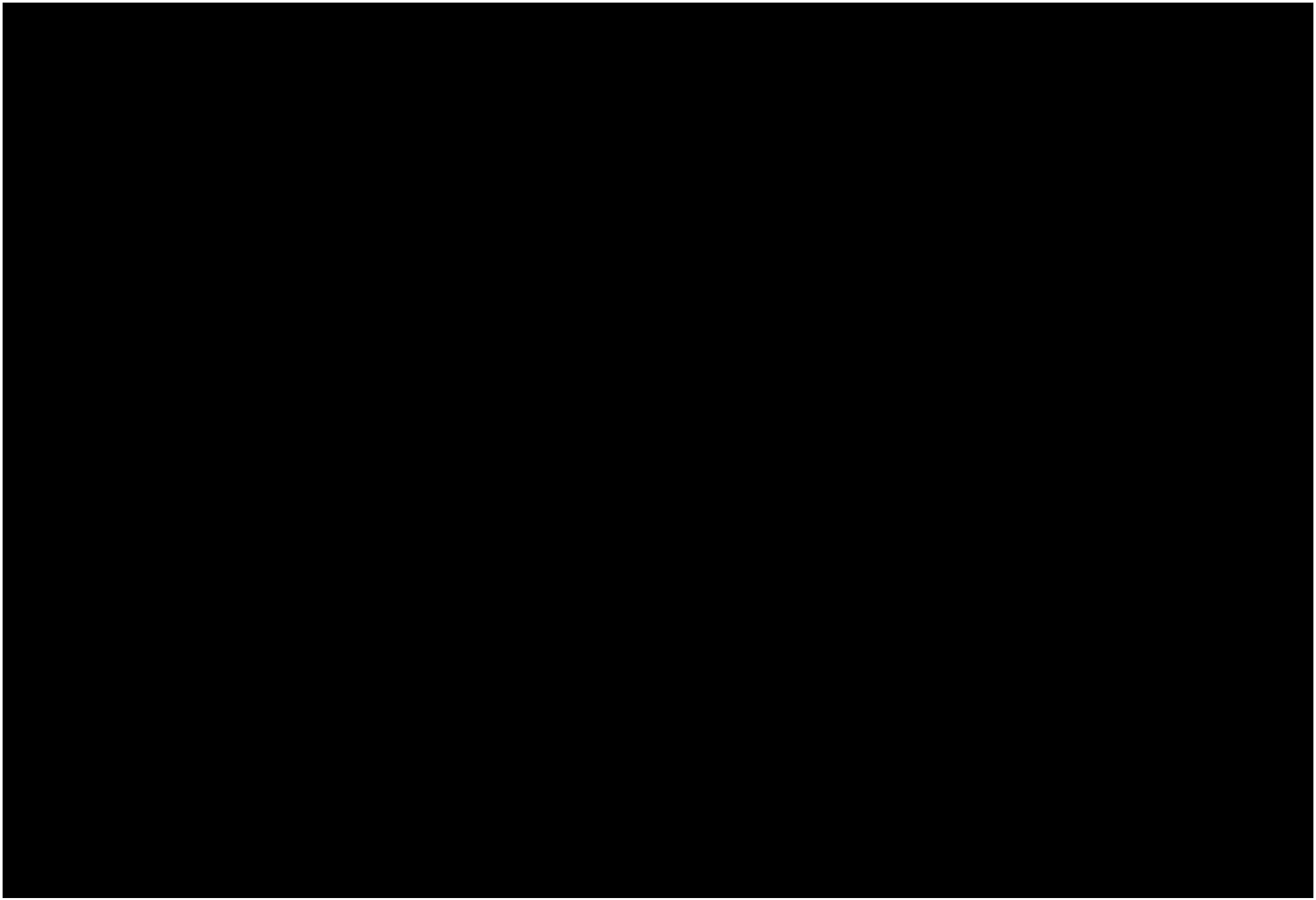
Date of Off Peak Day - 05/01/2021



Member Forecasted Off Peak Demand Day for June 2021

San Luis Valley Rural Electric Cooperative, Inc.

Date of Off Peak Day - 06/05/2021



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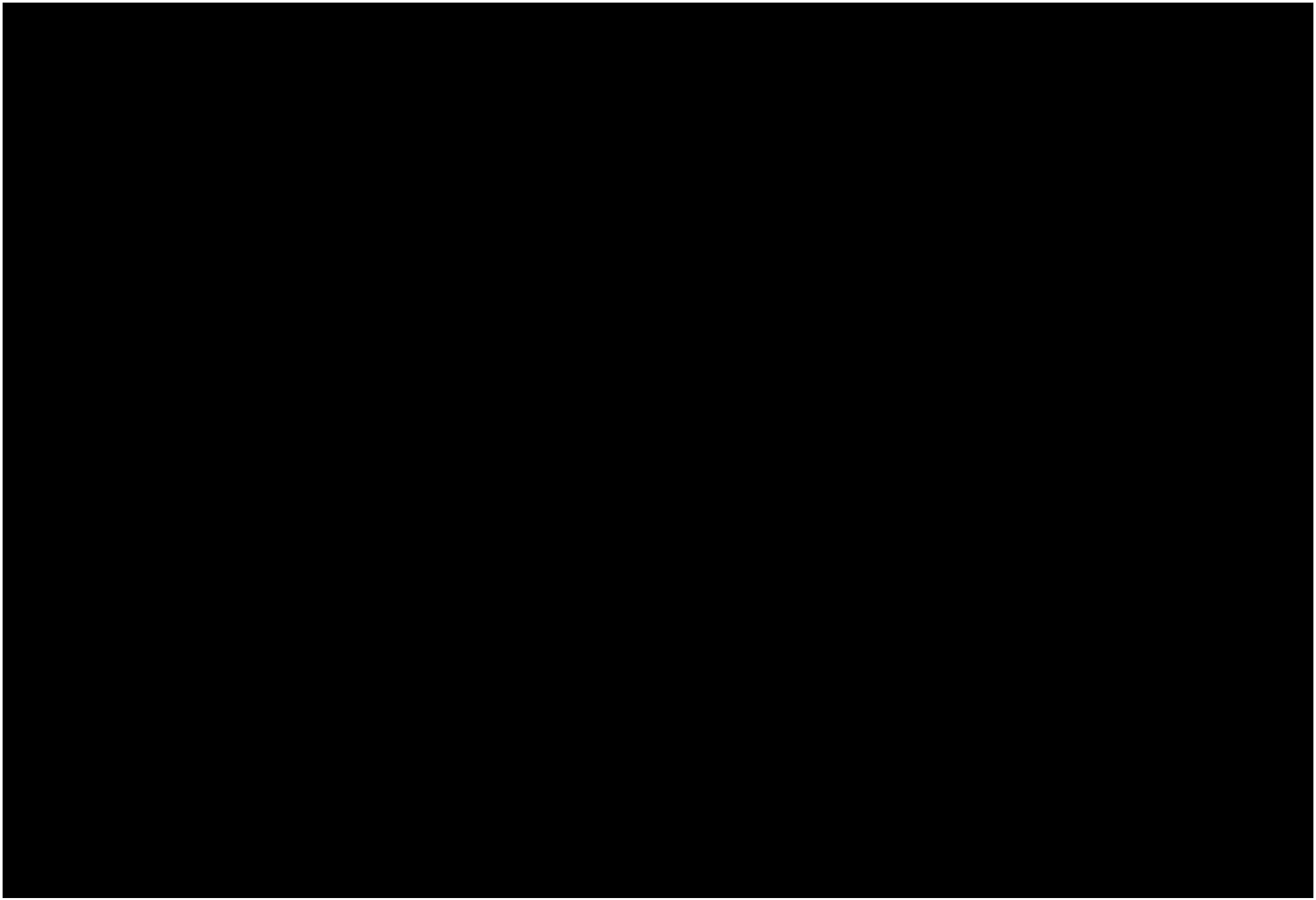
Member Forecasted Off Peak Demand Day for July 2021

San Luis Valley Rural Electric Cooperative, Inc.

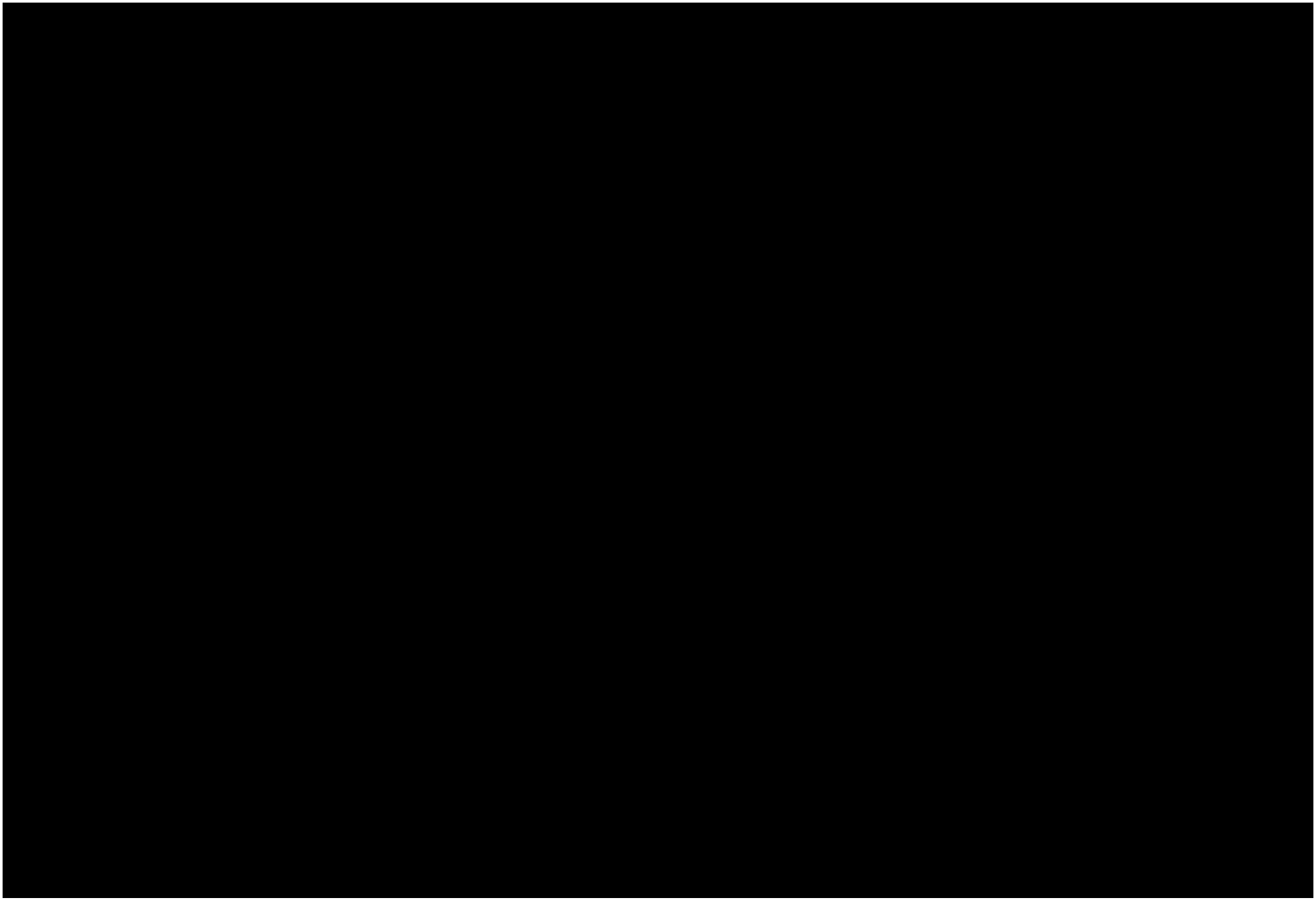
Date of Off Peak Day - 07/03/2021



Member Forecasted Off Peak Demand Day for August 2021

San Luis Valley Rural Electric Cooperative, Inc.

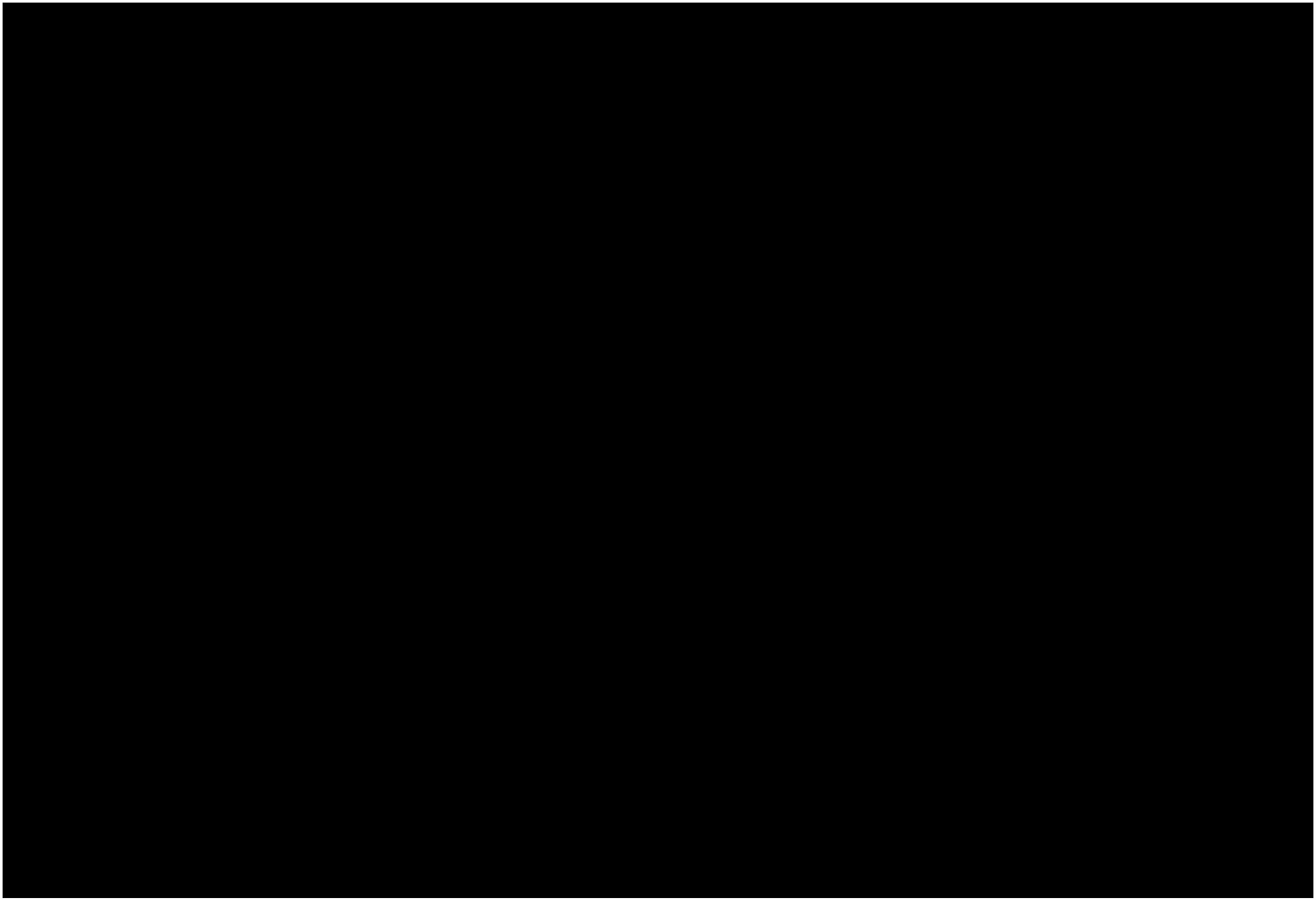
Date of Off Peak Day - 08/01/2021



Member Forecasted Off Peak Demand Day for September 2021

San Luis Valley Rural Electric Cooperative, Inc.

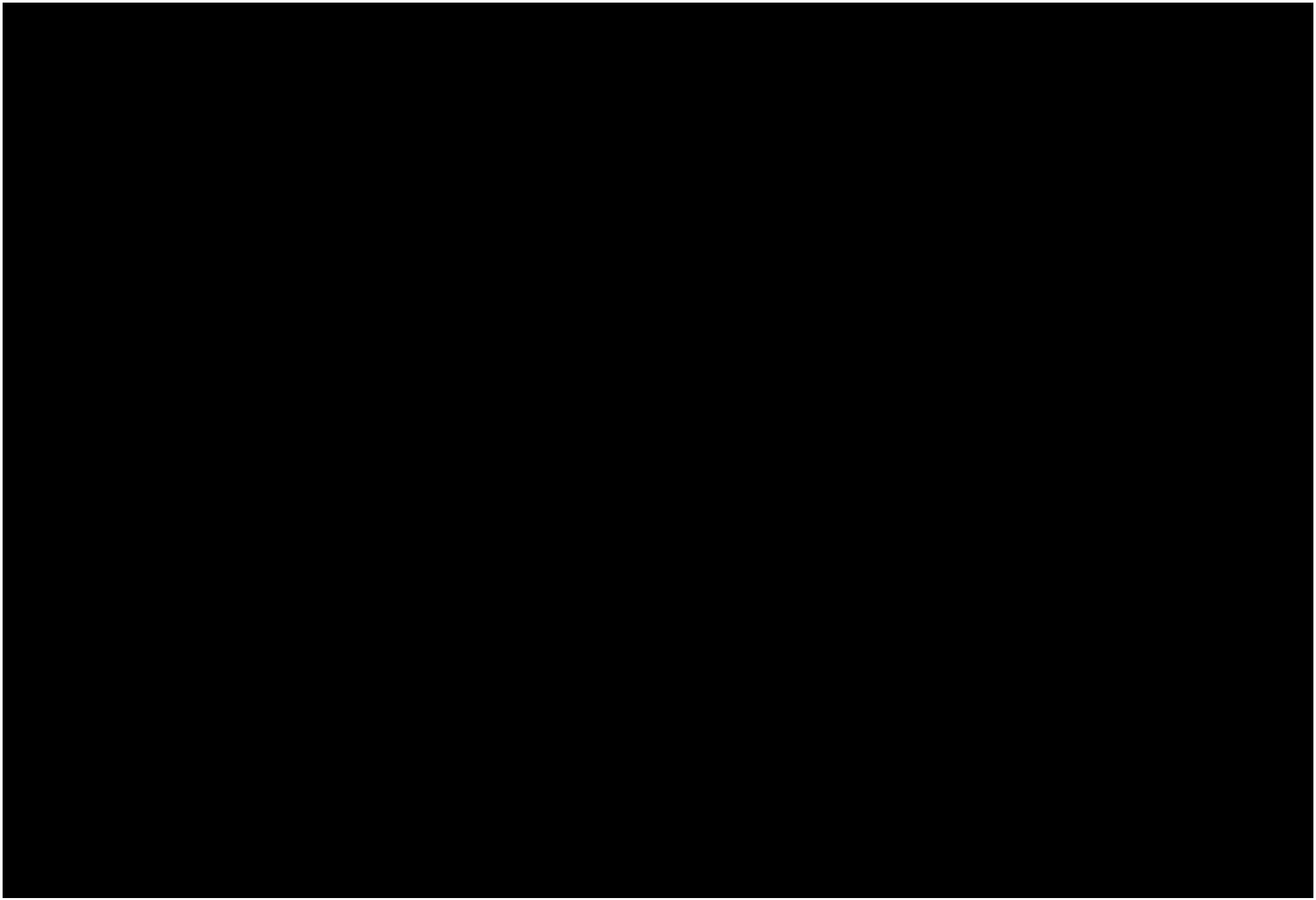
Date of Off Peak Day - 09/25/2021



Member Forecasted Off Peak Demand Day for October 2021

San Luis Valley Rural Electric Cooperative, Inc.

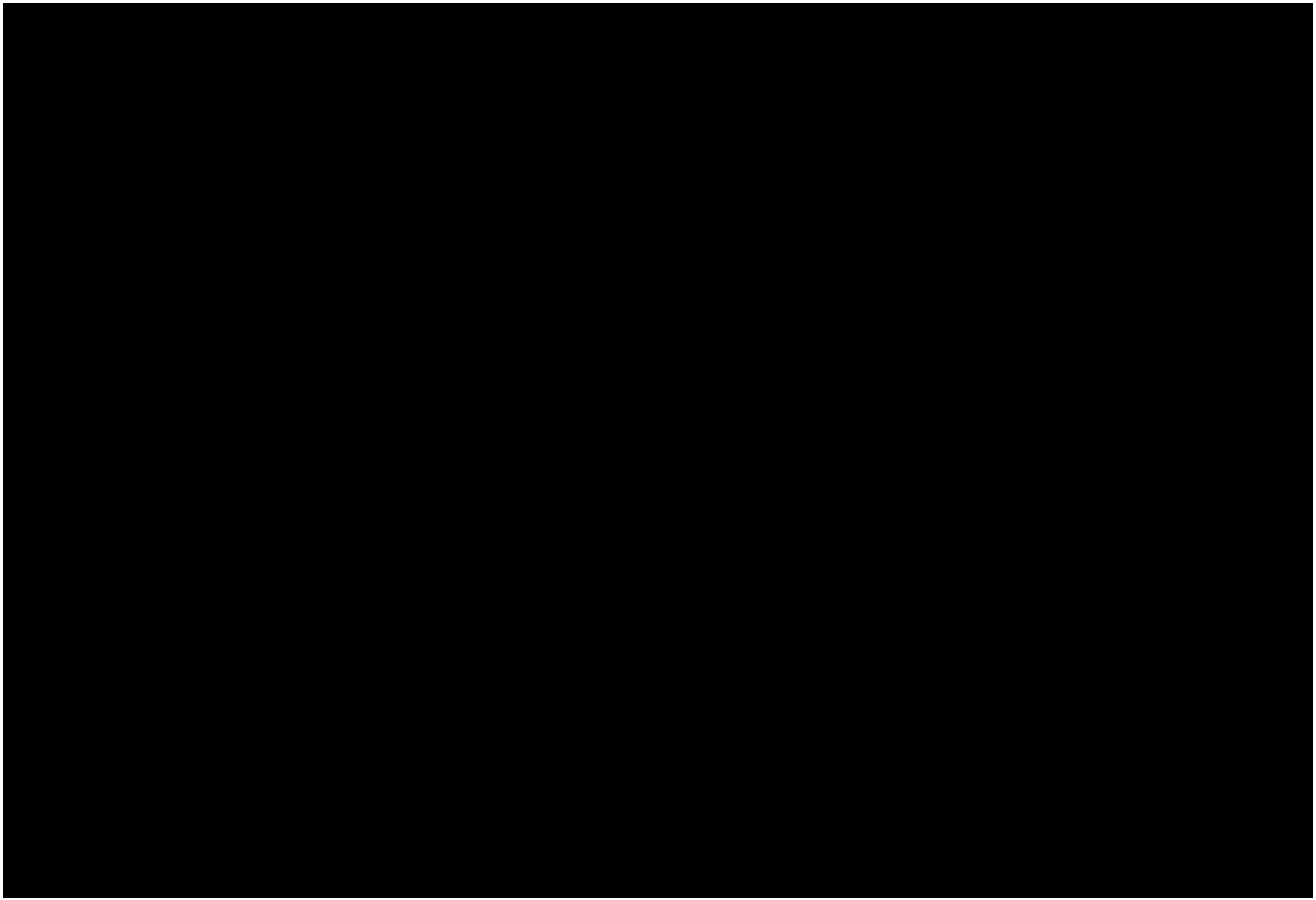
Date of Off Peak Day - 10/24/2021



Member Forecasted Off Peak Demand Day for November 2021

San Luis Valley Rural Electric Cooperative, Inc.

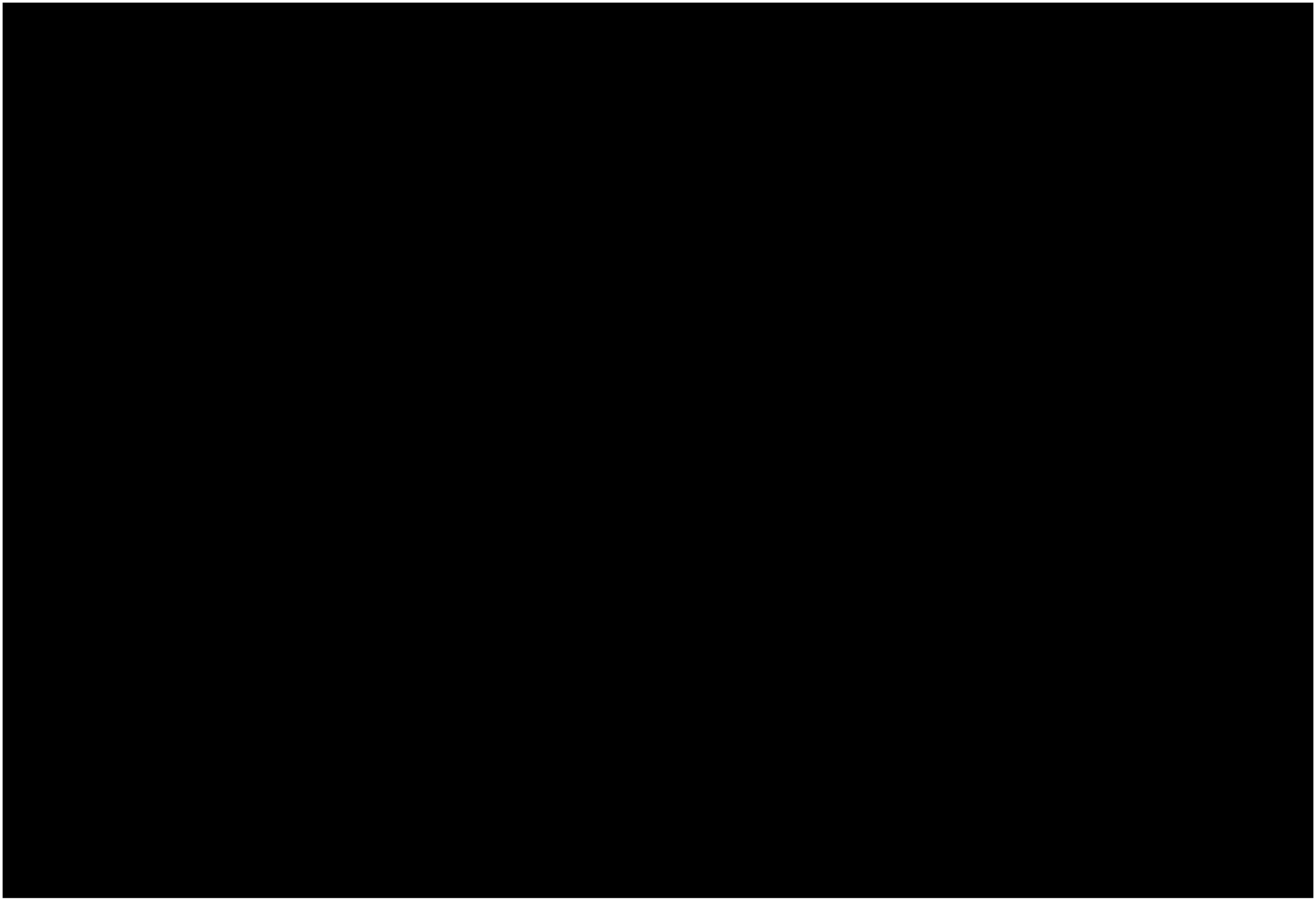
Date of Off Peak Day - 11/06/2021



Member Forecasted Off Peak Demand Day for December 2021

San Luis Valley Rural Electric Cooperative, Inc.

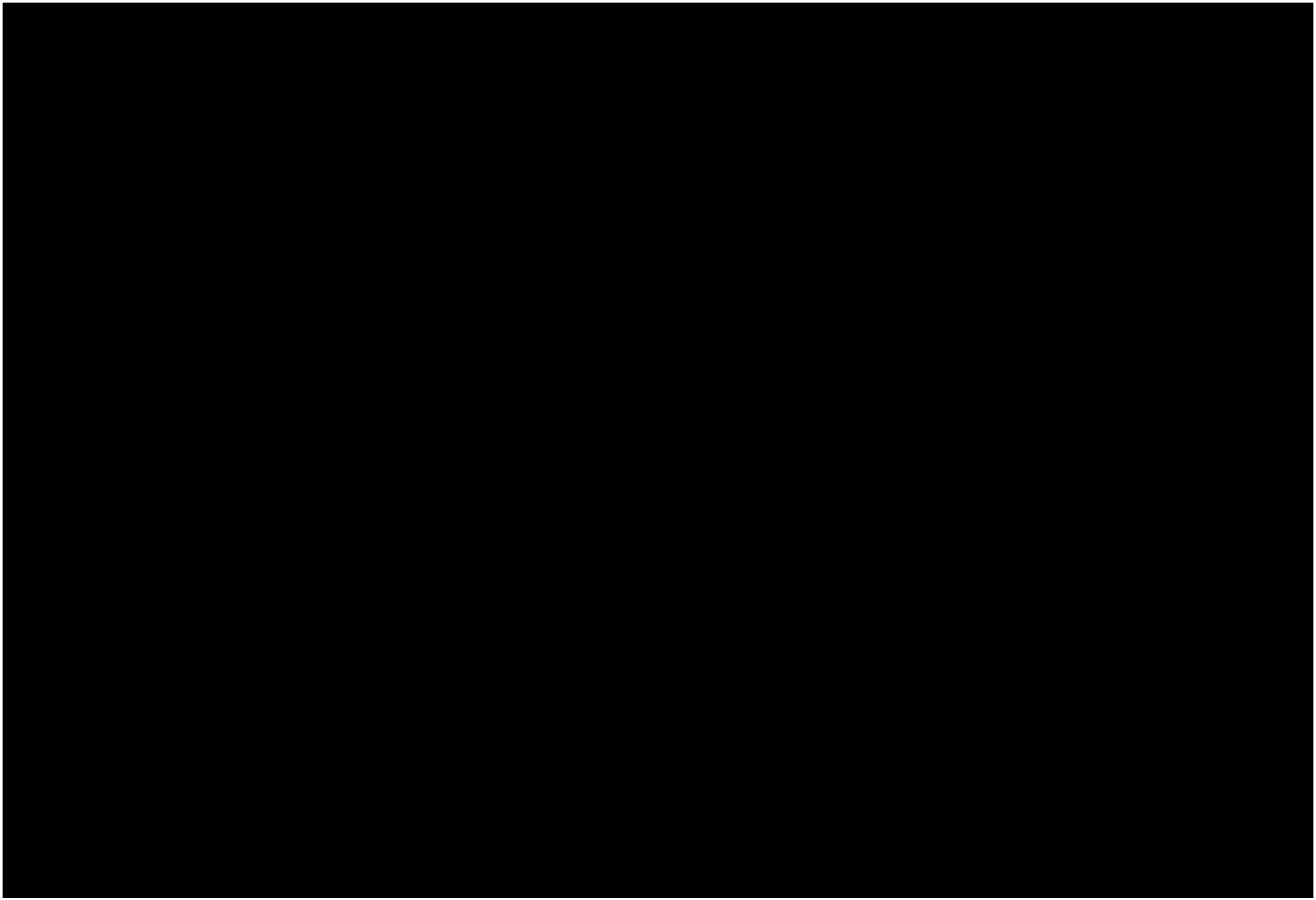
Date of Off Peak Day - 12/10/2021



Member Forecasted Off Peak Demand Day for January 2021

San Miguel Power Association, Inc.

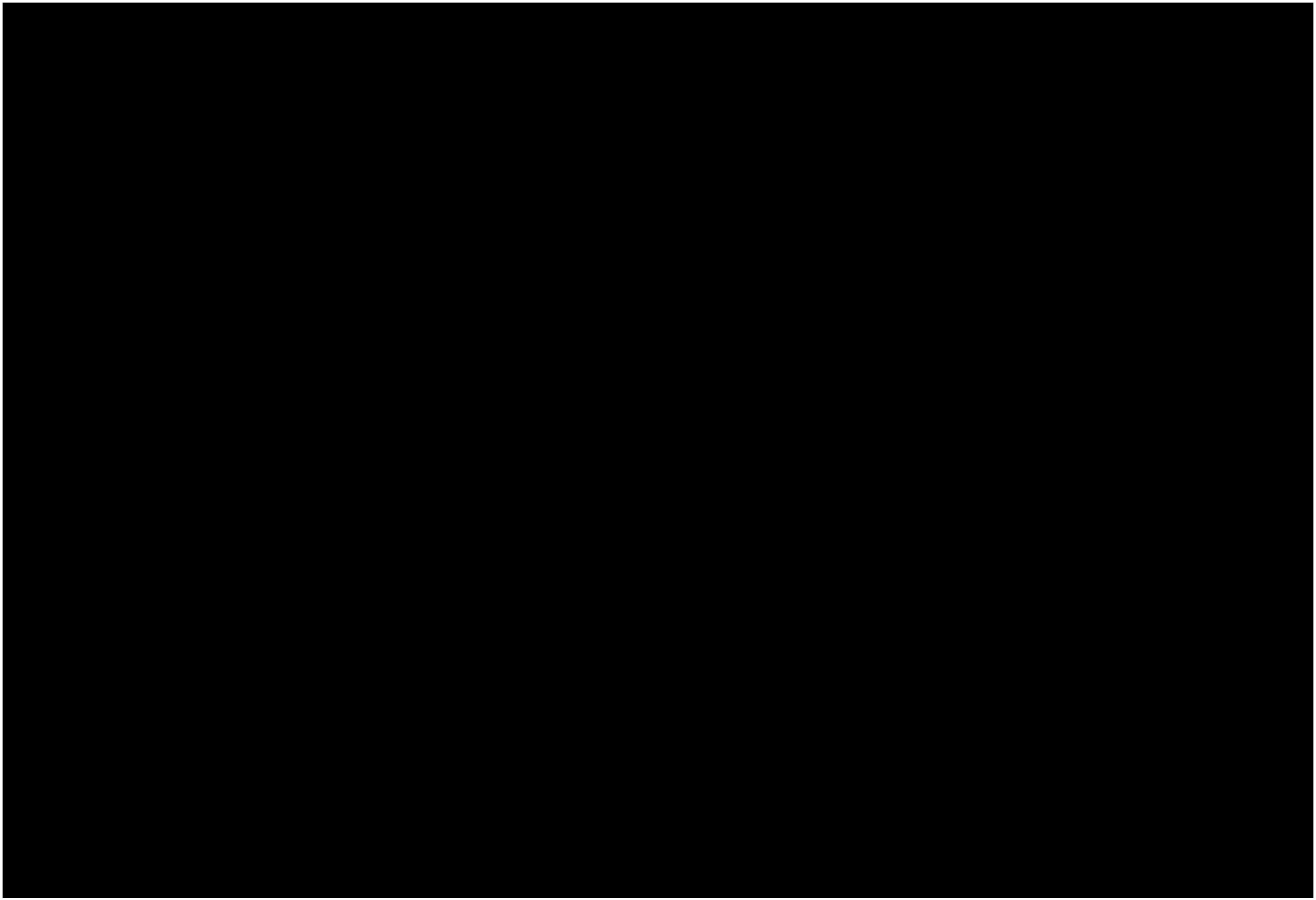
Date of Off Peak Day - 01/11/2021



Member Forecasted Off Peak Demand Day for February 2021

San Miguel Power Association, Inc.

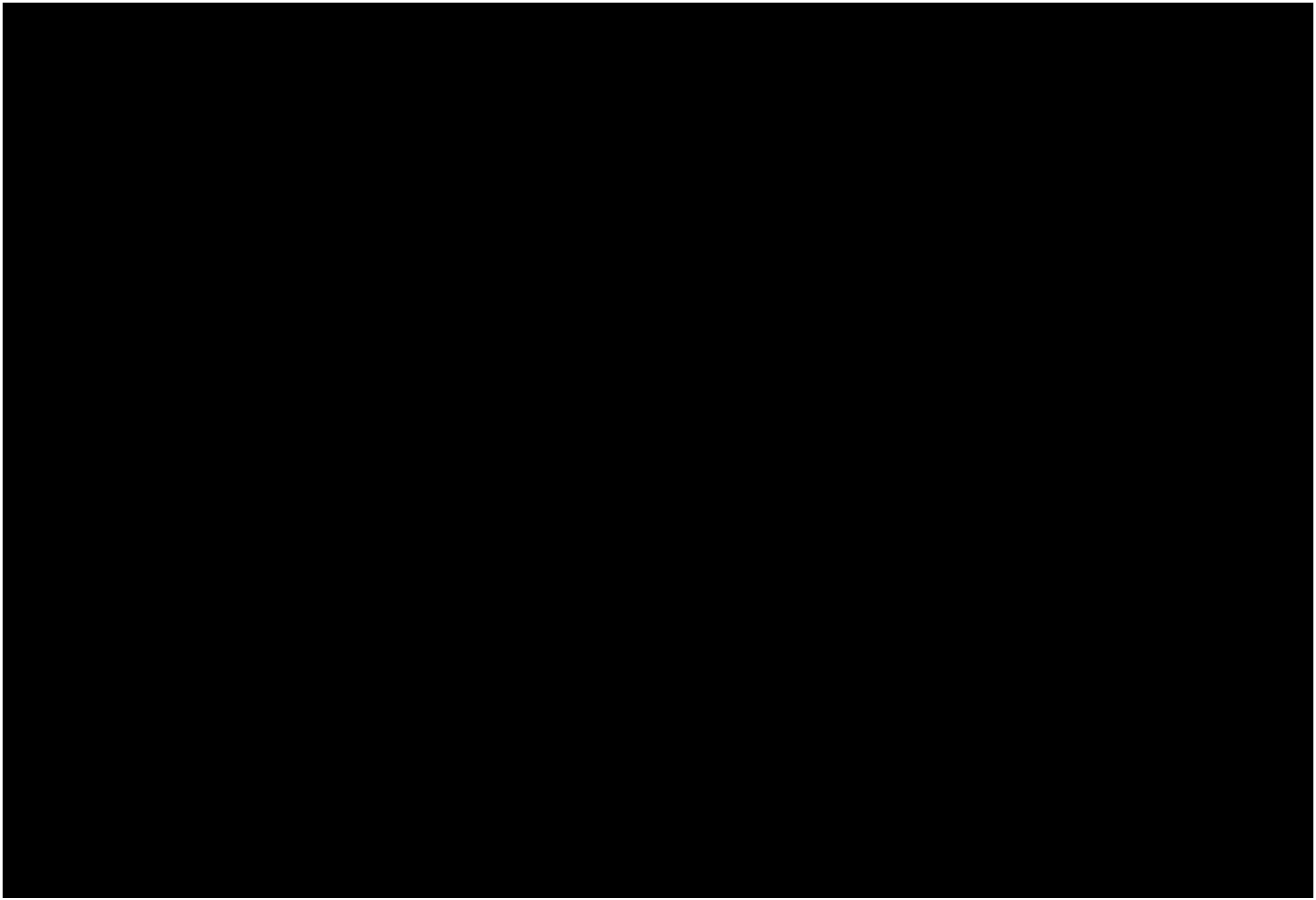
Date of Off Peak Day - 02/10/2021



Member Forecasted Off Peak Demand Day for March 2021

San Miguel Power Association, Inc.

Date of Off Peak Day - 03/21/2021



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Member Forecasted Off Peak Demand Day for April 2021

San Miguel Power Association, Inc.

Date of Off Peak Day - 04/30/2021

[redacted]

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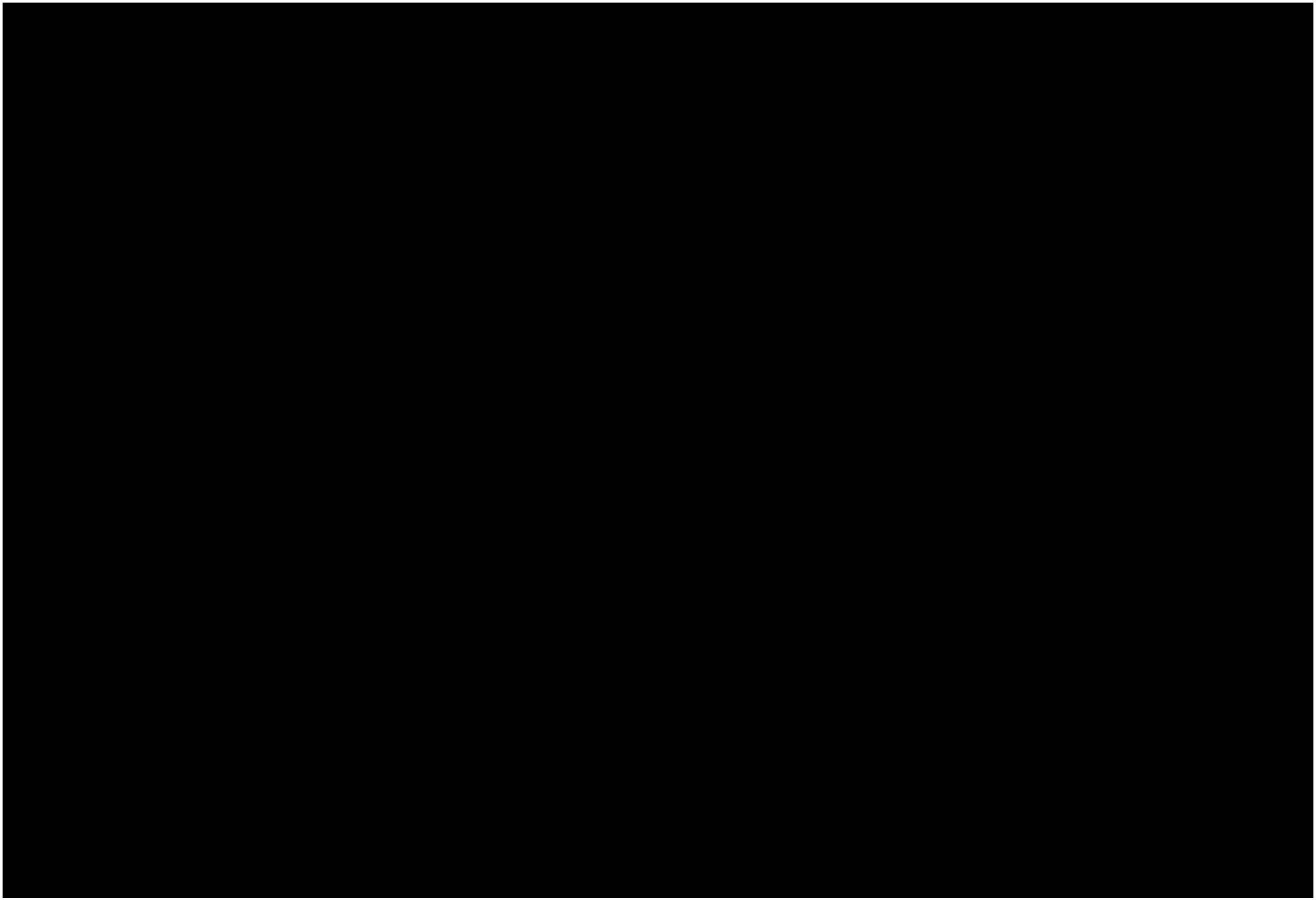
Member Forecasted Off Peak Demand Day for May 2021

San Miguel Power Association, Inc.

Date of Off Peak Day - 05/25/2021



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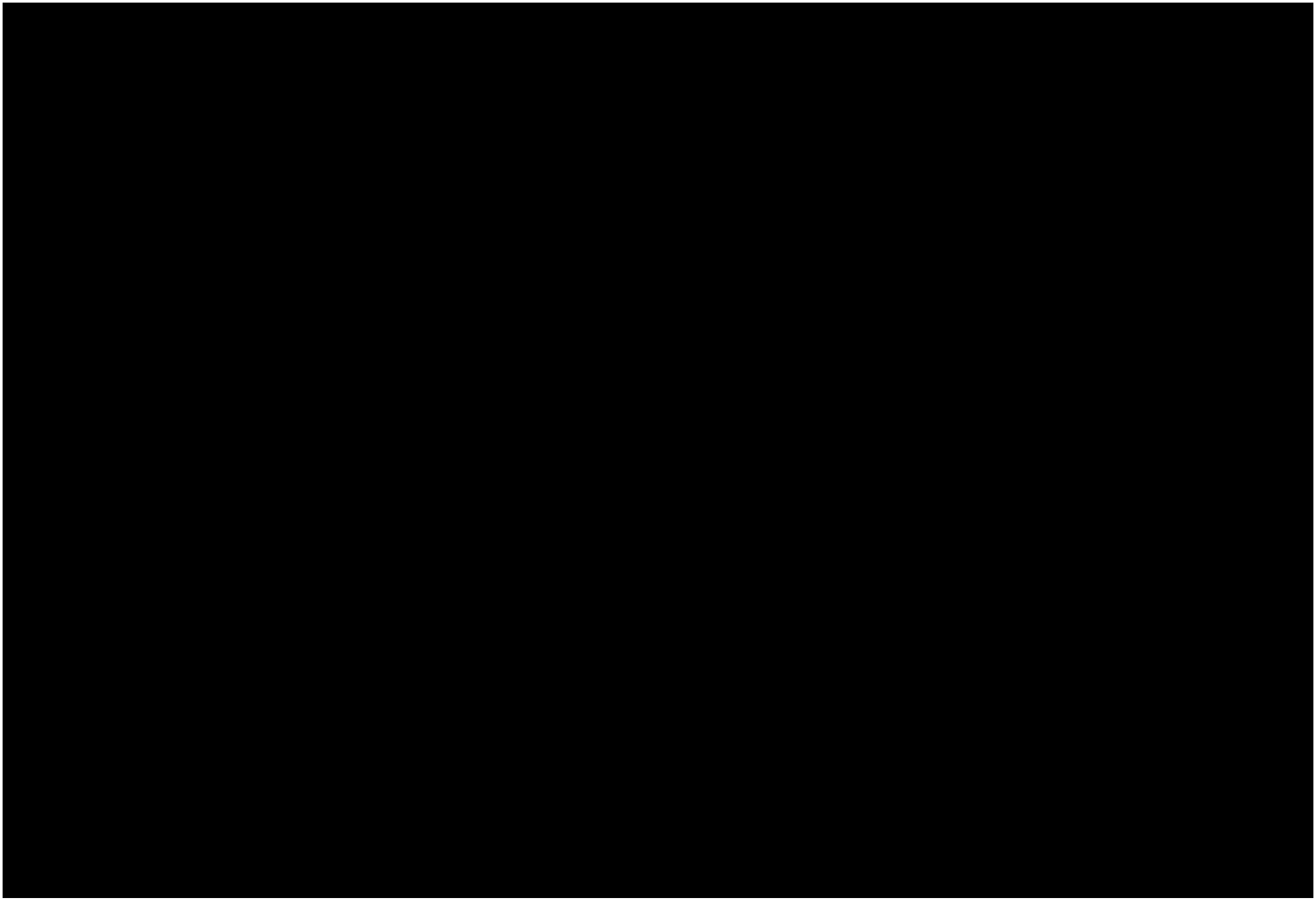
Member Forecasted Off Peak Demand Day for June 2021

San Miguel Power Association, Inc.

Date of Off Peak Day - 06/03/2021



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Member Forecasted Off Peak Demand Day for July 2021

San Miguel Power Association, Inc.

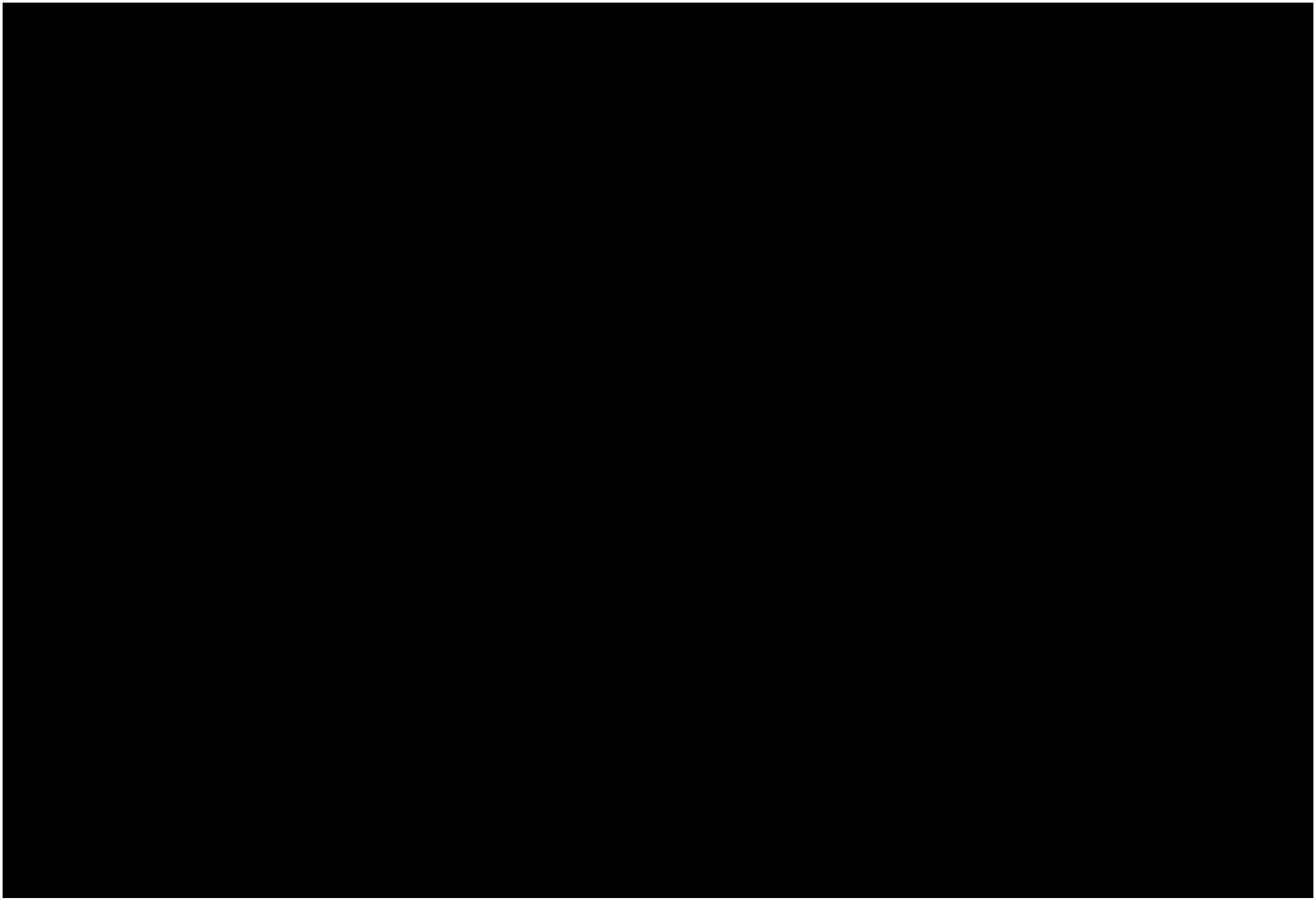
Date of Off Peak Day - 07/22/2021

[redacted]

Member Forecasted Off Peak Demand Day for August 2021

San Miguel Power Association, Inc.

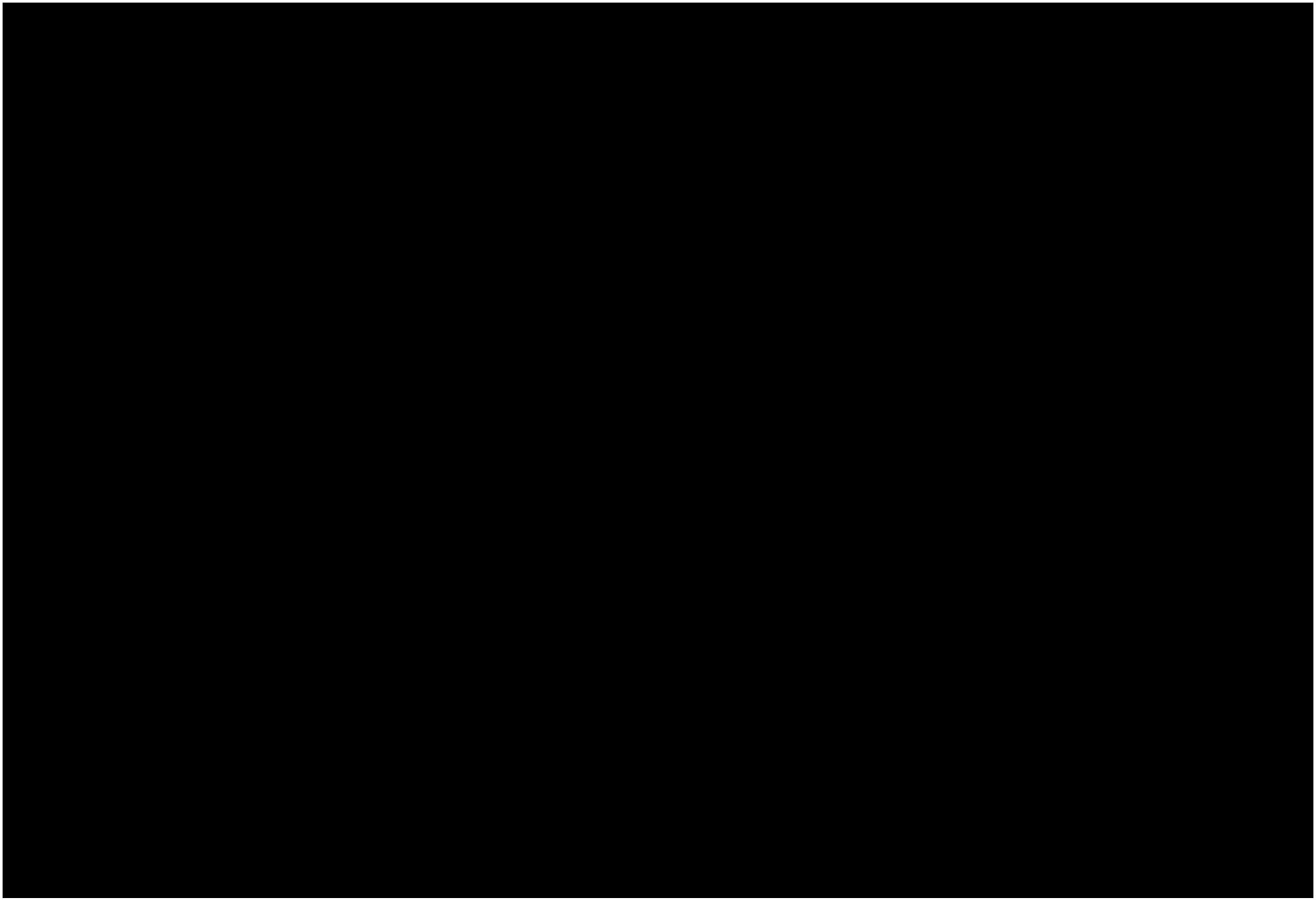
Date of Off Peak Day - 08/10/2021



Member Forecasted Off Peak Demand Day for September 2021

San Miguel Power Association, Inc.

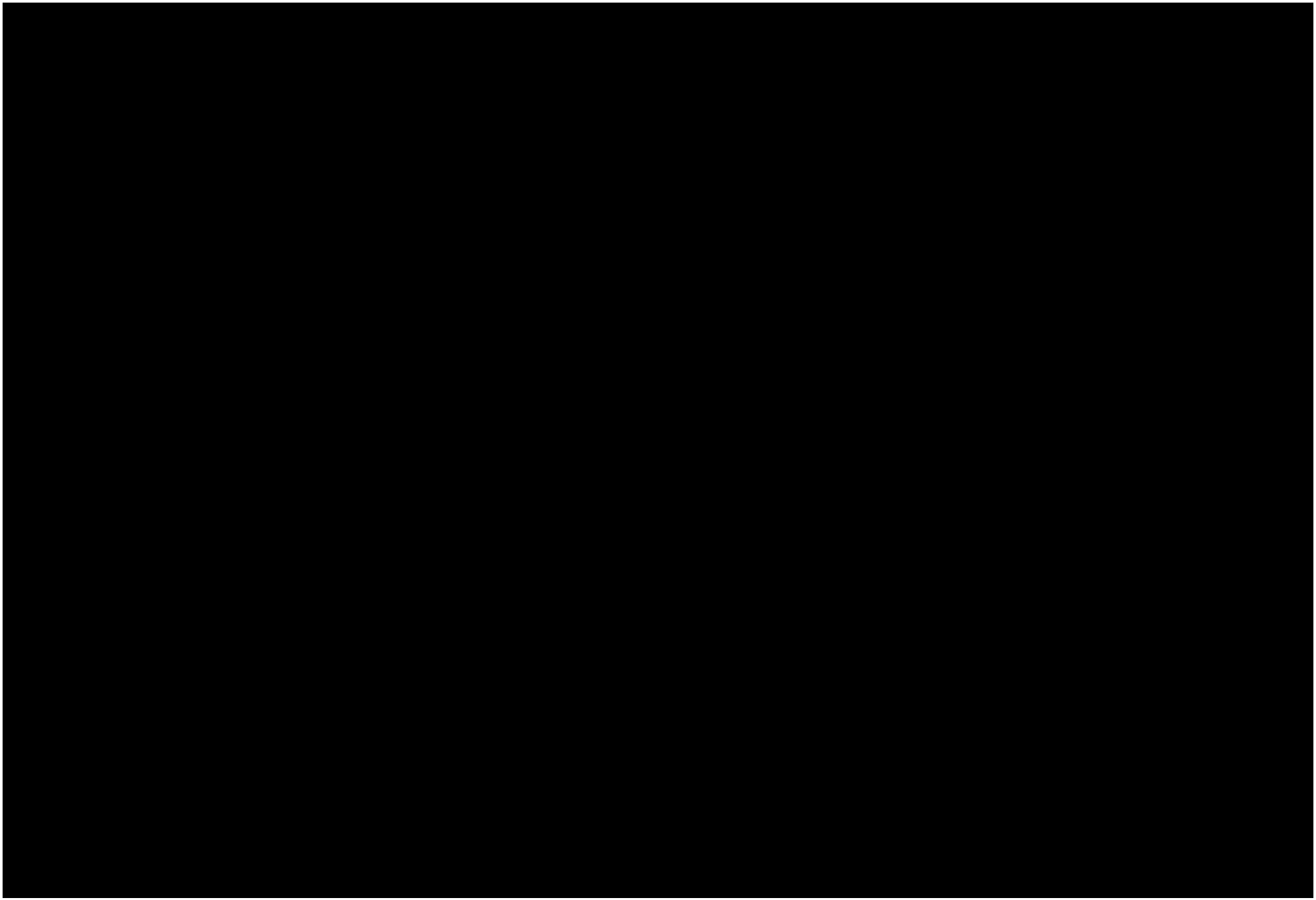
Date of Off Peak Day - 09/29/2021



Member Forecasted Off Peak Demand Day for October 2021

San Miguel Power Association, Inc.

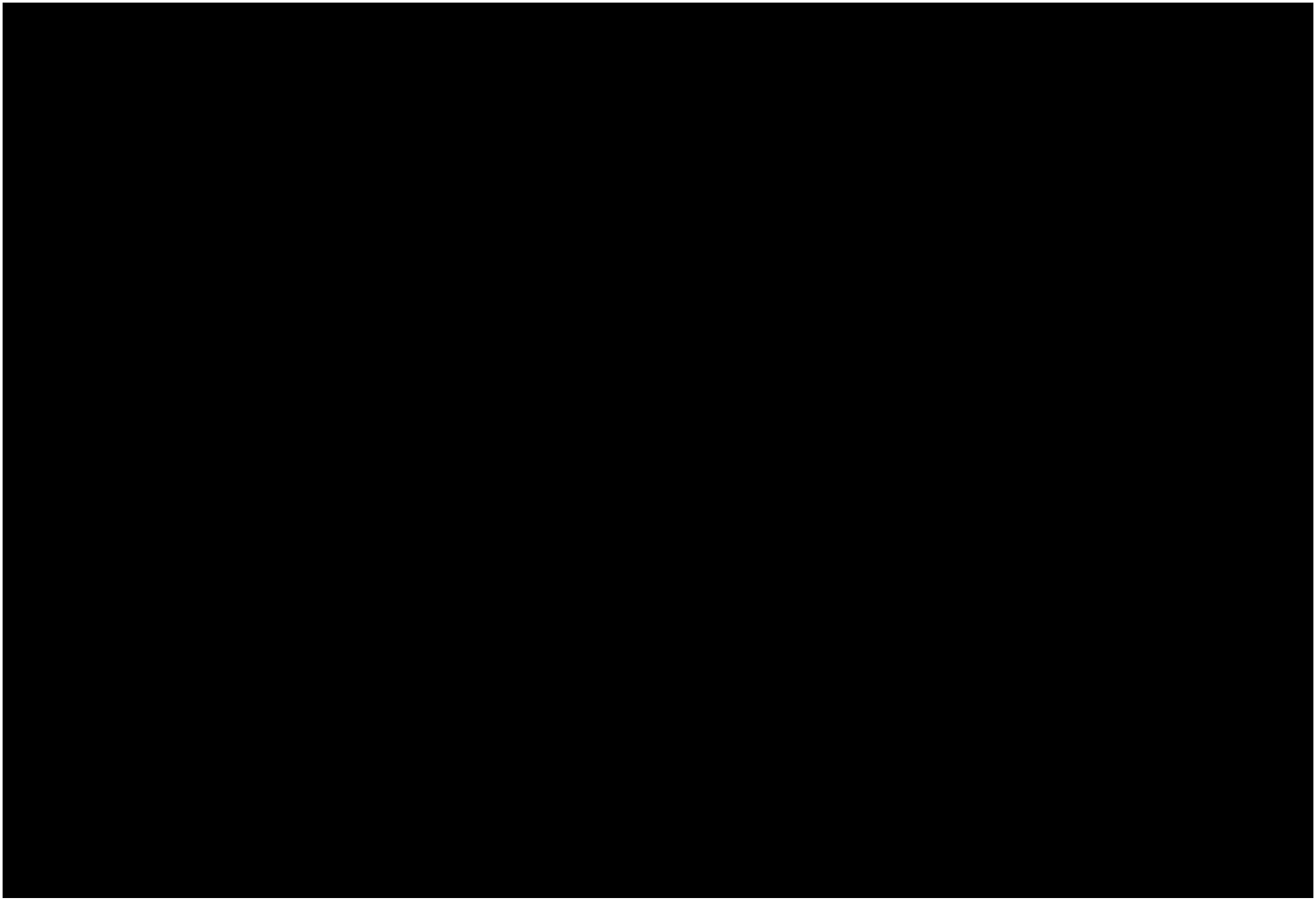
Date of Off Peak Day - 10/03/2021



Member Forecasted Off Peak Demand Day for November 2021

San Miguel Power Association, Inc.

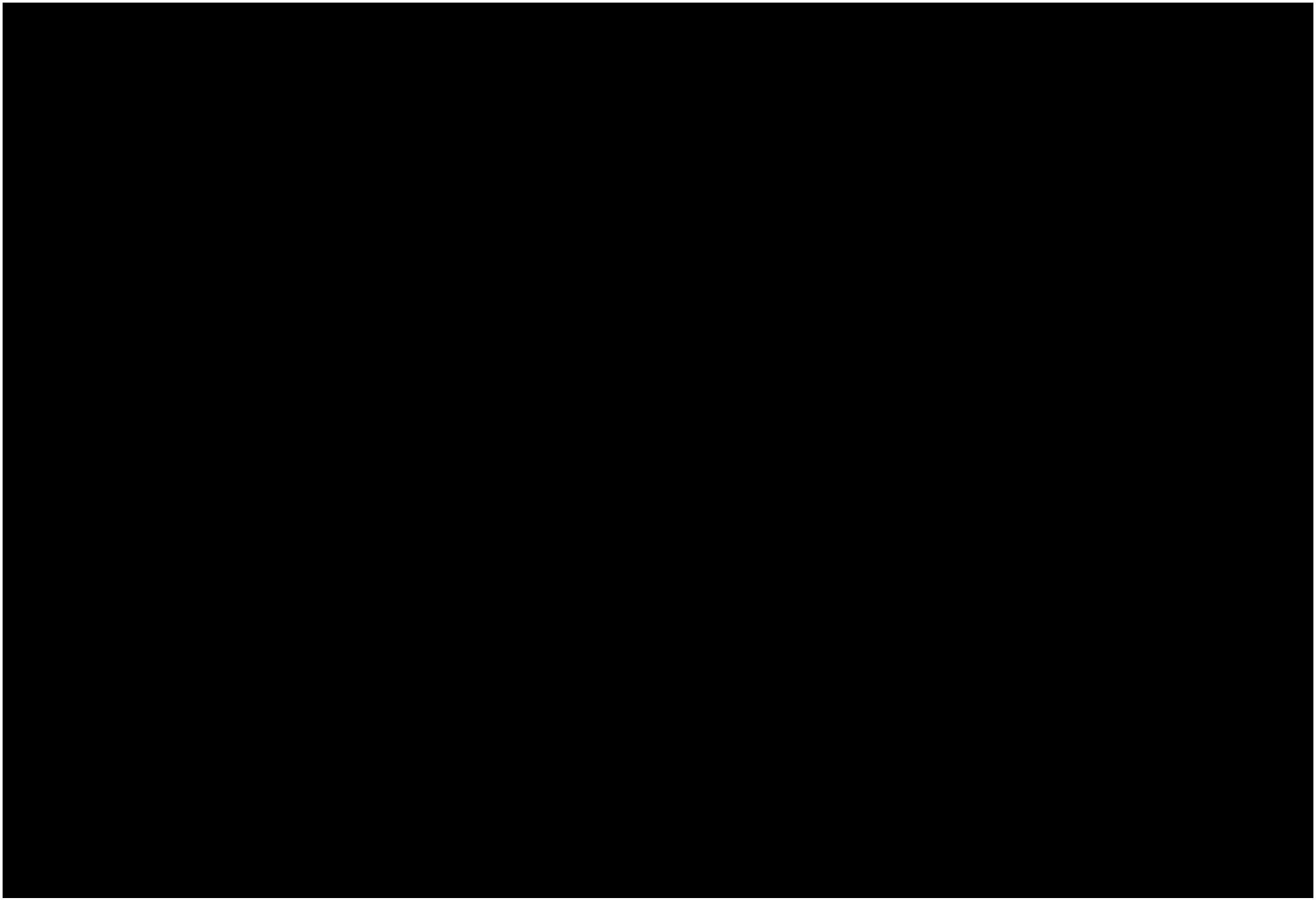
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

San Miguel Power Association, Inc.

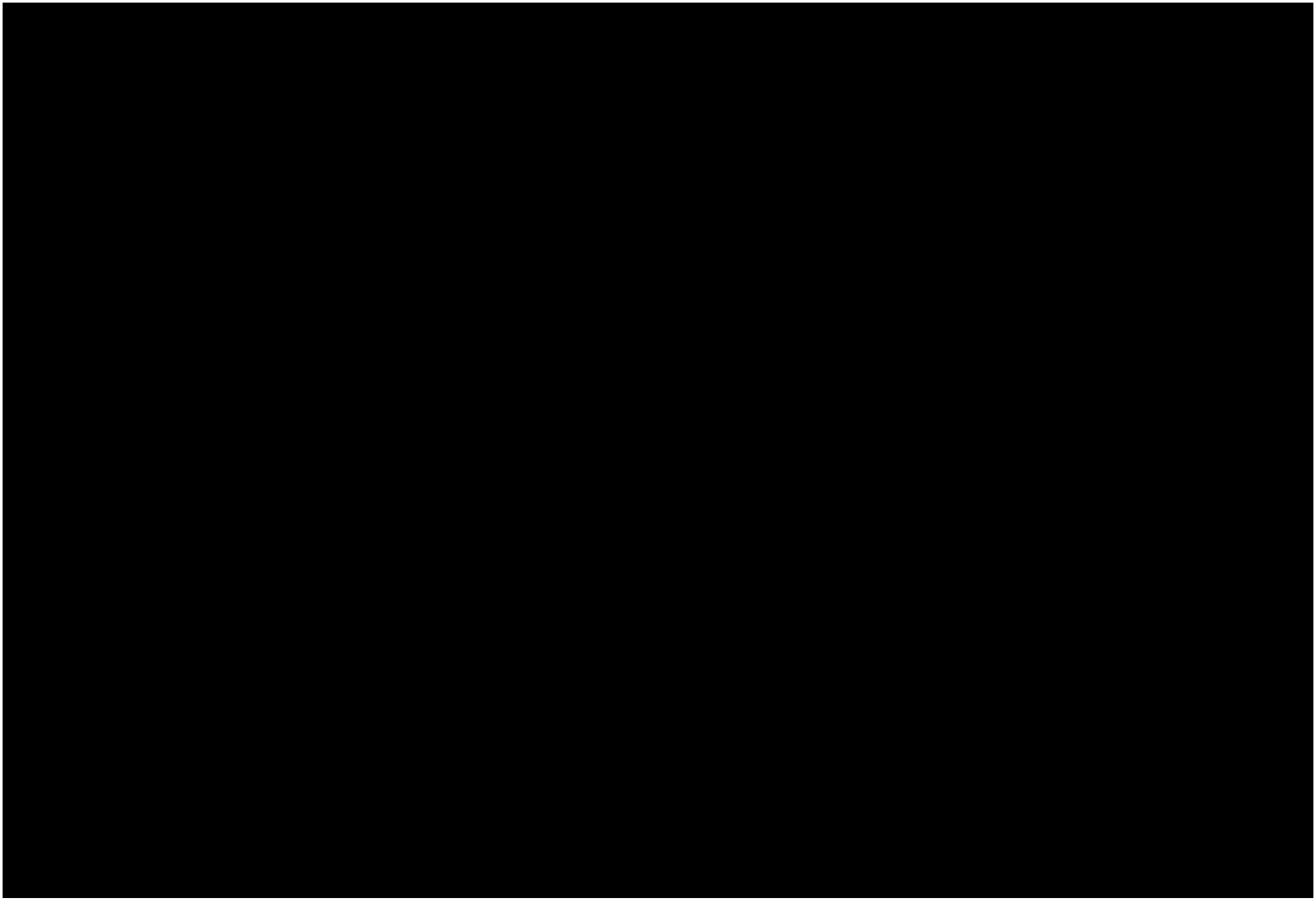
Date of Off Peak Day - 12/10/2021



Member Forecasted Off Peak Demand Day for January 2021

Socorro Electric Cooperative, Inc.

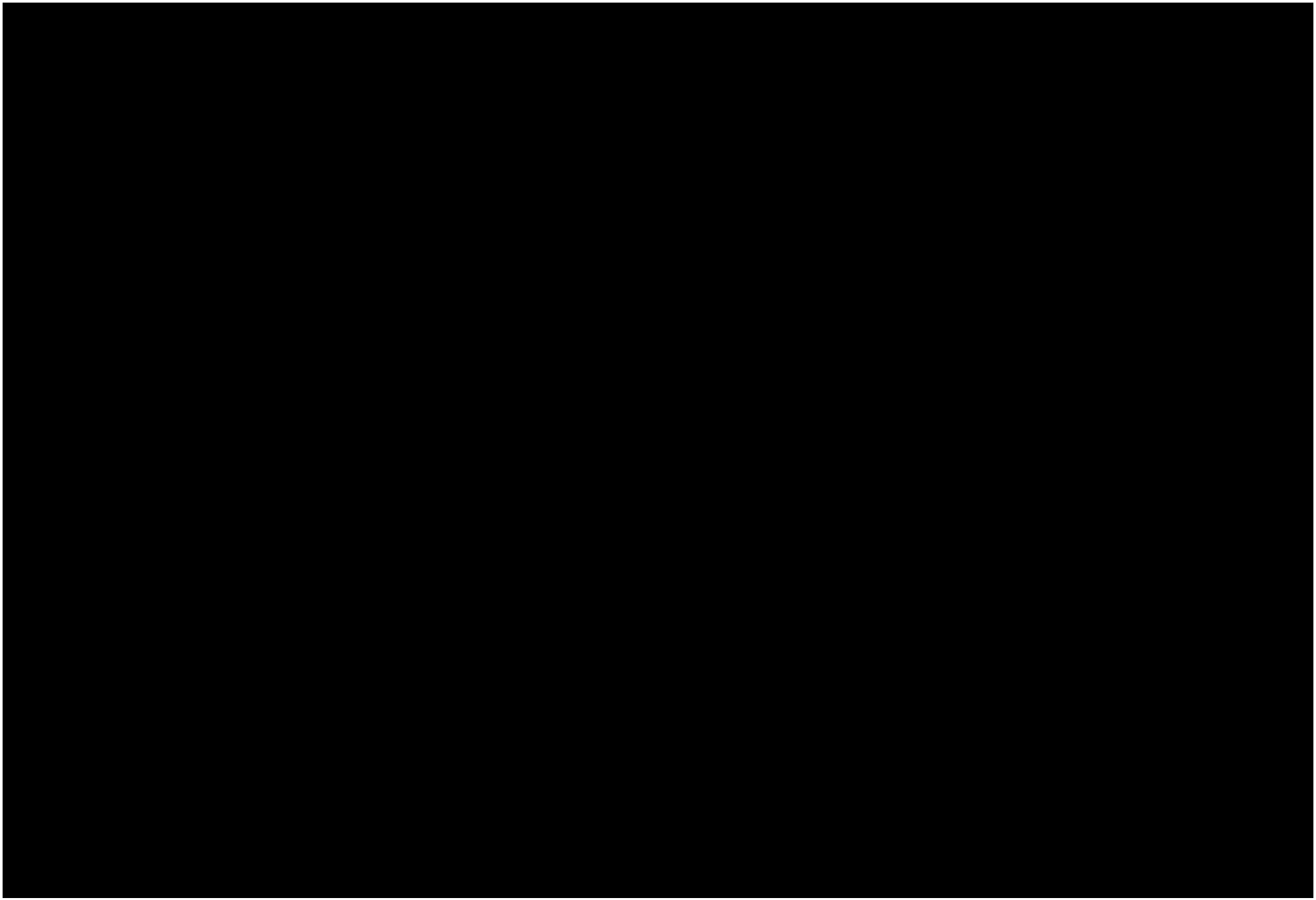
Date of Off Peak Day - 01/04/2021



Member Forecasted Off Peak Demand Day for February 2021

Socorro Electric Cooperative, Inc.

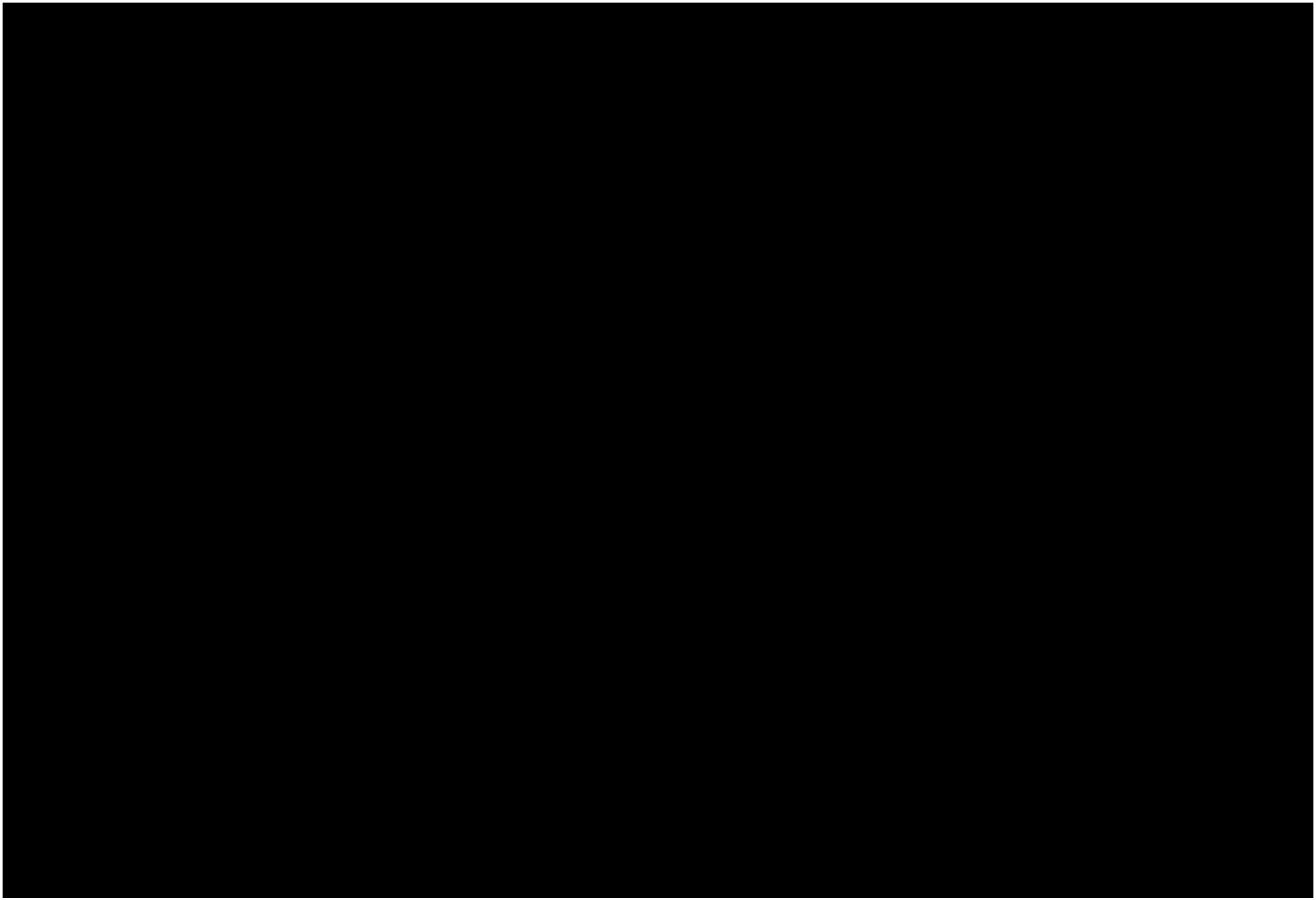
Date of Off Peak Day - 02/20/2021



Member Forecasted Off Peak Demand Day for March 2021

Socorro Electric Cooperative, Inc.

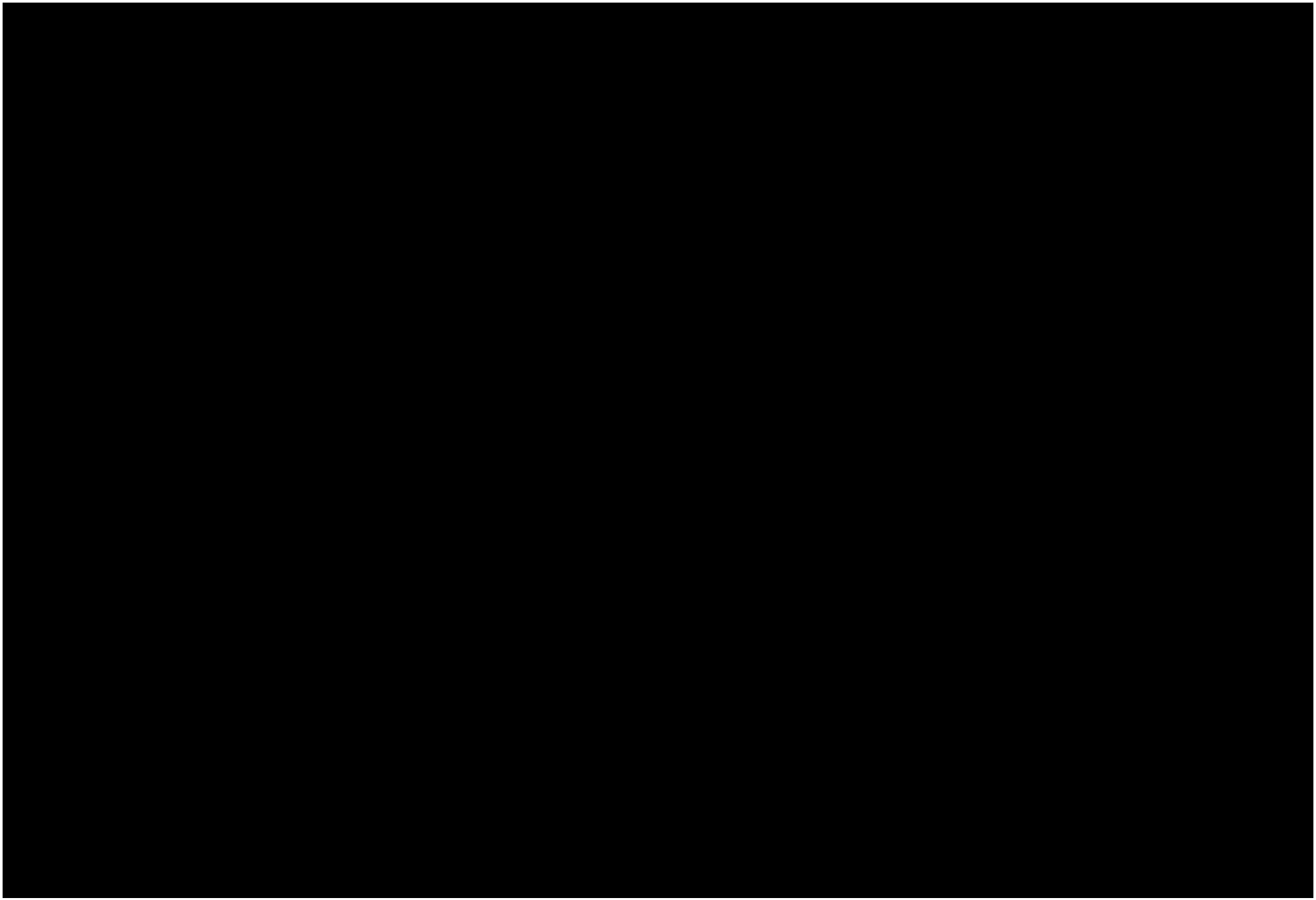
Date of Off Peak Day - 03/18/2021



Member Forecasted Off Peak Demand Day for April 2021

Socorro Electric Cooperative, Inc.

Date of Off Peak Day - 04/09/2021



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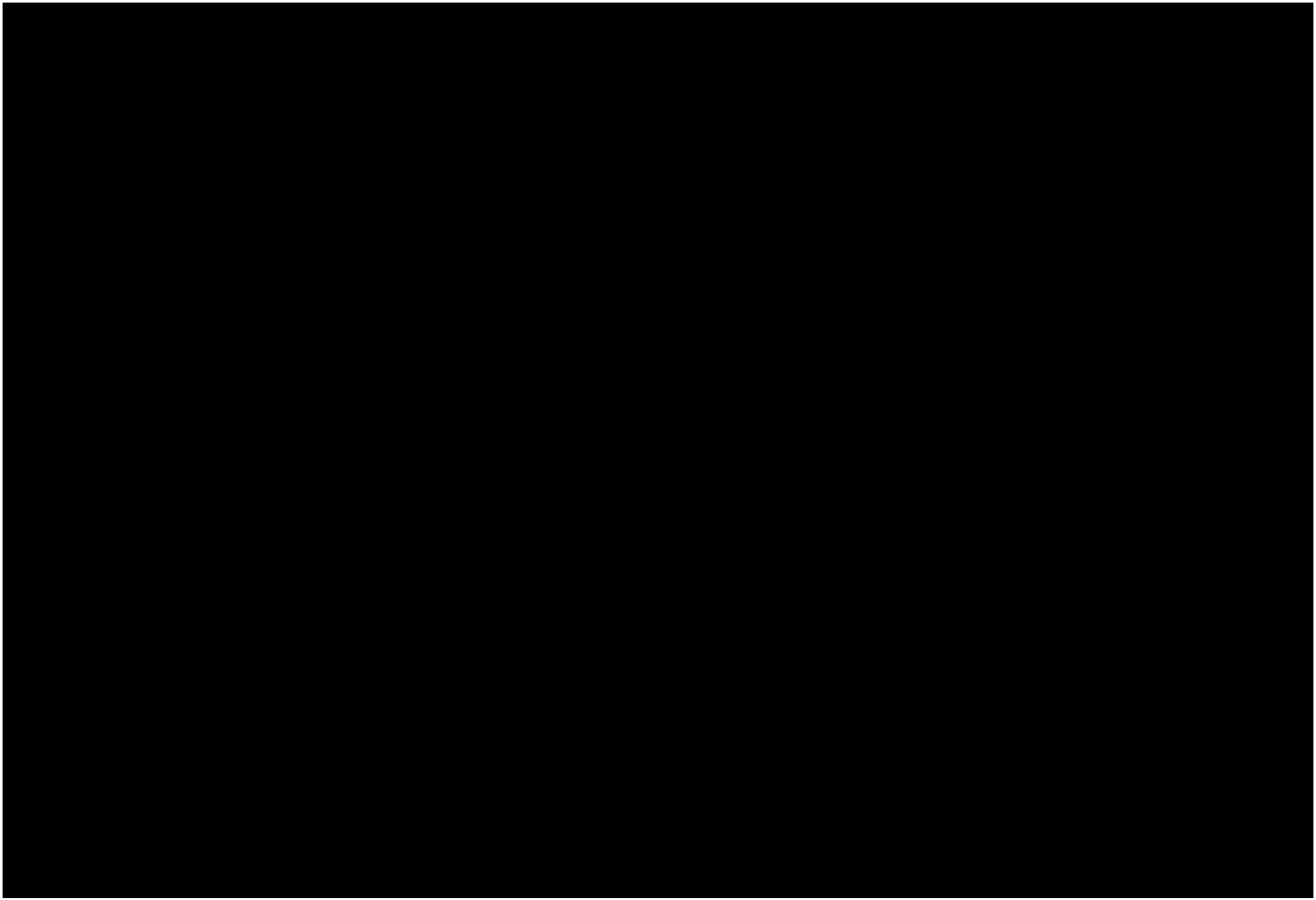
Member Forecasted Off Peak Demand Day for May 2021

Socorro Electric Cooperative, Inc.

Date of Off Peak Day - 05/30/2021



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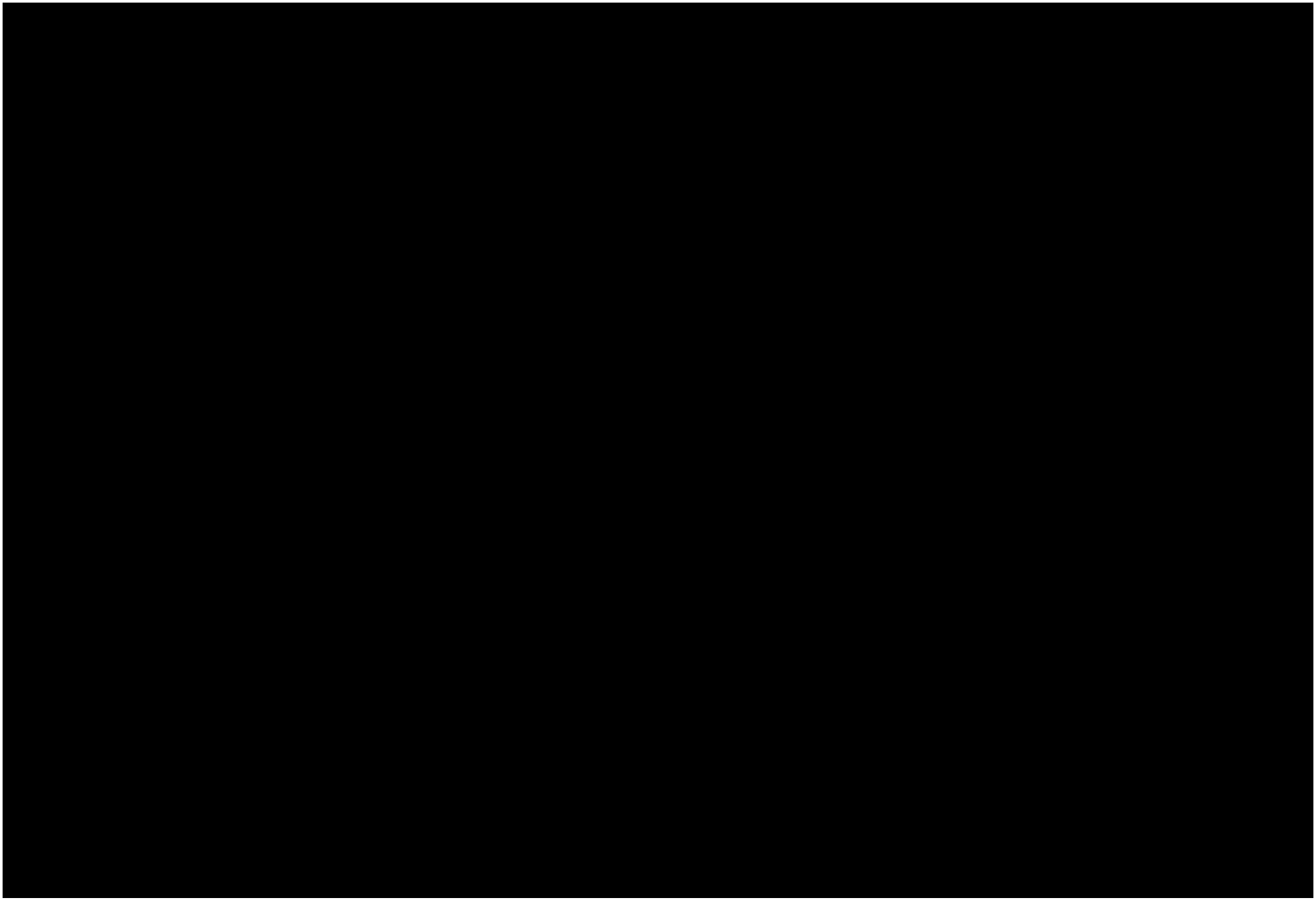
Member Forecasted Off Peak Demand Day for June 2021

Socorro Electric Cooperative, Inc.

Date of Off Peak Day - 06/02/2021



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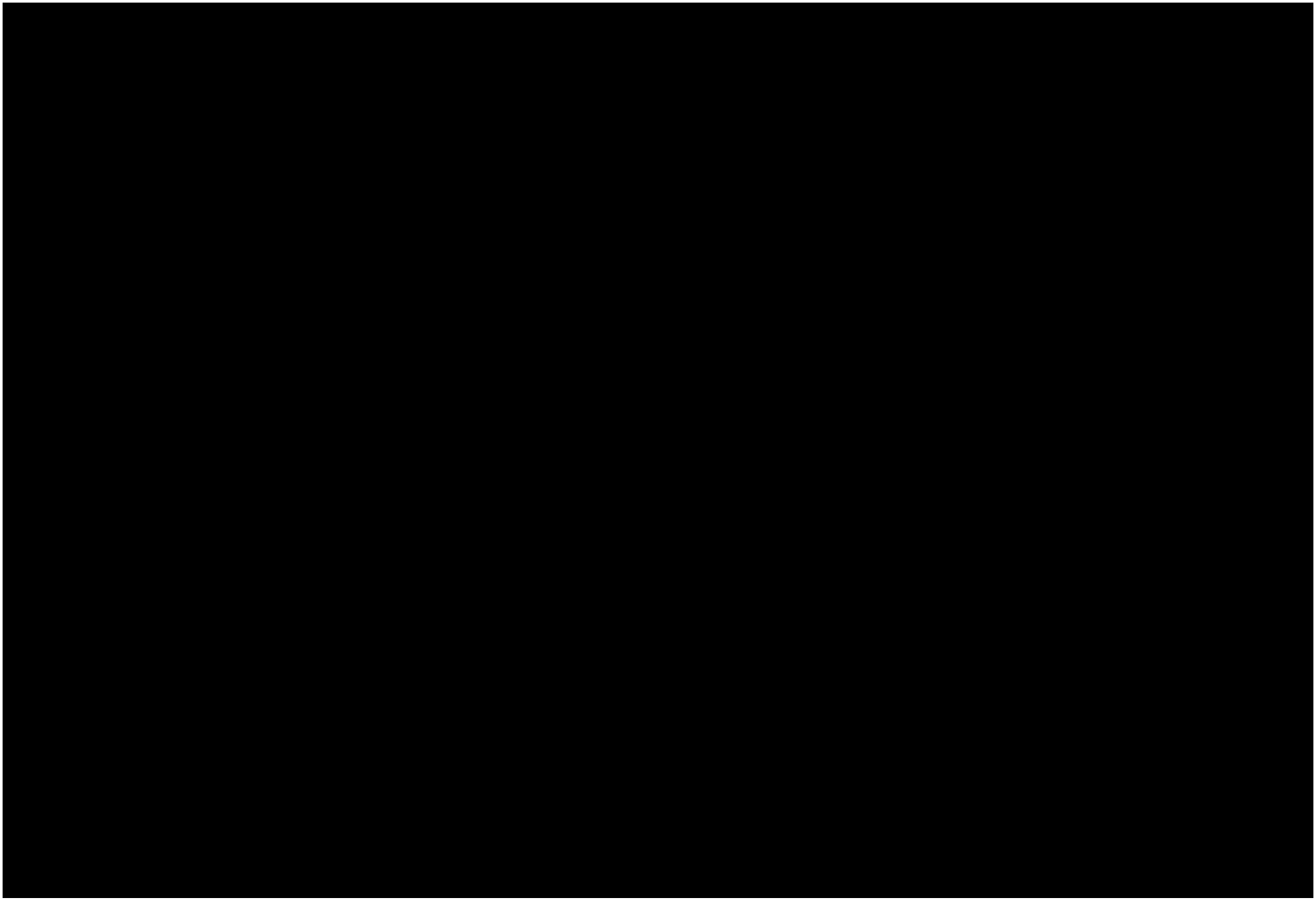
Member Forecasted Off Peak Demand Day for July 2021

Socorro Electric Cooperative, Inc.

Date of Off Peak Day - 07/04/2021



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Member Forecasted Off Peak Demand Day for August 2021

Socorro Electric Cooperative, Inc.

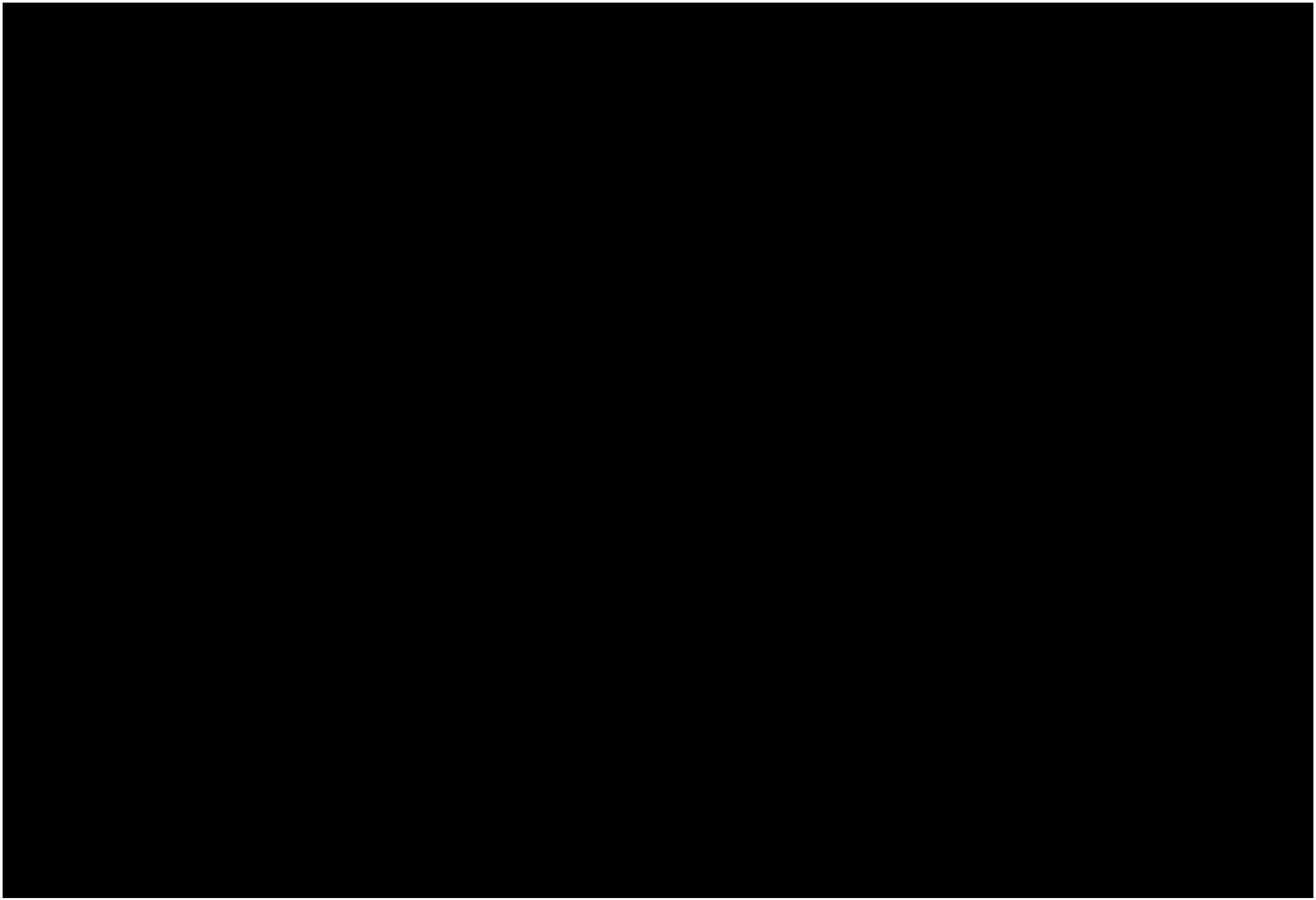
Date of Off Peak Day - 08/30/2021

[redacted]

Member Forecasted Off Peak Demand Day for September 2021

Socorro Electric Cooperative, Inc.

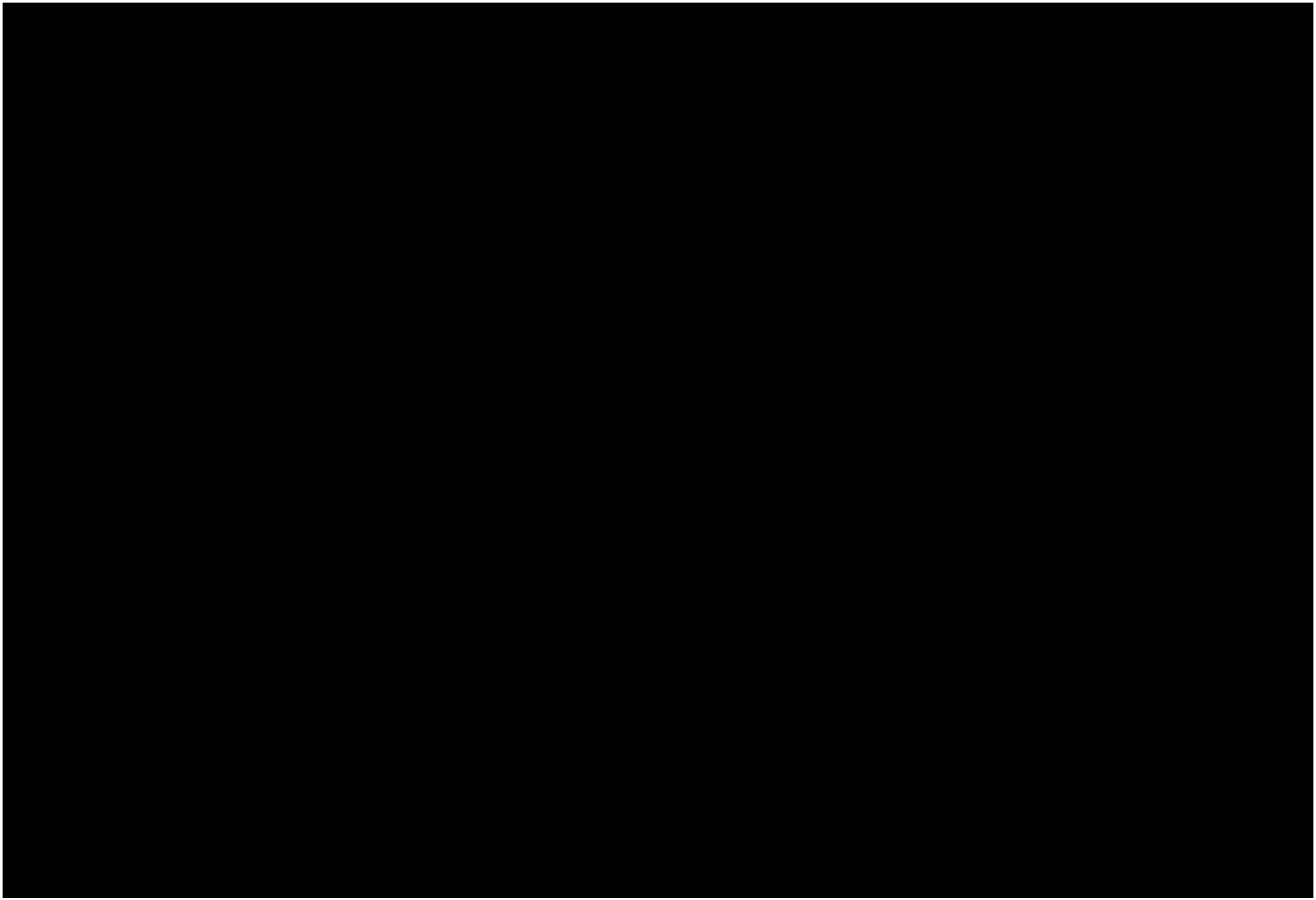
Date of Off Peak Day - 09/30/2021



Member Forecasted Off Peak Demand Day for October 2021

Socorro Electric Cooperative, Inc.

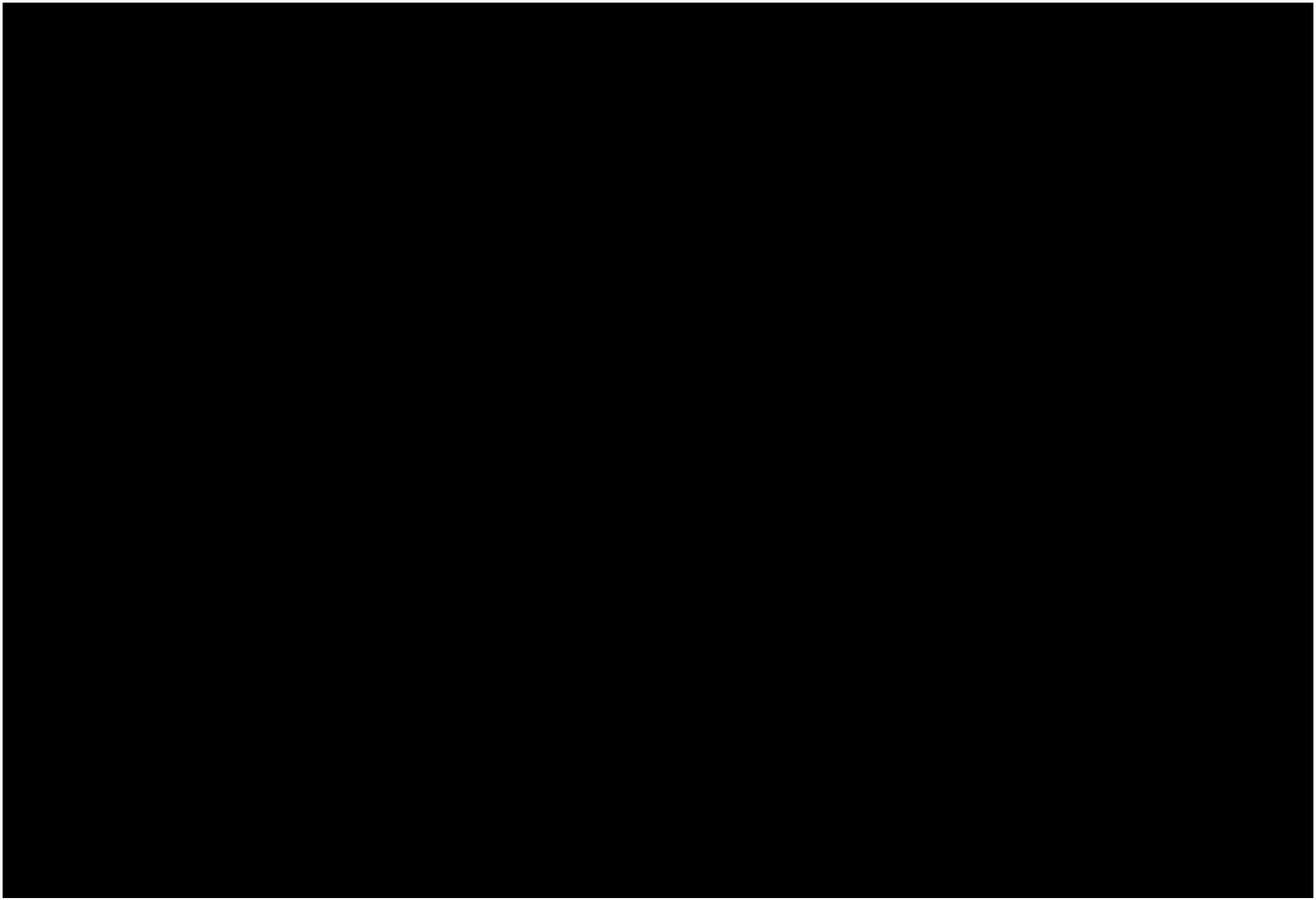
Date of Off Peak Day - 10/30/2021



Member Forecasted Off Peak Demand Day for November 2021

Socorro Electric Cooperative, Inc.

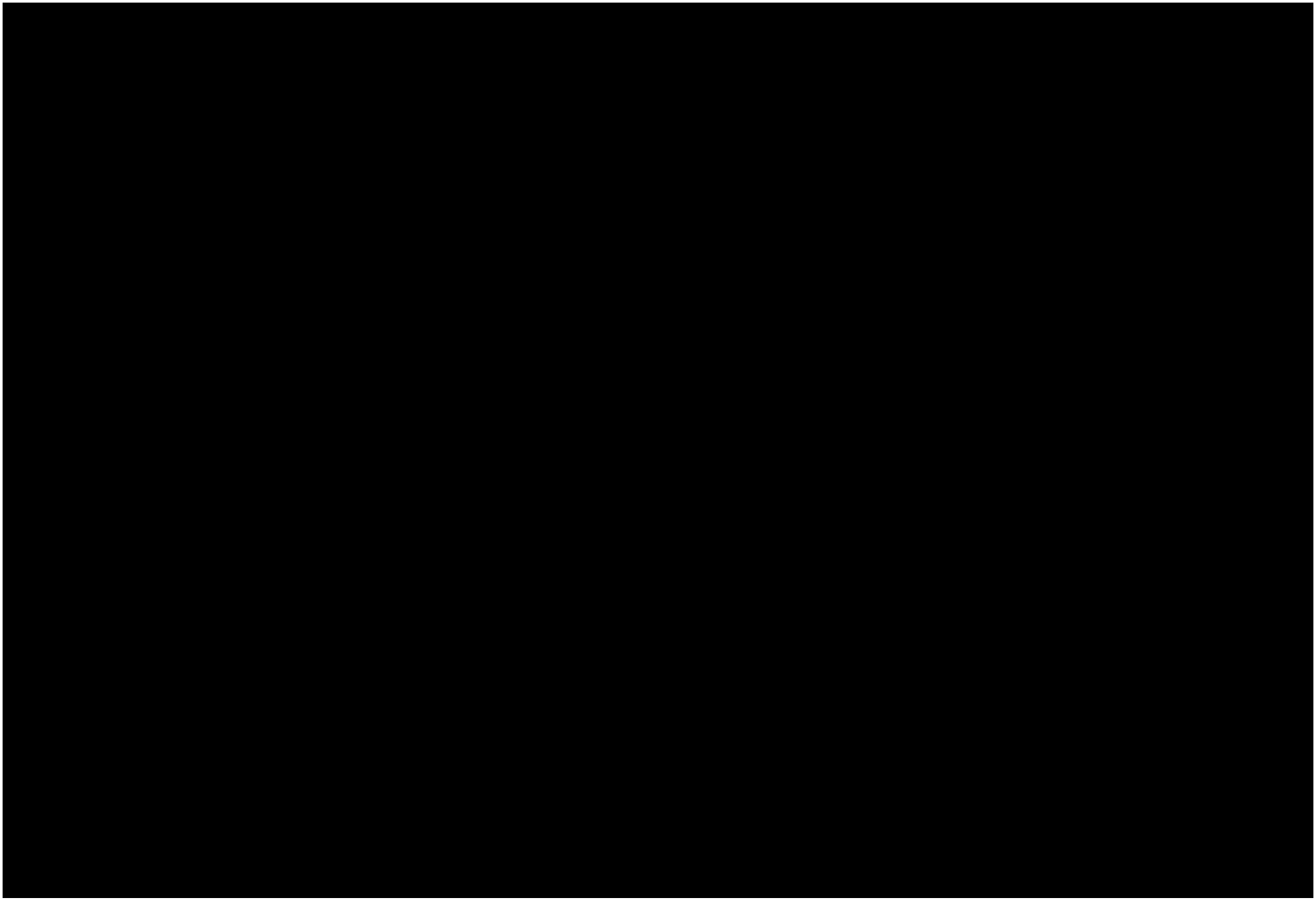
Date of Off Peak Day - 11/07/2021



Member Forecasted Off Peak Demand Day for December 2021

Socorro Electric Cooperative, Inc.

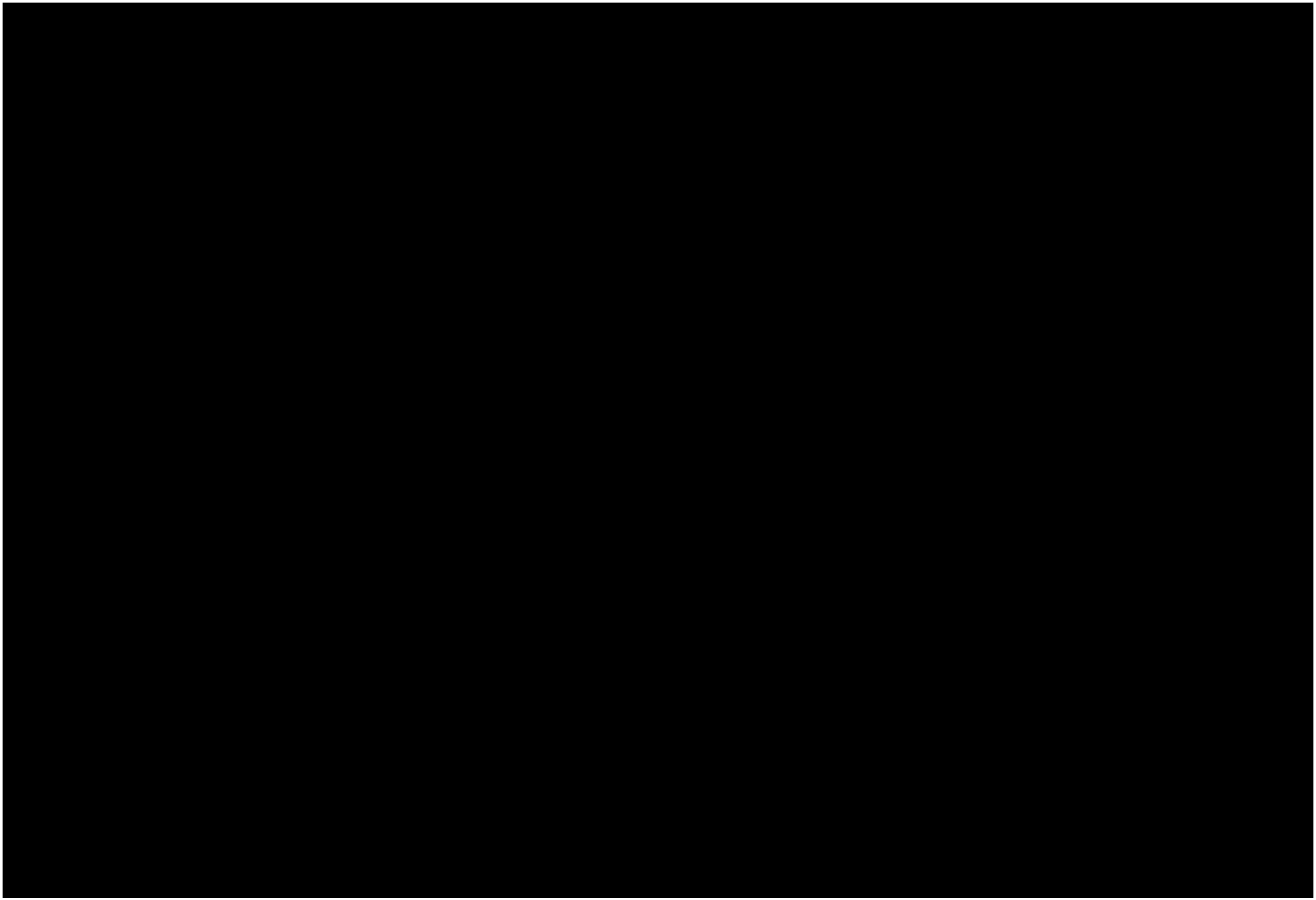
Date of Off Peak Day - 12/10/2021



Member Forecasted Off Peak Demand Day for January 2021

Springer Electric Cooperative, Inc.

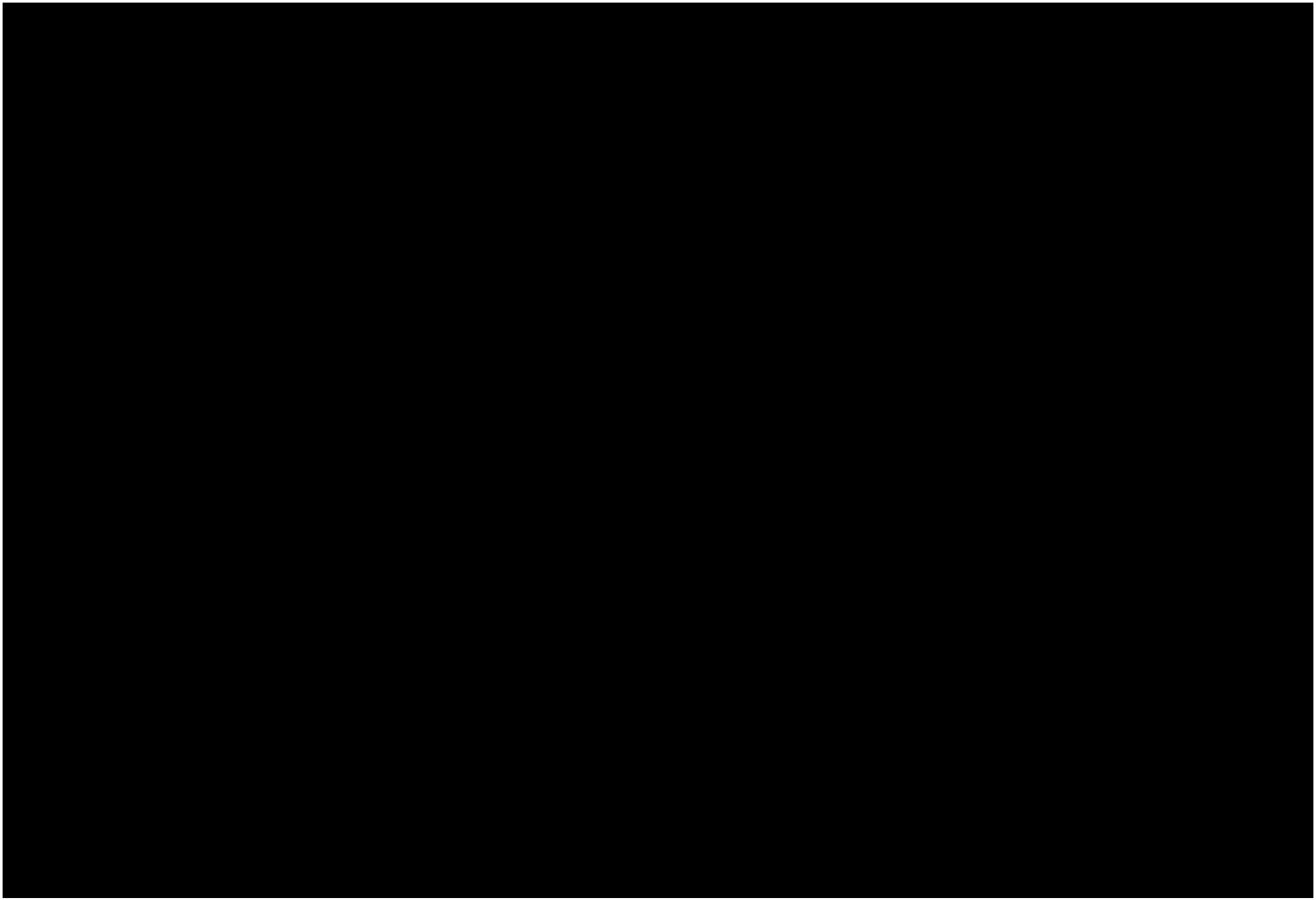
Date of Off Peak Day - 01/09/2021



Member Forecasted Off Peak Demand Day for February 2021

Springer Electric Cooperative, Inc.

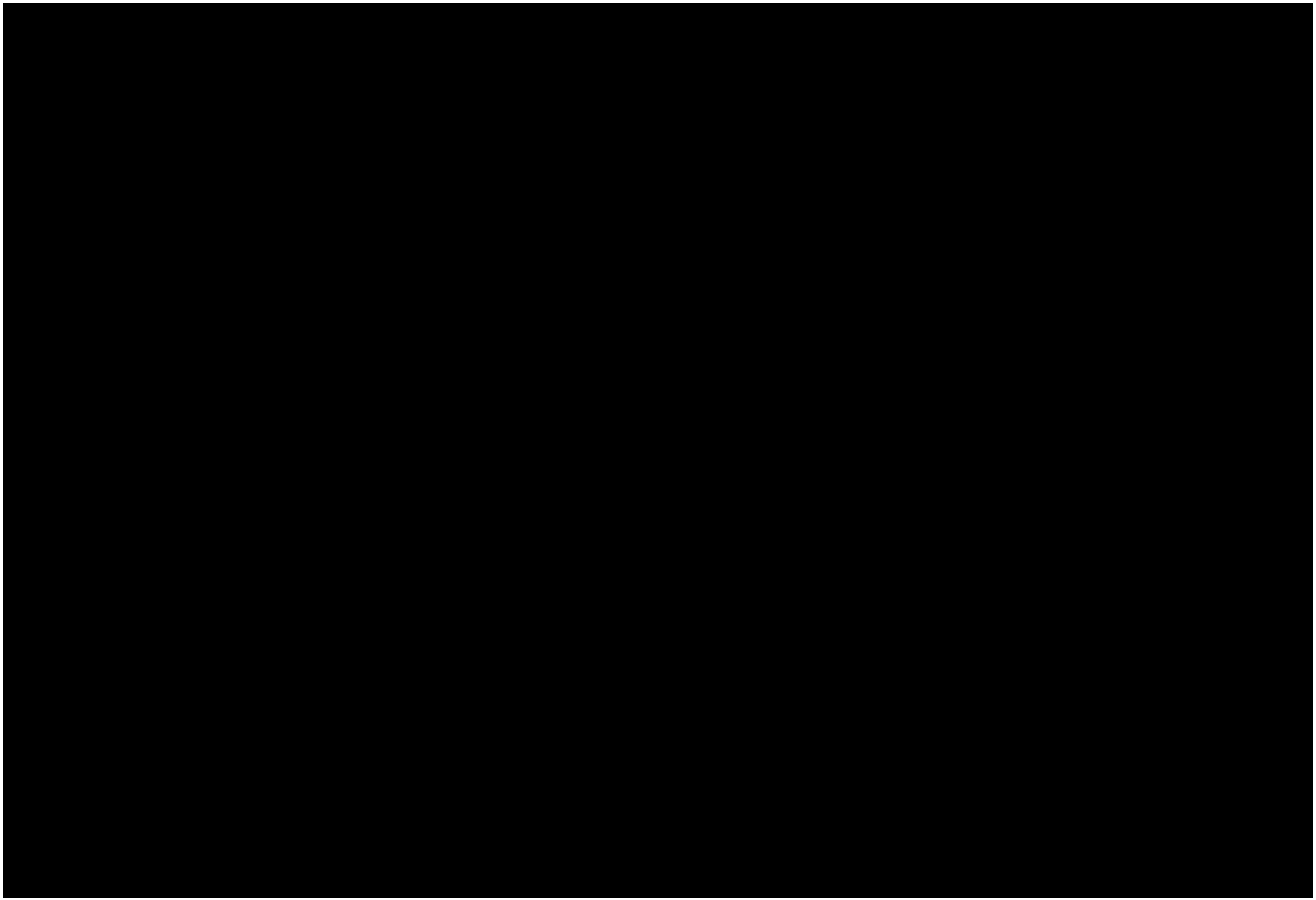
Date of Off Peak Day - 02/07/2021



Member Forecasted Off Peak Demand Day for March 2021

Springer Electric Cooperative, Inc.

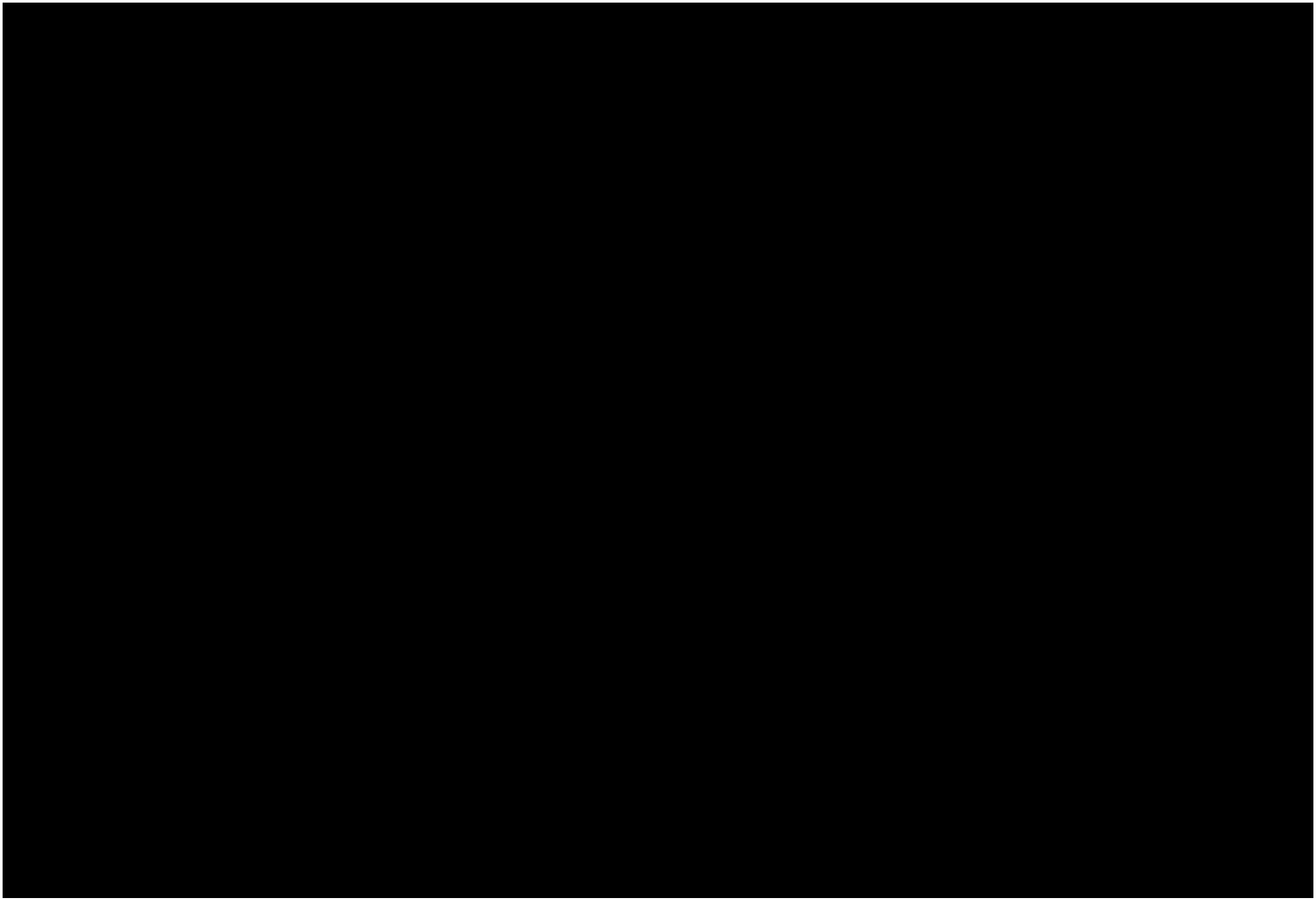
Date of Off Peak Day - 03/24/2021



Member Forecasted Off Peak Demand Day for April 2021

Springer Electric Cooperative, Inc.

Date of Off Peak Day - 04/26/2021



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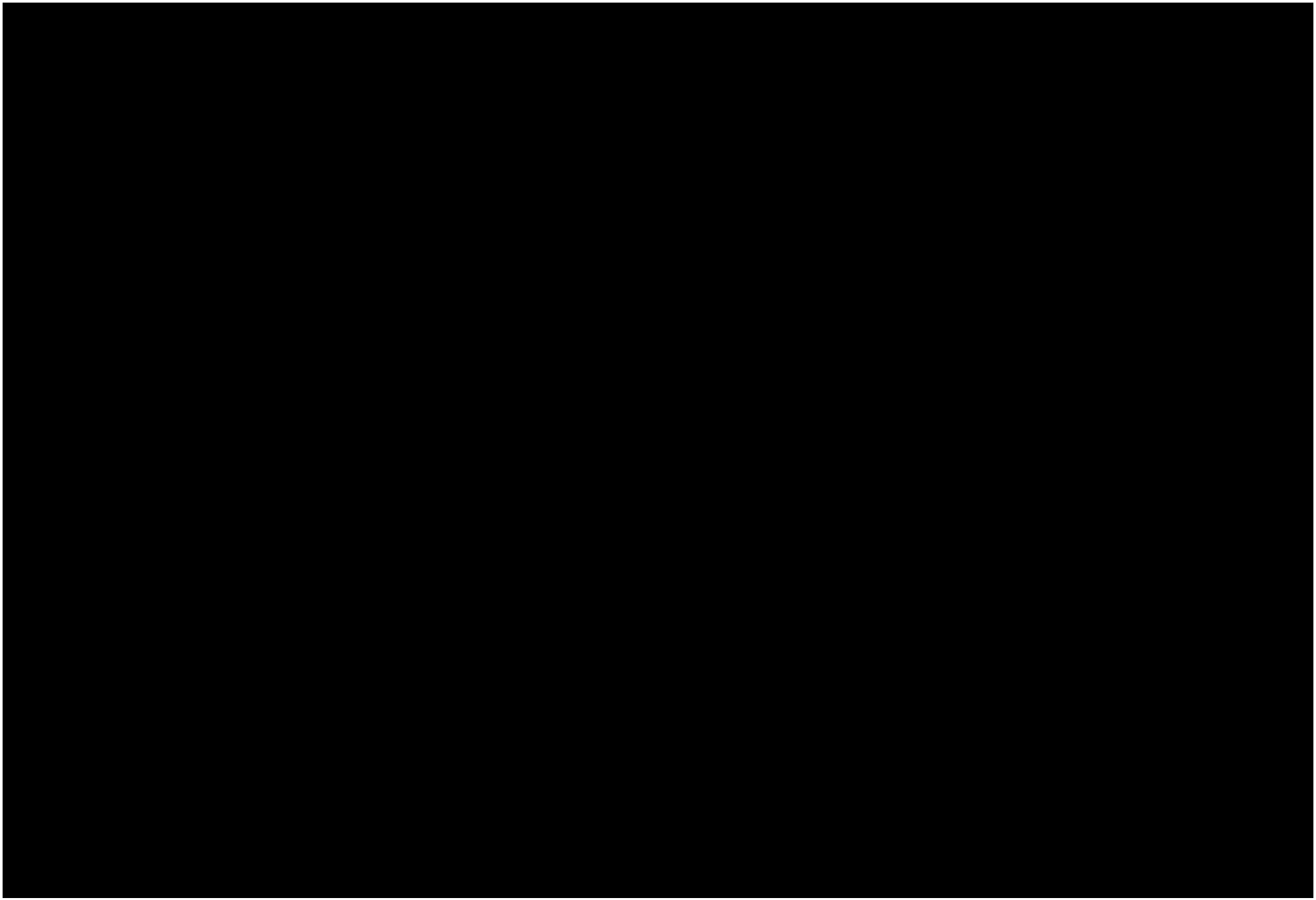
Member Forecasted Off Peak Demand Day for May 2021

Springer Electric Cooperative, Inc.

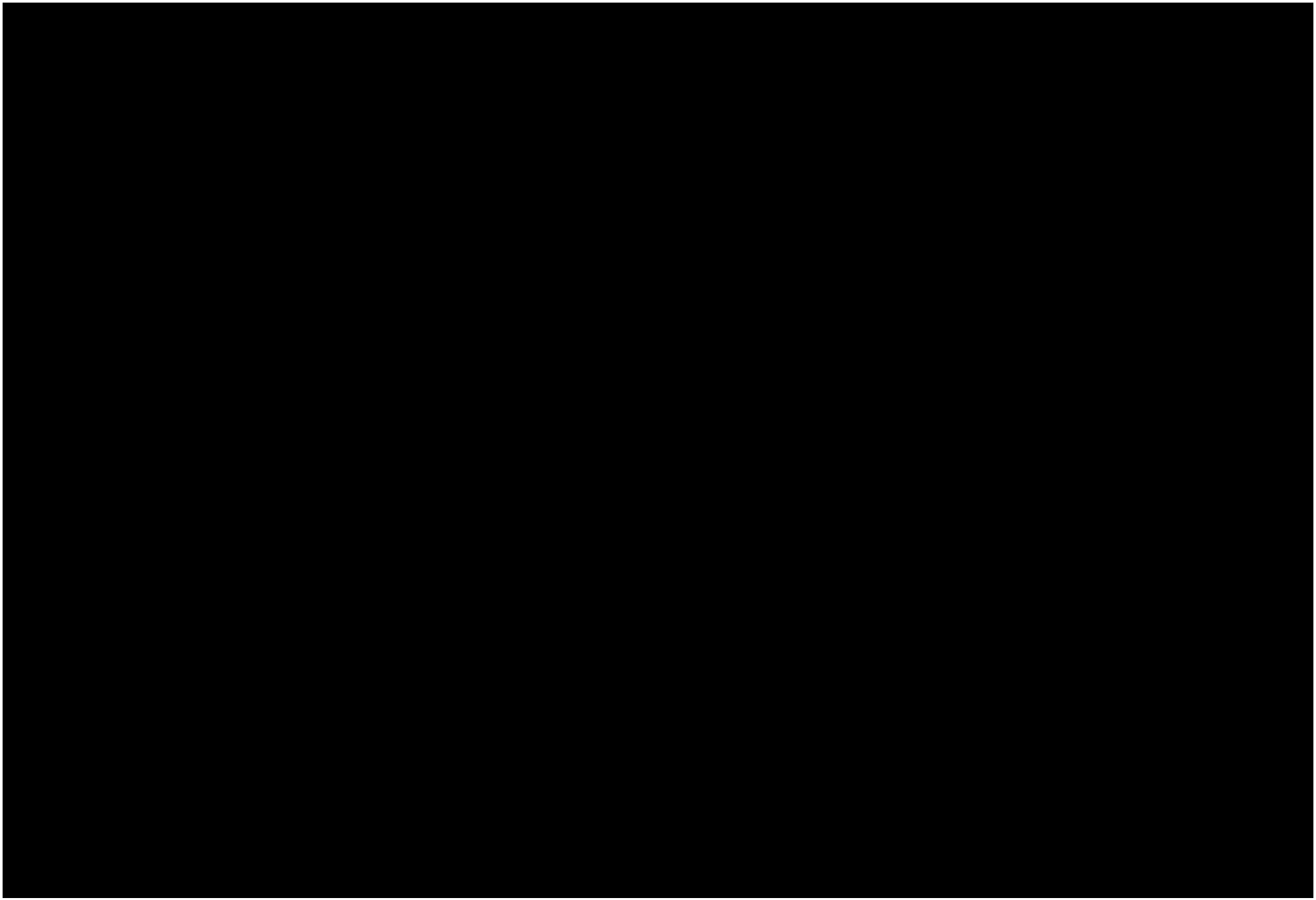
Date of Off Peak Day - 05/01/2021



Member Forecasted Off Peak Demand Day for June 2021

Springer Electric Cooperative, Inc.

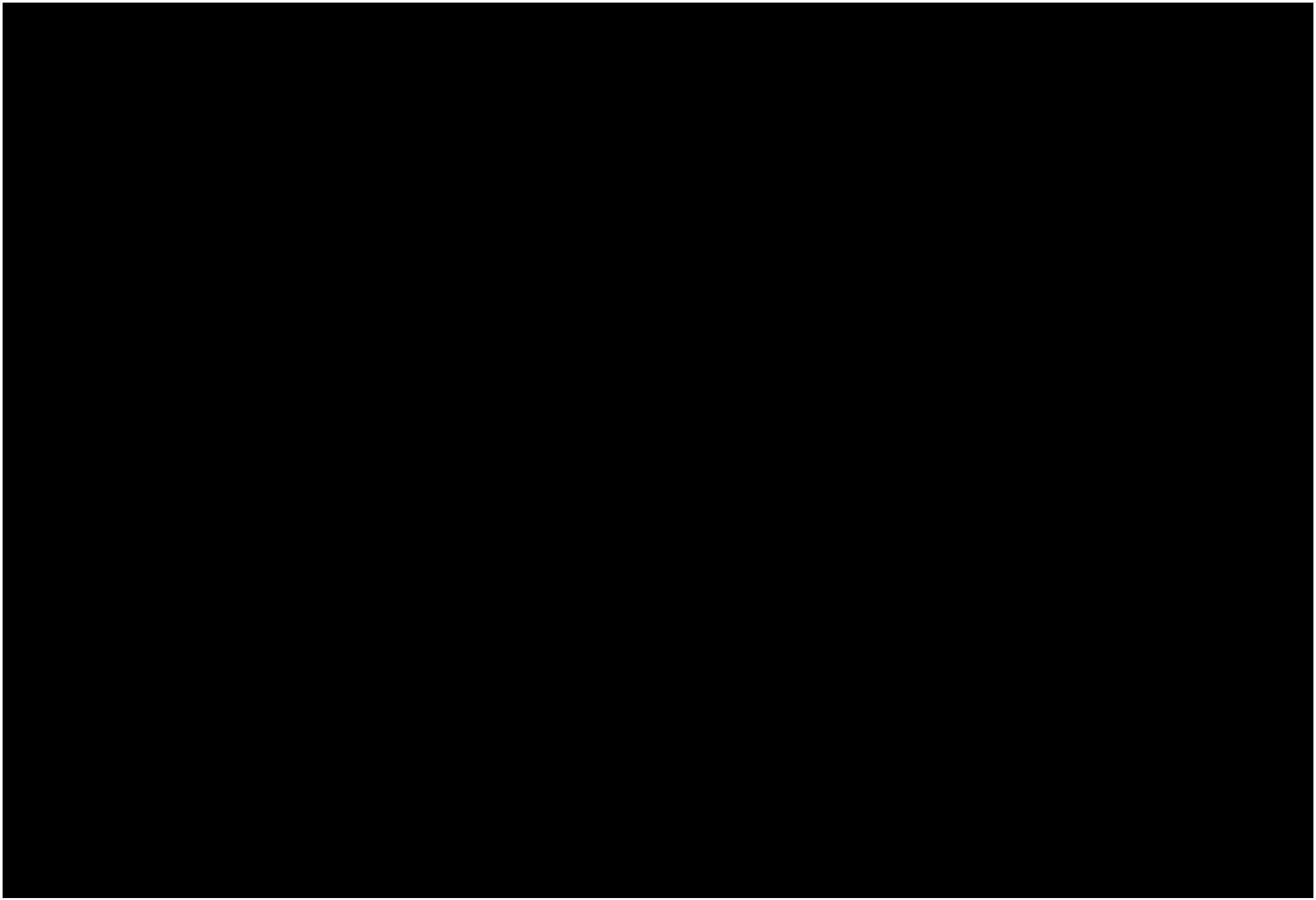
Date of Off Peak Day - 06/03/2021



Member Forecasted Off Peak Demand Day for July 2021

Springer Electric Cooperative, Inc.

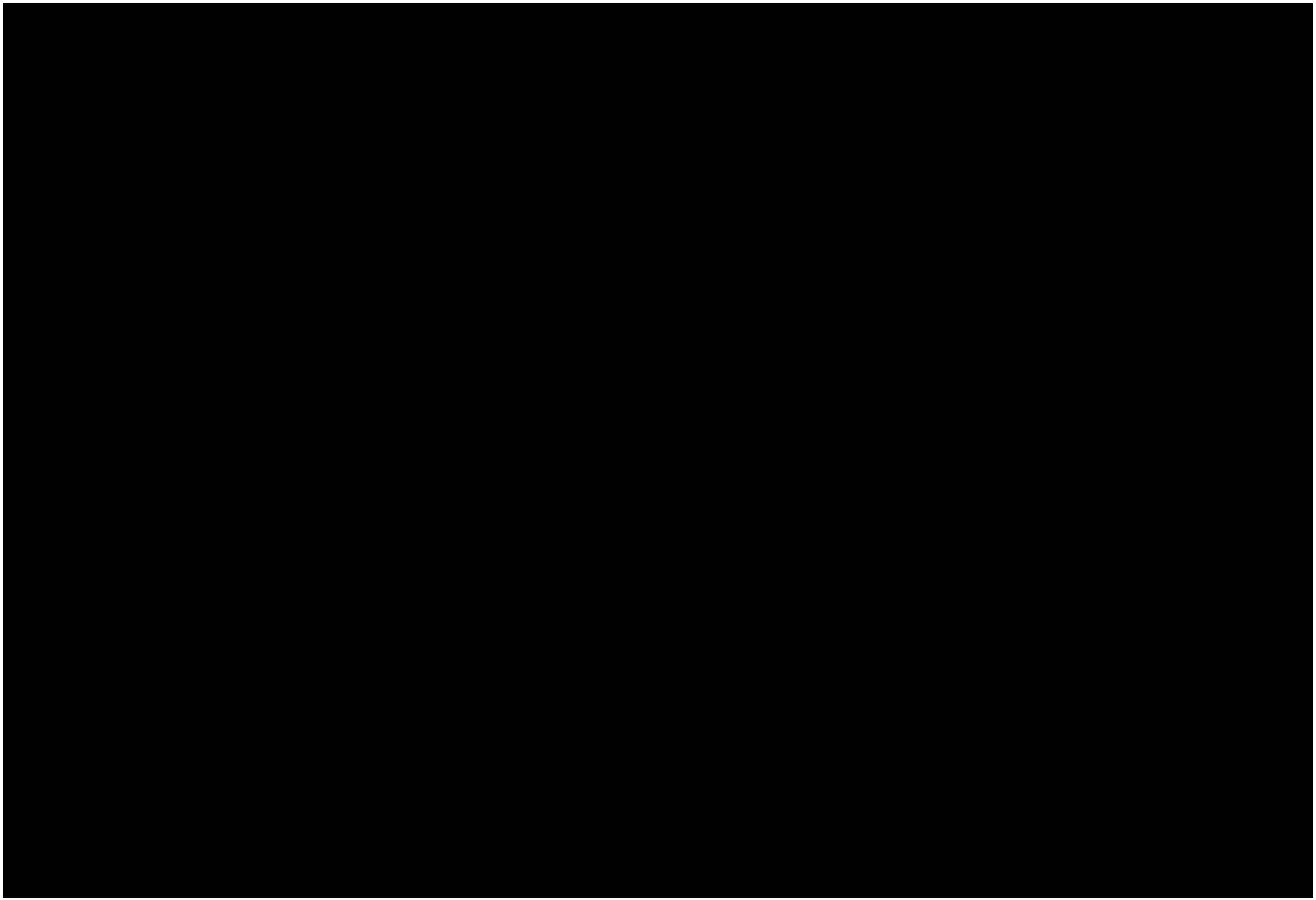
Date of Off Peak Day - 07/25/2021



Member Forecasted Off Peak Demand Day for August 2021

Springer Electric Cooperative, Inc.

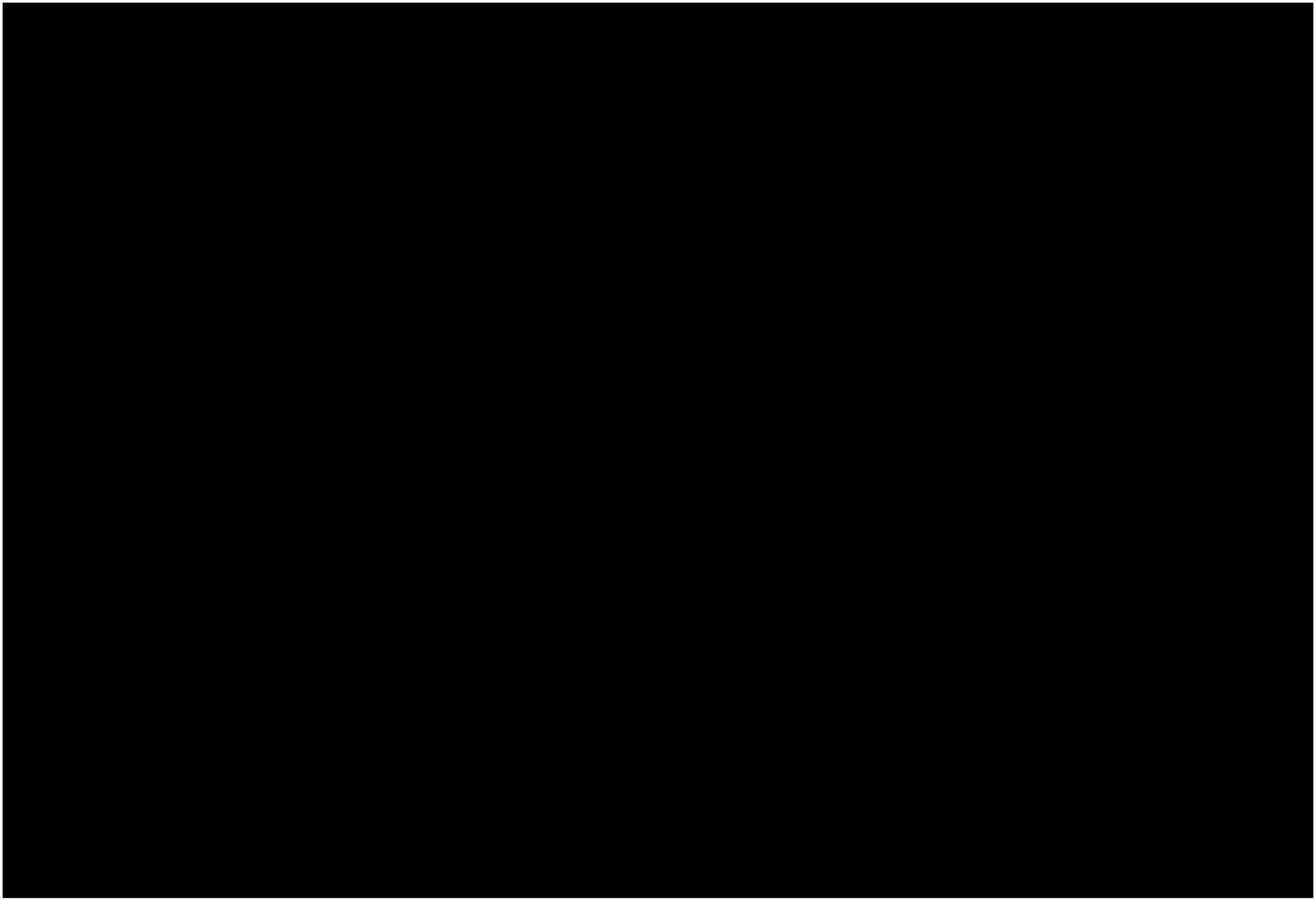
Date of Off Peak Day - 08/31/2021



Member Forecasted Off Peak Demand Day for September 2021

Springer Electric Cooperative, Inc.

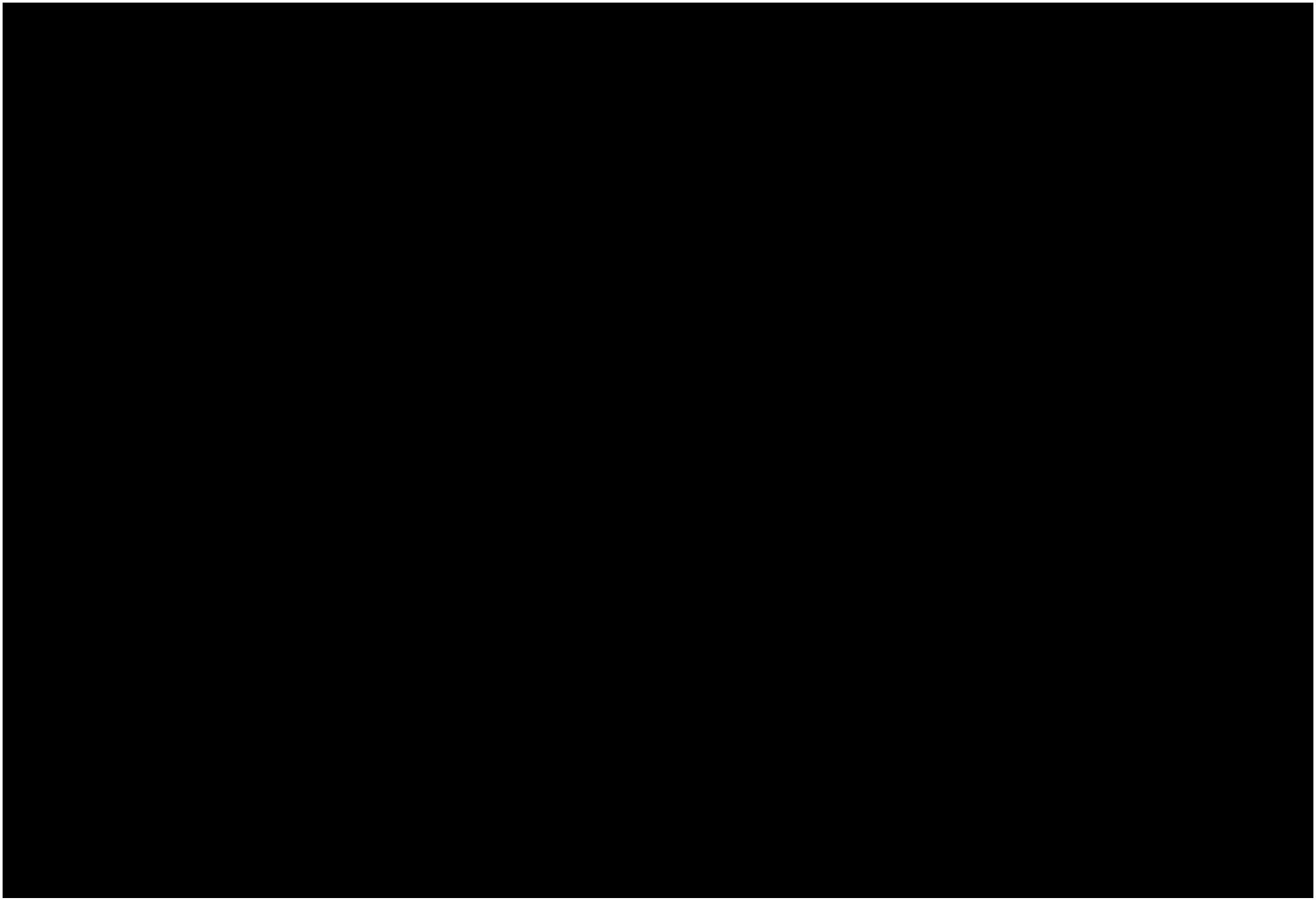
Date of Off Peak Day - 09/30/2021



Member Forecasted Off Peak Demand Day for October 2021

Springer Electric Cooperative, Inc.

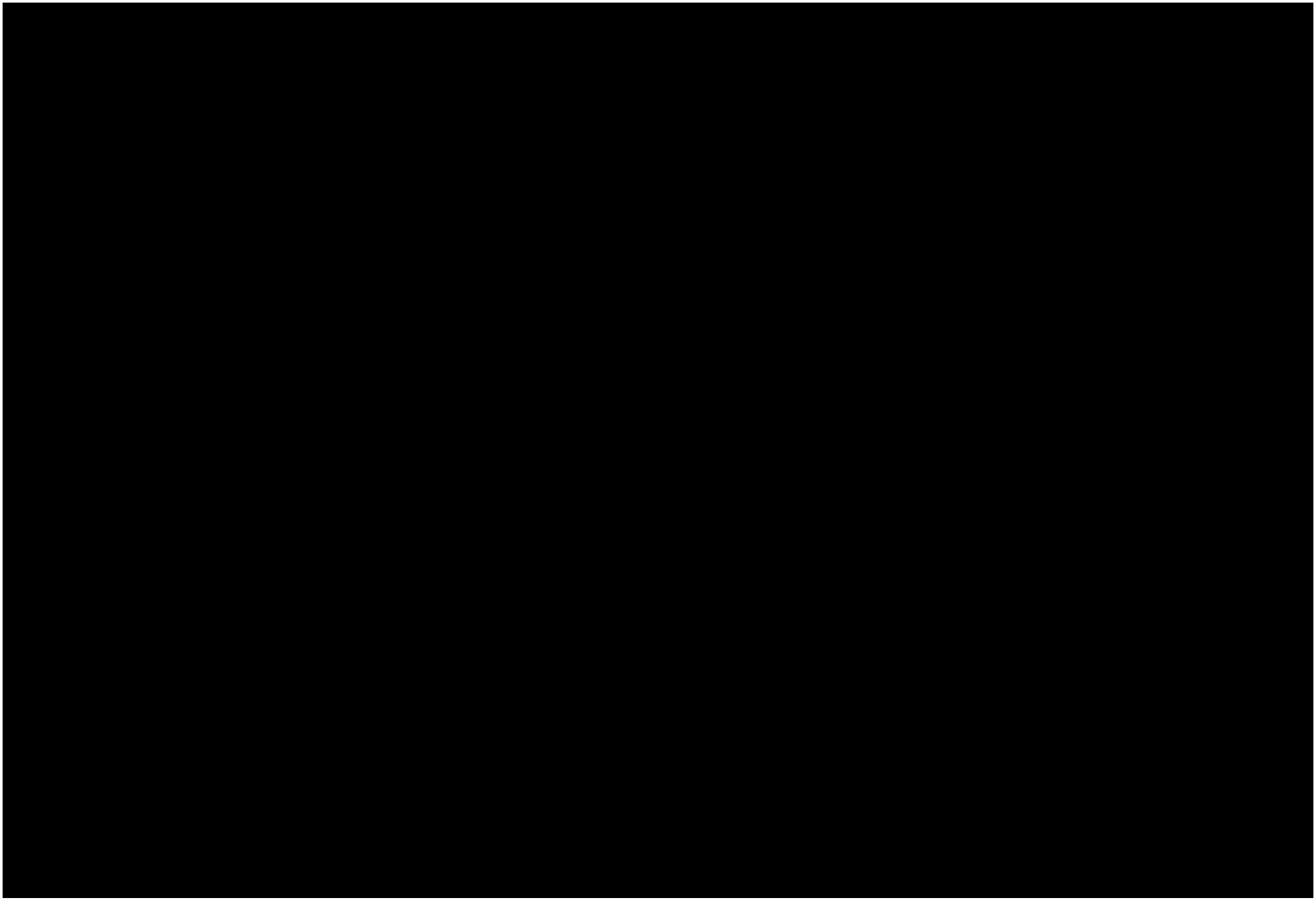
Date of Off Peak Day - 10/20/2021



Member Forecasted Off Peak Demand Day for November 2021

Springer Electric Cooperative, Inc.

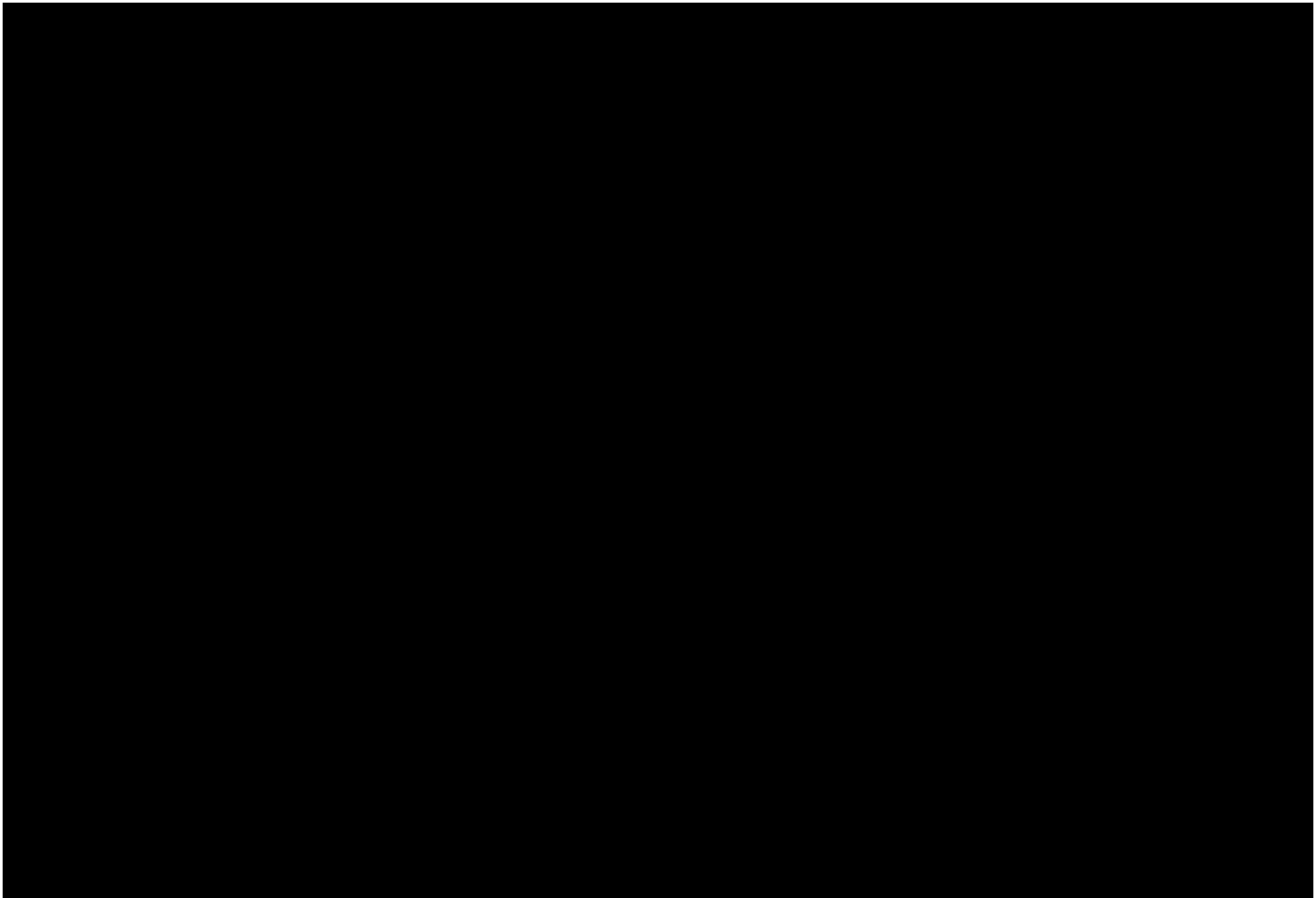
Date of Off Peak Day - 11/18/2021



Member Forecasted Off Peak Demand Day for December 2021

Springer Electric Cooperative, Inc.

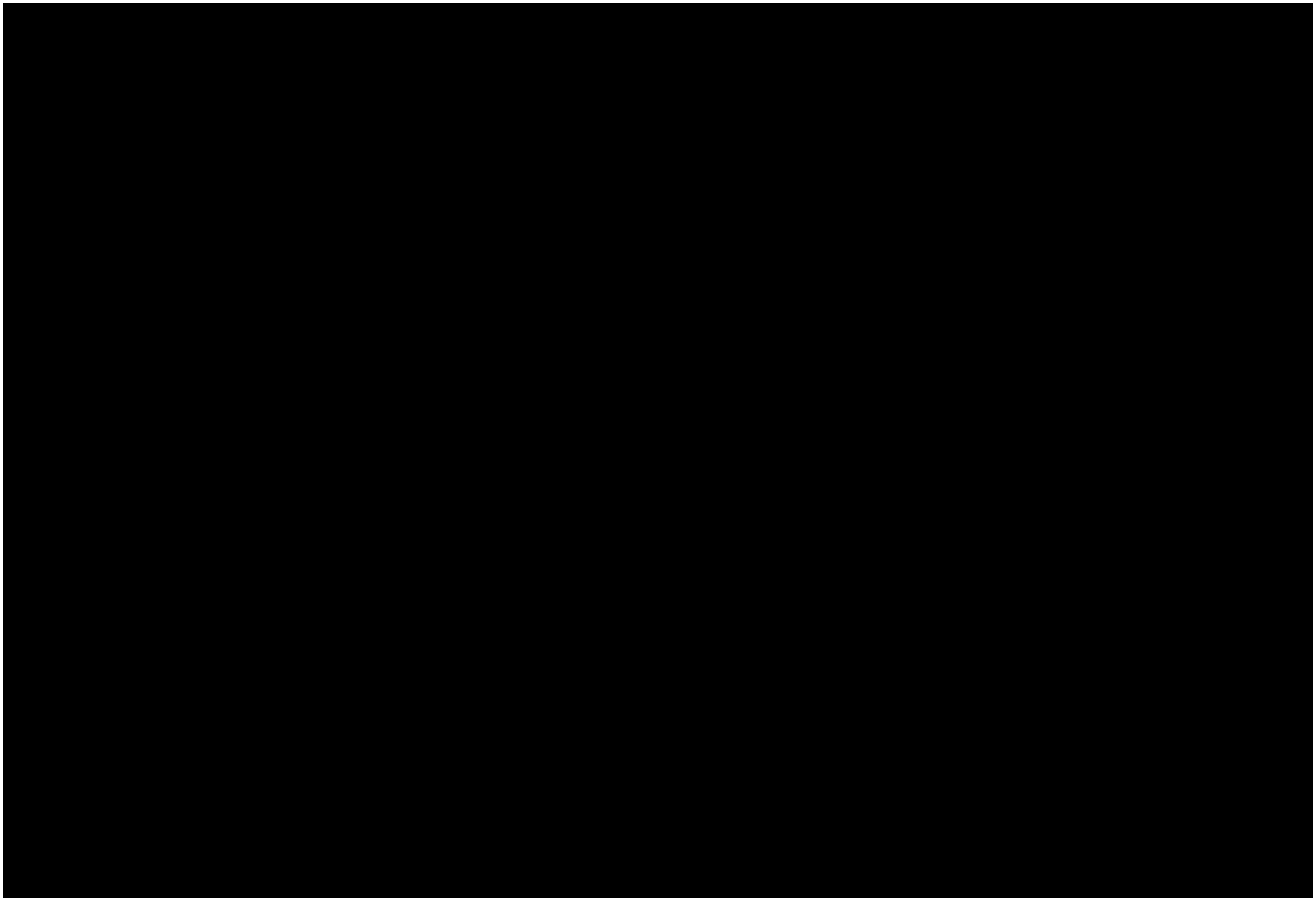
Date of Off Peak Day - 12/30/2021



Member Forecasted Off Peak Demand Day for January 2021

Southwestern Electric Cooperative, Inc.

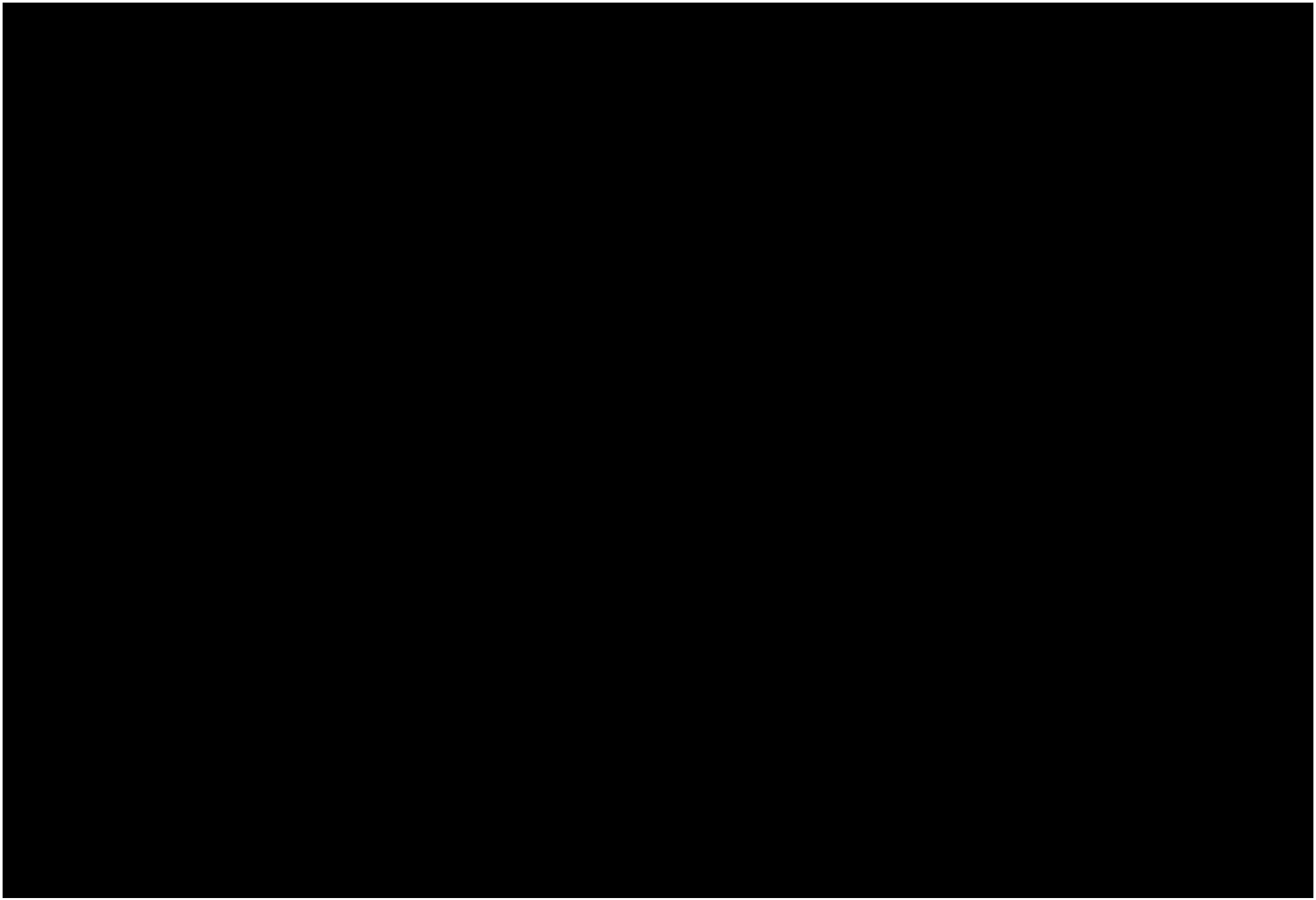
Date of Off Peak Day - 01/31/2021



Member Forecasted Off Peak Demand Day for February 2021

Southwestern Electric Cooperative, Inc.

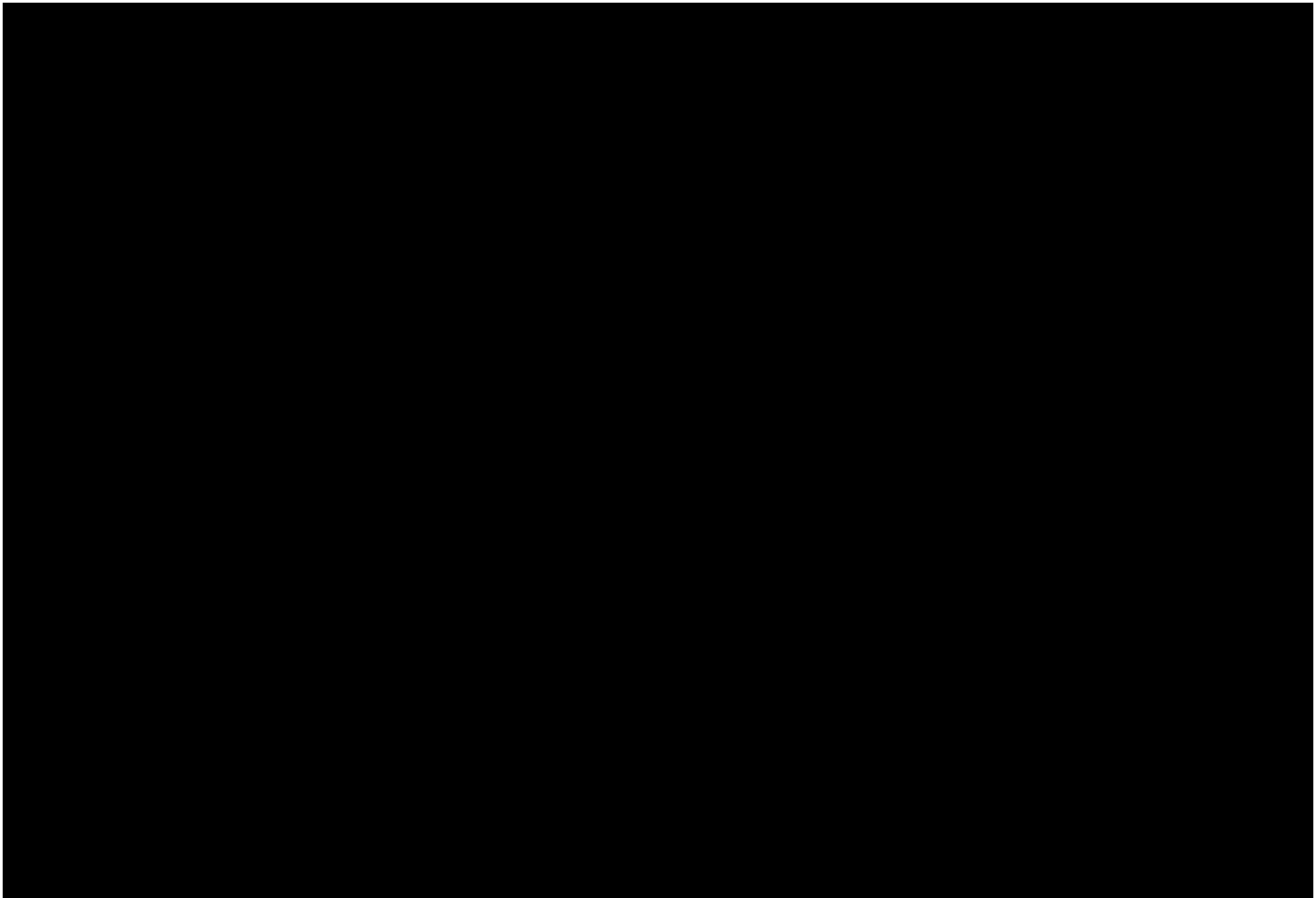
Date of Off Peak Day - 02/02/2021



Member Forecasted Off Peak Demand Day for March 2021

Southwestern Electric Cooperative, Inc.

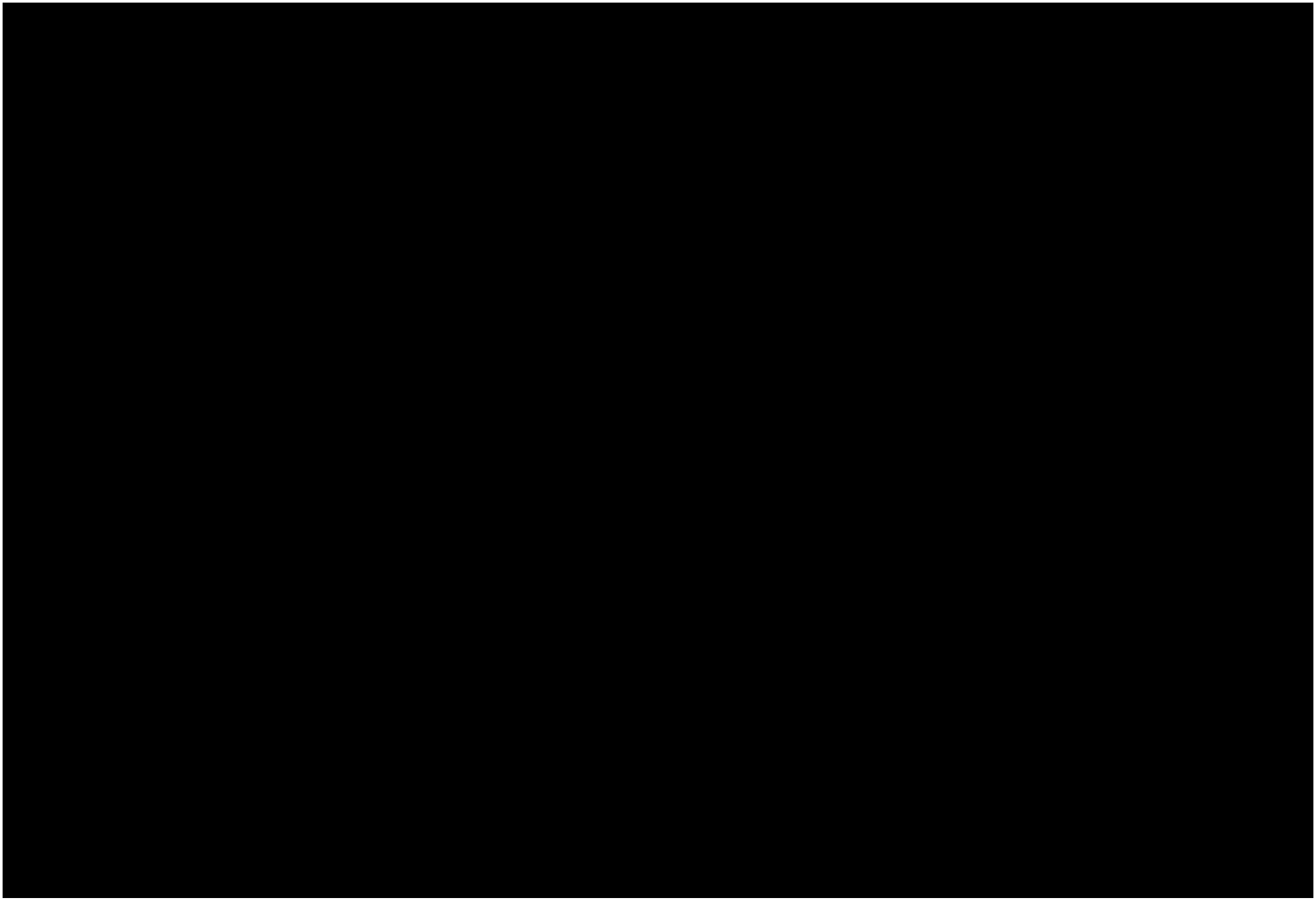
Date of Off Peak Day - 03/10/2021



Member Forecasted Off Peak Demand Day for April 2021

Southwestern Electric Cooperative, Inc.

Date of Off Peak Day - 04/13/2021



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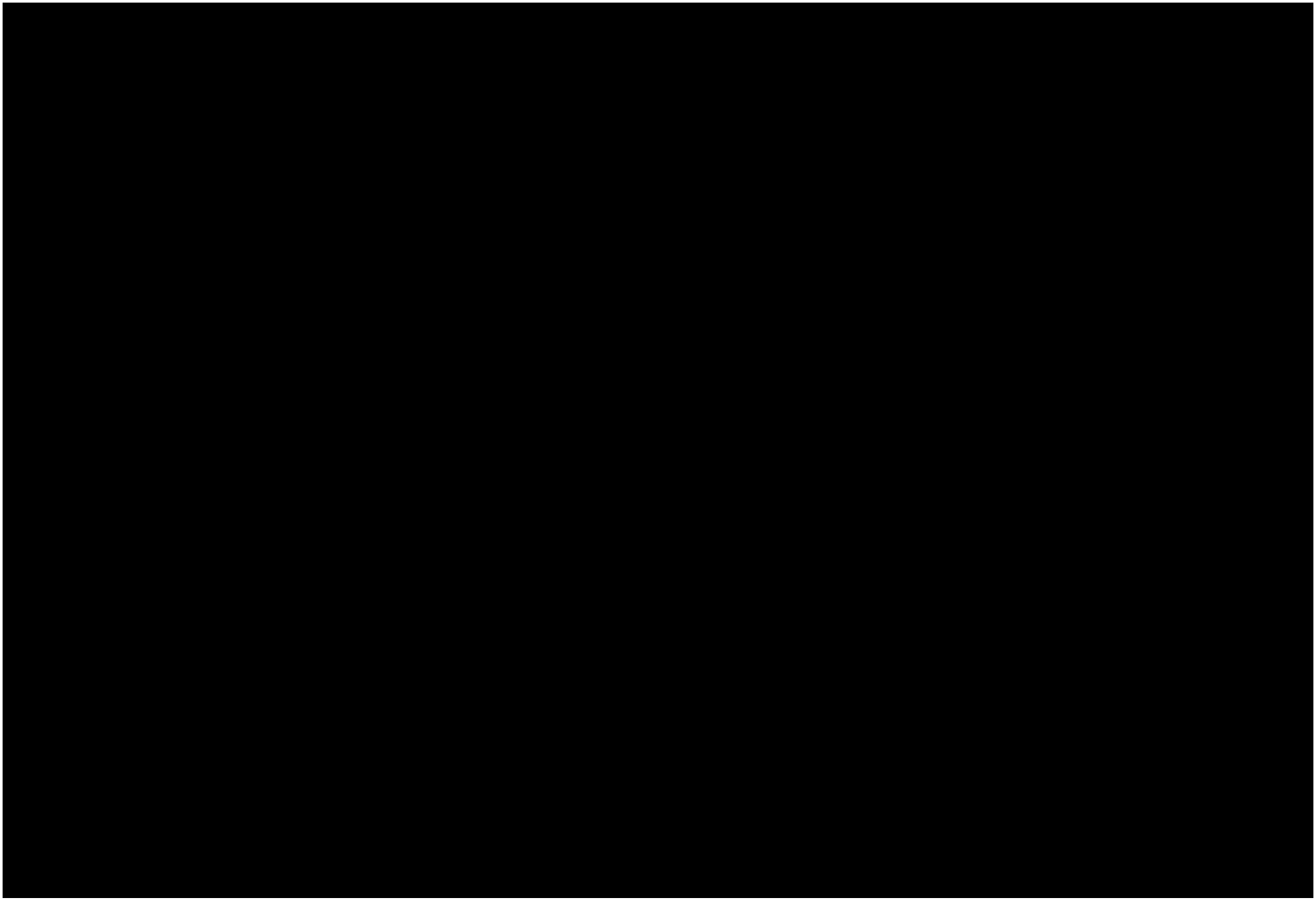
Member Forecasted Off Peak Demand Day for May 2021

Southwestern Electric Cooperative, Inc.

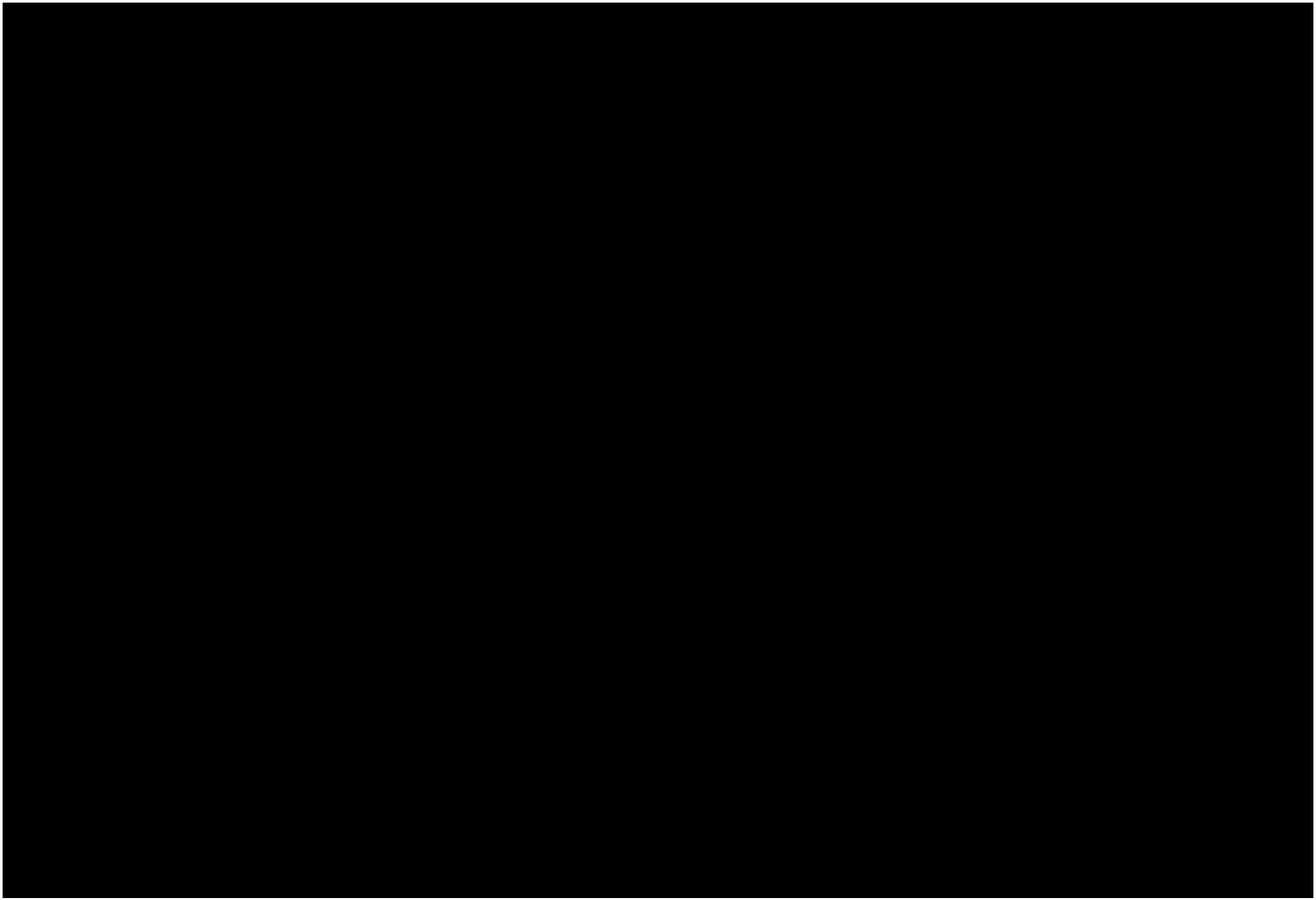
Date of Off Peak Day - 05/05/2021



Member Forecasted Off Peak Demand Day for June 2021

Southwestern Electric Cooperative, Inc.

Date of Off Peak Day - 06/03/2021



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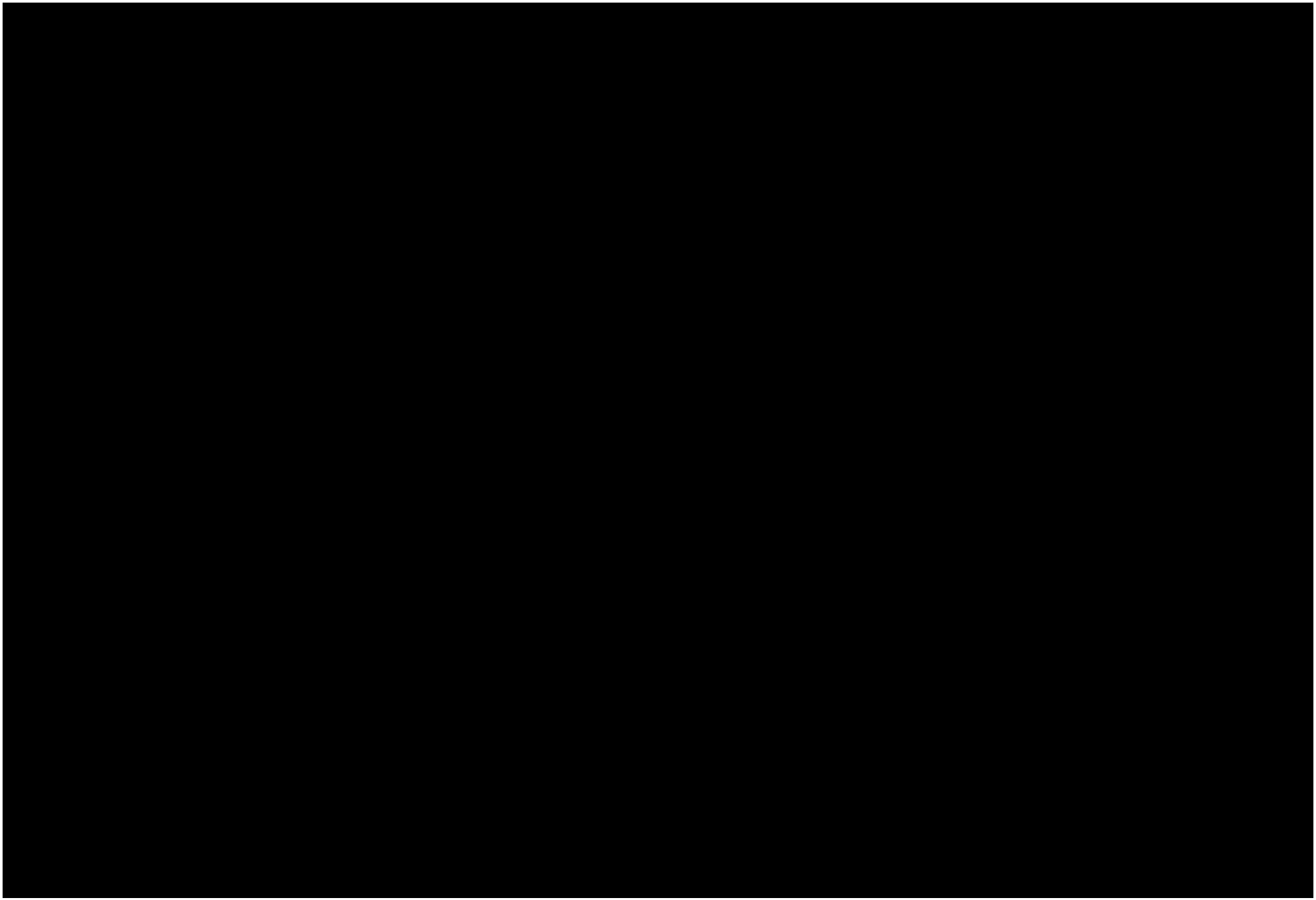
Member Forecasted Off Peak Demand Day for July 2021

Southwestern Electric Cooperative, Inc.

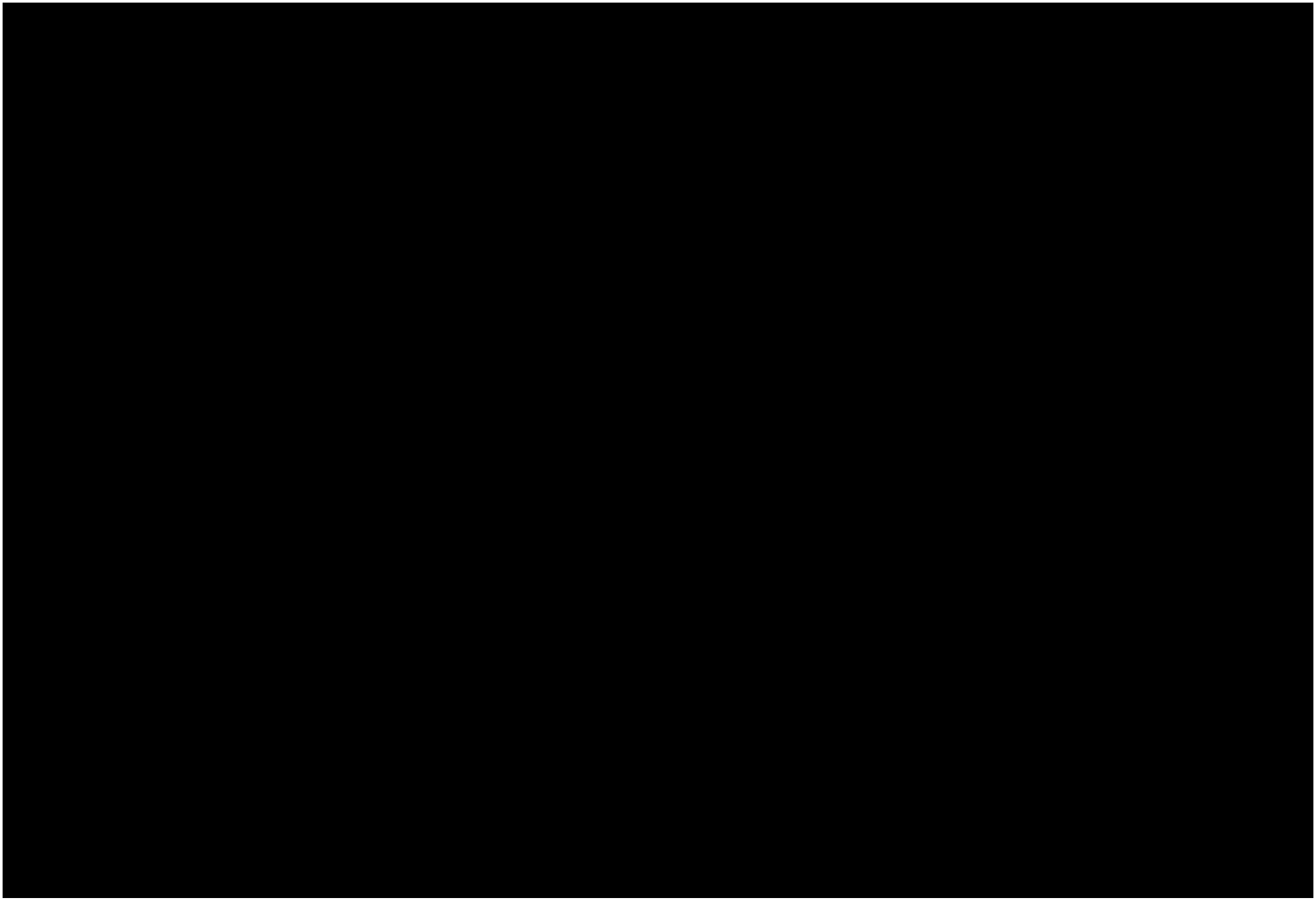
Date of Off Peak Day - 07/29/2021



Member Forecasted Off Peak Demand Day for August 2021

Southwestern Electric Cooperative, Inc.

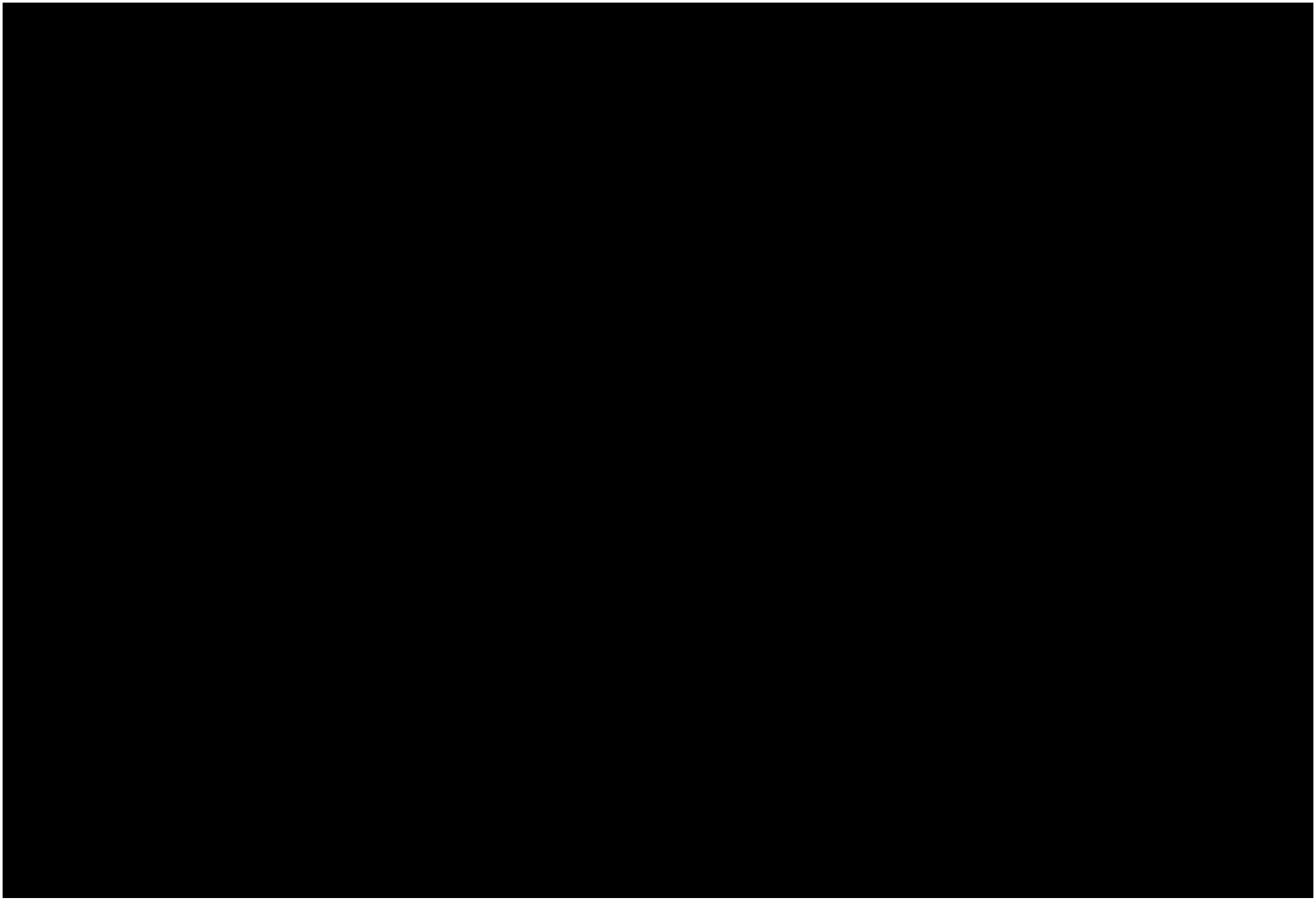
Date of Off Peak Day - 08/29/2021



Member Forecasted Off Peak Demand Day for September 2021

Southwestern Electric Cooperative, Inc.

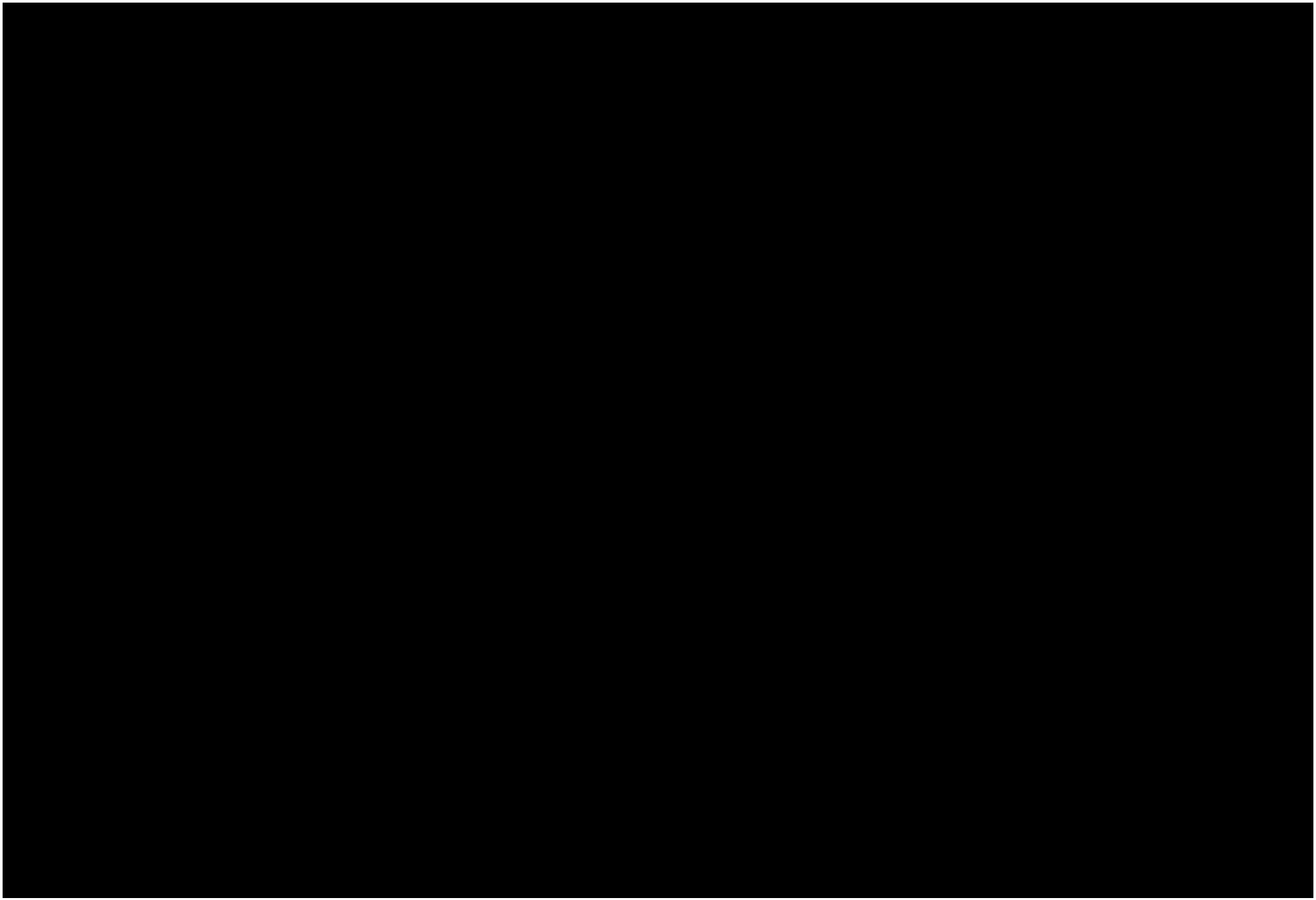
Date of Off Peak Day - 09/22/2021



Member Forecasted Off Peak Demand Day for October 2021

Southwestern Electric Cooperative, Inc.

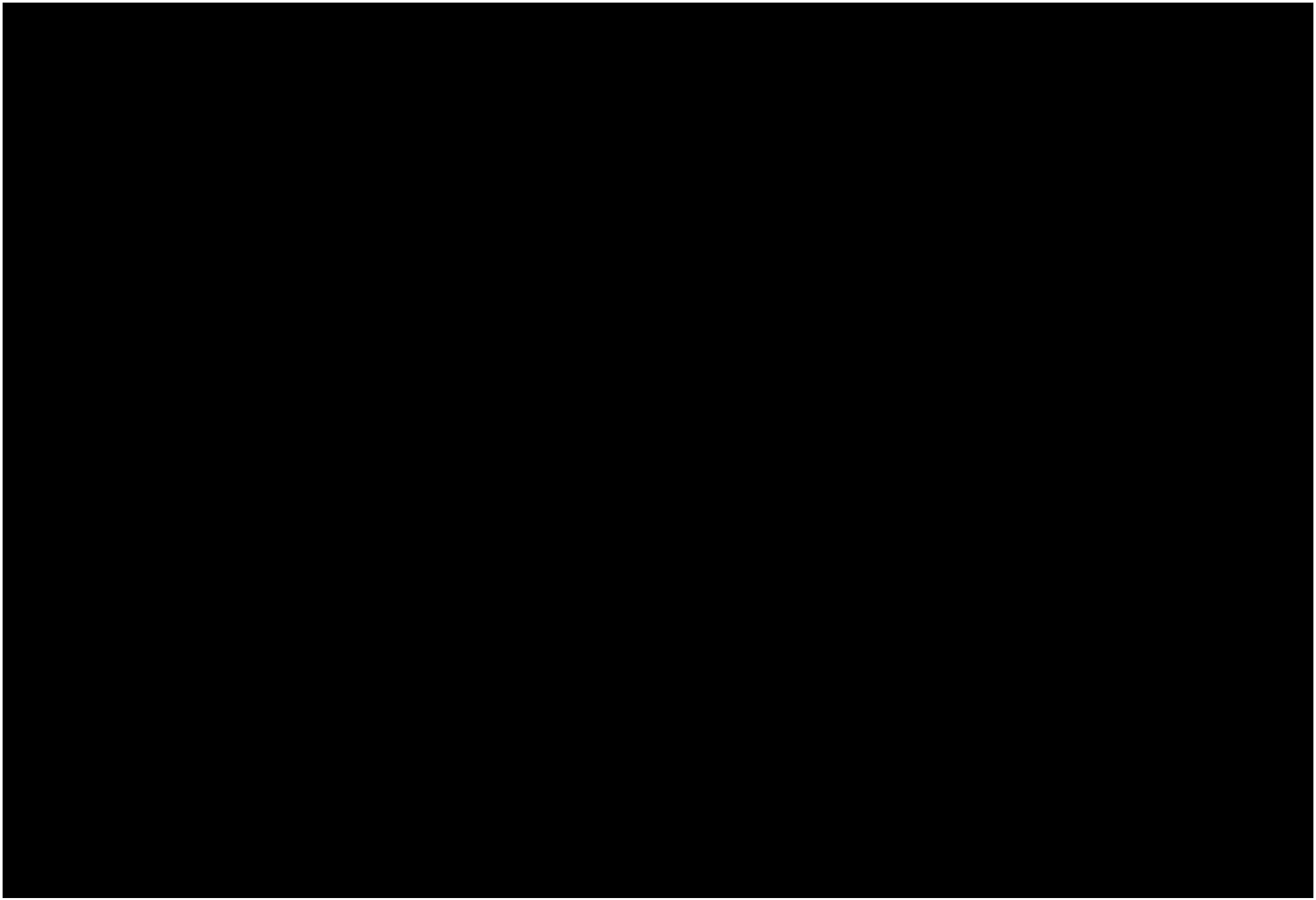
Date of Off Peak Day - 10/08/2021



Member Forecasted Off Peak Demand Day for November 2021

Southwestern Electric Cooperative, Inc.

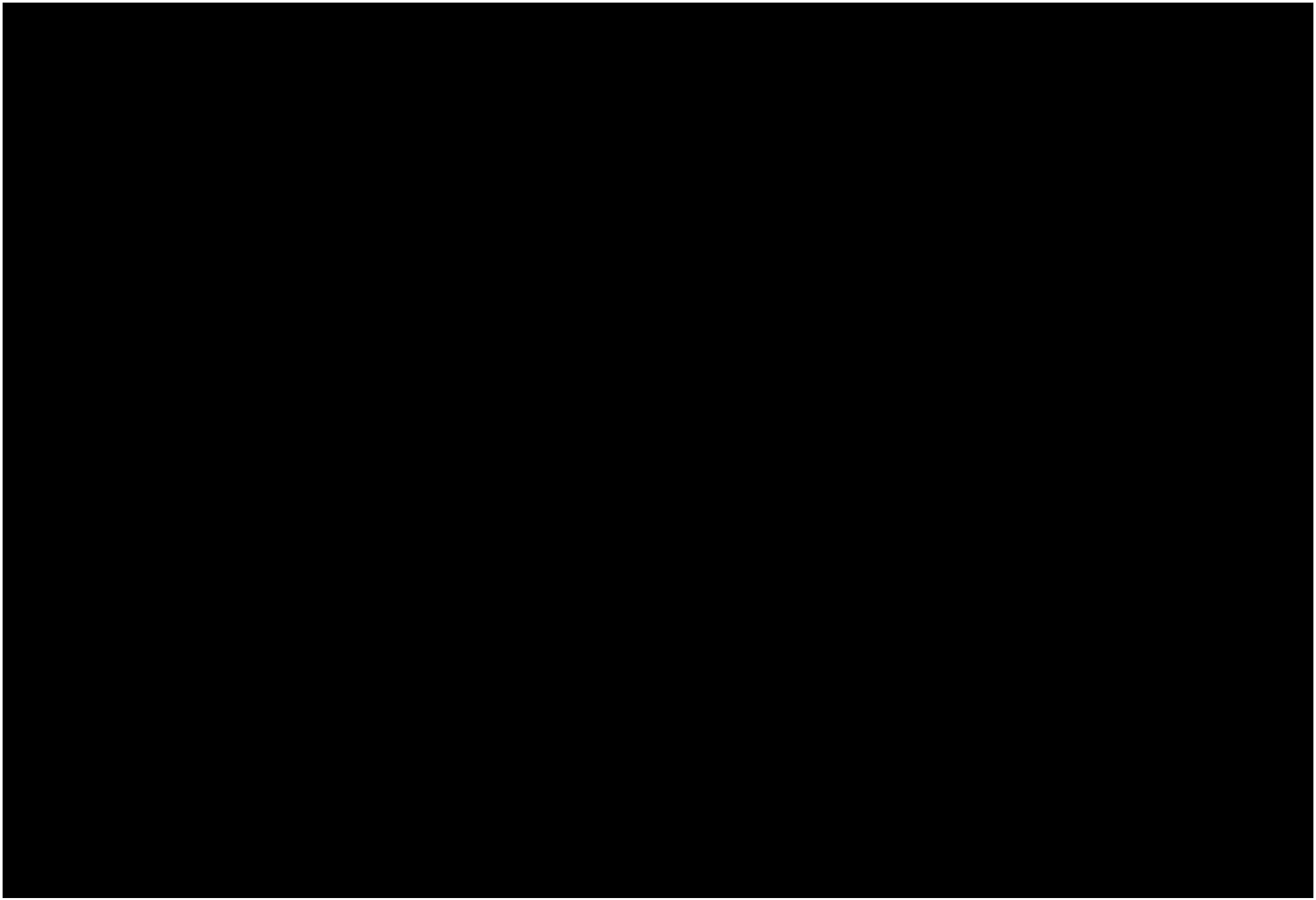
Date of Off Peak Day - 11/12/2021



Member Forecasted Off Peak Demand Day for December 2021

Southwestern Electric Cooperative, Inc.

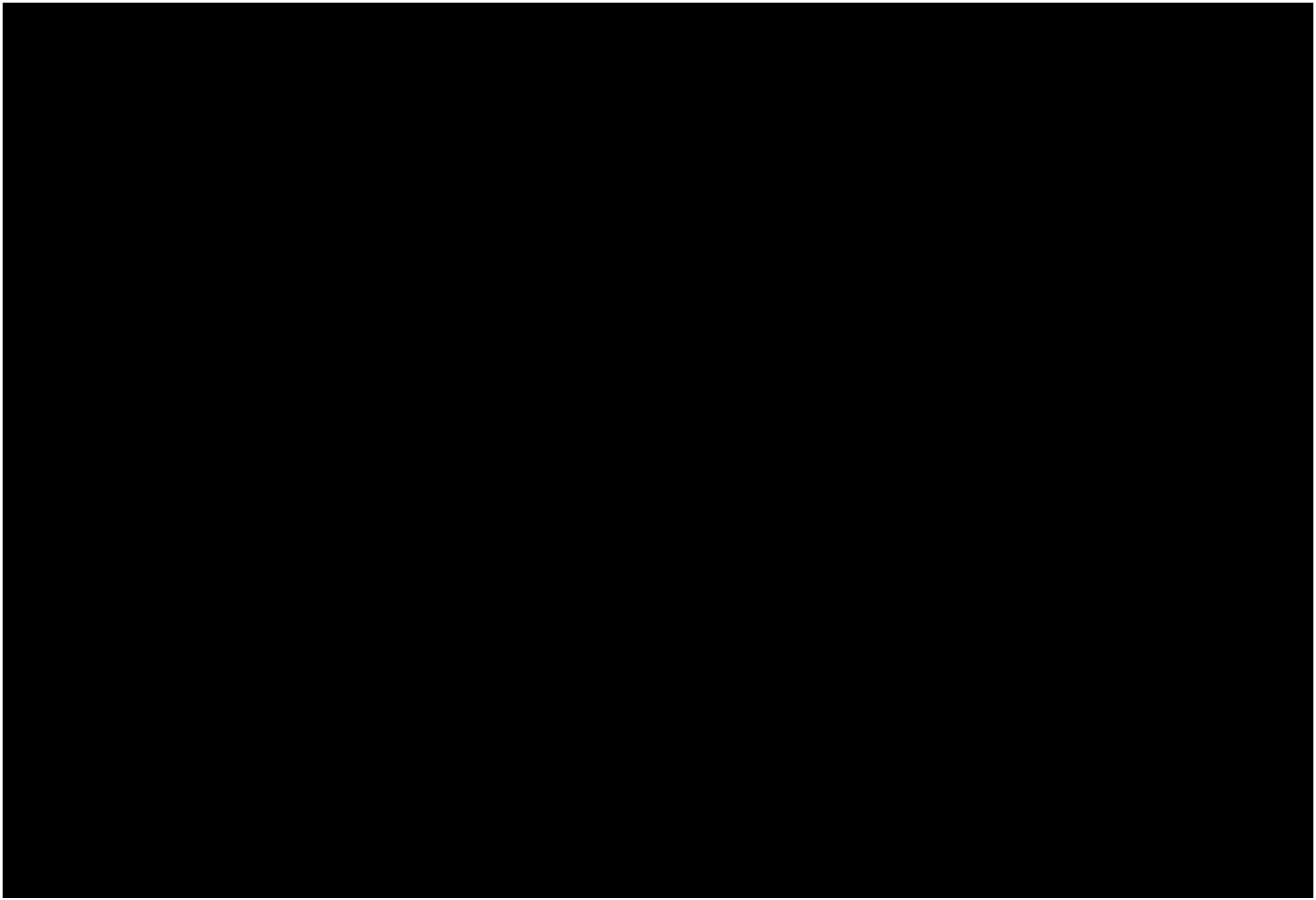
Date of Off Peak Day - 12/13/2021



Member Forecasted Off Peak Demand Day for January 2021

United Power, Inc.

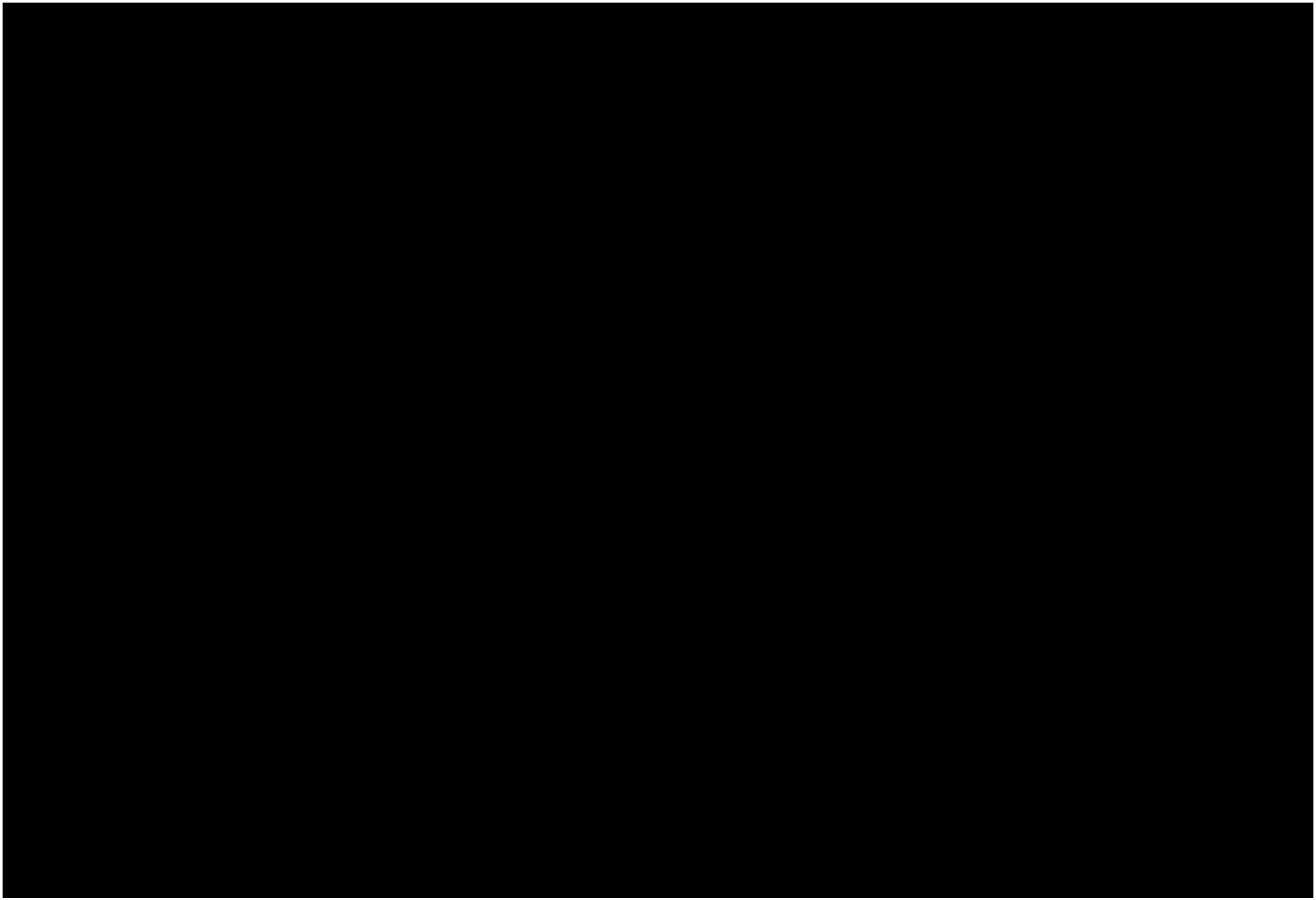
Date of Off Peak Day - 01/20/2021



Member Forecasted Off Peak Demand Day for February 2021

United Power, Inc.

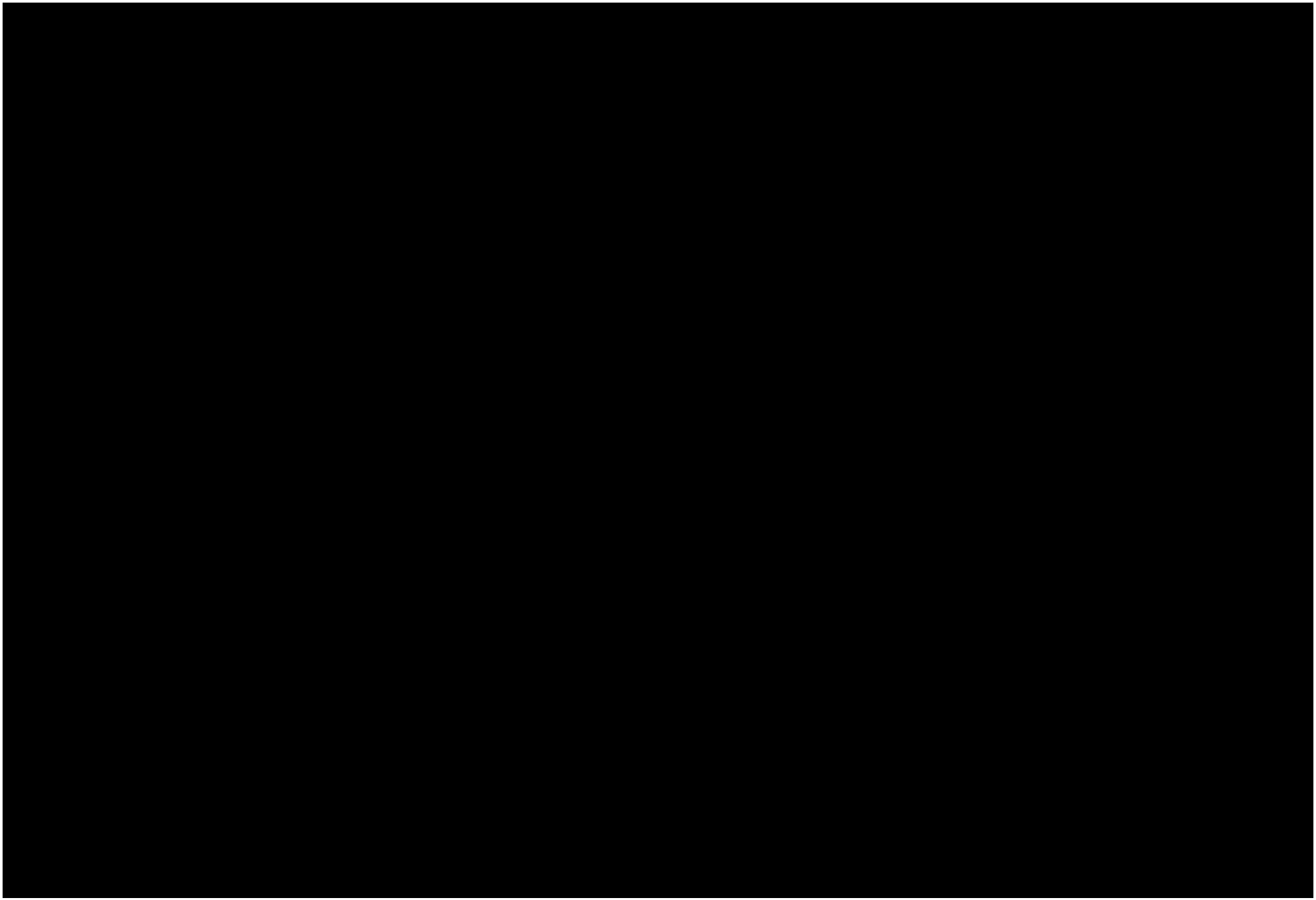
Date of Off Peak Day - 02/17/2021



Member Forecasted Off Peak Demand Day for March 2021

United Power, Inc.

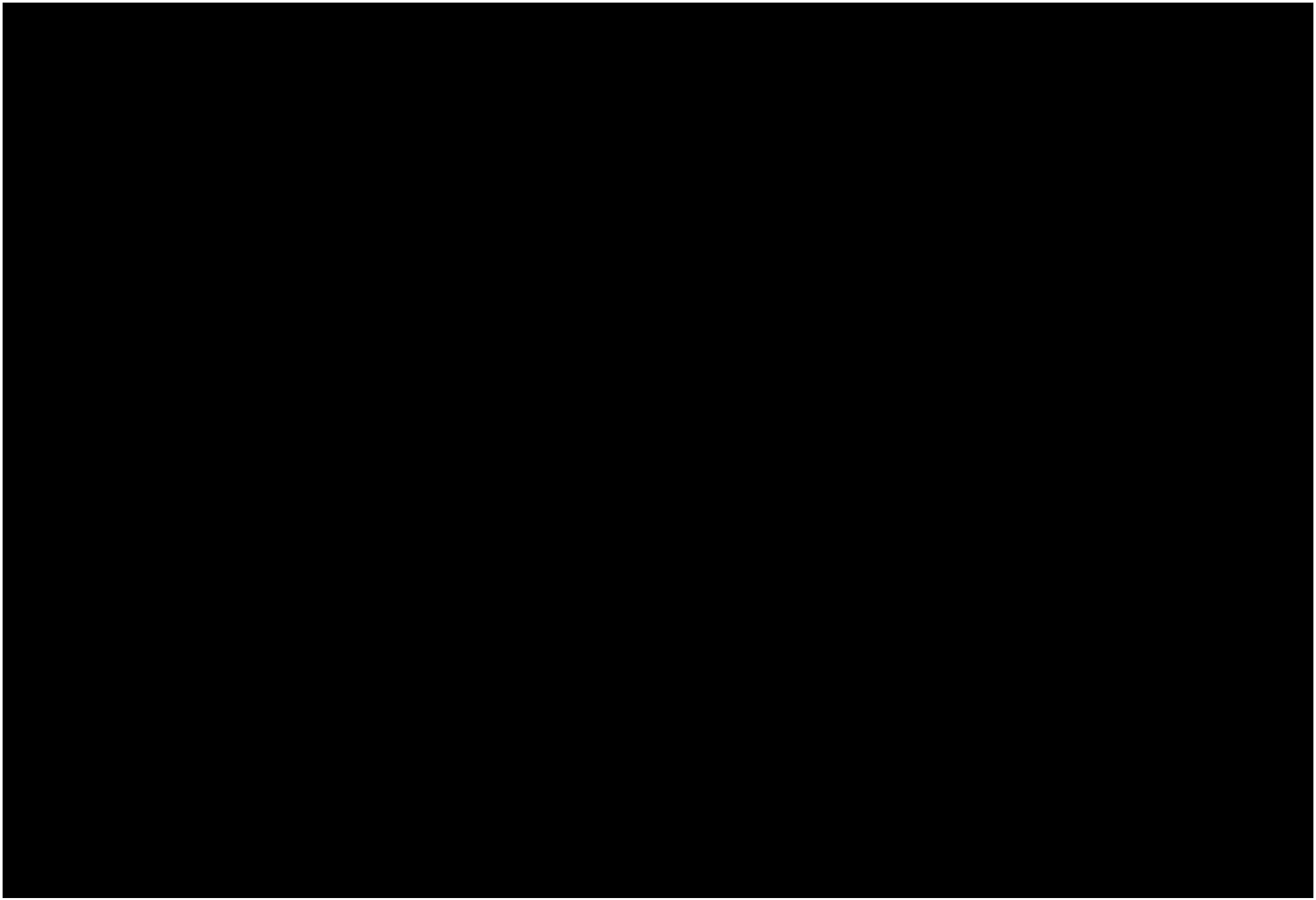
Date of Off Peak Day - 03/19/2021



Member Forecasted Off Peak Demand Day for April 2021

United Power, Inc.

Date of Off Peak Day - 04/07/2021



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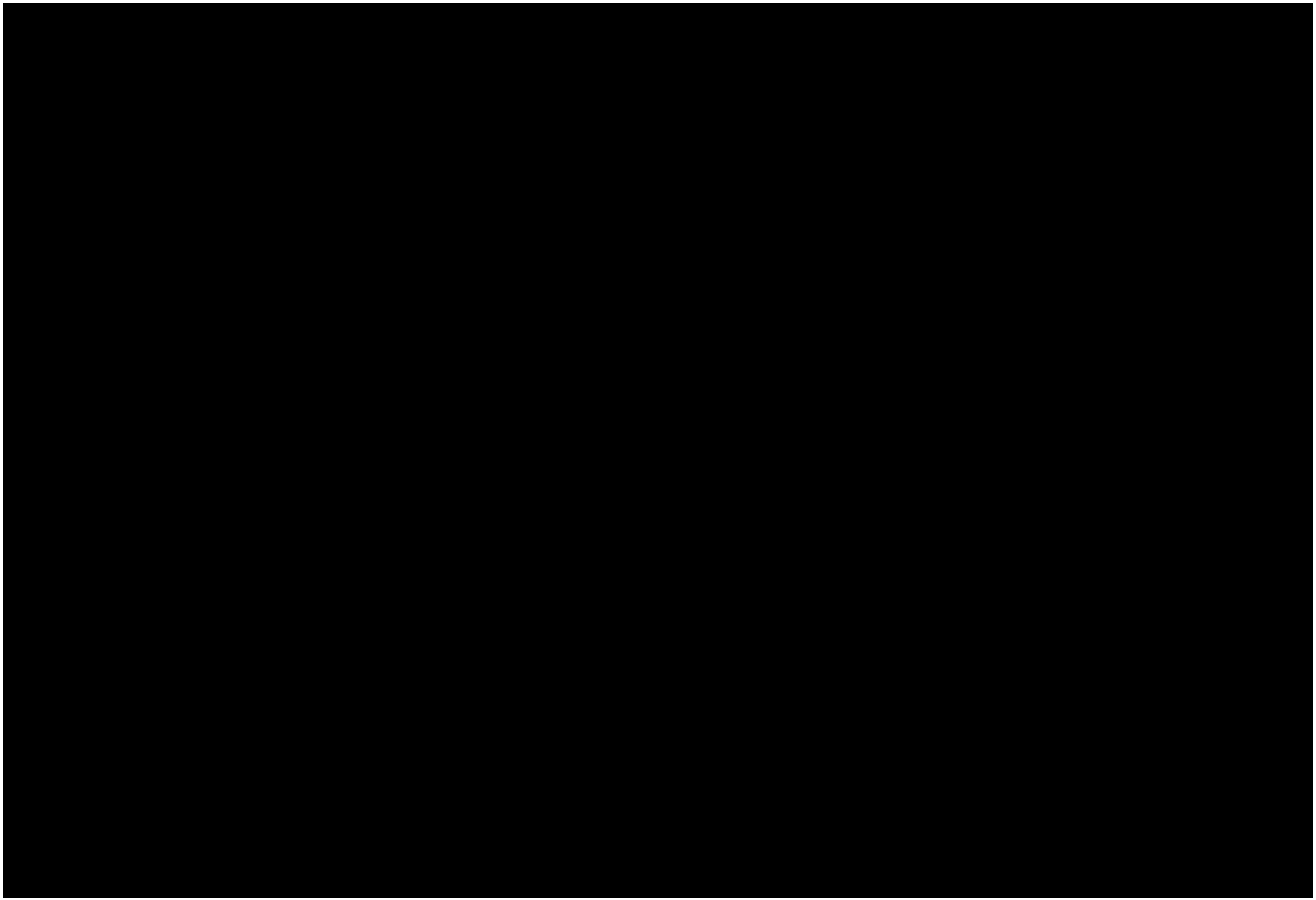
Member Forecasted Off Peak Demand Day for May 2021

United Power, Inc.

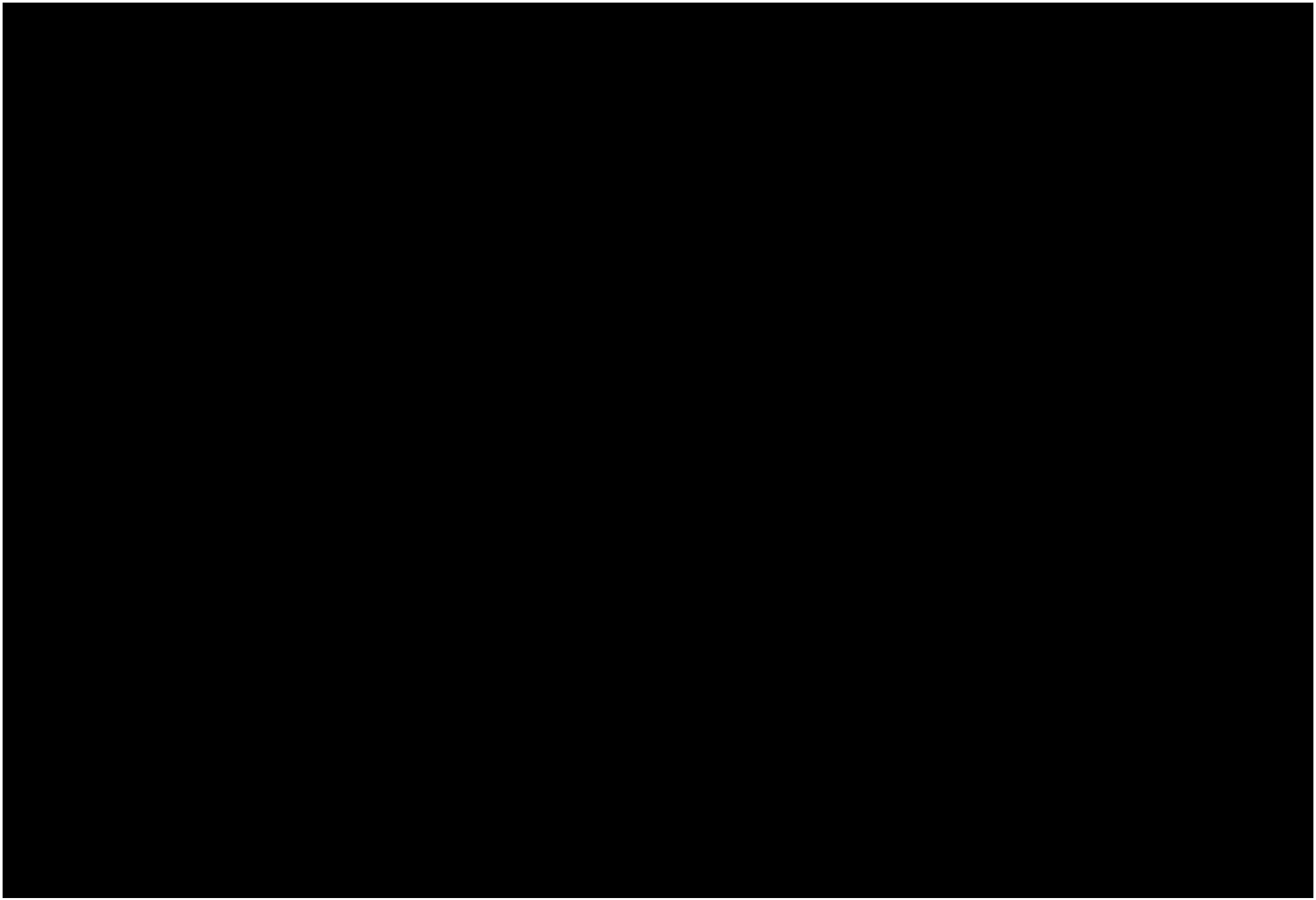
Date of Off Peak Day - 05/25/2021



Member Forecasted Off Peak Demand Day for June 2021

United Power, Inc.

Date of Off Peak Day - 06/12/2021



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Member Forecasted Off Peak Demand Day for July 2021

United Power, Inc.

Date of Off Peak Day - 07/04/2021

[redacted]

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Member Forecasted Off Peak Demand Day for August 2021

United Power, Inc.

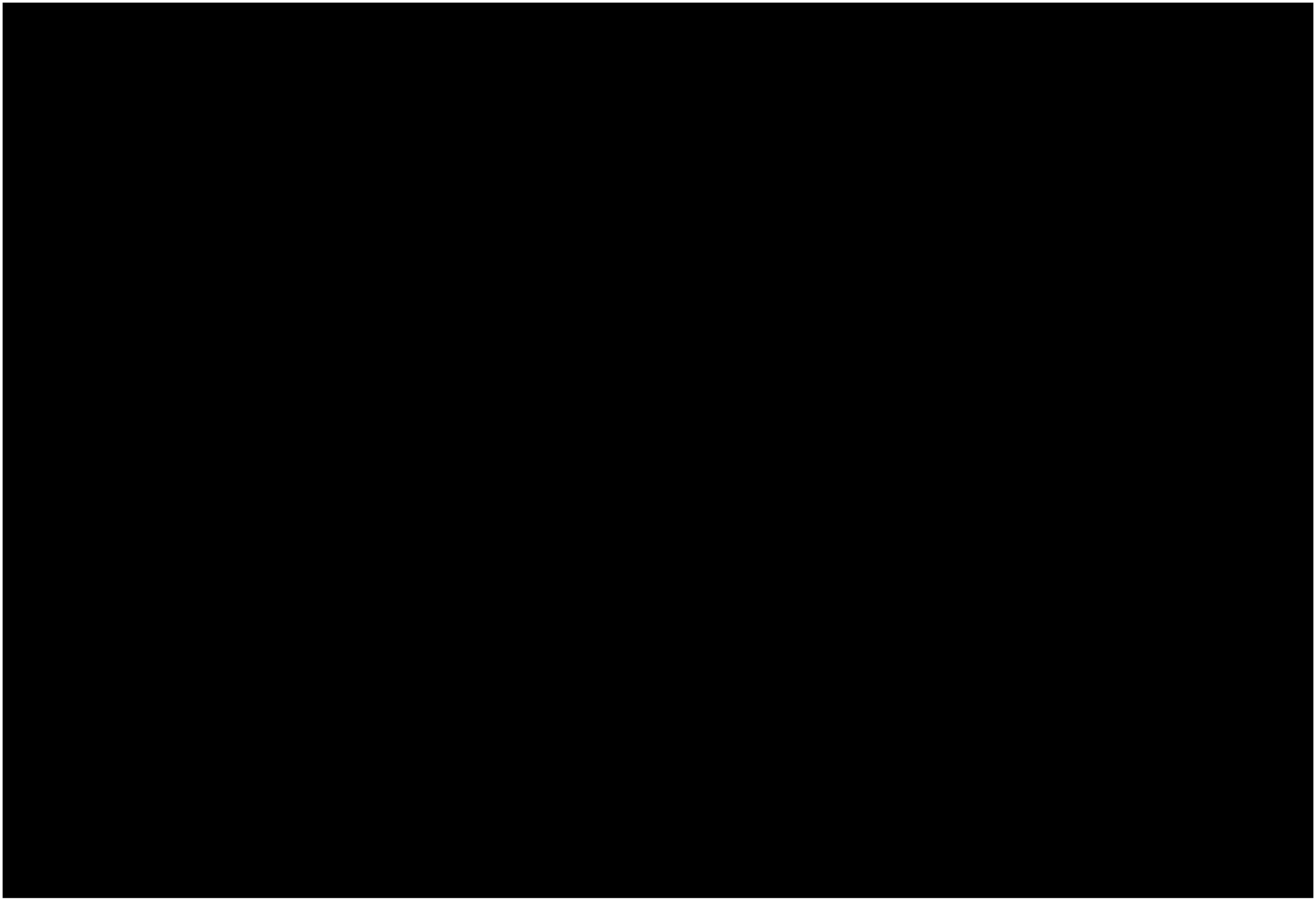
Date of Off Peak Day - 08/08/2021

[redacted]

Member Forecasted Off Peak Demand Day for September 2021

United Power, Inc.

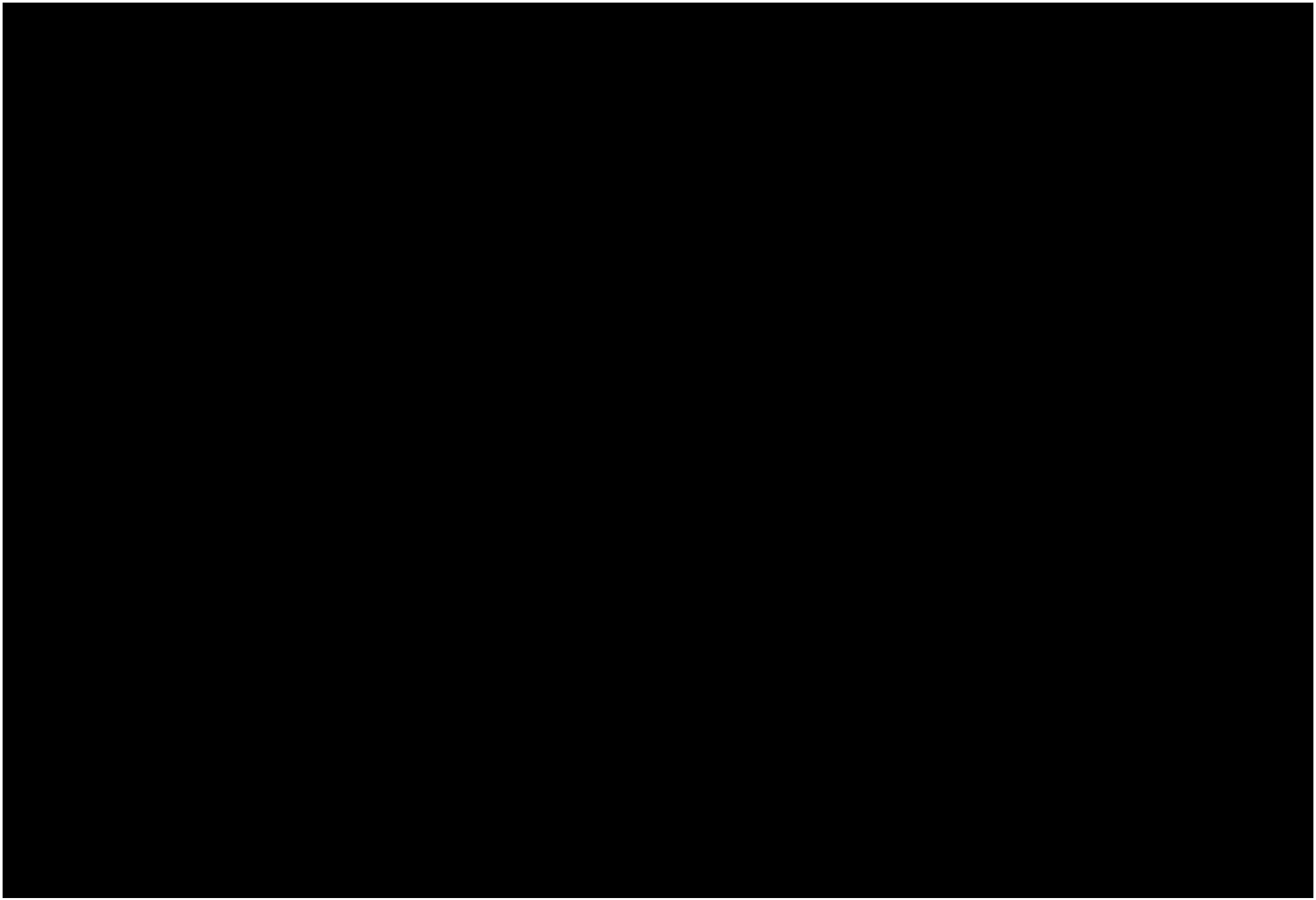
Date of Off Peak Day - 09/20/2021



Member Forecasted Off Peak Demand Day for October 2021

United Power, Inc.

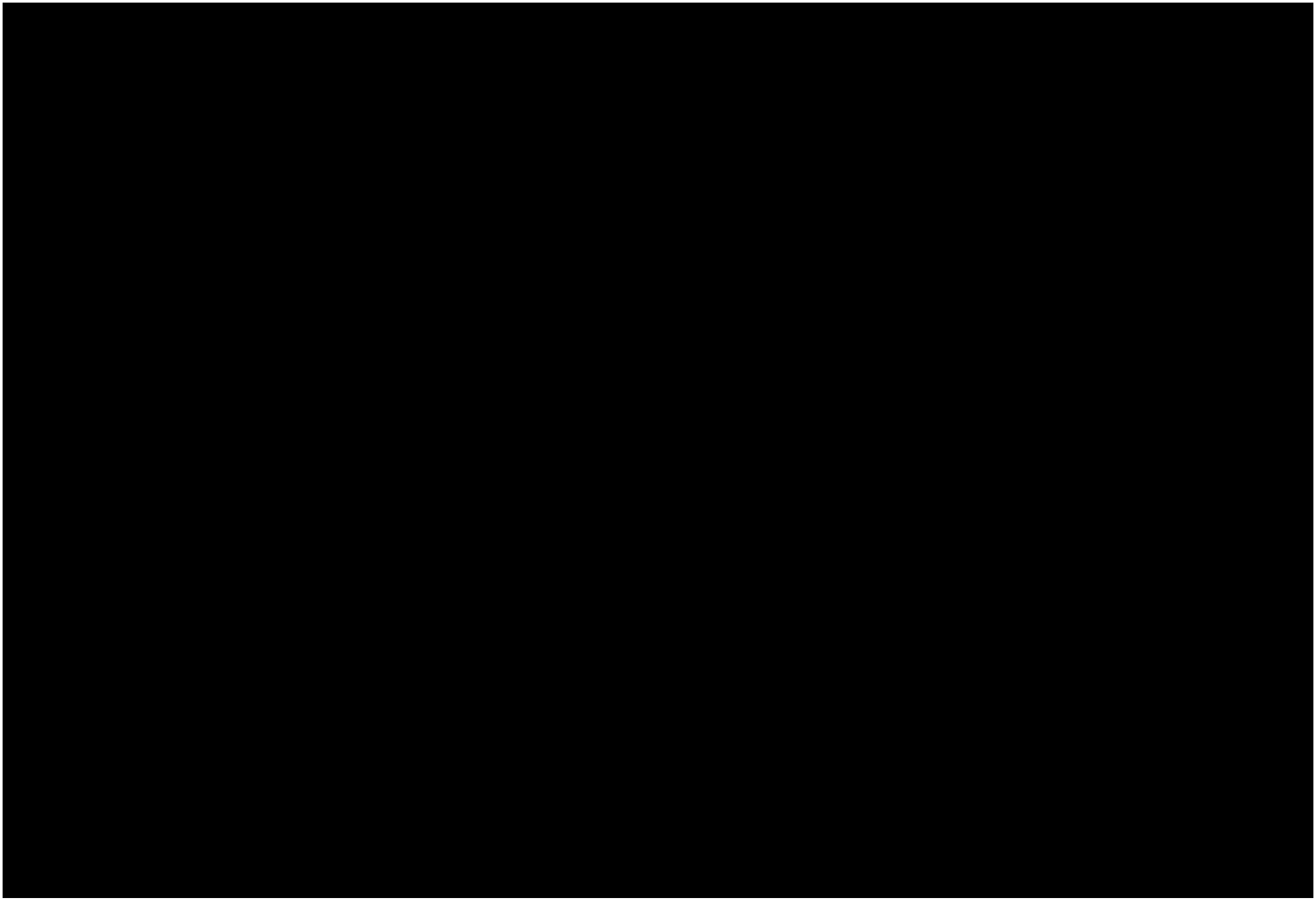
Date of Off Peak Day - 10/11/2021



Member Forecasted Off Peak Demand Day for November 2021

United Power, Inc.

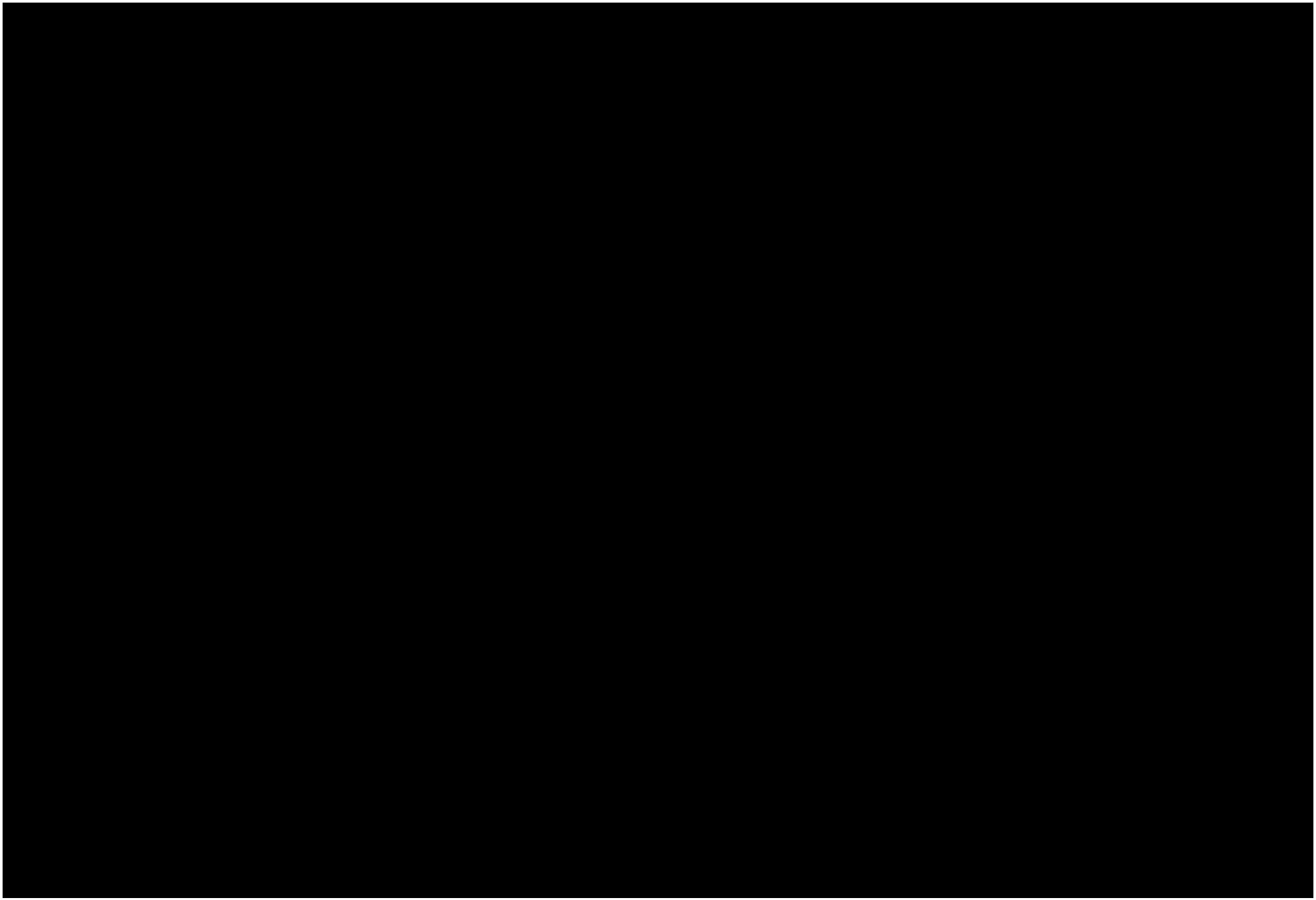
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

United Power, Inc.

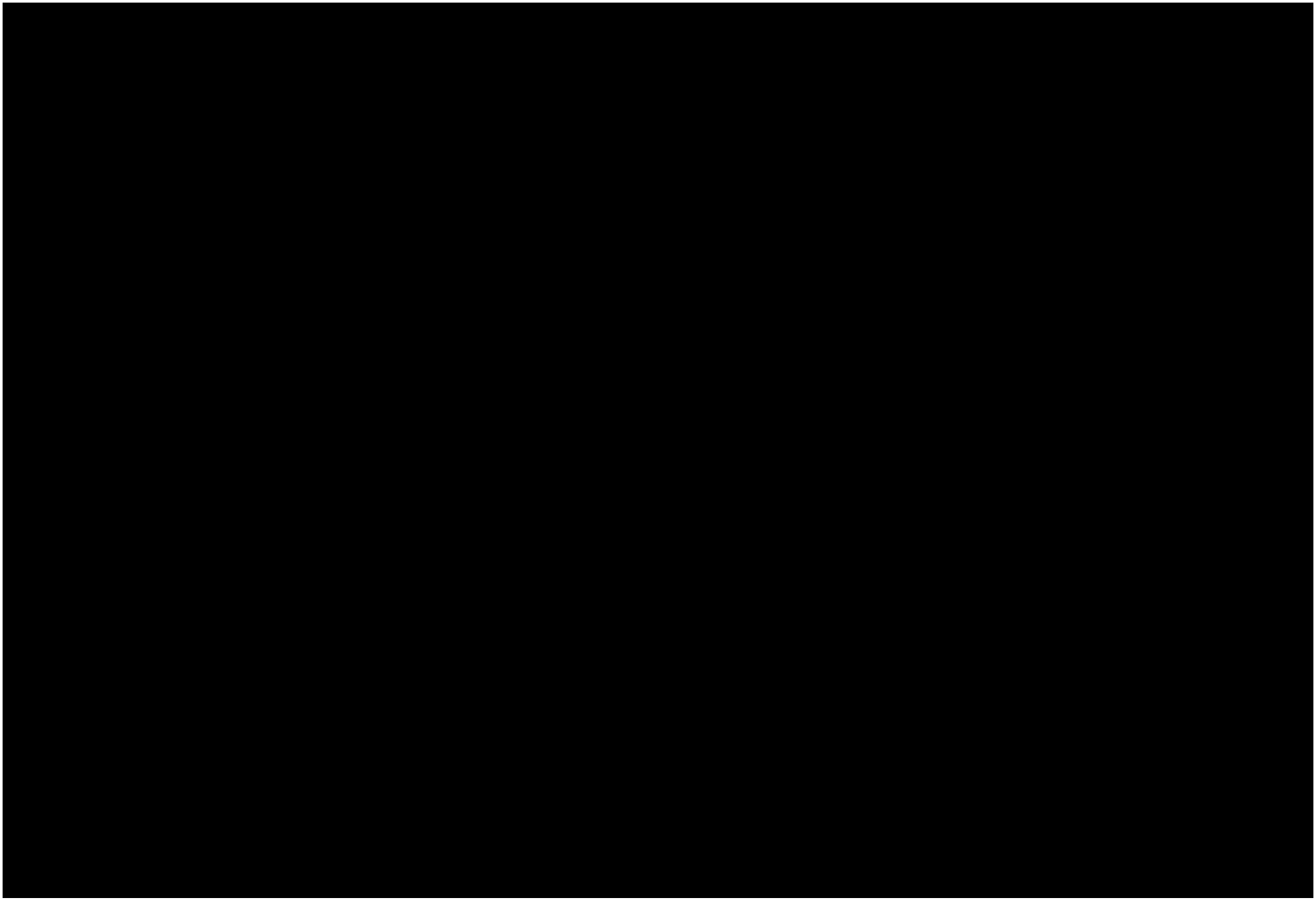
Date of Off Peak Day - 12/02/2021



Member Forecasted Off Peak Demand Day for January 2021

Wheat Belt Public Power District

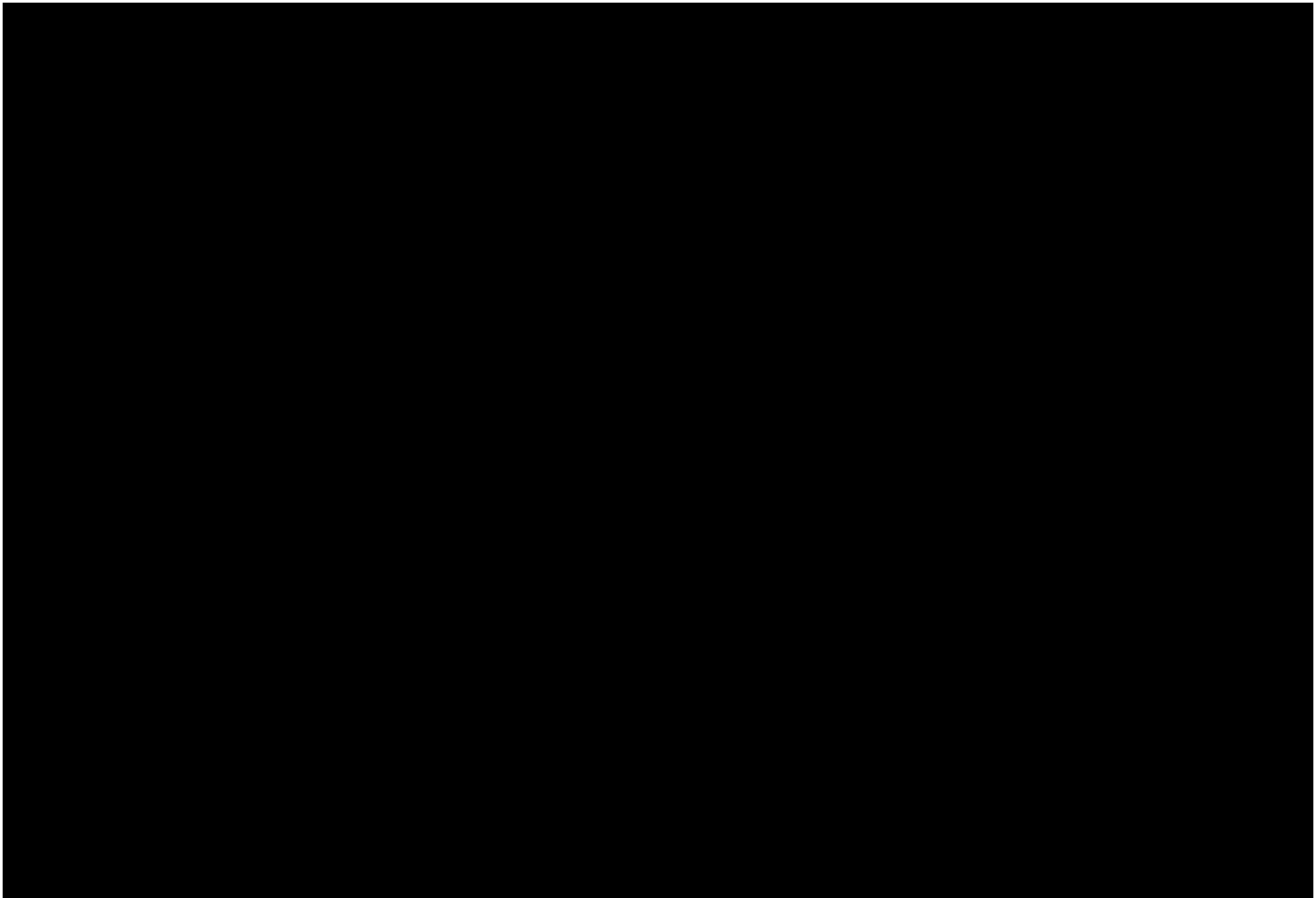
Date of Off Peak Day - 01/19/2021



Member Forecasted Off Peak Demand Day for February 2021

Wheat Belt Public Power District

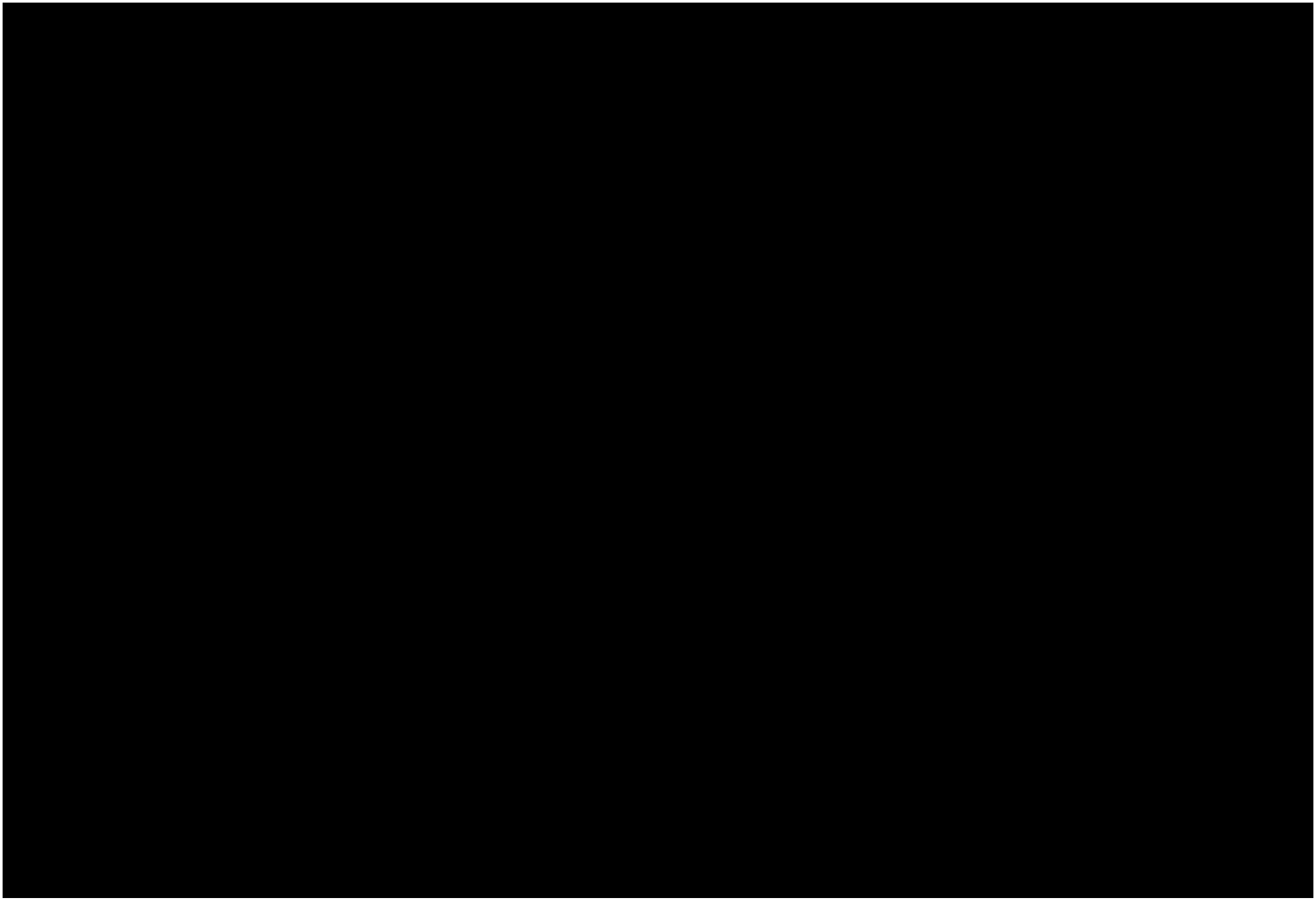
Date of Off Peak Day - 02/16/2021



Member Forecasted Off Peak Demand Day for March 2021

Wheat Belt Public Power District

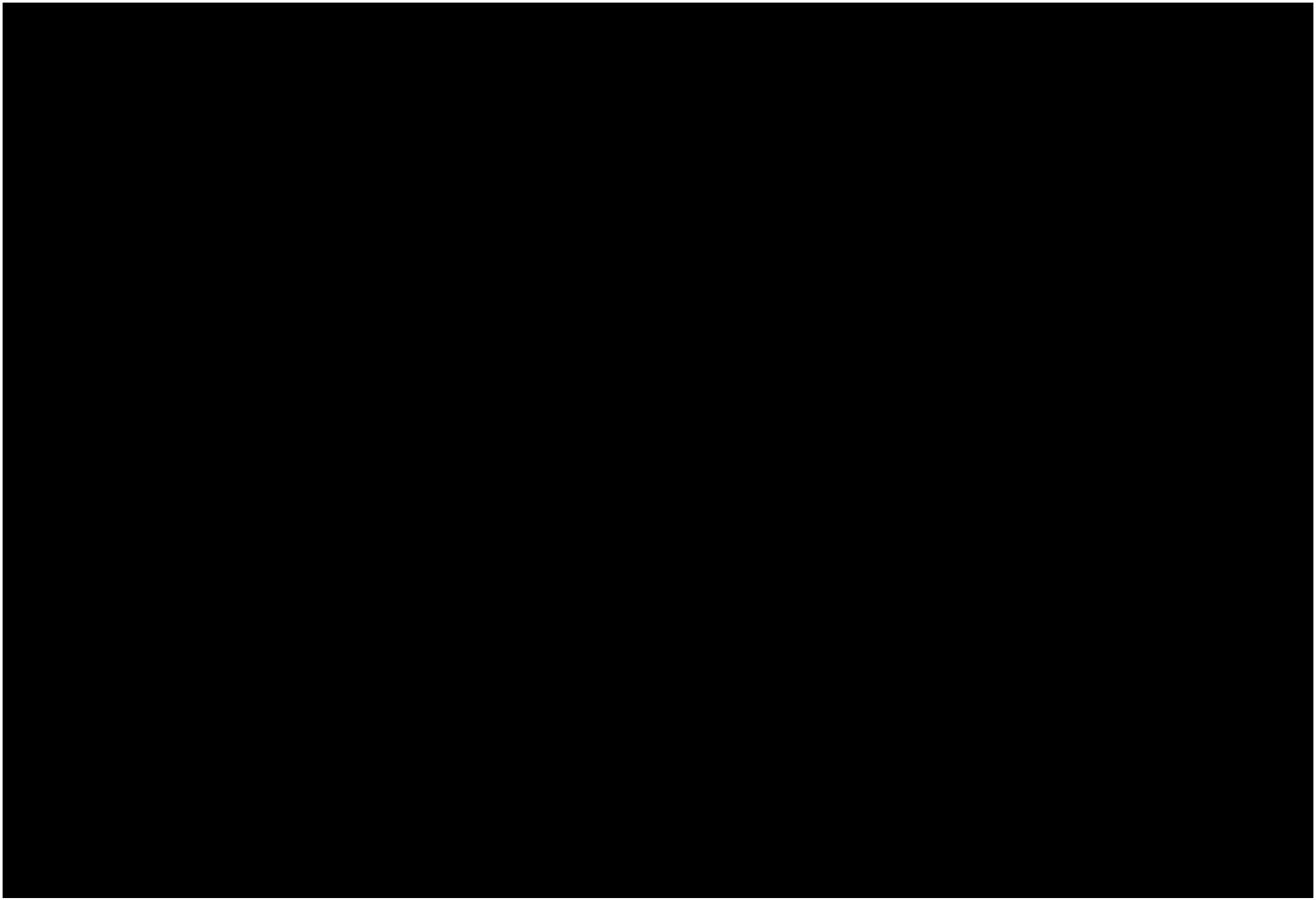
Date of Off Peak Day - 03/19/2021



Member Forecasted Off Peak Demand Day for April 2021

Wheat Belt Public Power District

Date of Off Peak Day - 04/10/2021



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Member Forecasted Off Peak Demand Day for May 2021

Wheat Belt Public Power District

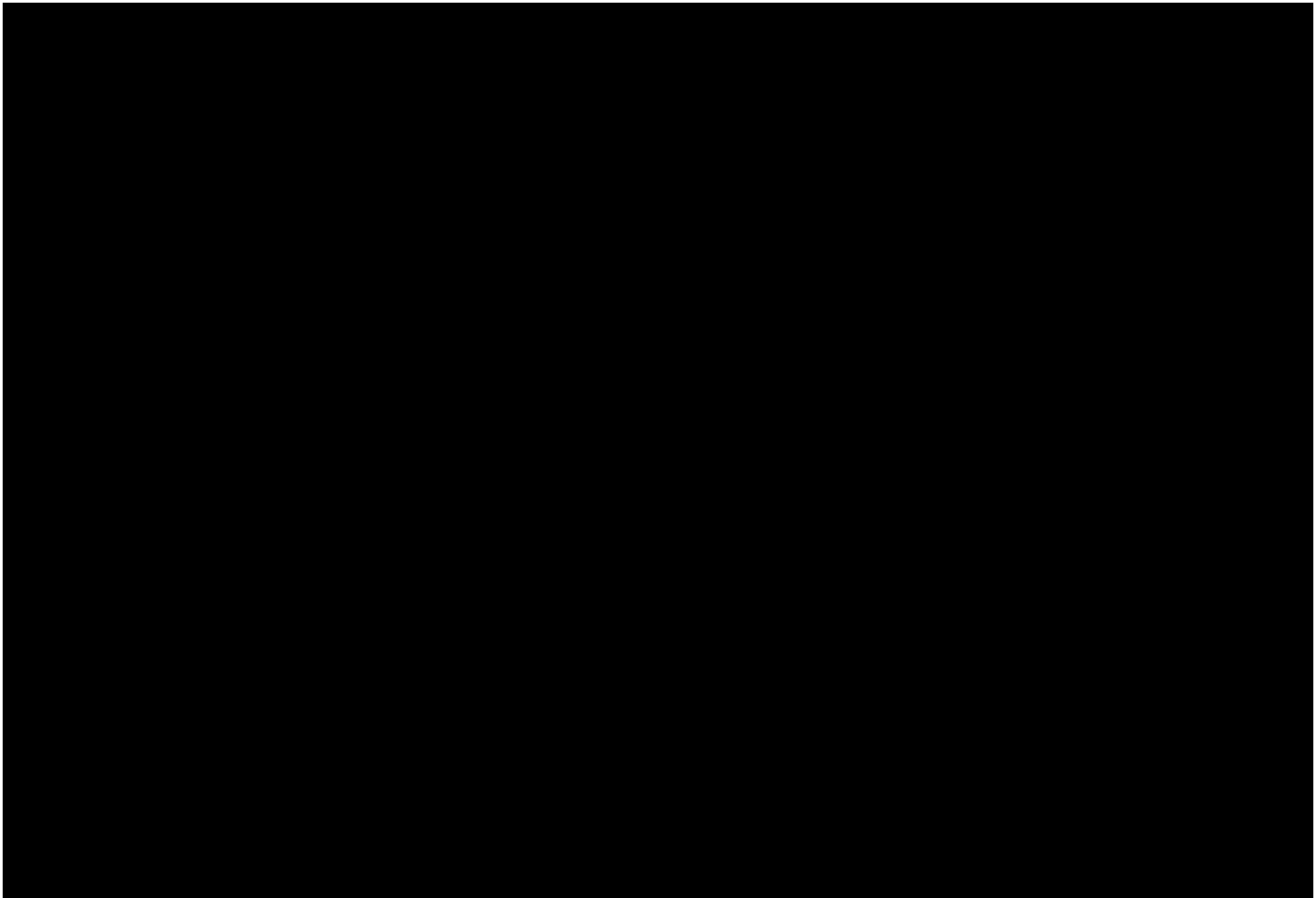
Date of Off Peak Day - 05/22/2021

[redacted]

Member Forecasted Off Peak Demand Day for June 2021

Wheat Belt Public Power District

Date of Off Peak Day - 06/21/2021



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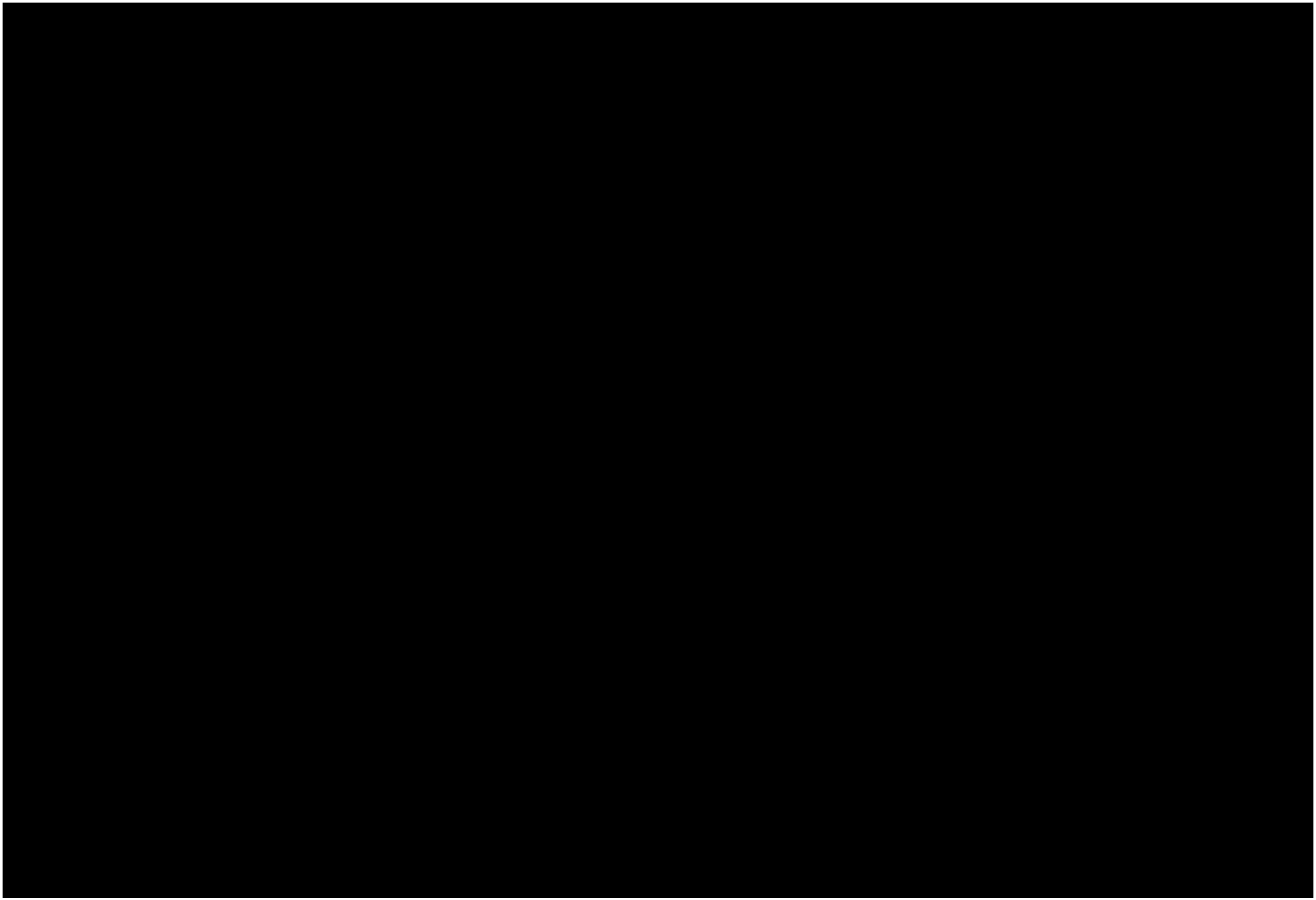
Member Forecasted Off Peak Demand Day for July 2021

Wheat Belt Public Power District

Date of Off Peak Day - 07/30/2021



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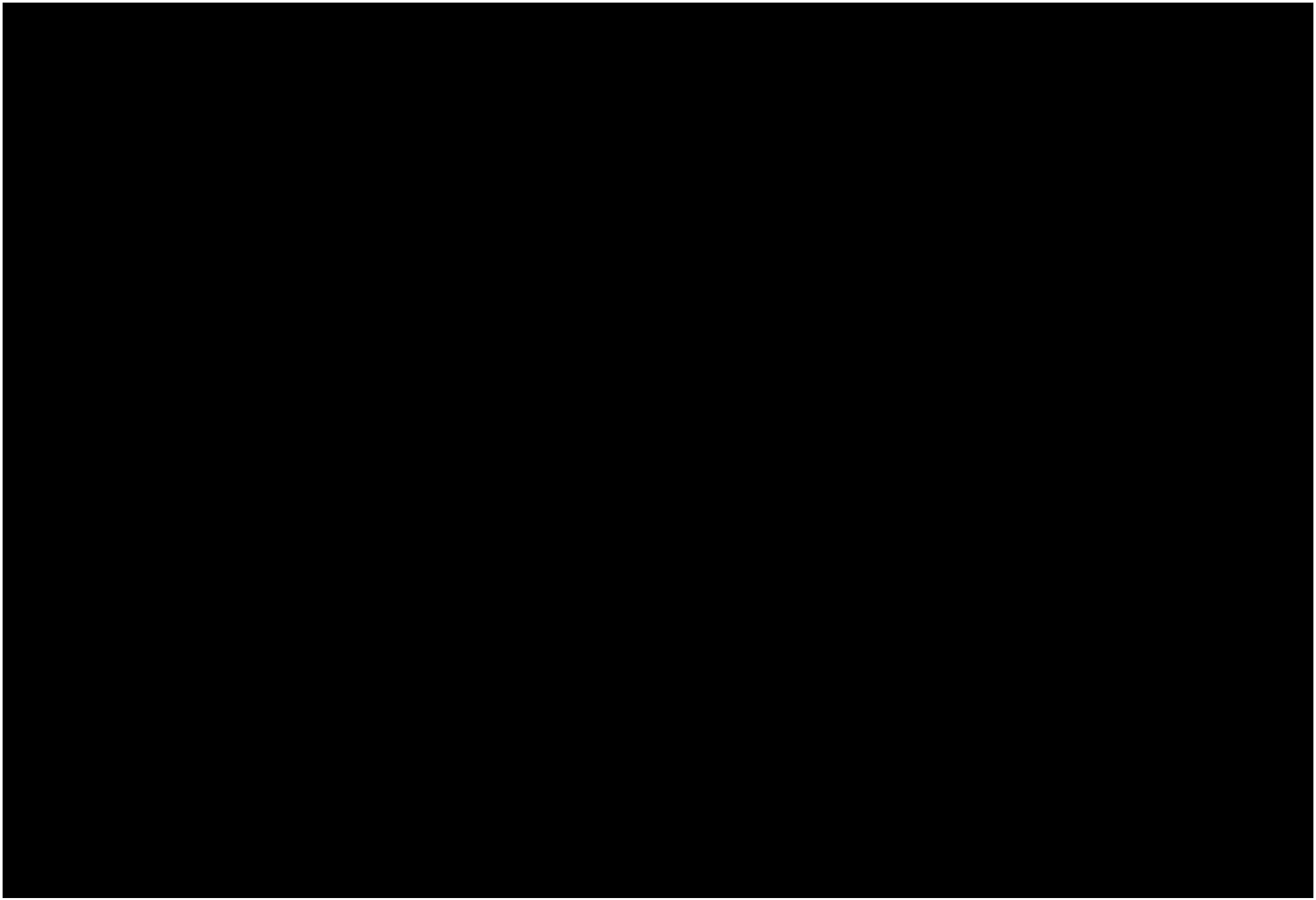
Member Forecasted Off Peak Demand Day for August 2021

Wheat Belt Public Power District

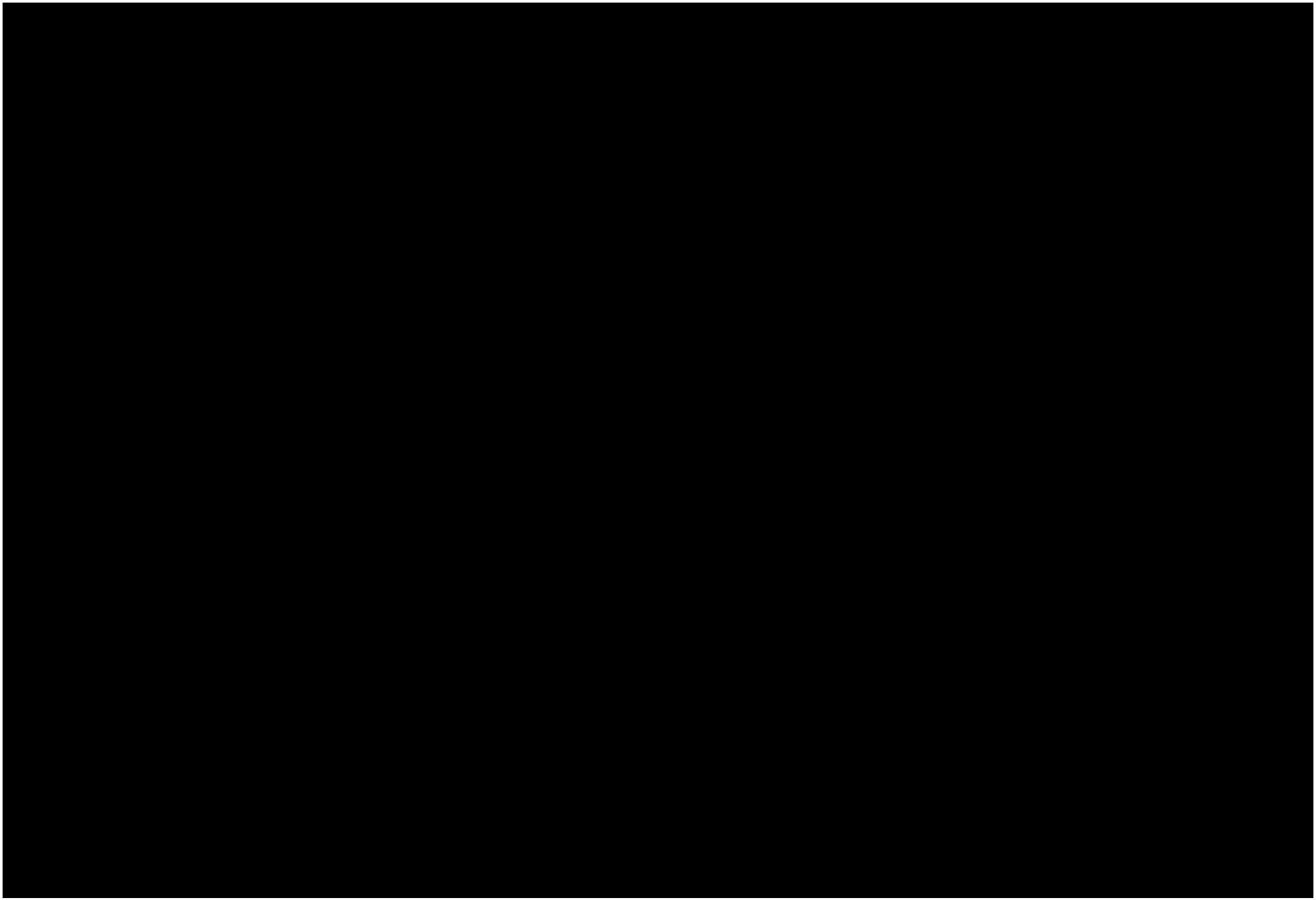
Date of Off Peak Day - 08/13/2021



Member Forecasted Off Peak Demand Day for September 2021

Wheat Belt Public Power District

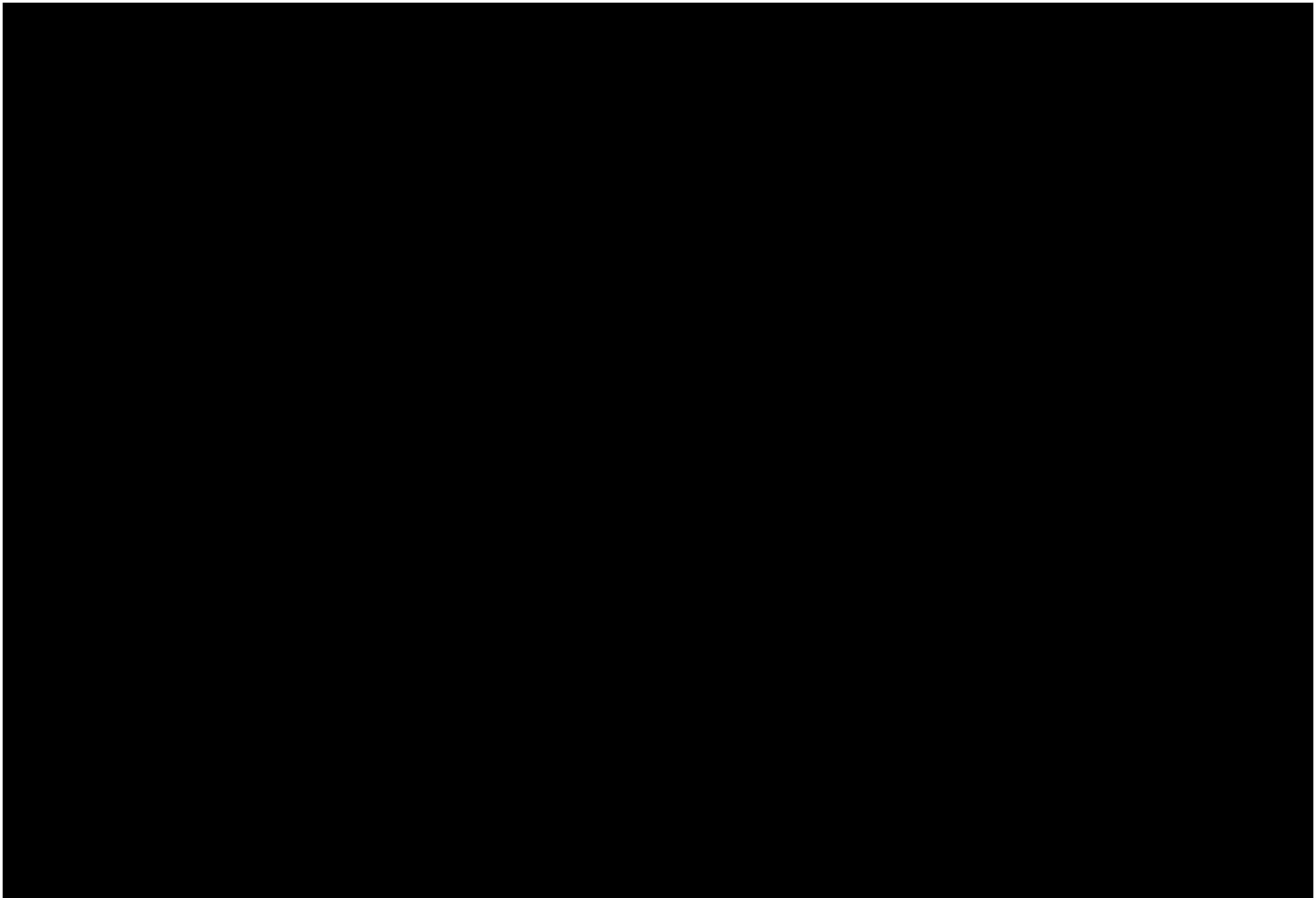
Date of Off Peak Day - 09/30/2021



Member Forecasted Off Peak Demand Day for October 2021

Wheat Belt Public Power District

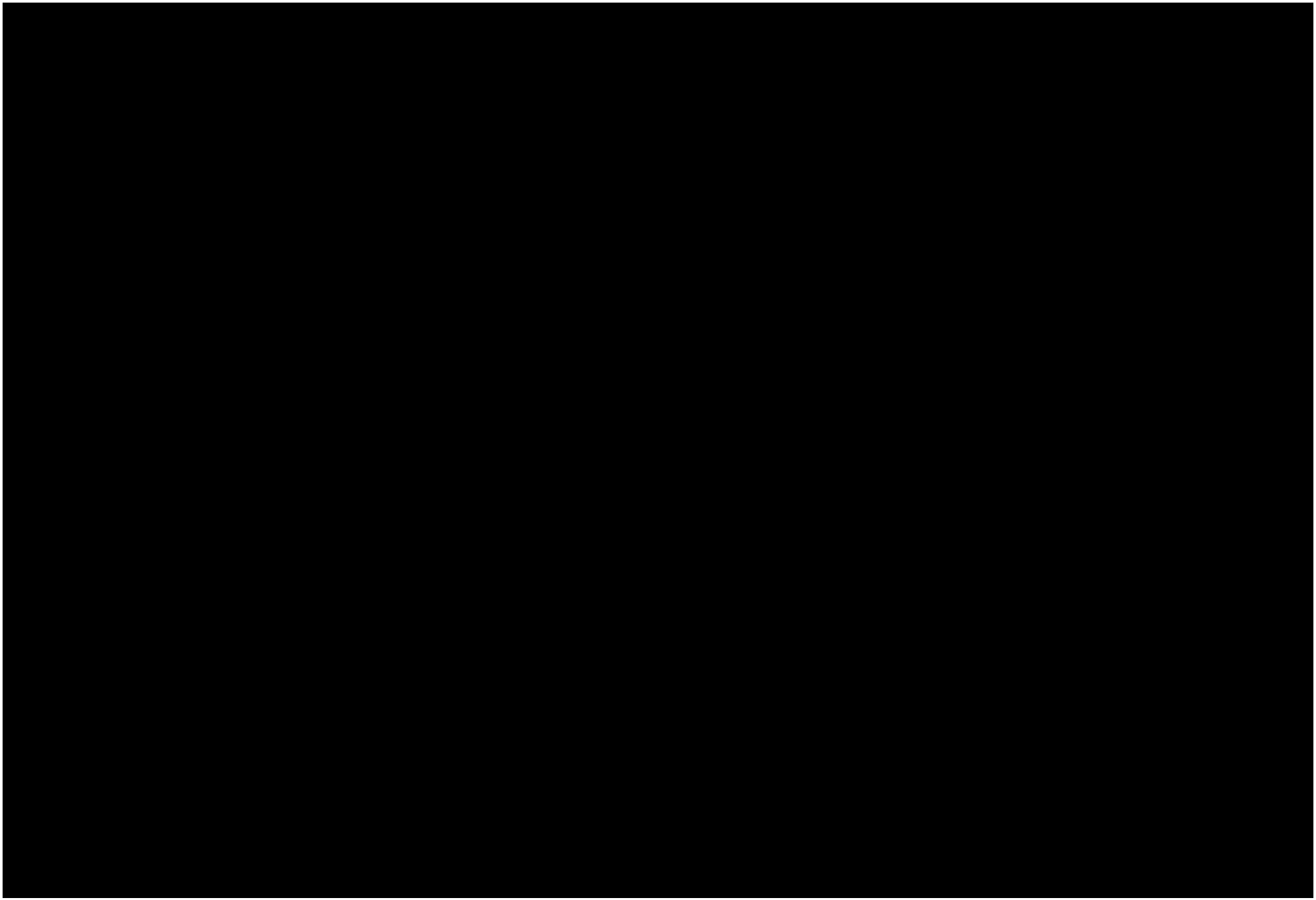
Date of Off Peak Day - 10/03/2021



Member Forecasted Off Peak Demand Day for November 2021

Wheat Belt Public Power District

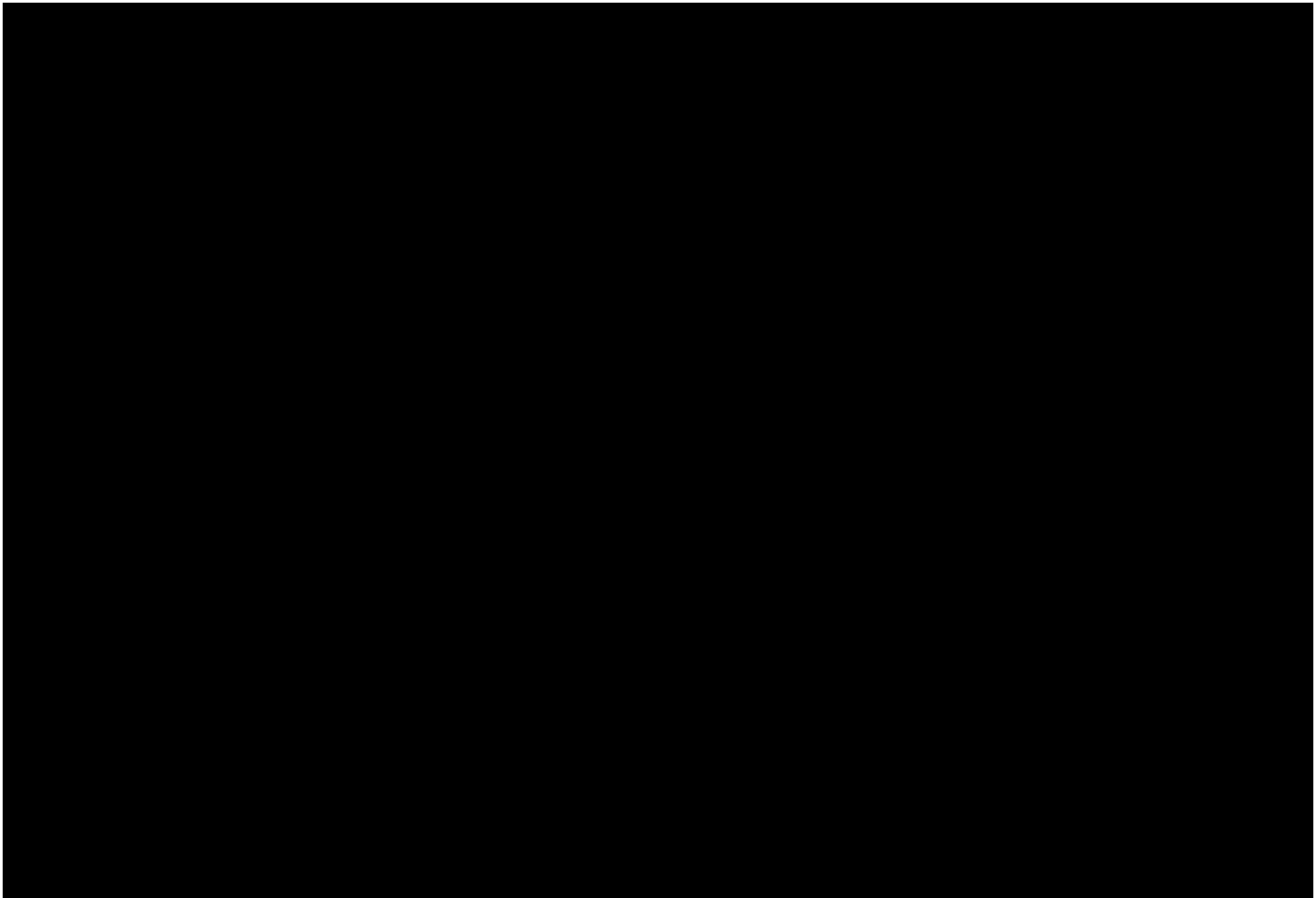
Date of Off Peak Day - 11/30/2021



Member Forecasted Off Peak Demand Day for December 2021

Wheat Belt Public Power District

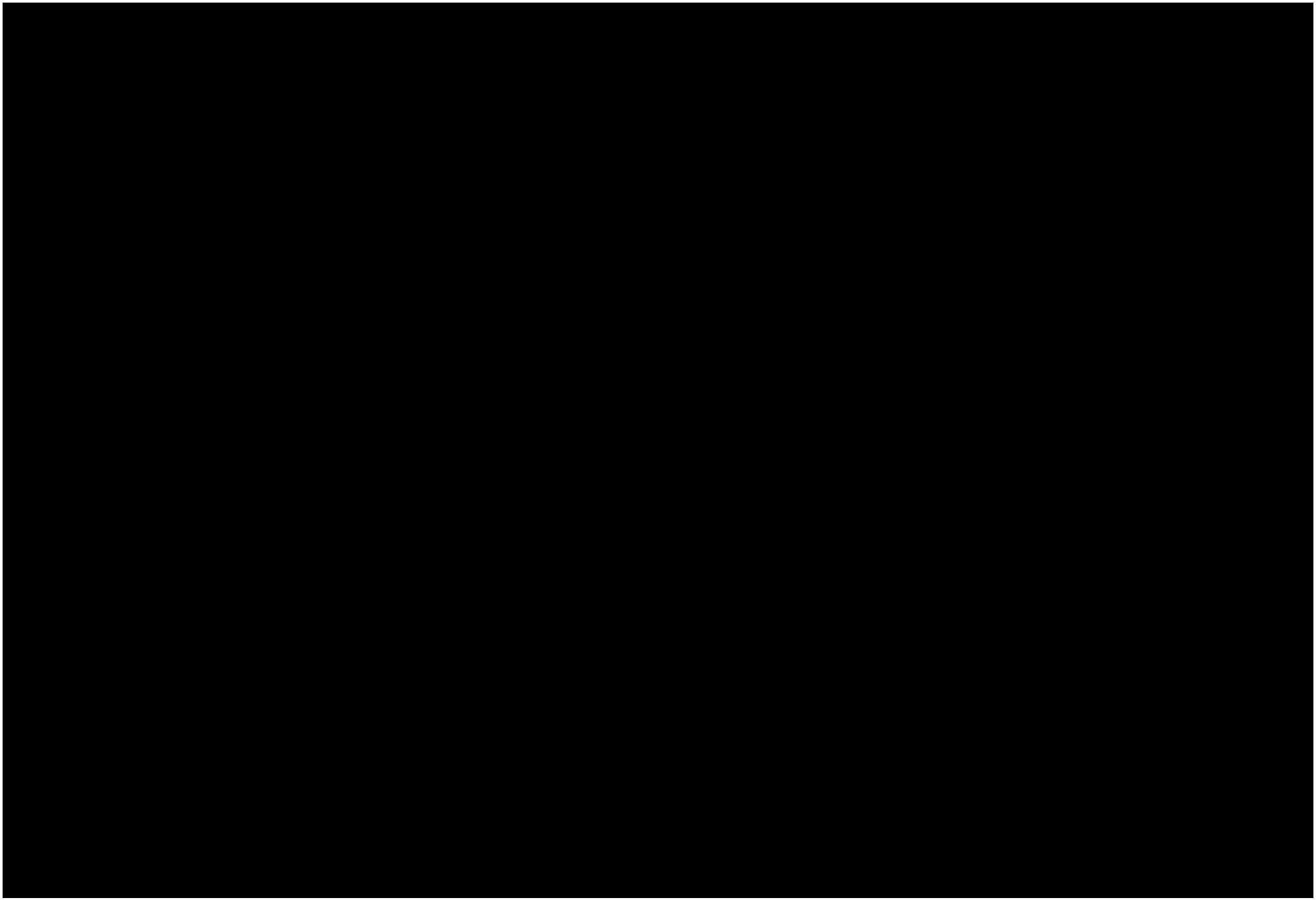
Date of Off Peak Day - 12/11/2021



Member Forecasted Off Peak Demand Day for January 2021

Wheatland Rural Electric Association, Inc.

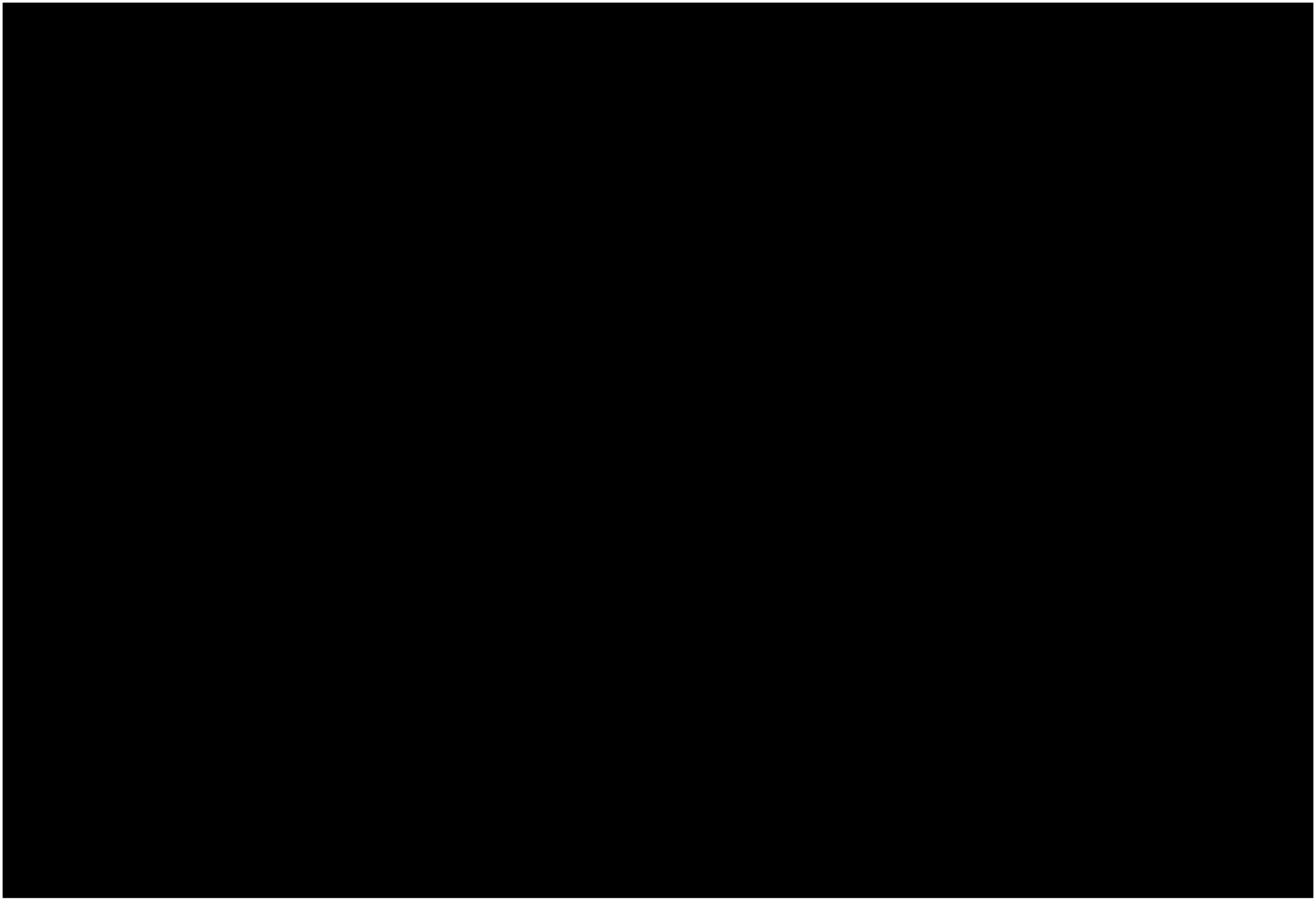
Date of Off Peak Day - 01/17/2021



Member Forecasted Off Peak Demand Day for February 2021

Wheatland Rural Electric Association, Inc.

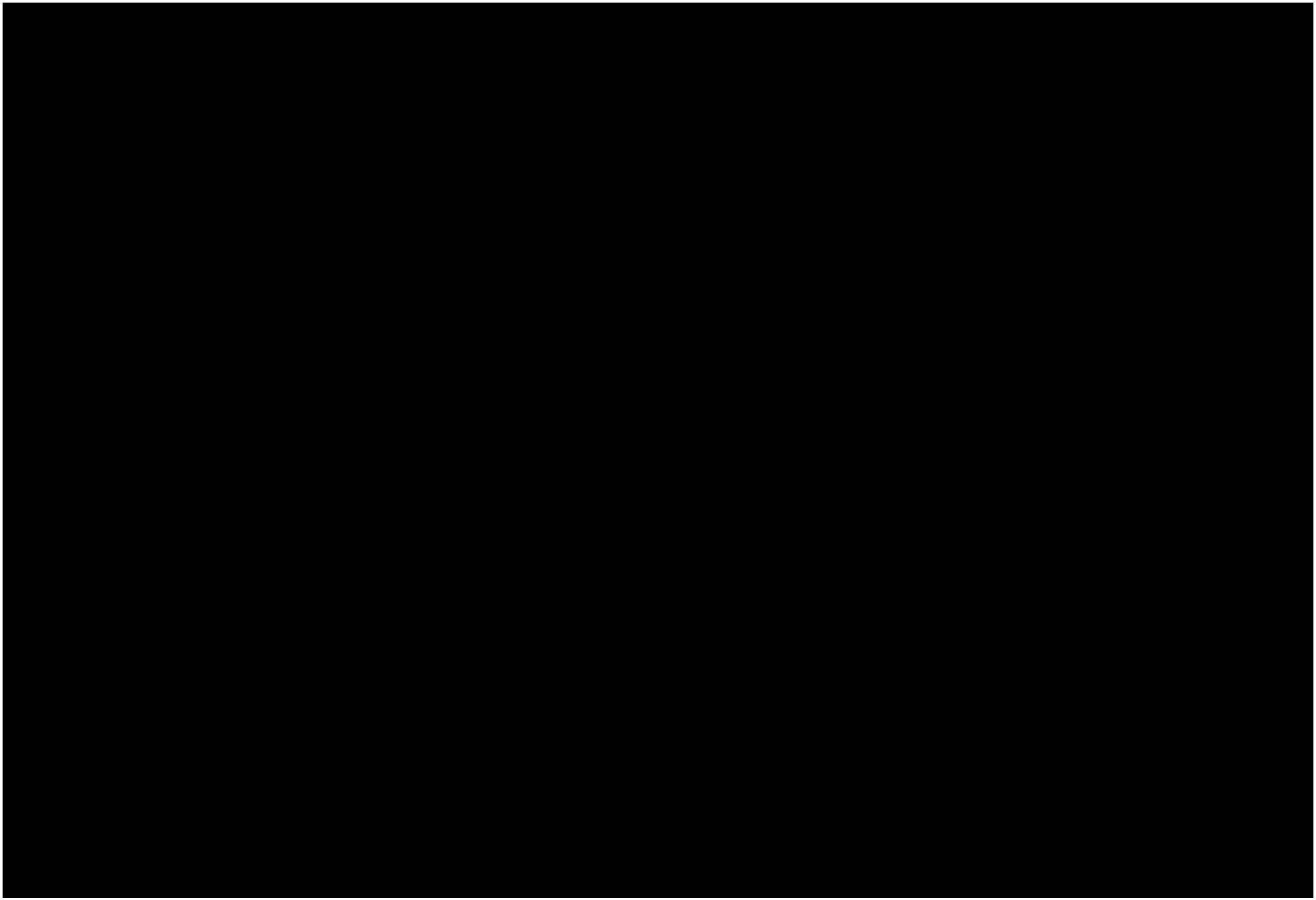
Date of Off Peak Day - 02/09/2021



Member Forecasted Off Peak Demand Day for March 2021

Wheatland Rural Electric Association, Inc.

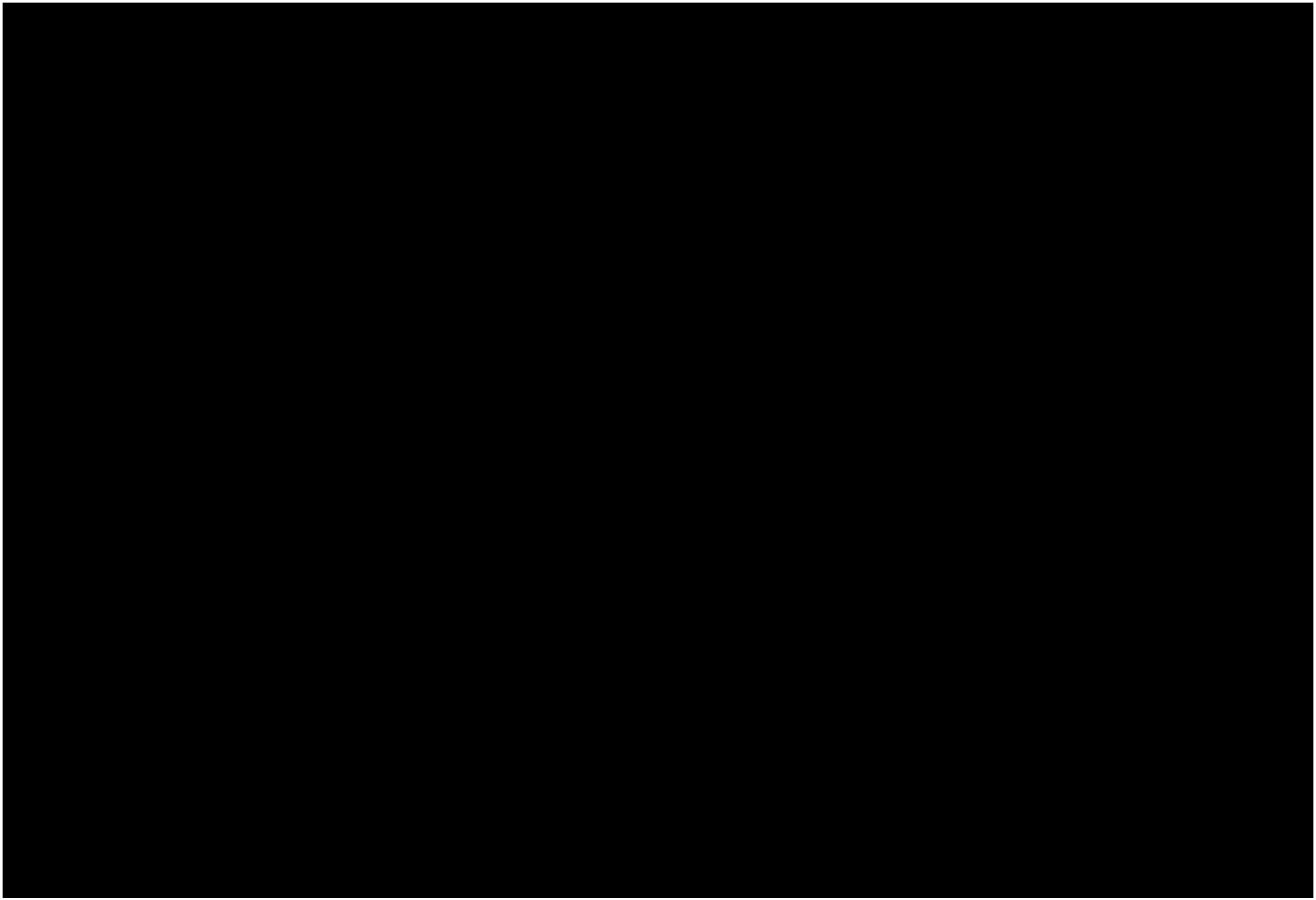
Date of Off Peak Day - 03/14/2021



Member Forecasted Off Peak Demand Day for April 2021

Wheatland Rural Electric Association, Inc.

Date of Off Peak Day - 04/29/2021



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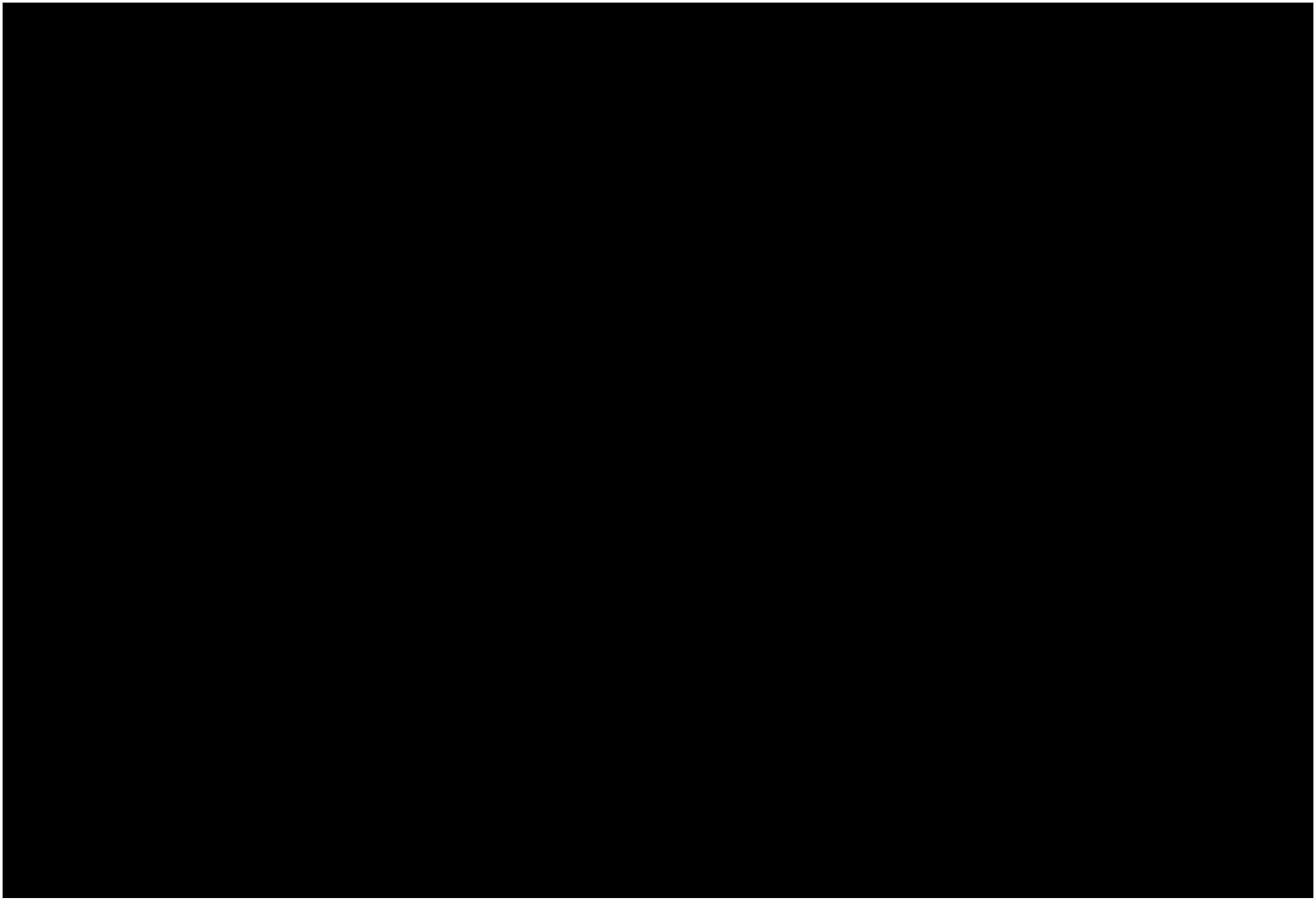
Member Forecasted Off Peak Demand Day for May 2021

Wheatland Rural Electric Association, Inc.

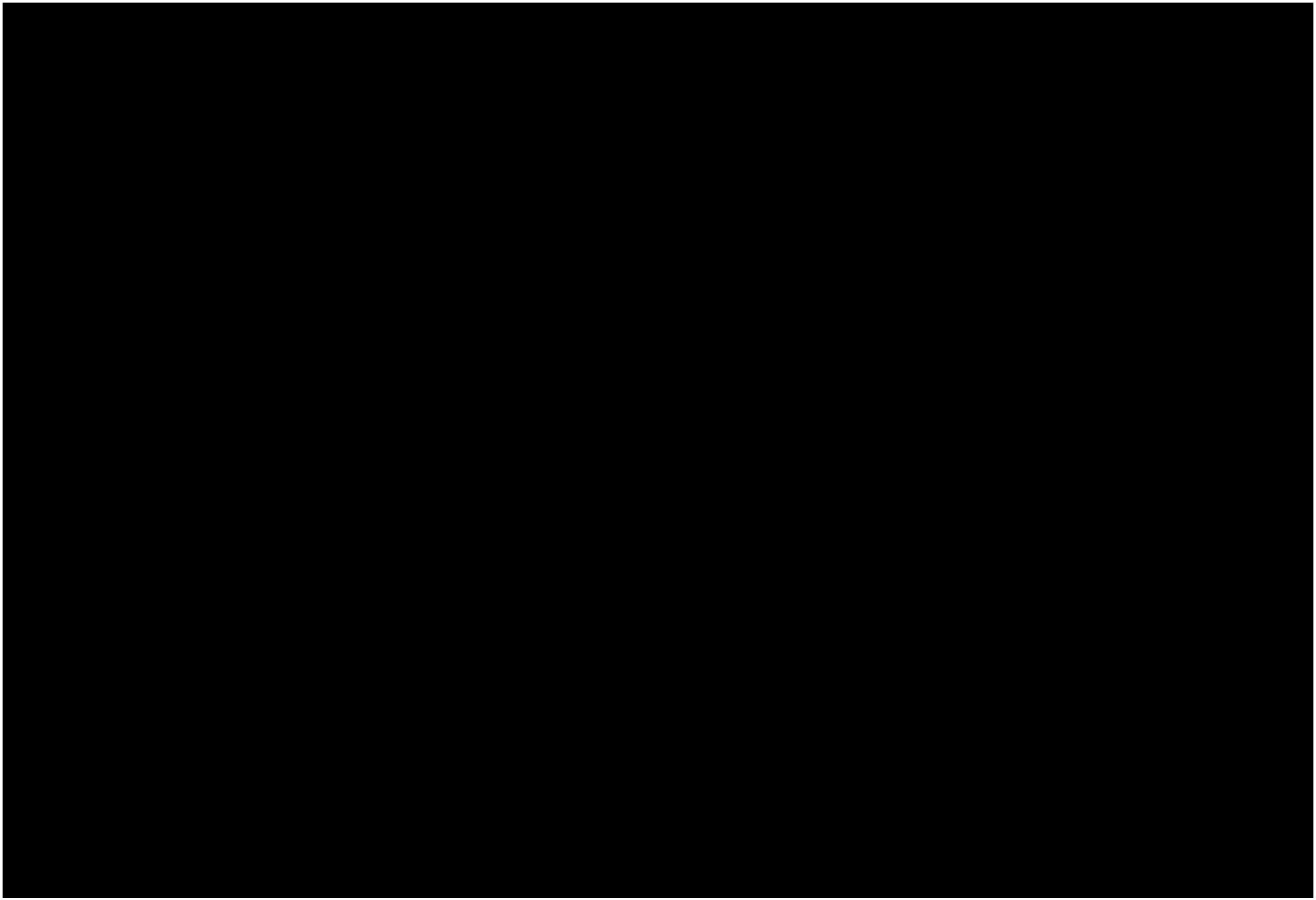
Date of Off Peak Day - 05/22/2021



Member Forecasted Off Peak Demand Day for June 2021

Wheatland Rural Electric Association, Inc.

Date of Off Peak Day - 06/01/2021



Member Forecasted Off Peak Demand Day for July 2021

Wheatland Rural Electric Association, Inc.

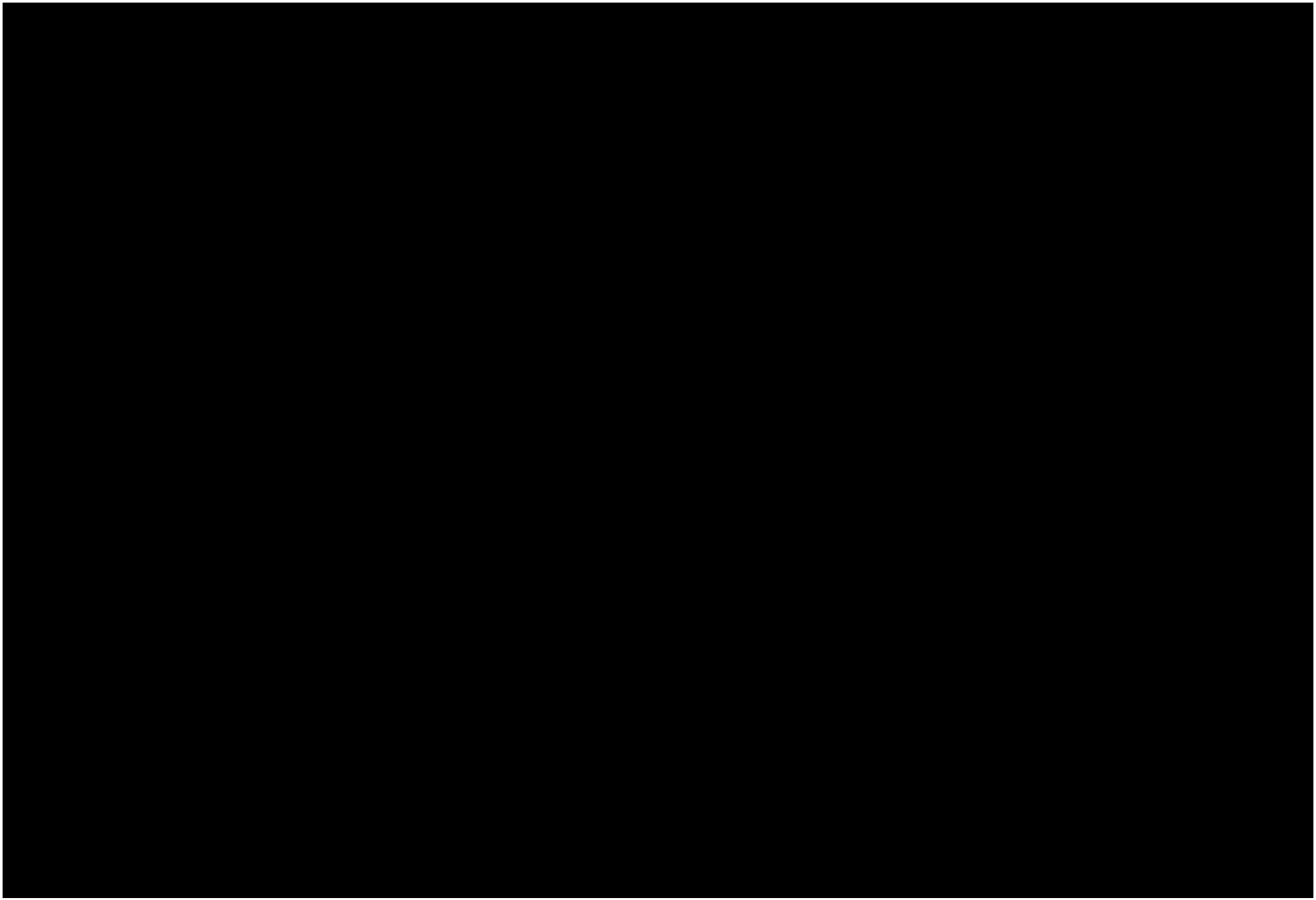
Date of Off Peak Day - 07/05/2021

[redacted]

Member Forecasted Off Peak Demand Day for August 2021

Wheatland Rural Electric Association, Inc.

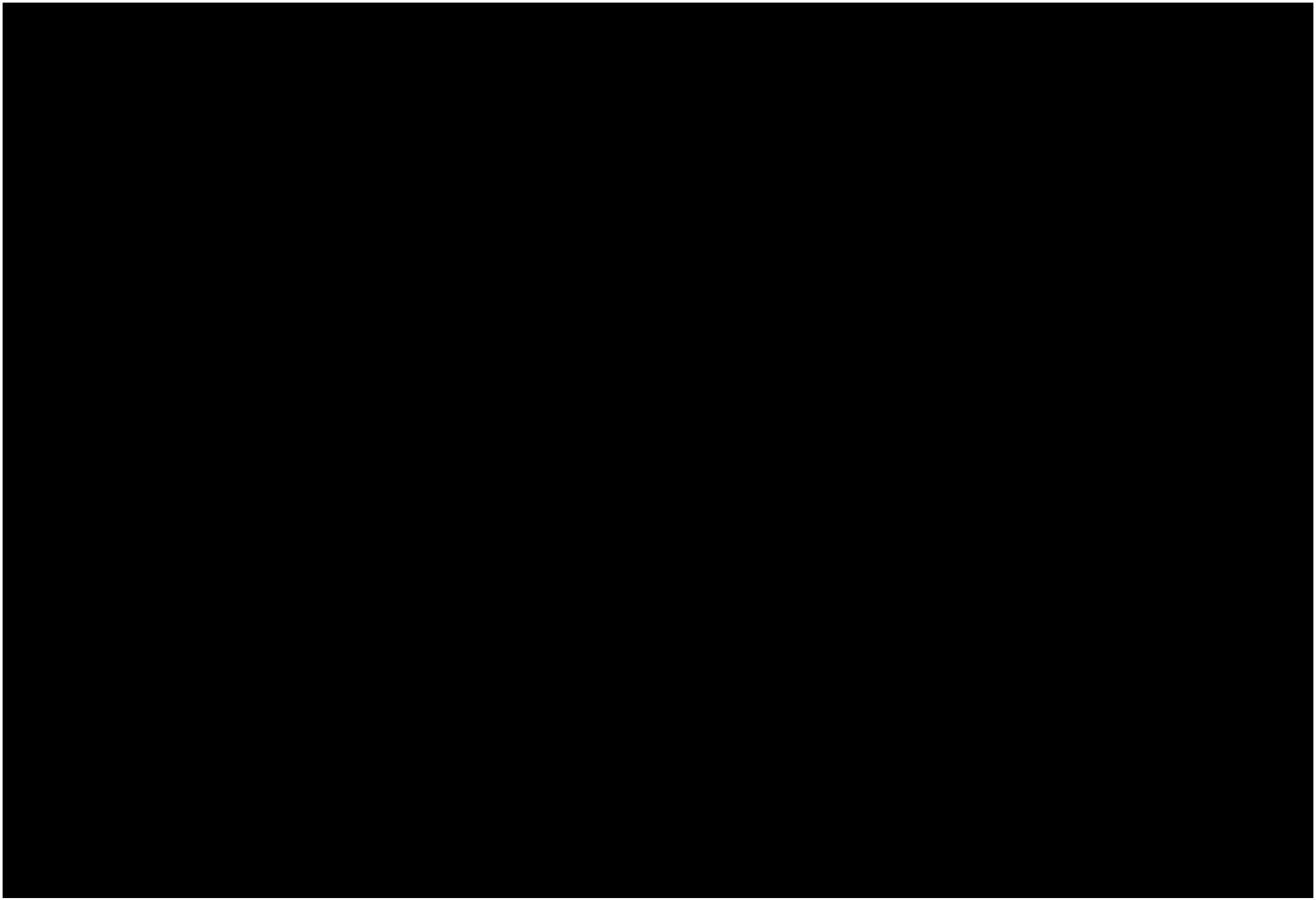
Date of Off Peak Day - 08/08/2021



Member Forecasted Off Peak Demand Day for September 2021

Wheatland Rural Electric Association, Inc.

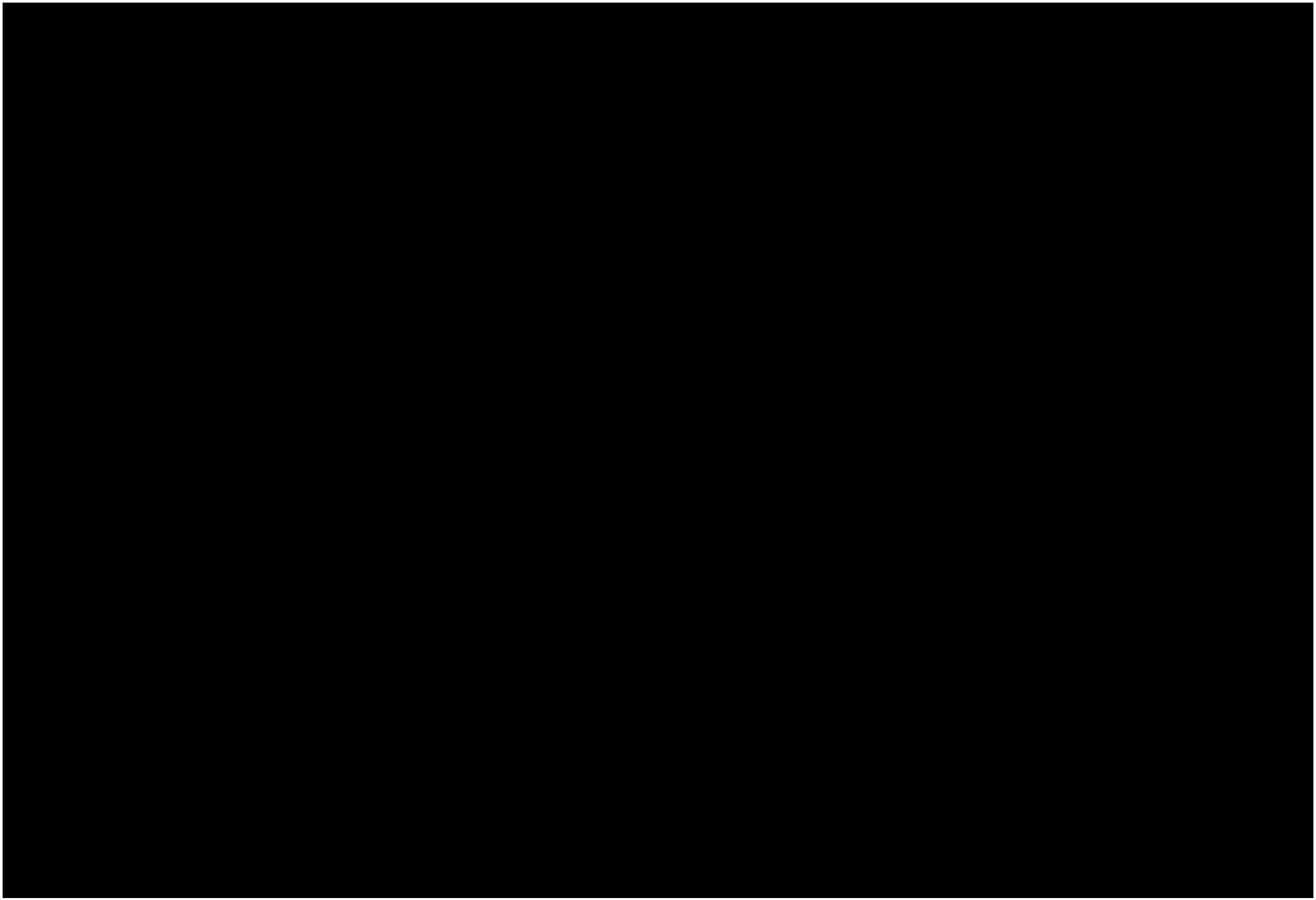
Date of Off Peak Day - 09/15/2021



Member Forecasted Off Peak Demand Day for October 2021

Wheatland Rural Electric Association, Inc.

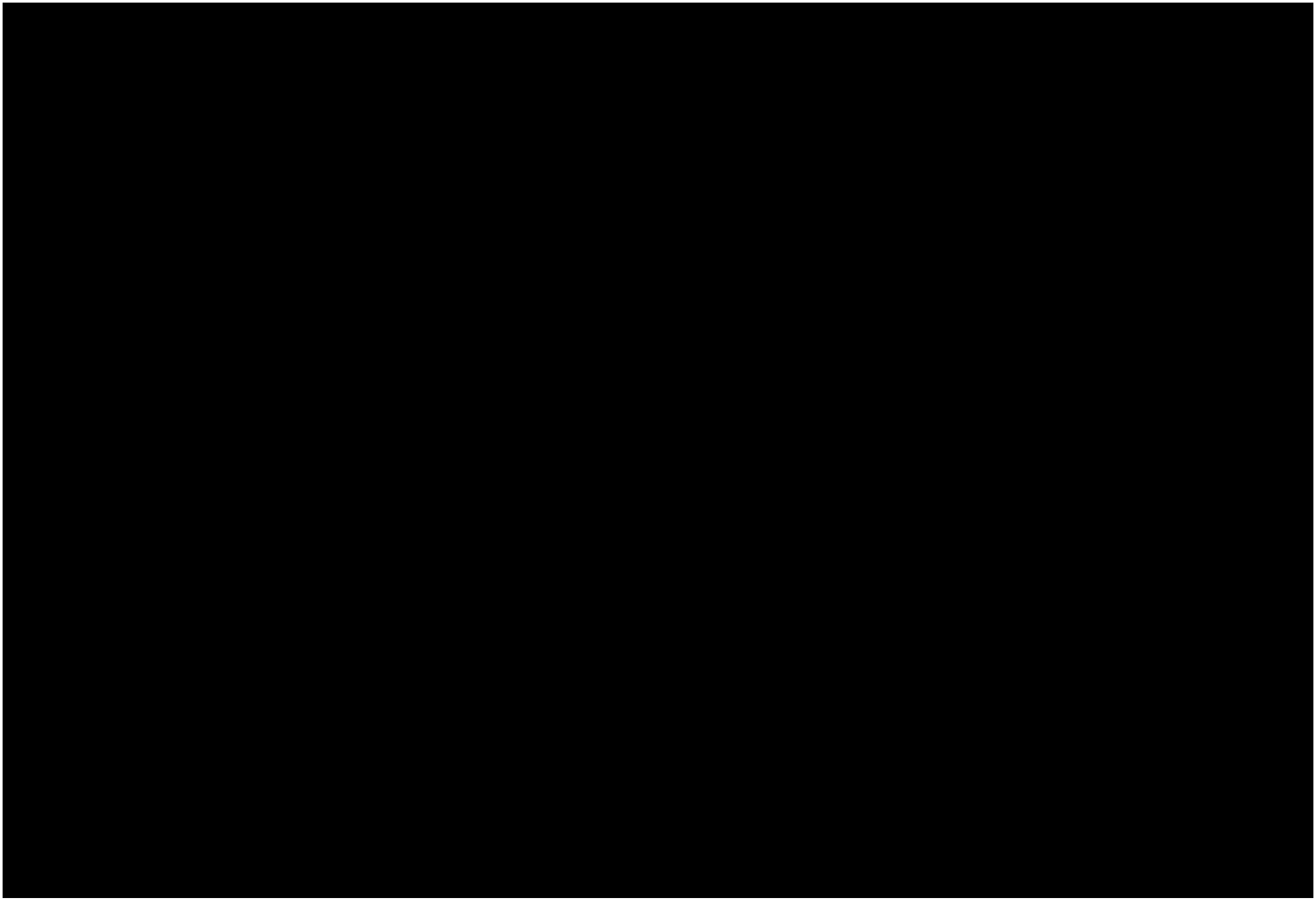
Date of Off Peak Day - 10/01/2021



Member Forecasted Off Peak Demand Day for November 2021

Wheatland Rural Electric Association, Inc.

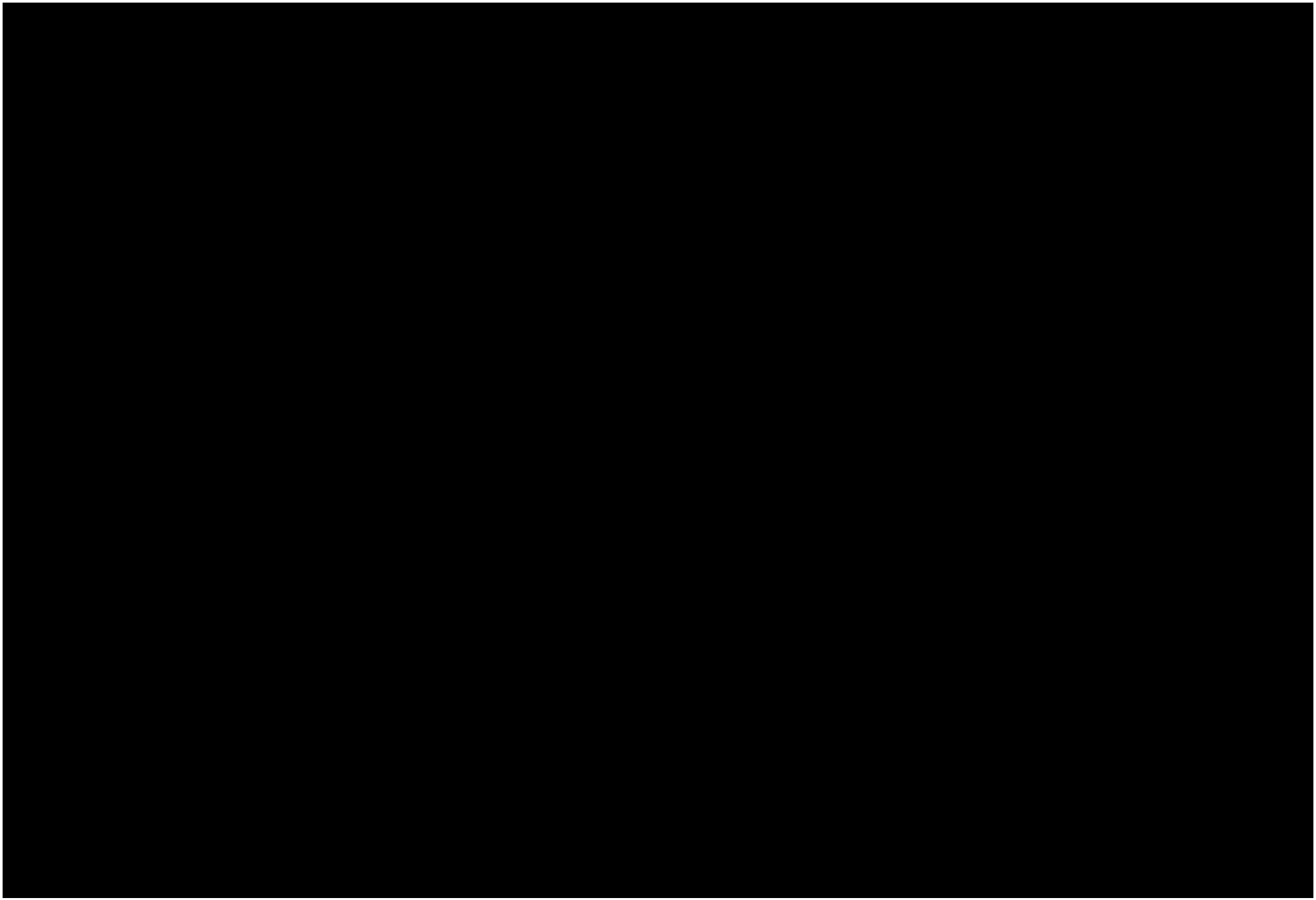
Date of Off Peak Day - 11/04/2021



Member Forecasted Off Peak Demand Day for December 2021

Wheatland Rural Electric Association, Inc.

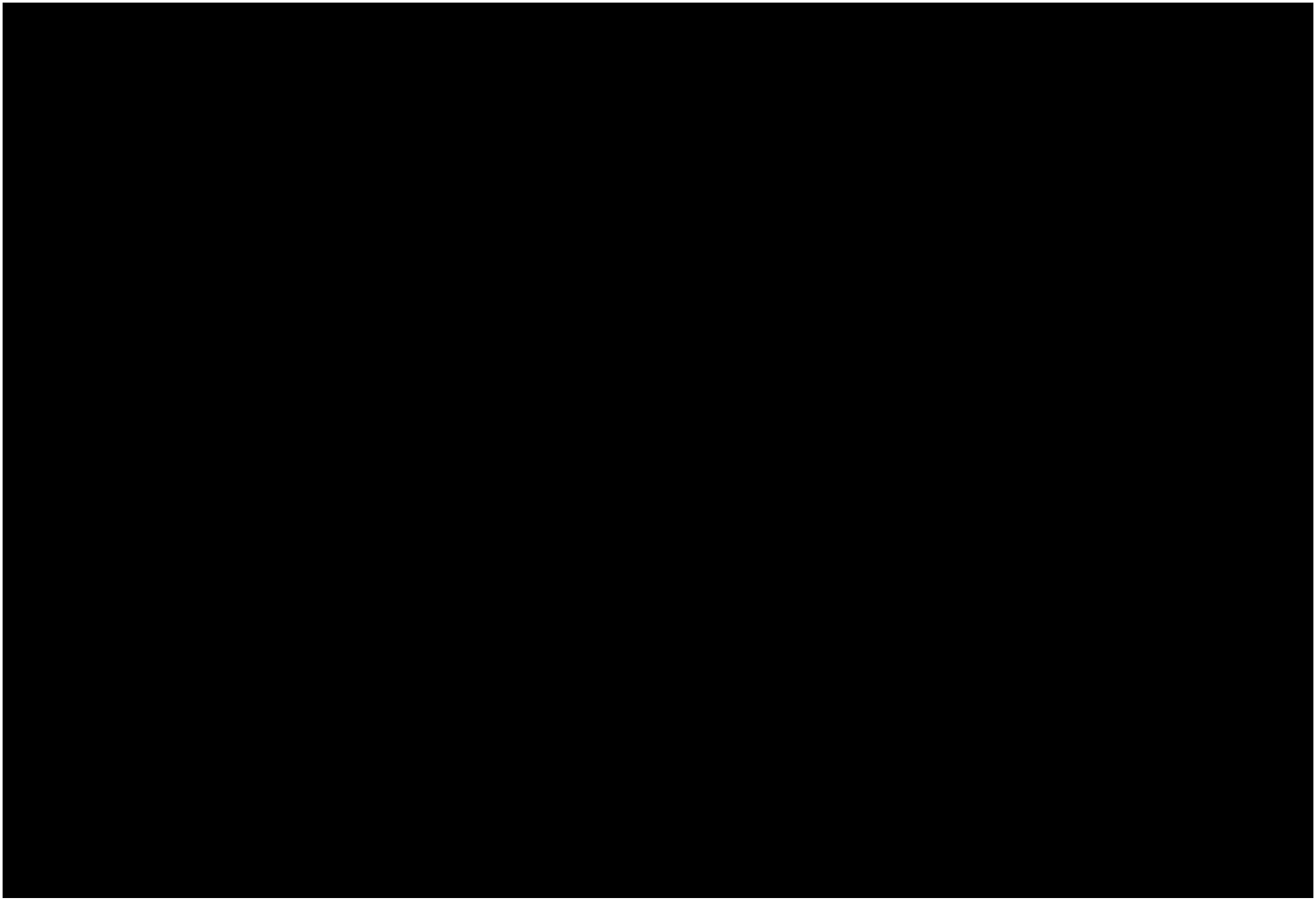
Date of Off Peak Day - 12/01/2021



Member Forecasted Off Peak Demand Day for January 2021

White River Electric Association, Inc.

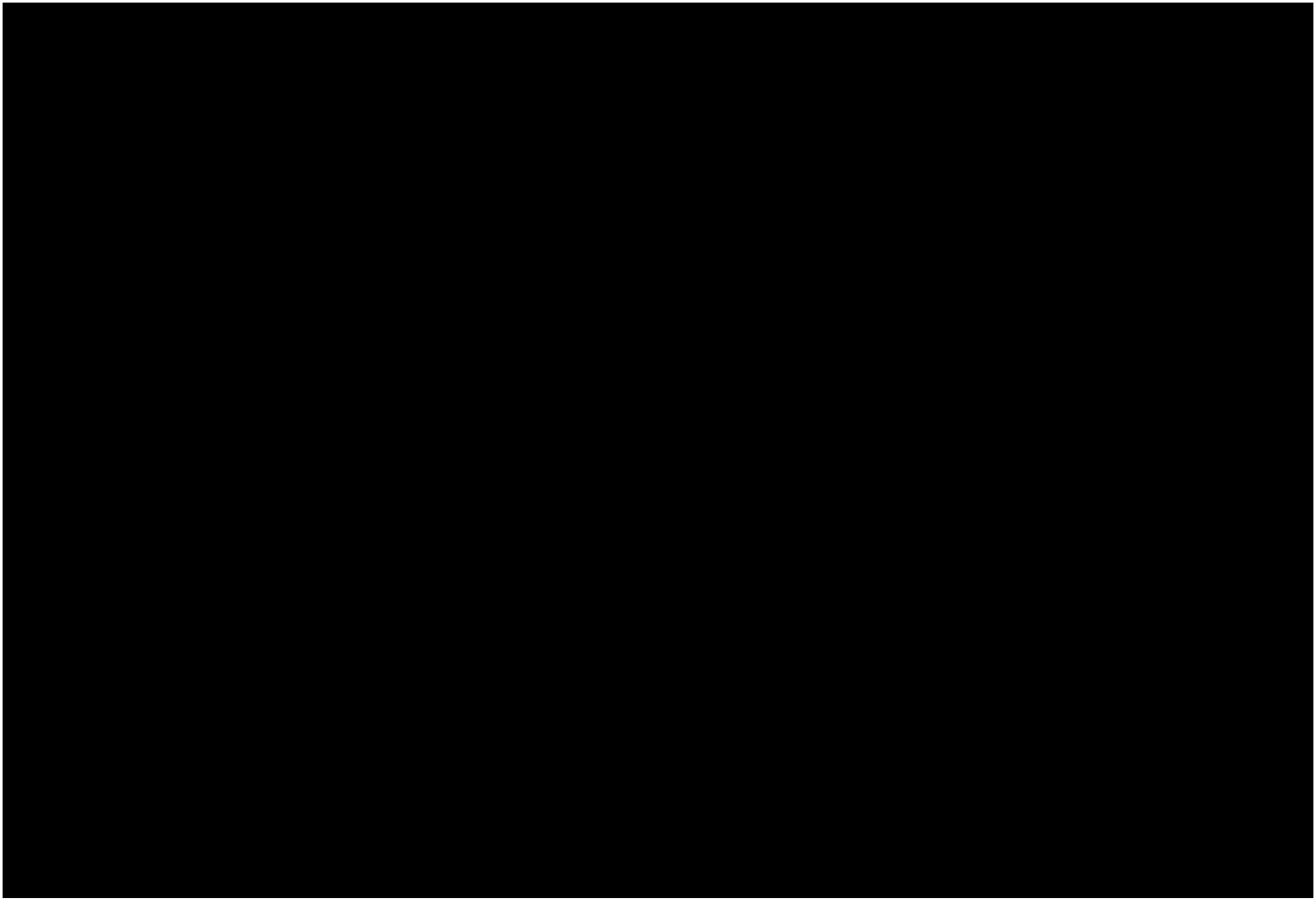
Date of Off Peak Day - 01/06/2021



Member Forecasted Off Peak Demand Day for February 2021

White River Electric Association, Inc.

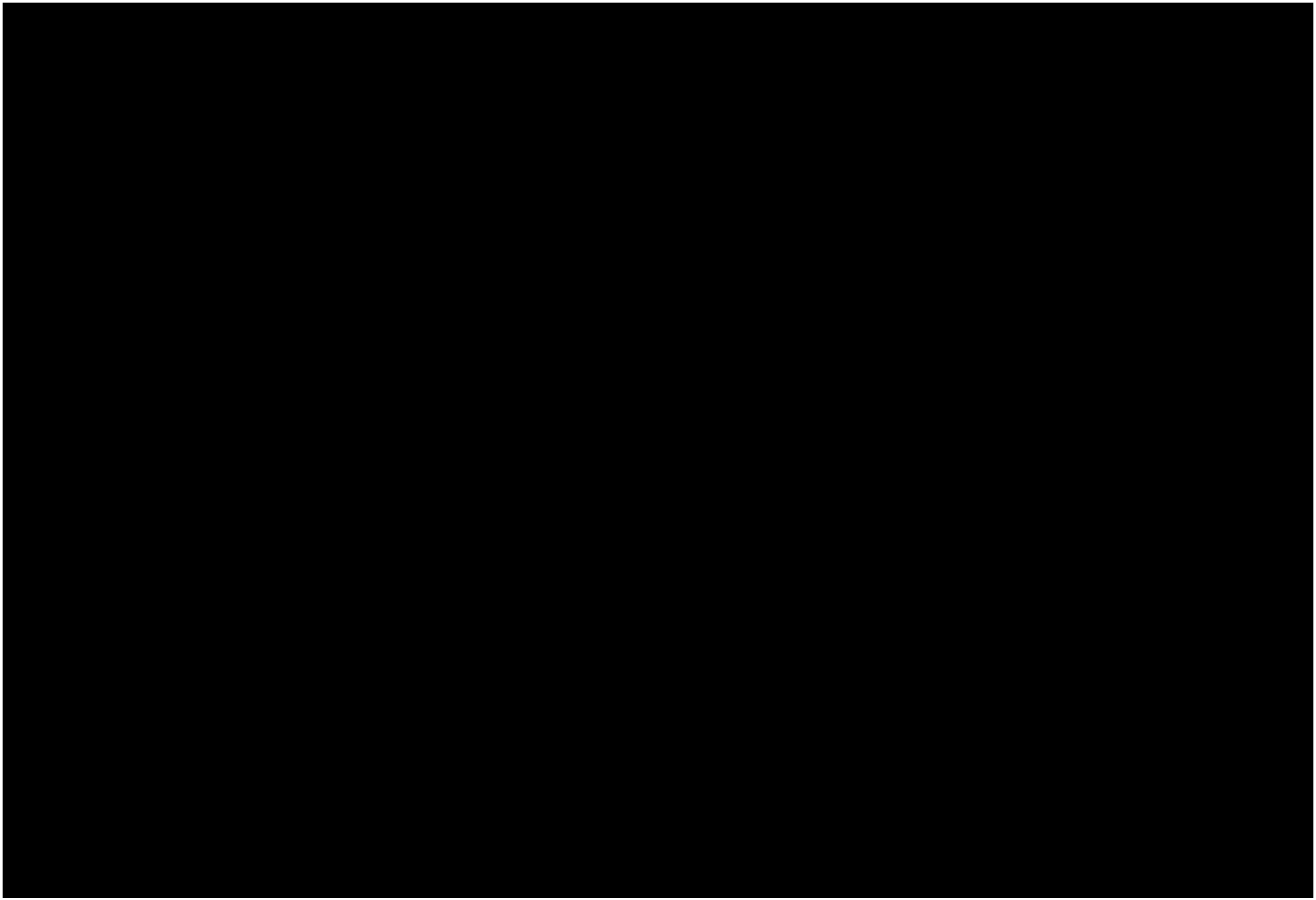
Date of Off Peak Day - 02/11/2021



Member Forecasted Off Peak Demand Day for March 2021

White River Electric Association, Inc.

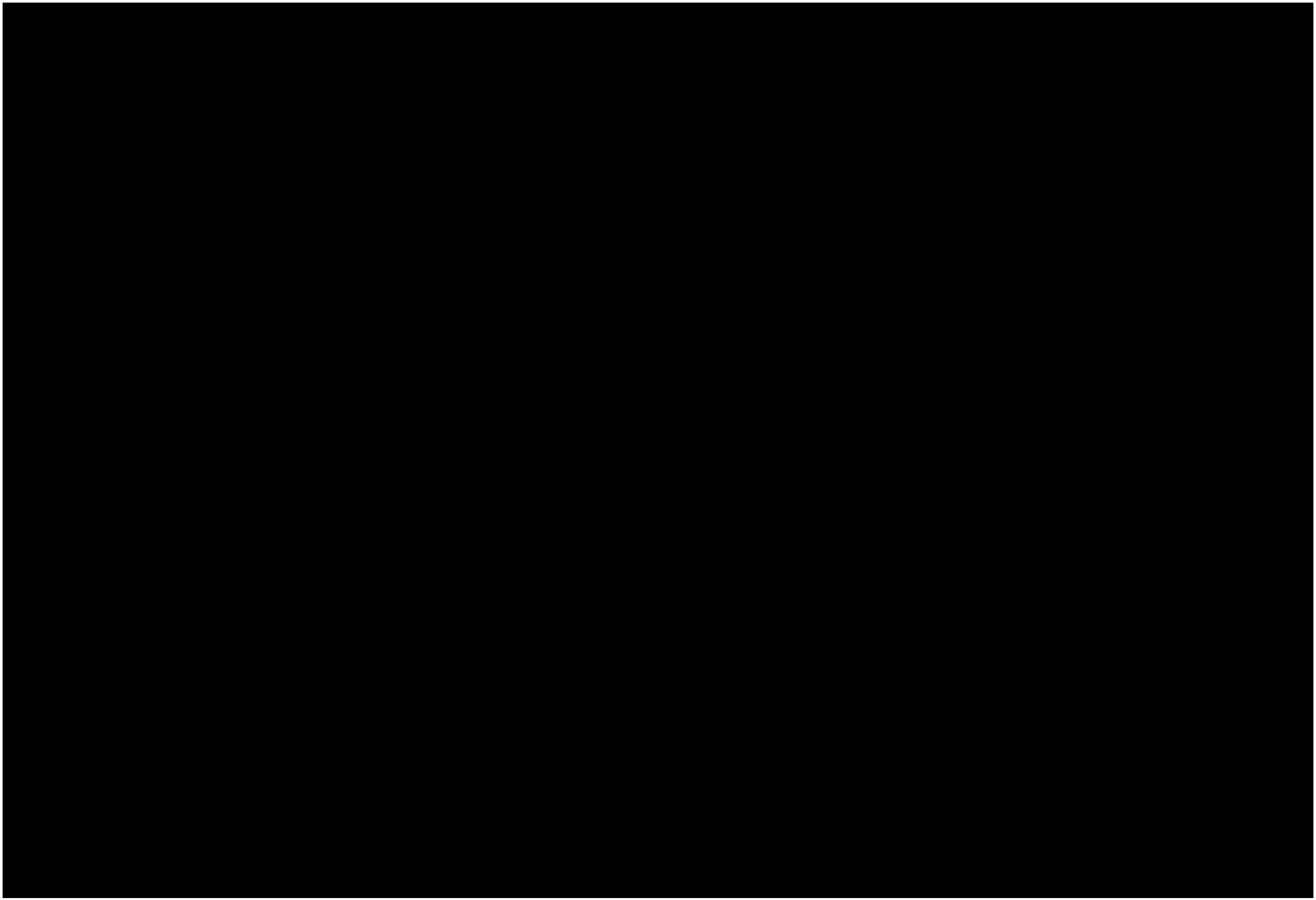
Date of Off Peak Day - 03/09/2021



Member Forecasted Off Peak Demand Day for April 2021

White River Electric Association, Inc.

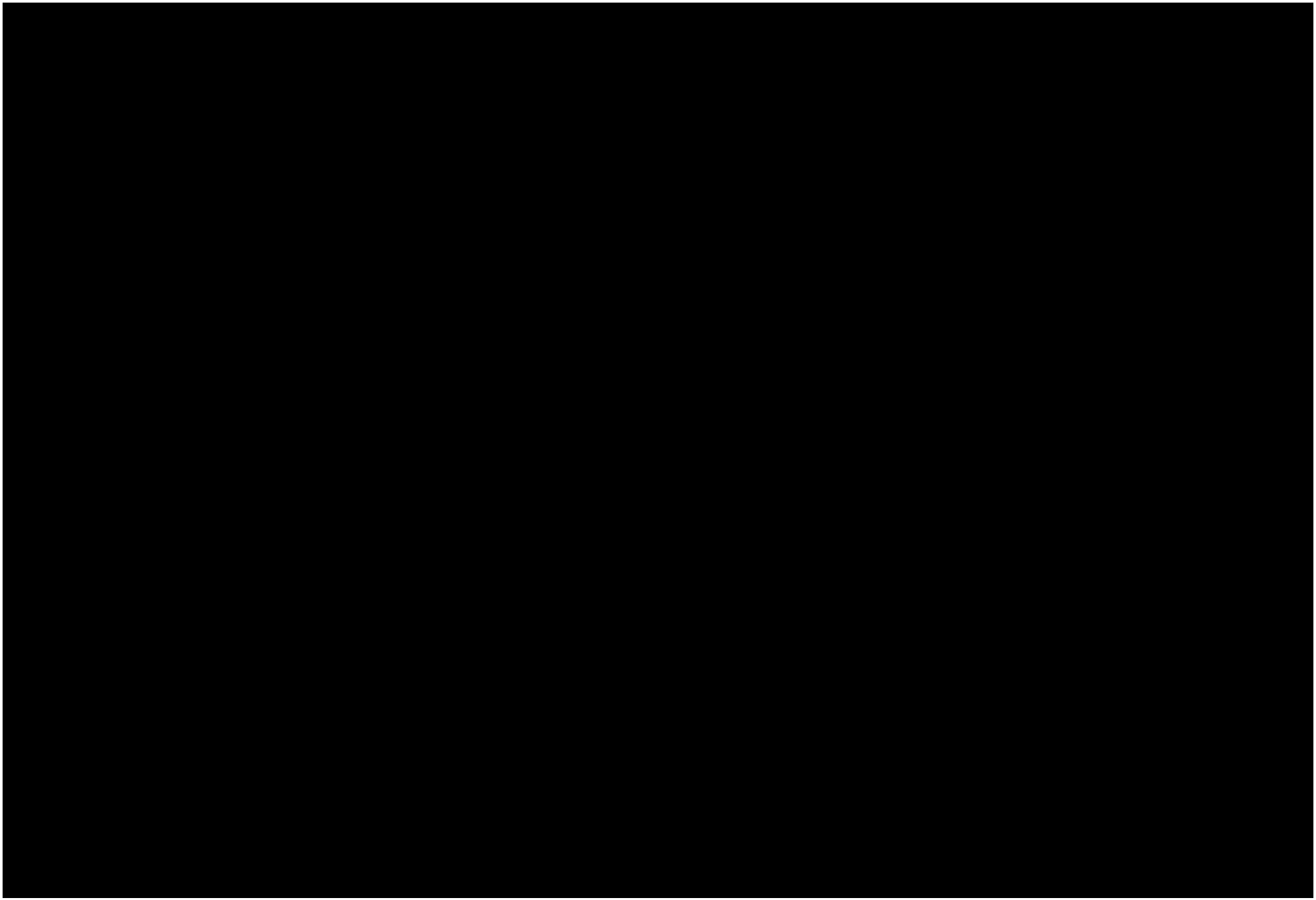
Date of Off Peak Day - 04/28/2021



Member Forecasted Off Peak Demand Day for May 2021

White River Electric Association, Inc.

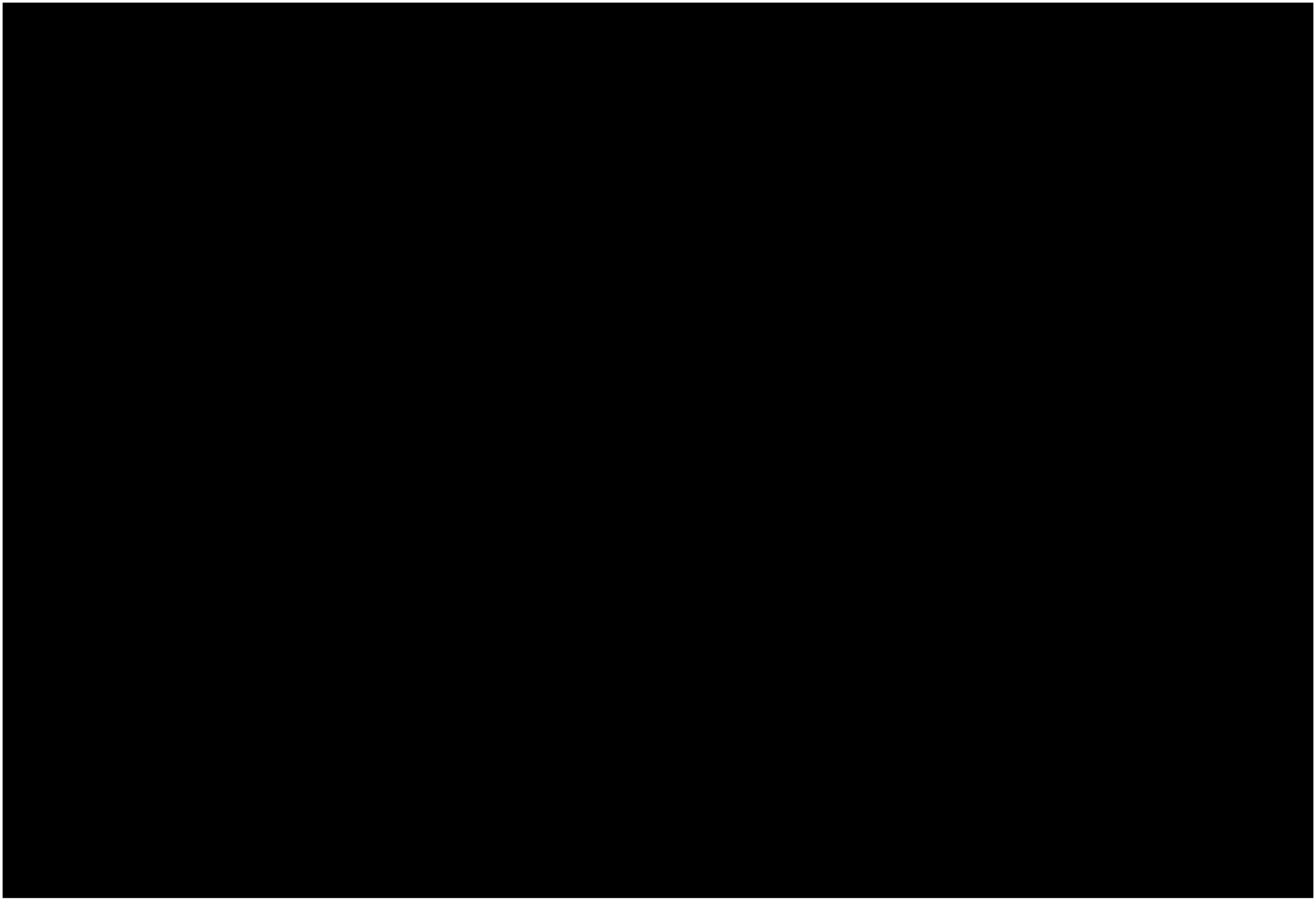
Date of Off Peak Day - 05/17/2021



Member Forecasted Off Peak Demand Day for June 2021

White River Electric Association, Inc.

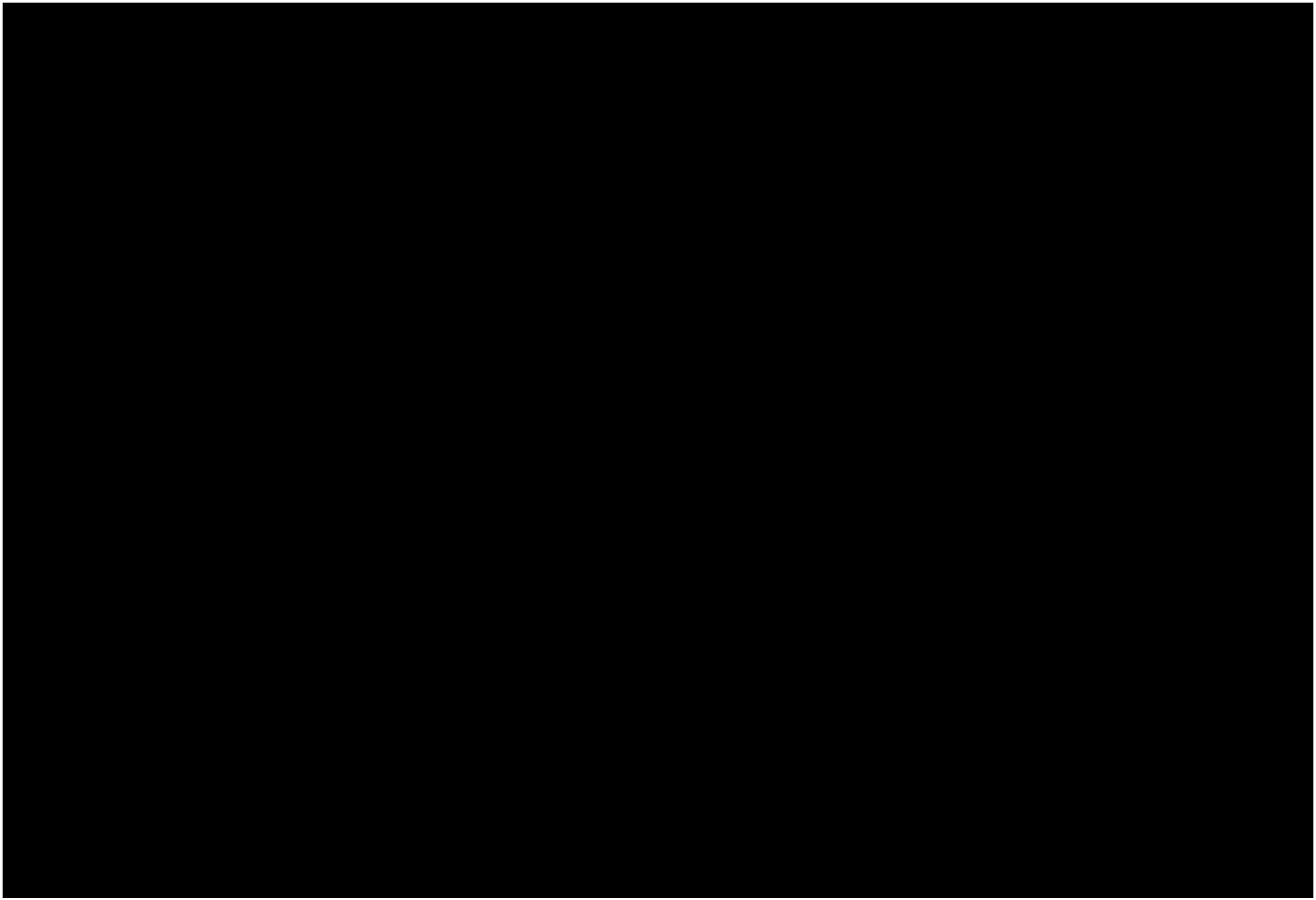
Date of Off Peak Day - 06/22/2021



Member Forecasted Off Peak Demand Day for July 2021

White River Electric Association, Inc.

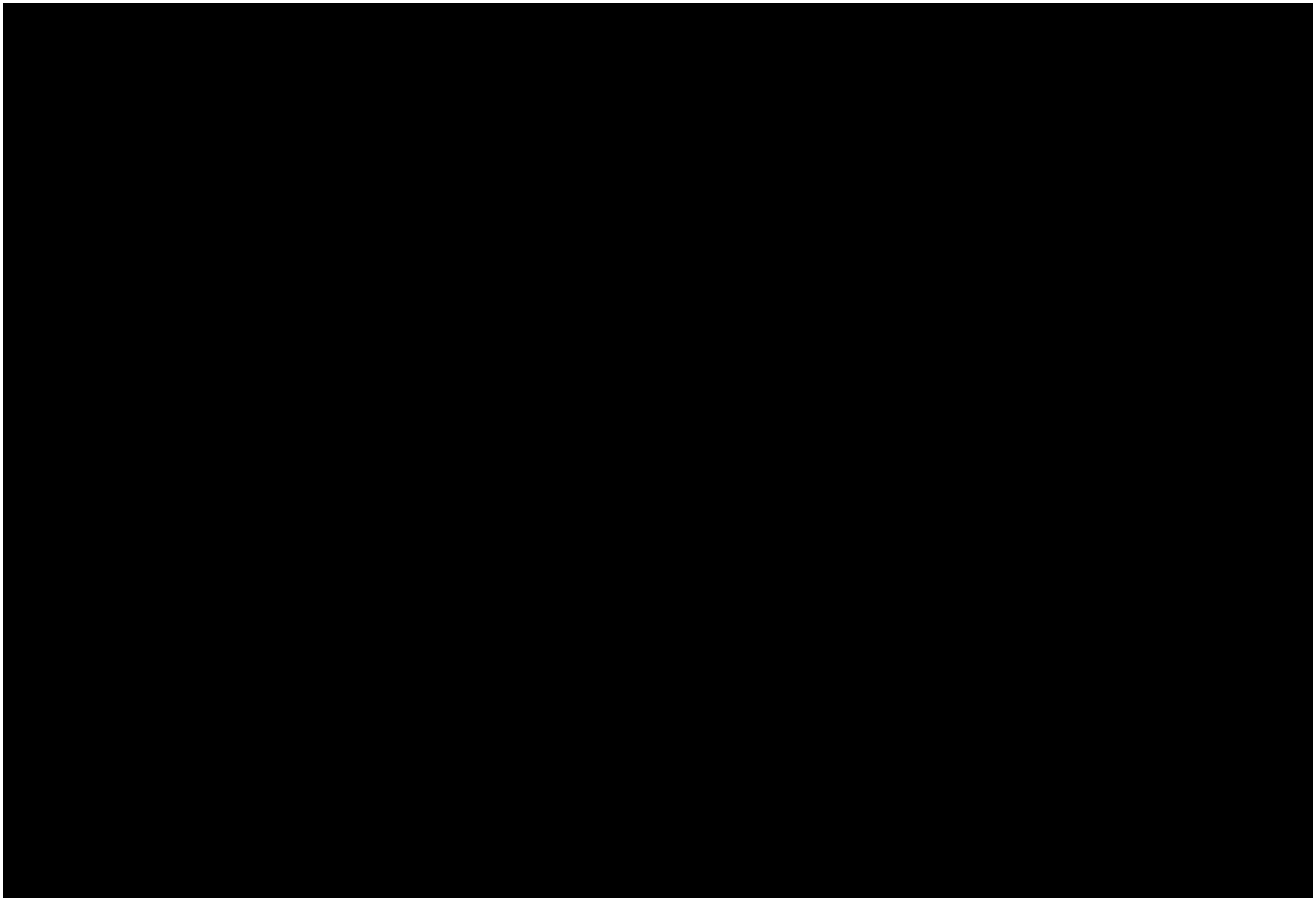
Date of Off Peak Day - 07/20/2021



Member Forecasted Off Peak Demand Day for August 2021

White River Electric Association, Inc.

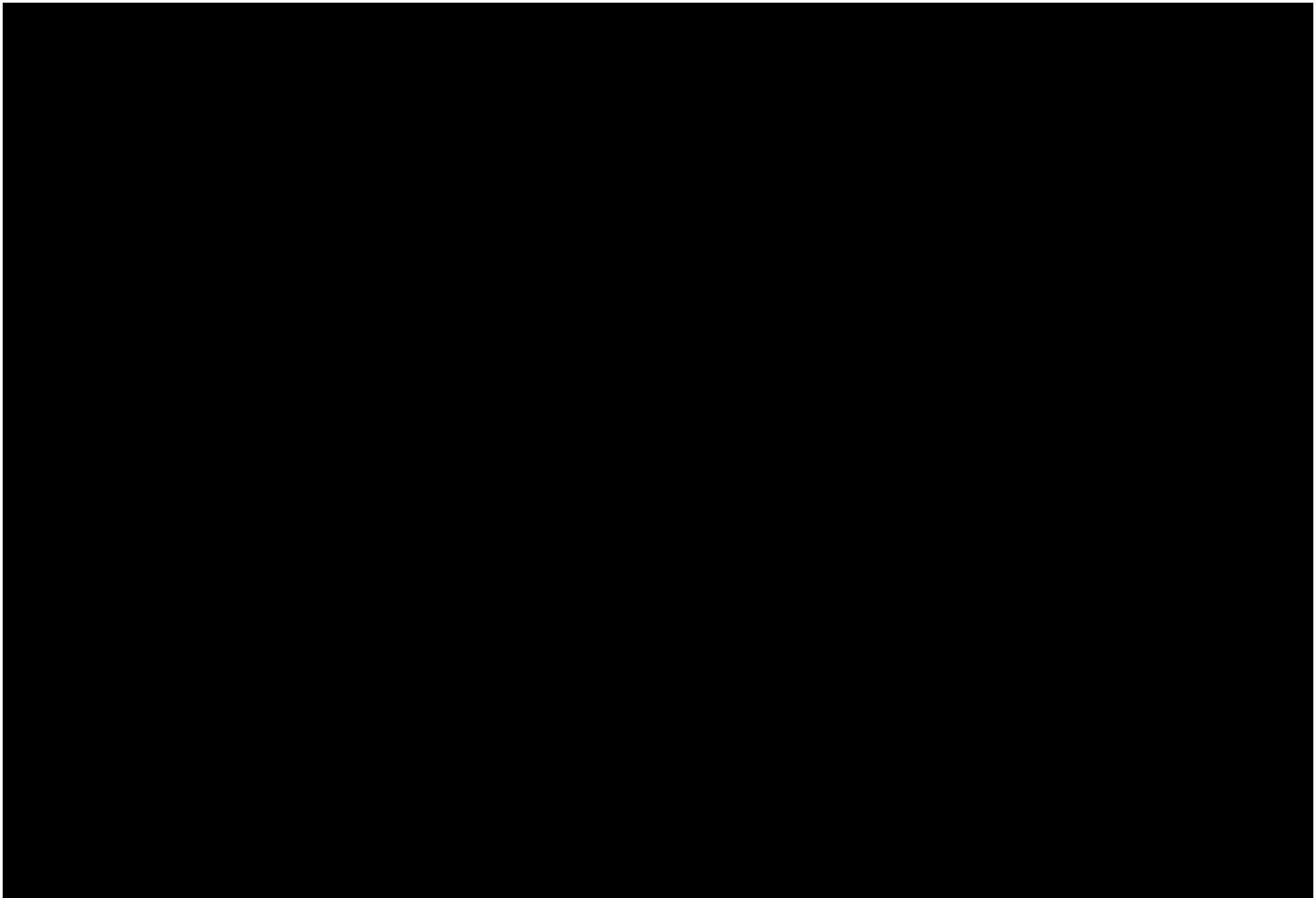
Date of Off Peak Day - 08/03/2021



Member Forecasted Off Peak Demand Day for September 2021

White River Electric Association, Inc.

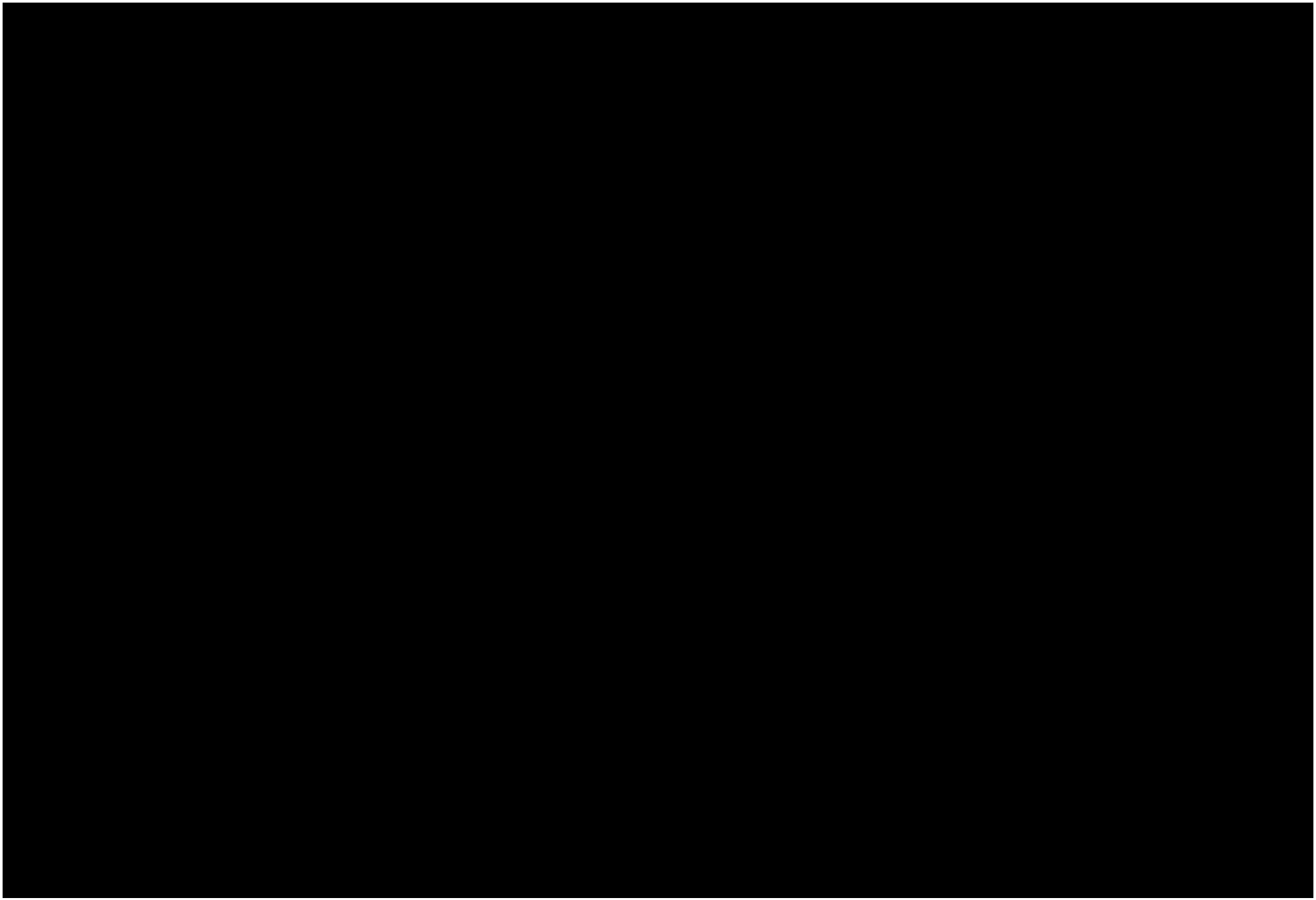
Date of Off Peak Day - 09/02/2021



Member Forecasted Off Peak Demand Day for October 2021

White River Electric Association, Inc.

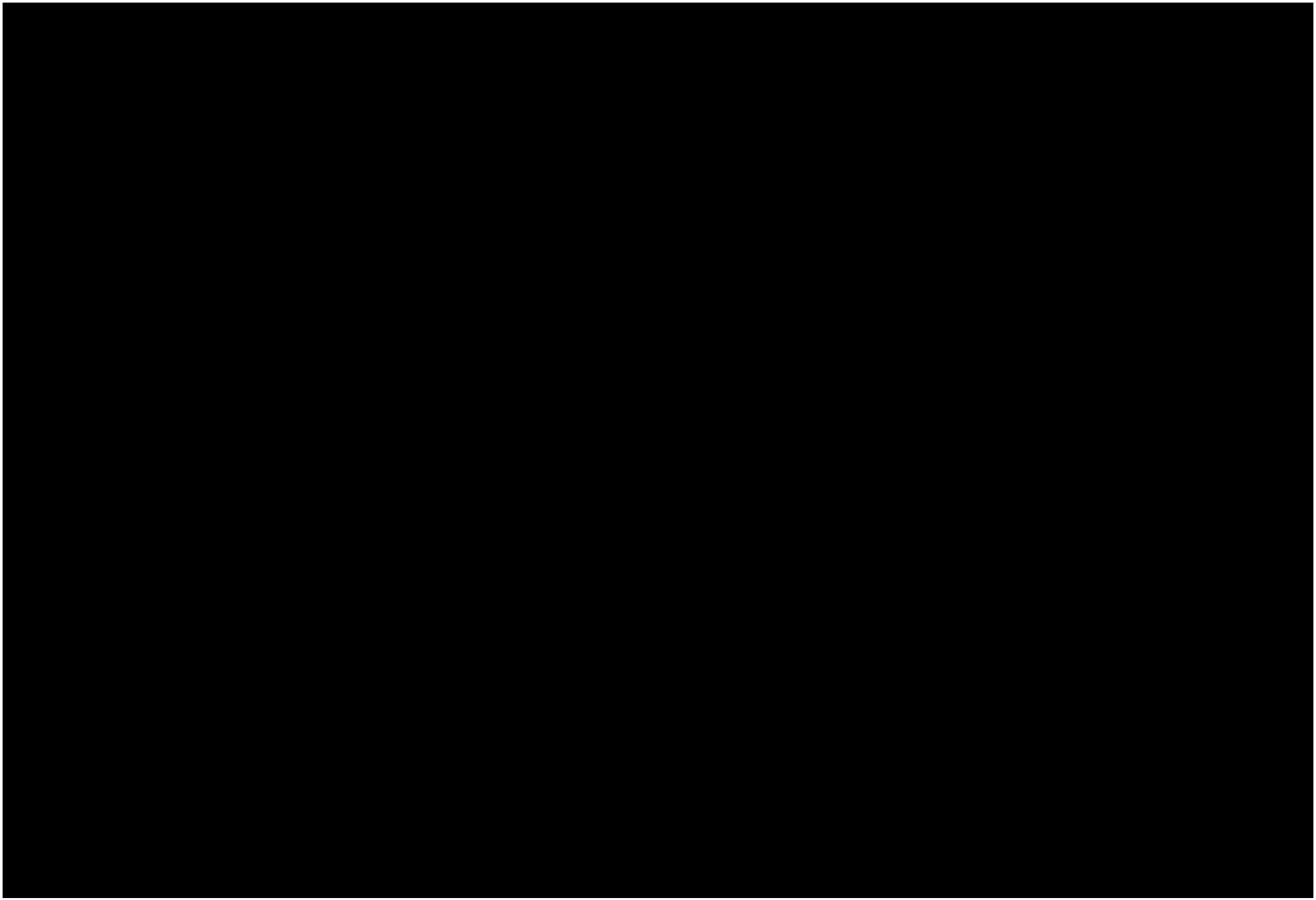
Date of Off Peak Day - 10/21/2021



Member Forecasted Off Peak Demand Day for November 2021

White River Electric Association, Inc.

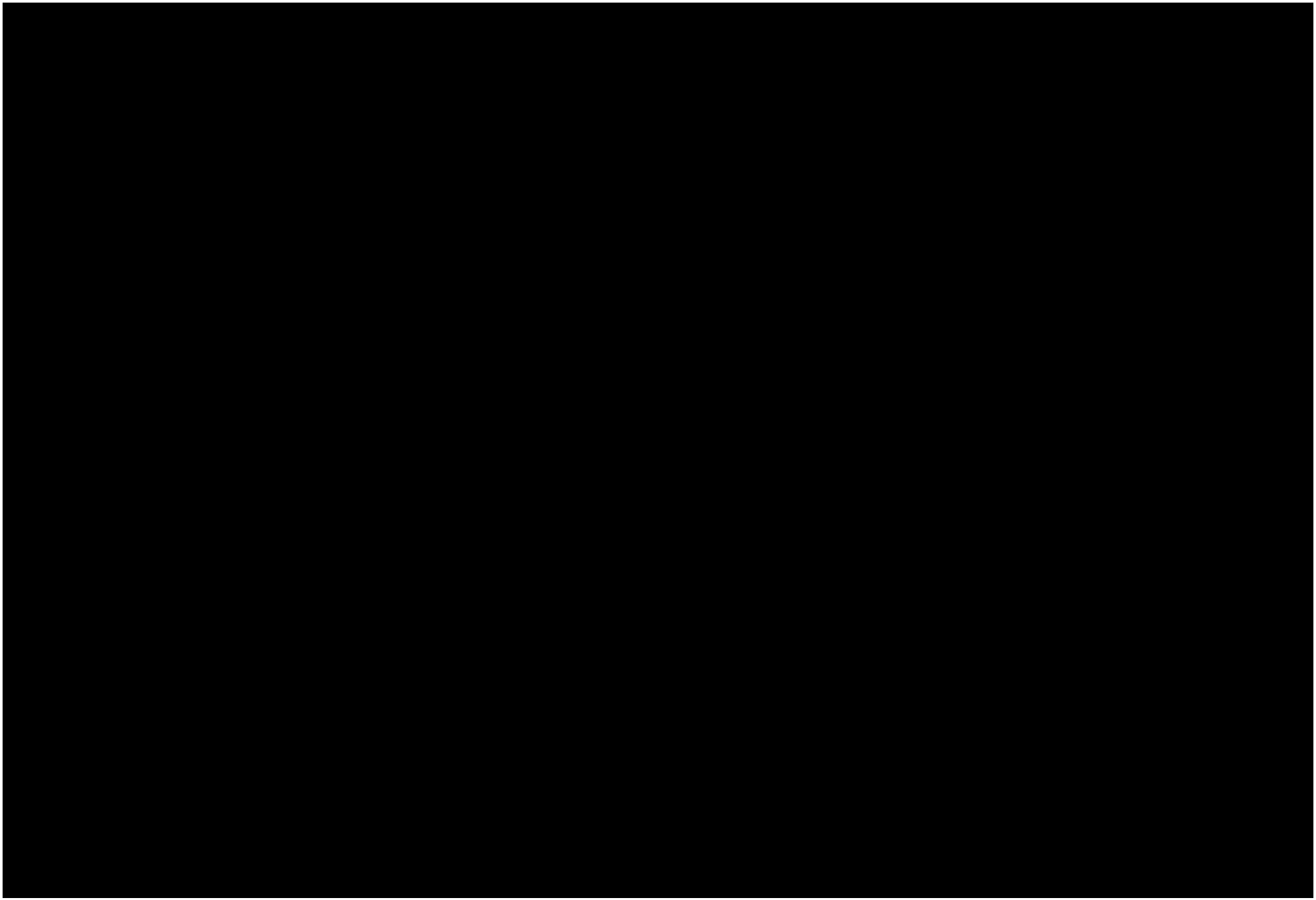
Date of Off Peak Day - 11/12/2021



Member Forecasted Off Peak Demand Day for December 2021

White River Electric Association, Inc.

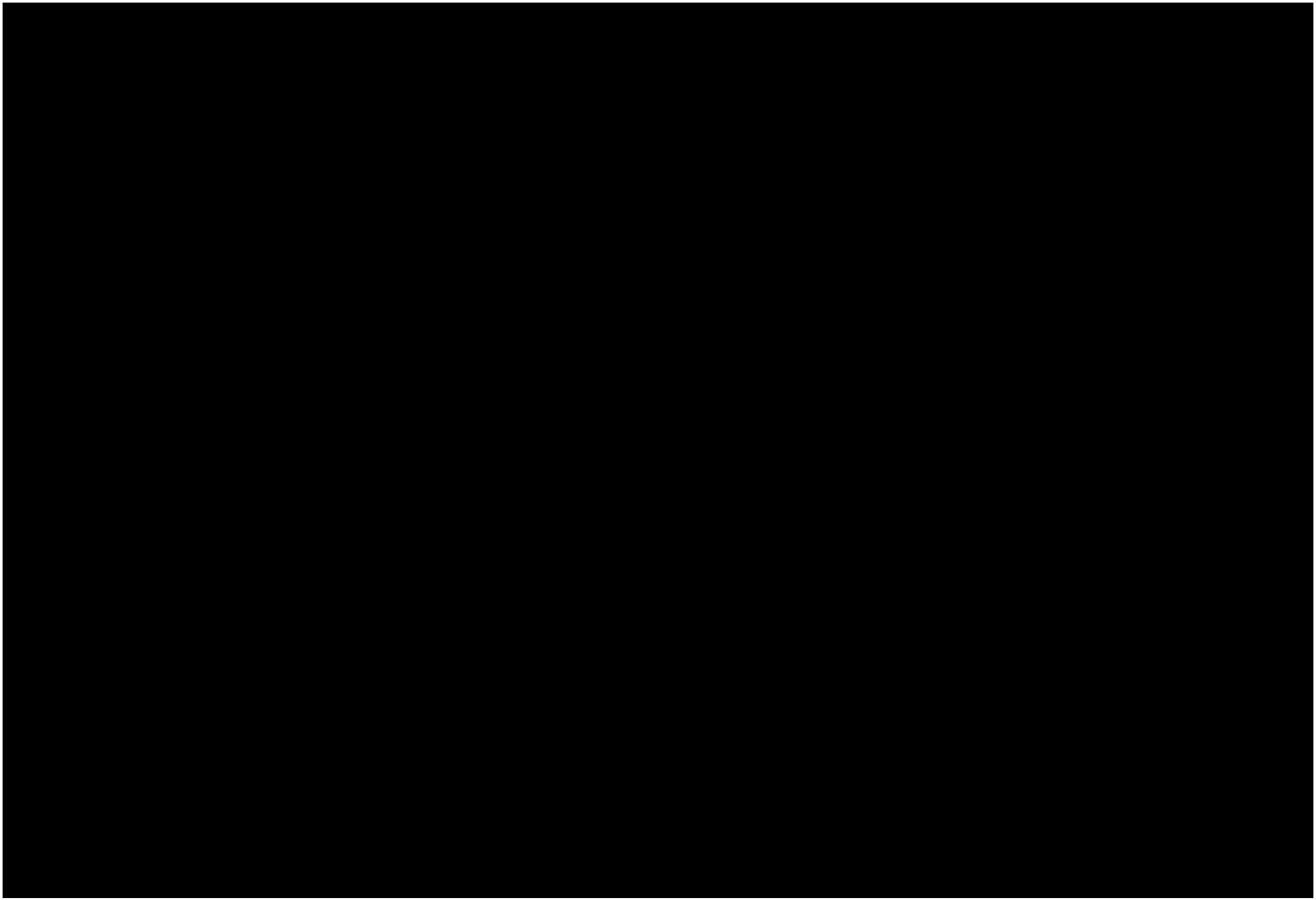
Date of Off Peak Day - 12/03/2021



Member Forecasted Off Peak Demand Day for January 2021

Wyrulec Company

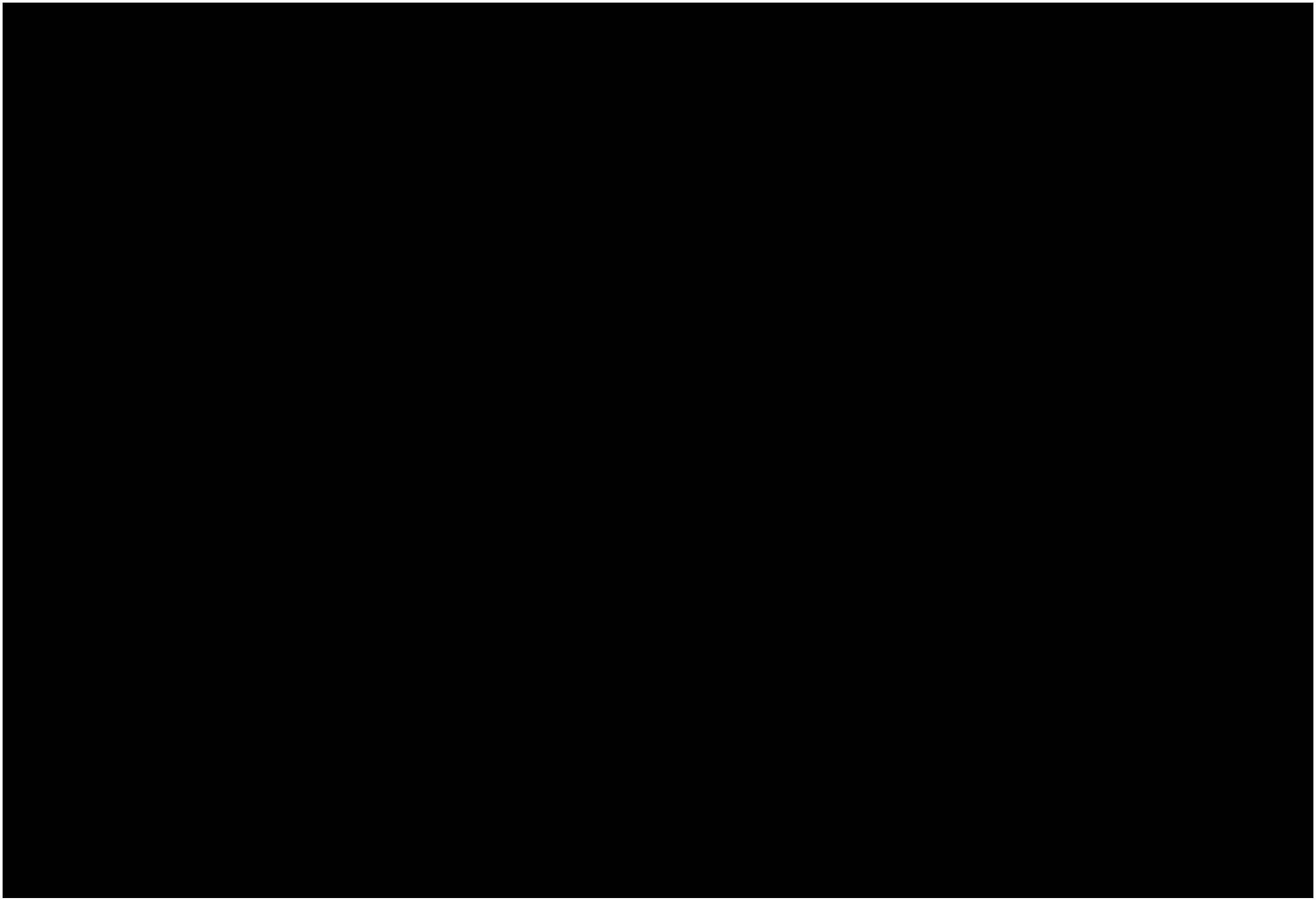
Date of Off Peak Day - 01/01/2021



Member Forecasted Off Peak Demand Day for February 2021

Wyrulec Company

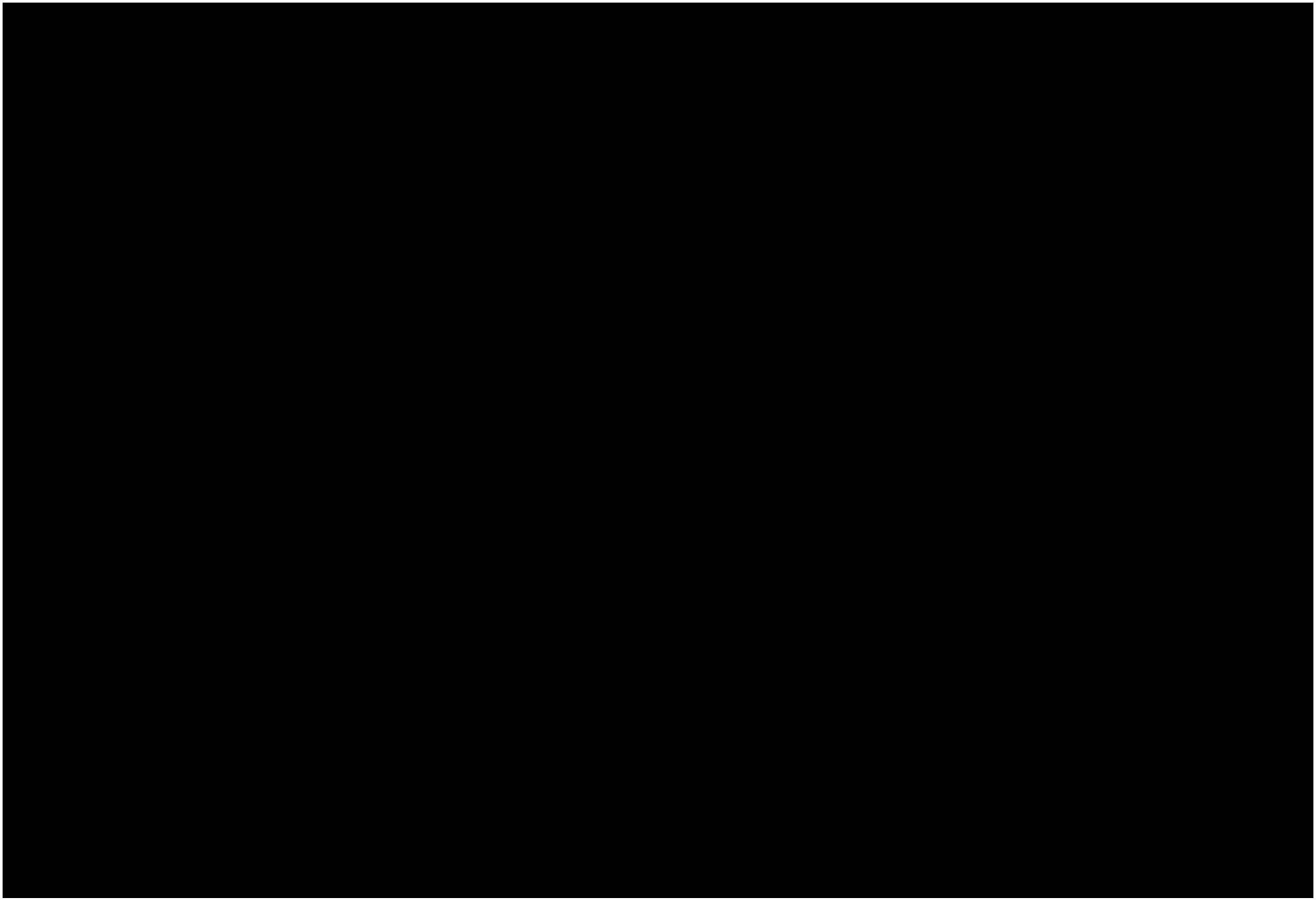
Date of Off Peak Day - 02/09/2021



Member Forecasted Off Peak Demand Day for March 2021

Wyrulec Company

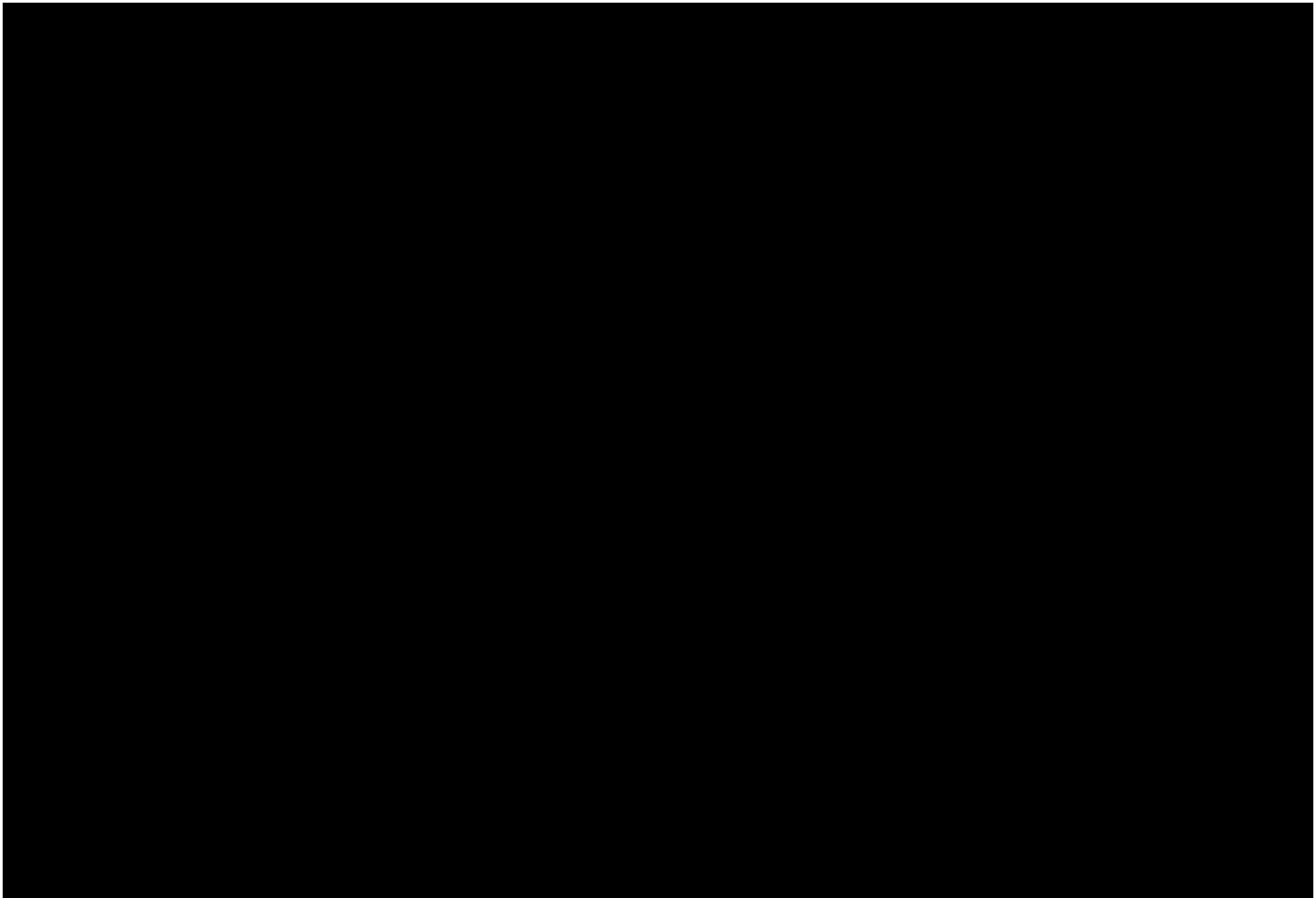
Date of Off Peak Day - 03/29/2021



Member Forecasted Off Peak Demand Day for April 2021

Wyrulec Company

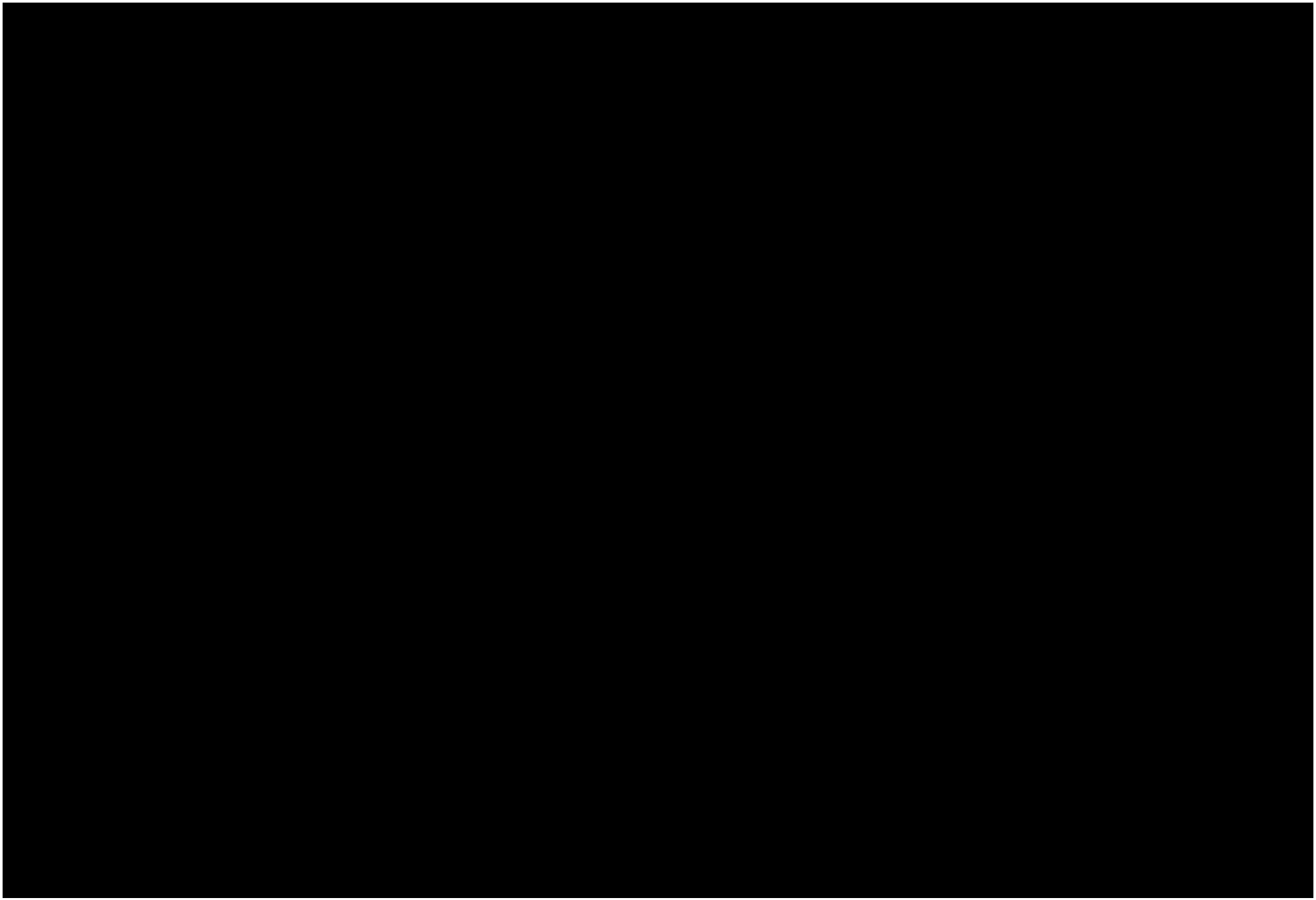
Date of Off Peak Day - 04/01/2021



Member Forecasted Off Peak Demand Day for May 2021

Wyrulec Company

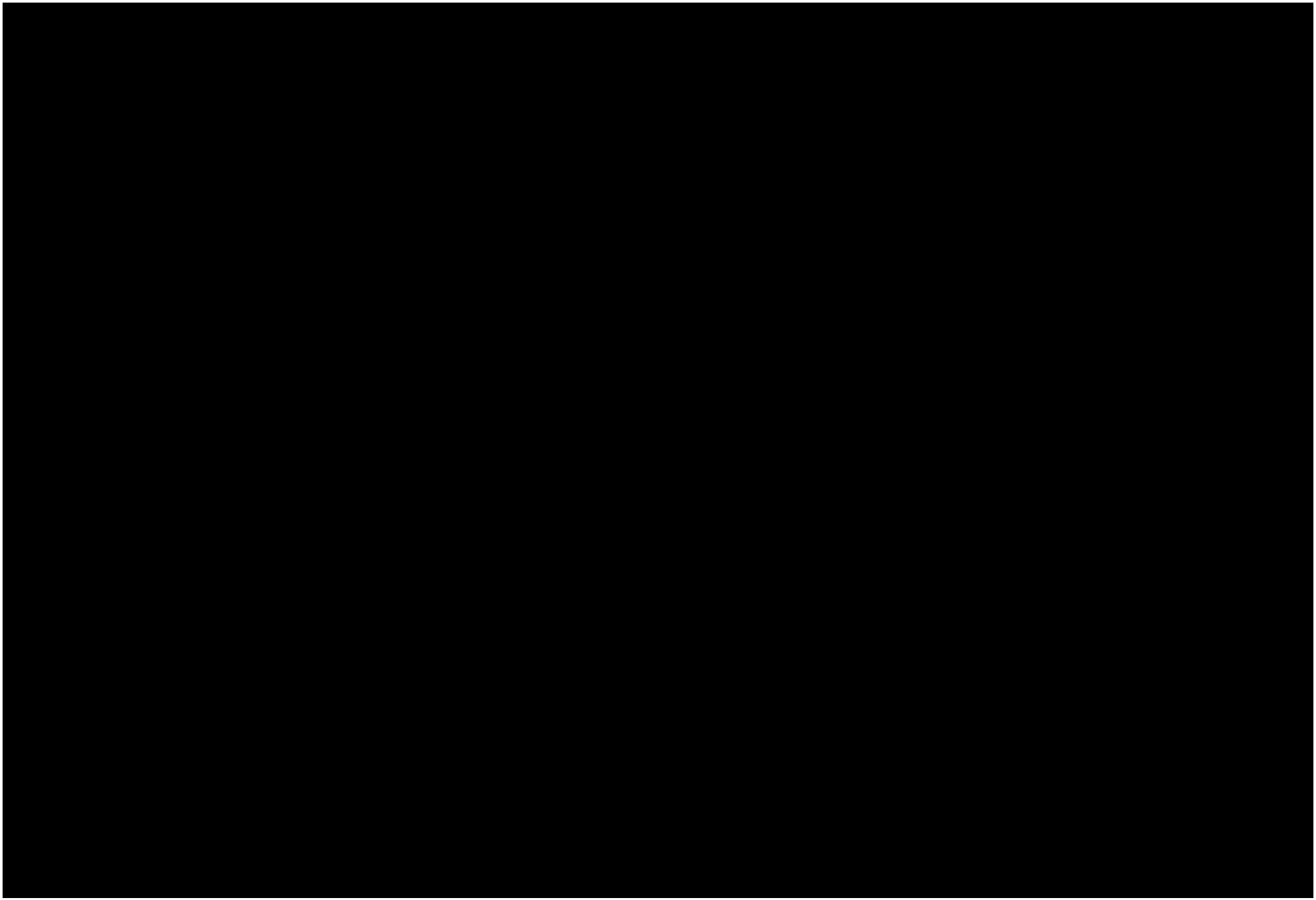
Date of Off Peak Day - 05/01/2021



Member Forecasted Off Peak Demand Day for June 2021

Wyrulec Company

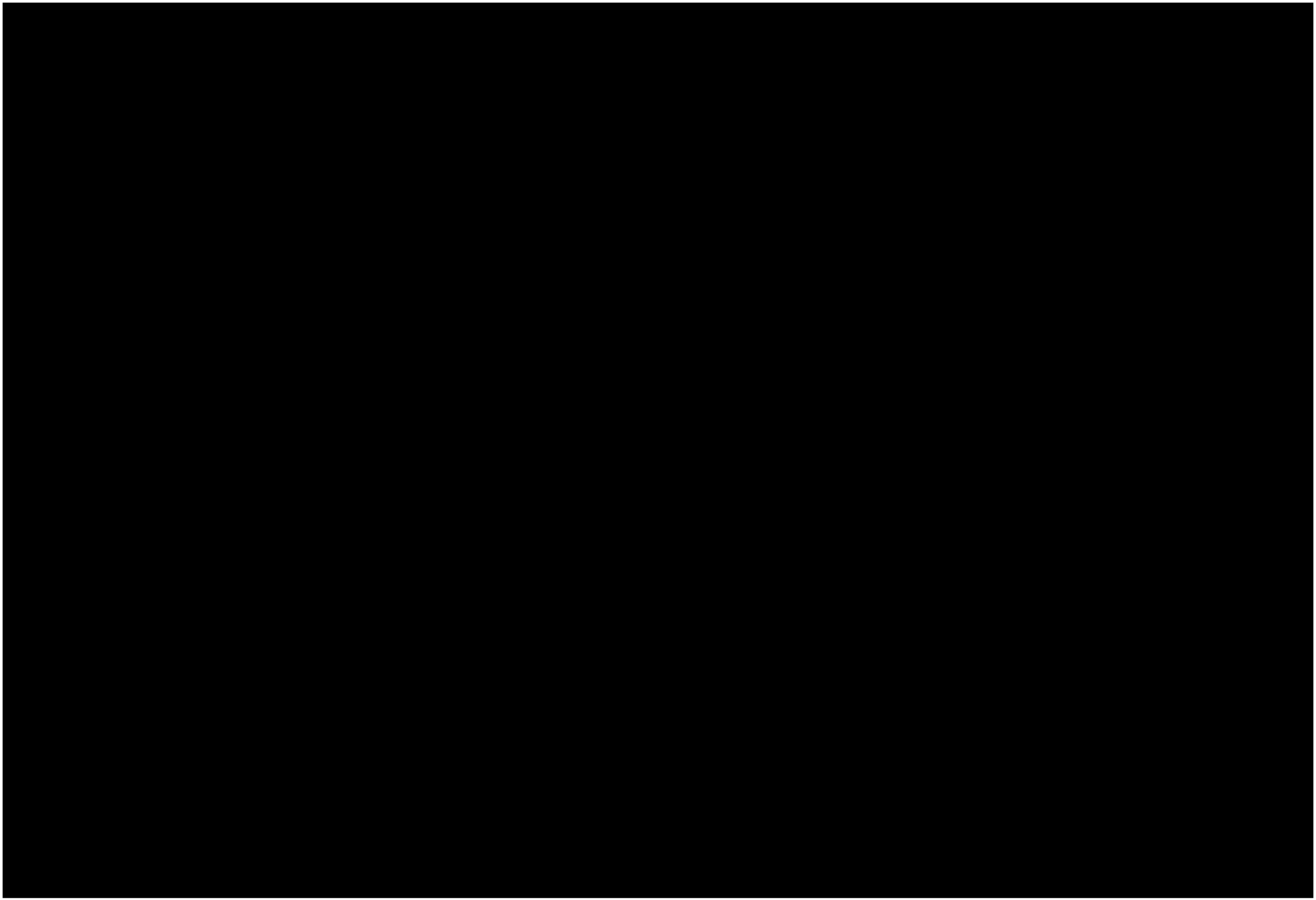
Date of Off Peak Day - 06/01/2021



Member Forecasted Off Peak Demand Day for July 2021

Wyrulec Company

Date of Off Peak Day - 07/06/2021



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Member Forecasted Off Peak Demand Day for August 2021

Wyrulec Company

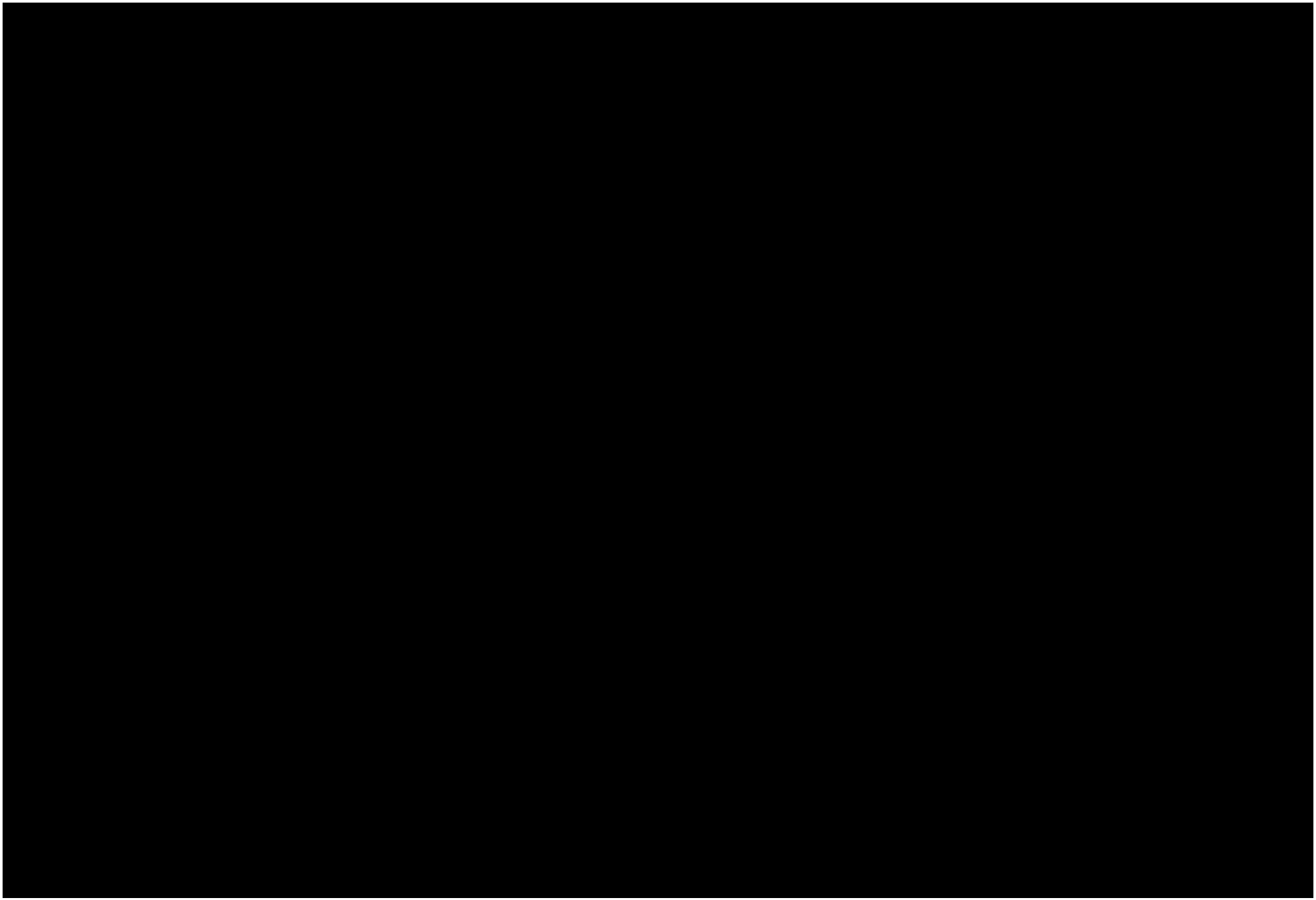
Date of Off Peak Day - 08/13/2021

[redacted]

Member Forecasted Off Peak Demand Day for September 2021

Wyrulec Company

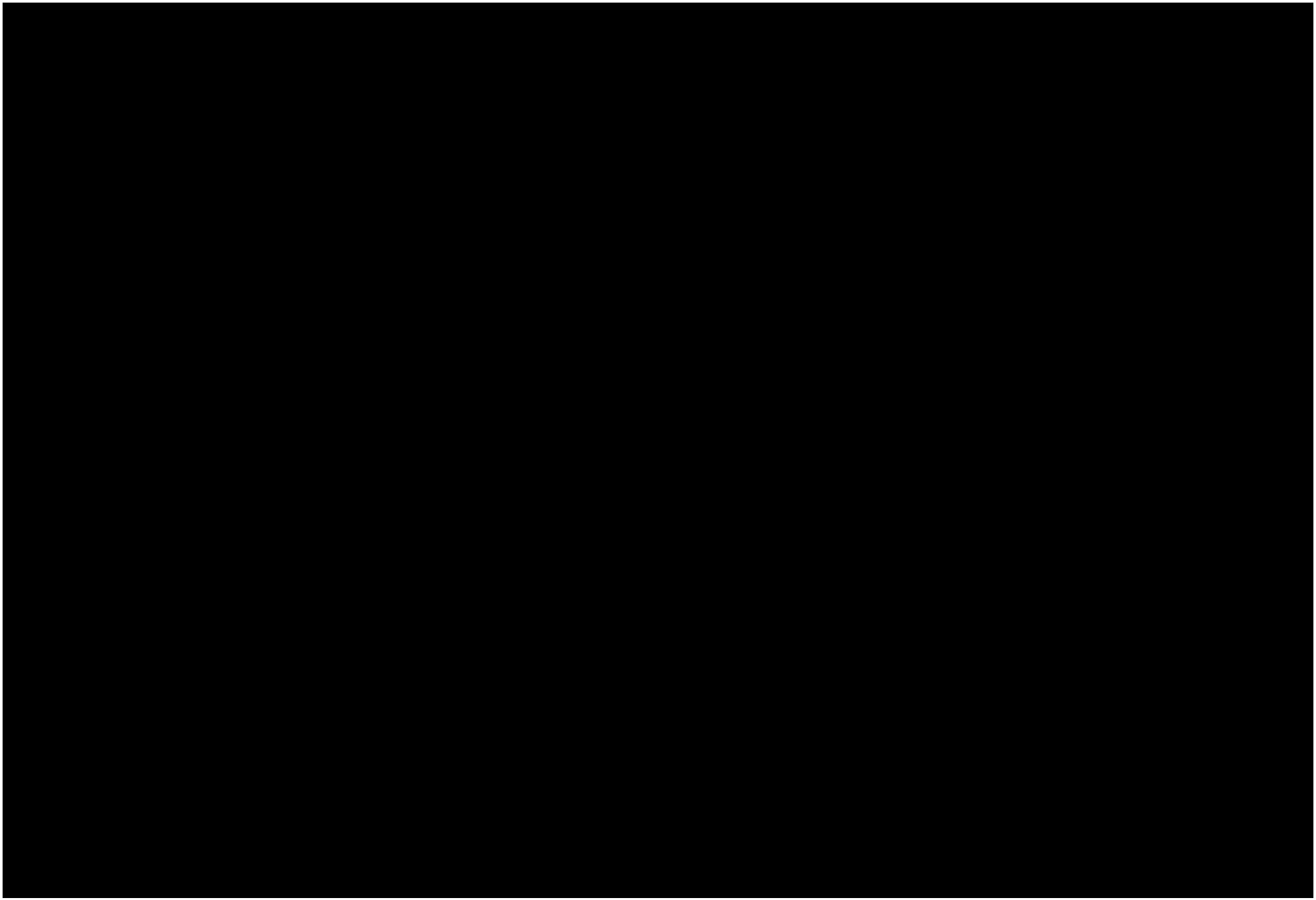
Date of Off Peak Day - 09/18/2021



Member Forecasted Off Peak Demand Day for October 2021

Wyrulec Company

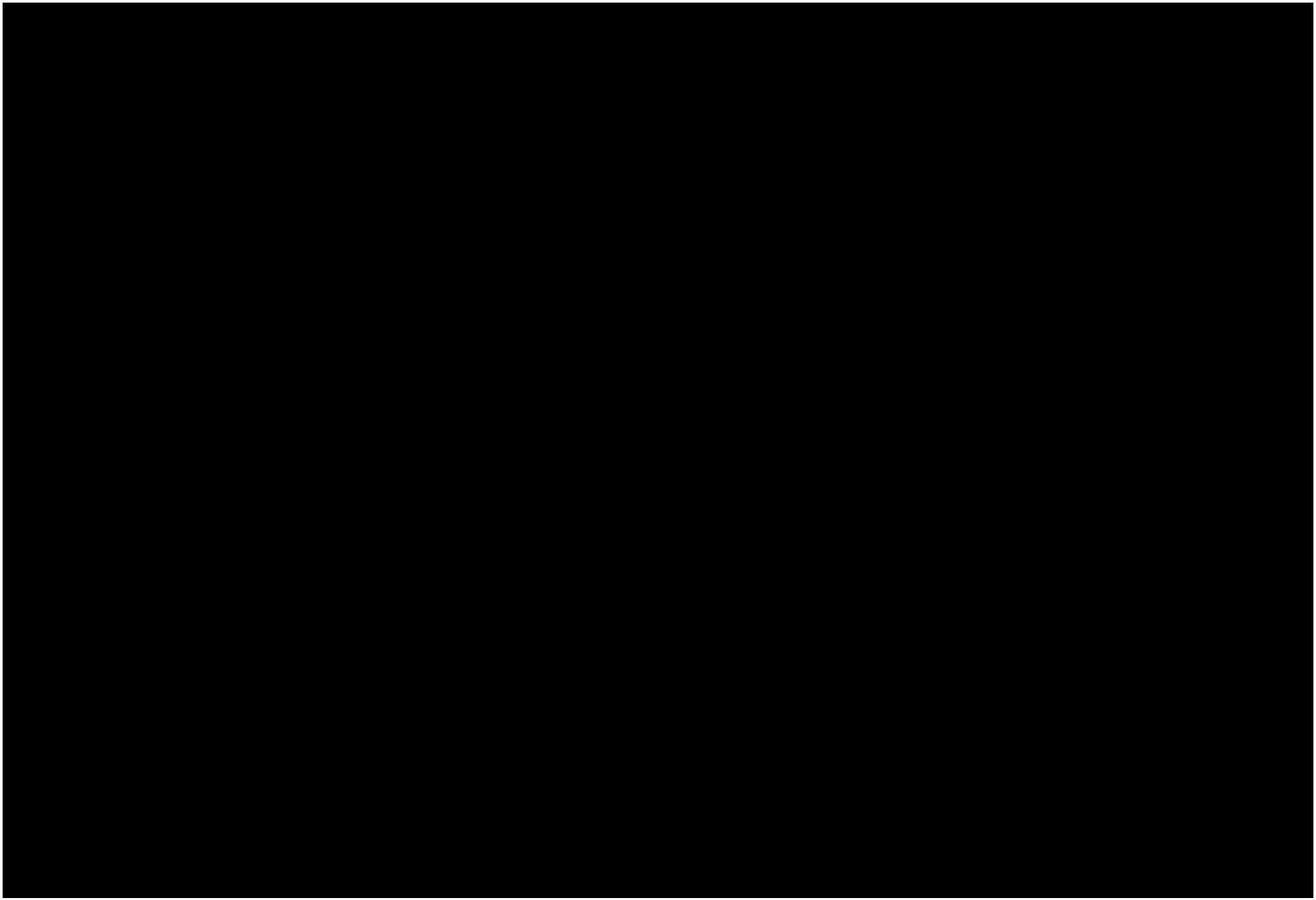
Date of Off Peak Day - 10/08/2021



Member Forecasted Off Peak Demand Day for November 2021

Wyrulec Company

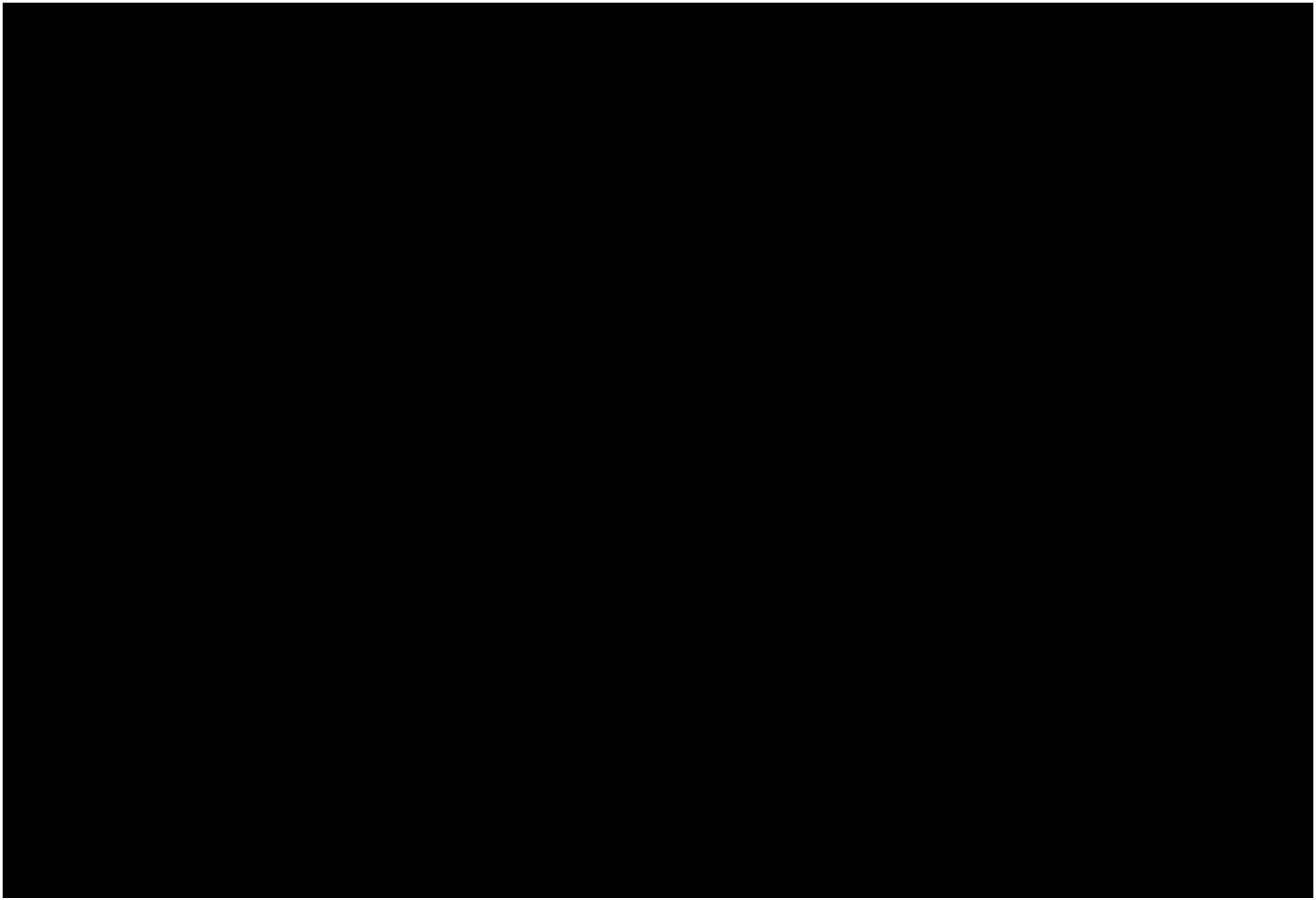
Date of Off Peak Day - 11/25/2021



Member Forecasted Off Peak Demand Day for December 2021

Wyrulec Company

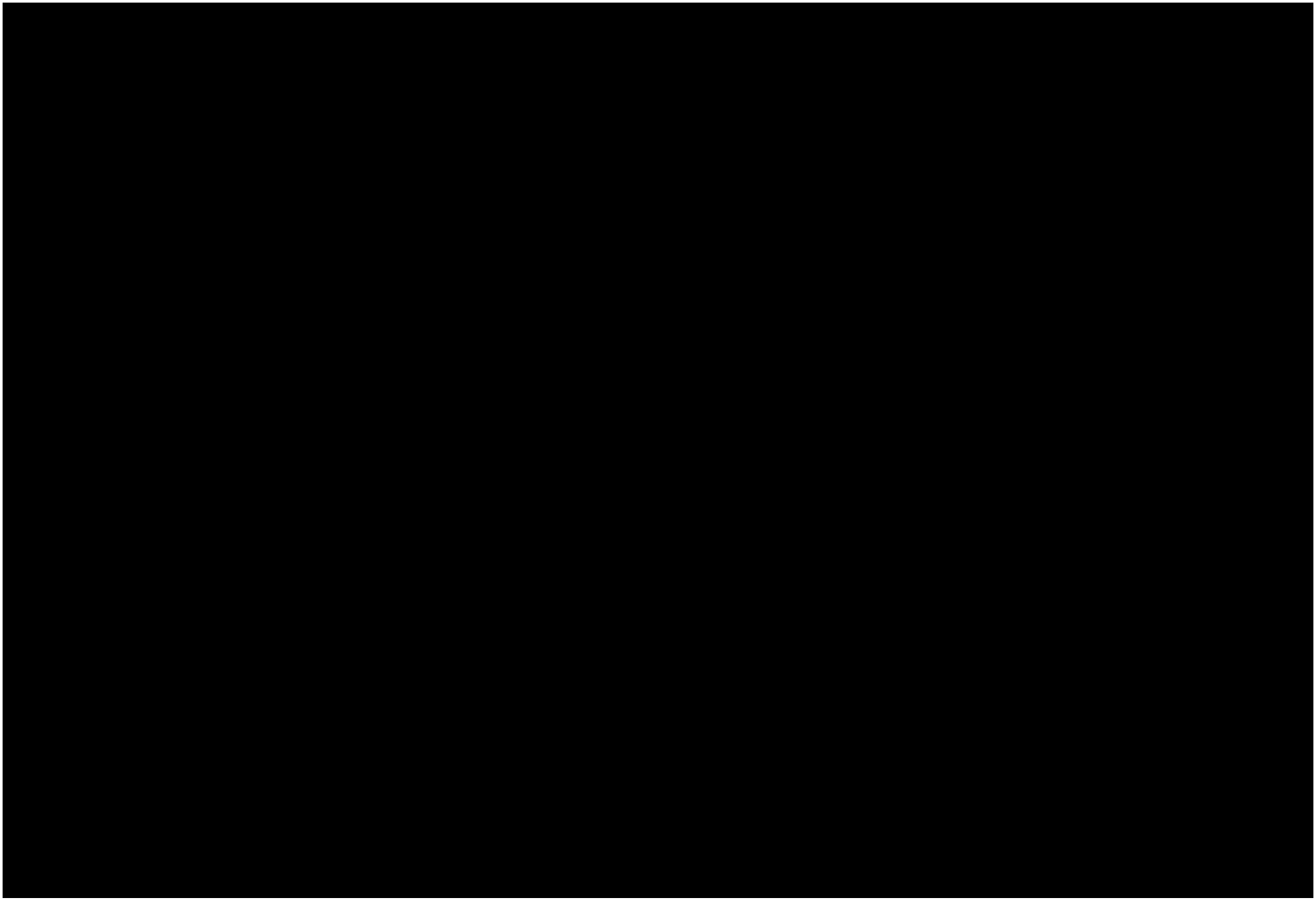
Date of Off Peak Day - 12/01/2021



Member Forecasted Off Peak Demand Day for January 2021

Y-W Electric Association, Inc.

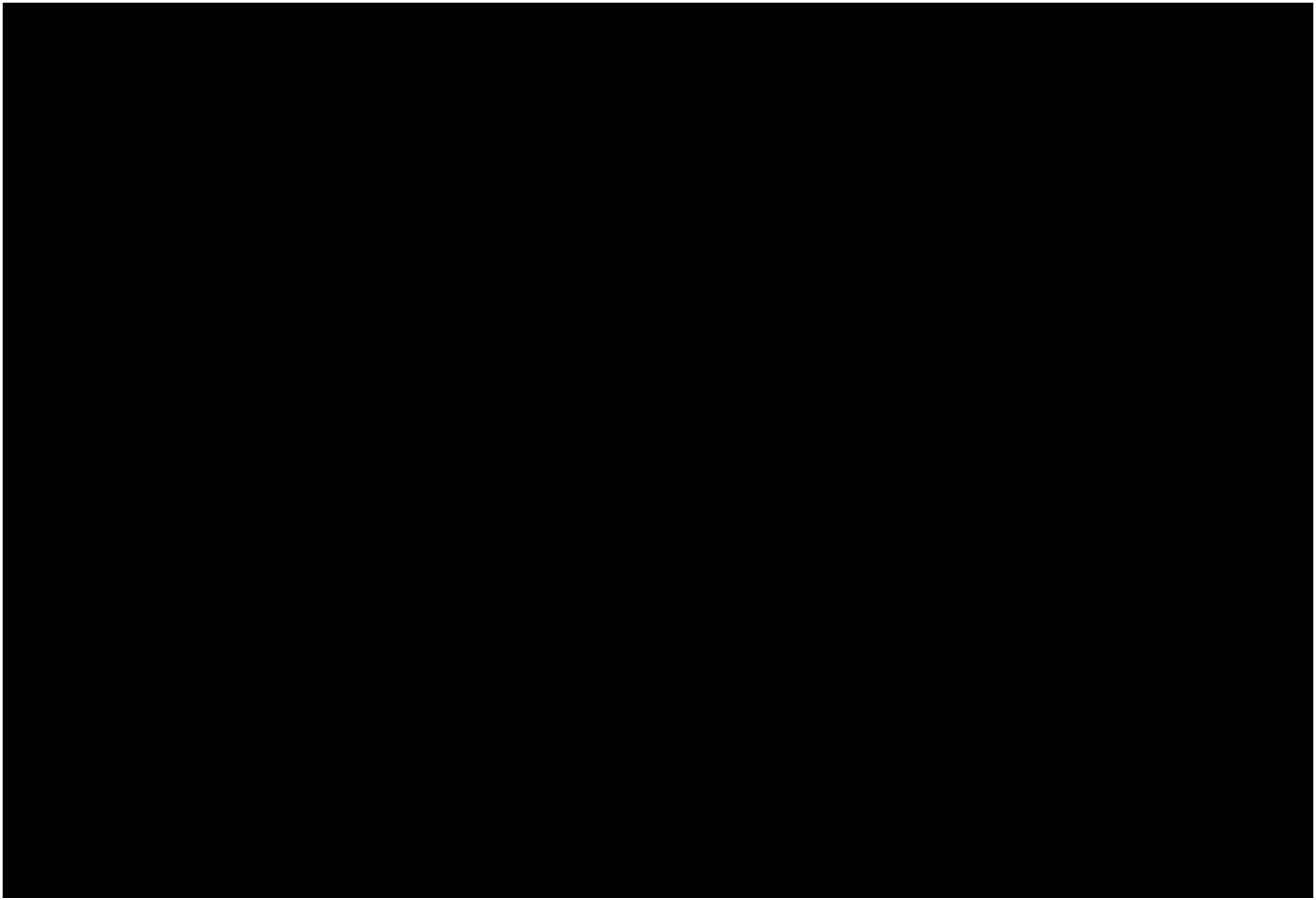
Date of Off Peak Day - 01/31/2021



Member Forecasted Off Peak Demand Day for February 2021

Y-W Electric Association, Inc.

Date of Off Peak Day - 02/11/2021



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Member Forecasted Off Peak Demand Day for March 2021

Y-W Electric Association, Inc.

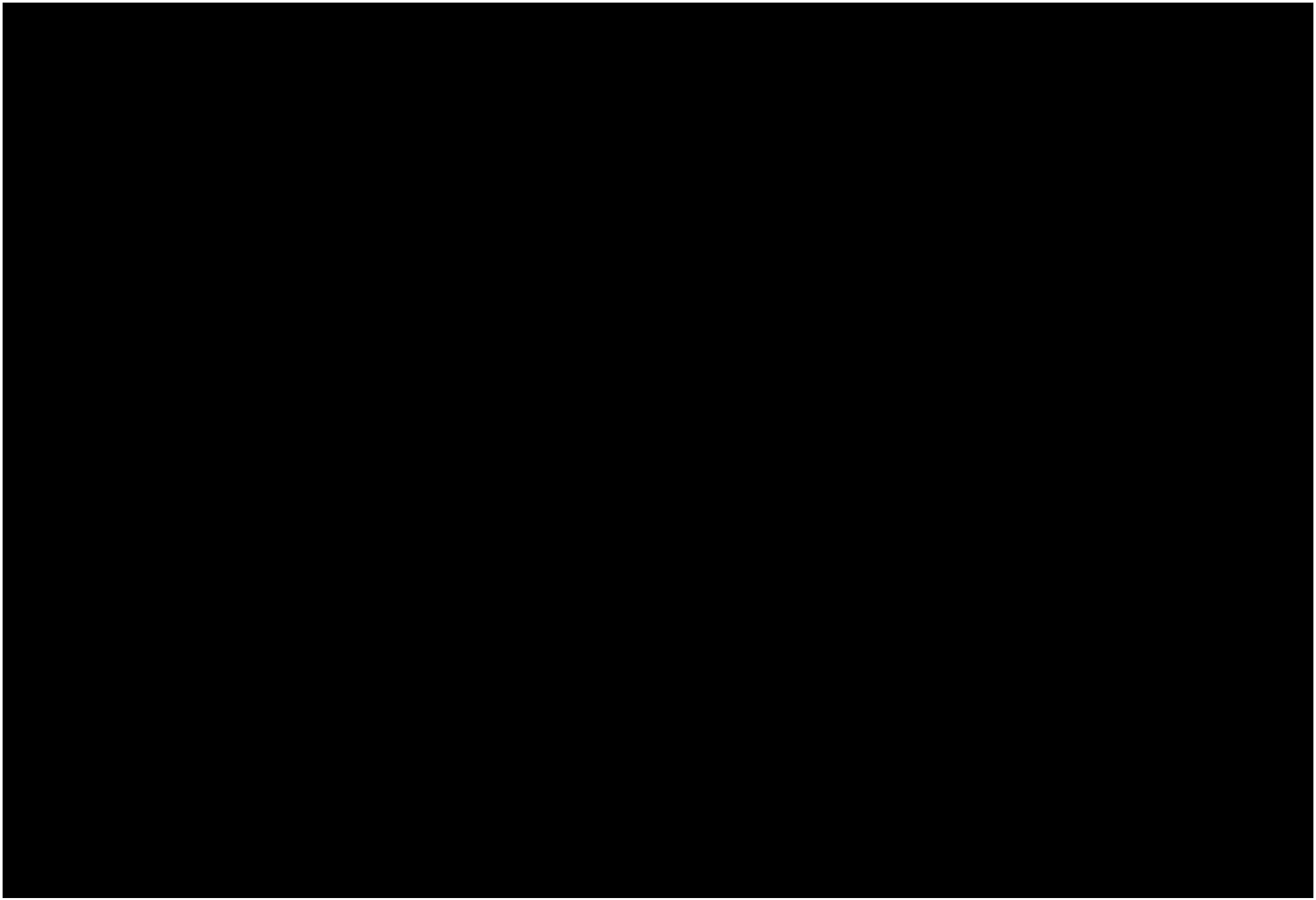
Date of Off Peak Day - 03/31/2021

[redacted]

Member Forecasted Off Peak Demand Day for April 2021

Y-W Electric Association, Inc.

Date of Off Peak Day - 04/20/2021



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Member Forecasted Off Peak Demand Day for May 2021

Y-W Electric Association, Inc.

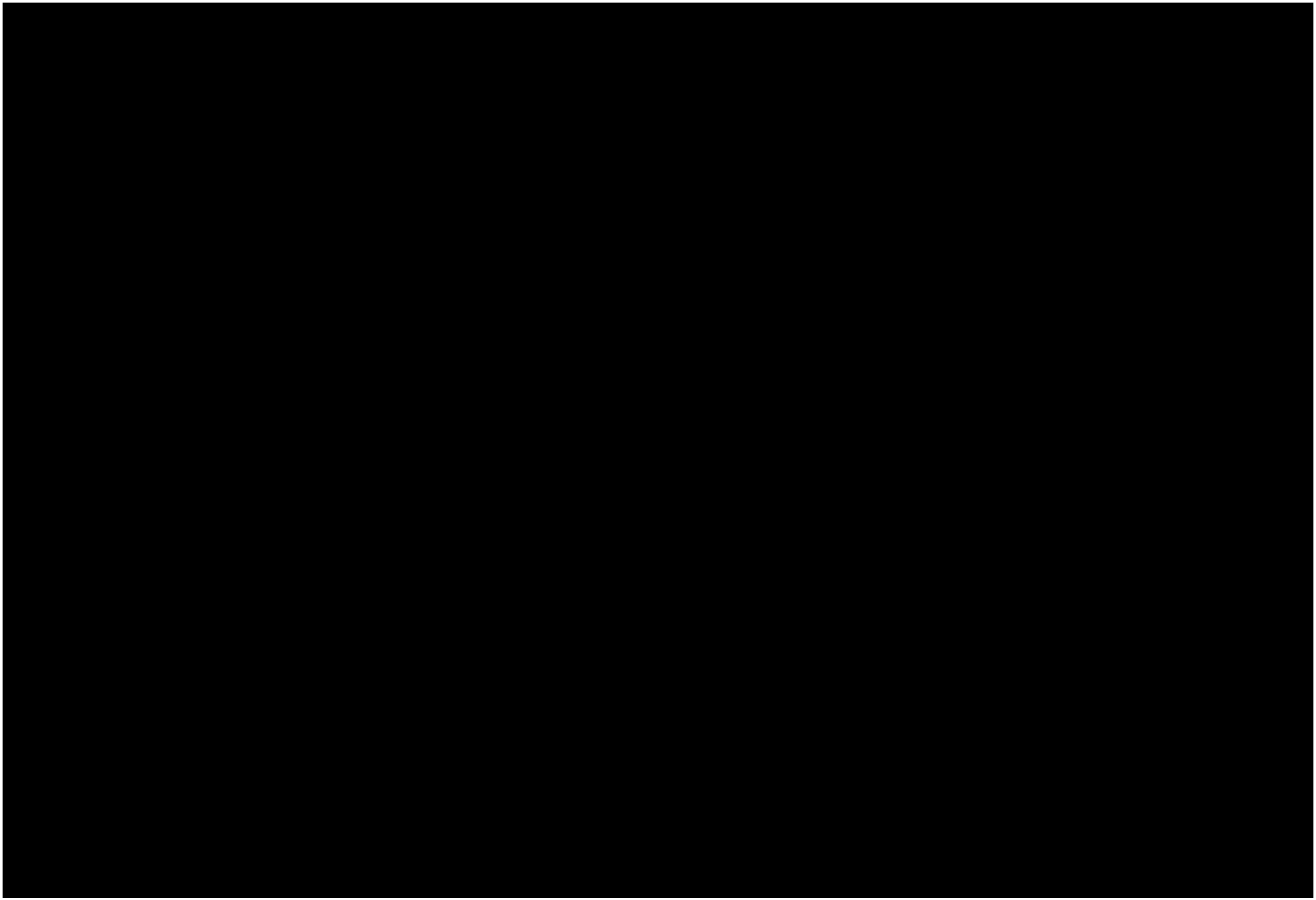
Date of Off Peak Day - 05/01/2021

[redacted]

Member Forecasted Off Peak Demand Day for June 2021

Y-W Electric Association, Inc.

Date of Off Peak Day - 06/01/2021



Member Forecasted Off Peak Demand Day for July 2021

Y-W Electric Association, Inc.

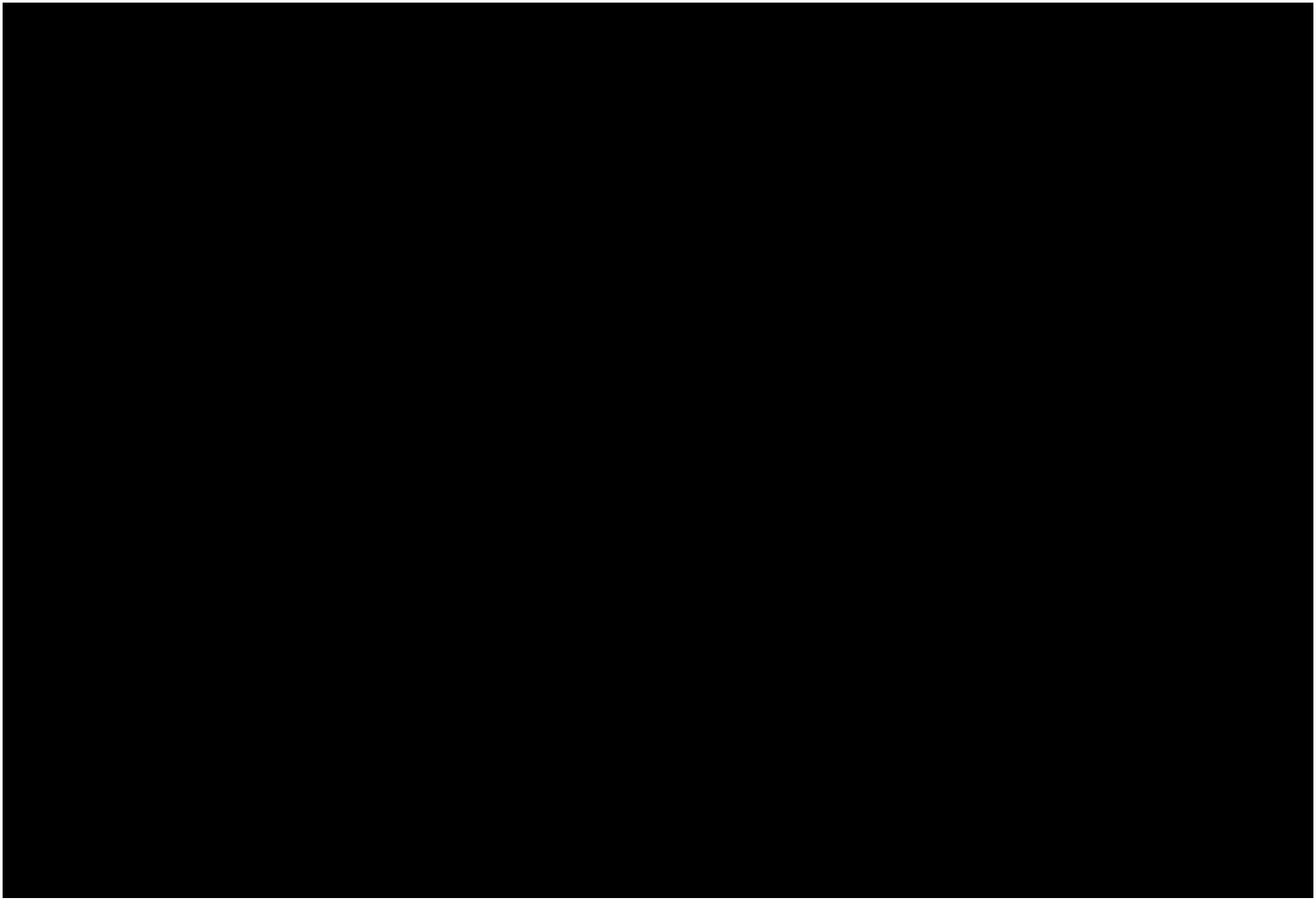
Date of Off Peak Day - 07/03/2021

[redacted]

Member Forecasted Off Peak Demand Day for August 2021

Y-W Electric Association, Inc.

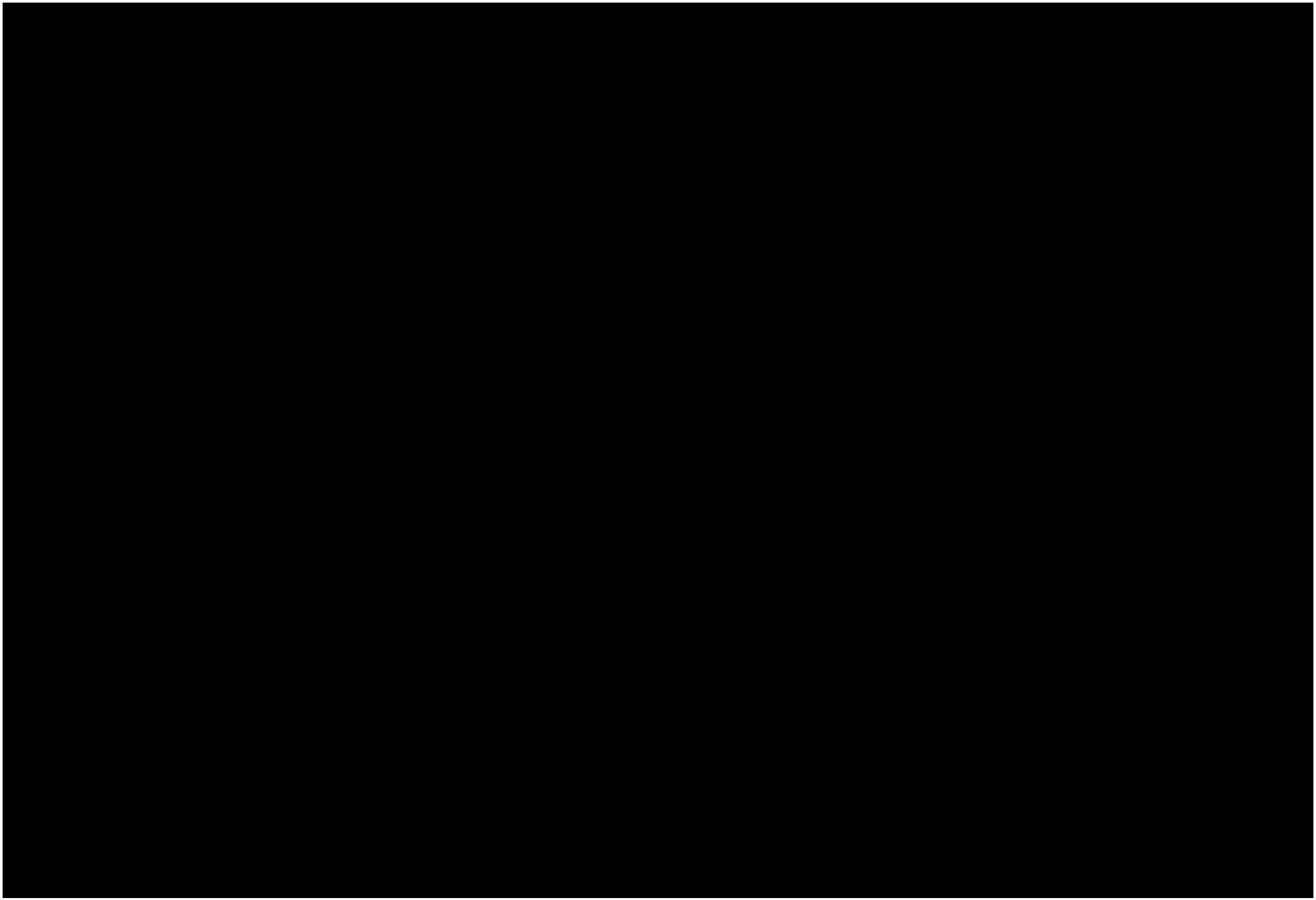
Date of Off Peak Day - 08/11/2021



Member Forecasted Off Peak Demand Day for September 2021

Y-W Electric Association, Inc.

Date of Off Peak Day - 09/30/2021



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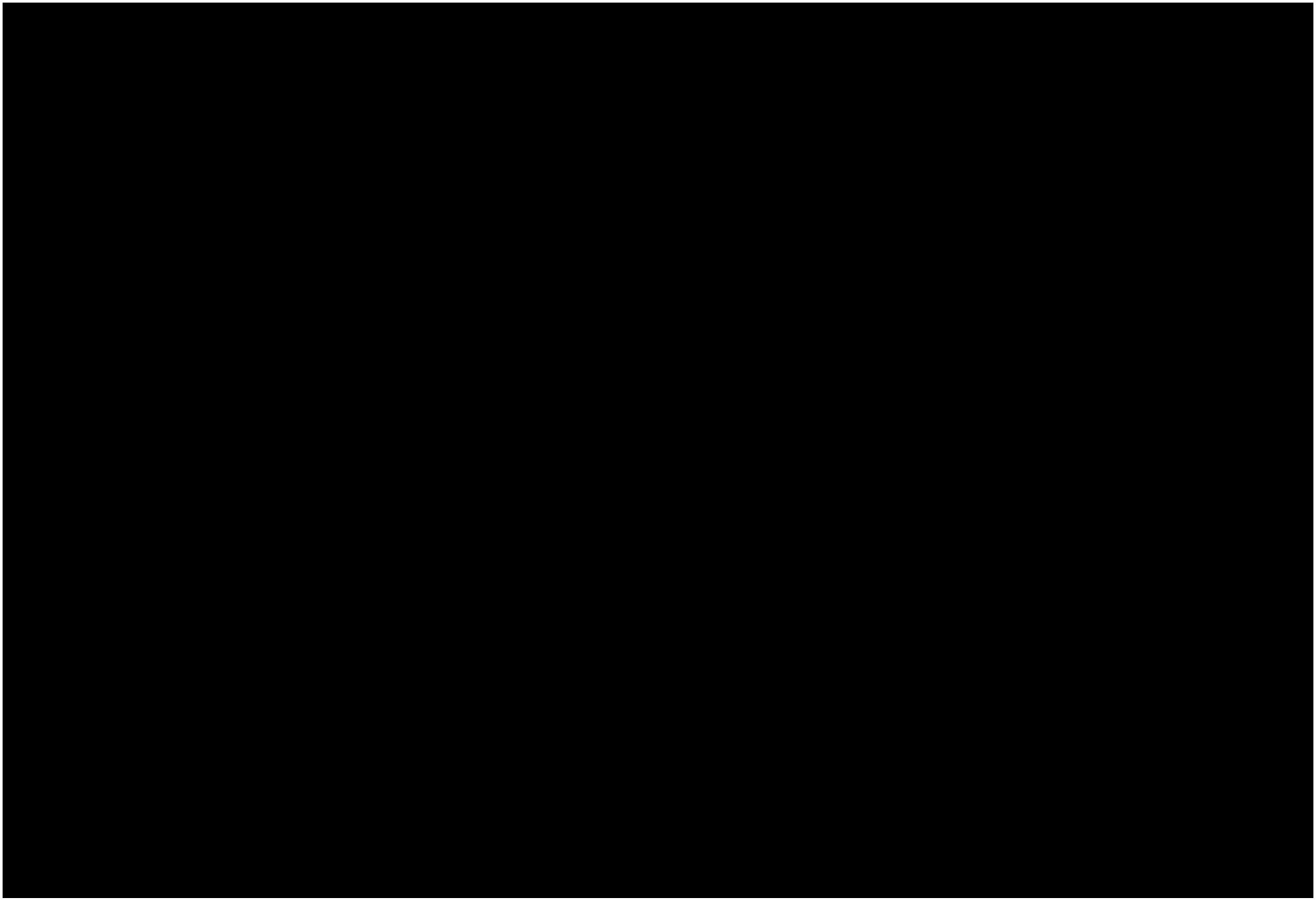
Member Forecasted Off Peak Demand Day for October 2021

Y-W Electric Association, Inc.

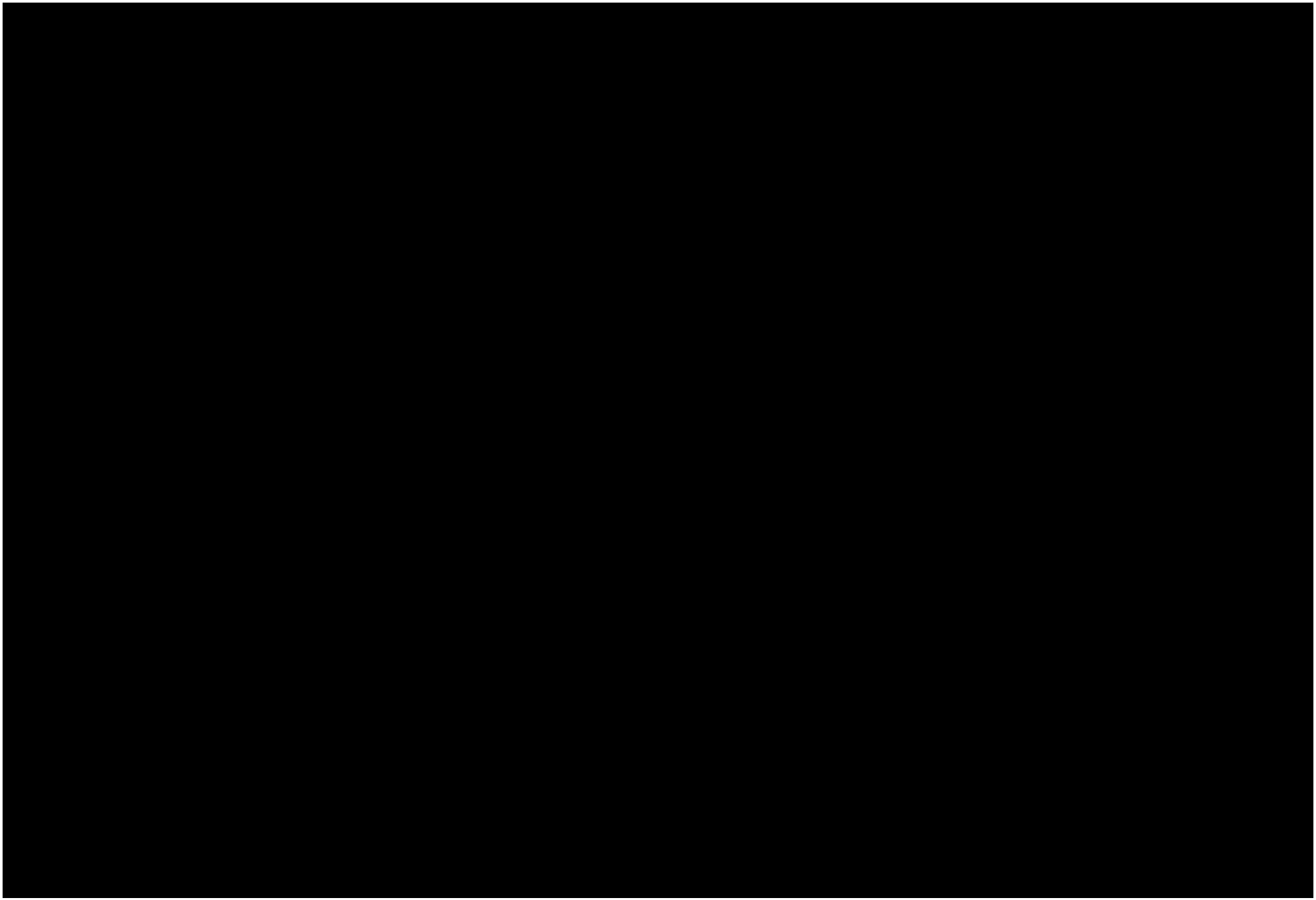
Date of Off Peak Day - 10/25/2021



Member Forecasted Off Peak Demand Day for November 2021

Y-W Electric Association, Inc.

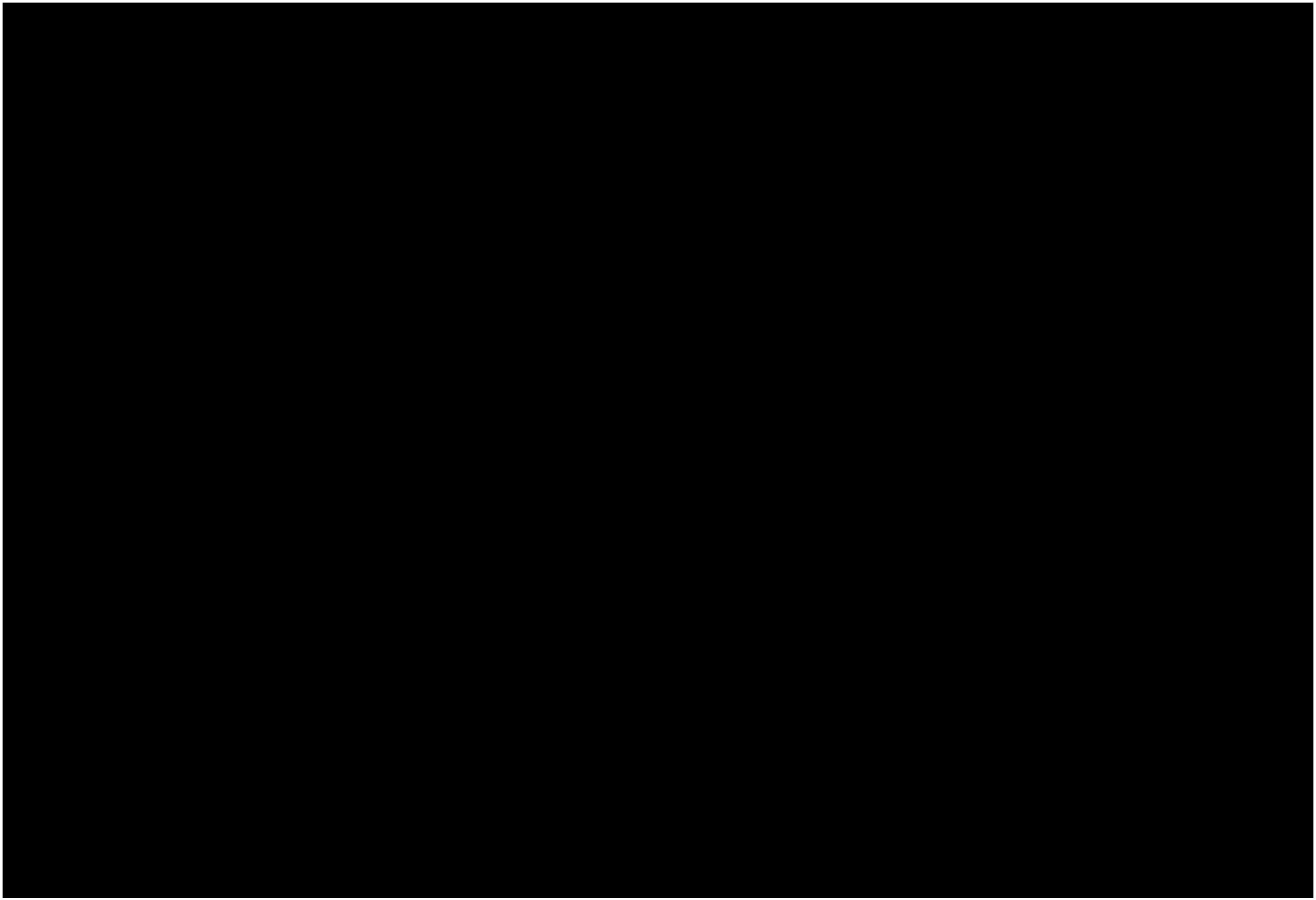
Date of Off Peak Day - 11/02/2021



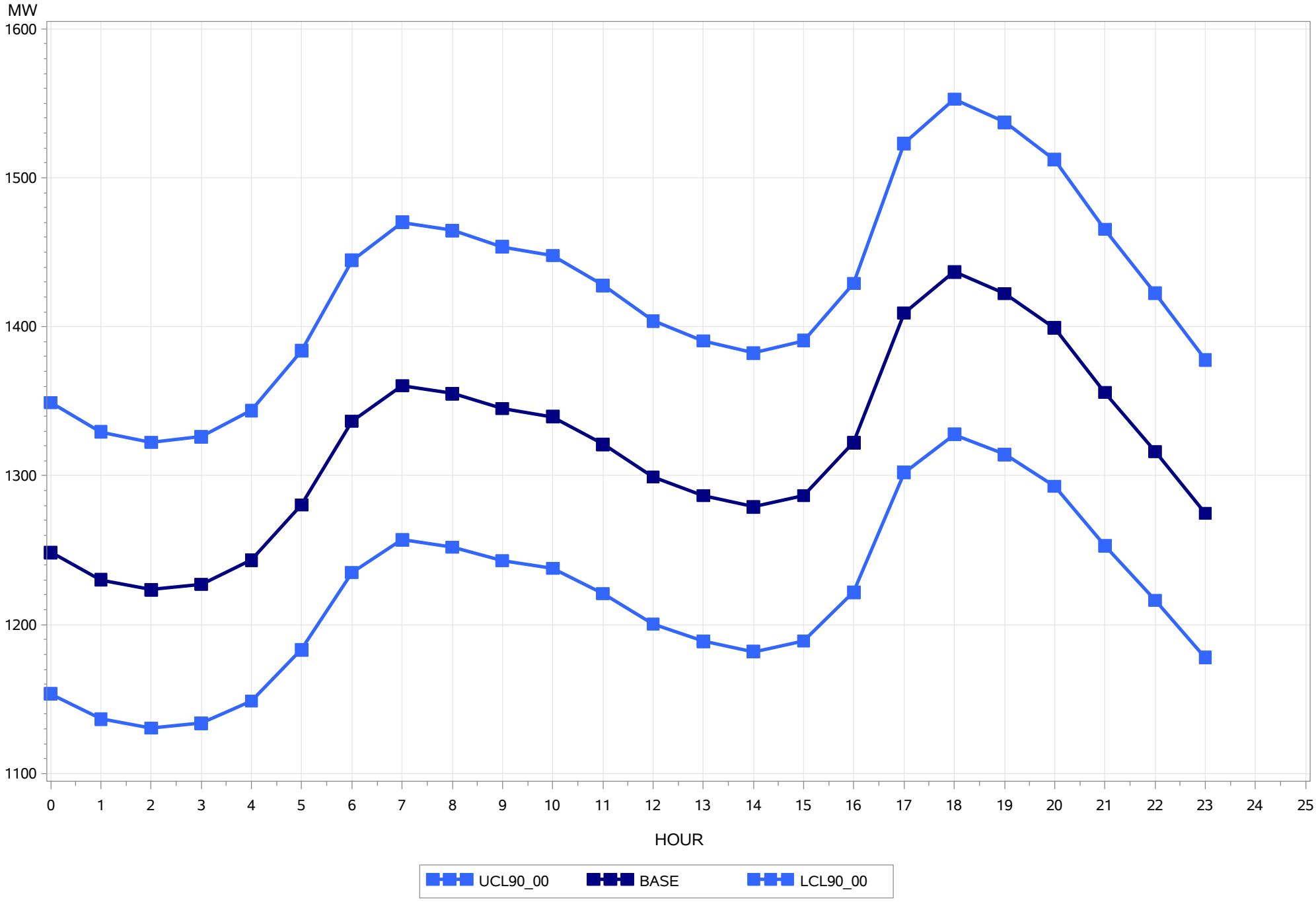
Member Forecasted Off Peak Demand Day for December 2021

Y-W Electric Association, Inc.

Date of Off Peak Day - 12/11/2021



Hourly Average Day for January 2021
STATE OF COLORADO



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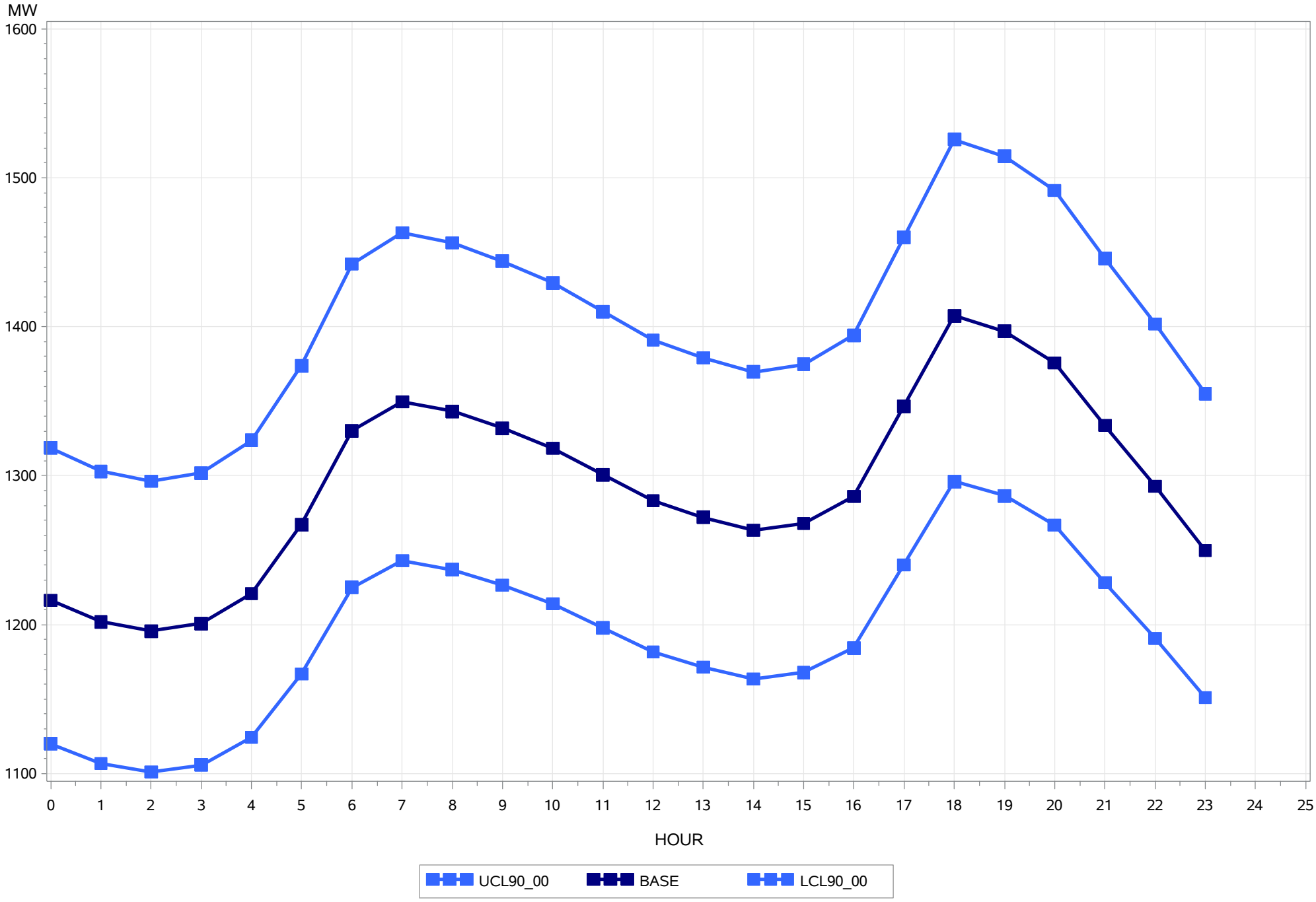
Hourly Average Day for February 2021
STATE OF COLORADO



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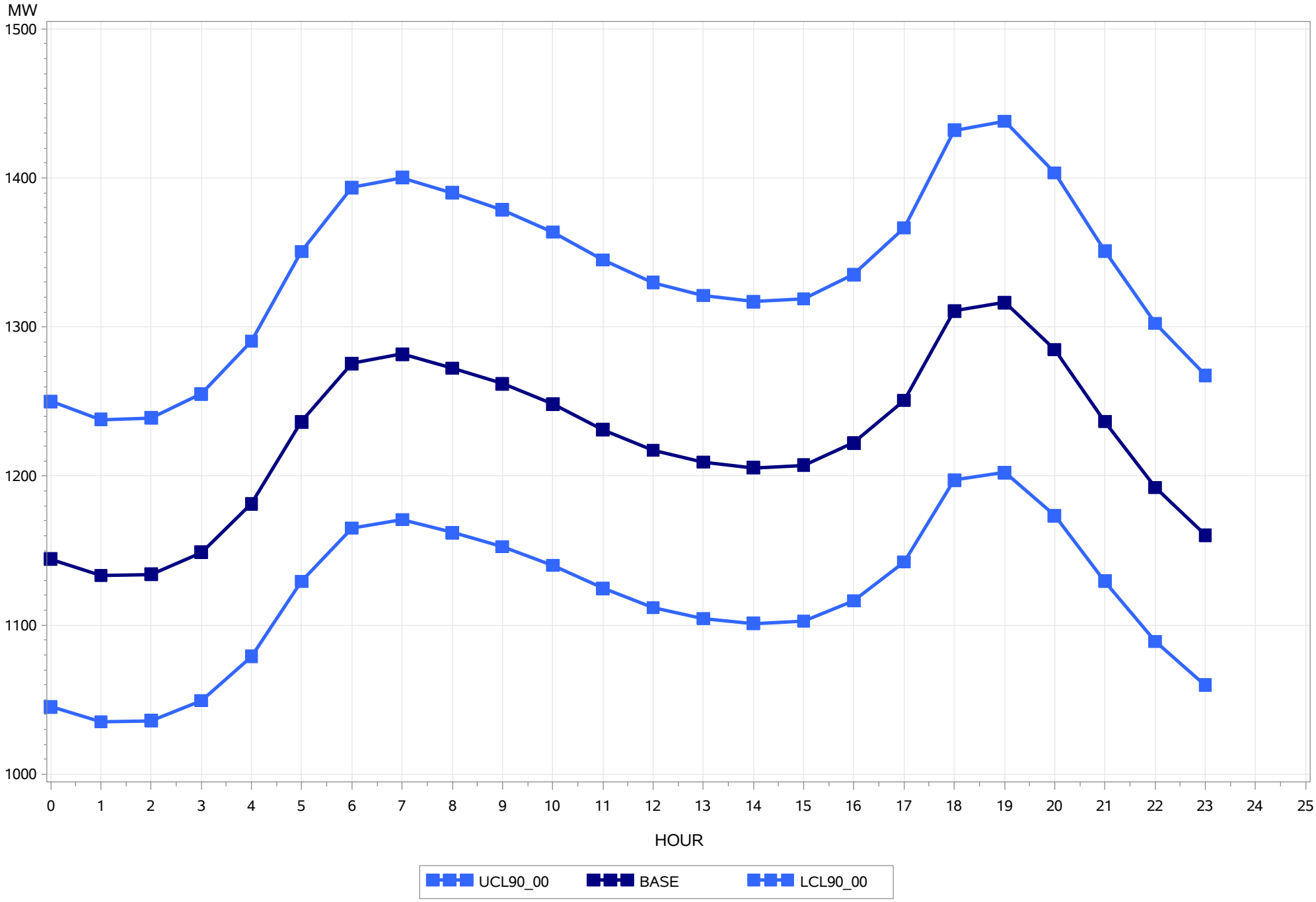
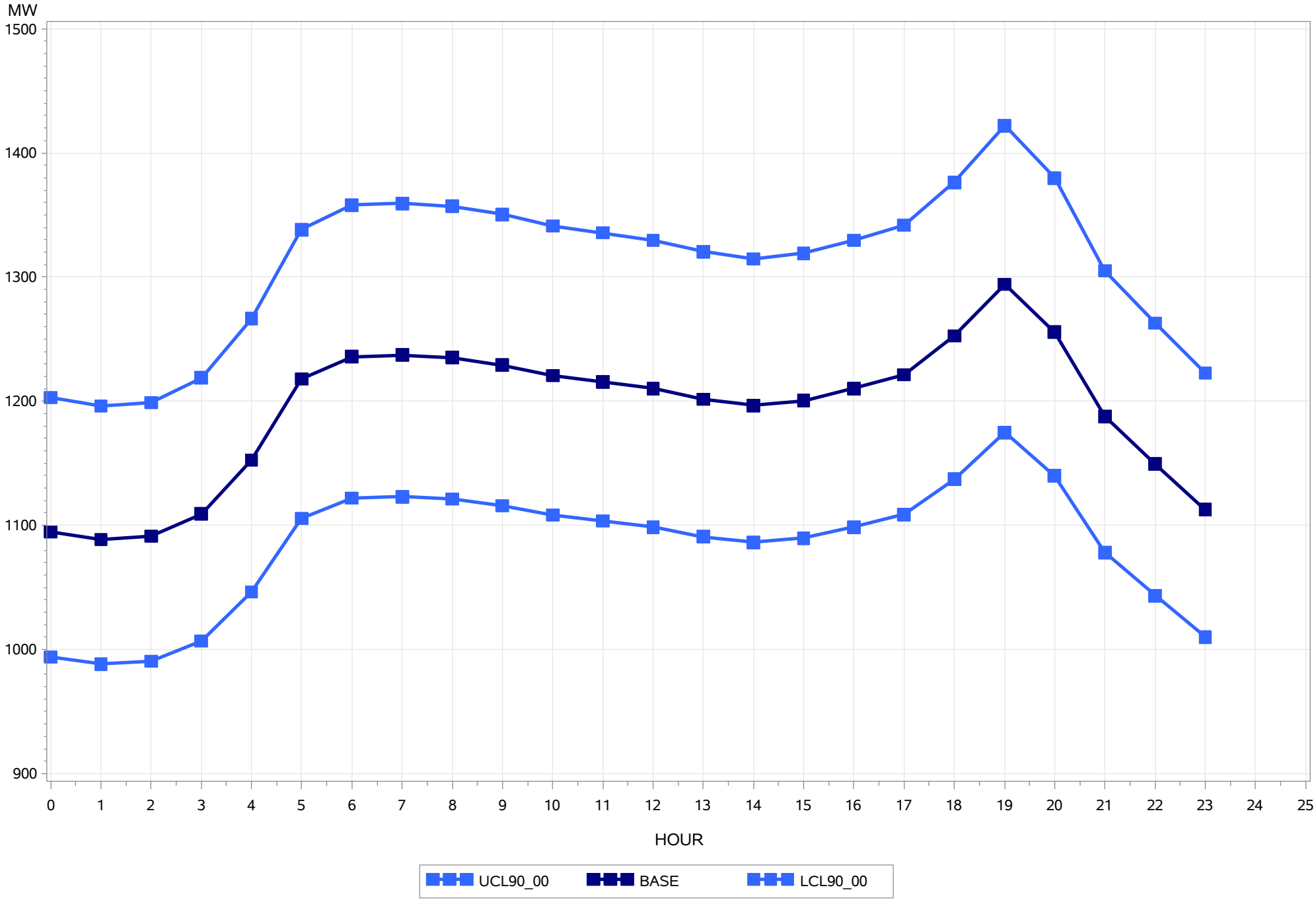
Hourly Average Day for March 2021
STATE OF COLORADO



Hourly Average Day for April 2021
STATE OF COLORADO



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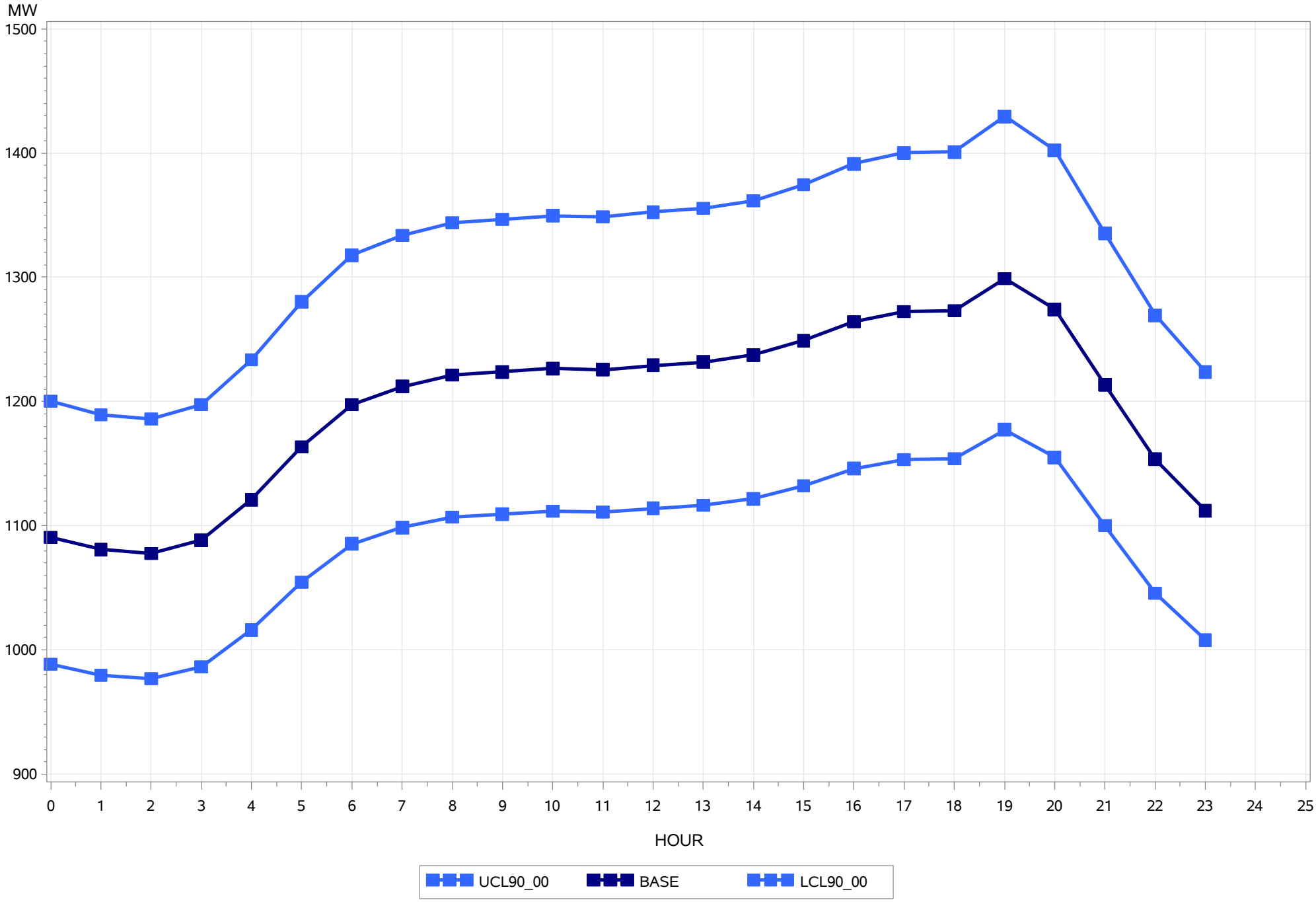
Hourly Average Day for May 2021
STATE OF COLORADO



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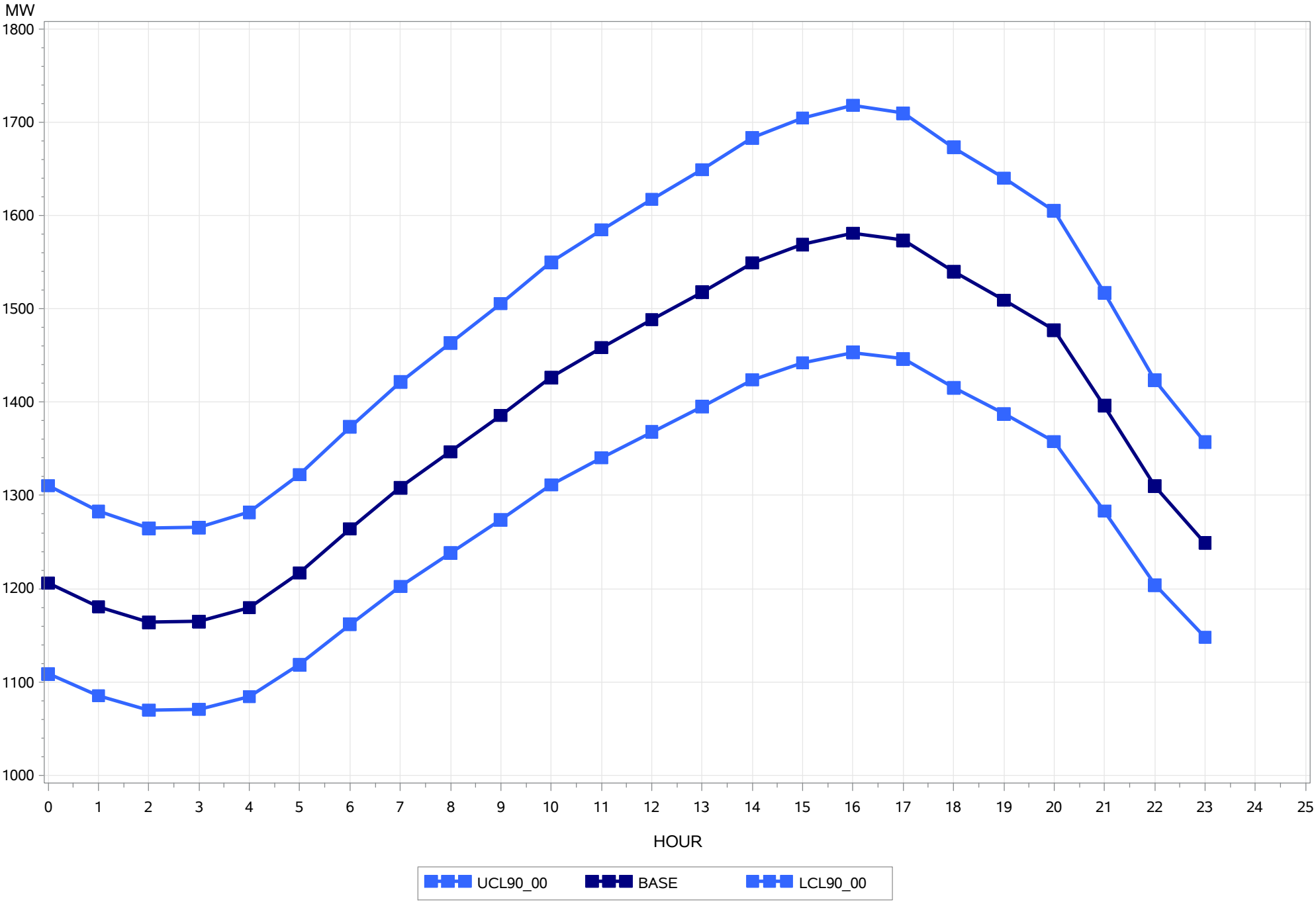
Hourly Average Day for June 2021
STATE OF COLORADO



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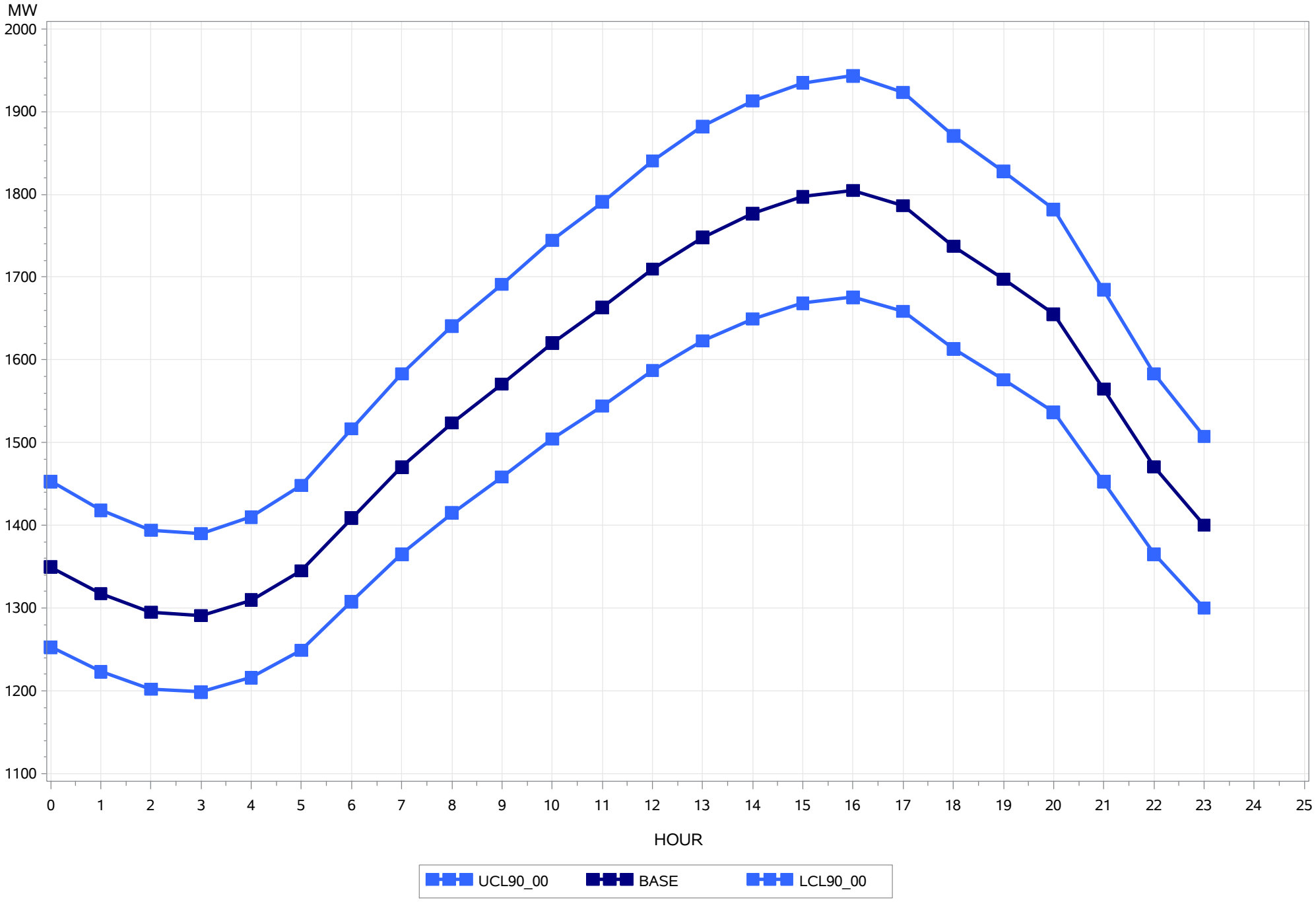
Hourly Average Day for July 2021
STATE OF COLORADO



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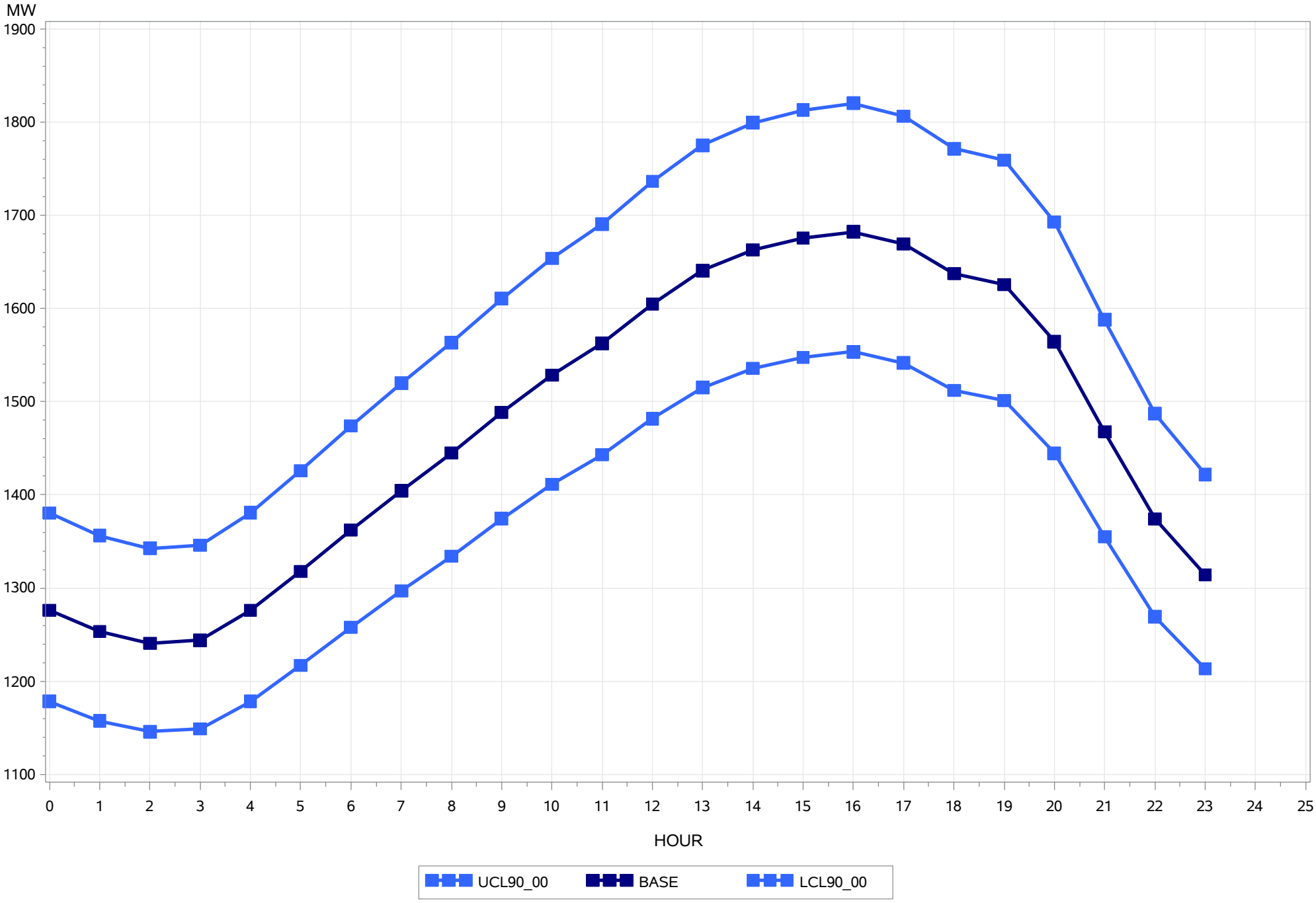
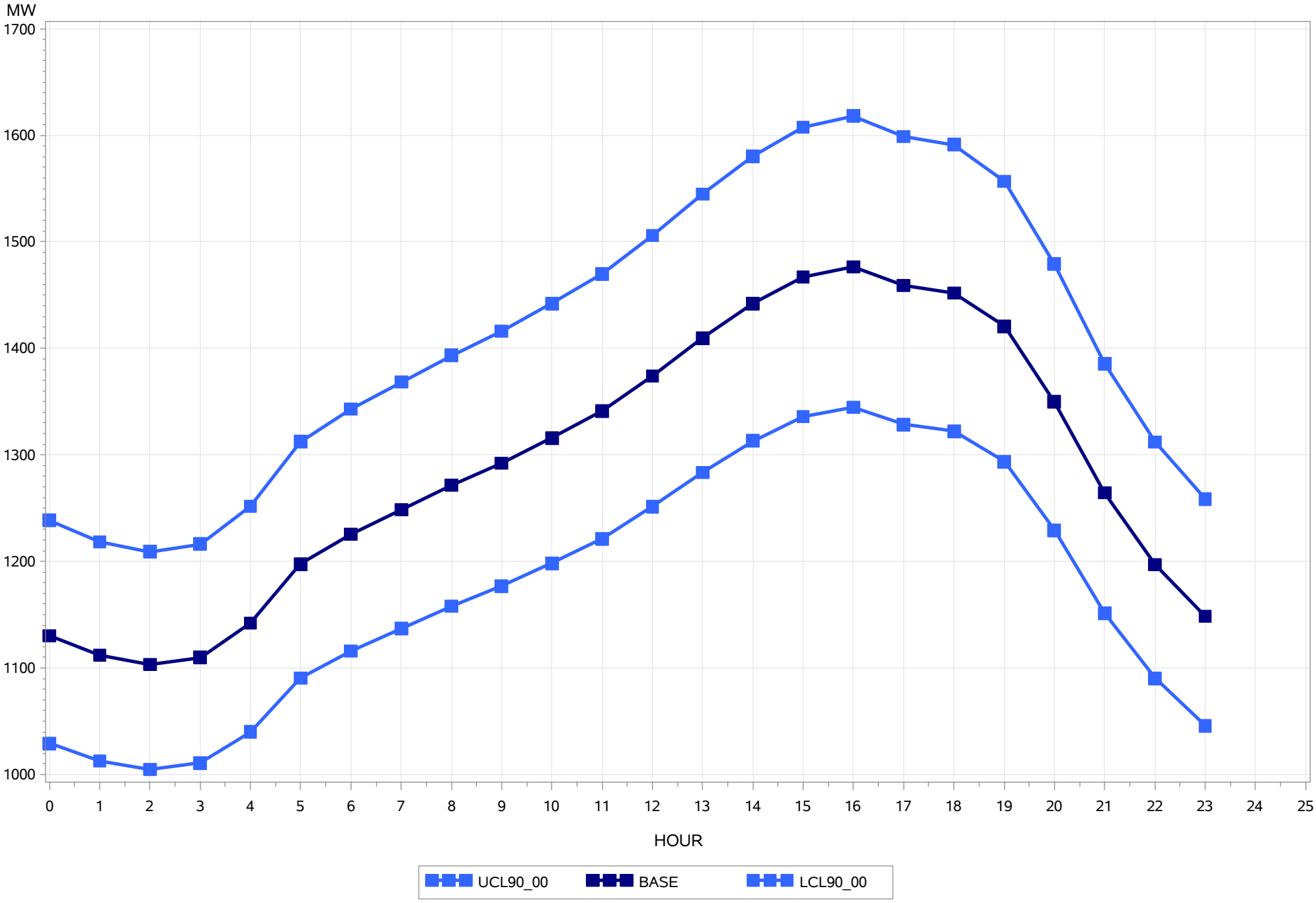
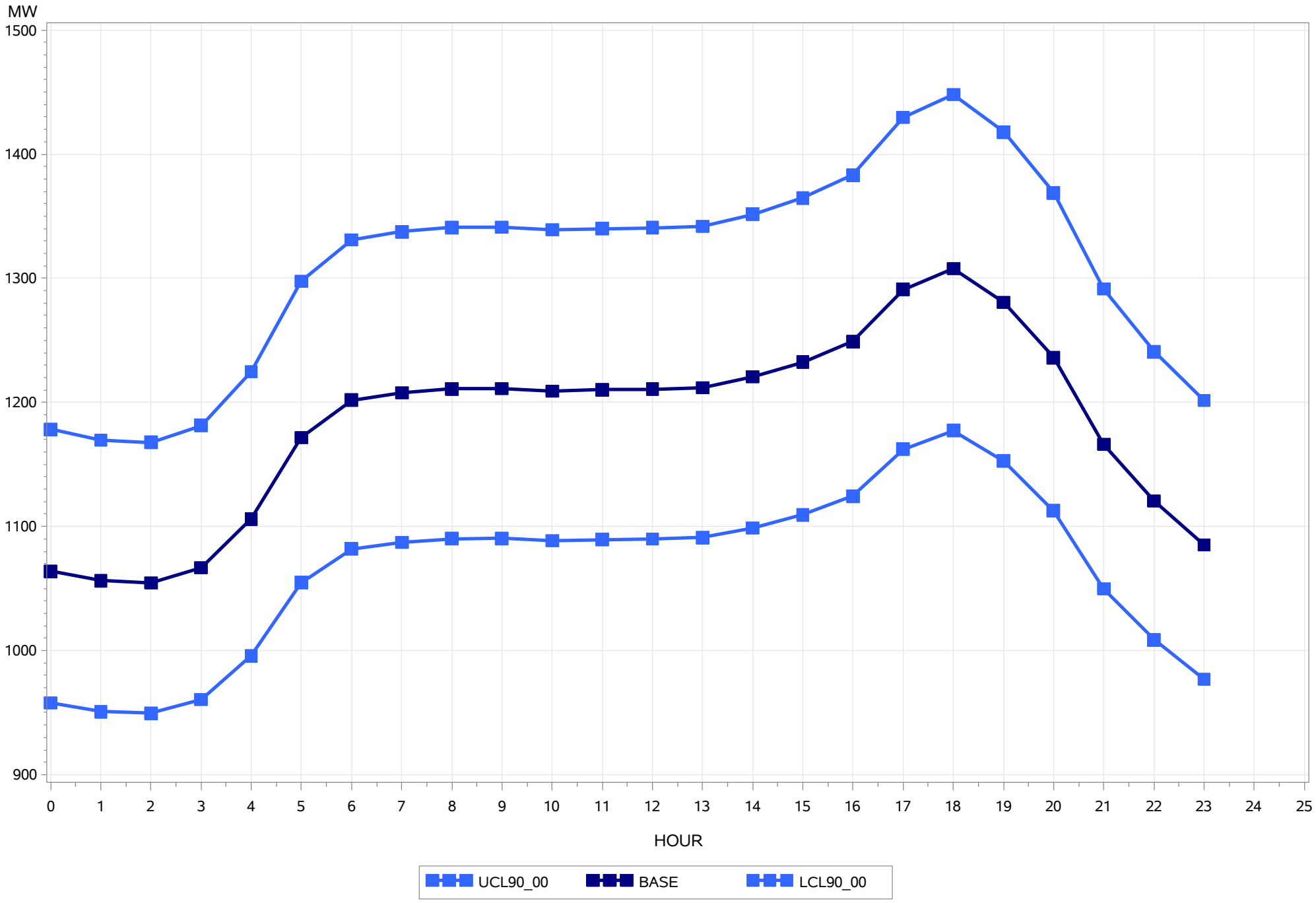
Hourly Average Day for August 2021
STATE OF COLORADO



Hourly Average Day for September 2021
STATE OF COLORADO



Hourly Average Day for October 2021
STATE OF COLORADO



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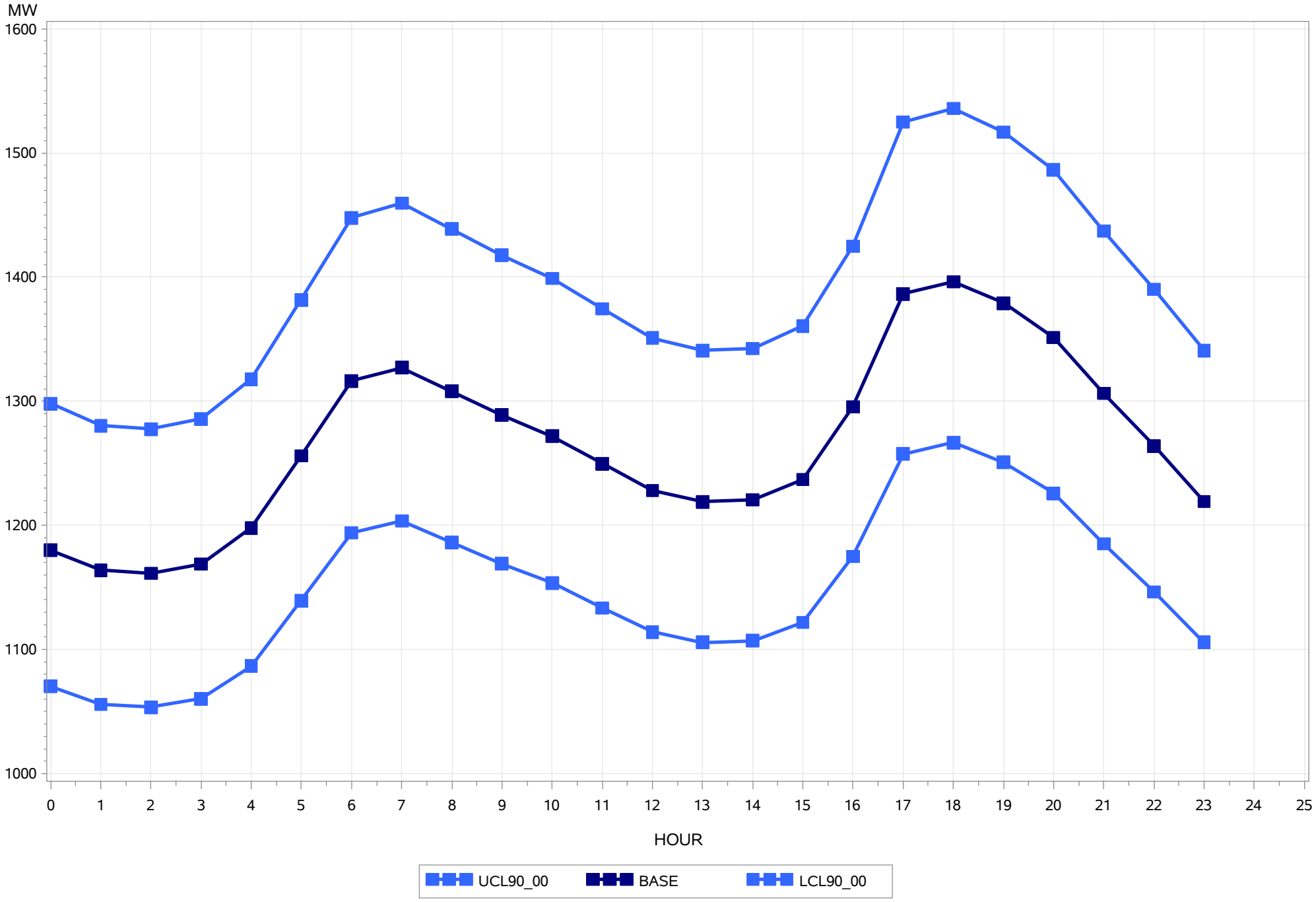
Hourly Average Day for November 2021
STATE OF COLORADO



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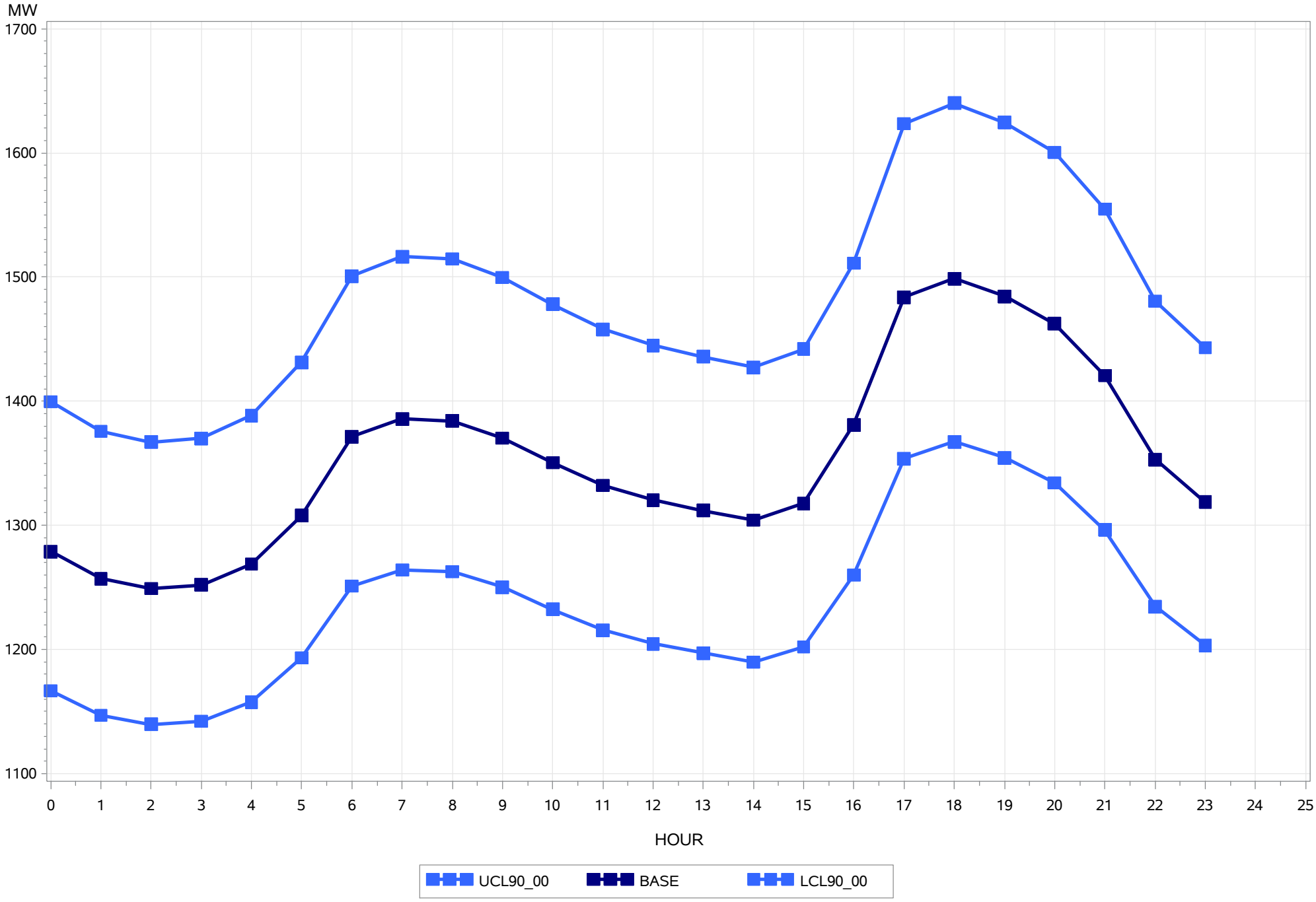
Hourly Average Day for December 2021
STATE OF COLORADO



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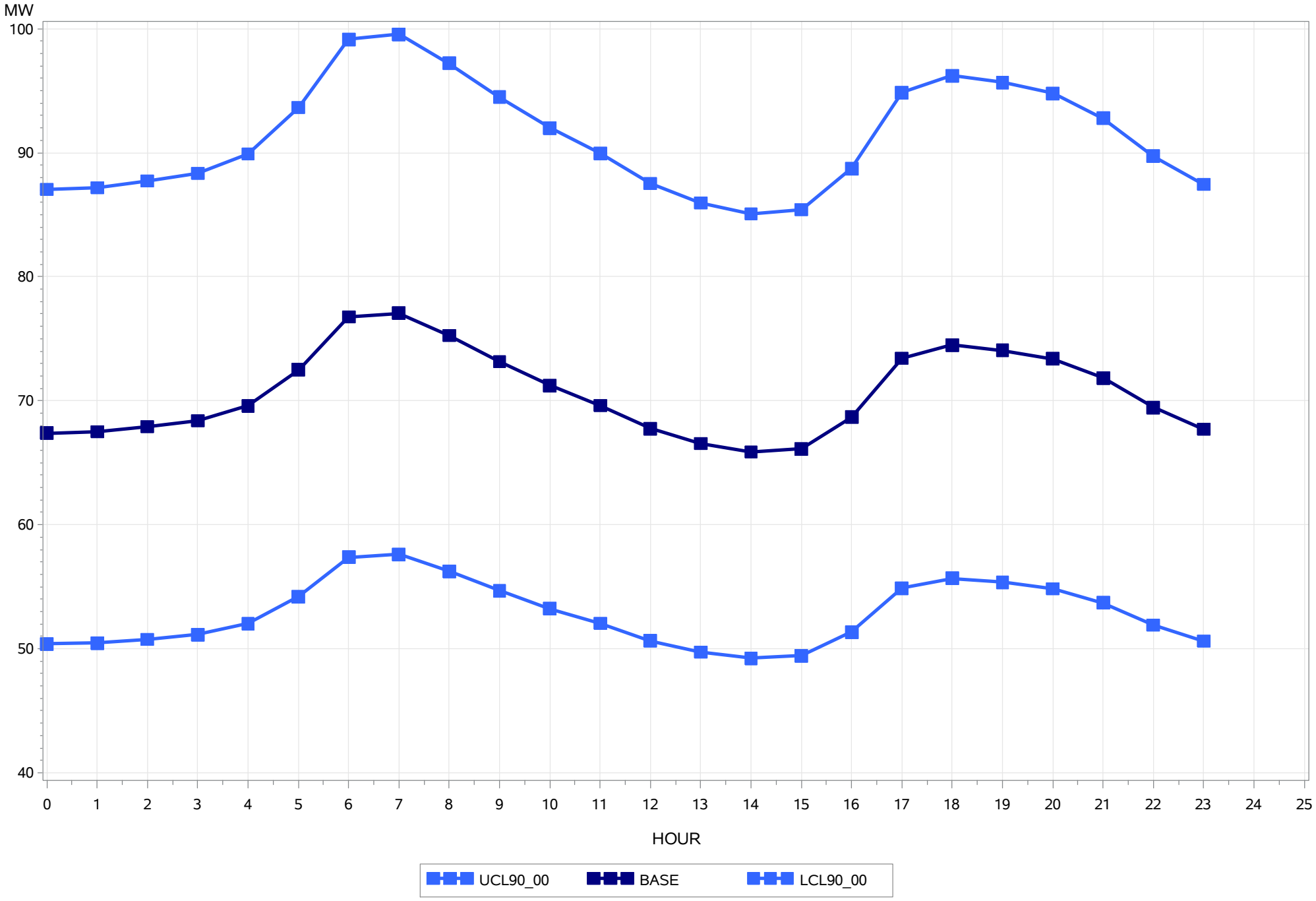
Hourly Average Day for January 2021
STATE OF NEBRASKA



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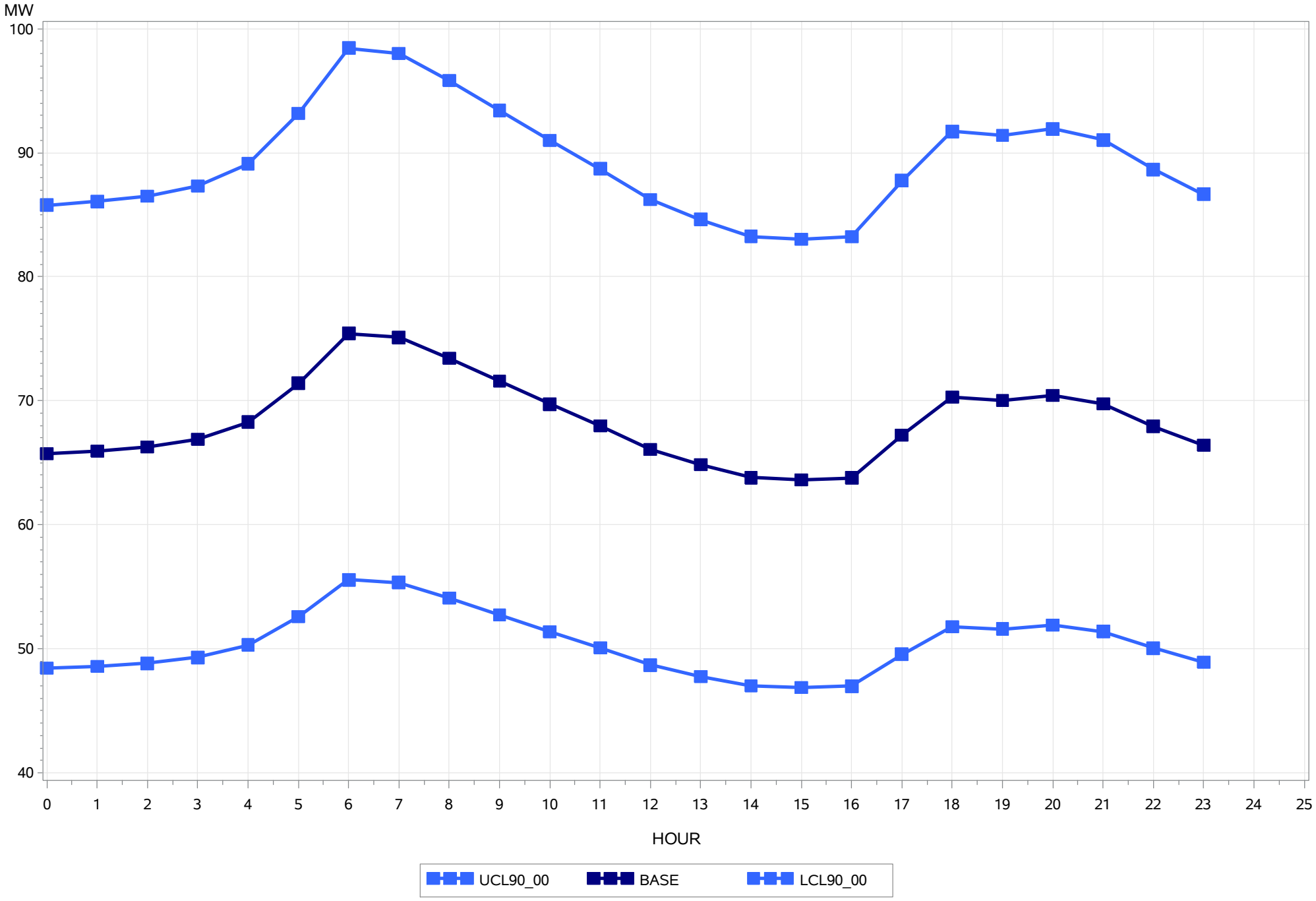
Hourly Average Day for February 2021
STATE OF NEBRASKA



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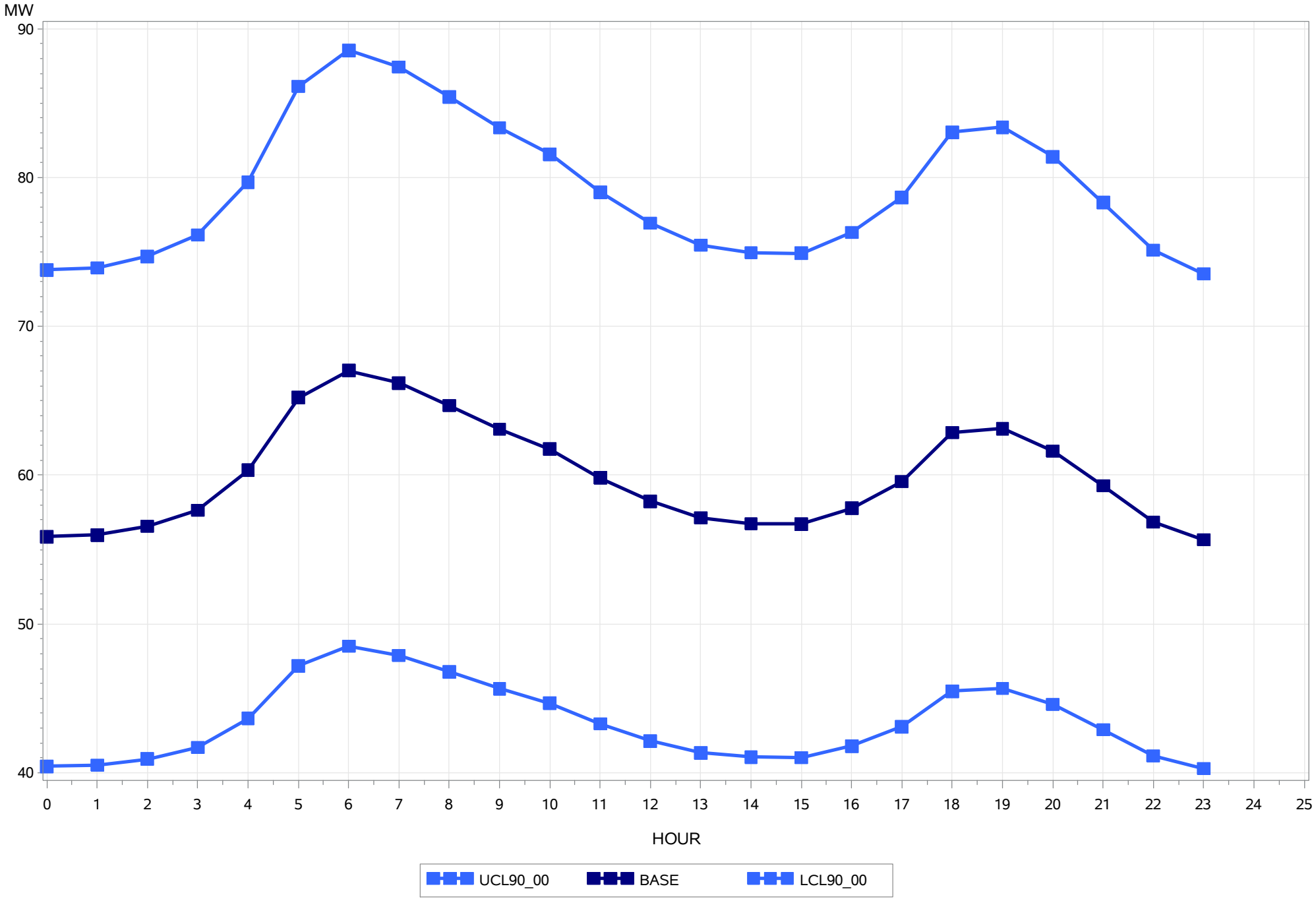
Hourly Average Day for March 2021
STATE OF NEBRASKA



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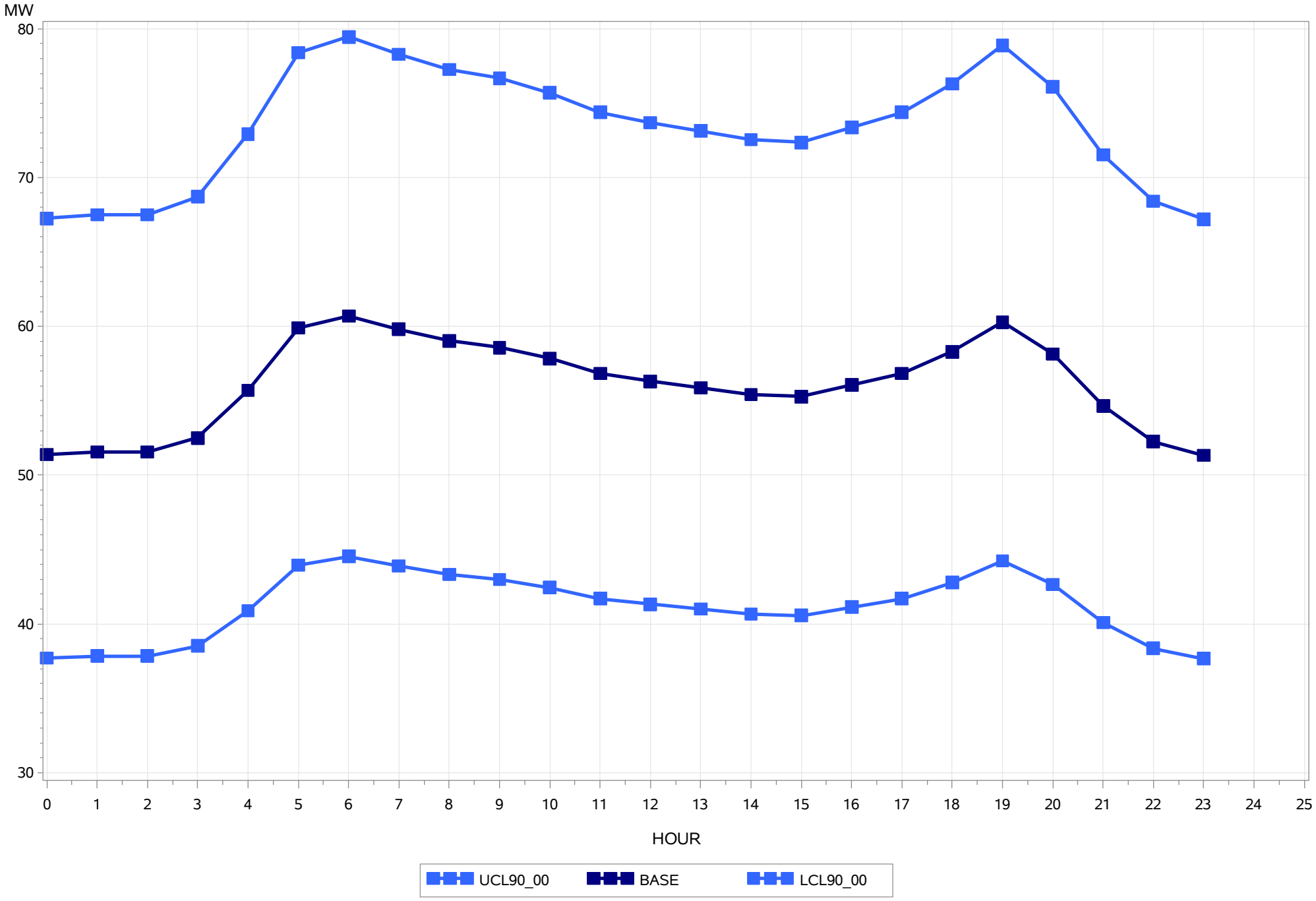
Hourly Average Day for April 2021
STATE OF NEBRASKA



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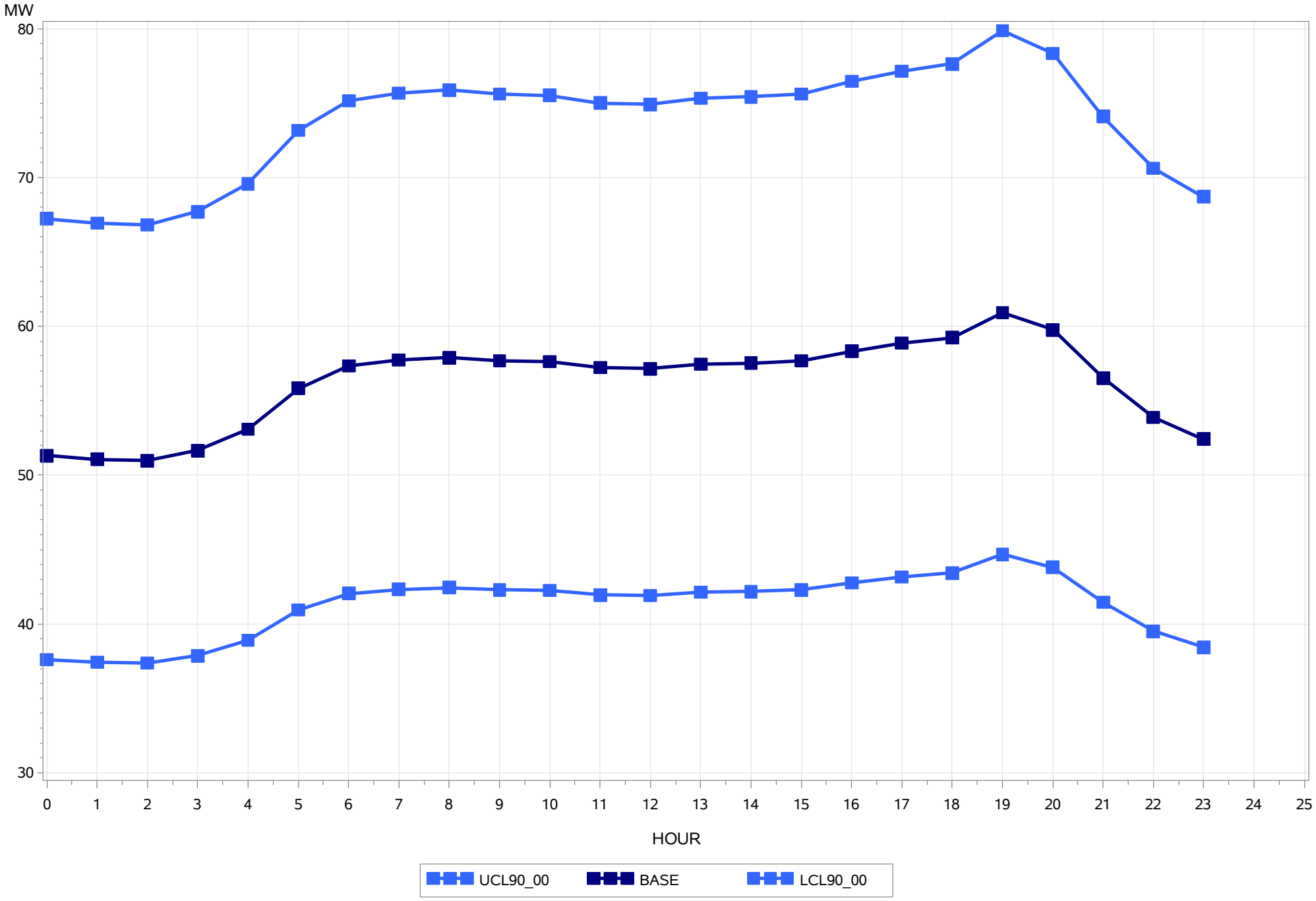
Hourly Average Day for May 2021

STATE OF NEBRASKA



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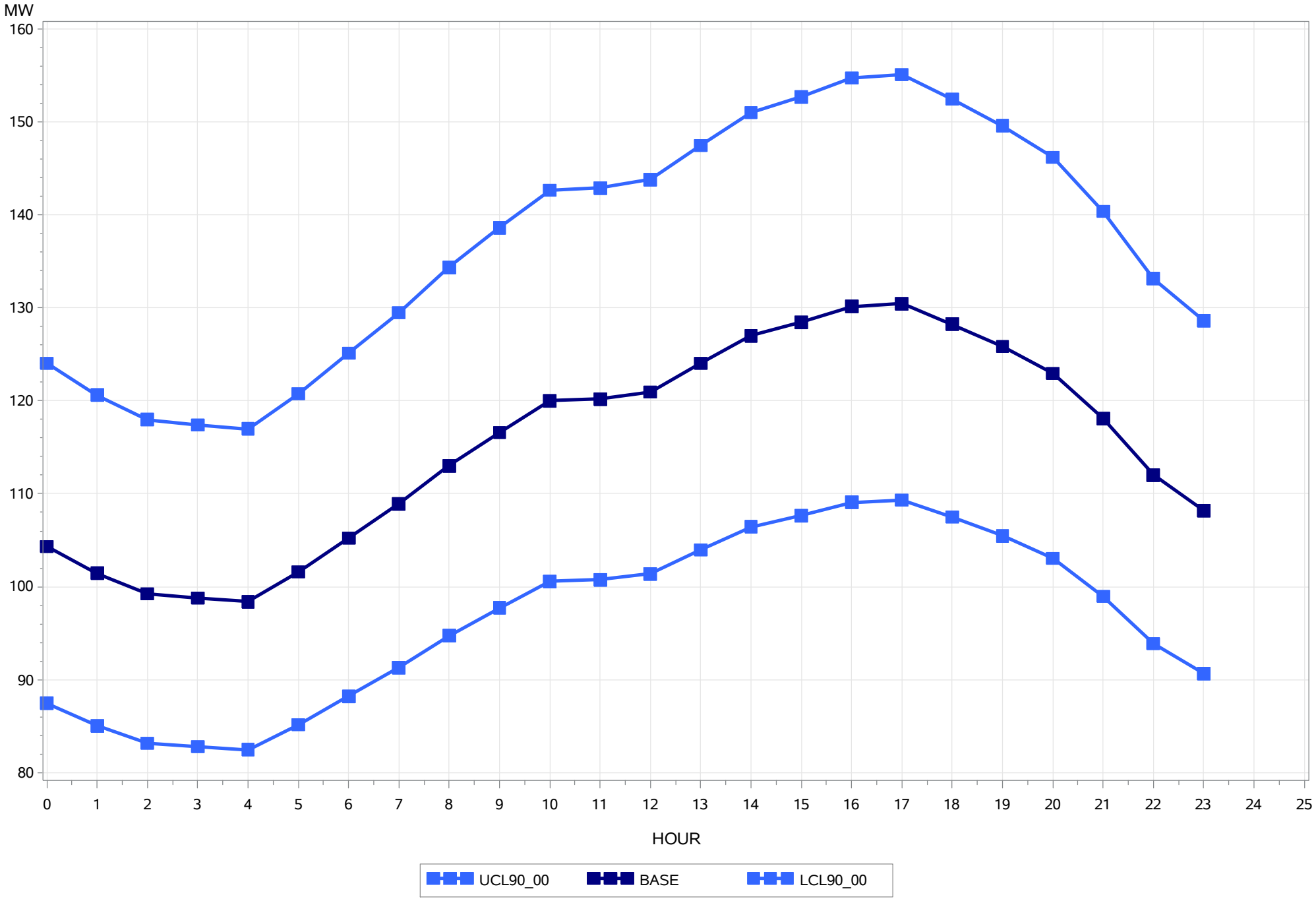
Hourly Average Day for June 2021
STATE OF NEBRASKA



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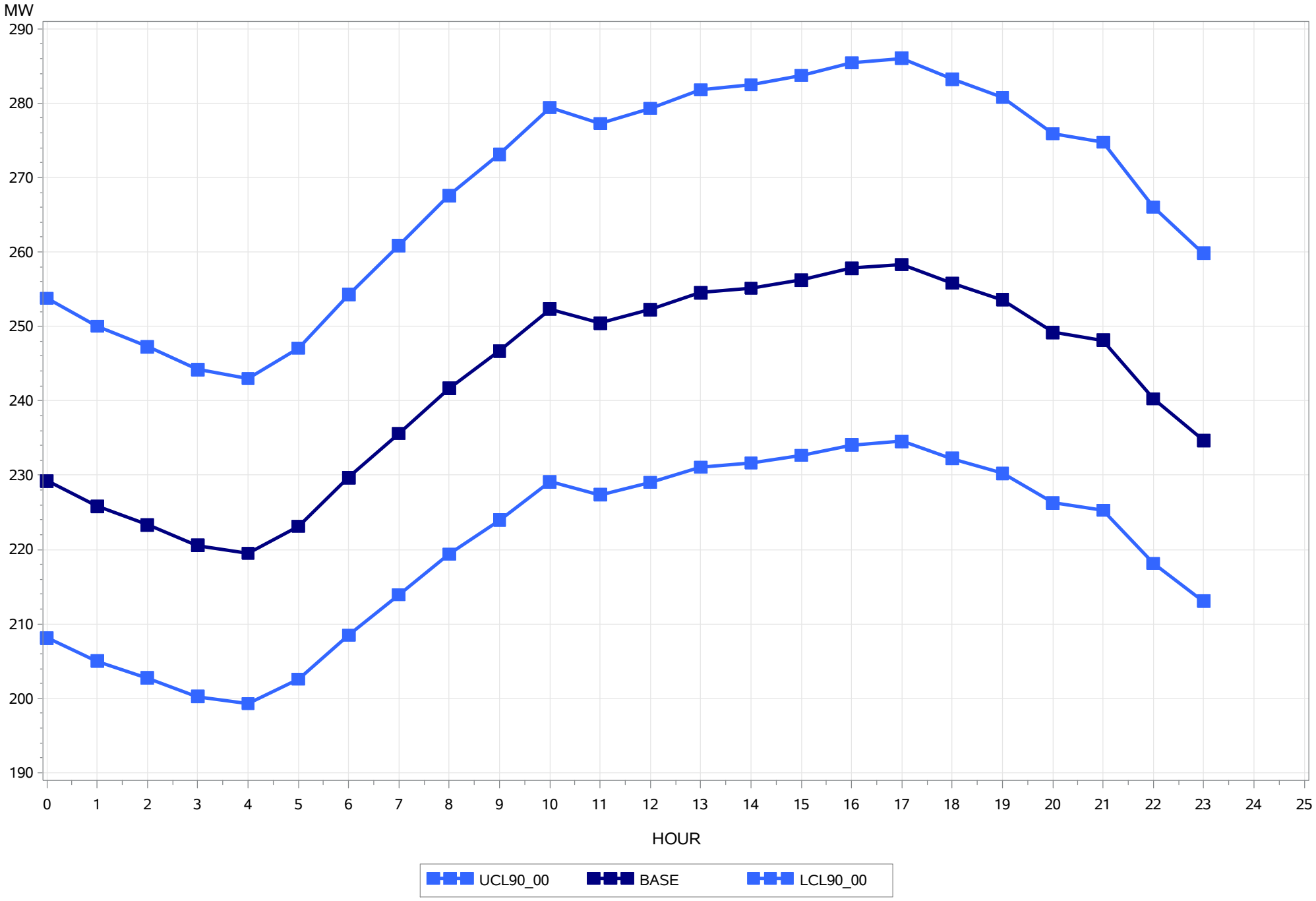
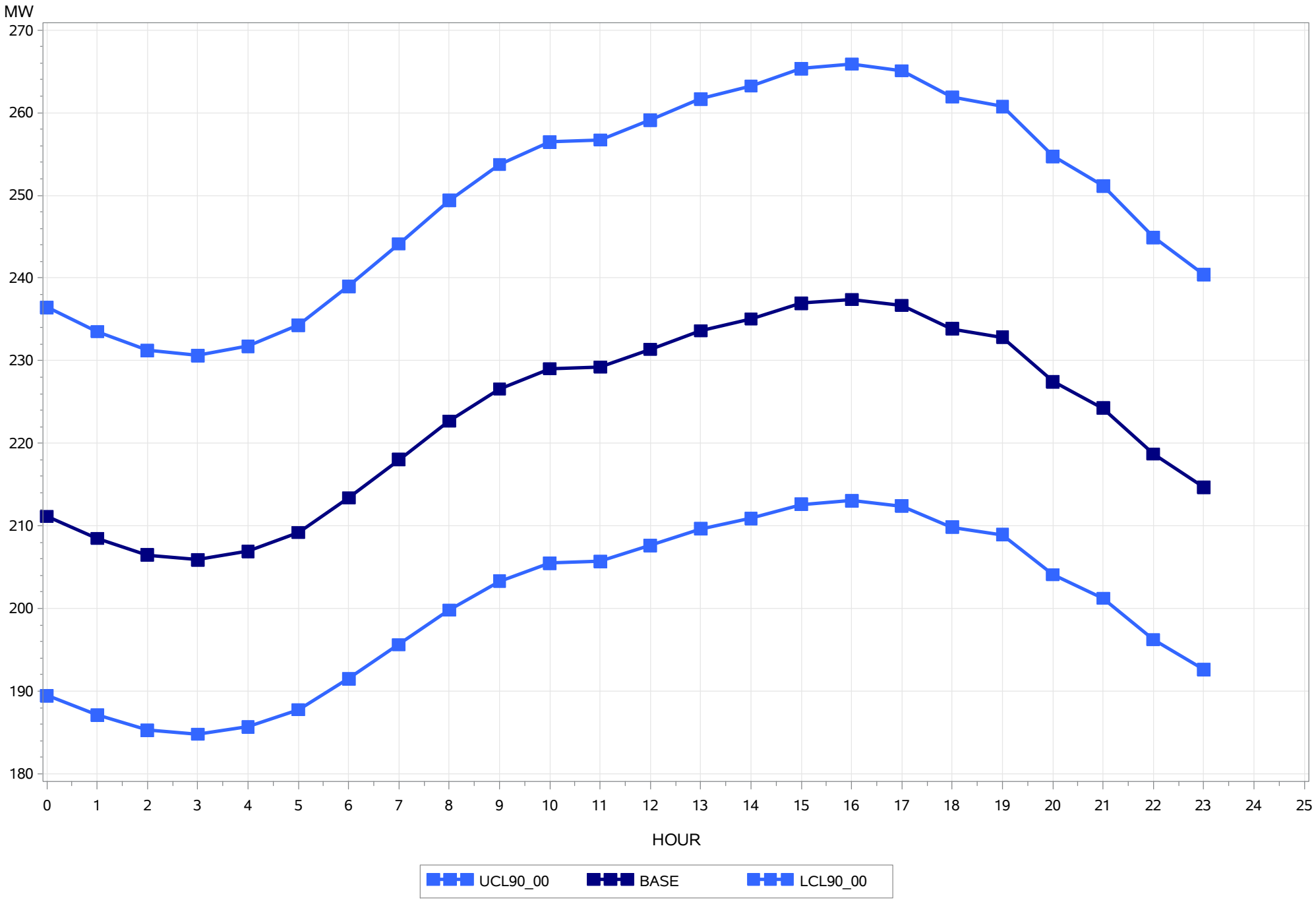
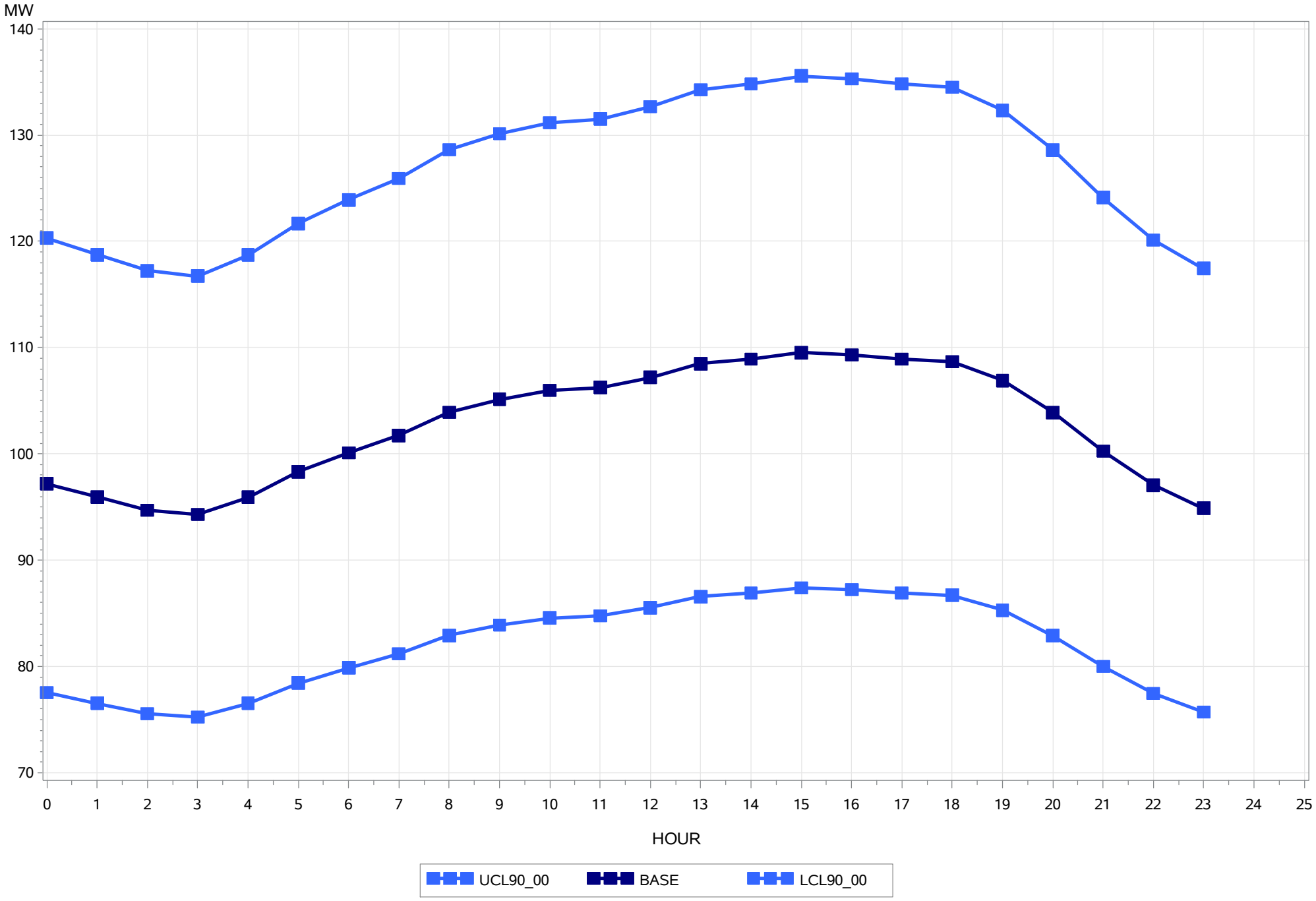
Hourly Average Day for July 2021
STATE OF NEBRASKA



Hourly Average Day for August 2021
STATE OF NEBRASKA



Hourly Average Day for September 2021
STATE OF NEBRASKA



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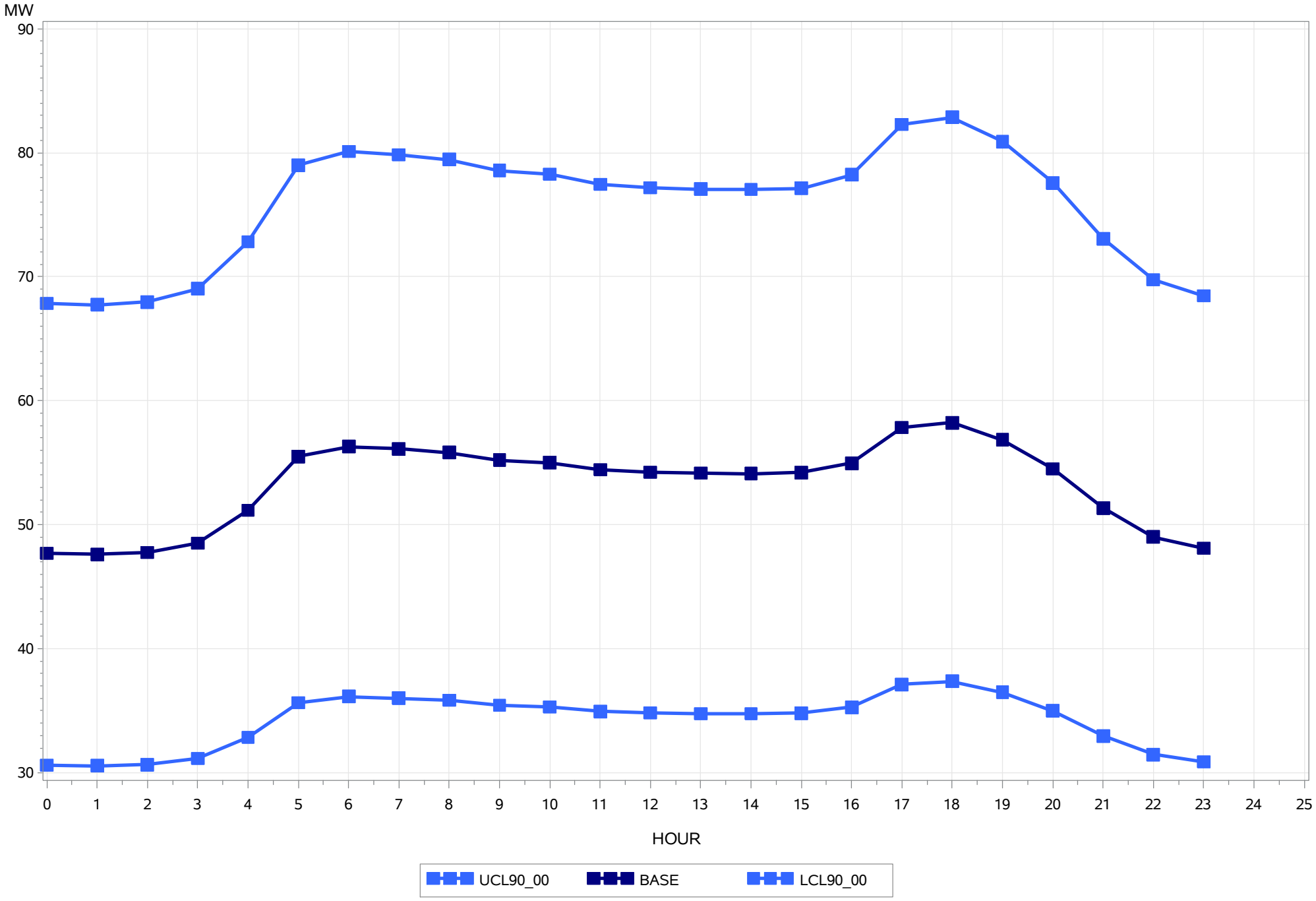
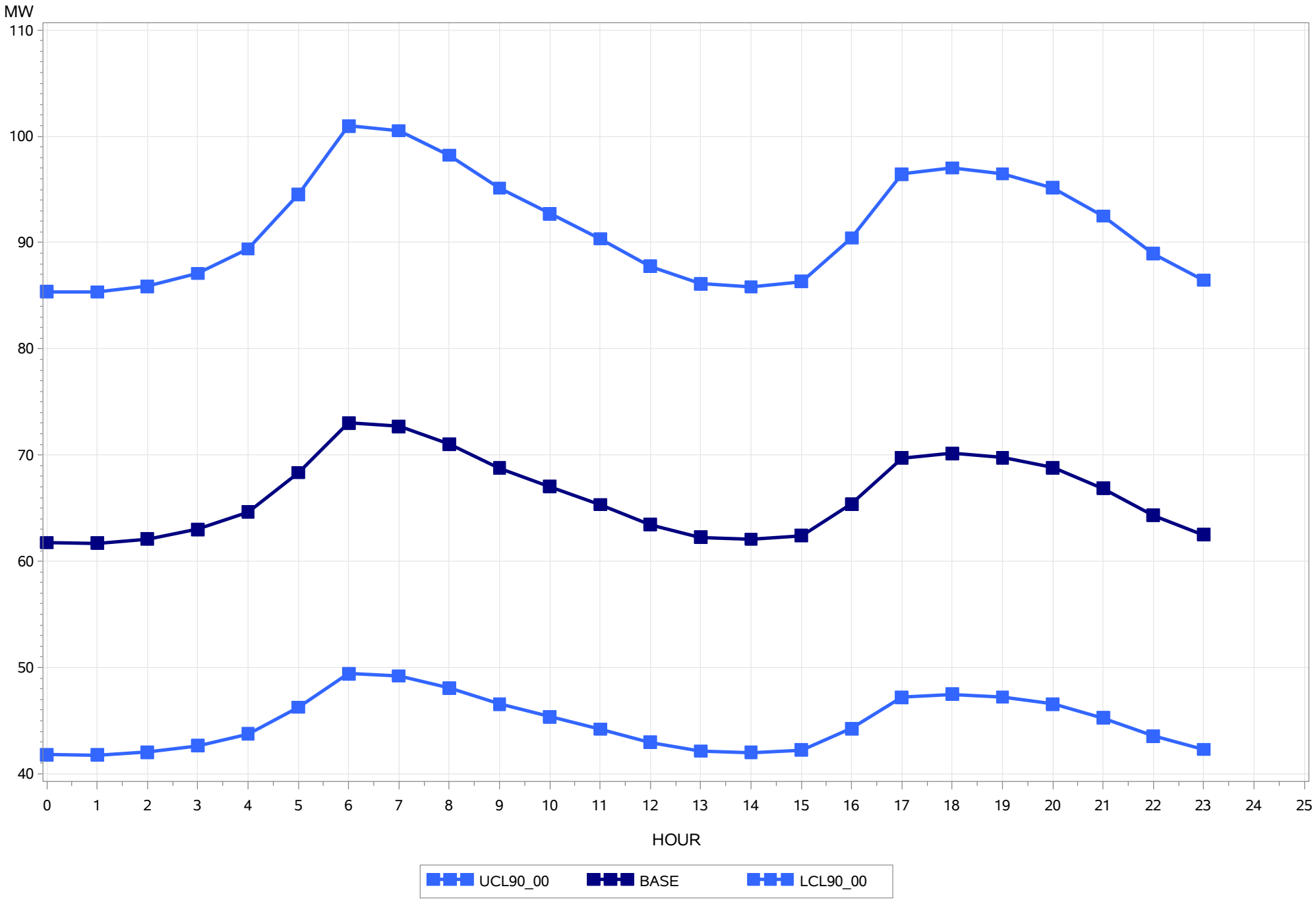
Hourly Average Day for October 2021
STATE OF NEBRASKA



Hourly Average Day for November 2021
STATE OF NEBRASKA



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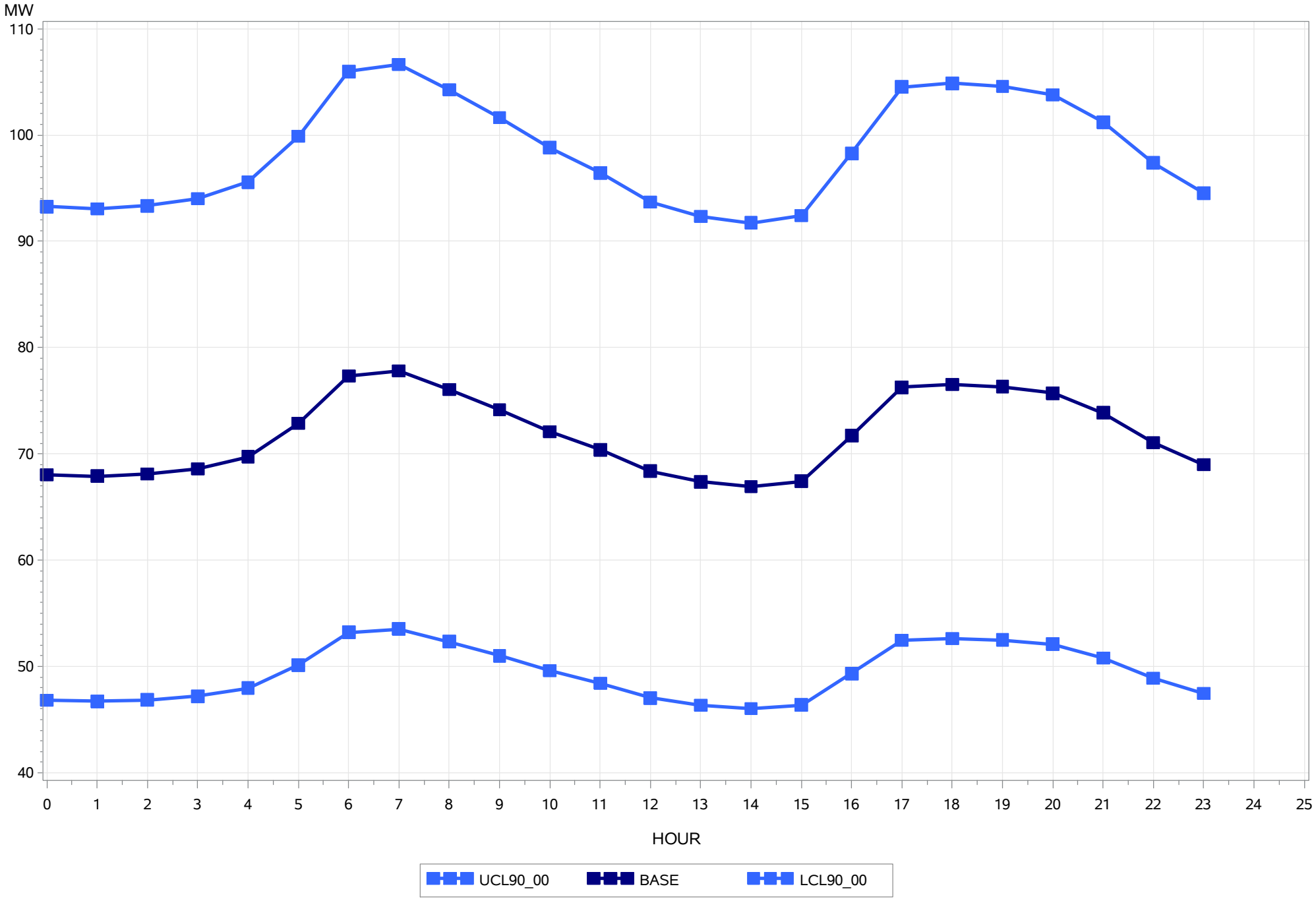
Hourly Average Day for December 2021
STATE OF NEBRASKA



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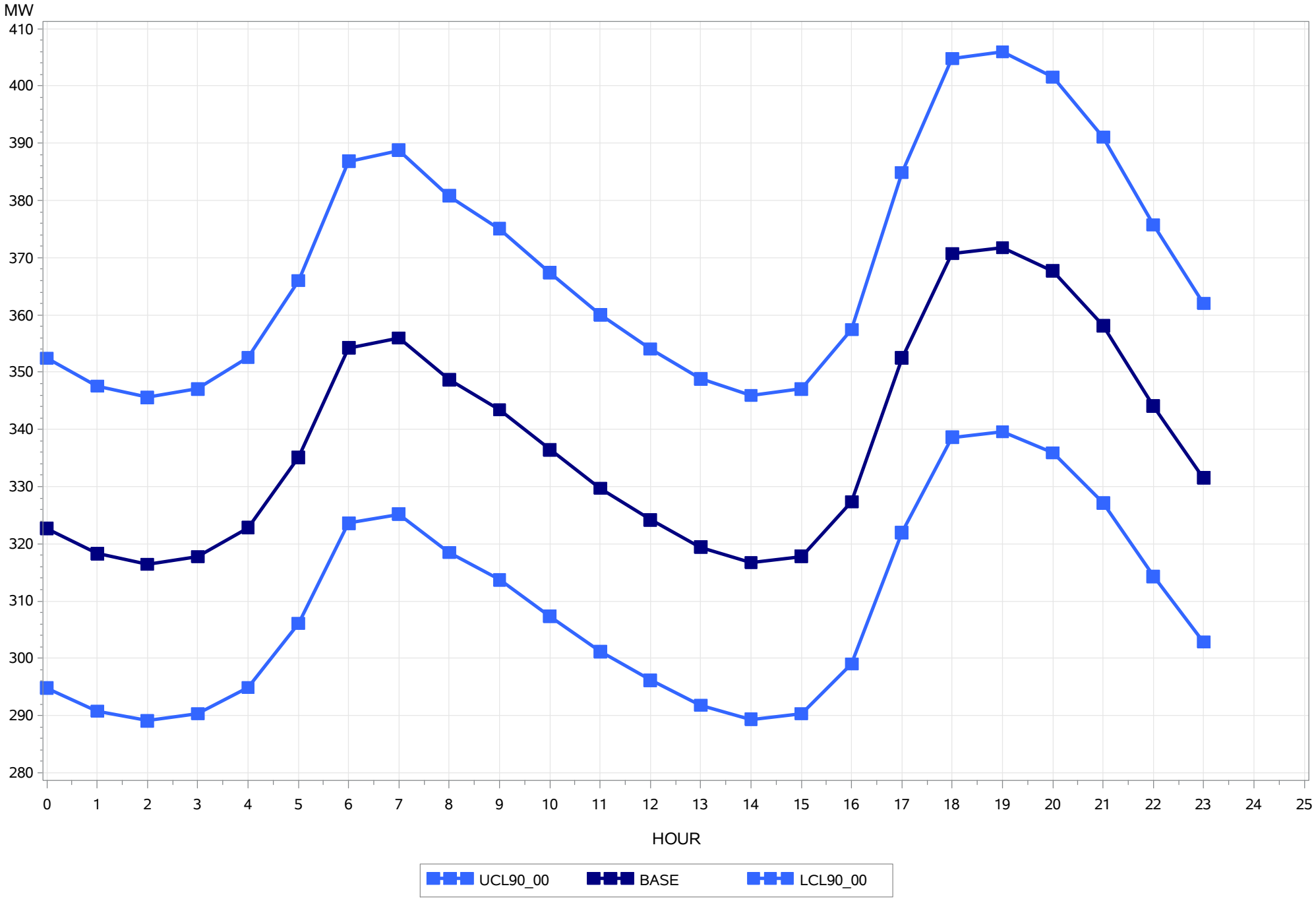
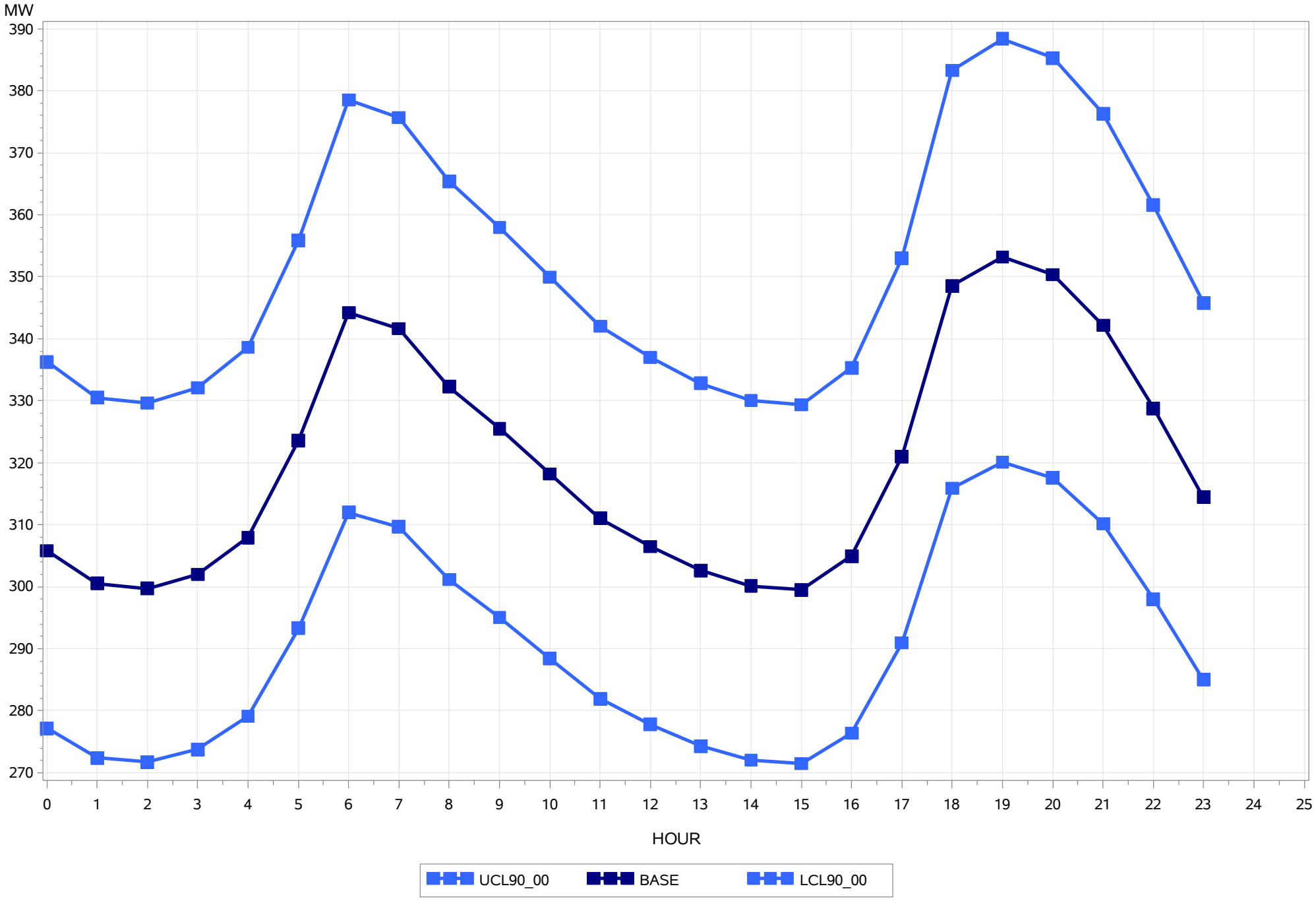
Hourly Average Day for January 2021
STATE OF NEW MEXICO



Hourly Average Day for February 2021
STATE OF NEW MEXICO



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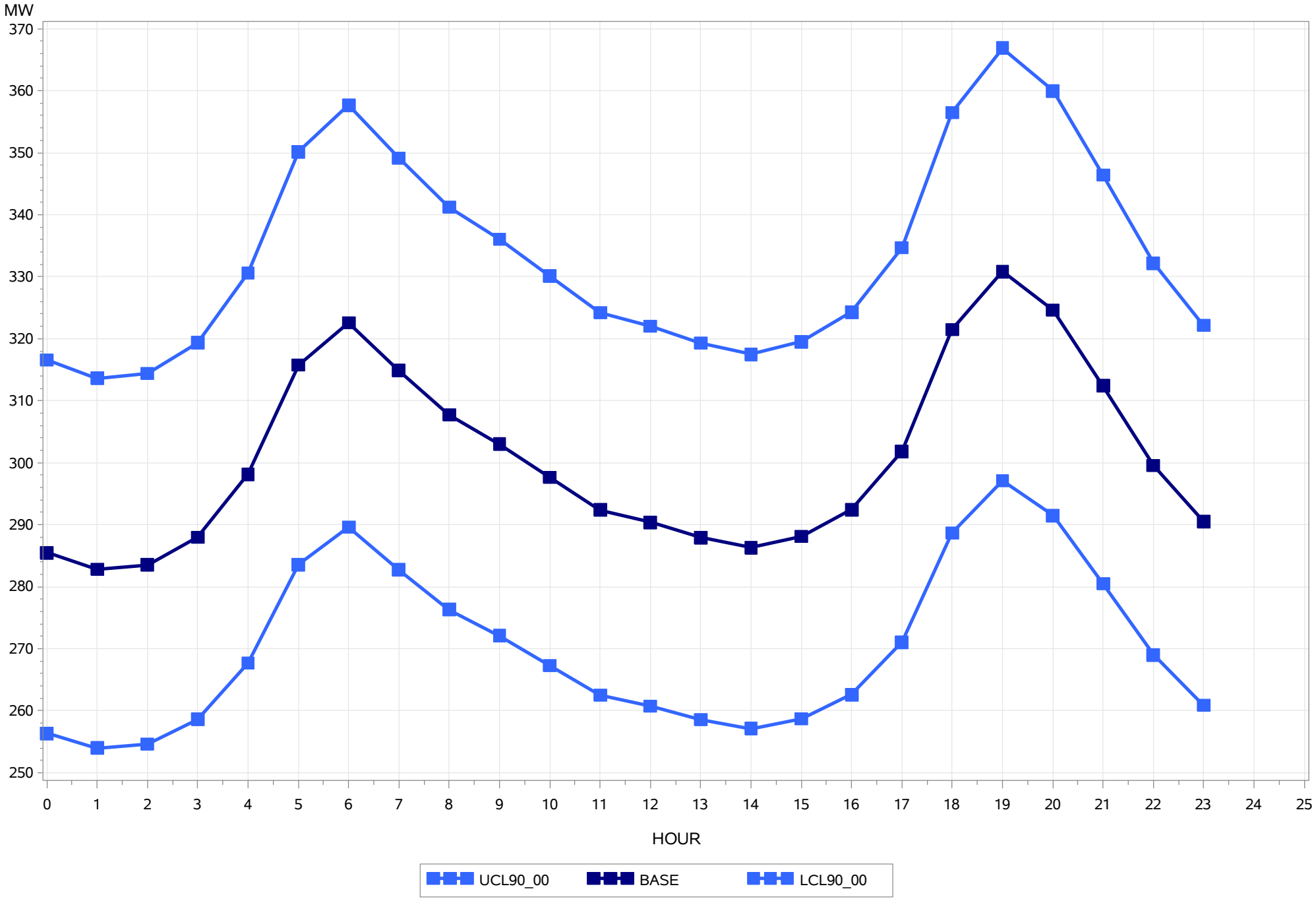
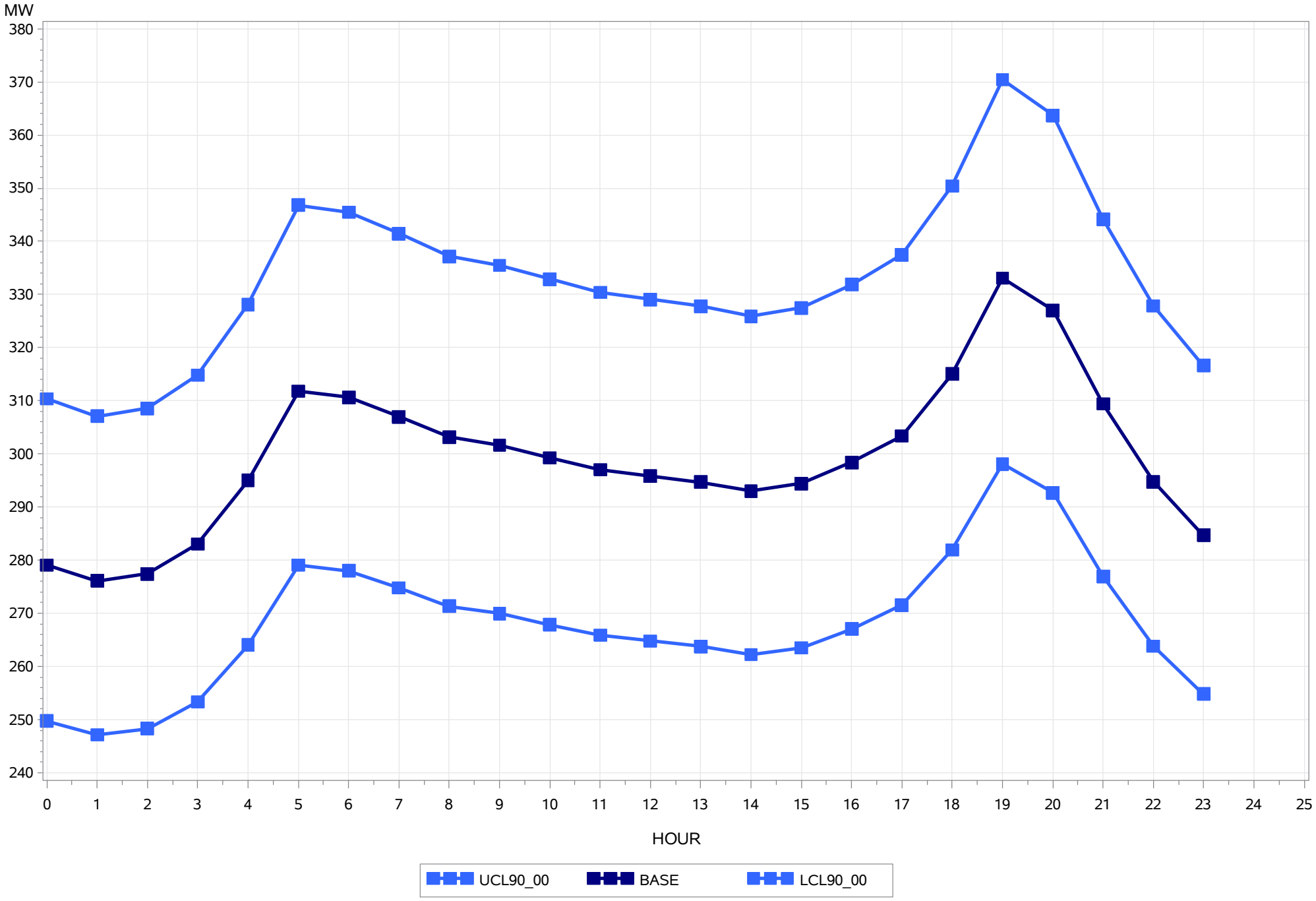
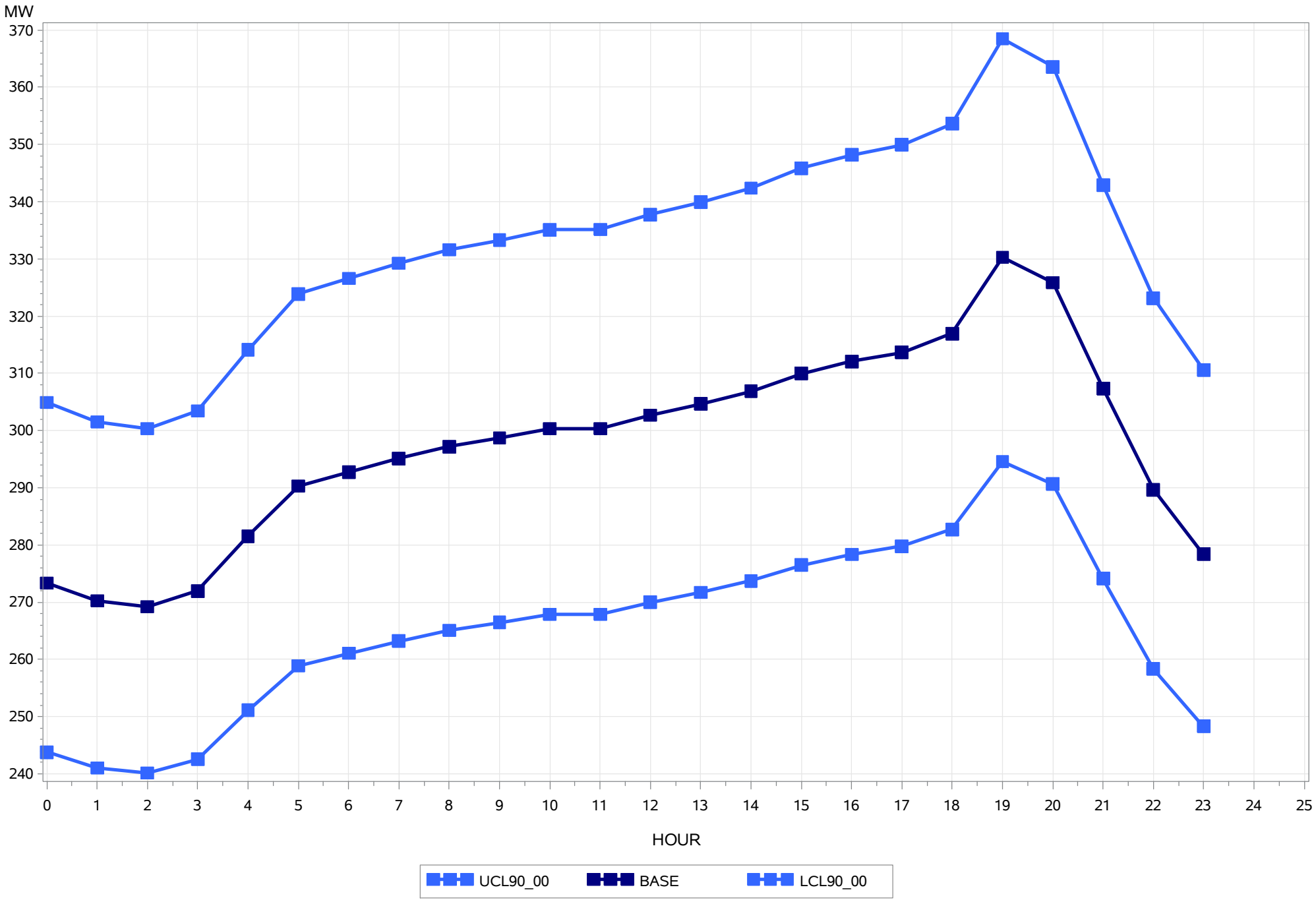
Hourly Average Day for March 2021
STATE OF NEW MEXICO



Hourly Average Day for April 2021
STATE OF NEW MEXICO



Hourly Average Day for May 2021
STATE OF NEW MEXICO



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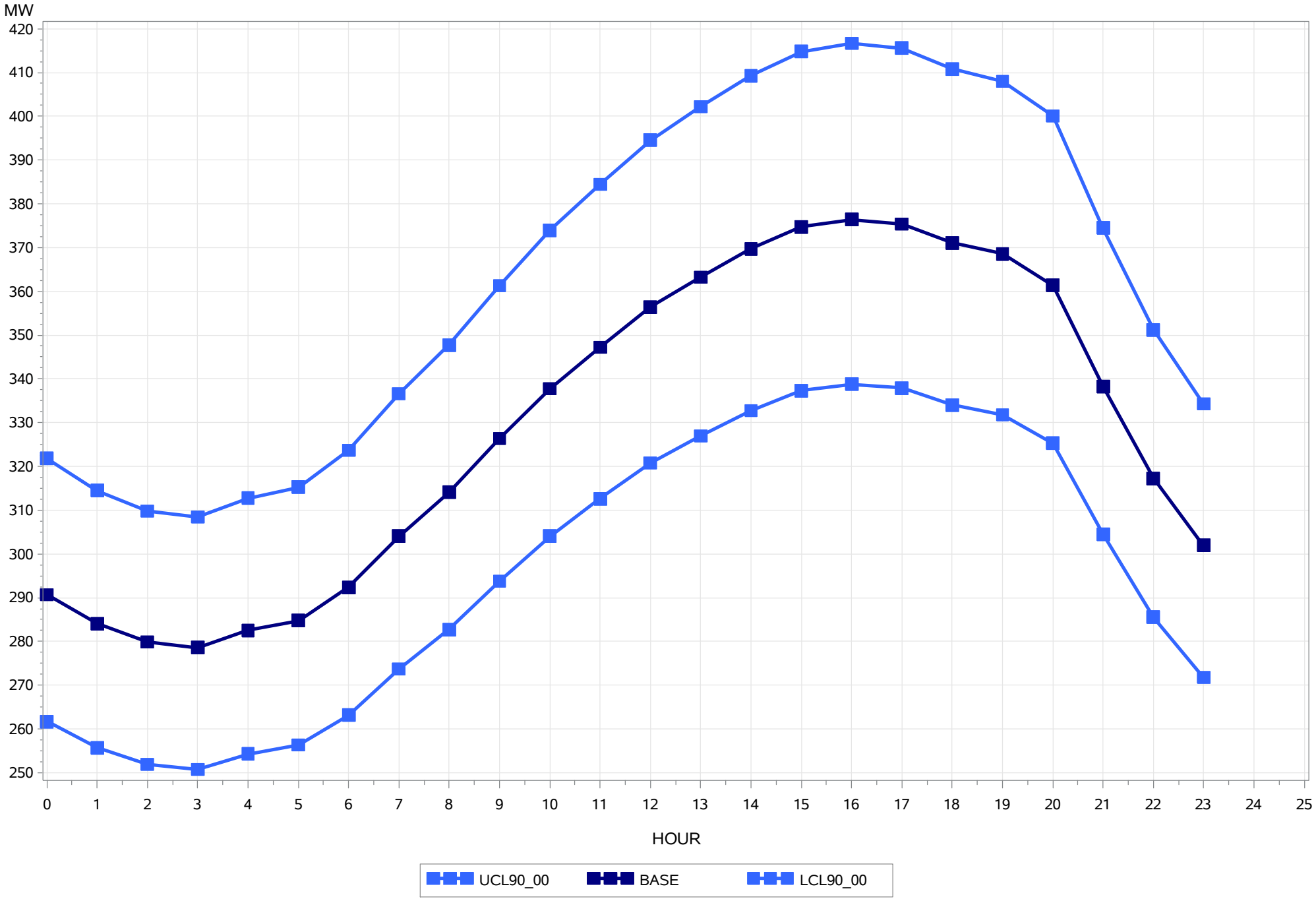
Hourly Average Day for June 2021
STATE OF NEW MEXICO



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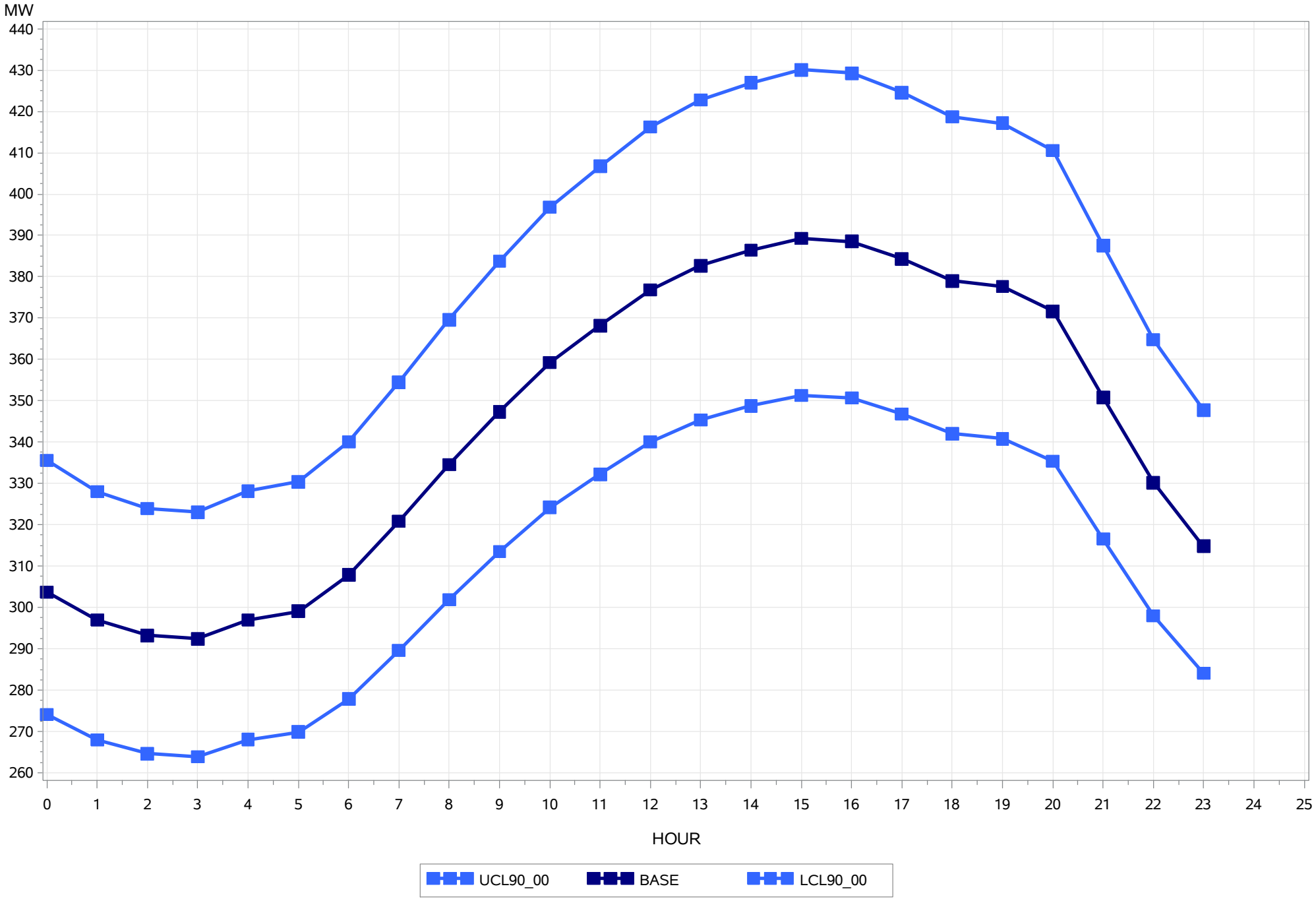
Hourly Average Day for July 2021
STATE OF NEW MEXICO



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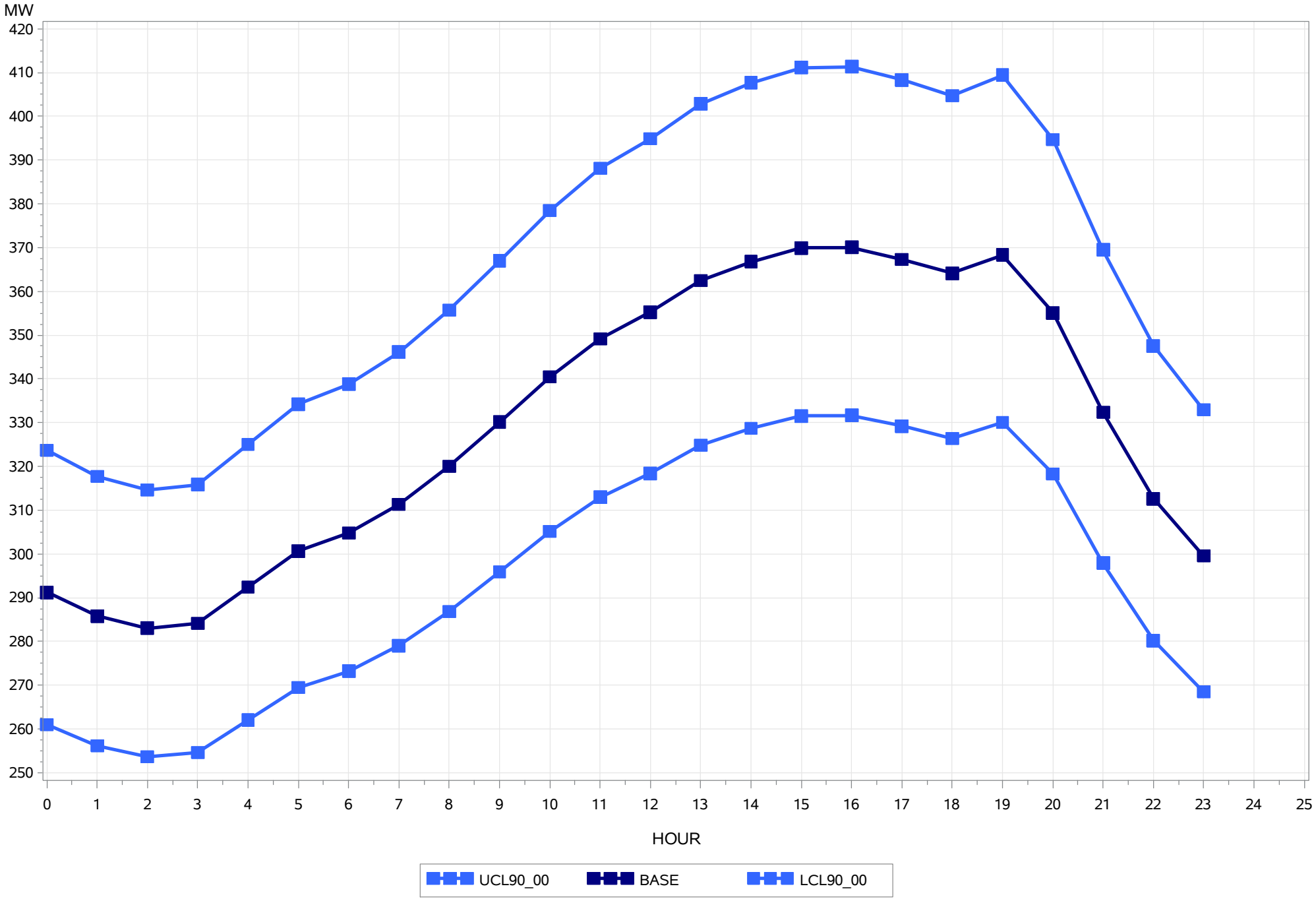
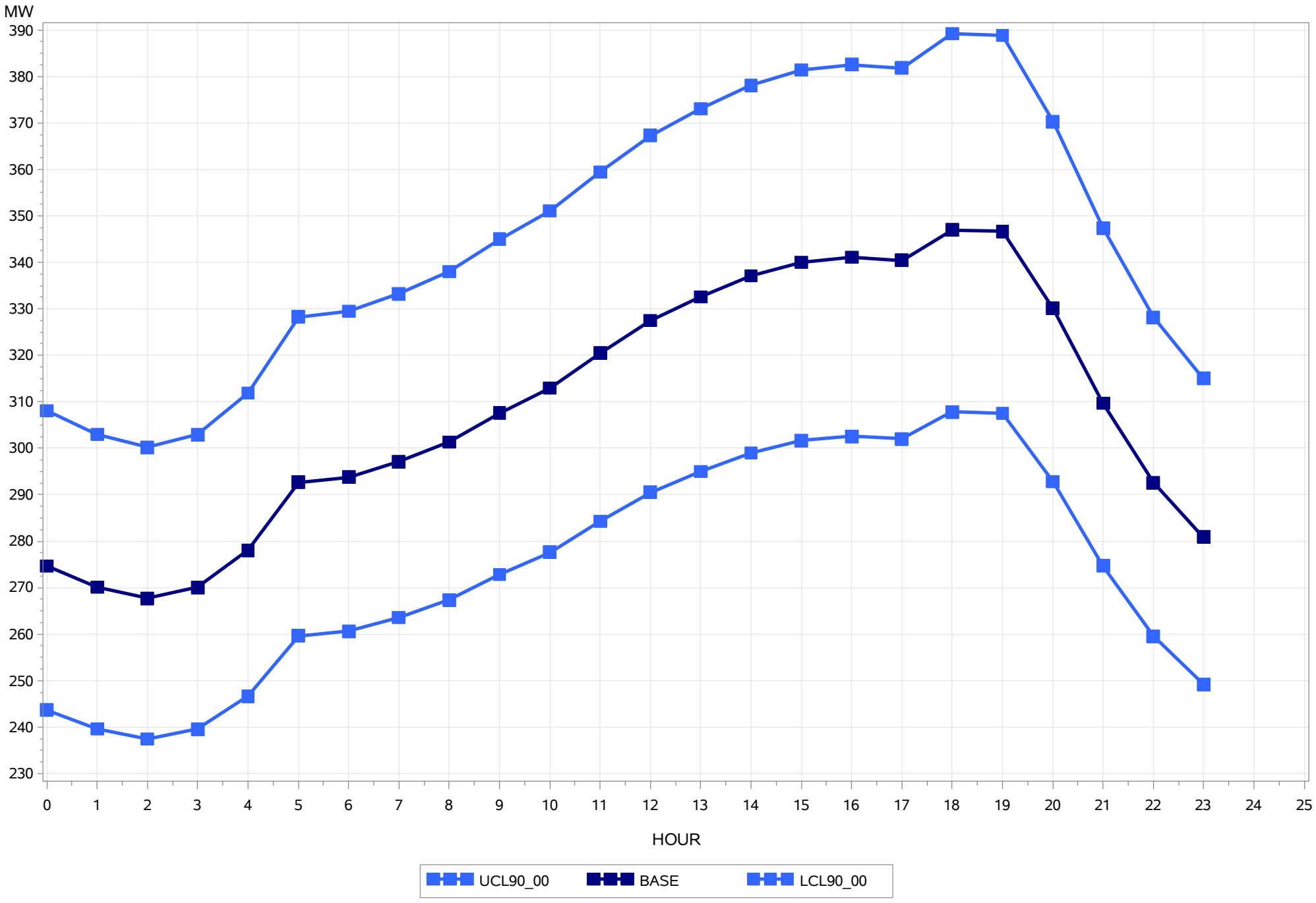
Hourly Average Day for August 2021
STATE OF NEW MEXICO



Hourly Average Day for September 2021
STATE OF NEW MEXICO



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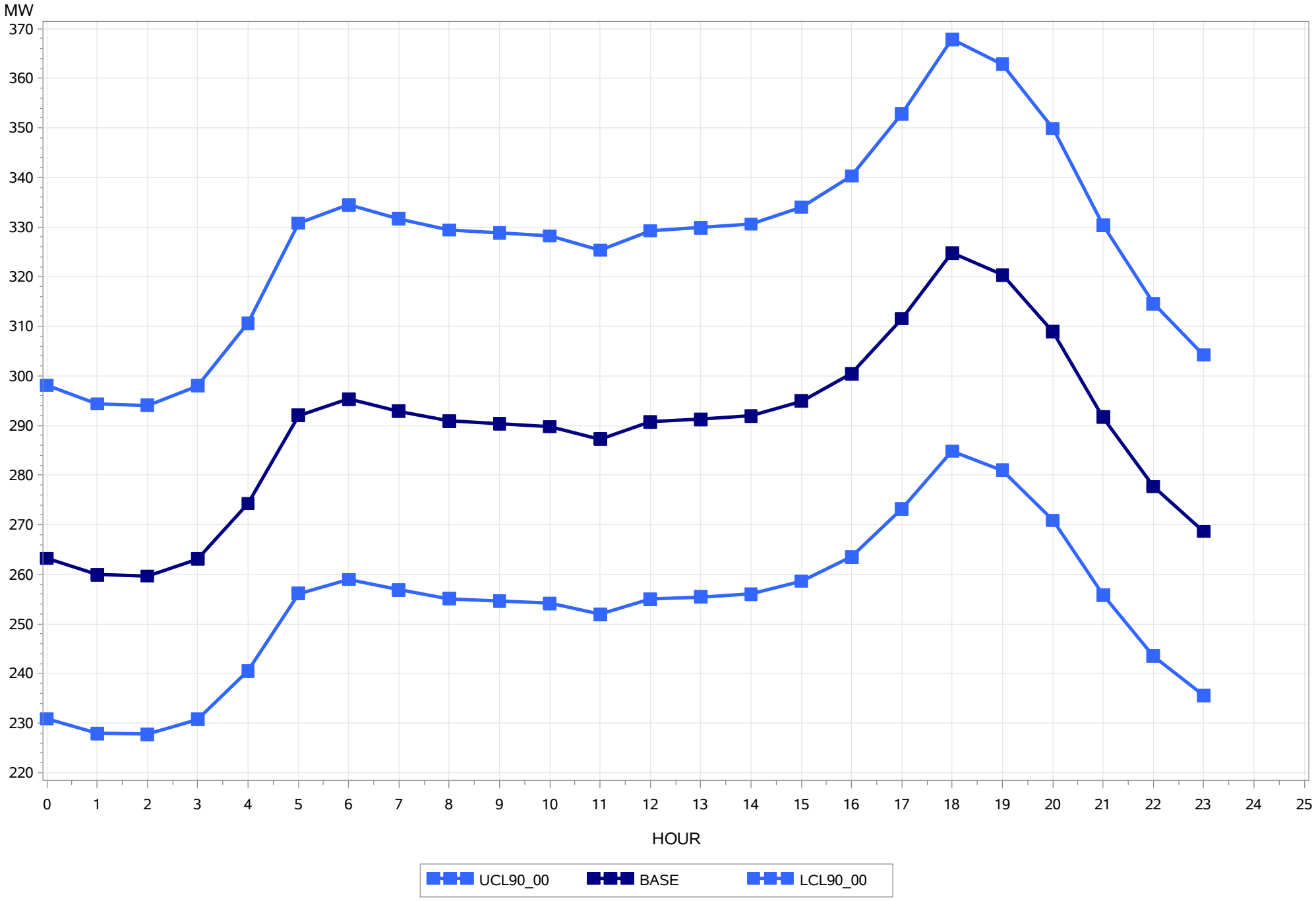
Hourly Average Day for October 2021
STATE OF NEW MEXICO



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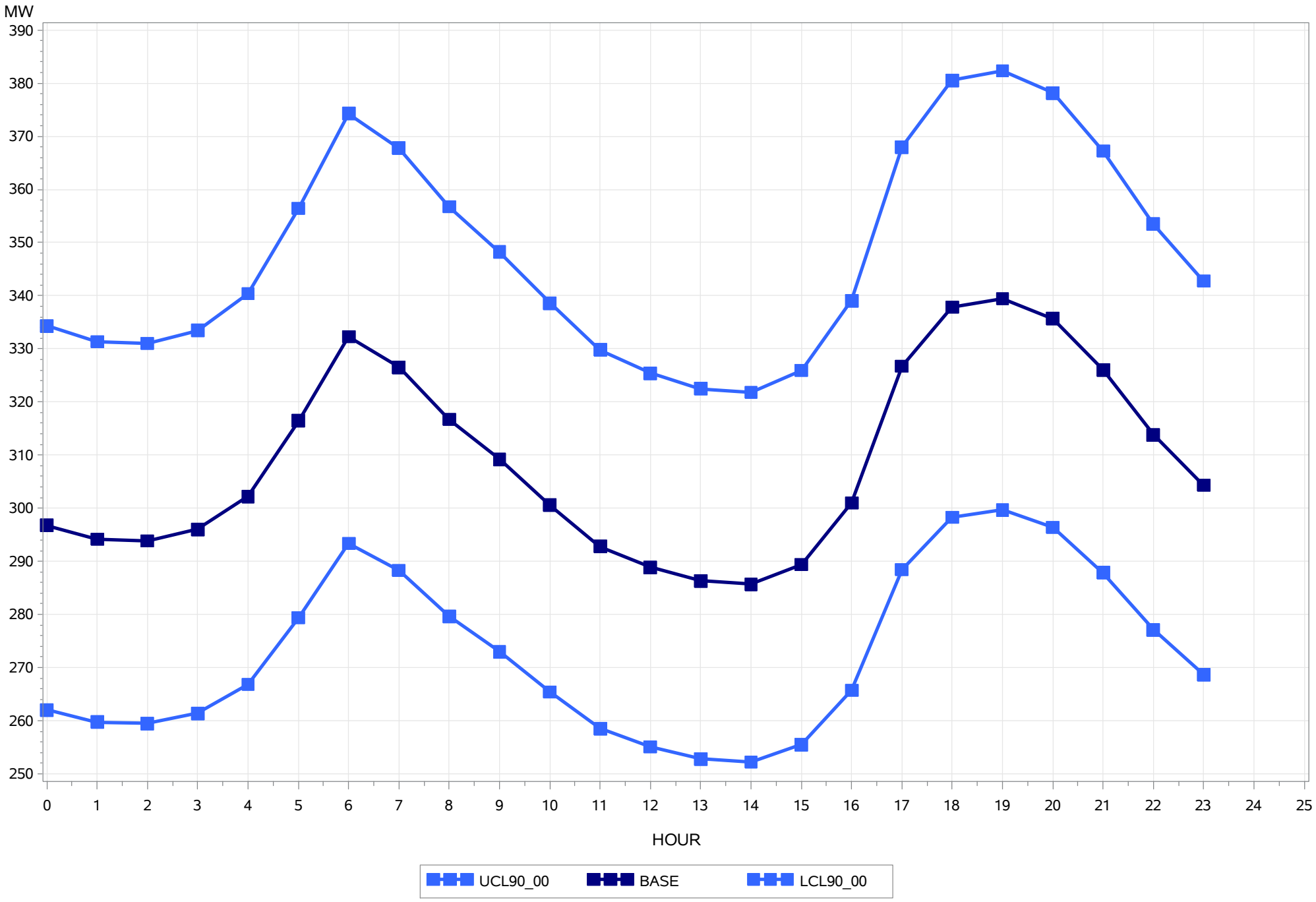
Hourly Average Day for November 2021
STATE OF NEW MEXICO



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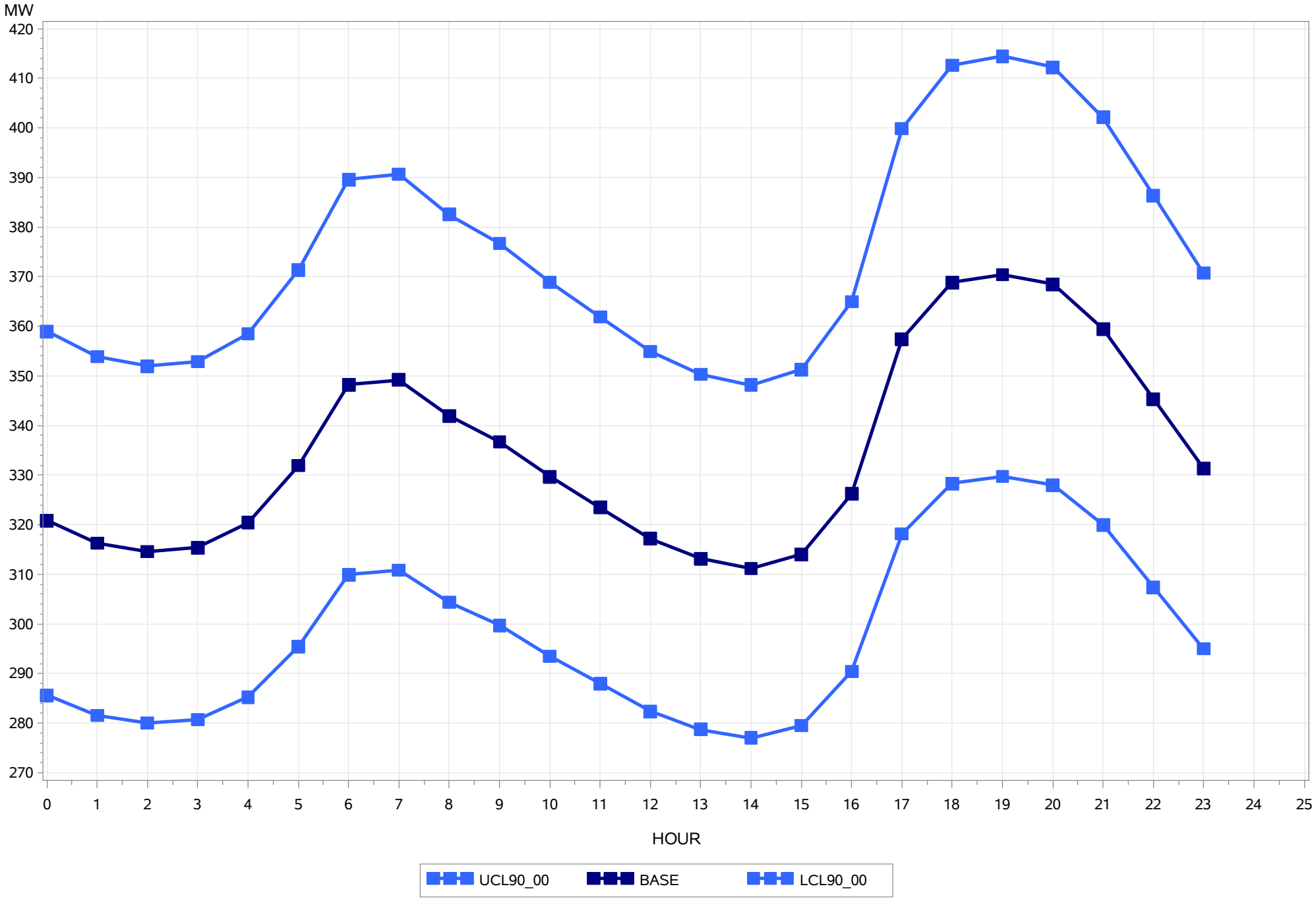
Hourly Average Day for December 2021
STATE OF NEW MEXICO



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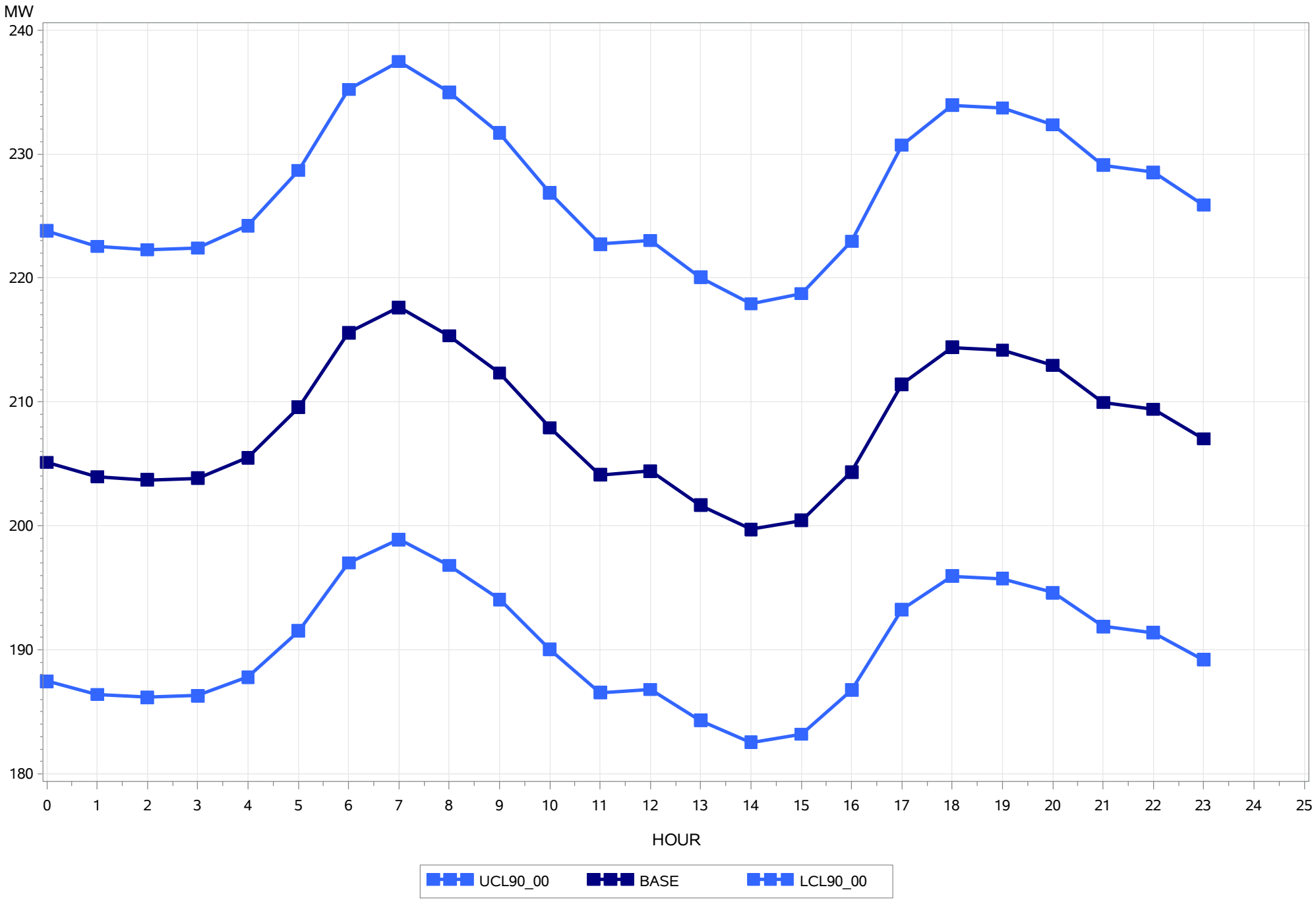
Hourly Average Day for January 2021
STATE OF WYOMING



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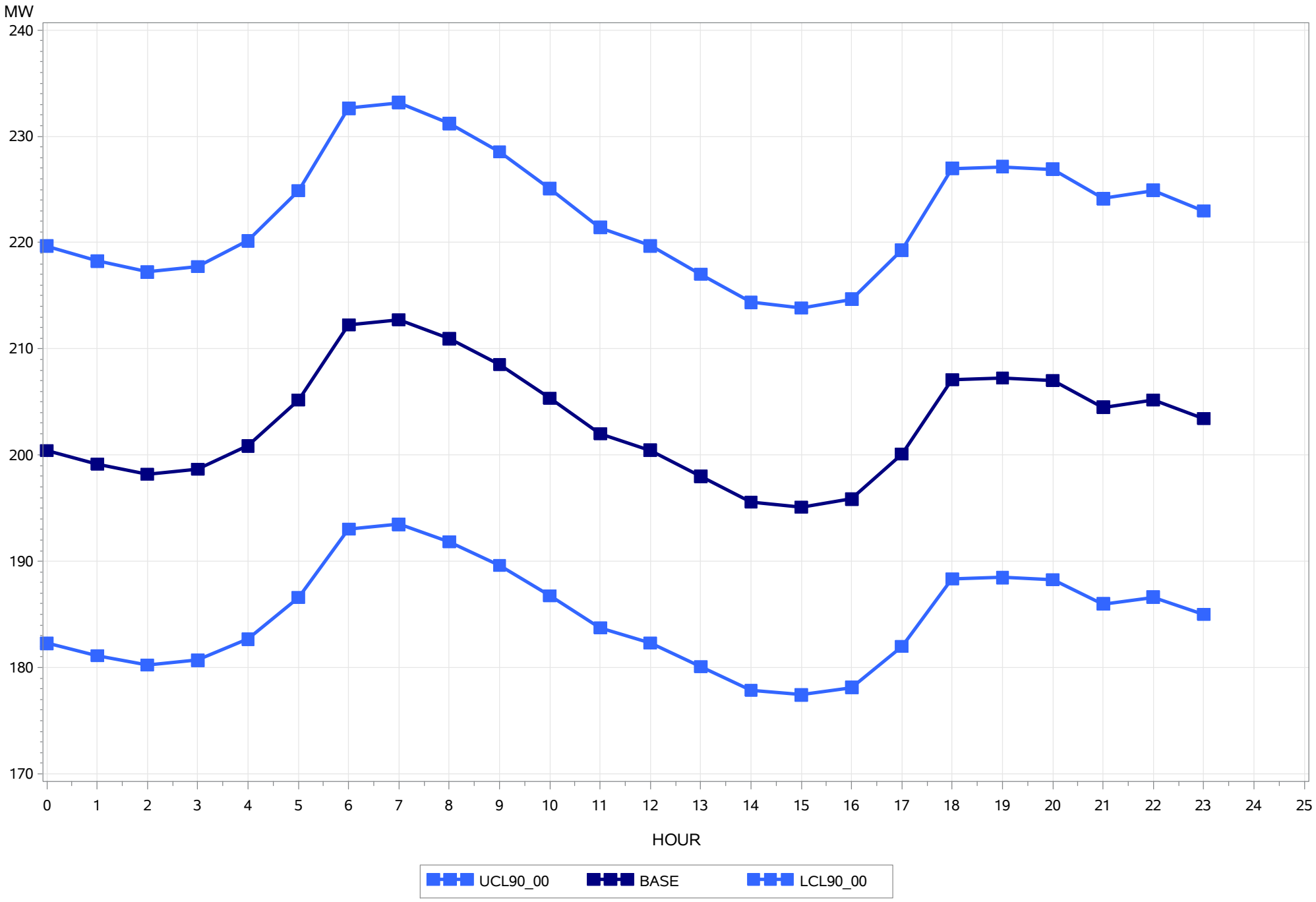
Hourly Average Day for February 2021
STATE OF WYOMING



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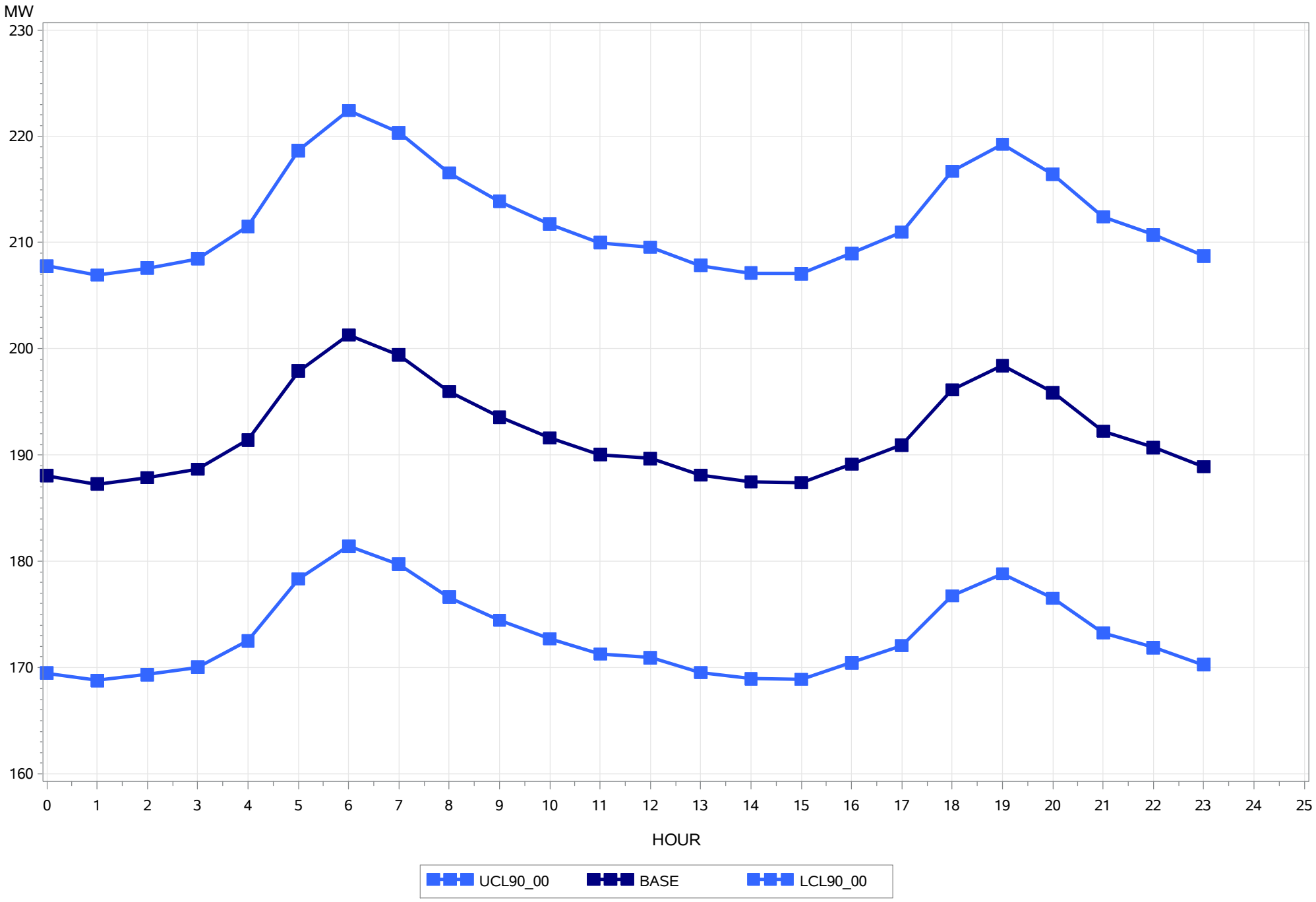
Hourly Average Day for March 2021
STATE OF WYOMING



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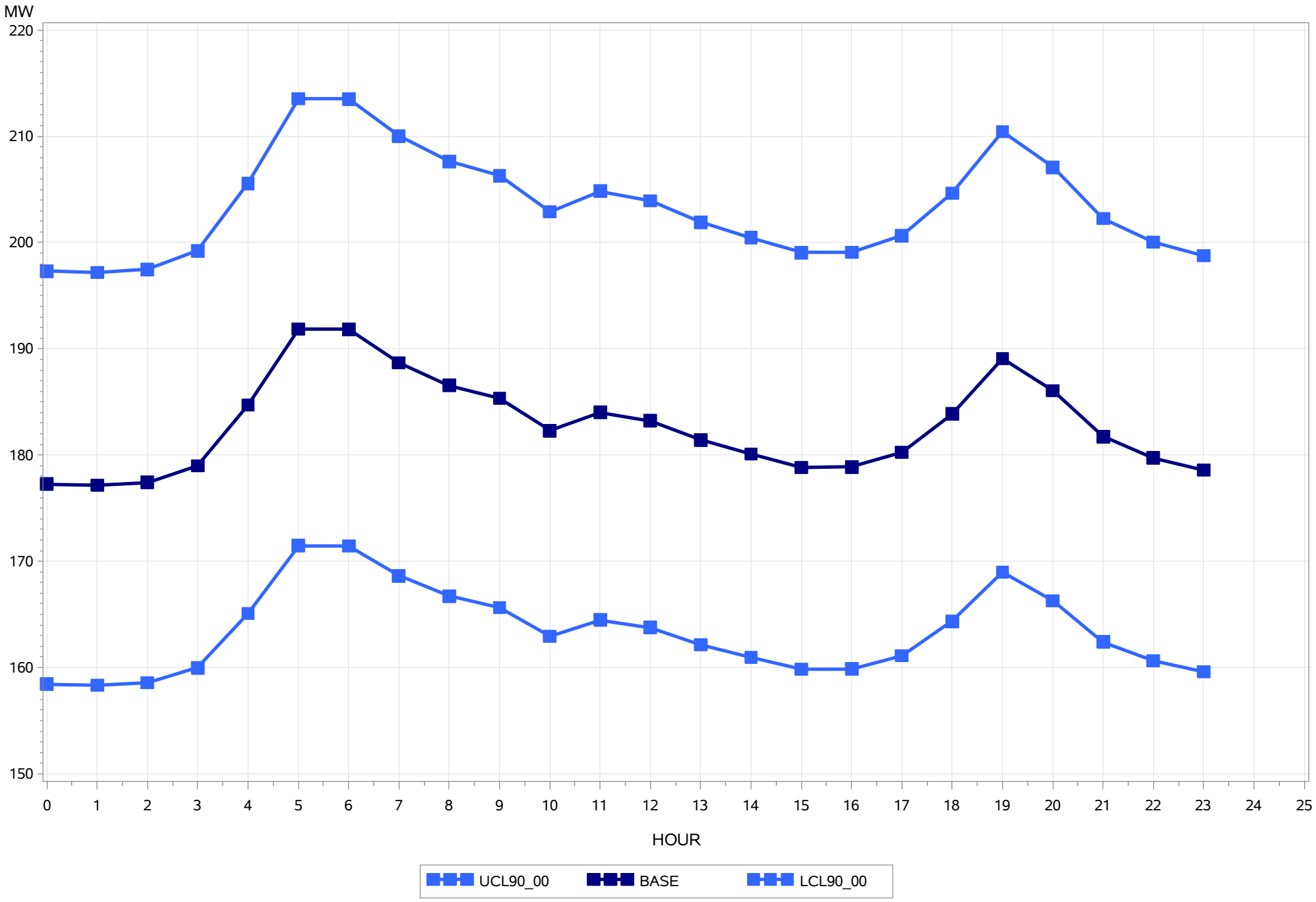
Hourly Average Day for April 2021
STATE OF WYOMING



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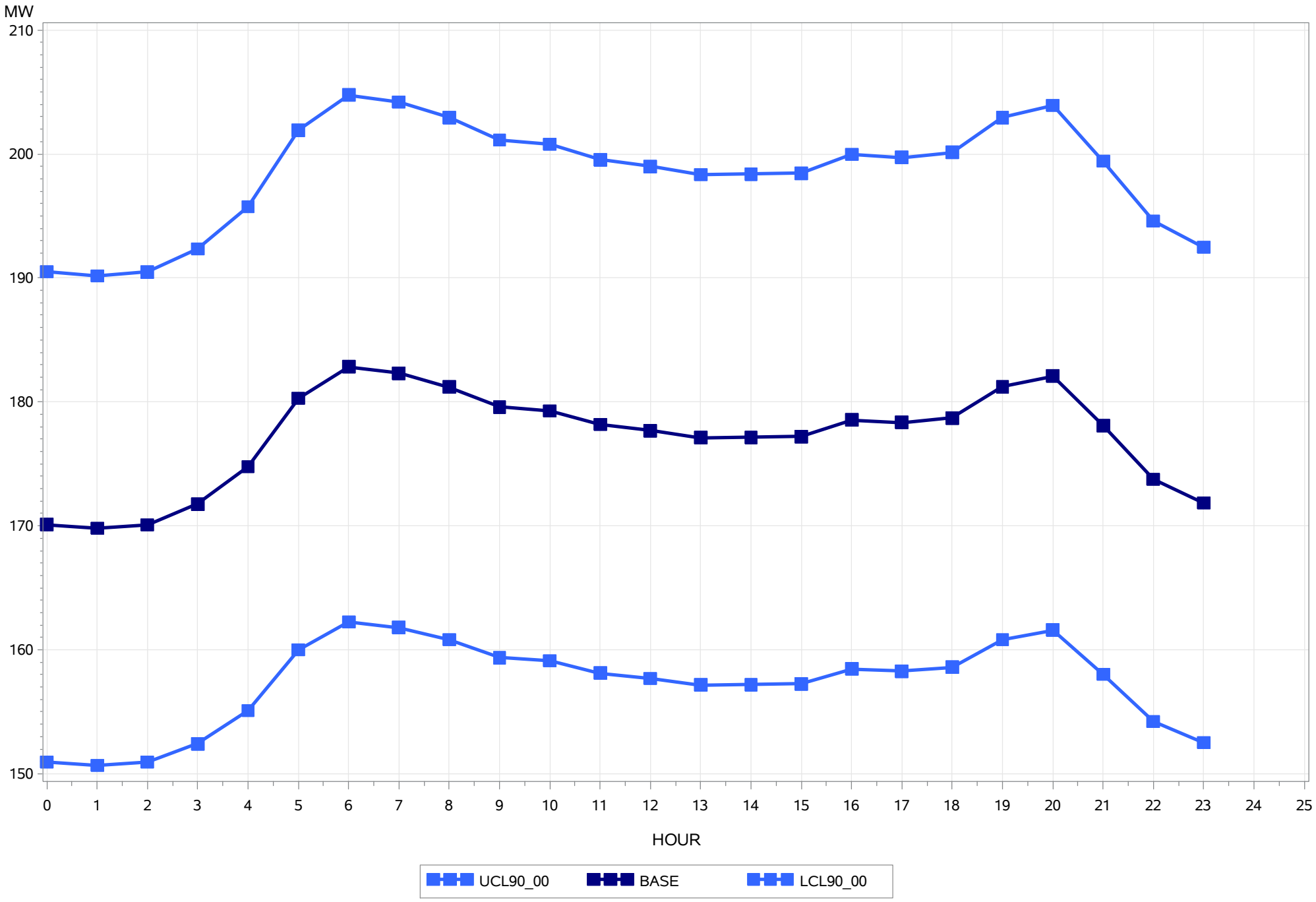
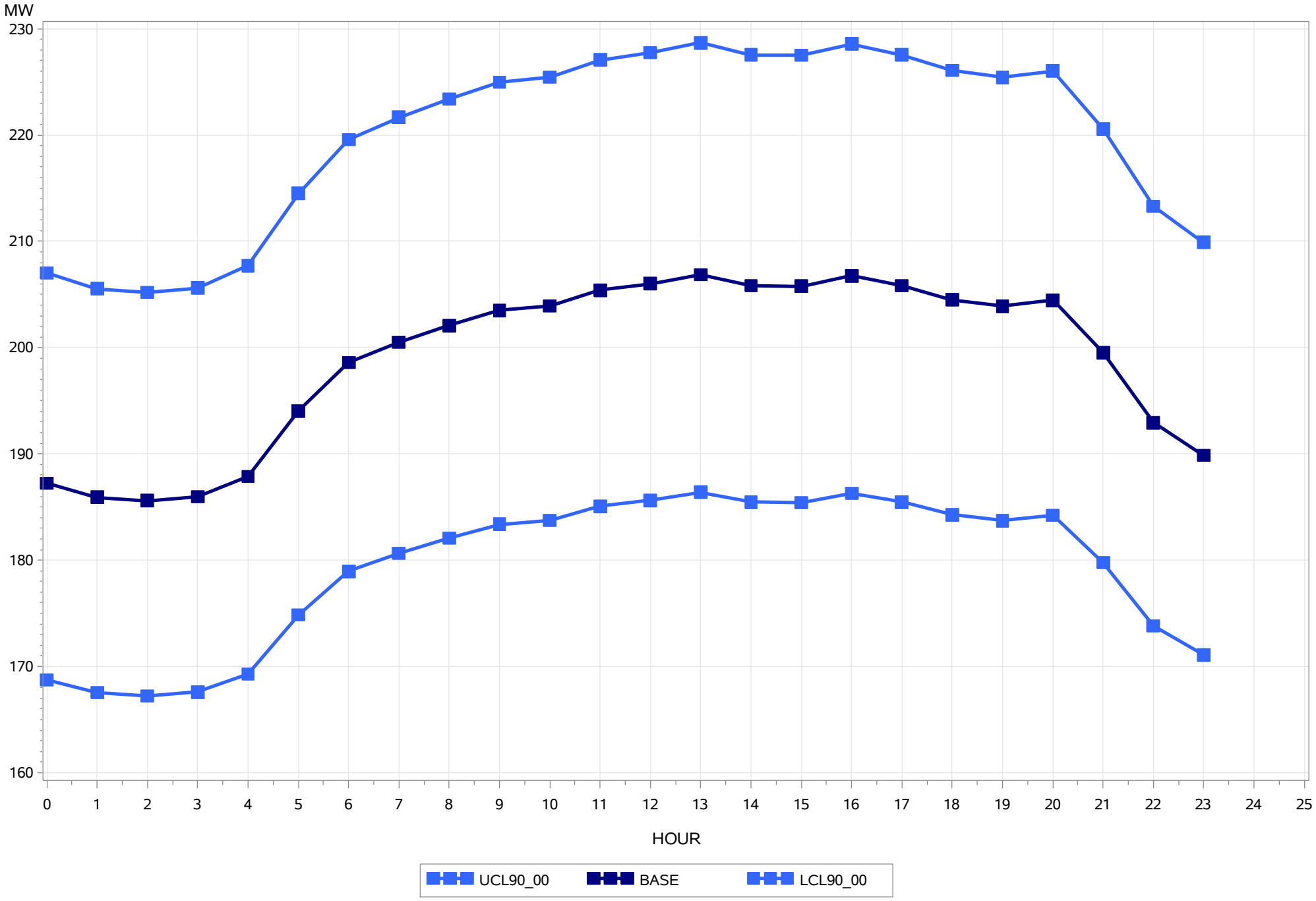
Hourly Average Day for May 2021
STATE OF WYOMING



Hourly Average Day for June 2021
STATE OF WYOMING



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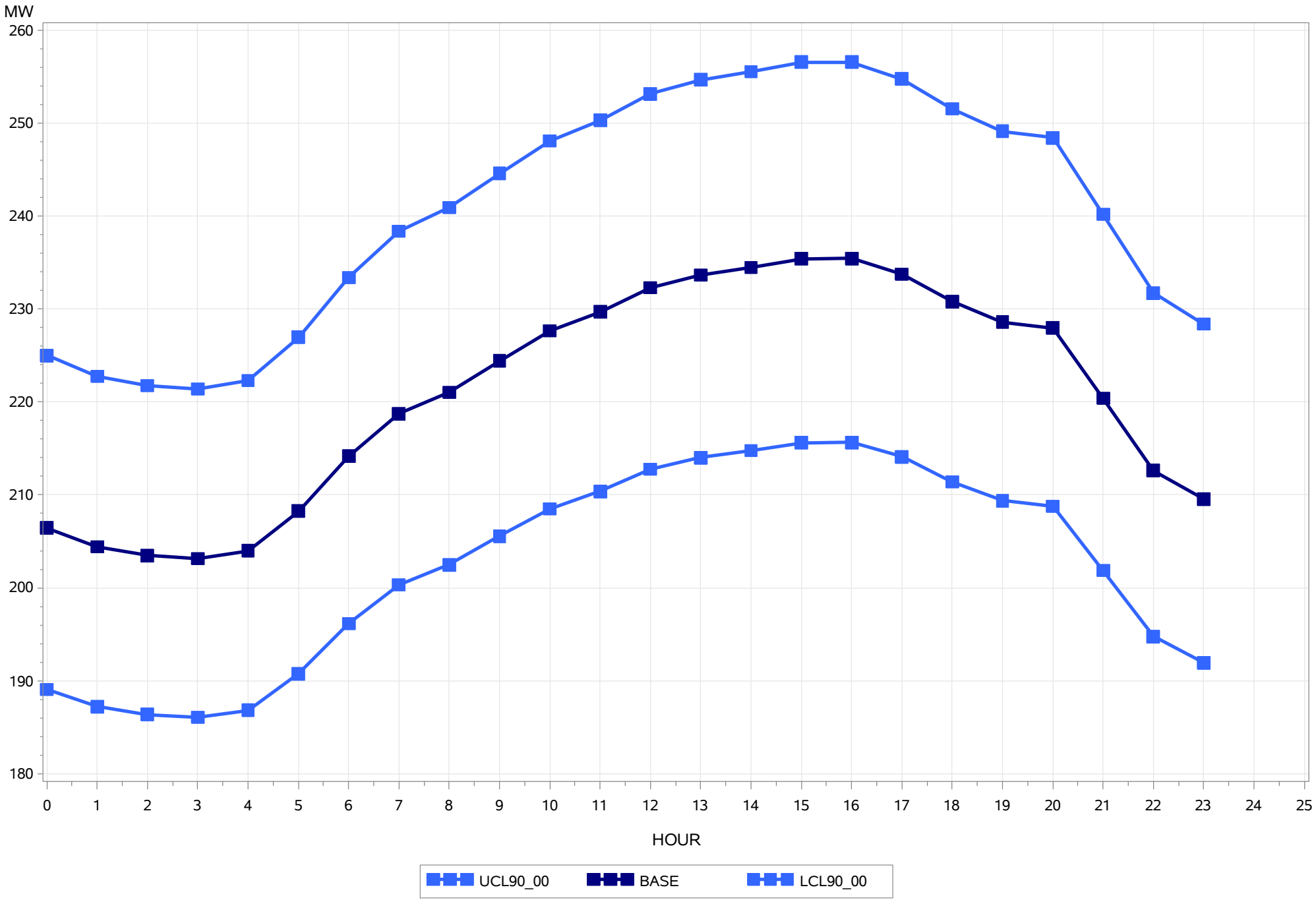
Hourly Average Day for July 2021
STATE OF WYOMING



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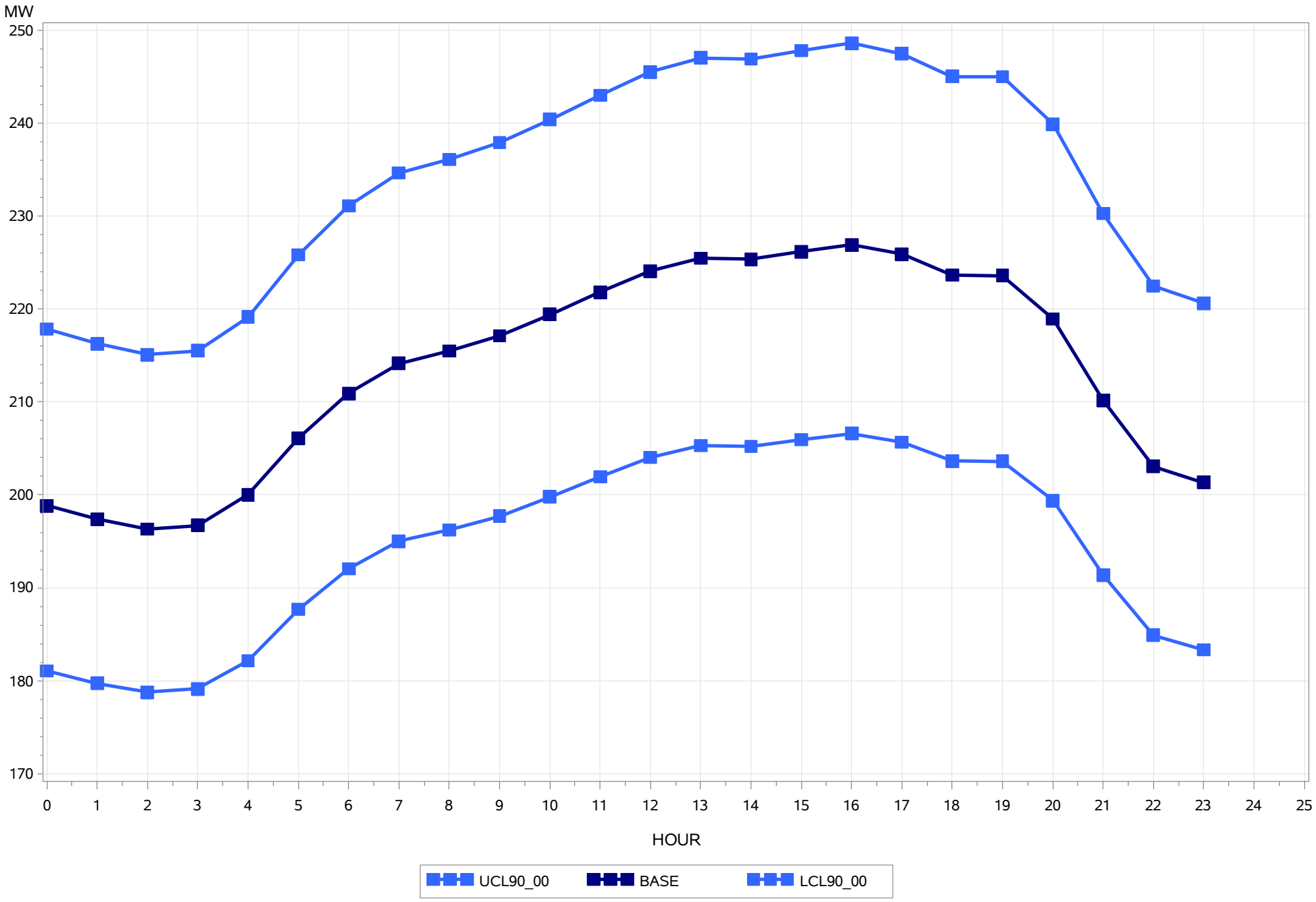
Hourly Average Day for August 2021
STATE OF WYOMING



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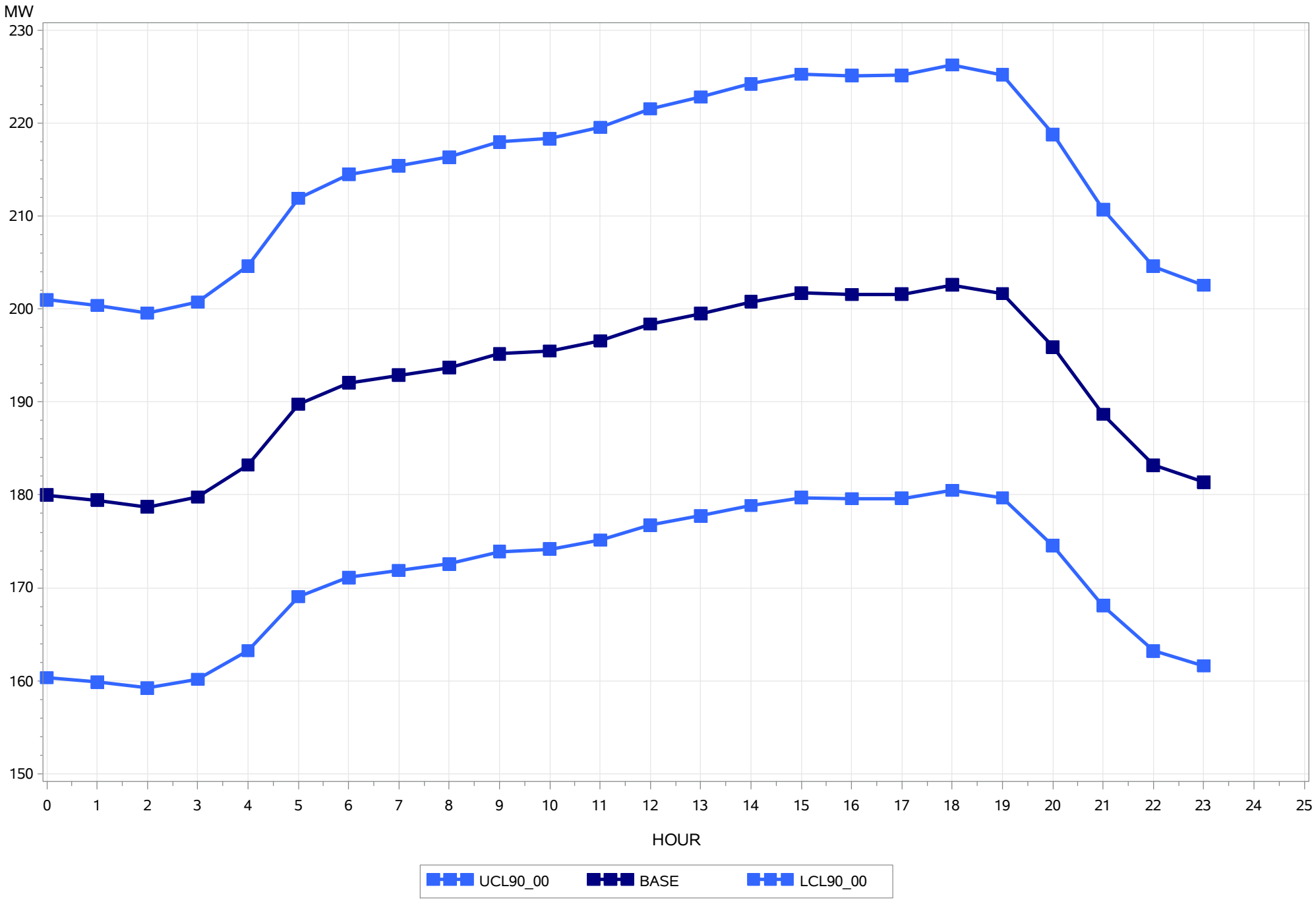
Hourly Average Day for September 2021
STATE OF WYOMING



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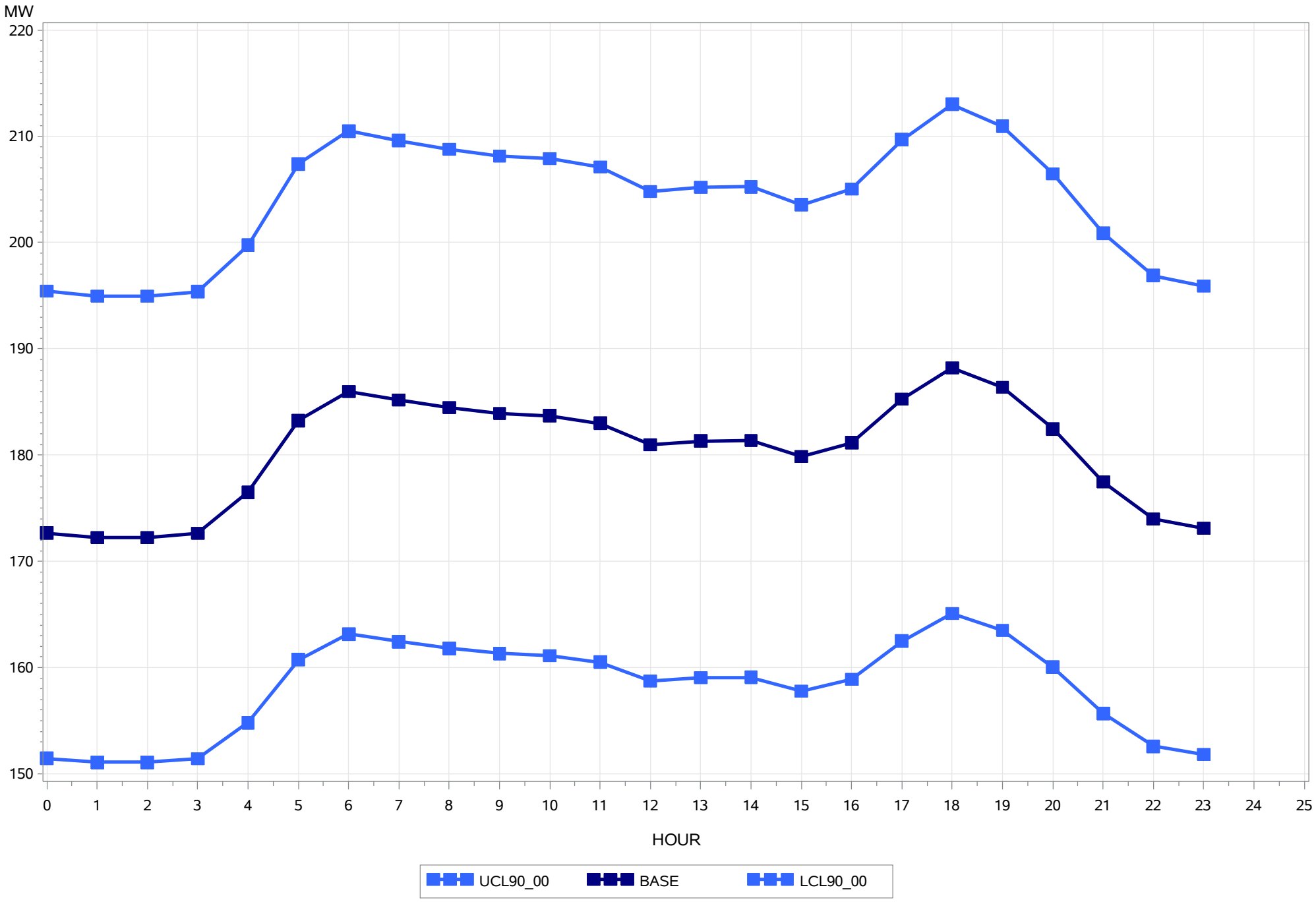
Hourly Average Day for October 2021
STATE OF WYOMING



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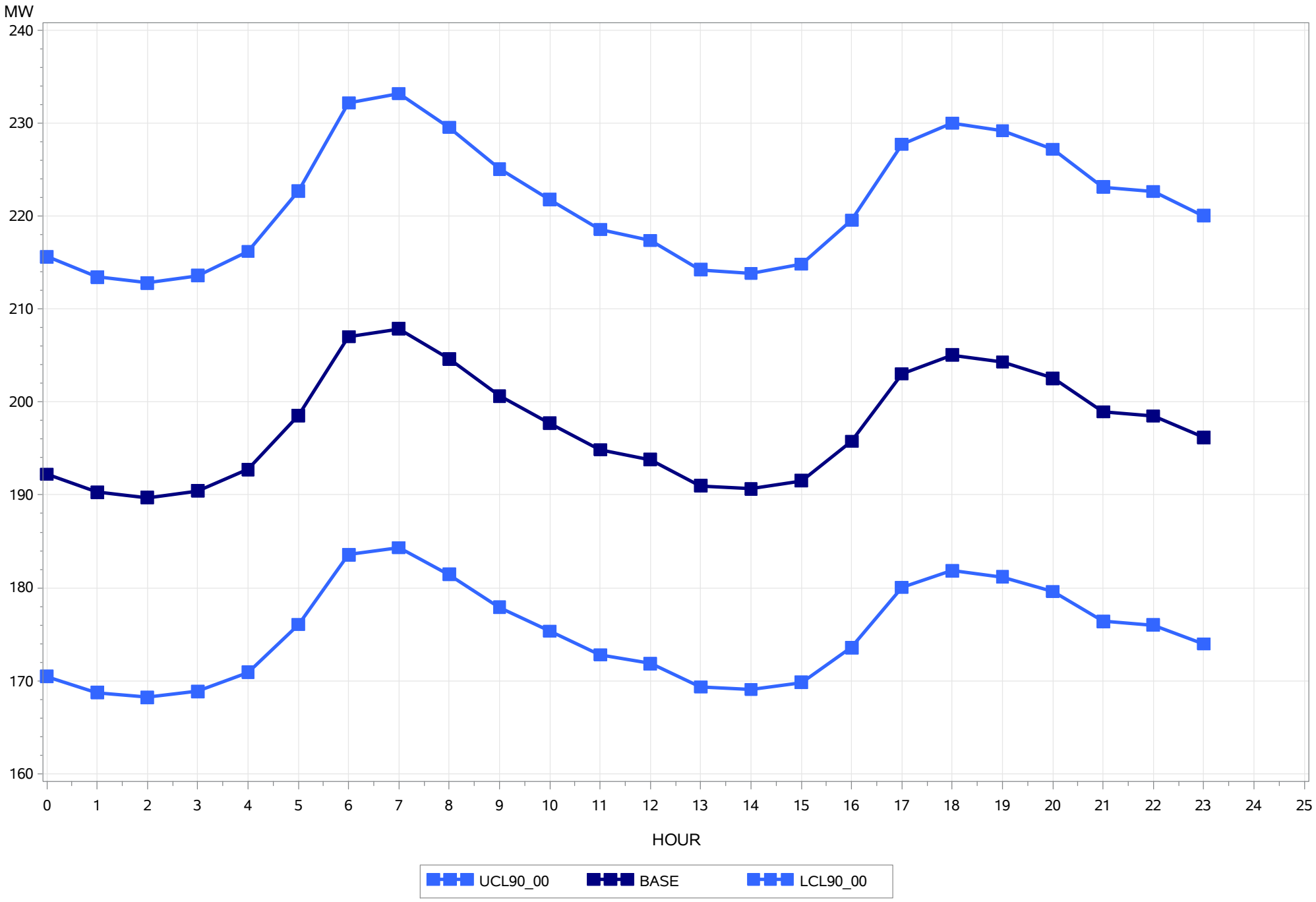
Hourly Average Day for November 2021
STATE OF WYOMING



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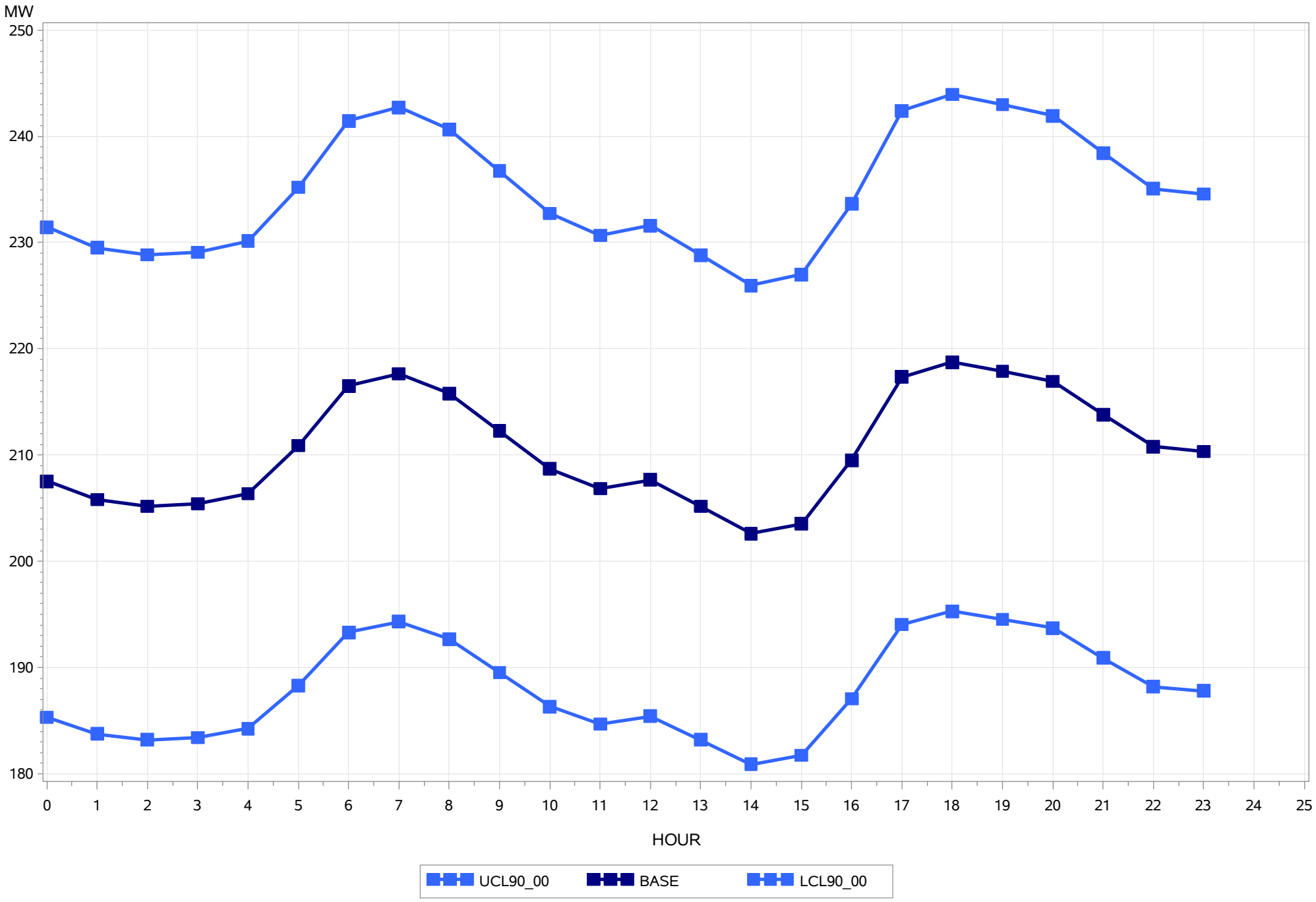
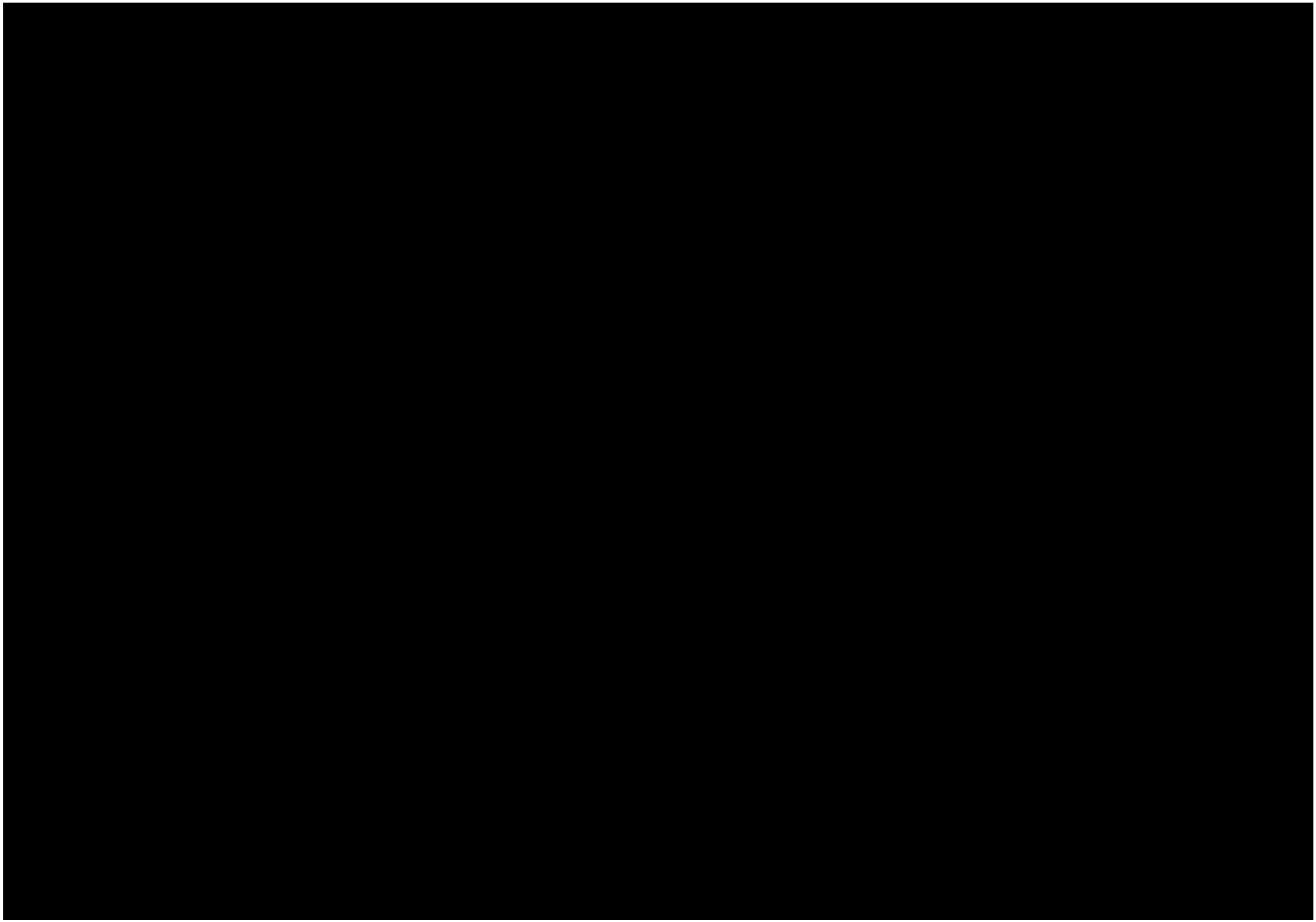
Hourly Average Day for December 2021
STATE OF WYOMING



Hourly Average Day for January 2021
Big Horn Rural Electric Company

[redacted]

Hourly Average Day for February 2021
Big Horn Rural Electric Company



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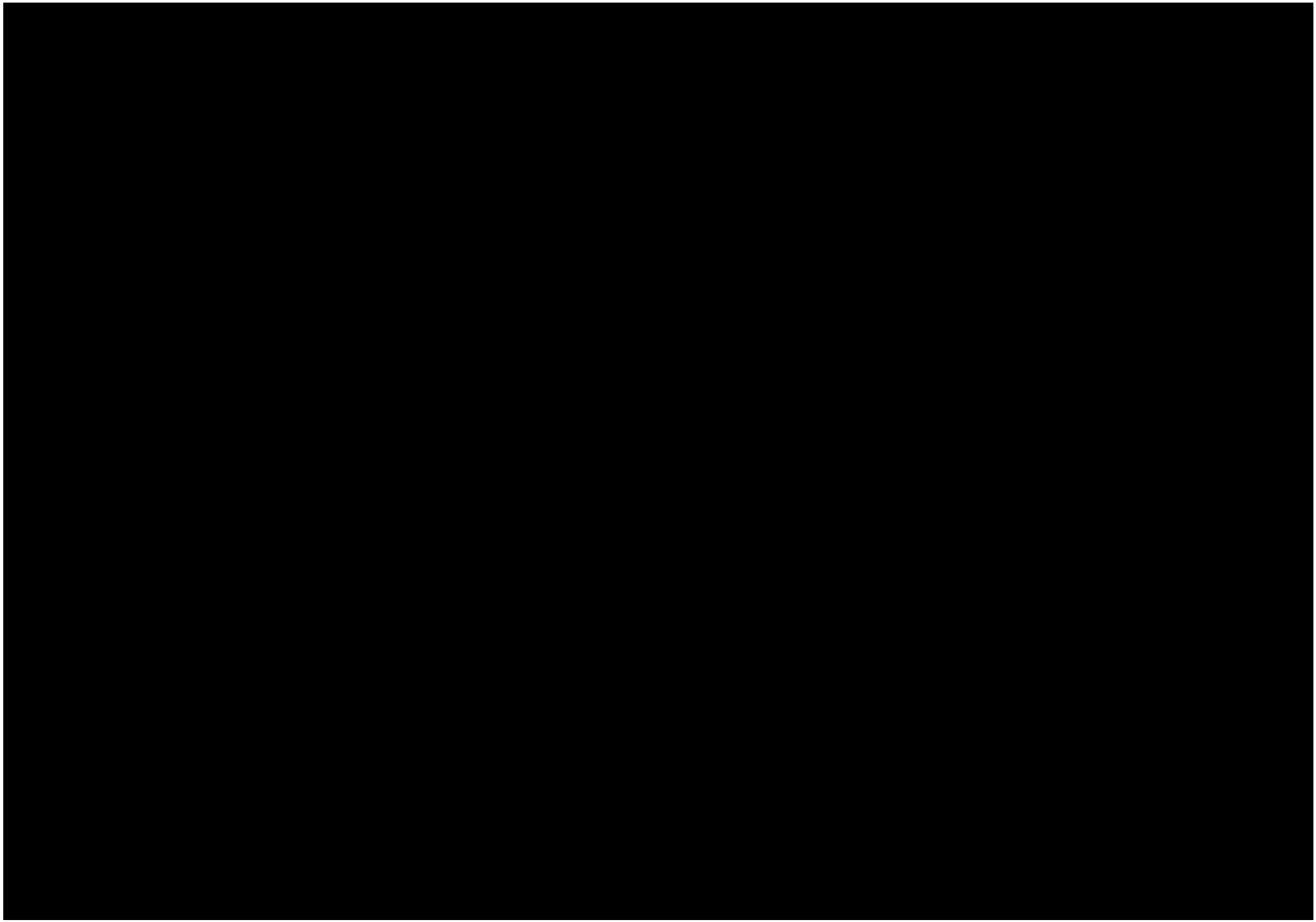
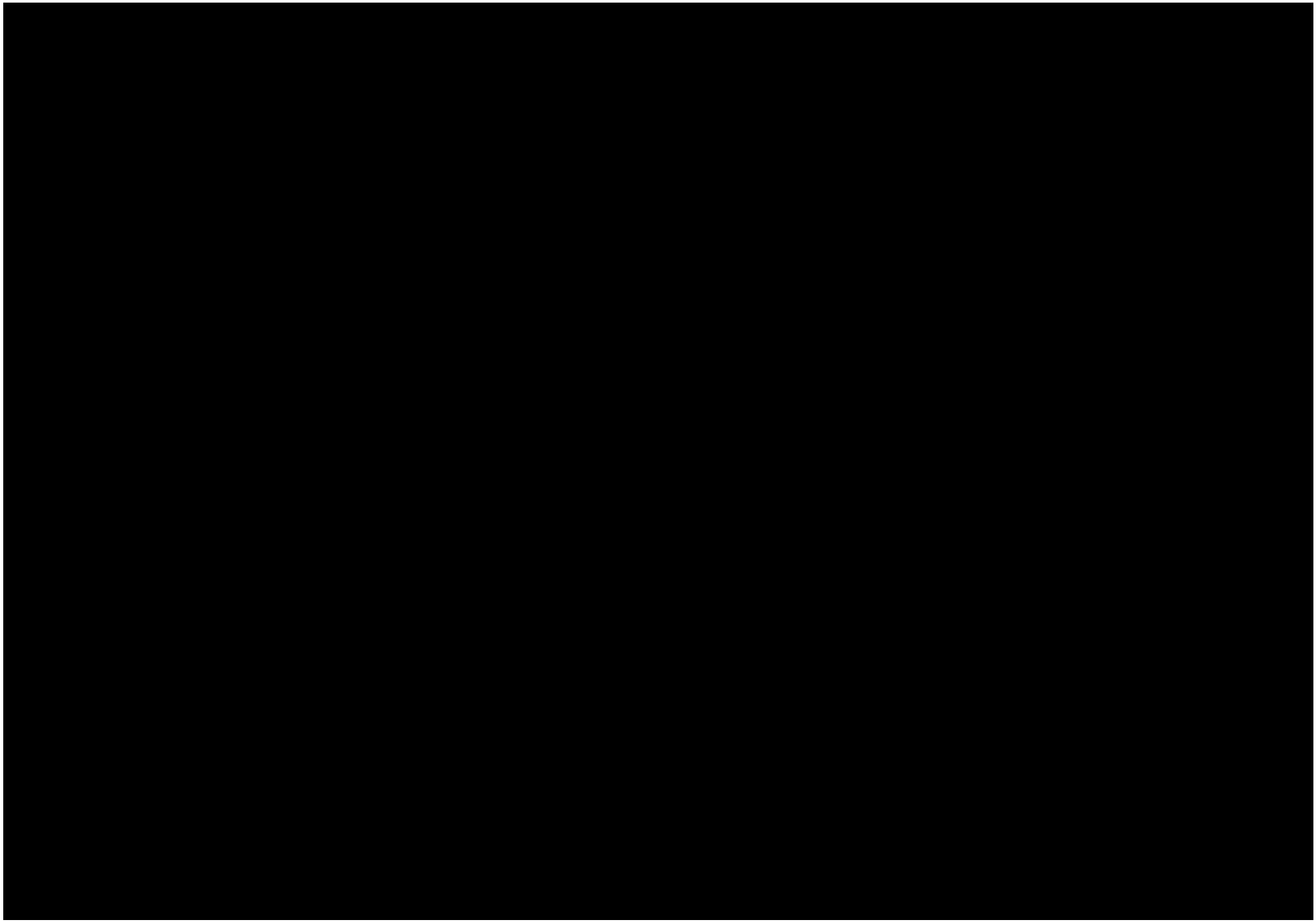
Hourly Average Day for March 2021

Big Horn Rural Electric Company



Hourly Average Day for April 2021

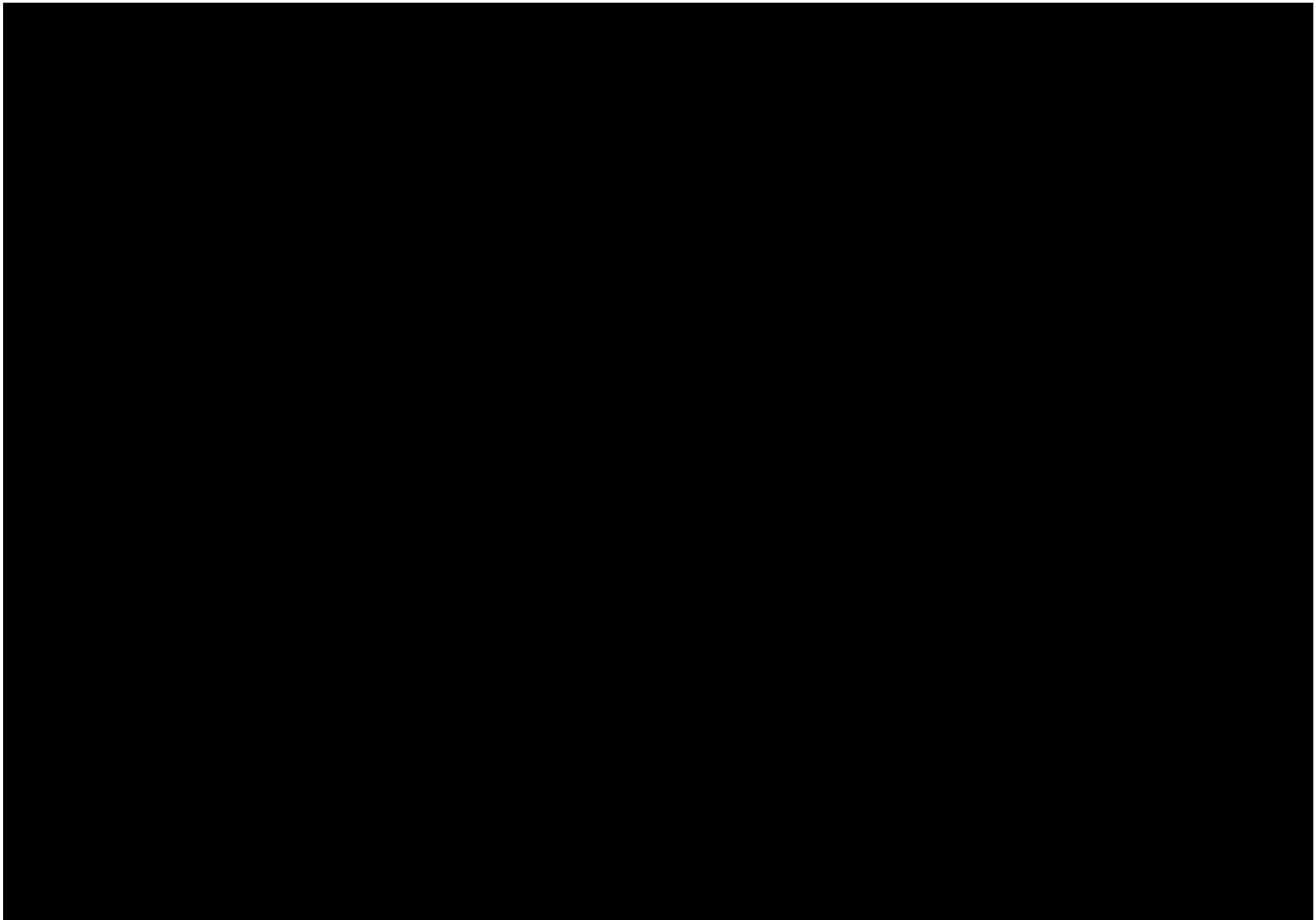
Big Horn Rural Electric Company



Hourly Average Day for May 2021
Big Horn Rural Electric Company

[redacted]

Hourly Average Day for June 2021
Big Horn Rural Electric Company



Hourly Average Day for July 2021

Big Horn Rural Electric Company

[redacted]

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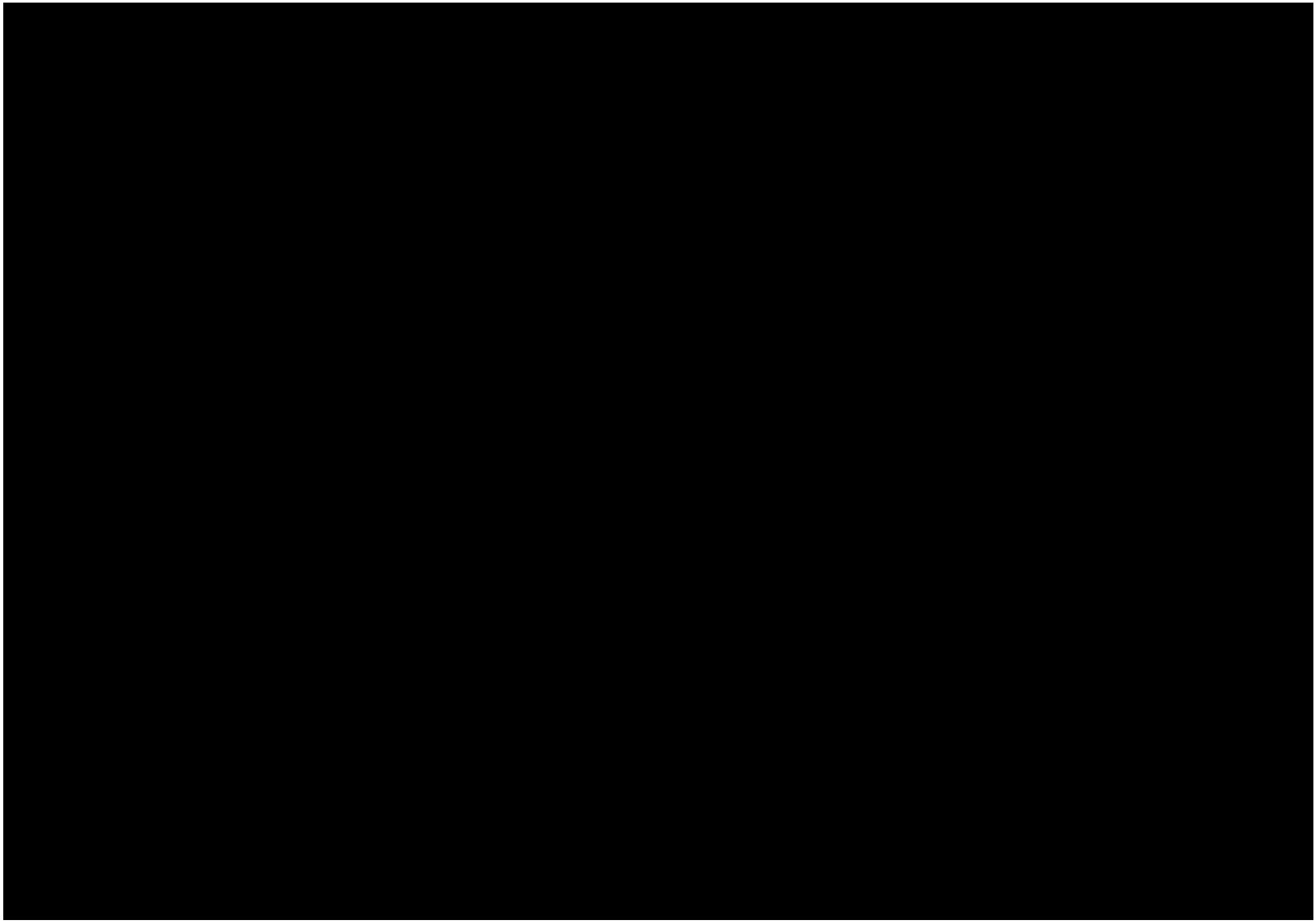
Hourly Average Day for August 2021

Big Horn Rural Electric Company



Hourly Average Day for September 2021

Big Horn Rural Electric Company

[redacted]

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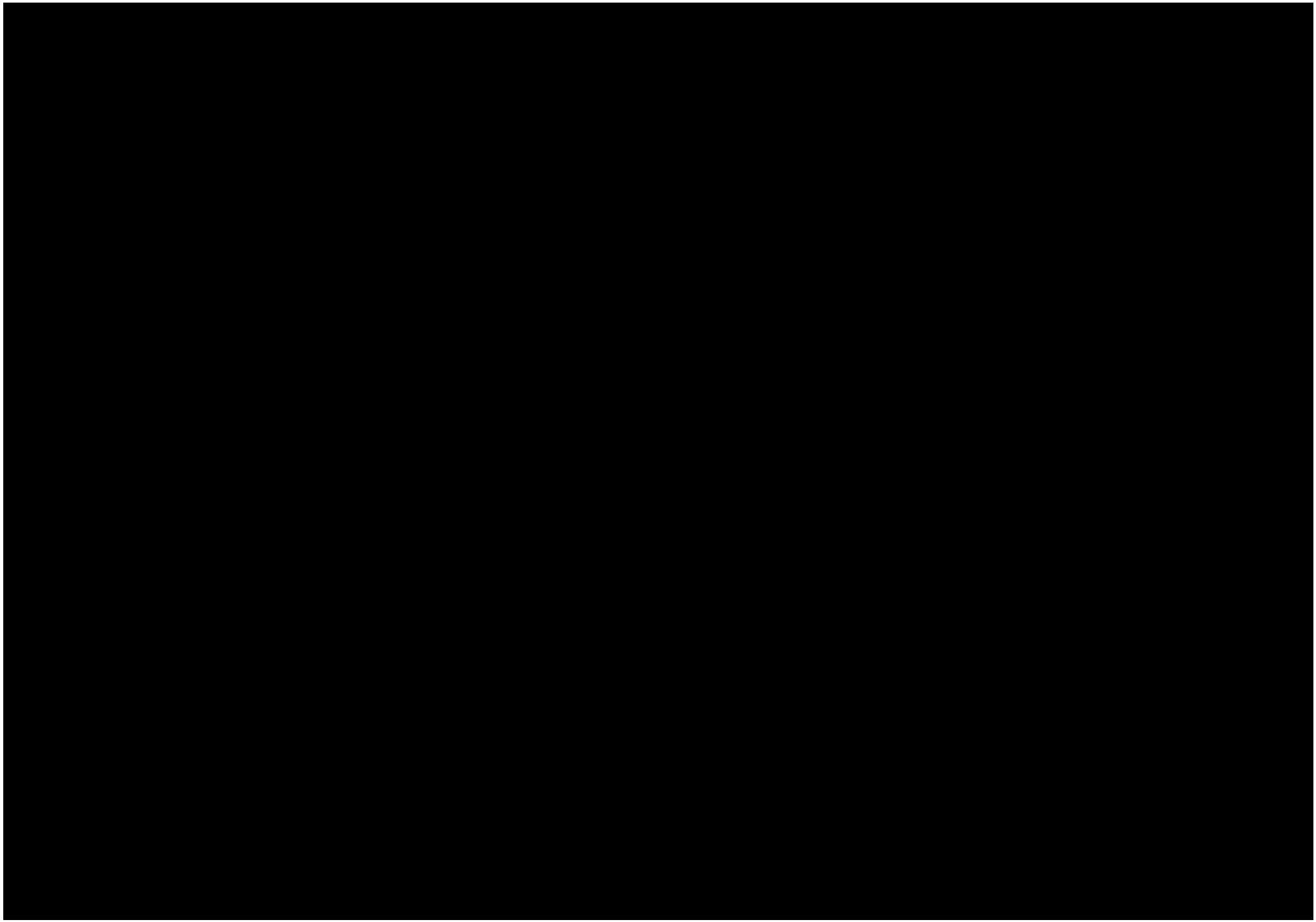
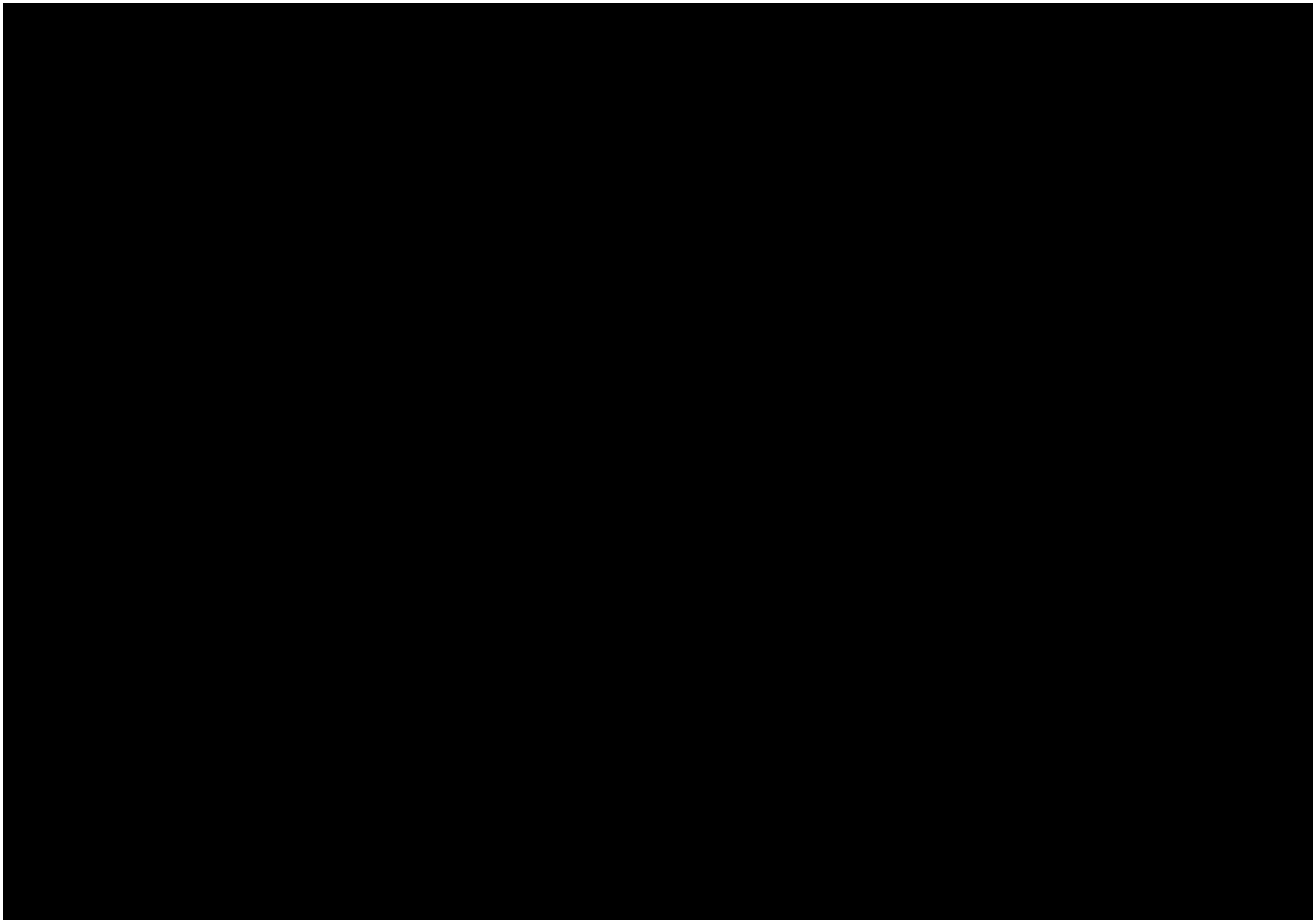
Hourly Average Day for October 2021

Big Horn Rural Electric Company



Hourly Average Day for November 2021
Big Horn Rural Electric Company



Hourly Average Day for December 2021
Big Horn Rural Electric Company

[redacted]

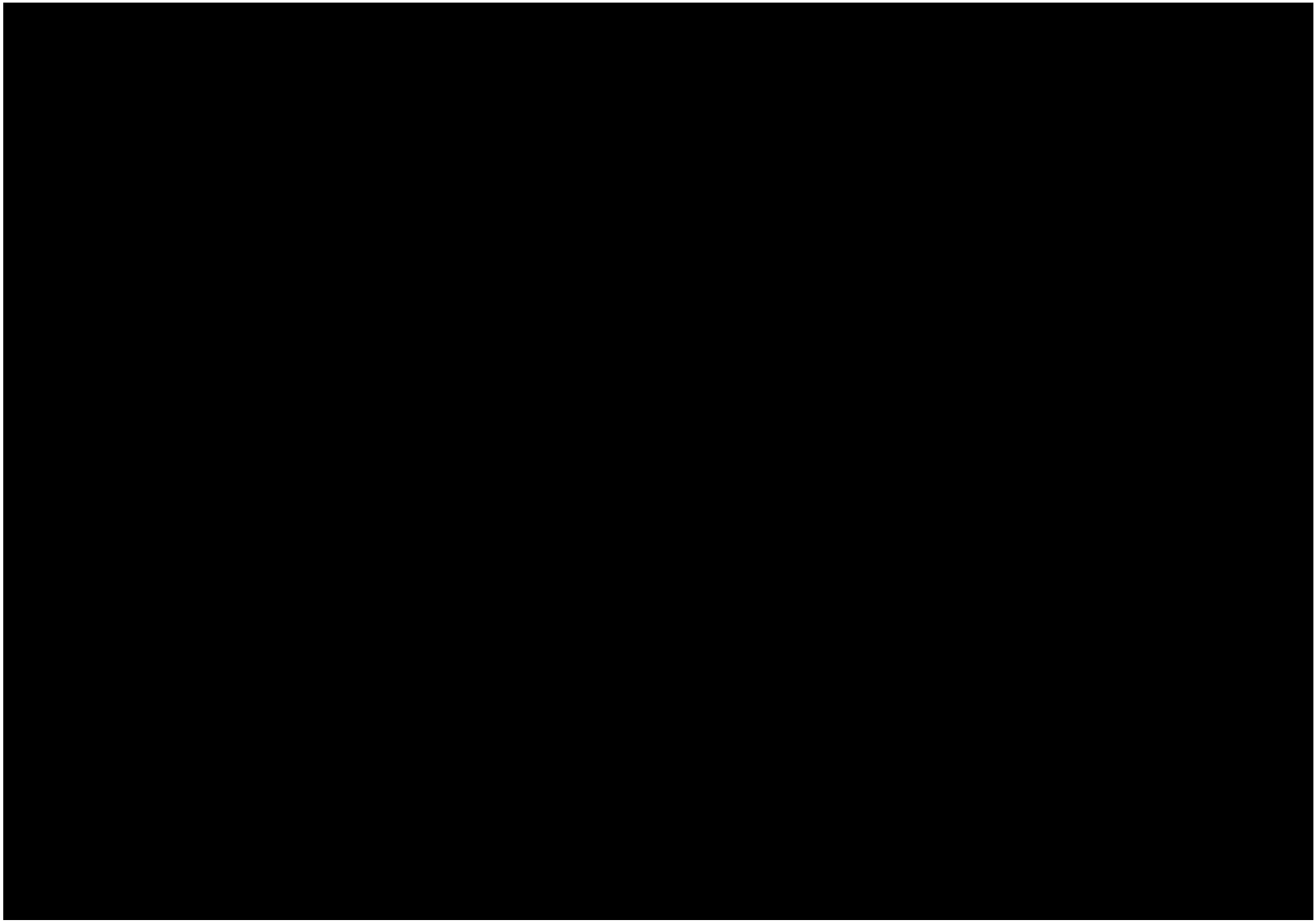
Hourly Average Day for January 2021

Carbon Power and Light, Inc.

[redacted]

Hourly Average Day for February 2021

Carbon Power and Light, Inc.



Hourly Average Day for March 2021
Carbon Power and Light, Inc.

[redacted]

Hourly Average Day for April 2021
Carbon Power and Light, Inc.

[redacted]

Hourly Average Day for May 2021

Carbon Power and Light, Inc.

[redacted]

Hourly Average Day for June 2021

Carbon Power and Light, Inc.

[redacted]

Hourly Average Day for July 2021

Carbon Power and Light, Inc.

[redacted]

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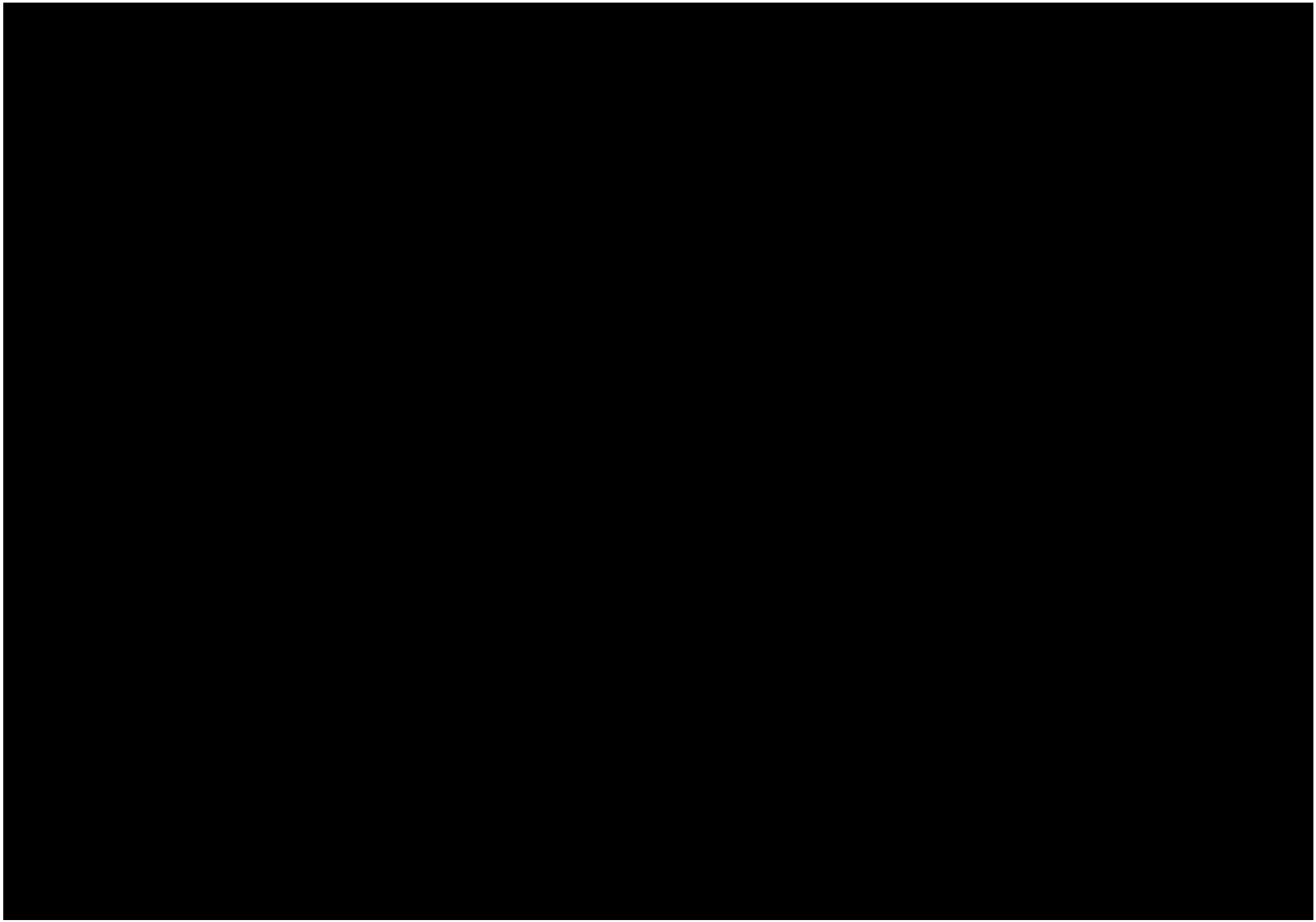
Hourly Average Day for August 2021

Carbon Power and Light, Inc.



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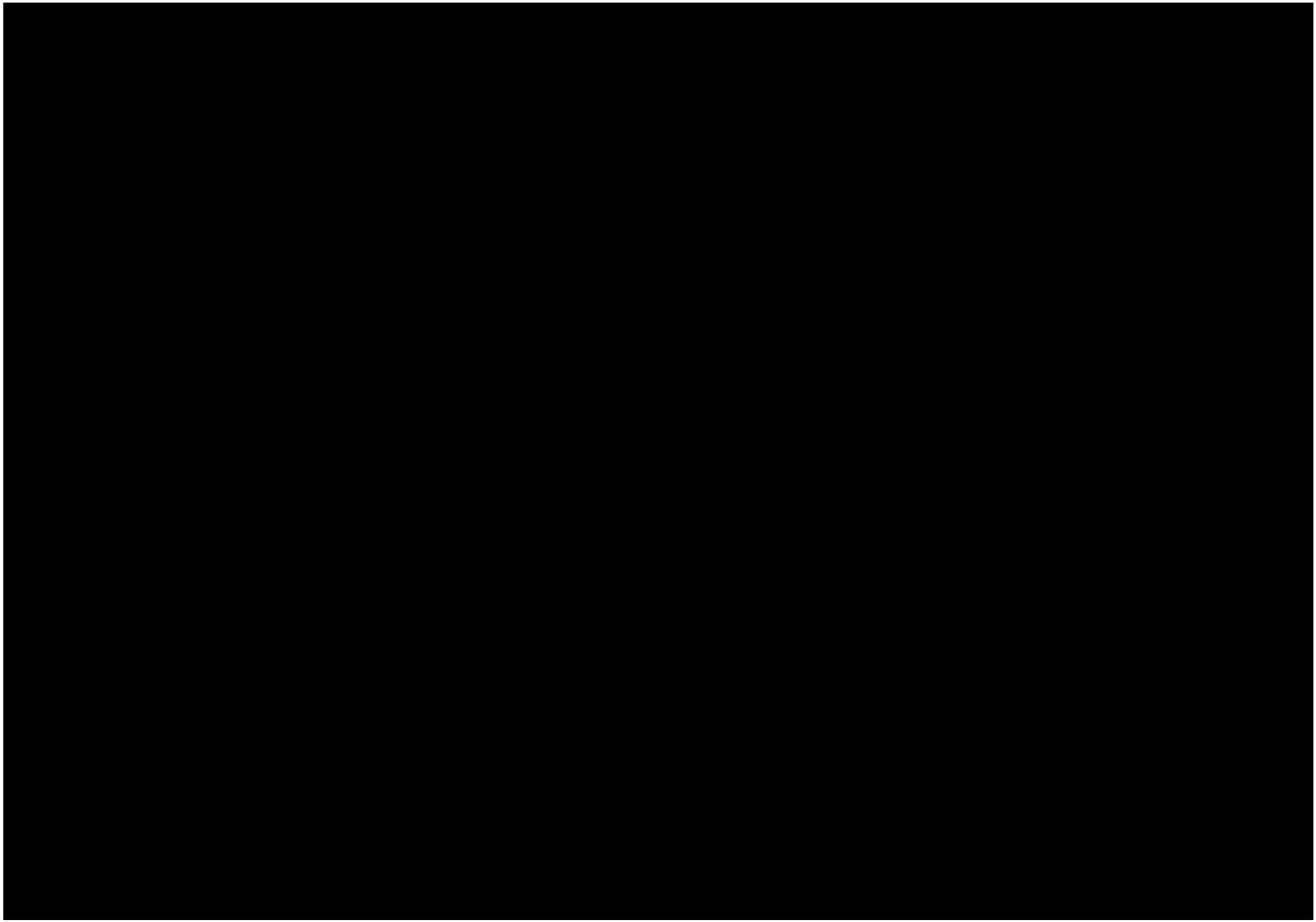
Hourly Average Day for September 2021

Carbon Power and Light, Inc.



Hourly Average Day for October 2021

Carbon Power and Light, Inc.

[redacted]

Hourly Average Day for November 2021

Carbon Power and Light, Inc.

[redacted]

Hourly Average Day for December 2021

Carbon Power and Light, Inc.

[redacted]

Hourly Average Day for January 2021

Continental Divide Electric Cooperative, Inc.

[redacted]

Hourly Average Day for February 2021

Continental Divide Electric Cooperative, Inc.

[redacted]

Hourly Average Day for March 2021
Continental Divide Electric Cooperative, Inc.

[redacted]

Hourly Average Day for April 2021

Continental Divide Electric Cooperative, Inc.

[redacted]

Hourly Average Day for May 2021

Continental Divide Electric Cooperative, Inc.

[redacted]

Hourly Average Day for June 2021

Continental Divide Electric Cooperative, Inc.

[redacted]

Hourly Average Day for July 2021

Continental Divide Electric Cooperative, Inc.

[redacted]

Hourly Average Day for August 2021

Continental Divide Electric Cooperative, Inc.

[redacted]

Hourly Average Day for September 2021

Continental Divide Electric Cooperative, Inc.

[redacted]

Hourly Average Day for October 2021

Continental Divide Electric Cooperative, Inc.

[redacted]

Hourly Average Day for November 2021

Continental Divide Electric Cooperative, Inc.

[redacted]

Hourly Average Day for December 2021

Continental Divide Electric Cooperative, Inc.

[redacted]

Hourly Average Day for January 2021
Columbus Electric Cooperative, Inc.

[redacted]

Hourly Average Day for February 2021
Columbus Electric Cooperative, Inc.

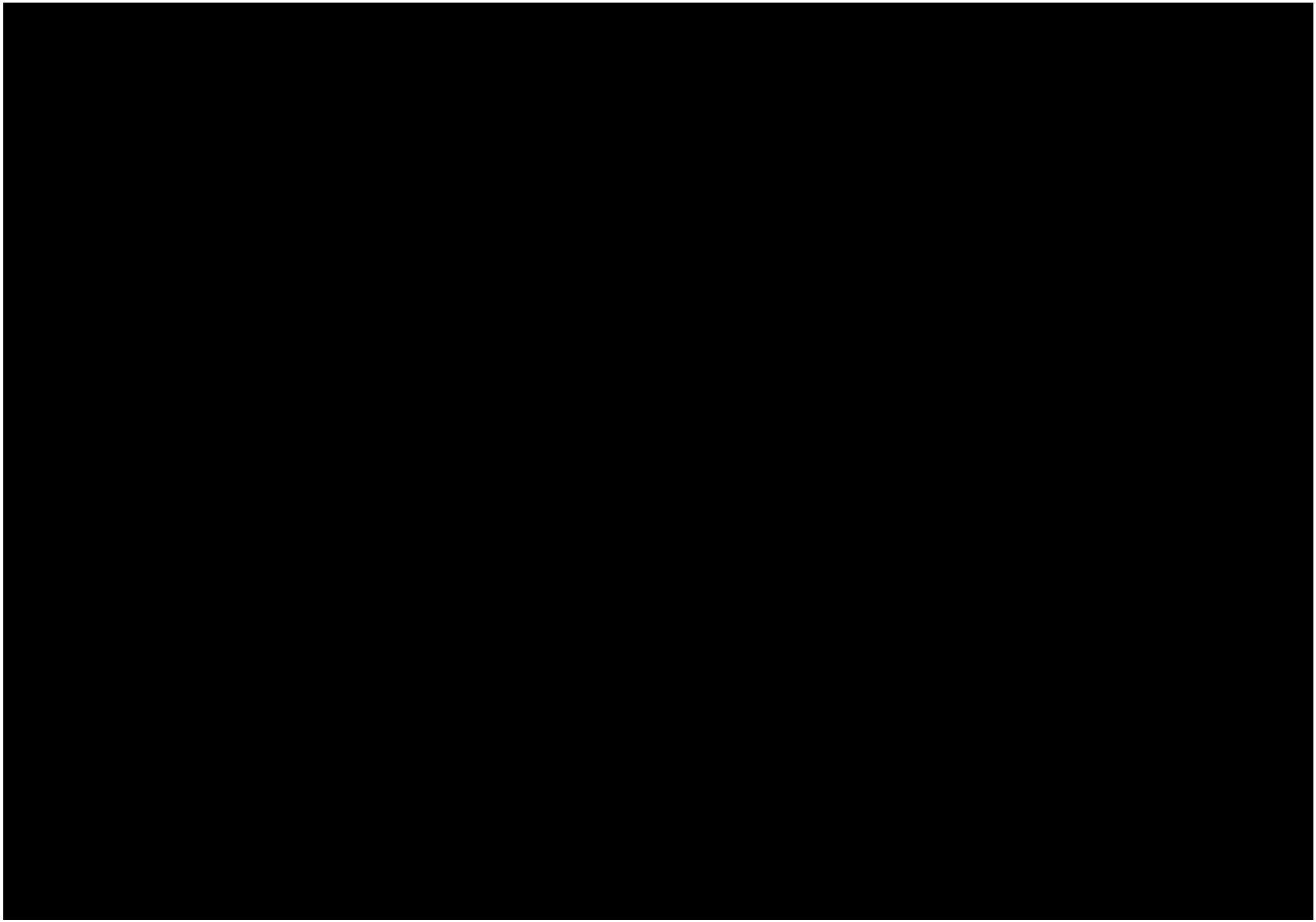
[redacted]

Hourly Average Day for March 2021
Columbus Electric Cooperative, Inc.

[redacted]

Hourly Average Day for April 2021

Columbus Electric Cooperative, Inc.



Hourly Average Day for May 2021
Columbus Electric Cooperative, Inc.

[redacted]

Hourly Average Day for June 2021
Columbus Electric Cooperative, Inc.

[redacted]

Hourly Average Day for July 2021
Columbus Electric Cooperative, Inc.

[redacted]

Hourly Average Day for August 2021
Columbus Electric Cooperative, Inc.

[redacted]

Hourly Average Day for September 2021
Columbus Electric Cooperative, Inc.

[redacted]

Hourly Average Day for October 2021
Columbus Electric Cooperative, Inc.

[redacted]

Hourly Average Day for November 2021
Columbus Electric Cooperative, Inc.

[redacted]

Hourly Average Day for December 2021
Columbus Electric Cooperative, Inc.

[redacted]

Hourly Average Day for January 2021
Central New Mexico Electric Cooperative, Inc.

[redacted]

Hourly Average Day for February 2021

Central New Mexico Electric Cooperative, Inc.

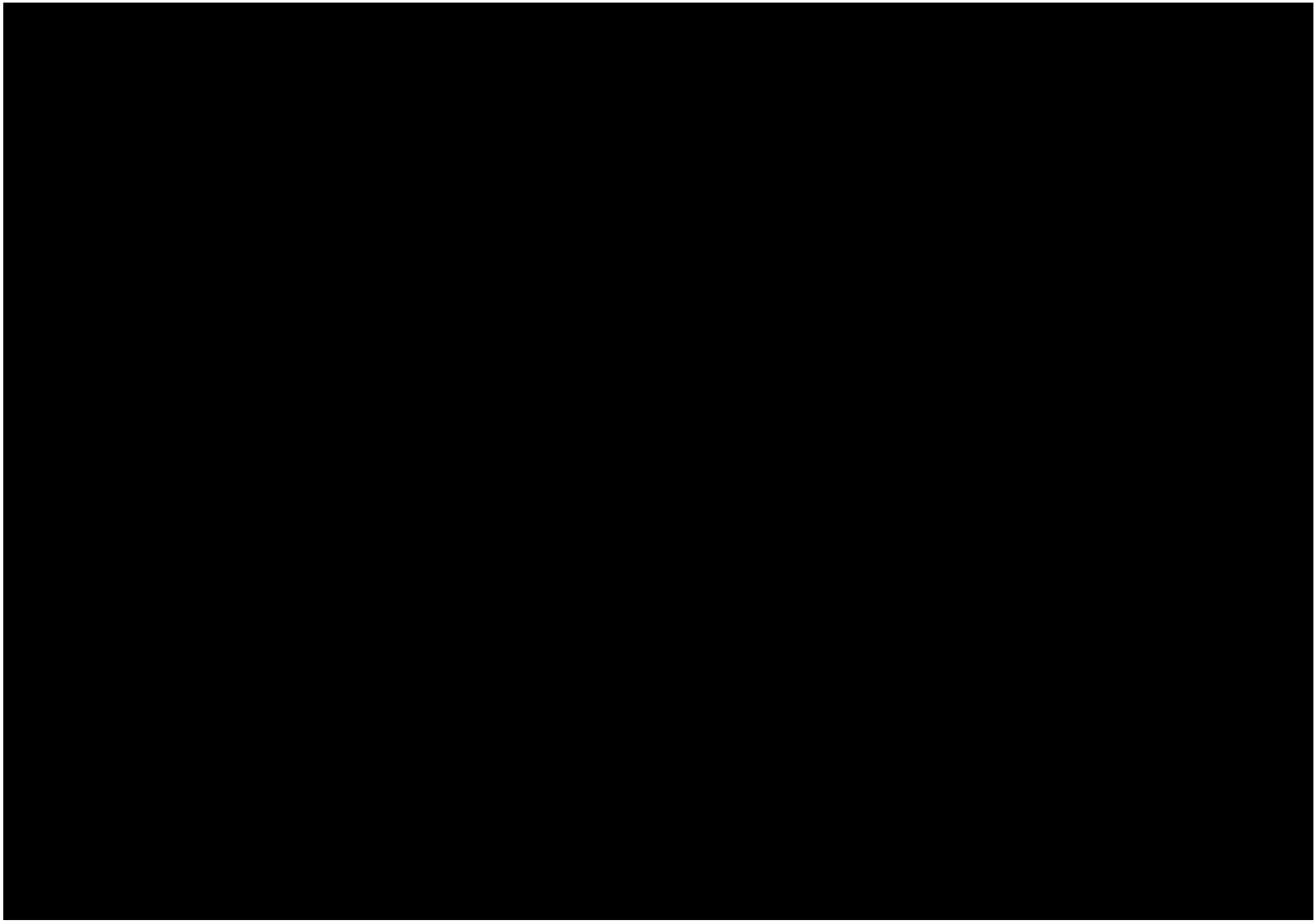
[redacted]

Hourly Average Day for March 2021
Central New Mexico Electric Cooperative, Inc.

[redacted]

Hourly Average Day for April 2021

Central New Mexico Electric Cooperative, Inc.



Hourly Average Day for May 2021

Central New Mexico Electric Cooperative, Inc.

[redacted]

Hourly Average Day for June 2021

Central New Mexico Electric Cooperative, Inc.

[redacted]

Hourly Average Day for July 2021

Central New Mexico Electric Cooperative, Inc.

[redacted]

Hourly Average Day for August 2021
Central New Mexico Electric Cooperative, Inc.

[redacted]

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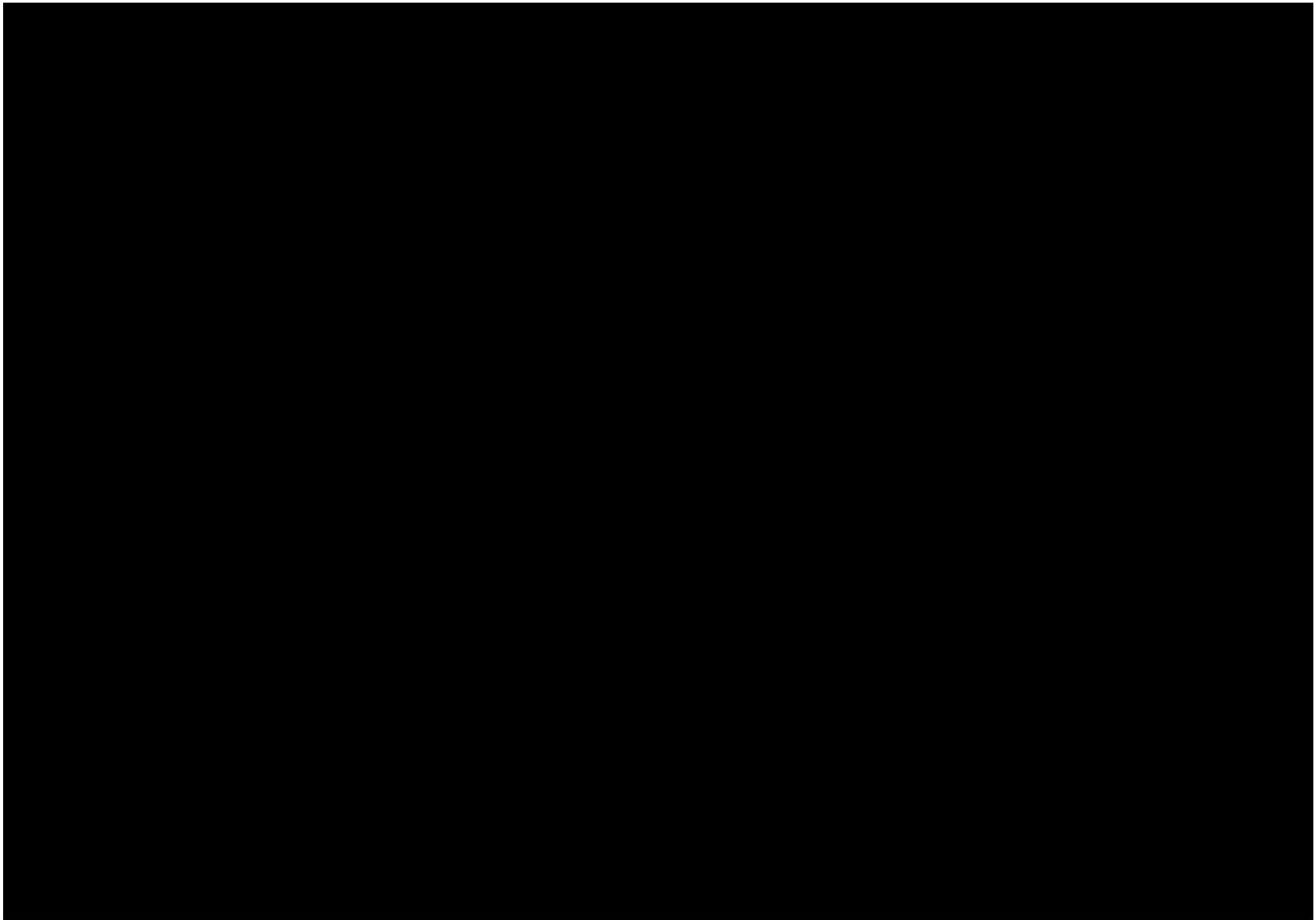
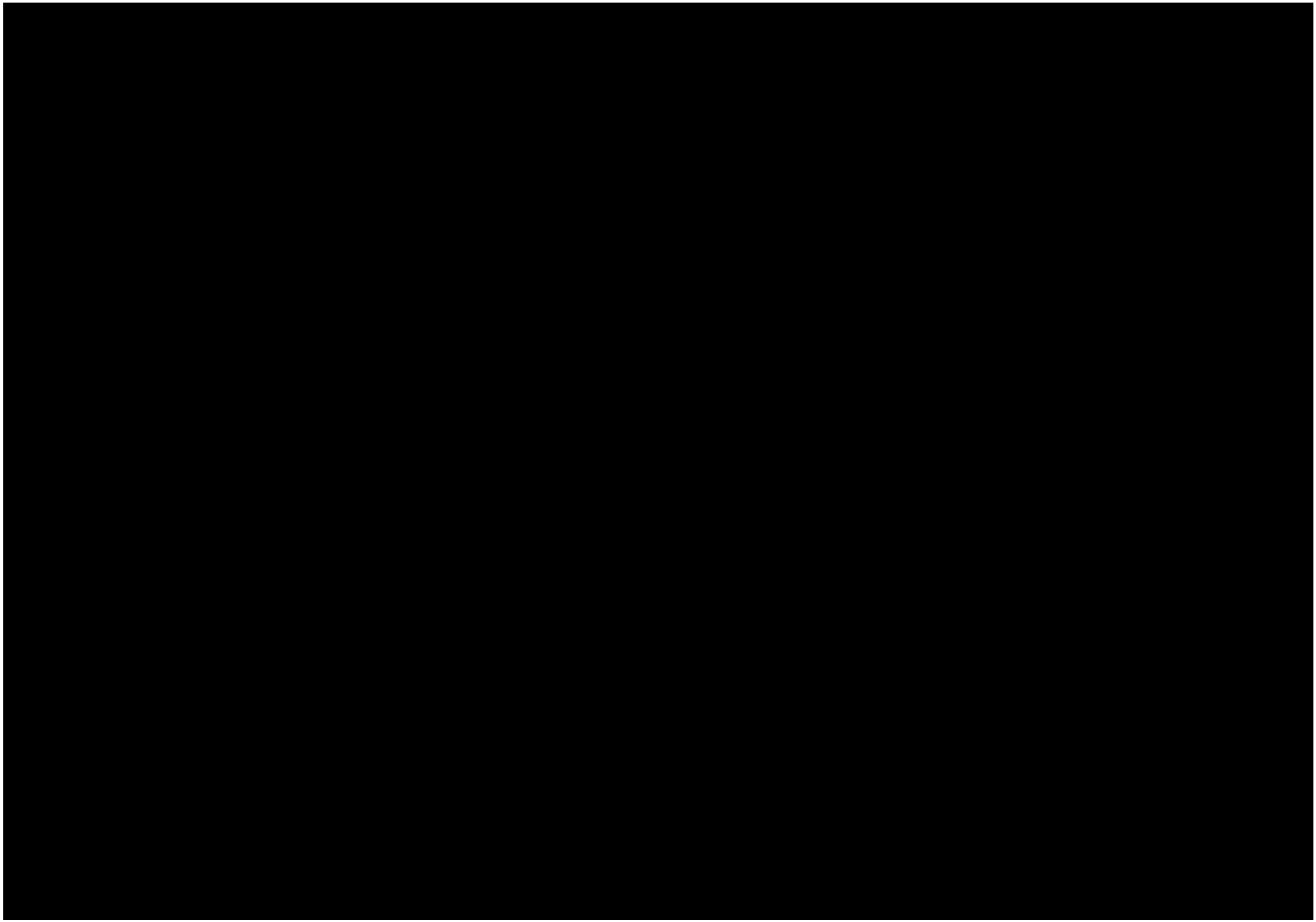
Hourly Average Day for September 2021

Central New Mexico Electric Cooperative, Inc.



Hourly Average Day for October 2021

Central New Mexico Electric Cooperative, Inc.



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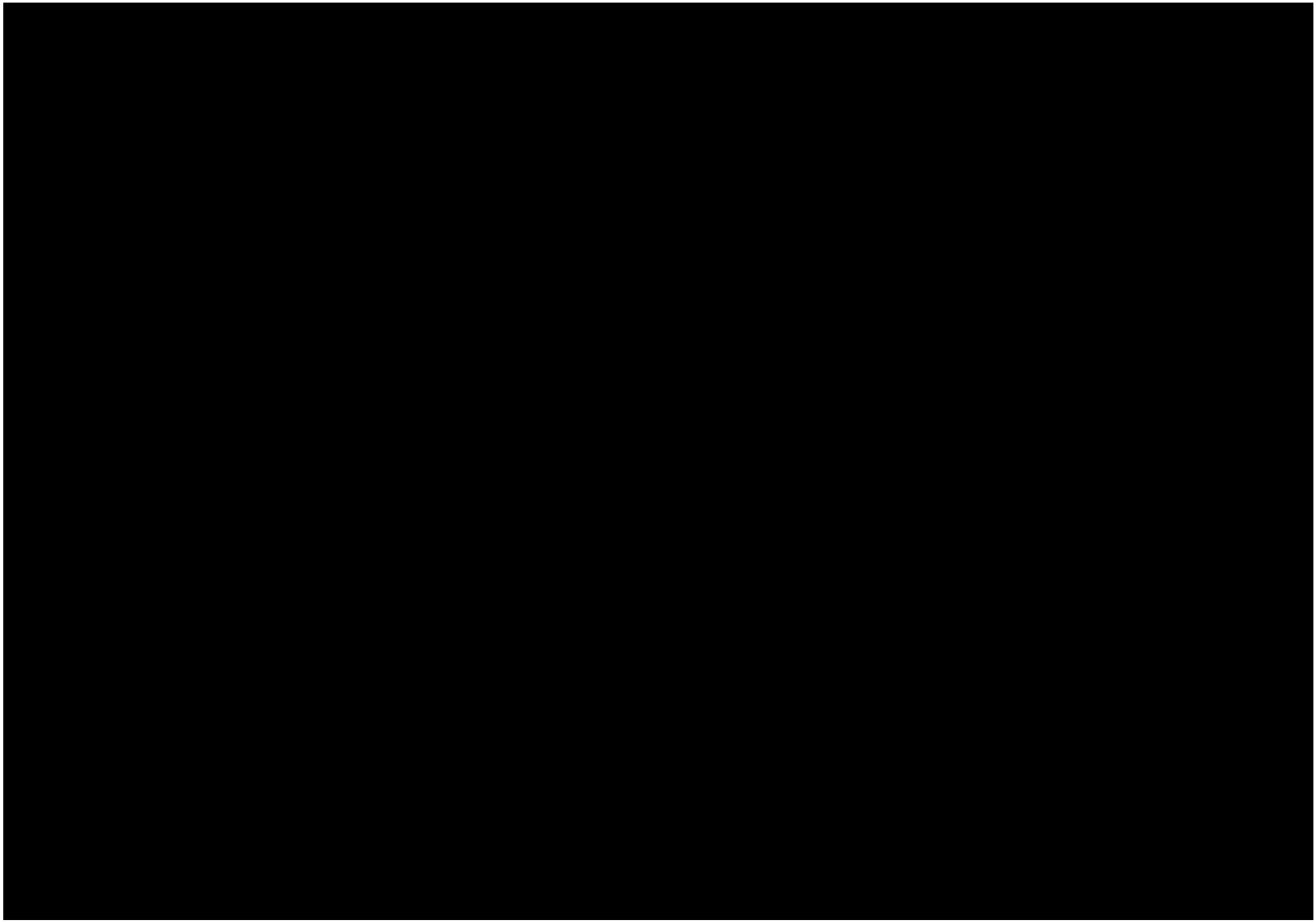
Hourly Average Day for November 2021

Central New Mexico Electric Cooperative, Inc.



Hourly Average Day for December 2021

Central New Mexico Electric Cooperative, Inc.

[redacted]

Hourly Average Day for January 2021

Chimney Rock Public Power District

[redacted]

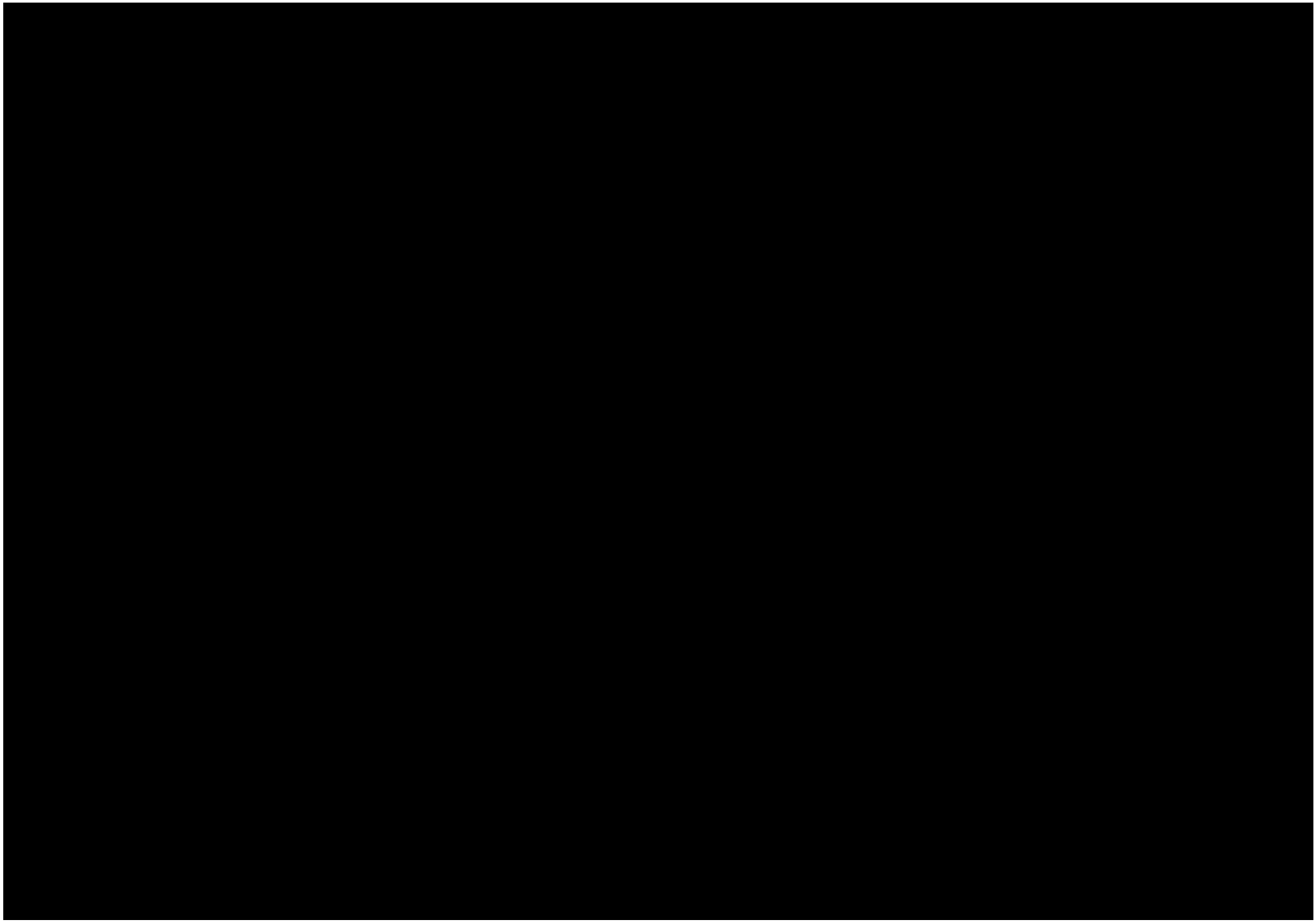
Hourly Average Day for February 2021

Chimney Rock Public Power District

[redacted]

Hourly Average Day for March 2021

Chimney Rock Public Power District



Hourly Average Day for April 2021

Chimney Rock Public Power District

[redacted]

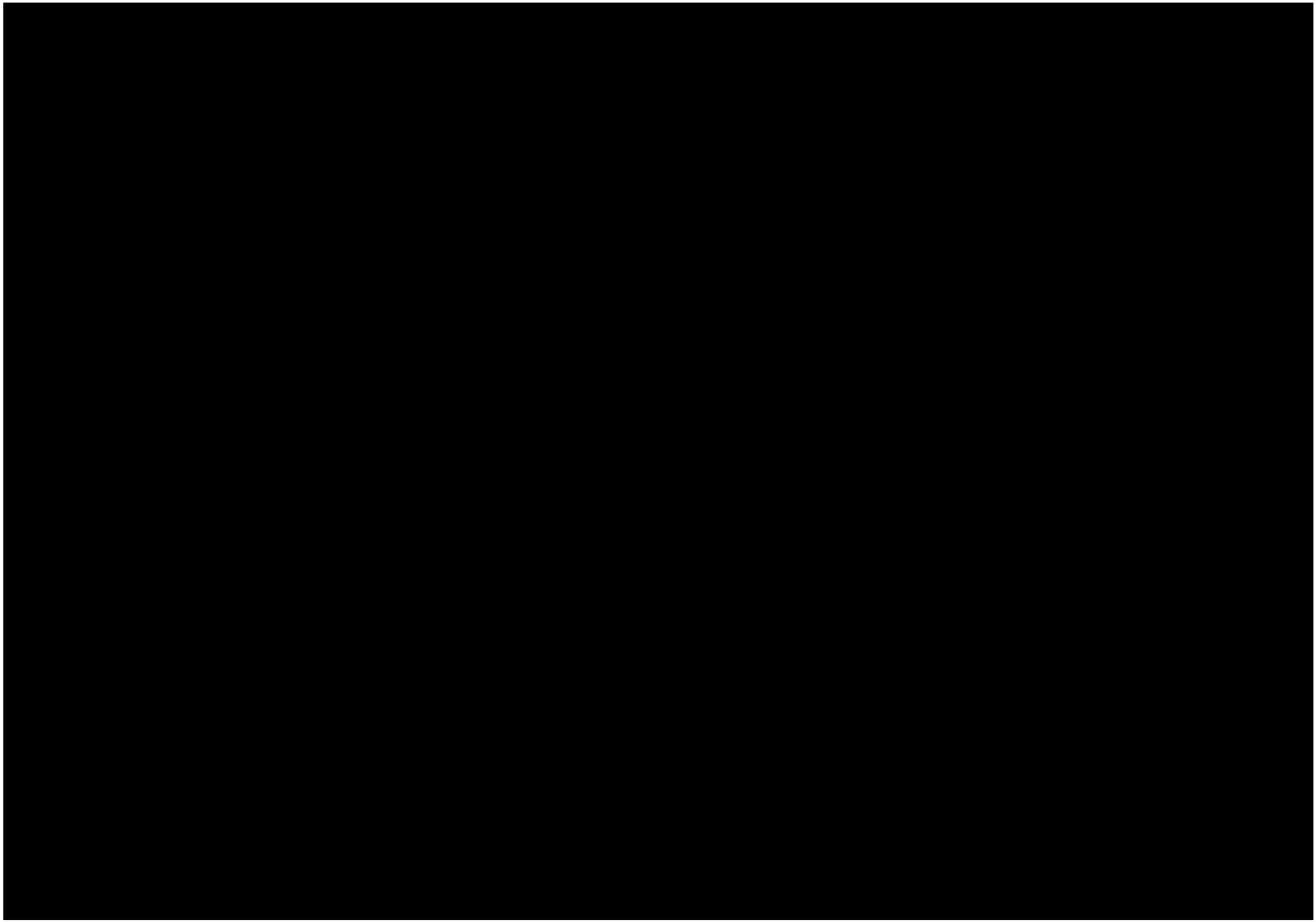
Hourly Average Day for May 2021

Chimney Rock Public Power District

[redacted]

Hourly Average Day for June 2021

Chimney Rock Public Power District



Hourly Average Day for July 2021

Chimney Rock Public Power District

[redacted]

Hourly Average Day for August 2021

Chimney Rock Public Power District

[redacted]

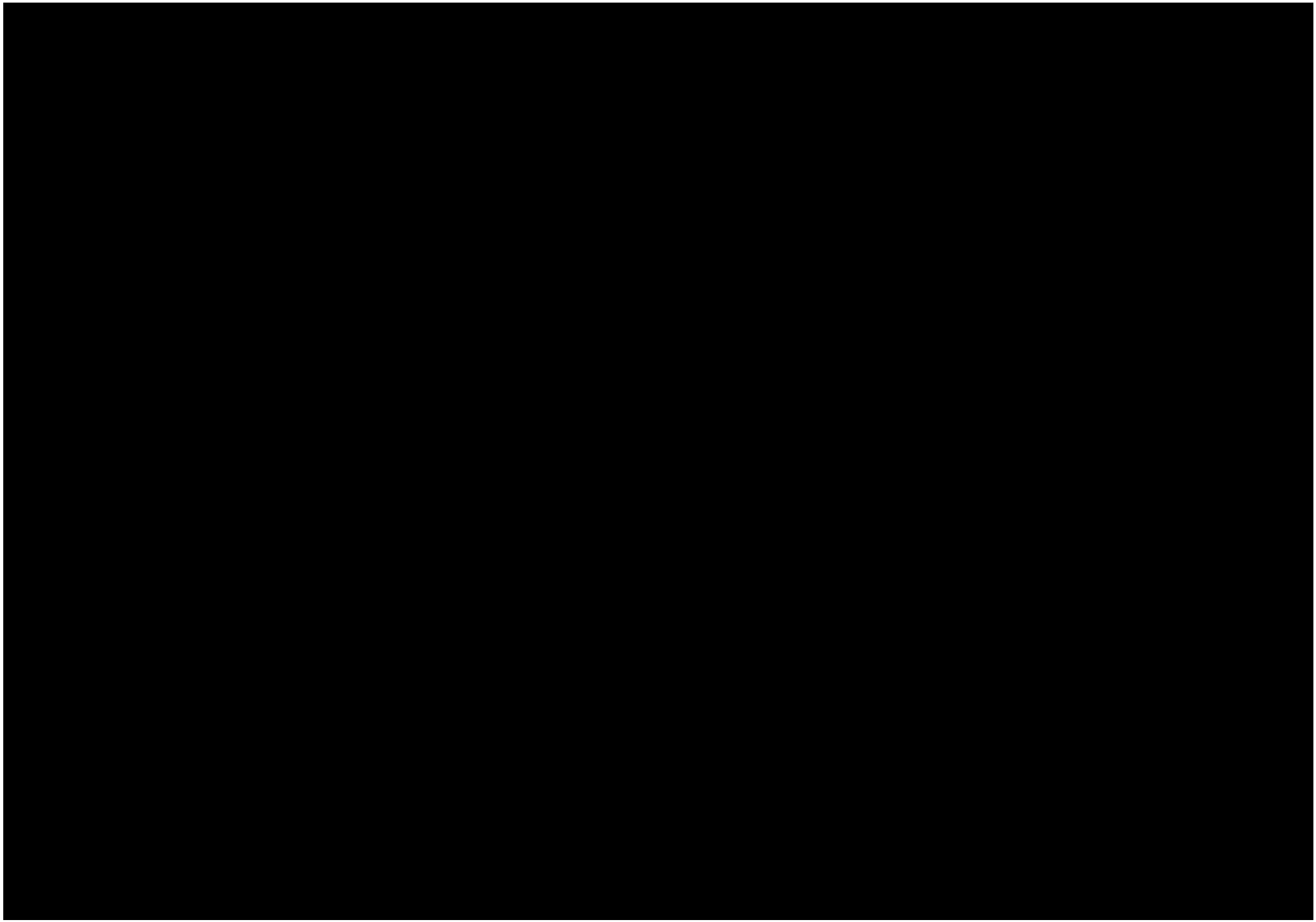
Hourly Average Day for September 2021

Chimney Rock Public Power District

[redacted]

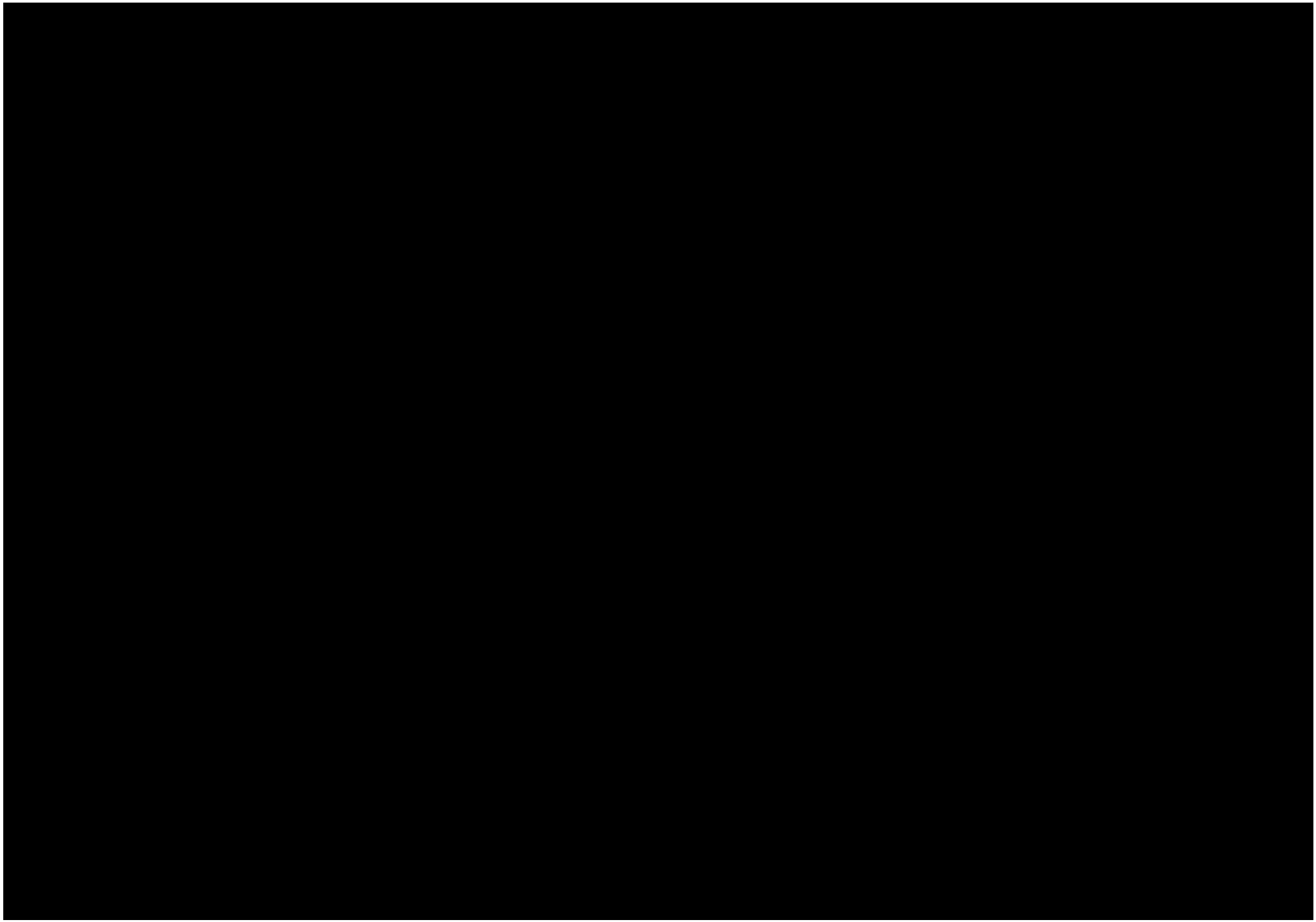
Hourly Average Day for October 2021

Chimney Rock Public Power District



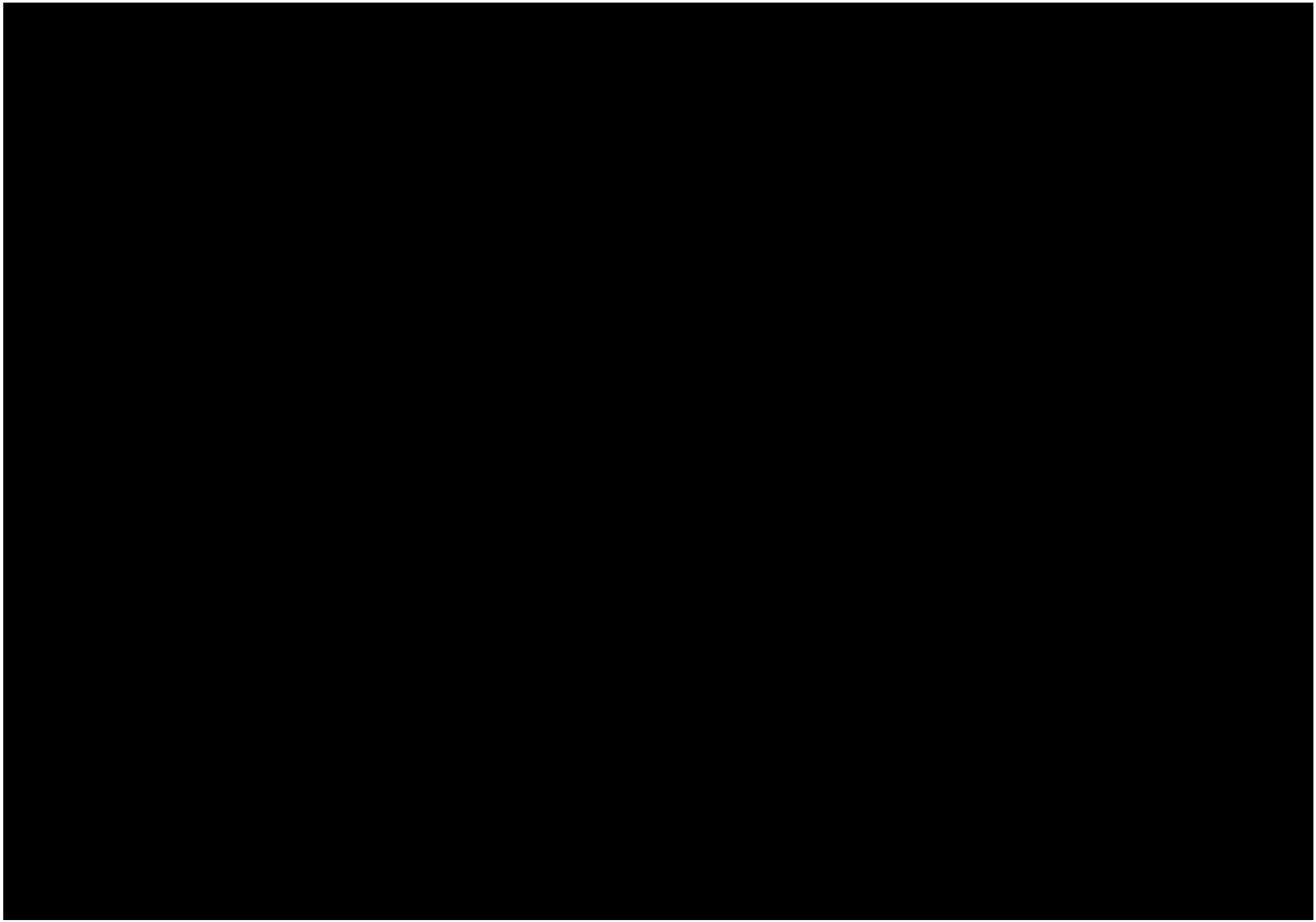
Hourly Average Day for November 2021

Chimney Rock Public Power District



Hourly Average Day for December 2021

Chimney Rock Public Power District



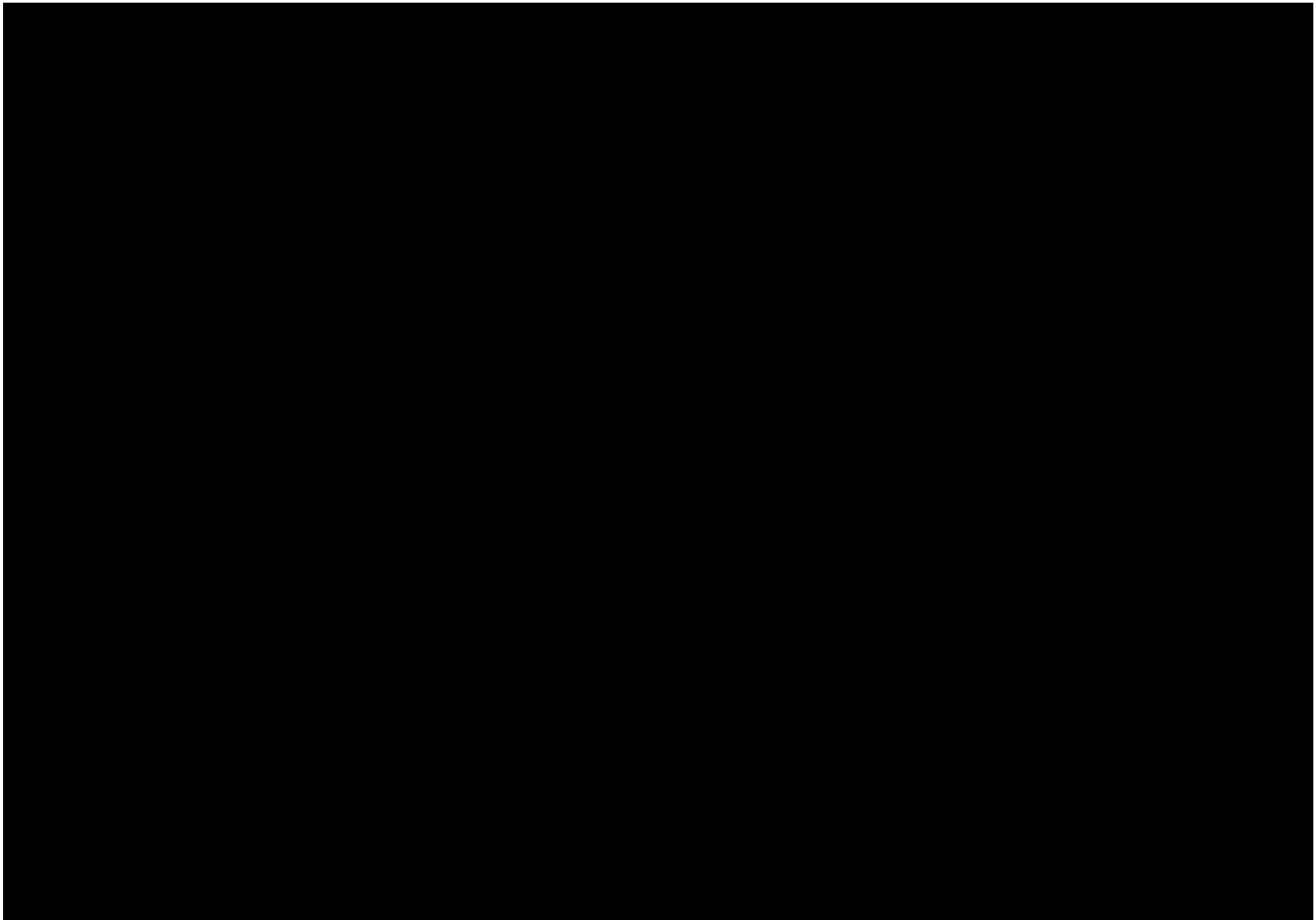
Hourly Average Day for January 2021

Empire Electric Association, Inc.

[redacted]

Hourly Average Day for February 2021

Empire Electric Association, Inc.



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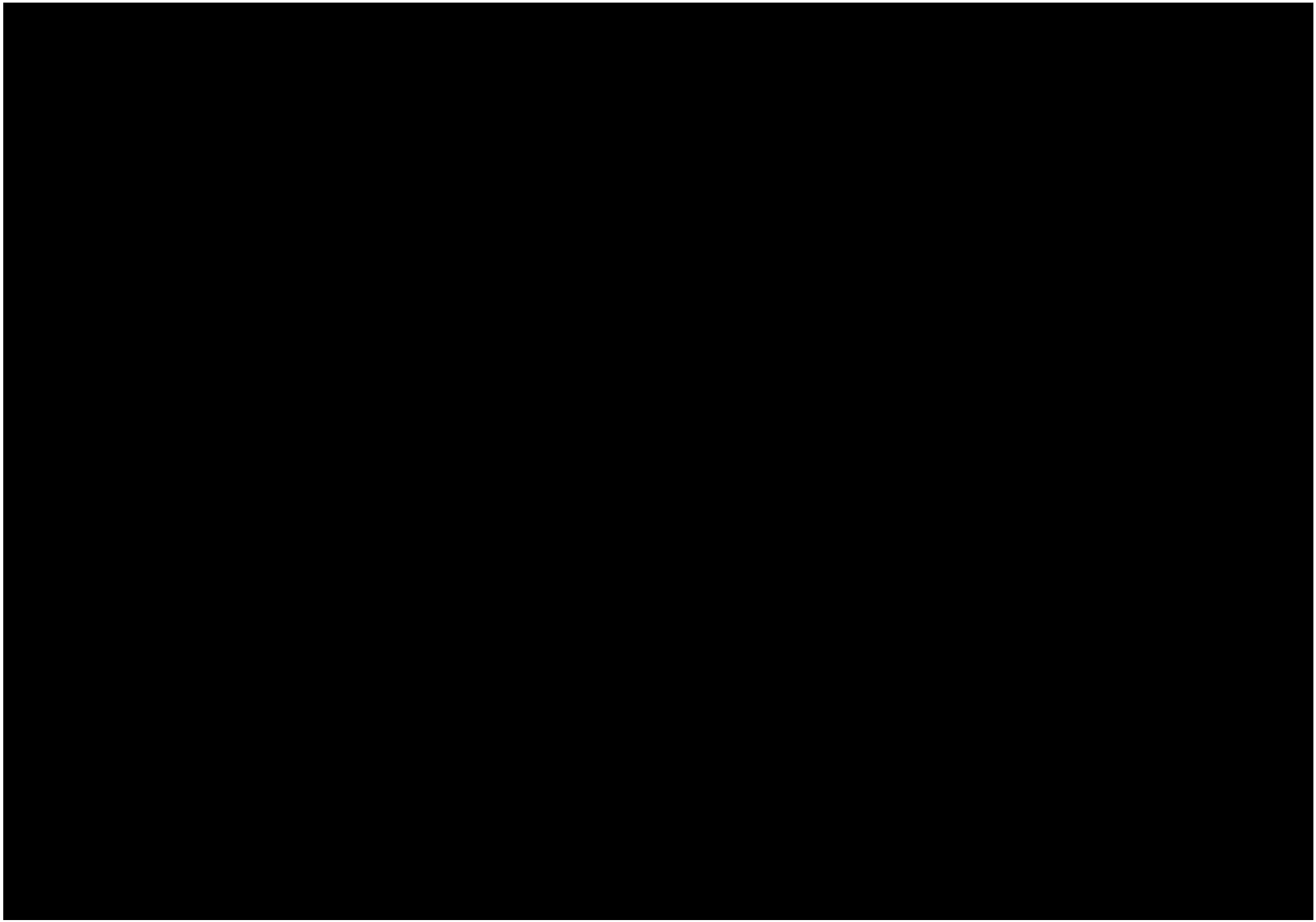
Hourly Average Day for March 2021

Empire Electric Association, Inc.



Hourly Average Day for April 2021

Empire Electric Association, Inc.

[redacted]

Hourly Average Day for May 2021

Empire Electric Association, Inc.

[redacted]

Hourly Average Day for June 2021

Empire Electric Association, Inc.

[redacted]

Hourly Average Day for July 2021

Empire Electric Association, Inc.

[redacted]

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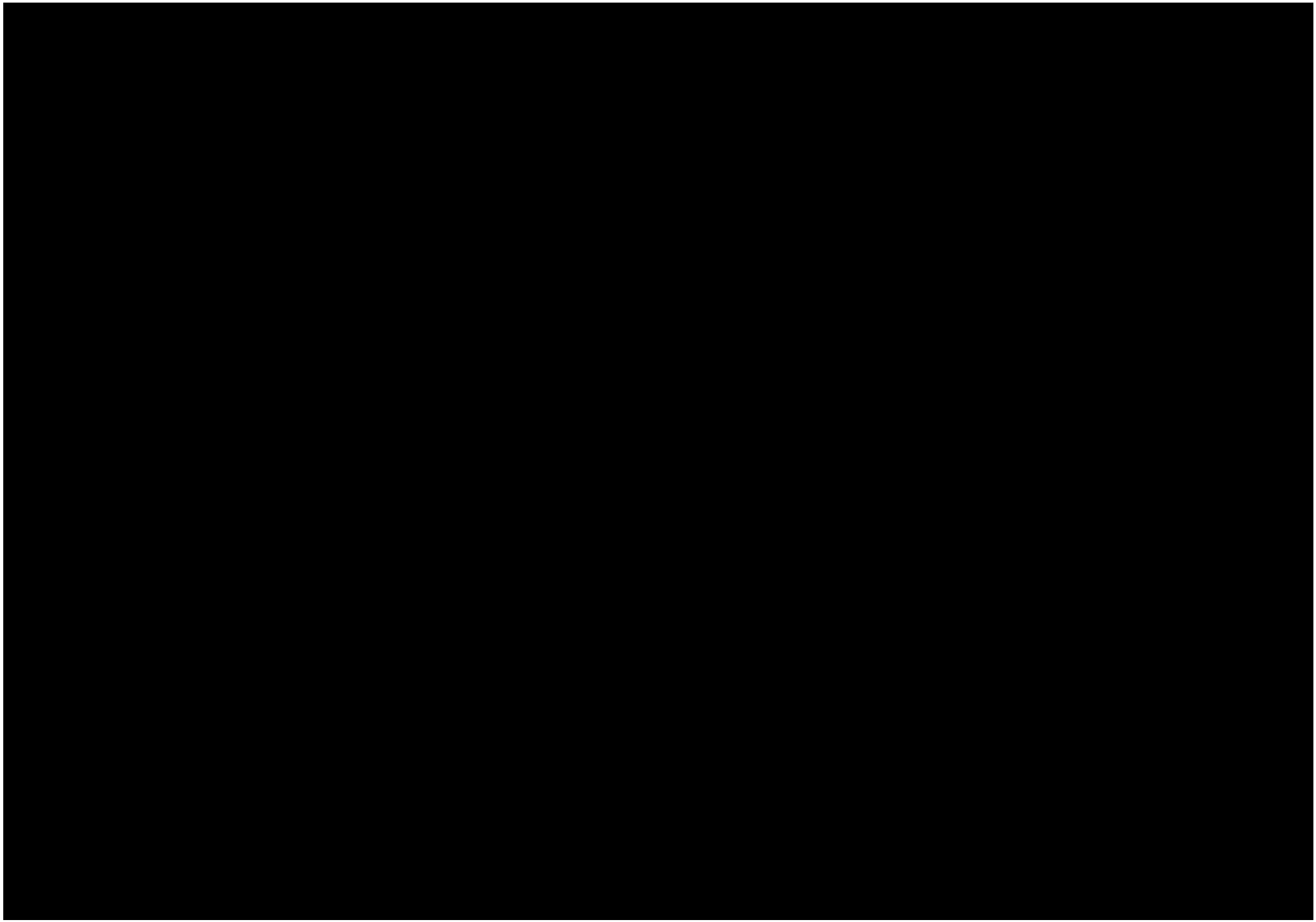
Hourly Average Day for August 2021

Empire Electric Association, Inc.



Hourly Average Day for September 2021

Empire Electric Association, Inc.

[redacted]

Hourly Average Day for October 2021

Empire Electric Association, Inc.

[redacted]

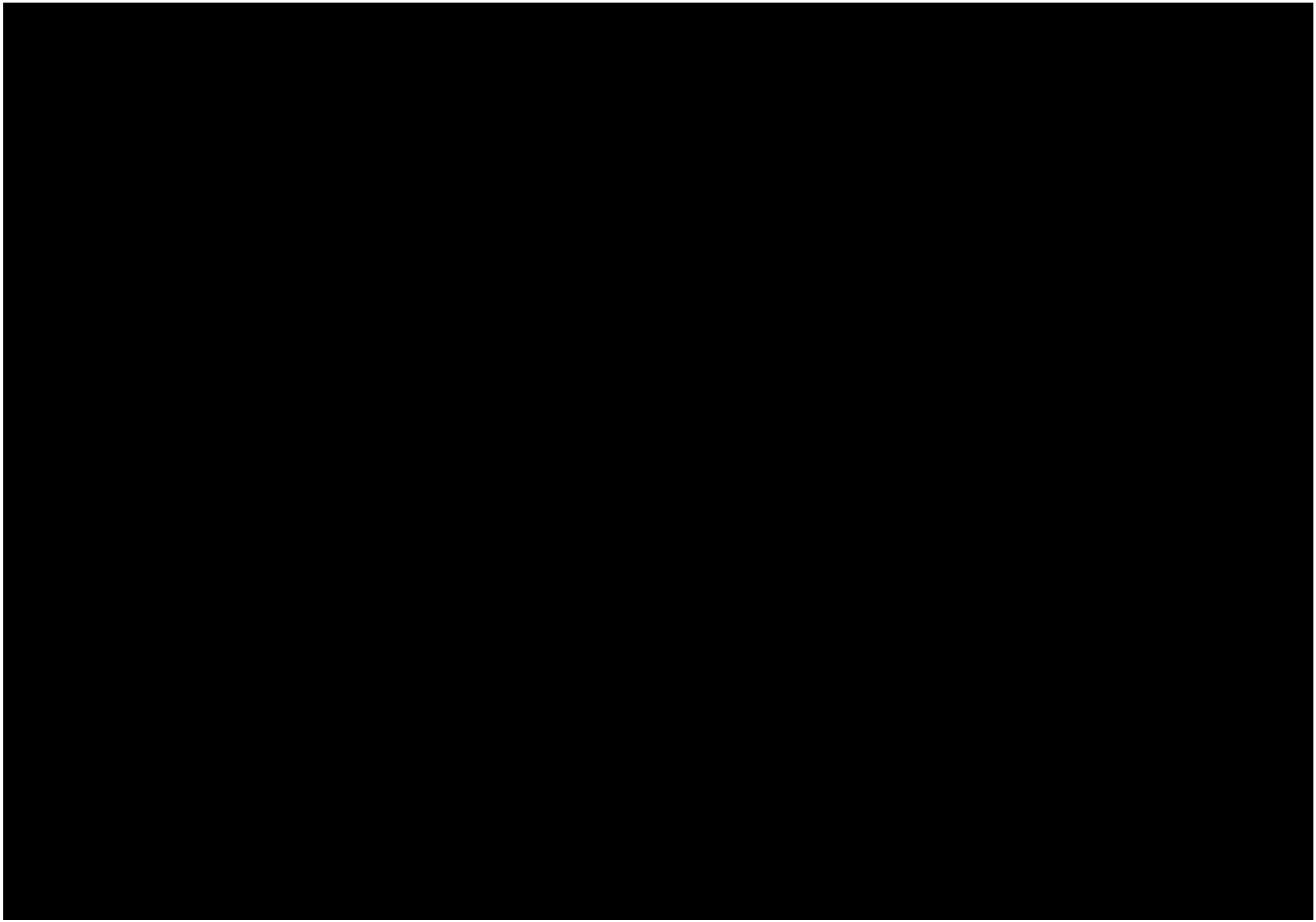
Hourly Average Day for November 2021

Empire Electric Association, Inc.

[redacted]

Hourly Average Day for December 2021

Empire Electric Association, Inc.



Hourly Average Day for January 2021

Gunnison County Electric Association, Inc.

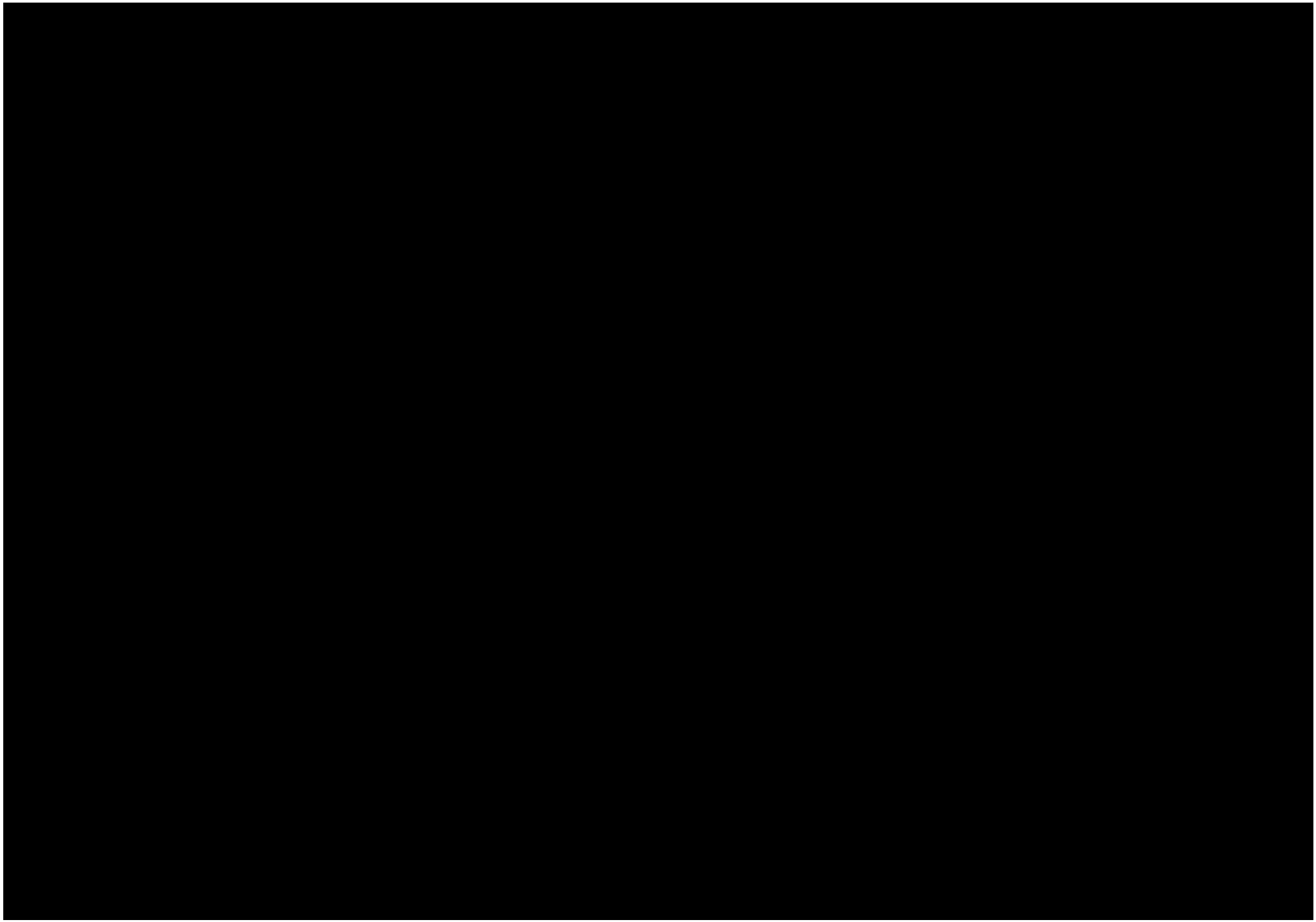
[redacted]

Hourly Average Day for February 2021
Gunnison County Electric Association, Inc.

[redacted]

Hourly Average Day for March 2021

Gunnison County Electric Association, Inc.



Hourly Average Day for April 2021
Gunnison County Electric Association, Inc.

[redacted]

Hourly Average Day for May 2021

Gunnison County Electric Association, Inc.

[redacted]

Hourly Average Day for June 2021
Gunnison County Electric Association, Inc.

[redacted]

Hourly Average Day for July 2021

Gunnison County Electric Association, Inc.

[redacted]

Hourly Average Day for August 2021
Gunnison County Electric Association, Inc.

[redacted]

Hourly Average Day for September 2021

Gunnison County Electric Association, Inc.

[redacted]

Hourly Average Day for October 2021

Gunnison County Electric Association, Inc.

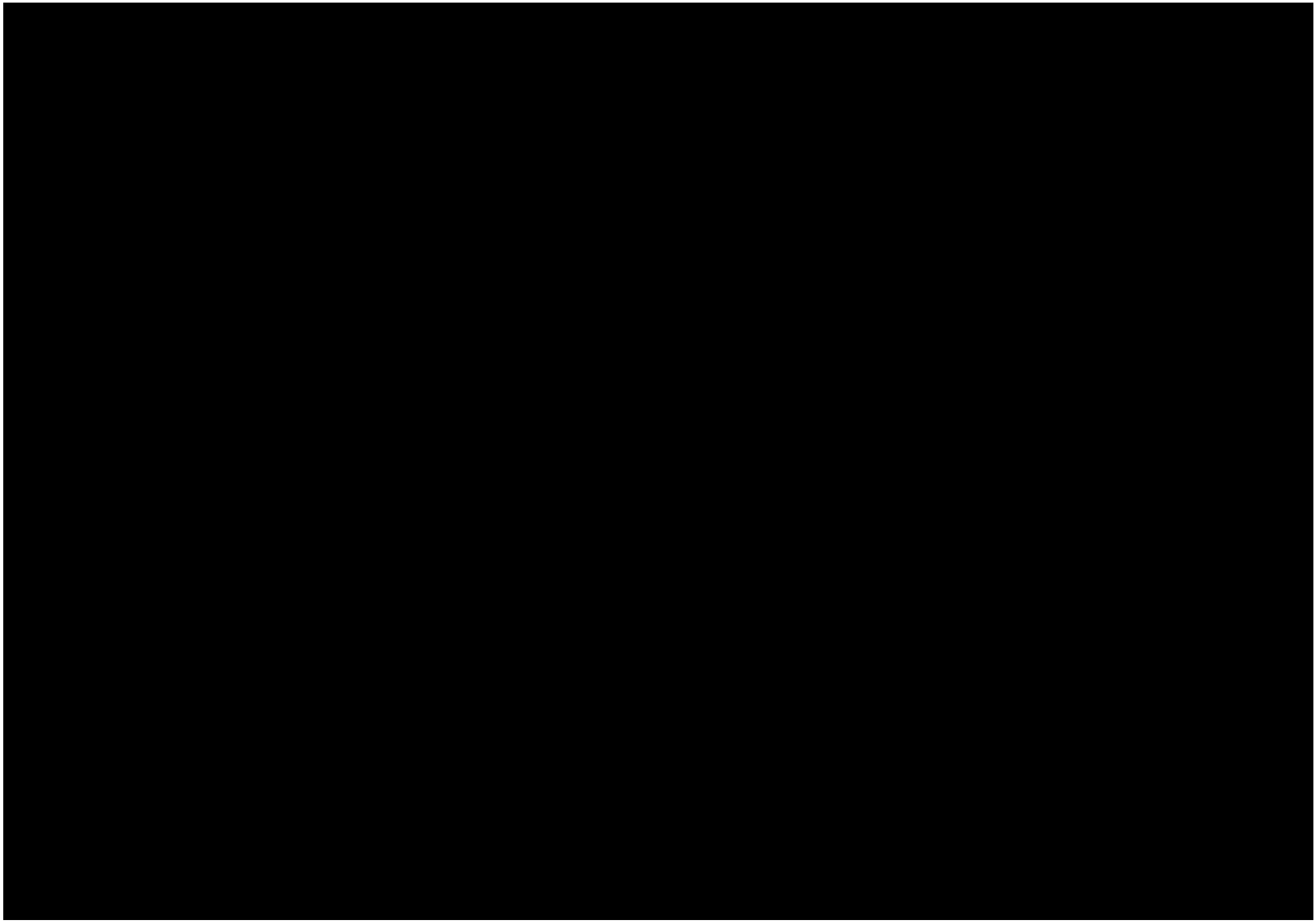
[redacted]

Hourly Average Day for November 2021

Gunnison County Electric Association, Inc.

[redacted]

Hourly Average Day for December 2021
Gunnison County Electric Association, Inc.



Hourly Average Day for January 2021
Garland Light and Power Company

[redacted]

Hourly Average Day for February 2021
Garland Light and Power Company

[redacted]

Hourly Average Day for March 2021
Garland Light and Power Company

[redacted]

Hourly Average Day for April 2021

Garland Light and Power Company

[redacted]

Hourly Average Day for May 2021
Garland Light and Power Company

[redacted]

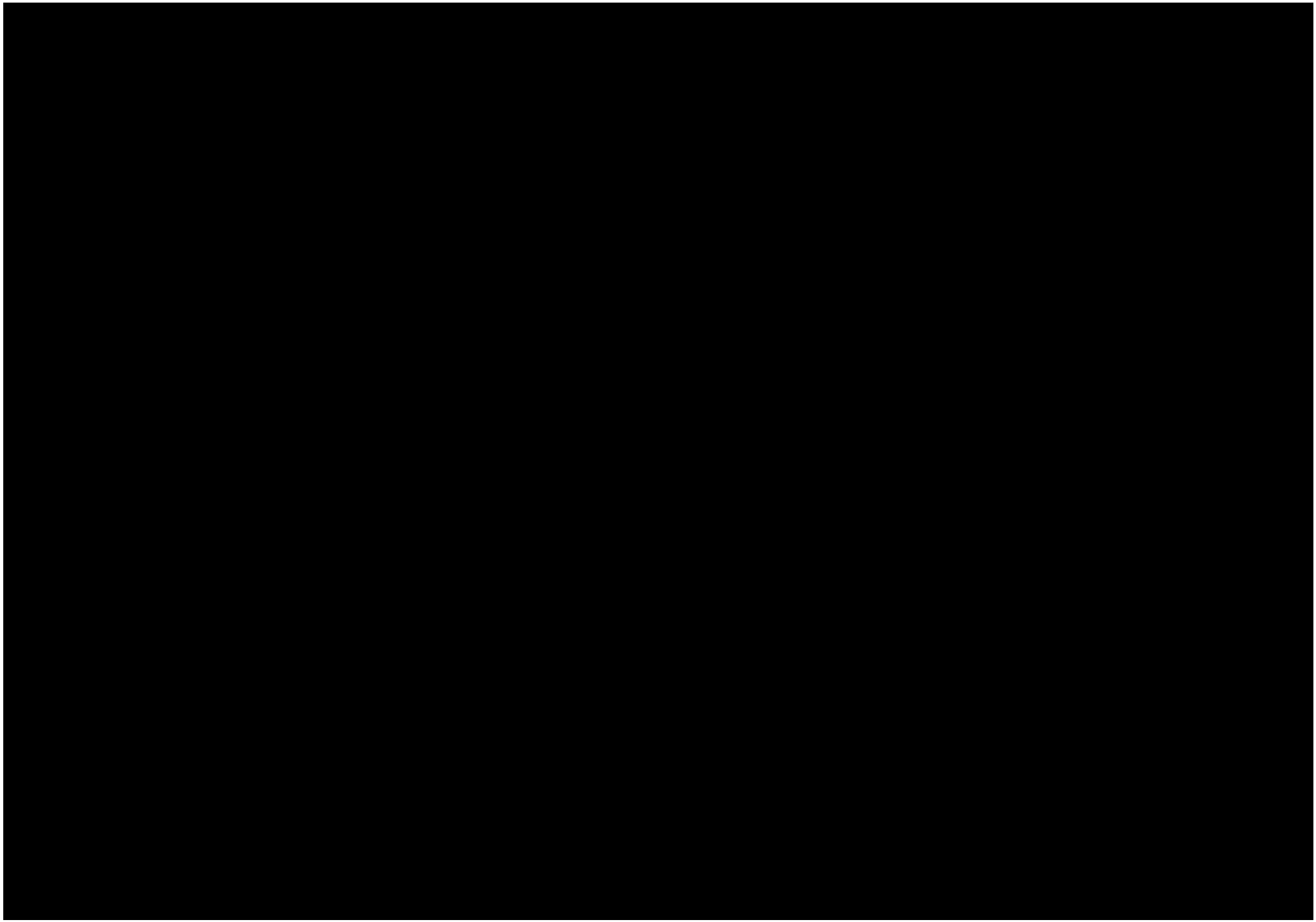
Hourly Average Day for June 2021

Garland Light and Power Company

[redacted]

Hourly Average Day for July 2021

Garland Light and Power Company



Hourly Average Day for August 2021

Garland Light and Power Company

[redacted]

Hourly Average Day for September 2021
Garland Light and Power Company

[redacted]

Hourly Average Day for October 2021
Garland Light and Power Company

[redacted]

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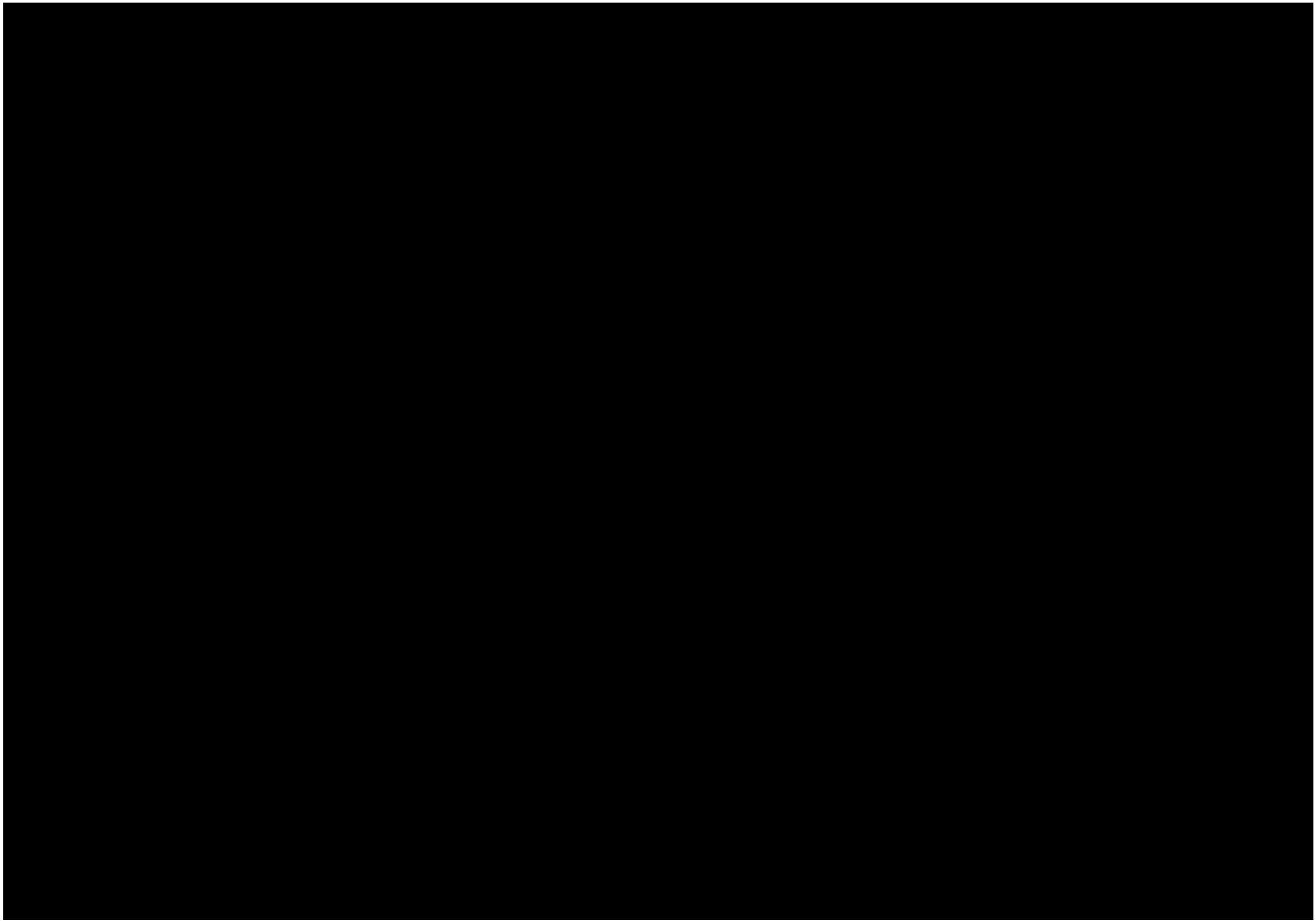
Hourly Average Day for November 2021

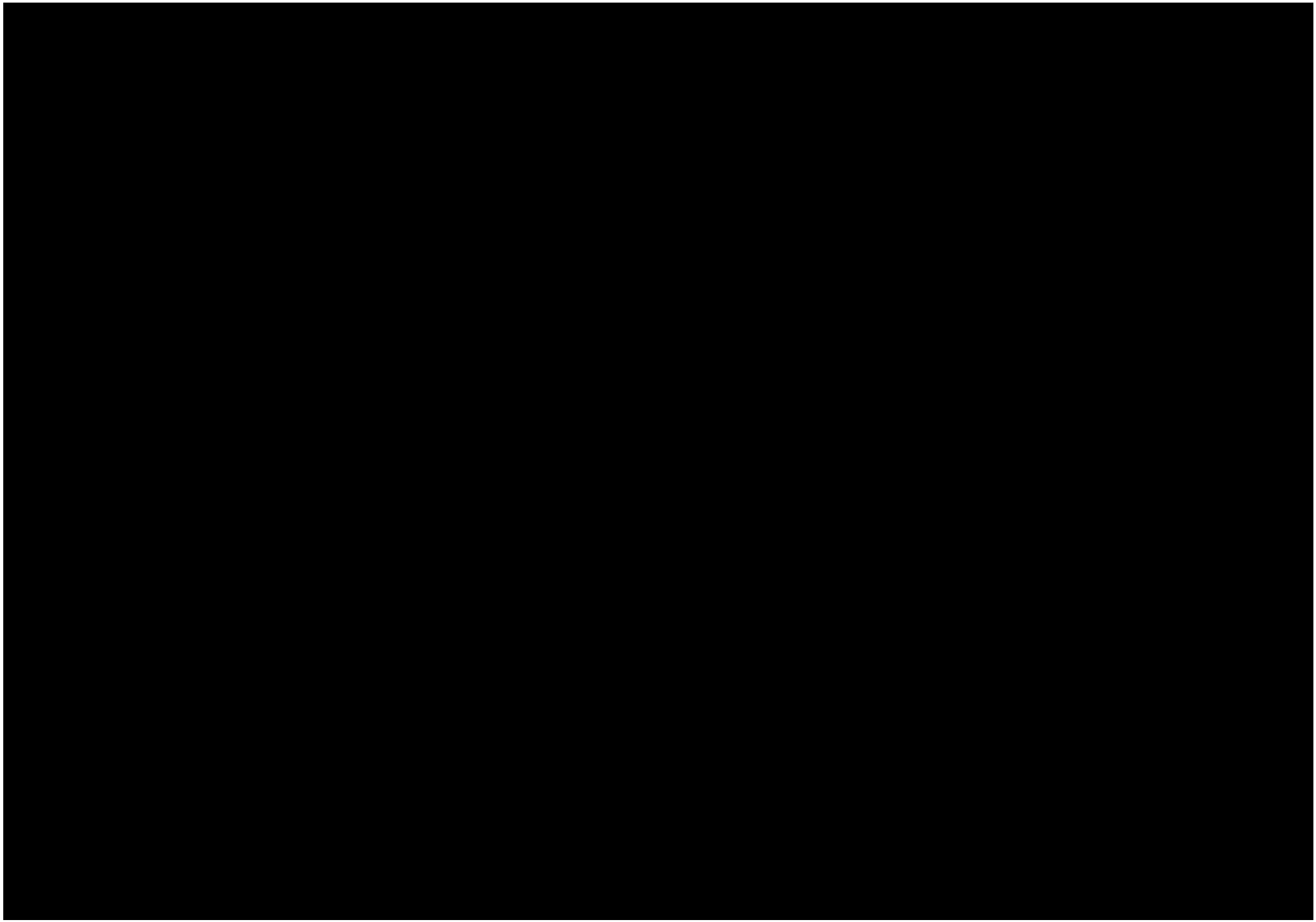
Garland Light and Power Company



Hourly Average Day for December 2021
Garland Light and Power Company

[redacted]

Hourly Average Day for January 2021
Highline Electric Association



Hourly Average Day for February 2021
Highline Electric Association

[redacted]

Hourly Average Day for March 2021
Highline Electric Association

[redacted]

Hourly Average Day for April 2021
Highline Electric Association

[redacted]

Hourly Average Day for May 2021
Highline Electric Association

[redacted]

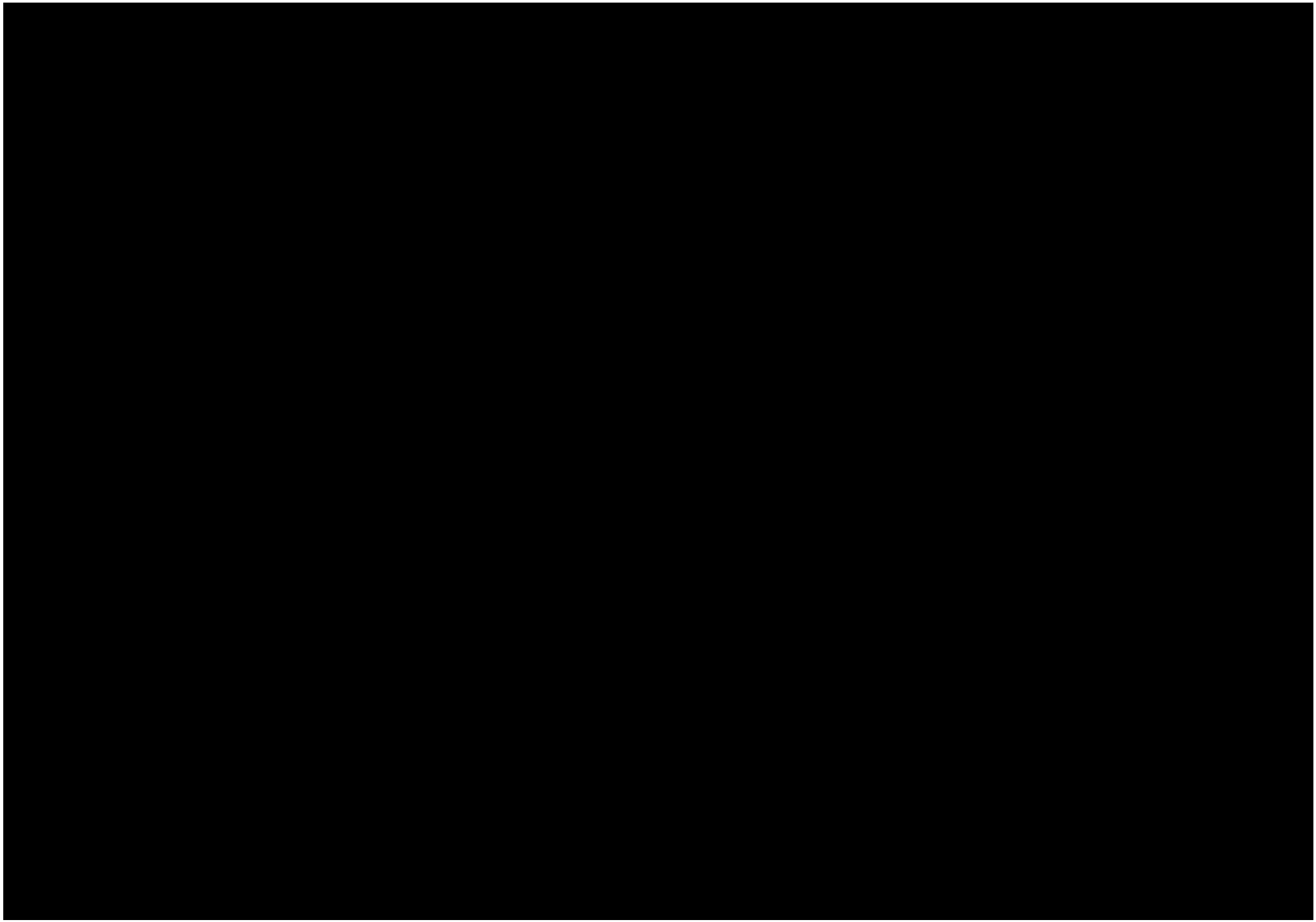
Hourly Average Day for June 2021
Highline Electric Association

[redacted]

Hourly Average Day for July 2021
Highline Electric Association

[redacted]

Hourly Average Day for August 2021
Highline Electric Association



Hourly Average Day for September 2021

Highline Electric Association

[redacted]

Hourly Average Day for October 2021
Highline Electric Association

[redacted]

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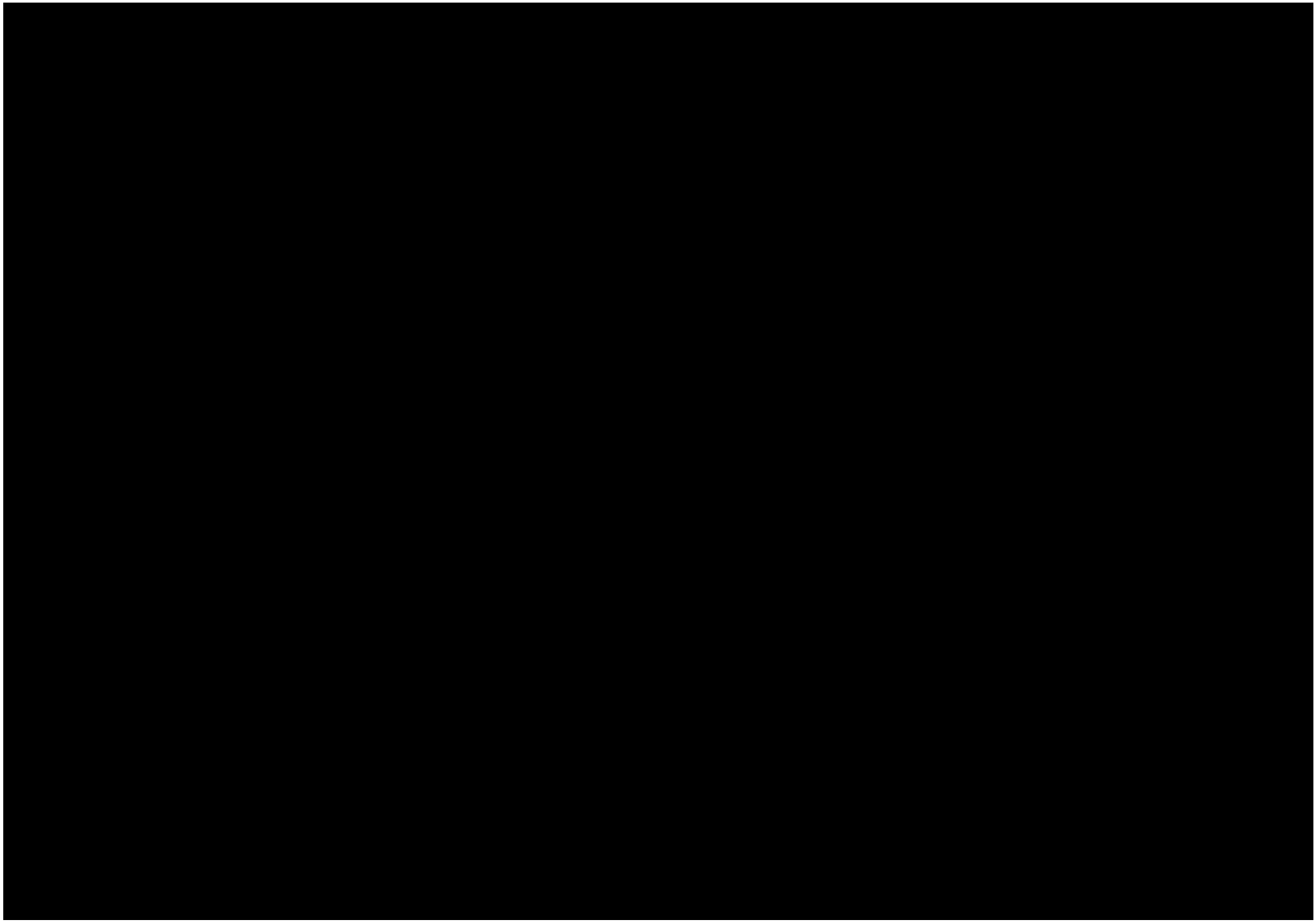
Hourly Average Day for November 2021

Highline Electric Association



Hourly Average Day for December 2021

Highline Electric Association

[redacted]

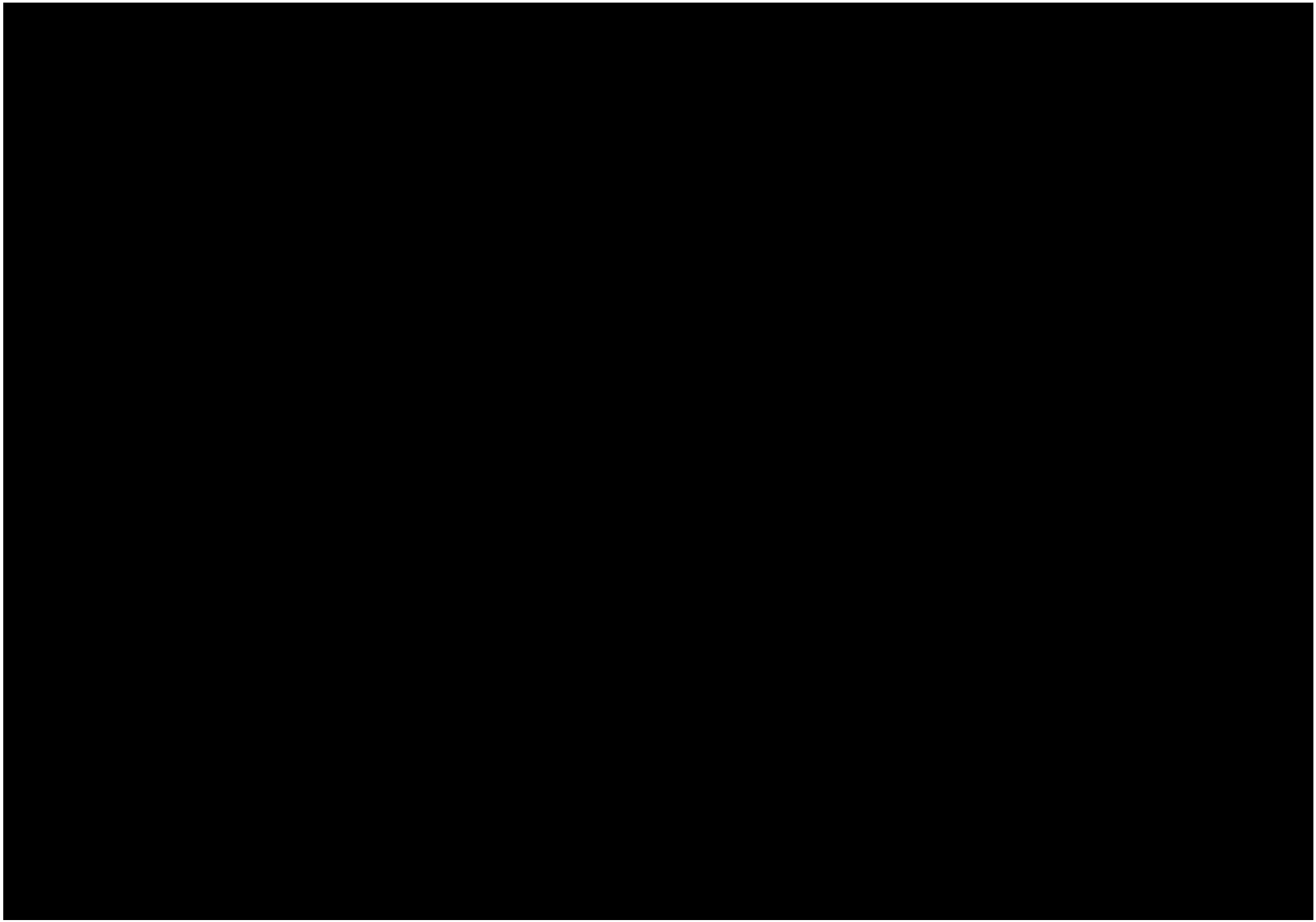
Hourly Average Day for January 2021

High Plains Power, Inc.

[redacted]

Hourly Average Day for February 2021

High Plains Power, Inc.



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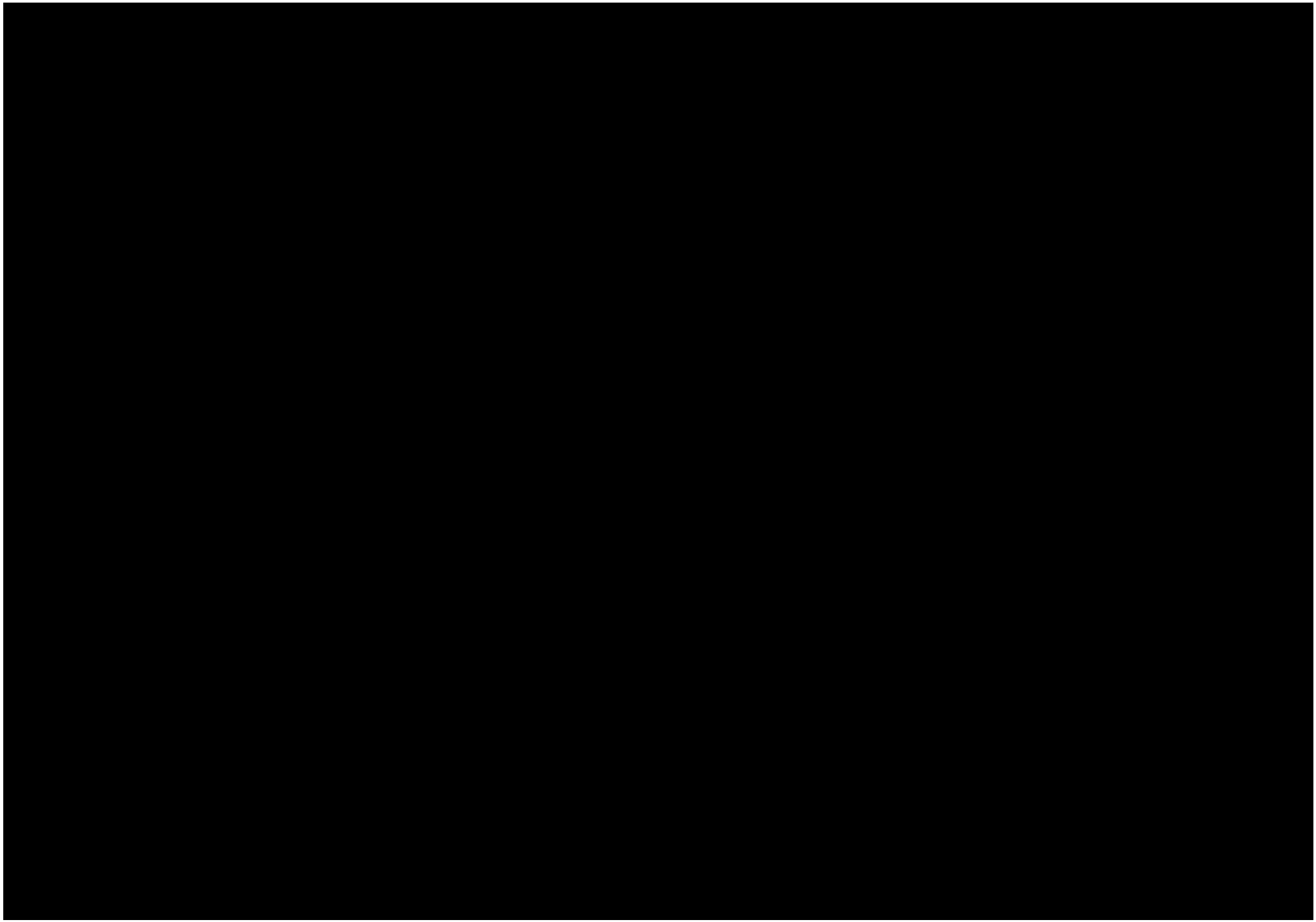
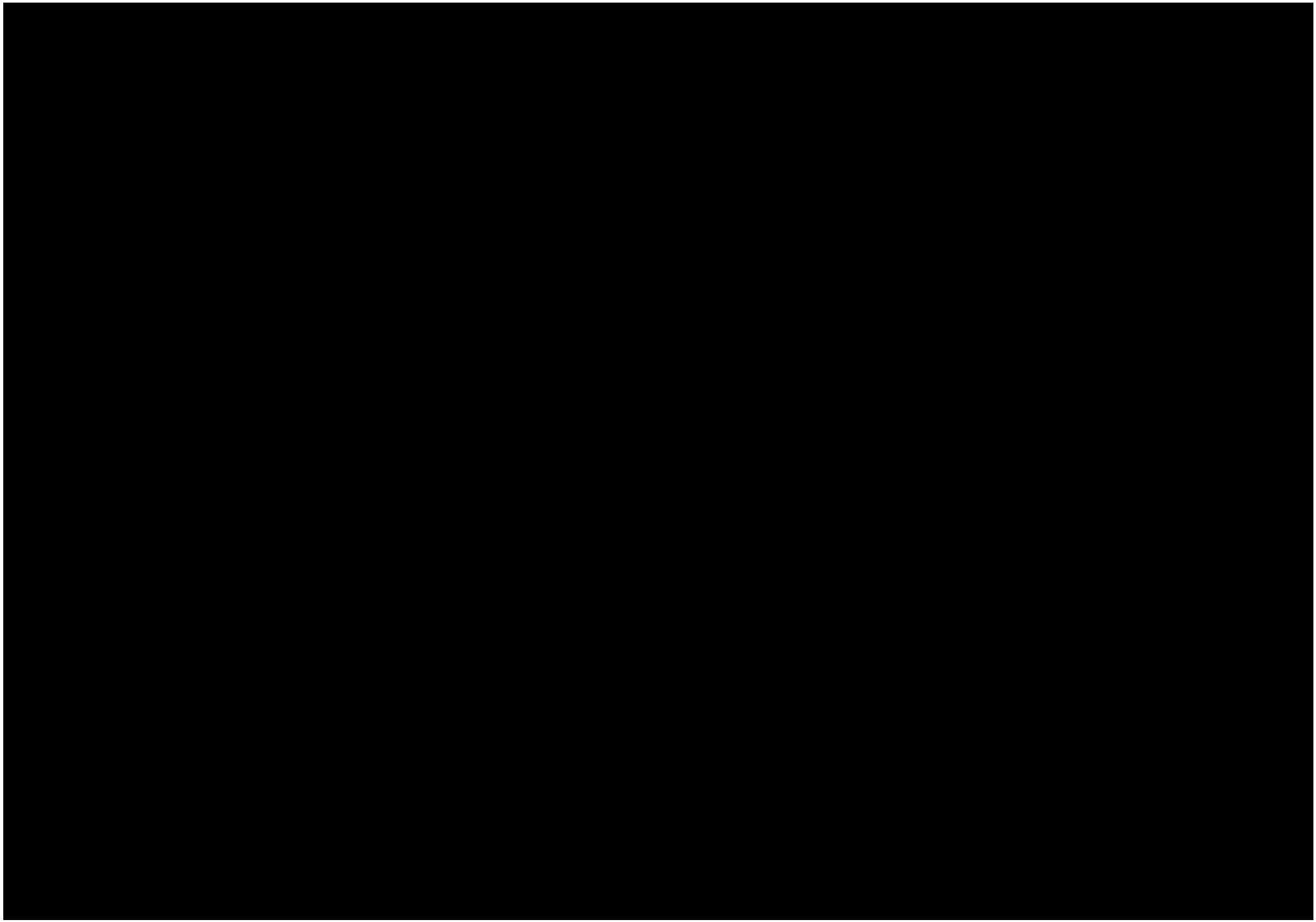
Hourly Average Day for March 2021

High Plains Power, Inc.



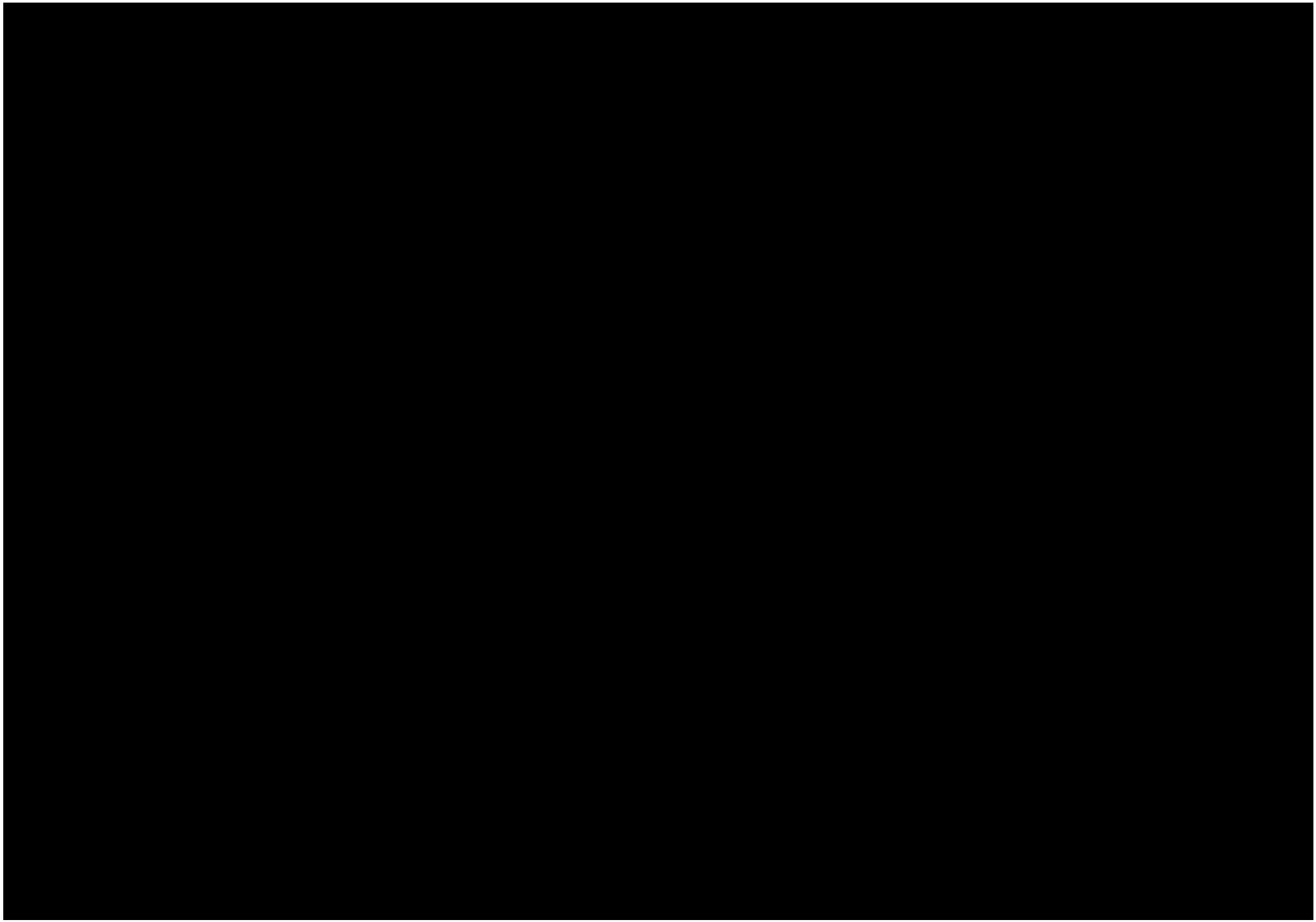
Hourly Average Day for April 2021

High Plains Power, Inc.



Hourly Average Day for May 2021

High Plains Power, Inc.



Hourly Average Day for June 2021

High Plains Power, Inc.

[redacted]

Hourly Average Day for July 2021

High Plains Power, Inc.

[redacted]

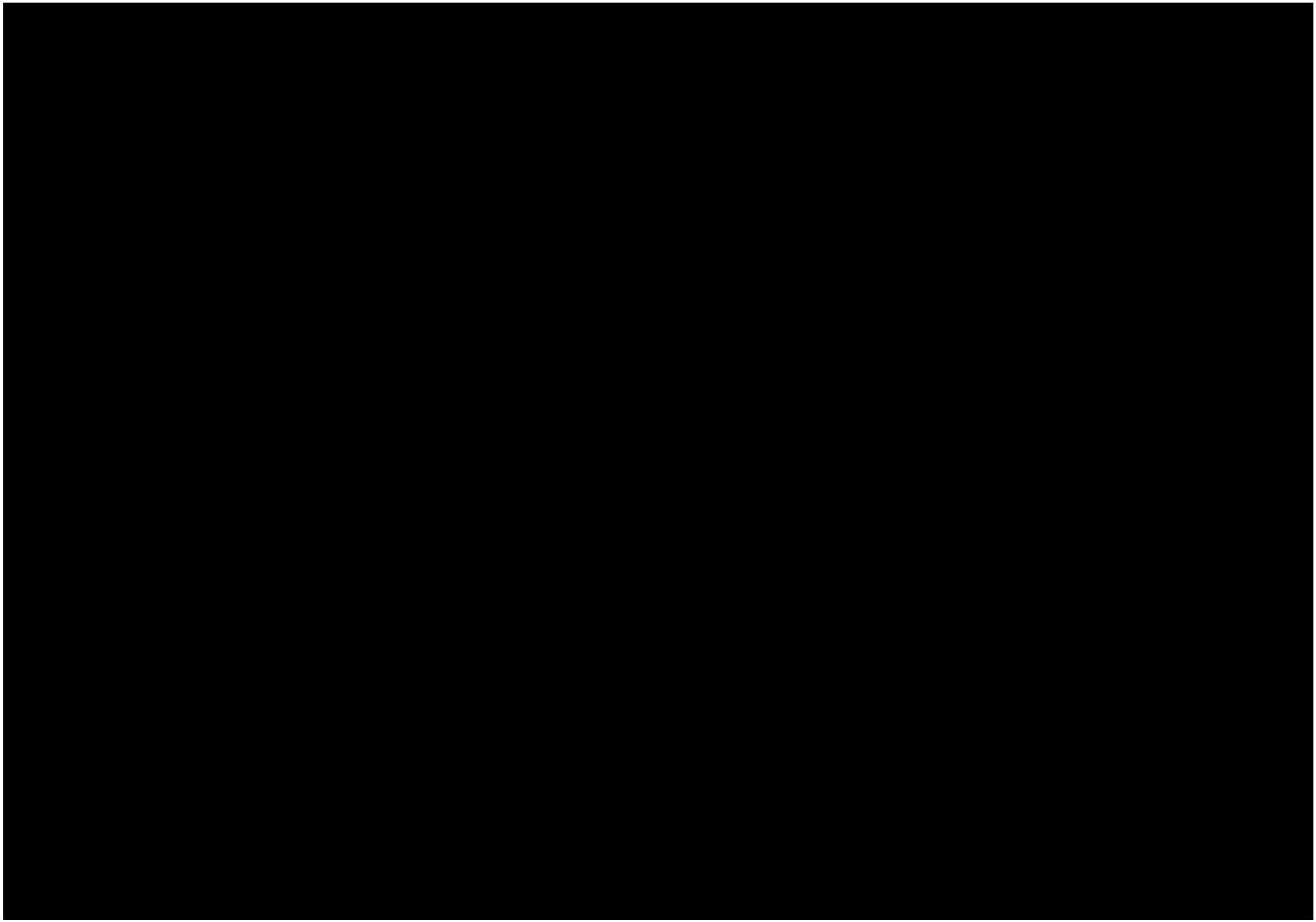
Hourly Average Day for August 2021

High Plains Power, Inc.

[redacted]

Hourly Average Day for September 2021

High Plains Power, Inc.



Hourly Average Day for October 2021

High Plains Power, Inc.

[redacted]

Hourly Average Day for November 2021

High Plains Power, Inc.

[redacted]

Hourly Average Day for December 2021

High Plains Power, Inc.

[redacted]

Hourly Average Day for January 2021

High West Energy, Inc.

[redacted]

Hourly Average Day for February 2021

High West Energy, Inc.

[redacted]

Hourly Average Day for March 2021

High West Energy, Inc.

[redacted]

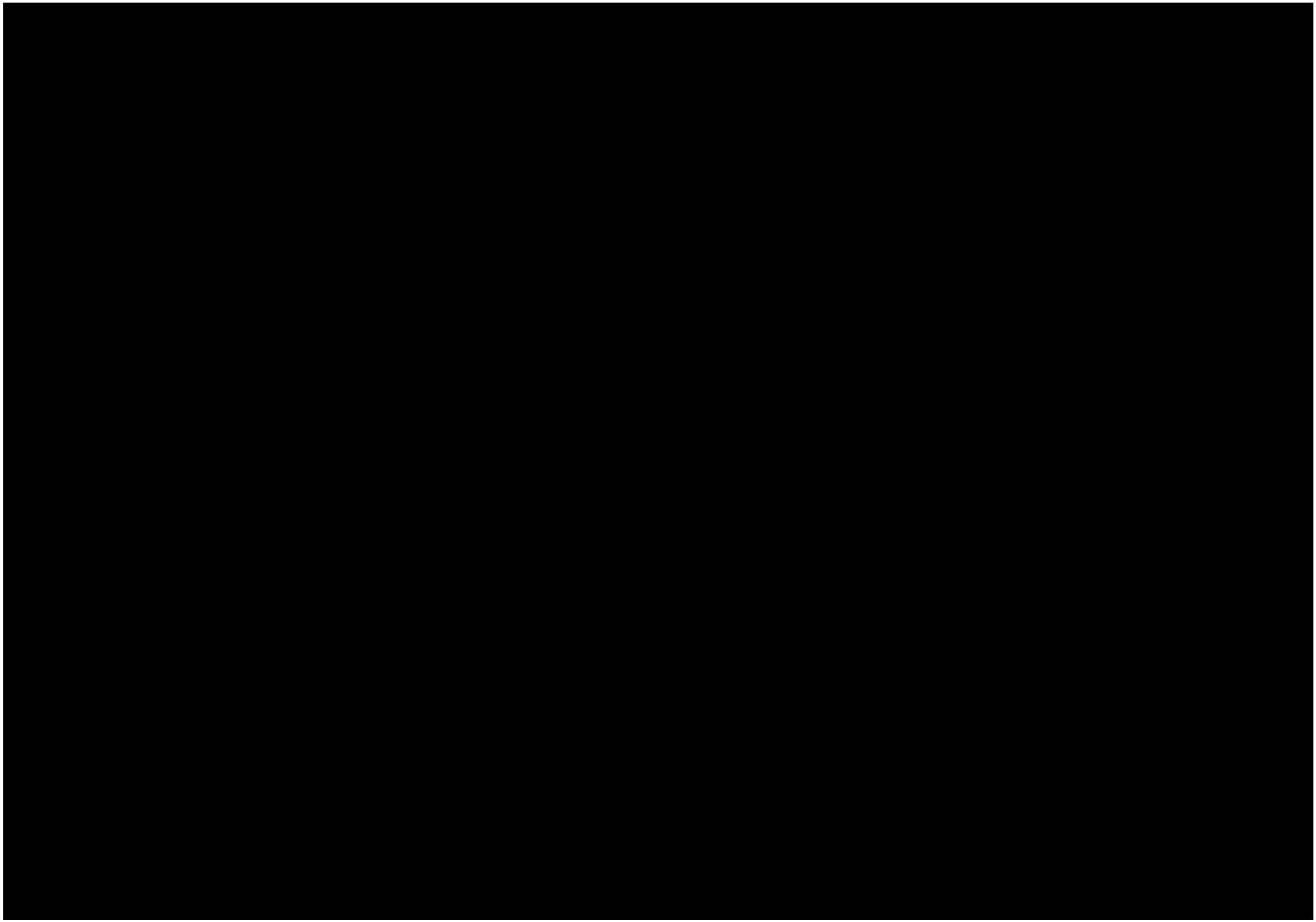
Hourly Average Day for April 2021

High West Energy, Inc.

[redacted]

Hourly Average Day for May 2021

High West Energy, Inc.



Hourly Average Day for June 2021

High West Energy, Inc.

[redacted]

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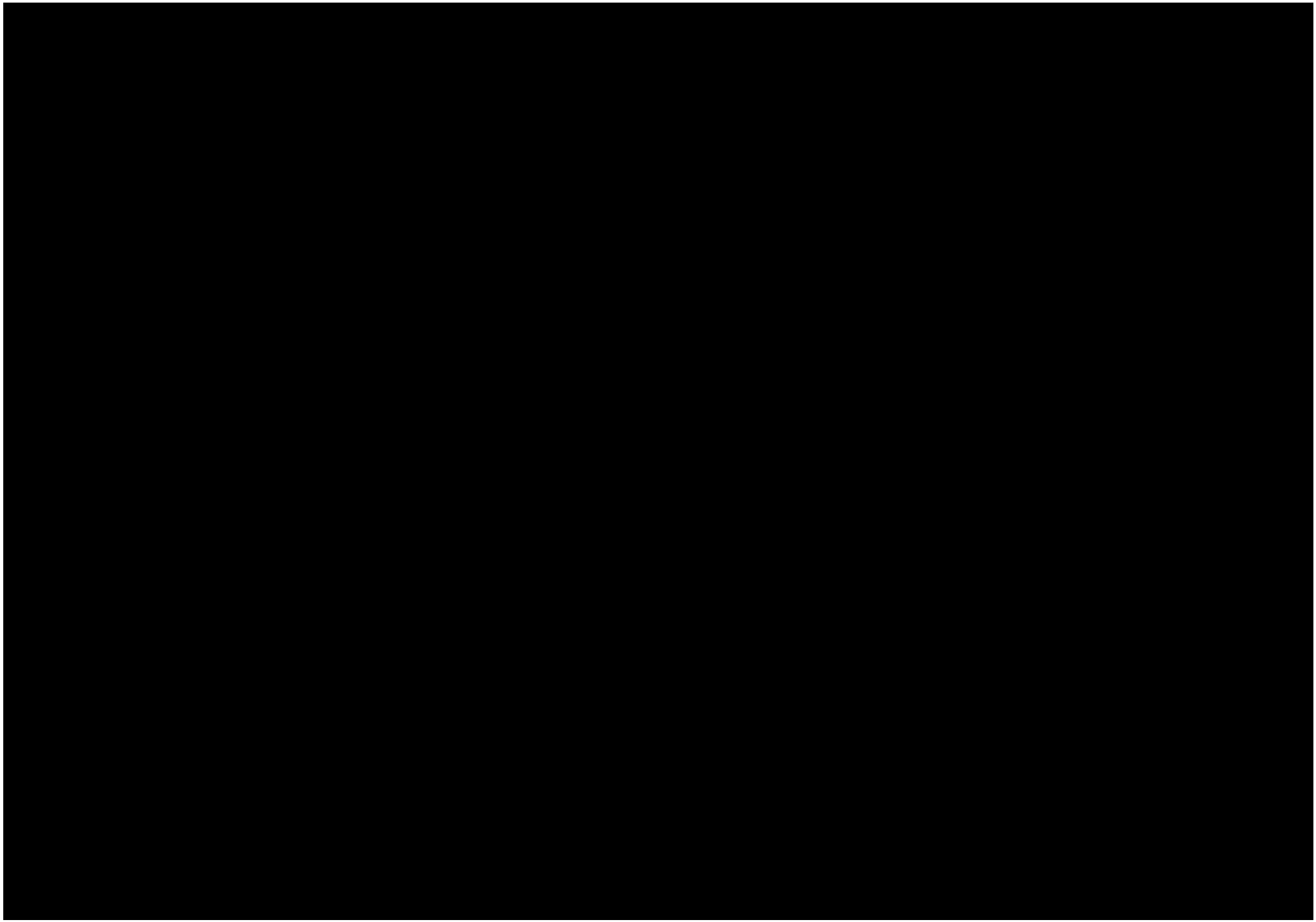
Hourly Average Day for July 2021

High West Energy, Inc.



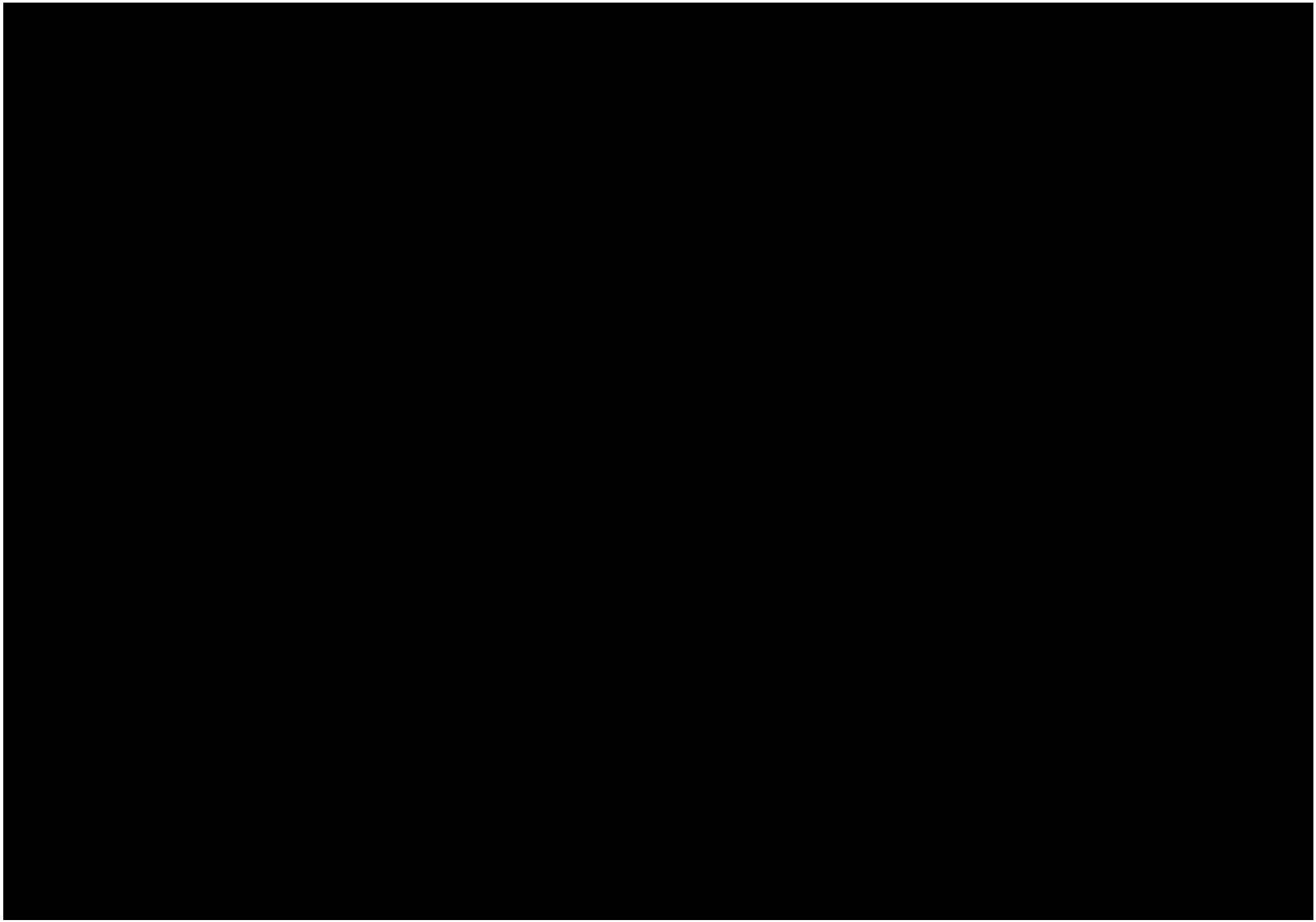
Hourly Average Day for August 2021

High West Energy, Inc.

[redacted]

Hourly Average Day for September 2021

High West Energy, Inc.



Hourly Average Day for October 2021

High West Energy, Inc.

[redacted]

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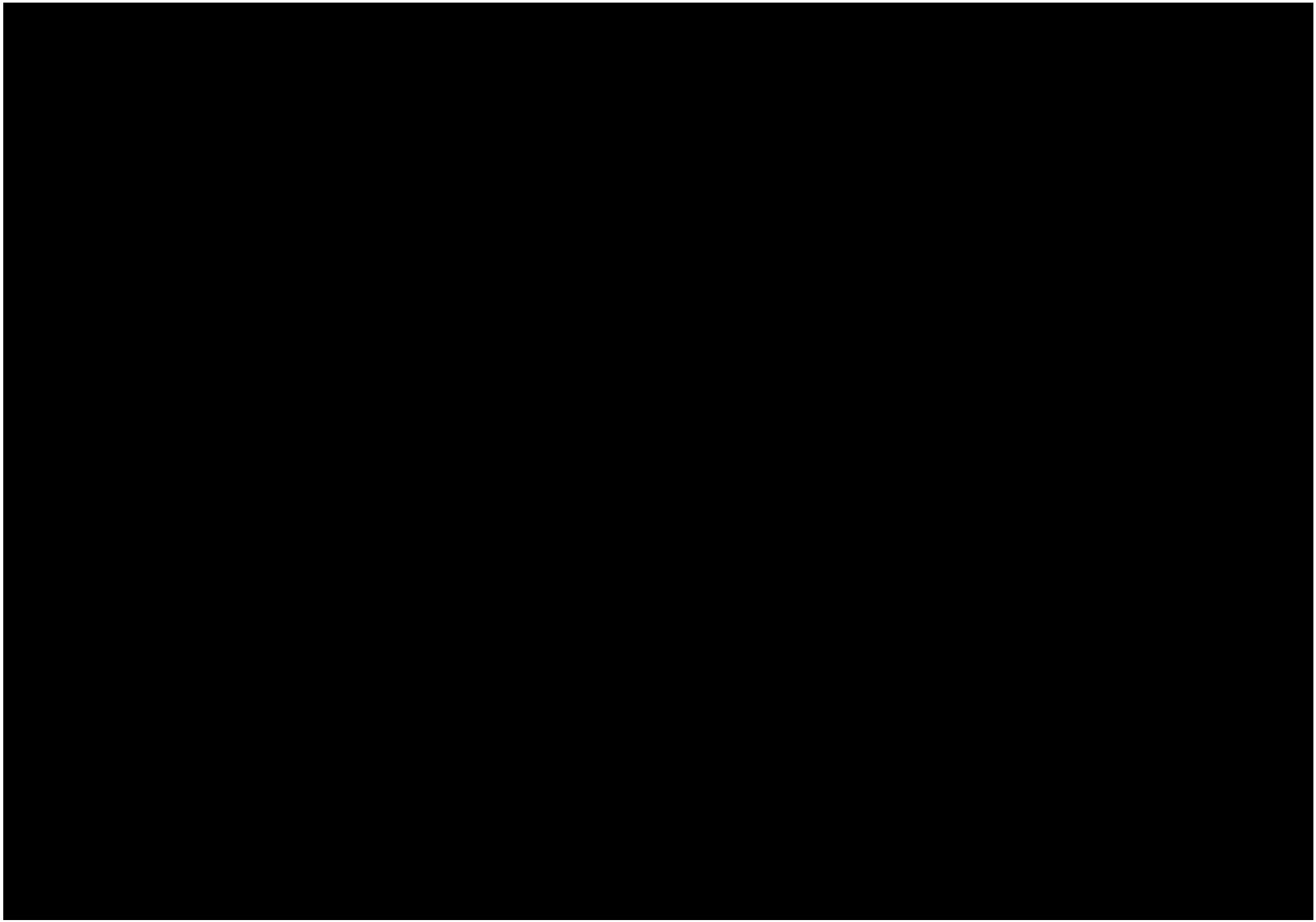
Hourly Average Day for November 2021

High West Energy, Inc.



Hourly Average Day for December 2021

High West Energy, Inc.

[redacted]

Hourly Average Day for January 2021

Jemez Mountains Electric Cooperative, Inc.

[redacted]

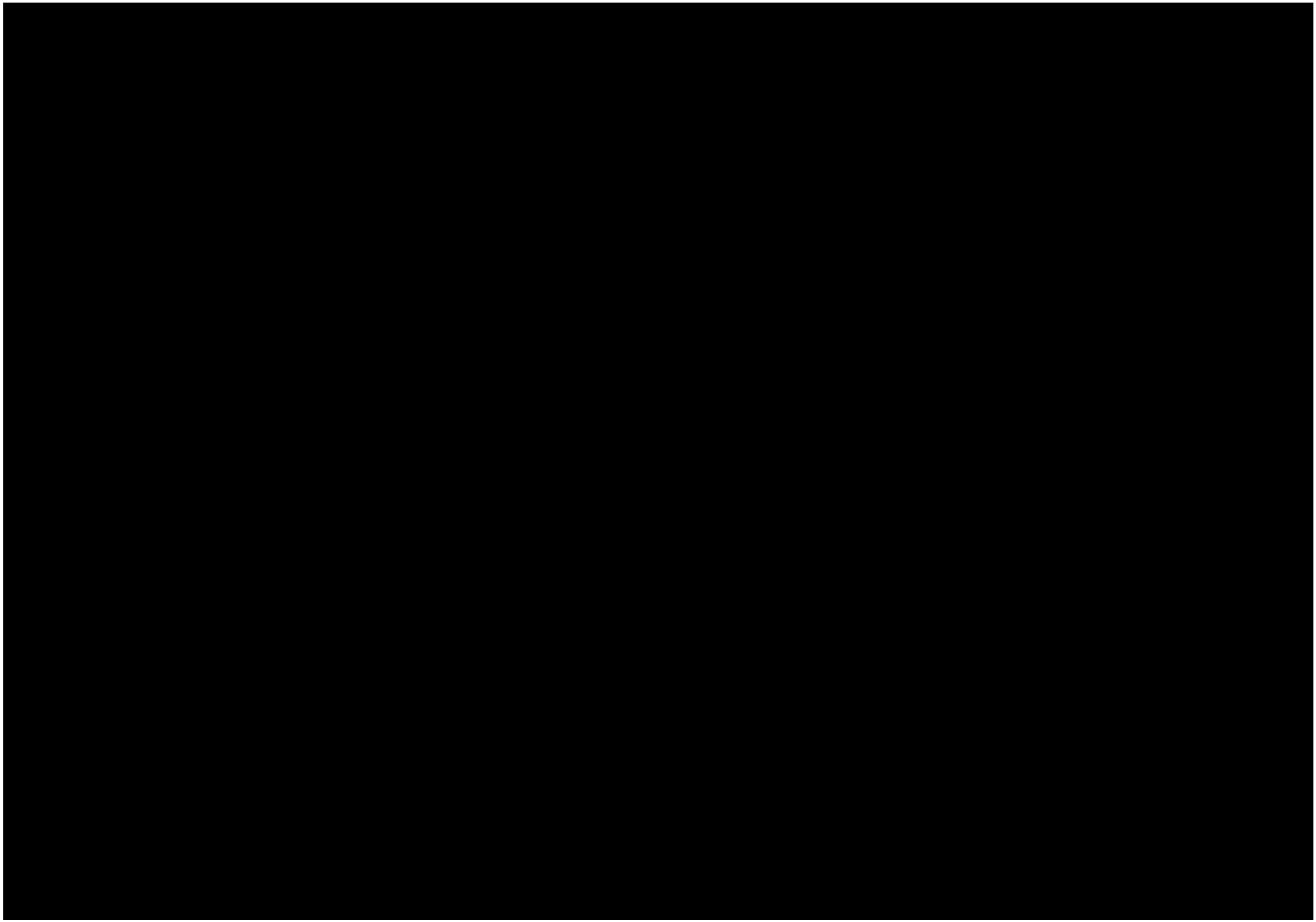
Hourly Average Day for February 2021

Jemez Mountains Electric Cooperative, Inc.

[redacted]

Hourly Average Day for March 2021

Jemez Mountains Electric Cooperative, Inc.



Hourly Average Day for April 2021

Jemez Mountains Electric Cooperative, Inc.

[redacted]

Hourly Average Day for May 2021

Jemez Mountains Electric Cooperative, Inc.

[redacted]

Hourly Average Day for June 2021

Jemez Mountains Electric Cooperative, Inc.

[redacted]

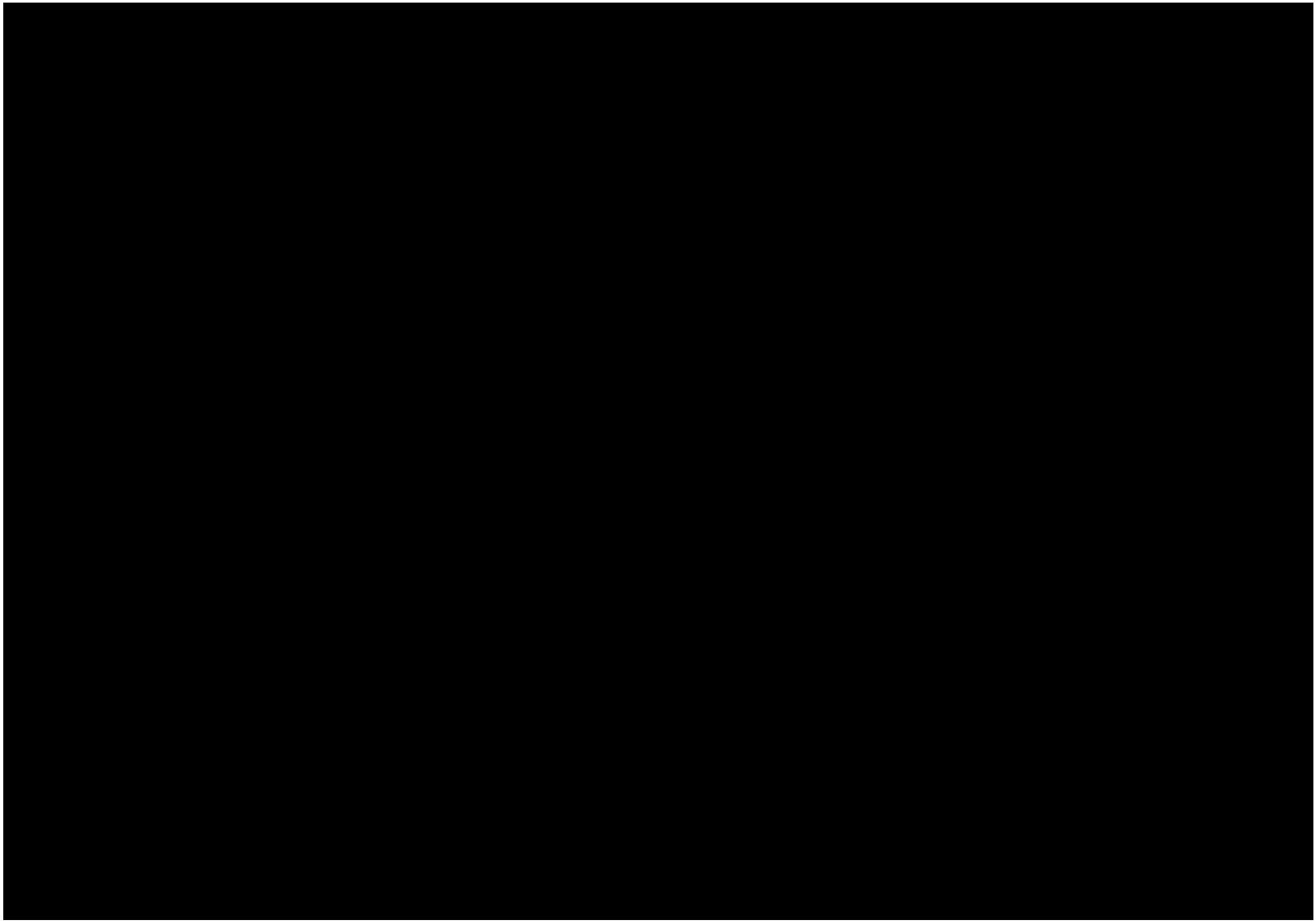
Hourly Average Day for July 2021

Jemez Mountains Electric Cooperative, Inc.

[redacted]

Hourly Average Day for August 2021

Jemez Mountains Electric Cooperative, Inc.



Hourly Average Day for September 2021

Jemez Mountains Electric Cooperative, Inc.

[redacted]

Hourly Average Day for October 2021

Jemez Mountains Electric Cooperative, Inc.

[redacted]

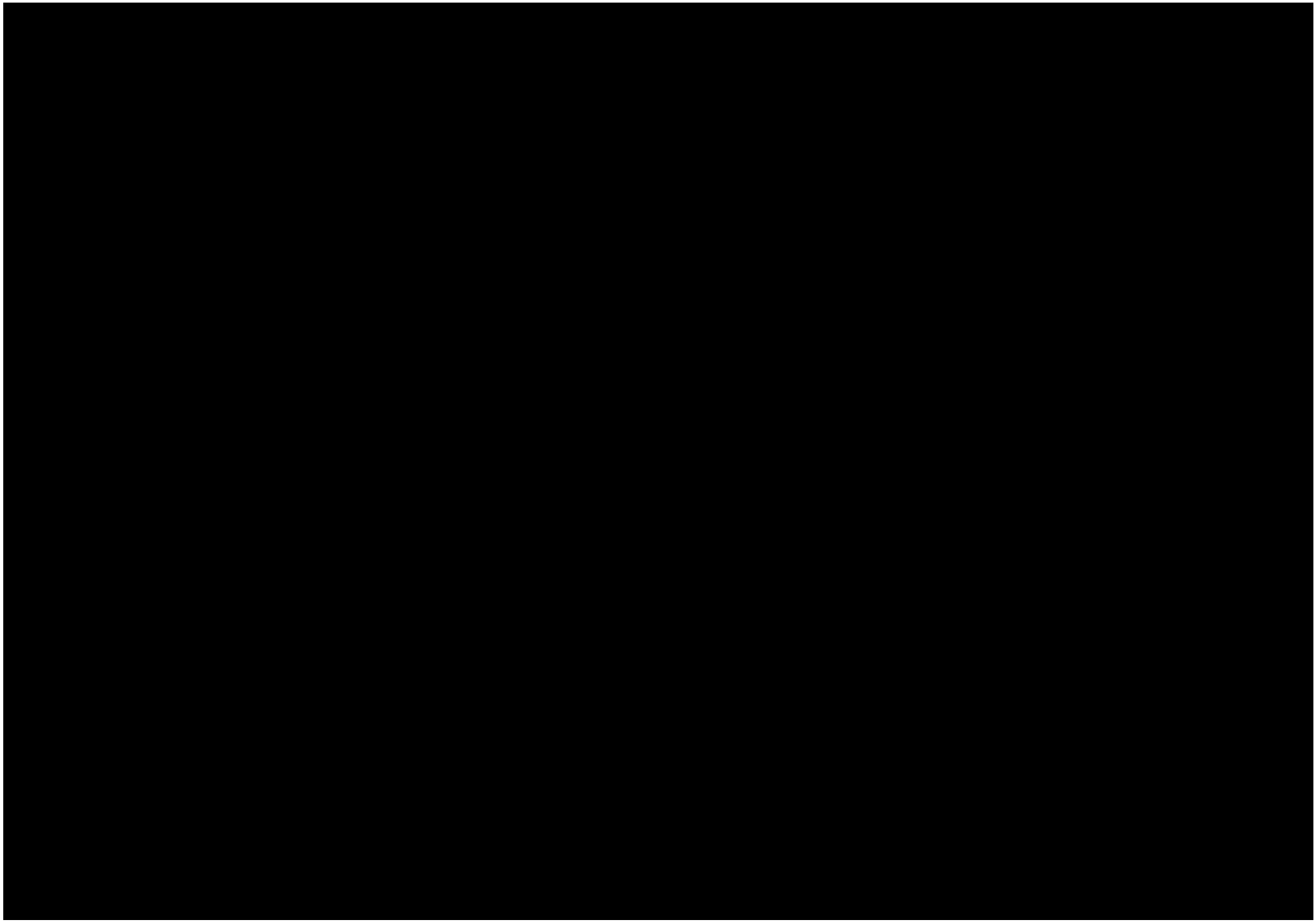
Hourly Average Day for November 2021

Jemez Mountains Electric Cooperative, Inc.

[redacted]

Hourly Average Day for December 2021

Jemez Mountains Electric Cooperative, Inc.



Hourly Average Day for January 2021

K.C. Electric Association, Inc.

[redacted]

Hourly Average Day for February 2021
K.C. Electric Association, Inc.

[redacted]

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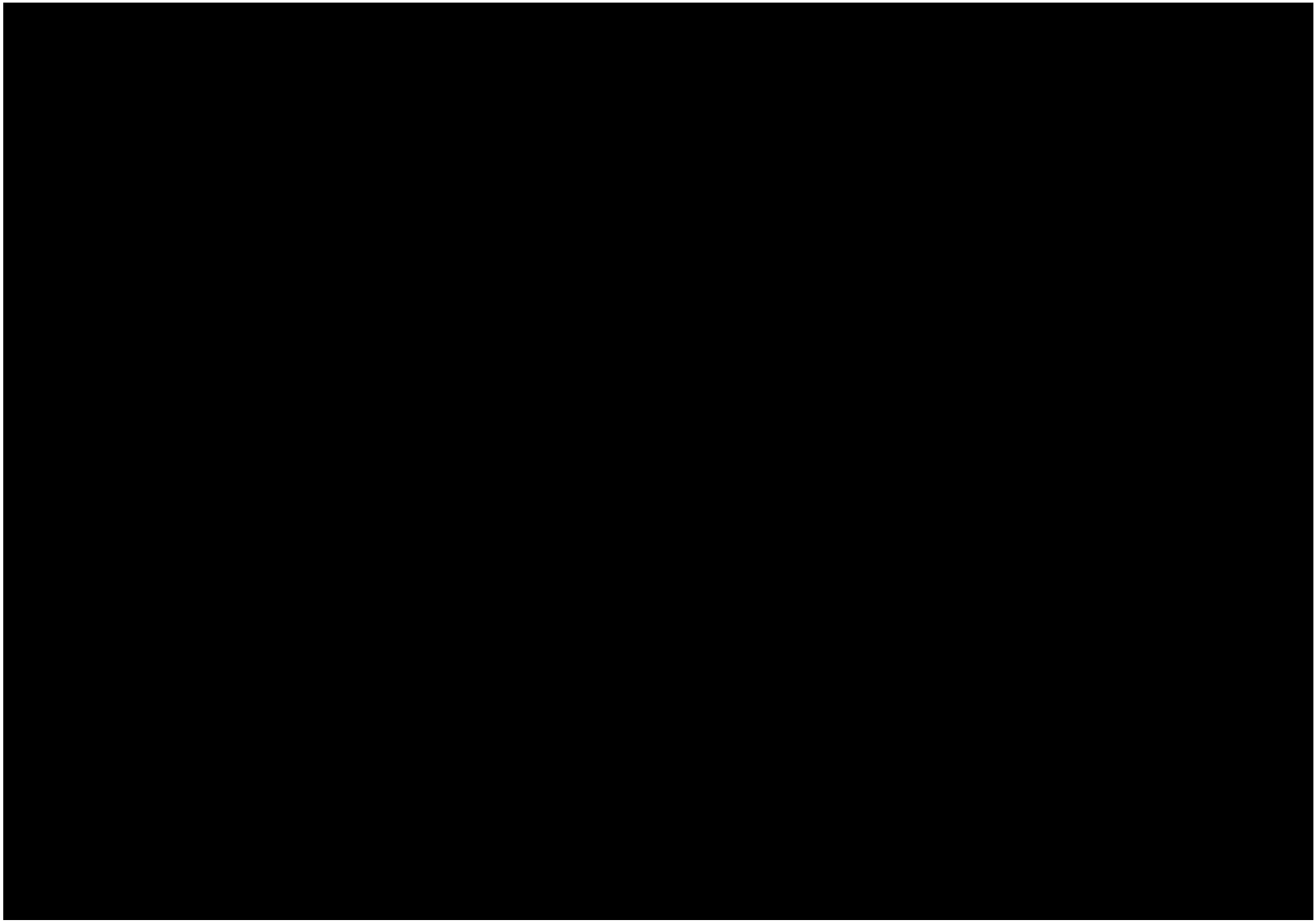
Hourly Average Day for March 2021

K.C. Electric Association, Inc.



Hourly Average Day for April 2021

K.C. Electric Association, Inc.

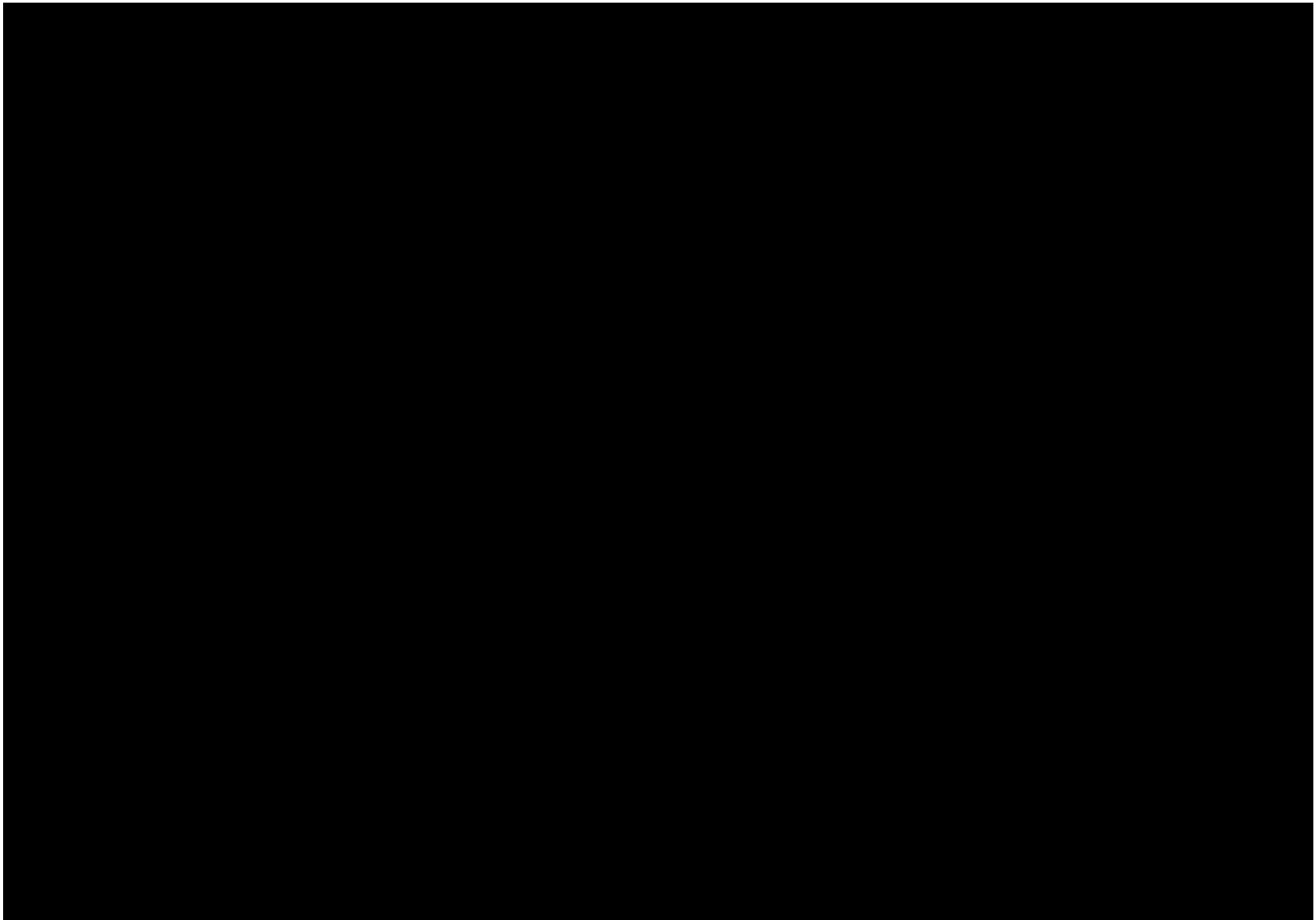
[redacted]

Hourly Average Day for May 2021
K.C. Electric Association, Inc.

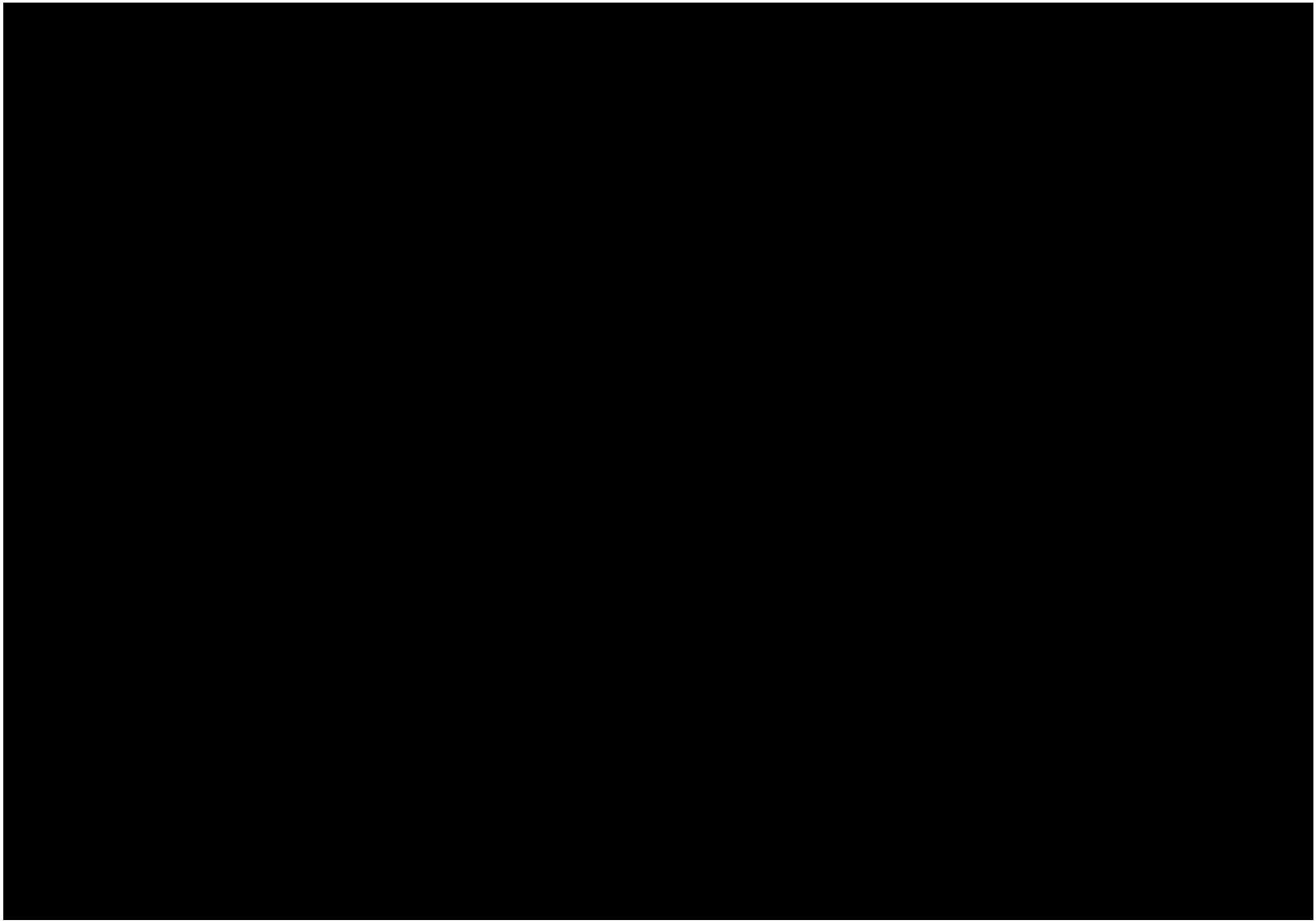
[redacted]

Hourly Average Day for June 2021

K.C. Electric Association, Inc.



Hourly Average Day for July 2021
K.C. Electric Association, Inc.



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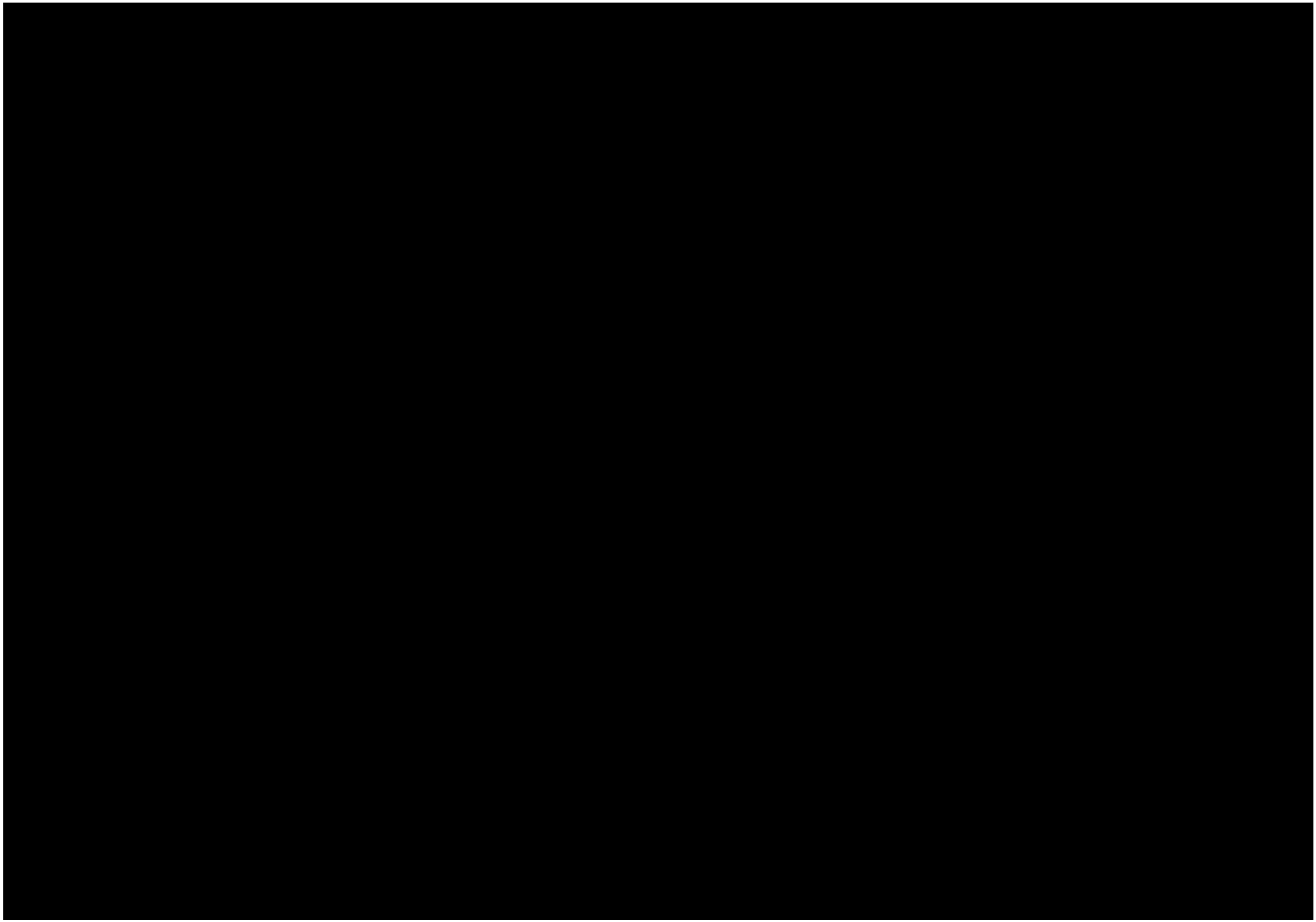
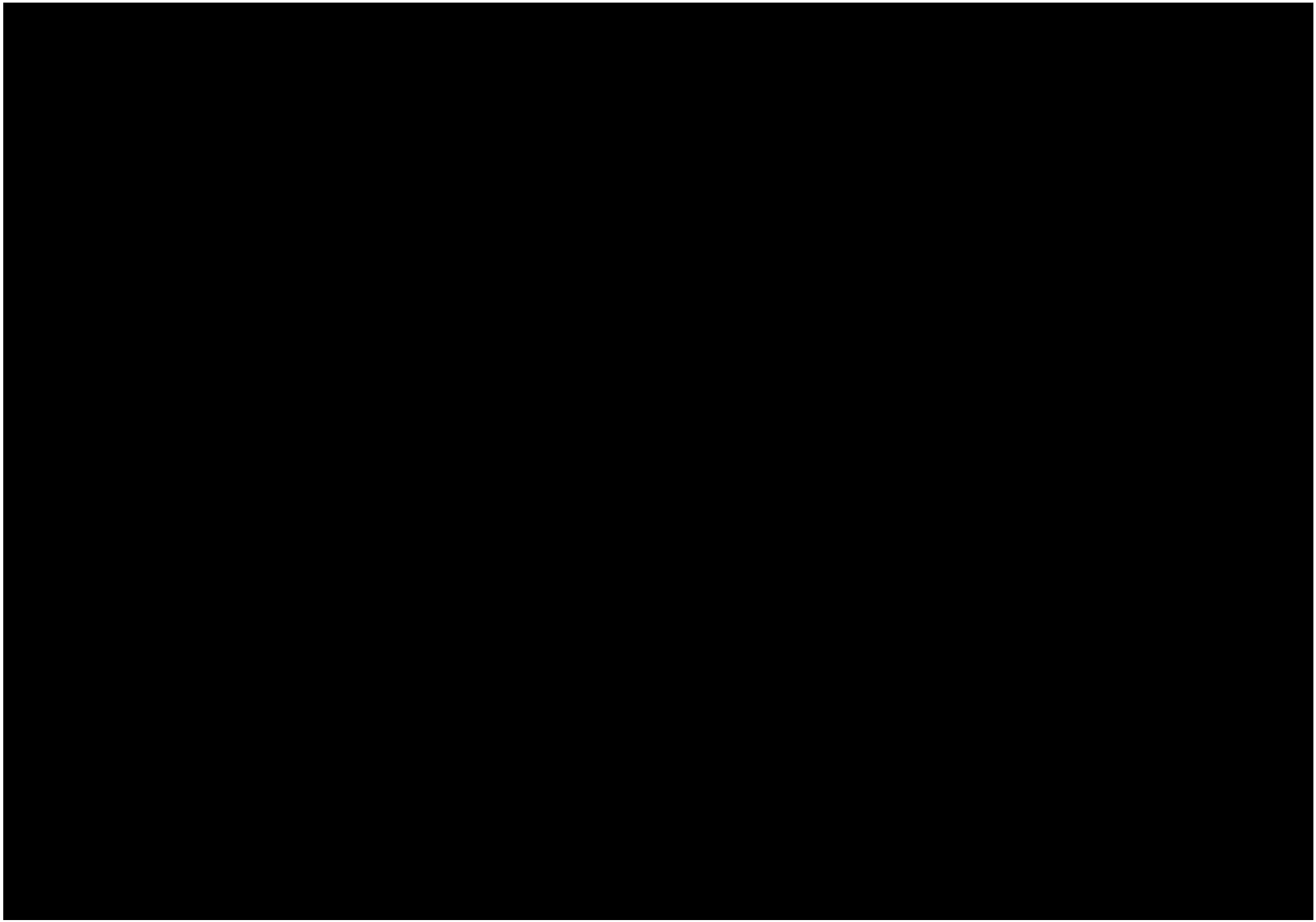
Hourly Average Day for August 2021

K.C. Electric Association, Inc.



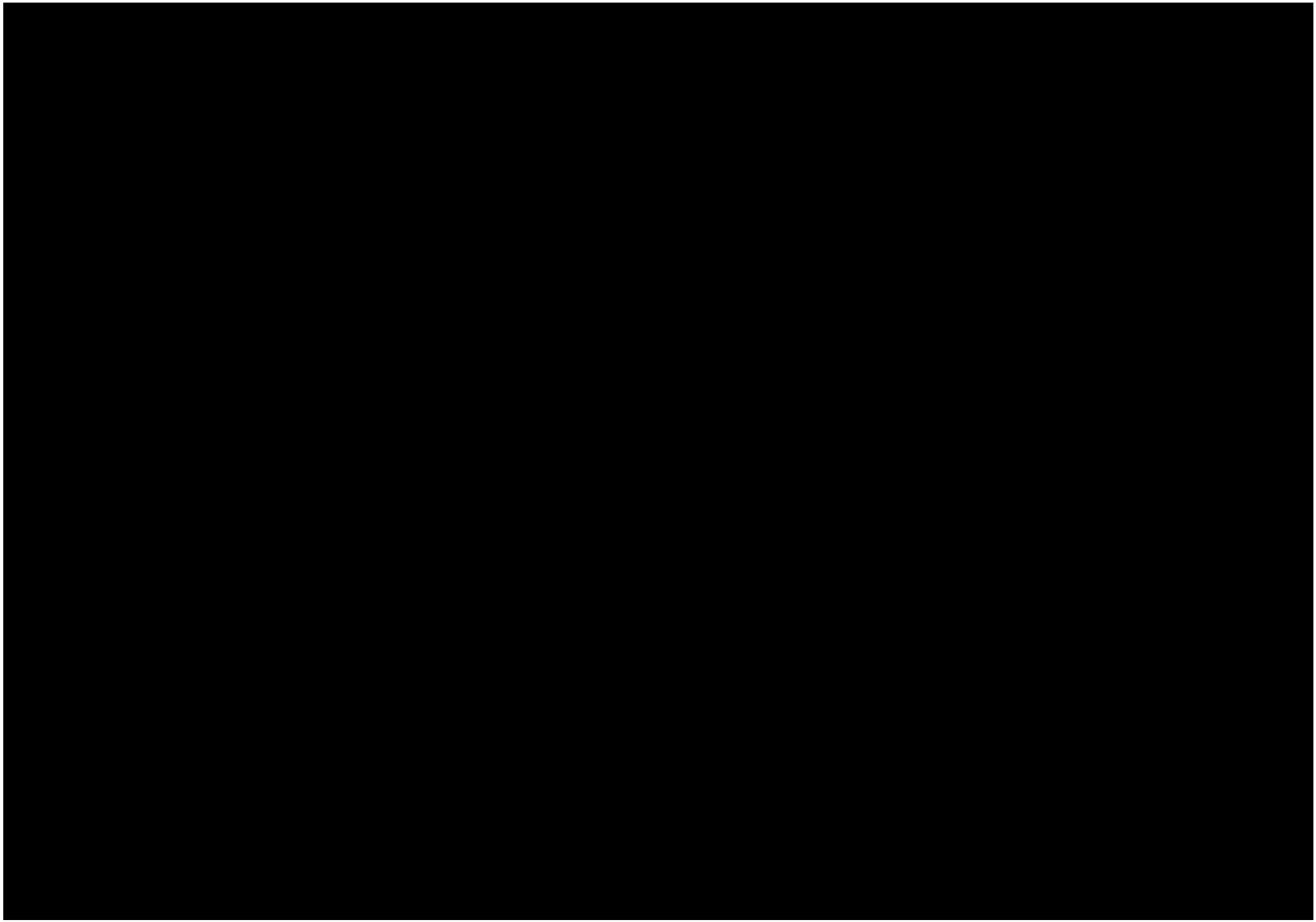
Hourly Average Day for September 2021

K.C. Electric Association, Inc.



Hourly Average Day for October 2021

K.C. Electric Association, Inc.



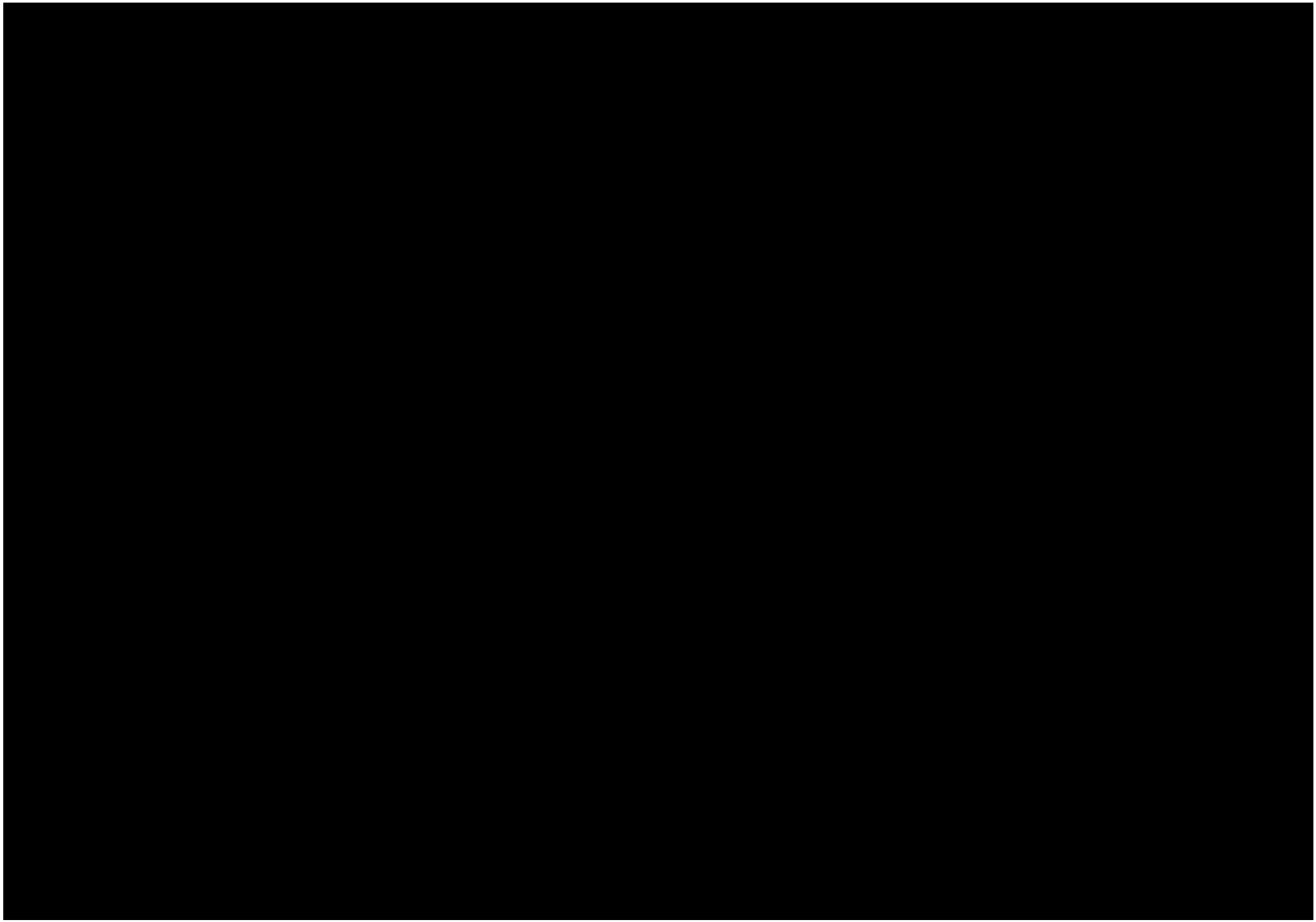
Hourly Average Day for November 2021

K.C. Electric Association, Inc.

[redacted]

Hourly Average Day for December 2021

K.C. Electric Association, Inc.



Hourly Average Day for January 2021
La Plata Electric Association, Inc.

[redacted]

Hourly Average Day for February 2021
La Plata Electric Association, Inc.

[redacted]

Hourly Average Day for March 2021

La Plata Electric Association, Inc.

[redacted]

Hourly Average Day for April 2021

La Plata Electric Association, Inc.

[redacted]

Hourly Average Day for May 2021

La Plata Electric Association, Inc.

[redacted]

Hourly Average Day for June 2021

La Plata Electric Association, Inc.

[redacted]

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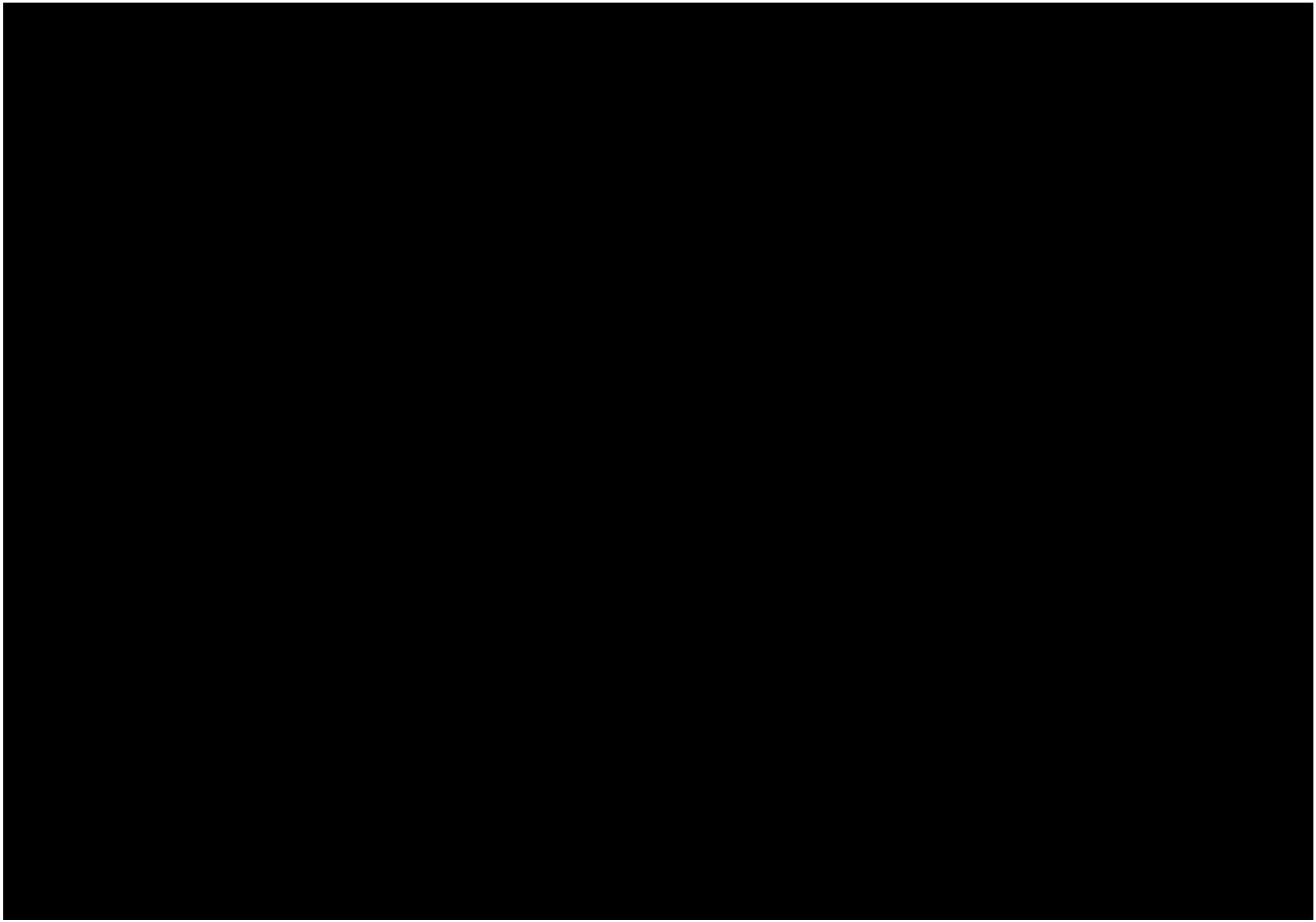
Hourly Average Day for July 2021

La Plata Electric Association, Inc.



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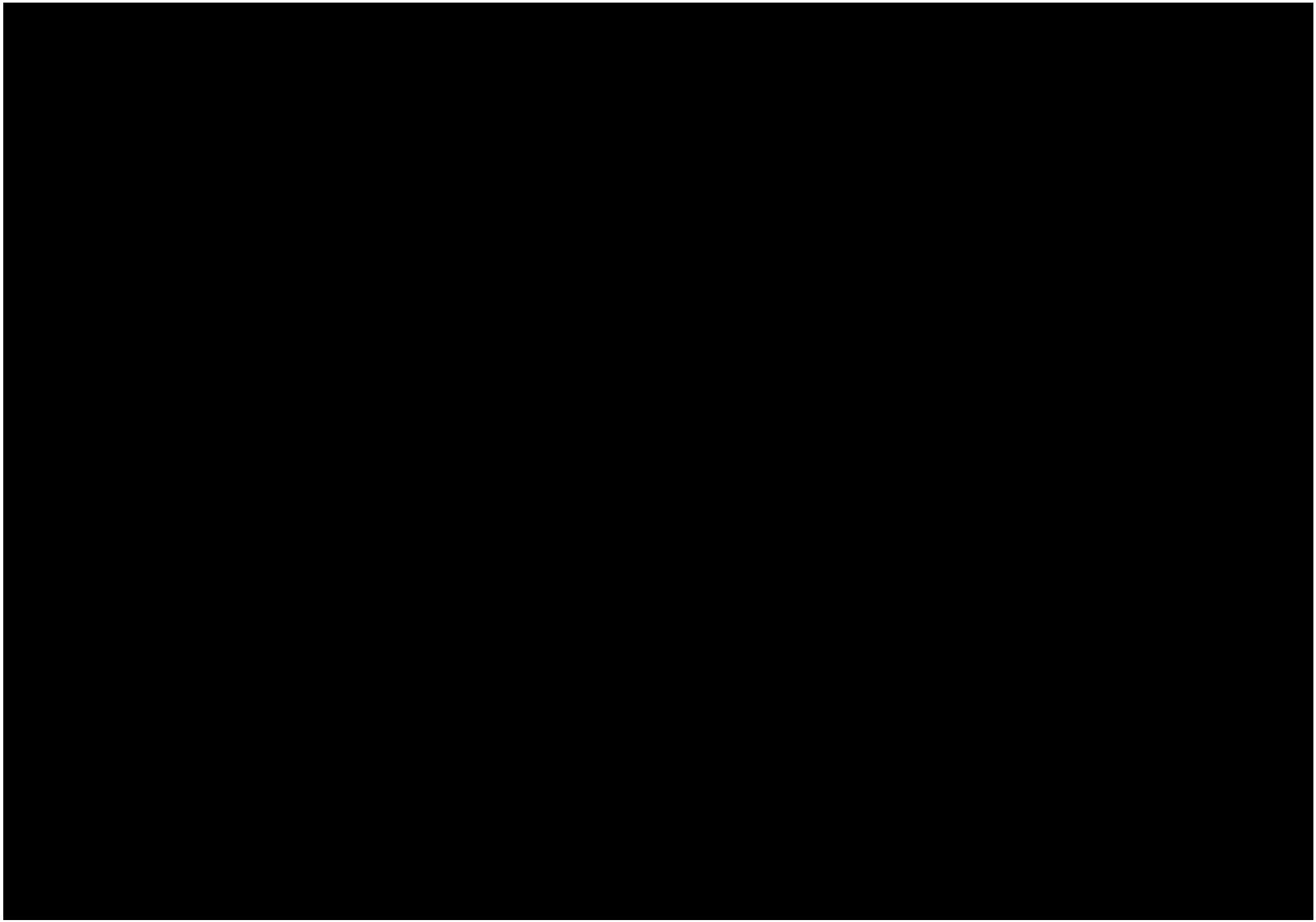
Hourly Average Day for August 2021

La Plata Electric Association, Inc.



Hourly Average Day for September 2021

La Plata Electric Association, Inc.

[redacted]

Hourly Average Day for October 2021

La Plata Electric Association, Inc.

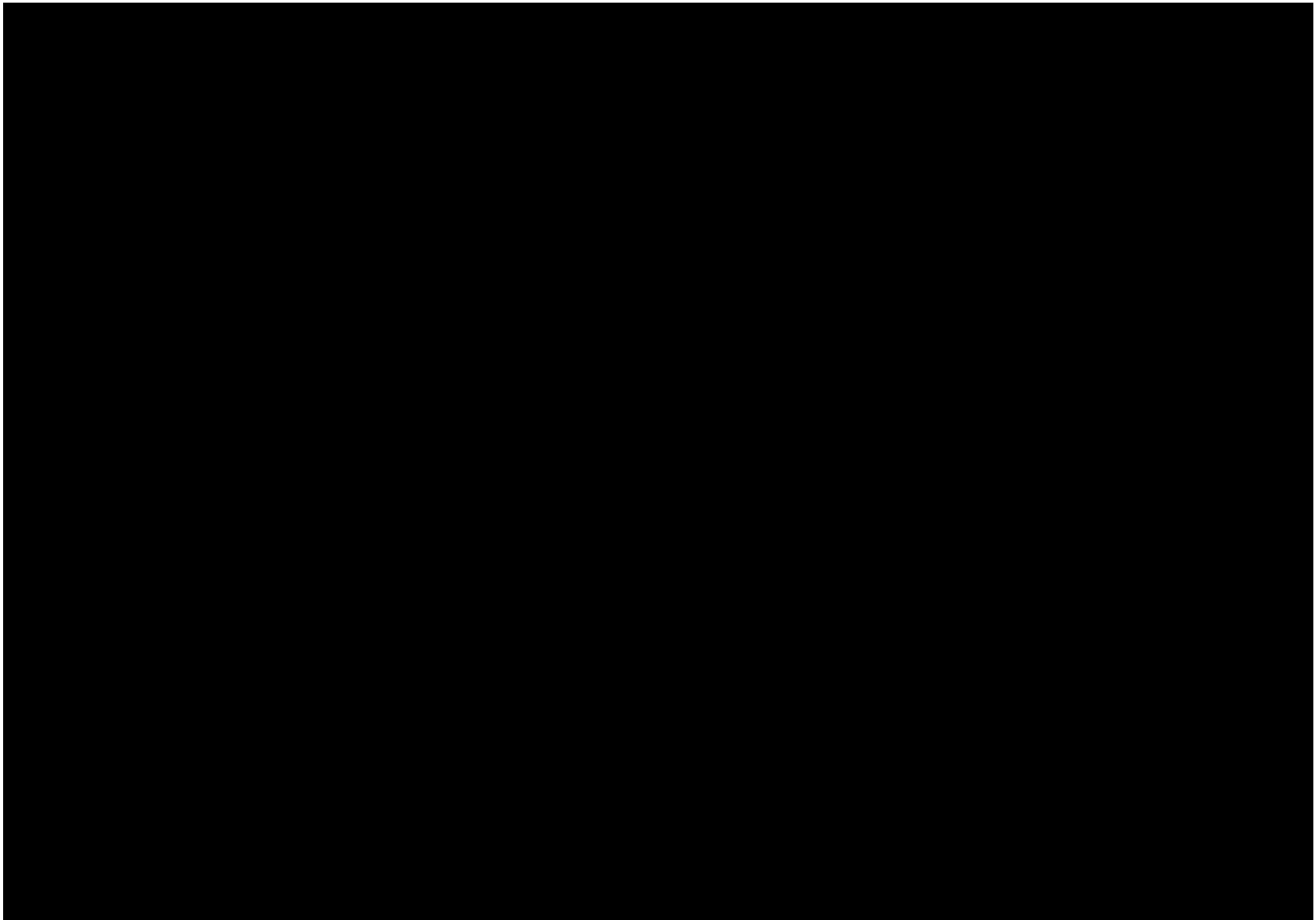
[redacted]

Hourly Average Day for November 2021

La Plata Electric Association, Inc.

[redacted]

Hourly Average Day for December 2021
La Plata Electric Association, Inc.

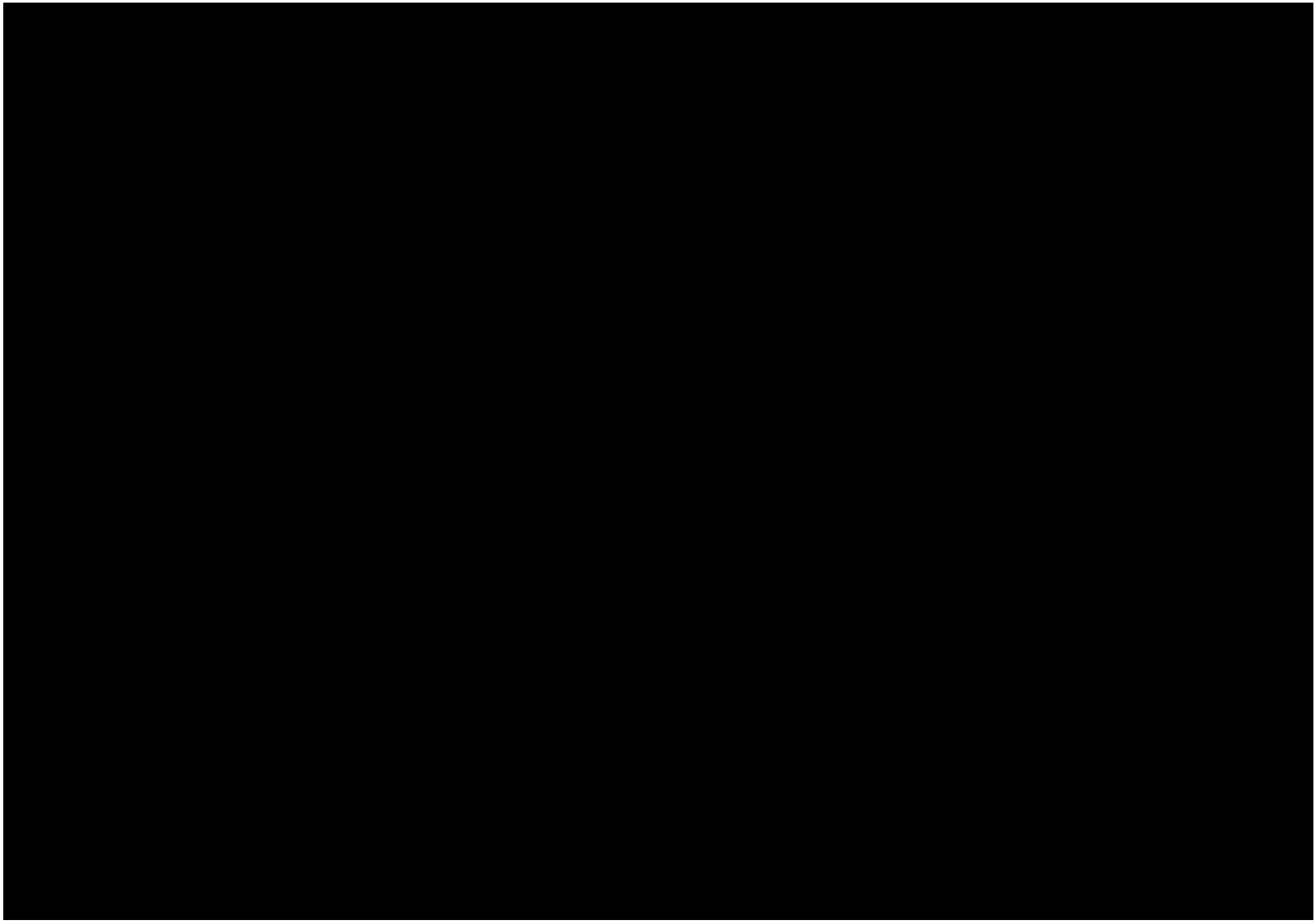


Hourly Average Day for January 2021

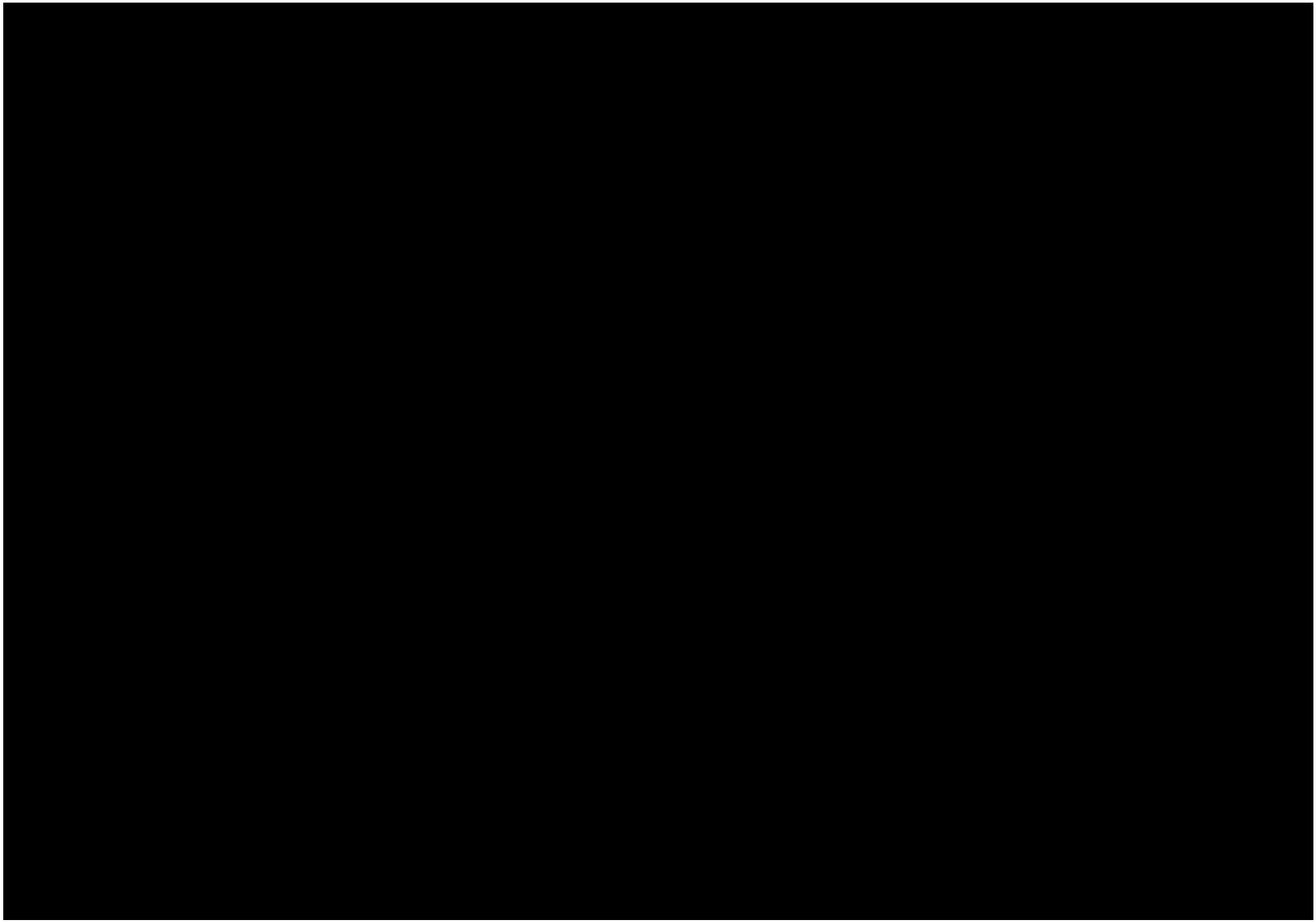
Morgan County Rural Electric Association

[redacted]

Hourly Average Day for February 2021
Morgan County Rural Electric Association

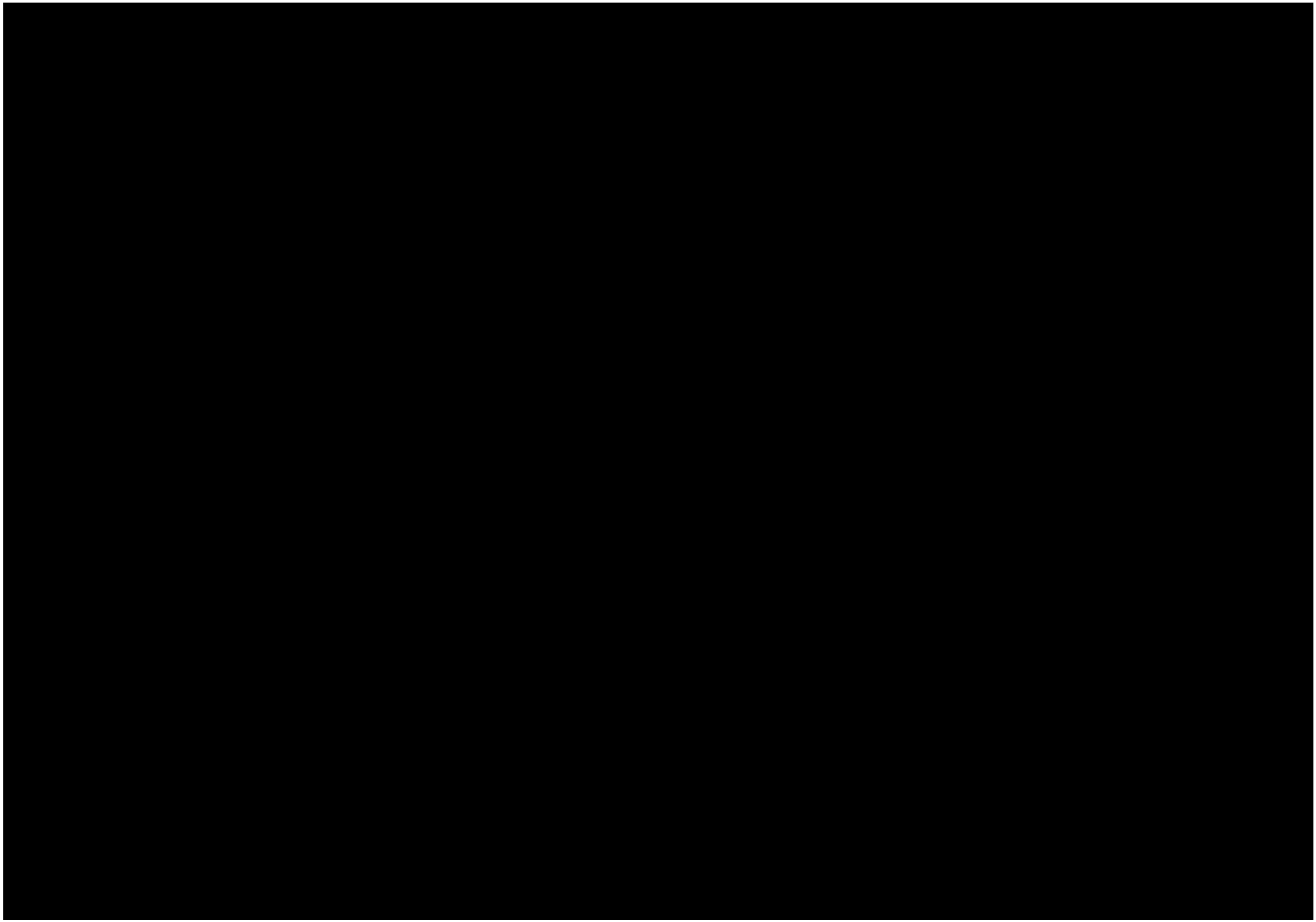


Hourly Average Day for March 2021
Morgan County Rural Electric Association

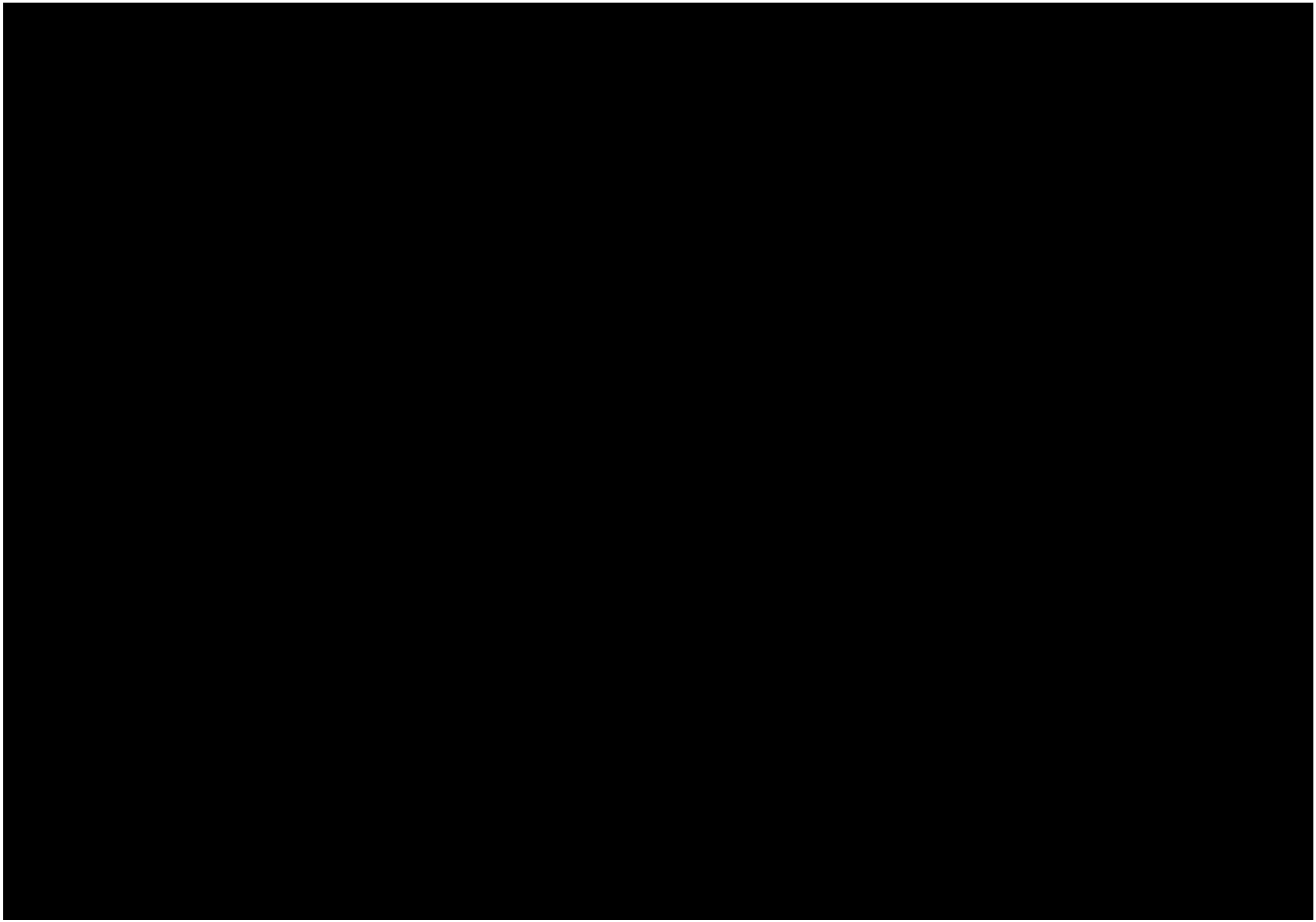


Hourly Average Day for April 2021

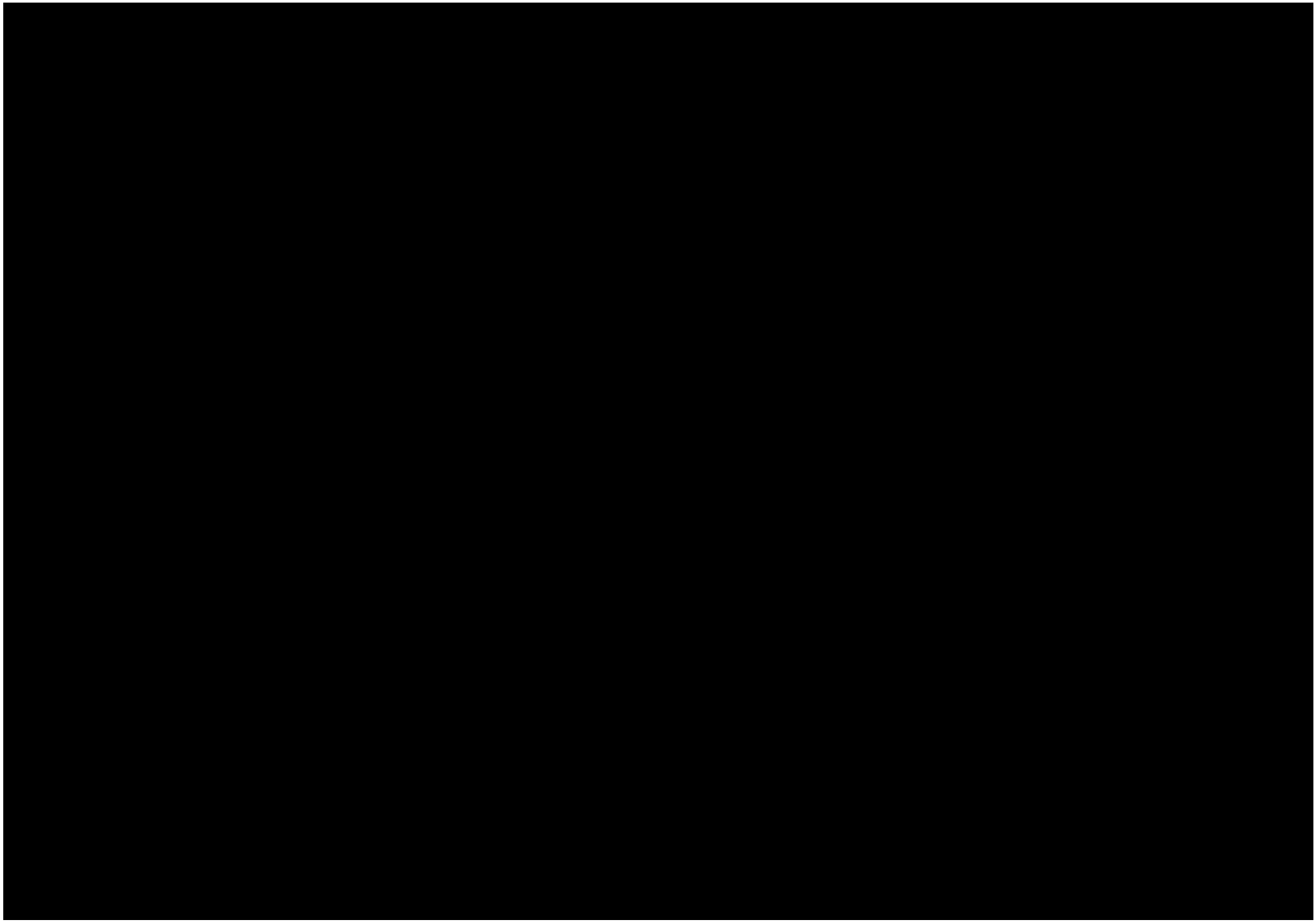
Morgan County Rural Electric Association



Hourly Average Day for May 2021
Morgan County Rural Electric Association



Hourly Average Day for June 2021
Morgan County Rural Electric Association



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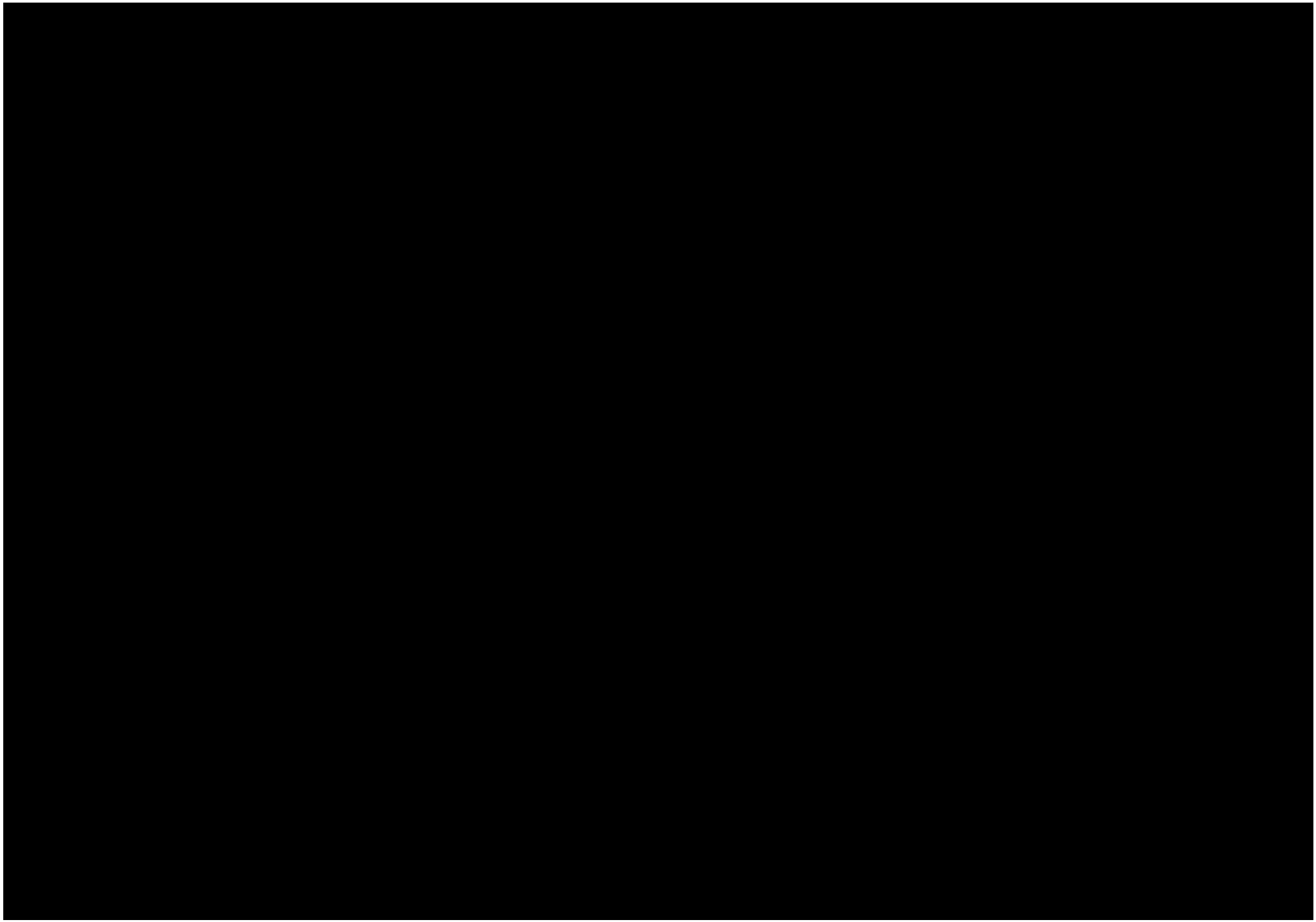
Hourly Average Day for July 2021

Morgan County Rural Electric Association



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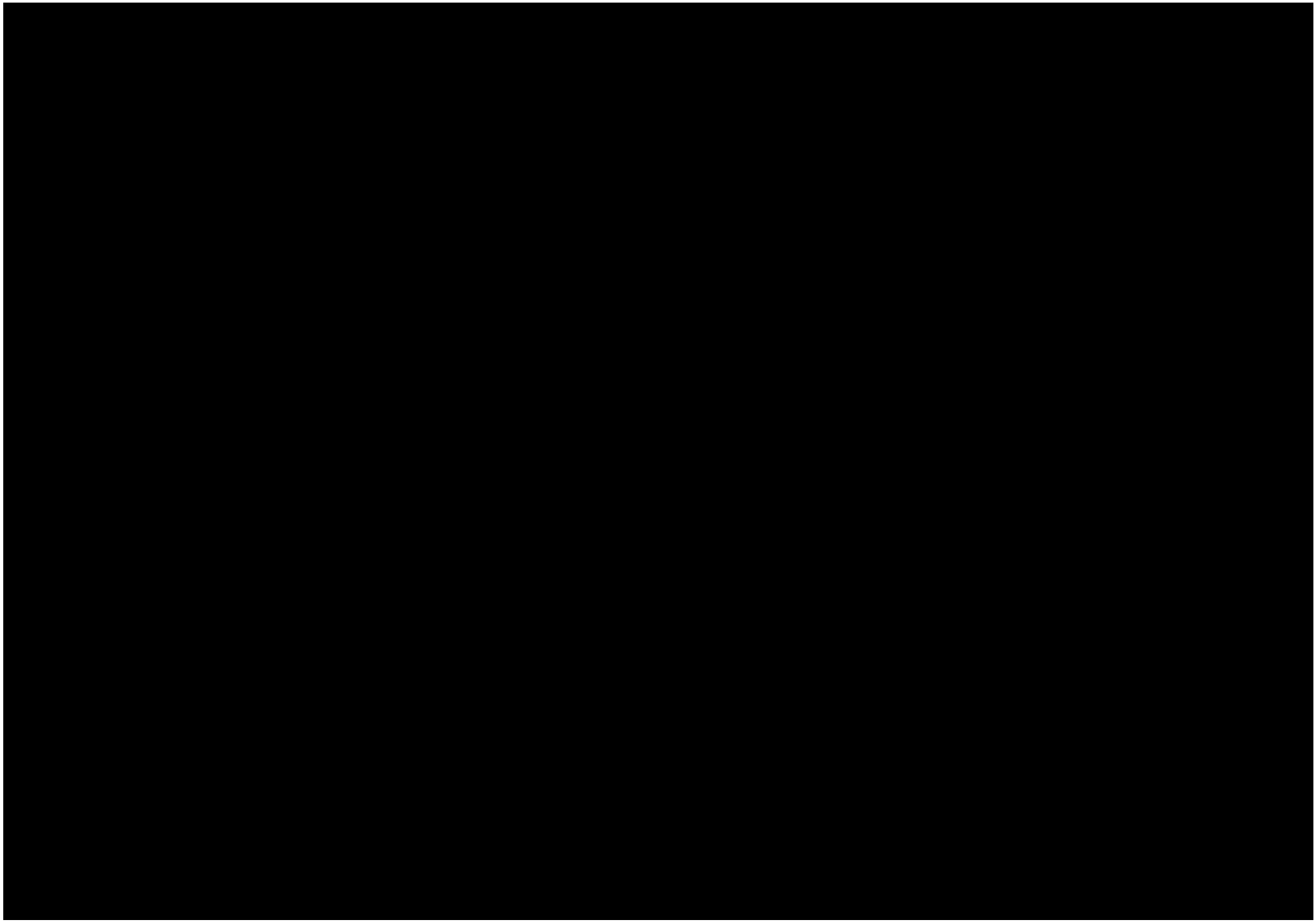
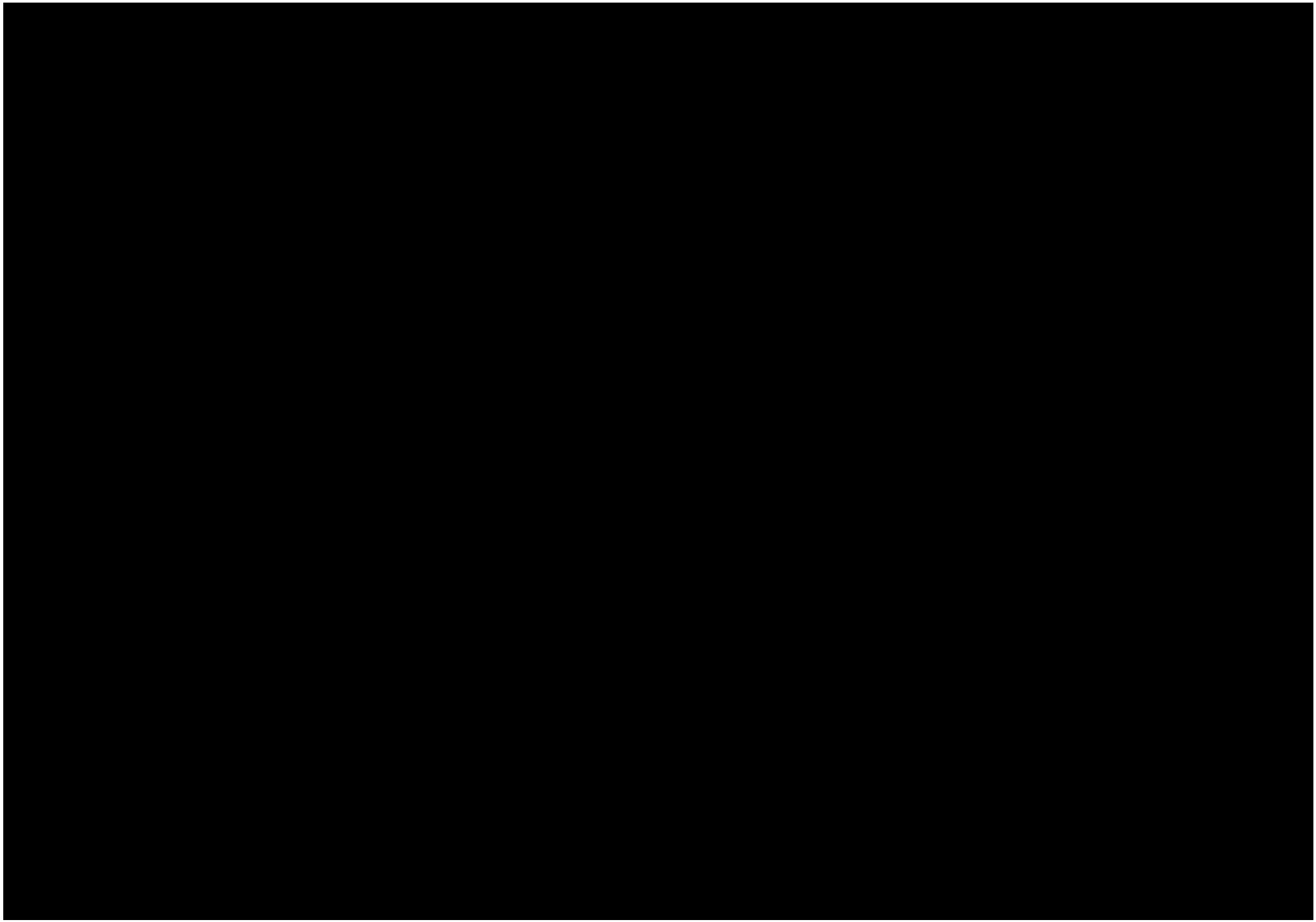
Hourly Average Day for August 2021

Morgan County Rural Electric Association



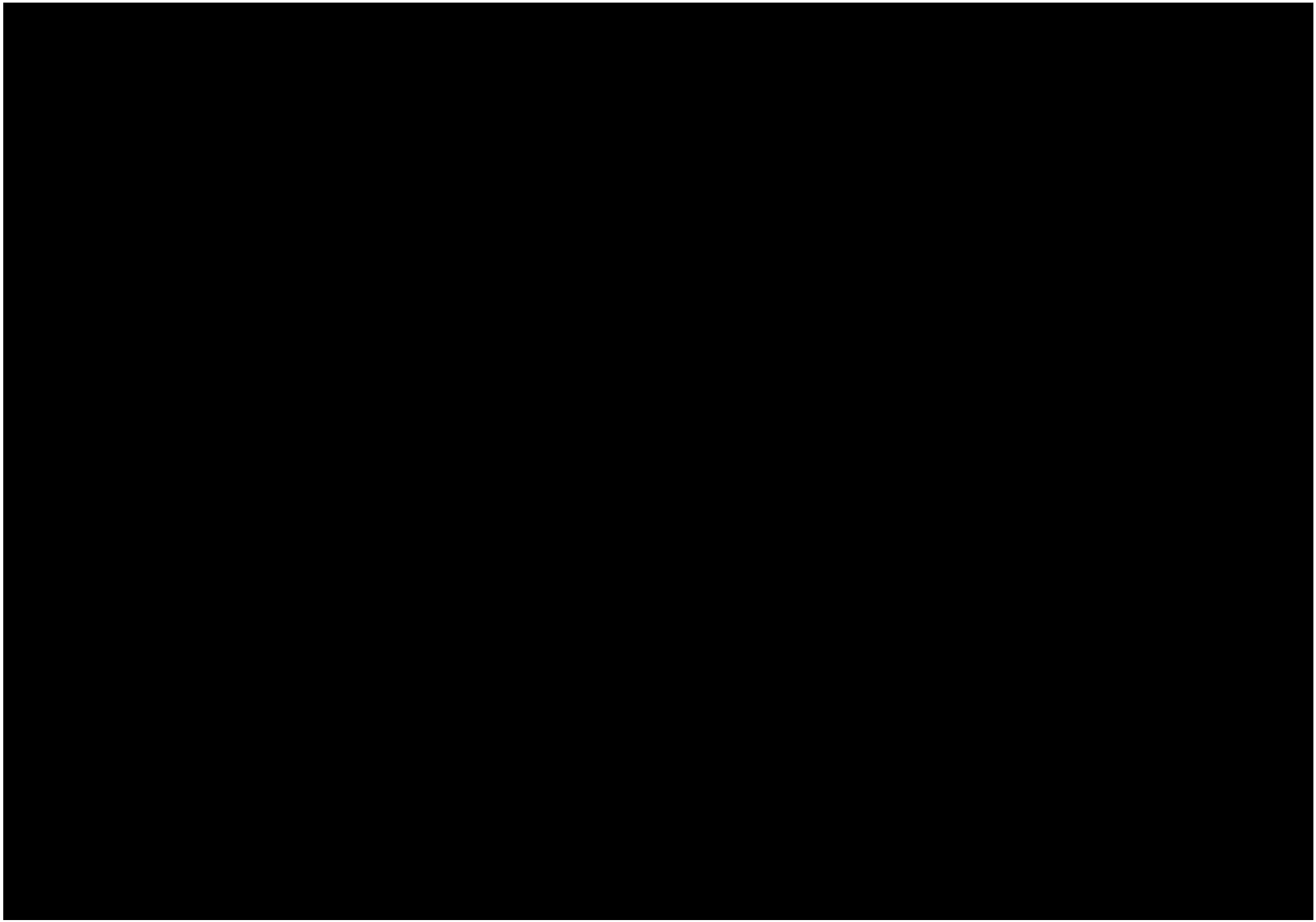
Hourly Average Day for September 2021

Morgan County Rural Electric Association



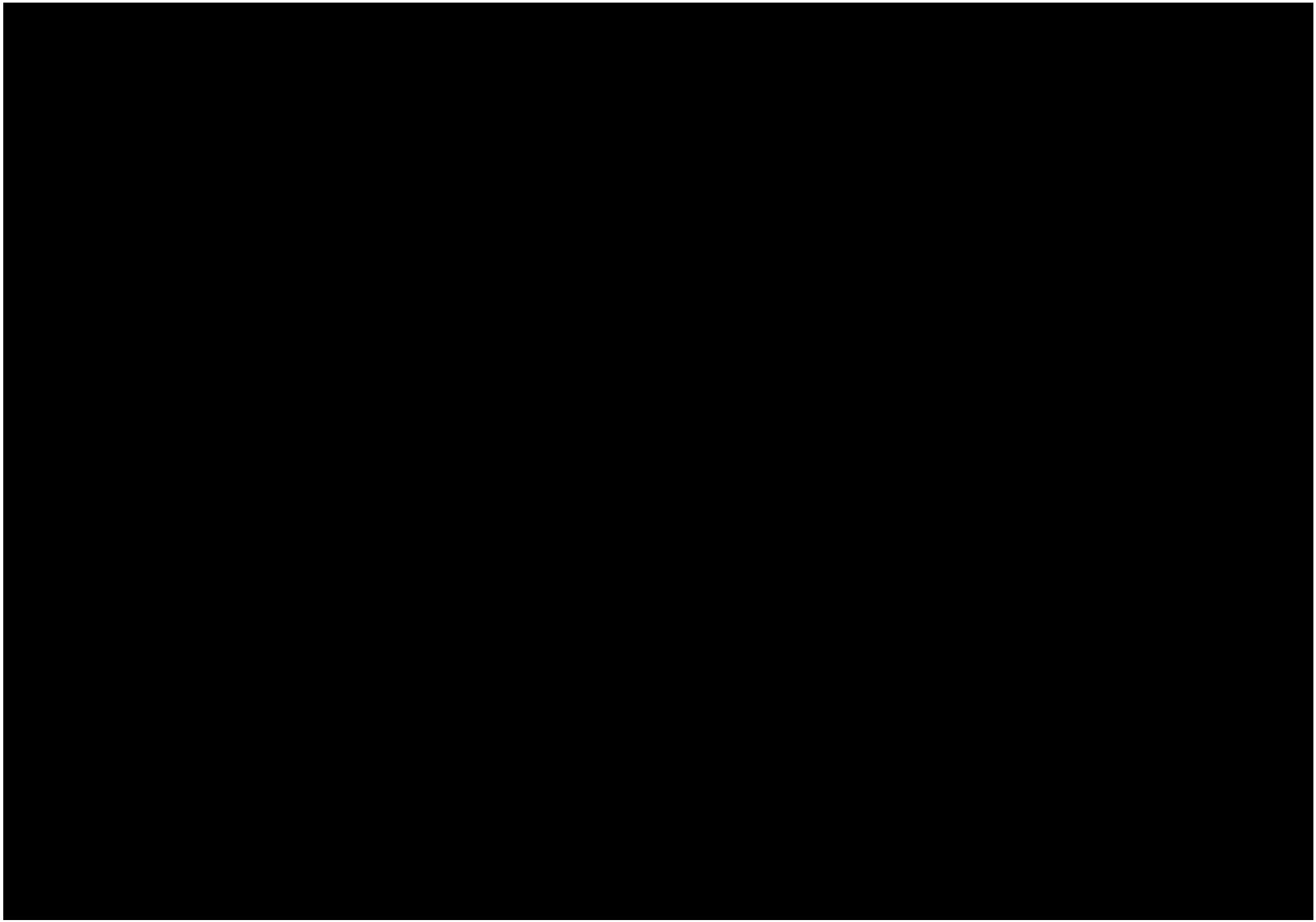
Hourly Average Day for October 2021

Morgan County Rural Electric Association



Hourly Average Day for November 2021

Morgan County Rural Electric Association



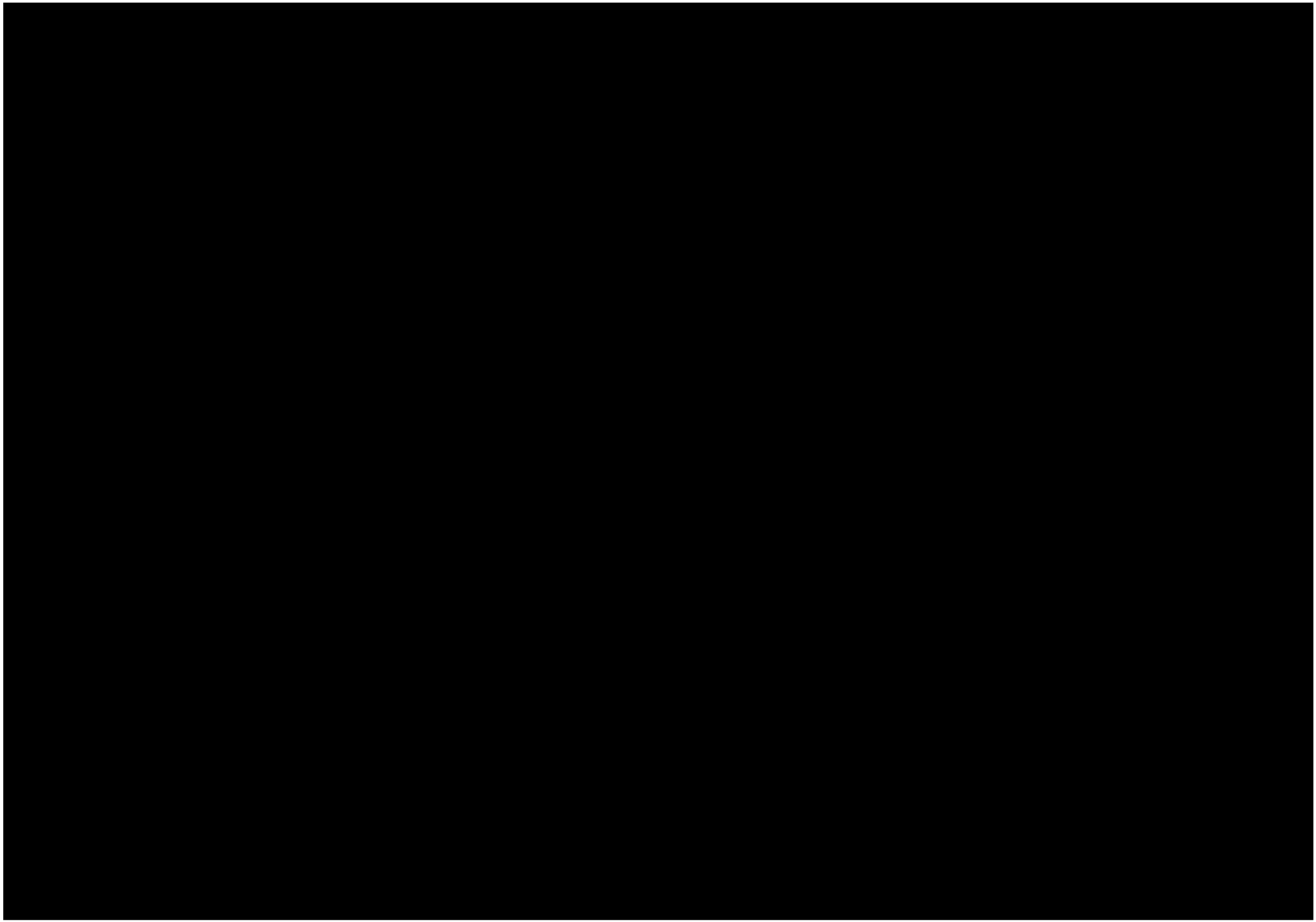
Hourly Average Day for December 2021

Morgan County Rural Electric Association

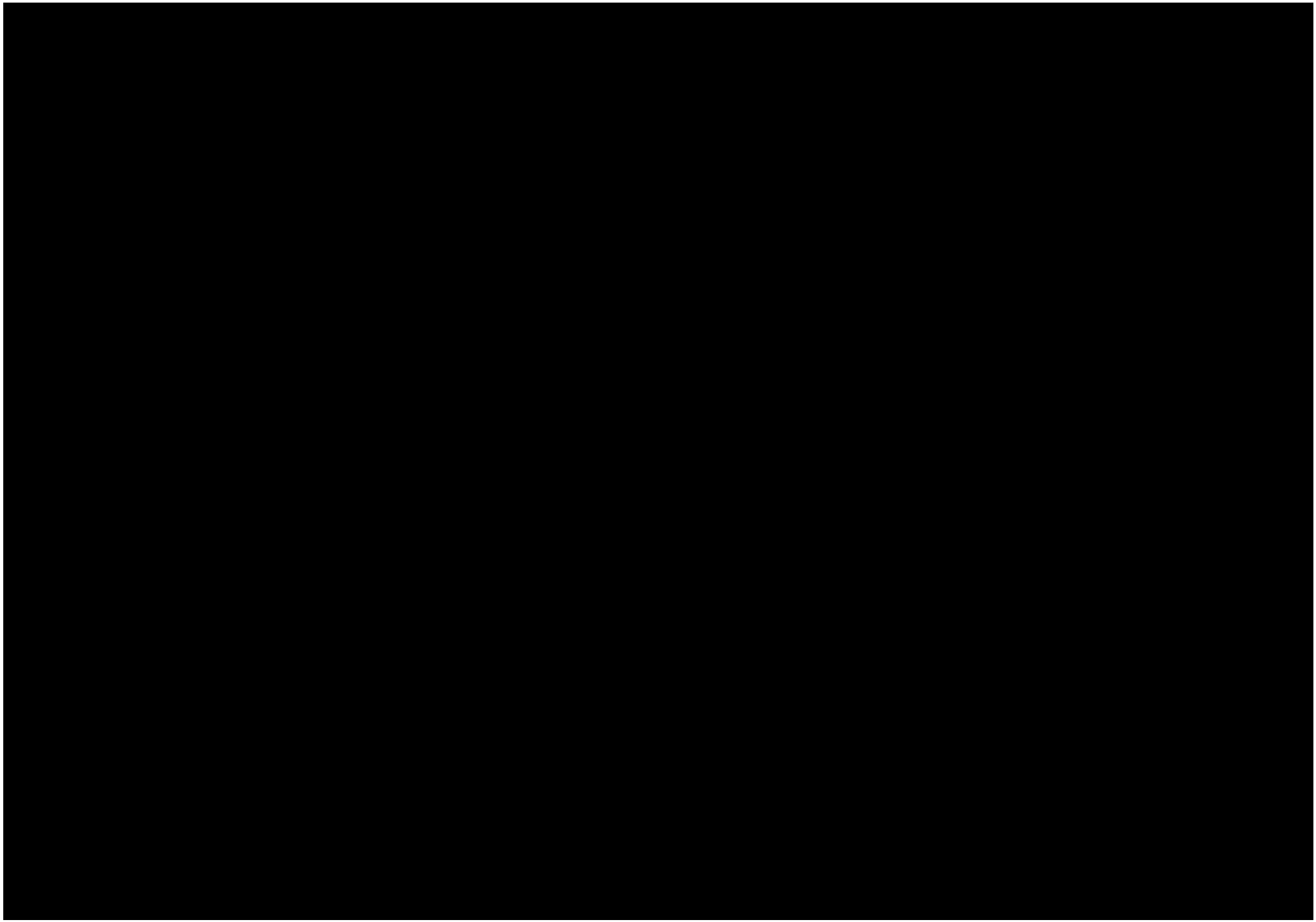
[redacted]

Hourly Average Day for January 2021

Mountain Parks Electric, Inc.



Hourly Average Day for February 2021
Mountain Parks Electric, Inc.



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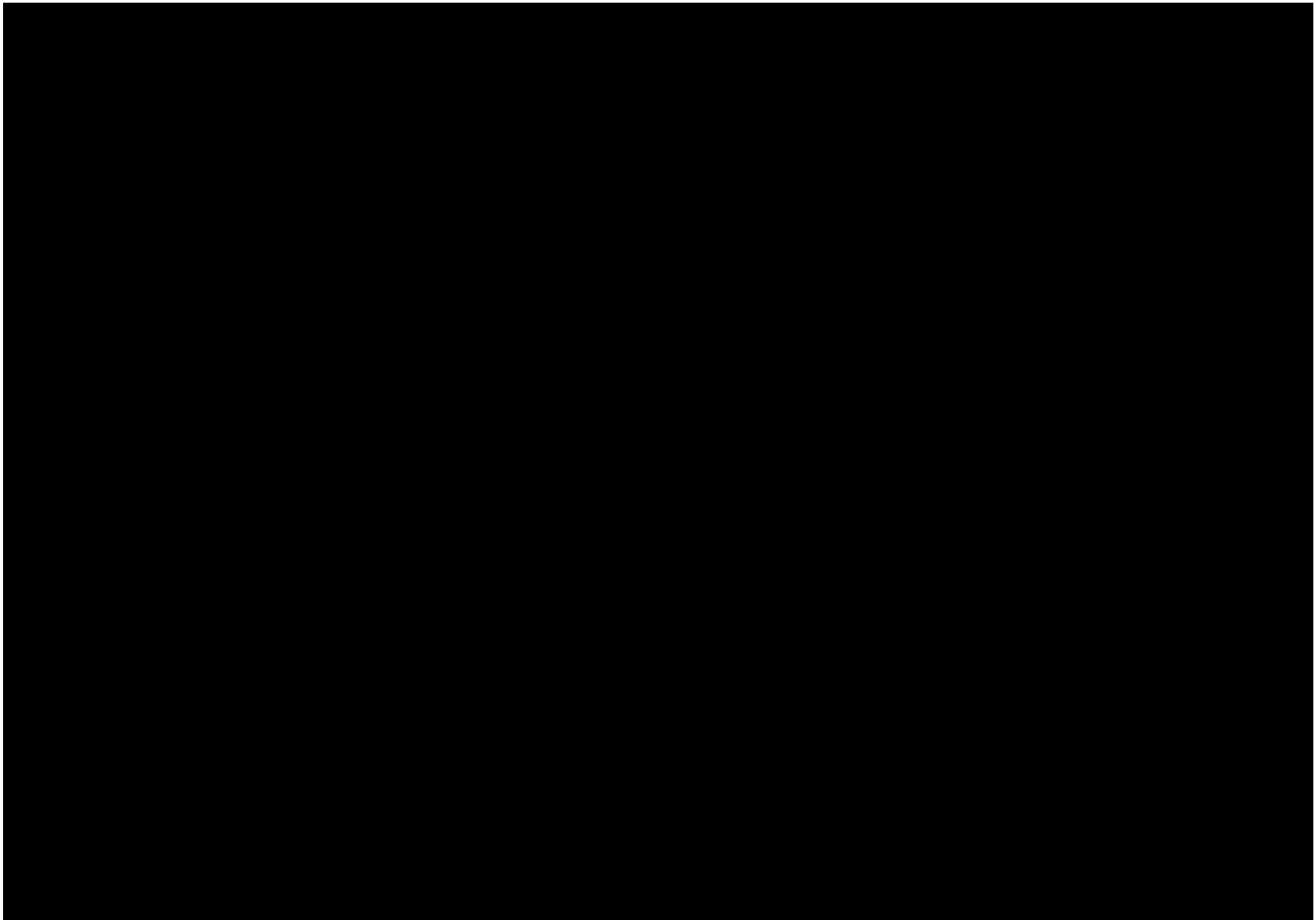
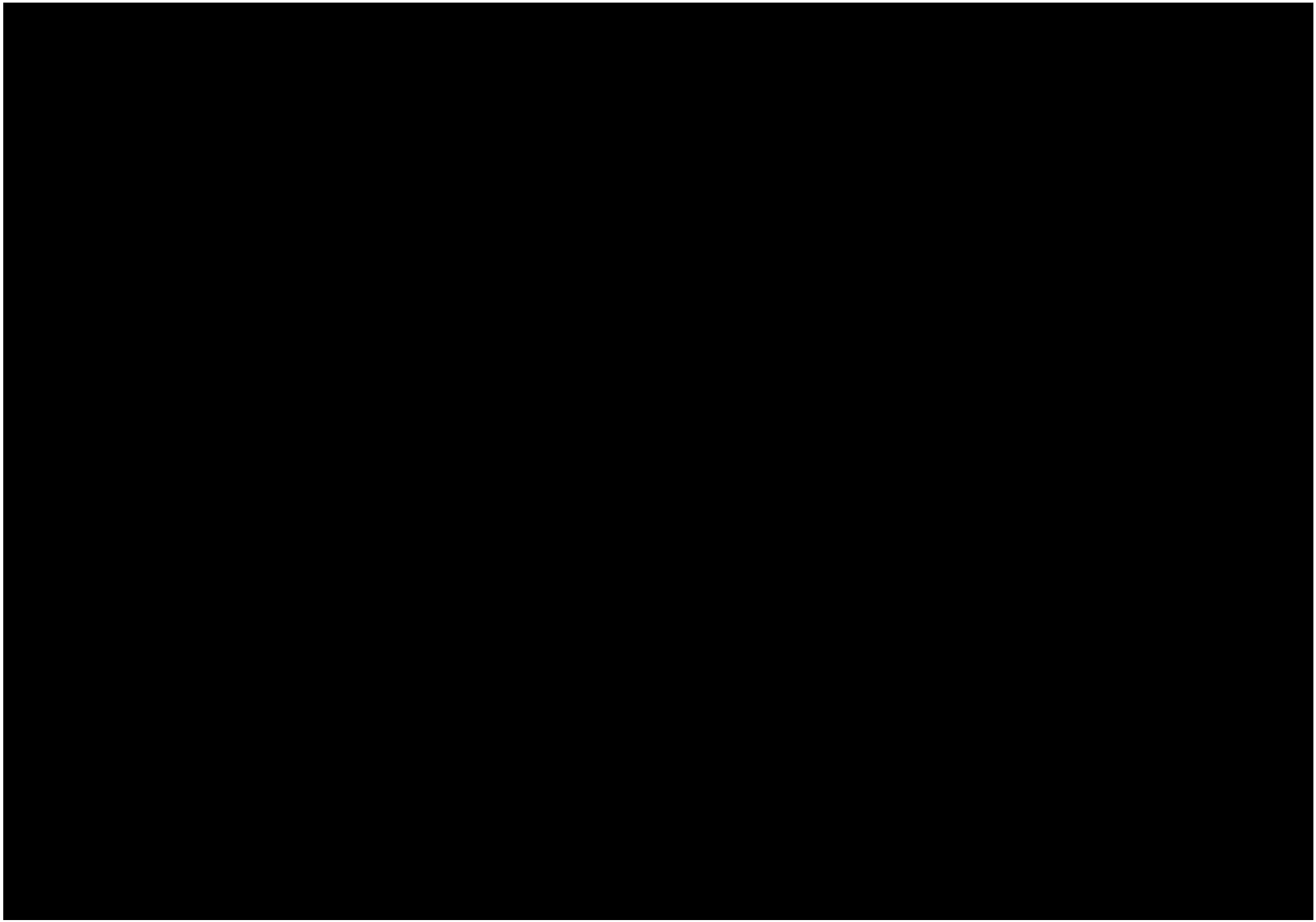
Hourly Average Day for March 2021

Mountain Parks Electric, Inc.



Hourly Average Day for April 2021

Mountain Parks Electric, Inc.



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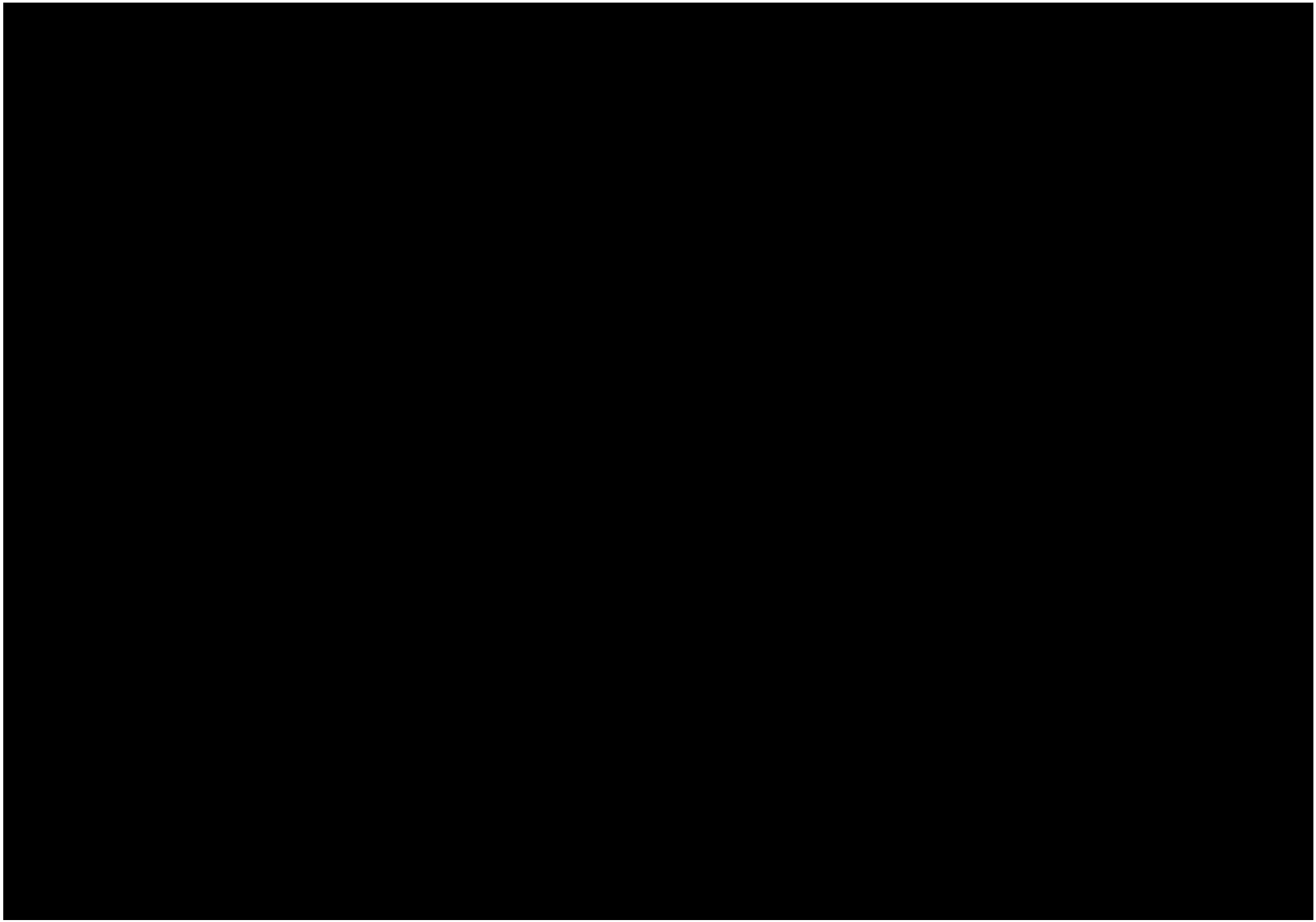
Hourly Average Day for May 2021

Mountain Parks Electric, Inc.



Hourly Average Day for June 2021

Mountain Parks Electric, Inc.

[redacted]

Hourly Average Day for July 2021

Mountain Parks Electric, Inc.

[redacted]

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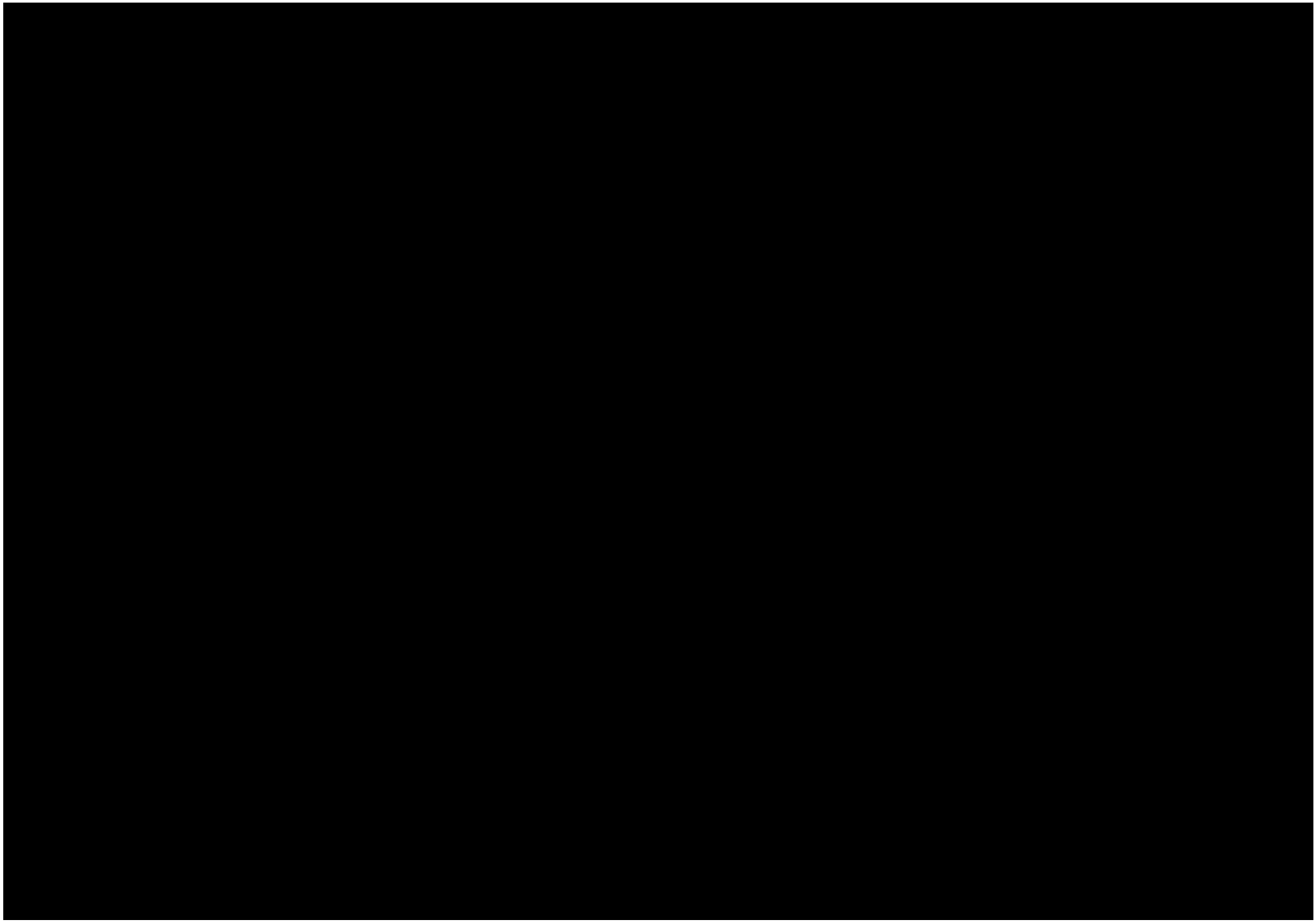
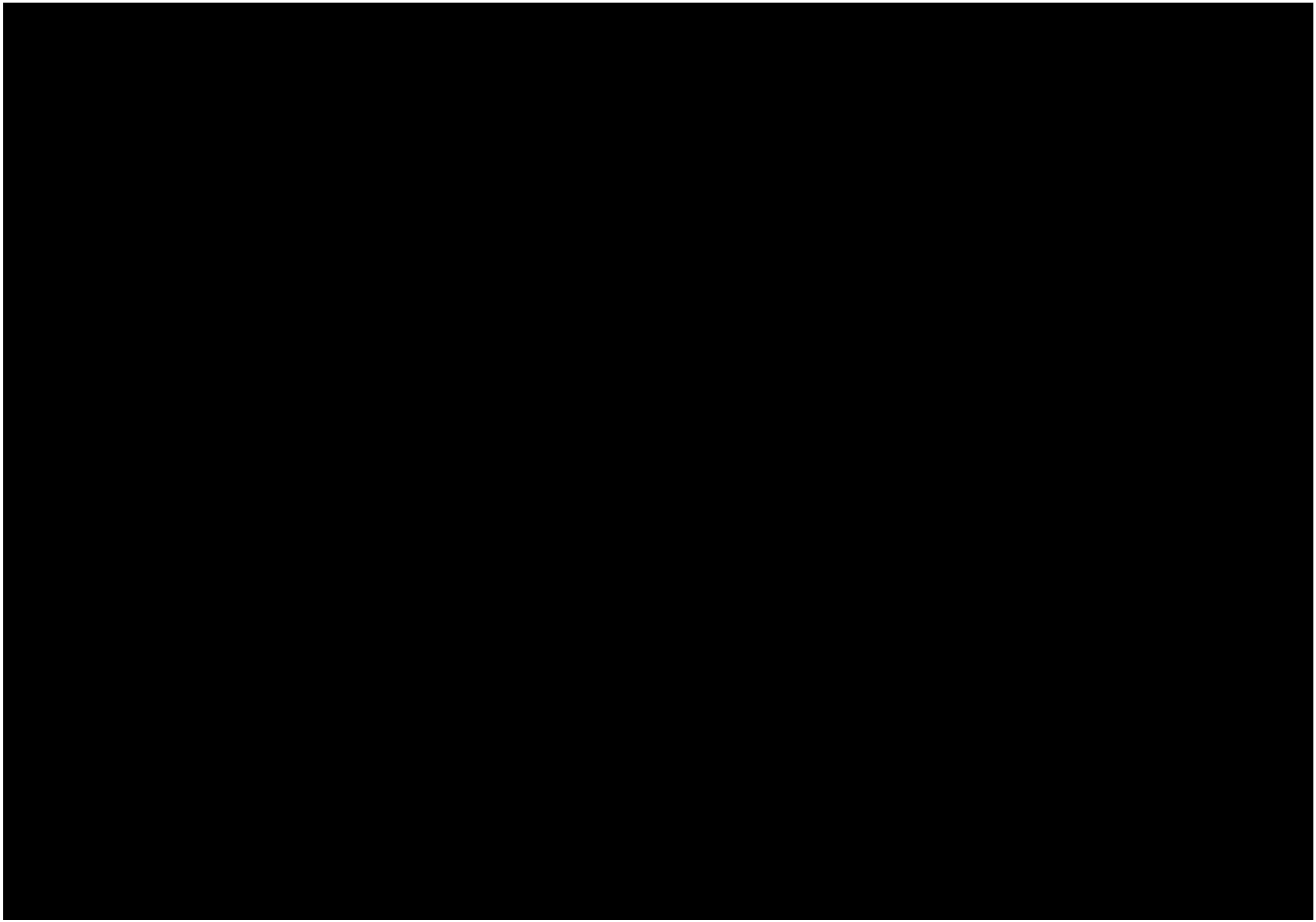
Hourly Average Day for August 2021

Mountain Parks Electric, Inc.



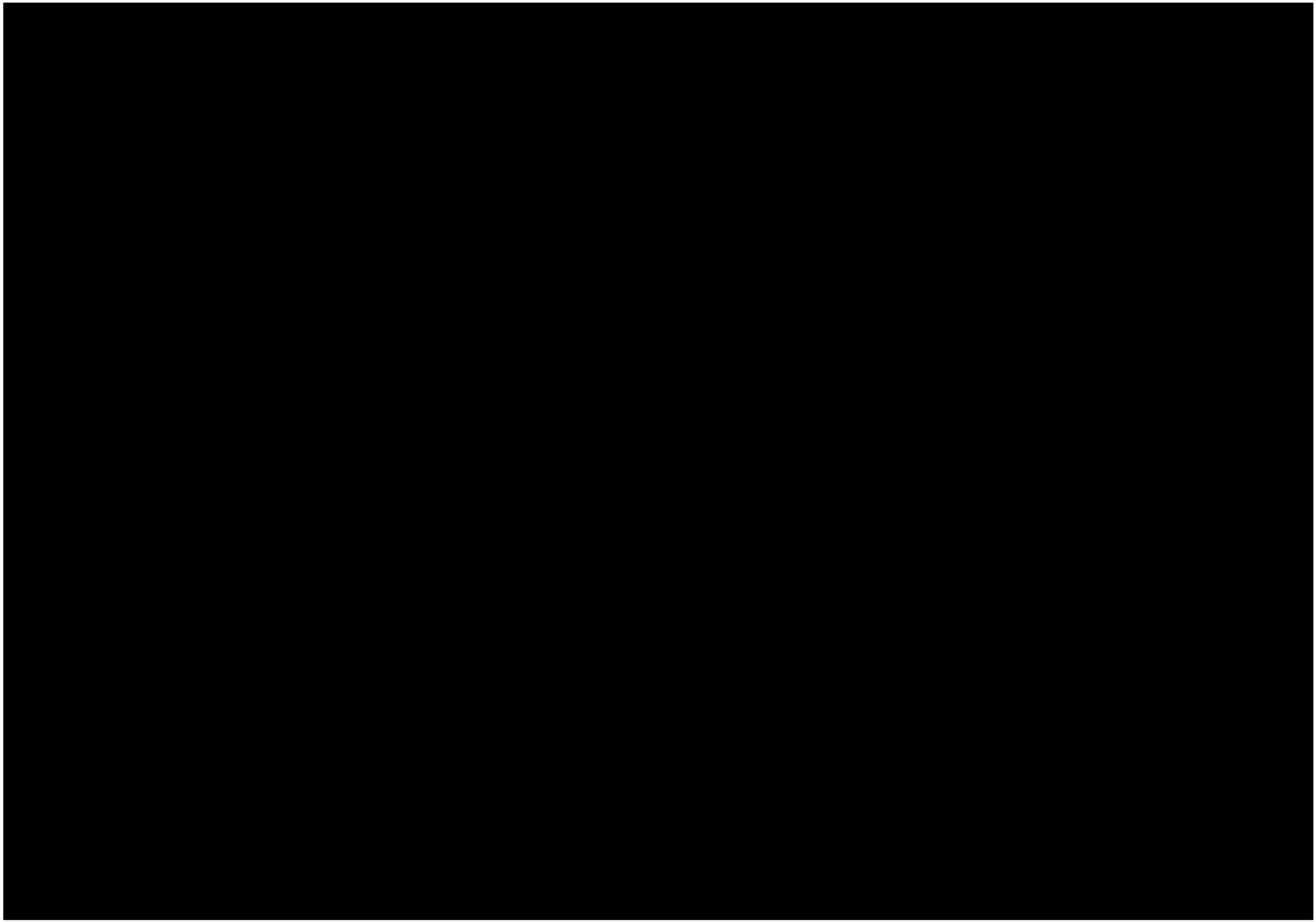
Hourly Average Day for September 2021

Mountain Parks Electric, Inc.



Hourly Average Day for October 2021

Mountain Parks Electric, Inc.



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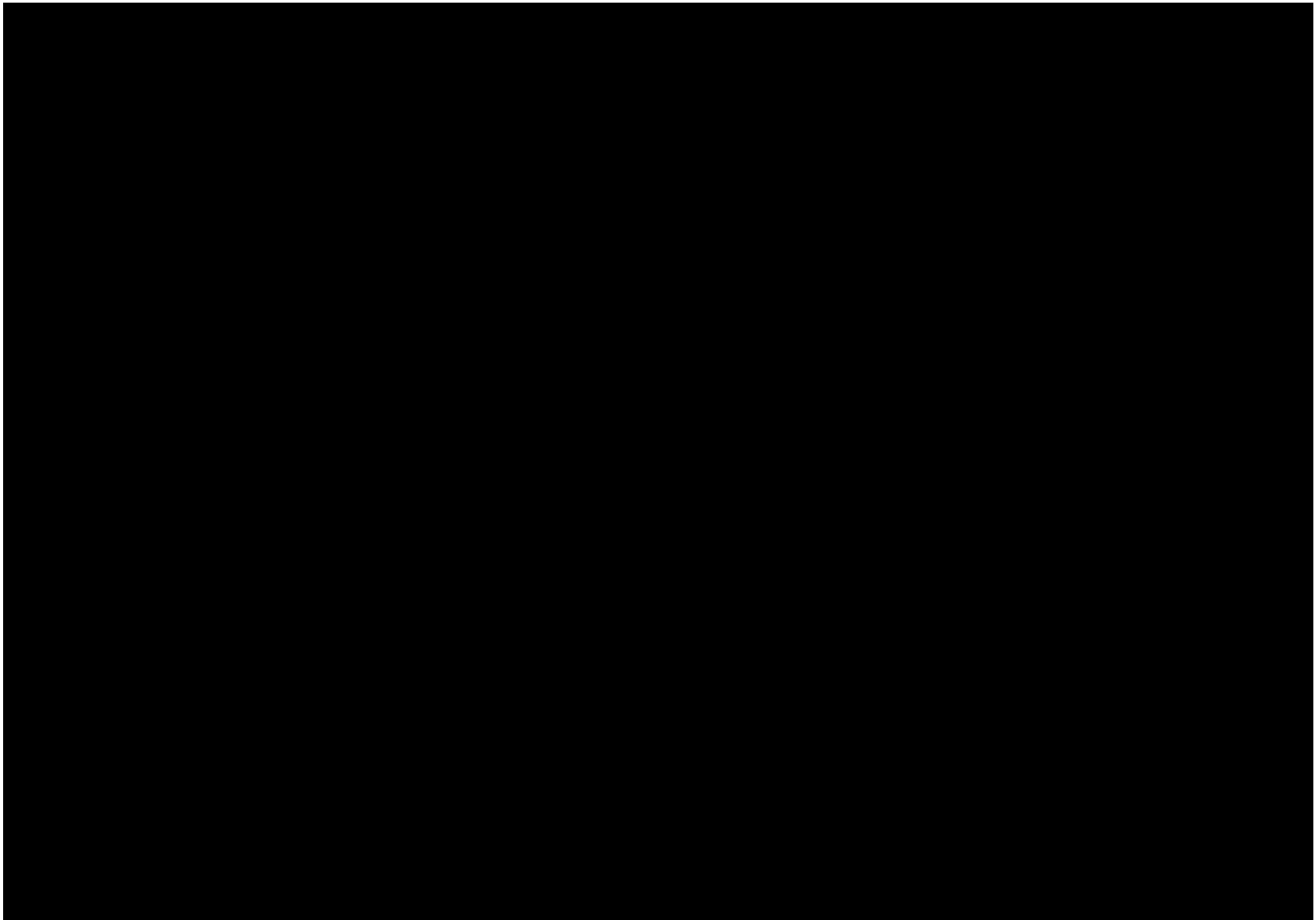
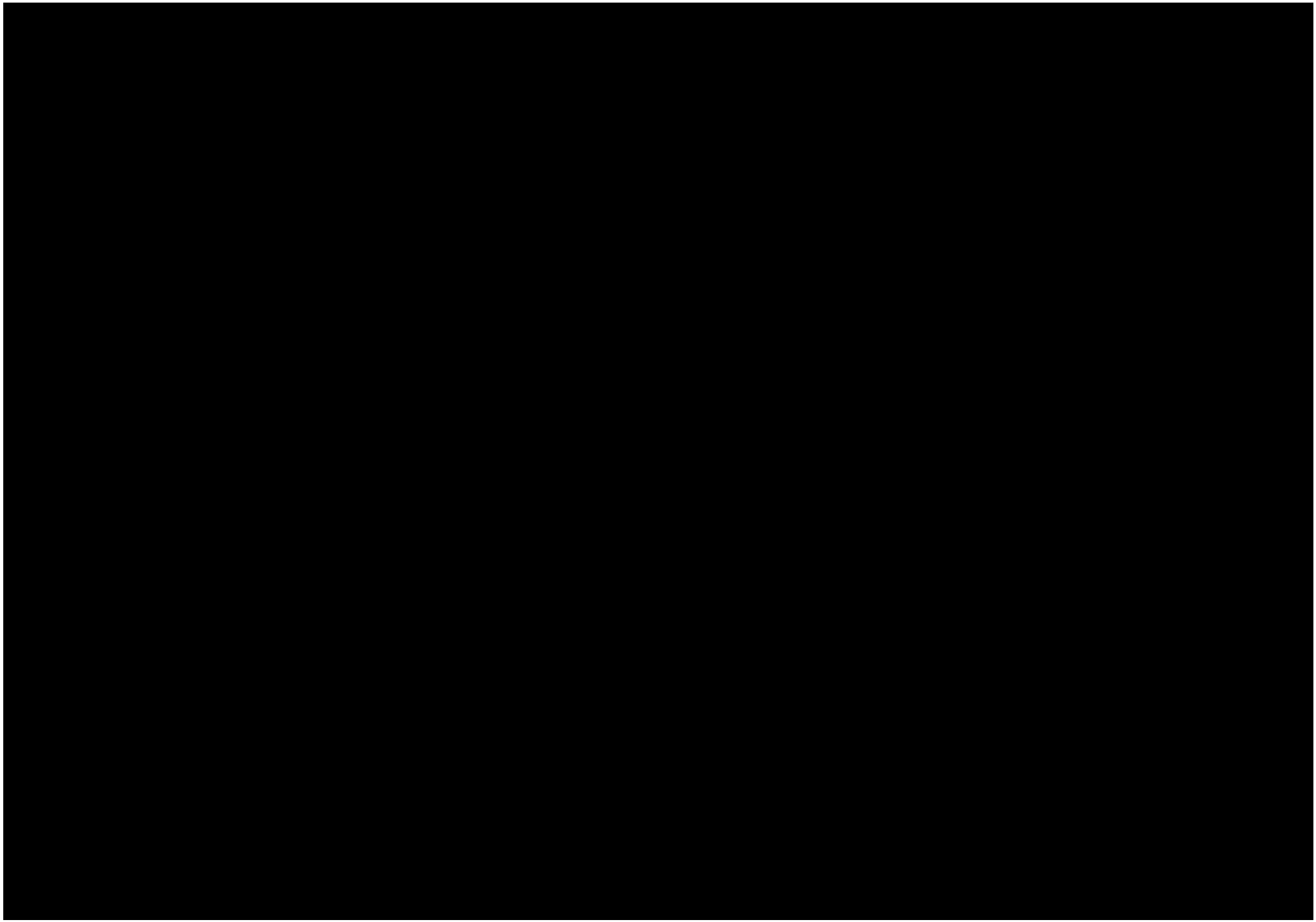
Hourly Average Day for November 2021

Mountain Parks Electric, Inc.



Hourly Average Day for December 2021

Mountain Parks Electric, Inc.



Hourly Average Day for January 2021

Mora-San Miguel Electric Cooperative, Inc.

[redacted]

Hourly Average Day for February 2021

Mora-San Miguel Electric Cooperative, Inc.

[redacted]

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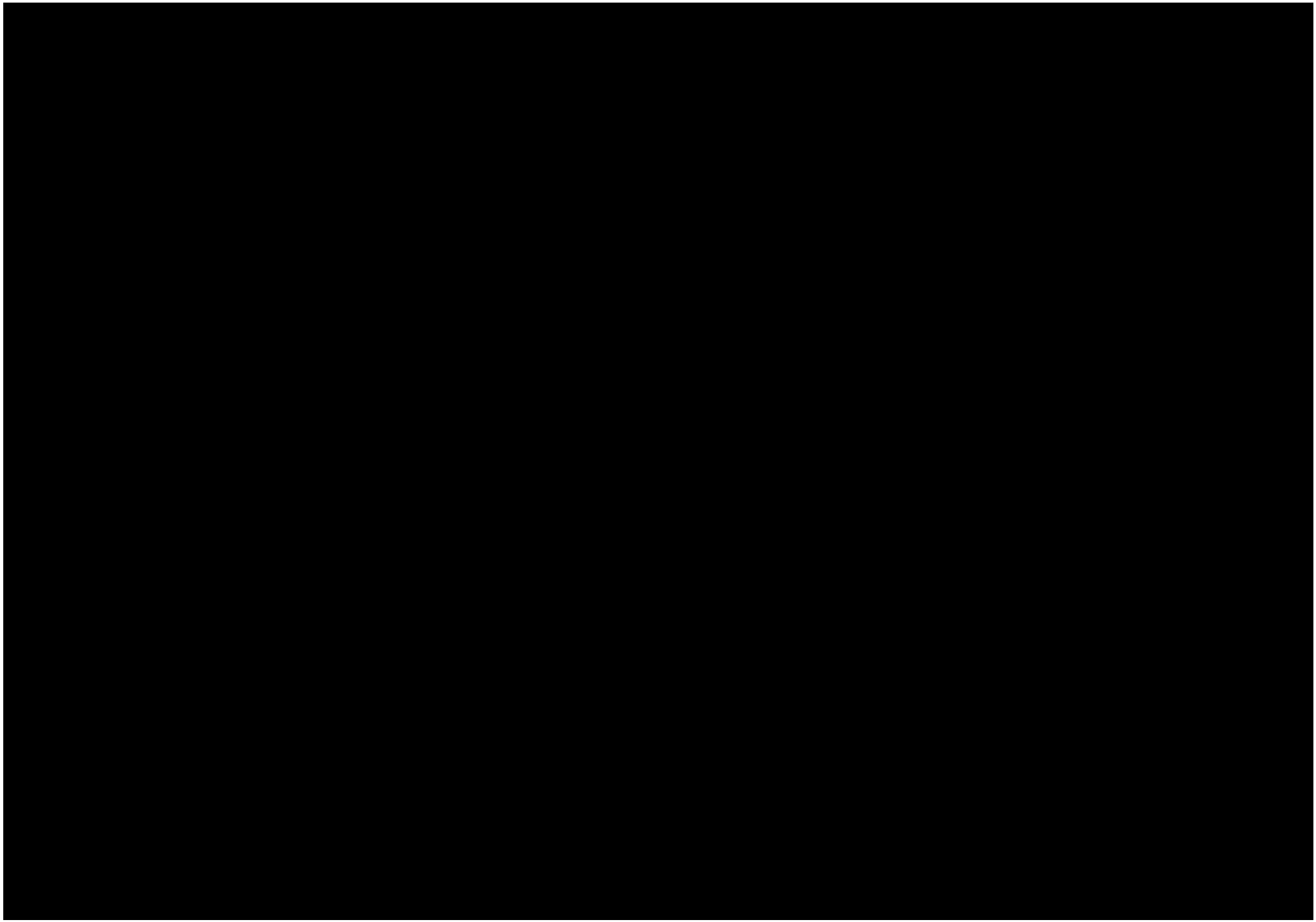
Hourly Average Day for March 2021

Mora-San Miguel Electric Cooperative, Inc.



Hourly Average Day for April 2021

Mora-San Miguel Electric Cooperative, Inc.

[redacted]

Hourly Average Day for May 2021

Mora-San Miguel Electric Cooperative, Inc.

[redacted]

Hourly Average Day for June 2021

Mora-San Miguel Electric Cooperative, Inc.

[redacted]

Hourly Average Day for July 2021

Mora-San Miguel Electric Cooperative, Inc.

[redacted]

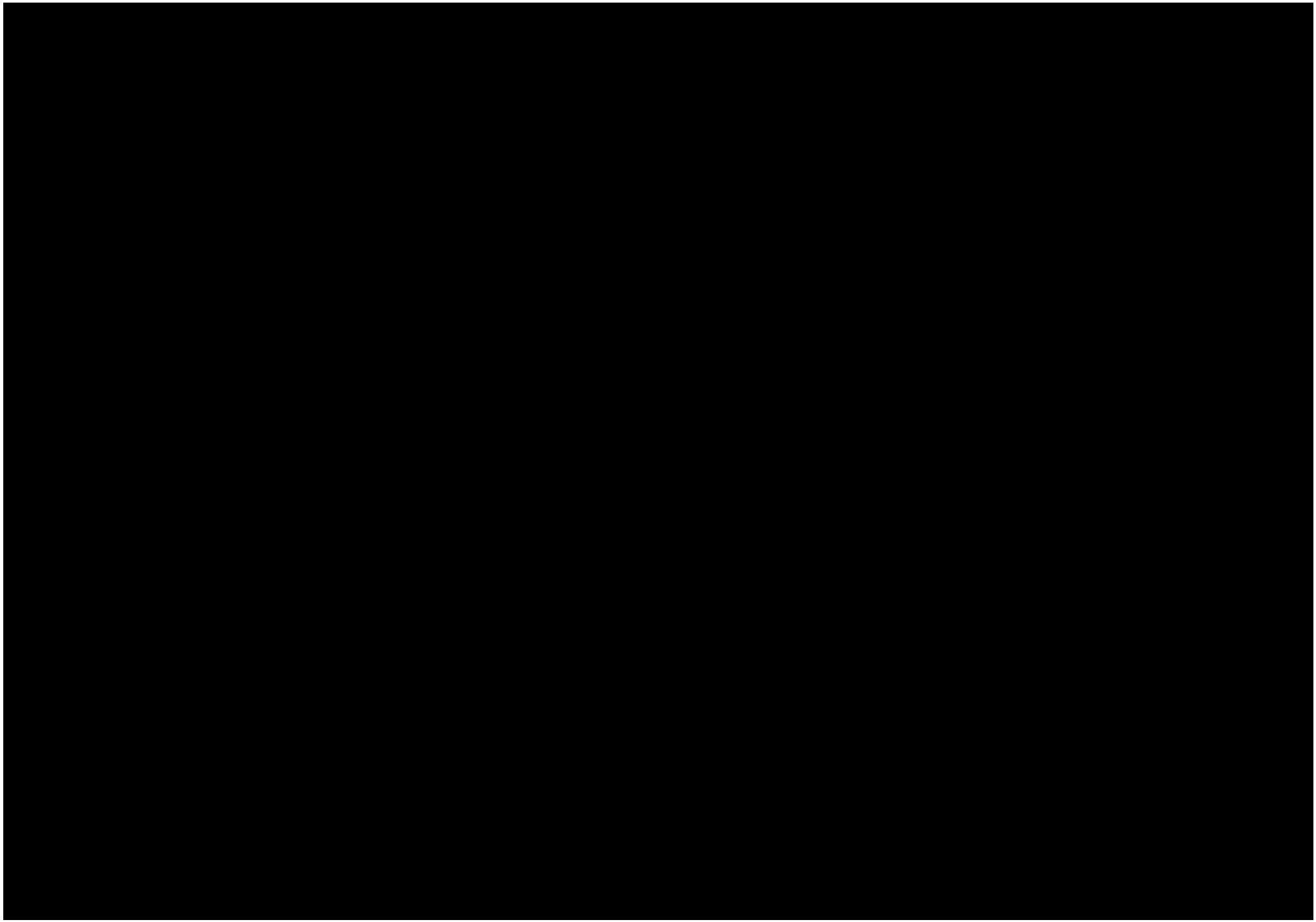
Hourly Average Day for August 2021

Mora-San Miguel Electric Cooperative, Inc.

[redacted]

Hourly Average Day for September 2021

Mora-San Miguel Electric Cooperative, Inc.



Hourly Average Day for October 2021

Mora-San Miguel Electric Cooperative, Inc.

[redacted]

Hourly Average Day for November 2021

Mora-San Miguel Electric Cooperative, Inc.

[redacted]

Hourly Average Day for December 2021

Mora-San Miguel Electric Cooperative, Inc.

[redacted]

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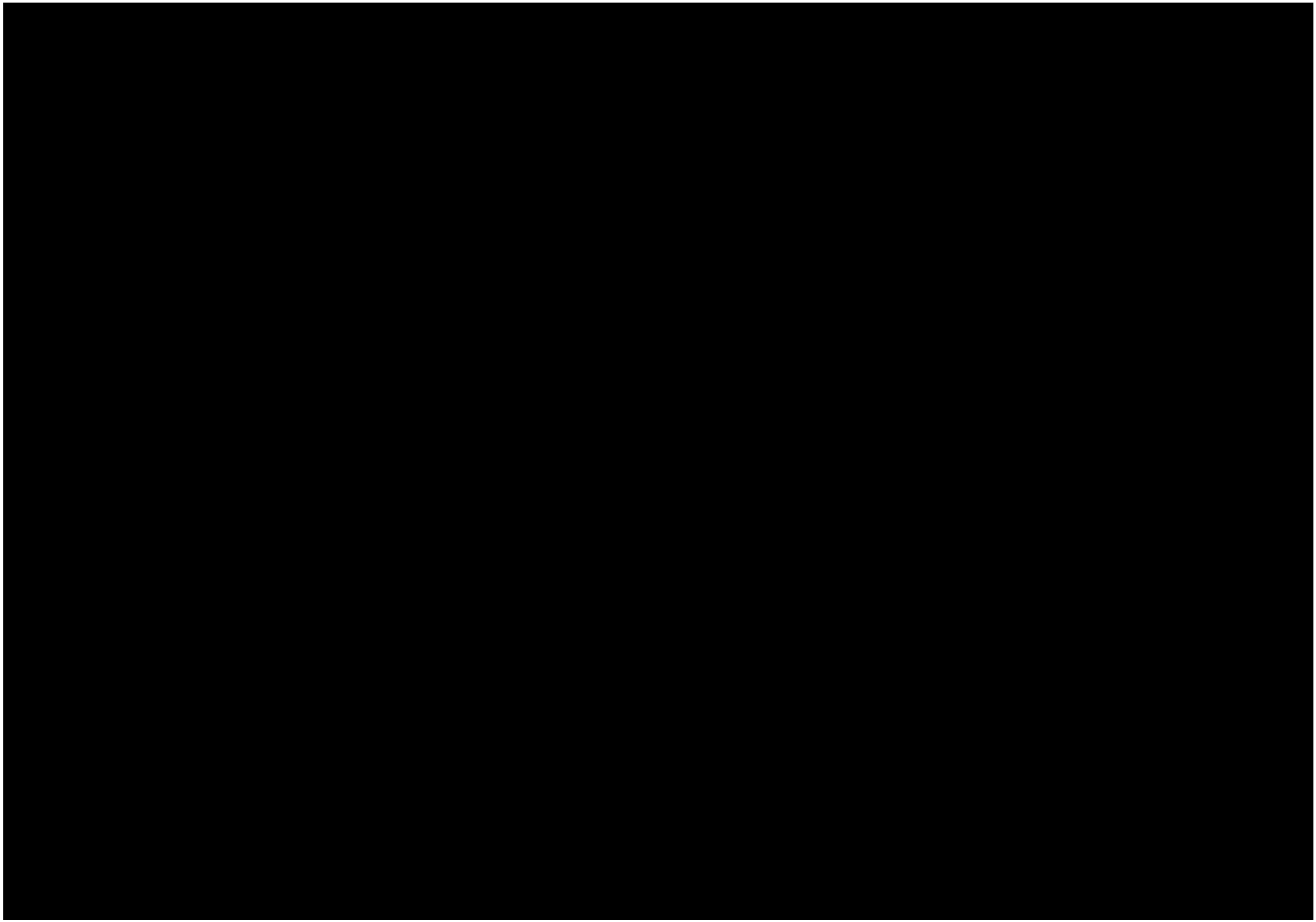
Hourly Average Day for January 2021

Mountain View Electric Association, Inc.



Hourly Average Day for February 2021

Mountain View Electric Association, Inc.

[redacted]

Hourly Average Day for March 2021
Mountain View Electric Association, Inc.

[redacted]

Hourly Average Day for April 2021

Mountain View Electric Association, Inc.

[redacted]

Hourly Average Day for May 2021

Mountain View Electric Association, Inc.

[redacted]

Hourly Average Day for June 2021

Mountain View Electric Association, Inc.

[redacted]

Hourly Average Day for July 2021

Mountain View Electric Association, Inc.

[redacted]

Hourly Average Day for August 2021

Mountain View Electric Association, Inc.

[redacted]

Hourly Average Day for September 2021

Mountain View Electric Association, Inc.

[redacted]

Hourly Average Day for October 2021

Mountain View Electric Association, Inc.

[redacted]

Hourly Average Day for November 2021

Mountain View Electric Association, Inc.

[redacted]

Hourly Average Day for December 2021

Mountain View Electric Association, Inc.

[redacted]

Hourly Average Day for January 2021

Midwest Electric Cooperative Corporation

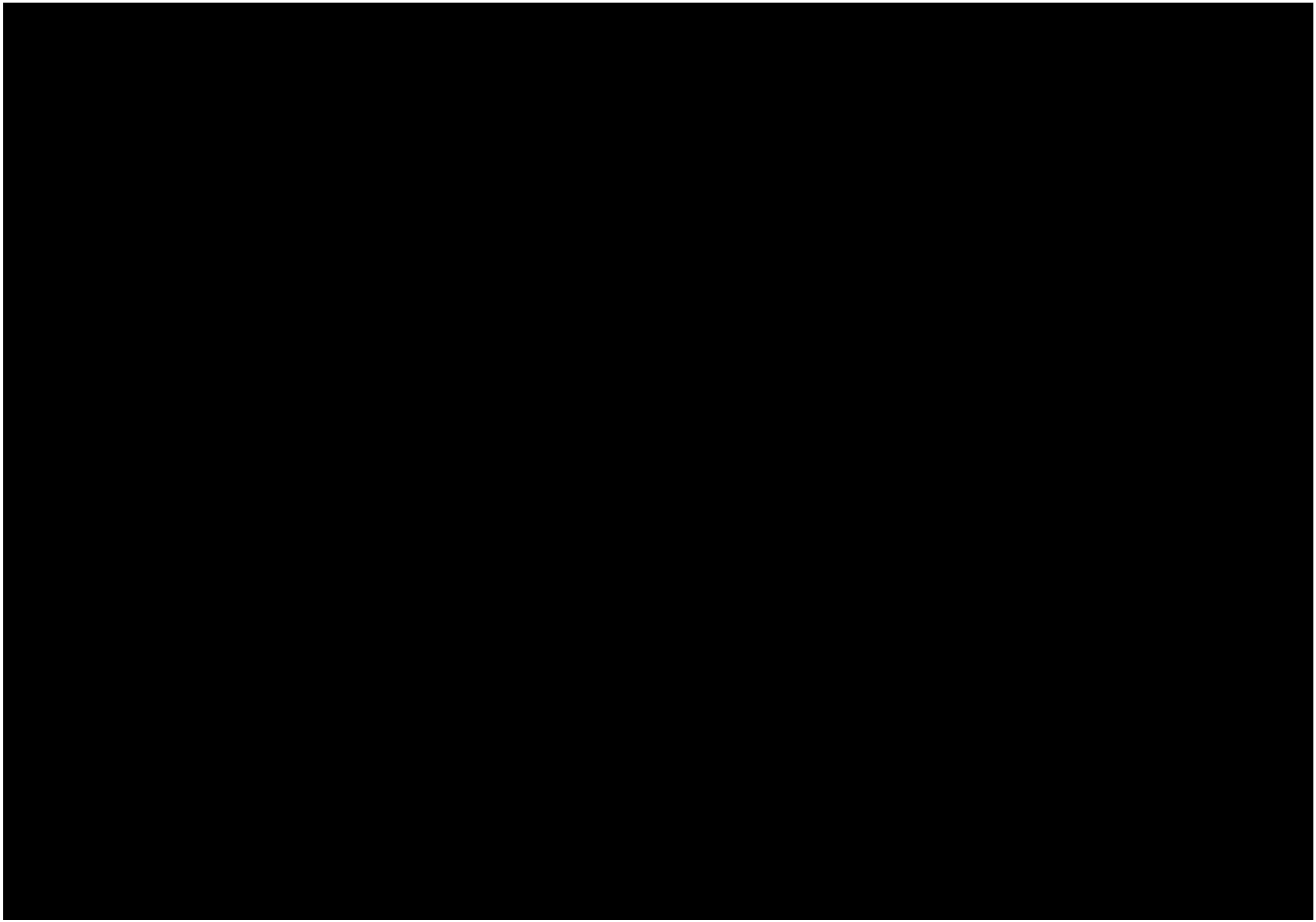
[redacted]

Hourly Average Day for February 2021

Midwest Electric Cooperative Corporation

[redacted]

Hourly Average Day for March 2021
Midwest Electric Cooperative Corporation

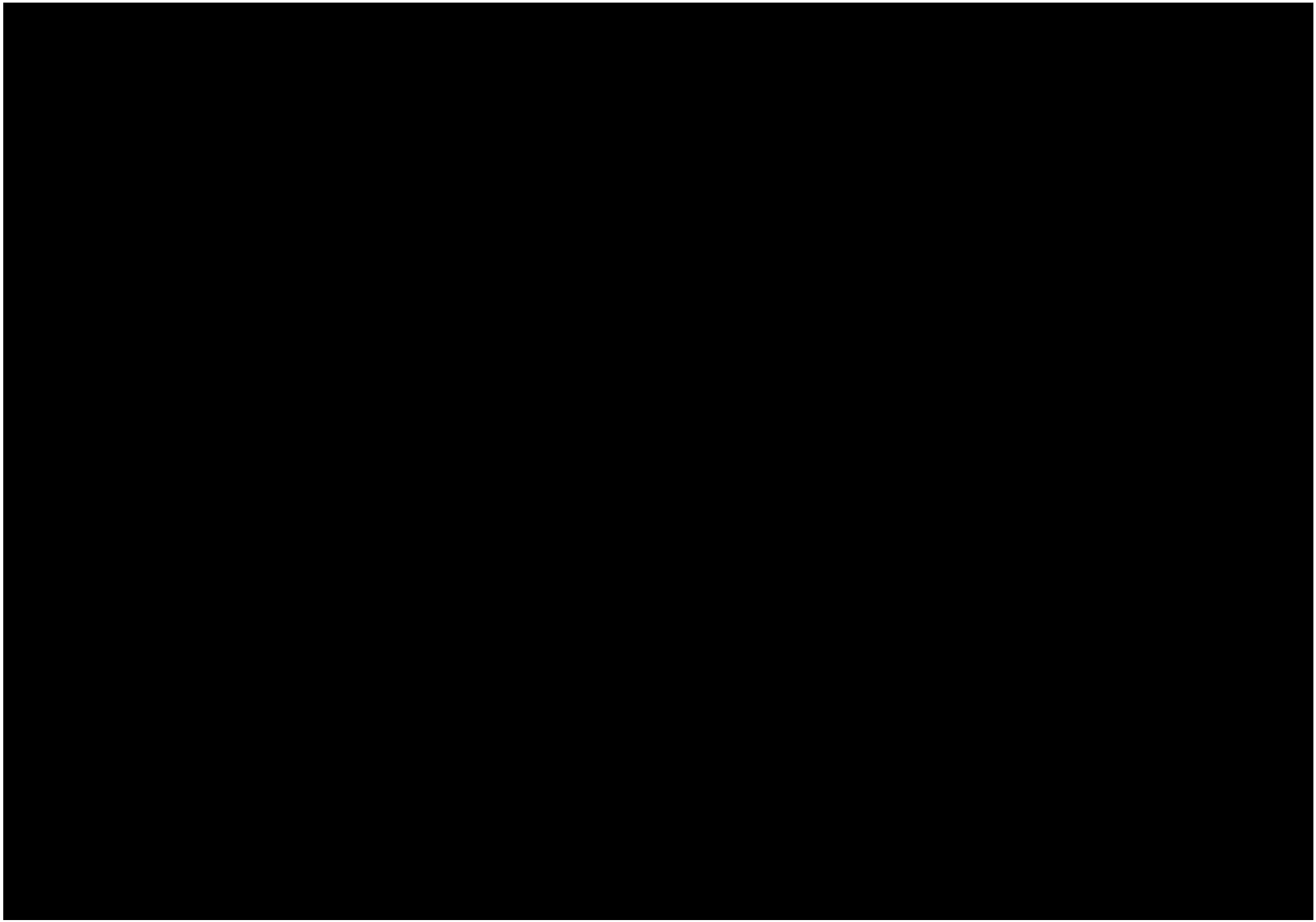


Hourly Average Day for April 2021

Midwest Electric Cooperative Corporation

[redacted]

Hourly Average Day for May 2021
Midwest Electric Cooperative Corporation

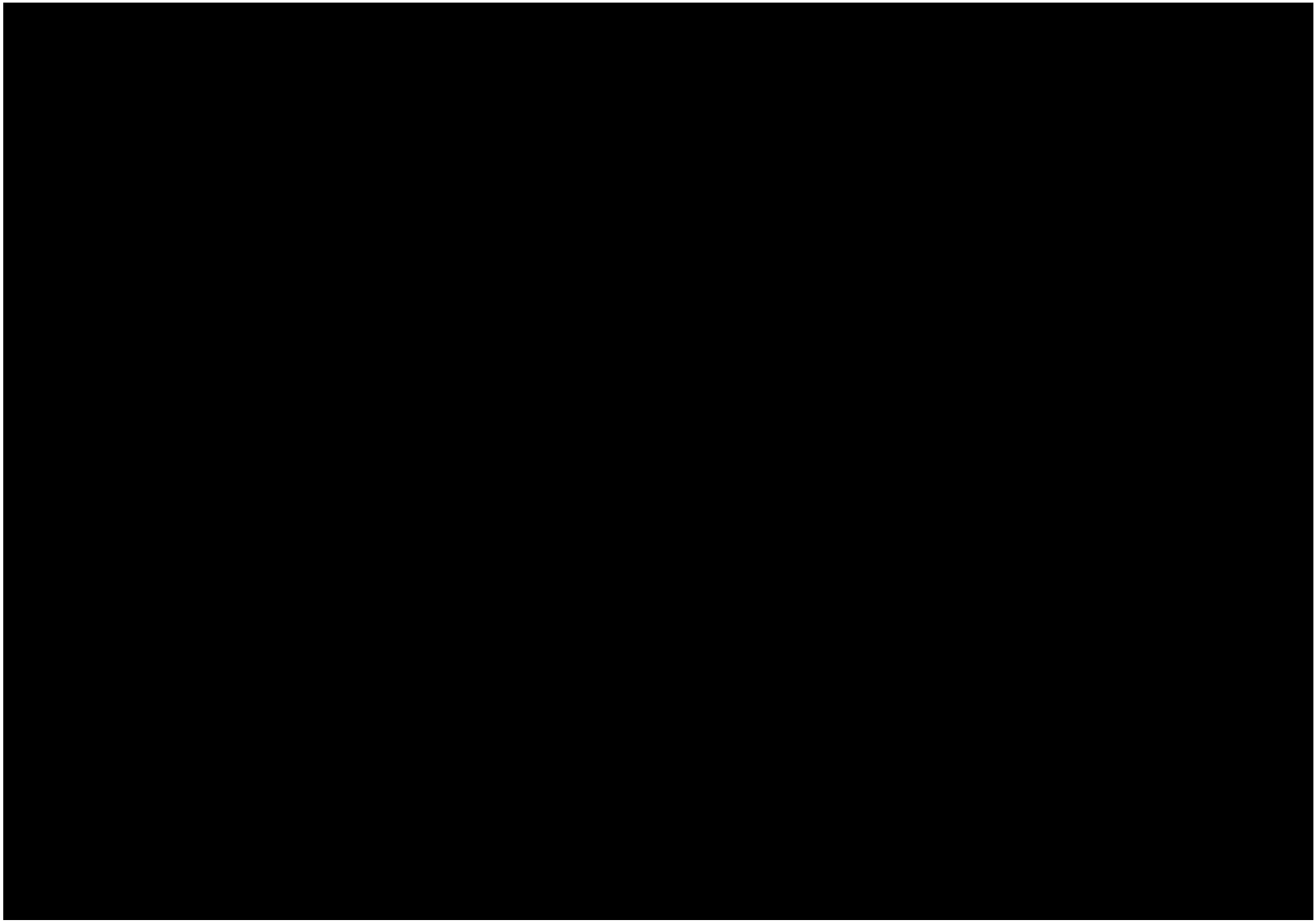


Hourly Average Day for June 2021
Midwest Electric Cooperative Corporation

[redacted]

Hourly Average Day for July 2021

Midwest Electric Cooperative Corporation



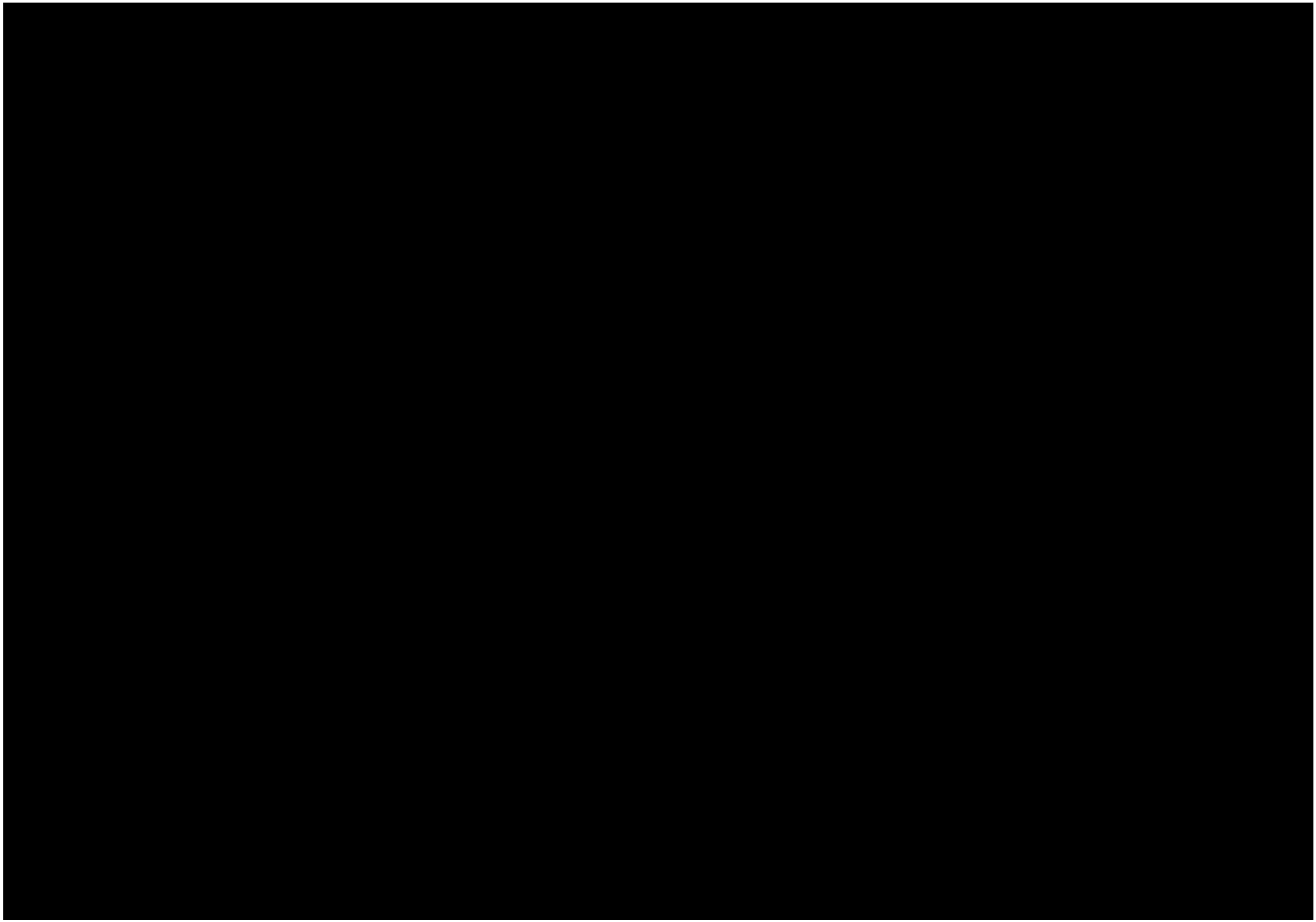
Hourly Average Day for August 2021

Midwest Electric Cooperative Corporation

[redacted]

Hourly Average Day for September 2021

Midwest Electric Cooperative Corporation



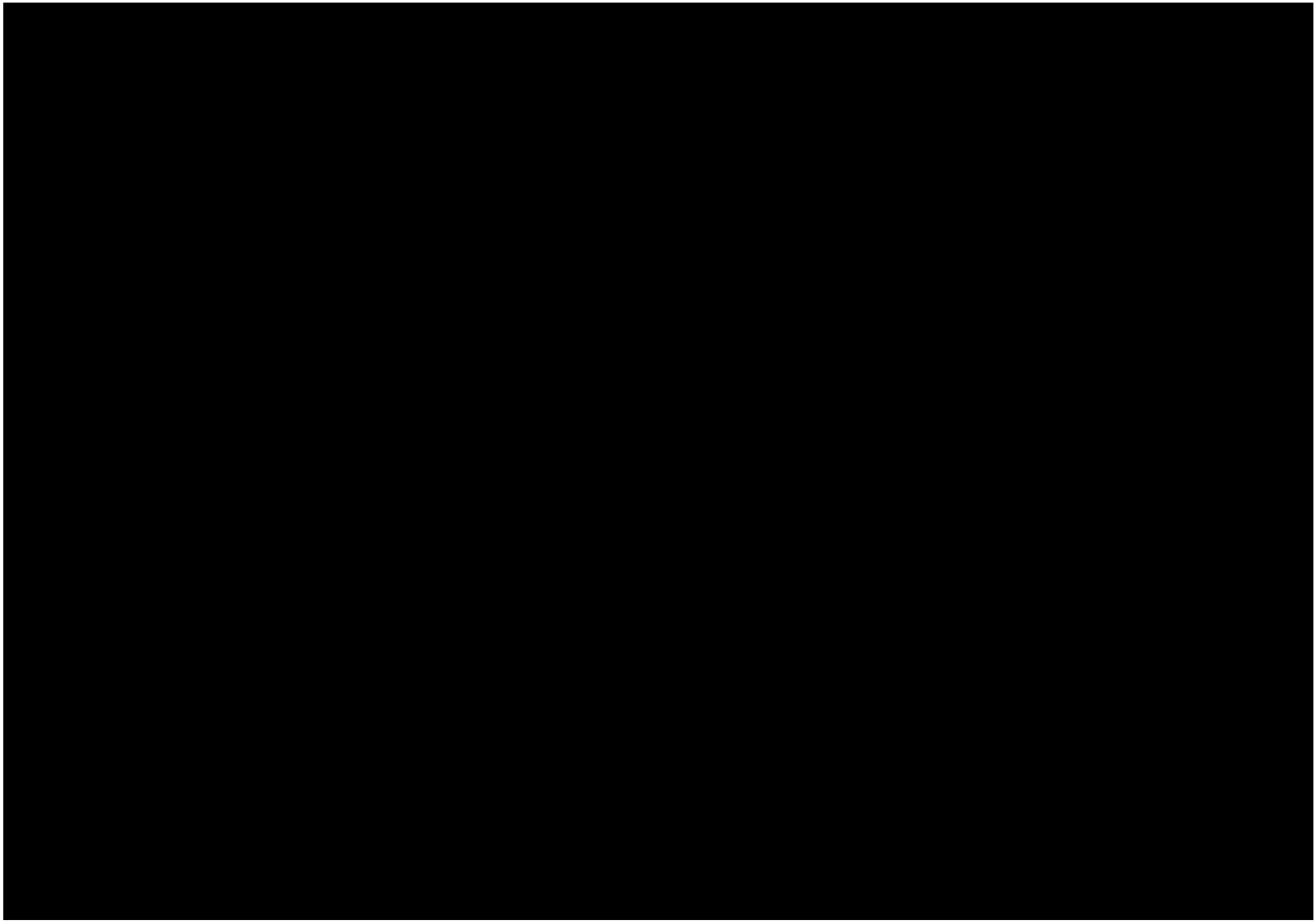
Hourly Average Day for October 2021

Midwest Electric Cooperative Corporation

[redacted]

Hourly Average Day for November 2021

Midwest Electric Cooperative Corporation



Hourly Average Day for December 2021

Midwest Electric Cooperative Corporation

[redacted]

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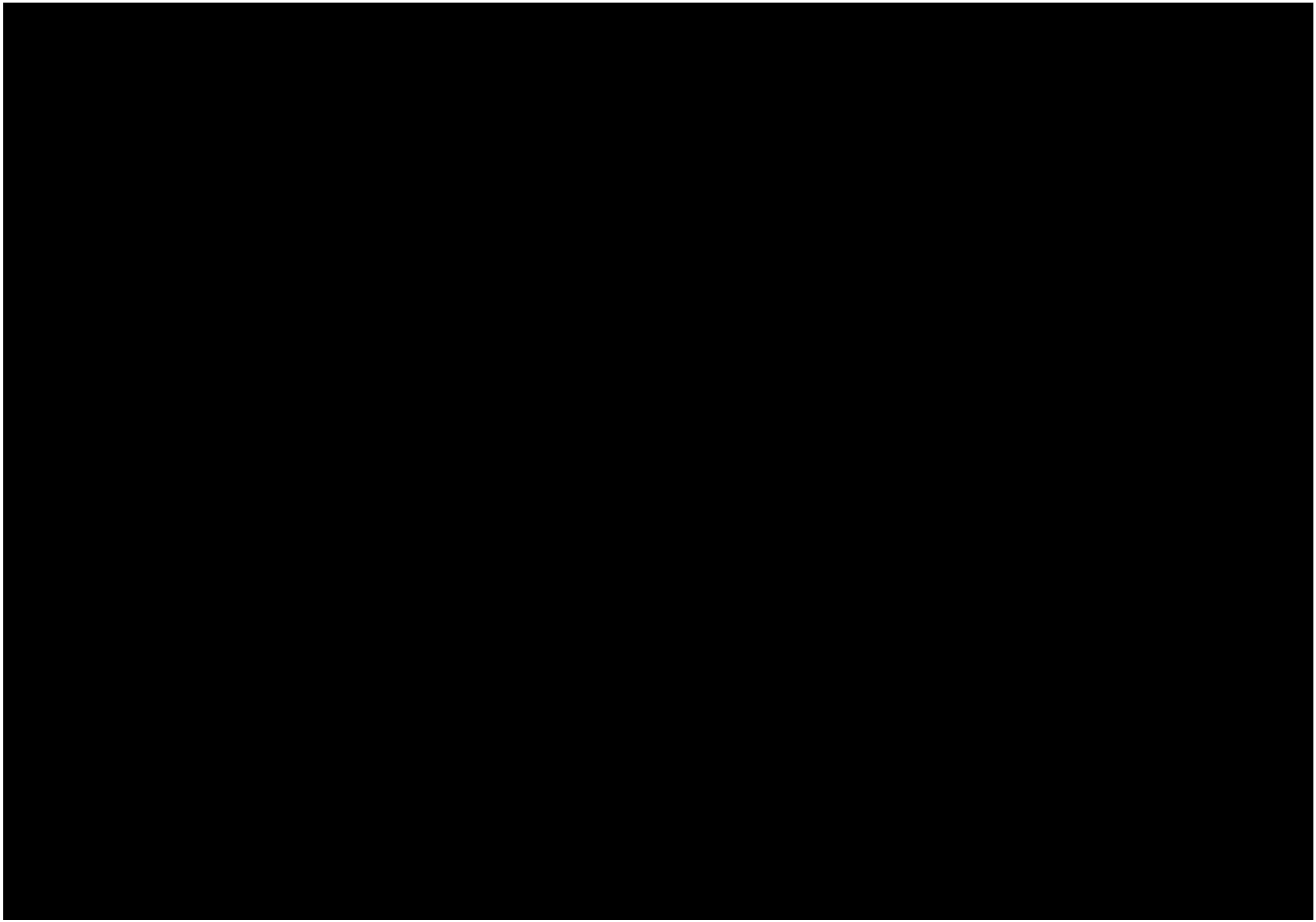
Hourly Average Day for January 2021

Niobrara Electric Association, Inc.



Hourly Average Day for February 2021

Niobrara Electric Association, Inc.

[redacted]

Hourly Average Day for March 2021

Niobrara Electric Association, Inc.

[redacted]

Hourly Average Day for April 2021

Niobrara Electric Association, Inc.

[redacted]

Hourly Average Day for May 2021

Niobrara Electric Association, Inc.

[redacted]

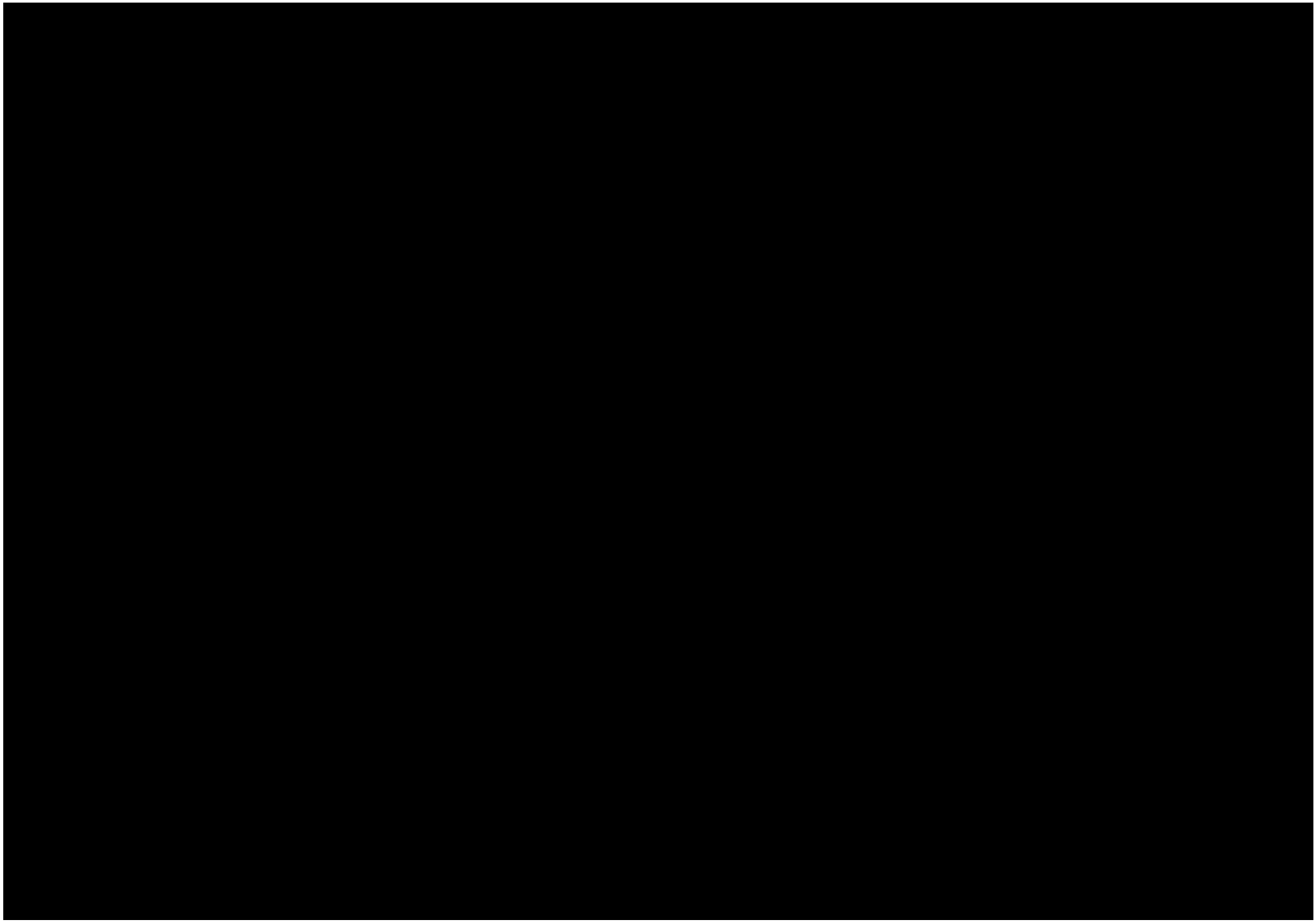
Hourly Average Day for June 2021

Niobrara Electric Association, Inc.

[redacted]

Hourly Average Day for July 2021

Niobrara Electric Association, Inc.



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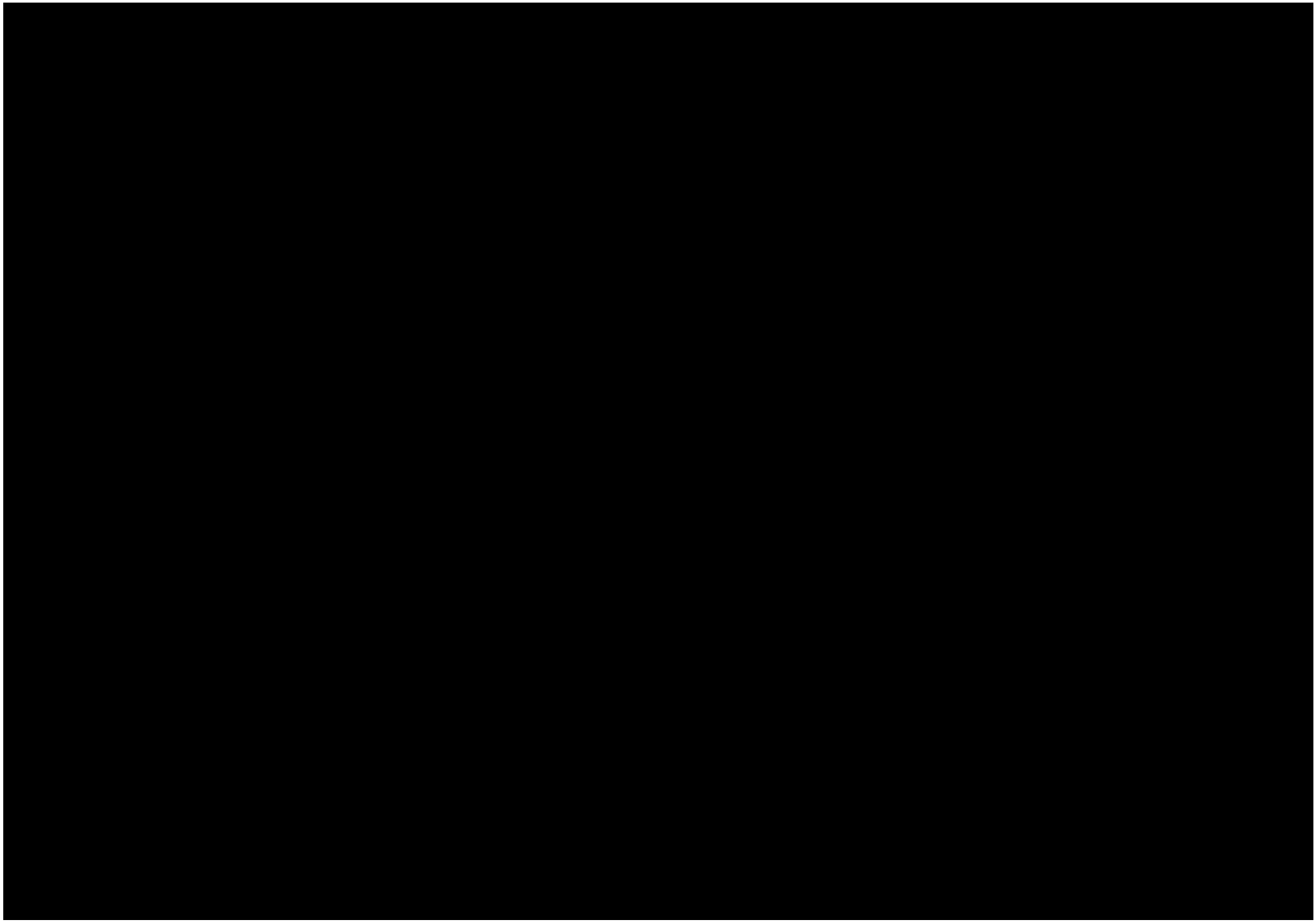
Hourly Average Day for August 2021

Niobrara Electric Association, Inc.



Hourly Average Day for September 2021

Niobrara Electric Association, Inc.

[redacted]

Hourly Average Day for October 2021

Niobrara Electric Association, Inc.

[redacted]

Hourly Average Day for November 2021

Niobrara Electric Association, Inc.

[redacted]

Hourly Average Day for December 2021

Niobrara Electric Association, Inc.

[redacted]

Hourly Average Day for January 2021

Northwest Rural Public Power District

[redacted]

Hourly Average Day for February 2021

Northwest Rural Public Power District

[redacted]

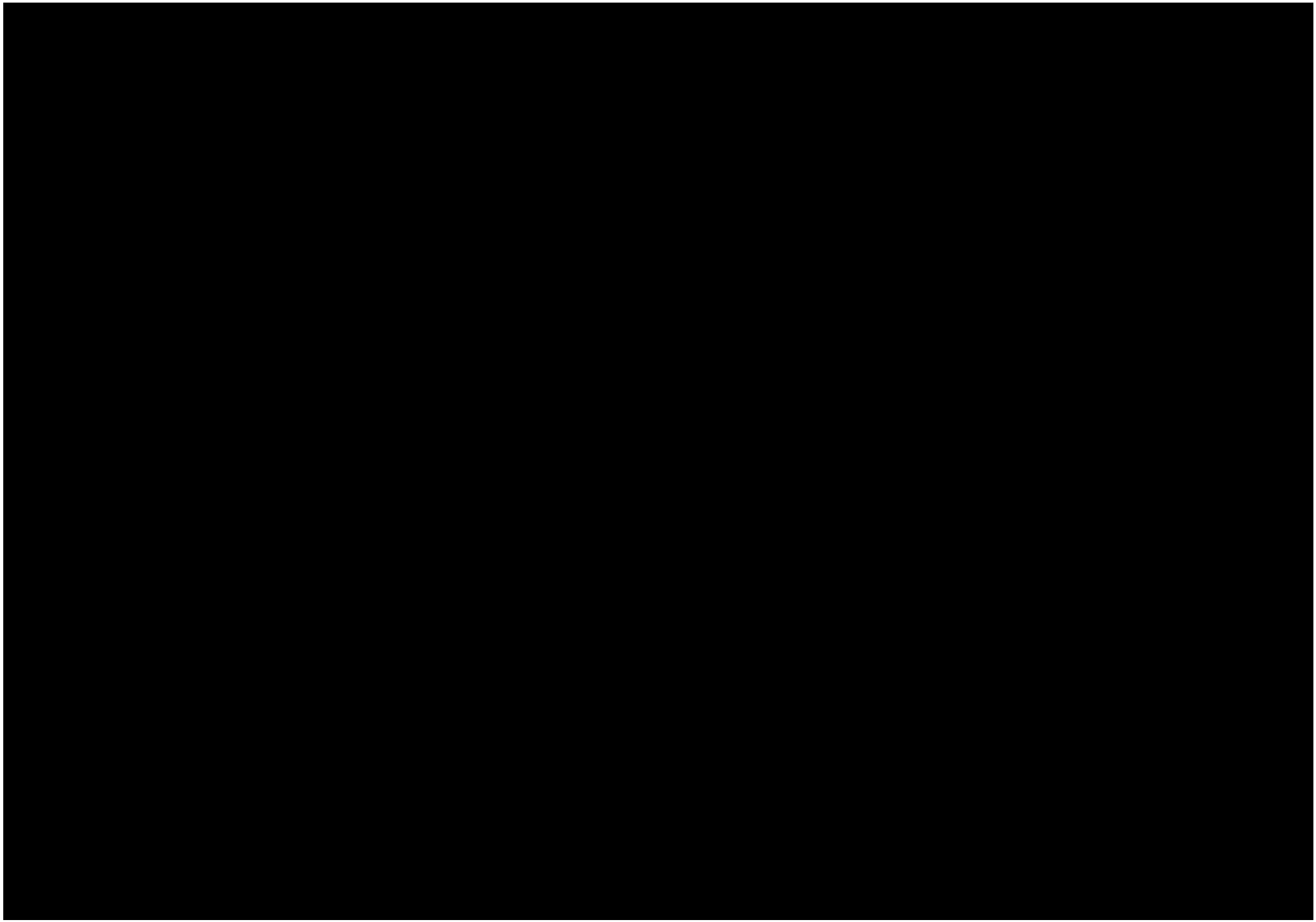
Hourly Average Day for March 2021

Northwest Rural Public Power District

[redacted]

Hourly Average Day for April 2021

Northwest Rural Public Power District



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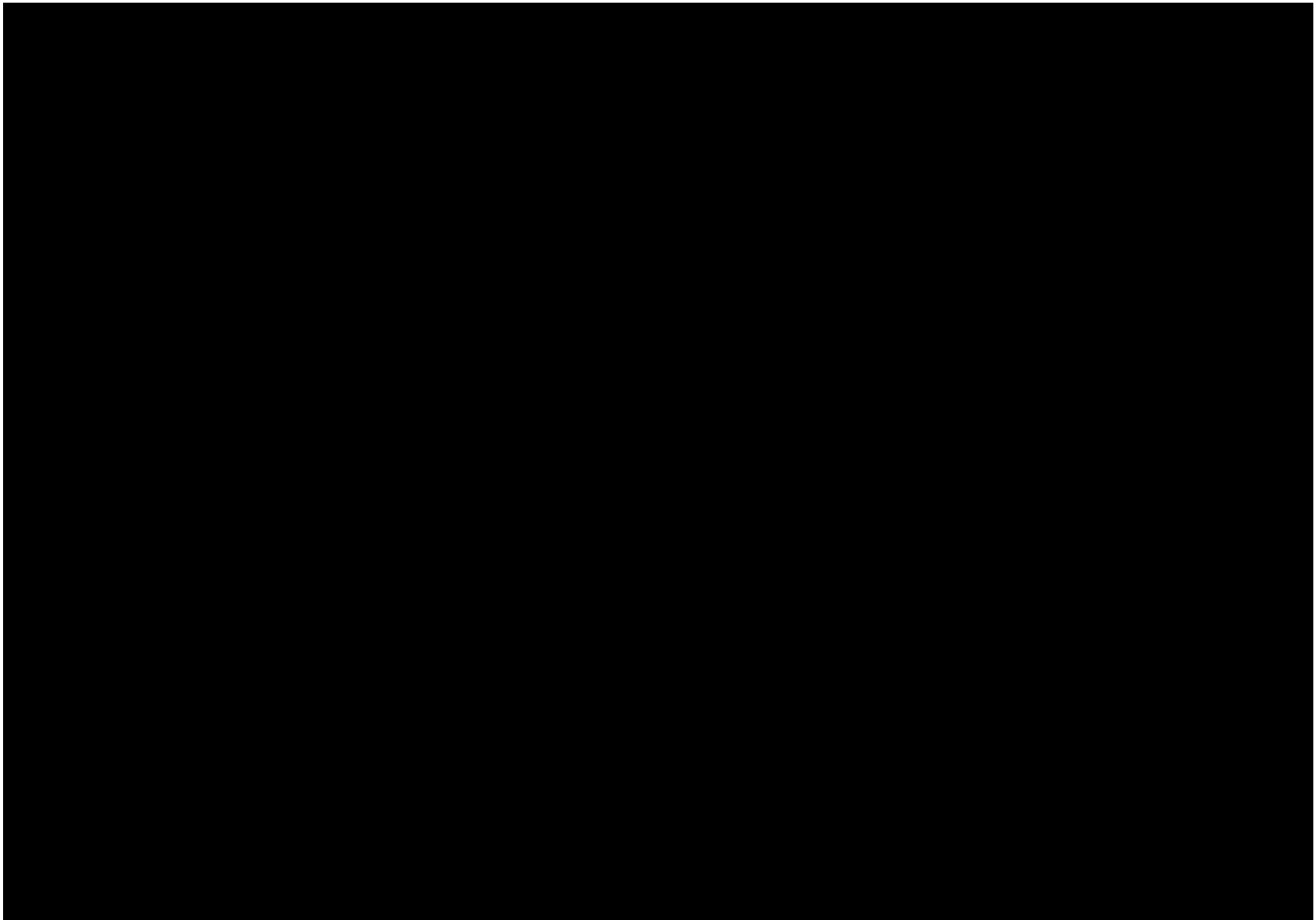
Hourly Average Day for May 2021

Northwest Rural Public Power District



Hourly Average Day for June 2021

Northwest Rural Public Power District

[redacted]

Hourly Average Day for July 2021

Northwest Rural Public Power District

[redacted]

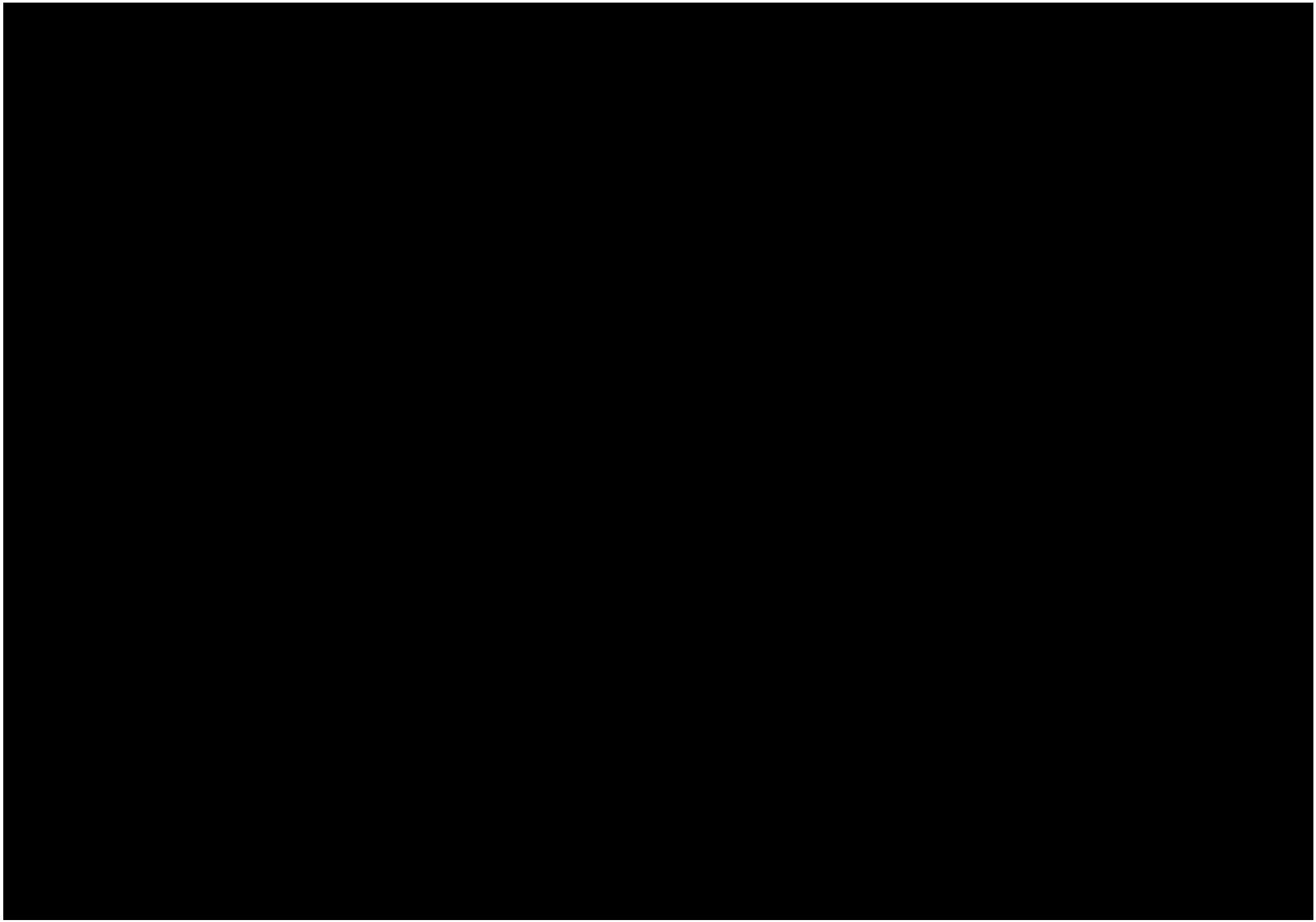
Hourly Average Day for August 2021

Northwest Rural Public Power District

[redacted]

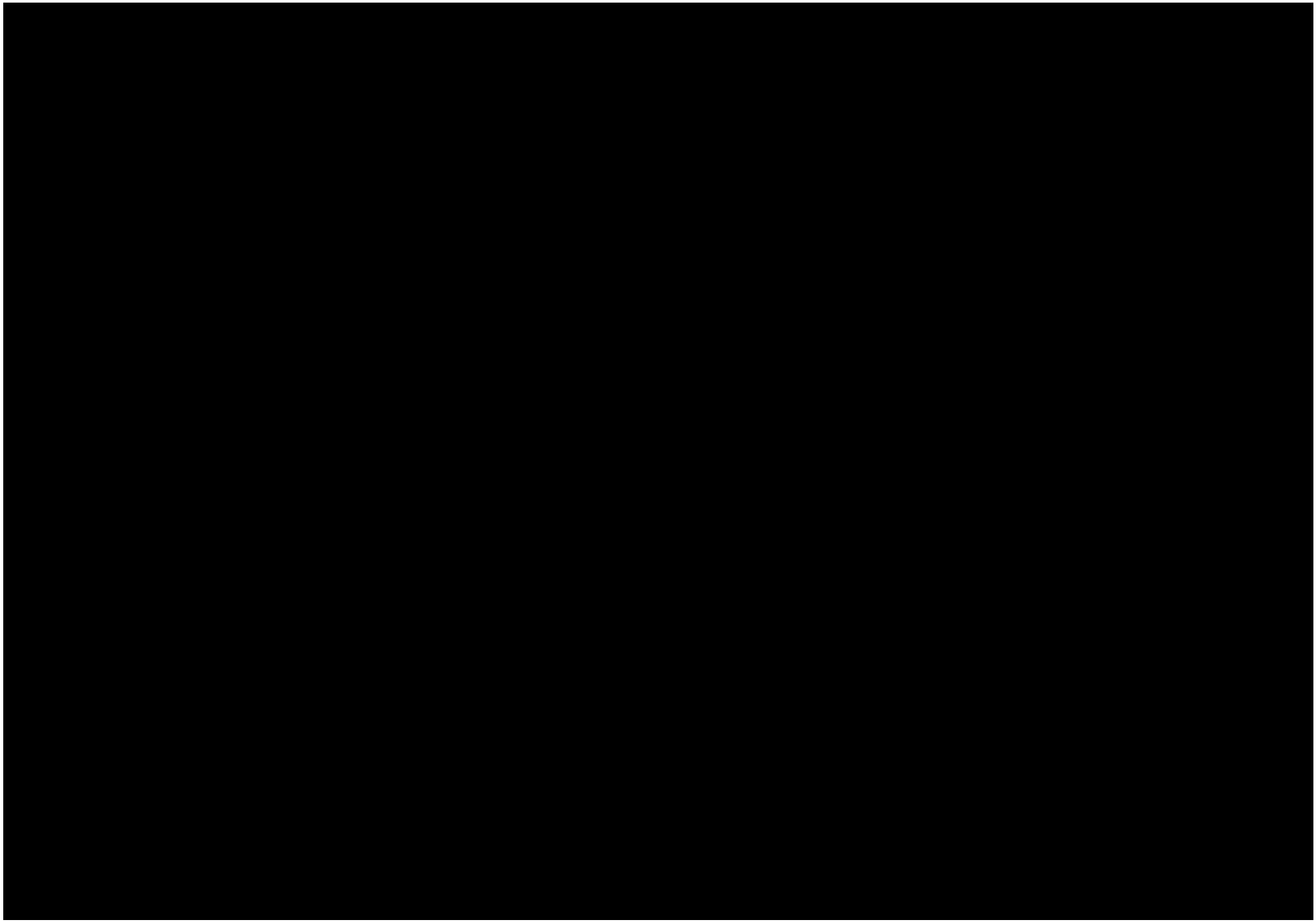
Hourly Average Day for September 2021

Northwest Rural Public Power District



Hourly Average Day for October 2021

Northwest Rural Public Power District



Hourly Average Day for November 2021

Northwest Rural Public Power District

[redacted]

Hourly Average Day for December 2021

Northwest Rural Public Power District

[redacted]

Hourly Average Day for January 2021

Otero County Electric Cooperative, Inc.

[redacted]

Hourly Average Day for February 2021

Otero County Electric Cooperative, Inc.

[redacted]

Hourly Average Day for March 2021

Otero County Electric Cooperative, Inc.

[redacted]

Hourly Average Day for April 2021

Otero County Electric Cooperative, Inc.

[redacted]

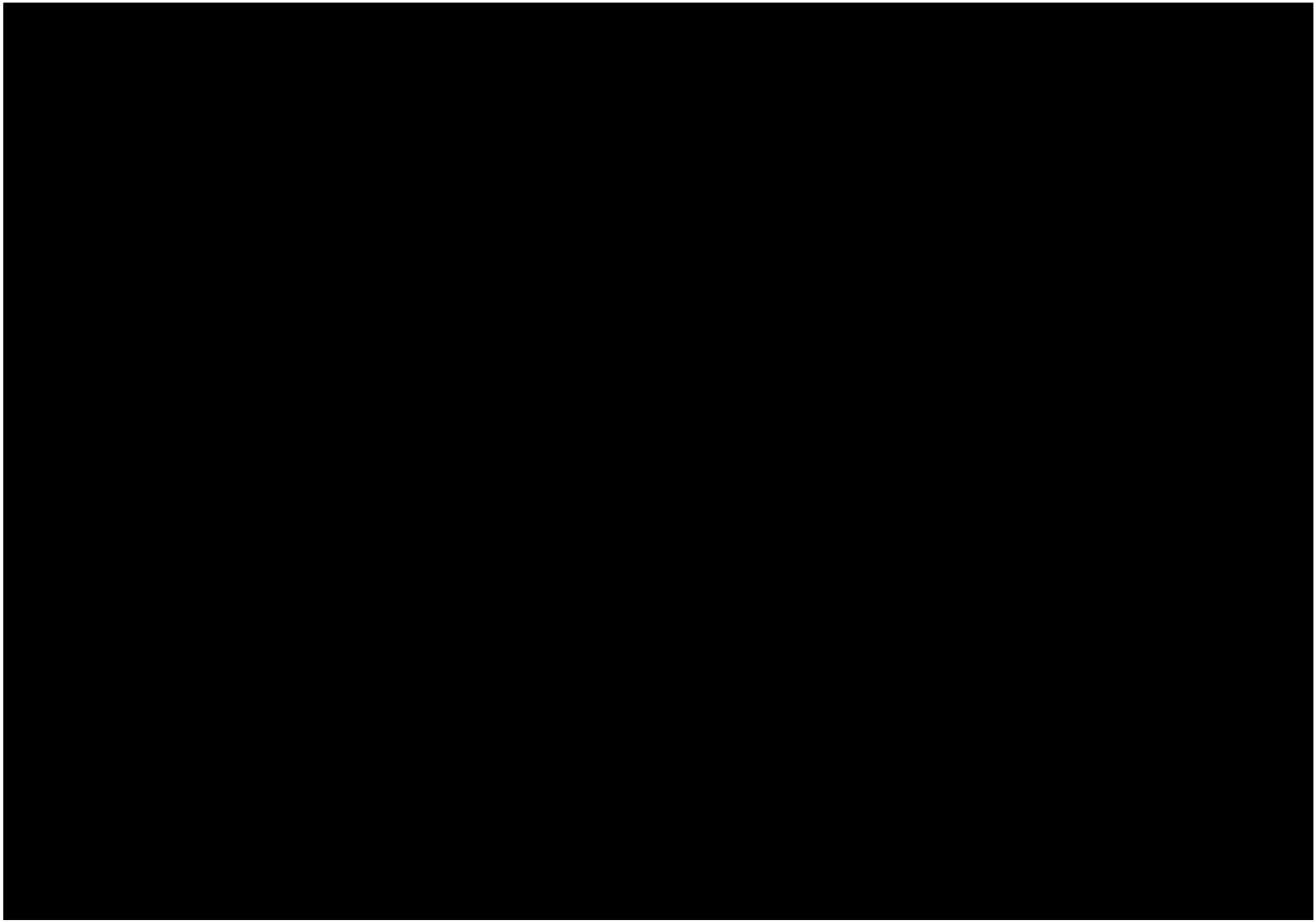
Hourly Average Day for May 2021

Otero County Electric Cooperative, Inc.

[redacted]

Hourly Average Day for June 2021

Otero County Electric Cooperative, Inc.



Hourly Average Day for July 2021

Otero County Electric Cooperative, Inc.

[redacted]

Hourly Average Day for August 2021

Otero County Electric Cooperative, Inc.

[redacted]

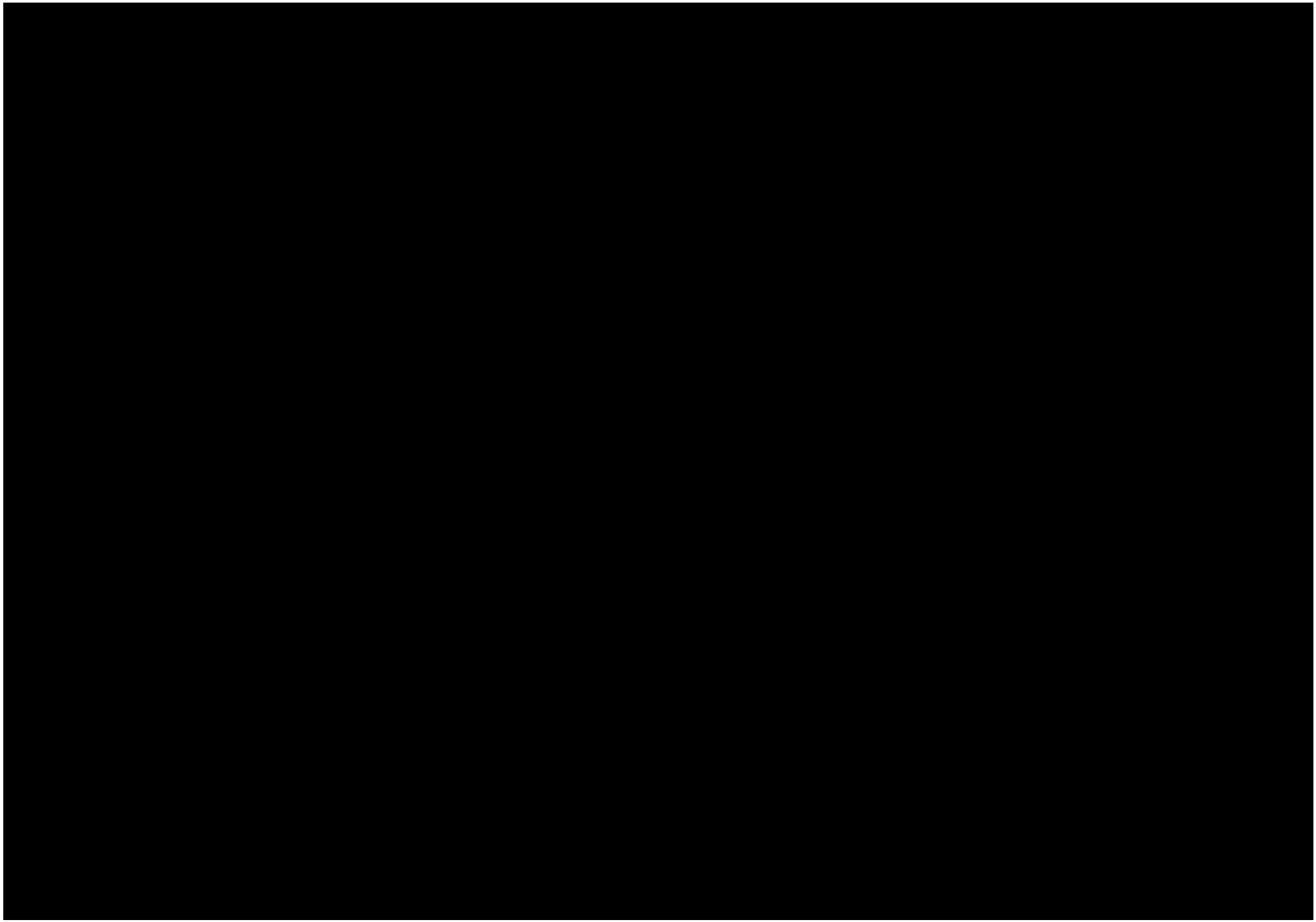
Hourly Average Day for September 2021

Otero County Electric Cooperative, Inc.

[redacted]

Hourly Average Day for October 2021

Otero County Electric Cooperative, Inc.



Hourly Average Day for November 2021

Otero County Electric Cooperative, Inc.

[redacted]

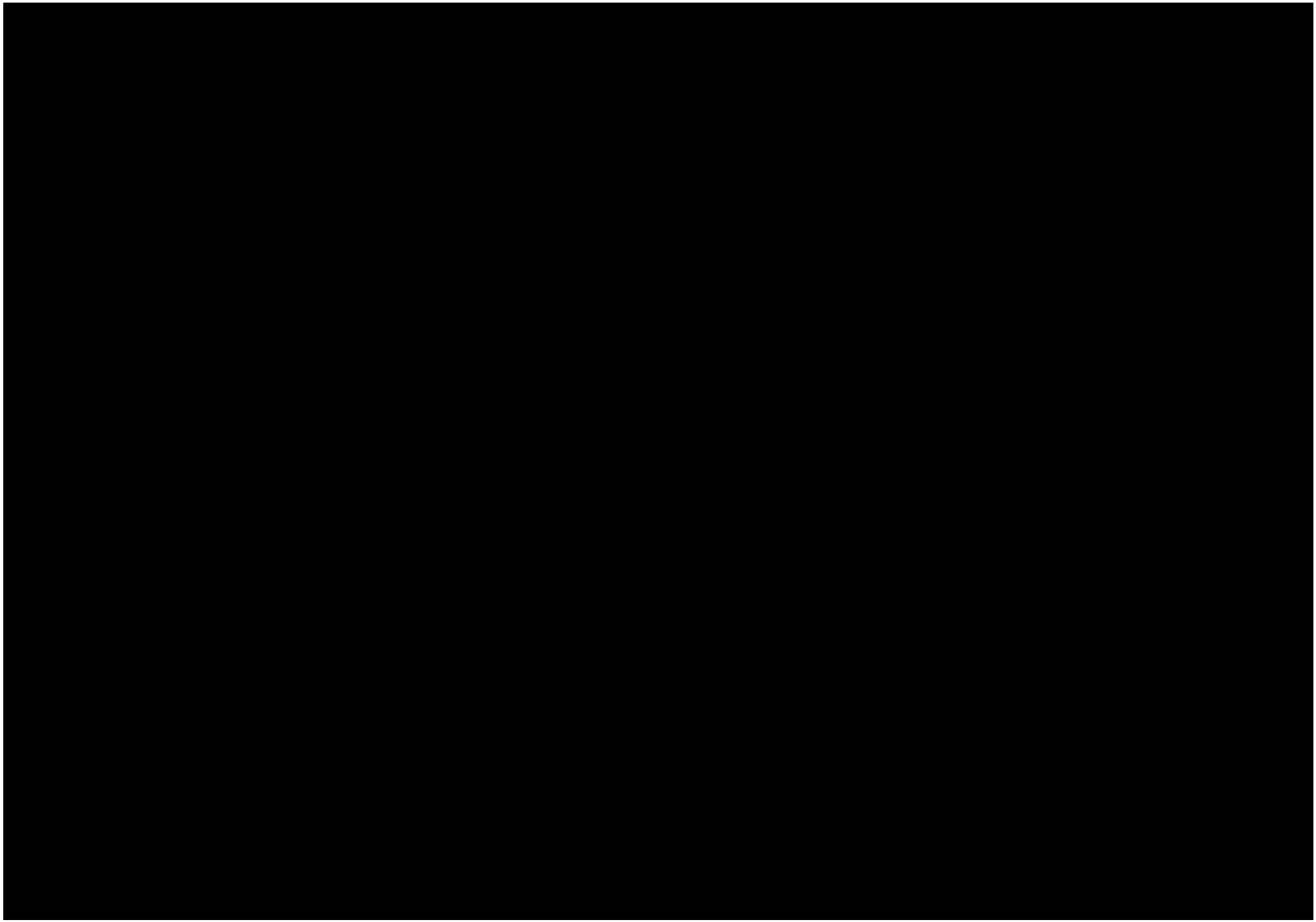
Hourly Average Day for December 2021

Otero County Electric Cooperative, Inc.

[redacted]

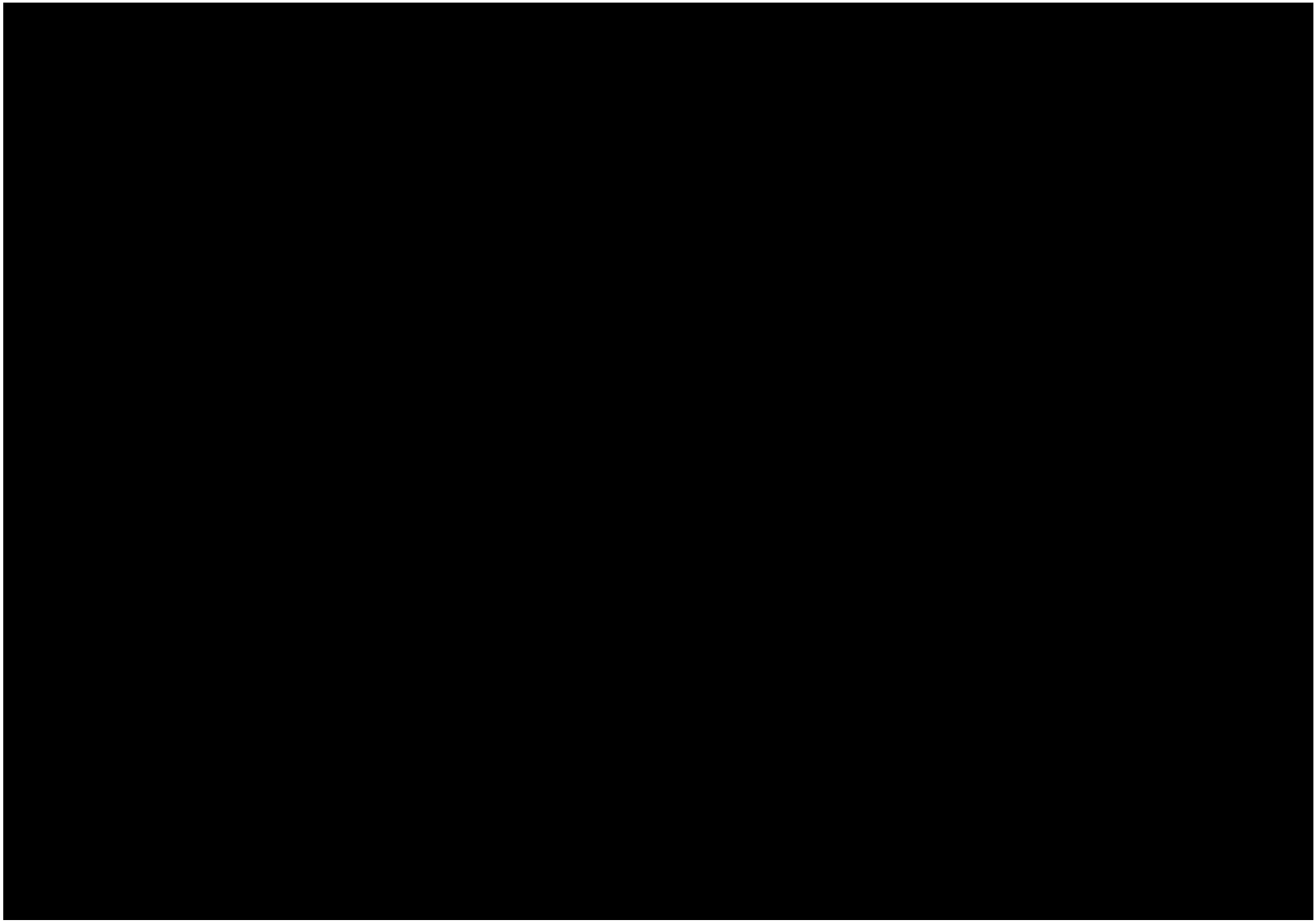
Hourly Average Day for January 2021

Panhandle Rural Electric Membership Association



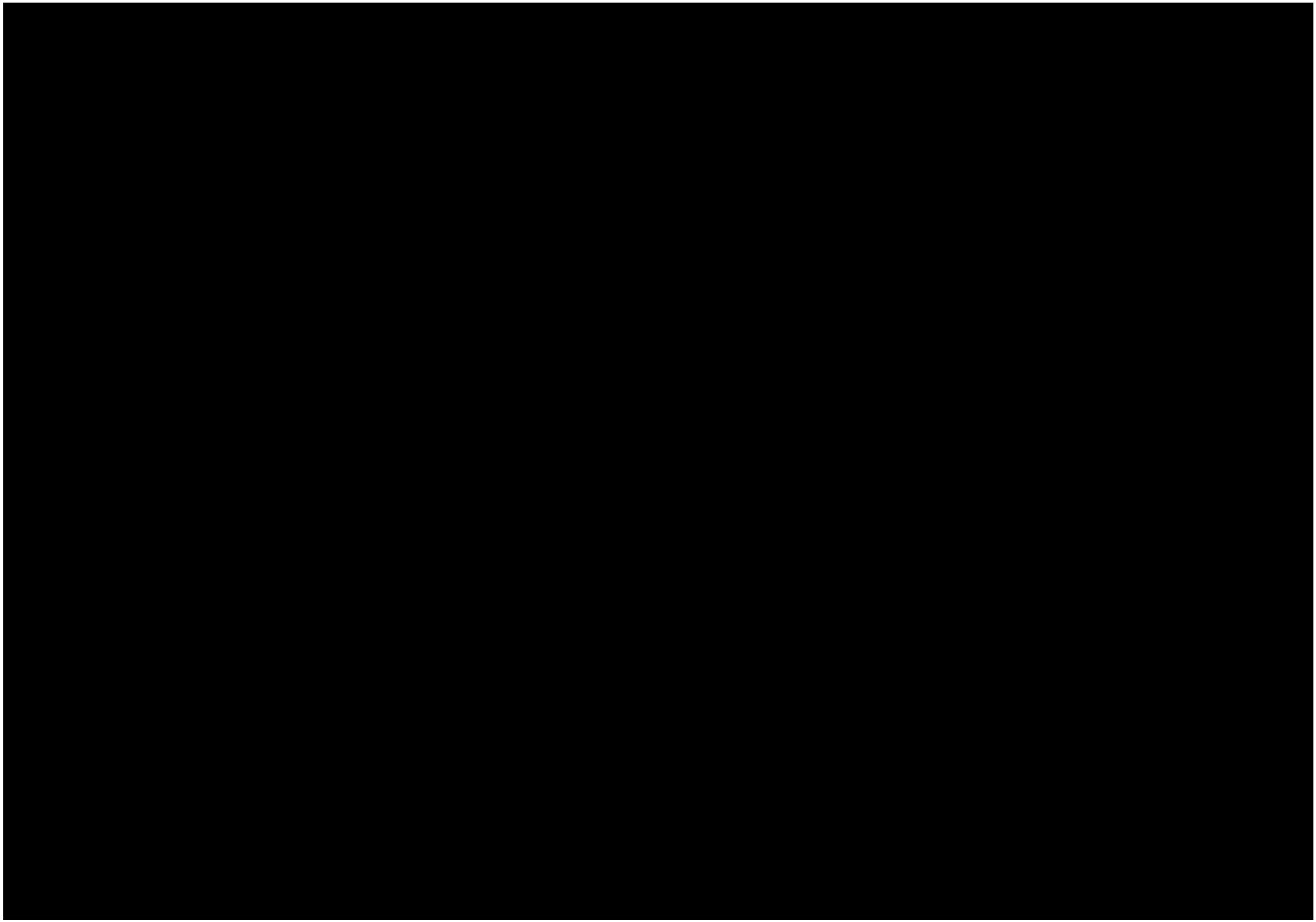
Hourly Average Day for February 2021

Panhandle Rural Electric Membership Association



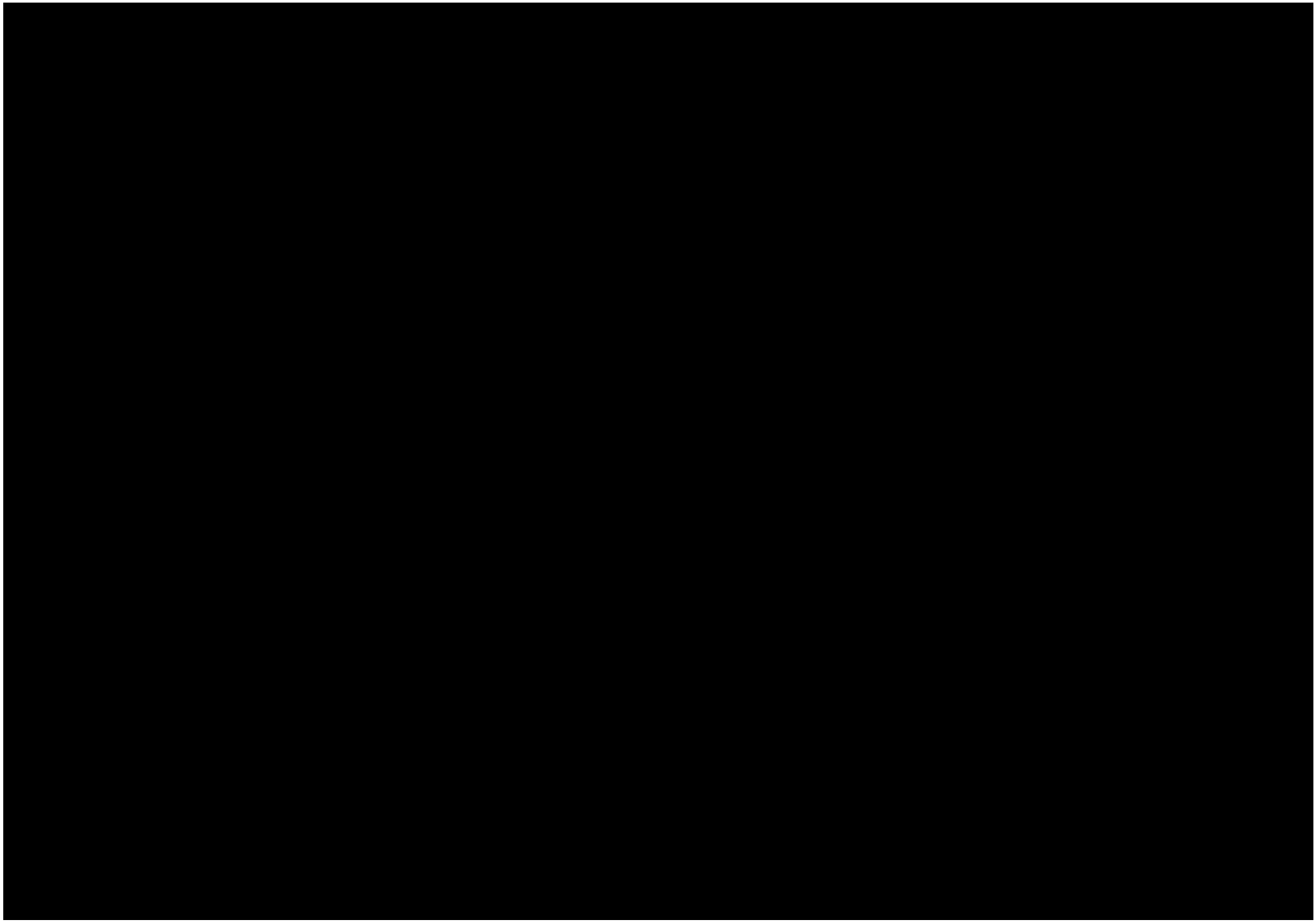
Hourly Average Day for March 2021

Panhandle Rural Electric Membership Association



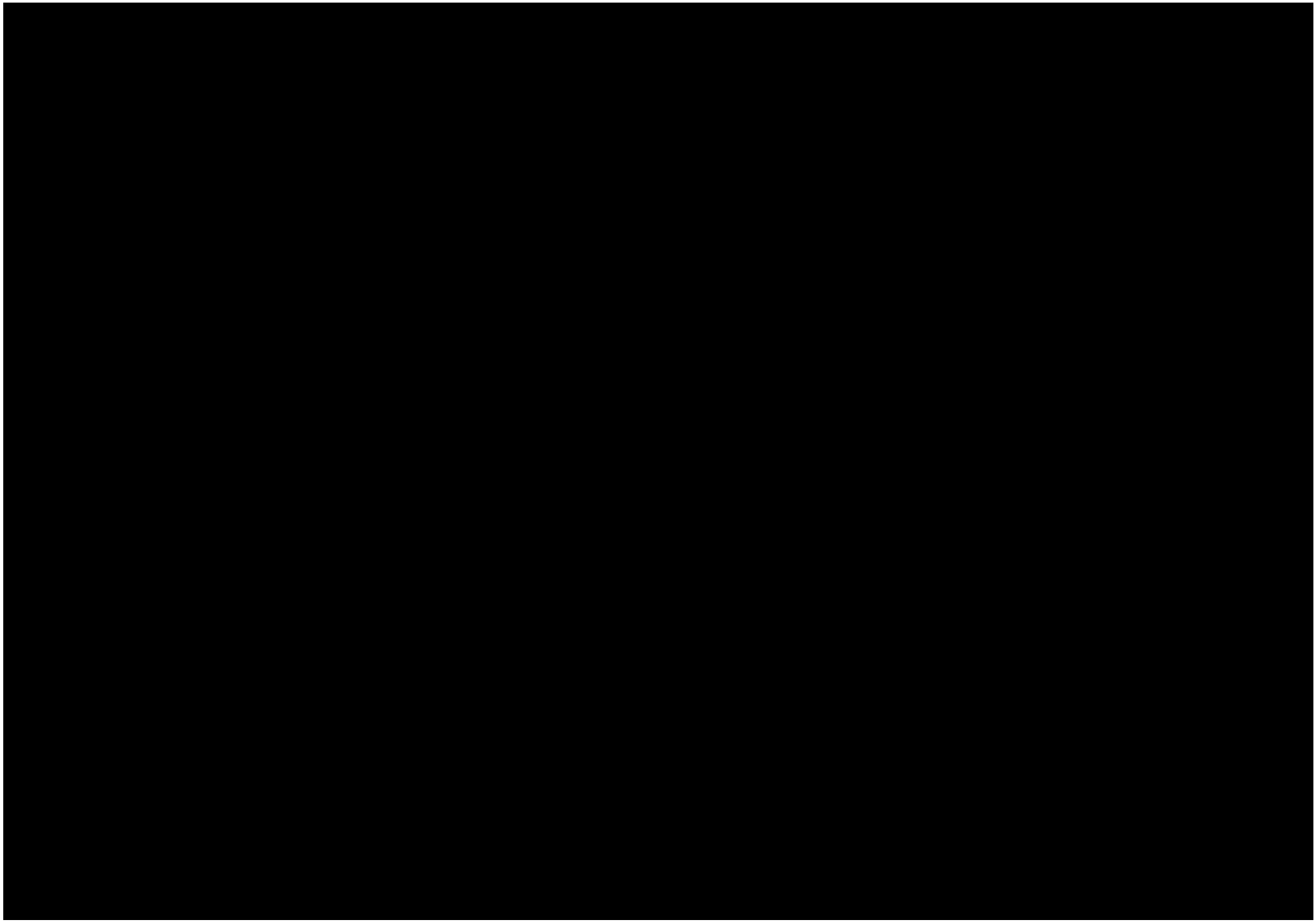
Hourly Average Day for April 2021

Panhandle Rural Electric Membership Association



Hourly Average Day for May 2021

Panhandle Rural Electric Membership Association



Hourly Average Day for June 2021

Panhandle Rural Electric Membership Association

[redacted]

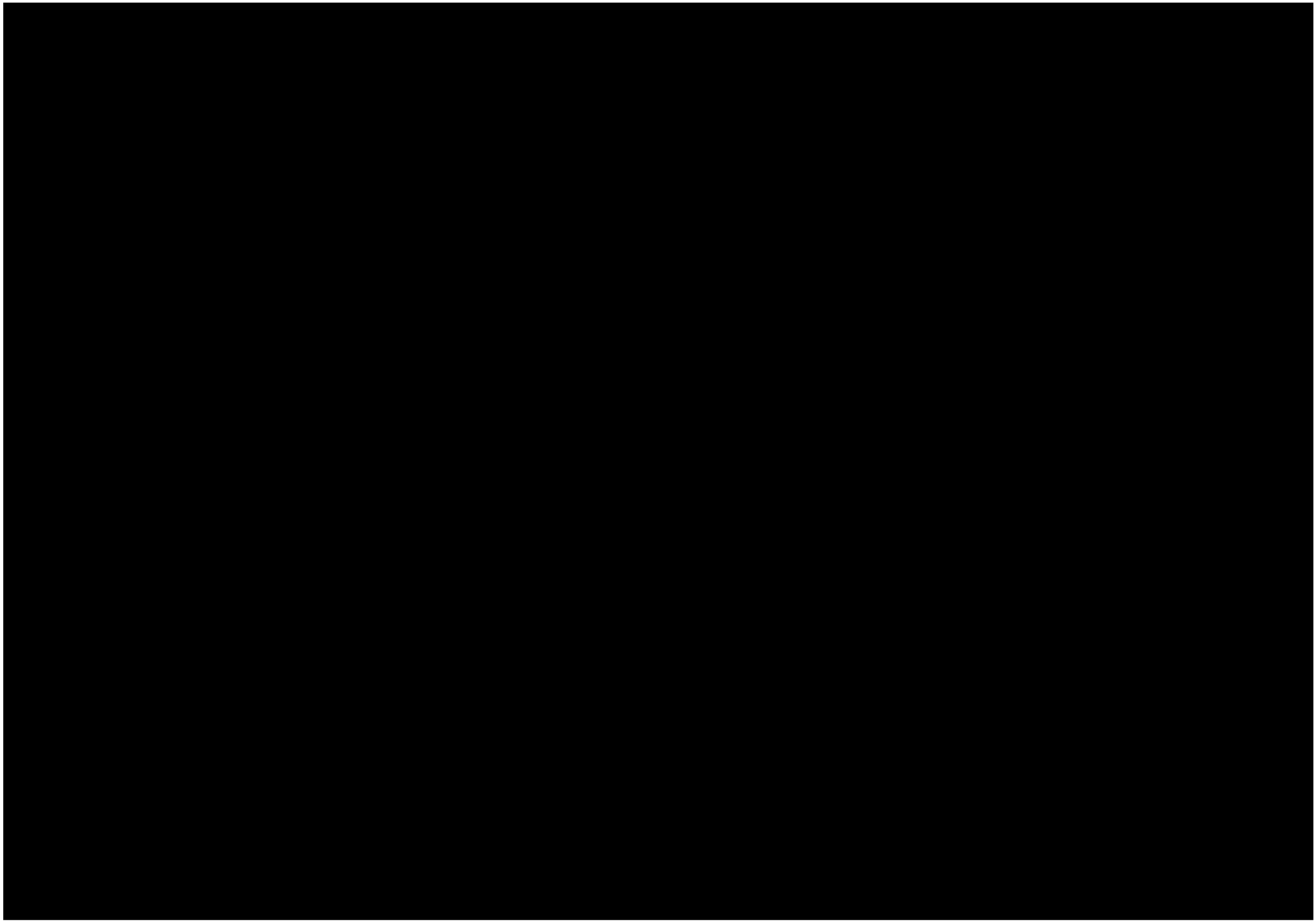
Hourly Average Day for July 2021

Panhandle Rural Electric Membership Association

[redacted]

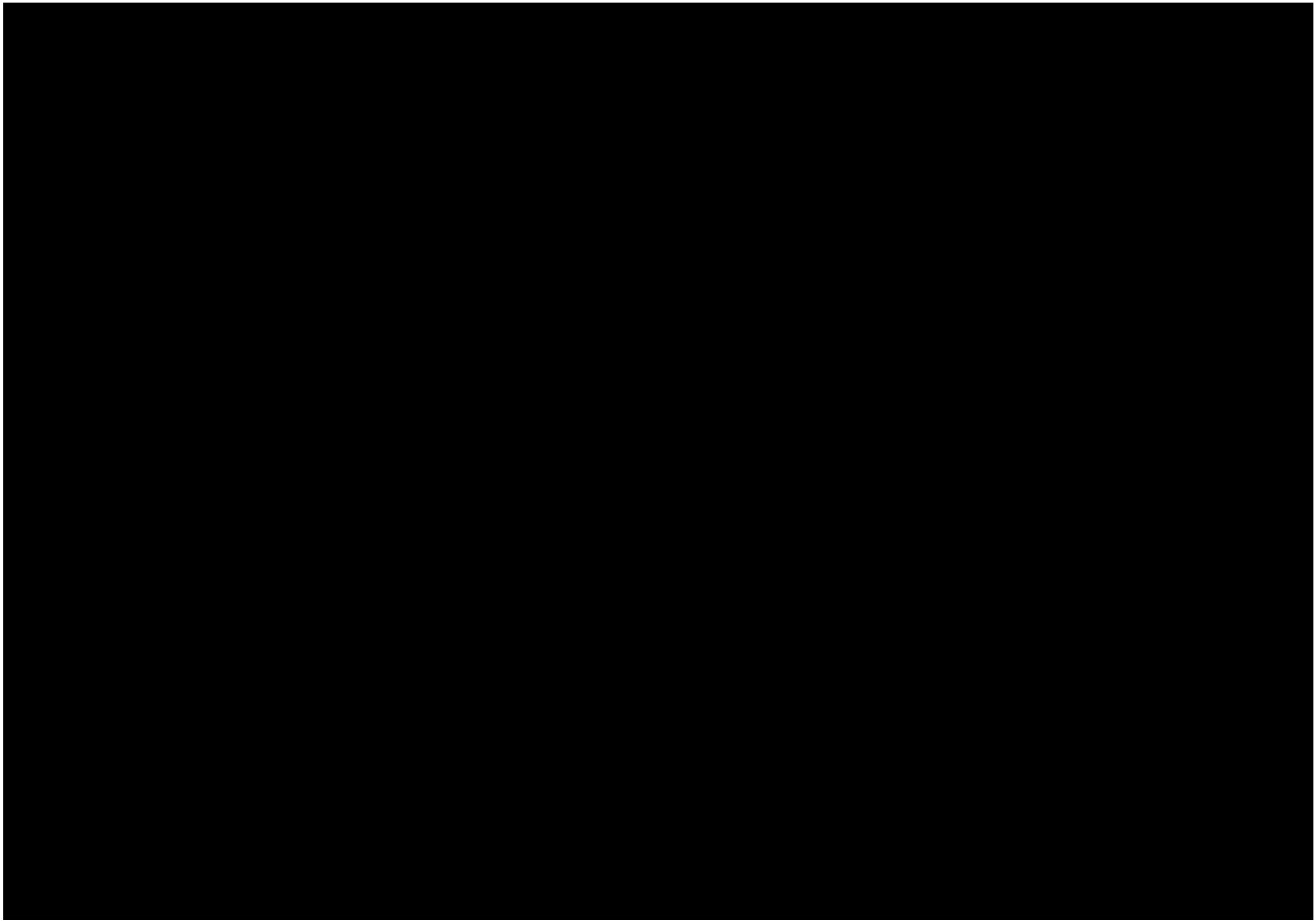
Hourly Average Day for August 2021

Panhandle Rural Electric Membership Association



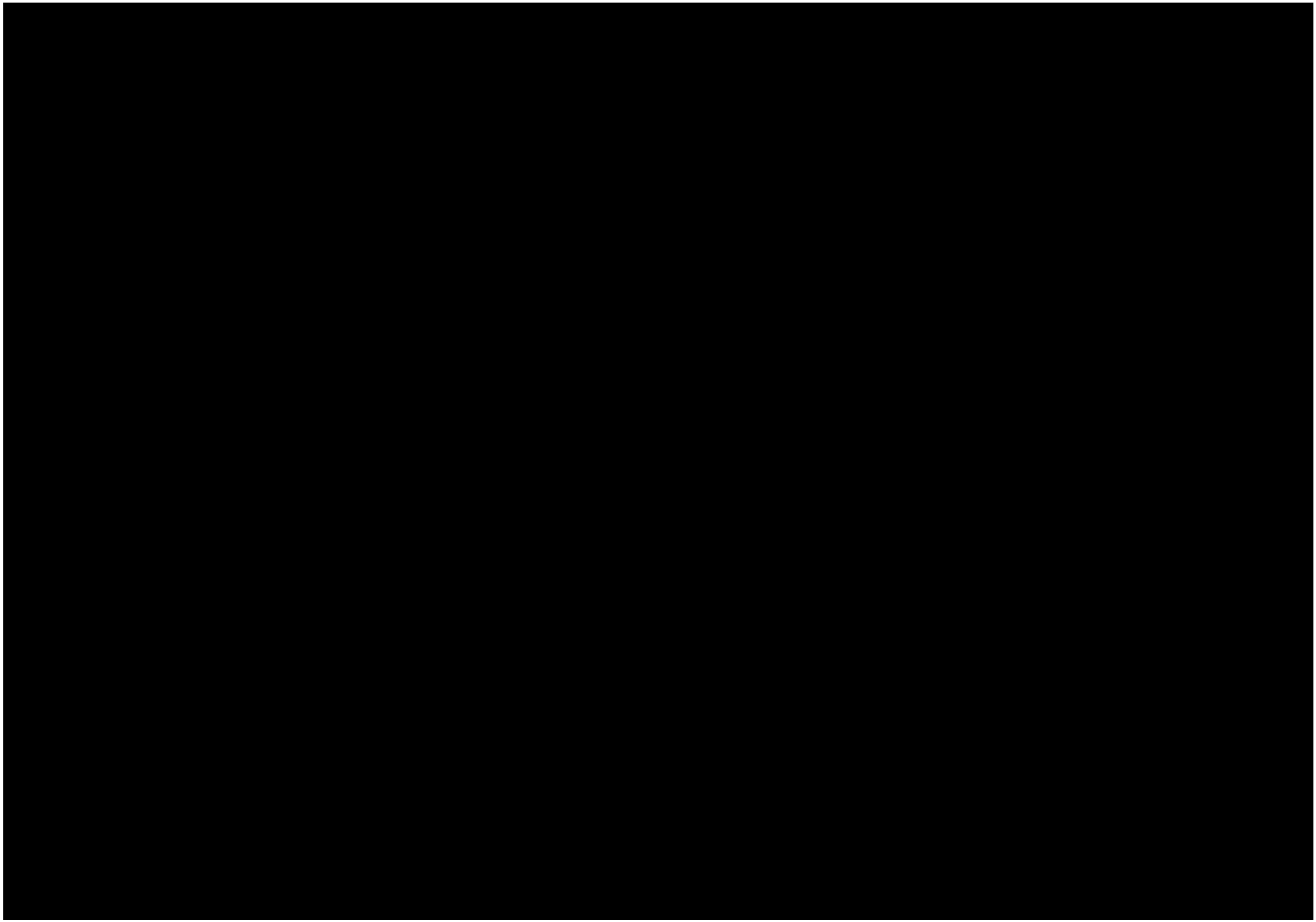
Hourly Average Day for September 2021

Panhandle Rural Electric Membership Association



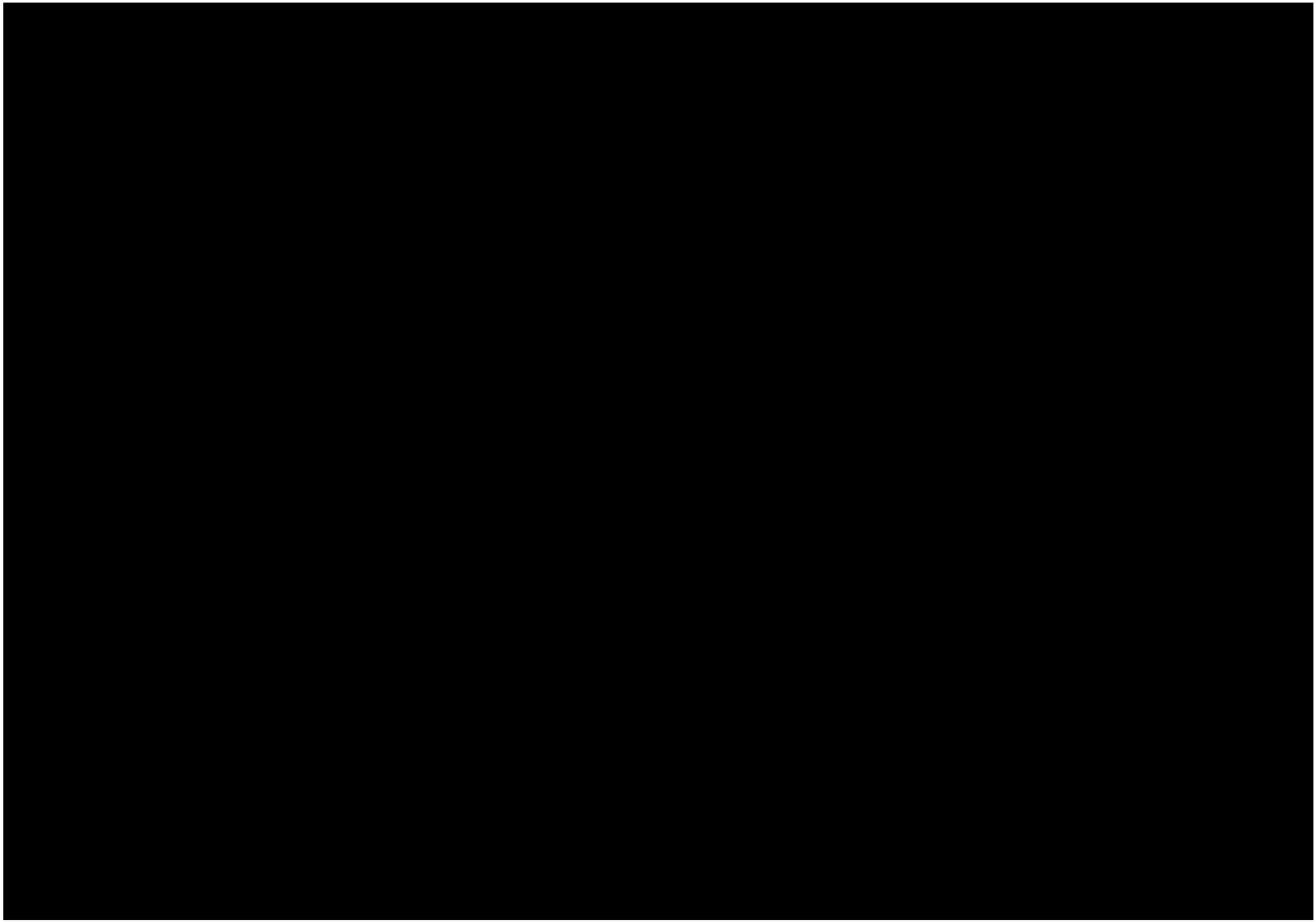
Hourly Average Day for October 2021

Panhandle Rural Electric Membership Association



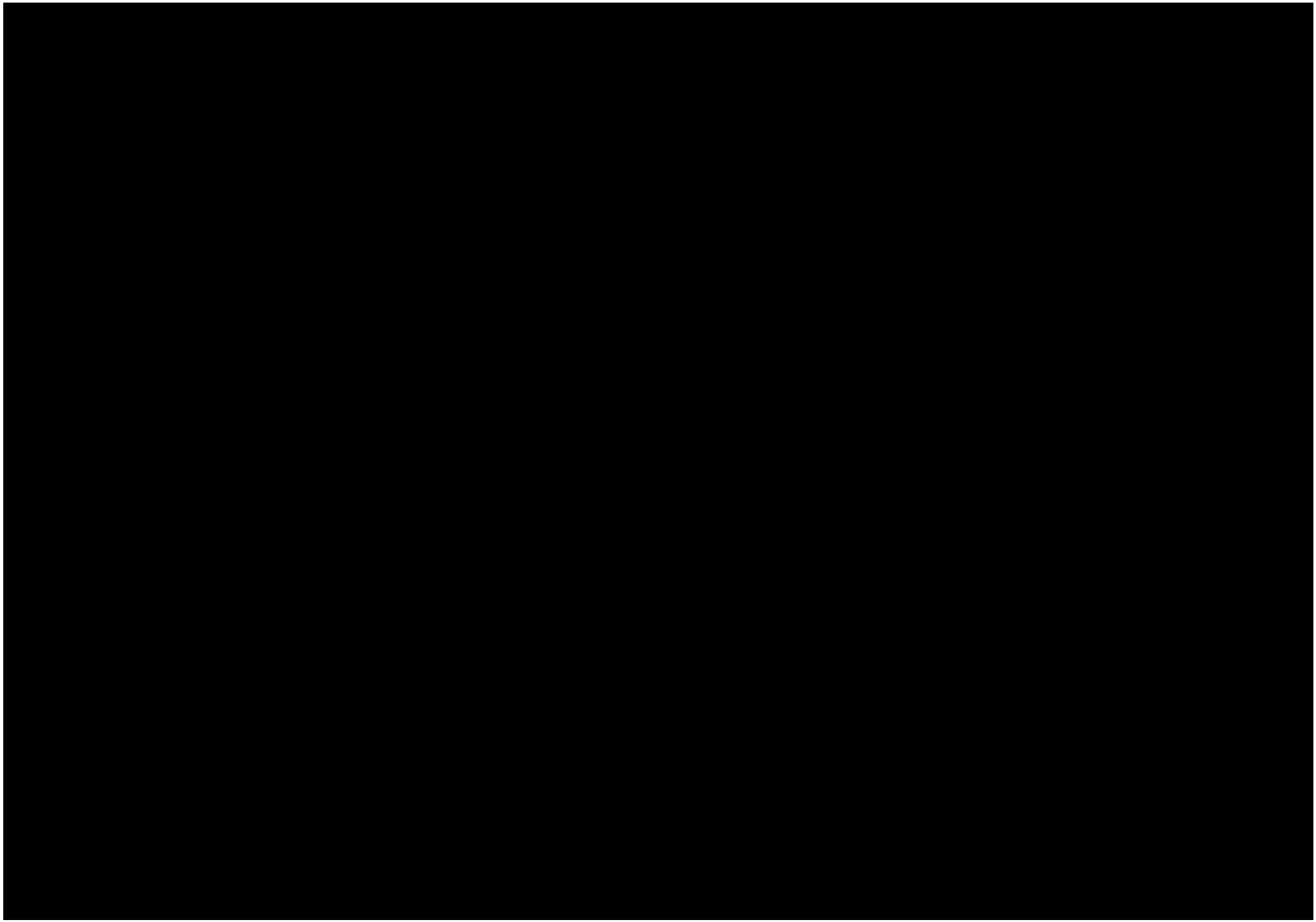
Hourly Average Day for November 2021

Panhandle Rural Electric Membership Association



Hourly Average Day for December 2021

Panhandle Rural Electric Membership Association



Hourly Average Day for January 2021

Poudre Valley Electric Association, Inc.

[redacted]

Hourly Average Day for February 2021

Poudre Valley Electric Association, Inc.

[redacted]

Hourly Average Day for March 2021

Poudre Valley Electric Association, Inc.

[redacted]

Hourly Average Day for April 2021

Poudre Valley Electric Association, Inc.

[redacted]

Hourly Average Day for May 2021

Poudre Valley Electric Association, Inc.

[redacted]

Hourly Average Day for June 2021

Poudre Valley Electric Association, Inc.

[redacted]

Hourly Average Day for July 2021

Poudre Valley Electric Association, Inc.

[redacted]

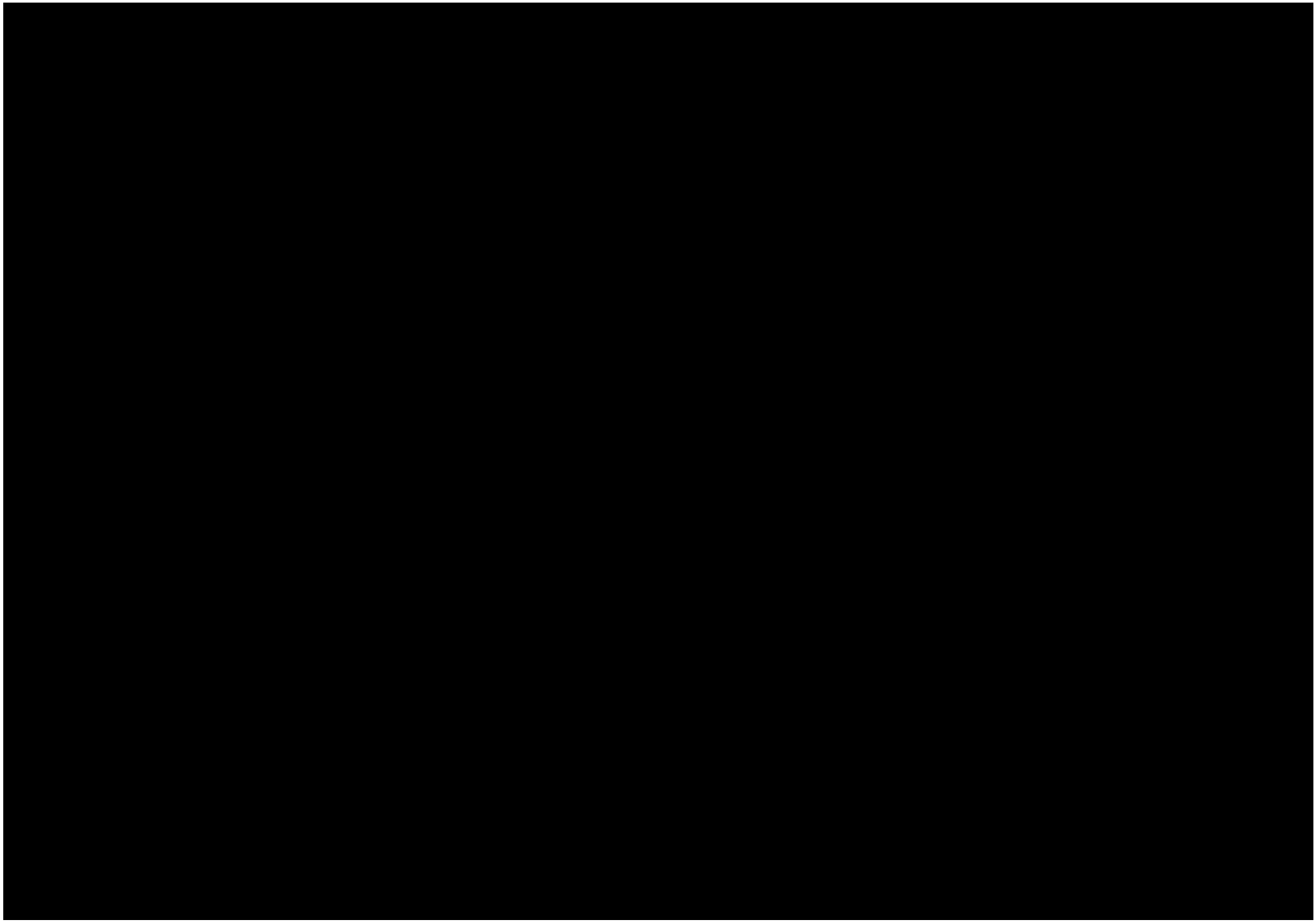
Hourly Average Day for August 2021

Poudre Valley Electric Association, Inc.

[redacted]

Hourly Average Day for September 2021

Poudre Valley Electric Association, Inc.



Hourly Average Day for October 2021

Poudre Valley Electric Association, Inc.

[redacted]

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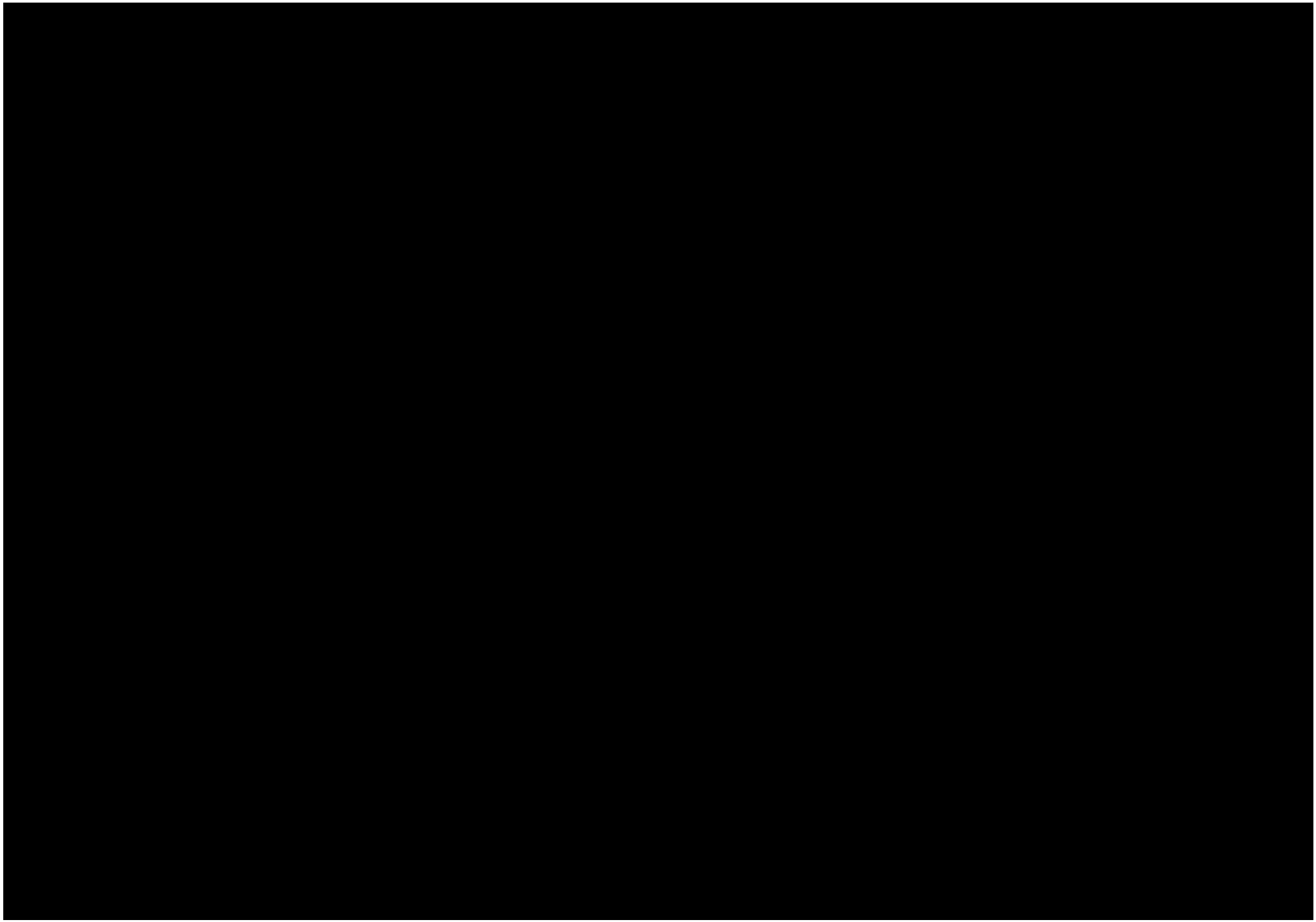
Hourly Average Day for November 2021

Poudre Valley Electric Association, Inc.



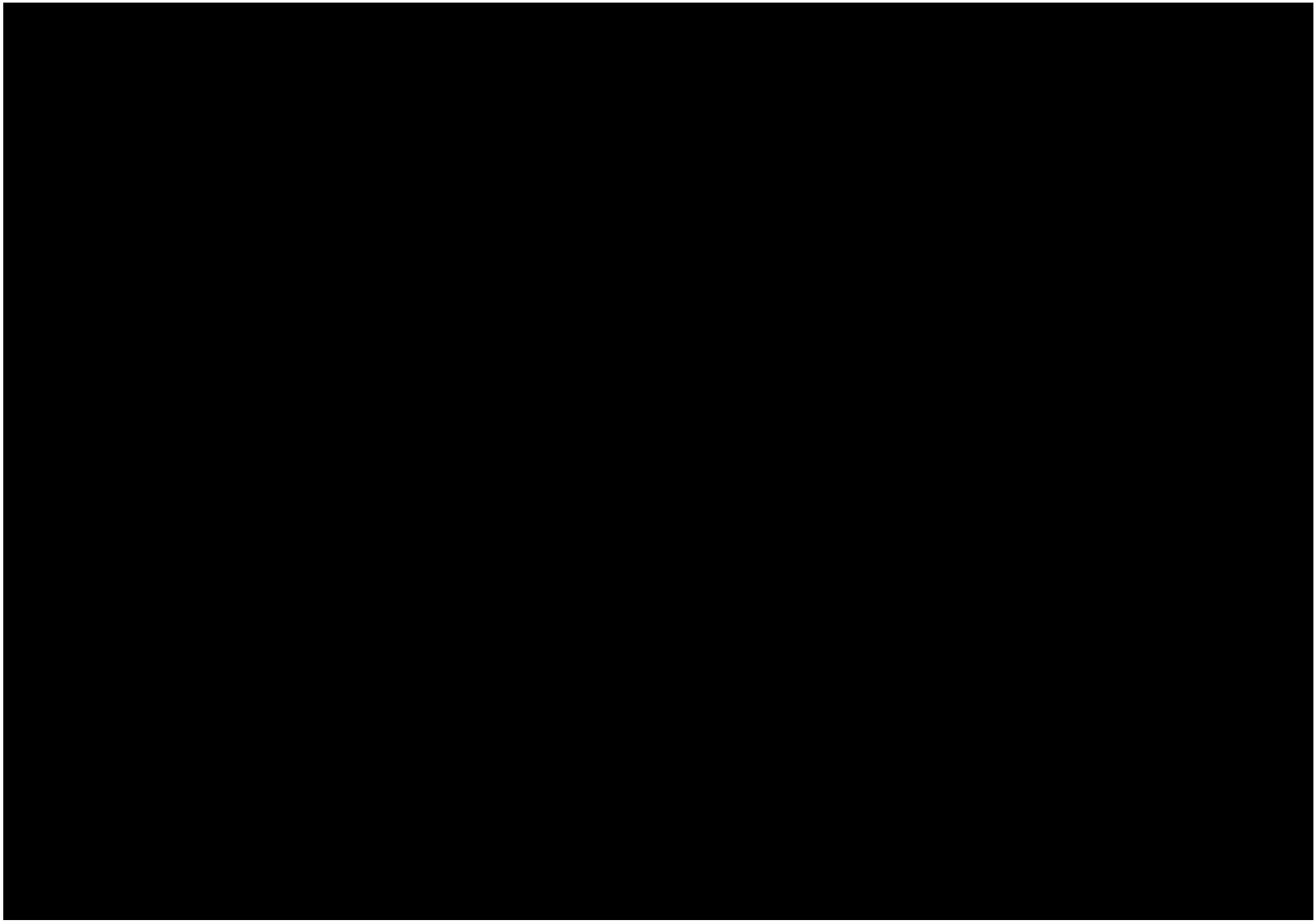
Hourly Average Day for December 2021

Poudre Valley Electric Association, Inc.

[redacted]

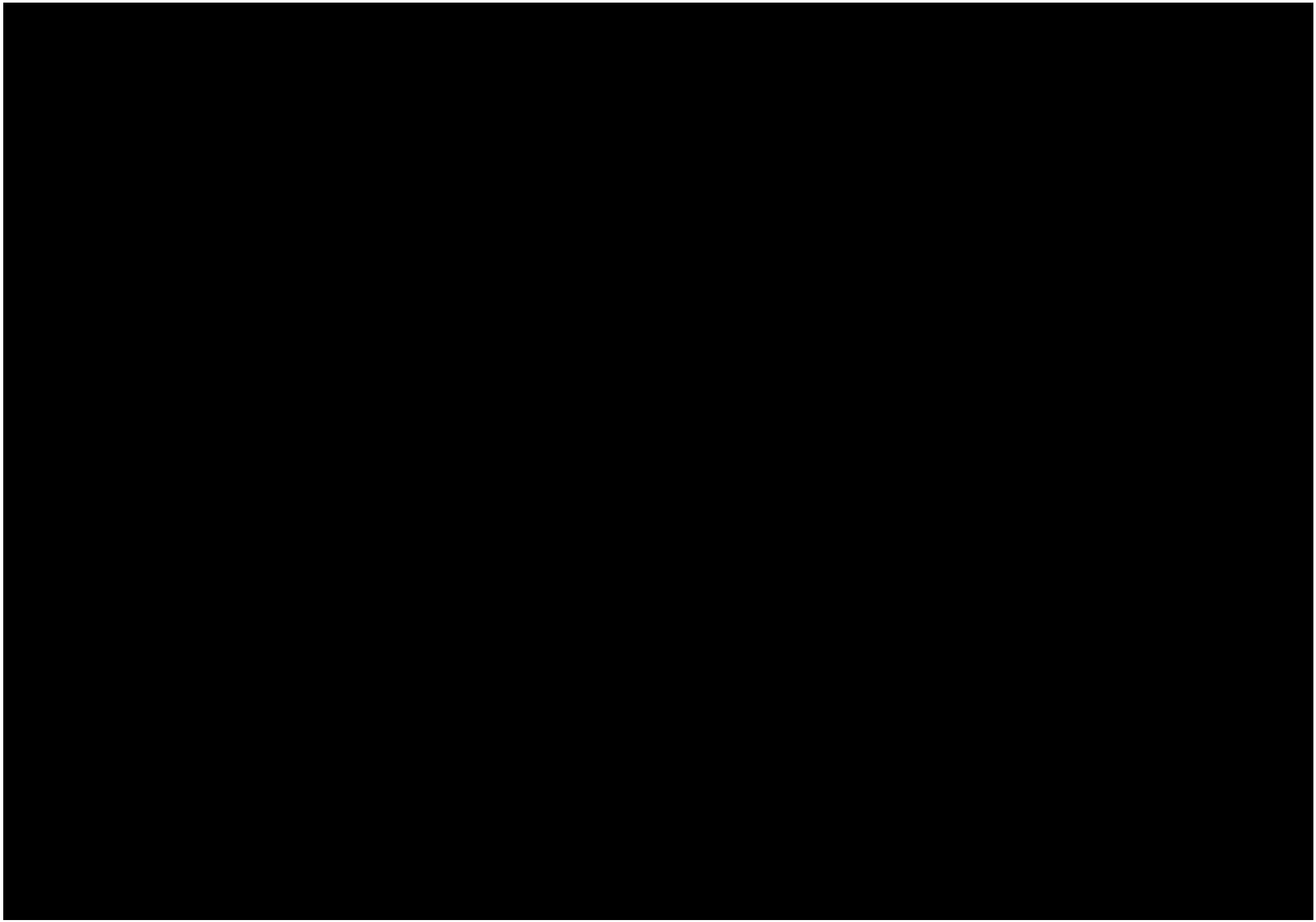
Hourly Average Day for January 2021

Northern Rio Arriba Electric Cooperative, Inc.



Hourly Average Day for February 2021

Northern Rio Arriba Electric Cooperative, Inc.



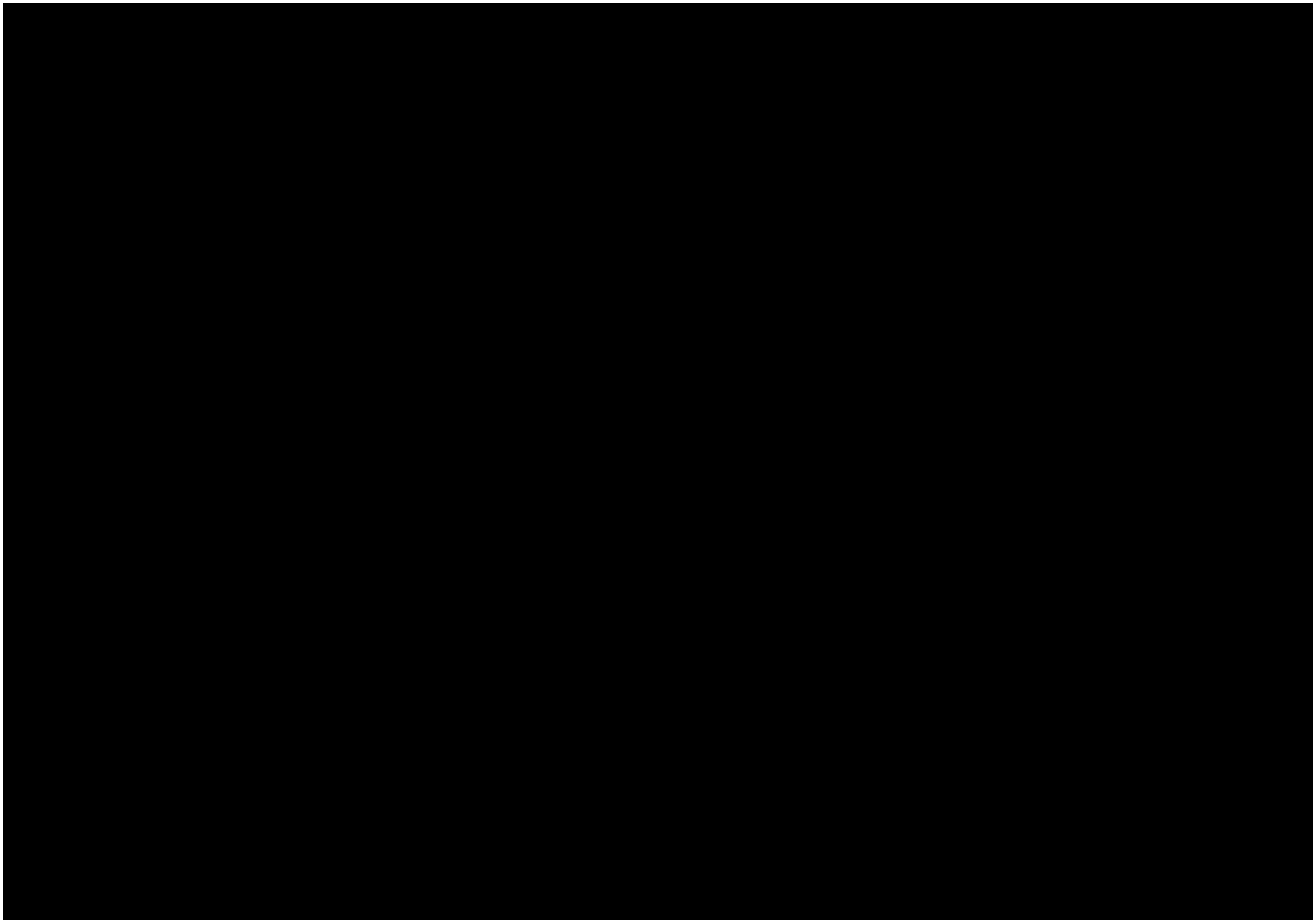
Hourly Average Day for March 2021

Northern Rio Arriba Electric Cooperative, Inc.

[redacted]

Hourly Average Day for April 2021

Northern Rio Arriba Electric Cooperative, Inc.



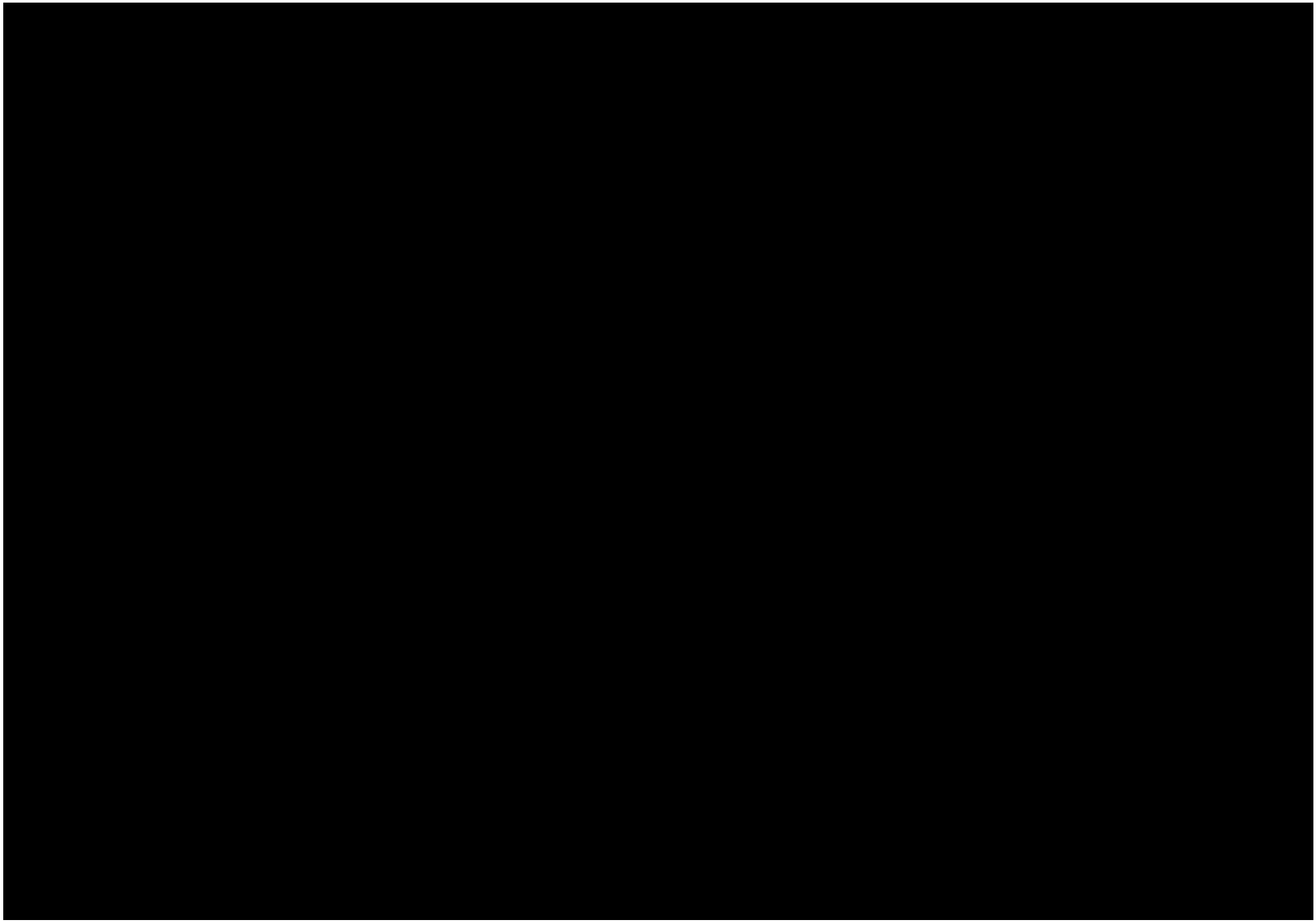
Hourly Average Day for May 2021

Northern Rio Arriba Electric Cooperative, Inc.

[redacted]

Hourly Average Day for June 2021

Northern Rio Arriba Electric Cooperative, Inc.



Hourly Average Day for July 2021

Northern Rio Arriba Electric Cooperative, Inc.

[redacted]

Hourly Average Day for August 2021

Northern Rio Arriba Electric Cooperative, Inc.

[redacted]

Hourly Average Day for September 2021

Northern Rio Arriba Electric Cooperative, Inc.

[redacted]

Hourly Average Day for October 2021

Northern Rio Arriba Electric Cooperative, Inc.

[redacted]

Hourly Average Day for November 2021

Northern Rio Arriba Electric Cooperative, Inc.

[redacted]

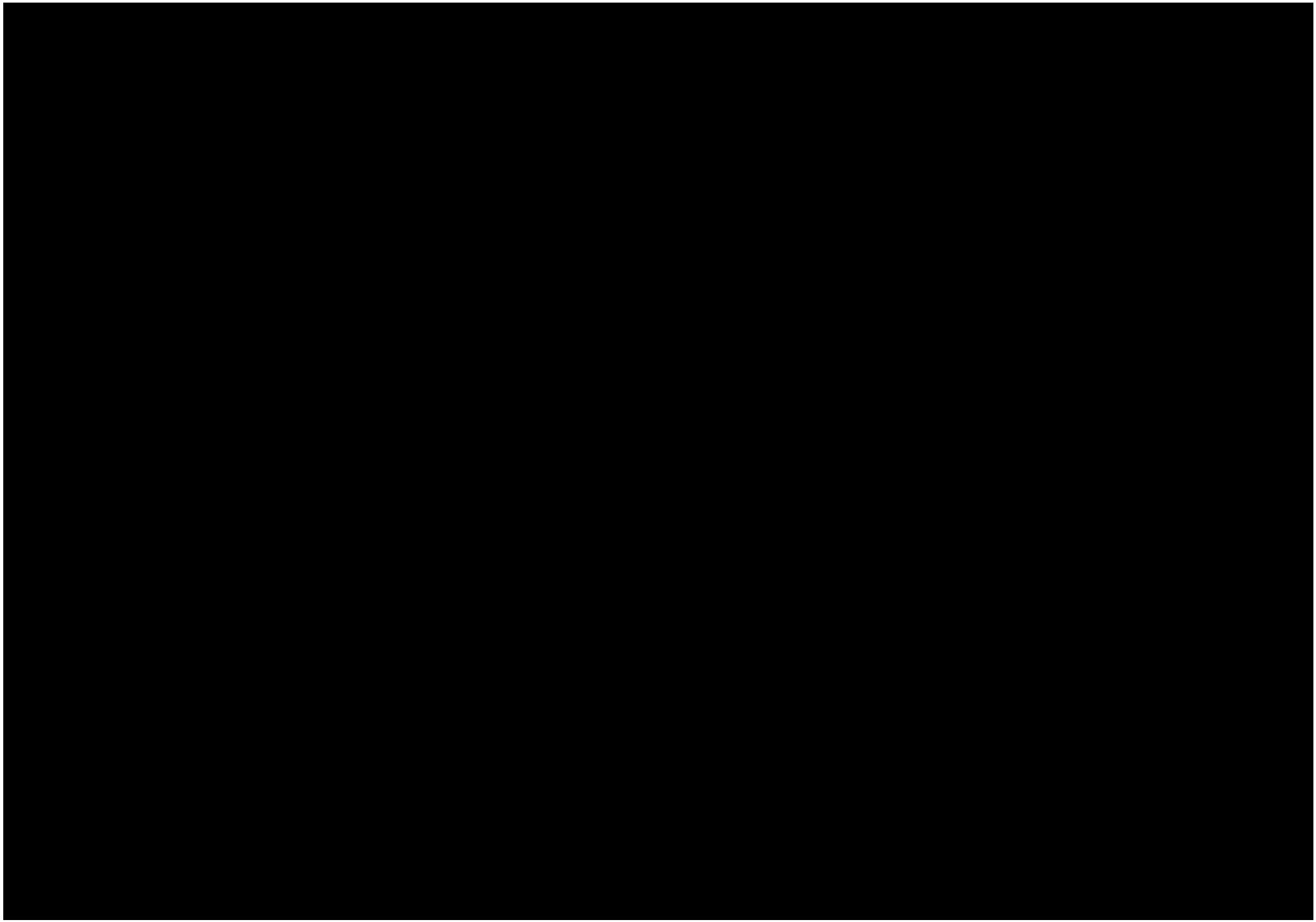
Hourly Average Day for December 2021

Northern Rio Arriba Electric Cooperative, Inc.

[redacted]

Hourly Average Day for January 2021

Roosevelt Public Power District

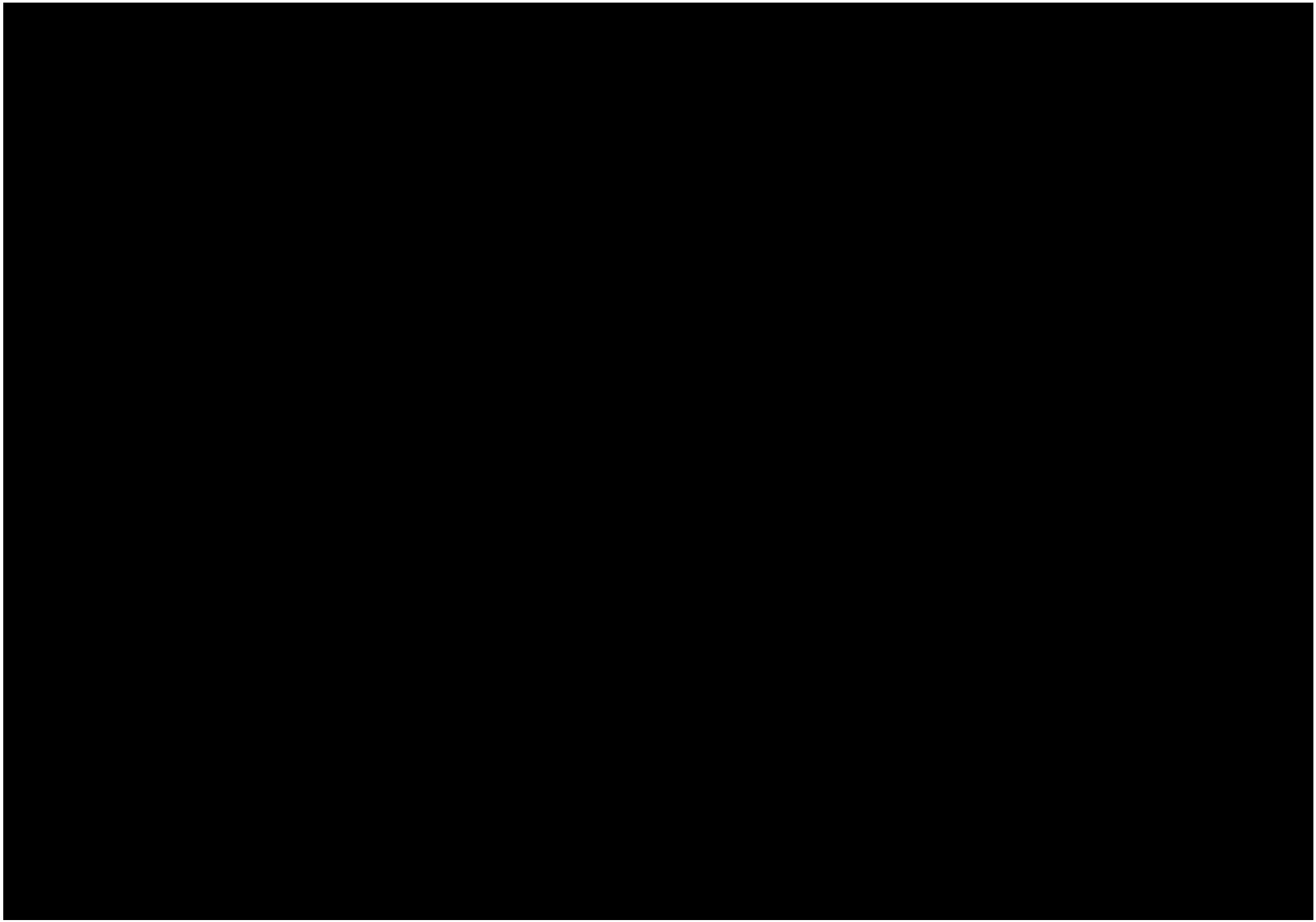


Hourly Average Day for February 2021
Roosevelt Public Power District

[redacted]

Hourly Average Day for March 2021

Roosevelt Public Power District



Hourly Average Day for April 2021

Roosevelt Public Power District

[redacted]

Hourly Average Day for May 2021

Roosevelt Public Power District

[redacted]

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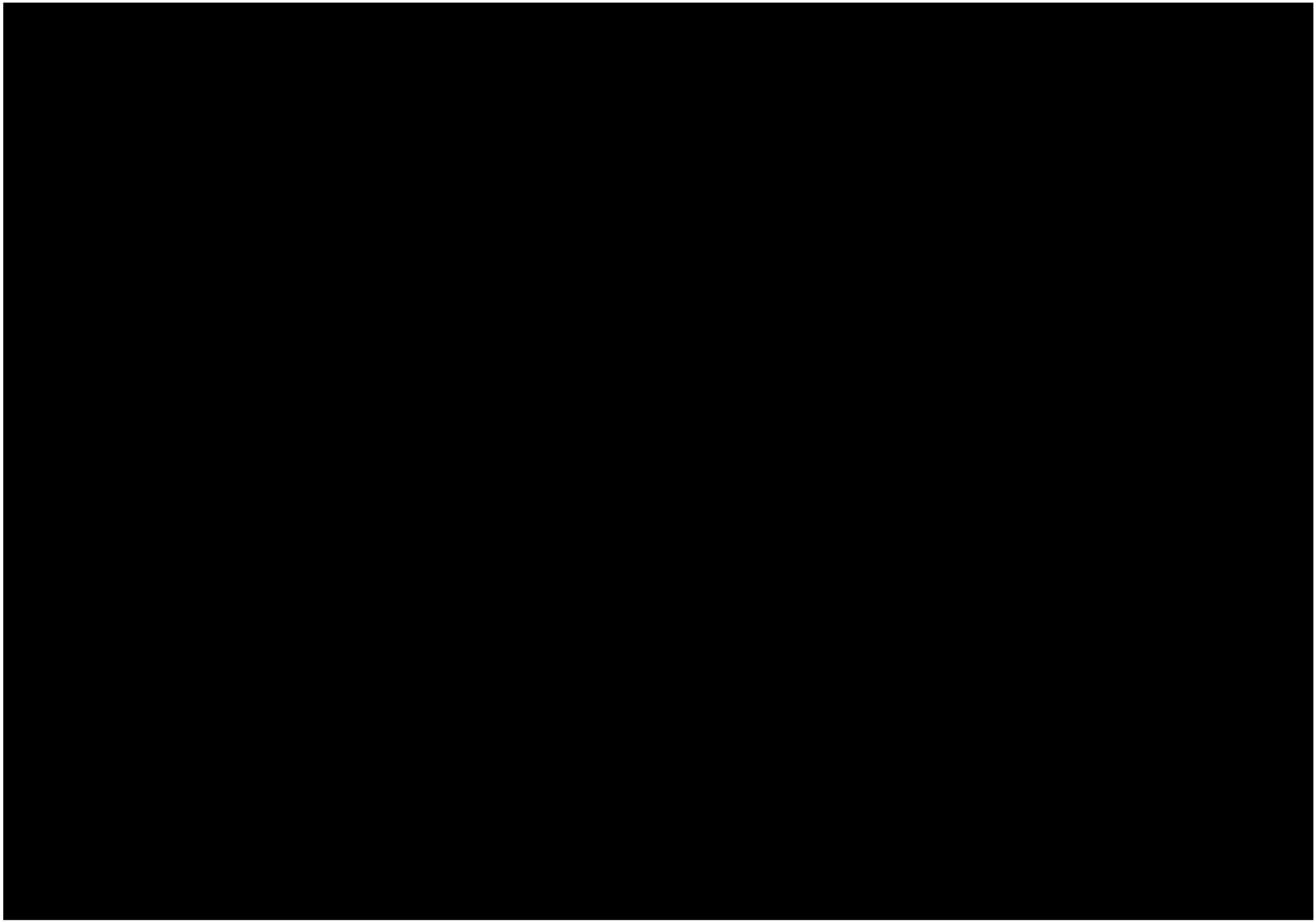
Hourly Average Day for June 2021

Roosevelt Public Power District



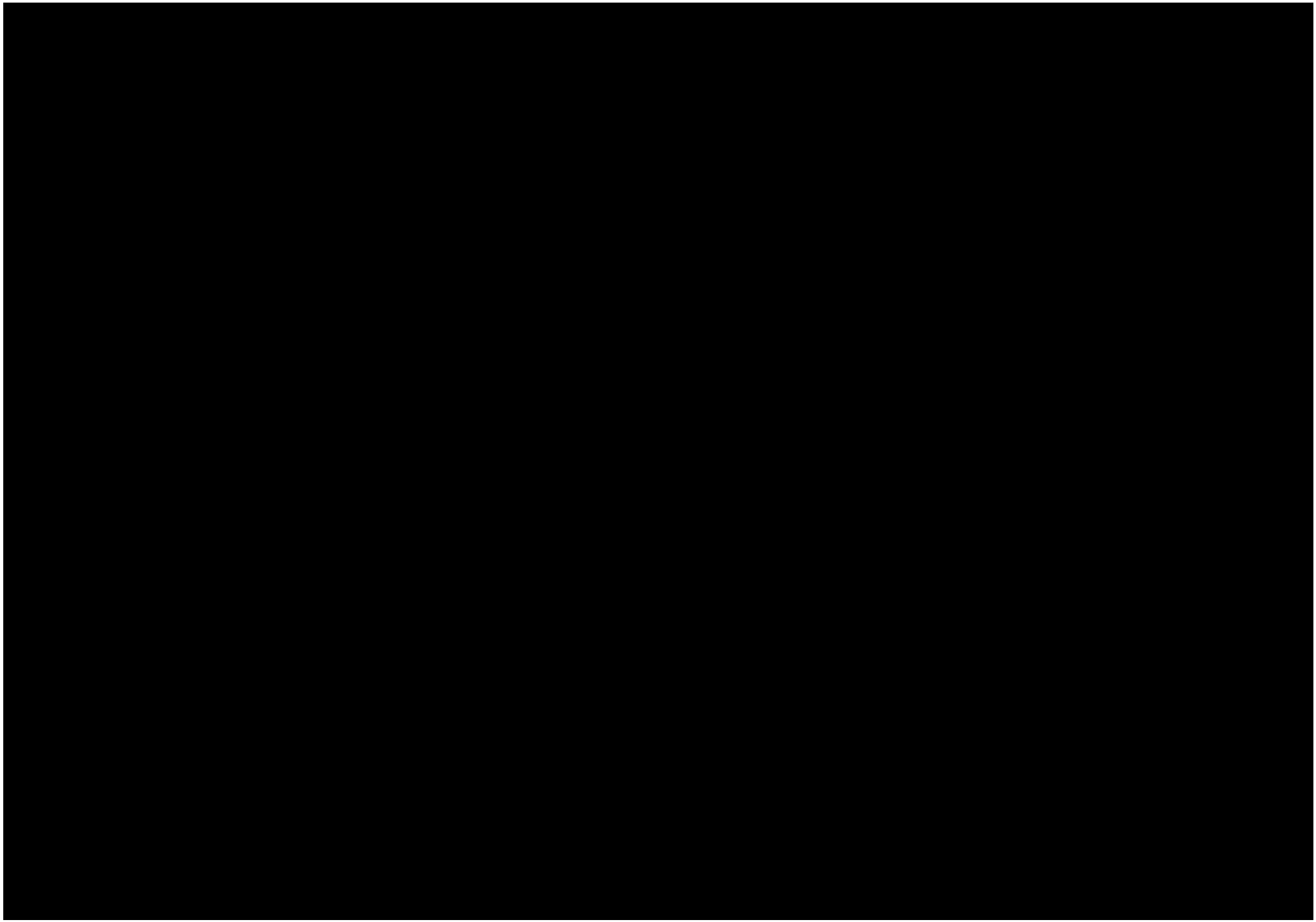
Hourly Average Day for July 2021

Roosevelt Public Power District

[redacted]

Hourly Average Day for August 2021

Roosevelt Public Power District



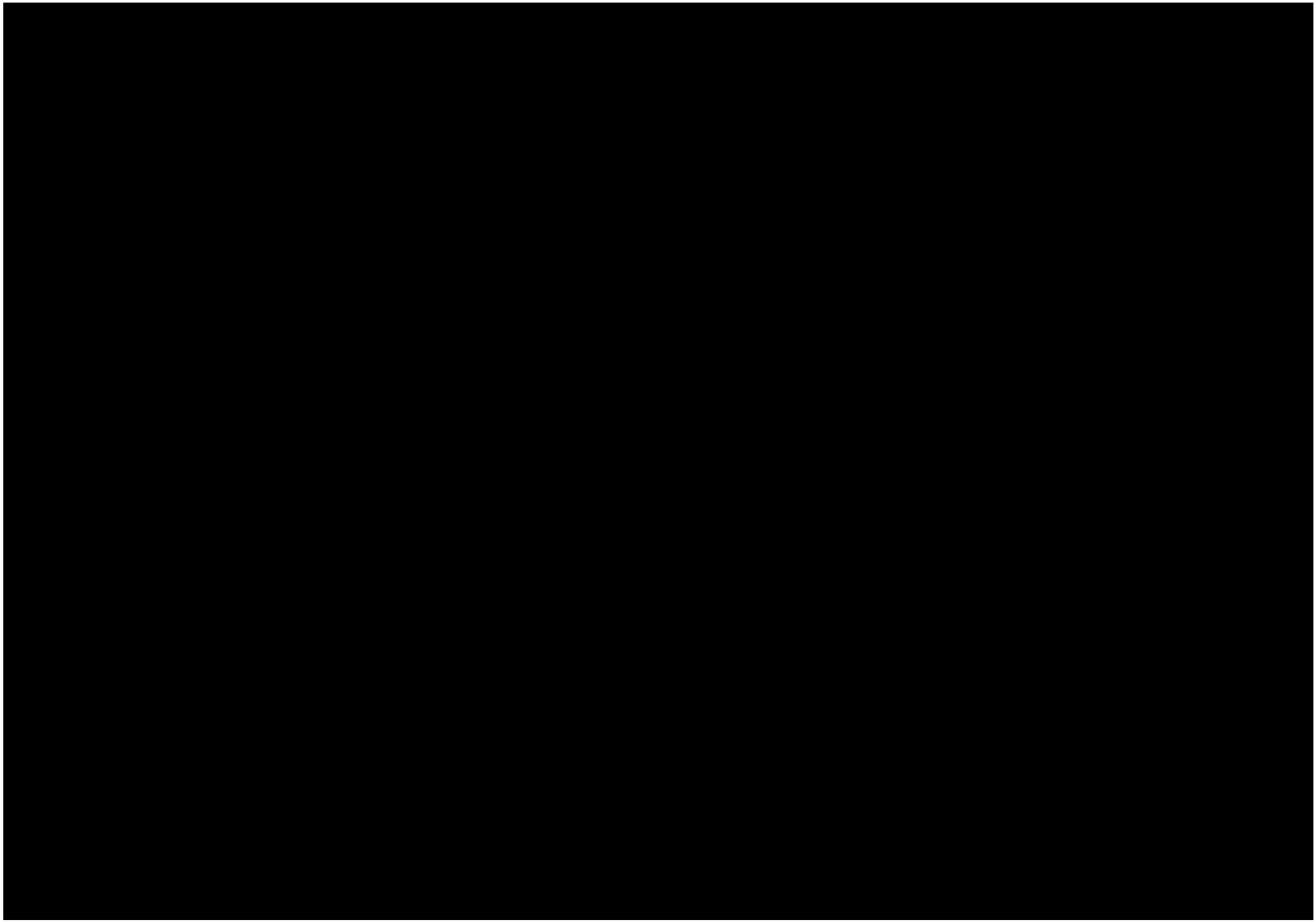
Hourly Average Day for September 2021

Roosevelt Public Power District

[redacted]

Hourly Average Day for October 2021

Roosevelt Public Power District



Hourly Average Day for November 2021

Roosevelt Public Power District

[redacted]

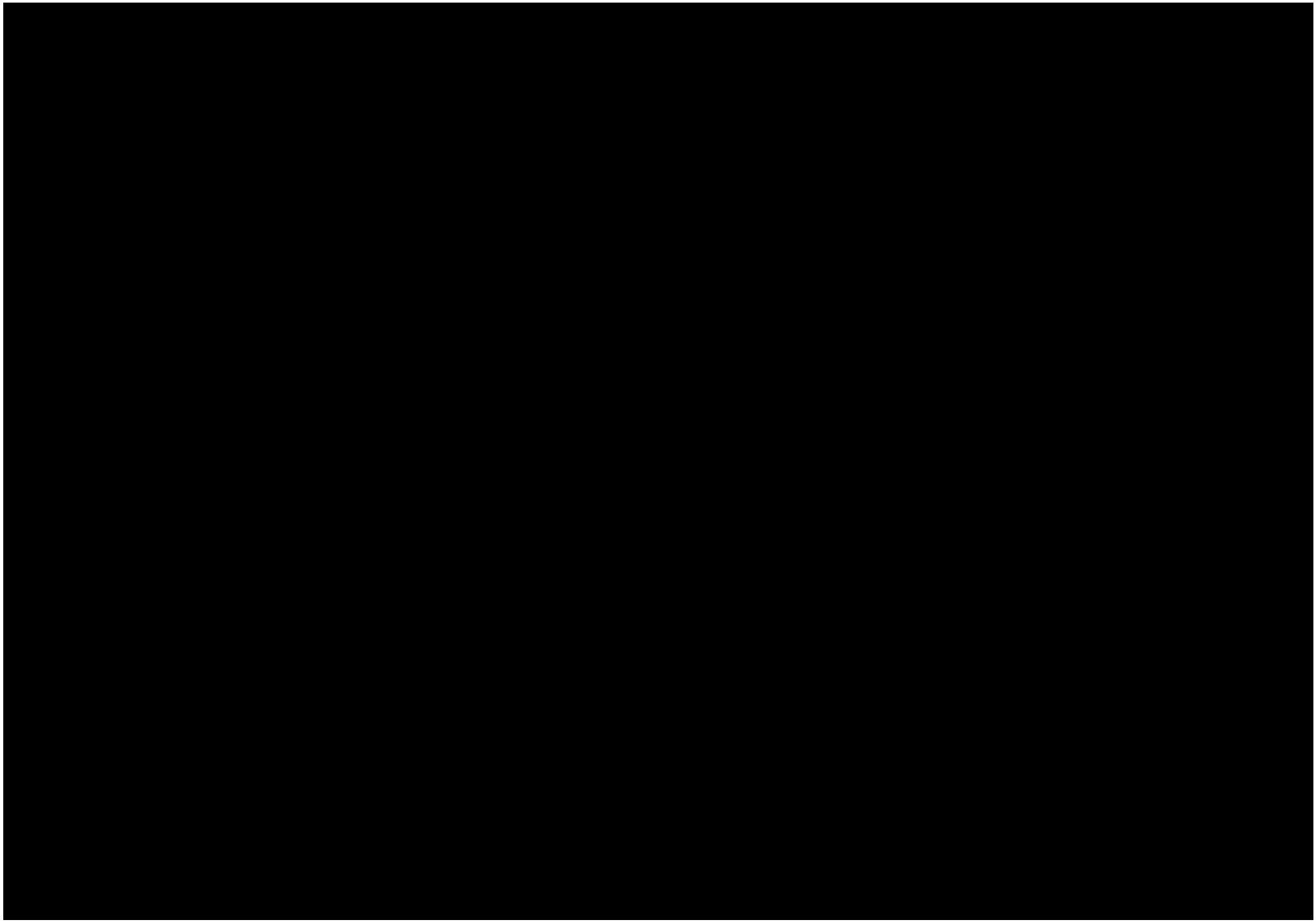
Hourly Average Day for December 2021

Roosevelt Public Power District

[redacted]

Hourly Average Day for January 2021

Sierra Electric Cooperative, Inc.



Hourly Average Day for February 2021

Sierra Electric Cooperative, Inc.

[redacted]

Hourly Average Day for March 2021

Sierra Electric Cooperative, Inc.

[redacted]

Hourly Average Day for April 2021

Sierra Electric Cooperative, Inc.

[redacted]

Hourly Average Day for May 2021

Sierra Electric Cooperative, Inc.

[redacted]

Hourly Average Day for June 2021

Sierra Electric Cooperative, Inc.

[redacted]

Hourly Average Day for July 2021

Sierra Electric Cooperative, Inc.

[redacted]

Hourly Average Day for August 2021

Sierra Electric Cooperative, Inc.

[redacted]

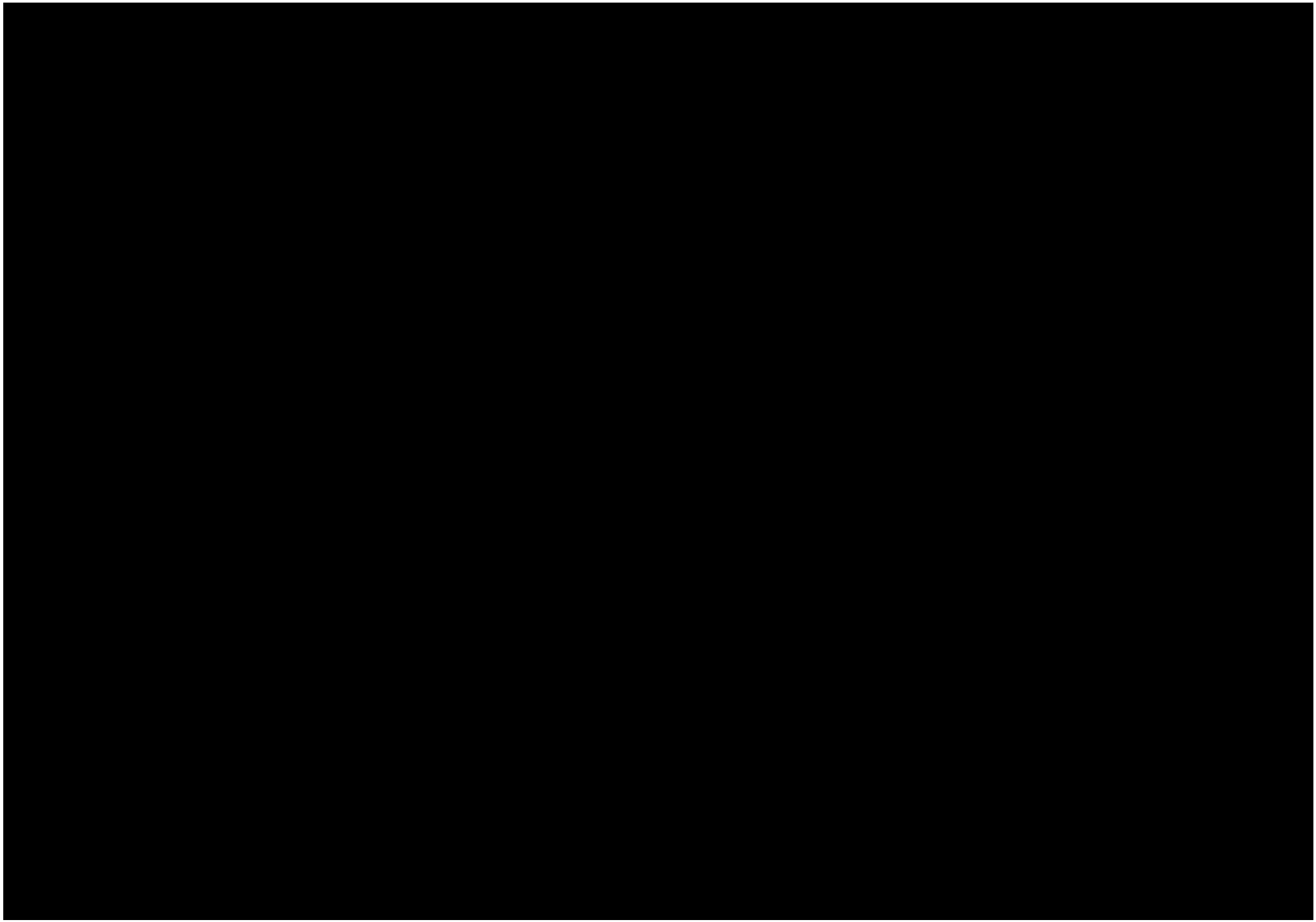
Hourly Average Day for September 2021

Sierra Electric Cooperative, Inc.

[redacted]

Hourly Average Day for October 2021

Sierra Electric Cooperative, Inc.



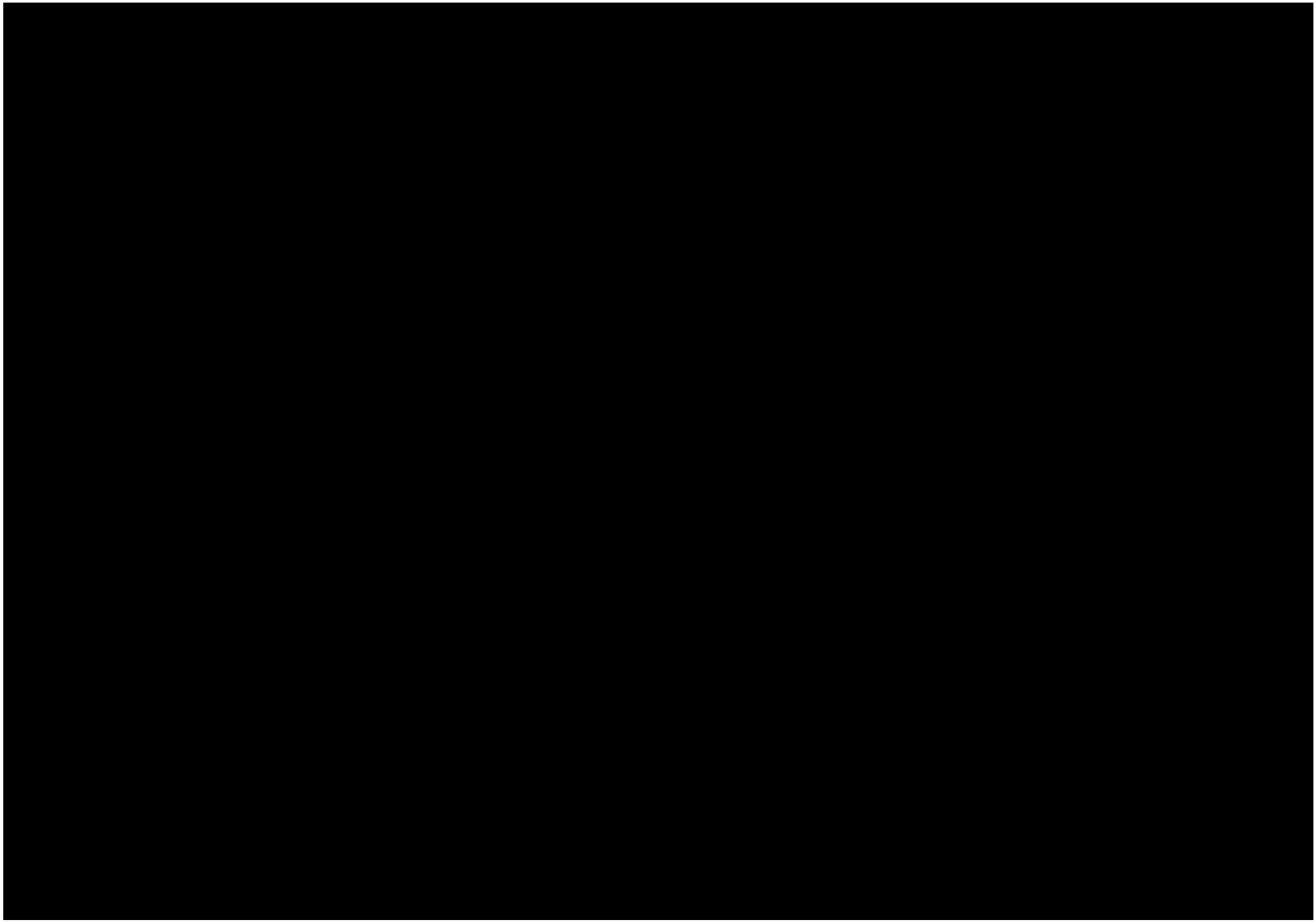
Hourly Average Day for November 2021

Sierra Electric Cooperative, Inc.

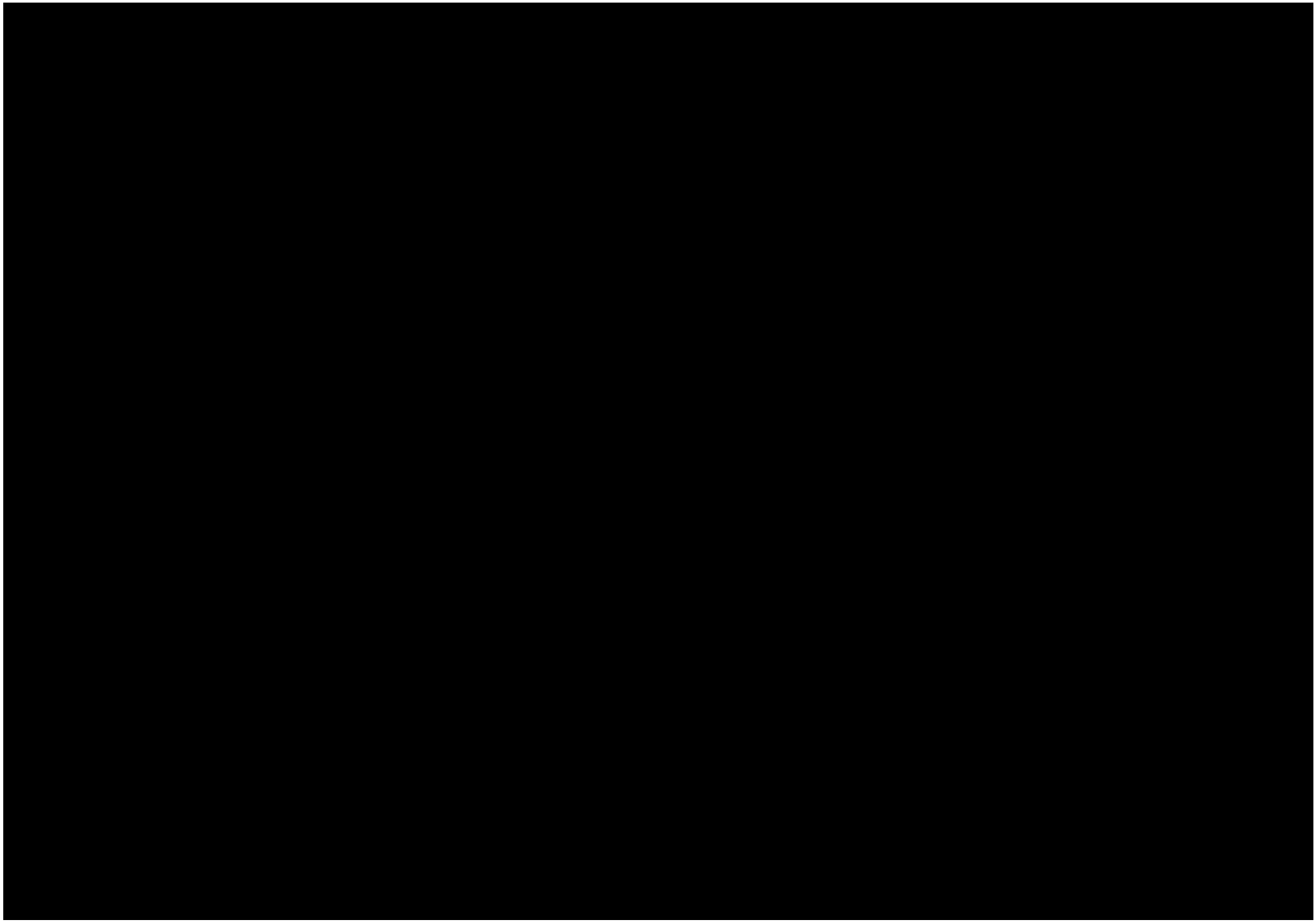
[redacted]

Hourly Average Day for December 2021

Sierra Electric Cooperative, Inc.



Hourly Average Day for January 2021
Sangre de Cristo Electric Association, Inc.



Hourly Average Day for February 2021

Sangre de Cristo Electric Association, Inc.

[redacted]

Hourly Average Day for March 2021

Sangre de Cristo Electric Association, Inc.

[redacted]

Hourly Average Day for April 2021

Sangre de Cristo Electric Association, Inc.

[redacted]

Hourly Average Day for May 2021

Sangre de Cristo Electric Association, Inc.

[redacted]

Hourly Average Day for June 2021

Sangre de Cristo Electric Association, Inc.

[redacted]

Hourly Average Day for July 2021
Sangre de Cristo Electric Association, Inc.

[redacted]

Hourly Average Day for August 2021

Sangre de Cristo Electric Association, Inc.

[redacted]

Hourly Average Day for September 2021

Sangre de Cristo Electric Association, Inc.

[redacted]

Hourly Average Day for October 2021

Sangre de Cristo Electric Association, Inc.

[redacted]

Hourly Average Day for November 2021

Sangre de Cristo Electric Association, Inc.

[redacted]

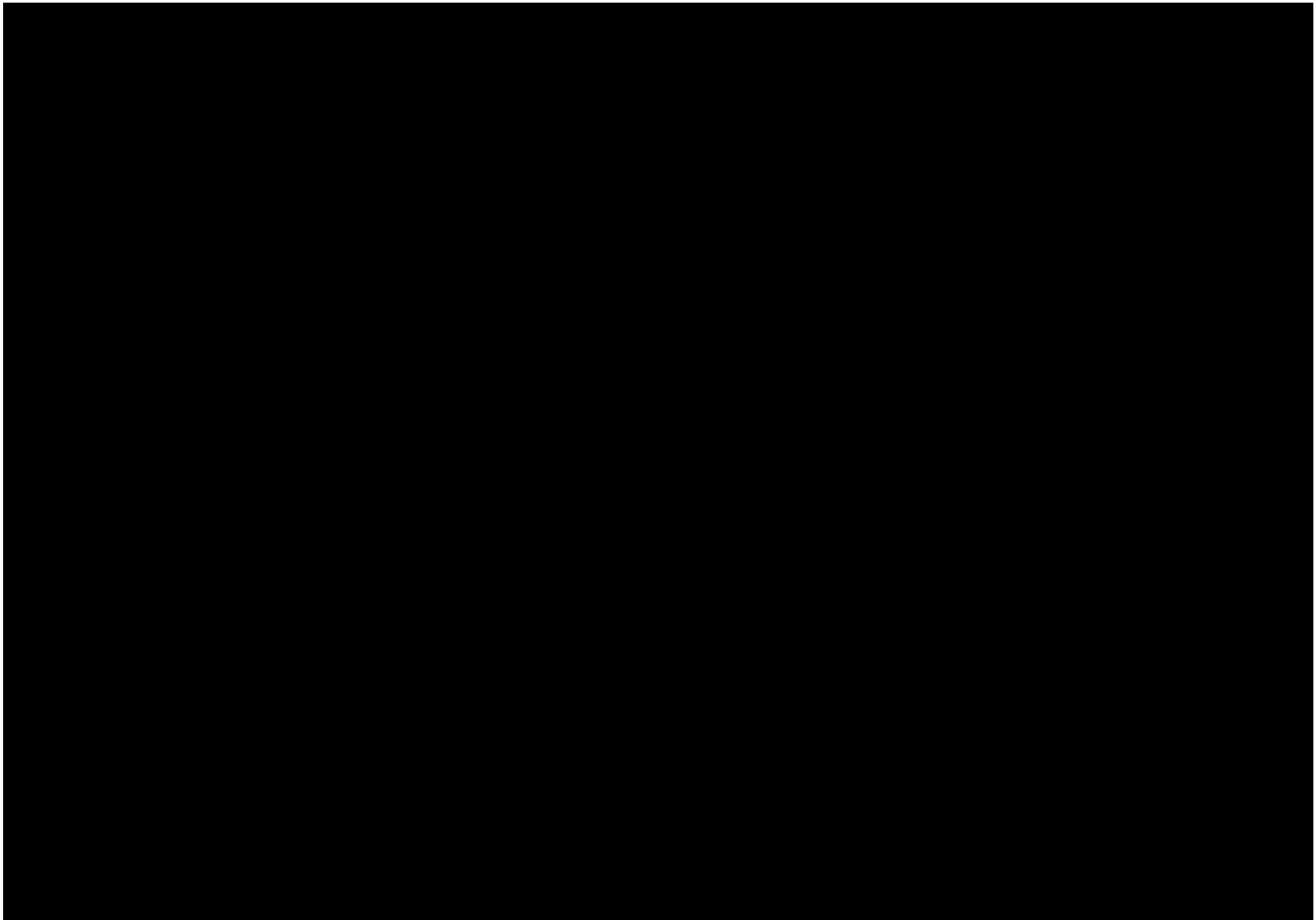
Hourly Average Day for December 2021

Sangre de Cristo Electric Association, Inc.

[redacted]

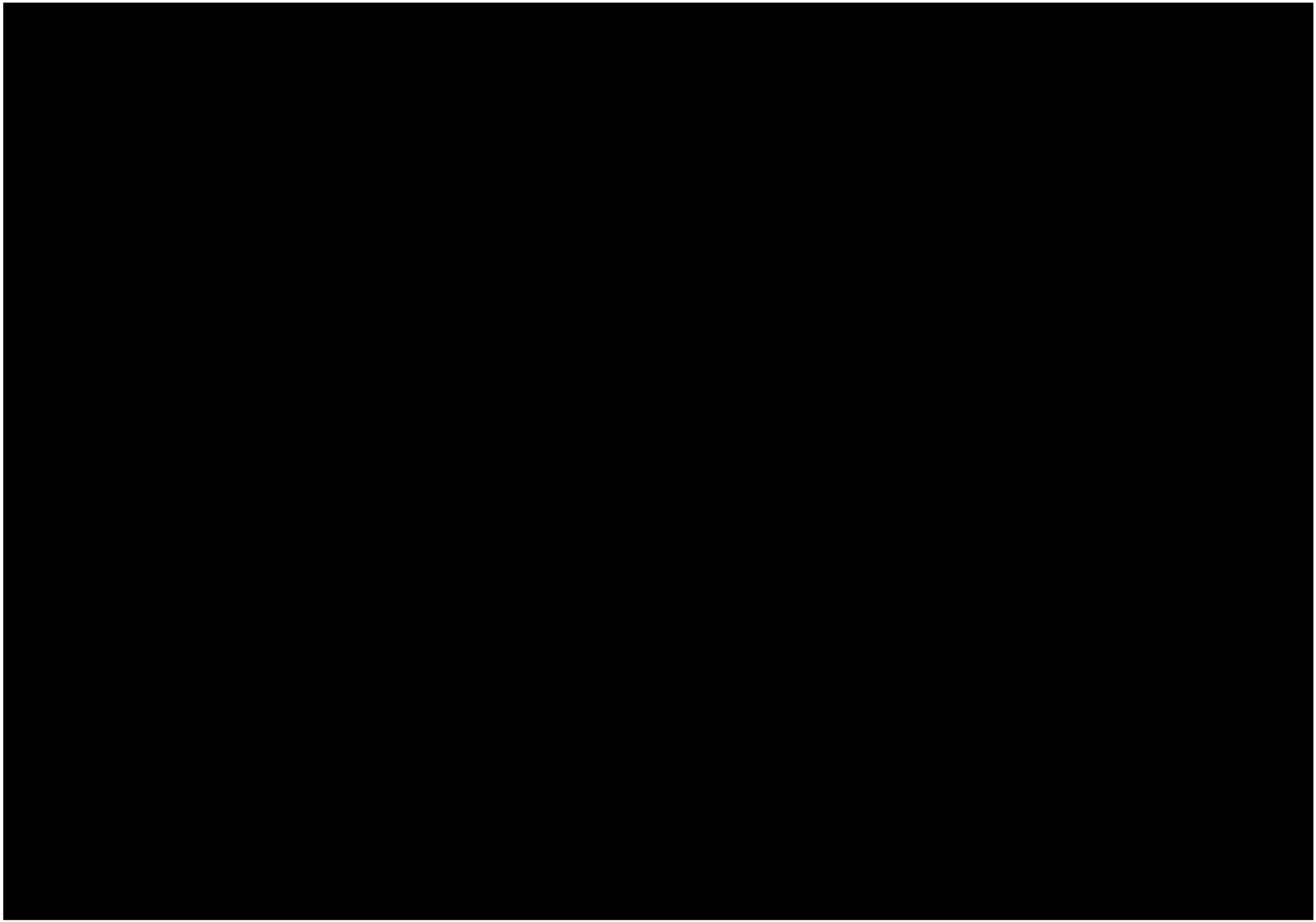
Hourly Average Day for January 2021

Southeast Colorado Power Association

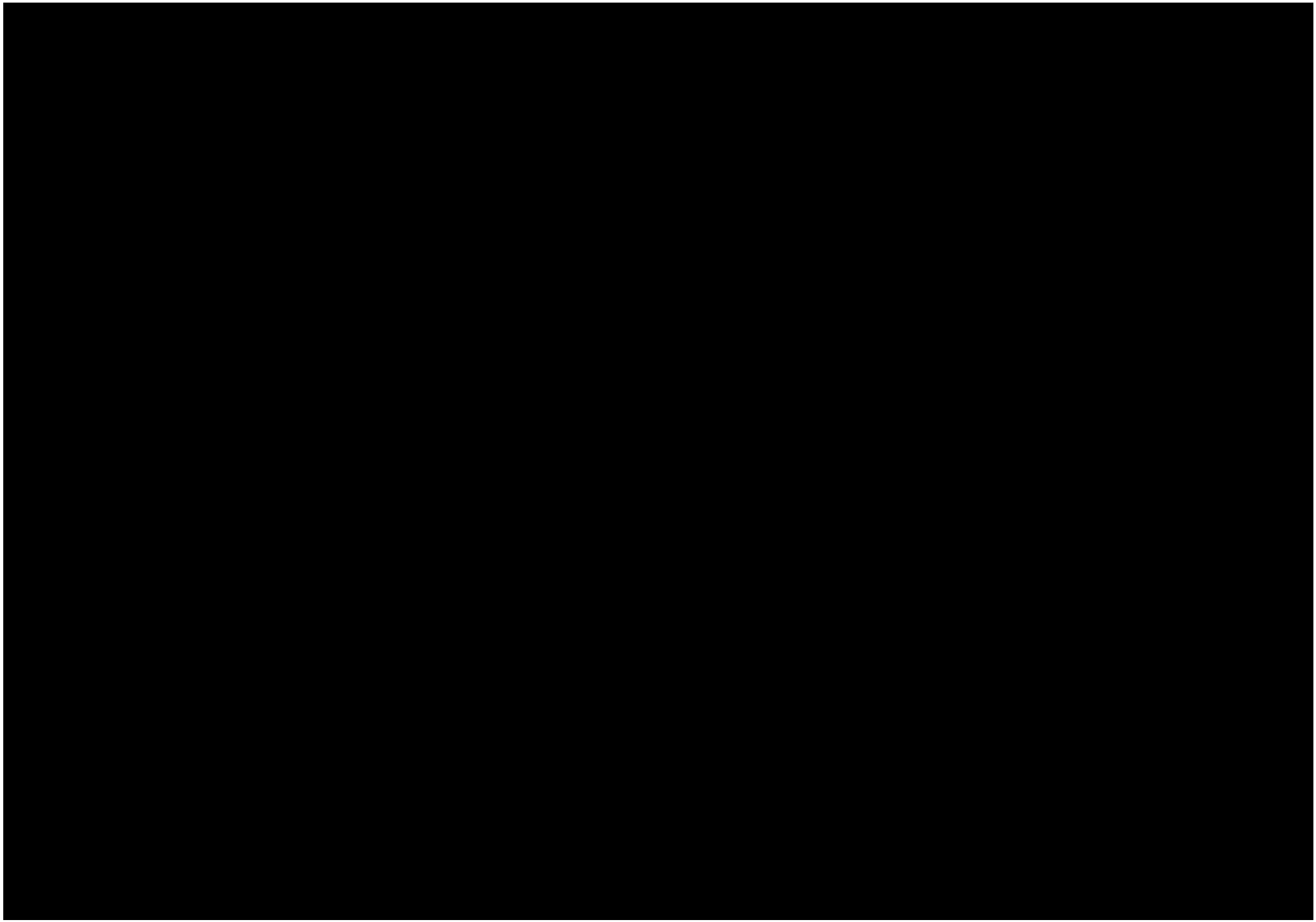


Hourly Average Day for February 2021

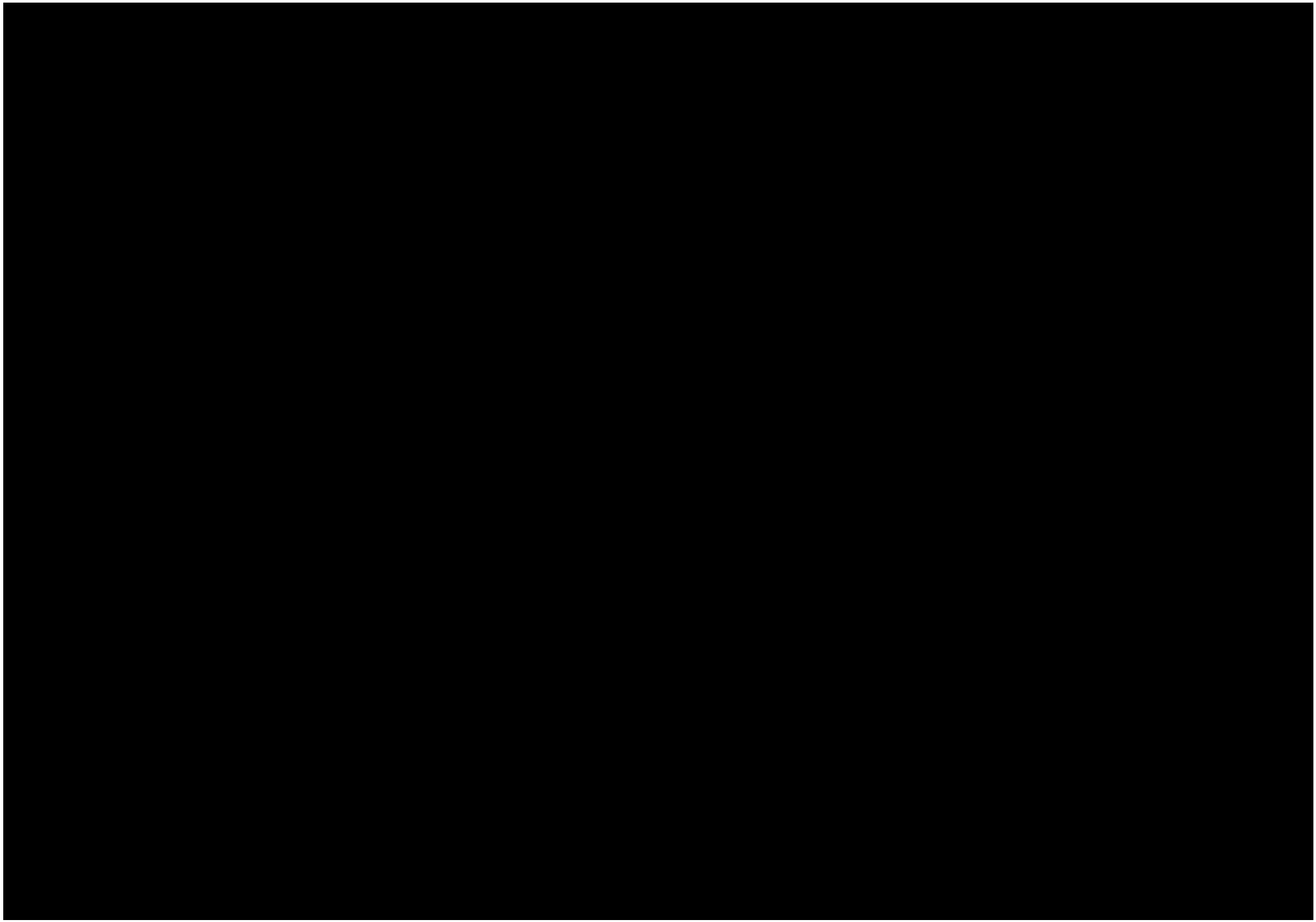
Southeast Colorado Power Association



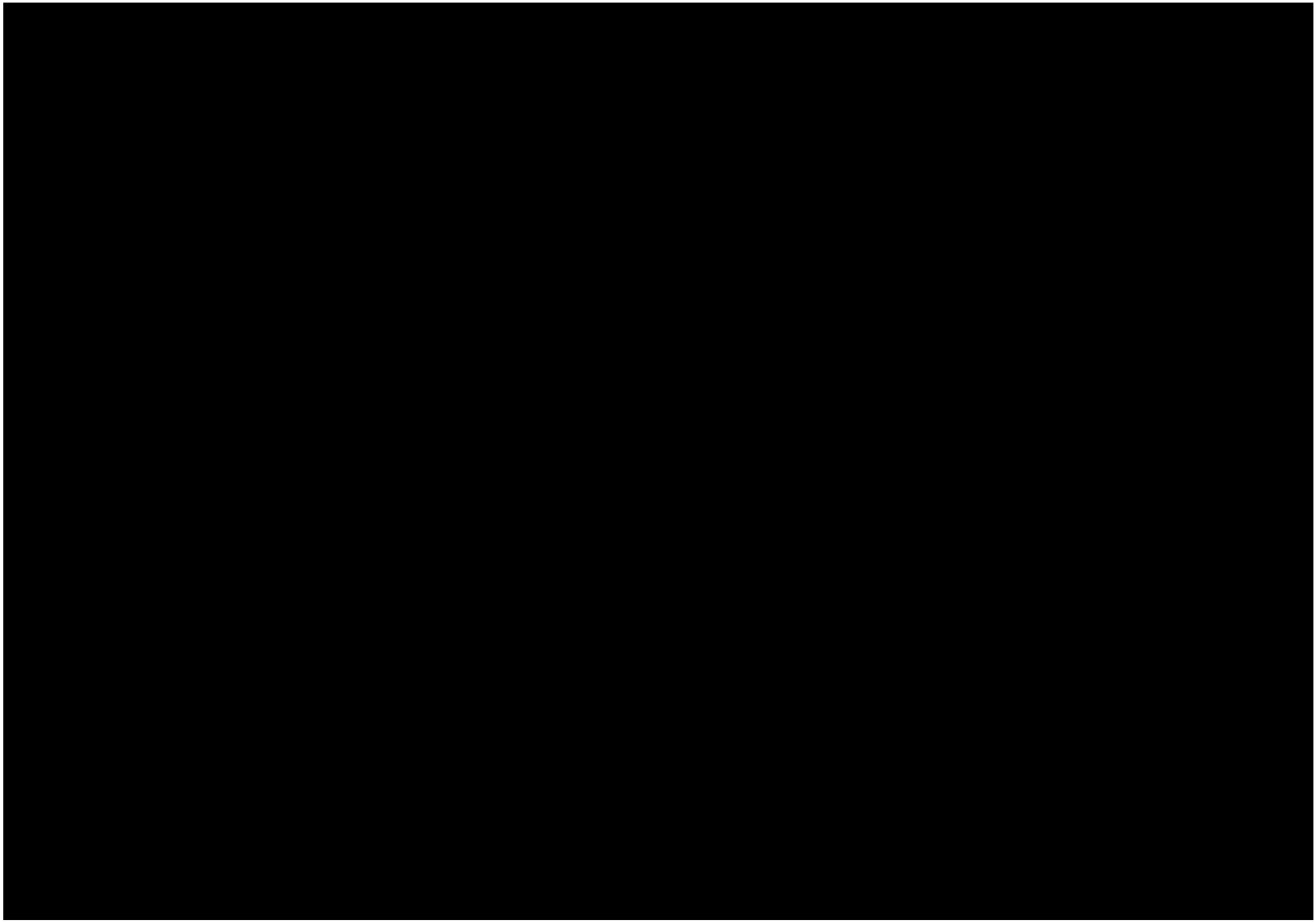
Hourly Average Day for March 2021
Southeast Colorado Power Association



Hourly Average Day for April 2021
Southeast Colorado Power Association



Hourly Average Day for May 2021
Southeast Colorado Power Association



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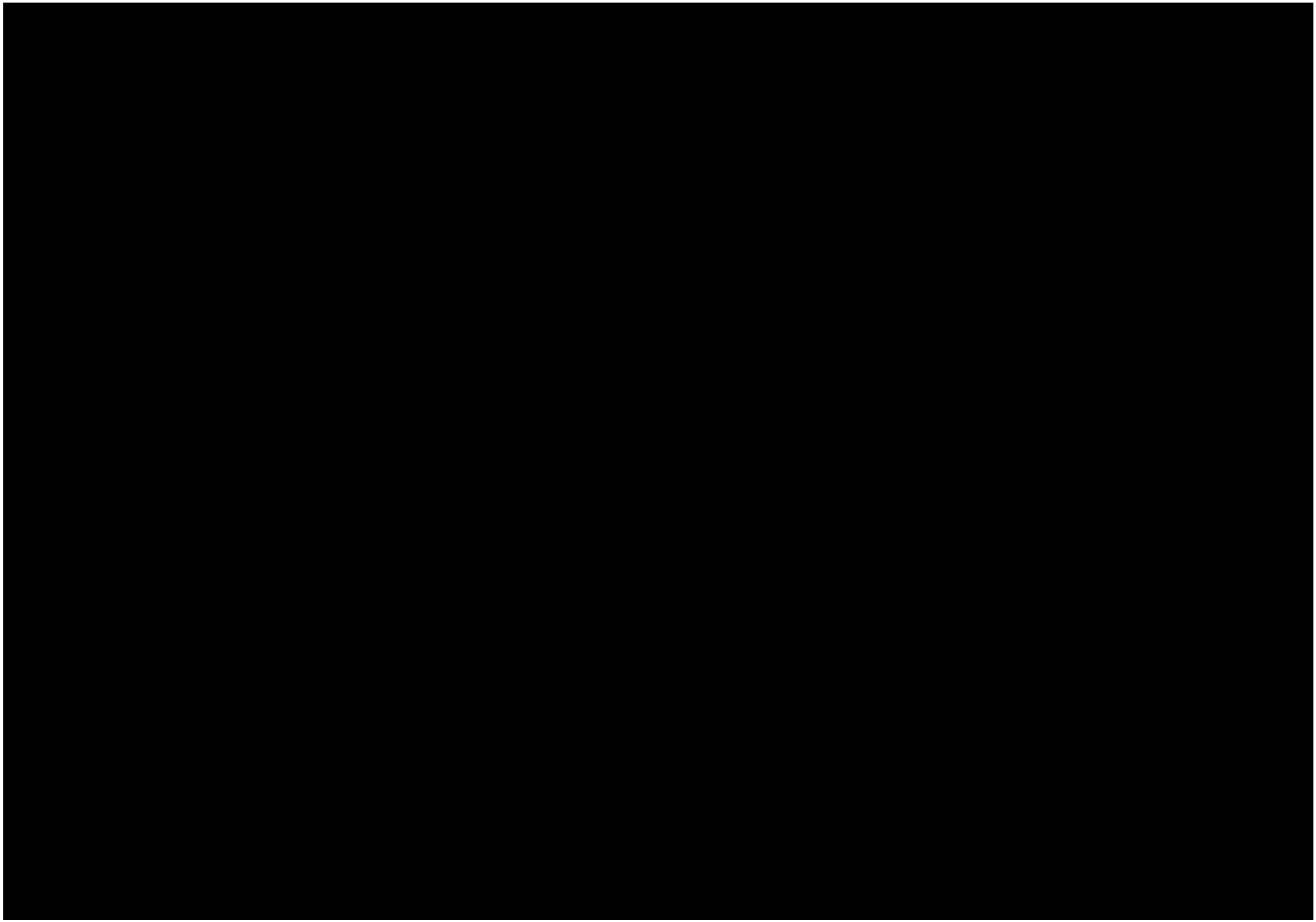
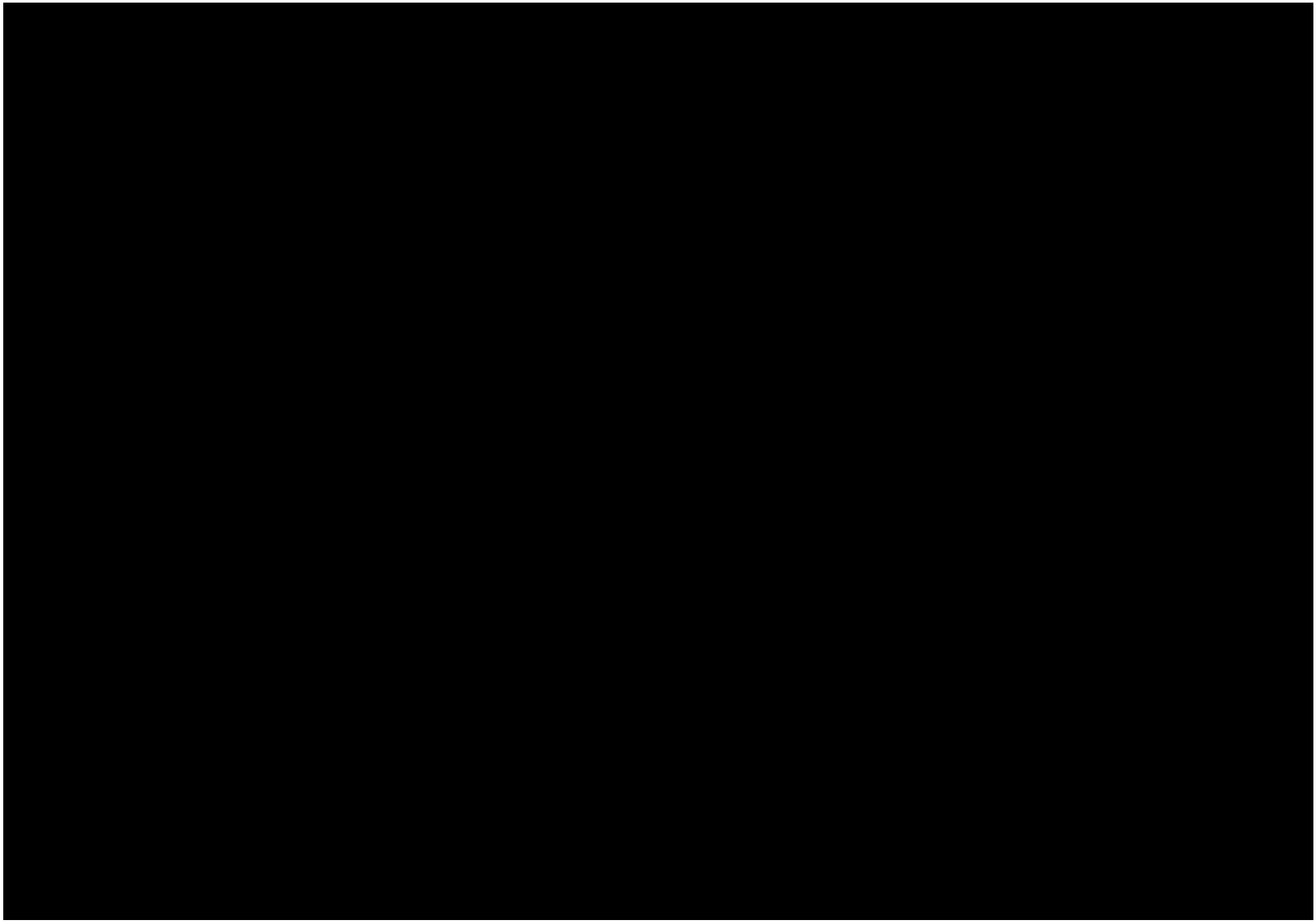
Hourly Average Day for June 2021

Southeast Colorado Power Association

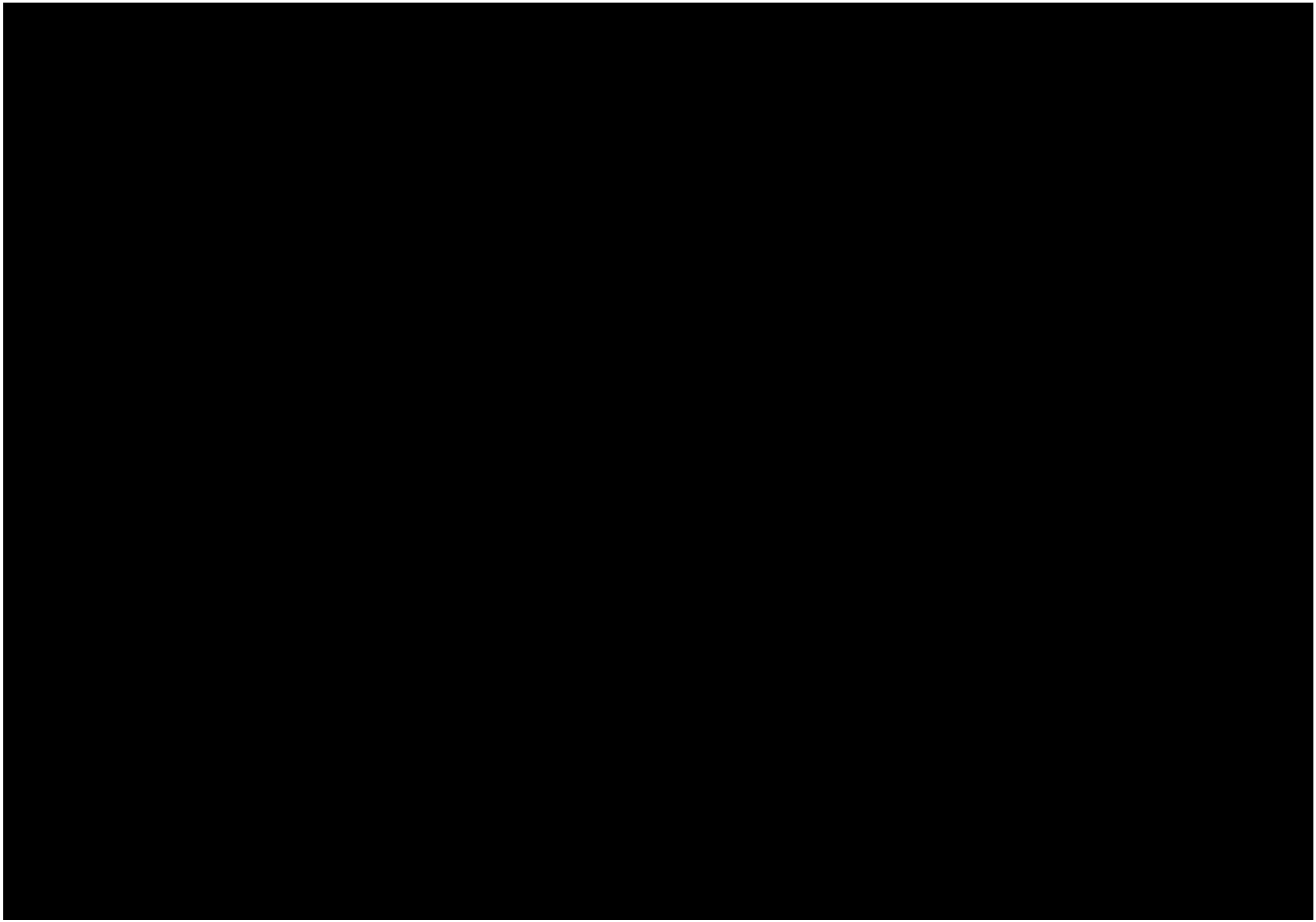


Hourly Average Day for July 2021
Southeast Colorado Power Association



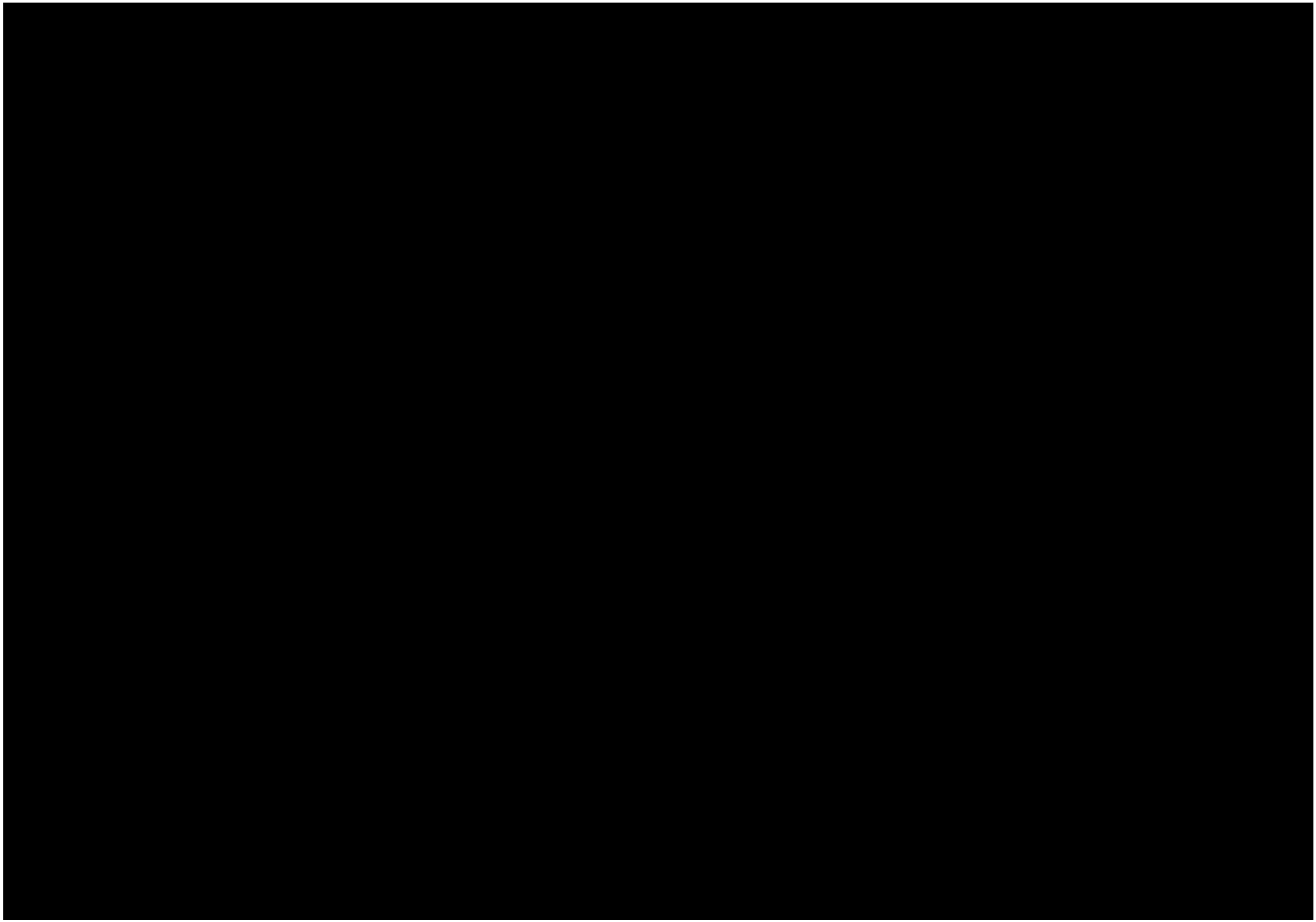
Hourly Average Day for August 2021

Southeast Colorado Power Association



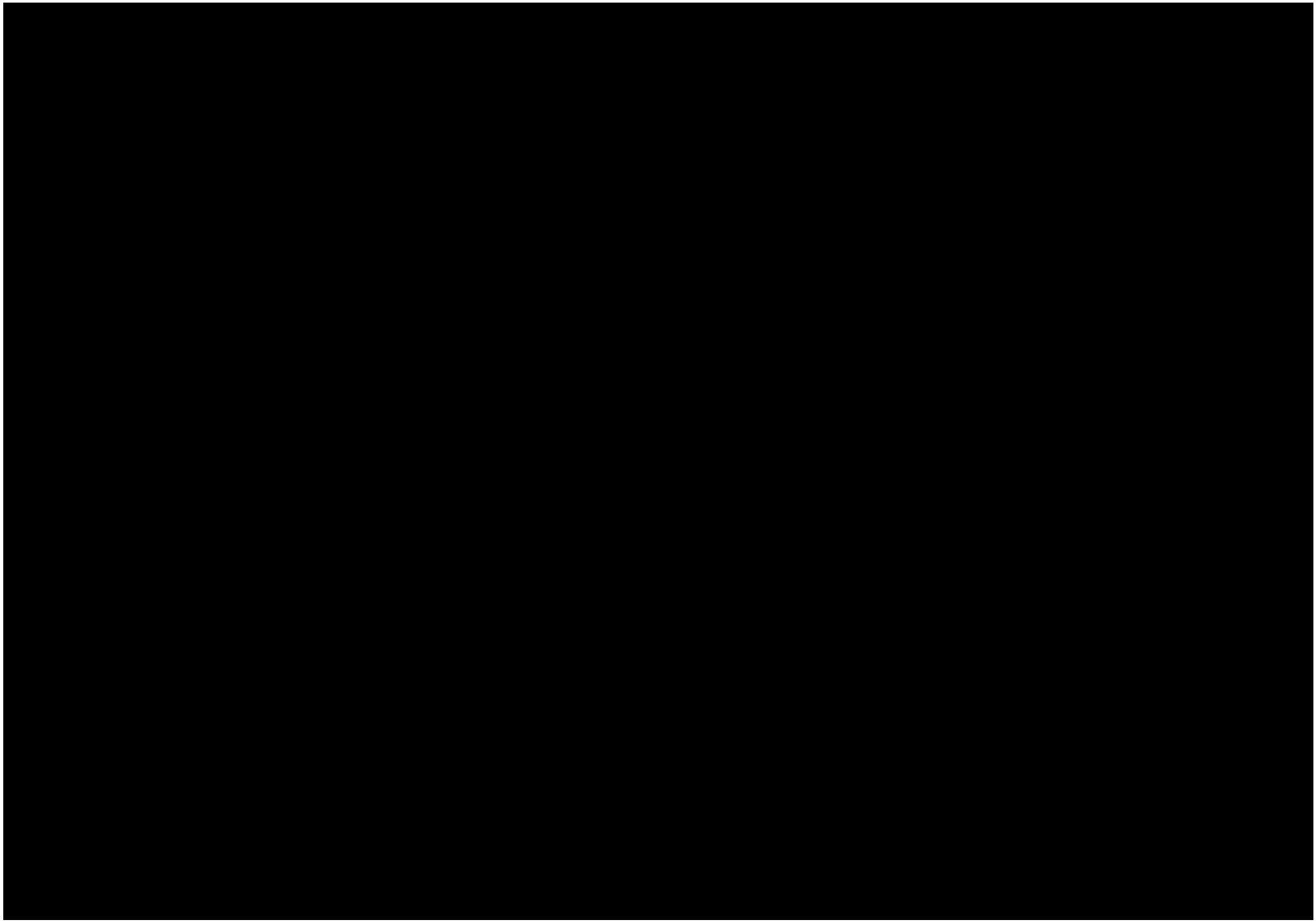
Hourly Average Day for September 2021

Southeast Colorado Power Association

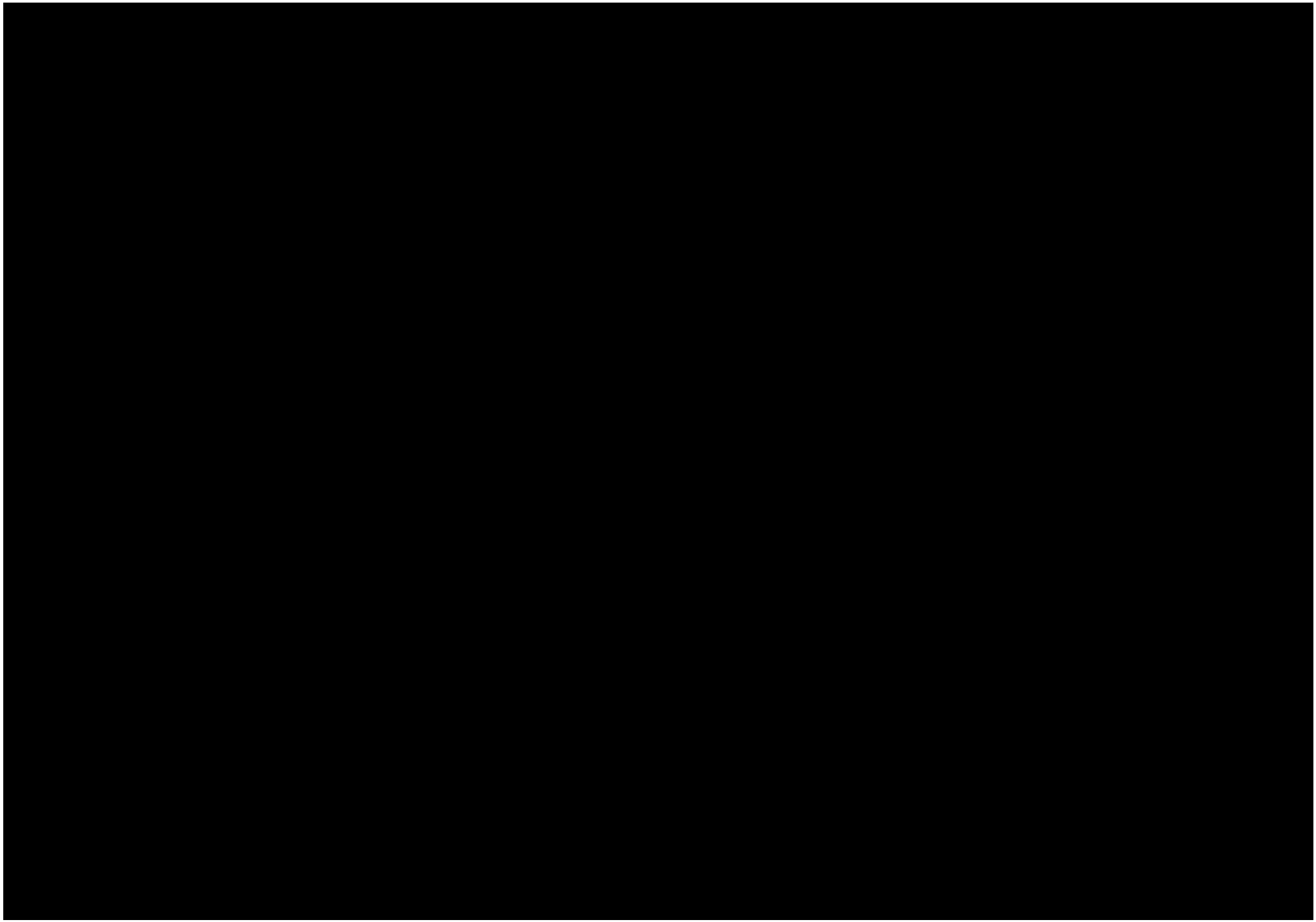


Hourly Average Day for October 2021

Southeast Colorado Power Association

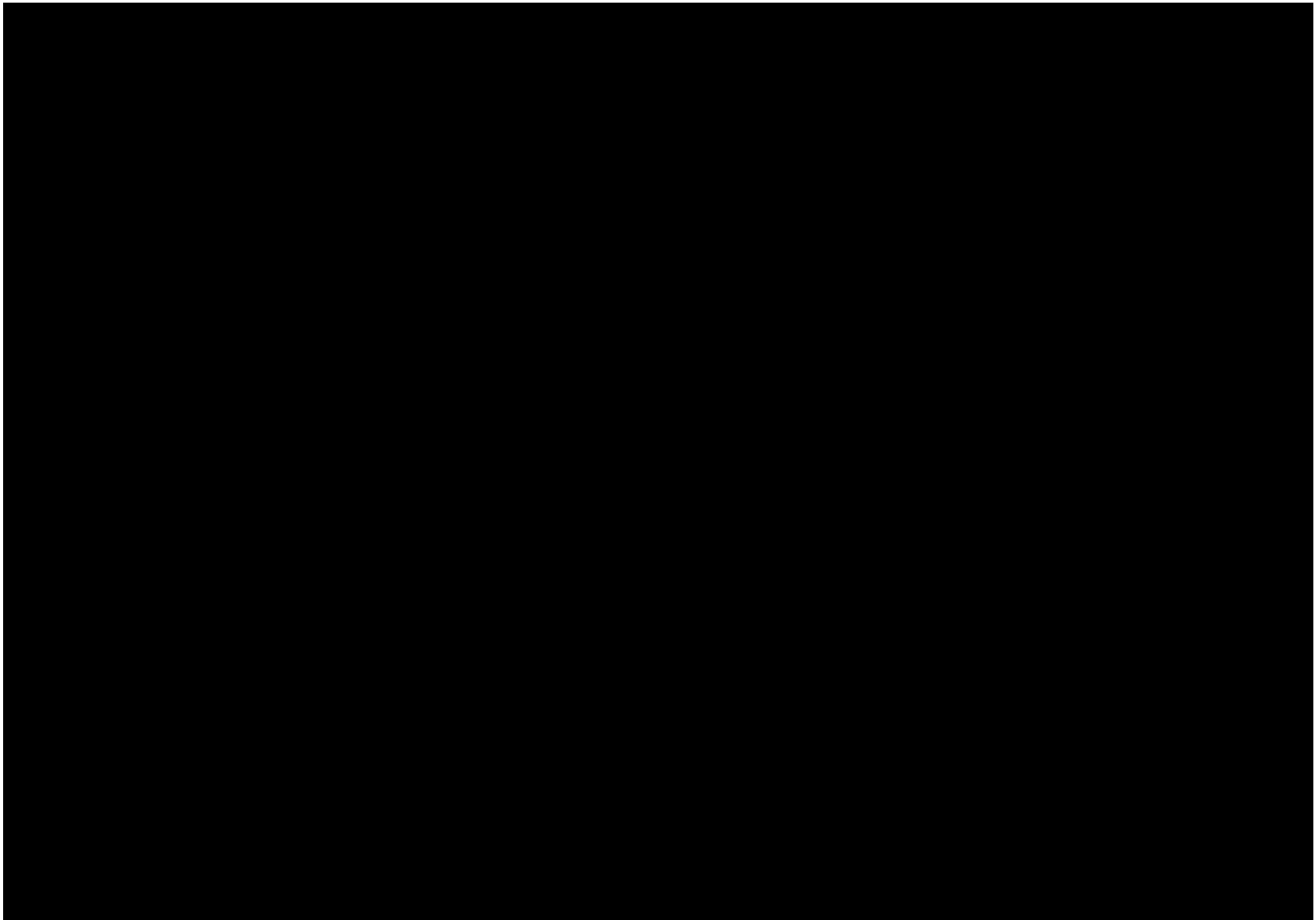


Hourly Average Day for November 2021
Southeast Colorado Power Association



Hourly Average Day for December 2021

Southeast Colorado Power Association



Hourly Average Day for January 2021

San Isabel Electric Association, Inc.

[redacted]

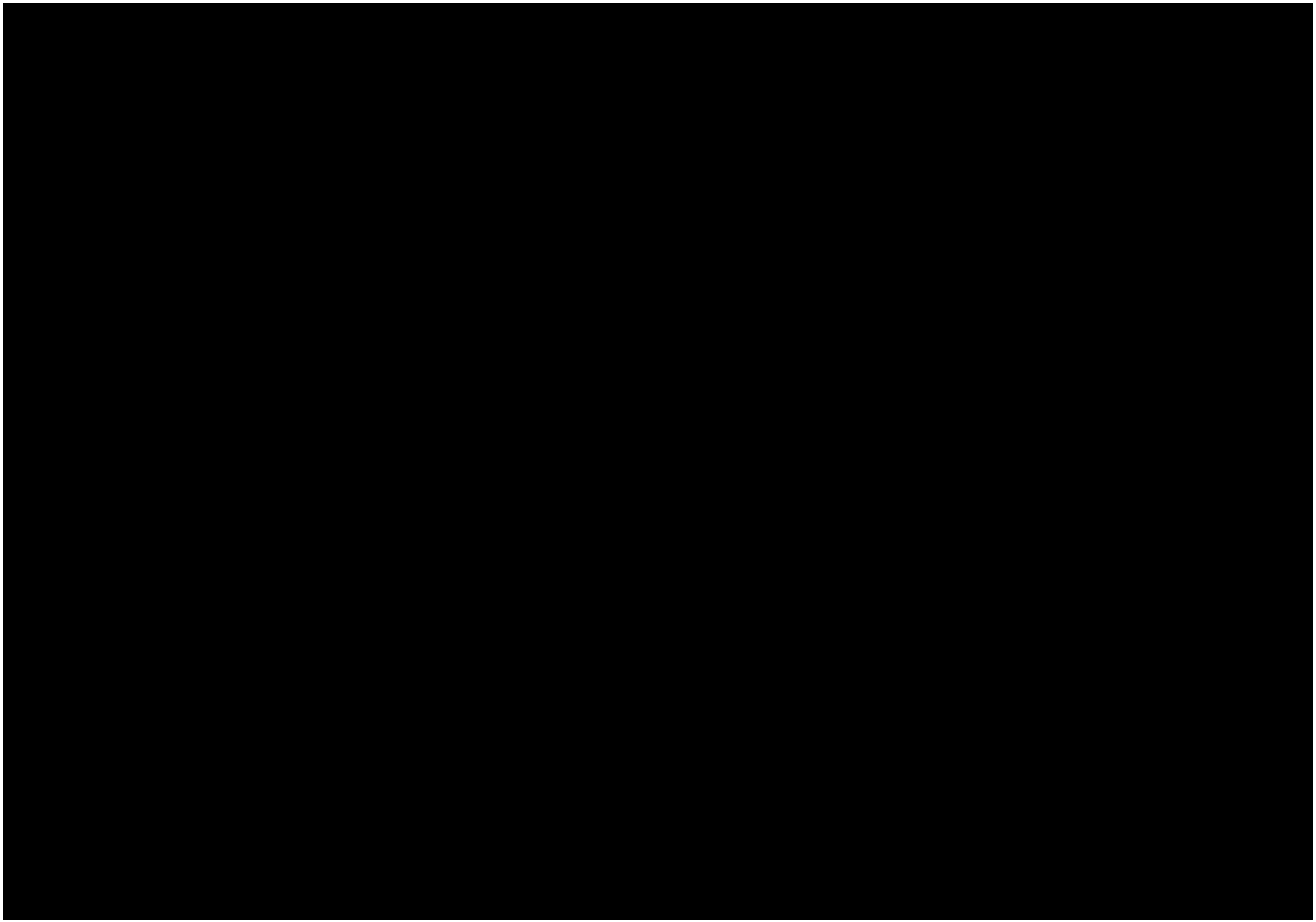
Hourly Average Day for February 2021

San Isabel Electric Association, Inc.

[redacted]

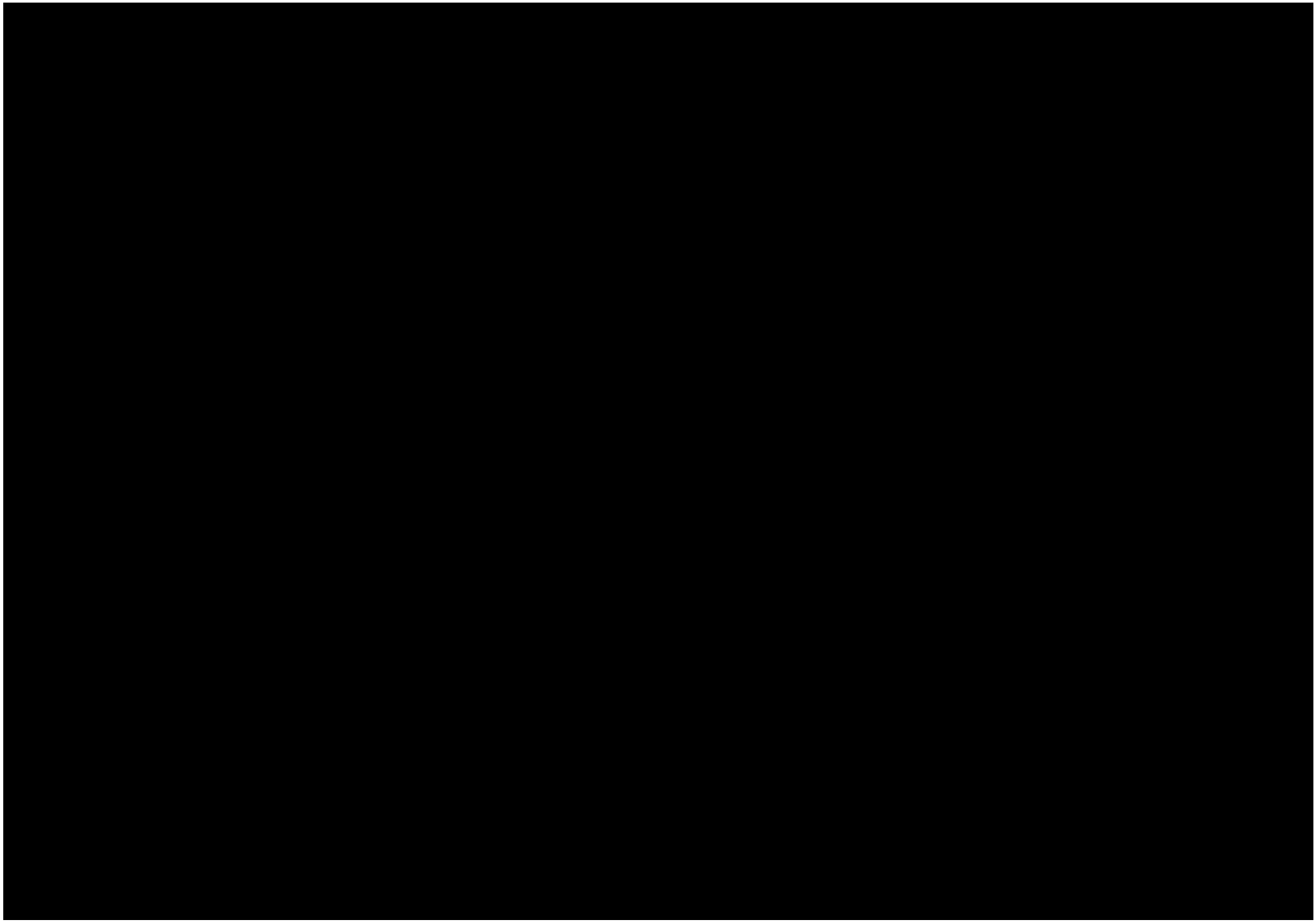
Hourly Average Day for March 2021

San Isabel Electric Association, Inc.



Hourly Average Day for April 2021

San Isabel Electric Association, Inc.



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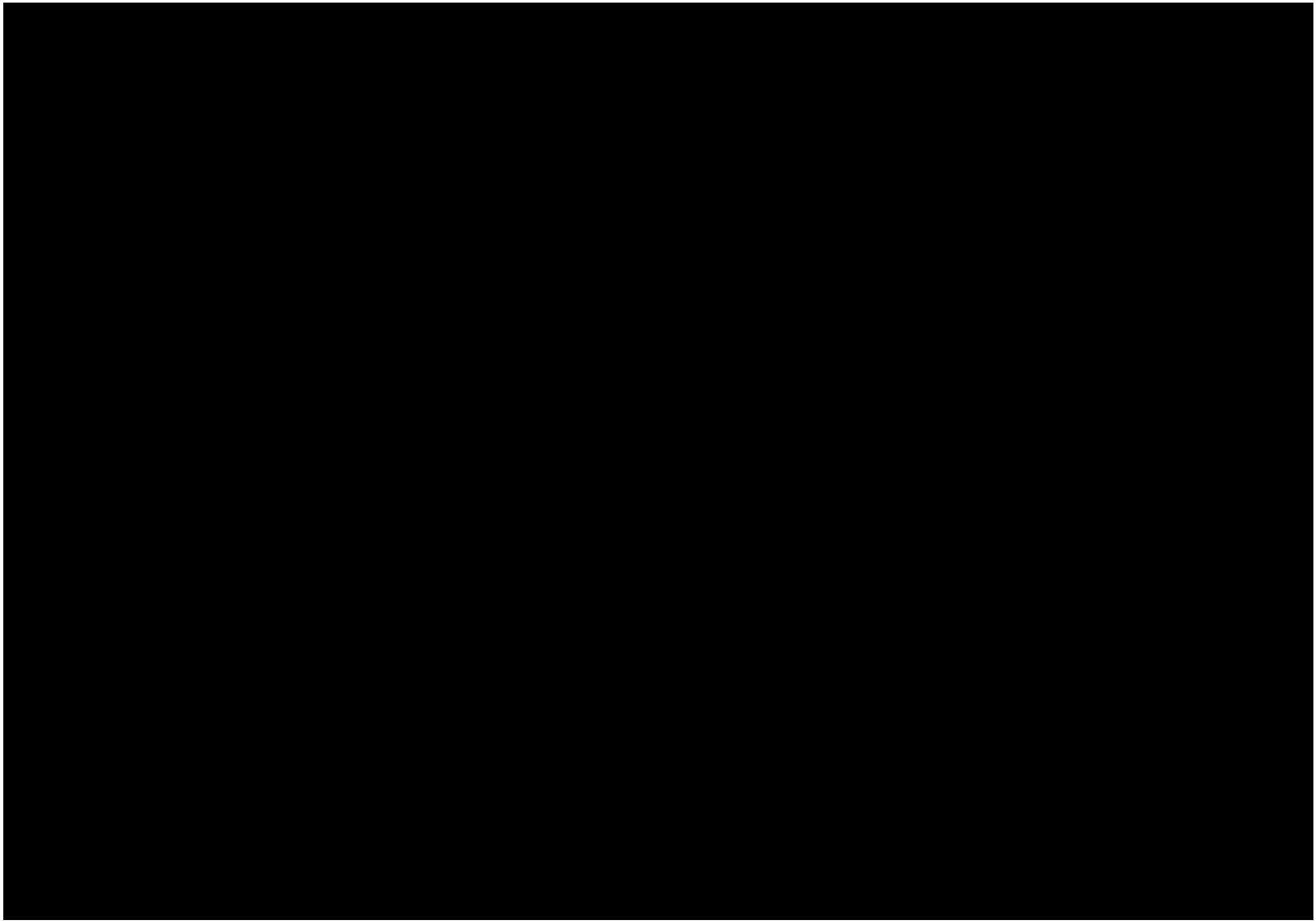
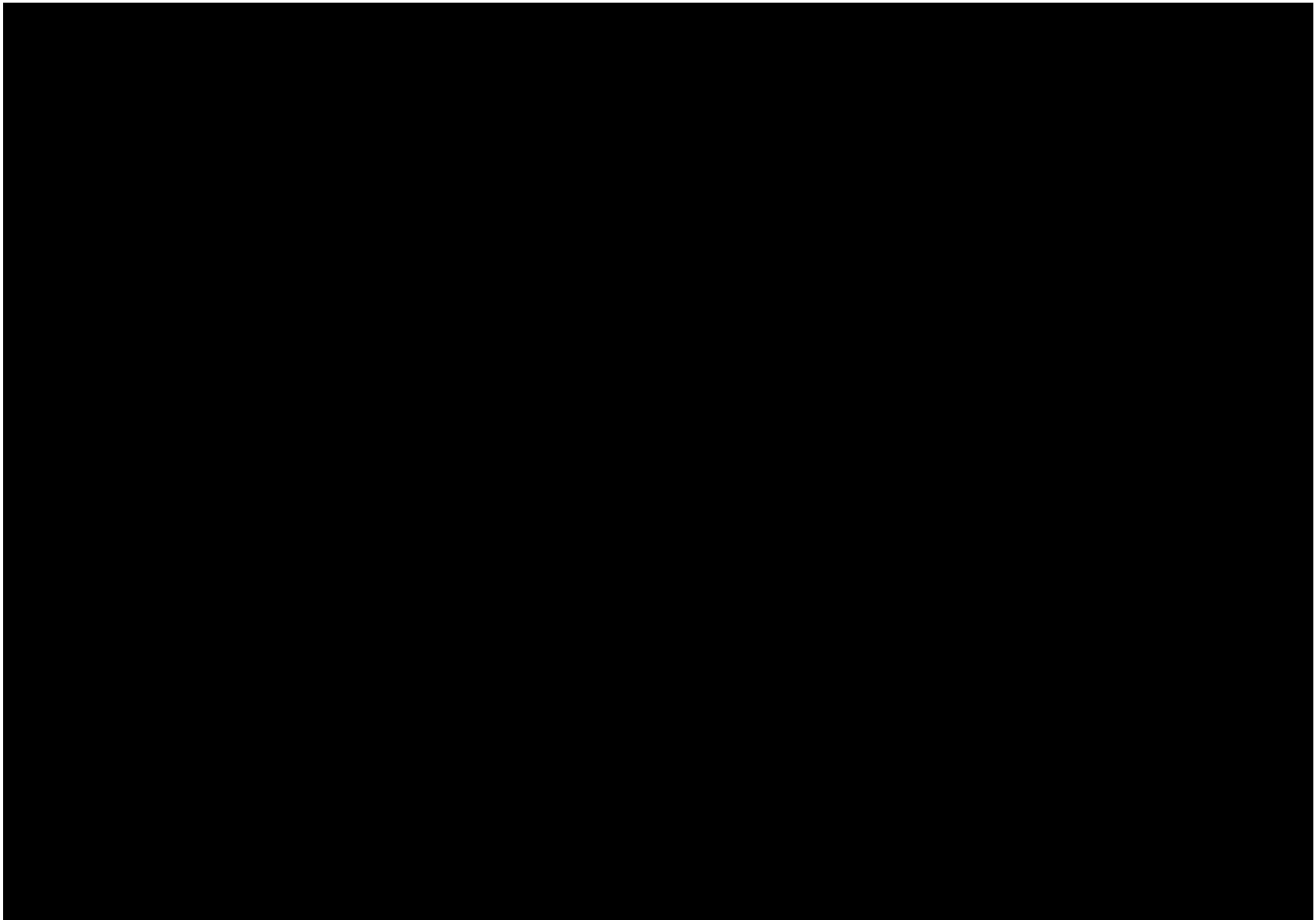
Hourly Average Day for May 2021

San Isabel Electric Association, Inc.



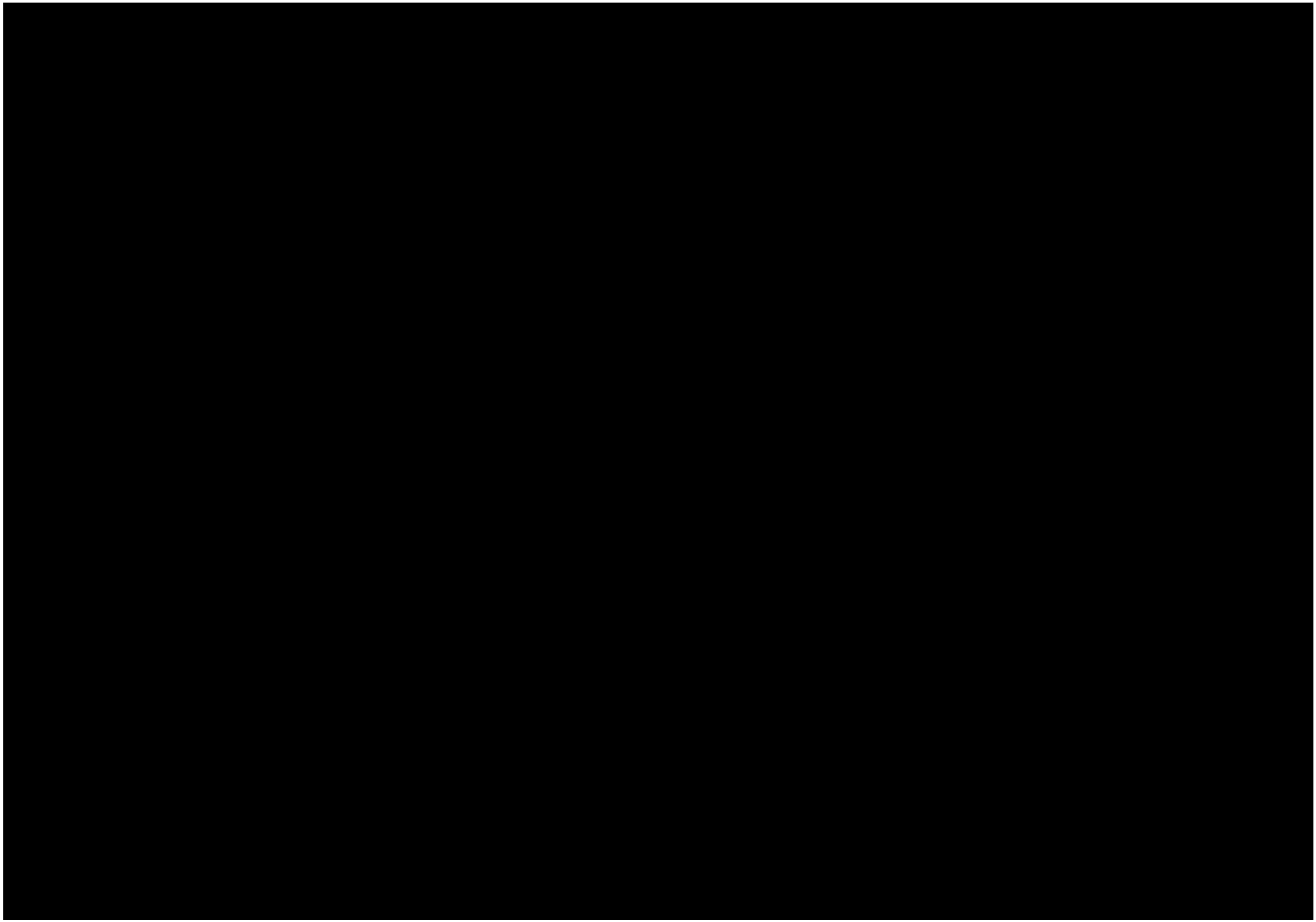
Hourly Average Day for June 2021

San Isabel Electric Association, Inc.



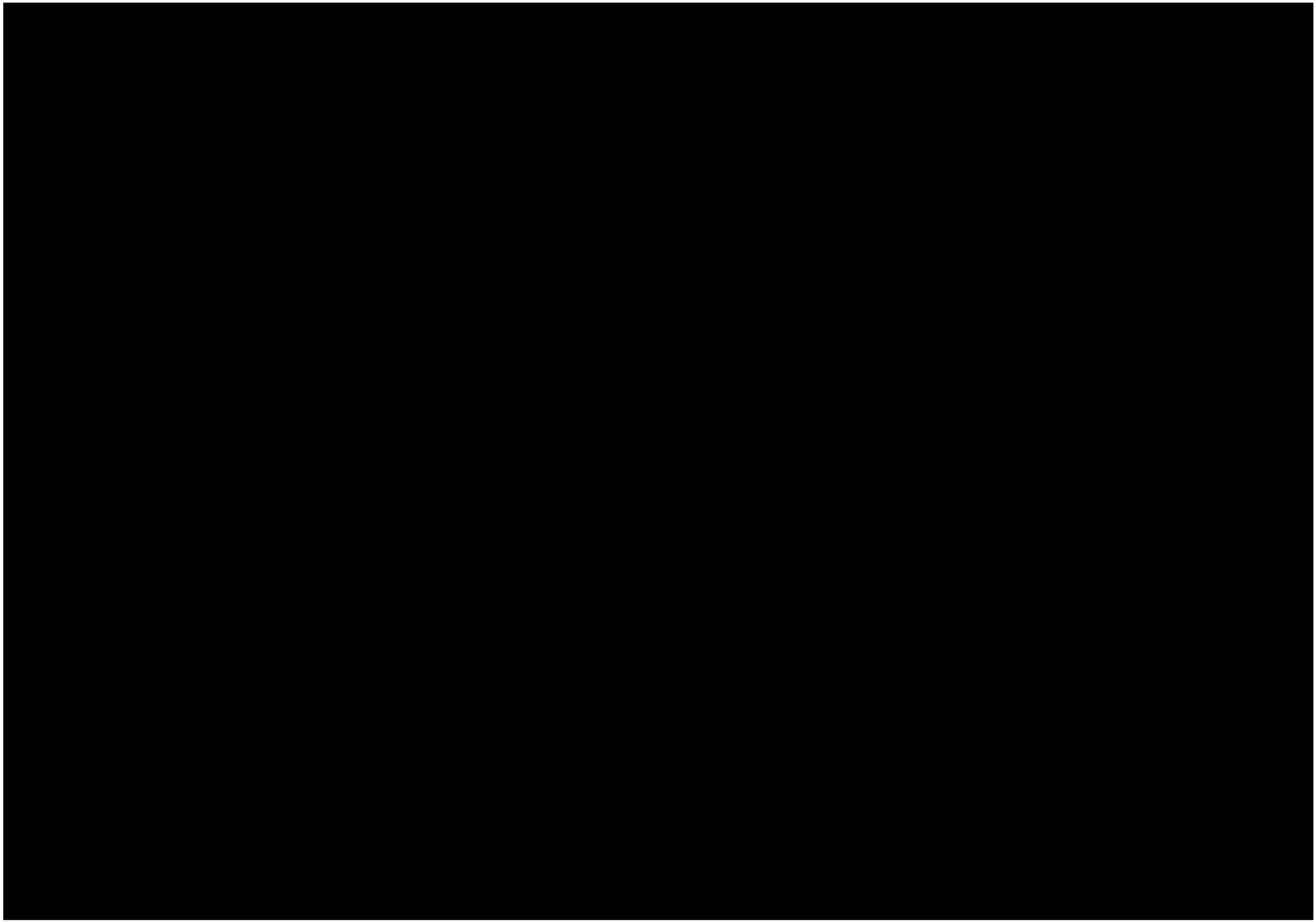
Hourly Average Day for July 2021

San Isabel Electric Association, Inc.



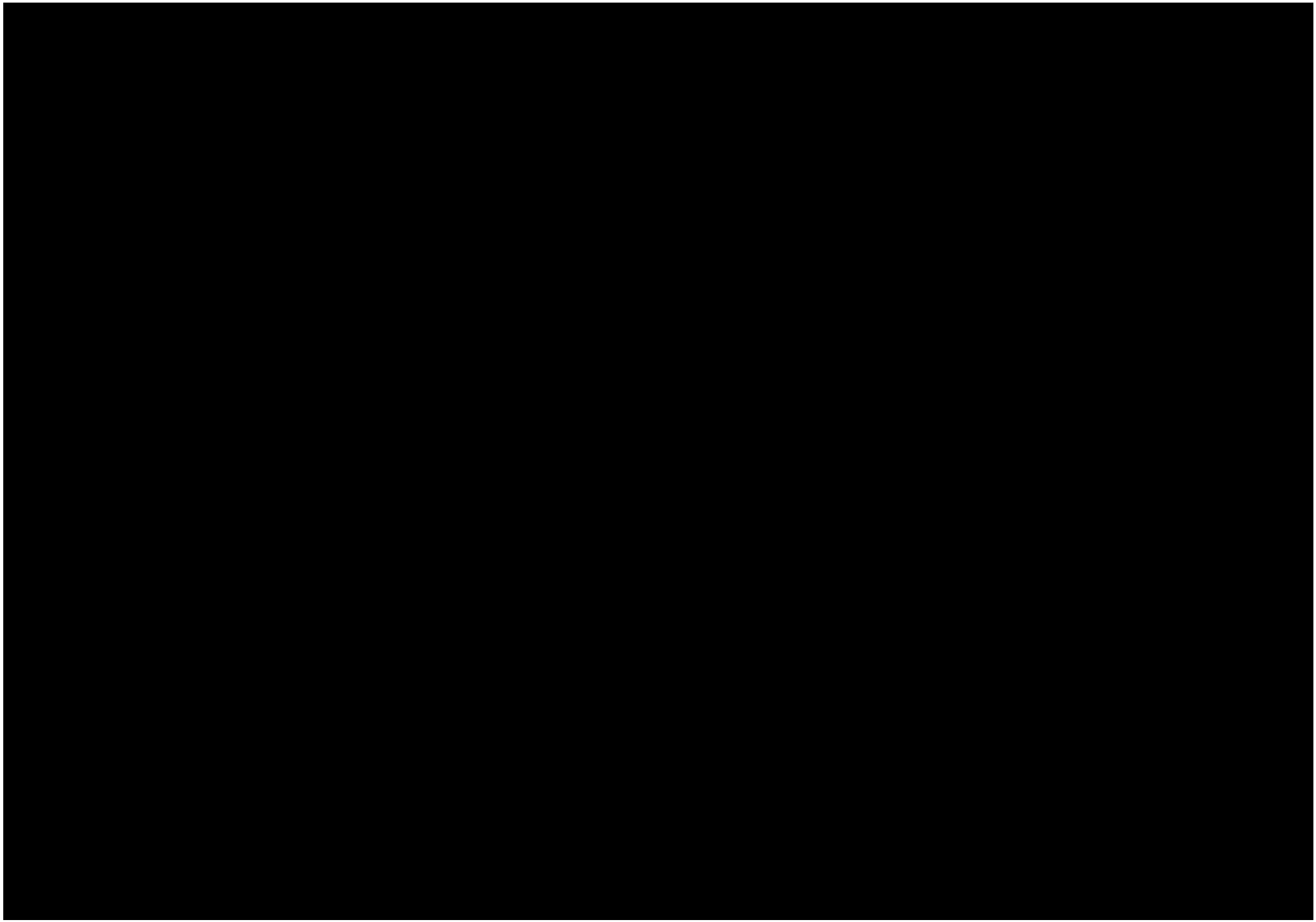
Hourly Average Day for August 2021

San Isabel Electric Association, Inc.



Hourly Average Day for September 2021

San Isabel Electric Association, Inc.



Hourly Average Day for October 2021

San Isabel Electric Association, Inc.

[redacted]

Hourly Average Day for November 2021

San Isabel Electric Association, Inc.

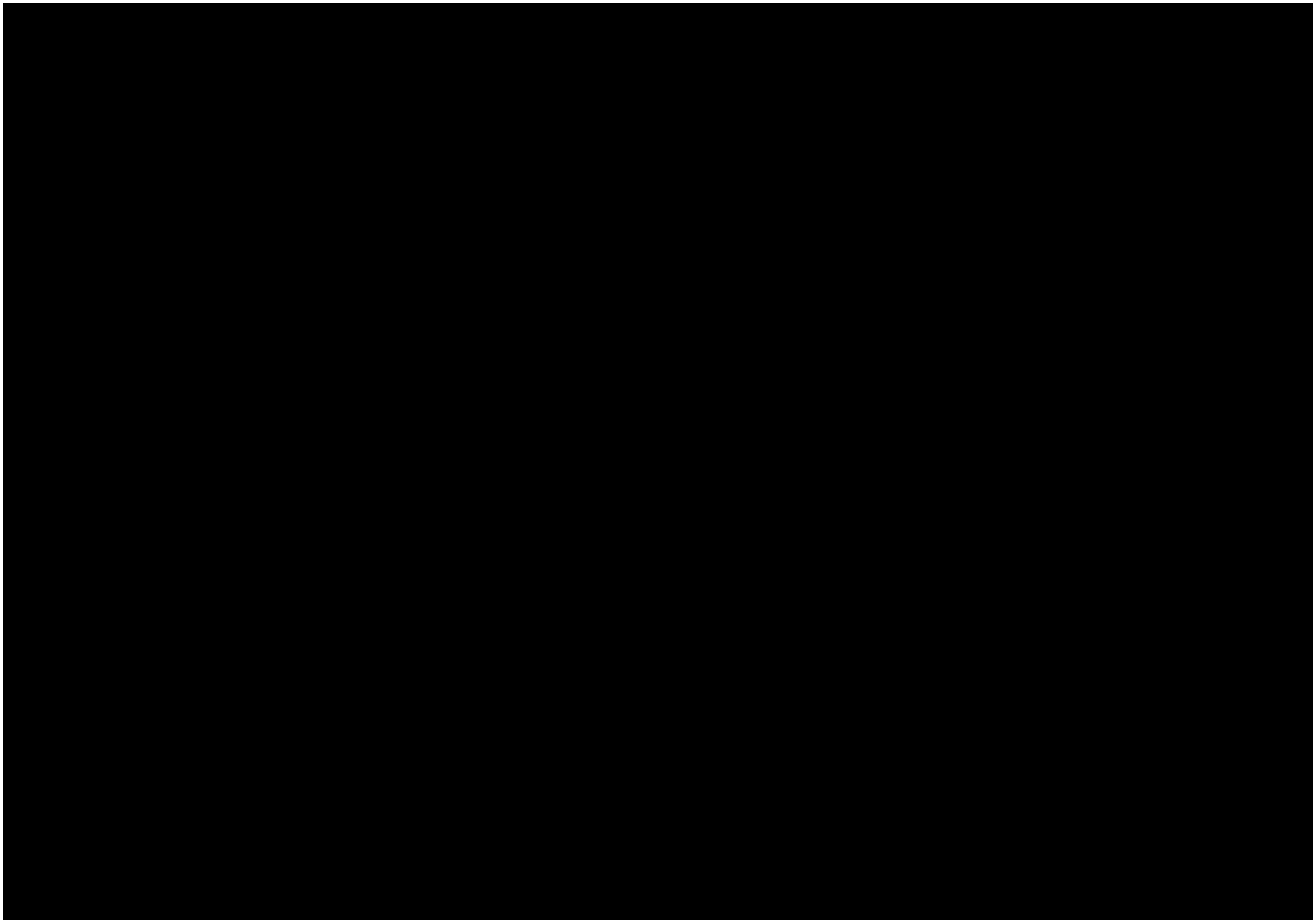
[redacted]

Hourly Average Day for December 2021

San Isabel Electric Association, Inc.

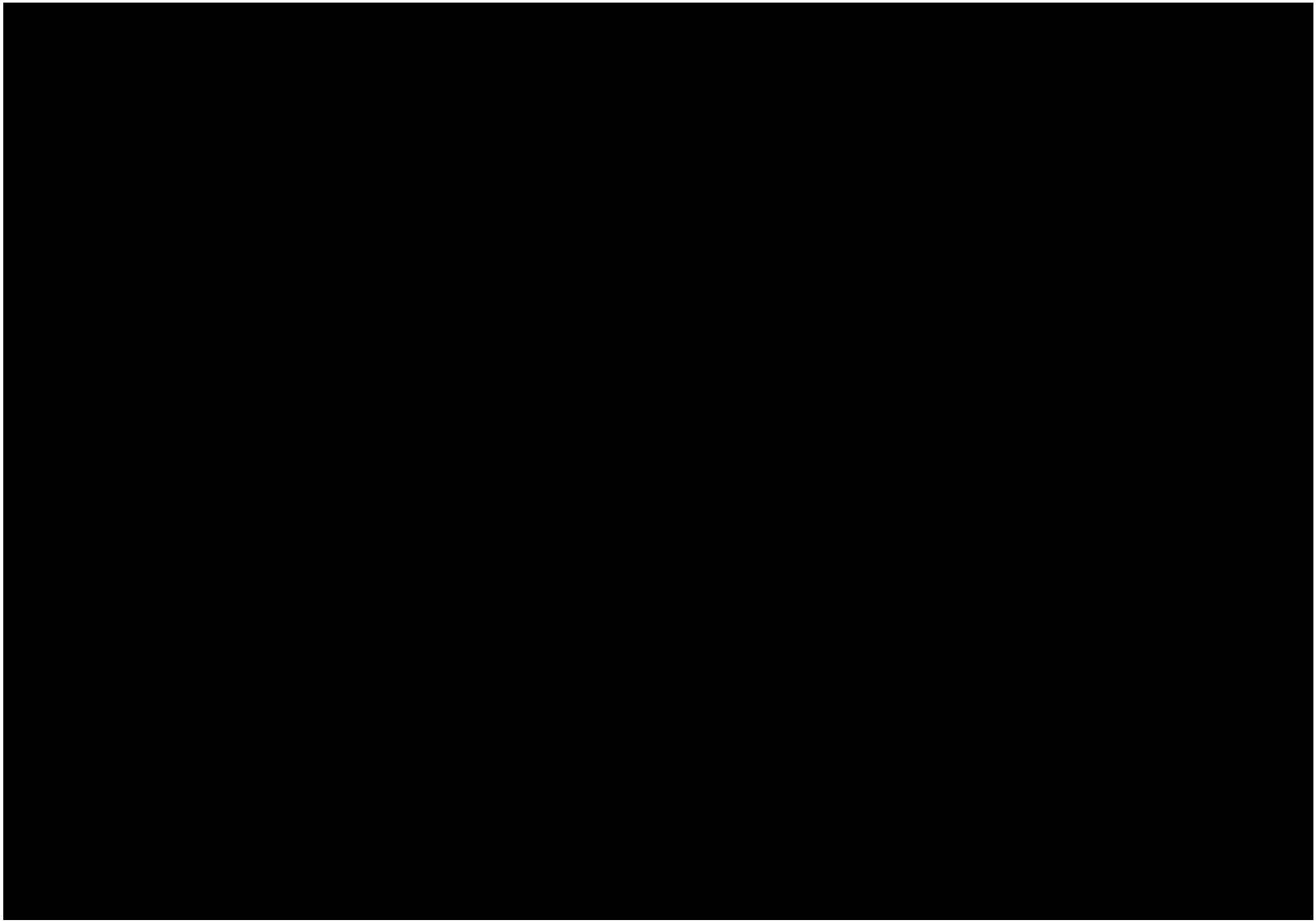
[redacted]

Hourly Average Day for January 2021
San Luis Valley Rural Electric Cooperative, Inc.



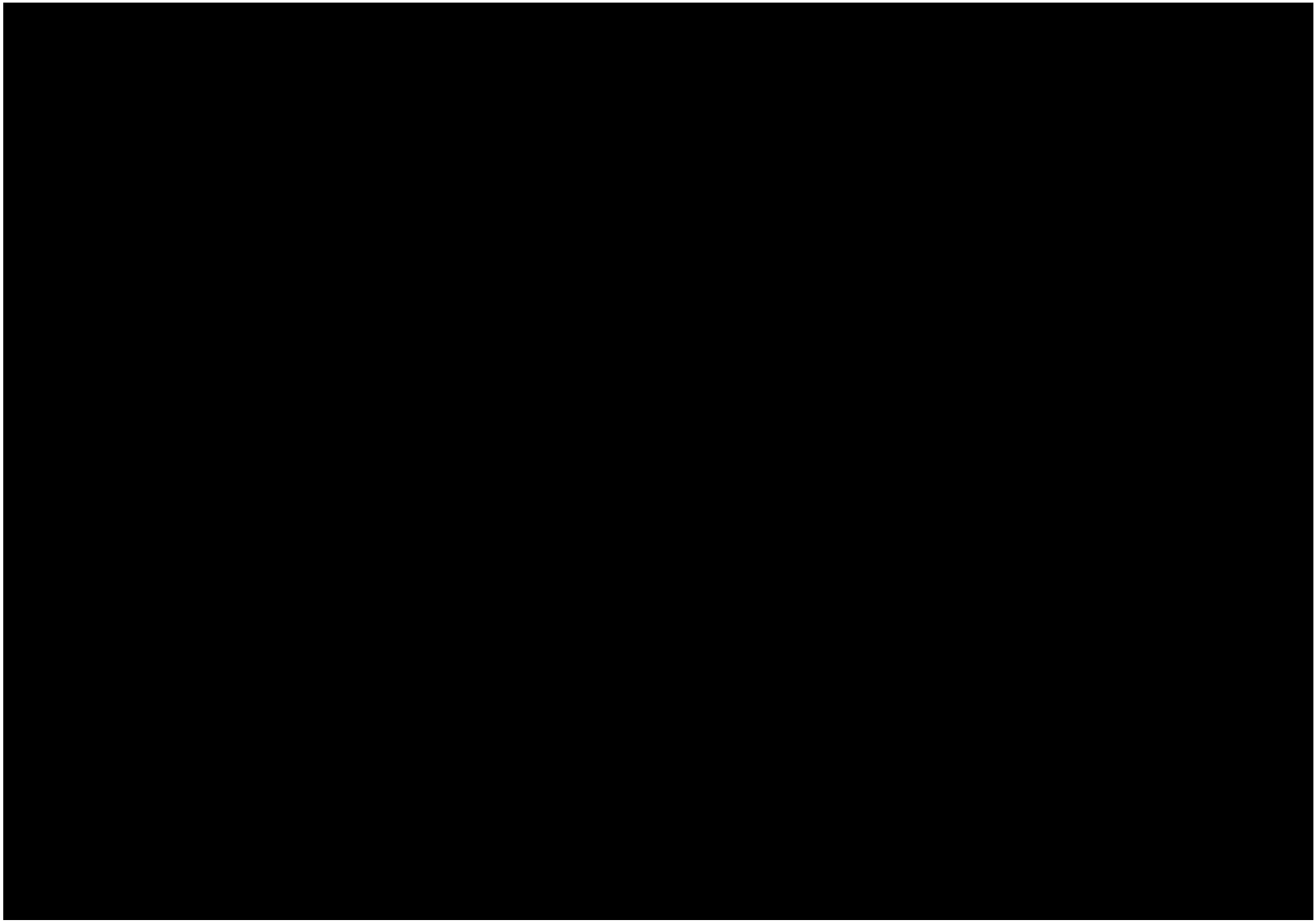
Hourly Average Day for February 2021

San Luis Valley Rural Electric Cooperative, Inc.



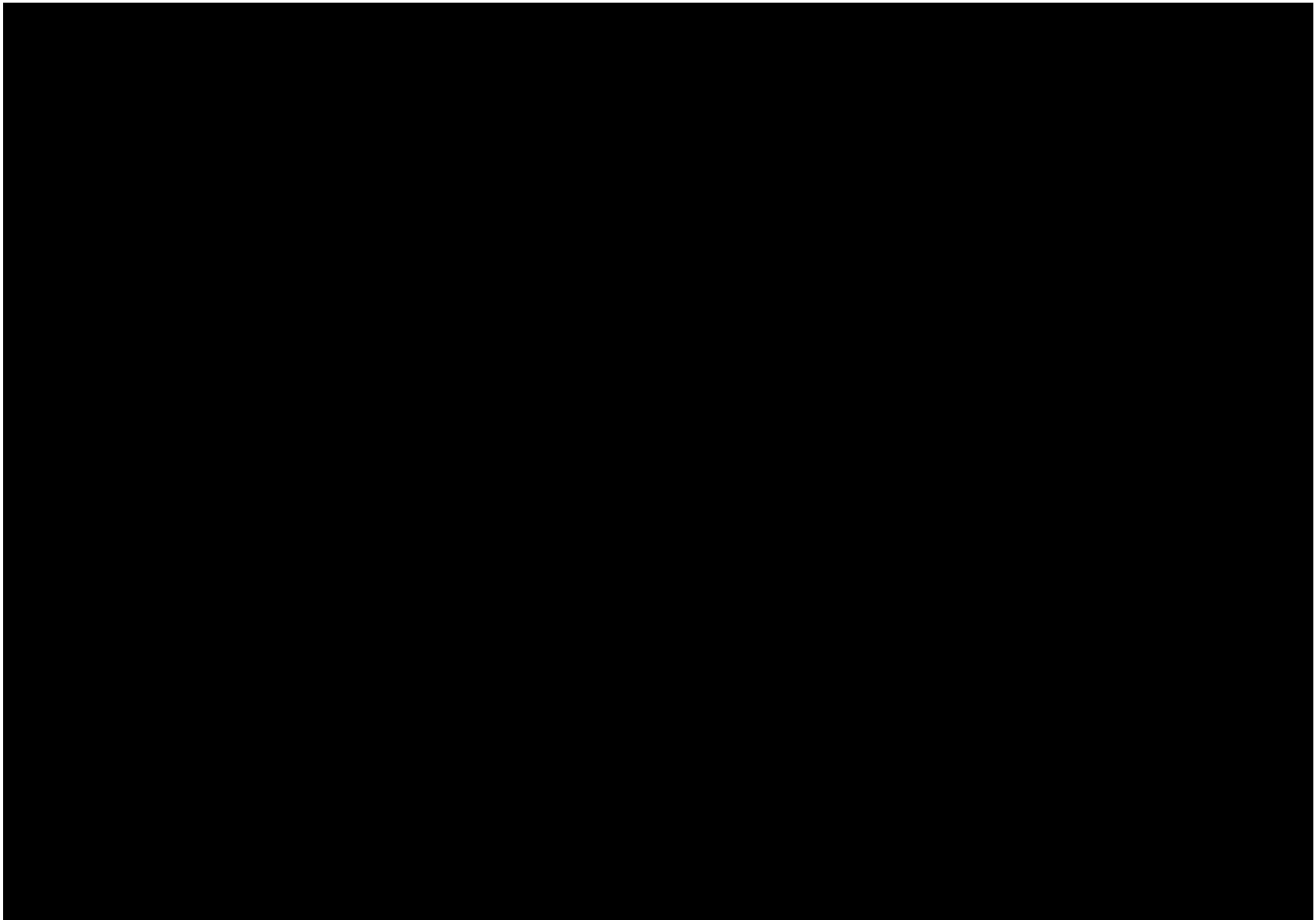
Hourly Average Day for March 2021

San Luis Valley Rural Electric Cooperative, Inc.



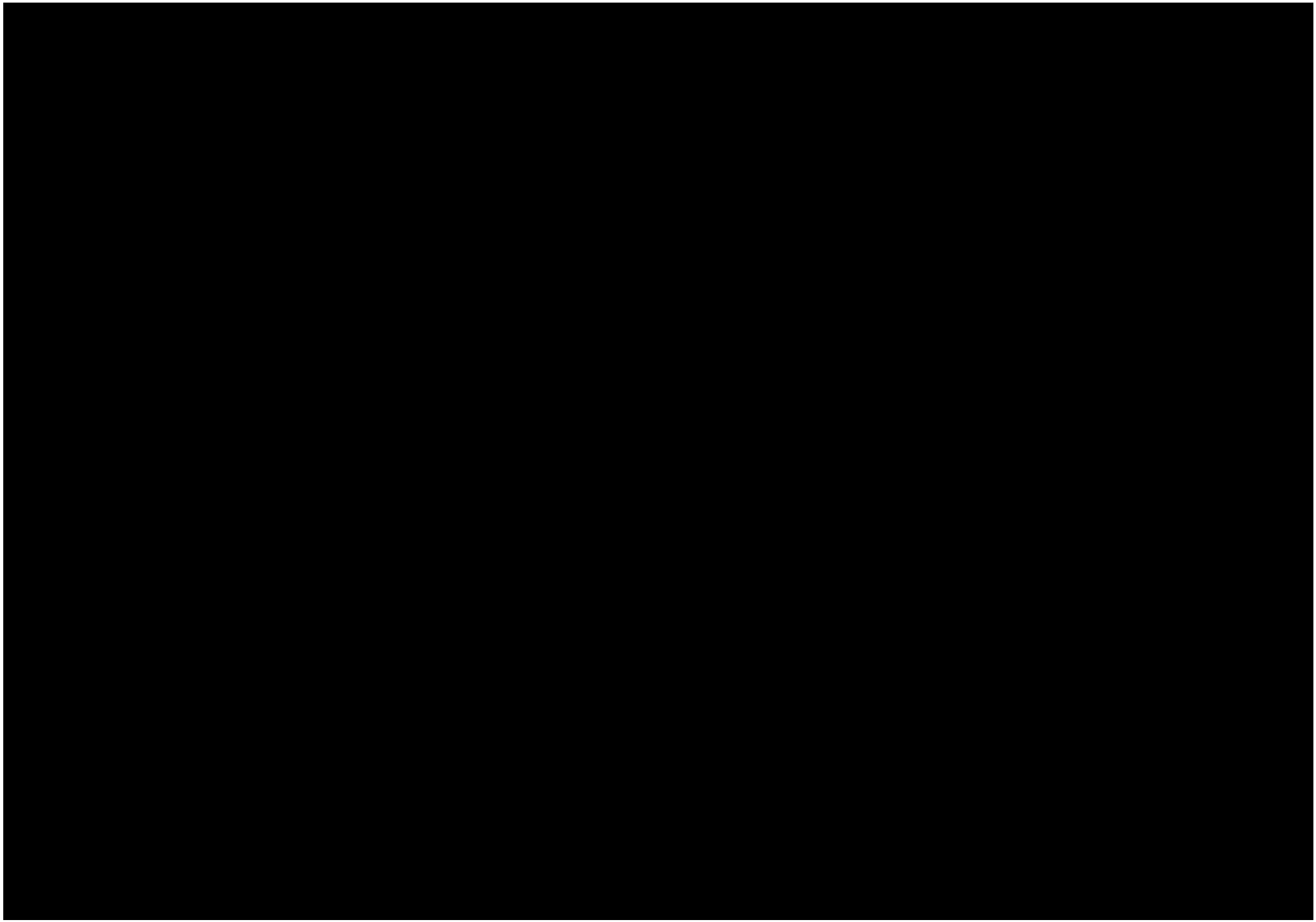
Hourly Average Day for April 2021

San Luis Valley Rural Electric Cooperative, Inc.



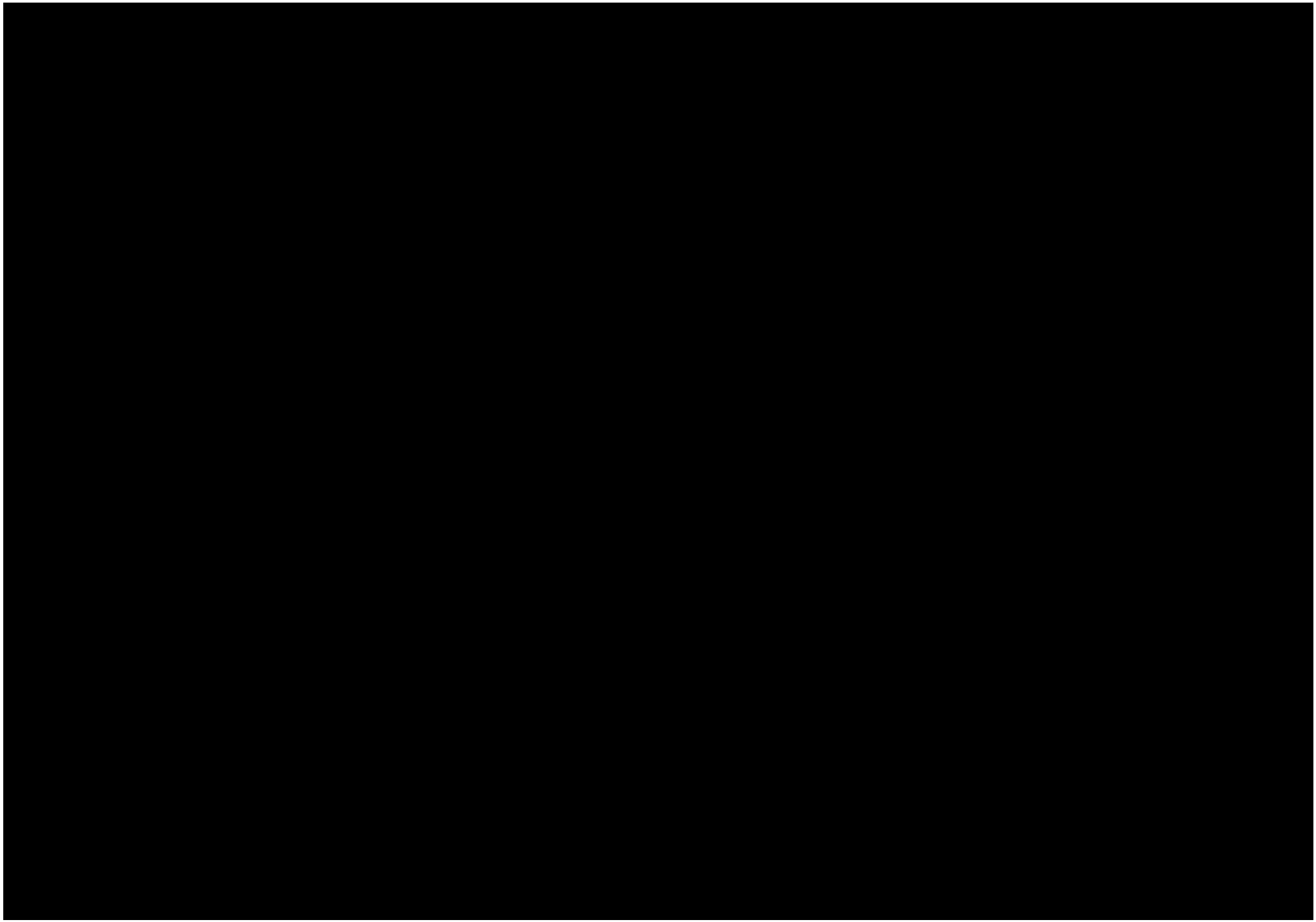
Hourly Average Day for May 2021

San Luis Valley Rural Electric Cooperative, Inc.



Hourly Average Day for June 2021

San Luis Valley Rural Electric Cooperative, Inc.



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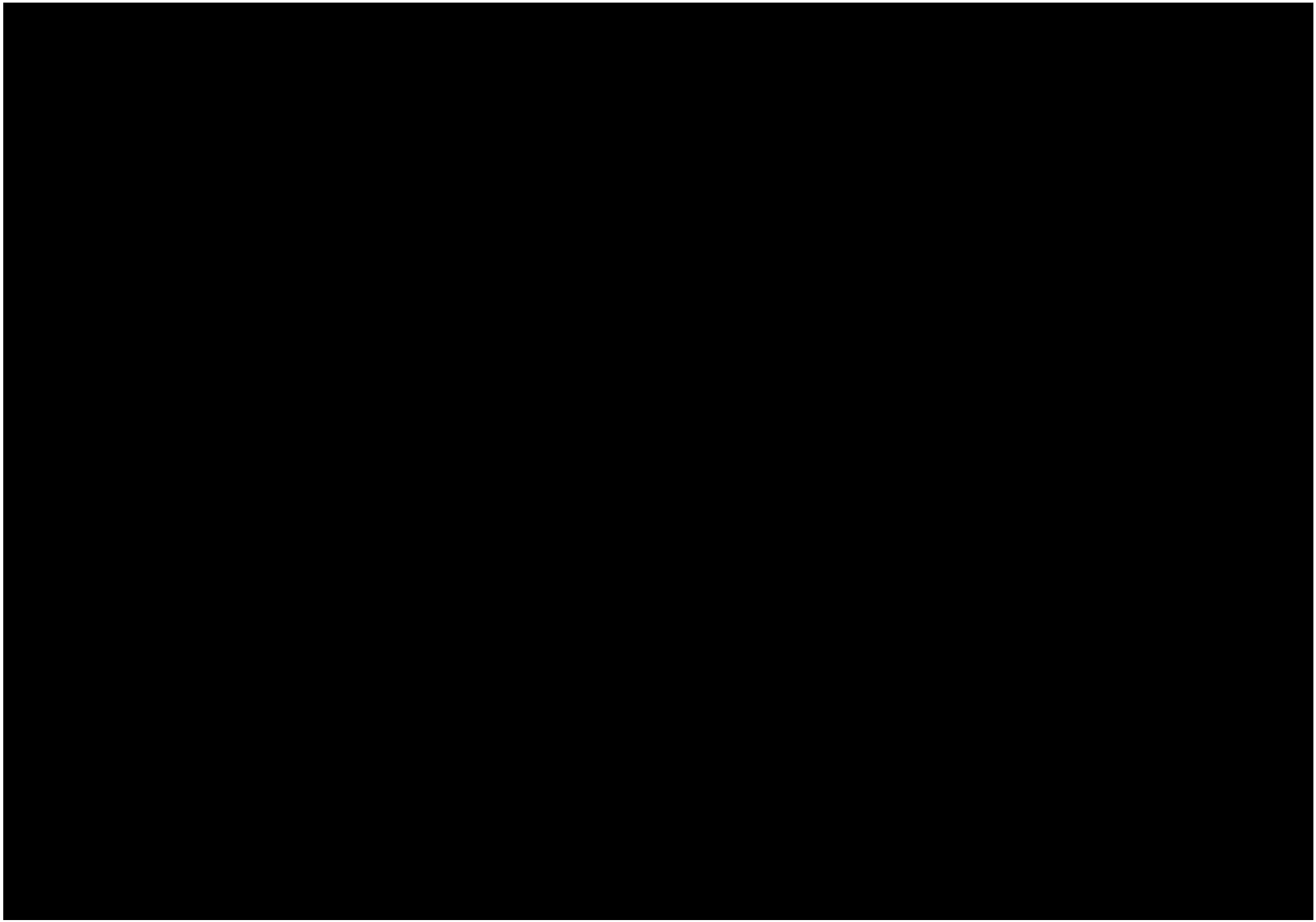
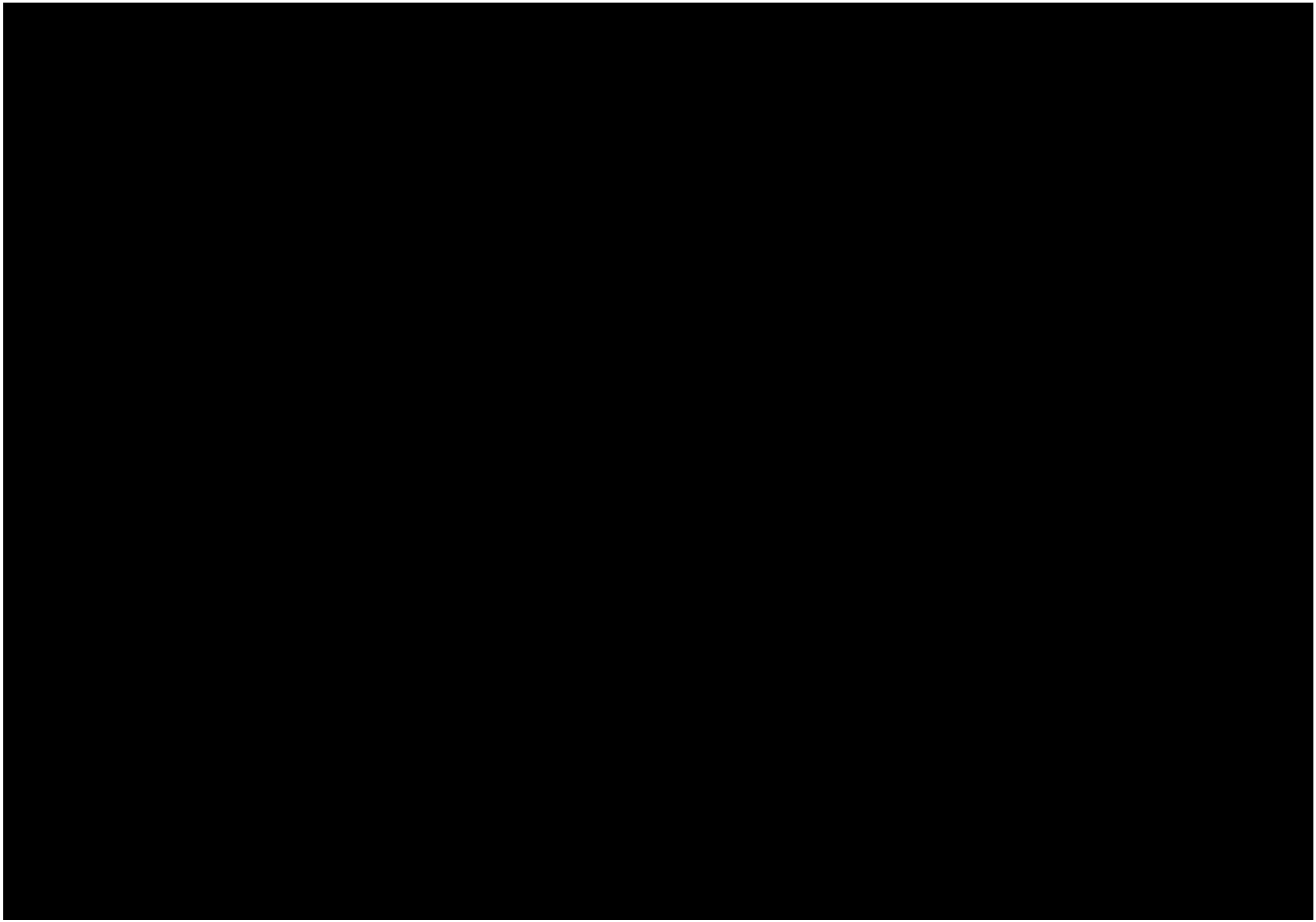
Hourly Average Day for July 2021

San Luis Valley Rural Electric Cooperative, Inc.



Hourly Average Day for August 2021

San Luis Valley Rural Electric Cooperative, Inc.



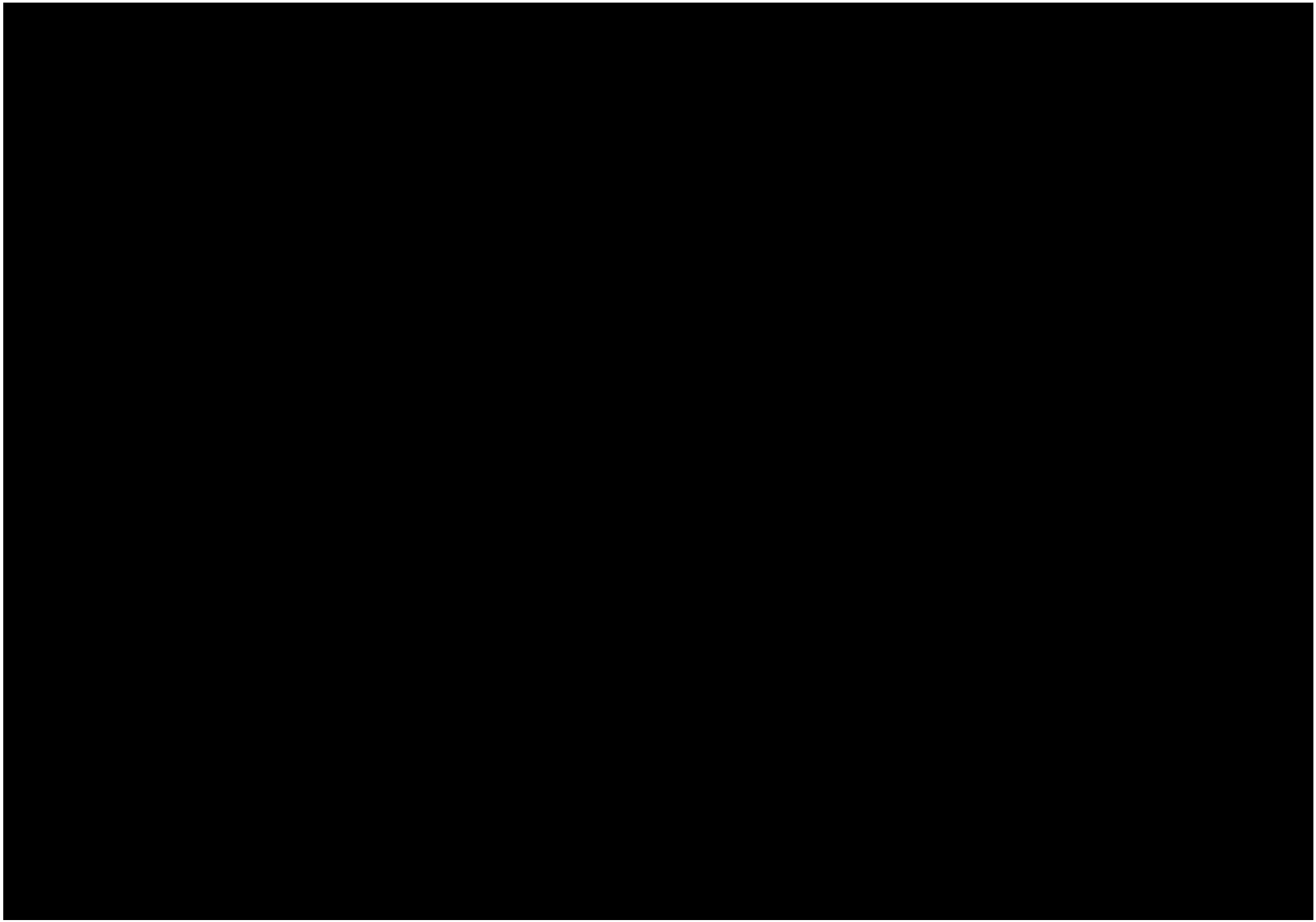
Hourly Average Day for September 2021

San Luis Valley Rural Electric Cooperative, Inc.

[redacted]

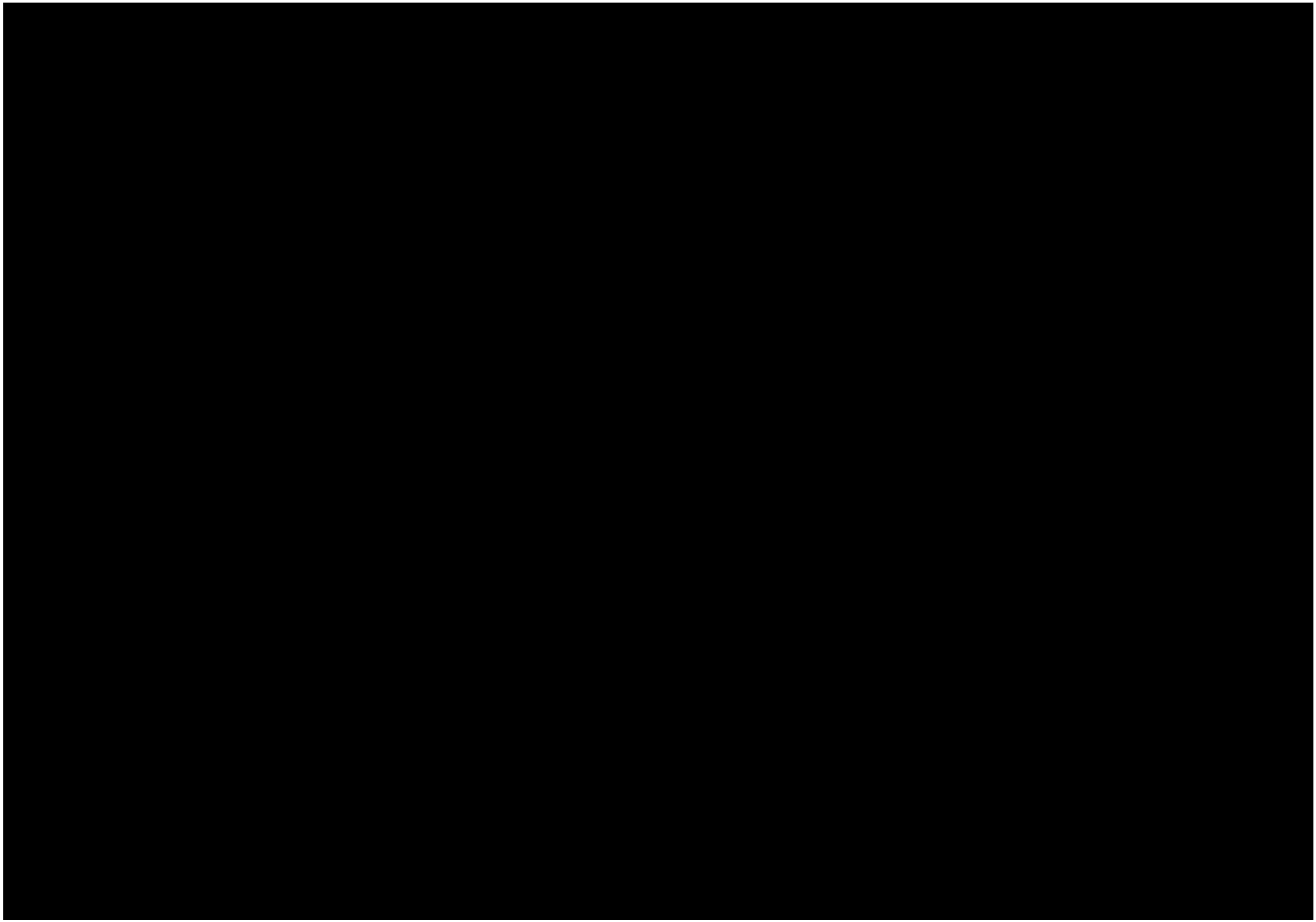
Hourly Average Day for October 2021

San Luis Valley Rural Electric Cooperative, Inc.



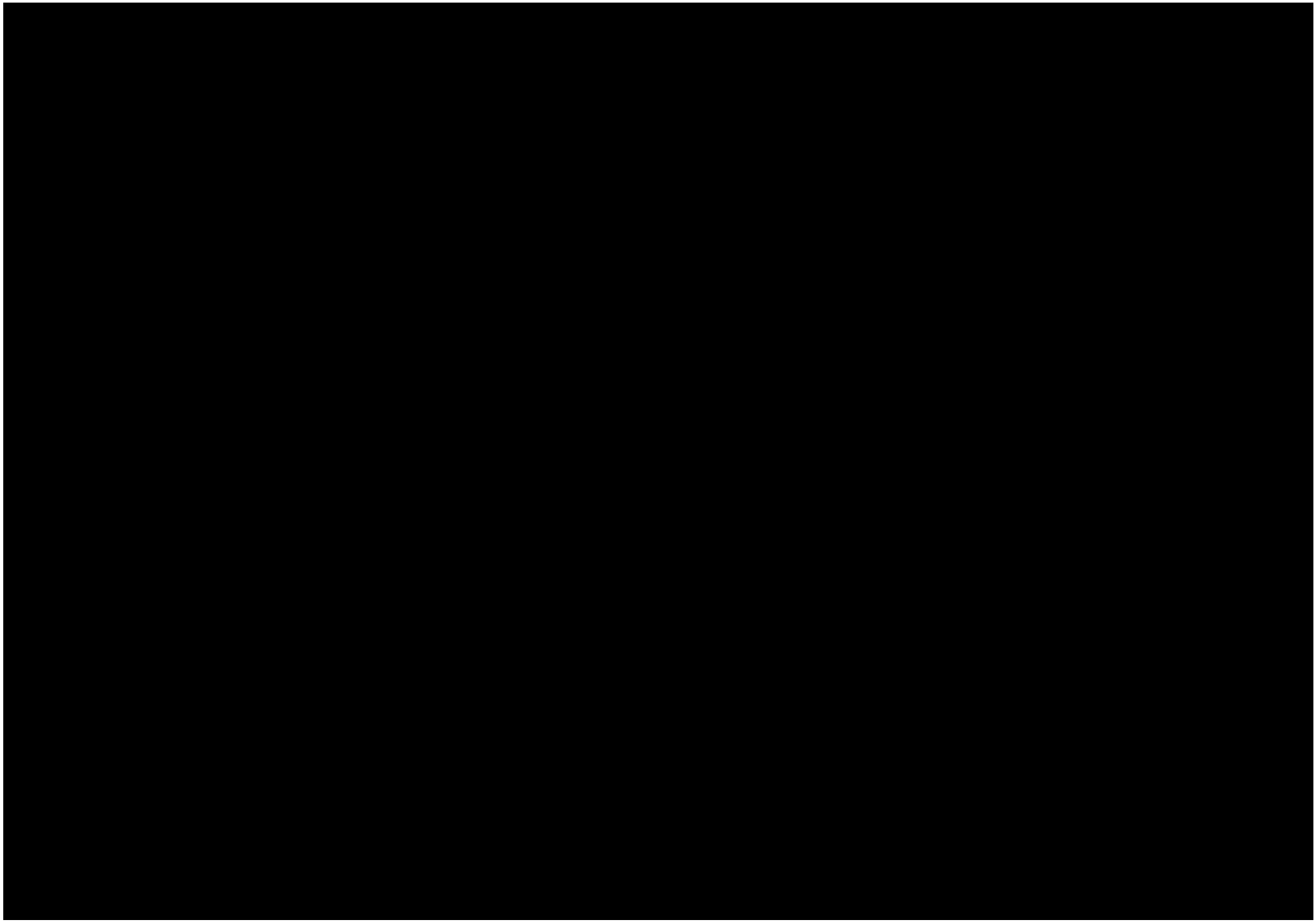
Hourly Average Day for November 2021

San Luis Valley Rural Electric Cooperative, Inc.



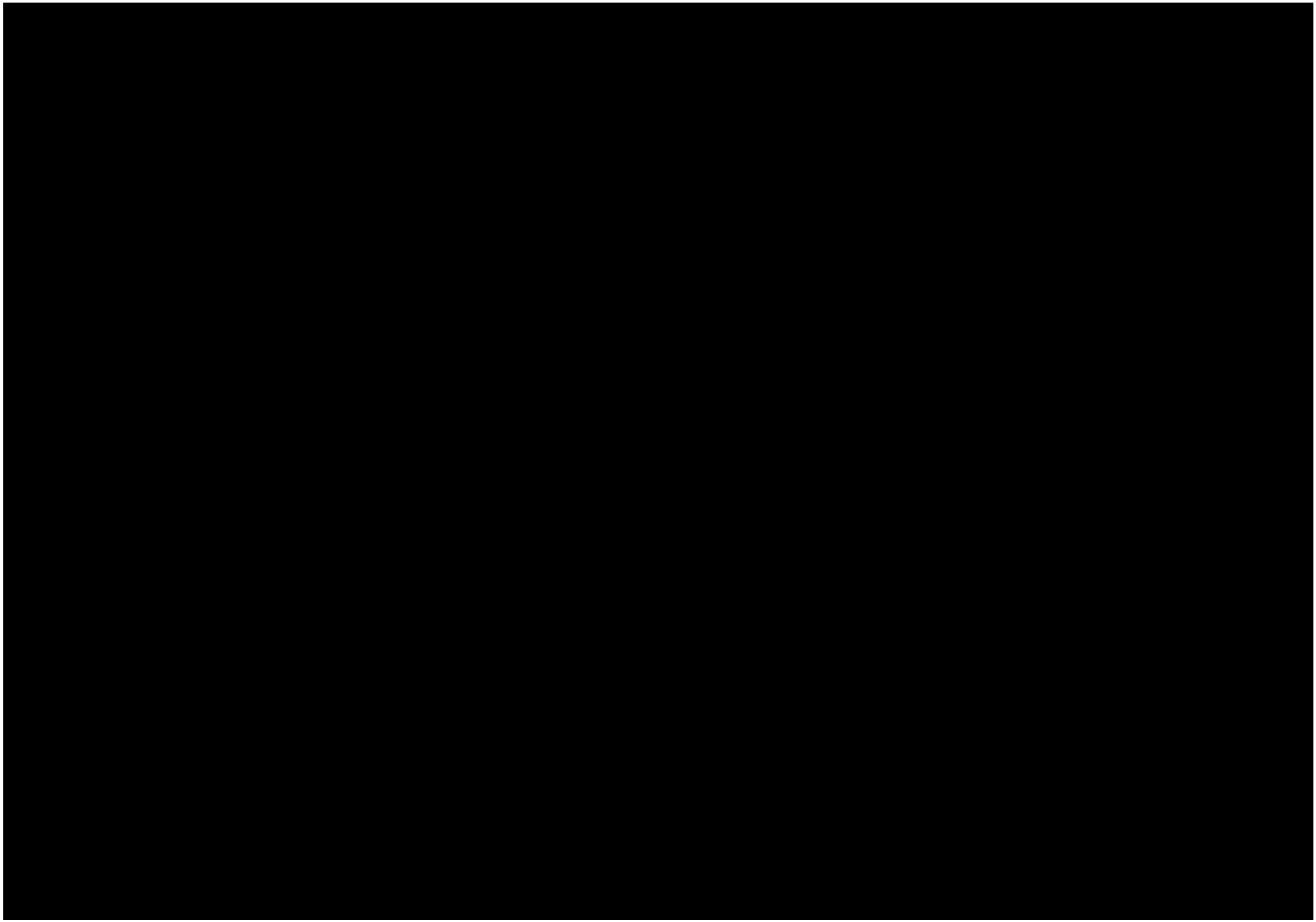
Hourly Average Day for December 2021

San Luis Valley Rural Electric Cooperative, Inc.



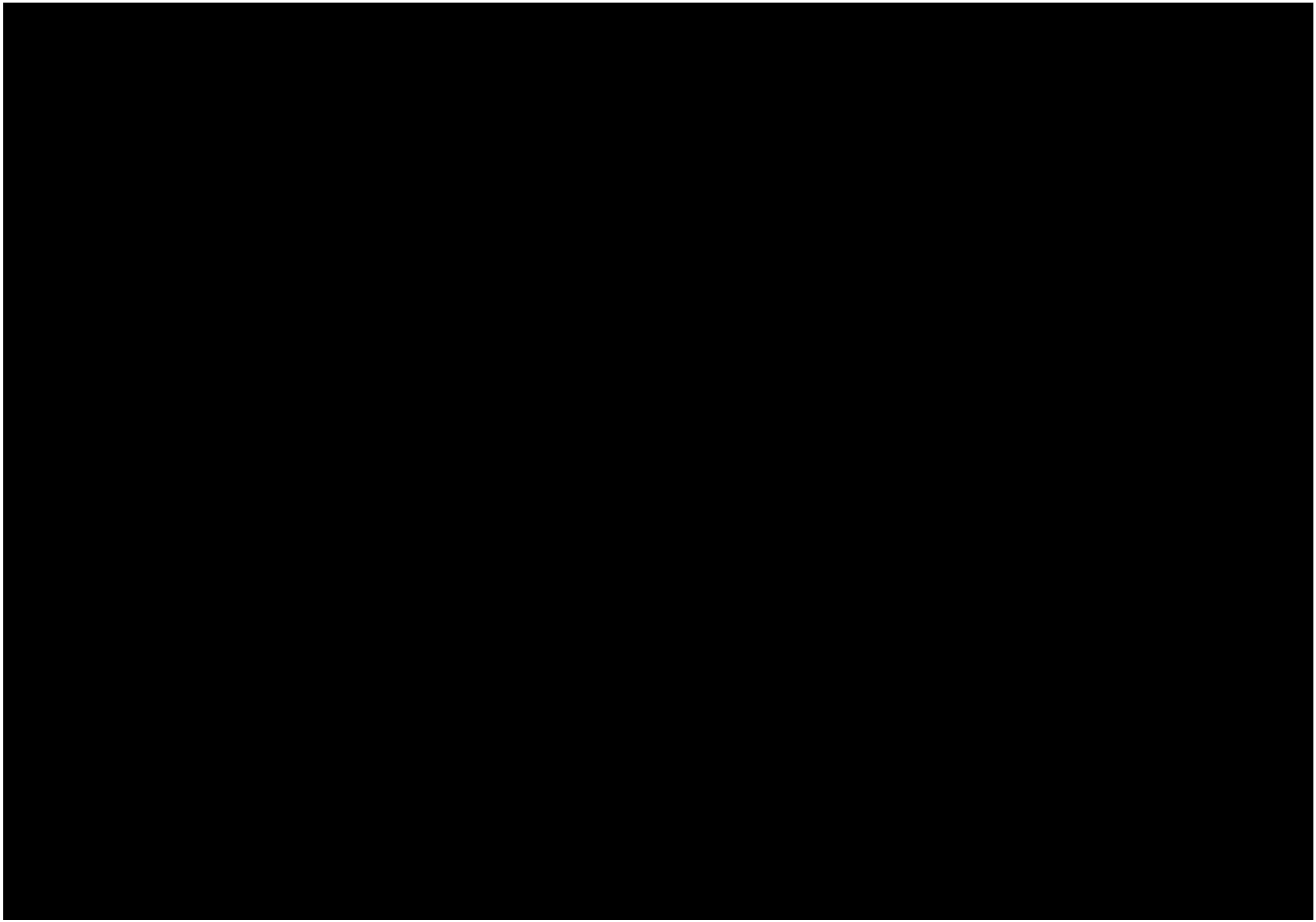
Hourly Average Day for January 2021

San Miguel Power Association, Inc.



Hourly Average Day for February 2021

San Miguel Power Association, Inc.



Hourly Average Day for March 2021

San Miguel Power Association, Inc.

[redacted]

Hourly Average Day for April 2021

San Miguel Power Association, Inc.

[redacted]

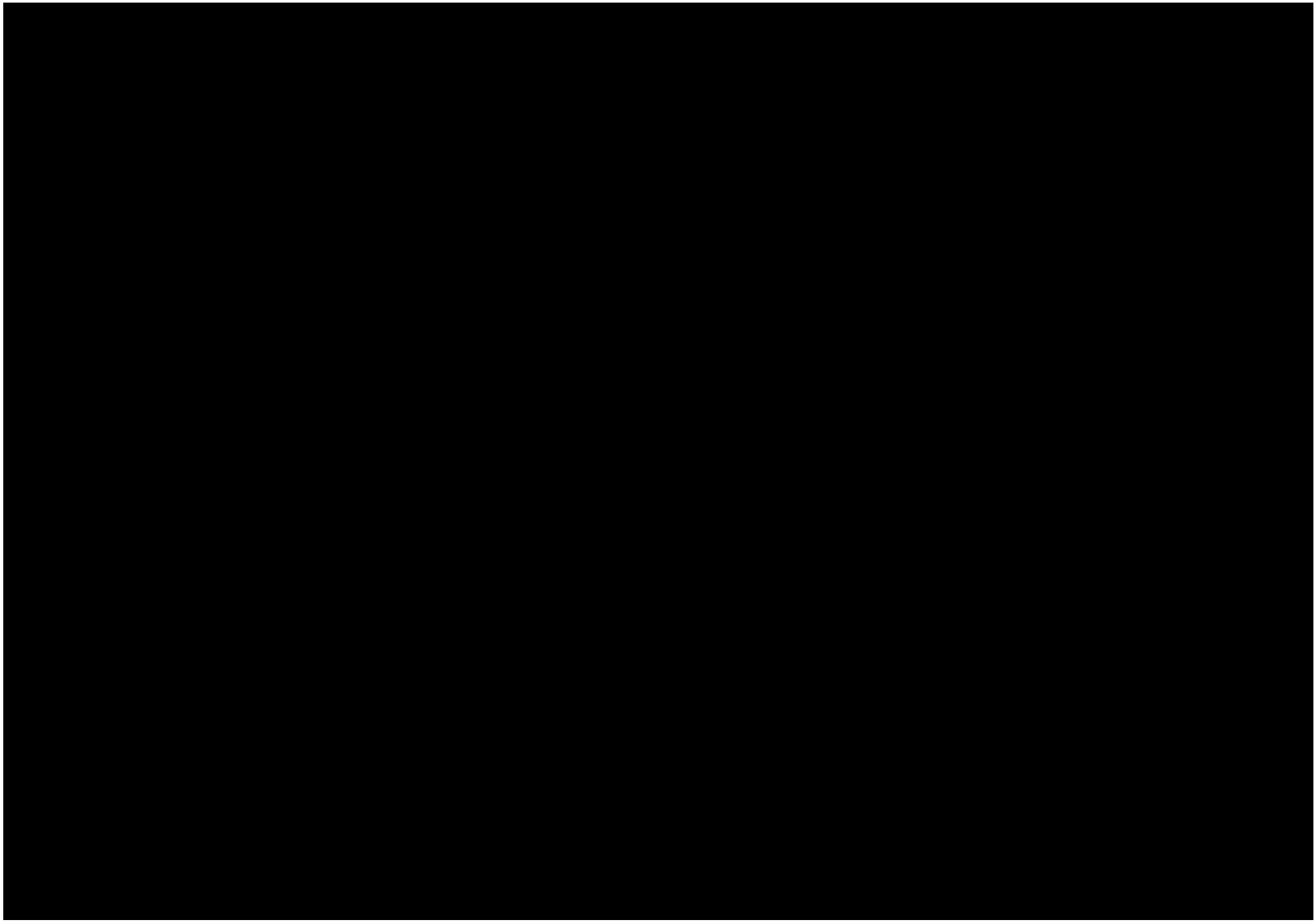
Hourly Average Day for May 2021

San Miguel Power Association, Inc.

[redacted]

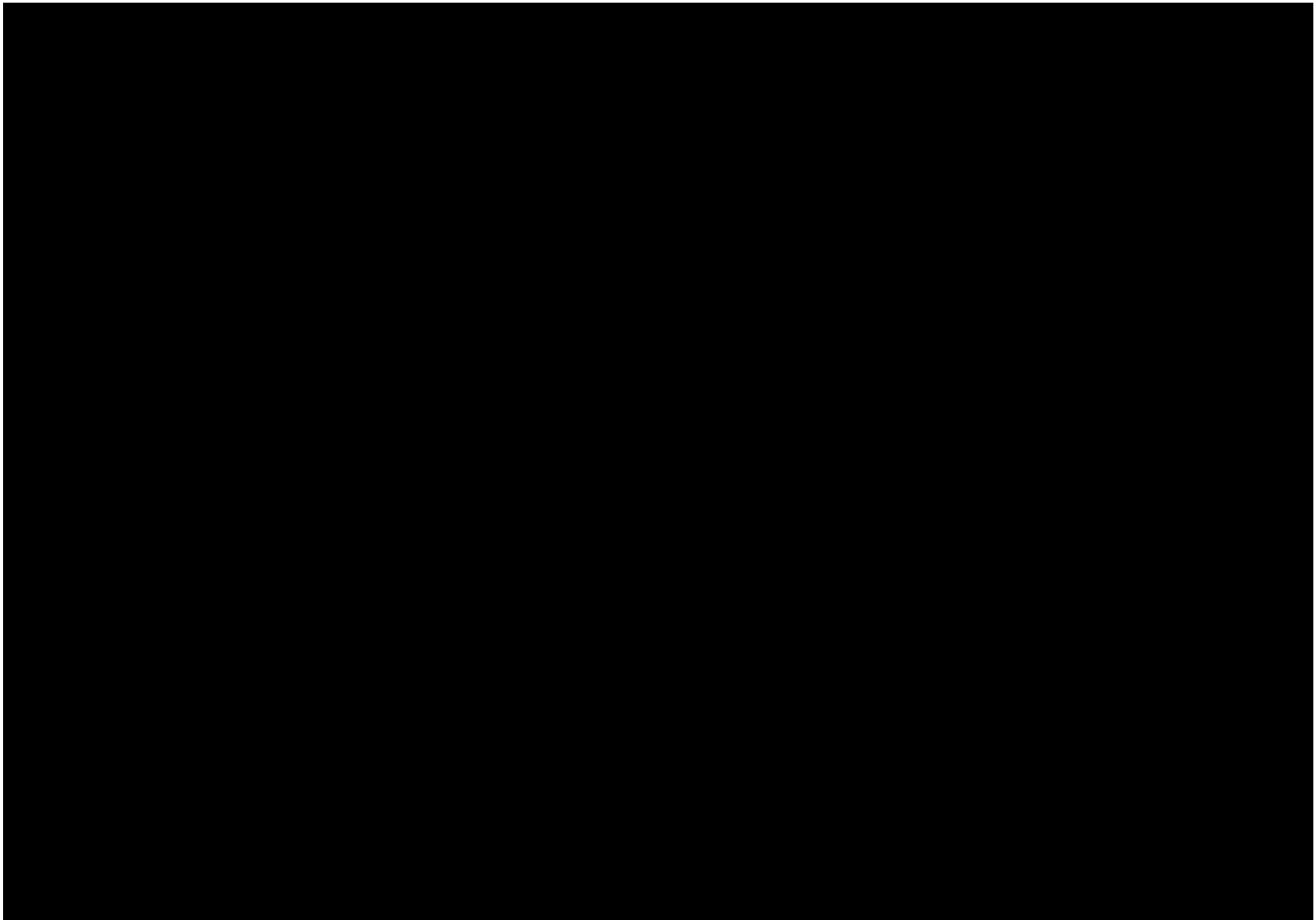
Hourly Average Day for June 2021

San Miguel Power Association, Inc.



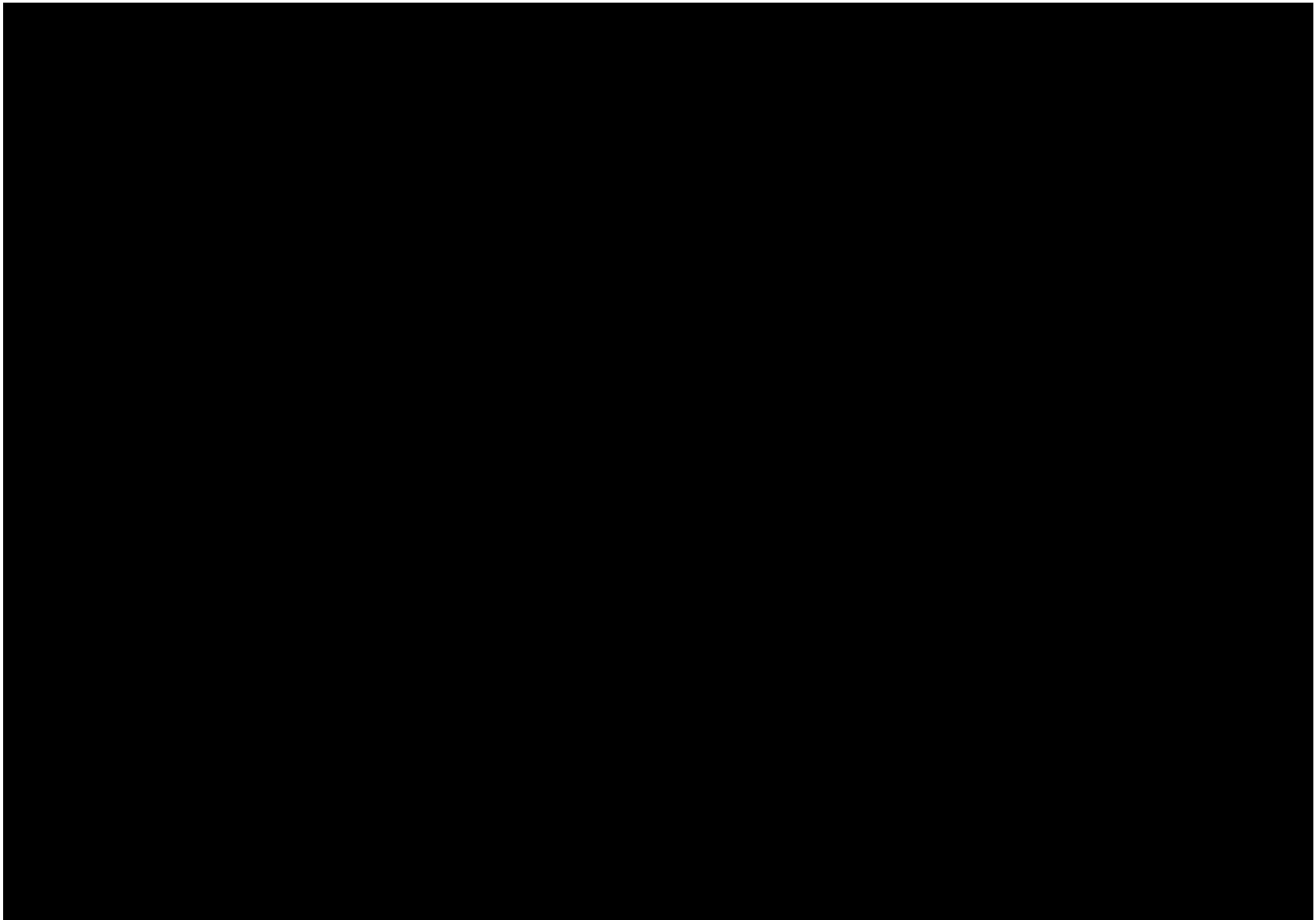
Hourly Average Day for July 2021

San Miguel Power Association, Inc.



Hourly Average Day for August 2021

San Miguel Power Association, Inc.



Hourly Average Day for September 2021

San Miguel Power Association, Inc.

[redacted]

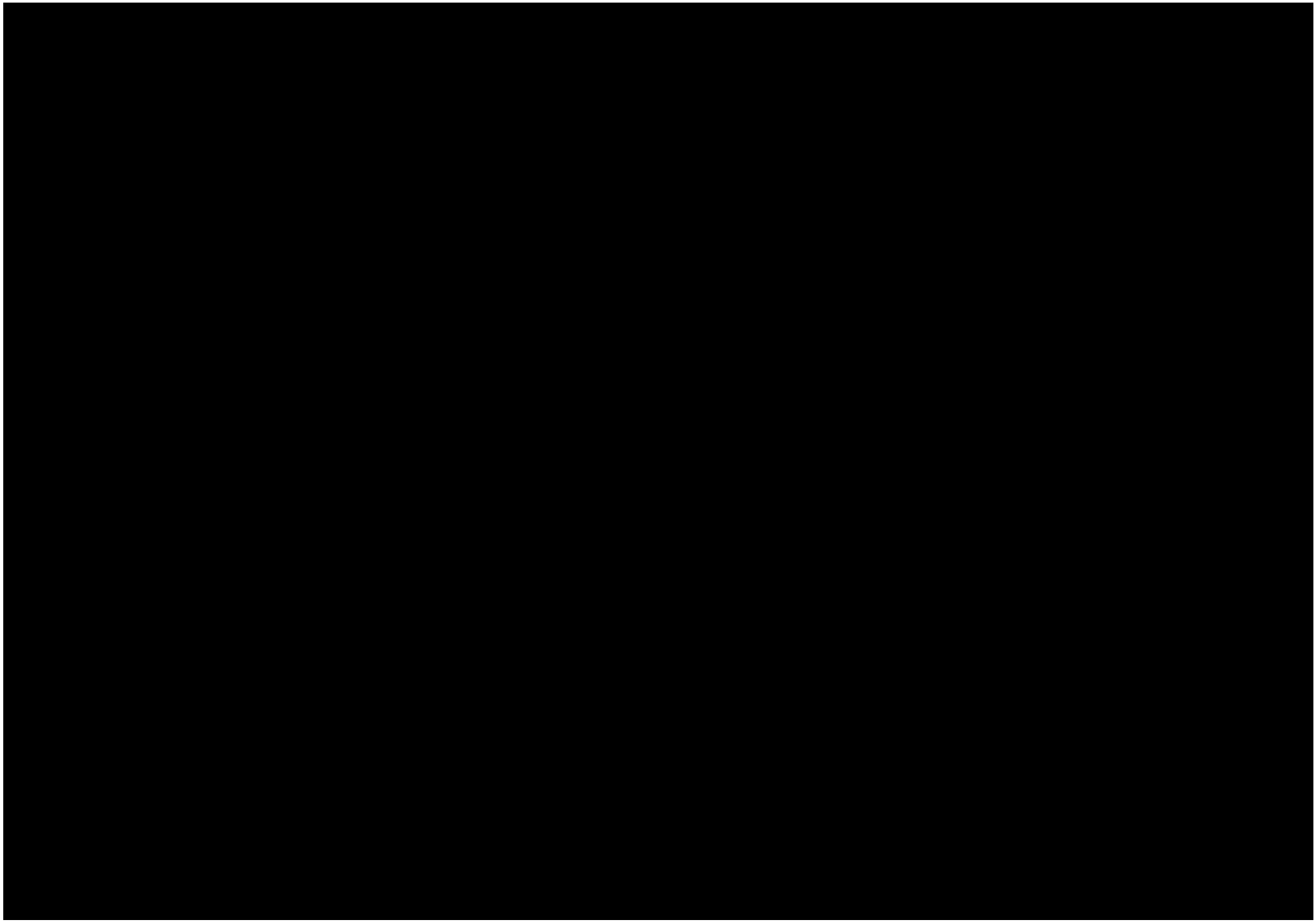
Hourly Average Day for October 2021

San Miguel Power Association, Inc.

[redacted]

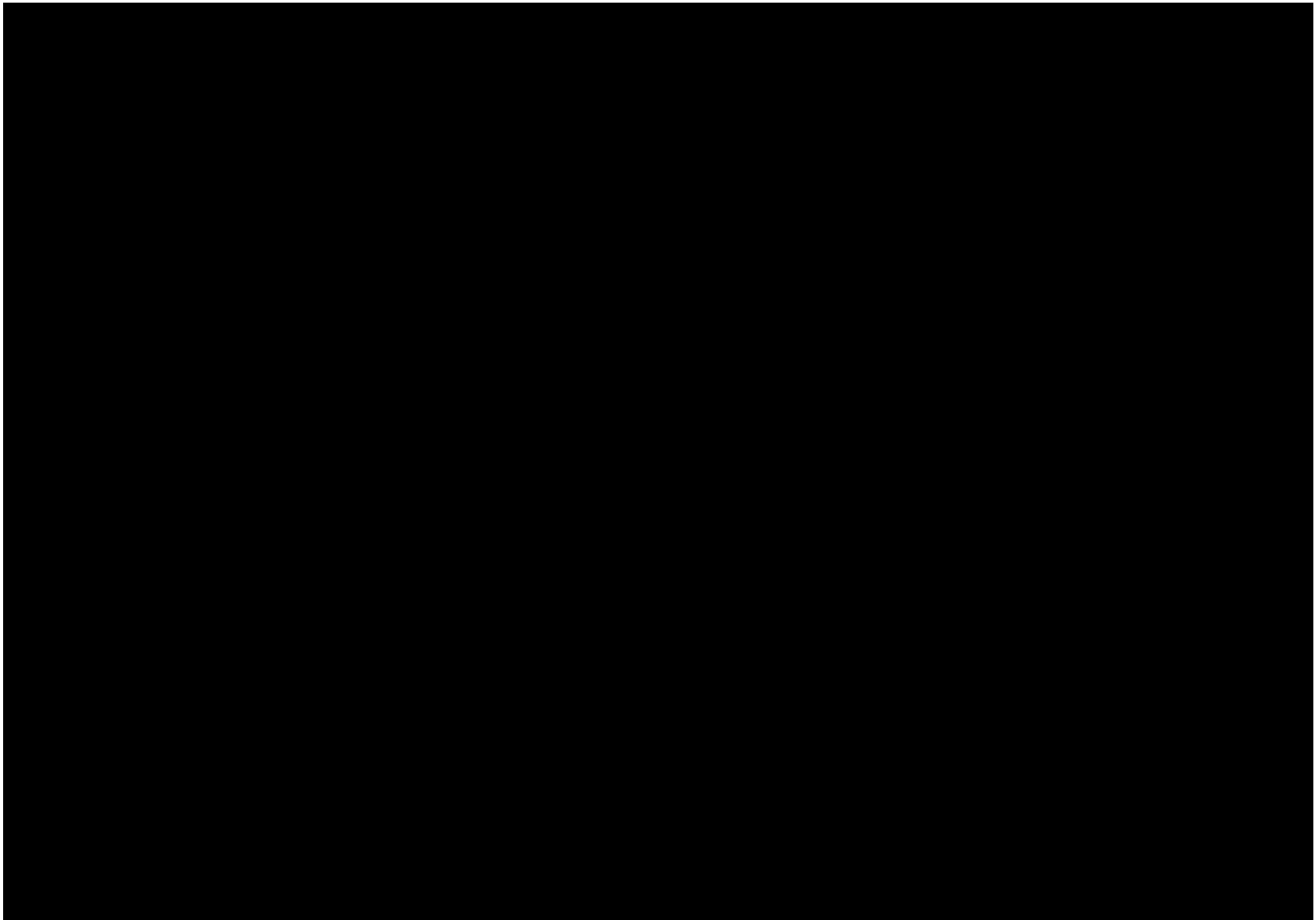
Hourly Average Day for November 2021

San Miguel Power Association, Inc.



Hourly Average Day for December 2021

San Miguel Power Association, Inc.



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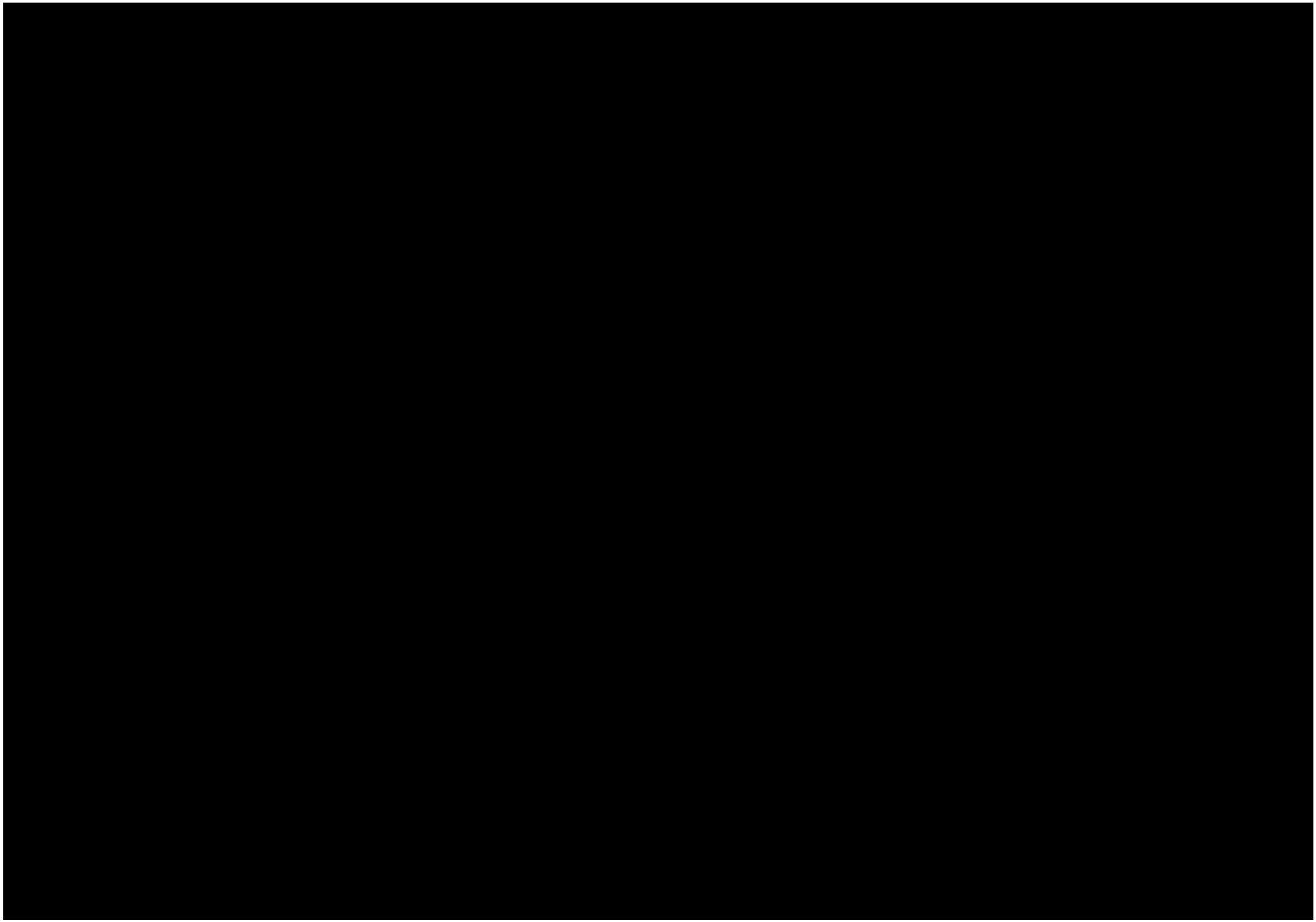
Hourly Average Day for January 2021

Socorro Electric Cooperative, Inc.

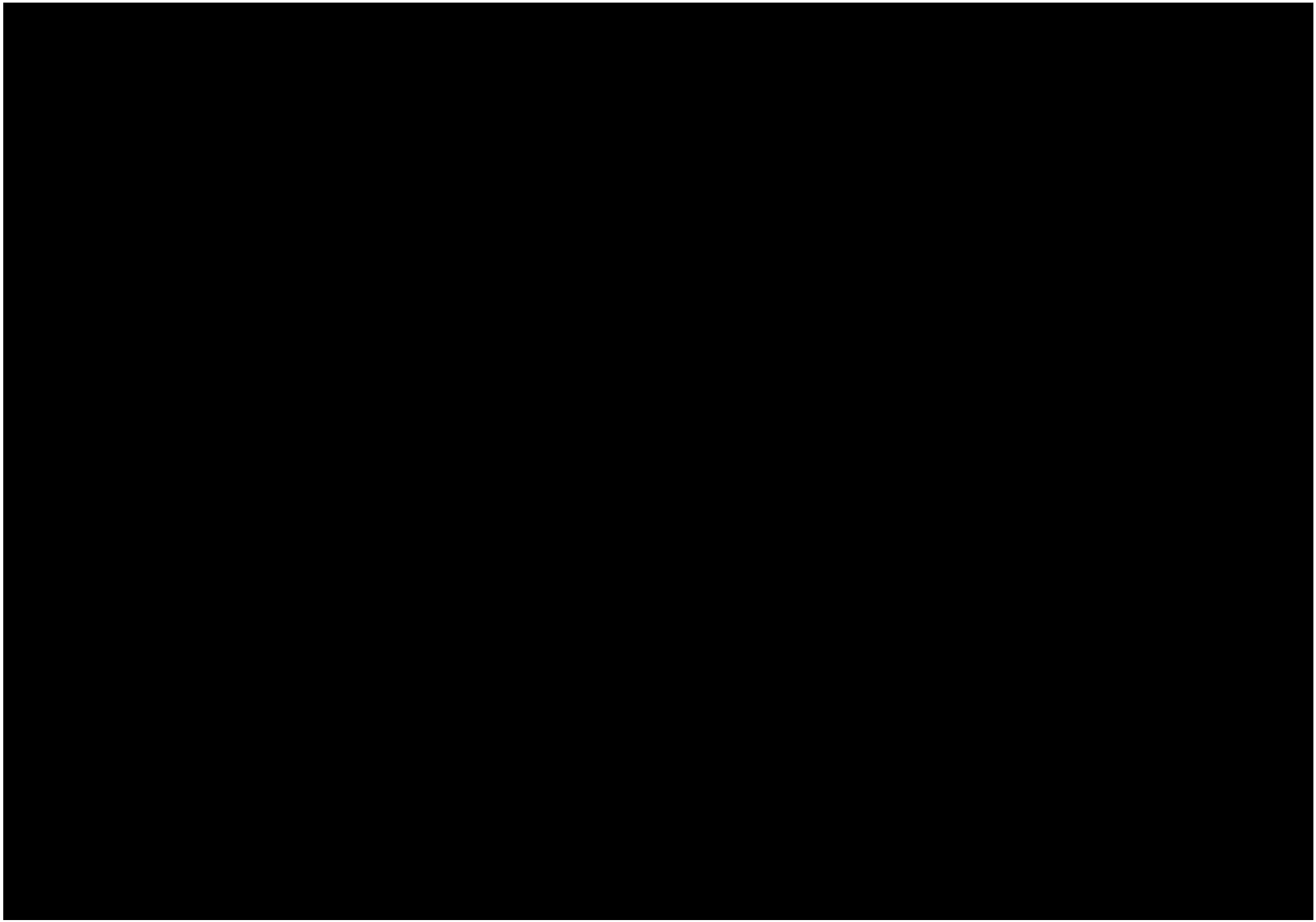


Hourly Average Day for February 2021
Socorro Electric Cooperative, Inc.

[redacted]

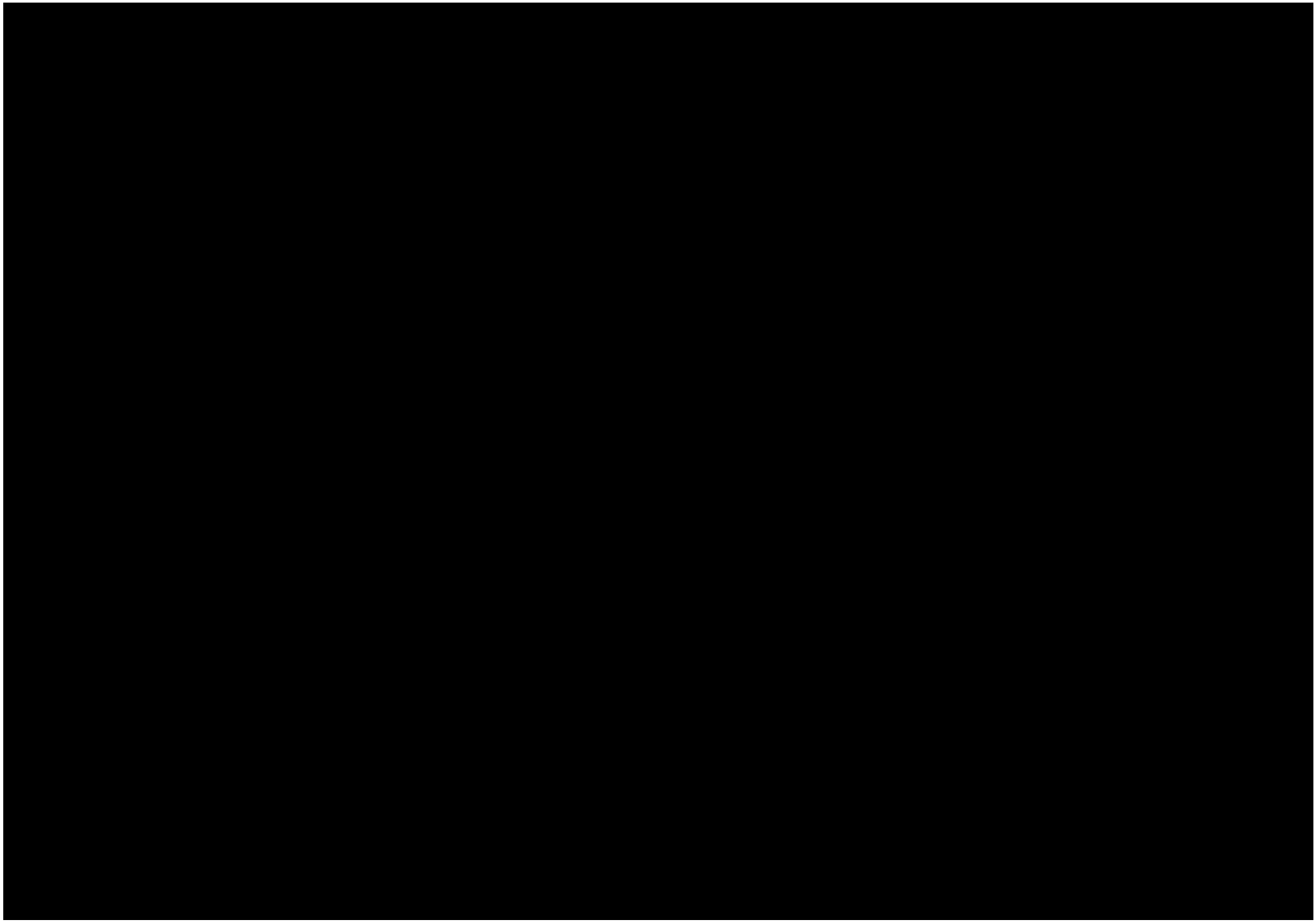
Hourly Average Day for March 2021

Socorro Electric Cooperative, Inc.



Hourly Average Day for April 2021

Socorro Electric Cooperative, Inc.



Hourly Average Day for May 2021

Socorro Electric Cooperative, Inc.

[redacted]

Hourly Average Day for June 2021

Socorro Electric Cooperative, Inc.

[redacted]

Hourly Average Day for July 2021

Socorro Electric Cooperative, Inc.

[redacted]

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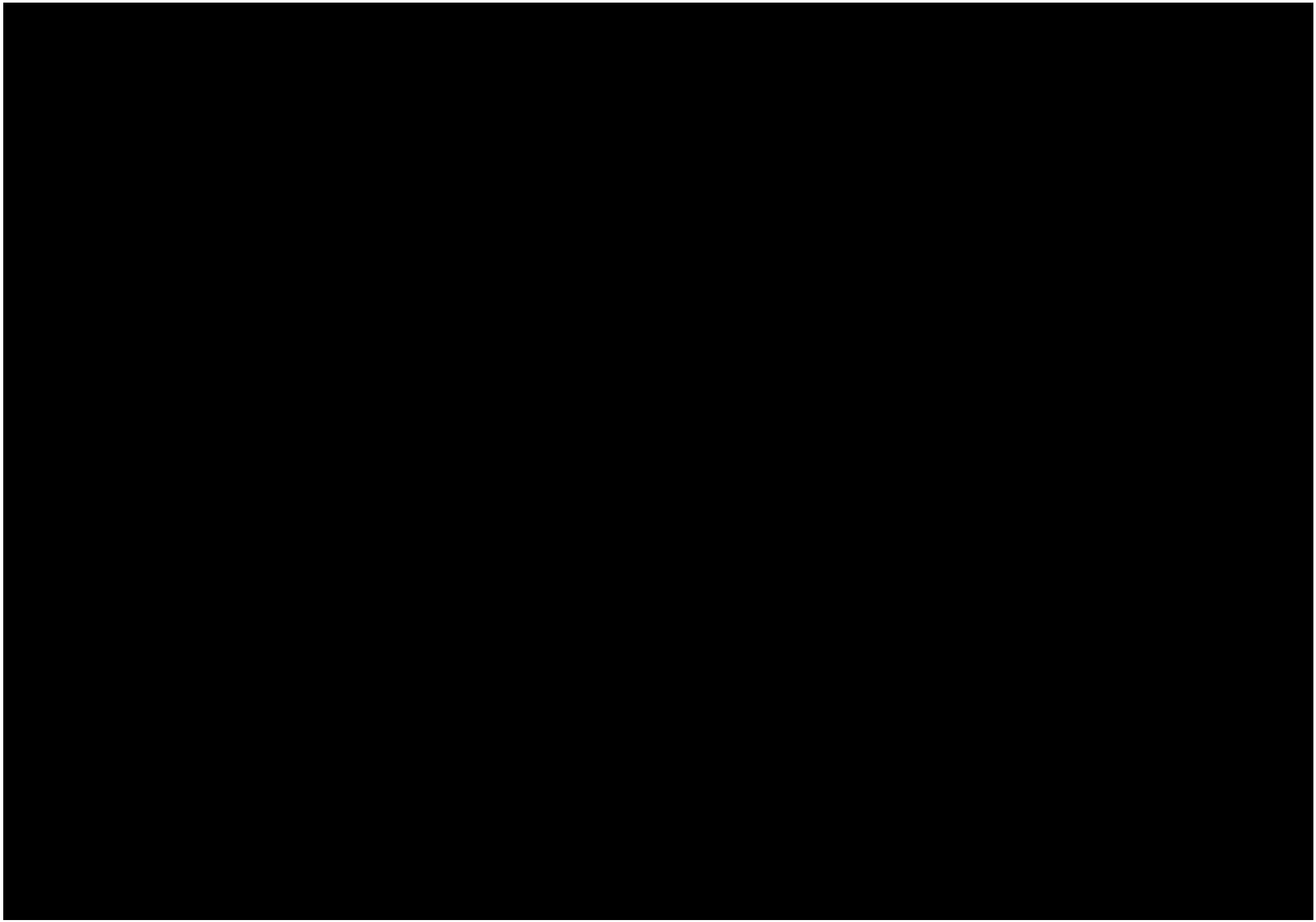
Hourly Average Day for August 2021

Socorro Electric Cooperative, Inc.

[redacted]

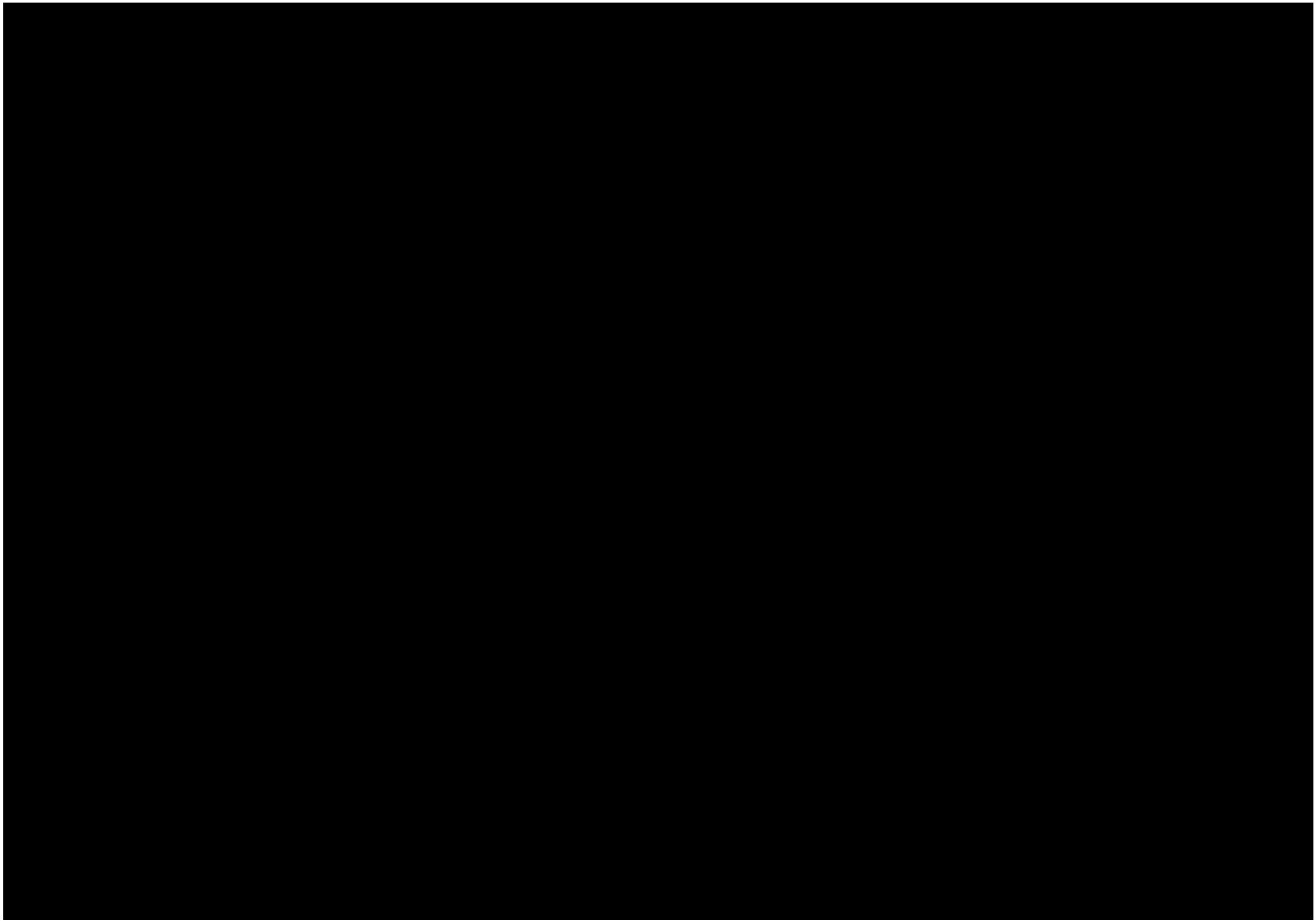
Hourly Average Day for September 2021

Socorro Electric Cooperative, Inc.



Hourly Average Day for October 2021

Socorro Electric Cooperative, Inc.



Hourly Average Day for November 2021

Socorro Electric Cooperative, Inc.

[redacted]

Hourly Average Day for December 2021

Socorro Electric Cooperative, Inc.

[redacted]

Hourly Average Day for January 2021

Springer Electric Cooperative, Inc.

[redacted]

Hourly Average Day for February 2021
Springer Electric Cooperative, Inc.

[redacted]

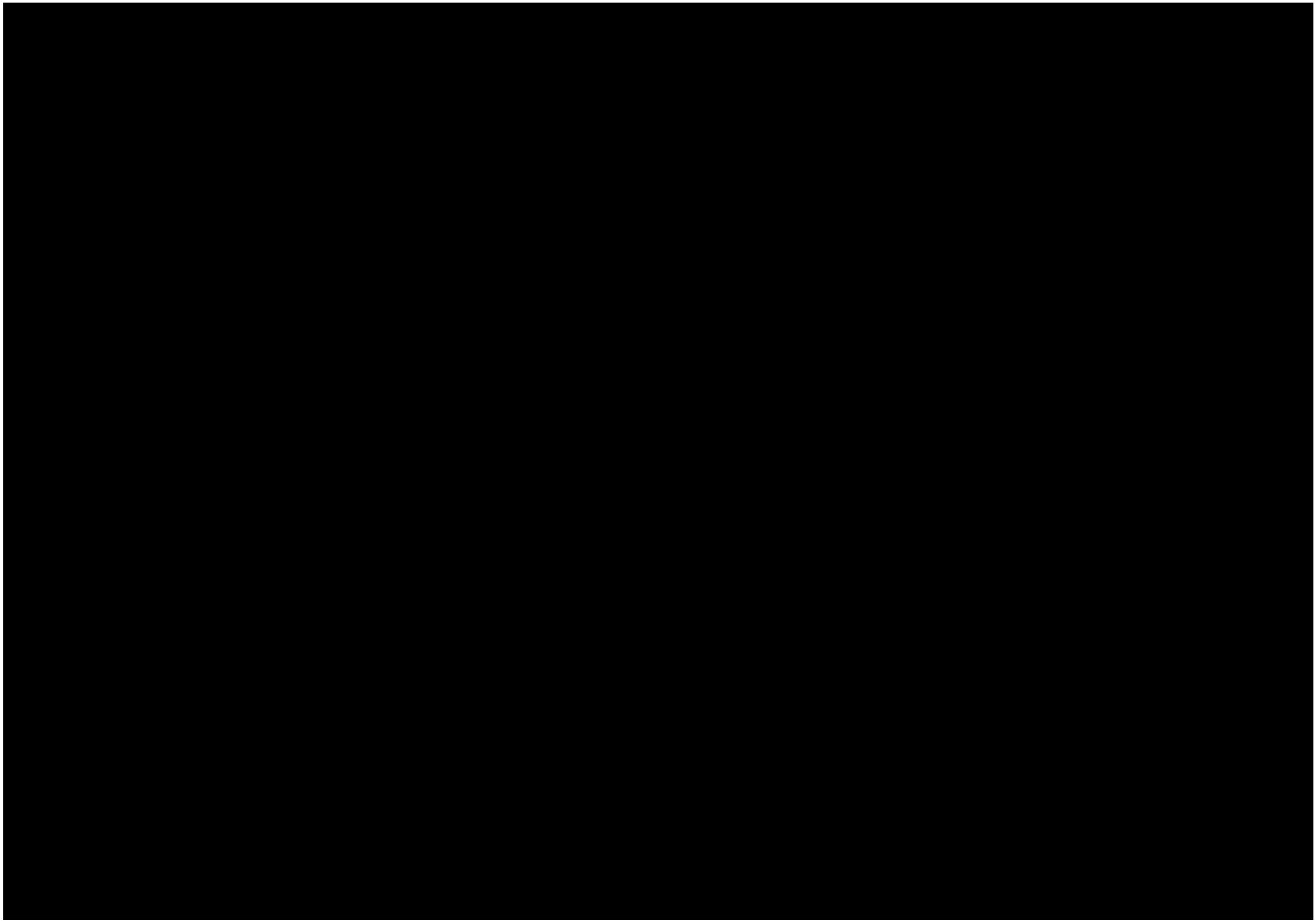
Hourly Average Day for March 2021

Springer Electric Cooperative, Inc.

[redacted]

Hourly Average Day for April 2021

Springer Electric Cooperative, Inc.



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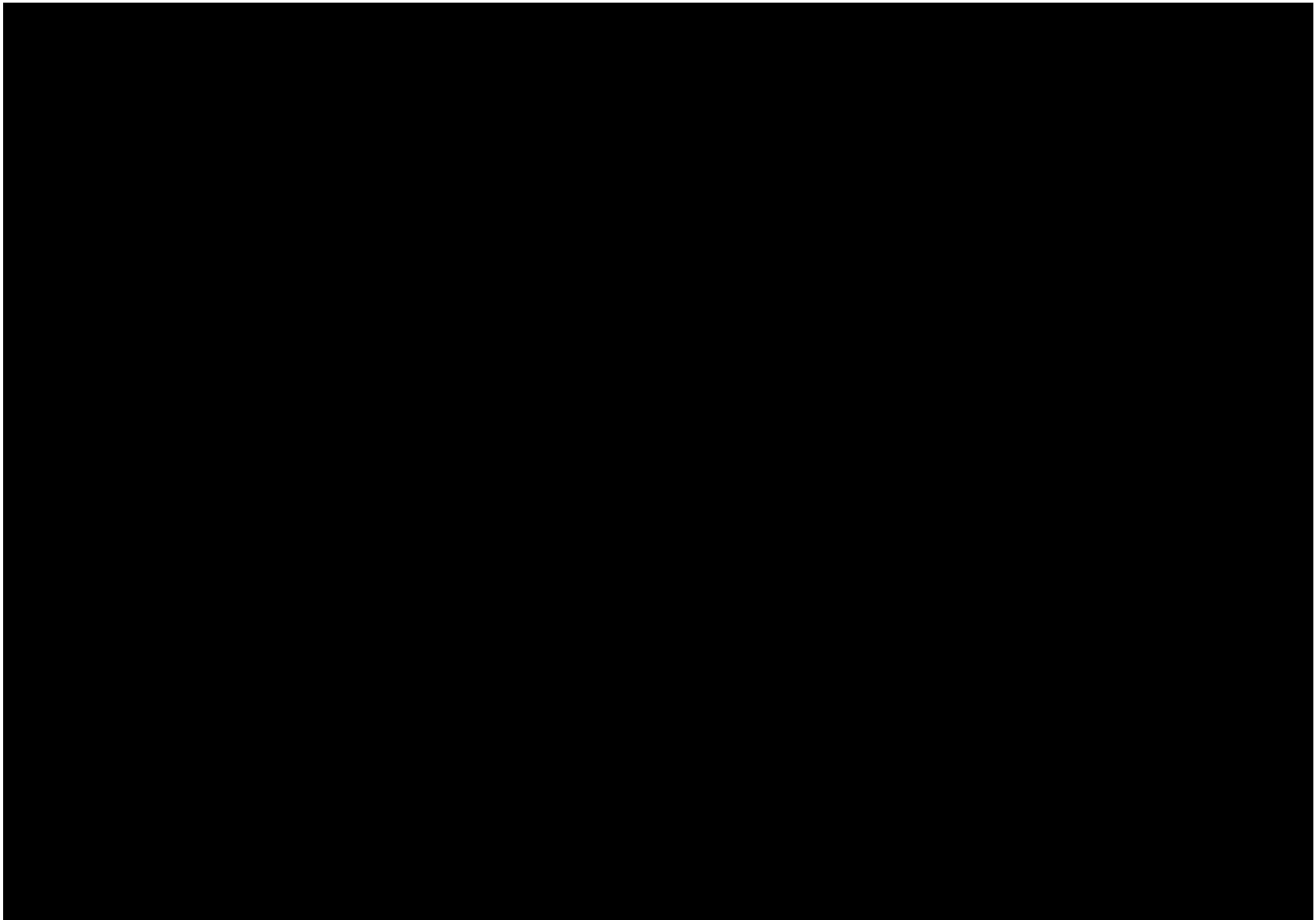
Hourly Average Day for May 2021

Springer Electric Cooperative, Inc.



Hourly Average Day for June 2021

Springer Electric Cooperative, Inc.

[redacted]

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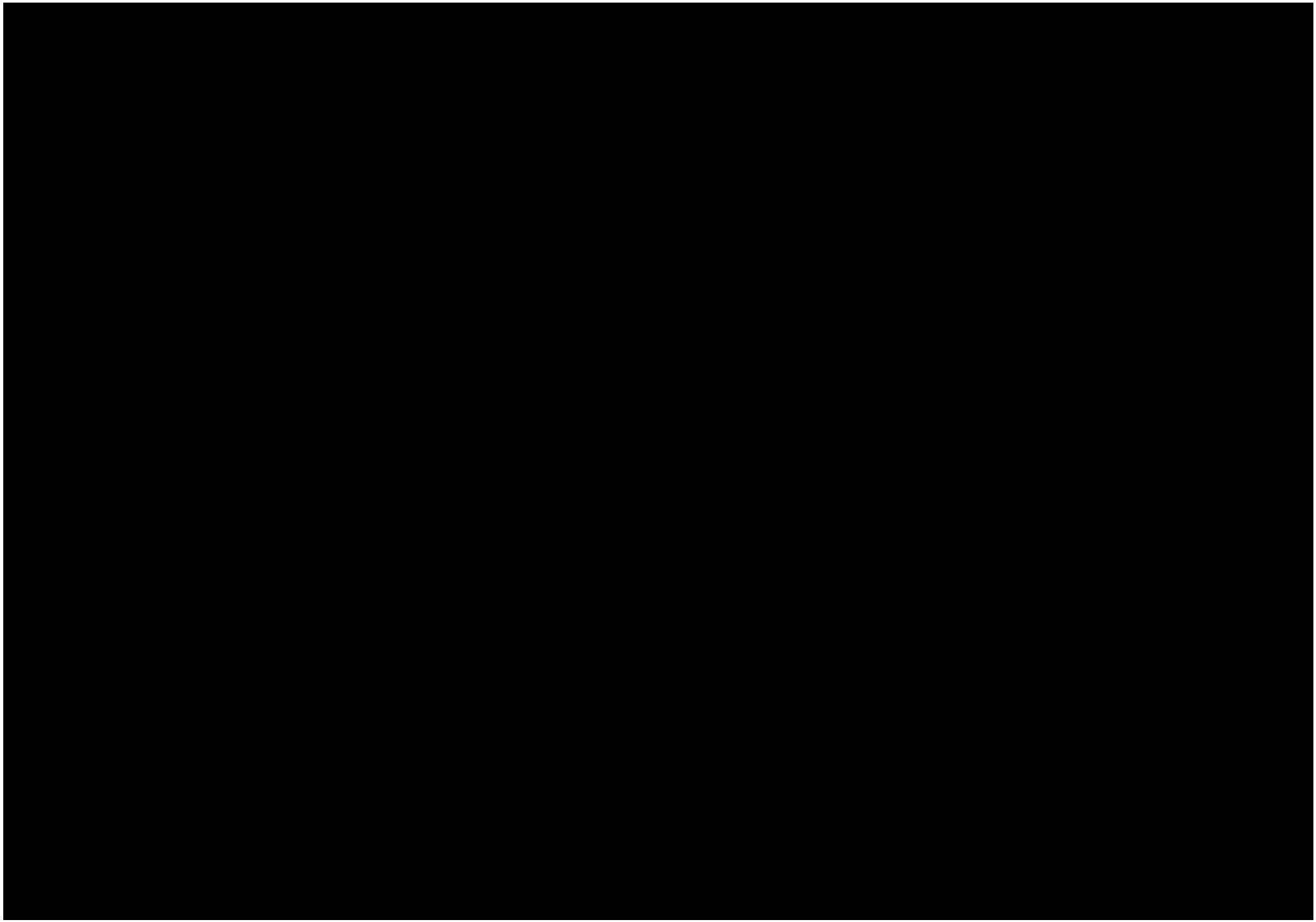
Hourly Average Day for July 2021

Springer Electric Cooperative, Inc.



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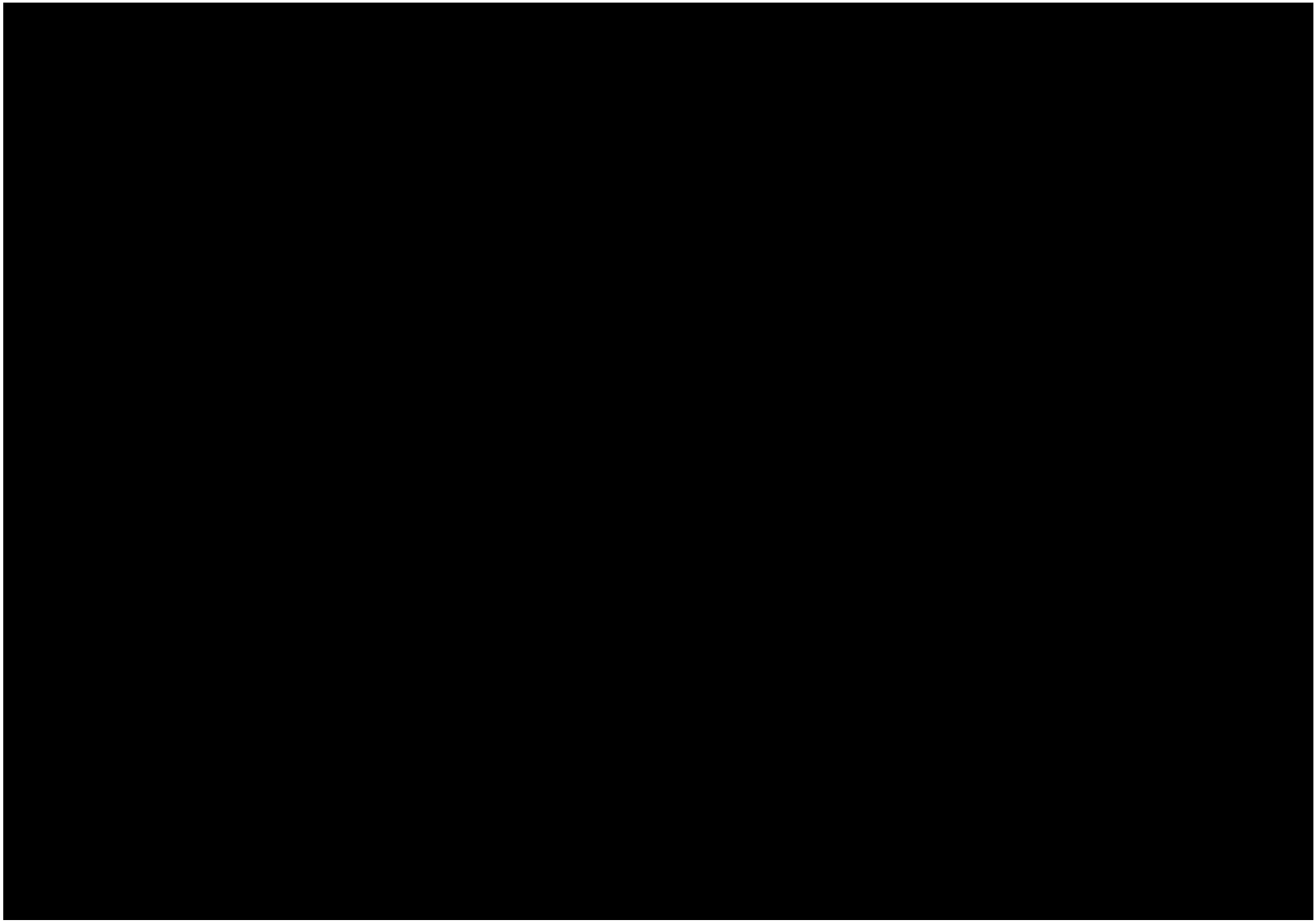
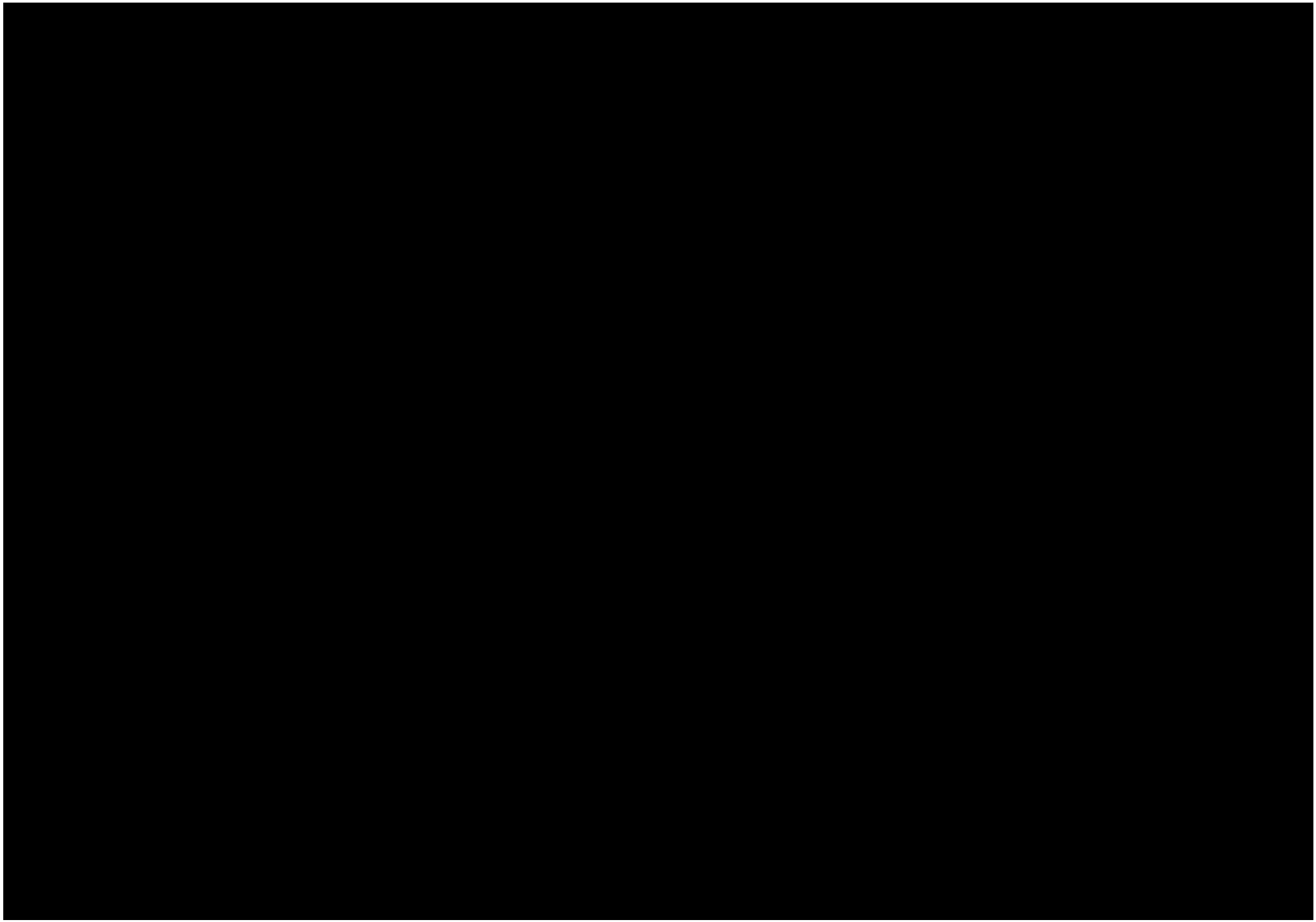
Hourly Average Day for August 2021

Springer Electric Cooperative, Inc.



Hourly Average Day for September 2021
Springer Electric Cooperative, Inc.



Hourly Average Day for October 2021

Springer Electric Cooperative, Inc.

[redacted]

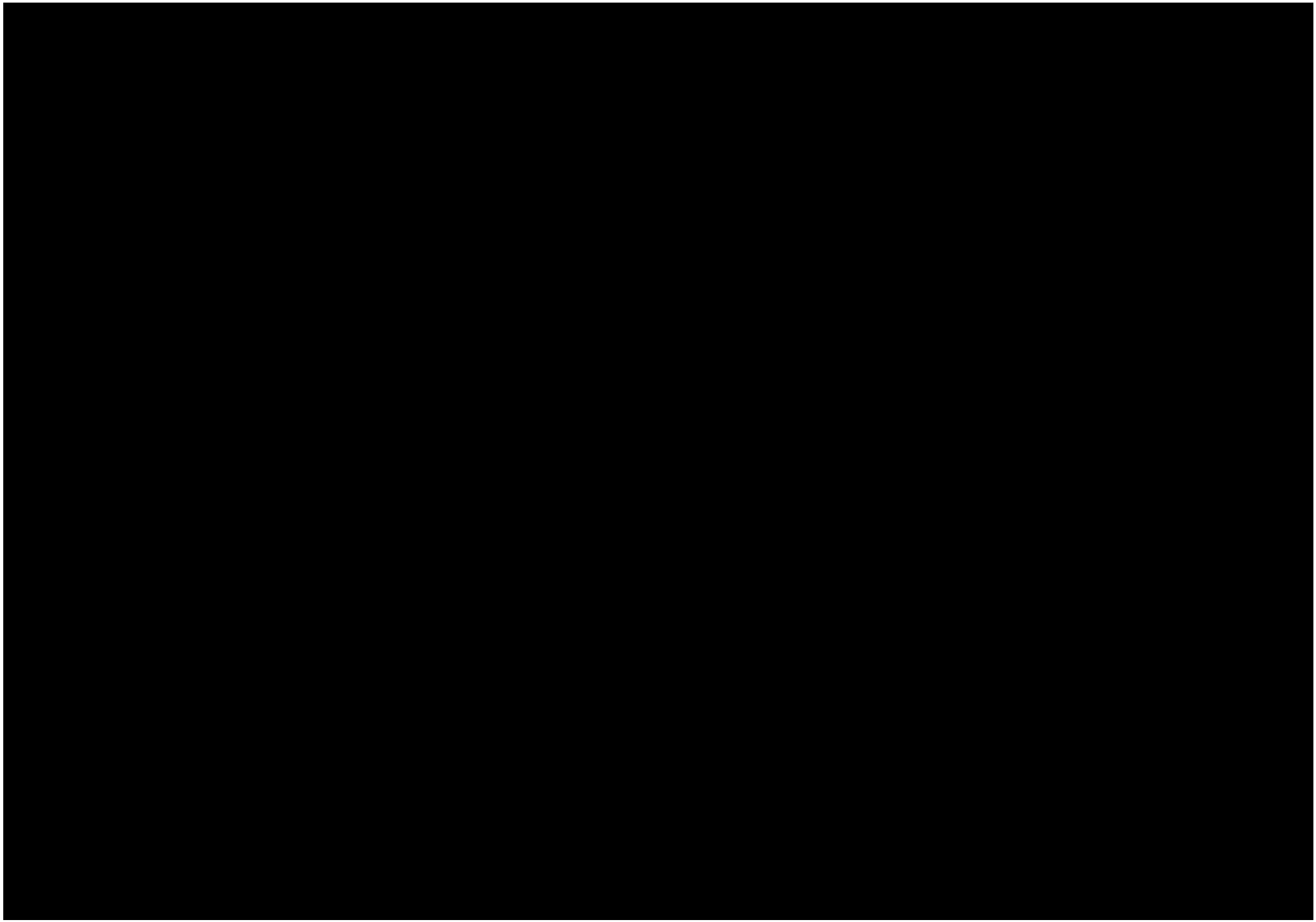
Hourly Average Day for November 2021

Springer Electric Cooperative, Inc.

[redacted]

Hourly Average Day for December 2021

Springer Electric Cooperative, Inc.



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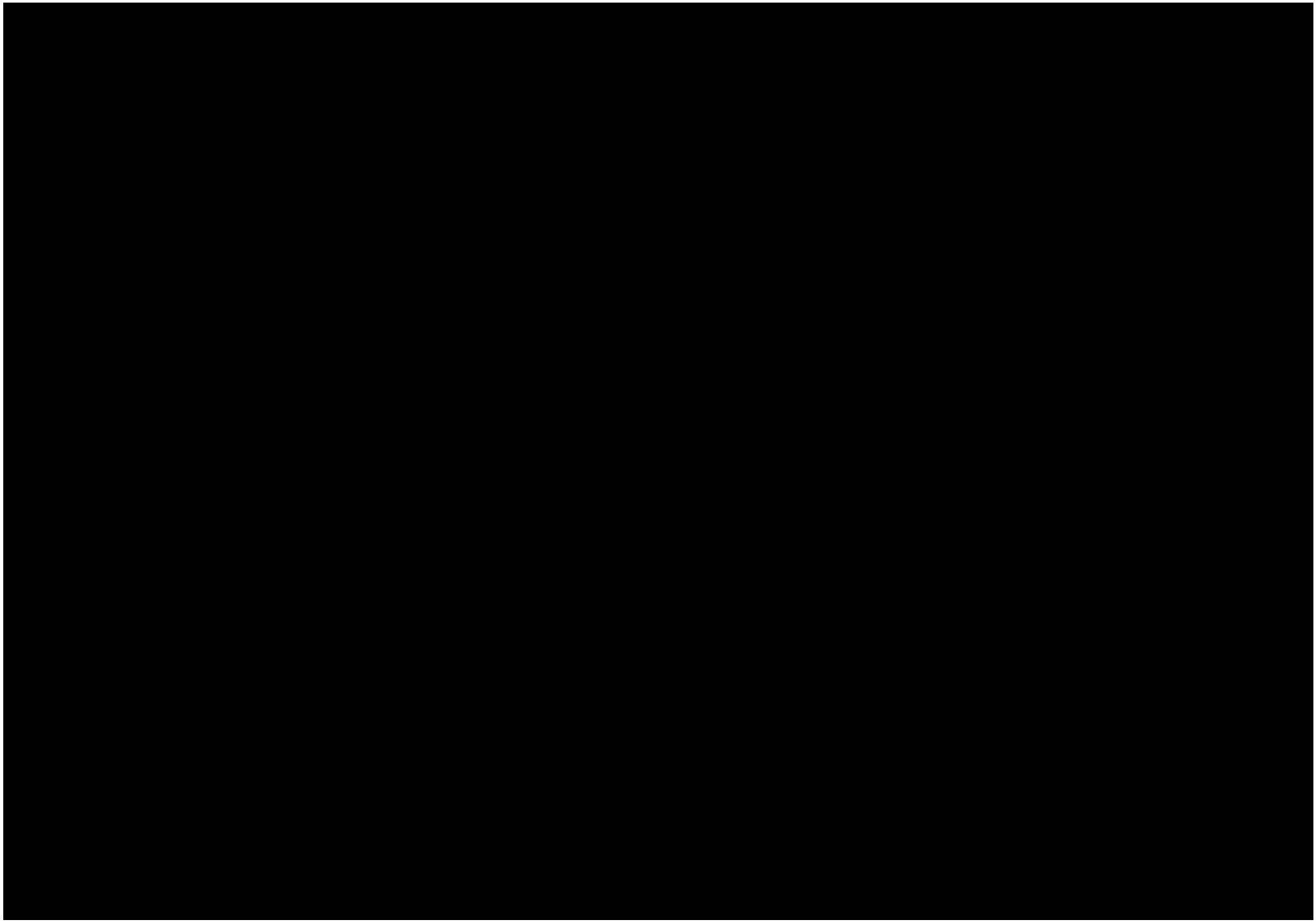
Hourly Average Day for January 2021

Southwestern Electric Cooperative, Inc.



Hourly Average Day for February 2021

Southwestern Electric Cooperative, Inc.

[redacted]

Hourly Average Day for March 2021

Southwestern Electric Cooperative, Inc.

[redacted]

Hourly Average Day for April 2021

Southwestern Electric Cooperative, Inc.

[redacted]

Hourly Average Day for May 2021

Southwestern Electric Cooperative, Inc.

[redacted]

Hourly Average Day for June 2021

Southwestern Electric Cooperative, Inc.

[redacted]

Hourly Average Day for July 2021

Southwestern Electric Cooperative, Inc.

[redacted]

Hourly Average Day for August 2021

Southwestern Electric Cooperative, Inc.

[redacted]

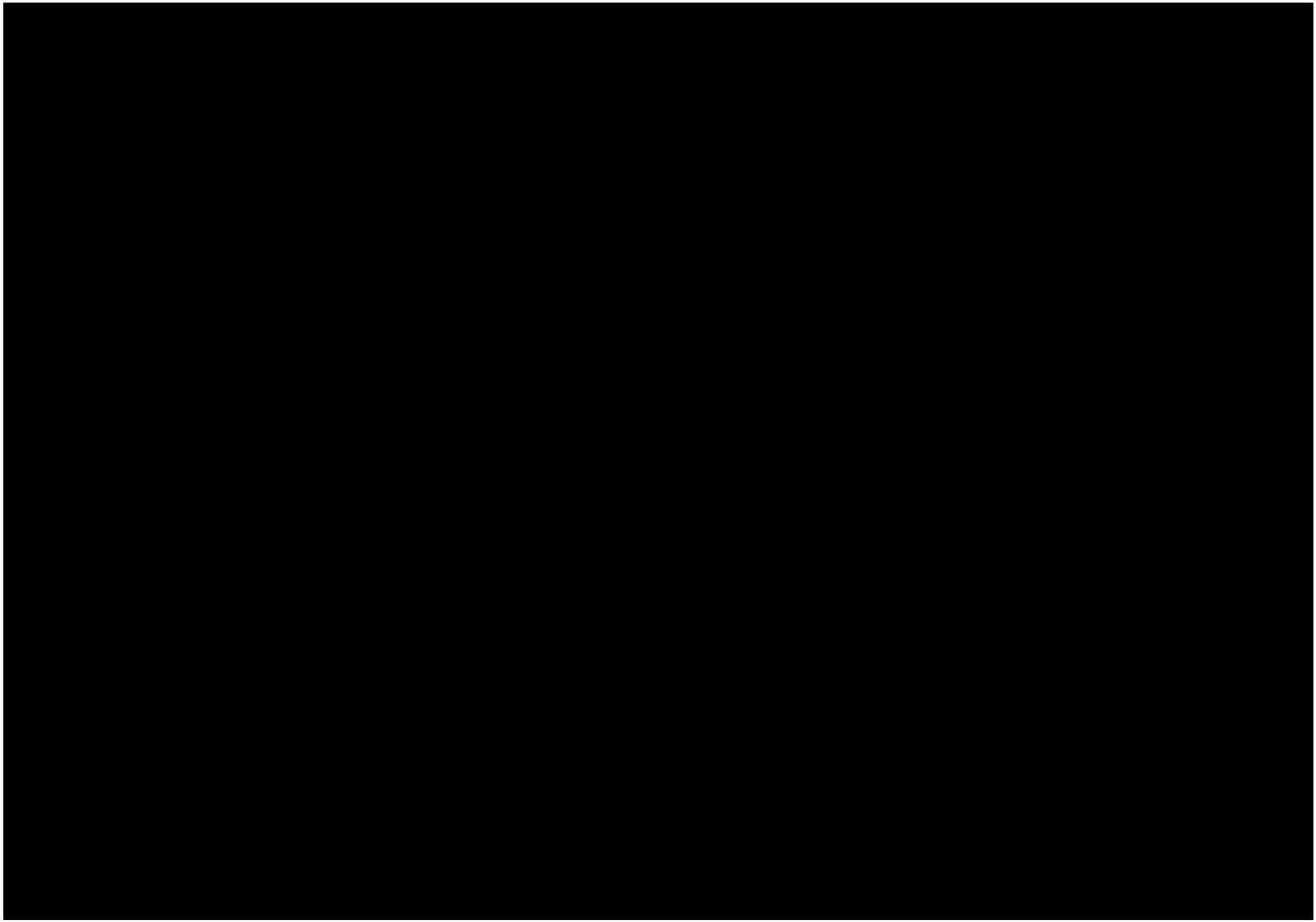
Hourly Average Day for September 2021

Southwestern Electric Cooperative, Inc.

[redacted]

Hourly Average Day for October 2021

Southwestern Electric Cooperative, Inc.



Hourly Average Day for November 2021

Southwestern Electric Cooperative, Inc.

[redacted]

Hourly Average Day for December 2021

Southwestern Electric Cooperative, Inc.

[redacted]

Hourly Average Day for January 2021

United Power, Inc.

[redacted]

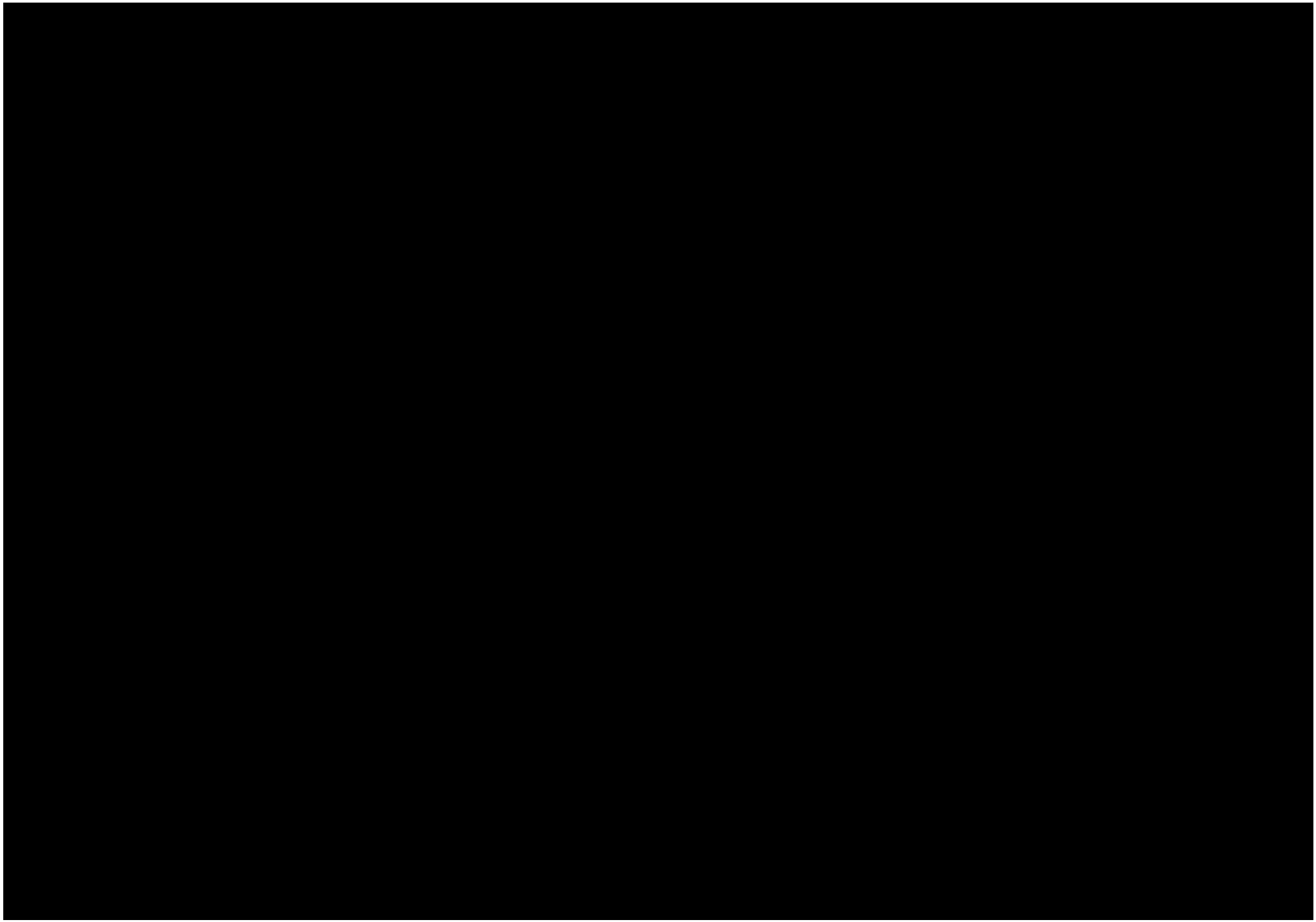
Hourly Average Day for February 2021

United Power, Inc.

[redacted]

Hourly Average Day for March 2021

United Power, Inc.



Hourly Average Day for April 2021

United Power, Inc.

[redacted]

Hourly Average Day for May 2021

United Power, Inc.

[redacted]

Hourly Average Day for June 2021

United Power, Inc.

[redacted]

Hourly Average Day for July 2021

United Power, Inc.

[redacted]

Hourly Average Day for August 2021

United Power, Inc.

[redacted]

Hourly Average Day for September 2021

United Power, Inc.

[redacted]

Hourly Average Day for October 2021

United Power, Inc.

[redacted]

Hourly Average Day for November 2021

United Power, Inc.

[redacted]

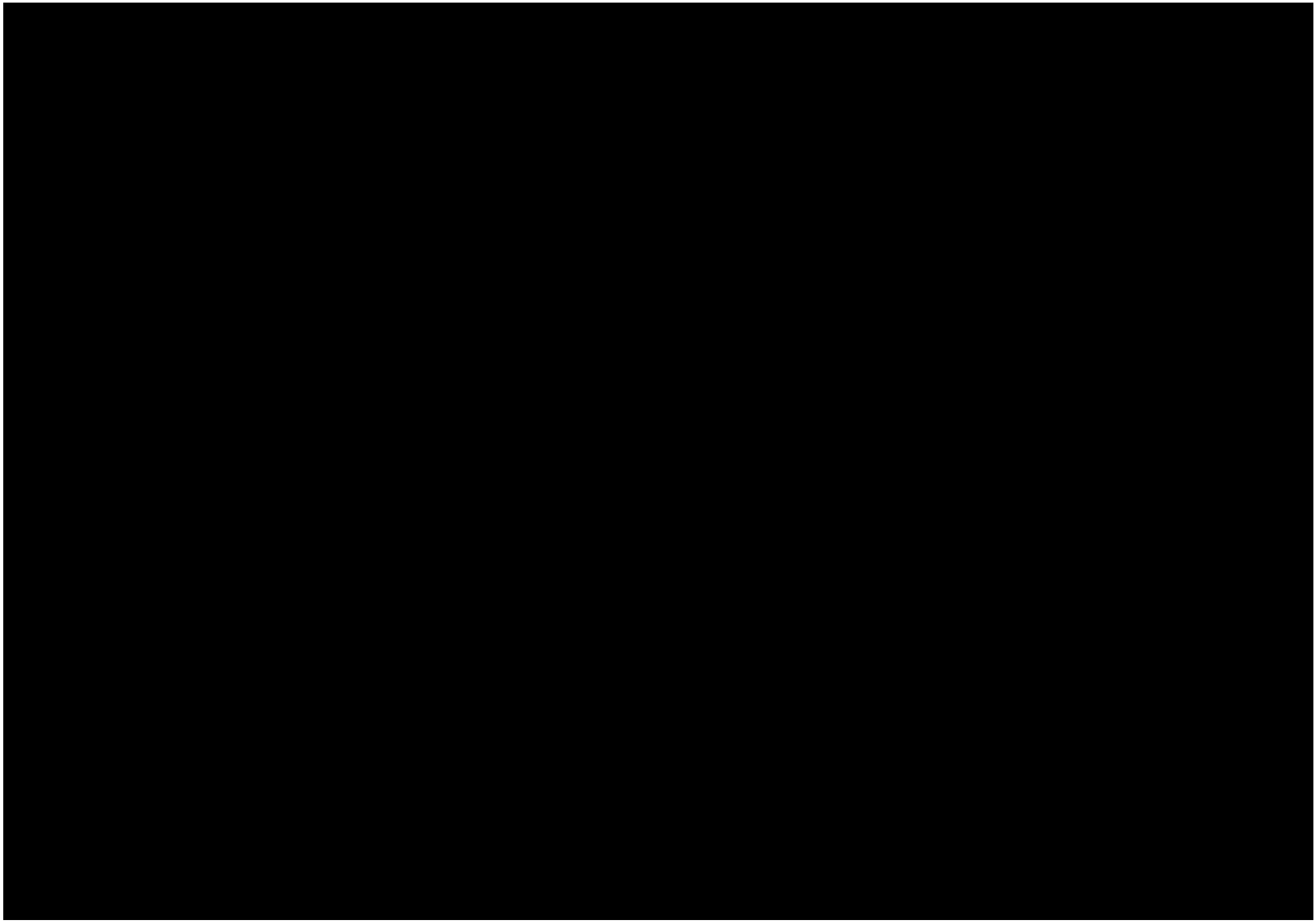
Hourly Average Day for December 2021

United Power, Inc.

[redacted]

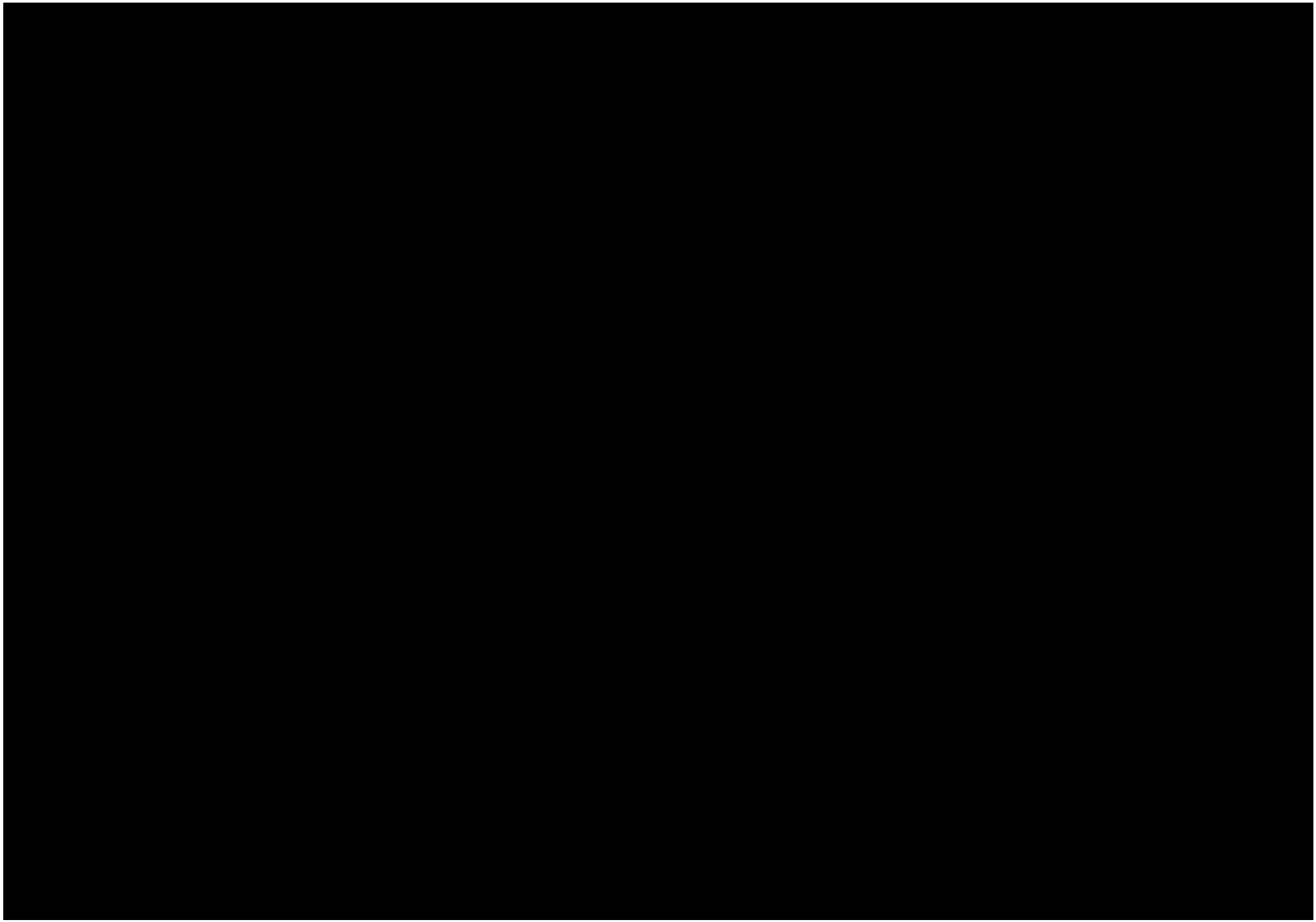
Hourly Average Day for January 2021

Wheat Belt Public Power District



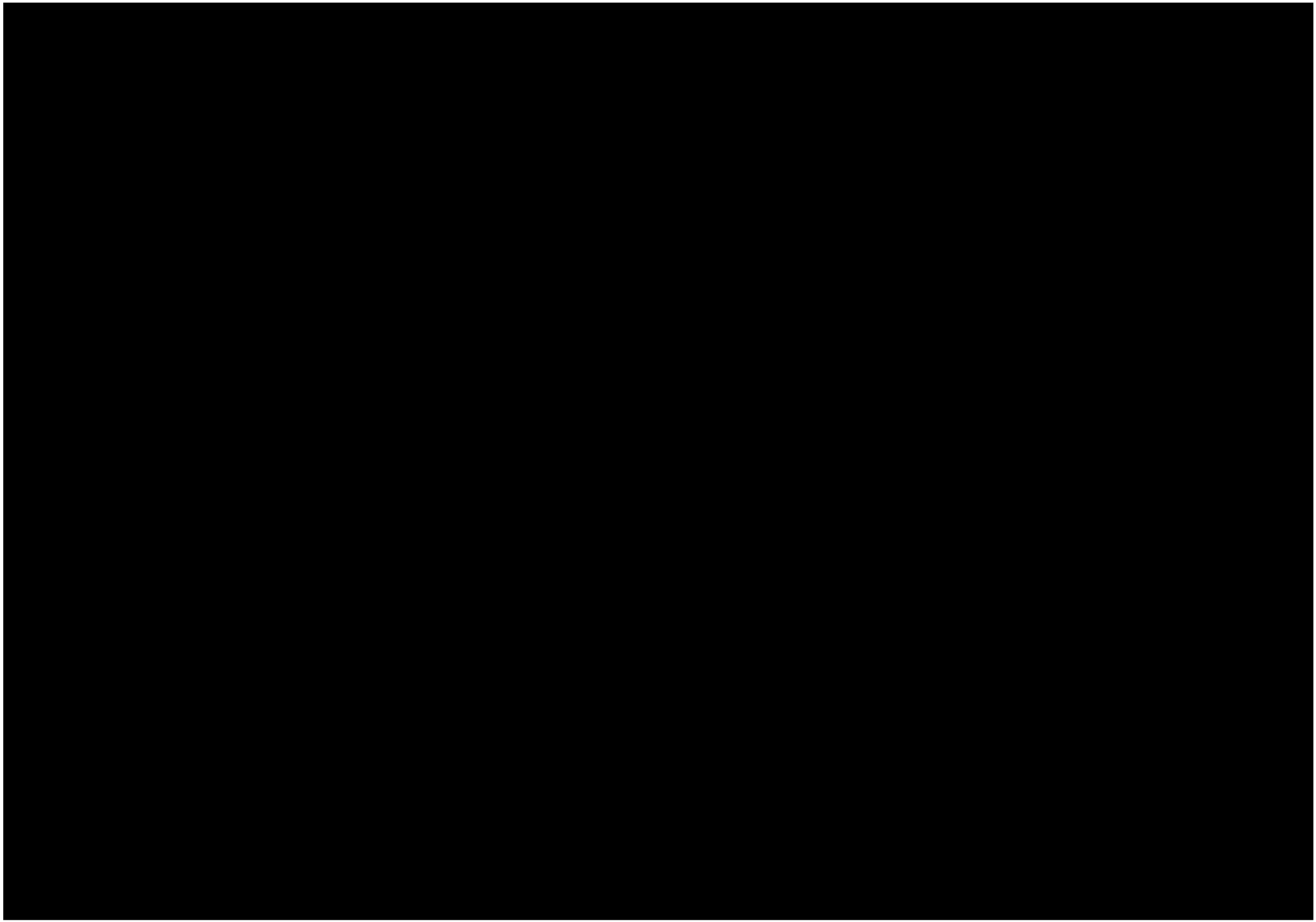
Hourly Average Day for February 2021

Wheat Belt Public Power District



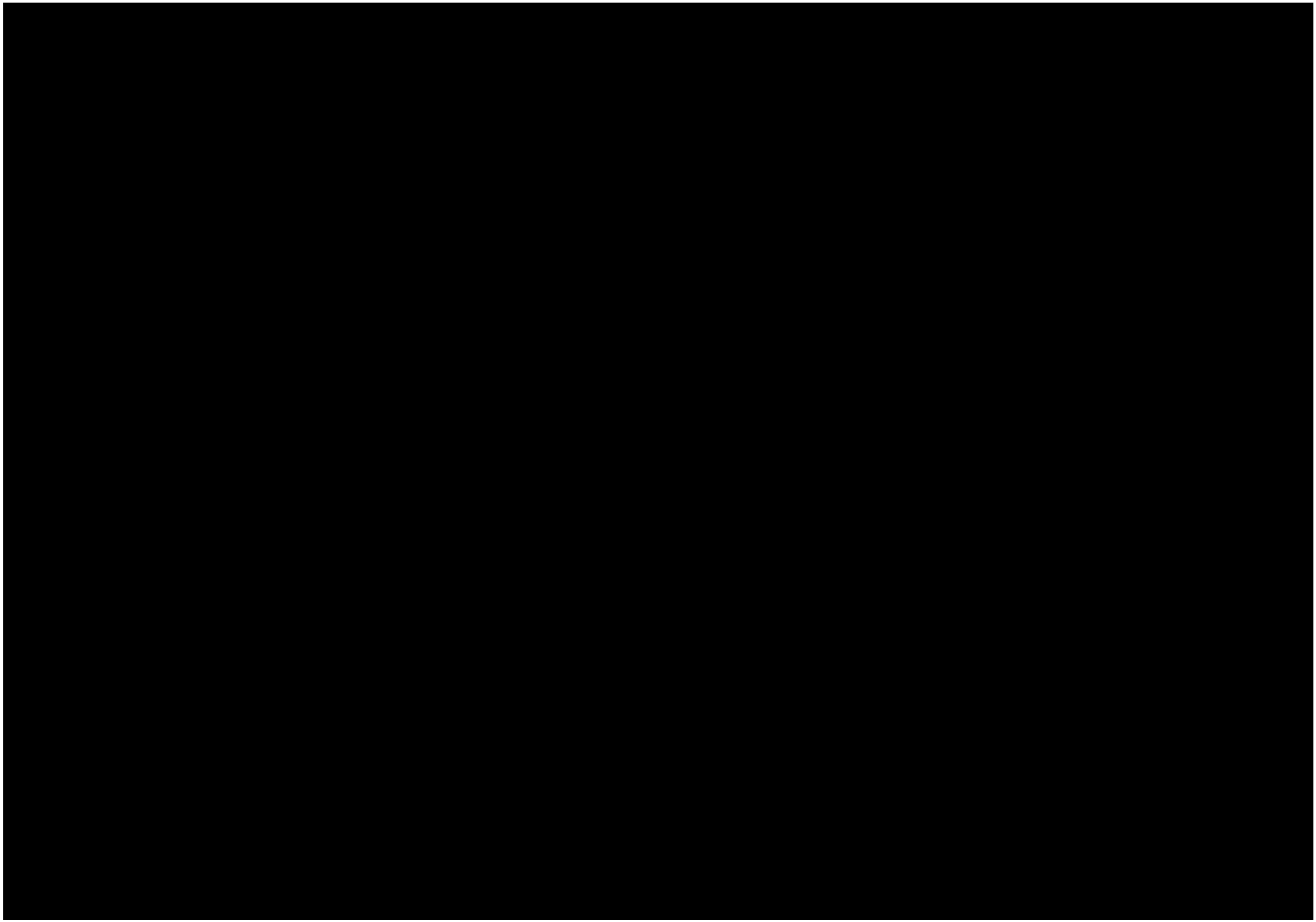
Hourly Average Day for March 2021

Wheat Belt Public Power District



Hourly Average Day for April 2021

Wheat Belt Public Power District



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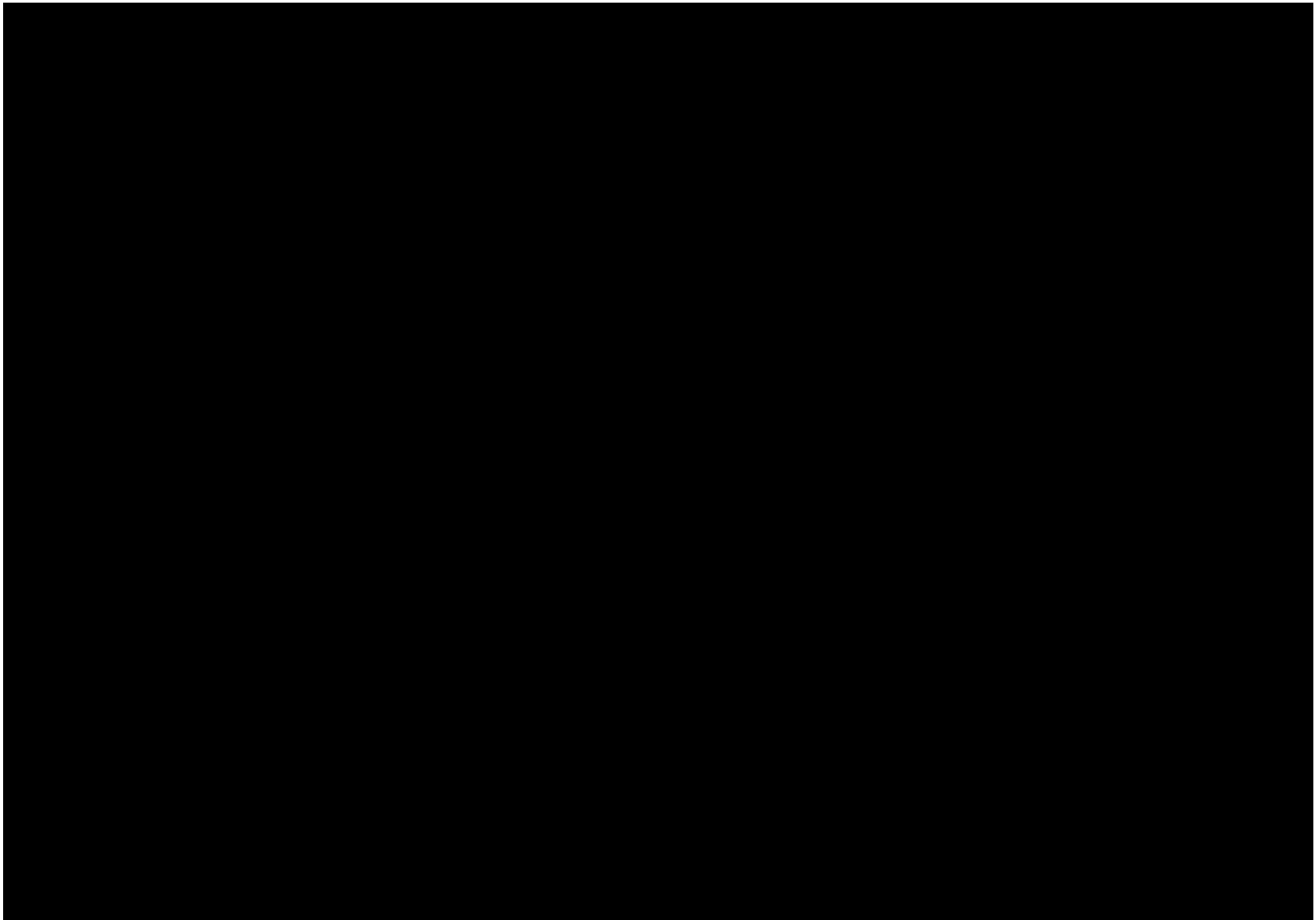
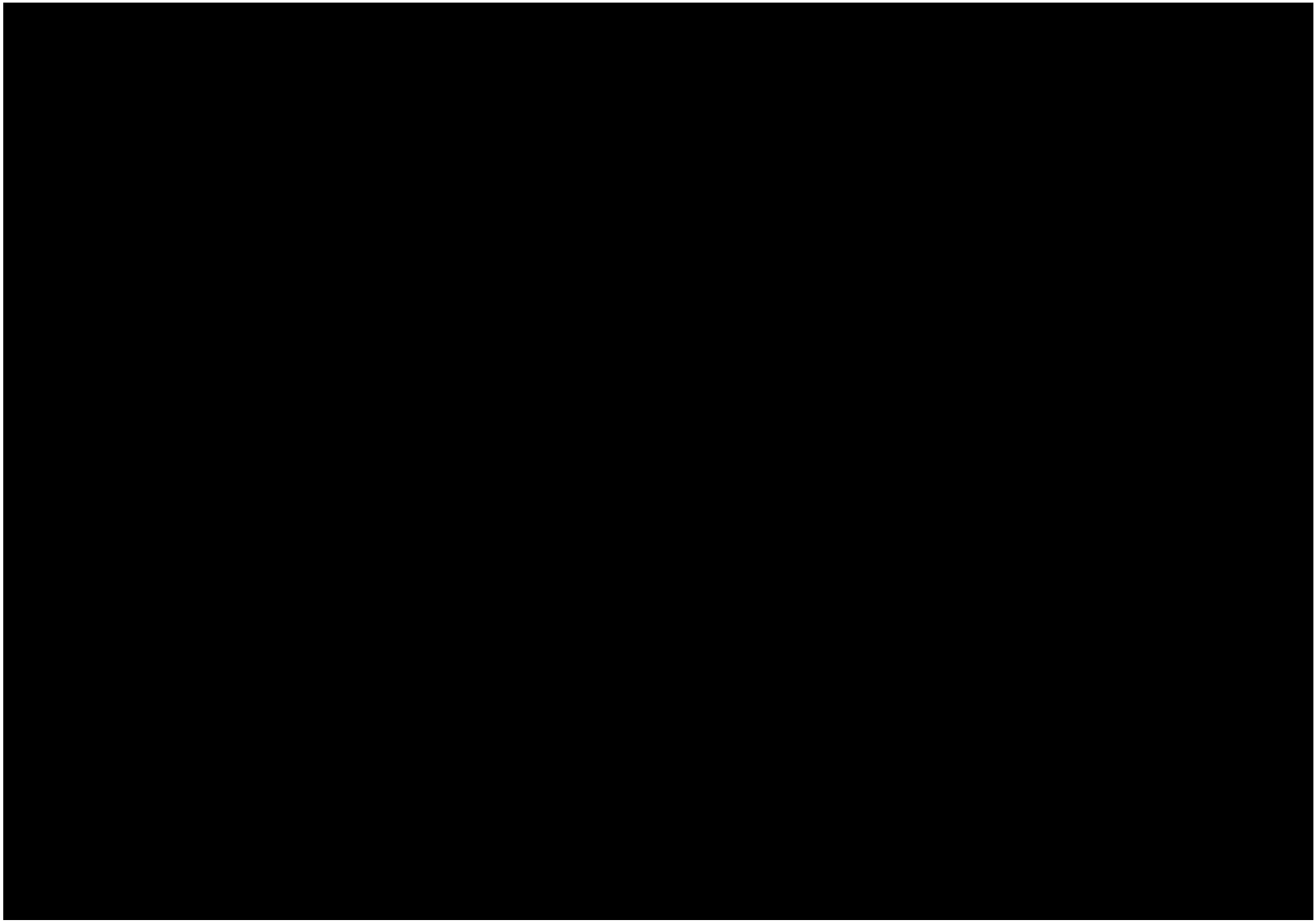
Hourly Average Day for May 2021

Wheat Belt Public Power District



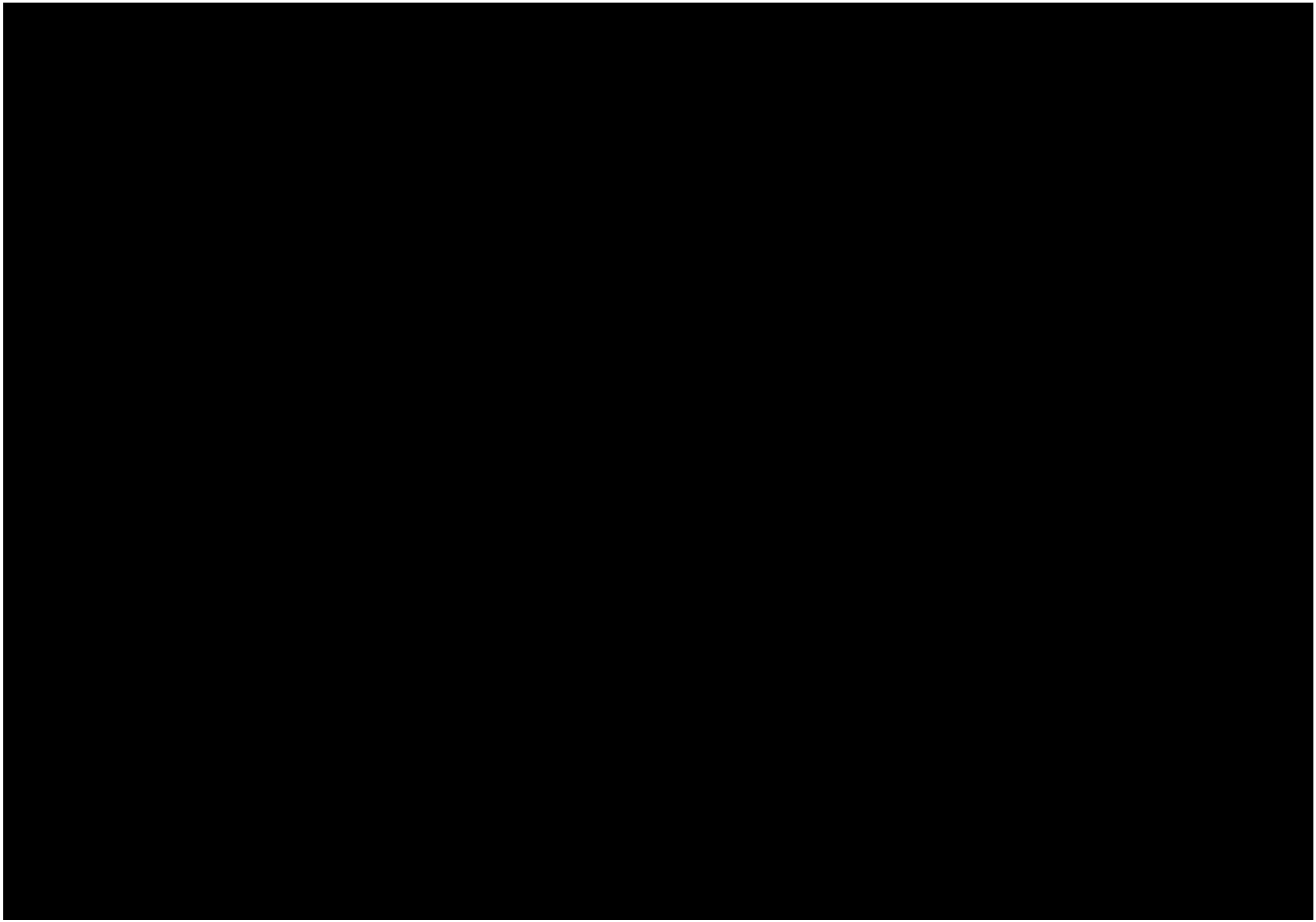
Hourly Average Day for June 2021

Wheat Belt Public Power District



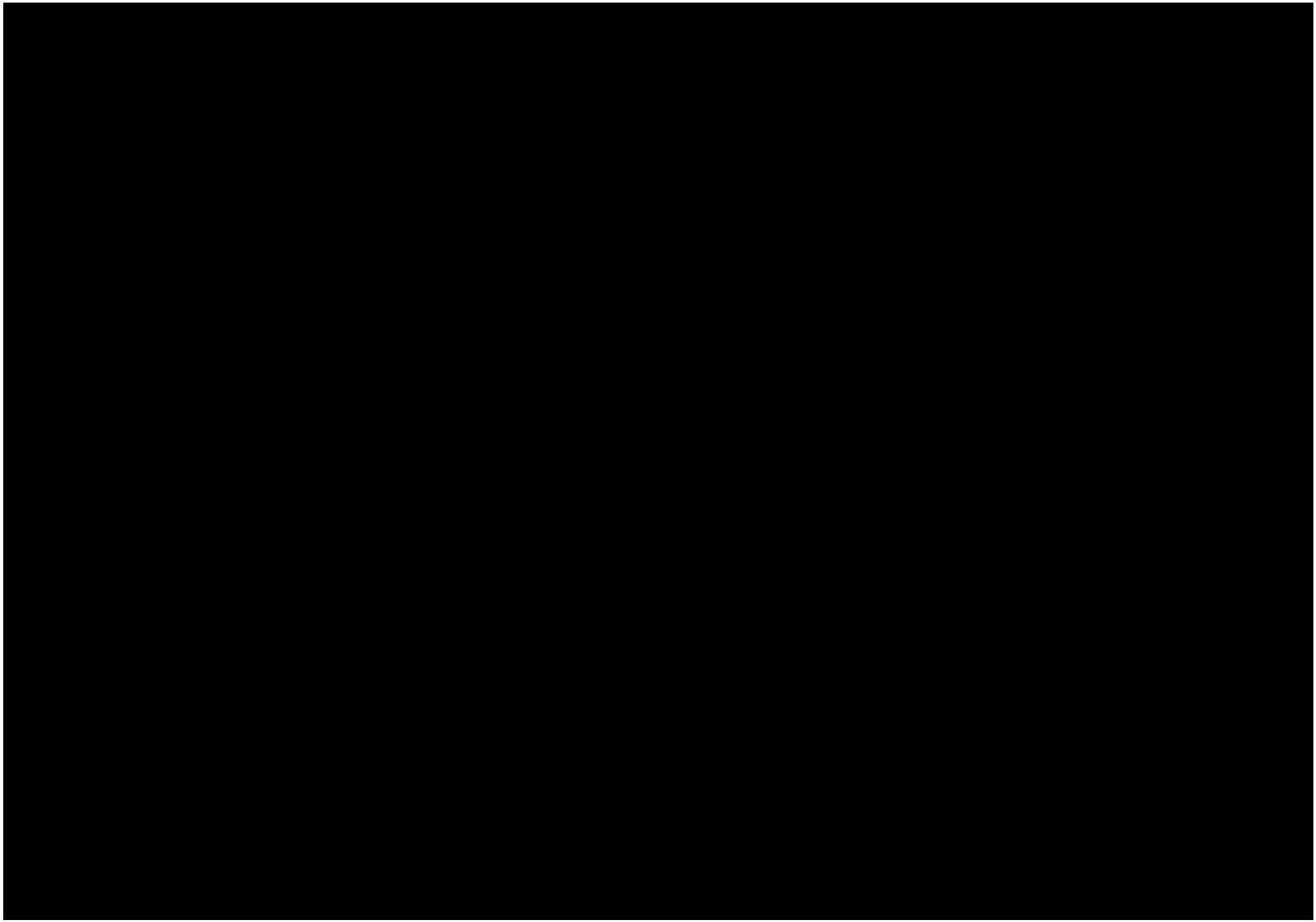
Hourly Average Day for July 2021

Wheat Belt Public Power District



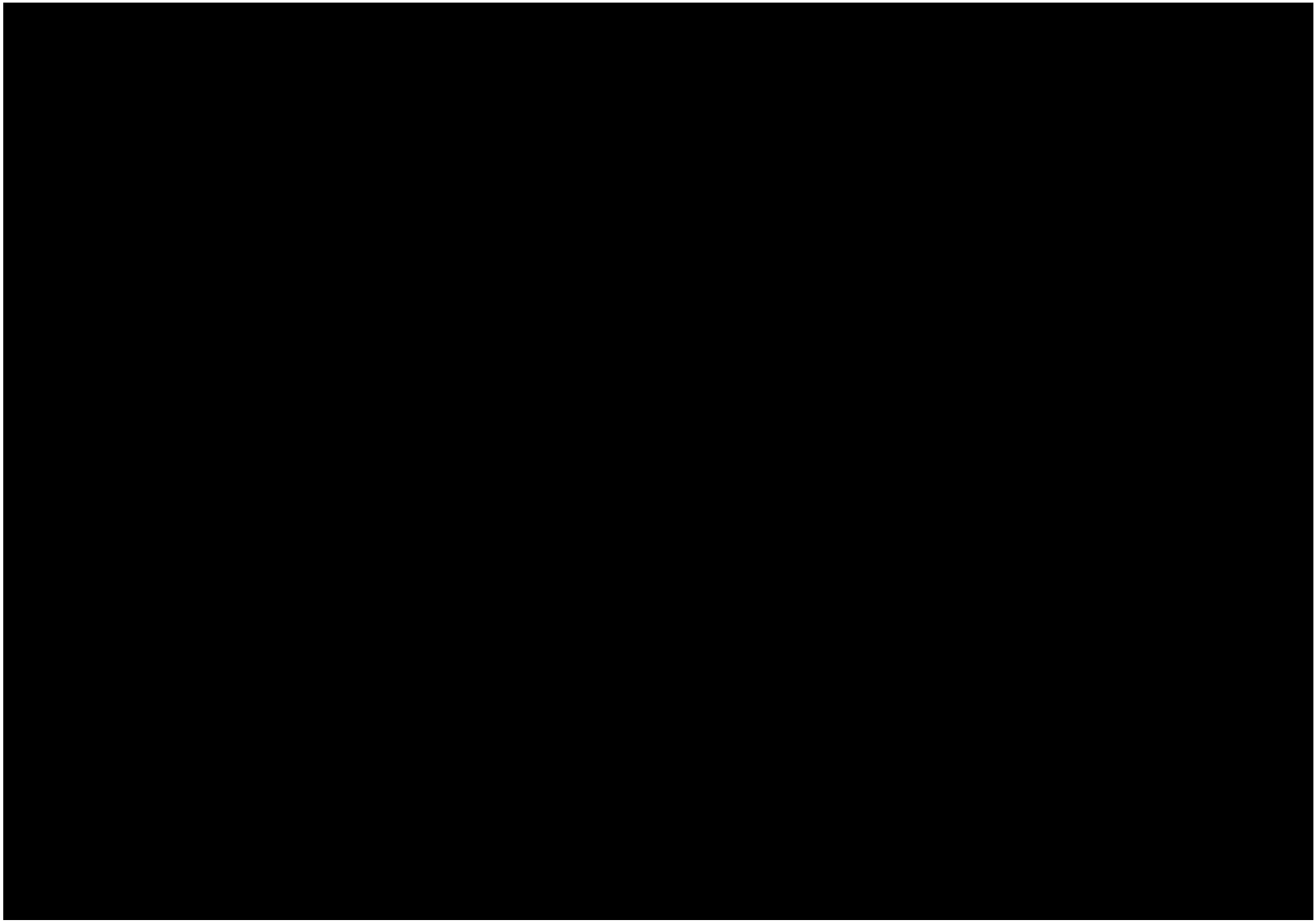
Hourly Average Day for August 2021

Wheat Belt Public Power District



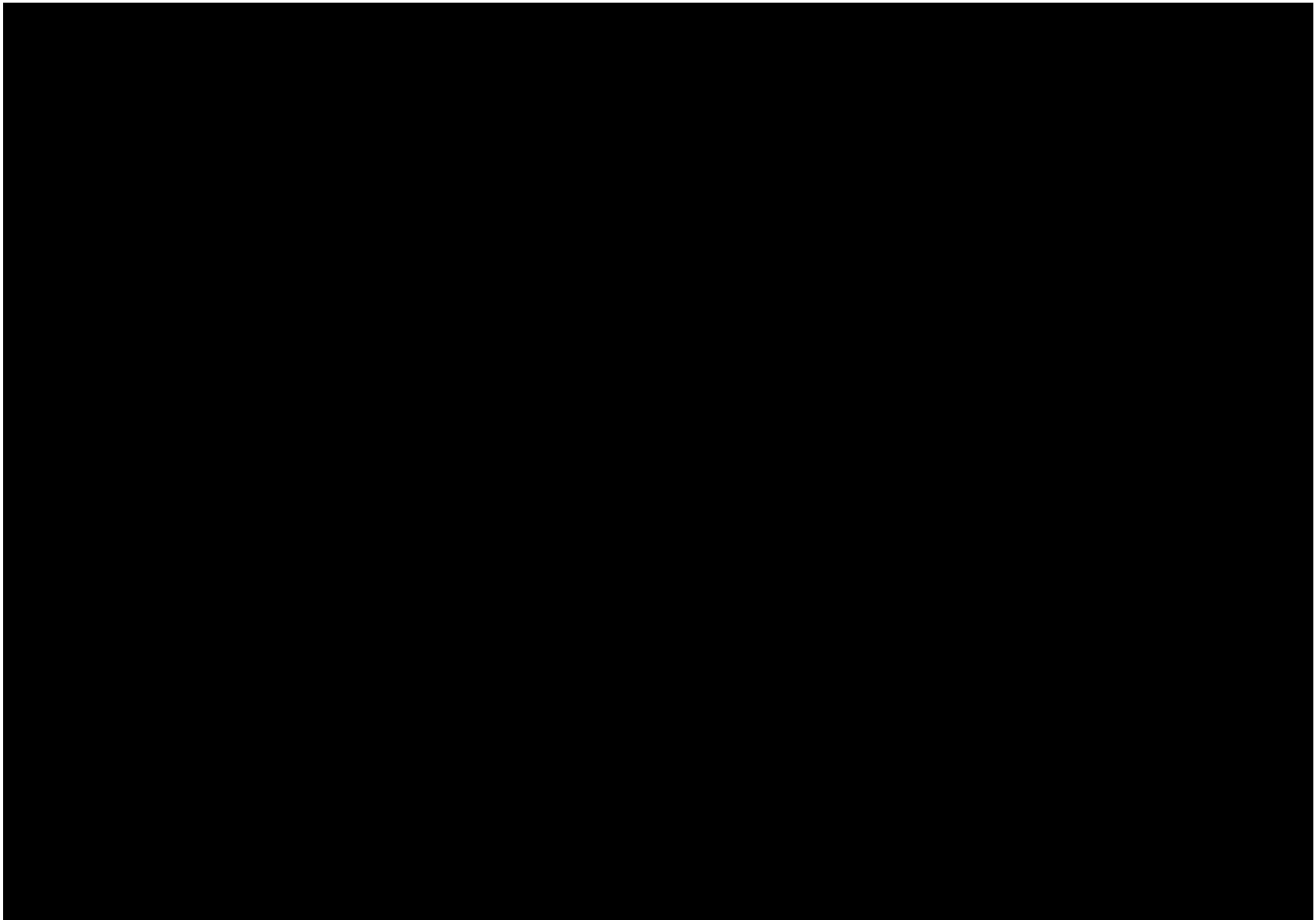
Hourly Average Day for September 2021

Wheat Belt Public Power District



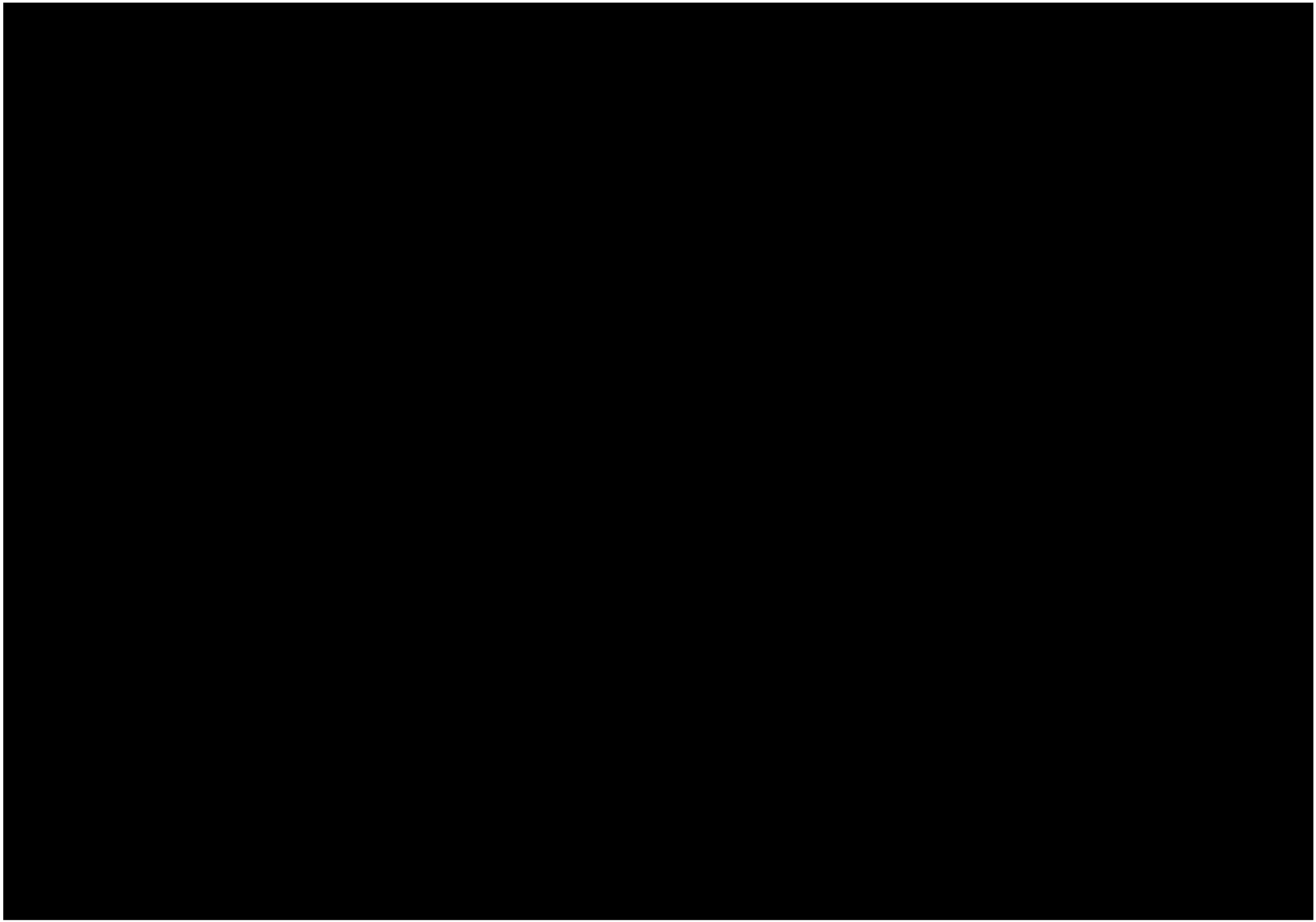
Hourly Average Day for October 2021

Wheat Belt Public Power District



Hourly Average Day for November 2021

Wheat Belt Public Power District



Hourly Average Day for December 2021

Wheat Belt Public Power District

[redacted]

Hourly Average Day for January 2021

Wheatland Rural Electric Association, Inc.

[redacted]

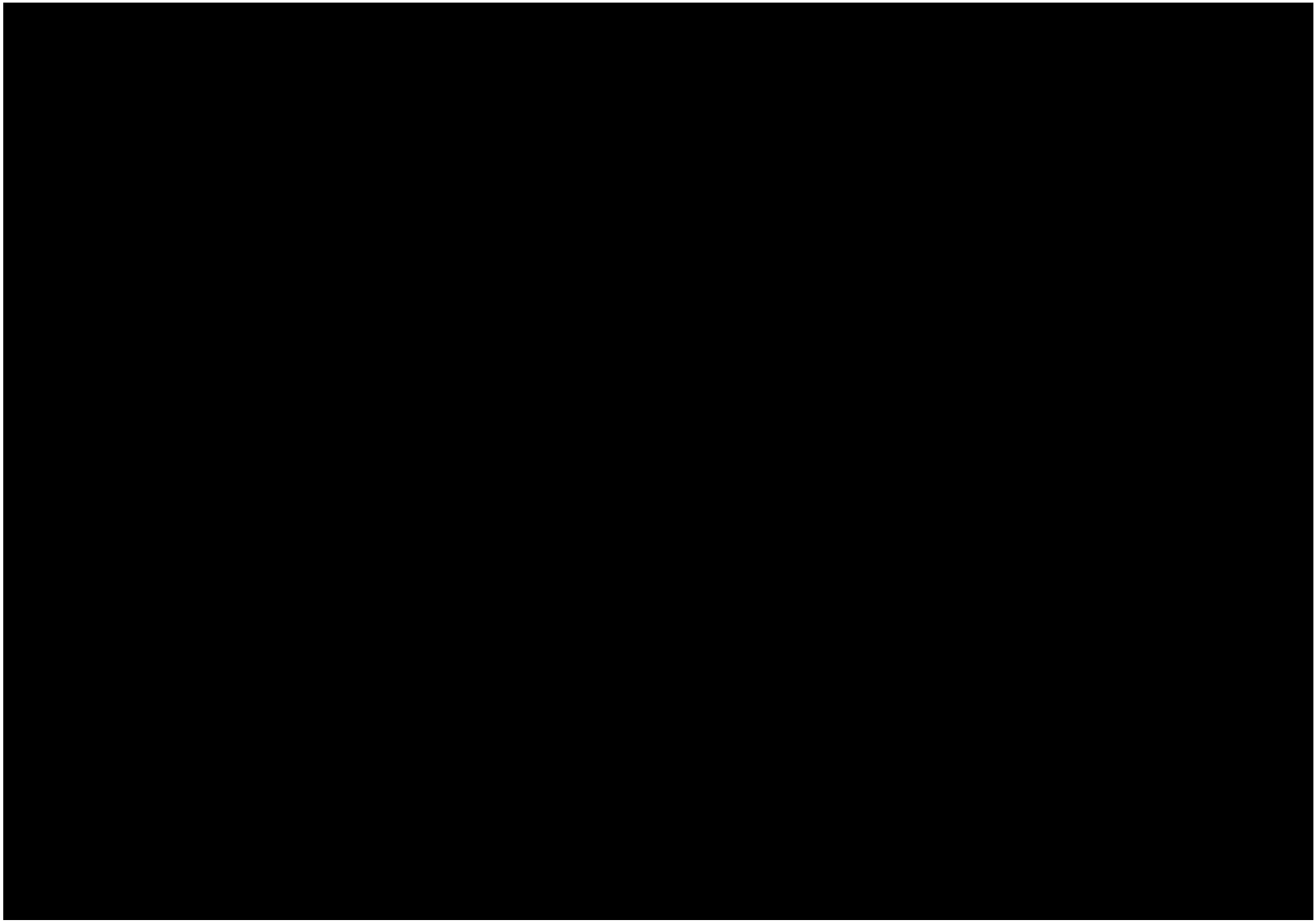
Hourly Average Day for February 2021

Wheatland Rural Electric Association, Inc.

[redacted]

Hourly Average Day for March 2021

Wheatland Rural Electric Association, Inc.



Hourly Average Day for April 2021

Wheatland Rural Electric Association, Inc.

[redacted]

Hourly Average Day for May 2021

Wheatland Rural Electric Association, Inc.

[redacted]

Hourly Average Day for June 2021

Wheatland Rural Electric Association, Inc.

[redacted]

Hourly Average Day for July 2021

Wheatland Rural Electric Association, Inc.

[redacted]

Hourly Average Day for August 2021

Wheatland Rural Electric Association, Inc.

[redacted]

Hourly Average Day for September 2021

Wheatland Rural Electric Association, Inc.

[redacted]

Hourly Average Day for October 2021

Wheatland Rural Electric Association, Inc.

[redacted]

Hourly Average Day for November 2021

Wheatland Rural Electric Association, Inc.

[redacted]

Hourly Average Day for December 2021

Wheatland Rural Electric Association, Inc.

[redacted]

Hourly Average Day for January 2021

White River Electric Association, Inc.

[redacted]

Hourly Average Day for February 2021

White River Electric Association, Inc.

[redacted]

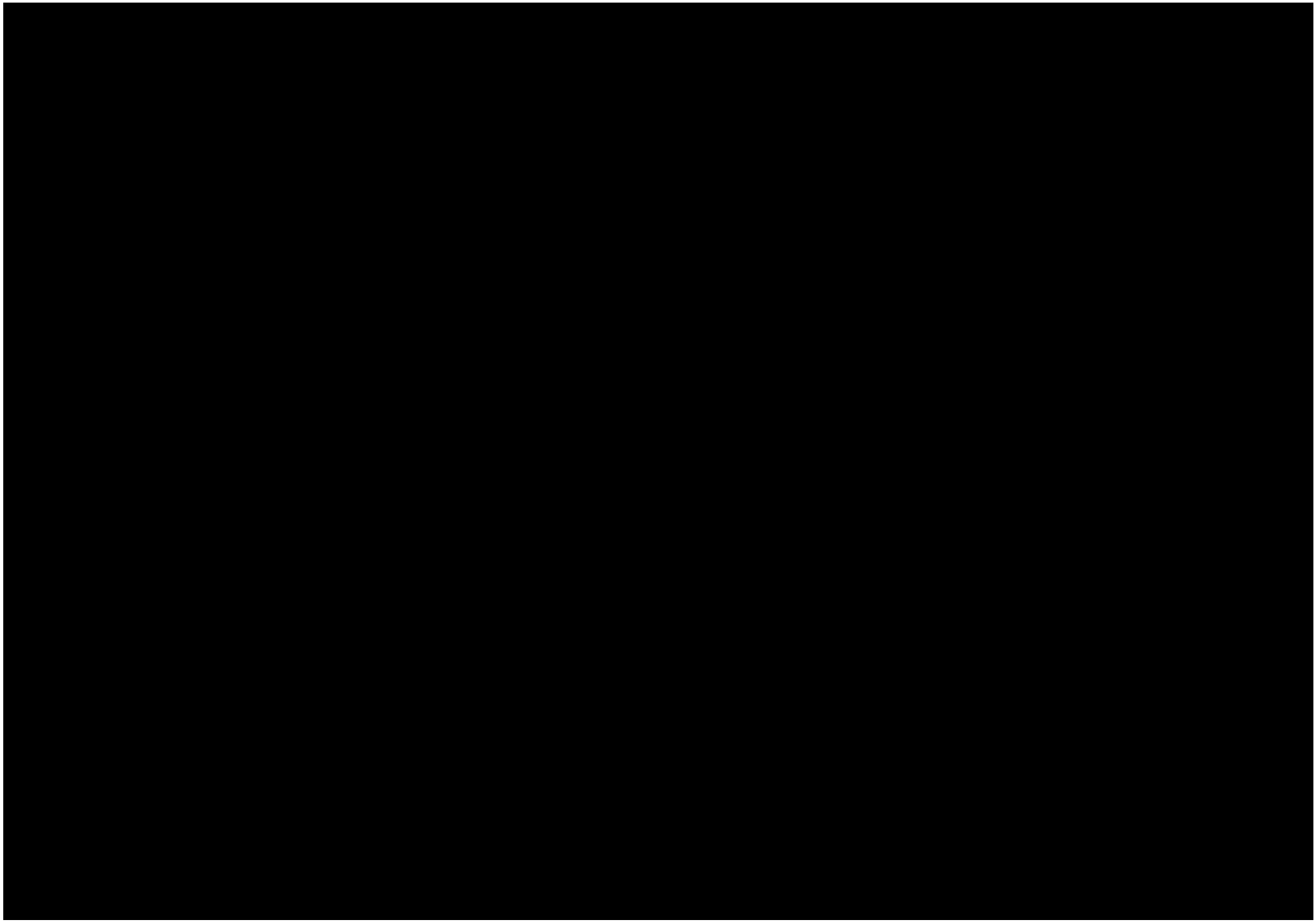
Hourly Average Day for March 2021

White River Electric Association, Inc.

[redacted]

Hourly Average Day for April 2021

White River Electric Association, Inc.



Hourly Average Day for May 2021

White River Electric Association, Inc.

[redacted]

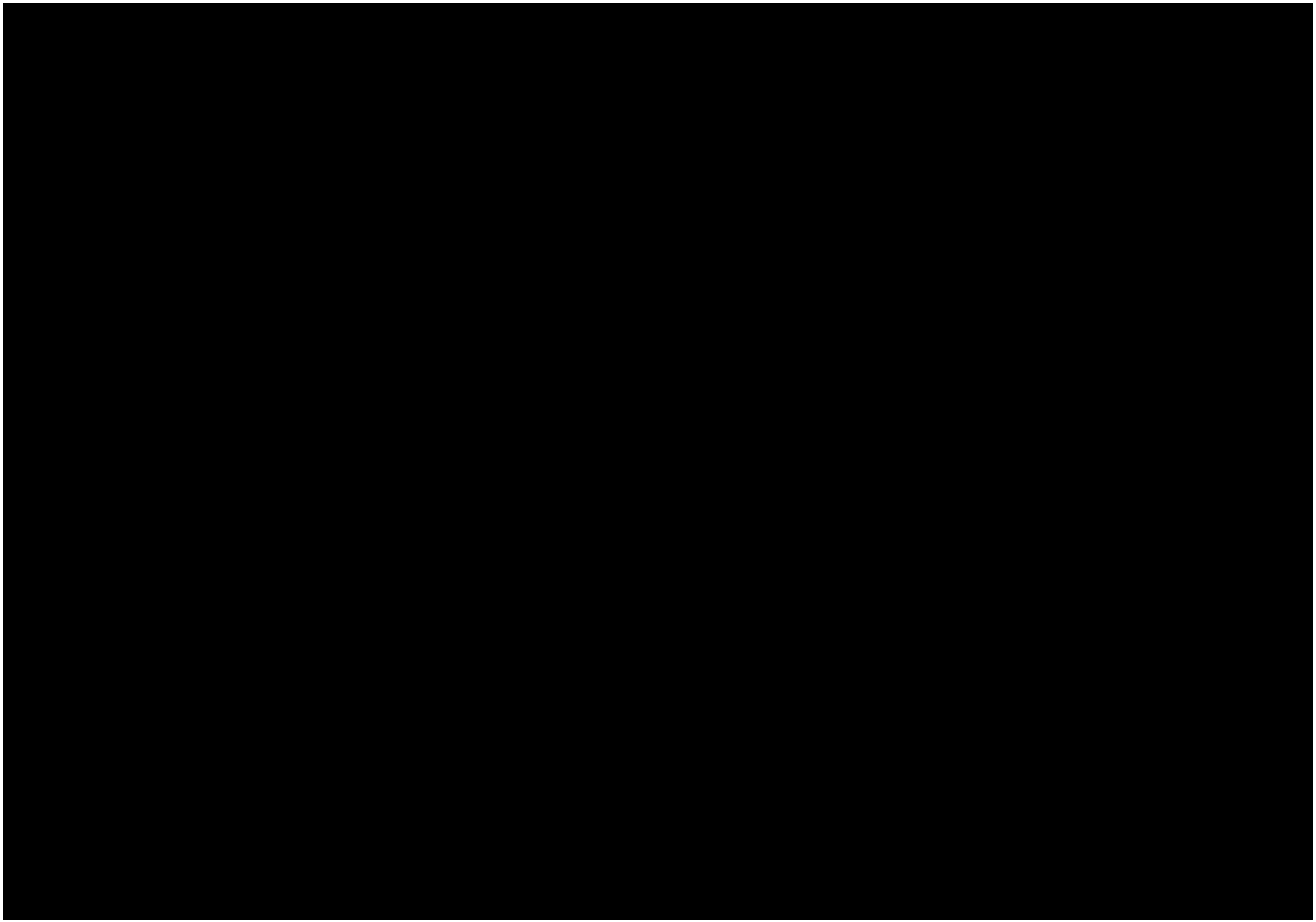
Hourly Average Day for June 2021

White River Electric Association, Inc.

[redacted]

Hourly Average Day for July 2021

White River Electric Association, Inc.



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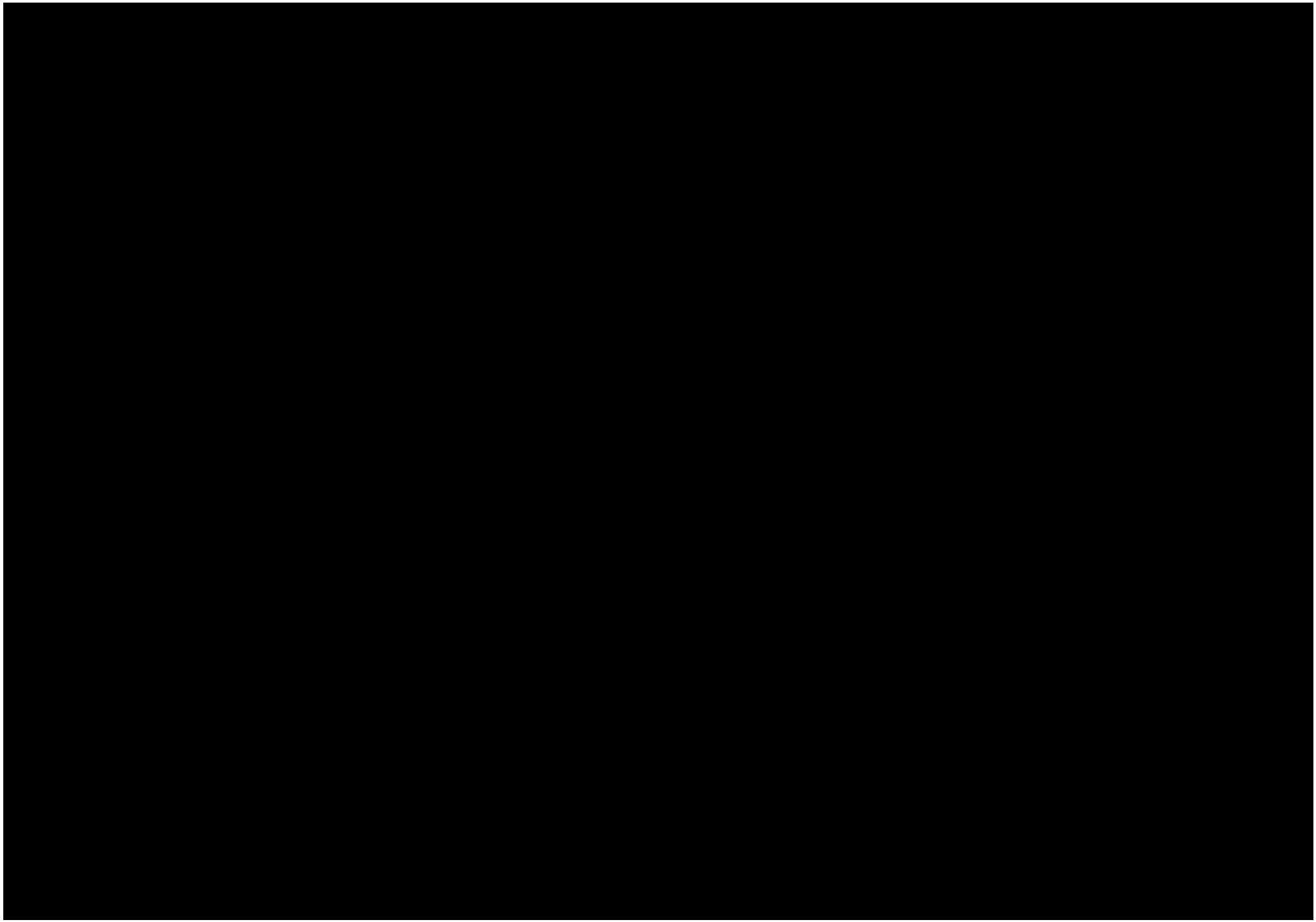
Hourly Average Day for August 2021

White River Electric Association, Inc.



Hourly Average Day for September 2021

White River Electric Association, Inc.

[redacted]

Hourly Average Day for October 2021

White River Electric Association, Inc.

[redacted]

Hourly Average Day for November 2021

White River Electric Association, Inc.

[redacted]

Hourly Average Day for December 2021

White River Electric Association, Inc.

[redacted]

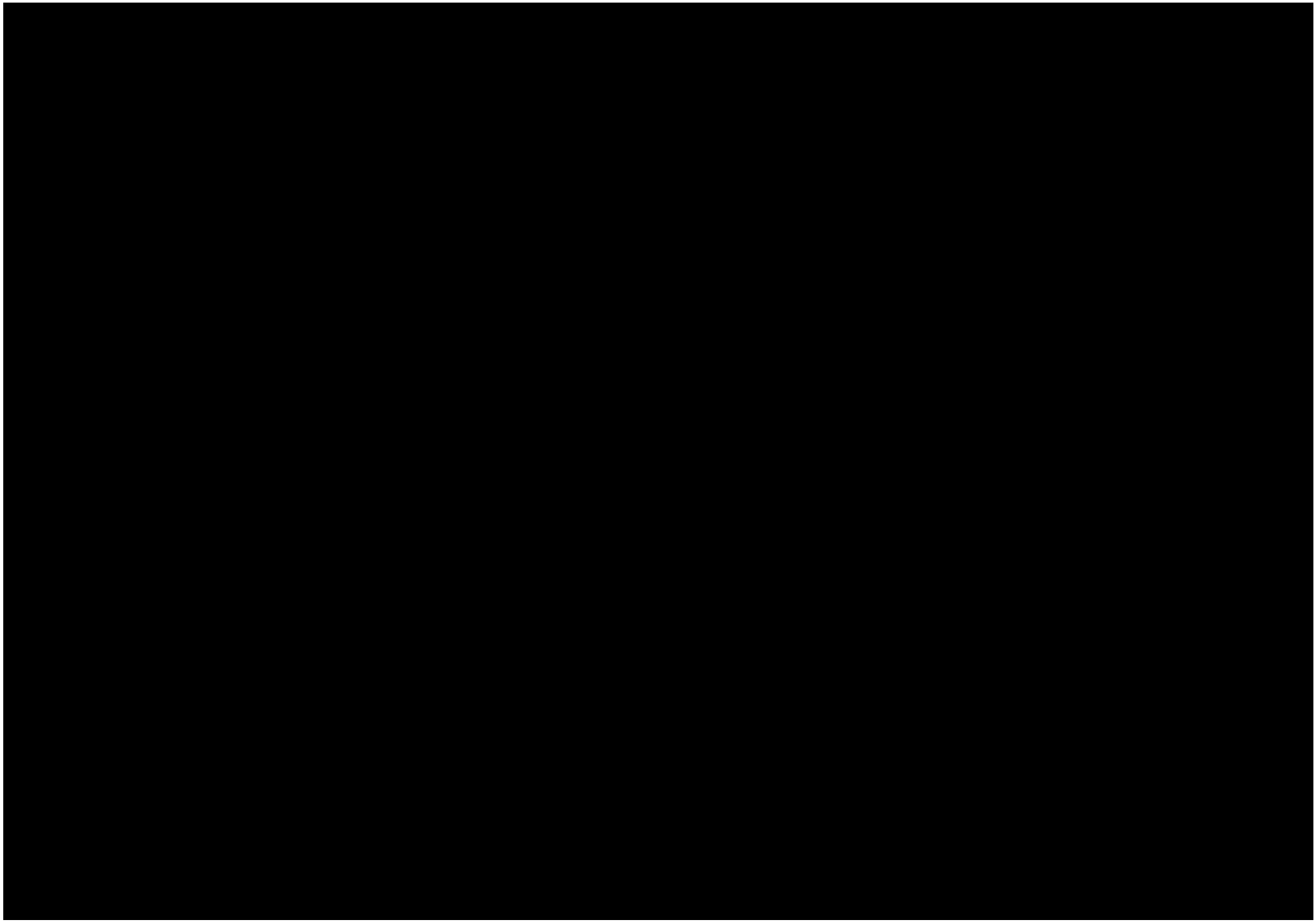
Hourly Average Day for January 2021

Wyrulec Company

[redacted]

Hourly Average Day for February 2021

Wyrulec Company



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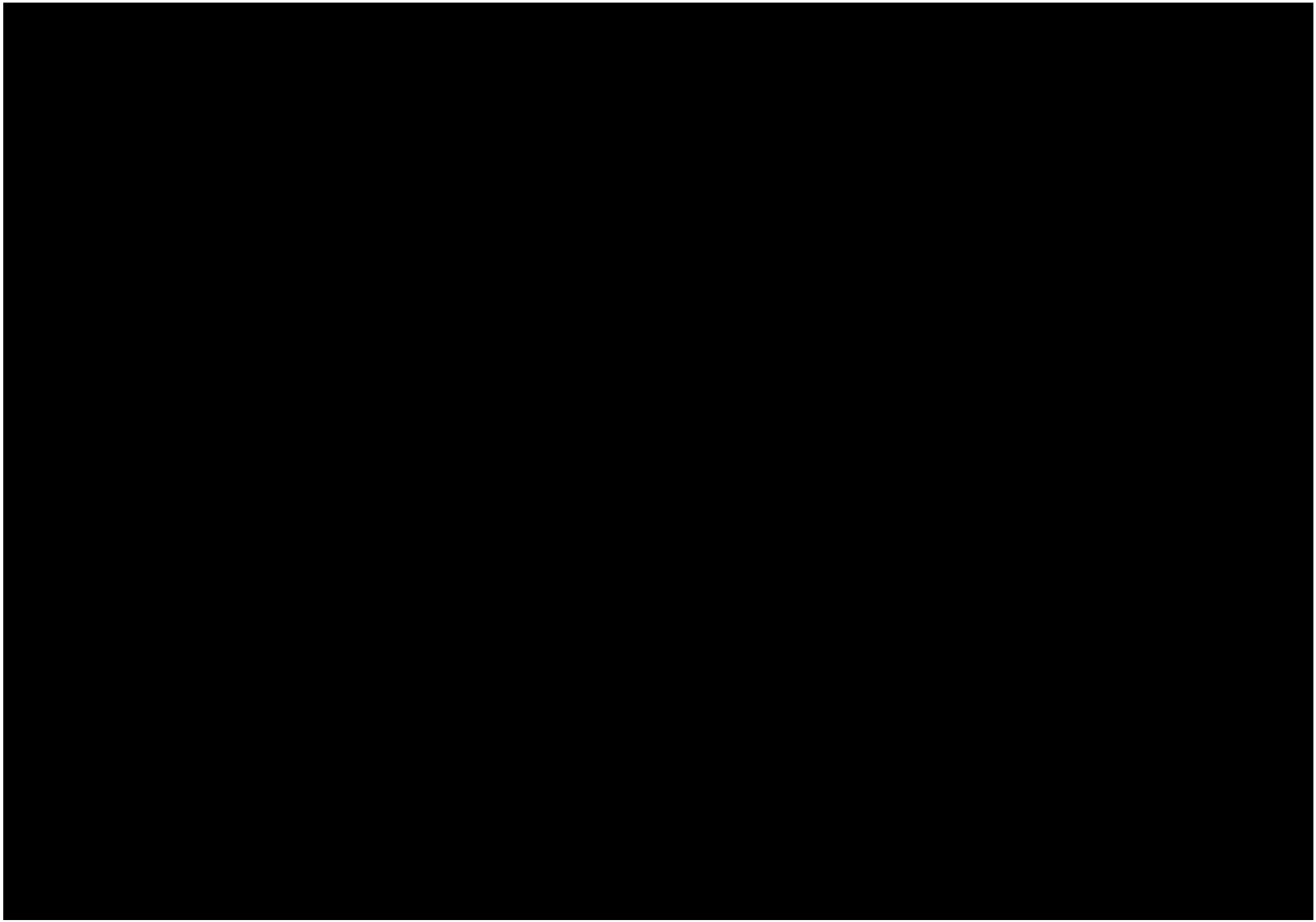
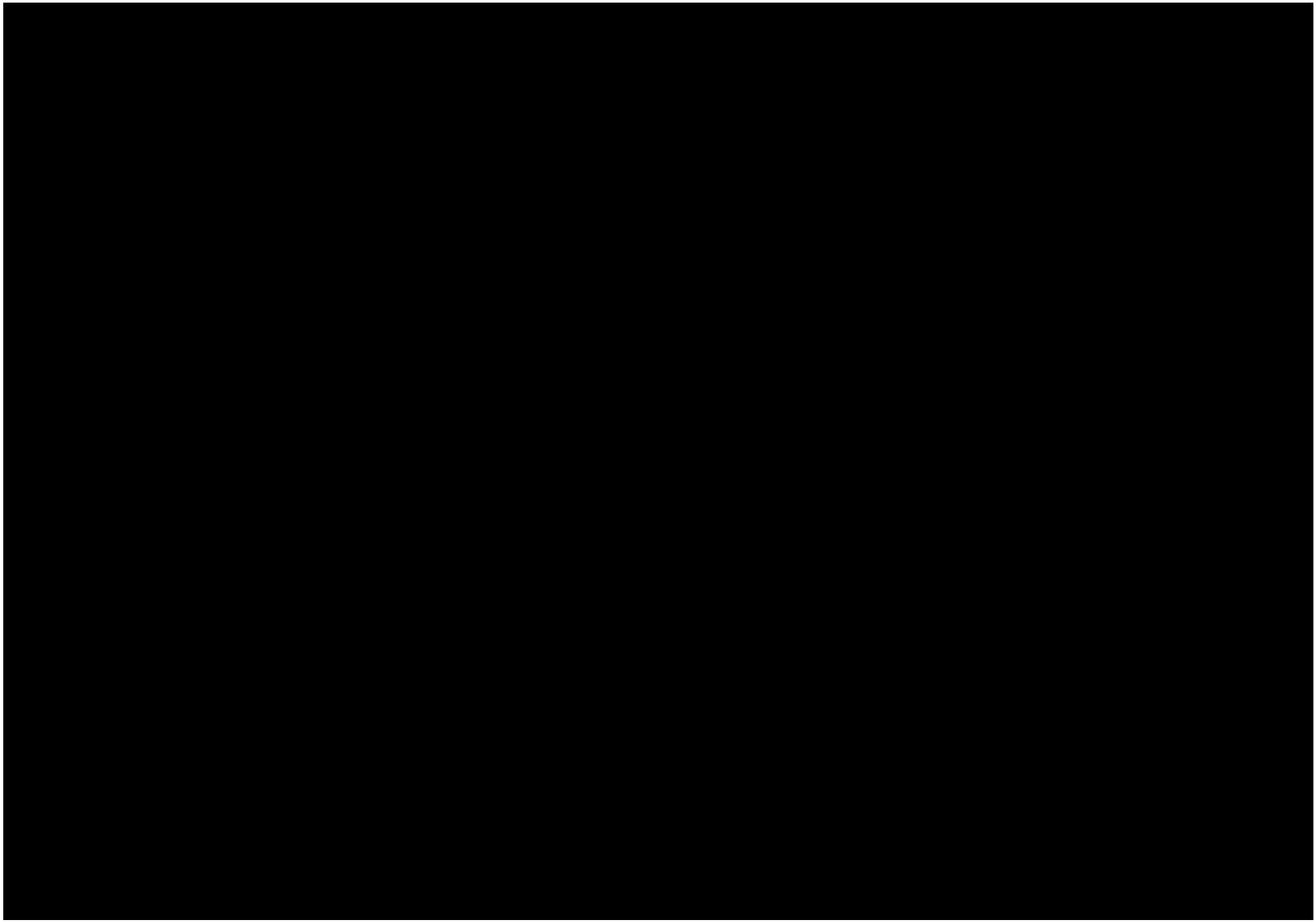
Hourly Average Day for March 2021

Wyrulec Company



Hourly Average Day for April 2021

Wyrulec Company



Hourly Average Day for May 2021

Wyrulec Company

[redacted]

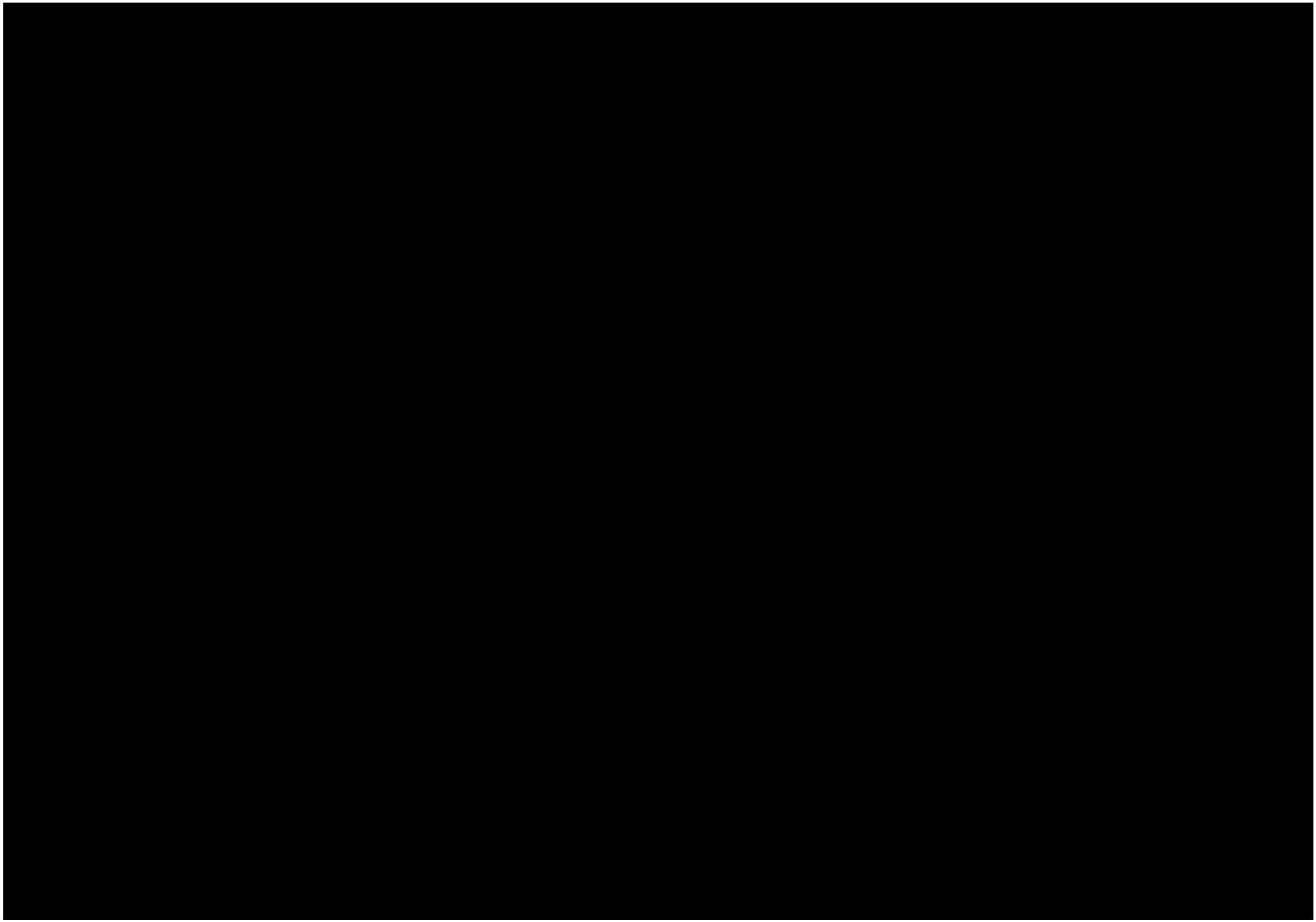
Hourly Average Day for June 2021

Wyrulec Company

[redacted]

Hourly Average Day for July 2021

Wyrulec Company



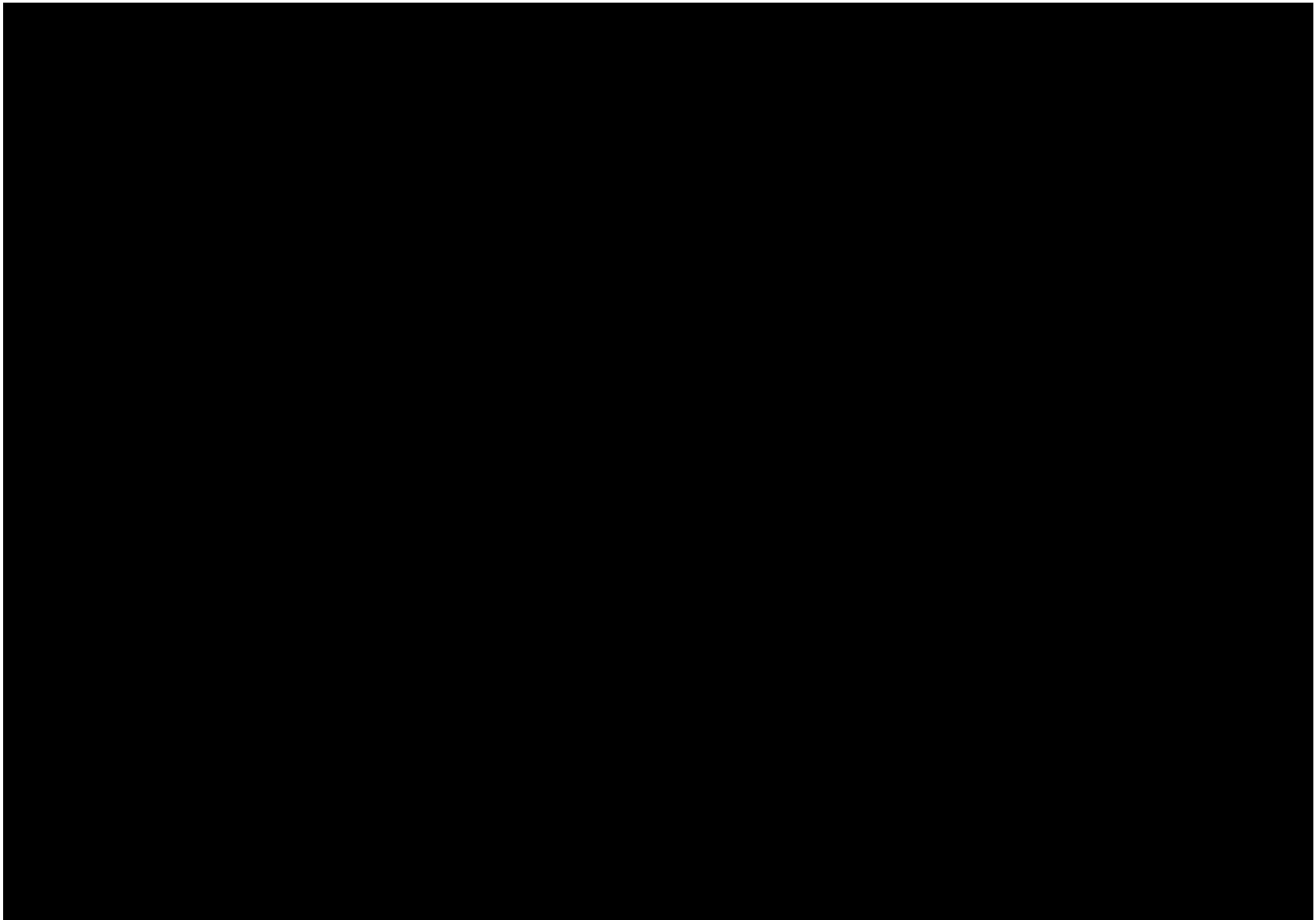
Hourly Average Day for August 2021

Wyrulec Company

[redacted]

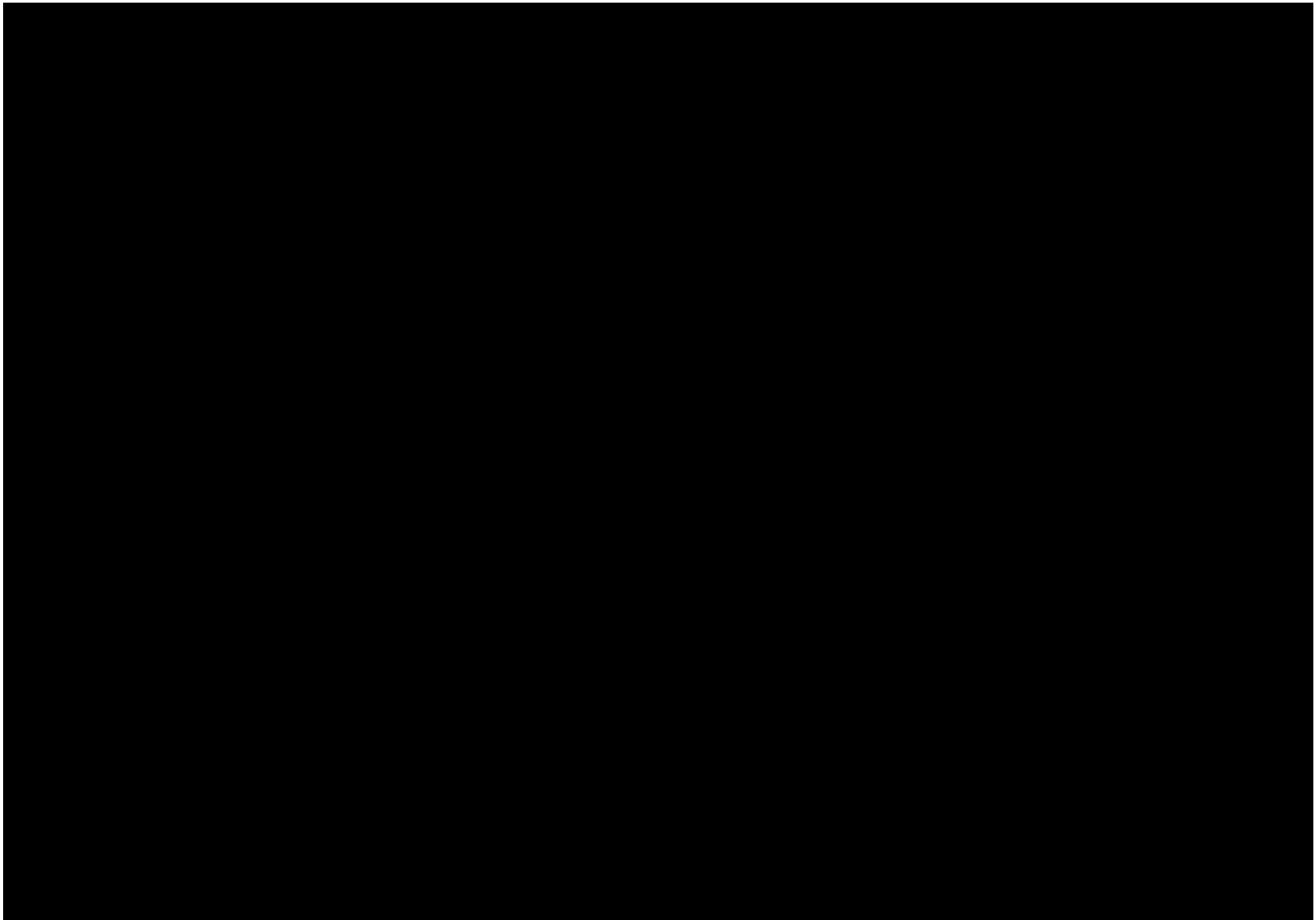
Hourly Average Day for September 2021

Wyrulec Company



Hourly Average Day for October 2021

Wyrulec Company



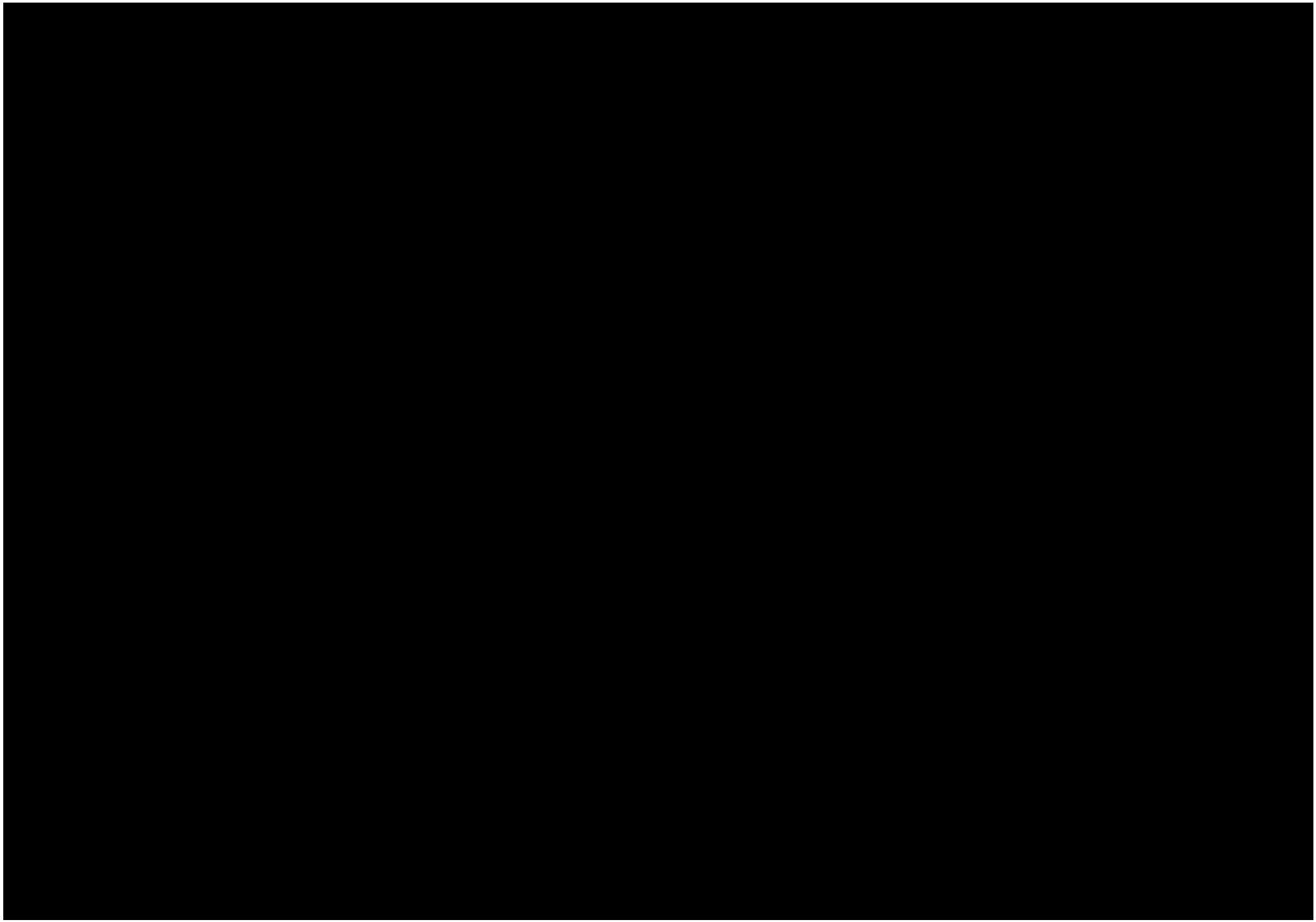
Hourly Average Day for November 2021

Wyrulec Company

[redacted]

Hourly Average Day for December 2021

Wyrulec Company



Hourly Average Day for January 2021
Y-W Electric Association, Inc.

[redacted]

Hourly Average Day for February 2021
Y-W Electric Association, Inc.

[redacted]

Hourly Average Day for March 2021

Y-W Electric Association, Inc.

[redacted]

Hourly Average Day for April 2021
Y-W Electric Association, Inc.

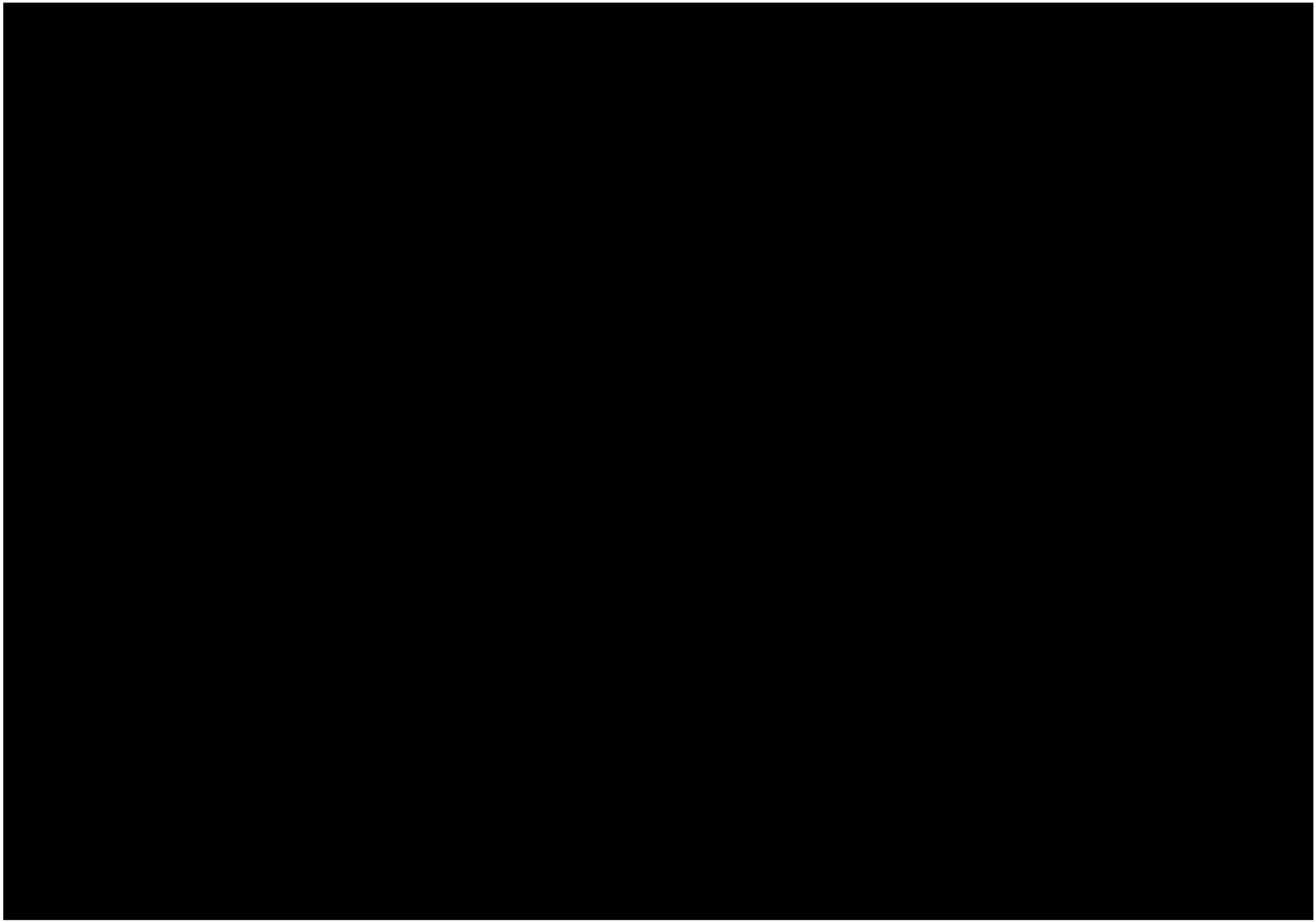
[redacted]

Hourly Average Day for May 2021

Y-W Electric Association, Inc.

[redacted]

Hourly Average Day for June 2021
Y-W Electric Association, Inc.



Hourly Average Day for July 2021

Y-W Electric Association, Inc.

[redacted]

Hourly Average Day for August 2021

Y-W Electric Association, Inc.

[redacted]

Hourly Average Day for September 2021

Y-W Electric Association, Inc.

[redacted]

Hourly Average Day for October 2021

Y-W Electric Association, Inc.

[redacted]

Hourly Average Day for November 2021

Y-W Electric Association, Inc.

[redacted]

Hourly Average Day for December 2021

Y-W Electric Association, Inc.

[redacted]

Attachment Vol II 4-1 Tri-State Facility Rating Report

TSGT 69 kV Facilities

Section	Conductor Rating MVA*	Terminal 1	Terminal 1 Equipment	Terminal 1 Rating MVA*	Terminal 1 30 Min MVA**	Terminal 2	Terminal 2 Equipment	Terminal 2 Rating MVA*	Terminal 2 30 Min MVA**
CAMT_HAMD_69_1	88	CARTER MOUNTAIN	CT	53	91	HAMILTON DOME	METER	84	84
CLAP_CLAY_69_1	32	CLAPHAM	METER	37	37	CLAYTON	***	***	***
COYJ_ABIQ_69_1	51	COYOTE JUNCTION	CT	17	18	ABIQUIU	***	***	***
COYJ_HERN_69_1	33	COYOTE JUNCTION	METER	50	50	HERNANDEZ	METER	41	41
COYJ_LJAR_69_1	33	COYOTE JUNCTION	CT	35	37	LA JARA	RELAY	35	35
CZCN_NBHL_69_1	100	CARRIZO CANYON	CT	71	94	NORTH BISCUIT HILL	***	***	***
EADS_WILC_69_1	54	EADS	***	***	***	WILLOW CREEK	RELAY	20	20
GRAN_WIGA_69_1	***	GRANBY	***	***	***	WINDY GAP	METER	42	42
GRANADA TAP_WILC_69_1	54****	GRANADA TAP	***	***	***	WILLOW CREEK	METER	31	31
HILLTOP TAP_VILA_69_1	54	HILLTOP TAP	***	***	***	VILAS	METER	42	42
HOOPER TAP_SALV_69_1	40	HOOPER TAP	***	***	***	SAN LUIS VALLEY	CT	47	50
HUGO_LIMO_69_1	32****	HUGO	***	***	***	LIMON (WACM)	CT	23	25
LAJT_LAJU_69_1	***	CITY OF LA JUNTA	***	***	***	LA JUNTA	RELAY	33	33
LBUF_CAMT_69_1	***	LITTLE BUFFALO BASI	***	***	***	CARTER MOUNTAIN	CT	23	25
MEEK_RIFP_69_1	40	MEEKER	CT	47	81	RIFLE (PSCO)	***	***	***
MONU_RUSS_69_1	***	MONUMENT	CT	59	62	RUSSELVILLE	***	***	***
RAMO_SFRK_69_1	57****	RAMON	NLSWITCH	71	87	SOUTH FORK (SLV)	***	***	***
RAMO_SFRK_69_2	57****	RAMON	NLSWITCH	71	87	SOUTH FORK (SLV)	***	***	***
SPGR_WAGM_69_1	32	SPRINGER	RELAY	17	17	WAGON MOUND	***	***	***
VILA_WLSH_69_1	54****	VILAS	METER	42	42	WALSH	METER	42	42

TSGT 115 kV Facilities

Section	Conductor Rating MVA*	Terminal 1	Terminal 1 Equipment	Terminal 1 Rating MVA*	Terminal 1 30 Min MVA**	Terminal 2	Terminal 2 Equipment	Terminal 2 Rating MVA*	Terminal 2 30 Min MVA**
AIPD_APTP_115_1	261	AIR PRODUCTS	METER	14	14	AIR PRODUCTS TAP	JUMPER	261	261
AKRO_OTIS_115_1	***	AKRON (WACM)	***	***	***	OTIS	NLSWITCH	119	119
ALGO_SYSI_115_1	74	ALGODONES (PNM)	RELAY	115	115	SAN YSIDRO	BUS	74	74
ALGR_ALGT_115_1	48	ALAMOGORDO (TS)	JUMPER	88	88	ALAMOGORDO (PNM)	JUMPER	88	88
ALGT_BLZR_115_1	167	ALAMOGORDO (PNM)	***	***	***	BLAZER	JUMPER	167	167
ALGT_HOLT_115_1	234	ALAMOGORDO (PNM)	METER	215	215	HOLLOMAN TAP	JUMPER	234	234
ALKA_CRBU_115_1	143	ALKALI	JUMPER	229	229	CRESTED BUTTE	NLSWITCH	119	145
ALKA_SKIT_115_1	143	ALKALI	JUMPER	229	229	SKITO	METER	36	36
ALTP_CABA_115_1	47	ALTA LUNA TAP	JUMPER	88	88	CABALLO	RELAY	110	110
ALTP_MIMB_115_1	47	ALTA LUNA TAP	JUMPER	88	88	MIMBRES (PNM)	***	***	***
ALVI_CRSW_115_1	97	ALVIN	BUS	99	99	CRETE SWITCH	SWITCH	119	145

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TSGT 115 kV Facilities

PUBLIC

Section	Conductor Rating MVA*	Terminal 1	Terminal 1 Equipment	Terminal 1 Rating MVA*	Terminal 1 30 Min MVA**	Terminal 2	Terminal 2 Equipment	Terminal 2 Rating MVA*	Terminal 2 30 Min MVA**
ALVI_SAND_115_1	97	ALVIN	BUS	99****	99****	SANDHILLS	JUMPER	175	175
ALVI_WAUN_115_1	68	ALVIN	BUS	99****	99****	WAUNETA	JUMPER	119	119
AMBR_TAYL_115_1	***	AMBROSIA LAKE (PNM	***	***	***	TAYLOR	NLSWITCH	119	145
AMES_BUBR_115_1	143	AMES (PSCO)	JUMPER	170	170	BURRO BRIDGE	NLSWITCH	119	145
AMES_SUNT_115_1	143	AMES (PSCO)	JUMPER	170	170	SUNSHINE	JUMPER	170	170
AMOE_BAYF_115_1	***	AMOCO EAST	***	***	***	BAYFIELD	METER	129	129
ANSZ_DOCN_115_1	142****	ANASAZI	JUMPER	315	315	DOE CANYON	JUMPER	170****	170****
ANSZ_YJSW_115_1	142****	ANASAZI	JUMPER	315	315	YELLOW JACKET SWIT	SWITCH	119****	145****
ANTO_ARIC_115_1	56	ANTON	SWITCH	119	145	ARICKAREE	JUMPER	92	92
ANTO_LDTP_115_1	68	ANTON	SWITCH	119	145	LINDON TAP	JUMPER	175	175
APTP_DOCN_115_1	261	AIR PRODUCTS TAP	JUMPER	261	261	DOE CANYON	CT	79	135
ARAP_WAAN_115_1	64	ARAPAHOE	JUMPER	118	118	WAANIBE	JUMPER	118	118
ARCH_MYRT_115_1	***	ARCHER (WACM)	***	***	***	MYERS TAP	JUMPER	175	175
ARCO_WALT_115_1	***	ARCO	***	***	***	WALSENBURG	CT	29	32
ARIC_JOES_115_1	97	ARICKAREE	SWITCH	119	145	JOES	RELAY	148	148
ARTH_HYAN_115_1	87	ARTHUR	SWITCH	119	145	HYANNIS	CT	7	12
ARTH_MCCO_115_1	87	ARTHUR	SWITCH	119	145	MCCONAUGHY	SWITCH	119	145
ATHE_CRET_115_1	147	ATHEY (IPPD)	***	***	***	CRETE	BUS	175****	175****
ATHE_ENDE_115_1	147	ATHEY (IPPD)	***	***	***	ENDERS (NPPD)	METER	207	207
AULT_BLAC_115_1	***	AULT (WACM)	***	***	***	BLACKHOLLOW	SWITCH	239	268
AULT_PIER_115_1	244	AULT (WACM)	***	***	***	PIERCE	JUMPER	244	244
BAYF_PAGO_115_1	85	BAYFIELD	NLSWITCH	119	145	PAGOSA	CT	39	67
BECK_BECT_115_1	271	BEAVER CREEK (WAC	SWITCH	239	291	BEAVER CREEK (TS)	JUMPER	324	324
BELL_BLVT_115_1	56	BELLEVUE	JUMPER	92	92	BELLVUE TAP	JUMPER	92	92
BELT_BERN_115_1	74	BELEN SWITCH (PNM)	RELAY	79	79	BERNARDO	BUS	148	148
BELT_WSWT_115_1	***	BELEN SWITCH (PNM)	METER	199	199	WILLARD SWITCH	BUS	197	216
BERN_SOCO_115_1	74	BERNARDO	BUS	148	148	SOCORRO	METER	90	90
BETH_ECKL_115_1	68	BETHEL	SWITCH	119	119	ECKLEY	RELAY	113	113
BETH_VRNN_115_1	68	BETHEL	SWITCH	119	119	VERNON	SWITCH	119	119
BFOR_BLACK FOREST TAP_115_1	173	BLACK FOREST	JUMPER	92	92	BLACK FOREST TAP	JUMPER	173	173
BGEO_ICTP_115_1	147	BIG GEORGE (WACM)	***	***	***	IRON CREEK TAP	JUMPER	175	175
BLAC_COBL_115_1	***	BLACKHOLLOW	SWITCH	239	268	COBB LAKE	***	***	***
BLACK FOREST TAP_BLSQ_115_1	173	BLACK FOREST TAP	JUMPER	173	173	BLACK SQUIRREL	METER	143	143
BLACK FOREST TAP_GRES_115_1	173	BLACK FOREST TAP	JUMPER	173	173	GRESHAM	JUMPER	173	173
BLCR_WLDH_115_1	147	BLUE CREEK	BUS	155	175	WILDHORSE	JUMPER	175	175
BLDR_CORT_115_1	143	BLUE DOOR	JUMPER	170	170	CORTEZ	NLSWITCH	239	291
BLDR_ECOR_115_1	143	BLUE DOOR	JUMPER	170	170	EAST CORTEZ	JUMPER	170	170
BLLK_SPGR_115_1	242	BLACK LAKE	SWITCH	239	242	SPRINGER	SWITCH	239	242

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TSGT 115 kV Facilities

PUBLIC

Section	Conductor Rating MVA*	Terminal 1	Terminal 1 Equipment	Terminal 1 Rating MVA*	Terminal 1 30 Min MVA**	Terminal 2	Terminal 2 Equipment	Terminal 2 Rating MVA*	Terminal 2 30 Min MVA**
BLLK_TAOS_115_1	238	BLACK LAKE	SWITCH	239	242	TAOS	CT	239	284
BLME_LACY_115_1	104	BLUE MESA	***	***	***	LAKE CITY	WAVETRAP	79	102
BLSQ_FULL_115_1	173	BLACK SQUIRREL	METER	143	143	FULLER	JUMPER	173	173
BLSQ_MERA_115_1	242	BLACK SQUIRREL	METER	143	143	MERIDIAN RANCH	NLSWITCH	239	242
BLVT_LAPO_115_1	68	BELLVUE TAP	JUMPER	92	92	LAPORTE	METER	21	21
BLVT_RIPP_115_1	56	BELLVUE TAP	JUMPER	92	92	RIPPLE	JUMPER	119	119
BLZR_CZCN_115_1	167	BLAZER	JUMPER	167	167	CARRIZO CANYON	CT	119	167
BMKR_YEJW_115_1	261	BASKET MAKER	SWITCH	239	261	YELLOWJACKET WES	SWITCH	119	145
BMRD_STBE_115_1	173	BURNT MILL	SWITCH	179	218	STEM BEACH	SWITCH	119	145
BODO_DURA_115_1	200	BODO PARK	CT	137	229	DURANGO	CT	168	229
BODO_HESP_115_1	200	BODO PARK	RELAY	115	115	HESPERUS	CT	194	241
BONN_BURL_115_1	173	BONNY CREEK	JUMPER	175	175	BURLINGTON	JUMPER	173	173
BONN_SFOR_115_1	147	BONNY CREEK	JUMPER	175	175	SOUTH FORK	BUS	197	215
BOOM_KERW_115_1	***	BOOMERANG	***	***	***	KERSEY WEST (WACM	***	***	***
BOOM_WELD_115_1	***	BOOMERANG	***	***	***	WELD	***	***	***
BOON_LAJU_115_1	130	BOONE	RELAY	164	164	LA JUNTA	CT	119	144
BOXB_ALLW_115_1	***	BOX BUTTE	METER	108	108	ALLIANCE (WACM)	***	***	***
BOXB_DUNL_115_1	***	BOX BUTTE	METER	108	108	DUNLAP (WACM)	***	***	***
BOXB_HEMI_115_1	87	BOX BUTTE	METER	53	53	HEMINGFORD	BUS	197	211
BOXE_TIMT_115_1	87	BOX ELDER	SWITCH	119	145	TIMNATH TAP	SWITCH	119	145
BOYD_GTWY_115_1	147	BOYD (PRPA)	***	***	***	GATEWAY	SWITCH	239	244
BRAC_WHIT_115_1	***	BRACEWELL	NLSWITCH	239	244	WHITNEY	NLCB	239	244
BRAC_WHIT_115_2	***	BRACEWELL	NLSWITCH	239	244	WHITNEY	NLCT	239	244
BRID_BRIW_115_1	***	BRIDGEPORT	BUS	113	134	BRIDGEPORT (WACM)	***	***	***
BRIG_ERSW_115_1	***	BRIGHTON (WAPA)	***	***	***	ERIE SWITCH	METER	215	215
BRIW_MCGR_115_1	***	BRIDGEPORT (WACM)	***	***	***	MCGREW	JUMPER	155	155
BROM_HNLK_115_1	175	BROMLEY	JUMPER	175	175	HENRY LAKE	CT	239	244
BROM_PRAI_115_1	244	BROMLEY	JUMPER	175	175	PRAIRIE CENTER	JUMPER	175	175
BRTT_MORI_115_1	***	BRITTON	RELAY	129	129	MORIARTY	BUS	148	148
BSAN_LACH_115_1	***	BIG SANDY	RELAY	125	125	LAST CHANCE	NLSWITCH	239	244
BSAN_LIMO_115_1	129	BIG SANDY	RELAY	219	219	LIMON	JUMPER	202	202
BSPR_BLCR_115_1	131	BIG SPRINGS (NPPD)	***	***	***	BLUE CREEK	BUS	155	175
BSPR_BRUL_115_1	***	BIG SPRINGS (NPPD)	***	***	***	BRULE (MECC)	SWITCH	119	145
BTHD_GTWY_115_1	131	BERTHOUD (PSCO)	***	***	***	GATEWAY	RELAY	76	76
BTHD_LNTR_115_1	131	BERTHOUD (PSCO)	***	***	***	LONE TREE	SWITCH	239	244
BUBR_SITP_115_1	143	BURRO BRIDGE	NLSWITCH	119	145	SILVERTON TAP	JUMPER	170	170
BUCN_LUDL_115_1	145	BURRO CANYON	RELAY	74	74	LUDLOW	JUMPER	173	173
BUCN_TERC_115_1	173	BURRO CANYON	METER	32	32	TERCIO	JUMPER	173	173

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TSGT 115 kV Facilities

PUBLIC

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BULL_HACN_115_1	85	BULLOCK	CT	79	135	HAPPY CANYON	WAVETRAP	79	102
BULL_SCTP_115_1	85	BULLOCK	CT	79	135	SPRING CREEK TAP	JUMPER	151	151
BURK_BURP_115_1	64	BURLINGTON (KC)	JUMPER	192	192	BURLINGTON (PSCO)	JUMPER	118	118
BURL_BURK_115_1	64	BURLINGTON	RELAY	123	123	BURLINGTON (KC)	JUMPER	192	192
BURP_WAAT_115_1	64	BURLINGTON (PSCO)	JUMPER	118	118	WAANIBE TAP	METER	35	35
BUSH_BUST_115_1	97	BUSHNELL	SWITCH	119	119	BUSHNELL TAP	SWITCH	119	145
BUST_KIMB_115_1	***	BUSHNELL TAP	SWITCH	119	145	KIMBALL (WACM)	***	***	***
BUST_PINE_115_1	***	BUSHNELL TAP	SWITCH	119	145	PINE BLUFFS (WACM)	***	***	***
BUVI_BUENA VISTA TAP_115_1	55	BUENA VISTA	NLSWITCH	119	145	BUENA VISTA TAP (PS	***	***	***
BWAT_GRTP_115_1	***	BLUE WATER	JUMPER	114	114	GRANTS TAP	JUMPER	114	114
BWAT_PEGS_115_1	310	BLUE WATER	BUS	197	232	ESCALANTE	SWITCH	239	259
BWAT_TAYL_115_1	***	BLUE WATER	JUMPER	148	148	TAYLOR	SWITCH	119	145
BWCK_RWCK_115_1	175	BLACKWOOD CREEK	JUMPER	175	175	RED WILLOW CREEK	JUMPER	175	175
CABA_COPPER FLATS_115_1	74	CABALLO	BUS	148	148	COPPER FLATS	***	***	***
CABA_HOT SPRINGS TAP_115_1	167	CABALLO	CT	119	148	HOT SPRINGS TAP	JUMPER	167	167
CAHO_DOCN_115_1	142****	CAHONE	METER	215	215	DOE CANYON	JUMPER	170****	170****
CAHO_GCTP_115_1	77	CAHONE	WAVETRAP	79	102	GREAT CUT TAP	JUMPER	135	135
CAHO_MAVR_115_1	315	CAHONE	CT	168	261	MAVERICK	JUMPER	315	315
CALK_CLTP_115_1	119	CARTER LAKE	JUMPER	92	92	CARTER LAKE TAP	***	***	***
CARM_WAVE_115_1	170	CARMEL	JUMPER	170	170	WAVERLY (TS)	JUMPER	238	238
CARM_ZINZ_115_1	238	CARMEL	JUMPER	170	170	ZINZER	JUMPER	170	170
CASC_COBA_115_1	143	CASCADE	CT	79	108	COAL BANK	JUMPER	170	170
CASC_TAMT_115_1	***	CASCADE	CT	79	132	TAMARRON TAP	***	***	***
CECK_SITP_115_1	143	CEMENT CREEK	JUMPER	170	170	SILVERTON TAP	JUMPER	170	170
CGUL_EL PASO TAP_115_1	85****	COYOTE GULCH	JUMPER	151****	151****	EL PASO TAP	JUMPER	151****	151****
CGUL_HESP_115_1	85	COYOTE GULCH	JUMPER	151****	151****	HESPERUS	SWITCH	239	291
CHEY_PONN_115_1	324	CHEYENNE (WACM)	***	***	***	PONNEQUIN (PSCO)	***	***	***
CINI_FWNT_115_1	114	CINIZA	METER	215	215	FORT WINGATE TAP	JUMPER	114	114
CINI_PEGS_115_1	114	CINIZA	METER	215	215	ESCALANTE	CT	239	244
CLAP_BRVD_115_1	184	CLAPHAM	METER	86	86	ROSEBUD (BRAVO DO	***	***	***
CLAP_GLAD_115_1	184	CLAPHAM	CT	119	129	GLADSTONE	CT	199	242
CMTP_CAMT_115_1	175	CARTER MOUNTAIN T	***	***	***	CARTER MOUNTAIN	NLCT	119	175
COBA_MOLAS LAKE TAP_115_1	143	COAL BANK	JUMPER	170	170	MOLAS LAKE TAP	JUMPER	170	170
COBL_TIMT_115_1	***	COBB LAKE	***	***	***	TIMNATH TAP	SWITCH	119	145
COLD_COVA_115_1	147	COLDWATER CREEK	SWITCH	239	244	COVALT	JUMPER	175	175
COLD_WLDH_115_1	147	COLDWATER CREEK	NLSWITCH	239	244	WILDHORSE	METER	107	107
COLF_GHSE_115_1	324	COLFER	JUMPER	324	324	GREENHOUSE	JUMPER	324	324
COLT_SIDN_115_1	***	COLTON (WACM)	***	***	***	SIDNEY (TS)	RELAY	164	164

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TSGT 115 kV Facilities

PUBLIC

Section	Conductor Rating MVA*	Terminal 1	Terminal 1 Equipment	Terminal 1 Rating MVA*	Terminal 1 30 Min MVA**	Terminal 2	Terminal 2 Equipment	Terminal 2 Rating MVA*	Terminal 2 30 Min MVA**
CORT_EMPI_115_1	143	CORTEZ	NLSWITCH	239	291	EMPIRE	JUMPER	170	170
COVA_LYNN_115_1	205	COVALT	SWITCH	239	244	LYNN	JUMPER	175	175
CRET_CRSW_115_1	147	CRETE	BUS	175****	175****	CRETE SWITCH	SWITCH	119	145
CRSW_LAMA_115_1	97	CRETE SWITCH	SWITCH	119	145	LAMAR NE	METER	107	107
CUCH_RODEO TAP_115_1	167	CUCHILLO	BUS	113	134	RODEO TAP	SWITCH	239	291
CURE_SCAL_115_1	***	CURECANTI (WACM)	***	***	***	SOUTH CANAL	JUMPER	170	170
CWCK_DACK_115_1	170	COW CREEK	JUMPER	170	170	DALLAS CREEK	SWITCH	119	145
CWCK_SCAL_115_1	170	COW CREEK	JUMPER	170	170	SOUTH CANAL	CT	14	16
CWCY_HOVE_115_1	142****	COW CANYON	CT	119****	203****	HOVENWEEP	SWITCH	119****	145****
CWCY_YJSW_115_1	142****	COW CANYON	CT	119****	203****	YELLOW JACKET SWIT	NLSWITCH	119****	145****
CZCN_HOWD_115_1	167	CARRIZO CANYON	METER	43	43	HOLLYWOOD (PNM)	***	***	***
CZPL_TOWA_115_1	169****	CORTEZ PIPELINE	SWITCH	119****	145****	TOWAOC CANAL	JUMPER	315****	315****
DACO_ERSW_115_1	175	DACONO	JUMPER	175	175	ERIE SWITCH	NLCT	239	323
DACO_RNVL_115_1	175	DACONO	JUMPER	175	175	RINN VALLEY	RELAY	196	196
DALT_GRWO_115_1	***	DALTON	SWITCH	119	134	GREENWOOD (WACM)	***	***	***
DALT_SIDW_115_1	***	DALTON	SWITCH	119	134	SIDNEY (WACM)	***	***	***
DAVP_DAVS_115_1	244	DAVIS TAP (PSCO)	***	***	***	DAVIS	JUMPER	244	244
DAVS_GHSE_115_1	244	DAVIS	JUMPER	244	244	GREENHOUSE	JUMPER	324	324
DAVS_GHSE_115_2	244	DAVIS	JUMPER	244	244	GREENHOUSE	JUMPER	324	324
DBKT_PUEW_115_1	173	DIAMONDBACK TAP	JUMPER	173	173	PUEBLO WEST	CT	79	135
DBKT_SWAL_115_1	173	DIAMONDBACK TAP	JUMPER	173	173	SWALLOWS	NLSWITCH	239	242
DELK_EYTP_115_1	***	DEERING LAKE	BUS	175	175	EAST YUMA TAP (WAC	***	***	***
DELK_NYUM_115_1	147	DEERING LAKE	JUMPER	175	175	NORTH YUMA	CT	168	175
DELK_OTIS_115_1	***	DEERING LAKE	RELAY	131	131	OTIS	SWITCH	119	119
DELK_YUMW_115_1	***	DEERING LAKE	RELAY	93	93	YUMA (WACM)	***	***	***
DELS_RNVL_115_1	175	DEL CAMINO SWITCH	JUMPER	175	175	RINN VALLEY	JUMPER	236	236
DELS_SLTR_115_1	131	DEL CAMINO SWITCH	METER	172	172	SLATER	NLSWITCH	239	244
DELT_LOPK_115_1	***	DEL CAMINO TAP	SWITCH	239	268	LONGS PEAK	***	***	***
DELT_MEAD_115_1	268	DEL CAMINO TAP	SWITCH	239	268	MEADOW (PRPA)	***	***	***
DICK_HORT_115_1	***	DIXON CREEK (PRPA)	***	***	***	HORSETOOTH TAP	SWITCH	119	145
DONA_LCRU_115_1	153	DONA ANA	JUMPER	234	234	LAS CRUCES	RELAY	254	254
DONA_PICA_115_1	153	DONA ANA	RELAY	183	183	PICACHO (PNM)	FAC008_PNM	159	183
DONA_WSAT_115_1	234	DONA ANA	JUMPER	234	234	WHITE SANDS TAP	JUMPER	234	234
DOSP_GNVY_115_1	170	DOUGHSPOON	JUMPER	170	170	GUNNISON VALLEY	JUMPER	170	170
DOSP_STAR_115_1	170	DOUGHSPOON	JUMPER	170	170	STARR NELSON	METER	129	129
DOWF_CEMX_115_1	68	DOWE FLATS	JUMPER	119	119	CEMEX	JUMPER	119	119
DUBA_ERVB_115_1	108	DUTTON BASIN	SWITCH	119	145	ERVAY BASIN	CT	19	21
DURA_ANRV_115_1	***	DURANGO	METER	64	64	ANIMAS RIVER (WACM	***	***	***

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DURA_GRVW_115_1	238	DURANGO	BUS	238	238	GRANDVIEW	JUMPER	238****	238****
DURA_HESP_115_1	127	DURANGO	JUMPER	151	151	HESPERUS	NLSWITCH	239	244
DURA_SHEN_115_1	238	DURANGO	BUS	229	238	SHENANDOAH	JUMPER	238	238
ECKL_ROBB_115_1	68	ECKLEY	METER	10	10	ROBB	CB	83	99
ECKL_WRCT_115_1	***	ECKLEY	METER	86	86	WRAY TAP	***	***	***
ECOR_LOCN_115_1	143	EAST CORTEZ	JUMPER	170	170	LOST CANYON	SWITCH	119	145
ELBU_FRNT_115_1	48	ELEPHANT BUTTE	***	***	***	FRONTIER	CT	119	193
ELBU_SOCO_115_1	97	ELEPHANT BUTTE	***	***	***	SOCORRO	METER	90	90
ELPT_GLTP_115_1	85	EL PASO TAP	JUMPER	151	151	GLADE (FEU)	***	***	***
ELSI_ELST_115_1	97	ELSIE	JUMPER	175	175	ELSIE TAP	METER	64	64
ELSI_RWCK_115_1	175	ELSIE	JUMPER	175	175	RED WILLOW CREEK	JUMPER	175	175
ELST_PAXT_115_1	131	ELSIE TAP	METER	143	143	PAXTON	BUS	155	155
ELST_ROSC_115_1	244	ELSIE TAP	METER	215	215	ROSCOE	SWITCH	239	244
EMAN_FOLK_115_1	242	EMIL ANDERSON	JUMPER	173	173	FOREST LAKES	METER	107	107
EMAN_MONU_115_1	145	EMIL ANDERSON	JUMPER	173	173	MONUMENT	CT	168	173
EMIG_WILD_115_1	147	EMIGRANT	SWITCH	119	145	WILDCAT	SWITCH	119	145
EMNT_PEVY_115_1	238	EAST MONTROSE	CT	119	203	PEACH VALLEY	JUMPER	238	238
EMPI_GCTP_115_1	77	EMPIRE	RELAY	165	165	GREAT CUT TAP	JUMPER	135	135
EMPI_LOCN_115_1	77	EMPIRE	RELAY	130	130	LOST CANYON	WAVETRAP	79	102
ERSW_LZDG_115_1	***	ERIE SWITCH	METER	216	216	LAZY DOG	SWITCH	239	244
ERVB_RADE_115_1	108	ERVAY BASIN	CT	19	21	RADERVILLE (WACM)	***	***	***
ESTN_MORI_115_1	***	ESTANCIA	***	***	***	MORIARTY	BUS	148	148
ESTN_WSWT_115_1	***	ESTANCIA	***	***	***	WILLARD SWITCH	JUMPER	148	148
EYTP_ECKL_115_1	***	EAST YUMA TAP (WAC	***	***	***	ECKLEY	METER	86	86
EYTP_SHRM_115_1	68	EAST YUMA TAP (WAC	***	***	***	SCHRAMM	JUMPER	119	119
FALC_FULL_115_1	173	FALCON	JUMPER	173	173	FULLER	JUMPER	173	173
FALC_GEES_115_1	92	FALCON	JUMPER	173	173	GEESEN	RELAY	140	140
FLAT_HORT_115_1	***	FLATIRON (WACM)	***	***	***	HORSETOOTH TAP	SWITCH	119	145
FLAT_WAGW_115_1	***	FLATIRON (WACM)	***	***	***	WAGON WHEEL	JUMPER	155	155
FLYH_MONU_115_1	***	FLYING HORSE	***	***	***	MONUMENT	CT	168	173
FRAS_MILL_115_1	170	METTLER (FRASER)	METER	108	108	MILL (PSCO)	CT	168	170
FRNT_PICA_115_1	48	FRONTIER	RELAY	112	112	PICACHO (PNM)	CT	79	96
FULT_PKWY_115_1	***	FULTON	***	***	***	PARKWAY	SWITCH	239	291
FWNT_MDTP_115_1	114	FORT WINGATE TAP	BUS	114	114	MENDOZA TAP	JUMPER	114	114
GALL_MDTP_115_1	114	GALLUP	BUS	114	114	MENDOZA TAP	JUMPER	114	114
GALL_YATH_115_1	112	GALLUP	JUMPER	167	167	YA-TA-HEY (PNM)	***	***	***
GARY_BECK_115_1	***	GARY	SWITCH	239	291	BEAVER CREEK (WAC	***	***	***
GARY_WOOD_115_1	***	GARY	SWITCH	239	291	WOODROW	***	***	***

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GEES_LRSN_115_1	92	GEESEN	RELAY	163	163	LORSON RANCH	JUMPER	173	173
GEES_SAFB_115_1	92	GEESEN	METER	21	21	SHREIVER	JUMPER	173	173
GERI_EMIG_115_1	***	GERING (WACM)	***	***	***	EMIGRANT	NLSWITCH	119	145
GERI_MCGR_115_1	***	GERING (WACM)	***	***	***	MCGREW	JUMPER	155	155
GLAD_BVDW_115_1	321****	GLADSTONE	CT	199	321	BRAVO DOME WEST	***	***	***
GLAD_SPGR_115_1	184	GLADSTONE	CT	199	242	SPRINGER	METER	215	215
GLDO_PODO_115_1	***	GLENDO (WACM)	***	***	***	PODOLAK	SWITCH	119	145
GMES_GMET_115_1	143	GARNET MESA	JUMPER	170	170	GARNET MESA TAP	JUMPER	170	170
GMES_GNVY_115_1	170	GARNET MESA	JUMPER	170	170	GUNNISON VALLEY	JUMPER	170	170
GMET_HOTC_115_1	151	GARNET MESA TAP	JUMPER	170	170	HOTCHKISS	SWITCH	119	145
GMET_PEVY_115_1	151	GARNET MESA TAP	JUMPER	170	170	PEACH VALLEY	JUMPER	238	238
GOPT_MAIN_115_1	142****	GOODMAN POINT	NLSWITCH	239****	261****	MAIN	SWITCH	119****	145****
GOPT_SACN_115_1	142****	GOODMAN POINT	SWITCH	239****	261****	SAND CANYON	NLCT	119****	145****
GRES_MONU_115_1	145	GRESHAM	JUMPER	173	173	MONUMENT	CT	159	172
GRJC_STAR_115_1	95	GRAND JUNCTION (PS	***	***	***	STARR NELSON	JUMPER	170	170
GRNP_GRTP_115_1	58	GRANTS	BUS	114	114	GRANTS TAP	BUS	114	114
GRNT_OGAL_115_1	147	GRANT	CT	159	162	OGALLALA	RELAY	221	221
GRNT_OGAN_115_2	175	GRANT	CT	159	175	OGALLALA (NPPD)	JUMPER	175	175
GRNT_SPCK_115_1	147	GRANT	SWITCH	119	143	SPRING CREEK (MECC	SWITCH	119	145
GRTP_SFIT_115_1	***	GRANTS TAP	JUMPER	114	114	SAN FIDEL TAP	***	***	***
GRVW_BAYF_115_1	238	GRANDVIEW	JUMPER	238****	238****	BAYFIELD	SWITCH	119	145
HACN_MONT_115_1	95	HAPPY CANYON	WAVETRAP	79	102	MONTROSE	SWITCH	119	145
HAMD_JIM READY TAP_115_1	88	HAMILTON DOME	JUMPER	139	139	JIM READY TAP	JUMPER	155	155
HARB_BOYS_115_1	***	HARRIS BRIDGE	JUMPER	175	175	BOYSEN (WACM)	***	***	***
HARB_PIBU_115_1	***	HARRIS BRIDGE	JUMPER	175	175	PILOT BUTTE (WACM)	***	***	***
HECK_HELT_115_1	97	HELL CREEK	SWITCH	119	145	HELL CREEK TAP	JUMPER	175	175
HECK_SAGE_115_1	97	HELL CREEK	SWITCH	119	145	SAGEBRUSH	SWITCH	119	145
HELT_LIBE_115_1	97	HELL CREEK TAP	JUMPER	175	175	LIBERTY	CT	59	64
HELT_SFOR_115_1	97	HELL CREEK TAP	JUMPER	175	175	SOUTH FORK	RELAY	148	148
HERN_NRTN_115_1	***	HERNANDEZ	JUMPER	238	238	NORTON (PNM)	***	***	***
HERN_OCTP_115_1	169	HERNANDEZ	WAVETRAP	159	205	OJO CALIENTE TAP	SWITCH	239	291
HERN_OJO_115_1	***	HERNANDEZ	BUS	238	238	OJO (PNM)	***	***	***
HESP_SPCT_115_1	95	HESPERUS	CT	119	129	SPRING CREEK TAP (L	***	***	***
HIDA_PYRA_115_1	215	HIDALGO (PNM/EPE)	***	***	***	PYRAMID SWITCH	METER	216	216
HIDA_PYRA_115_2	212	HIDALGO (PNM/EPE)	***	***	***	PYRAMID SWITCH	METER	216	216
HOLO_HOLT_115_1	47	HOLLOMAN	***	***	***	HOLLOMAN TAP	JUMPER	88	88
HOLT_WSAT_115_1	234	HOLLOMAN TAP	JUMPER	234	234	WHITE SANDS TAP	JUMPER	234	234
HORT_MASO_115_1	147	HORSETOOTH TAP	METER	27	27	MASONVILLE	JUMPER	175	175

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HORT_TRIL_115_1	268	HORSETOOTH TAP	METER	27	27	TRILBY	SWITCH	119	145
HOSP_HOT SPRINGS TAP_115_1	48	HOT SPRINGS	***	***	***	HOT SPRINGS TAP	***	***	***
HOTC_NFOR_115_1	143	HOTCHKISS	CT	119	145	NORTH FORK	CT	194	208
HOVE_SACN_115_1	142****	HOVENWEEP	NLSWITCH	119****	145****	SAND CANYON	NLCT	119****	145****
HYGI_LYON_115_1	***	HYGIENE	***	***	***	LYONS	SWITCH	119	145
ICTP_IRNC_115_1	244	IRON CREEK TAP	SWITCH	239	244	IRON CREEK	JUMPER	244	244
ICTP_LVLL_115_1	147	IRON CREEK TAP	JUMPER	175	175	LOVELL (WACM)	CT	168	175
IDAL_SFOR_115_1	147	IDALIA	BUS	175	175	SOUTH FORK	BUS	197	215
IDAL_VERT_115_1	147	IDALIA	BUS	175	175	VERNON SWITCH	RELAY	224	224
INTP_INTE_115_1	119	HIGHLINE INTERSTAT	JUMPER	119	119	INTERSTATE	METER	72	72
JACI_KIMB_115_1	***	JACINTO	SWITCH	119	145	KIMBALL (WACM)	***	***	***
JACI_SIDW_115_1	***	JACINTO	SWITCH	119	145	SIDNEY (WACM)	***	***	***
JARI_OROG_115_1	148	JARILLA	SWITCH	119	145	ORO GRANDE (EPE)	***	***	***
JIM READY TAP_THET_115_1	88	JIM READY TAP	JUMPER	155	155	THERMOPOLIS (TS)	JUMPER	155	155
JOES_LIBE_115_1	68	JOES	JUMPER	119	119	LIBERTY	JUMPER	99	99
JRDY_JIM READY TAP_115_1	108	JIM READY	JUMPER	139	139	JIM READY TAP	JUMPER	193	193
JUAN_NFOR_115_1	143	JUANITA	***	***	***	NORTH FORK	CT	194	215
KEOT_CLKB_115_1	244	KEOTA	JUMPER	244	244	CHALK BLUFFS	JUMPER	175	175
KEOT_RDBX_115_1	244	KEOTA	JUMPER	244	244	REDBOX	JUMPER	244	244
KEOT_RDBX_115_2	244	KEOTA	JUMPER	244	244	REDBOX	JUMPER	244	244
KERW_SKER_115_1	244	KERSEY WEST (WACM	***	***	***	SOUTH KERSEY	JUMPER	244	244
KRTP_KERS_115_1	***	KERSEY TAP	***	***	***	KERSEY	CT	79	135
LACH_LDTP_115_1	68	LAST CHANCE	JUMPER	119	119	LINDON TAP	JUMPER	175	175
LACH_SWOD_115_1	***	LAST CHANCE	NLSWITCH	239	244	SOUTH WOODROW	***	***	***
LAGT_LAGR_115_1	***	LAGRANGE TAP (WAC	***	***	***	LAGRANGE	BUS	175	175
LAGT_ROUN_115_1	***	LAGRANGE TAP (WAC	***	***	***	ROUND TOP	JUMPER	92	92
LAJU_LAMS_115_1	130	LA JUNTA	METER	107	107	LAMSO (LAMAR SOUT	JUMPER	173	173
LAMA_SPCK_115_1	147	LAMAR NE	METER	144	144	SPRING CREEK (MECC	SWITCH	119	145
LAMR_VILA_115_1	202	LAMAR CO (TS)	NLCT	194	242	VILAS	METER	107	107
LAMR_WILC_115_1	202	LAMAR CO (TS)	NLCT	194	242	WILLOW CREEK	METER	107	107
LAMS_WILC_115_1	130	LAMSO (LAMAR SOUT	JUMPER	173	173	WILLOW CREEK	METER	107	107
LARA_OASI_115_1	***	LARAMIE (WACM)	***	***	***	OASIS	SWITCH	119	145
LJAR_TREO_115_1	74	LA JARA	RELAY	80	80	TORREON	JUMPER	238	238
LOCK_LOCT_115_1	56	LOST CREEK	JUMPER	92	92	LOST CREEK TAP	JUMPER	92	92
LOCN_MANCOS TAP_115_1	238	LOST CANYON	NLCT	239	261	MANCOS TAP	JUMPER	238	238
LOCN_TOWA_115_1	169****	LOST CANYON	CT	168	170	TOWAOC CANAL	JUMPER	315****	315****
LORE_YOCN_115_1	138	LORENCITO	***	***	***	YORK CANYON	CT	39	43
LRSN_RANC_115_1	92	LORSON RANCH	JUMPER	173	173	RANCHO	SWITCH	119	145

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LUDL_TYTP_115_1	92	LUDLOW	CT	39	43	TYRONE TAP	SWITCH	239	242
LUDL_WALT_115_1	145	LUDLOW	JUMPER	173	173	WALSENBURG	METER	64	64
LYNN_SNCK_115_1	97	LYNN	JUMPER	175	175	SNAKE CREEK	NLSWITCH	119	145
LYON_DOWF_115_1	68	LYONS	METER	21	21	DOWE FLATS	JUMPER	119	119
LYON_WAGW_115_1	***	LYONS	SWITCH	119	145	WAGON WHEEL	JUMPER	155	155
LZDG_TERR_115_1	***	LAZY DOG	NLSWITCH	239	244	TERRY STREET (PRPA	***	***	***
MAIN_CZPL_115_1	169****	MAIN	NLSWITCH	119****	145****	CORTEZ PIPELINE	SWITCH	119****	145****
MAIN_MOQI_115_1	95****	MAIN	SWITCH	119****	145****	MOQUI C	JUMPER	170****	170****
MAIN_YEJW_115_1	142****	MAIN	NLSWITCH	119****	145****	YELLOW JACKET WES	CT	119****	145****
MANC_MANCOS TAP_115_1	77****	MANCOS	SWITCH	119	145	MANCOS TAP	JUMPER	135	135
MANCOS TAP_SHEN_115_1	238	MANCOS TAP	JUMPER	238	238	SHENANDOAH	JUMPER	238	238
MAVR_MONT_115_1	315	MAVERICK	JUMPER	315	315	MONTROSE	NLCT	194	238
MAVR_NORW_115_1	170	MAVERICK	JUMPER	170	170	NORWOOD	JUMPER	238	238
MAY_OASI_115_1	97	MAY	JUMPER	175	175	OASIS	CT	19	21
MBWT_OASI_115_1	***	MEDICINE BOW TAP (	***	***	***	OASIS	SWITCH	119	145
MCCO_OGAL_115_1	87	MCCONAUGHY	SWITCH	119	145	OGALLALA	CTMAXRATIO	19	21
MERA_PEYT_115_1	242	MERIDIAN RANCH	SWITCH	239	242	PEYTON	NLSWITCH	239	242
MIDW_RANC_115_1	92	MIDWAY (WACM)	CT	119	145	RANCHO	SWITCH	119	145
MLTH_MLTP_115_1	244	MONOLITH	SWITCH	179	218	MONOLITH TAP	JUMPER	244	244
MODL_PICN_115_1	92	MODEL TAP	SWITCH	119	145	PINON CANYON	JUMPER	173	173
MODL_PRGA_115_1	92	MODEL TAP	SWITCH	119	145	PURGATOIRE	SWITCH	119	145
MODL_TYTP_115_1	92	MODEL TAP	SWITCH	119	145	TYRONE TAP	SWITCH	239	242
MOLA_MOLAS TAP_115_1	143	MOLAS	JUMPER	57	57	MOLAS TAP	JUMPER	170	170
MOLAS TAP_SITP_115_1	143	MOLAS TAP	JUMPER	170	170	SILVERTON TAP	JUMPER	170	170
MONT_SCAL_115_1	***	MONTROSE	RELAY	160	160	SOUTH CANAL	JUMPER	170	170
MONT_SCTP_115_1	95	MONTROSE	SWITCH	119	145	SPRING CREEK TAP	JUMPER	170	170
MONU_PALK_115_1	***	MONUMENT	CT	159	173	PALMER LAKE	***	***	***
MYRS_MYRT_115_1	147	MYERS	CTMAXRATIO	14	25	MYERS TAP	JUMPER	175	175
MYRT_POCK_115_1	***	MYERS TAP	JUMPER	175	175	POLE CREEK	CT	119	145
NMES_PEVY_115_1	151	NORTH MESA	BUS	151	151	PEACH VALLEY	JUMPER	238	238
NMES_SCTP_115_1	151	NORTH MESA	NLSWITCH	119	145	SPRING CREEK TAP	JUMPER	151	151
NORW_WIME_115_1	133	NORWOOD	JUMPER	238	238	WILSON MESA	SWITCH	179	218
NUNT_PIER_115_1	244	NUNN TAP (WACM)	***	***	***	PIERCE	JUMPER	244	244
NUNT_ROCK_115_1	324	NUNN TAP (WACM)	***	***	***	ROCKPORT	SWITCH	119	145
NYUM_BRDT_115_1	175	NORTH YUMA	METER	10	10	BURDETT	SWITCH	59	72
NYUM_RWIL_115_1	175	NORTH YUMA	CT	79	129	RED WILLOW	BUS	175	175
OCTP_TAOS_115_1	169	OJO CALIENTE TAP	SWITCH	239	291	TAOS	CT	239	269
OGAL_BRUL_115_1	***	OGALLALA	RELAY	208	208	BRULE (MECC)	SWITCH	119	145

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TSGT 115 kV Facilities

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Section	Conductor Rating MVA*	Terminal 1	Terminal 1 Equipment	Terminal 1 Rating MVA*	Terminal 1 30 Min MVA**	Terminal 2	Terminal 2 Equipment	Terminal 2 Rating MVA*	Terminal 2 30 Min MVA**
OGAL_OGAN_115_1	***	OGALLALA	BUS	260	268	OGALLALA (NPPD)	***	***	***
OGAL_OGAW_115_1	268	OGALLALA	RELAY	31	31	OGALLALA (WACM)	***	***	***
OGAL_ROSC_115_1	244	OGALLALA	SWITCH	239	268	ROSCOE	SWITCH	239	244
OLTP_OLCK_115_1	175	OLIVE CREEK TAP	JUMPER	175	175	OLIVE CREEK	CT	19	33
OLTP_VERT_115_1	147	OLIVE CREEK TAP	JUMPER	175	175	VERNON SWITCH	RELAY	224	224
OLTP_WRAY_115_1	147	OLIVE CREEK TAP	JUMPER	175	175	WRAY (TS)	METER	216	216
OWCK_PONN_115_1	324	OWL CREEK	SWITCH	239	291	PONNEQUIN (PSCO)	***	***	***
OWCK_ROCK_115_1	324	OWL CREEK	NLSWITCH	239	291	ROCKPORT	SWITCH	119	145
PEYT_CALH_115_1	242	PEYTON	NLSWITCH	239	242	CALHAN	RELAY	56	56
PHDO_PLAY_115_1	74	PHELPS DODGE	JUMPER	167	167	PLAYAS	JUMPER	148	148
PIBU_WIND RIVER TAP_115_1	147	PILOT BUTTE (WACM)	CT	168	287	WIND RIVER TAP	JUMPER	175	175
PIEW_PUET_115_1	92	PUEBLO WEST	JUMPER	173	173	PUEBLO WEST TAP	BUS	173	173
PKWY_LAFA_115_1	***	PARKWAY	NLSWITCH	239	291	LAFAYETTE (PSCO)	***	***	***
PLAI_PATP_115_1	175	PLAINSVIEW	JUMPER	175	175	PLAINSVIEW TAP	***	***	***
PLAP_WALC_115_1	97	PLATTE (PACE)	JUMPER	155	155	WALCOTT	JUMPER	175	175
PLAY_PYRA_115_1	74	PLAYAS	JUMPER	148	148	PYRAMID SWITCH	RELAY	78	78
PLAZ_RAMO_115_1	143	PLAZA	JUMPER	238	238	RAMON	CB	239	261
PLAZ_STAN_115_1	143	PLAZA	JUMPER	238	238	STANLEY	JUMPER	170****	170****
PLAZ_ZINZ_115_1	238	PLAZA	JUMPER	238	238	ZINZER	JUMPER	170	170
POCK_QUAL_115_1	97	POLE CREEK	METER	53	53	QUALLS	SWITCH	119	145
POCK_ROUN_115_1	***	POLE CREEK	CT	119	145	ROUND TOP	JUMPER	92	92
PRAI_REUN_115_1	244	PRAIRIE CENTER	JUMPER	175	175	REUNION	CT	119	203
PROV_LOCT_115_1	***	PROSPECT VALLEY (W	***	***	***	LOST CREEK TAP	JUMPER	92	92
PUET_STBE_115_1	92	PUEBLO WEST TAP	BUS	173	173	STEM BEACH	SWITCH	119	142
PUET_WSTA_115_1	145	PUEBLO WEST TAP	BUS	173	173	WEST STATION (BHCE	***	***	***
RDBX_RTAL_115_1	244	REDBOX	JUMPER	244	244	REDTAIL	JUMPER	244	244
RDBX_RTAL_115_2	244	REDBOX	JUMPER	244	244	REDTAIL	JUMPER	244	244
RILK_WAVP_115_1	175	RICHARD LAKE (PRPA)	***	***	***	WAVERLY (PV)	JUMPER	175	175
RILT_TIMT_115_1	***	RICHARD LAKE TAP (	***	***	***	TIMNATH TAP	METER	108	108
RIPP_WELT_115_1	68	RIPPLE	JUMPER	119	119	WELLINGTON TAP	SWITCH	119	119
RIVE_WIND RIVER TAP_115_1	147	RIVERTON	METER	138	138	WIND RIVER TAP	JUMPER	175	175
RNST_RNSV_115_1	118	RAINSVILLE TAP	JUMPER	118	118	RAINSVILLE	JUMPER	118	118
RODEO TAP_ELBU_115_1	167	RODEO TAP	JUMPER	167	167	ELEPHANT BUTTE	***	***	***
RODEO TAP_HOT SPRINGS TAP_115	167	RODEO TAP	JUMPER	167	167	HOT SPRINGS TAP	JUMPER	167	167
ROUN_SENT_115_1	97	ROUND TOP	SWITCH	119	145	SENTINEL	SWITCH	119	119
ROWE_ROWT_115_1	74	ROWE	JUMPER	114	114	ROWE TAP (PNM)	***	***	***
RWIL_WAGE_115_1	175	RED WILLOW	JUMPER	175	175	WAGES	BUS	175	175
SALV_STAN_115_1	143	SAN LUIS VALLEY	NLSWITCH	119	145	STANLEY	JUMPER	170	170

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TSGT 115 kV Facilities

PUBLIC

Section	Conductor Rating MVA*	Terminal 1	Terminal 1 Equipment	Terminal 1 Rating MVA*	Terminal 1 30 Min MVA**	Terminal 2	Terminal 2 Equipment	Terminal 2 Rating MVA*	Terminal 2 30 Min MVA**
SALV_WAVE_115_1	143	SAN LUIS VALLEY	SWITCH	119	145	WAVERLY (TS)	JUMPER	238	238
SAND_WREM_115_1	97	SANDHILLS	JUMPER	175	175	WRAY EMERGENCY T	JUMPER	175	175
SHRH_SHTP_115_1	175	SHERIDAN HILL	METER	10	10	SHERIDAN HILL TAP	***	***	***
SKIT_SKIW_115_1	143	SKITO	SWITCH	119	145	SKITO (WACM)	***	***	***
SKIT_SKIW_115_2	143	SKITO	SWITCH	119	145	SKITO (WACM)	***	***	***
SLTR_DELT_115_1	175	SLATER	METER	150	150	DEL CAMINO TAP	JUMPER	175	175
SMOK_WAAT_115_1	64	SMOKY HILL	JUMPER	118	118	WAANIBE TAP	CTMAXRATIO	39	67
SNCK_ALLW_115_1	***	SNAKE CREEK	SWITCH	119	145	ALLIANCE (WACM)	***	***	***
SNCK_MORL_115_1	***	SNAKE CREEK	SWITCH	119	145	MORRILL COUNTY	***	***	***
SPGR_BISN_115_1	82	SPRINGER	NLCT	239	242	BISON	JUMPER	154	154
SPGR_RNST_115_1	92	SPRINGER	RELAY	215	215	RAINSVILLE TAP	JUMPER	173	173
STAR_MONT_115_1	95	STARR NELSON	RELAY	138	138	MONTROSE	NLSWITCH	119	129
STBE_GCCP_115_1	92	STEM BEACH	METER	32	32	GCC CEMENT PLANT	***	***	***
STBE_WALT_115_1	92	STEM BEACH	RELAY	103	103	WALSENBURG	SWITCH	119	139
STEW_EMIG_115_1	***	STEGALL (WACM)	***	***	***	EMIGRANT	SWITCH	119	145
STLK_RNST_115_1	92	STORRIE LAKE	RELAY	149	149	RAINSVILLE TAP	JUMPER	173	173
STLK_VALN_115_1	***	STORRIE LAKE	METER	129	129	VALENCIA (PNM)	***	***	***
STOC_WAVE_115_1	143	STOCKADE	JUMPER	170	170	WAVERLY (TS)	METER	10	10
SUNT_TELL_115_1	143	SUNSHINE	JUMPER	238	238	TELLURIDE	RELAY	65	65
SUNT_WIME_115_1	133	SUNSHINE	JUMPER	170	170	WILSON MESA	SWITCH	179	218
SUNY_HESP_115_1	200	SUNNYSIDE	RELAY	392	392	HESPERUS	METER	129	129
SUTH_PAXT_115_1	131	SUTHERLAND (NPPD)	***	***	***	PAXTON	BUS	155	155
SYSI_TREO_115_1	74	SAN YSIDRO	BUS	74	74	TORREON	JUMPER	238	238
THET_THEW_115_1	98	THERMOPOLIS (TS)	JUMPER	155	155	THERMOPOLIS (WACM	***	***	***
TROW_WALC_115_1	68	TROWBRIDGE	JUMPER	119	119	WALCOTT	JUMPER	119	119
VANB_BISN_115_1	82	VAN BREMMER	BUS	173	173	BISON	JUMPER	154	154
VANB_YOCN_115_1	82	VAN BREMMER	JUMPER	173	173	YORK CANYON	WAVETRAP	79	102
VRNN_VERT_115_1	68	VERNON	SWITCH	119	119	VERNON SWITCH	NLSWITCH	239	244
WAAN_WAAT_115_1	92	WAANIBE	JUMPER	118	118	WAANIBE TAP	JUMPER	118	118
WAGE_WAUN_115_1	68	WAGES	JUMPER	155	155	WAUNETA	JUMPER	119	119
WALS_SPPK_115_1	92	WALSENBURG	CT	29	32	SPANISH PEAKS	JUMPER	173	173
WAVP_WELT_115_1	175	WAVERLY (PV)	JUMPER	175	175	WELLINGTON TAP	SWITCH	119	145
WELD_WHIT_115_1	133	WELD	***	***	***	WHITNEY	NLCB	239	244
WELL_WELT_115_1	68	WELLINGTON	JUMPER	169	169	WELLINGTON TAP	SWITCH	119	119
WHIT_WDTP_115_1	133	WHITNEY	SWITCH	239	244	WINDSOR TAP (WAPA)	***	***	***
WIBY_LOCT_115_1	***	WILLOBY	***	***	***	LOST CREEK TAP	JUMPER	92	92
WILL_WSWT_115_1	97	WILLARD	BUS	160	167	WILLARD SWITCH	RELAY	39	39
WINR_WIND RIVER TAP_115_1	147	WIND RIVER	CT	59	64	WIND RIVER TAP	JUMPER	175	175

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TSGT 115 kV Facilities

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WRAW_WREM_115_1	97	WRAY (WACM)	***	***	***	WRAY EMERGENCY T	JUMPER	175	175
WRAY_WRAW_115_1	***	WRAY (TS)	NLCT	239	244	WRAY (WACM)	***	***	***
WRAY_WRCT_115_1	***	WRAY (TS)	CT	239	244	WRAY TAP	***	***	***
WRAY_WREM_115_1	97	WRAY (TS)	CT	168	180	WRAY EMERGENCY T	JUMPER	175	175
WSWT_DRAN_115_1	***	WILLARD SWITCH	METER	32	32	DURAN	***	***	***
WSWT_HLMS_115_1	***	WILLARD SWITCH	NLCT	119	120	HIGH LONESOME MES	***	***	***
YJSW_YEJW_115_1	142****	YELLOW JACKET SWIT	NLSWITCH	119****	145****	YELLOW JACKET WES	SWITCH	119****	145****

TSGT 138 kV Facilities

Section	Conductor Rating MVA*	Terminal 1	Terminal 1 Equipment	Terminal 1 Rating MVA*	Terminal 1 30 Min MVA**	Terminal 2	Terminal 2 Equipment	Terminal 2 Rating MVA*	Terminal 2 30 Min MVA**
AXBA_HAYD_138_1	125	AXIAL BASIN	RELAY	130	130	HAYDEN (WACM)	***	***	***
AXBA_MEEK_138_1	125	AXIAL BASIN	RELAY	129	129	MEEKER	CT	202	204
CALR_WRCY_138_1	114	CALAMITY RIDGE	***	***	***	WHITE RIVER CITY	JUMPER	204	204
FRAS_WIGA_138_1	172	METTLER (FRASER)	METER	168	168	WINDY GAP	JUMPER	204	204
GORP_KREM_138_1	***	GORE PASS	JUMPER	204	204	KREMMLING (WACM)	***	***	***
GORP_OACK_138_1	***	GORE PASS	CT	143	151	OAK CREEK TAP	***	***	***
GORP_WIGA_138_1	282	GORE PASS	SWITCH	286	349	WINDY GAP	SWITCH	286	327
MEEK_MASW_138_1	***	MEEKER	METER	100	100	MAGNOLIA SWITCH	***	***	***
MEEK_RIFP_138_1	125	MEEKER	RELAY	137	137	RIFLE (PSCO)	***	***	***
MEEK_WRCY_138_1	114	MEEKER	RELAY	137	137	WHITE RIVER CITY	JUMPER	204	204
NCWCD_WIGA_138_1	114	NCWCD	***	***	***	WINDY GAP	METER	100	100
TROU_WIGA_138_1	***	TROUBLESOME	***	***	***	WINDY GAP	JUMPER	204	204

TSGT 230 kV Facilities

Section	Conductor Rating MVA*	Terminal 1	Terminal 1 Equipment	Terminal 1 Rating MVA*	Terminal 1 30 Min MVA**	Terminal 2	Terminal 2 Equipment	Terminal 2 Rating MVA*	Terminal 2 30 Min MVA**
AMBR_PEGS_230_1	328	AMBROSIA LAKE (PNM	RELAY	1527	1527	ESCALANTE	CT	398	431
AMSA_DIFF_230_1	***	AMASA (PACE)	***	***	***	DIFFICULTY	NLSWITCH	478	583
ARCH_WYCH_230_1	648	ARCHER (WACM)	***	***	***	WAYNE CHILD	METER	327	327
ARLI_FTCK_230_1	489	ARLINGTON	NLCT	239	406	FOOT CREEK (PACE)	***	***	***
ARNO_ERSW_230_1	648	ARNOLD	JUMPER	648	648	ERIE SWITCH	JUMPER	648	648
ARNO_SIPR_230_1	648	ARNOLD	JUMPER	648	648	SIPRES	JUMPER	648	648

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TSGT 230 kV Facilities

PUBLIC

Section	Conductor Rating MVA*	Terminal 1	Terminal 1 Equipment	Terminal 1 Rating MVA*	Terminal 1 30 Min MVA**	Terminal 2	Terminal 2 Equipment	Terminal 2 Rating MVA*	Terminal 2 30 Min MVA**
AULT_CARY_230_1	***	AULT (WACM)	***	***	***	CAREY	NLCB	796	947
BALK_KNUT_230_1	648	BARR LAKE (PSCO)	NLSWITCH	637	648	KNUTSON	METER	288	288
BECP_STO2_230_1	***	BEAVER CREEK (PSC	***	***	***	STORY (TS)	METER	276	276
BECT_STO2_230_1	292	BEAVER CREEK (TS)	JUMPER	537	537	STORY (TS)	METER	415	415
BFHD_GRFD_230_1	647	BUFFALO HEAD (WAP	***	***	***	GRIEVE FIELD	***	***	***
BLRR_GORP_230_1	***	BLUE RIVER (PSCO)	***	***	***	GORE PASS	WAVETRAP	463	598
BOYD_GTWY_230_1	***	BOYD (PRPA)	***	***	***	GATEWAY	JUMPER	648	648
BSAN_LINC_230_1	642	BIG SANDY	METER	576	576	LINCOLN	METER	576	576
BSAN_WDTK_230_1	274	BIG SANDY	METER	432	432	WINDTALKER	JUMPER	642	642
BURL_CARO_230_1	642	BURLINGTON	METER	327	327	CAROUSEL	***	***	***
BURL_LMCK_230_1	274	BURLINGTON	RELAY	412	412	LANDSMAN CREEK	RELAY	412	412
BURL_WRAY_230_1	642	BURLINGTON	NLCT	478	583	WRAY (TS)	JUMPER	642	642
CARY_TIMB_230_1	***	CAREY	NLSWITCH	796	947	TIMBERLINE (PRPA)	***	***	***
COMA_MIDP_230_1	***	COMANCHE (PSCO)	WAVETRAP	478	616	MIDWAY (PSCO)	***	***	***
COMA_WALT_230_1	642	COMANCHE (PSCO)	***	***	***	WALSENBURG	CT	358	609
CRAI_CRAT_230_1	***	CRAIG	CT	159	270	CRAIG TRANSFER (PS	***	***	***
CRAI_HAYD_230_1	***	CRAIG	METER	518	518	HAYDEN (WACM)	***	***	***
CRAI_HAYD_230_2	528	CRAIG	JUMPER	621	621	HAYDEN (WACM)	***	***	***
CRAI_RIFL_230_1	***	CRAIG	NLCB	796	863	RIFLE (WACM/PSCO)	***	***	***
CRT1_WDTK_230_1	***	CROSSING TRAILS 1	***	***	***	WINDTALKER	CT	637	642
DAJO_LRS2_230_1	542	DAVE JOHNSTON (PA	***	***	***	LARAMIE RIVER (MBP	METER	831	831
DIFF_SHBN_230_1	***	DIFFICULTY	NLSWITCH	478	583	SHIRLEY BASIN (PACE	***	***	***
FLUP_JLGR_230_1	***	FORT LUPTON (PSCO)	***	***	***	J L GREEN	NLCB	637	648
FLUP_JMSH_230_1	***	FORT LUPTON (PSCO)	***	***	***	J M SHAFER	NLCT	637	648
GHSE_HNLK_230_1	648	GREENHOUSE	JUMPER	648	648	HENRY LAKE	JUMPER	648	648
GHSE_JMSH_230_1	648	GREENHOUSE	CT	637	648	J M SHAFER	JUMPER	648	648
GLAD_WALT_230_1	642	GLADSTONE	NLCT	637	642	WALSENBURG	CT	358	518
GORP_HAYD_230_1	612	GORE PASS	METER	719	719	HAYDEN (WACM)	***	***	***
GTWY_LOPK_230_1	***	GATEWAY	JUMPER	648	648	LONGS PEAK	***	***	***
HNLK_FLUP_230_1	***	HENRY LAKE	JUMPER	648	648	FORT LUPTON (PSCO)	***	***	***
HNLK_RVDL_230_1	***	HENRY LAKE	JUMPER	648	648	RIVERDALE (PSCO)	***	***	***
HNLK_STO2_230_1	648	HENRY LAKE	METER	518	518	STORY (TS)	CT	637	844
JLGR_WSHT_230_1	***	J L GREEN	SWITCH	637	648	WASHINGTON (XCEL)	***	***	***
LAMP_LAMR_230_1	325	LAMAR CO (PSCO)	***	***	***	LAMAR CO (TS)	CT	337	433
LINC_MIDW_230_1	642	LINCOLN	METER	576	576	MIDWAY (WACM)	***	***	***
LMCK_WDTK_230_1	274	LANDSMAN CREEK	RELAY	414	414	WINDTALKER	JUMPER	642	642
LOCN_CURE_230_1	***	LOST CANYON	JUMPER	476	476	CURECANTI (WACM)	***	***	***
LOCN_SHIP_230_1	***	LOST CANYON	JUMPER	476	476	SHIPROCK (WACM)	***	***	***

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TSGT 230 kV Facilities

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NFOR_CURE_230_1	***	NORTH FORK	RELAY	717	717	CURECANTI (WACM)	***	***	***
NFOR_RIFL_230_1	***	NORTH FORK	RELAY	669	669	RIFLE (WACM/PSCO)	***	***	***
NYUM_SPCY_230_1	***	NORTH YUMA	SWITCH	478	583	SPRING CANYON (PSC	***	***	***
NYUM_STO2_230_1	292	NORTH YUMA	WAVETRAP	318	411	STORY (TS)	METER	287	287
NYUM_WRAY_230_1	292	NORTH YUMA	SWITCH	478	583	WRAY (TS)	METER	327	327
PAWN_STO2_230_1	***	PAWNEE (PSCO)	***	***	***	STORY (TS)	JUMPER	648	648
PONC_SALV_230_1	693	PONCHA (WACM)	***	***	***	SAN LUIS VALLEY	METER	180	180
REUN_BALK_230_1	***	REUNION	JUMPER	648	648	BARR LAKE (PSCO)	NLSWITCH	637	648
REUN_SSAD_230_1	***	REUNION	JUMPER	648	648	SILVER SADDLE (PSC	***	***	***
RIFP_RIFL_230_1	631	RIFLE (PSCO)	***	***	***	RIFLE (WACM/PSCO)	***	***	***
RIGS_RIFL_230_1	***	RIFLE GENERATION	WAVETRAP	159	172	RIFLE (WACM/PSCO)	***	***	***
RIVE_RIVP_230_1	630	RIVERTON	BUS	630	647	RIVERTON (PACE)	CB	796	948
SIDN_SPCY_230_1	***	SIDNEY	JUMPER	537	537	SPRING CANYON (PSC	***	***	***
SIDN_STEW_230_1	451	SIDNEY	WAVETRAP	318	411	STEGALL (WACM)	BUS	394	465
SIPR_HNLK_230_1	648	SIPRES	JUMPER	648	648	HENRY LAKE	JUMPER	648	648
THEP_RIVP_230_1	***	THERMOPOLIS (PACE)	NLSWITCH	478	583	RIVERTON (PACE)	***	***	***

TSGT 345 kV Facilities

Section	Conductor Rating MVA*	Terminal 1	Terminal 1 Equipment	Terminal 1 Rating MVA*	Terminal 1 30 Min MVA**	Terminal 2	Terminal 2 Equipment	Terminal 2 Rating MVA*	Terminal 2 30 Min MVA**
AULT_CRAI_345_1	1014	AULT (WACM)	***	***	***	CRAIG	WAVETRAP	717	924
AULT_LRS3_345_1	1627	AULT (WACM)	***	***	***	LARAMIE RIVER (MBP	***	***	***
BONA_CRAI_345_1	***	CRAIG	CT	896	971	BONANZA (PACE)	***	***	***
CRAI_MEE3_345_1	1014	CRAIG	CT	896	946	MEEKER345	WAVETRAP	956	1233
GRJC_MONT_345_1	1585	GRAND JUNCTION (PS	***	***	***	MONTROSE	CT	925	1166
GRJC_RIFP_345_1	***	GRAND JUNCTION (PS	***	***	***	RIFLE (PSCO)	***	***	***
HESP_MONT_345_1	1585	HESPERUS	CT	717	1115	MONTROSE	CT	925	971
HESP_SJUA_345_1	1585	HESPERUS	CT	717	1115	SAN JUAN (PNM)	***	***	***
KEOT_STO3_345_1	1627	KEOTA	NLCB	1792	1944	STORY (MBPP)	FAC008_PSCO	956	1233
LRS3_KEOT_345_1	1627	LARAMIE RIVER (MBP	***	***	***	KEOTA	RELAY	1438	1438
MEE3_MCBR_345_1	***	MEEKER345	METER	647	647	MCBRYDE (WREA)	RELAY	3633	3633
MEE3_RIFP_345_1	1014	MEEKER345	WAVETRAP	956	1233	RIFLE (PSCO)	***	***	***
OJO_TAOS_345_1	782	OJO (PNM)	RELAY	1190	1190	TAOS	CT	755	1242

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Attachment Vol II 4-2 Tri-State 10-year Transmission Plan







AMENDED

10-YEAR TRANSMISSION PLAN

For the State of Colorado

To comply with

Rule 3627

of the

Colorado Public Utilities Commission

Rules Regulating Electric Utilities

February 3, 2020

Web addresses updated as of 6/08/2020

Colorado PUC E-Filings System

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ACRONYMS AND ABBREVIATIONS

Acronym or Abbreviation	Term
2018 Filing	2018 Rule 3627 10-Year Transmission Plan
2020 Plan	2020 10-Year Transmission Plan for the State of Colorado
AQCC	Air Quality Control Commission
ARPA	Arkansas River Power Authority
ATC	Available Transfer Capability
ATCID	Available Transfer Capability Implementation Document
BES	Bulk Electric System
Black Hills	Black Hills Colorado Electric, LLC, d/b/a Black Hills Energy
BHCE	Black Hills Colorado Electric, LLC, d/b/a Black Hills Energy
BHCT	Black Hills/Colorado Transmission
CBM	Capacity Benefit Margin
CBMID	Capacity Benefit Margin Implementation Document
CCOD	City and County of Denver
CCPG	Colorado Coordinated Planning Group
CDOT	Colorado Department of Transportation
CDPHE	Colorado Department of Public Health and Environment
CEII	Critical Energy Infrastructure Information
CEO	Colorado Energy Office
CEP	Clean Energy Plan
CEPP	Colorado Energy Plan Portfolio
City of Raton	Raton Public Service Company
Commission or CPUC	Colorado Public Utilities Commission
Companies	Black Hills, Tri-State and Public Service
Company	Black Hills, Tri-State or Public Service
CPCN	Certificate of Public Convenience and Necessity
CSG	Community Solar Garden
CSU	Colorado Springs Utilities
DSM	Demand-Side Management
EPA	Environmental Protection Agency
EPAct	Energy Policy Act of 2005
ERP	Electric Resource Plan
ERP/APR	Electric Resource Plan Annual Progress Report
ERZ	Energy Resource Zone

Acronym or Abbreviation	Term
Executive Order B 2019 008	The Zero Emission Vehicle Mandate
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
GHG	Greenhouse Gas
HB18-1270	Colorado House Bill 18-1270 (the Energy Storage Procurement Act)
HB19-1261	Colorado House Bill 19-1261 (the GHG Reduction Bill)
HVDC	High Voltage Direct Current
IREA	Intermountain Rural Electric Association
KCEA	K.C. Electric Association
KCEC	K.C. Electric Association
kV	Kilovolt
LEV	Low Emission Vehicle
L&R	Load and Resource
LFRTF	Lamar Front Range Task Force
LGIP	Large Generator Interconnection Procedures
LTC	Load Tap-Changing
LTP	Local Transmission Plan
MEAN	Municipal Electric Agency of Nebraska
MW	Megawatts
MVAR	Mega Volt Ampere Reactive
MVEA	Mountain View Electric Association
NECO	Northeast Colorado
NERC	North American Electric Reliability Corporation
NREL	U.S. Department of Energy's National Renewable Energy Laboratory
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff
OCC	Colorado Office of Consumer Counsel
Order 1000	FERC Order No. 1000 Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities
PA	Planning Authority
PNM	Public Service Company of New Mexico
PRPA	Platte River Power Authority
PST	Phase Shifting Transformer

Acronym or Abbreviation	Term
Public Service	Public Service Company of Colorado
PV	Photovoltaic
P-V	Voltage Stability
RCTF	Rush Creek Task Force
REP	Responsible Energy Plan
RES	Renewable Energy Standard
RTO	Regional Transmission Organization
SB07-100	Colorado Senate Bill 07-100
SB18-009	Colorado Senate Bill 18-009 (the Energy Storage Rights Bill)
SB19-236	Colorado Senate Bill 19-236 (the PUC Sunset Bill)
Sierra	Sierra Subregional Planning Group
SLV	San Luis Valley
SOL	System Operating Limits
SPG	Sub-regional planning group
SPP	Southwest Power Pool
SWAT	Southwest Area Transmission Group
SWEP	Southwest Weld Expansion Project
TBD	To Be Determined
TCPC	Transmission Coordination and Planning Committee
TP	Transmission Provider
Tri-State	Tri-State Generation and Transmission Association, Inc.
TRMID	Transmission Reliability Margin Implementation Document
TTC	Total Transfer Capability
WECC	Western Electricity Coordinating Council
Western/WAPA	Western Area Power Administration (also WAPA)

I. Executive Summary

The purpose of transmission planning is to ensure the present and future reliability of the interconnected bulk electric transmission system. Planning is performed to meet customer needs by facilitating the timely and coordinated development of transmission infrastructure projects on a cost-effective and reliable basis. In order to promote an efficient utilization of the transmission system, planning also takes into account drivers such as public policy initiatives, environmental concerns, and stakeholder interests, which are collected via numerous meaningful input opportunities throughout the planning process.

In 2011, the Colorado Public Utilities Commission ("Commission" or "CPUC") adopted Rules 3625 through 3627, which set forth requirements for transmission planning applicable to Commission-regulated utilities. The rules require these utilities to establish a process to coordinate the planning of additional electric transmission in Colorado in a comprehensive and transparent manner. The process is to be conducted on a statewide basis and is to take into account the needs of all stakeholders. This 2020 10-Year Transmission Plan for the State of Colorado ("2020 Plan") is the result of a cooperative effort among Black Hills Colorado Electric, LLC, d/b/a Black Hills Energy ("Black Hills"), Tri-State Generation and Transmission Association, Inc. ("Tri-State"), and Public Service Company of Colorado ("Public Service") (each a "Company" and collectively the "Companies"), and is the fifth 10-Year transmission plan that the Companies have filed under Rule 3627.

Since filing the first 10-Year transmission plan in 2012, the Companies have continued to coordinate the transmission planning process with all Colorado Transmission Providers ("TPs") and interested stakeholders through active outreach efforts and coordinated planning activities in a variety of transmission planning venues. The 2020 Plan is the culmination of a collaborative process and includes transmission facilities that the Companies, individually or jointly, may construct or participate in over the next 10 years in the state of Colorado. The 2020 Plan includes two types of projects.

"Planned Projects" are projects for which the companies generally have a level of commitment such that proposed schedules for completion have been drafted, site control has been established, or the project has received budgetary approvals. These include projects that are required to meet reliability and load growth needs, planned interconnection of new generation, or to meet enacted public policy requirements. "Conceptual Projects", on the other hand, may not have specific in-service dates, and their implementation depends on numerous factors, some of which include forecasted load growth and generation needs, economic considerations, public policy initiatives, and regional transmission development.

The Companies are confident that the 2020 Plan and the individual transmission projects included in the 2020 Plan meet all applicable reliability criteria and do not negatively impact the system of any other TP or the overall transmission system in the near-term and long-term planning horizons. Projects included in the 2020 Plan do not duplicate existing or planned transmission facilities of any other transmission provider in Colorado. Finally, the Companies are confident that the coordination and stakeholder outreach processes described herein effectively have solicited and addressed the interests of stakeholders.

When possible, individual transmission projects have been designed to accommodate the collective needs of multiple TPs and stakeholders. Changes in regulatory requirements, regulatory approvals, or underlying assumptions such as load forecasts, generation or transmission expansions, economic issues, and other utilities' plans may impact this 2020 Plan and could result in changes to in-service dates or project scopes.

Public policy initiatives, such as recent and future federal and local mandates, also may impact the 2020 Plan and the transmission planning process in general. Examples of public policies and legislation potentially impacting the Companies include Colorado House Bill 19-1261, Senate Bill 19-236 (including the "Colorado Transmission Coordination Act"), Senate Bill 19-077, Executive Order B 2019 002, Colorado's

Renewable Energy Standard, Senate Bill 07-100, and the U.S. Environmental Protection Agency's ("EPA") Affordable Clean Energy Rule.

Section II provides background information about the transmission planning process—including coordinated regional and statewide efforts, as well as internal practices of each Company. Sections III and IV of this report provide additional details for these and other projects that the Companies have identified in their transmission planning processes; complete details and supporting information can be found in Appendices D-I. Sections V to VIII address compliance with specific legal, regulatory and technical requirements of Rule 3627 and Federal Energy Regulatory Commission ("FERC") Orders, with an emphasis on stakeholder outreach efforts.

This 2020 Plan identifies 74 significant transmission projects. These projects are listed in Table 1 and shown geographically in Figure 1. Figures 2 and 3 are maps depicting transmission projects in the Denver-Metro area and in Black Hills' 10-Year Transmission Plan, respectively. Larger maps of the state plan showing chronological stages of development are provided in Appendix A. Larger versions of the Denver-Metro and Black Hills maps are provided in Appendices B and C.

Table 1. Significant transmission projects included in the 2020 Plan

Map #	Project Name	In-Svc (1)	Cost (MIL)	BH	TS	PS	Other	Purpose
1	Arequa Gulch 115 kV Capacitor	2018	$0.85	√				R
2	Boyd 230/115 kV Substation Expansion	2018	$10.0				PRPA	R
3	Missile Site – Shortgrass 345kV Transmission	2018	$104.9			√		G
4	Moon Gulch 230 kV Substation	2018	$1.7			√		L
5	Two Basins Relocation Project	2018	$24.1			√		R
6	Bluestone Valley Substation Phase 1	2019	$12.0			√		R
7	Cottonwood 230/115 kV Autotransformer Replacement	2019	$3.0				CSU	R
8	La Junta 115 kV Area Upgrades	2019	$3.9	√				R

Map #	Project Name	In-Svc [1]	Cost (MIL)	BH	TS	PS	Other	Purpose
9	Pawnee-Daniels Park 345 kV	2019	$169.4			√		G,R
10	Portland 115/69 kV Transformer Replacement	2019	$3.7	√				R
11	Sunshine-Telluride Line Uprate	2019	$3.1		√			R
12	Thornton Substation	2019	$21.4			√		L
13	West Station 115 kV Substation Upgrades	2019	$6.5	√				R
14	Ault 345/230 kV XFMR Replacement	2020	$7.8				WAPA	R
15	Boone-La Junta 115 kV Rebuild	2020	$20.9	√				R
16	CEPP Voltage Support	2020	$93.6			√		G
17	Midway KV1A Replacement	2020	$2.0				WAPA	R
18	Nixon-Kelker 230kV Transmission	2020	$0.5				CSU	R
19	NREL Substation	2020	$10.4			√		G
20	Shortgrass – Cheyenne Ridge 345kV Transmission	2020	$62.3			√		G
21	Shortgrass Switching Station	2020	$20.6			√		G
22	Sisson Project	2020	$18.8		√			L
23	Western Colorado Trans Upgrade	2020	$57.2		√			R
24	Williams Creek 230kV Switching Station	2020	$9.1				CSU	G
25	Avery Substation	2021	$10.3			√		L
26	Barker Distribution Substation	2021	$29.8			√		L
27	Del Camino-Slater 115kV Line Uprate	2021	$1.4		√			L,R
28	Desert Cove-Fountain Valley-Midway 115kV	2021	$5.08	√				R
29	Hogback Ranch 115kV Substation	2021	$9.9	√				R
30	Pueblo West 115kV Distribution Sub	2021	$4.5	√				R
31	Salt Creek 115kV Sub	2021	$6.4	√				R
32	South Fowler Substation	2021	$5.1	√				R
33	Airport Memorial-Nyberg 115kV Rebuild	2022	$3.7	√				R
34	Ault-Cloverly 230/115 kV Transmission Project	2022	$66.7			√		L,R
35	Avon-Gilman 115 kV Transmission	2022	$11.4			√		R

Map #	Project Name	In-Svc [(1)]	Cost (MIL)	BH	TS	PS	Other	Purpose
36	Boone-South Fowler 69/115kV Conversion	2022	$6.6	√				R
37	Burlington-Burlington (KCEA) Rebuild	2022	$0.7		√			R
38	CEPP Switching Station Bid S085	2022	$12.0			√		G
39	CEPP Switching Station Bid X645	2022	$20.0			√		G
40	CSU Flow Mitigation	2022	TBD			√	CSU	R
41	Falcon-Midway 115 kV Line Uprate	2022	$3.8		√			R
42	Greenwood-Denver Terminal 230kV Line	2022	$50.3			√		G,L,R
43	High Point Distribution Substation	2022	$9.0			√		L
44	JG Kalcevik Project	2022	$14.8		√			L,R
45	Mirasol (formerly Badger Hills) Switching Station (CEPP Bid X647)	2022	$12.0			√		G
46	North Penrose 115kV Distribution Sub	2022	$4.5	√				R
47	Titan Distribution Substation	2022	$13.0			√		L
48	Vollmer Project	2022	$7.1		√			L
49	West Station-Greenhorn 115kV Line Rebuild	2022	$4.5	√				R
50	West Station to Hogback 115 kV Transmission Project	2022	$24.0	√				L,R
51	Dove Valley Distribution Substation	2023	TBD			√		L
52	Southwest Weld Expansion Project	2023	$70.0		√			L,R
53	Burlington-Lamar 230 kV	2024	$58.4		√			G,L,R
54	San Luis Valley-Poncha 230 kV #2[2]	2025	$58.0		√	√		R, G
55	Stock Show Distribution Substation	2026	TBD			√		L
56	Bluestone Valley Substation Phase 2	TBD	TBD			√		L
57	Falcon-Paddock-Calhan 115 kV	TBD	$33.4		√			R
58	Glenwood-Rifle 115 kV Transmission	TBD	TBD			√		L,R

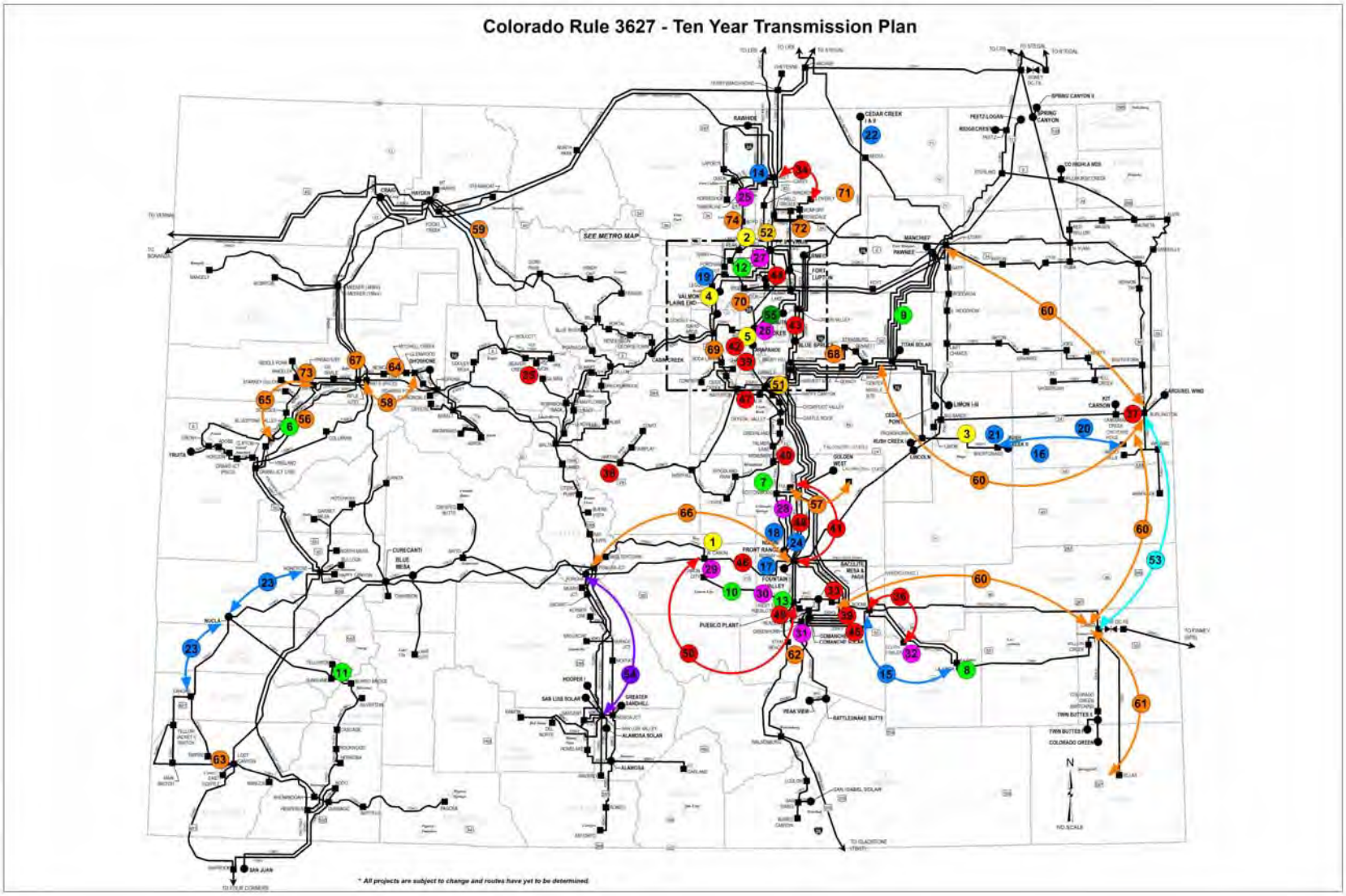
[2] The in-service date and cost for this project are Tri-State estimates and not that of Public Service, though a project may be jointly proposed at some future date.

Map #	Project Name	In-Svc [1]	Cost (MIL)	BH	TS	PS	Other	Purpose
59	Hayden-Foidel-Gore 230 kV	TBD	TBD			√		R
60	Lamar Front Range Transmission	TBD	TBD		√	√		G,R
61	Lamar-Vilas 230 kV Transmission	TBD	TBD		√	√		G
62	Lime Road Delivery Point	TBD	$8.1		√			L
63	Lost Canyon-Main Switch 115 kV	TBD	$22.6		√			L,R
64	New Castle Distribution Substation	TBD	TBD			√		L
65	Parachute-Cameo 230 kV #2	TBD	TBD			√		L,R
66	Poncha – Front Range 230 kV	TBD	TBD			√		G
67	Rifle-Story Gulch 230 kV Transmission	TBD	TBD			√		L
68	Sandy Creek Distribution Substation	TBD	TBD			√		L
69	Solterra Distribution Substation	TBD	TBD			√		L
70	Superior Distribution Substation	TBD	TBD			√		L
71	Weld County Expansion Transmission	TBD	TBD			√		G,R
72	Weld-Rosedale-Box Elder-Ennis 230/115 kV	TBD	TBD			√		L,R
73	Wheeler-Wolf Ranch 230 kV Transmission	TBD	TBD			√		L
74	Wilson Distribution Substation	TBD	$4.0			√		L

Key: R – Reliability, L – Load-serving, G – Generation, TBD – To Be Determined

Note 1: In-service dates are based on best estimates at the time of this filing. Changed needs, load forecasts, permitting activities, timelines for delivery of major equipment, etc. can and will impact project viability and final in-service dates.

Figure 1. Statewide map of significant transmission projects in the 2020 Plan



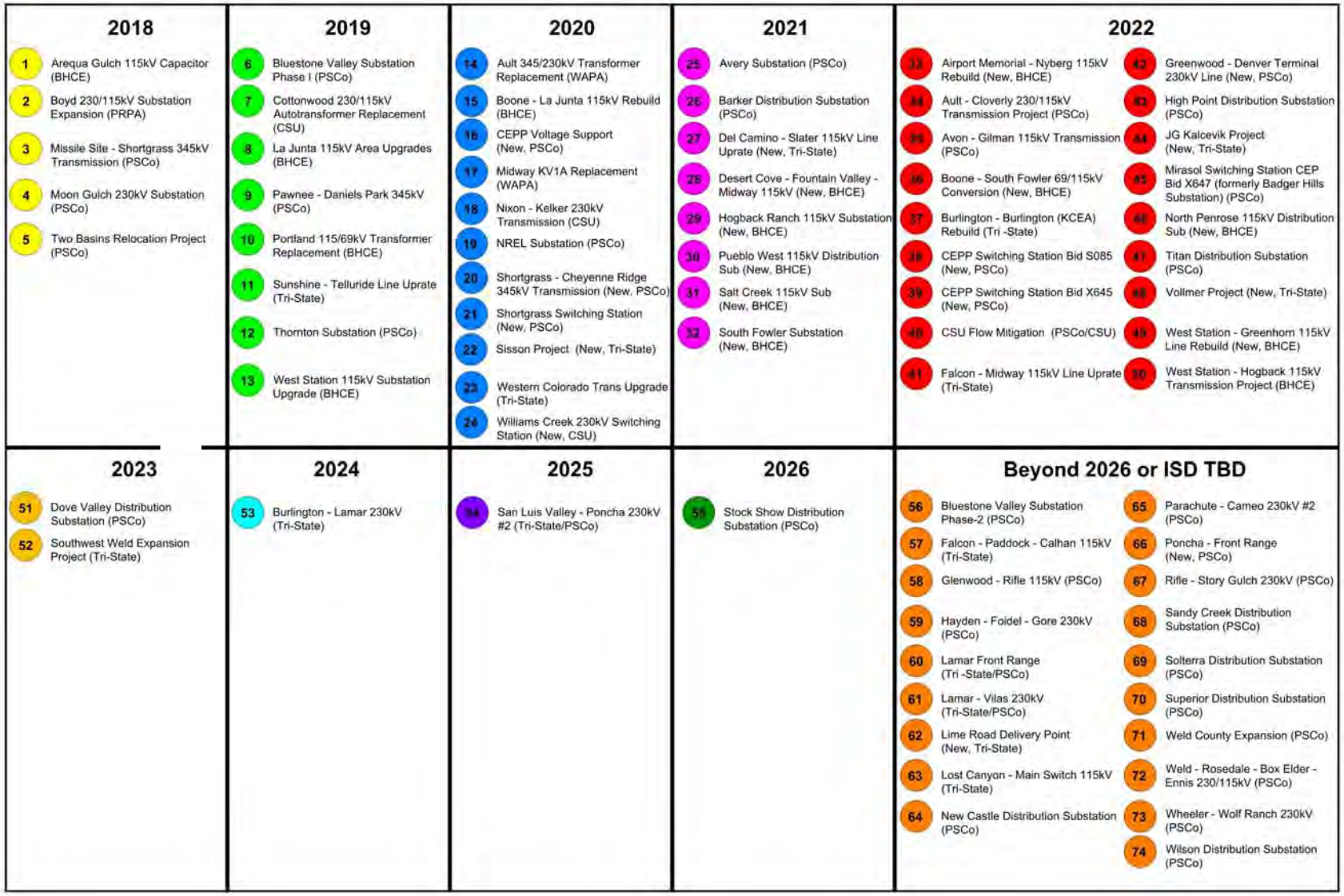

2018
1 Arequa Gulch 115kV Capacitor (BHCE)
2 Boyd 230/115kV Substation Expansion (PRPA)
3 Missile Site - Shortgrass 345kV Transmission (PSCo)
4 Moon Gulch 230kV Substation (PSCo)
5 Two Basins Relocation Project (PSCo)
2019
6 Bluestone Valley Substation Phase I (PSCo)
7 Cottonwood 230/115kV Autotransformer Replacement (CSU)
8 La Junta 115kV Area Upgrades (BHCE)
9 Pawnee - Daniels Park 345kV (PSCo)
10 Portland 115/69kV Transformer Replacement (BHCE)
11 Sunshine - Telluride Line Uprate (Tri-State)
12 Thornton Substation (PSCo)
13 West Station 115kV Substation Upgrade (BHCE)
2020
14 Ault 345/230kV Transformer Replacement (WAPA)
15 Boone - La Junta 115kV Rebuild (BHCE)
16 CEPP Voltage Support (New, PSCo)
17 Midway KV1A Replacement (WAPA)
18 Nixon - Kelker 230kV Transmission (CSU)
19 NREL Substation (PSCo)
20 Shortgrass - Cheyenne Ridge 345kV Transmission (New, PSCo)
21 Shortgrass Switching Station (New, PSCo)
22 Sisson Project (New, Tri-State)
23 Western Colorado Trans Upgrade (Tri-State)
24 Williams Creek 230kV Switching Station (New, CSU)
2021
25 Avery Substation (PSCo)
26 Barker Distribution Substation (PSCo)
27 Del Camino - Slater 115kV Line Uprate (New, Tri-State)
28 Desert Cove - Fountain Valley - Midway 115kV (New, BHCE)
29 Hogback Ranch 115kV Substation (New, BHCE)
30 Pueblo West 115kV Distribution Sub (New, BHCE)
31 Salt Creek 115kV Sub (New, BHCE)
32 South Fowler Substation (New, BHCE)
2022
33 Airport Memorial - Nyberg 115kV Rebuild (New, BHCE)
34 Ault - Cloverly 230/115kV Transmission Project (PSCo)
35 Avon - Gilman 115kV Transmission (PSCo)
36 Boone - South Fowler 69/115kV Conversion (New, BHCE)
37 Burlington - Burlington (KCEA) Rebuild (Tri -State)
38 CEPP Switching Station Bid S085 (New, PSCo)
39 CEPP Switching Station Bid X645 (New, PSCo)
40 CSU Flow Mitigation (PSCo/CSU)
41 Falcon - Midway 115kV Line Uprate (Tri-State)
42 Greenwood - Denver Terminal 230kV Line (New, PSCo)
43 High Point Distribution Substation (PSCo)
44 JG Kalcevik Project (New, Tri-State)
45 Mirasol Switching Station CEP Bid X647 (formerly Badger Hills Substation) (PSCo)
46 North Penrose 115kV Distribution Sub (New, BHCE)
47 Titan Distribution Substation (PSCo)
48 Vollmer Project (New, Tri-State)
49 West Station - Greenhorn 115kV Line Rebuild (New, BHCE)
50 West Station - Hogback 115kV Transmission Project (BHCE)
2023
51 Dove Valley Distribution Substation (PSCo)
52 Southwest Weld Expansion Project (Tri-State)
2024
53 Burlington - Lamar 230kV (Tri-State)
2025
54 San Luis Valley - Poncha 230kV #2 (Tri-State/PSCo)
2026
55 Stock Show Distribution Substation (PSCo)
Beyond 2026 or ISD TBD
56 Bluestone Valley Substation Phase-2 (PSCo)
57 Falcon - Paddock - Calhan 115kV (Tri-State)
58 Glenwood - Rifle 115kV (PSCo)
59 Hayden - Foidel - Gore 230kV (PSCo)
60 Lamar Front Range (Tri -State/PSCo)
61 Lamar - Vilas 230kV (Tri-State/PSCo)
62 Lime Road Delivery Point (New, Tri-State)
63 Lost Canyon - Main Switch 115kV (Tri-State)
64 New Castle Distribution Substation (PSCo)
65 Parachute - Cameo 230kV #2 (PSCo)
66 Poncha - Front Range (New, PSCo)
67 Rifle - Story Gulch 230kV (PSCo)
68 Sandy Creek Distribution Substation (PSCo)
69 Solterra Distribution Substation (PSCo)
70 Superior Distribution Substation (PSCo)
71 Weld County Expansion (PSCo)
72 Weld - Rosedale - Box Elder - Ennis 230/115kV (PSCo)
73 Wheeler - Wolf Ranch 230kV (PSCo)
74 Wilson Distribution Substation (PSCo)

Figure 2. Denver-Metro map of transmission projects in the 2020 Plan

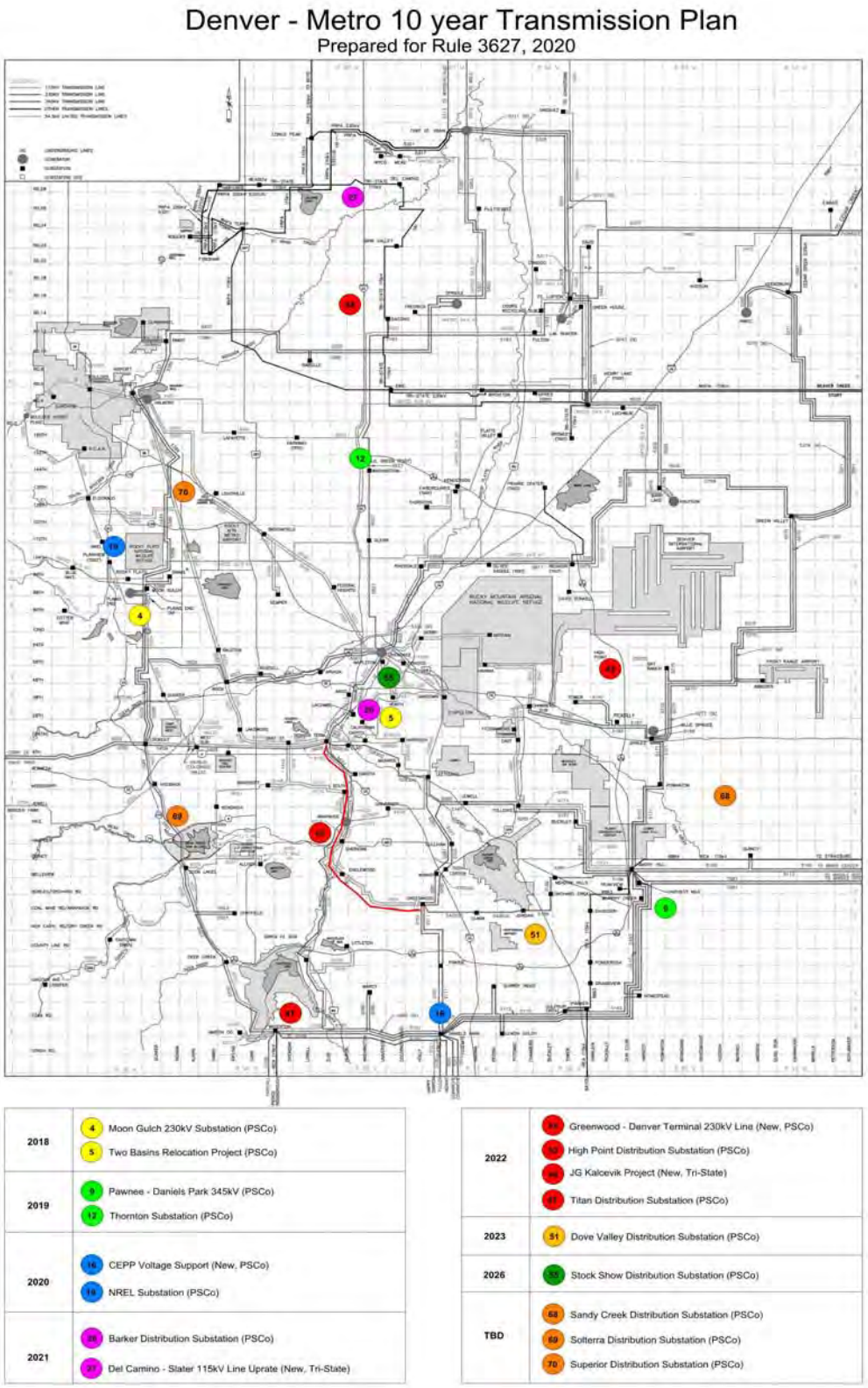
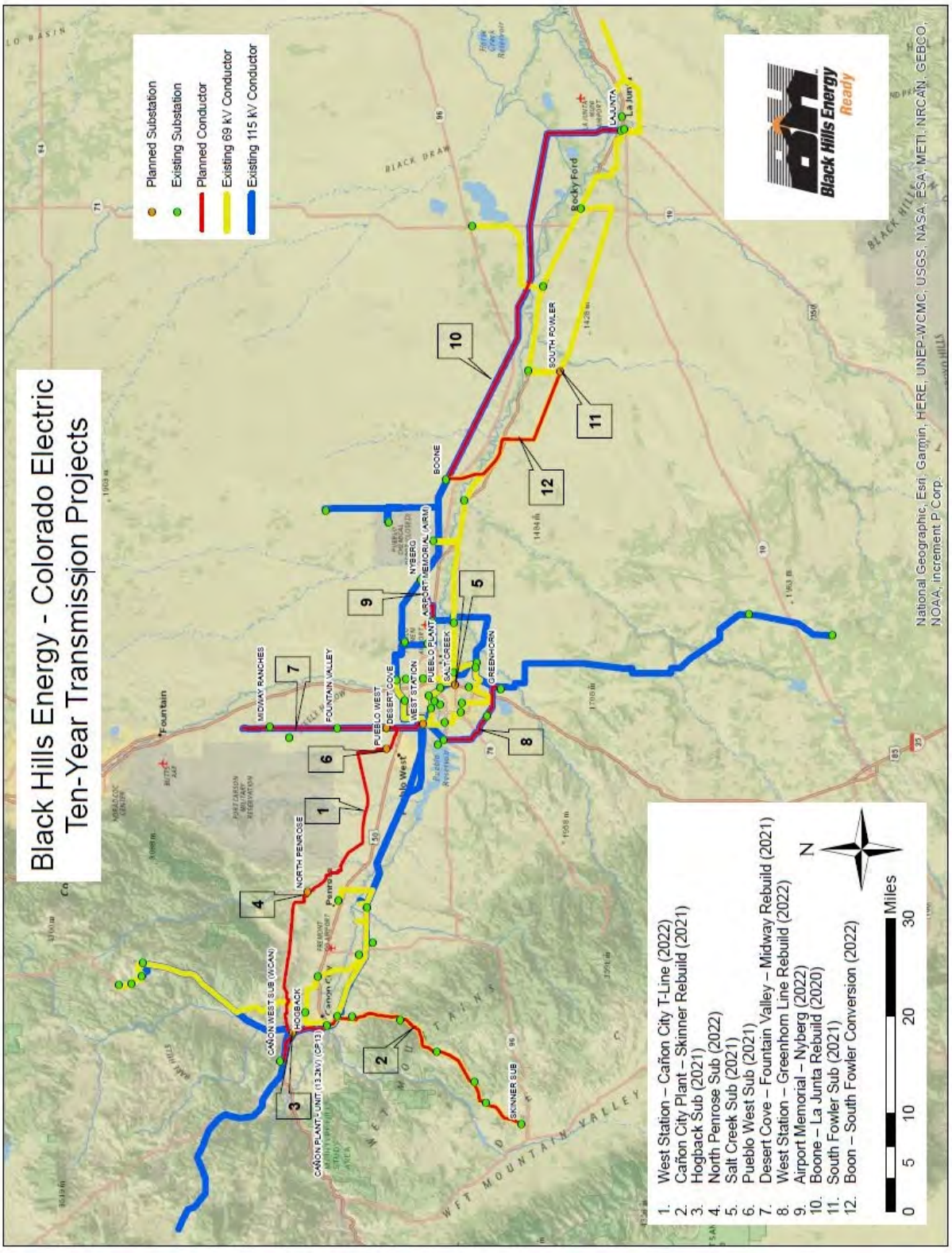


Figure 3. Pueblo area map of transmission projects in the 2020 Plan



II. Transmission Planning in Colorado

A. Coordinated Planning

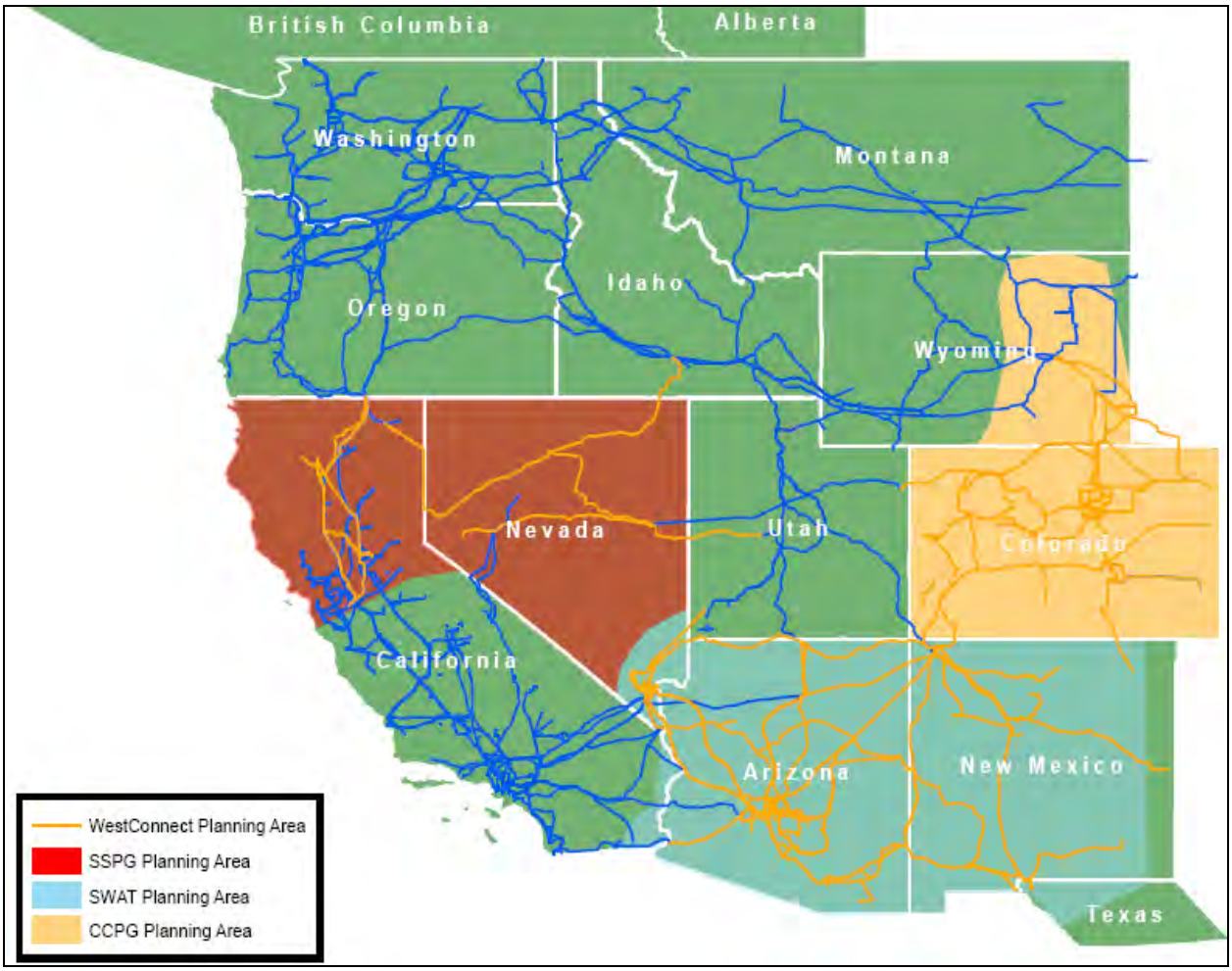
The Companies' transmission planning processes are intended to facilitate the development of electric infrastructure that maintains reliability and meets load growth. Because Colorado does not have a Regional Transmission Organization ("RTO"), each TP in the State is responsible for planning its own transmission system. To ensure that this process is as seamless and efficient as possible, the Companies participate in coordinated transmission planning at regional, sub-regional, and local levels.

The Companies are active members and participants in regional and subregional transmission planning organizations, including the WECC, WestConnect, and the Colorado Coordinated Planning Group ("CCPG"). WECC is the forum responsible for coordinating and promoting Bulk Electric System ("BES") reliability in the entire Western Interconnection.

WestConnect is one of four planning "regions"[3] within WECC established for regional transmission planning to comply with FERC Order No. 1000*, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities* ("Order 1000"). WestConnect includes three sub-regional planning groups ("SPGs"): CCPG, Southwest Area Transmission Group ("SWAT"), and Sierra Subregional Planning Group ("Sierra").

[3] The other three are Columbia Grid, Northern Tier Transmission Group, and the California Independent System Operator.

Figure 4. WestConnect Planning Subregional Group Footprints



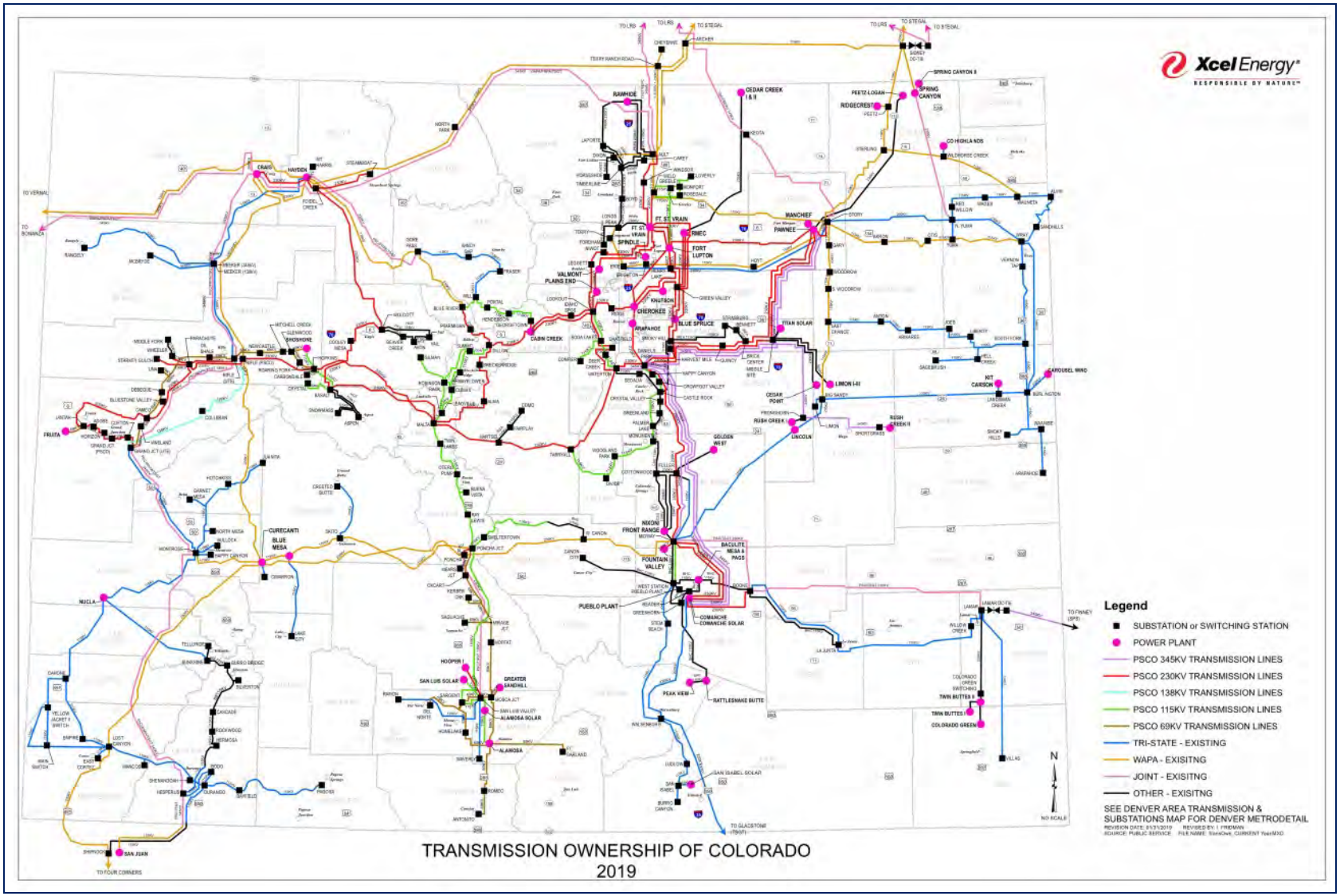
CCPG, which was formed in 1991, is a planning forum that cooperates with state and regional agencies to ensure a high degree of reliability in planning, development and operation of the transmission system in the Rocky Mountain Region. Figure 4 shows the planning areas of the CCPG and other subgroups of WestConnect.

The Companies have a long history of coordinated transmission planning with each other and other Transmission Planners in Colorado. As shown in Figure 5, the Colorado transmission system includes many jointly owned lines. Given the integrated nature and ownership of the transmission grid in Colorado, coordinated transmission

planning has been commonplace in Colorado since even before the adoption of Rule 3627.

As part of the Large Generator Interconnection Procedures ("LGIP"), the Companies often coordinate with each other as well as with other TPs in Colorado on the impacts of any proposed generation projects on the transmission system.

Figure 5. Transmission Ownership in the State of Colorado (2019)



Internally, and through WestConnect and CCPG, each Company performs annual system assessments to verify compliance with reliability standards, to determine related system improvements, and to demonstrate adherence to the standards and criteria set forth by North American Electric Reliability Corporation ("NERC") and WECC. Compliance is certified annually.

During the coordinated planning process, a wide range of factors and interests are considered by the Companies, including, but not limited to:

- The needs of network transmission service customers to integrate loads and resources;
- Transmission infrastructure upgrades necessary to interconnect new generation resources;
- The minimum reliability standard requirements promulgated by NERC and WECC;
- Bulk electric system considerations above and beyond the NERC and WECC minimum reliability standard requirements;
- Transmission system operational flexibility, which supports economic dispatch of interconnected generation resources; and
- Various regional and sub-regional transmission projects planned by other utilities and stakeholders.

This comprehensive internal, regional, and sub-regional planning process ensures that transmission plans continue to be carefully coordinated with all TPs in the State of Colorado.

B. Public Policy Issues

In addition to planning for load growth and reliability, Companies must consider proposed and enacted public policy initiatives, such as Colorado House Bill 19-1261, Senate Bill 19-236 (including the "Colorado Transmission Coordination Act"), Senate Bill

19-077, Executive Order B 2019 002, Colorado's Renewable Energy Standard, Colorado Senate Bill 07-100 ("SB07-100"), and the U.S. EPA Affordable Clean Energy Rule. Two of the Companies, Black Hills and Public Service, are subject to the requirements of SB07-100, which requires Colorado's rate-regulated electric utilities to identify areas that have a high potential for beneficial resource development. A discussion of SB07-100 and other public policy-related planning is included in Section V.

Colorado's Seventy-Second General Assembly enacted climate-action legislation in the 2019 Regular Session. The legislation will transition the state toward a clean-energy, low-carbon economy. The legislation establishes public policy requirements applicable to transmission planning for the 10- and 20-year periods of this Rule 3627 Report. We describe the applicable parts of this legislation for Colorado's transmission infrastructure, as follows:

Senate Bill 19-236 ("the PUC Sunset Bill")

The primary purpose of this bill is to reauthorize the CPUC, by appropriations, for a seven-year period to September 1, 2026. Reauthorization is required by the sunset process. Additionally, the bill carries numerous requirements for utilities and the CPUC to achieve an affordable, reliable, clean electric system. Of these requirements, four are viewed as significant drivers for transmission development in Colorado.

1. Clean Energy Plan ("CEP")

Senate Bill 19-236's CEP requirement is only mandatory for retail utilities providing electric service to more than 500,000 customers. *See* C.R.S. 40-2-125.5. While Public Service is the only public utility subject to this mandatory requirement to formulate a CEP, the legislation provides that other public utilities may "opt in" to CEP regulation upon notification to the Commission. However, the statute expressly excludes municipally owned utilities from CEP regulation. Public utilities that are

subject to the CEP requirement must include a CEP as part of the first Electric Resource Plan ("ERP") the public utility files after January 1, 2020. The PUC determines whether a CEP/ERP, as filed, is in the public interest.

A CEP seeks to reduce the qualifying retail utility's carbon dioxide emissions associated with electricity sales to the qualifying retail utility's electricity customers by 80 percent from 2005 levels by 2030. Further, a CEP seeks to achieve providing a qualifying retail utility's customers with energy generated from 100% clean energy resources by 2050.

Clean energy resources generate or store electricity without emitting carbon dioxide into the atmosphere. Clean energy resources include, without limitation, those generating resources deemed eligible energy resources under the state's Renewable Energy Standard ("RES") pursuant to C.R.S. § 40-2-124(1)(a). CEP activities that may be undertaken to meet the CEP targets under Senate Bill 19-236 include retirements of existing generation facilities, changes in system operations, or other necessary actions to achieve the reduction targets.

A CEP must ensure rate stability for customers served by the utility. Senate Bill 19-236 provides that the "Commission shall establish a maximum electric retail rate impact of 1.5 percent of the total electric bill annually for each customer for implementation of the approved additional clean energy plan activities" through at least 2030 through a CEP revenue rider to afford customers certainty of this maximum rate impact.

New transmission development for a CEP will be reviewed by the PUC under existing transmission planning processes and cost recovery, namely: Rule 3206, Rule 3627, SB07-100, and the Transmission Cost Adjustment. Senate Bill 07-100 Energy Resource Zones will apply to the beneficial resources required for CEP compliance.

In summary, a CEP will present significant drivers for transmission planning, namely:

- New interconnection facilities for clean energy resources;
- Decommissioning, or redevelopment, of existing transmission facilities associated with the potential for accelerated fossil-fuel retirements.

Transmission planning must enable a transition from plant retirements to new generating resources that ensures reliability and resiliency.

2. Cost of Carbon

Senate Bill 19-236 additionally requires public utilities to perform a "cost of carbon" analysis under certain circumstances. *See* C.R.S. §40-3.2-106. This "cost of carbon" analysis requirement applies to the following categories of proceedings: ERPs or any utility plan or application that considers or proposes the acquisition of new electric generating resources or the retirement of existing utility generation; proceedings pertaining to RES; electric demand-side management proceedings; and plans or applications for transportation electrification or other forms of beneficial electrification. The cost of carbon dioxide emissions is based on the social cost of carbon dioxide developed by the federal government. This equals $46 per short ton starting in 2020 and escalates thereafter.

In ERP proceedings, the cost of carbon dioxide emissions must apply to the evaluation of all existing electric generation resources and to any new resources evaluated or proposed as part of the resource modelling. The statute prescribes modeling and analysis steps for evaluating resource portfolios, with and without the cost of carbon dioxide.

In summary, cost-of-carbon planning will result in similar requirements as a CEP for transmission planners, namely: new interconnection facilities and accelerated

decommissioning, or redevelopment, of existing transmission facilities, which together may serve to reduce carbon intensity of the electric utility sector while ensuring reliability and resiliency of the grid.

3. Colorado Transmission Coordination Act

The Colorado Transmission Coordination Act, C.R.S. § 40-2.3-101 *et seq.*, requires the CPUC to open an investigatory proceeding on the potential costs and benefits of participation by Colorado's electric public utilities in a centralized market: specifically, an energy imbalance market, a regional transmission organization, a power pool, or a joint tariff. The statutory timeline is prescribed as follows:

(1) On or before July 1, 2021, the CPUC shall hold a public comment hearing to consider whether electric public utilities should participate in an energy imbalance market, regional transmission organization, power pool, or joint tariff.

(2) On or before December 1, 2021, the CPUC shall issue a decision determining whether participation in an energy imbalance market, regional transmission organization, power pool, or joint tariff is in the public interest.

(3) On or before July 1, 2022, if the CPUC determines that electric utility participation in an energy imbalance market, regional transmission organization, power pool, or joint tariff is in the public interest, the CPUC shall direct electric utilities to take appropriate actions and conduct proceedings the CPUC deems appropriate to pursue participation in an energy imbalance market, regional transmission organization, power pool, or joint tariff.

Adoption of a centralized market is uncertain. If adopted and implemented, a centralized market could be transformative but is highly dependent on the form and function of the determined market design. A centralized market has the potential to

change the locational mix of generating resources and provide congestion relief on the grid through market operations. While relieving congestion is a driver of transmission planning now, a centralized market also may give a market price signal at zones or nodes along the grid. These market prices are known as "Locational Marginal Price" or "LMP". An LMP is a market-clearing price that includes the energy charge, a congestion charge, and transmission system losses. High LMPs at zones/nodes mean more transmission congestion. LMPs may drive investment needs for, and locations of, new transmission facilities to relieve congestion.

4. Wholesale Electric Coops and Resource Planning

Senate Bill 19-236 additionally directs the Commission to promulgate new rules that require wholesale electric cooperatives to submit an application for approval of an integrated or ERP. *See* C.R.S. § 40-2-134. In developing such rules, the Commission must consider, among other factors determined by the Commission, whether wholesale electric cooperatives: serve a multistate operational jurisdiction; have a not-for-profit ownership structure; and have a resource plan that meets the energy policy goals of Colorado.

The Commission issued a Notice of Proposed Rulemaking on July 31, 2019, addressing this statutory requirement and proposing an electric resource planning process applicable to wholesale electric cooperatives. Final rules are pending.

Consistent with this rulemaking, Tri-State expects to continue to interconnect new renewable facilities while retiring certain legacy facilities, and anticipates making transmission improvements as appropriate to accommodate these changes.

House Bill 19-1261 ("the GHG Reduction Bill")

House Bill 19-1261 requires the Air Quality Control Commission ("AQCC") to promulgate rules and regulations for statewide greenhouse gas ("GHG") pollution abatement. *See* C.R.S. § 25-7-105.

Because these rules and regulations will target statewide GHG abatement from all sources, multiple sectors of Colorado's economy will be considered for compliance (transportation, electric generation, industrial manufacturing, etc.). The statewide goals are, at a minimum, a 26 percent reduction in statewide GHG pollution by 2025, a 50 percent reduction in GHG pollution by 2030, and a 90 percent reduction in GHG pollution by 2050 measured relative to statewide GHG pollution levels.

It is anticipated that the AQCC will consider opportunities to incentivize renewable energy resources, issues related to the beneficial use of electricity to reduce GHG, and whether program design could enhance the reliability of electric service.

For transmission planning, the GHG Reduction Bill presents the potential for new load growth and/or changing demand levels and characteristics (beneficial electrification), and shifting generation resources and locational mix (renewable energy and clean-energy adoptions).

Senate Bill 19-077 ("the Electric Vehicles Bill")

Statutory provisions enacted through Senate Bill 19-077 in C.R.S. §§40-1-103.3, 40-3-116, and 40-5-107 may expand electric vehicle infrastructure in Colorado. Charging ports and fueling stations are presently operated by third parties and as non-regulated services of public utilities. Senate Bill 19-077 authorizes utility ownership of electric vehicle charging infrastructure. The bill enables a regulatory approval process for electric utilities to invest in charging facilities and provide incentive rebates; thus, the investments and rebates may earn a return at the utility's authorized weighted-average

cost of capital. Where approved, the costs for the investments and rebates may be recovered from all customers of the electric utility similar to recovery of distribution system investments. Natural gas public utilities may provide fueling stations for alternative fuel vehicles as non-regulated services only.

The regulatory process for electric utilities will commence by May 15, 2020, and every three years thereafter, with the filing of a transportation electrification plan application by each jurisdictional utility. The application filing will request Commission authorization of a proposed transportation electrification program in the utility's certificated service territory; specifically, regulated activities and capital spending for electric vehicle charging facilities, electric vehicle make-ready infrastructure investments, and associated electrical equipment. The transportation electrification program may include community-based, multifamily charging infrastructure, car share programs, and electrification of public transit. The regulatory process will consider impacts on low-income customers, and access by low-income, moderate income, and underserved communities. The legislation provides that the retail rate impact from the development of electric vehicle infrastructure must not exceed one-half of 1 percent of the total annual revenue requirements of the utility. The legislation specifies that in evaluating the retail rate impact, the Commission "shall consider revenues from electric vehicles in the utility's service territory."

Widespread deployment of electric vehicles will represent load growth for transmission planning requirements within the 10-year period of this report. Further, adoption of electric vehicles will provide benefits to the grid. With charging electric vehicles essentially acting as energy storage, there may be an ability to integrate variable renewable resources and off-peak generation.

House Bill 18-1270 ("the Energy Storage Procurement Act")

House Bill 18-1270 directs the Commission to develop a framework to incorporate energy storage systems in utility procurement and planning processes. *See*

C.R.S. § 40-2-201, *et seq*. The legislation broadly addresses resource acquisition and resource planning, and transmission and distribution system planning functions of electric utilities. Energy storage systems may be owned by an electric utility or any other person.

House Bill 18-1270 required the Commission to adopt rules for procurement and planning by February 1, 2019, to create conditions under which the procurement or ownership of energy storage systems by an electric utility will provide systemic benefits. These benefits include increased integration of energy into the grid; improved reliability of the grid; a reduction in the need for increased generation during periods of peak demand; and, the avoidance, reduction, or deferral of investment by the electric utility.

Decision C18-1124 in Proceeding No. 18R-0623E, mailed on December 12, 2018, adopted permanent rules in 4 *Code of Colorado Regulations* (CCR) 723-3. The rule requirements on transmission planning are relevant to this 10-year planning period.

Governor Jared Polis Administration's "Roadmap to 100% Renewable Energy by 2040 and Bold Climate Action"

On May 30, 2019, Governor Polis unveiled a roadmap to 100% renewable energy by 2040 and bold climate action. The roadmap seeks to transition the state of Colorado to 100% renewable energy by 2040. Toward this end, the roadmap has seven components, namely:

1. Grow green jobs and save consumers money.
2. More zero emission vehicles and commuting options.
3. Support local commitment to 100% renewable energy.
4. Modernize the Public Utilities Commission.
5. Promote energy efficiency.
6. Move toward zero emissions buildings.
7. Ensure a just and equitable transition for all of Colorado.

A transition to 100% renewable energy would have a significant impact on transmission planning in the 10-year period with load growth. Specifically, electrification of transportation will represent load growth; notably, the Governor's plan strives for 940,000 zero emission vehicles by 2030 and $14 million of transit bus fleet conversions. Similarly, electrification of buildings will represent load growth as space heating and manufacturing needs shift from direct fossil fuels to electricity. The Governor's plan has three financing programs for residential and commercial building improvements: C-Pace, RENU, and the Colorado Clean Energy Fund. In FY2019, approximately $30 million was financed by C-Pace and RENU alone.

Executive Order B 2019 008 ("the Zero Emission Vehicle Mandate")

On January 17, 2019, Executive Order B 2019 002 – Supporting a Transition to ZEV –was issued by Governor Polis. Four areas are directed in the Executive Order to further the state toward a higher electric vehicle market share:

1. Creates a transportation electrification workgroup composed of 17 members, appointed by the Governor. The members represent state agencies and offices. The workgroup will develop, coordinate, and implement state programs and strategies for transportation electrification with annual reports to the Governor.

2. Directs the Colorado Department of Public Health and Environment ("CDPHE") to develop rules for a Colorado Zero Emission Vehicle Program pursuant to Colorado's authority under section 177 of the federal Clean Air Act, 42 U.S.C. § 7507.

3. Revises the spending for the remaining funds available in Colorado's $70 million VW Beneficiary Mitigation Plan for electrification of transportation, including transit buses, school buses, and trucks. Furthermore, if additional

settlement or lawsuit funds are received by Colorado, those funds will assist consumers' transition to ZEVs.

4. Directs the Colorado Department of Transportation to develop a department-wide ZEV and clean transportation plan.

In compliance with the Executive Order, the Air Quality Control Commission ("AQCC") adopted a ZEV rule on August 16, 2019. The rule is codified at 5 *CCR* 1001-24, Part C. For the 2023 vehicle model year, a specified percentage of vehicles *offered for sale* in Colorado must be ZEV. The percentage shall be consistent with California Code of Regulations, Title 13, Section 1962.2. The percentage is more than 5 percent zero emission vehicles by 2023 and more than 6 percent zero emission vehicles by 2025. The vehicles covered by the ZEV rule are passenger car and light-duty trucks.

The ZEV rule follows the Low Emission Vehicle ("LEV") rule adopted by AQCC on November 16, 2018. The rule is codified at 5 *CCR* 1001-24, Part B. The LEV rule complied with Executive Order B 2018 006 issued by Governor John Hickenlooper on June 18, 2018. For the 2022 vehicle model year, sales of passenger cars, light-duty trucks, medium-duty passenger vehicles or medium-duty vehicles must meet the LEV III Criteria emissions and GHG emissions codified by California Code of Regulations, Title 13, Sections 1961.2 and 1961.3, respectively. The proposed ZEV program will reduce total GHG emissions by 3.5 million short tons cumulatively by 2030.

For transmission planning, electrification of transportation as directed in the ZEV rule will represent load growth. However, in the near term, there are regulatory uncertainties. The ZEV rule is facing federal challenges by the Administration of President Donald Trump under authority of the Clean Air Act.

Senate Bill 18-009 ("the Energy Storage Rights Bill")

Senate Bill 18-009, enacted in C.R.S. § 40-2-130, protects the rights of Colorado electricity consumers to install, interconnect, and use energy storage systems on their property without the burden of unnecessary restrictions or regulations and without unfair or discriminatory rates or fees. In particular, Senate Bill 18-009 prohibits electric utilities from requiring additional customer-sited meters to monitor the energy storage system where a single net energy meter is installed (with exceptions for certain large energy systems). Moreover, Senate Bill 18-009 ensures that statutory net metering, as provided for in C.R.S. § 40-2-124, is neither altered nor superseded.

Senate Bill 18-009 requires the CPUC to adopt conforming rules. In rulemaking Proceeding No. 19R-0096E, the CPUC has proposed additions and amendments at Rule 3850 (Interconnection Procedures and Standards) to *inter alia* implement Senate Bill 18-009. Notably, a proposed definition for "distributed energy resource" has replaced the former definition for "small generating facility". Distributed energy resources, or DERs, is proposed to be defined as customers' sources of electric power, including retail renewable distributed generation, other small generation facilities, and energy storage systems. Distributed energy resources, or DERs, will be subject to PUC-approved interconnection procedures upon adoption of final rules.

C. Emerging Issues

1. Wildfire Risk Mitigation

One only needs to look to California to see the impact a wildfire can have on the electric system and community at large. Given that, the companies believe that investment in wildfire mitigation and grid resiliency is the most prudent course of action to moderate the risks associated with extreme weather events. Wildfire mitigation efforts have been and will continue to be centered on long-term investments in projects targeted at enhancing grid resiliency, expanding vegetation management, and

accelerating system hardening and equipment maintenance throughout the companies' service territories.

2. Energy Storage and Non-wires Alternatives

Non-wires alternatives to address capacity needs and reliability constraints related to load growth is an emerging topic for consideration during transmission planning. As such, an additional work group at CCPG, the Energy Storage Work Group (ESWG), has been created to analyze the benefits and challenges for energy storage and other non-wire alternative technologies. Studies may include geo-targeted energy efficiency, demand-side management, demand response, distributed generation, energy storage, and potentially other technologies. The first meeting for the ESWG was held on January 23, 2020.

3. Distributed Energy Resources (DER)

The increase of customer-sited DER may alter transmission system requirements. Most utilities have been able to model customer DER primarily on distribution systems as net load. Increasing DER penetration presents new challenges with modeling and operation of distribution and transmission systems. DERs also may present opportunities to address load growth and provide resiliency, if planned correctly. DERs tend to be more expensive than larger-scale generation options, and so cost-effectiveness will be a factor in the growth of DERs over time. It will be important to understand policies and consider investments that may be needed in the 10-year horizon.

4. Grid Resiliency with Inverter-Based Resources

The influx of inverter-based resources combined with conventional power plant closures has raised concerns of grid resiliency. The Blue Cut Fire (2016) and Canyon 2 Fire (2017) in California triggered approximately 900 MW and 1200 MW, respectively, of

solar PV generation to cease generation during transmission system faults. These events and other system observations have led NERC to develop Reliability Guidelines to assist utilities and manufacturers in maintaining a resilient grid. Recent Reliability Guidelines include the following:

- Integrating Inverter-Based Resources into Low Short Circuit Strength Systems (December 2017)
- BPS-Connected Inverter-Based Resource Performance (September 2018)
- Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources (September 2019)

At the regional level, WECC's Studies Subcommittee has a Change to System Inertia with High Renewable Implementation Task Force (SITF) evaluating the reliability impacts on the Western Interconnection as conventional resources are retired during increased implementation of inverter-based resources. The companies believe that it will be important to understand and apply the Reliability Guidelines as they are developed, as well as participate in regional study efforts to ensure proper analysis is performed to maintain grid resiliency.

III. Company Plan Narratives

A. Black Hills 10-Year Plan Overview

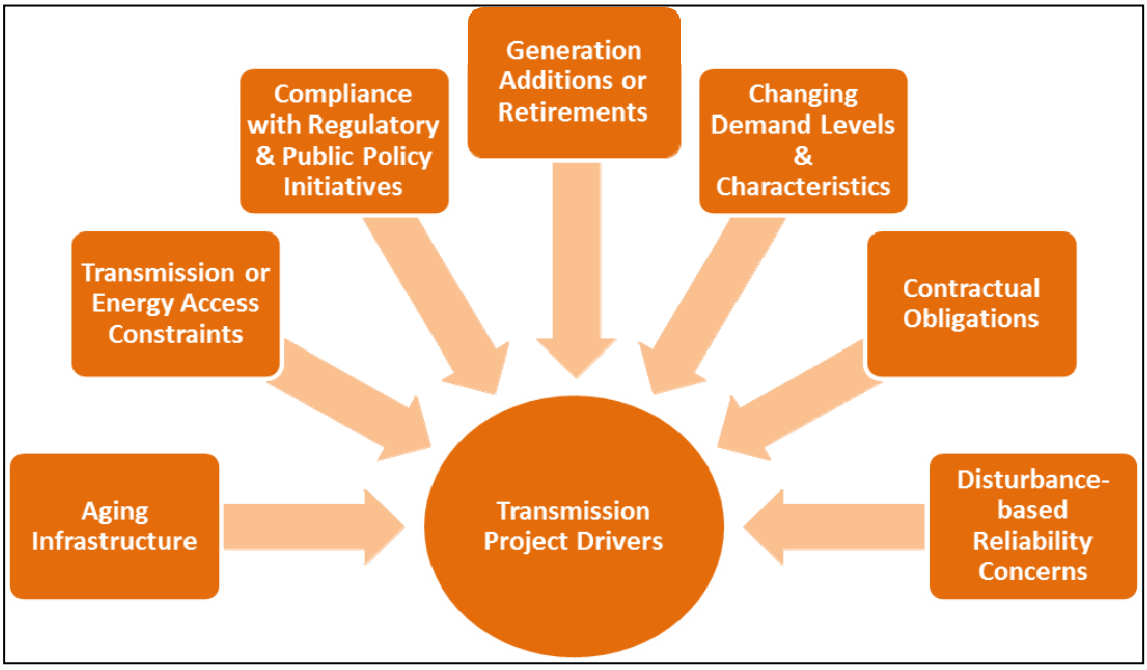
1. Black Hills Service Territory

Black Hills Colorado Electric, LLC, a division of Black Hills Corporation, serves over 98,000 customers in south-central Colorado. The counties served are parts of Crowley, Custer, El Paso, Fremont, Otero, Pueblo, and Teller. Twenty-one communities are served, and of these, the largest communities are Pueblo, Cañon City, and Rocky Ford.

The Black Hills planning process emphasizes education, participation, and coordination, with the ultimate goal of contributing to the development of an optimal long-term road map for transmission development in Colorado, consistent with Rule 3627.

Throughout its transmission planning process, Black Hills considers a number of variables and inputs, the first of which is a specific need or set of needs that drive the development of a certain project. Figure 6 shows a selection of needs that commonly give rise to projects within the Company's planning horizon.

Figure 6. Needs that Drive Transmission Development



Needs may arise from a single entity, or they may coincide with the needs of multiple entities, in which case a joint project may be appropriate. Once a need has been identified, Company planners begin searching for a solution. As solution alternatives are developed, the following considerations may come into play:

- Potential of each alternative to augment or inhibit potential future projects
- Cost of implementation and availability of project funding
- Required implementation schedule
- Environmental and societal impacts
- Project life expectancy
- Tangible benefits to customers
- Geographic and physical constraints
- Ability to integrate with existing and planned transmission projects
- Impact to telecom, transportation, and other energy-related networks

Black Hills transmission planners, through coordination with the stakeholder community, evaluate the weight of the above considerations to determine the best

overall solution to the identified need, ensuring that the solution is financially prudent, publicly acceptable and physically feasible. Often a small subset of these factors will comprise a majority of the justification for a project.

Because communication and stakeholder participation is critical at all stages of planning, Black Hills performs its planning process on an annual basis in an open, transparent, coordinated and non-discriminatory fashion to ensure the opportunity for direct participation is offered to all stakeholders. Consistent with FERC Order Nos. 890 and 1000, Black Hills promotes participation in the planning process to all interested parties, and coordinates study efforts and results with other utilities as well as regional planning organizations such as West Connect, CCPG, and various groups within WECC.

Planning reliability studies are conducted annually to satisfy NERC and WECC requirements. Additional studies are performed as necessary to address specific purposes including, but not limited to, transmission service requests, generator interconnections, transmission interconnections, load interconnections and transfer capability assessments. This process and related discussions are subject to FERC's Critical Energy Infrastructure Information ("CEII") procedures.

Black Hills planners employ software models representative of the transmission system during the timeframe of interest, including current load and resource information, existing and planned infrastructure, service commitments, facility ratings and parameters, valid disturbance events, and any operating constraints to be observed. Additionally, all guidelines, requirements and applicable criteria, as well as 10-Year load and resource projections (submitted annually by network customers), are reviewed and included in the study plan. These study models allow planners to identify conditions and timeframes during which the transmission system will or will not satisfy all reliability and economic requirements.

If a planning study identifies a deficiency in transmission system performance, various mitigation options are evaluated to determine an optimal solution to meet the long-term needs of all affected parties. Evaluation of each potential project is coordinated with interested stakeholders and neighboring transmission providers to avoid duplication, minimize impacts and the likelihood of unmet obligations, and maximize the overall benefit of a project.

Routine planning is conducted for a wide range of scenarios to evaluate the performance of the transmission system over a 10- to 20-year period. In a given study year, viable system upgrades and transmission initiatives are compiled to create the Black Hills 10-Year Local Transmission Plan, which is evaluated annually and updated as needed to reflect ongoing project needs. Potential changes in reliability requirements, planned generation, transmission, load growth, and regulations require the build-out of a flexible, robust transmission system that meets customer needs under a wide range of foreseeable circumstances within the planning horizon.

2. Black Hills Projects

A. Renewable Advantage (200 MW)

On November 22, 2019, Black Hills Colorado Electric, LLC filed an application at the Commission to amend its 2016 Electric Resource Plan with a competitive solicitation for up to 200 MW of renewable energy and energy storage. The competitive solicitation is known as Renewable Advantage. The application was docketed in Proceeding No. 19A-0660E.

The Company's expected load and resource balance was determined in Phase I of the 2016 ERP and completed in January 2017. There have been no significant changes to the load and resource balance. The Company has no material need for new capacity through December 31, 2023.

This notwithstanding, the Company's indicative analysis provides that procuring energy from renewable resources and/or energy storage, with an in-service date no later than December 31, 2023, may produce significant benefits for customers. The benefits are energy fuel cost savings and emission reductions beyond the state's Renewable Energy Standard (30% of retail electricity sales by 2020). The fuel cost savings will be implemented through the ECA rate mechanism. The procurement will have no negative impact to the RESA fund. The emission reductions could bring the Company's service territory to approximately 55-65% renewable.

The Company's indicative analysis is based, in part, on modeling of recent bid price results from PSCo's renewable competitive solicitation. The PSCo renewable competitive solicitation was held from July 1 through August 1, 2019. The median bid price was $24.00 MWh for Solar PV and $36.30 MWh for SolarPV+Storage. Black Hills Energy has modeled these median bid prices for a 200 MW generic resource, showing customers savings in every year of the life of the generic resource.

An important consideration for any procurement of renewable or storage resources under Renewable Advantage will be to minimize any transmission cost impacts to customers.

The Company has identified five existing substations where minimal or no upgrades to the broader network transmission system are expected with the addition of 200 MW. While the Company has not specifically studied these locations, there is a high degree of confidence that these five substations can accommodate the new resources with lesser amounts of upgrades and costs. The preferred locations for interconnection are:

1. West Station Substation
2. Baculite Mesa Substation
3. Nyberg Substation

4. Boone Substation
5. Midway Substation

Further, it is appropriate to limit the addition of new renewable and storage resources to 200 MW for two primary reasons. First, a contingency scenario indicates that forcing any amount beyond 200 MW on a single 222 MVA-rated line, or on a single 120 MVA- or 160 MVA-rated line, would require significant spending for line rebuilds, system improvements, and/or generation curtailment to successfully interconnect the project. Thus, 200 MW is a prudent approach for mitigating transmission cost impacts. Second, the Company's transmission planning only studies a moment in time and not real-time (minute-to-minute) operating situations that can occur when variable generation ramps quickly. As the Company's renewable penetration increases, it will be increasingly difficult to balance the Company's generation and load in real-time. The 200 MW bid amount for the Renewable Advantage is about equal to the Company's minimum system load, a prudent limit for balancing the Company's generation and load in real-time conditions.

B. Transmission Projects

Black Hills' load growth has increased over the past couple of years, driven primarily by large industrial load expansions as well as some commercial load growth. The Black Hills projects included in the 2020 Plan largely reflect the continued strategy of infrastructure upgrades of additions to enhance reliability. Since most of Black Hills' projects are reliability-driven equipment replacements or upgrades, the focus on best-cost considerations was narrowed as appropriate.

In the 2020 Plan, which was the result of an open and coordinated planning approach on regional, sub-regional and local levels, Black Hills documents a procedure to address foreseeable local reliability, integrity and load service issues. Detailed project information can be found in Appendix D.

Since the filing of the 2018 10-Year Plan, Black Hills has completed three projects: Arequa Gulch 115kV Capacitor, Portland 115/69 kV Transformer Replacement, and West Station 115 kV Substation Upgrades. Black Hills identified 11 planned projects within the upcoming 10-year planning horizon that represent $89.52 million in capital expenditures between 2020 and 2023. The projects were identified to increase reliability within Black Hills' network transmission system, to support voltage, and to meet the requirements associated with expected load growth and generation development. The reliability-driven projects are required under various NERC Reliability Standards to address anticipated system performance issues. The projects in this section were coordinated with stakeholders and neighboring entities to ensure the best solution is achieved while avoiding duplication of facilities.

Planned projects are categorized according to the three distinct geographic areas within Black Hills' Colorado service territory.

Cañon City area

Three projects, shown in Table 2, address reliability and integrity concerns in the Cañon City area. Local load growth has resulted in the need for additional capacity in the area, as well as local voltage support. A new transmission line into the area and a substation rebuild will improve load service and operational flexibility.

Table 2. Cañon City area projects included in the Black Hills 2020 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
West Station – Hogback Transmission Line[4]	1/2022	$24.00	Not required

[4] This line also is known as the Southern Colorado Reliability Upgrade Project.

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
115/69 kV Hogback Ranch Substation Build	9/2021	$9.90	Not required
115kV North Penrose Distribution Substation	1/2022	$4.5	A planned project included in the 2018 Rule 3206 filing (Proceeding No. 18M-0005E)

The Black Hills planning process identified these projects as solutions for expected concerns regarding reliability and anticipated load growth in the Cañon City area. The primary driver of the West Station – Cañon City Transmission Line was to increase the reliability of Black Hills' transmission system feeding Cañon City and the surrounding area. Load growth in the Cañon City area has led to reliability concerns following the loss of the two transmission lines connecting that area to the Pueblo part of the Black Hills system. To mitigate these concerns, several options were considered. The West Station – Cañon City 115 kV Transmission Line build is set to rectify the burden of load growth in the area. The new connection also enables the future replacement of stressed transmission lines at a greatly reduced operational risk.

The Hogback Ranch project provides the added benefit of adding a 115/69 kV source near the existing North Cañon 69 kV substation. This will offload the existing Cañon City transformer and add operational flexibility to the local 69 kV system. The new source may provide future improved backup service to the Cripple Creek area via the normal open 69 kV line for emergency situations. The initial scope of the West Station-West Cañon project was coordinated with other entities to explore opportunities for joint participation in the project. This was done to potentially meet a wider range of system needs while minimizing the impact to the local landscape through the potential use of double circuit towers and utilization of existing transmission corridors when possible. The project was identified as an SB07-100 project in the 2015 study because it facilitates a larger resource injection from Energy Resource Zone ("ERZ") 4. Refer to

the Black Hills Corporation 2020 SB07-100 Study Report included in Appendix L for more information.

The North Penrose Distribution Substation consists of constructing a new substation to accommodate two 115/13.2kV, 25MVA transformers. Currently, the community of Penrose is served radially on a 69kV line with limited contingency backup alternatives. This addition will provide the community with another source, while also offloading the 115/69kV transformers at Portland.

Pueblo area

Five projects, shown in Table 3, address reliability and contingency concerns in the Pueblo area. There has been unanticipated significant growth in the Pueblo area that will be accommodated through these future projects.

Table 3. Pueblo area projects included in the Black Hills 2020 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
115 kV Salt Creek Substation	Q3 2021	$6.4	Not required
115 kV Desert Cove - Fountain Valley – Midway Rebuild	11/20/2021	$5.08	Not required
115kV Pueblo West Distribution Substation	1/2021	$4.5	A planned project included in the 2018 Rule 3206 filing (Proceeding No. 18M-0005E)
115kV West Station-Greenhorn Line Rebuild	9/2022	$4.5	Not required
115kV Airport Memorial – Nyberg Rebuild	9/2022	$3.7	Not required

The 115 kV Salt Creek Substation project was determined by the planning team to be a way to rectify growth concerns for the increasing demand in Colorado. Salt Creek Substation would relieve some of the load from existing distributions systems, while also supplying contingency and maintenance switching options. The addition of this substation also allows for increased capacity and contingency with distribution systems within the same area. The project is currently in land negotiation phases; therefore, the total project cost is TBD.

The 115kV Desert Cove – Fountain Valley – Midway rebuild is a result of studies that determined inadequacies in heavy summer conditions. The potential for high power flows in the north-south direction could result in a Category P2 and P4 230kV breaker failure and loss of 230kV lines. This situation would lead to inadequate thermal ratings on the 115kV Desert Cover – Fountain Valley – Midway line. To mitigate this potential issue, the 14-mile line is to be rebuilt and replaced with a minimum rating of 1110A end to end.

The 115kV Pueblo West Distribution Substation will be built to ultimately accommodate two 115/13.2kV, 25MVA transformers. This project is required to serve new industrial and agricultural load as well as contingency back-up for existing distribution infrastructure. This substation additionally addresses low voltage concerns under peak demand conditions for the area.

The 115kV West Station – Greenhorn Line rebuild is to address the age of the infrastructure. The existing 336 ACSR conductor will be replaced to increase the capacity of the line. This project will be a 12.1-mile-long rebuild that uses the current right-of-way. The project, once completed, will increase the line ratings to accommodate current summer and winter ratings.

The 115kV Airport Memorial – Nyberg rebuild is to increase the thermal capability of the lines by replacing the 336 ACSR line with 795 ACSR. Overloads on this line were identified in previous 10-year planning assessments under a contingency of losing both

the Boone-Comanche 230kV and Nyberg-Baculite Mesa 115kV lines. By replacing this line, the thermal capacity can be increased to accommodate the load under the studied contingency.

Rocky Ford area

Three projects, as shown in Table 4, address reliability and contingency concerns in the Rocky Ford area.

Table 4. Rocky Ford area projects included in the Black Hills 2020 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Boone – La Junta 115 kV Rebuild	1//2020	$15.24	Not required
South Fowler Substation	10/2021	$5.10	Not required
Boone – South Fowler 69/115kV Conversion	9/2022	$6.6	Not required

The Boone-La Junta 115 kV line rebuild is a multi-year project beginning in 2018 and ending in 2020. The entire 45-mile length of the line will be rebuilt using larger conductors to address age-related integrity issues, as well as provide additional capacity on the only transmission line serving that portion of the Black Hills system. The modest load growth forecasted for the area did not necessitate the need to implement the project at a higher operating voltage.

Previously known as “La-Junta Area Upgrades”, the South Fowler Substation and Boon-South Fowler 69/115kV conversion replaces this project. Under a study that was geared to determine the integrity of the 69kV infrastructure, it was deemed that a significant number of lines needed to be rebuilt within the near-term planning horizon. The addition of the South Fowler substation proves to be beneficial for offering additional capacity to the area, along with operational flexibility when rebuilding neighboring aged 69kV lines. The Boone-South Fowler 69/115kV conversion will be

accomplished using 795 ACSR on double circuit structures to accommodate the new line, while maintaining a connection from Boone to Huerfano. This line will be a 19-mile build and is set to improve the reliability of the line regarding increased voltage.

Information concerning the specific Colorado projects included in the Black Hills 2020 10-Year Plan is contained in Appendix D. Additional general information can be found at https://www.blackhillsenergy.com/transmission-rates-and-planning/transmission-projects

B. Tri-State 10-Year Plan Overview

1. Tri-State Planning Process

Tri-State's transmission planning process is intended to facilitate the timely and coordinated development of transmission infrastructure that maintains system reliability and meets customer needs, while continuing to provide reliable, responsible, cost-based electric power to its 43 electrical cooperatives and public power districts (Member Systems). With Member Systems in four states (Colorado, Nebraska, New Mexico, and Wyoming), Tri-State is a regional power provider with only a portion of its planned transmission facilities located in Colorado and therefore included in this plan.

The primary objectives of Tri-State's transmission planning process are to meet the needs of network and point-to-point customers, maintain reliability, accommodate load growth, and coordinate interconnections. The key elements of Tri-State's transmission planning process are:

- Maintaining safe, reliable electric service to its members at the lowest possible cost;
- Improving efficiency of electric system operations;
- Providing open and non-discriminatory access to its transmission facilities; and

- Planning new transmission infrastructure in a coordinated, open, transparent and participatory manner.

Tri-State's primary planning activities center on the preparation of the 10-Year Capital Construction Plan for approval by the Tri-State Board. All projects included in Tri-State's 10-Year Capital Construction Plan adhere to NERC and WECC Standards and Criteria, FERC Order No. 890 Planning Principles, and coordinated regional planning principles, as well as the criteria outlined in Rule 3627.

Tri-State implements its transmission planning process through various studies, including:

- Reliability studies (for both bulk system infrastructure and sub-transmission);
- System impact studies;
- Transmission service requests;
- Generator interconnection studies;
- Facilities studies; and
- Economic studies.

Tri-State's Member Systems create long-range plans and other work plans that they provide periodically to Tri-State's Transmission Planning Department. When Member Systems' plans indicate the need for system upgrades or new construction, Member Systems apply to Tri-State Transmission Planning for a new or modified delivery point to be served from the Tri-State transmission system. The application contains sufficient information for Tri-State Transmission Planning to identify and consider alternatives to meet the Member Systems' requirements in a manner consistent with immediate and long-term needs in the context of the overall transmission system development.

Tri-State's contribution to the 2020 Plan was developed through an open, transparent, and participatory process that considered the needs and requirements of a wide range of stakeholders and regulatory bodies, including Tri-State's Member

Systems; transmission service customers; national and regional reliability organizations; and other transmission providers in Colorado and the region. Tri-State solicited input from a broad and diverse community of stakeholders including Member Systems, independent power producers, independent transmission companies, renewable energy advocates, environmental advocates, and federal, state, and local government agencies in the areas potentially affected by the proposed transmission projects.

The result of this coordinated and comprehensive process is a 10-Year transmission plan that includes transmission, distribution, and substation projects. Project summary information found in the following section and Appendix E focuses on the projects that involve the construction of new transmission lines in the State of Colorado. These transmission projects consist of some projects that are primarily intended to fulfill a load-serving need, some that are primarily intended to serve an identified reliability need, and some projects that are intended to provide transmission system congestion relief to better accommodate existing and future generation resources. In addition to these primary purposes, each project is a part of the bulk electric system in Colorado and therefore provides some additional benefits to the overall Colorado electric transmission system.

To understand the context and basis of Tri-State's 2020 Plan, it is important to recognize the key differences between Tri-State and other Colorado utilities. Tri-State is a generation and transmission cooperative formed and owned by its 43 member distribution cooperatives and public power systems located in four states: Colorado, Nebraska, New Mexico, and Wyoming. The territories served by Tri-State's Member Systems cover a total of approximately 200,000 square miles. This large service area results in a load density that is significantly lower than that served by urban utilities. As a cost-based cooperative, Tri-State does not operate for profit and its Board of Directors, elected by the 43 Members, sets the rates charged to Tri-State's Member Systems accordingly. Tri-State's primary mission is to provide its Member Systems reliable, affordable, and responsible wholesale electric power. Tri-State does not

engage in speculative investments or other activities that are not consistent with its mission.

2. Tri-State Projects

While Tri-State's overall 2020 Transmission Plan includes transmission, sub-station, and distribution projects throughout Wyoming, Nebraska, Colorado, and New Mexico, this summary focuses on the larger transmission projects in Colorado. Many of these projects provide multiple benefits in terms of load serving, reliability improvements, congestion relief, or the accommodation of new generation. It should be noted that the 2020 Plan includes some projects listed in the 2018 Plan.

In January 2020, Tri-State's board of directors approved and announced that Tri-State is implementing its Responsible Energy Plan ("REP"), a transition to clean energy that will provide reliable, affordable, and responsible electricity for its Member Systems. The REP commits Tri-State and its Member Systems to significant reductions in emissions of carbon dioxide attributable to Tri-State's electricity sales to its Colorado members, including early retirement of coal-fired electric generating stations in Colorado by 2030. That commitment is combined with a commitment to a precedent-setting investment in renewable energy resources to offset the loss of conventional resources. The implementation of the REP will directly impact transmission planning.

While the full extent of new renewable energy resources are not yet known, Tri-State anticipates significant transmission infrastructure needs in eastern Colorado in support of these new resources based on the region's high potential for economic wind generation. Studies completed in the CCPG Lamar Front Range Task Force have identified several viable transmission alternatives that would support increased generation in the region by building new 345 kV infrastructure between major transmission hubs, including Lamar, Burlington, and Story switching stations.

As explained in Tri-State's Responsible Energy Plan, there is a pressing need to streamline siting and permitting processes so that transmission and generation infrastructure can be constructed in time to meet Colorado's greenhouse gas emission reduction requirements and renewable energy goals. While such streamlining will not be developed through the Commission's transmission planning rules and processes, the current siting and permitting challenges will be factors considered as Tri-State identifies the transmission system improvements needed to implement the REP's clean energy transition.

Tri-State does not yet have enough information to include in this filing transmission alternatives that may be pursued in connection with the REP. Over the next year, as resource plans are further developed with stakeholder input and eventual approval of an ERP by the Commission, Tri-State will work with stakeholders to develop transmission plans to accommodate the future resource additions and retirements. Tri-State will keep the Commission informed through future Rule 3206 and Rule 3627 filings.

Table 5. Load serving projects included in the Tri-State 2020 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Burlington-Lamar 230 kV	2024	$58.4	Issued
Lost Canyon-Main Switch 115 kV**	TBD	$22.6	NR
Southwest Weld Expansion Project	2023	$70	Issued
Del Camino-Slater 115kV Line Uprate	2021	$1.4	NR
Sisson Project	2020	$18.8	NR
JG-Kalcevik Project	2022	$14.8	NR
Vollmer Project	2022	$7.1	NR
Lime Road Delivery Point**	TBD	$8.1	NR

*****These are conceptual projects***

Burlington-Lamar

Past studies in the Boone-Lamar area of Colorado have shown voltage collapse for the Boone-Lamar 230 kV line outage with cross-trips of all generation injected at Lamar 230 kV. In order to mitigate these violations and provide for future growth and potential new generation, Tri-State determined the best solution was to construct a new 230 kV transmission line from the existing Burlington substation to the existing Lamar substation.

Lost Canyon Main Switch 115kV

There is heavy load growth in the CO2 Loop consisting of the Yellow Jacket Switch-Main Switch-Sand Canyon-Hovenweep-Yellow Jacket 115 kV system. Constructing the new Lost Canyon-Main Switch 115 kV line will provide support to reliably meet the future load growth for the CO2 Loop in southwestern Colorado.

Southwest Weld Expansion Project

Due to large scale oil and gas development in southwest Weld County and native load growth, Tri-State is planning on constructing approximately 49 aggregate miles of 115 kV and 230 kV transmission lines to meet the forecasted demand of approximately 300 Megawatts (“MW”) within the next five years. Six potential 115 kV load-serving substations and/or line taps may be constructed by Tri-State, while new 69 kV transmission lines and substations will be constructed by United Power for the project.

Del Camino-Slater 115 kV Line Uprate

This project will replace all the remaining spans of 397.5 ACSR conductor on the Del-Camino Slater line with 477 ACSR. The increased line rating will address the limited load-serving capability of the line and allow continued area load growth.

Sisson Project

There is large oil and gas development in northwestern Colorado. This project will add approximately 20 miles of new 115 kV transmission to radially serve the new

Sisson substation radially north from the existing Keota substation. The line and substation addition will increase load-serving capability in northwestern Colorado.

JG Kalcevik Project

There is significant load growth and development north of Denver along the I-25 corridor. This project will add approximately 2 miles of 115 kV transmission to loop the existing Erie-Dacono 115kV line through the new JG Kalcevik substation. The line and substation addition will increase load-serving capability north of Denver.

Vollmer Project

There is significant load growth and development northeast of Colorado Springs. This project will tap the existing Jackson Fuller-Black Squirrel 115kV line and add approximately 2 miles of 115 kV transmission to serve the new Vollmer substation. The line and substation addition will increase load-serving capability in northeast Colorado Springs.

Lime Road Delivery Point

There is oil and gas development south of Pueblo. This project will tap the existing Stem Beach-GCC Cement Plant 115kV line and add approximately 3 miles of 115 kV transmission to serve the new Lime Road substation. The line and substation addition will increase load-serving capability in south Pueblo.

Table 6. Reliability projects included in the Tri-State 2020 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Western Colorado Transmission Upgrade Project	2020	$57.2	Issued
Burlington-Burlington (KCEA) Rebuild	2022	$0.7	NR
Burlington-Lamar 230 kV	2024	$58.4	Issued
Falcon-Midway 115 kV Line Uprate	2022	$3.8	NR

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Falcon-Paddock-Calhan 115 kV Line**	TBD	$33.4	NR
Lost Canyon-Main Switch 115 kV**	TBD	$22.6	NR
San Luis Valley-Poncha 230kV #2	2025	$58	Req'd
Southwest Weld Expansion Project	2023	$70	Issued
Del Camino-Slater 115 kV Line Uprate	2021	$1.4	NR
JG Kalcevik Project	2022	$14.8	NR
Lamar Front Range**	TBD	TBD	Req'd

These are conceptual projects

Western Colorado Transmission Upgrade Project

The 40-mile long Montrose-Nucla and Nucla-Cahone 115 kV transmission lines are old, overloaded, undersized, and must be rebuilt. To ensure continued reliability of the southwest Colorado transmission system, Tri-State is replacing them with new, higher capacity lines rated for 230 kV operation. This project will increase the load-serving capability of the southwest Colorado transmission system and also eliminate the need for the existing Nucla Remedial Action Scheme, which trips the Montrose-Nucla line when it starts to overload after contingencies/outages in the area.

Burlington-Burlington (KCEA) Rebuild

Under peak loading conditions, the K.C. Electric Association ("KCEA") 69 kV system fed from Smoky Hill substation cannot be switched to the west to pick up additional load for the loss of the Limon source after the Smoky Hill transformer is replaced with a larger unit. To mitigate this limitation, Tri-State will phase-raise the existing Burlington-Burlington KCEA line to increase the thermal rating of the line. The increased capacity will also help K.C. Electric Association serve new load in the area.

Burlington-Lamar

See description in Section III.B.2, Load Serving.

Falcon-Midway Line Uprate

The current Falcon-Midway 115 kV transmission line has a thermal rating of 95 MVA, which leads to forecasted overloads from an outage on Tri-State's 115 kV Falcon-Fuller line. In order to mitigate this problem, Tri-State is raising, moving, or rebuilding structures along the line to increase the overall line rating to 145 MVA. The increased capacity will help serve Mountain View Electric Association's ("MVEA") customer load in the area.

Falcon-Paddock-Calhan 115 kV Line

The current Falcon-Paddock-Calhan 69 kV transmission line will be rebuilt to create a 115 kV loop in MVEA's central system. The 115 kV line will improve system reliability by looping the existing radial 115 kV and 69 kV substations in MVEA's system and provide increased voltage support. The 115 kV line also will help serve MVEA's customer load growth in the area.

Lost Canyon Main Switch

See description in Section III.B.2, Load Serving.

San Luis Valley-Poncha 230 kV #2

New high-voltage transmission must be built in the San Luis Valley ("SLV") region of south-central Colorado to maintain electric system reliability and customer load-serving capability, and to accommodate development of potential generation resources. Tri-State and Public Service, working through CCPG, facilitated a study of the transmission system immediately in and around the SLV and developed system alternatives that would improve the transmission system between the SLV and Poncha Springs, Colorado. Both Tri-State and Public Service have electric customer loads in the SLV region that are served radially from transmission that

originates at or near Poncha. The study concluded that, at a minimum, an additional 230 kV line is needed to increase system reliability. Studies show that this could be accomplished by either adding a new 230 kV line or rebuilding an existing lower voltage line and operating it at 230 kV.

Southwest Weld Expansion Project

See description in Section III.B.2, Load Serving.

Del Camino-Slater 115 kV Line Uprate

See description in Section III.B.2, Load Serving.

JG Kalcevik Project

See description in Section III.B.2, Load Serving.

Lamar Front Range

The Lamar Front Range Project was developed jointly through the CCPG to significantly improve load-serving capability, reliability, and potential resource accommodation in eastern and southeastern Colorado. The project could provide connectivity to the bulk transmission systems of Tri-State and PSCo, and provide strong “looped service” to areas with long radial transmission configurations. In concept, the project could create a transmission system capable of at least 2000 MW of new generation in eastern and southeastern Colorado. As the actual transmission needs in the original Lamar Front Range Project area have been smaller over the last few years, several projects have been implemented at a smaller scale, but in a manner consistent with the outline of the original Lamar Front Range Project.

This conceptual project is currently being re-evaluated in the Lamar Front Range Task Force under CCPG. The project identifies transmission element additions that are needed to meet both companies’ needs, including delivery of future generation to loads in the Denver and Front Range areas. The conceptual Lamar Front Range

project under study envisions 345 kV transmission lines connecting Lamar to the Pueblo area, Lamar to the Burlington area, and the Burlington area to the Missile Site, Story and Pawnee areas.

Table 7. Generation Congestion projects in the Tri-State 2020 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Burlington-Lamar 230 kV	2024	$58.4	Issued
Lamar Front Range**	TBD	TBD	Req'd
Lamar-Vilas 230 kV**	TBD	$90	Req'd

***These are conceptual projects**

Burlington-Lamar

See description in Section III.B.2, Load Serving.

Lamar Front Range

See description in Section III.B.2, Reliability.

Lamar-Vilas 230 kV Transmission

See description in Section III.C.2, Public Service Conceptual Plans.

Information concerning the specific Colorado projects included in the Tri-State 2020 10-Year plan is contained in Appendix E. Additional information and supporting documentation can be found at:
*http://*www.tristate.coop/transmission-planning

C. Public Service 10-Year Plan Overview

Public Service is one of four electric utility operating companies of Xcel Energy Inc., which is an investor-owned utility serving approximately 1.5 million electric customers in the State of Colorado. Public Service serves approximately 75 percent of the state's

population. Its electric system is summer-peaking with a 2019 peak customer demand of 6881 MW. The entire Public Service transmission network is located within the State of Colorado and consists of over 4,700 miles of transmission lines. Colorado is on the eastern edge of the WECC transmission system, which constitutes the Western Interconnection. The Western Interconnection operates asynchronously from the Eastern Interconnection. The Public Service transmission system is interconnected with the transmission system of its affiliate, Southwestern Public Service Company, via a jointly owned tie line with a 210 MW High Voltage Direct Current ("HVDC") back-to-back converter station. Most of the Public Service retail service customers are located in the Denver-Boulder metro area. However, the Public Service retail service territory also includes the I-70 corridor to Grand Junction, the San Luis Valley region, and the cities and towns of Greeley, Sterling, and Brush. The Company's largest retail electric customer is EVRAZ North America, an industrial steel mill, located in Pueblo.

1. Public Service Planning Process

The goal of coordinated planning, as described in Commission Rule 3627 and historically practiced by Public Service and other TPs, is to develop the best possible transmission plan to meet present and future demands for electricity, taking into account a number of diverse factors. At its most basic level, transmission planning strives to meet customers' energy needs in a reliable and cost-effective manner.

The Public Service transmission planning process is intended to achieve the following objectives:

- Maintain reliable electric service;
- Improve the efficiency of electric system operations, including the provision of open and non-discriminatory access to our transmission facilities pursuant to FERC requirements;
- Identify and promote new investments in transmission infrastructure in a coordinated, open, transparent, and participatory manner; and

- Involve stakeholders during the transmission planning process and review of alternatives.

There are multiple drivers to the planning process, including customer load growth, accommodation of new resources, retirement of existing resources, compliance with state and federal rules and standards, replacement of aging infrastructure, and public policy initiatives. The planning process is coordinated with all the other transmission providers in the state to avoid duplication and reduce costs to the end use customer.

As described in earlier sections, coordinated transmission planning in the State of Colorado depends on careful consideration of numerous factors and variables, as well as thoughtful consideration of input from organizations and individuals on the regional, sub-regional, and local level.

One of the strategic priorities for Public Service is to be a leader in transitioning its generation toward cleaner energy. The goal is to serve customers with cleaner, reliable energy through increased ownership of wind and solar generation, invest in the grid, including advanced technologies and transmission that enable more renewable energy, and reduce carbon and other emissions. This strategy has impacted transmission planning over the last two years and will continue to impact planning into the future.

In September 2018, the Commission approved the 2017 Company's Preferred Colorado Energy Plan Portfolio (CEPP), which stemmed from the PSCo 2016 Electric Resource Plan. As a result of the CEPP, PSCo will be retiring 660 MW of coal-fired generation at Comanche, and adding almost 1000 MW of new wind generation and over 700 MW of new solar generation to its system. In 2019, Xcel Energy released its Corporate Responsibility Report, also referred to as Destination 2050, which describes the Company's vision for a carbon-free future by 2050.

Destination 2050 lays out an interim goal to reduce carbon emissions produced from the electricity that serves our customers by 80 percent from 2005 levels by 2030.

The 2017 CEPP, the Clean Energy Plan (to be filed by Public Service in its next Electric Resource Planning process) and Destination 2050 have had significant impacts to the Public Service transmission planning processes as will be described in later sections of this report.

2. Public Service Projects

Table 8, below, lists the Public Service projects. Note that some costs may have changed from previous filings with the PUC, due to changes in costs for issues such as materials, permitting, construction, and administration.

Table 8. Public Service 10-Year Plan

Project Name	ISD	Cost (millions)	CPCN
Completed			
Missile Site - Shortgrass 345 kV Transmission	2018	$104.9	G
Two Basins Relocation	2018	$24.1	NR
Bluestone Valley Substation Phase 1	2019	$12.0	NR
Moon Gulch 230 kV Substation	2018	$1.7	G
Thornton Substation	2019	$21.4	G
Pawnee-Daniels Park 345 kV Transmission	2019	$169.4	G
New to 2020 Filing			
Shortgrass Switching Station	2020	$20.6	G
CEPP Voltage Support	2020	$93.6	R
Greenwood – Denver Terminal 230kV line	2022	$50.3	R
CEPP Switching Station Bid X645	2022	$20.0	R
CEPP Switching Station Bid S085	2022	$12.0	R
Shortgrass – Cheyenne Ridge 345 kV Transmission	2020	$62.3	G
Previously Listed Projects			
NREL Substation	2020	$10.4	NR
Avery Substation	2021	$10.3	G
Ault-Cloverly 230/115 kV Transmission	2022	$66.7	G

Project Name	ISD	Cost (millions)	CPCN
Avon-Gilman 115 kV Transmission	2022	$11.4	NR
CSU Flow Mitigation	2022	TBD	R
Mirasol (formerly Badger Hills) Switching Station (CEPP Bid X647)	2022	$12.0	R
Conceptual			
Weld-Rosedale-Box Elder – Ennis 230/115kV	TBD	TBD	R
Weld County Expansion Transmission	TBD	TBD	R
Bluestone Valley Substation Phase 2	TBD	TBD	NR
Glenwood-Rifle 115 kV Transmission	TBD	TBD	U
Hayden-Foidel-Gore 230 kV	TBD	TBD	U
Lamar-Front Range Transmission	TBD	TBD	R
Lamar-Vilas 230 kV Transmission	TBD	TBD	R
Parachute-Cameo 230 kV #2 Transmission	TBD	TBD	R
Rifle-Story Gulch 230 kV Transmission	TBD	TBD	R
Wheeler-Wolf Ranch 230 kV Transmission	TBD	TBD	NR
San Luis Valley – Poncha 230 kV[3]	TBD	TBD	R
Poncha – Front Range 230 kV	TBD	TBD	R
Distribution Driven Projects			
Barker Distribution Substation	2021	$29.8	NR
Wilson Distribution Substation	TBD	$4.0	NR
Titan Distribution Substation	2022	$13.0	G
Dove Valley Distribution Substation	2023	TBD	NR
High Point Distribution Substation	2022	$9.0	R
Stock Show Distribution Substation	2026	TBD	NR
New Castle Distribution Substation	TBD	TBD	NR
Solterra Distribution Substation	TBD	TBD	U
Superior Distribution Substation	TBD	TBD	U
Sandy Creek Distribution Substation	TBD	TBD	U

[3] Tri-State lists as “planned” with 2025 ISD.

Key: R – Required, NR – Not Required, G – Granted, U - Uncertain

Public Service’s transmission plan does not currently include multi-state transmission projects. However, Public Service watches for such opportunities. While some of the elements of the current transmission plan could be used as components of a regional transmission project, Public Service has not identified regional project opportunities at this time to include in this plan.

Following is a brief, narrative description of each Public Service project included in Table 1 and how it fits into the overall 2020 Plan. Information for the auxiliary projects shown in Table 8, as well as maps of the Public Service projects for each of the time-frames listed below can be found in Appendix F. Projects are arranged by their anticipated in-service dates.

Planned Projects

Public Service's planned transmission projects can generally be placed in two basic categories. The first category consists of projects that are needed primarily for load growth or reliability purposes. These include both new projects as well as rebuilds or upgrades to existing transmission lines. Native load peak demand in Public Service's service territory has remained fairly flat during the past five years. The expiration of wholesale contracts and the participation of wholesale customers in the Comanche 3 power plant have contributed to this flat load growth. Since 2009, the Public Service firm wholesale load has decreased, but the loss of wholesale load was offset by load growth within the retail sector. The level of load growth also is due to increases in energy efficiency and demand-side management programs, changes in appliance efficiency, and the increase in use of on-site photovoltaic energy systems. Public Service presently projects the native load to grow by about 0.7% from 2019 to 2026.

The second category consists of projects that are planned primarily to accommodate new generation resources. For Public Service, these projects tend to be associated with its electric resource plans, such as the 2017 CEPP. Senate Bill 07-100 also plays a role in the development of those plans, since it is intended to promote proactive planning to accommodate beneficial resources. These projects tend to include large transmission projects to access specific areas of the state that have the potential to host future generation facilities. Through the SB07-100 process, Public Service has developed plans to access each ERZ in Colorado. Some of these plans may be used or modified to accommodate the future Clean Energy Plan and Destination 2050 goals.

Projects Implemented Since 2018

This section describes the Public Service projects that have been placed in-service since the 2018 Rule 3627 10-Year Transmission Plan ("2018 Filing"). The following project(s) consisted of upgrades or additions to existing substations.

Missile Site - Shortgrass 345 kV Transmission

This project was described in the 2018 filing as the Rush Creek – Missile Site 345 kV Transmission Project, or Rush Creek Gen-tie. The project includes the 600 MW Rush Creek wind generation project and an approximately 82-mile 345 kV transmission line that has been built in parts of Arapahoe, Elbert, and Lincoln counties. Since the transmission line is a radial line that accommodates new generation, it is sometimes referred to as a "gen-tie". The Rush Creek wind project includes two collector stations. One collector is located at the new Pronghorn Switching Station, located approximately 42 miles from Missile Site Substation. The second collector is located at the new Shortgrass Switching Station, which is located at the eastern end of the gen-tie, approximately 40 miles from Pronghorn Switching Station.

Construction started on the transmission line in August 2017 and it was placed in service in July 2018 with an approximate cost of $104.9 million.

As part of the Settlement Agreement for the Rush Creek Wind Project proceedings, Public Service took a leadership role in the Rush Creek Task Force created within the CCPG. The task force analyzed the costs and benefits of 19 alternative proposals to potentially integrate the gen-tie as a network facility. The process provided a forum for stakeholder participation and comment.

Two Basins Relocation Project

This project consisted of relocating three existing 115 kV transmission lines that connect to the North Substation. The project was necessary to accommodate the City and

County of Denver ("CCOD") Two Basins Storm Water Drainage Project, which provides 100-year storm protection for certain areas of the city. The project also was required to accommodate the Colorado Department of Transportation ("CDOT") I-70 Expansion Project. The project involved: 1) Re-locating a portion of the existing North-Capitol Hill 115 kV underground line. 2) Re-locating the entire existing North-California 2.25-mile 115 kV underground line and replacing it with new conductor, and 3) Re-locating and replacing four overhead structures on the existing North-Sandown 115 kV line. The CPUC determined that the project was in the ordinary course of business and did not require a Certificate of Public Convenience and Necessity ("CPCN"). The project was placed in-service in 2018 and a cost of $24.1 million.

Bluestone Valley Substation (Phase 1)

The 2018 filing listed Bluestone Valley Substation as a new substation project to improve reliability and provide additional load interconnections for customers in the area. The original scope of this project consisted of a new Bluestone Valley 230/69 kV Substation. The substation would include a 230/69 kV transformer and would interconnect the existing Parachute-Cameo 230 kV line and the existing DeBeque-Cameo 69 kV line. From Bluestone Valley Substation, a new line would be constructed to a new Grand Valley Power Clear Creek Substation. Public Service split this project into two phases: A 69 kV phase ("Phase 1") and a 230 kV phase ("Phase 2"). To expedite reliability improvements to the lower voltage network, Public Service has completed Phase 1. Phase 2 is still considered conceptual and may be constructed at a later time based on local load growth. Phase 1 included construction of a new Bluestone Valley 69 kV Switching Station that connects to the existing DeBeque-Cameo 69 kV line. The project resulted in a DeBeque-Bluestone Valley-Cameo 69 kV line. Phase 1 of this project was placed in-service 2019, at a cost of $12.0 million.

Moon Gulch Substation

Moon Gulch Substation is a new distribution substation built in the City of Arvada within Jefferson County. The substation taps the existing Plains End-Simms 230 kV line. The substation was built to serve load growth in the Arvada area and also to provide backup

service to the existing Eldorado and Ralston distribution substations. The project was placed in-service in 2018 at a cost of $1.7 million.

Thornton Substation

This project consisted of constructing a new substation in Thornton to serve the increase in customer distribution load in that area. This new substation serves the City of Thornton in the north metro Denver area and provides back-up support to the existing Glenn and Washington distribution substations. The project was placed in-service in 2019, at a transmission cost of $21.4 million.

Pawnee-Daniels Park Transmission

The Pawnee-Daniels Park 345 kV Transmission Project consists of a new 125-mile 345 kV transmission line from the Pawnee Substation in northeastern Colorado to the Daniels Park Substation, south of the Denver-Metro area. The project also resulted in the construction of a new Harvest Mile 345 kV Substation, near Smoky Hill Substation, and a new Harvest Mile-Daniels Park 345 kV line. The project also interconnects with the Missile Site 345 kV Substation. This project was planned in accordance with Senate Bill 07-100, in that it accommodates generation in designated ERZs 1 and 2. The Pawnee-Daniels Park Project was placed in-service in December 2019, at a cost of $169.4 million.

Planned Transmission and Substation Projects (Not Previously Listed)

This section describes the Public Service projects that have not been included in previous Rule 3627 filings.

Planned Projects Related to the 2017 Colorado Energy Plan Portfolio

Shortgrass – Cheyenne Ridge 345 kV Transmission Line Project and Shortgrass Switching Station

The Shortgrass – Cheyenne Ridge 345 kV Transmission Line Project consists of an approximately 73-mile, 345 kV transmission line which will extend from the Shortgrass Switching Station to the Cheyenne Ridge wind farm collector stations. The Shortgrass Switching Station not only provides an interconnection for part of the Rush Creek wind generation, but also will interconnect the 300 MW Bronco Plains wind project and the Cheyenne Ridge 500 MW wind project that are included in the Company's CEPP. The project is located in Lincoln, Kit Carson and Cheyenne counties. The project was granted a CPCN, is estimated to cost approximately $52.7 million, and is scheduled to go in service in 2020.

Greenwood -Denver Terminal 230 kV Transmission Project

The Greenwood – Denver Terminal Project consists of an approximately 15 miles of new 230 kV transmission line between the Company's existing Greenwood and Denver Terminal substations. The line is needed to accommodate the 2017 CEPP. The new line will be implemented by rebuilding existing transmission facilities from the Greenwood Substation to the Denver Terminal Substation within existing right-of-way (ROW). The existing Greenwood, Arapahoe, and Denver Terminal substations all will require modifications to accommodate the project. The project is located in six different city boundaries: Centennial, Greenwood Village, Littleton, Englewood, Sheridan and Denver. The Project is estimated to cost approximately $50.3 million and it is planned to be in service by December 31, 2022. The Company plans to file a CPCN for this project early in 2020.

CEPP Voltage Control Facilities

A series of network voltage control devices need to be installed on the Public Service transmission system to accommodate the CEPP generation. The Company is proposing the facilities described in the table below.

Table 9. CEPP Voltage Control Facilities

Substation / Switchyard Location	Implementation Devices to be installed	Estimated In-Service Date	Estimated Cost (millions)
CF&I Furnace	± 95 MVAR STATCOM	Dec. 2023	$32.0
	One (1) dynamic voltage support device		
	85 MVAR of shunt capacitance		
	One (1) 85 MVAR capacitor		
Daniels Park	120 MVAR of shunt capacitance	Dec. 2020	$3.6
	One (1) 120 MVAR capacitor		
Harvest Mile	240 MVAR of shunt capacitance	June 2020	$5.4
	Two (2) 120 MVAR capacitors		
Missile Site	360 MVAR of shunt capacitance	June 2020	$9.5
	Three (3) 120 MVAR capacitors		
	Rush Creek Master Voltage Controller AVSO	Dec. 2020	$5.2
Pronghorn	± 150 MVAR STATCOM	Dec. 2020	$31.7
	One (1) dynamic voltage support device		
Shortgrass	60 MVAR of shunt reactance	April 2020	$6.2
	Two (2) 30 MVAR reactors		
Total			**$93.6**

The cost of the combined facilities is estimated to be approximately $93.6 million and they will be placed in service between 2020 and 2023. A CPCN was filed for this project in December 2019.

CEPP Generation Interconnection Facilities

In addition to the Shortgrass Pronghorn, and Mirasol (formerly Badger Hills – discussed in the Planned Transmission Projects from Previous Filings below) switching stations, other interconnection facilities must be constructed to accommodate the CEPP generation. At this time, the facilities include expanding two existing substations and constructing two new switching stations. The new switching stations include one that will connect to the Hartsel – Tarryall 230 kV line, and one that will connect to one Comanche – Daniels Park 345 kV line. The two existing substation that are proposed to be modified are the Boone and Midway 115 kV substations. The Company intends to file a CPCN for these facilities in 2020.

Planned Transmission Projects (Listed in Previous Rule 3627 Filings)

NREL Switching Station

This project consists of a new switching station that taps the existing Plainview-Eldorado 115 kV line south of Boulder. The U.S. Department of Energy's National Renewable Energy Laboratory ("NREL") operates a hybrid generation facility at its National Wind Technology Center, located approximately 1 mile east of the line. This facility is currently interconnected via distribution service, so the generation capacity is limited. This project is needed to interconnect the generation to the transmission system and allow for additional generation interconnections. The project does not require a CPCN, has a planned in-service date of 2020, with an estimated cost of $10.4 million.

CSU Flow Mitigation Project

This project was described in the 2018 filing as the addition of a phase shifting transformer ("PST") to the Monument Substation on the Monument-Flying Horse 115 kV transmission line, to control power flows through the Colorado Springs Utilities ("CSU") transmission system. Studies have shown that when there are heavy power transfers on the transmission system between Pueblo and the Denver, there is a potential for unacceptable loading to occur on the CSU transmission system. As a temporary mitigation measure, Public Service has implemented an operating procedure that opens up a 115 kV line on the north end of the system where the CSU and Public Service systems connect. The issue has been studied through the Douglas Elbert and El Paso (DEEP) Subcommittee of the CCPG. Upon completion of additional studies, the DEEP Subcommittee developed an alternative solution that consisted of a series reactor rather than a phase shifting transformer. The series reactor alternative accomplishes the same goal, but with advantages to the phase shifting transformer. The series reactor project had an estimated cost of $9.9 million and a potential in-service date of 2022. Recently, CSU has been evaluating additional alternatives. Public Service is continuing to work with CSU, TSGT, and the DEEP Subcommittee to determine a final long-term

transmission solution to mitigate the potential overloads. The project will likely require a CPCN.

Mirasol Switching Station

This project was described in the 2018 filing as a Badger Hills 345/230 kV substation. The project is presently planned as a 230 kV switching station. This project is one of several interconnecting switching stations that will be needed to accommodate generation associated with the Public Service 2017 CEPP. The Mirasol Switching Station will be located approximately 12 miles southeast of Comanche Substation, and will interconnect one of the Comanche - Midway 230 kV lines. The project is being designed to have the flexibility to allow for additional generation interconnections, as well as existing and future transmission lines. The project has a planned in-service date of 2022, with an estimated cost of $12 million. The Company intends to include this project with the other interconnection switching stations when it files a CPCN for these facilities in 2020.

Ault-Cloverly 230/115 kV Transmission Project

The Ault-Cloverly Project consists of approximately 25 miles of new 230 kV and 115 kV transmission lines originating at the existing Western Area Power Administration ("WAPA") Ault Substation near the town of Ault, and terminating at the Public Service Cloverly Substation on the northeast edge of Greeley. The transmission also will interconnect with two new PSCo substations: Husky Substation, which will replace and is planned to be built near the existing PSCo Ault 44 kV Substation, and Graham Creek Substation, which will replace and is planned to be built near the existing PSCo Eaton 44 kV Substation. One objective of the project is to improve reliability by replacing the existing 44 kV system in the area with higher voltage transmission facilities. However, the project also will increase the load-serving and generation resource capability in the area.

The project was granted a CPCN and has a planned in-service date of 2022 with an estimated cost of $66.7 million.

Avon-Gilman 115 kV Transmission Project

The Avon-Gilman 115 kV Transmission Project consists of constructing a new 10-mile 115 kV line in Eagle County for reliability and to provide an alternate transmission source to Holy Cross Energy customers. The project does not require a CPCN, has a planned in-service date of 2022, and has an estimated cost of $11.4 million.

3. Public Service Conceptual Plans

Conceptual Plans

The following transmission plans are considered conceptual in that they have no specific in-service date. Implementation of these plans is primarily affected by load forecasts and electric resource needs. Once a need is established, in-service dates can depend on many factors, including but not limited to regulatory proceedings, siting and land permitting, coordination of construction outages, and material delivery times. Public Service continues to assess the system conditions that may drive implementation for these plans.

Conceptual Plans Related to Load Growth

Bluestone Valley Substation (Phase 2)

As mentioned previously, this project has been divided into two phases. Phase 2 of the project would consist of expanding the substation to include 230 kV facilities, which would include a 230/69 kV transformer and interconnect the Rifle-Cameo 230 kV line. Implementation of Phase 2 will depend on the local load growth.

Glenwood-Rifle Transmission

This plan has been described in previous filings, and consists of upgrading the Glenwood Springs-Mitchell Creek-New Castle-Silt Tap line from 69 kV to 115 kV and new construction to reroute the Silt-Rifle line to the Rifle Substation at 115 kV. A portion

of the rerouted 115 kV line will be double-circuited with the Rifle-Hopkins 230 kV line. Costs for the plan have not been estimated, and moving forward with the plan will depend on load growth around Glenwood Springs.

Hayden-Foidel Creek-Gore Pass 230 kV Transmission

This plan has been described in previous filings and would consist of tying the Hayden-Gore Pass 230 kV line into the Foidel Creek Substation to increase reliability in the region. Reliability concerns are being mitigated by adding reactors at the Wolcott 230 kV bus, so there are no plans to move forward with this project at this time.

Parachute-Cameo 230 kV #2 Transmission

This project has been described in previous filings and is an extension of the Rifle-Parachute 230 kV line. It would consist of a new, approximately 30-mile 230 kV transmission line that would connect the existing Parachute and Cameo substations on the western slope of Colorado. Its primary purpose would be to increase reliability and to serve load growth in the region. Preliminary analysis estimated the cost to be approximately $48 million, but actual costs, and implementation of the project will depend on load growth in the area.

Rifle-Story Gulch Transmission

The project has been described in previous filings and would consist of a new radial 230 kV transmission line that would be used to serve customer loads in Garfield County. The line would be approximately 25 miles long and run between the existing Rifle (Ute) Substation to a new Story Gulch Substation. Preliminary analysis estimated the project cost to be approximately $24 million, but actual costs and implementation will depend on load growth in the area.

Wheeler-Wolf Ranch

The project has been described in previous filings and would consist of a new radial 230 kV transmission line that would be used to serve customer loads in Garfield County. The line would be approximately 18 miles long and run between the existing Wheeler

Substation to a new Wolf Ranch Substation. The line also would interconnect to the Middle Fork Substation. Preliminary analysis estimated the project to cost approximately $17 million, but actual costs and implementation will depend on load growth in the area.

Conceptual Plans Related to SB07-100 / Clean Energy Plan Goals

Weld-Rosedale-Box Elder - Ennis 230 & 115 kV Transmission Lines

This project was referred to in the 2018 filing as the Weld – Rosedale – Milton 230 kV project. However, Public Service has been evaluating alternatives that would terminate at locations other than Milton within its service territory. As mentioned in the 2018 filing, Public Service has been working through the CCPG Northeast Colorado ("NECO") Subcommittee to develop a transmission plan for the area south of Greeley. The objective is to continue the replacement of the existing 44 kV system in the area, increase the ability to accommodate future load growth, and allow for beneficial resource development. The plan also should align with other transmission projects and plans in the area, including the Ault-Cloverly Project and the Southwest Weld Expansion Project ("SWEP"). A 230 kV line from Weld to Rosedale and a 230 kV or 115 kV line from Rosedale to Box Elder to Ennis would meet the objectives. However, until the NECO studies are completed and an actual project is recommended, the projects are listed as conceptual with no specified in-service date or estimated costs.

Weld County Transmission Expansion

This plan was described in the 2018 filing as a means to allow interconnection of new resources and complement other transmission plans in Northeast Colorado such as the Ault-Cloverly 230/115kV Project and the Weld-Rosedale-Box Elder-Ennis 230 and 115kV Transmission Project. The Weld County Expansion continues to be a general planning placeholder that captures the planning efforts for Northeast Colorado, including the Greeley area. This project may be considered as a third or eastern phase of the planning efforts in the area that have been taking place in the CCPG NECO Subcommittee. The Weld County Expansion could be a combination of planned and

conceptual projects, such as the Ault-Cloverly Project, and the Weld-Rosedale-Box Elder - Ennis 230 & 115 kV lines, or, the Weld County Expansion could be a new project. Regardless, the Weld County Expansion may be a project that could enable Public Service to meet its Clean Energy Plan goals.


WELLINGTON
HUNN
PIERCE
AULT
AULT
FORT COLLINS
TIMNATH
SEVERANCE
EATON
CLOVERLY
WELD
WINDSOR
LOVELAND
KERSEY
LA SALLE
ROSEDALE
EVANS
JOHNSTOWN
MILLIKEN
GILCREST
BERTHOUD
BOX ELDER
ENNIS
KEENESBURG
HUDSON
Weld County
Transmission Expansion
Substation
Transmission Project Areas
345kV Electric Transmission Line
230kV Electric Transmission Line
115kV Electric Transmission Line
44kV Electric Transmission Line
0
5 Miles

Lamar-Front Range Transmission

The Lamar-Front Range plan originally was planned as a means to deliver an estimated 2000 MW of new generation from energy resources near Lamar and Burlington to load centers along the Front Range. The plan was conceived as a joint project between Public Service and Tri-State. A primary driver for Public Service was to meet an SB07-100 objective to plan transmission from the ERZ-3. The original plan included the following transmission components:

- Two 345 kV transmission circuits between Lamar and Avondale
- Two 345 kV transmission circuits between Lamar and Burlington
- Two 345 kV transmission circuits between Burlington and Big Sandy
- One 345 kV transmission line between Big Sandy and Missile Site
- One 345 kV transmission line between Big Sandy and Story
- One 345 kV transmission line between Story and Pawnee
- A new Avondale Substation
- Two 230 kV transmission circuits between Lamar and Vilas

The original Lamar-Front Range project was estimated to cost approximately $900 million. However, since the project is being re-evaluated, revised cost estimates have not been determined.

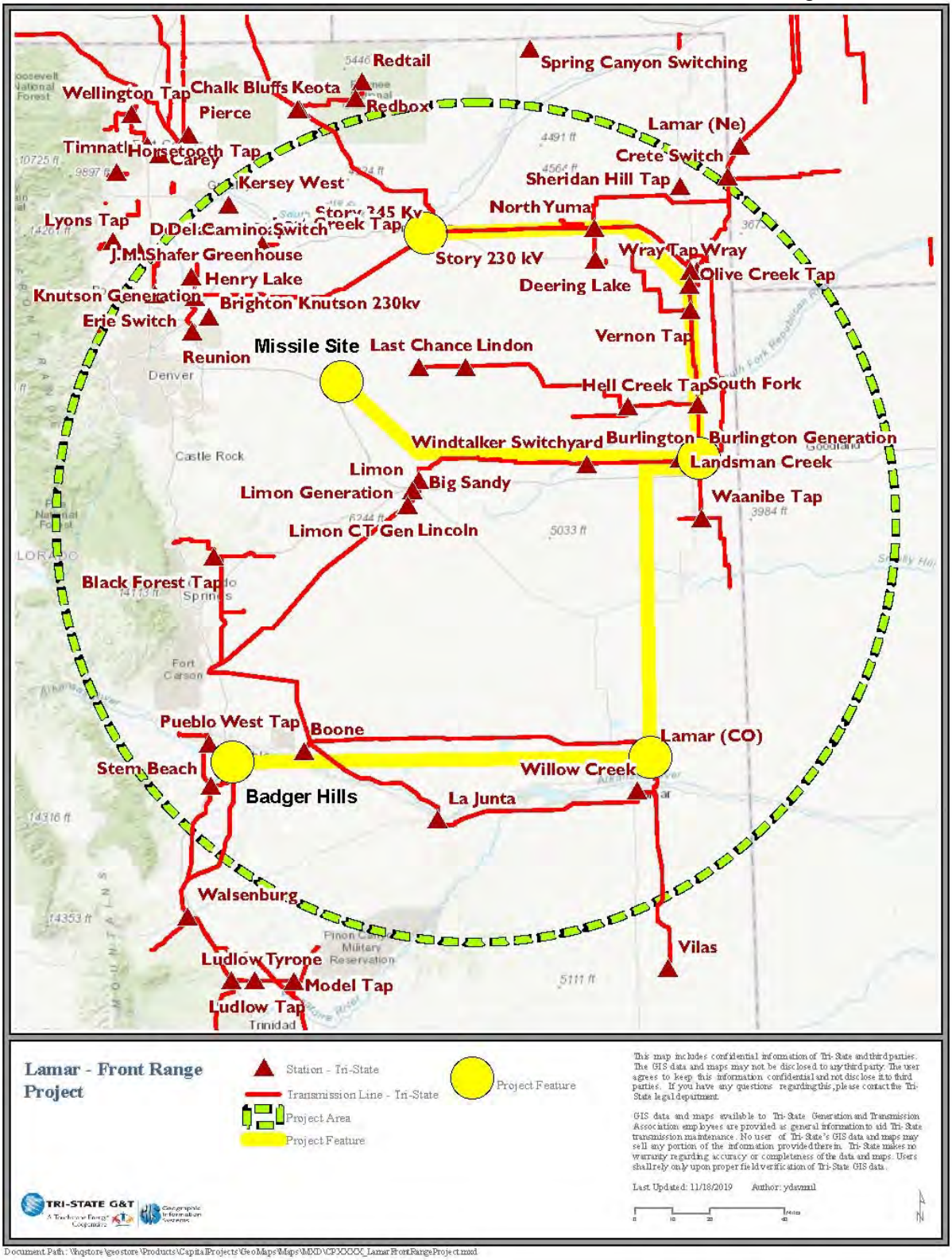
Since the plan was developed, a number of significant projects that could either be considered segments of, or are consistent with the design of the plan have been implemented or planned. These include:

- Construction of the Missile Site – Pronghorn – Shortgrass 345 kV line
- Construction of the Burlington – Wray 230 kV line
- Plans for the Shortgrass – Cheyenne Ridge 345 kV line
- Plans for a Burlington – Lamar 230 kV line

As a result, in 2019, the CCPG Lamar-Front Range Task Force (LFRTF) was formed to revisit the Lamar-Front Range Transmission Project. The objective of the task force is to evaluate transmission alternatives in eastern and southeast Colorado that will facilitate the delivery of new renewable and other low-cost generation to load centers, improve transmission system reliability, and increase the operational flexibility of both transmission and generation assets.

The LFRTF evaluated numerous transmission alternatives. No preferred alternative has been identified, but some alternatives and combinations of alternatives show technical merit and meet the overall objective. For example, a potential plan that may be able to advance Public Service's future Clean Energy Plan objectives might include the following components:

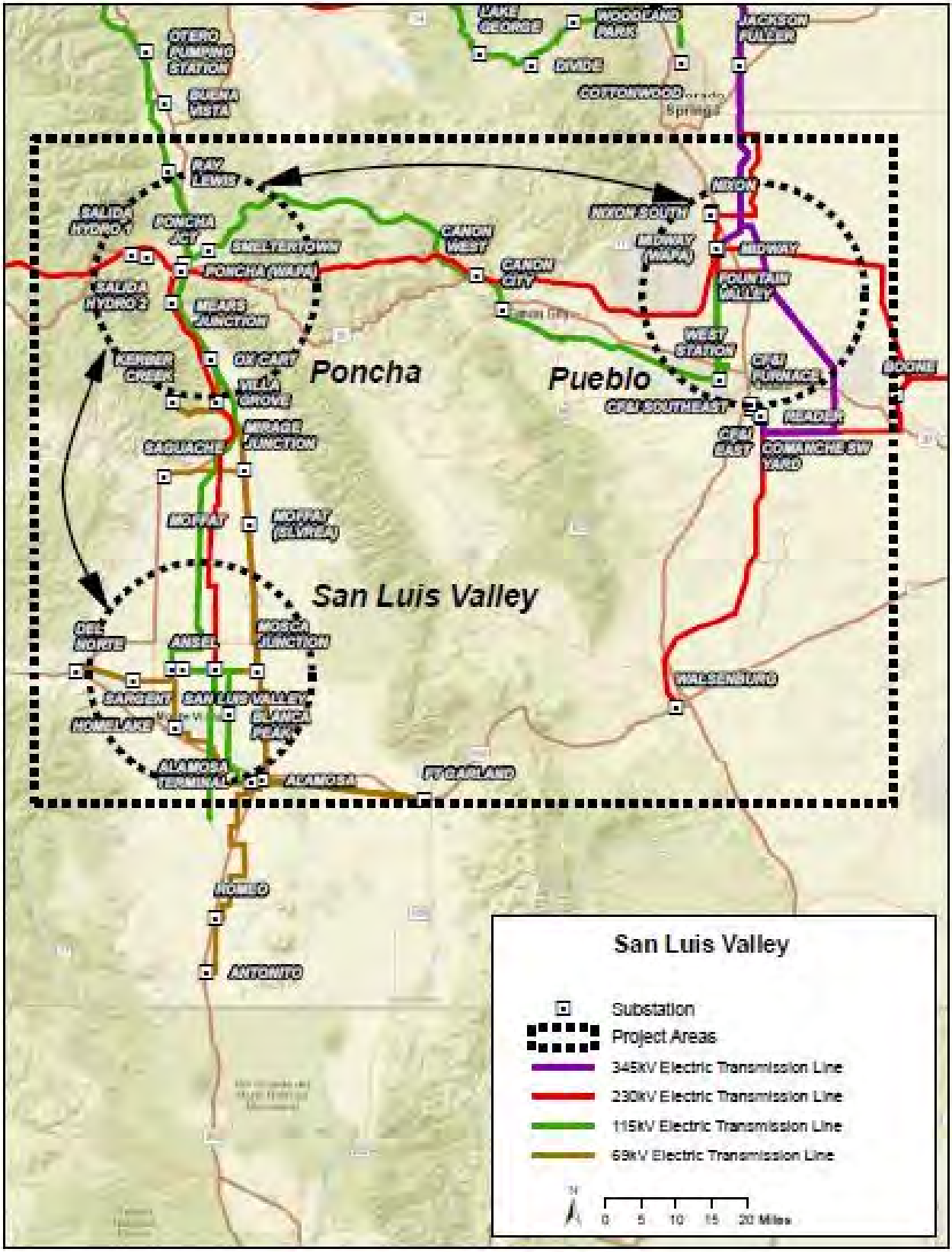
- Networking the Missile Site – Cheyenne Ridge 345 kV line to Burlington
- New 345 kV transmission from Burlington – Lamar – Comanche
- New 345 kV transmission from Burlington – Missile Site
- New 345 kV transmission from Burlington - Pawnee



Document Path: \\hqstore\geostore\Products\CapitalProjects\GeoMaps\Maps\MXD\CP\XXXX_LamarFrontRangeProject.mxd

San Luis Valley

Similar to Tri-State, Public Service also recognizes that new high-voltage transmission in the San Luis Valley would improve electric system reliability and customer load-serving capability, and accommodate development of potential generation resources. Studies indicated that a new 230 kV transmission line from the San Luis Valley Substation to Poncha Substation would be a first step to accomplish the reliability objectives. Transmission beyond Poncha to the Front Range would enhance reliability and provide additional generation export out of the San Luis Valley and help meet the Public Service Clean Energy Plan goals.


Poncha
Pueblo
San Luis Valley
OTERO PUMPING STATION
BUENA VISTA
LAKE GEORGE
WOODLAND PARK
DIVIDE
COTTONWOOD Springs
JACKSON FULDER
RAY LEWIS
NIXON
NIXON SOUTH
BALIDA HYDRO 1
PONCHA JCT
SINGLE TEE TOWN
PONCHA (XCEL)
CANON WEST
CANON CITY
MIDWAY (XCEL)
MIDWAY
FOUNTAIN VALLEY
BALIDA HYDRO 2
MIAMI JUNCTION
WEST STATION
KENYON CREEK
OIL CLAY
HILL GROVE
CF&I FURNACE
BOONE
CF&I SOUTHEAST
HEADER
MIRAGE JUNCTION
CF&I EAST
COMANCHE SW YARD
SARGUACHE
MORAY
MORAY (XCEL)
DEL NORTE
ANSEL
MOSCA JUNCTION
WALSENBURG
SANGRE
SAN LUIS VALLEY
HOMELAKE
BLANCA (XCEL)
ALAMOSA TERMINAL
ALAMOSA
FT GARLAND
HOMELO
ANTONITO
San Luis Valley
Substation
Project Areas
345kV Electric Transmission Line
230kV Electric Transmission Line
115kV Electric Transmission Line
69kV Electric Transmission Line
N
0 5 10 15 20 Miles

Other Long-Range Distribution Planning Substation Projects

Public Service, the Colorado Office of Consumer Counsel, ("OCC") and Staff of the Colorado Public Utilities Commission agreed through discussions related to Proceeding No. 14A-1002E to identify potential new distribution substation sites in rapidly growing areas. Below is a list of conceptual new substation projects under consideration by the Company. This is provided for informational purposes only. At this time, Public Service is not seeking Commission determination of the need for CPCNs for these projects or any Commission action. Most in-service dates for these projects are TBD.

Table 10. Long-Range Distribution Planning Substation Projects

Substation Project Name	Transmission Voltage	Approximate location	Potential ISD	Cost ($M)
Barker	230 kV	Across from Coors Field in Denver	2021	$29.8
Dove Valley	115 kV	Near I-25 and C-470 in Arapahoe County	2023	TBD
High Point	115 kV or 230 kV	Near Denver International Airport; Adams County	2022	$9
Titan	230 kV	Near Sterling Ranch in Douglas County	2022	$13
Stock Show	115 kV	Denver	2026	TBD
Wilson	115 kV	Loveland	TBD	TBD
Solterra	230 kV	Lakewood	TBD	TBD
New Castle	69 kV	New Castle	TBD	TBD
Superior	115 kV	Town of Superior	TBD	TBD
Sandy Creek	230 kV	Arapahoe County, near future Sandy Creek development	TBD	TBD

Additional Information

Information concerning the specific Colorado projects included in the Public Service 2020 10-Year Plan is contained in Appendix F. Additional information and supporting documentation can be found at:

http://www.transmission.xcelenergy.com/Planning/Planning-for-Public-Service-Company-of-Colorado

https://www.rmao.com/public/wtpp/PSCO_Studies.html

http://www.oatioasis.com/psco/index.html

IV. Projects of Other CCPG Transmission Providers

In addition to the projects planned by Black Hills, Tri-State, and Public Service contained in this 2020 Plan, a thorough understanding of all transmission projects planned in Colorado requires consideration of projects planned by other utilities and TPs.

Table 11. Colorado Springs Utilities Projects

In-Service	Project Name	Description	Purpose
2020	Williams Creek 230 kV Switching Station	Install a new substation on the Nixon-Claremont 230 kV line necessary to interconnect new Palmer Solar PV plant	Generation interconnection
2020	Nixon-Kelker 230 kV Line Uprate	Increase clearance on Nixon-Kelker 230 kV line to increase facility rating on the line.	Increase facility rating
2019	Cottonwood 230/115kV Autotransformer Replacement.	Install a new, upgraded 230/115 kV autotransformer at Cottonwood substation.	Increase system load serving capacity and provide compliance with the Long Lead Time Equipment requirement in the NERC Transmission Planning Standard TPL-001-4. (The existing Cottonwood auto will be refurbished and stored on site as a system spare.)

This information is provided voluntarily by CSU for the purposes of making sure the CPUC has the most complete information for planned project coordination purposes only.

Additional information concerning the specific Colorado projects included in the CSU Plan are contained in Appendix G.

Table 12. Platte River Power Authority Projects

In-Service	Project Name	Description	Purpose
2018	Boyd 230/115kV Substation Expansion	Add 230/115kV transformer T2 and reconfigure 230kV and 115kV yards to breaker-and-a-half arrangement.	Improve system reliability in the Loveland area.

This information is provided voluntarily by Platte River Power Authority ("PRPA") for the purposes of making sure the CPUC has the most complete information for planned project coordination purposes only.

Additional information concerning the specific Colorado project included in the PRPA is contained in Appendix H.

Table 13. Western Area Power Authority Projects

In-Service	Project Name	Description	Purpose
2020	Midway KV1A Replacement	Replacing KV1A at Midway	Replacing aging equipment and increasing size
2020	Ault 345/230 kV XFMR Replacement	Replacing the 345/230 kV Transformer at Ault	Increased reliability

This information is provided voluntarily by WAPA for the purposes of making sure the CPUC has the most complete information for planned project coordination purposes only.

Additional information concerning the specific Colorado projects included in the WAPA are contained in Appendix I.

V. Senate Bill 07-100 Compliance and Other Public Policy Considerations

In addition to planning for load growth and reliability, Companies must consider proposed and enacted public policies. Two of the Companies, Black Hills and Public Service, are subject to the requirements of Colorado Senate Bill 07-100 ("SB07-100") (codified at C.R.S. § 40-2-126).

Historically, the SB07-100 filings were made by Black Hills and Public Service by October 31 of each odd-numbered year. Those filings were subsequently combined into a single Proceeding with the Rule 3627 filing pursuant to Decision No. R17-0747 in Proceeding 17R-0489E, which amended Rule 3627 to require electric utilities subject to Commission rate regulation to include their transmission plans for energy resource plans specified in C.R.S. 40-2-126(2) with their transmission plans due February 1 of each even-numbered year. As stated in SB07-100, Black Hills and Public Service are required to:

a. Designate ERZs
b. Develop plans for the construction or expansion of transmission facilities necessary to deliver electric power consistent with the timing of the development of beneficial energy resources located in or near such zones
c. Consider how transmission can be provided to encourage local ownership of renewable energy facilities
d. Submit proposed plans, designations, and applications for Certificates of Public Convenience and Necessity to the Commission for simultaneous review

Black Hills and Public Service have performed transmission planning activities to comply with the requirements of SB07-100 as part of the larger, coordinated planning efforts described above. As of 2017, Colorado's ERZs remain as they were defined in the 2015 SB07-100 reports, created by consulting multiple sources of information as well as public feedback. As shown in Figure 7, Colorado's five ERZs are:

ERZ 1 (Northeast Colorado)

Includes all or part of Sedgwick, Phillips, Yuma, Washington, Logan, Morgan, Weld, and Larimer Counties. ERZ 1 presents energy development opportunities for natural gas, wind, and thermal resources.

ERZ 2 (East-central Colorado)

Includes all or part of Yuma, Washington, Adams, Arapahoe, Elbert, El Paso, Lincoln, Kit Carson, Kiowa, and Cheyenne Counties. ERZ 2 presents energy development opportunities for natural gas, wind, and thermal resources.

ERZ 3 (Southeast Colorado)

Includes all of part of Baca, Prowers, Kiowa, Crowley, Otero, Bent, and Las Animas Counties. ERZ 3 represents the potential for wind resource development.

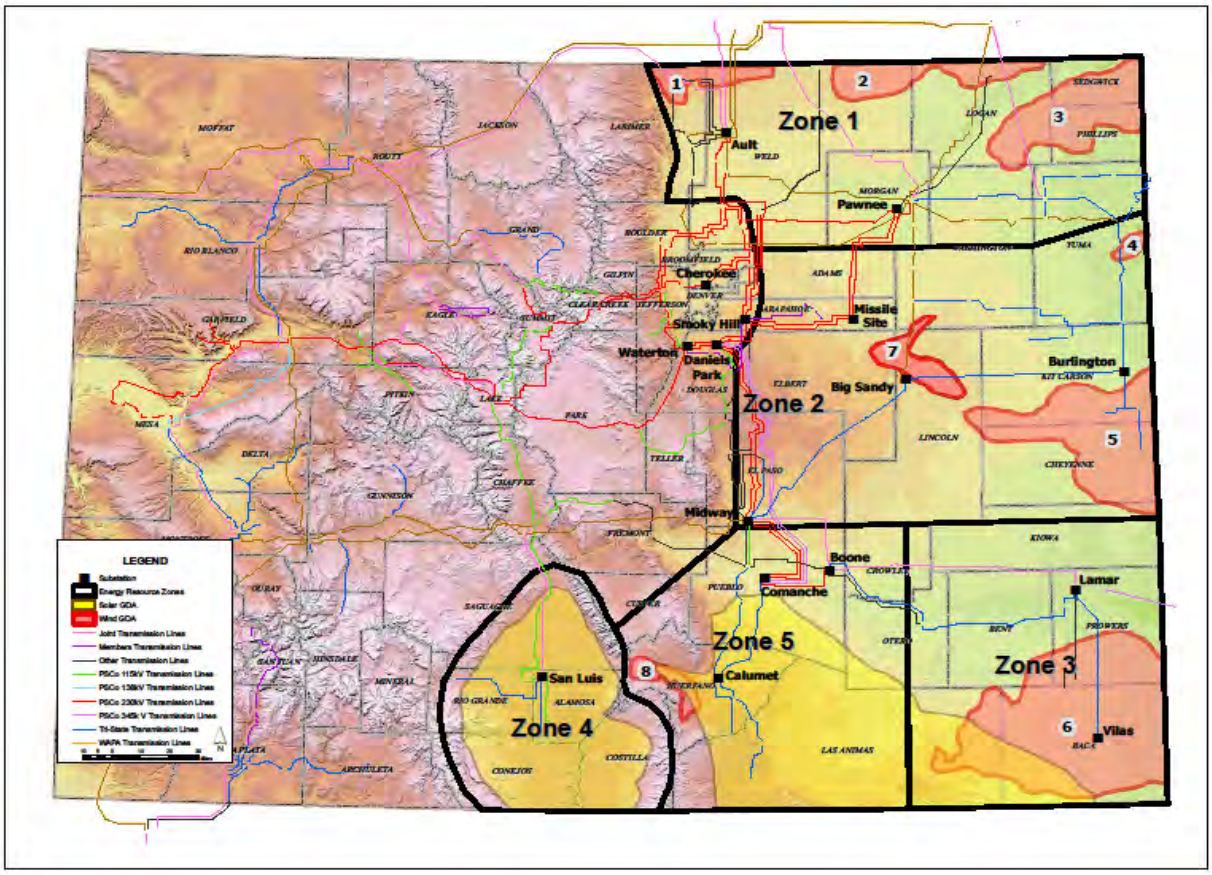
ERZ 4 (San Luis Valley)

Includes all or part of Costilla, Conejos, Rio Grande, Alamosa, and Saguache Counties. ERZ 4 presents energy development opportunities for solar resource development.

ERZ 5 (South-central Colorado)

Includes all or part of Huerfano, Pueblo, Otero, Crowley, Custer, and Las Animas counties. ERZ 5 in South Central Colorado includes the area around Pueblo and south along the I-25 corridor which includes both potential wind and solar resources.

Figure 7. Map of SB07-100 Energy Resource Zones



In addition to the public policy requirements of SB07-100, all three Companies may be subject to federal and Colorado state regulations related to carbon emission reductions from existing power plants. The Companies will continue to coordinate with each other and stakeholders with respect to the transmission planning implications of any new federal regulations and may address issues in subsequent 10-Year transmission plans.

A. Black Hills Summary

Black Hills encouraged all interested parties to participate in the 2019 SB07-100 study process. An open stakeholder SB07-100 Kick-off Meeting was held in conjunction with the Q1 Black Hills Colorado Transmission ("BHCT") Transmission Coordination and Planning Committee ("TCPC") on April 23, 2019, to inform stakeholders of the proposed study plan and to provide an opportunity for suggestions and feedback on the study process. The kick-off meeting had no external participants. A follow-up e-mail was sent on October 10, 2019, to invite stakeholders to respond with their input while updating them on the progress of the study work. Meeting notices and presentations were distributed via e-mail and posted on the Black Hills Open Access Same-Time Information System ("OASIS") page at http://www.oatioasis.com/bhct/ as well as on a Colorado SB07-100 webpage established on the Black Hills Corporation website; https://www.blackhillsenergy.com/our-company/transmission-rates-and-planning.

For the 2019 SB07-100 cycle, Black Hills selected to re-evaluate the resource injection capacity from ERZ-5, which initially was performed as part of the 2013 SB07-100 cycle. That decision was based on the completion of transmission system upgrades since that time, as well as ongoing interest to develop generation in the area as indicated by Black Hills' generation interconnection queue. The transmission system was evaluated under 2023 peak summer load levels to identify any significant adverse impact to the reliability and operating characteristics of the Western Electricity Coordinating Council ("WECC") bulk transmission system and, more specifically, to the Black Hills and surrounding transmission systems. Steady state voltage and thermal analyses examined system performance without additional projects in order to establish a baseline for comparison. Performance was re-evaluated with resource injections modeled and compared to the baseline performance to determine the impact of the injections on area transmission reliability.

The power flow analysis was performed with pre-contingency solution parameters that allowed adjustment of load tap-changing ("LTC") transformers, static VAR devices

including switched shunt capacitors and reactors, and DC taps. Post-contingency solution parameters allowed adjustment of DC taps and automatically switched shunt devices, as well as adjustment of manually switched shunt devices outside the study area. Area interchange control was disabled and generator VAR limits were applied immediately for all solutions. The solution method implemented was a fixed-slope decoupled Newton solution.

Black Hills SB07-100 Conclusions

Black Hills utilized an open and transparent process in conducting its 2019 Colorado Senate Bill 07-100 study. Stakeholders were provided several opportunities for involvement and input into the study process and scope. Through this process, Black Hills believes it has fulfilled the requirements of Colorado Senate Bill 07-100, codified at C.R.S. § 40-2-126.

Baculite Mesa 115kV Substation: The 2023HS study results indicated that the BHCE transmission system could accommodate a 200MW injection at the Baculite Mesa 115kV substation with no required upgrades, assuming all planned projects are in service.

Nyberg 115kV Substation: Additionally, the study results indicated that the BHCE transmission system could accommodate a 75MW injection at the Nyberg 115kV substation. Higher levels of injection into this substation caused overloads on XCEL's Boone 230/115kV transformer during a P2 breaker failure contingency at Nyberg.

South Fowler 115kV Substation: The analysis also looked at injections at the planned South Fowler 115kV substation. The results indicated that the BHCE transmission system could accommodate at 75MW injection at this location. Higher levels of injection into this substation caused overloads on XCEL's Boone 230/115kV transformer during a P2 breaker failure contingency at Nyberg. The breaker failure at Nyberg cuts off the

only 115kV paths to the west portion of BHCE's system. This forces the power through the Boone 230/115kV transformer.

West Station 115kV Substation: The last injection point that was included in the analysis was the West Station 115kV substation. The results indicated that the BHCE transmission system could accommodate a 175MW injection at this location. High levels of injection caused overloads on the Fountain Valley – Midway 115kV transmission line. These results included the planned rebuild rating for this line. Increasing this rating further would require substantial terminal equipment upgrades at the Midway substation.

Designate Energy Resource Zones

On November 24, 2008, Public Service filed with the Commission an information report that identified its five ERZs within Colorado. Four of the ERZs identified by PSCo are located in close geographical proximity to the Black Hills system, specifically ERZs 2, 3, 4 and 5. In the 2011 SB07-100 study report, Black Hills identified two ERZs (ERZ-1 & ERZ-2), both of which were located within the PSCo defined ERZ-5. In order to avoid confusion, Black Hills has adopted the five PSCo defined ERZs within Colorado.

Develop plans for the construction or expansion of transmission facilities necessary to deliver electric power consistent with the timing of the development of beneficial energy resources located in or near such zones.

Black Hills identified the impacts of the various resource scenarios on the Black Hills transmission system and identified projects that ensure reliable delivery of beneficial energy resources from the designated ERZ-5 to customer loads.

Consider how transmission can be provided to encourage local ownership of renewable facilities, whether through renewable energy cooperatives as provided in Colo. Rev. Stat. § 7-56-210, or otherwise.

The identified new transmission projects will facilitate renewable resource development in ERZ-5 in excess of Black Hills' forecasted resource needs. The studied resource injections are in relatively close proximity to Black Hills customers and would be facilitated by a direct physical connection to the Black Hills electric system.

Submit proposed plans, designations, and applications for Certificates of Public Convenience and Necessity to the Commission for simultaneous review.

Black Hills believes that the 115 kV transmission projects it has identified to facilitate the reliable delivery of beneficial energy resources to customer load are "in the ordinary course of its business" and do not require CPCNs, pursuant to Colo. Rev. Stat. §§ 40-2-126(3) and 40-5-101. The resource injection amounts identified in this report are indicative of potential system performance under the evaluated scenarios, but should not be construed to reflect firm system capability. In-depth analysis and coordination is required to establish a more comprehensive projection of potential system performance following implementation of the identified system upgrades.

B. Public Service Summary

Public Service began filing SB07-100 reports in October 2007. Public Service has developed plans for nine transmission projects to expand transmission capability for the delivery of beneficial energy resources from ERZs. These projects are listed in Table 14.

Public Service has completed the first five projects listed in Table 14. These projects have enabled Public Service to interconnect 1400 MW of wind in eastern and northeastern Colorado, and accommodates an additional 600 MW of wind from the Rush Creek Wind Project. The table below lists the name of the project, the ERZ that the project would serve, and a tentative schedule for implementation. The status of the projects that remain planned or conceptual are described in more detail in Section III.

Table 14. Public Service SB07-100 Projects

	Project	ERZ	ISD	Status
1	Missile Site 230 kV Switching Station	2	2010	Project placed in-service November 2010.
2	Midway-Waterton 345 kV Transmission Project	3,4,5	2011	CPCN granted on July 16, 2009. Project placed in-service May 2011.
3	Pawnee-Smoky Hill 345 kV Transmission Project	1,2	2013	CPCN granted on February 29, 2009. Project placed in-service June 2013.
4	Missile Site 345 kV Substation	2	2012	CPCN granted on June 8, 2010. Project placed in-service December 2012.
5	Pawnee-Daniels Park 345 kV	1,2	2019	CPCN granted on April 9, 2015. Project placed in service December 2019.
6	Lamar-Front Range 345 kV	2,3	TBD	Plan being re-evaluated through CCPG. Certain segments may be implemented in a phased approach.
7	Lamar-Vilas 230 kV	3	TBD	(See Lamar – Front Range)
8	Weld County Expansion	1	TBD	Studies ongoing through CCPG
9	San Luis Valley	4,5	TBD	Studies Complete

1. *Projects That Have Been Completed or Planned*

Missile Site 230 kV Switching Station (ERZ-2)

The Missile Site 230 kV Switching Station Project consisted of a new switching station near Deer Trail, Colorado, that connects the existing Pawnee-Daniels Park 230 kV transmission line into and out of the Missile Site 230 kV Switching Station. The project has allowed interconnection of new generation in ERZ-2.

The Missile Site 230 kV Switching Station was placed in-service in November 2010. Public Service interconnected the 250 MW Cedar Point wind project in 2011.

Missile Site 345 kV Switching Station (ERZ-2)

The Missile Site 345 kV Substation expanded the Missile Site 230 kV Switching Station to allow additional generation and transmission interconnections from ERZ-2 at the 345 kV voltage level. The substation bisects the Pawnee-Smoky Hill 345 kV Transmission Project. In addition to connecting the Pawnee-Smoky Hill 345 kV line, the substation also allows for future 345 kV transmission connections. These include connections to the Pawnee-Daniels Park 345 kV Project. The Missile Site 345 kV Substation was placed in-service in December 2012. The Limon Wind Energy Center brought about 600 MW of wind generation into Missile Site in 2014, and in 2018, the Rush Creek Project added another 600 MW. The Bronco Plains and Cheyenne Ridge projects will interconnect another 800 MW in 2020.

Midway-Waterton 345 kV Transmission Project (ERZs 3, 4, and 5)

The project consists of 82 miles of 345 kV transmission line from the Midway Substation, near Colorado Springs, to the Waterton Substation, southwest of Denver. The Midway-Waterton 345 kV project accommodates additional generation resources in ERZs 3, 4, and 5. The Midway-Waterton 345 kV Transmission Project was placed in-service in May 2011.

Pawnee-Smoky Hill 345 kV Transmission Project (ERZs 1 and 2)

This project consists of developing approximately 95 miles of 345 kV transmission line between the Pawnee Substation near Brush, Colorado, and the Smoky Hill Substation, east of Denver. The project allowed for additional resources in ERZ-1 and ERZ-2, interconnected at or near the Pawnee and Missile Site substations. The project was designed to facilitate construction of the Pawnee-Daniels Park 345 kV Project. This project was placed in-service in June 2013.

Pawnee-Daniels Park 345 kV (ERZs 1 and 2)

The Pawnee-Daniels Park 345 kV Transmission Project is described in Section III.C.2. The project consists of building a 125-mile 345 kV transmission line from the Pawnee Substation in northeastern Colorado to the Daniels Park Substation, south of the Denver-Metro area. The project also will result in constructing a new Harvest Mile 345 kV Substation, near Smoky Hill Substation, and a new Harvest Mile-Daniels Park 345 kV line. The project also will interconnect with the Missile Site 345 kV Substation. This project was planned in accordance with Senate Bill 07-100, in that it will accommodate generation in designated Energy Resource ERZs 1 and 2. The project was placed in-service in December 2019, at an estimated cost of $169.4 million.

2. *Projects that are Planned or Conceptual*

The projected in-service dates of these conceptual projects identified in Table 13 above can be affected by CPCN approval, revisions to load forecasts, resource plans, siting and land permitting, coordination of construction outages, and material delivery times. Because all of these projects are presently in the conceptual stage, assessments will continue on whether the stated factors will cause any modifications to these projects, in terms of configuration, timing, or otherwise.

Lamar-Front Range 345 kV (ERZs 2 and 3)

This project is described in Section III.C.2 and was planned as a high voltage project that covered vast portions of eastern Colorado to accommodate resources in ERZs 2 and 3. The original Lamar-Front Range project was estimated to cost approximately $900 million. Recently, Tri-State and Public Service have been planning and implementing projects that align with the original Lamar-Front Range plan. These include the Tri-State Burlington-Lamar 230 kV line and the Public Service Missile Site – Cheyenne Ridge 345 kV line.

Also, since 2019, the CCPG LFRTF has been re-evaluating how the Lamar – Front Range plan might be modified, based on recent changes and plans to the transmission system in Colorado. As mentioned in the Public Service 10-Year Plan Overview, a plan evaluated by the LFRTF that shows technical merit and could meet Public Service SB07-100 and SB19-236 Clean Energy Plan objectives includes the following components:

- Networking the Missile Site – Cheyenne Ridge 345 kV line to Burlington
- New 345 kV transmission from Burlington – Lamar – Comanche
- New 345 kV transmission from Burlington – Missile Site
- New 345 kV transmission from Burlington - Pawnee

Lamar-Vilas 230/345 kV (ERZ-3)

The Lamar-Vilas project has been associated with the Lamar-Front Range Plan. The Lamar-Vilas line could consist of approximately 60 miles of high-voltage transmission from Lamar Substation to the existing Vilas Substation to provide access to additional resources in ERZ-3 and Baca County.

Weld County Transmission Expansion (ERZ-1)

This plan is described in Section III.B.2 as a means to accommodate additional generation resources in ERZ-1. As a result of the potential for load growth and the Public Service plan to replace aging 44 kV infrastructure in the area, other projects have been planned and are being developed in the area that align with, and may ultimately replace the Weld County Expansion Project. Public Service is implementing the Ault-Cloverly 230/115kV Project and Tri-State is implementing the planned SWEP, which may connect transmission from the Denver-Metro area to the south of Greeley system. The CCPG NECO Subcommittee has been working to develop a comprehensive transmission plan for Northeast Colorado to serve a variety of needs. Studies indicate that a Weld-Rosedale 230 kV line and a Rosedale Box Elder - Ennis 115 kV

Transmission Lines would be a prudent next step to meet the objectives. The Weld County Expansion could be a combination of the planned Ault-Cloverly Project, and SWEP and conceptual Weld-Rosedale-Box Elder - Ennis 230 & 115 kV lines, or the Weld County Expansion may be a new project that could be considered as a third or eastern phase of the planning efforts in the area.

When specific projects have been recommended, Public Service will inform stakeholders and develop plans for implementation.

San Luis Valley (ERZs 4 and 5)

This plan has been described in Section III.B.2 and has been planned as a means to accommodate potential generation from ERZs 4 and 5, in addition to improving the reliability of the transmission system in the San Luis Valley area of Colorado. Studies were performed in the CCPG San Luis Valley Subcommittee, which identified that additional 230 kV transmission from San Luis Valley to Poncha to the Front Range would enable additional resource accommodation. As specific projects are planned and recommended, Public Service will inform stakeholders and develop plans for implementation.

VI. Stakeholder Outreach Efforts

Per Rule 3627(g), "Government agencies and other stakeholders shall have an opportunity for meaningful participation in the planning process." "Government agencies include affected federal, state, municipal and county agencies. Other stakeholders include organizations and individuals representing various interests that have indicated a desire to participate in the planning process." *See* Rule 3627(g)(I). The following sections summarize each Company's approach to government agency and stakeholder outreach and participation pertaining to Rule 3627. Processes specific to the stakeholder input directives of FERC Order No. 890 are discussed in Section VII.D.

A. Black Hills Outreach Summary

Black Hills recognizes the importance of stakeholder involvement throughout the transmission planning process and considers a stakeholder to be any person, group or entity that has an expressed interest in participating in the planning process, is affected by the transmission plan, or can provide meaningful input to the process that may affect the development of the final plan.

Stakeholders are encouraged to participate in Black Hills' transmission planning through the regular meetings held by the TCPC as part of the annual study process under FERC Order No. 890. The TCPC is an advisory committee consisting of individuals or entities who are interested in providing input to Black Hills' Transmission Plan. The TCPC study process consists of a comprehensive evaluation of the Black Hills and surrounding transmission systems for critical scenarios throughout the 10-year planning horizon. Stakeholders are notified of the initial meeting at the start of the study cycle and invited to participate. An opportunity is provided to comment on the scope of the study at this point in the process. Relevant system modeling data is requested from the stakeholders, as well as any economic study or alternative scenario requests. Once the study cases are compiled, another open stakeholder meeting is held to review and

finalize the data and study scope. A third stakeholder meeting is held to review preliminary study results and discuss potential solutions to any identified problems. This process allows the TCPC to develop a comprehensive transmission plan to meet the needs of all interested parties. A final stakeholder meeting is held to approve the study report and Local Transmission Plan ("LTP"). Following each meeting, contact information for the transmission planner performing the study is provided to allow for ongoing questions or comments regarding the study process. Updates on the progress of the TCPC study efforts also are provided to regional planning groups, such as the CCPG, to promote involvement from a larger stakeholder body.

A list of potential stakeholders was created during the initial TCPC study cycle and has continued to evolve through active invitations, recommendations from existing participants, and outreach at CCPG meetings. Black Hills is continually modifying its stakeholder list in order to invite a more comprehensive group of participants into the transmission planning process.

Two quarterly meeting invites were sent in 2019 as part of Black Hills' annual TCPC process. The primary kick-off taking place on April 23, 2019, and a second invite on October 10, 2019. Meeting notifications were sent to the stakeholder contact list, announced at the CCPG meetings and posted on Black Hills' OASIS web page.

Black Hills' Q1 stakeholder meeting is typically more educational in nature and was held via web/phone conference on April 23, 2019. It served the purpose of presenting the transmission planning process to stakeholders, describing the scope of the 2019 assessment, reviewing the current 10-Year Transmission Plan and soliciting feedback on the study scope, the stakeholder outreach process, and potential alternatives to the projects within the 10-Year Plan.

Black Hills' Q3 stakeholder meetings were sent out via e-mail on October 10, 2019. This meeting served the purpose of an update and solicitation for feedback regarding the progress of the study and conclusions. Although there were no updates made since

the kick-off meeting, this invite was to allow any part to request a meeting if it was deemed necessary. No interest was shown to pursue an official meeting after the invite was sent.

Black Hills' Q4 stakeholder meeting was not held, as cases from CCPG were not received until the week of December 20, 2019. At that time, an e-mail was sent to stakeholders presenting our updated study scope and list of scenarios included for stakeholder question and comment. The study work has been started and results will be presented at the 2020 Q1 stakeholder meeting.

A limited number of external stakeholders attended the quarterly meetings. The stakeholder meetings produced some dialog on specific projects, but substantive feedback regarding the planning process and future projects was not received. Black Hills relied heavily on coordination with affected utilities and internal review of alternatives to ensure that the projects selected and presented in the Rule 3627 Transmission Plan were optimal and adequate for the needs of its network transmission system and Colorado's goals of fostering beneficial energy resources to meet load growth.

For more information regarding the stakeholder process utilized in the 2019 or earlier Black Hills TCPC planning processes, including meeting notices, notes, presentations and contact information, refer to the Black Hills' Transmission Planning page; https://www.blackhillsenergy.com/our-company/transmission-rates-and-planning
Stakeholder outreach information also is available in the Transmission Planning folder on the Black Hills OASIS at: http://www.oatioasis.com/bhct

B. Tri-State Outreach Summary

Tri-State performs transmission planning-related stakeholder outreach as a standard part of its day-to-day business consistent with its policy of planning in an open, coordinated, transparent and participatory manner. This outreach encompasses

various efforts including: Rule 3627 specific meetings and stakeholder communications; FERC Order No. 890 specific meetings and communications; project-specific meetings and communications; and CCPG participation.

As described in Rule 3627(g)(I), stakeholders include federal, state, county, and municipal government agencies as well as other non-governmental organizations and individuals having an interest in the transmission planning process. Tri-State identifies potential governmental stakeholders based generally on a five-mile area surrounding proposed transmission facilities. Federal agencies in the areas of the transmission projects included in Tri-State's 2020 10-Year Transmission Plans typically include the Bureau of Land Management, the U.S. Forest Service, the National Park Service, and the Department of Defense. Potentially interested state agencies include the Colorado State Land Board and associated Stewardship Trust Lands, and the Colorado Division of Parks and Wildlife. Outreach to county and local governments typically includes communications to relevant elected officials as well as administrators, managers, and land planning, economic development, and legal staffs. In some instances, Tri-State's governmental outreach also included agencies such as parks and school districts.

Contact lists for non-governmental stakeholders were developed through various transmission planning forums such as CCPG and other WestConnect planning groups, as well as individuals and organizations that have participated in previous Tri-State stakeholder meetings. When known, Tri-State also included stakeholders identified as being interested in specific proposed projects. The resulting non-governmental stakeholders included other utilities, Tri-State Member Systems, energy and transmission project developers, environmental groups, economic development organizations, various advocacy groups, and elected officials not already included in the governmental outreach communications.

In 2019, Tri-State hosted one transmission planning-related stakeholder outreach meeting in connection with development of the 2020 10-Year Transmission Plan. The meeting was on August 21, 2019, and provided a summary of new information related

to Tri-State's ongoing transmission planning activities as well as updates on current projects and coordination with CCPG's long range transmission planning efforts. This meeting also constituted Tri-State's FERC Order No. 890 stakeholder meeting and provided an opportunity for stakeholders to provide input in connection with all of Tri-State's long-range transmission plans. All such input and relevant alternatives were considered and included in the appropriate biennial transmission plans submitted to the Colorado Public Utilities Commission pursuant to Rule 3627. No alternatives were proposed at this meeting.

In addition to this larger stakeholder meeting addressing system-wide and Colorado-specific transmission projects, Tri-State also conducted a number of meetings related to individual proposed transmission projects. These meetings and other project-related communications included relevant government agencies, economic development entities, and other interested organizations and persons to inform them of the proposed project and provide an opportunity for feedback and consideration of potential alternatives. The nature and timing of outreach efforts related to specific projects was generally dependent on the development status of the project.

Details of Tri-State's meetings, including a list of attendees and a meeting presentation video which includes questions and comments received together with Tri-State's responses thereto, and relevant presentations can be found at:
http://www.tristategt.org/stakeholder-outreach

Tri-State also participates in the CCPG's transmission planning efforts. As discussed in Section VI.D. of this Plan, the CCPG planning process includes additional stakeholder outreach and a further opportunity for stakeholder participation in and input into the overall Colorado coordinated transmission planning process, which includes Tri-State's proposed projects. Additional information concerning CCPG stakeholder opportunities is available at the WestConnect website.

Tri-State confirms that, as required by Commission Rule 3627(g)(V), this 2020 10-Year Transmission Plan is available to all government agencies and other stakeholders through Tri-State's Transmission Planning website at:
*http://*www.tristate.coop/transmission-planning

Tri-State has informed all stakeholders of the availability of the 2020 10-Year Transmission Plan.

C. Public Service Outreach Summary

Rule 3627 requires a summary of stakeholder participation and input and how this input was incorporated in the transmission plan. The rule states that government agencies and other stakeholders shall have an opportunity for meaningful participation in the planning process. The government agencies include affected federal, state, municipal and county agencies. In addition, Rule 3627 provides that other stakeholders, including organizations and individuals representing various interests that have indicated a desire to participate in the planning process, must also have an opportunity for meaningful participation. Under Rule 3627, Public Service is required to actively solicit input from the appropriate government agencies and stakeholders to identify alternative solutions. In addition to the Public Service outreach efforts listed below, the Company actively participates in numerous CCPG groups, where it also engages with and responds to comments presented by stakeholders. The following is a synopsis of the outreach that the Company performed relevant to this rule. Also, Appendix K lists some responses to comments received from two stakeholders.

Rule 3627 Webinars

The Company developed an informational PowerPoint presentation that included information on the long-range plans developed as part of Rule 3627. Two, two-hour-long webinars were held – the first on Friday, August 16, 2019, and the second on Wednesday, September 11, 2019 - to give stakeholders opportunity to participate and comment on transmission plans, either in person (at the Xcel Energy offices in

downtown Denver) or via the Internet. E-mail invitations with exact verbiage will be provided at the request of the Commission.

More than 500 individuals representing the following stakeholder groups—including all state legislators in both the House and Senate—received invitations to the webinars:

- Elected officials
- Federal, state and local government officials
- Environmental groups
- Energy developers
- Chambers of commerce
- Business and industry
- Planning and economic development agencies
- Large energy users
- Citizens and advocacy groups
- Intervenors on past PSCo filings
- Organizations involved in transmission planning (*e.g.*, CCPG members)

Invitations also were sent to the CCPG's distribution list, which includes representatives from other utilities including Black Hills, WAPA and Tri-State, as well as stakeholders representing environmental interests, consulting firms, law firms, and other individuals and groups. Local government elected officials, including county commissioners in counties that could be impacted by projects in the Public Service's portion of the 2020 Plan, were also invited along with local planning office representatives and other staff officials from local governments and agencies. Because routing had not been started on some of these projects, which were still in the planning phase, individual landowners who might be impacted were not identified.

Information on Xcel Energy's transmission projects in Colorado was provided to all invitees via a link in the e-mail, but since then, the web address was redirected to the following: http://www.transmission.xcelenergy.com/Projects/Colorado

Attendance at the August 16, 2019, session included eight in-person attendees external to PSCo and approximately 60 webinar attendees, although an actual count was difficult to gauge, as participant count decreased and increased during the course of the presentation. Since self-identification was optional, it was not possible to determine whether additional participants entered the webinar or participants already in attendance reconnected after becoming disconnected from the webinar. Attendance at the September 11, 2019, session included five in-person attendees external to Public Service and approximately 20 webinar attendees.

The PowerPoint presentation discussed at the session consisted of three basics parts. Because the level of knowledge surrounding transmission and transmission planning of the attendees was not known, part one provided an overview of electric transmission to acquaint attendees with basic information about how the system works and what constitutes the transmission system. Part two covered the transmission planning process, provided an overview of how and why planning is done, and outlined the many factors that are considered when developing plans. Part three reviewed all projects included in Public Service's portion of the 2020 Plan. Public comment from the webinar covered a wide range of topics. Written comments were received from the Office of Consumer Council and Western Resource Advocates. The written comments and Public Service responses to these comments are included in Appendix K.

FERC Order 890 Stakeholder Meetings

The Company facilitates two open stakeholder meetings per year to meet the requirements of FERC Order 890. The meetings are held in the first and fourth quarters every year at the Xcel Energy office in Denver, and the content is very similar to that presented in the Rule 3627 webinars. In the last two years, FERC Order 890 meetings were held on March 15, 2018, December 5, 2018, March 20, 2019, and December 4, 2019. Public Service has taken a similar approach to Tri-State, where the Rule 3627 and FERC Order 890 meetings are referred to as open stakeholder meetings that will

meet the objectives of both rules. Meeting agendas, presentations (referred to as "Transmission Plans", and notes are available at:
http://www.oatioasis.com/psco/index.html under "FERC 890 Postings".

PROJECT-SPECIFIC OUTREACH

Pawnee-Daniels Park Project

The Pawnee-Daniels Park Project was energized on December 26, 2019. Final site restoration and revegetation work will continue throughout spring and summer 2020. Public Service will continue to work with landowners and impacted communities throughout the remainder of restoration activities.

Avery Substation Project

Public Service is proposing to construct the Avery Substation and Transmission Line project. The new Avery Substation will enable the company to serve existing and new load in the vicinity of Timnath, Severance and Windsor along the eastern side of the Interstate 25 corridor. Avery Substation will assist in providing back up to the existing Cobb Lake and Windsor Substations, which are reaching their capacity. It also will provide reliability to our existing and future customer load. The project consists of a new electric distribution substation, an associated overhead double-circuit 230 kV electric transmission line and overhead distribution feeder lines near the towns of Windsor, Severance and Timnath, Colorado. Power for the proposed 1.4-mile 230 kV transmission line will be provided by interconnecting the existing PRPA Timberline-Ault 230 kV transmission line. Public Service is currently evaluating in the land use permitting process with the Town of Windsor for the substation and a portion of the transmission line. Land use permits for other portions of the transmission line have been approved. This connection will supply the proposed Avery Substation with the electrical supply needed to power the distribution feeders serving the immediate communities.

Land use permitting for portions of the transmission line in unincorporated Weld County was completed in September 2018. A Conditional Use Grant application for the substation and the last half-mile of line was submitted to the Town of Windsor in December 2018. Hearings were held at the Windsor Planning Commission and Town Board in February 2019. The Town Board continued the hearing due to questions about the location and information needed from the landowner. Based on landowner feedback, Public Service decided to withdraw the application and attempt to resolve the primary concerns from the public and the town. This resulted in a new site alternative that was presented to the public at an open house on July 9, 2019.

Based on feedback at the open house, the new site was chosen as the preferred location and a new application was submitted on August 27, 2019, with this proposed site.

The Conditional Use Grant was recommended for approval by the Planning Commission on November 6 and was approved by the Town Board on November 25, 2019. It is anticipated that construction on the substation will commence at the end of Q1 or beginning of Q2 2020. Public Service staff will conduct public outreach as needed to support construction.

Ault-Cloverly 230/115 kV Transmission Project

The Ault-Cloverly 230/115 kV Transmission Project will increase electric reliability and load-serving capability of the Xcel Energy electric transmission system in and around the Greeley area, and will provide accommodation for new generation resources in the region while aligning with other transmission planning efforts in the area. The company filed a CPCN application with the CPUC on March 9, 2017, to construct the Northern Colorado Area Plan; Proceeding Number 17A-0146E.

The company held three open house meetings for the Northern Colorado Area Plan in 2018, and submitted a 1041 permit application in November 2018. Following several public comments voicing opposition to the southwestern portion of the preferred route,

the company amended its application to include the WAPA/Ault to Husky to Graham Creek portion of the line, with the intention of applying for a separate permit for the Graham Creek to Cloverly portion of the line. On June 18, 2019, the Weld County Planning Commission unanimously recommended denial to the Board of County Commissioners. Following this denial, the company determined the best course of action would be to withdraw the 1041 permit application. The company is now starting over with a new siting and community engagement effort. In the coming months, we will be hosting a Community Working Group, consisting of 12 to 20 community members and leaders to participate in the routing effort. Additionally, the second of four planned open house meetings (the first meeting was held in November 2019) will be hosted in late January in the town of Eaton. The 1041 Areas and Activities of State Interest land use permit application will be submitted in late spring/summer 2020, with Planning Commission and Board of County Commissioner hearings taking place in summer/fall 2020.

Greenwood - Denver Terminal

The Company is proposing the upgrade of approximately 15.4 miles of existing transmission facilities to 230 kV by rebuilding and/or reconductoring existing transmission facilities from the Greenwood Substation to the Denver Terminal Substation within existing right-of-way (ROW). The CPCN submittal for the project is targeted for early 2020. The project is located in six different jurisdictional boundaries: Centennial, Greenwood Village, Littleton, Englewood, Sheridan and Denver.

Outreach activities completed to date have been with elected officials and planning staff. The list below summarizes meetings that have taken place to date:

- September 16, 2019 – City of Englewood City Manager
- September 23, 2019 – City of Centennial Councilmembers
- September 25, 2019 – City of Greenwood Village Mayor and City Manager
- September 27, 2019 – City of Littleton staff
- October 3, 2019 – City of Sheridan City Manager and staff

- October 4, 2019 – City of Greenwood Village staff
- October 9, 2019 – City of Centennial Mayor and City Manager
- The City of Denver Council members were notified informally by the Company Area Manager
- November 4, 2019 – City of Littleton School District
- November 6, 2019 – City of Centennial City Planner and Public Works
- November 11, 2019 – City of Englewood City Planner and Public Works
- January 7, 2020 – Pre-Submittal Application submitted to City of Denver Planning and Development
- February 11, 2020 – Scheduled informal presentation at City of Littleton City Council public hearing.

Future meetings with the City of Englewood elected officials and the staff of the remaining cities are being scheduled. Public meetings, including open houses and neighborhood associations, will be held in February 2020.

Barker Substation

The Company is proposing the installation of equipment in the currently empty Barker Substation site and a new double circuit buried transmission line from the Barker Substation to the existing LaCombe Substation. The project is located within the City of Denver and outreach to the city is anticipated to begin in January 2020.

Glenwood-Rifle Transmission Line

In 2019, Public Service staff met with Glenwood Springs city management to discuss the Glenwood to Mitchell Creek Transmission Line Rebuild project. The Project consists of rebuilding approximately two miles of 69kV transmission line to 115kV transmission line, which will be initially operated at 69kV. Currently, the team is evaluating alternatives that include rebuilding outside of the existing alignment due to vegetation and ROW constraints in the current alignment. Public outreach is planned to begin in 2020, with a public open house and communications with elected officials tentatively planned in the first quarter of 2020.

Cheyenne Ridge Wind Farm and 345 kV Transmission Line Project

The Cheyenne Ridge 500 MW wind farm and 73-mile 345 kV transmission line is one of the projects that makes up a portion of the company's Colorado Energy Plan. The project is located in Lincoln, Kit Carson and Cheyenne counties, and, when complete, will generate enough renewable energy to power 270,000 homes. The company completed its purchase of the project asset from Tradewind Energy, who developed and permitted the project, in June 2019.

During the development phase of the project, Tradewind Energy engaged with many stakeholders, including county planning staff, landowners, Colorado Division of Wildlife, Colorado Department of Public Health and Environment, the Nature Conservancy, United States Fish and Wildlife Service, Colorado Department of Transportation, and the Colorado State Historic Preservation Office. After the company's purchase of the project, engagement with these stakeholders has continued.

The project commenced construction in July 2019 and is expected to reach commercial operations in December 2020. Since taking ownership of the project in June 2019, the company has sent a brochure on project updates to stakeholders and landowners. The brochure contains an update of the construction activities that have occurred to date and a high-level project schedule. The company also is hosting a project website that provides project updates, project photos, and contact information for questions and concerns. The website can be found at the following URL: https://www.xcelenergy.com/energy_portfolio/renewable_energy/wind/co_wind_power/cheyenne_ridge_wind_project

The Company plans to continue stakeholder engagement in 2020 with the issuance of future project brochures, updates to the project website, landowner liaison efforts, and coordination with Lincoln, Kit Carson and Lincoln counties, and the Colorado Department of Transportation.

D. CCPG Outreach Summary

To ensure stakeholders in Colorado have multiple opportunities to provide input and receive a broader perspective on the evolution of Colorado's transmission system, TPs also leverage the CCPG stakeholder input process in developing the 10-Year transmission plan. CCPG has a subgroup called the 3627 Subcommittee. The Subcommittee serves as a forum for coordination among the Colorado electric utilities that are required to comply with PUC Rule 3627, and for receipt and consideration of stakeholder proposals submitted in connection with 10-Year transmission plans. Since the 2012 filing, TPs have worked with CCPG to formalize and document processes for receiving, evaluating, and providing feedback on stakeholder submitted alternatives. Stakeholders are provided opportunities for meaningful participation through multiple channels, including an online form that can be emailed, by participating in open meetings via teleconference, or by actively attending quarterly meetings. Full documentation of the process by which stakeholder input, suggestions, and alternatives are to be categorized, evaluated, and recorded is included in Appendix J as well as on the CCPG website at:
http://regplanning.westconnect.com/ccpg_stakeholder_opportunities.htm

Generally, the process is initiated by the stakeholder filling out a form and supplying it to the CCPG chair. The form requests the following information:

- Study or project name
- New study or alternative
- Narrative description
- Study horizon date
- Geographic footprint of interest
- Load and resource parameters
- Transmission modeling
- Suggested participants
- Policy issues to address

- Type of study
- Other factors

Once the CCPG chair receives the request, a determination will be made as to whether adequate information has been provided. The chair may contact the requester to ask for additional details. The chair will facilitate an ad-hoc review group ("Review Group") to review and categorize the request. The Review Group will determine:

- If the request is reasonable from a reliability planning perspective.
- Who should be responsible? (CCPG or a smaller sub-group of CCPG; or should the study be forwarded to a larger group such as WestConnect or WECC)?
- The likely schedule for completing the analysis requested.

The Review Group may consider the following questions to determine the response to the request:

- Which portion(s) of the CCPG transmission system shall be under consideration in the study?
- Would the request be of interest to multiple parties?
- Does the request raise policy issues of national, regional, or state interest?
- Can the objectives of the study be met by existing or planned studies?
- Would the study provide information of broad value to customers, regulators, transmission providers and other interested Stakeholders?
- Does the request require an economic (production cost) simulation or can it be addressed through technical studies, (power flow and stability analysis)?

Once the Review Group has determined that the request is reasonable and has verified the purpose and intent of the request, a written response will be developed and provided to the requester and CCPG.

If the Review Group determines that the request cannot be accommodated by CCPG or any TP, an explanation will be provided. If the Review Group determines that the request can be accommodated, then the response will provide information as to the recommended logistics for how the request will be handled, including the responsible parties and a schedule for completion. CCPG maintains a record of all comments and requests received, as well as their disposition. These records also will be posted on the CCPG section of the WestConnect website.

CCPG Northeast Colorado Subcommittee Stakeholder Input Process

The CCPG NECO Subcommittee is the forum for coordinated planning of the transmission system that generally covers Weld, Morgan, Adams, Washington, Logan, Sedgwick, Phillips and Yuma counties and also extends to portions of Boulder and Larimer counties. The objective of the NECO Subcommittee consists of developing transmission plans that will support and facilitate load growth, allow for future generation injection, coordinate with reliability improvements in the Greeley area, and complement other longer-term transmission plans in northeast Colorado. In 2017, the group recommended the Ault – Cloverly 230/115 kV project as the Northern Greeley Area Plan (NGAP).

Public Service filed for a CPCN for the Northern Greeley Area Transmission Plan Project in 2017 and the NECO Study Report was included in the testimony. On March 1, 2018, a CPCN was granted in the Recommended Decision by the Public Utilities Commission for the Proceeding No. 17A-0146E.

In 2017-2019, the NECO Subcommittee changed its focus to the transmission system south of Greeley. The objectives are similar to the north of Greeley studies, which are to reliably replace the existing 44 kV system, increase the ability to accommodate future load growth, allow for beneficial resource development and align with other transmission projects in the area.

In 2018-2019, the NECO Subcommittee met on:

- May 2, 2018
- June 6, 2018
- July 17, 2019

The subcommittee has performed studies to evaluate the present load-serving and generation interconnection capabilities. At least 11 alternatives were evaluated. Presently, the alternative that meets not only the NECO objective, but also can assist with the Public Service 80x30 objectives appears to be a new 230 kV line from Weld – Rosedale, and a 115 kV line from Rosedale – Box Elder – Ennis.

Colorado Energy Plan Task Force

The Colorado Energy Plan Task Force (CEPTF) was formed to inform stakeholders of the studies being performed to evaluate the Company's 2016 ERP and 2017 CEP. Public Service chaired and performed the study work for the CEPTF.

The following stakeholders participated in the CEPTF:

- Basin Electric Power Company
- Black Hills Corporation
- Bright Energy Storage
- Buckyball Systems
- Colorado Public Utilities Commission
- Colorado Springs Utilities
- Dietze & Davis
- Intermountain Rural Electric Association
- Lucky Corridor
- Tormoen Hickey LLC
- Colorado Office of Consumer Council
- Western Area Power Administration
- Western Resource Advocates

- Tri-State
- TradeWind Energy

Meetings were held on:

- November 1, 2017
- November 27, 2017
- March 8, 2018
- October 18, 2018
- March 1, 2019
- July 17, 2019

The CEPTF provided a forum to inform stakeholders of key findings and recommendations related to the transmission issues associated with implementation of the CEP Portfolio, which include:

- There are no significant transmission deficiencies caused directly by the retirement of Comanche Units 1 & 2. The system will remain reliable and there are no transient stability issues.
- Implementation of the CEP Portfolio requires additional voltage control facilities and a network upgrade in the Denver metro area.
- The voltage control facilities include a mix of static and dynamic devices that are needed to maintain adequate voltage performance.
- The recommended network upgrade consists of a new Greenwood Denver Terminal 230 kV line. At least eight transmission alternatives were evaluated based on stakeholder input.

CCPG Lamar Front Range Stakeholder Input Process

In 2019, the Lamar-Front Range Task Force (LFRTF), which was facilitated by Tri-State, revisited the Lamar-Front Range studies completed in 2013. In 2013, the Lamar-Front Range plan was identified through extensive transmission analysis to facilitate

addition of new resources in eastern Colorado, improve transmission system reliability, and increase operational flexibility. The 2013 plan was conceived as a joint project between Public Service and Tri-State. A primary driver for Public Service was to meet an SB07-100 objective to plan transmission from the ERZ-3. The overall plan included the following transmission components:

- Two 345 kV transmission circuits between Lamar and Avondale
- Two 345 kV transmission circuits between Lamar and Burlington
- Two 345 kV transmission circuits between Burlington and Big Sandy
- One 345 kV transmission line between Big Sandy and Missile Site
- One 345 kV transmission line between Big Sandy and Story
- One 345 kV transmission line between Story and Pawnee
- A new Avondale Substation
- Two 230 kV transmission circuits between Lamar and Vilas

Since completion of the 2013 Lamar-Front Range studies, the eastern Colorado transmission system has materially changed with the addition of new resources and transmission facilities. The goal of the task force was to evaluate potential transmission alternatives to the Lamar-Front Range plan.

In April 2019, the LFRTF finalized a study scope and began evaluating transmission alternatives. The LFRTF performed technical analysis of 26 alternatives that facilitated the addition of new resources in eastern Colorado. Several other alternatives were considered, but not included in the technical analysis. The costs of the alternatives for this analysis were based on indicative (planning level) capital construction costs. The benefits of the alternatives were measured primarily in terms of how much incremental generation a particular alternative could accommodate compared to cost of the alternative. Other costs and benefits may be achieved, but were not the focus of this analysis. The LFRTF provided an open stakeholder forum to analyze the costs and benefits of alternative transmission proposals.

The LFRTF has held seven regularly scheduled meetings since February 2019 to discuss study assumptions, study methodology, potential alternatives, cost estimates, and benefits. The LFRTF Subcommittee participant list consisted of 38 stakeholders representing the following entities:

- Apex Clean Energy
- Black Hills
- Buckyball Systems
- Colorado Energy Office
- Colorado Springs Utilities
- Dietze and Davis, P.C.
- Juwi
- Independent Transmission Company
- Invenergy
- New Law Group
- Orion Renewable Energy Group
- Platte River Power Authority
- Savion Energy
- State of Colorado – Office of Consumer Counsel
- State of Colorado – Public Utilities Commission
- Tradewind Energy
- Tri-State Generation & Transmission
- Western Area Power Administration
- Xcel Energy

Meetings were held on:

- February 6, 2019
- March 7, 2019
- April 4, 2019

- June 6, 2019
- June 27, 2019
- July 30, 2019
- September 12, 2019

Prior to the March 2019 meeting, four stakeholders submitted transmission alternatives for consideration. The LFRTF addressed the stakeholder comments during the course of the study process, which was documented in meeting notes.

The LFRTF stakeholders evaluated numerous alternative proposals and agreed to perform technical analysis of the following 14 standalone alternatives:

1A. New 345 kV line from Burlington to Shortgrass to Big Sandy to Story to Pawnee Substation
1B. Alt 1A without Big Sandy Substation interconnection
2. New 345 kV line from Cheyenne Ridge to Burlington to Big Sandy to Missile Site Substation
3A. New 345 kV line from Missile Site to Cheyenne Ridge to Wray to Story to Pawnee Substation; Replace Burlington-Lamar 230 kV Project with New 345 kV line from Cheyenne Ridge to Lamar Substation; New 230 kV line from Cheyenne Ridge to Burlington Substation
3B. Alt 3A without Wray Substation interconnection
4A. New 345 kV line from Missile Site to Burlington to Wray to Story to Pawnee Substation; Replace Burlington-Lamar 230 kV Project with New 345 kV line from Burlington to Lamar Substation
4B. Alt 4A without Wray Substation interconnection
5. New 345 kV line from Lamar to Midway Substation
6. New 345 kV line from Lamar to Comanche Substation
7A. New 345 kV line from Badger Hills to Lamar to Boone Substation; Replace Burlington-Lamar 230 kV Project with New 345 kV line from Cheyenne Ridge to Lamar Substation; New 230 kV line from Cheyenne Ridge to

Burlington Substation; Sectionalize Comanche to Daniels Park 345 kV line #1 or # 2 at Badger Hills Substation

7B. Alt 7A without New 345 kV line from Lamar to Boone 345 kV

8A. New 345 kV line from Badger Hills to Lamar to Boone Substation; Sectionalize Comanche to Daniels Park 345 kV line #1 or # 2 at Badger Hills Substation

8B. Alt 8A without New 345 kV line from Lamar to Boone 345 kV

9. New 345 kV line from Badger Hills to Lamar to Boone Substation; Sectionalize Comanche to Daniels Park 345 kV line #1 or # 2 at Badger Hills Substation; New 345 kV line from Lamar to Cheyenne Ridge Substation

The LFRTF stakeholders evaluated the standalone alternative results and agreed to perform technical analysis of the following twelve combined alternatives:

Alt 3A + 5
Alt 3B + 5
Alt 3A + 7A
Alt 3A + 7B
Alt 3B + 7A
Alt 3B + 7B
Alt 4A + 5
Alt 4B + 5
Alt 4A + 7A
Alt 4A + 7B
Alt 4B + 7A
Alt 4B + 7B

Meetings to review and approve a draft study report are forthcoming. All supporting documentation including meeting agendas, presentations, and notes are accessible from the CCPG – Lamar Front Range Task Force website located at:

http://regplanning.westconnect.com/ccpg_lamar_tf.htm

Energy Storage and Non-wires Alternatives Working Group

As the Companies' strive to reduce carbon emissions, it is recognized that future challenges will require leveraging a portfolio of innovative technologies to support the Companies' goals of a cleaner and more reliable bulk electric system. As a part of this effort, Public Service has initiated and established the Energy Storage Work Group (ESWG) within the Colorado Coordinated Planning Group (CCPG). ESWG will analyze the performance and integration of such systems to identify benefits and challenges for energy storage and other non-wire alternative technologies. The ESWG will evaluate these technologies and develop recommendations for consideration of CCPG and stakeholders. Recommendations will focus on the integration of energy storage resources into the bulk electric system as well as non-wire alternative technologies to address capacity needs and reliability constraints as they relate to the bulk electric system. The ESWG aims to accomplish these goals by assembling resources from the various members of the CCPG as well as external subject matter experts as needed.

The ESWG held its first meeting on January 23, 2020. Several meetings will be scheduled through the remainder of the year as need.

VII. 10-Year Transmission Plan Compliance Requirements

A. Efficient Utilization on a Best-Cost Basis: Rule 3627(b)(I)

Each Company endeavors to conduct transmission planning with the goal of achieving best-cost solutions that balance numerous factors and result in optimal transmission projects. Rule 3627(b)(I) defines “best-cost” as “balancing cost, risk and uncertainty and includes proper consideration of societal and environmental concerns, operational and maintenance requirements, consistency with short-term and long-term planning opportunities, and initial construction cost."

The Companies recognize that a project that is financially impractical will experience difficulty in gaining support from the Commission, customers, shareholders in the case of Black Hills and Public Service, and members in the case of Tri-State. However, cost is not the only consideration when selecting and developing transmission projects. The Companies take a number of factors into consideration when planning the long-term build-out of the transmission system, including but not limited to the following:

- Load projections
- Project partnership opportunities
- Regional congestion
- Transportation corridors
- Transmission corridors
- City and county zoning
- Geographic features
- Societal and environmental impacts
- Operational and maintenance requirements
- Consistency with short-term and long-term planning opportunities
- Initial construction cost

The impact each factor has on a particular project varies based on the nature of the project. Nevertheless, each factor is considered to some extent during the planning stage.

Take the fairly broad environmental and societal concerns factor, for example. As its name implies, this factor considers how a project relates to the natural environment and the public in general – both positively and negatively. In the context of transmission planning, this usually means:

- The negative effects to the local environment from constructing a new transmission line or substation.
- The net positive impact to the environment of constructing a particular new transmission facility as an alternative to a different project over a more sensitive area.
- The positive impact to the environment of utilizing existing transmission corridors or upgrading existing facilities rather than constructing new ones.
- The positive impact to the environment and society if a project gives transmission customers access to a more diverse mix of generation resources, which can potentially reduce overall emissions and energy costs.
- The positive impacts to society by providing stable and reliable electricity. This is particularly important in rural areas where a single transmission outage has the potential to de-electrify entire regions.

For example, a planner may determine, by inspection, that a certain alternative is not practical because it would require a new transmission line over sensitive or exceptionally rugged terrain. This occurred in the CCPG San Luis Valley Subcommittee. The Subcommittee was tasked with evaluating the performance of alternatives to improve several deficiencies in the San Luis Valley transmission system, the biggest deficiency being that a single line outage can cause widespread outages to customers served by Public Service and Tri-State in Saguache, Mineral, Rio Grande, Alamosa, Costilla, and Conejos counties. One proposed alternative was to add a second 230 kV line to the

San Luis Valley from either Montrose or Pagosa Springs. Electrically speaking, a new transmission line from either of these sources would likely improve reliability in the San Luis Valley. However, the Subcommittee declined to analyze them in part because these alternatives would require the construction of new transmission lines across rugged mountainous regions. Given the potential costs, environmental impacts, and permitting and construction challenges, it was decided these alternatives did not justify the effort required to model and analyze them. More information on the work of the CCPG San Luis Valley Subcommittee can be found in the Colorado Coordinated Planning Group San Luis Valley Subcommittee report in Appendix M.

Operational and maintenance concerns also are considered in the planning process. These factors include things such as:

- Spare equipment strategies, particularly for equipment that if failed, would take longer than six months to replace.
- The ability of the system to allow maintenance outages of lines and transformers.
- The capability of the system to accommodate required and increased demands on limited transmission path transfer limits.
- The capacity of the system to allow generators to output their full energy without operating restrictions or operating procedures (congestion).
- Increasing system robustness so that the use of load shedding, special protection, and cross tripping schemes can be minimized.

For example, operational and maintenance concerns were considered by the CCPG Northeast Colorado Subcommittee in its 2017 Northern Greeley Area Transmission Plan System Impact Study Report. The study focused on improving the Greeley area 44kV transmission system, which is antiquated and operated in a mostly radial fashion. The Subcommittee proposed and evaluated several potential transmission projects to improve system reliability and maintenance of the transmission system in the Greeley area. More information on this study can be found in the Northern Greeley Area Transmission Plan System Impact Study Report included in Appendix N.

Good transmission planning requires that alternatives be evaluated in the context of short-term and long-term planning opportunities as well. In planning vernacular, this means considering:

- The relative ability of transmission alternatives to serve more loads, whether it is in the near-term or long-term planning horizon;
- The capability of new transmission alternatives to allow the injection and export of new generation resources; and
- The manner in which transmission alternatives align with longer-term transmission strategies.

The CCPG Northeast Colorado Subcommittee explicitly considered each of these factors in the 2017 Northern Greeley Area Transmission study. Voltage Stability ("P-V") analysis was performed for each studied alternative to compare its relative strength. This type of analysis is a common way to consider the relative ability of various transmission alternatives to serve future loads. The Northern Greeley Area Transmission Study considered the ability of each alternative to allow new resources out of the Greeley area and each alternative's ability to align with a longer-term area transmission plan known as the Southwest Weld Expansion Project located to the south of Greeley.

In general, a primary method of identifying and addressing many of the planning factors is through stakeholder participation in the planning process. Since planning is one of the initial stages of transmission project development, a preliminary evaluation of the aforementioned factors is typically performed as a screening process, with progressively more meaningful, in-depth evaluation occurring through the siting, permitting, and construction stages of development.

Adherence to best-cost principles is formally reflected by each Company in its internal policies. For example, Tri-State policy requires careful consideration of:

- Cost comparison of alternatives for providing capacity to serve load
- The use of existing delivery points and sub-transmission system
- Early construction of other delivery points planned by the member and/or neighboring utilities
- Alternate locations for the new delivery point
- Possible augmentation of the distribution system in lieu of transmission facility construction

The Companies perform an economic feasibility study of the best alternatives using the "single-entity concept," taking into consideration the total costs to the lead Company, as well as other affected utilities or member cooperatives. During the economic study, the following criteria are evaluated:

- Electrical performance of existing and proposed facilities, to include voltage drop, power flow, and losses
- Estimated capital and annual costs
- Wheeling costs
- Reliability
- Environmental considerations
- Coordination with other transmission providers' long-range transmission plans

In addition, the Companies incorporate "best cost" considerations through their interactions with various federal, state, and local regulatory bodies. Among other requirements, FERC has imposed planning requirements on utilities through its Order No. 890 and Order No. 1000, both of which include considerations consistent with Rule 3627's "best cost" approach. These FERC requirements are discussed further below.

All of the Companies participate in Commission dockets and initiatives, spending significant time and resources for Notices of Proposed Rulemaking, outreach efforts, meetings with Commission Staff and actively participating in initiatives in which the Commission has expressed interest. In addition, the Companies participate with Commission staff in the development of the conceptual long-range plans for Colorado's electric transmission infrastructure. The Companies individually meet with representatives of the Colorado Energy Office ("CEO") and take into consideration CEO's suggestions. The Companies also meet with local governmental officials. These meetings transcend simple permitting requests and consider factors such as the economic development aspirations of the communities, cultural concerns of communities, and the environmental aspects of transmission infrastructure expansion contemplated in various regions.

B. Reliability Criteria: Rule 3627(b)(II)

The Energy Policy Act of 2005 ("EPAct") amended the Federal Power Act ("FPA") to create mandatory electric reliability standards for the U.S. bulk power system. In compliance with these federal laws, FERC certified NERC as the electric reliability organization responsible for developing and enforcing the mandatory reliability standards authorized by the EPAct. NERC also utilizes delegation agreements with regional reliability organizations, such as WECC. Various mandatory reliability standards relating to bulk power system planning, operations, and maintenance have been implemented by NERC and WECC as a result of the EPAct with the potential for fines of up to $1 million per day for serious violations that could impact the integrity of the bulk power system.

The NERC Reliability Standards can be found at NERC's website.
www.nerc.com/pa/stand/Pages/default.aspx

The WECC TPL Standards can be found at WECC's website.
www.wecc.biz/Standards/Pages/Default.aspx

Each of the Companies take NERC and WECC compliance extremely seriously and stringently adhere to all applicable standards and criteria. Additional information concerning each Company's reliability compliance efforts is provided below.

1. *Black Hills Reliability Criteria*

On top of NERC and WECC requirements, the following additional guidelines are utilized in the planning process for determining acceptable levels of service for the Black Hills service territory:

- Transmission line loadings should not exceed 100 percent of continuous seasonal rating or the established equipment or operating limits.
- Transformer loading under system intact conditions should not exceed 100 percent of the normal rating.
- Transformer loading under contingency conditions should not exceed 100 percent of the emergency rating.
- Transmission bus voltage levels during normal conditions will be maintained between 0.95 p.u. and 1.05 p.u. of nominal system voltage.
- Transmission bus voltages during contingency conditions will be maintained between 0.90 p.u. and 1.1 p.u. of nominal system voltage.
- Following a disturbance, all machines in the system shall remain in synchronism as demonstrated by their relative rotor angles for all Category P1 contingencies.
- A generator that pulls out of synchronism in the simulation shall not result in the tripping of any additional transmission facilities.
- If a machines maximum relative rotor angle swing exceeds or equals 16 degrees any time two seconds after the fault has cleared, the damping shall be greater than 3% as defined by:

$$\%\,Damping = \frac{\ln\left[\frac{1st\ Cycle\ Peak - 1st\ Cycle\ Min}{Final\ Cycle\ Peak - Final\ Cycle\ Min}\right]}{Cycle\ Count * 2\pi} * 100$$

- For events where the maximum machine relative rotor angle swings are within a 16 degree window are assumed adequately damped

Additional details on the reliability criteria observed by Black Hills are provided on pages 15-18 of the Black Hills Open Access Transmission Tariff ("OATT") Attachment K Methodology, Criteria, and Process Business Practices document, available in Appendix L.

2. *Tri-State Reliability Criteria*

In addition to complying with NERC and WECC standards and criteria, Tri-State observes its own set of internal criteria for planning studies. Tri-State performs an annual assessment of its regional interconnected transmission system elements utilizing simulation modeling cases created by WECC members. This annual assessment takes into account Tri-State's members in four states, with associated projects located in Colorado included in this plan.

The modeling cases selected represent projected loads and transmission system topology for the year one through five horizon and the year six through ten horizon. These cases are selected to demonstrate system performance covering a range of forecasted demand levels and the most critical system conditions and study years. This analysis examines heavy and light loading scenarios, typically in cases modeling year one, year five, and year ten, unless other factors, such as known major system changes, dictate selection of another year. Cases created by WECC ensure that all projected firm transfers and established normal (pre-contingency) operating procedures are modeled, as well as existing and planned reactive power resources.

The transmission system is analyzed considering the planned projects for each utility in the study area. This assessment includes one or more current or past studies, which together address the entire Tri-State area of service.

Additional information concerning Tri-State's reliability criteria is available in its Engineering Standards Bulletin and is updated periodically. The most current version at the time of this filing can be found in Appendix M.

3. *Public Service Reliability Criteria*

In addition to fulfilling NERC and WECC standards and criteria, Public Service observes internal company criteria for planning studies. The most recent internal criteria can be found in Appendix N.

C. Legal and Regulatory Requirements: Rule 3627(b)(III)

Per Rule 3627(b)(III), “Each ten year transmission plan shall demonstrate compliance with…[a]ll legal and regulatory requirements, including renewable energy portfolio standards and resource adequacy requirements.” The following sections provide information concerning each Company's compliance with such legal and regulatory requirements.

1. Black Hills Legal Requirements

Black Hills’ portion of the 2020 Plan complies with all applicable NERC and WECC reliability standards, as well as other applicable legal and regulatory requirements, including the Colorado RES. For information on resource planning, for both resource adequacy and RES statutory compliance, please refer to the most current Proceeding 16A-0436E as follows:

Proceeding No. 16A-0436E

- Resource Planning, ERP - Phase I 2016 and Phase II 2017

  Black Hills' 2016 ERP was docketed at the Colorado Public Utilities Commission in Proceeding No. 16A-0436E. The Company's ERP application was filed on June 3, 2016, pursuant to Commission rules and the RES codified at C.R.S. § 40-24-124.

  The ERP covered a Planning Period of 25 years from January 2016 through December 2040, and a Resource Acquisition Period of seven years from January 2016 through December 2022. The Planning Period pertains to ERP Phase I, a Commission determination of resource need. The Resource Acquisition Period pertains to ERP Phase II, a competitive solicitation for resource acquisition.

  On January 17, 2017, Recommended Decision No. R17-0039 was entered for Phase I and became a decision of the Commission by operation of law. The decision adopted a settlement agreement filed on November 10, 2016. The settlement agreement modified certain terms of the Company's ERP application. Specifically, the settlement agreement approved, in pertinent part, a resource need of up to 60 MW from RES-eligible energy resources for commercial operation in 2019. The 60 MW will enable the Company to comply with the 30% RES requirement in 2020. Standalone REC bids, to fulfill the 60 MW resource need, were not allowed under the settlement agreement. The settlement agreement approved evaluation criteria for utility-owned resource bids. Finally, the settlement agreement stipulated a timeline for Phase II to ensure that federal production tax credits can be advantaged for eligible bids.

  A Phase II competitive solicitation for 60 MW of eligible energy resources was conducted by the company on June 23, 2017. The Company received over 100 individual bids from multiple project developers for

eligible energy resources from wind, solar PV, and other resources. An independent evaluator was retained (Accion Group) to observe the Company's bid solicitation and evaluation process, and report findings. Based on the evaluation process, Bid 1117-1 was ranked the highest overall, including both economic and noneconomic evaluation criteria. Economic criteria identified Bid 1117-1 with the lowest NPVRR and the most avoided cost savings of all the bids offered in the Company's solicitation.

Bid 1117-1 is a PPA for 60 MW supplied by a wind facility located in Huerfano and Las Animas counties. The output of approximately 201,500 MWh of energy and renewable energy credits annually will enable the Company to comply with the 30% RES beginning in 2020. The awarded Bid 1117-1 will be online for commercial operation no later than December 31, 2019.

- RES Compliance Plan, 2018-2021

  The settlement agreement in ERP Proceeding No. 16A-0436E approved acquisition of on-site solar photovoltaic ("PV") and community solar garden ("CSG") resources for RES compliance.

  The PV capacity is established at 1,500 kW per year for the compliance period, 2018-2021. The settlement agreement stipulated categories for PV system sizes and incentive levels.

  The CSG program was defined in the settlement agreement to be comprised of two RFP offerings by the Company based on the type of subscribers. Each year, the Company will solicit and award up to 500 kW of CSGs for 100% low-income subscribers and up to 2,000 kW of CSGs for open subscribers. The settlement agreement stipulated 0 kW as the minimum purchase amount and 2,500 kW as the maximum purchase

amount from CSG installations each compliance year, 2018-2021. The Company expects that 15.12 MW of CSGs will operate by end of 2021.

2. Tri-State Legal Requirements

Tri-State's 2020 Plan complies with all applicable NERC and WECC reliability standards, as well as other applicable legal and regulatory requirements including Company and member compliance with the Colorado RES.

For the period 2015 through 2019, the Colorado RES requires that 6 percent of Tri-State's Member Systems' retail energy sales be served by renewable generation, growing to 20 percent in 2020 and beyond. In addition, as a qualifying wholesale utility, the Colorado RES requires Tri-State to generate or cause to be generated at least 20 percent of the energy it provides to its Colorado Member Systems at wholesale from eligible energy resources in the year 2020 and thereafter. As the wholesale power provider for its Member Systems, Tri-State's 2020 Plan is developed to ensure that the necessary transmission system capabilities will be in place to meet both its Colorado Members Systems' and its own RES requirements.

For additional information on resource adequacy requirements and resource requirements to meet the RES, please refer to Tri-State's Integrated Resource Plan/Electric Resource Plan and Electric Resource Plan Annual Progress Reports available in Appendix M.

As discussed previously, Tri-State may be subject to federal and state regulations related to carbon emission reductions from existing power plants, such as the regulations that will be promulgated pursuant to Colorado HB 19-1261. While no such regulations have been promulgated as of the date of this 10-Year Plan, Tri-State anticipates that such regulations may be promulgated within the next two years and, if so, will address them in the next 10-Year Transmission Plan. Tri-State also notes that, since it operates an interconnected, interstate transmission system,

its transmission system may be impacted as a result of federal compliance and carbon emission reduction plans enacted in other states in which Tri-State operates.

3. Public Service Legal Requirements

Public Service's 2020 Plan complies with its currently operative ERP, approved by the Commission in Proceeding 16A-0396E in its Phase II decision, C18-0761. Additional information on Public Service resource adequacy and compliance with Commission rules related to ERPs is available at:
https://www.xcelenergy.com/company/rates_and_regulations/resource_plans

Public Service's 2020 Plan additionally complies with its currently operative RES Compliance Plan approved by the Commission as modified by settlement in Decision C16-1075 in Proceeding 16A-0139E. [5] Public Service's 2020 Plan also complies with the specifications set forth in its 2020-2021 RES Compliance Plan, filed in Proceeding 19A-0369E, and currently under Commission consideration.

Information on Public Service compliance with RES requirements is available at:
https://www.xcelenergy.com/company/rates_and_regulations/filings

D. Opportunities for Meaningful Participation: FERC Order No. 890

In addition to the CCPG planning processes, each of the Companies has its own FERC Order No. 890 stakeholder process as described below. For additional information on stakeholder involvement pertinent to Rule 3627, please refer to Section VI.

[5] Public Service's 2017-2019 RES Compliance Plan was subsequently extended through the first quarter of 2020 by Decision R19-0807 in Proceeding No. 19A-0369E.

1. *Black Hills Participation Strategy*

For Black Hills, the FERC Order No. 890 Stakeholder Process is included in its Attachment K to its Open Access Transmission Tariff ("OATT"), which is included in Appendix L of this document. Additional information concerning Black Hills' FERC Order No. 890 processes can also be found in Appendix L.

2. *Tri-State Participation Strategy*

Attachment K to Tri-State's OATT demonstrates Tri-State's transmission planning processes consistency with FERC Order No. 890 planning principles. As discussed previously in this 2020 Plan, all projects included herein have been identified and developed through Tri-State's transmission planning process.

Attachment K to Tri-State's OATT can be updated periodically, and is available on Tri-State's OASIS at:
http://www.oasis.oati.com/tsgt/index.html

The most current version at the time of Attachment K is located in Appendix M.

3. *Public Service Participation Strategy*

For Public Service, the FERC Order No. 890 stakeholder process is included in the Xcel Energy Joint OATT Attachment R, available at the following website:
https://www.oasis.oati.com/woa/docs/PSCO/PSCOdocs/PSCo_Attachment_R_5-5-2020.pdf
Additional information concerning the Public Service FERC Order No. 890 processes can be found at:
http://www.oatioasis.com/psco/index.html under "FERC 890 Postings".

E. Coordination Among Transmission Providers: FERC Order No. 1000

In July 2011, FERC issued a final rule related to transmission planning and cost allocation, FERC *Order 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities* ("Order 1000"). This order builds on planning principles already established in FERC Order No. 890, as previously discussed. FERC Order No. 1000 requires that transmission owning and operating public utilities:

1) Participate in a regional transmission planning process that produces a regional transmission plan.
2) Amend their OATT to describe procedures that provide for the consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes.
3) Remove from Commission-approved tariffs and agreements a federal right of first refusal for certain new transmission facilities.
4) Improve coordination between neighboring transmission planning regions for interregional transmission facilities.
5) Participate in a regional transmission planning process that has a regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation.
6) Participate in a regional transmission planning process that has an interregional cost allocation method for the cost of certain new transmission facilities that are located in two or more neighboring transmission planning regions and are jointly evaluated by the regions.

WestConnect is one of four planning "regions"[6] within WECC established for regional transmission planning to comply with Order 1000. Public Service and Black Hills have designated WestConnect as their Order 1000 compliant planning regions. Tri-State has joined WestConnect as a coordinating transmission owner, which means it is not subject to all of the requirements under Order 1000 such as accepting binding cost allocation for regional transmission projects. The WestConnect planning process is described in Black Hills' and Public Service's OATTs (Attachment K and R respectively; links are provided above) as well in documentation found on the WestConnect website (http://www.westconnect.com/). The WestConnect website also houses information and announcements for many public planning meetings. WestConnect accepts stakeholder input throughout the planning process.

WestConnect develops a regionally coordinated transmission plan that begins with the determination of regional reliability, economic and public policy needs. The more cost-effective or efficient solutions to meet identified regional needs are included in the regional plan. These regional projects may be new projects in addition to the projects developed through the local or sub-regional planning processes or may replace local projects in some instances. If WestConnect determines Colorado utilities benefit from a regional project, then those Colorado utilities may be responsible for a portion of the cost of the regional project.

Additionally, WestConnect coordinates with the other western Order 1000 planning regions. This coordination also is described in Black Hills' and Public Service's planning attachments to their respective OATTs.

[6] The other three are Columbia Grid, Northern Tier Transmission Group, and the California Independent System Operator.

VIII. 10-Year Transmission Plan Supporting Documentation

A. Methodology, Criteria, & Assumptions

1. *Facility Ratings (FAC-008-3)*

NERC Reliability Standard FAC-008-3 requires that transmission and generation owners document the methodology used to develop ratings of their equipment. The standard requires that the transmission or generation owner supply its methodology to specific NERC registered entities upon request. FAC-008-3 also requires transmission and generation owners to establish facility ratings per the methodology established through FAC-008-3. Each transmission and generation owner has documented ratings for each of its facilities. The standard requires the transmission or generation owner to supply its facility ratings to specific NERC registered entities (i.e. associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s)) upon request. These documents are not publicly available and are not required to be per NERC standards. NERC Reliability Standard MOD-032-1 requires applicable entities to provide equipment characteristics, including established facility ratings, to NERC and WECC according to established reporting requirements. This is accomplished through the WECC Base Case Compilation Schedule as prescribed by the Data Preparation Procedural Manual.

a. Black Hills Ratings

Documentation of Black Hills' FAC-008-3 methodology is available in Appendix L.

b. Tri-State Ratings

Documentation of Tri-State's Facility Rating's methodology is available in its Engineering Standards Bulletin. The most current version of Tri-State's

Engineering Standard's Bulletin at the time of this filing can be found in Appendix M.

c. Public Service Ratings

Documentation of Public Service FAC-008-003 methodology can be found in Appendix N.

2. *Transmission Base Case Data: Power Flow, Stability, Short Circuit*

The Companies utilize transmission system power flow and transient dynamics modeling data prepared by WECC. Through its Annual Study Program, WECC facilitates the preparation of at least 10 models per year. The models represent a variety of system conditions out to a 10-Year planning horizon. WECC's 10-Year Regional Transmission Plan is an Interconnection-wide perspective on: 1.) expected future transmission and generation in the Western Interconnection, 2.) what transmission capacity may be needed under a variety of futures, and 3.) other related insights.

WECC members participate in the data preparation process for the models and Public Service coordinates the data for the Rocky Mountain region. Prior to being used for planning studies, the models are reviewed and adjusted to reflect the most current and accurate system elements, ratings, and operating conditions for the region to be studied. Short circuit data is coordinated between neighboring TPs as needed and periodically coordinated at the CCPG level.

Instructions for obtaining access to WECC base cases are as follows:

a. An organization requesting WECC base case(s) must either be a WECC member or they must execute the "Nonmember Confidentiality Agreement for WECC Data."

b. Non-members may obtain the confidentiality agreement from WECC by requesting the agreement from a WECC Stakeholder Services representative.

The submission must include a statement from the organization explaining why they have a legitimate business need for the WECC base case(s).

B. Load Modeling

Pursuant to each Company's OATT, network customers are required to submit 10-Year projected network loads and network resources by October 1 of each year. This information is then compiled with existing data and information to provide a basis for identification of the minimum transmission system enhancements required to ensure that a sufficiently robust transmission system is in place to meet all network customer requirements under all scenarios.

1. *Forecasts*

The Companies rely on the most recent and accurate load forecasts when developing system planning models. General load forecast assumptions are posted on each transmission provider's Company or OASIS site.

a. Black Hills Forecasts

In 2016, Black Hills filed with the Commission its latest ERP, which included details on expected customer growth based on load forecast information submitted annually by network customers. The ERP, in conjunction with the network customer forecast updates, is used in the development of Load and Resource ("L&R") reports submitted to WECC on an annual basis. Once the L&R report is developed, this forecast is disaggregated to the respective transmission system load buses. There are two types of load buses: (1) a load bus where the

load does not change over time (e.g. a single large industrial load bus); and (2) a load bus where the load changes over time (e.g. a residential load). Black Hills uses its knowledge of load characteristics along with historical loading observations to estimate the individual load bus data in time. The load bus forecasts are summed and compared to the WECC L&R report aggregate load forecast. If the two forecasts do not match, the variable bus load forecasts are adjusted until the two forecasts match. Through this procedure, the WECC L&R reports, including the assumptions in the latest ERP, are reflected in the transmission planning models used within the WECC footprint. Deviations from the ERP load forecast are commonplace in transmission studies depending on the purpose of the planning analysis being performed and the study scenario of interest. The load assumptions included in the planning model are typically specified within each planning study report for reference.

Details related to Black Hills' load forecast can be found in Black Hills' 2016 ERP in Colo. Consolidated Proceeding No. 16A-0436E; specifically, Attachment LS-1 included in Appendix L of this report.

b. Tri-State Forecasts

General load forecast information is available on Tri-State's OASIS at:
http://www.oasis.oati.com/tsgt/index.html
The Load Forecast Descriptive Statement available at the time of this filing is located in Appendix M.

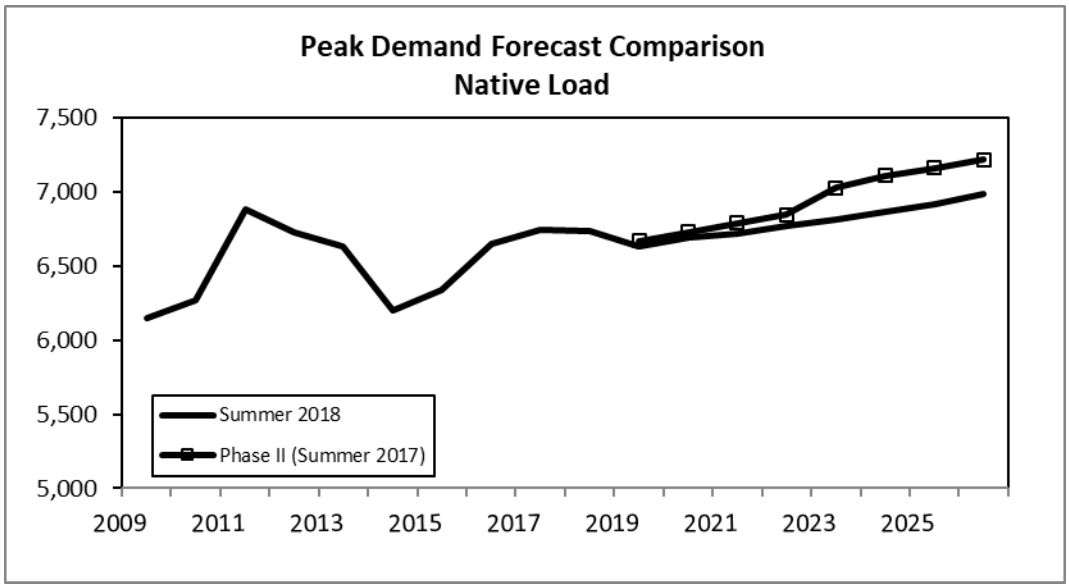
Tri-State prepares load forecasts on a system-wide and regional basis with regional forecasts used for resource planning purposes. Tri-State receives load forecasts from its network customers by October 1 of each year. These loads are modeled as required for inclusion in the planning models developed in conjunction with neighboring entities.

Tri-State's most recent transmission plans utilize 2018 load forecast data. Base forecast data for these plans is available in Appendix A of Tri-State's ERP/APR, located in Appendix M.

c. Public Service Forecasts

The load forecast used in this filing is the Summer 2018 PSCo Load Forecast, which was provided publicly in the Company's 2016 Electric Resource Plan Annual Progress Report filed dated October 31, 2018 (Proceeding No. 16A-0396E) and the PSCo Load Forecast that was provided publicly in the Company's 2016 Electric Resource Plan Modeling Assumptions Update filed in August 2017. The following figure shows a comparison between the two forecasts. The drivers of the changes in the forecast are discussed in Appendix N. The Company notes that while it has developed more recent load forecasts (e.g., as provided in the Company's 2016 Electric Resource Plan Annual Progress Report dated October 2019 filed in Proceeding No. 16A-0396E and in Proceeding No. 19A-0409E), the Summer 2018 forecast was the most current publicly available forecast at the time the Company began the analysis and preparation of this Rule 3627 Report.

Figure 8. Public Service Historic and Forecast Demand



In addition to native load forecasts, Public Service receives forecasts from its wholesale customers, which it incorporates into the overall forecast. Transmission planners allocate the loads on a substation-by-substation basis, based on historical trends. Additional information is included in Appendix N.

2. *Demand-Side Management*

The effects of Demand-Side Management ("DSM") program savings are typically taken into account within the load forecasts described previously. Within the context of power system modeling, DSM is simply reflected in the power flow model as reduced load and therefore included in planning studies.

a. Black Hills DSM

Details related to the effects of DSM savings estimates on Black Hills' load forecast can be found in the 2016 Black Hills ERP; specifically, Attachment LS-1, which is included in Appendix L of this document.

b. Tri-State DSM

Load forecasts provided for bulk electric transmission planning typically include existing DSM and other load-reducing programs, including member energy efficiency programs and local distributed generation. These programs are reflected in the power flow model as reduced load and are inherently included in studies. For transmission planning, load forecasts that contain load-reducing factors may be used for specific projects or for individual Tri-State members with DSM, local distributed generation, or other energy efficiency programs. For such cases, please refer to individual project planning studies. For Tri-State's system load forecast, these are described in Tri-State's 2018 Annual Progress Report to the 2015 ERP found at:
https://www.tristategt.org/resource-planning

c. Public Service DSM

Public Service accounts for DSM through reduction in its load forecast based, in part, on the goals established by the Commission. Additional information is included in Appendix N.

C. Generation and Dispatch Assumptions

Generator and associated equipment models are typically included in the WECC Annual Base Case Compilation Schedule base cases as required by the Data Preparation Manual. The detail of generation models utilized within planning studies can vary depending on the nature of the study. For example, a Large Generator Interconnection study for a wind facility may explicitly model each individual wind turbine and the associated collector system to properly assess the low voltage ride through capabilities of the facility. That same facility may be modeled as a single equivalent wind turbine with an equivalence collector system within a long-range planning study where the

performance of individual wind turbines is not a concern. The scope of the technical study will influence the level of detail that is modeled.

1. *Black Hills Assumptions*

At the most basic level, Black Hills dispatches existing generation to meet the demand requirements of its system, including load and losses. The objective of a particular study often drives the individual generator dispatch levels. For example, a peak demand summer baseline scenario may consist of a majority of dispatchable baseload generation online and an appropriate mix of wind and solar PV to meet the demand requirements. An off-peak demand spring or fall scenario may have the available wind generation dispatched at its nameplate capacity with the dispatchable baseload generation and solar generation reduced to capture the impacts of that particular dispatch pattern. Existing power purchase agreements and other contractual arrangements may be reflected in certain study scenarios to further stress the transmission system. Black Hills also may include speculative generation (as identified in the current version of the Black Hills Colorado Electric Generation Interconnection Request Queue, included in Appendix L) in certain transmission studies as dictated by the study objective. Additionally, existing and/or conceptual generation may be dispatched beyond the demand requirements of the study case to facilitate a net export of energy from the study area. A listing of existing and planned resources utilized in planning studies is typically included in each specific study report.

2. *Tri-State Assumptions*

Tri-State's transmission planning function receives generation assumptions from its network customers--Tri-State Power Management, Arkansas River Power Authority (“ARPA”), Municipal Electric Agency of Nebraska (“MEAN”), Raton Public Service Company (“City of Raton”), Public Service Company of Colorado (“PSCO”), Kit Carson Electric Cooperative (“KCEC”) and Public Service Company of New Mexico

("PNM")--annually by October 1. These generation assumptions are utilized to ensure a sufficiently robust transmission system to meet network customers' needs over a 10-Year planning horizon.

Generation assumptions, including dispatch assumptions, and corresponding data for other transmission plans are project-specific. Therefore, the individual transmission studies should be referenced for generation assumptions relative to each such project.

3. Public Service Assumptions

Public Service transmission planning models reflect generation dispatch based on internal procedures that take into account production costs, maintenance schedules, and other factors. Procedures include:

- Modeling of generator planned outages with outage period of 6 months or more
- In general, if not needed to meet load requirements, high production cost generation plants are modeled out of service. If resources are needed, these units may be modeled
- Public Service combustion turbine generators are typically modeled at or near full output
- Public Service large coal-fired plants are typically modeled at or near full output. These units are considered "base loaded", in that they usually operate around the clock if generation adjustments are necessary, these generators are generally adjusted last
- Hydro generation has net dependable seasonal ratings. Each seasonal rating reflects the average generation that can be continuously maintained over the duration of the daily peak period for the respective season. In winter, the daily period is approximately five hours long. All generators on-line should be

producing reactive power ("MVARs"). Generator bus voltage scheduling may be necessary if the generating unit is acting in a condensing mode (consuming MVARs)

- Pumped Hydro generators are modeled appropriately in pumping mode during off peak hours.

Renewable generation, including wind and solar are modeled based on Public Service Variable Energy Resource Dispatch Assumptions. System changes, load transfers, and other topology changes also are coordinated through CCPG.

D. Methodologies

1. *System Operating Limits (FAC-010)*

System Operating Limits ("SOL") is defined in NERC Reliability Standard FAC-010-3 as the responsibility of the Planning Authority ("PA") to ensure reliable planning of the Bulk Electric System. SOL is required to be established per FERC standards but is not required to be publicly available.

a. Black Hills SOL

Black Hills has defined both Operational Criteria, which are limits for typical every day/normal operations, and SOLs, which are limits that are of an emergency nature and must be acted upon promptly to ensure facility ratings are not exceeded. Black Hills' SOLs are communicated to the Southwest Power Pool ("SPP") Reliability Coordinator so that when an SOL is exceeded, the Reliability Coordinator will be aware of the concern and be able to provide assistance in ensuring the SOL violation is removed. Black Hills' SOLs are summarized below:

- BES Transmission Line SOLs are exceeded when the line rating is exceeded.

- BES Voltage SOLs are exceeded when the Emergency Voltage rating is exceeded. The Emergency Voltage is plus/minus 10% of the nominal voltage.
- BES transformer SOLs are exceeded when their loaded MVA is between 100% and 125% of the established FOA Rating for more than 30 minutes, OR, their loaded MVA exceeds 125% of the established FOA Rating for any period of time.

b. Tri-State SOL

Tri-State is not a PA and, therefore, uses the SOL methodology as defined by the applicable PA.

c. Public Service SOL

Public Service has one SOL for the TOT7, which is located north of the Denver metro area. SOLs are required to be established per FERC standards, but are not required to be publicly available. The TOT7 studies are conducted annually. The results of those studies are available upon request.

2. *Available Transmission System Capability Methodology (MOD-001)*

Available Transmission System Capability Methodology is available and posted per NERC Standard MOD-001 at NERC's website.

a. Black Hills TTC

Black Hills utilizes the Rated System Path Methodology for determining Total Transfer Capability ("TTC") and Available Transfer Capability ("ATC") for all Posted Paths and in all ATC time horizons. The determination of TTC is based on the maximum flow of a path while meeting all reliability criteria for single initiating event outages. In the event that the path is flow-limited and a reliability limit

cannot be reached, the transfer capability of the path is set to the thermal rating of the path. For further details on the calculation of transfer capability, refer to Black Hills' ATC Implementation Document ("ATCID") included in Appendix L.

b. Tri-State TTC

Tri-State's TTC path values for jointly owned paths that are interfaces identified and rated through WECC processes and OTC determinations are based upon the Rated System Path Methodology (NERC MOD-29-2a). Tri-State has TTC allocations on WECC rated Paths 30 (TOT1A), 31 (TOT2A), 36 (TOT3), 39 (TOT5), 47 (SNMI), and 48 (NNMI). These paths are studied by the path operator with actual flow levels at the combined path ratings under simulated N-1 scenarios to ensure that the planning reliability criteria are being met. The path participants have previously used studies and negotiations to determine the manner in which the TTC will be allocated to each of the participants.

For jointly owned paths that are not WECC-rated paths, the TPs determine the appropriate combined TTC and the allocation of it is based upon contractual capacity entitlements. This allocation is done outside of any WECC approval process since these are Tri-State TTC/ATCID minor paths that are not part of an interface and do not impact any major recognized WECC paths.

Tri-State utilizes TTC values based upon thermal facility ratings for all flow-limited paths that are owned solely by Tri-State. If the NERC MOD-029-2a requirement R2.1 simulation studies result in sufficient flow ability on a path segment to determine a reliability limit, then the TTC on the ATC path segment is set to the simulated flow corresponding to the reliability limit while at the same time satisfying all planning criteria.

In addition, Tri-State has created many extended ATC paths that are defined by a serial concatenation of rated path segments. The resulting TTC and ATC for

each extended ATC path is based upon the lowest TTC and ATC of all the serial path segments included in each path definition.

The ATCID provides for the documentation of required information as specified in the NERC MOD Standards and the NAESB OASIS Standards regarding the calculation methodology and information sharing of ATC specific to this TP. The ATCID for Tri-State is available on Tri-State's OASIS at: http://www.oasis.oati.com/tsgt/index.html

The ATCID can be updated periodically and the most recent version of the ATCID at the time of this filing can be found in Appendix M.

c. Public Service TTC

The ATCID (MOD-001) for Public Service is available on Public Service's OASIS, by clicking on "ATC Information" and then "ATCID Implementation Document".

The ATCID can be updated periodically, and the most recent version at the time of this filing can be found in Appendix N.

3. *Capacity Benefit Margin (MOD-004)*

Capacity Benefit Margin ("CBM") methodology is available and posted per NERC Standard MOD-004.

a. Black Hills Capacity Benefit Margin (MOD-004)

Black Hills does not implement CBM in the assessment of ATC. The Capacity Benefit Margin Implementation Document ("CBMID") for Black Hills is included in Appendix L.

b. Tri-State CBM

Based on FERC's allowance for TPs to not use CBM, Tri-State does not allow for the use of CBM and, as such, its value is set to zero (0) in the ATC equations for all paths posted by Tri-State. Furthermore, Tri-State's practice is to not maintain CBM. Tri-State will review its CBM practice, at least annually, and will post any changes to the OASIS as needed. The CBMID for Tri-State is available on Tri-State's OASIS, by clicking on "ATC Information" and then "Capacity Benefit Margin Statement (CBMID)".

The CBMID can be updated periodically, and the most recent version at the time of this filing can be found in Appendix M.

c. Public Service CBM

The CBMID for Public Service is available on Public Service's OASIS, by clicking on "ATC Information" and then "CBM Implementation Document (CBMID)".

The CBMID can be updated periodically, and the most recent version at the time of this filing can be found in Appendix N.

4. *Transmission Reliability Margin Calculation Methodology (MOD-008)*

NERC Standard MOD-008-1, Transmission Reliability Margin Calculation Methodology, requires that each Transmission Operator prepare and keep current a Transmission Reliability Margin Implementation Document ("TRMID").

a. Black Hills Transmission Reliability Margin (MOD-008)

A copy of the current TRMID for Black Hills is located in Appendix L.

b. Tri-State TRM

The TRMID for Tri-State is available on Tri-State's OASIS at:
http://www.oasis.oati.com/tsgt/index.html

The TRMID can be updated periodically, and the most recent version at the time of this filing is located in Appendix M.

c. Public Service TRM

The TRMID for Public Service is available on Public Service's OASIS, by clicking on "ATC Information" and then "TRM Implementation Document (TRMID)".

The TRMID can be updated periodically and the most recent version at the time of this filing is located in Appendix N.

E. Status of Upgrades

Projects that constitute upgrades to existing transmission facilities are discussed in Section III of this Plan and the associated appendices.

F. Studies and Reports

Most of the Companies' study documentation can be found by starting at the sections of the WestConnect website that are dedicated to the CCPG:

http://www.westconnect.com/planning_ccpg.php
Additional Company-specific study and reporting resources are described below.

1. Black Hills Reporting

Public access to transmission market information, generator interconnection and transmission service requests, business practices, planning study reports and other topics related to the Black Hills transmission system is provided on Black Hills' OASIS at:

http://www.oatioasis.com/bhct

2. Tri-State Reporting

Planning studies and related reports for Tri-State transmission projects in Colorado are located at Tri-State's website at:

http://www.tristategt.org/transmission-projects

Generator interconnection, transmission service request, and other OATT study reports related to Tri-State's transmission system are provided on Tri-State's OASIS at:

http://www.oasis.oati.com/tsgt/index.html

3. Public Service Reporting

Planning studies and related reports for Public Service transmission projects in Colorado are located at the following links:

https://www.rmao.com/public/wtpp/PSCO_Studies.html
http://www.oatioasis.com/psco/index.html
http://www.transmission.xcelenergy.com/Planning/Planning-for-Public-Service-Company-of-Colorado

G. In-Service Dates

Information concerning the expected in-service date for each utility's facilities identified in the 2020 Plan and the entities responsible for constructing and financing each facility is contained in Table 1, Section III and Appendices A-I.

H. Economic Studies

The purpose of economic planning studies is to identify significant and recurring congestion on the transmission system and/or address the integration of new resources and/or loads. Such studies may analyze any or all of the following: (i) the location and magnitude of the congestion, (ii) possible remedies for the elimination of the congestion, (iii) the associated costs of congestion, (iv) the costs associated with relieving congestion through system enhancements (or other means), and, as appropriate (v) the economic impacts of integrating new resources and/or loads. Economic studies are generally described as being either “local” or “regional” in nature.

1. *Black Hills Economic Study Policies*

Black Hills conducts economic planning studies through the procedures outlined in its OATT Attachment K, which is included in Appendix L.

Black Hills will accept requests for economic studies on an annual basis. Information on making a request is available in the Attachment K Economic Study Request Form, as shown in Appendix L. Upon receiving a valid request for an economic study, Black Hills, with input from its stakeholder committee, will classify the request as local, subregional or regional. Black Hills will engage the appropriate resources to study up to one economic study request that has been classified as local on a biannual basis. All economic study requests that have been classified as subregional or regional will be forwarded to the WECC for inclusion in the appropriate study program. Since the 2018 Rule 3627 filing, Black Hills has not received any economic study requests, nor has it performed any economic studies.

2. *Tri-State Economic Study Policies*

Western Interconnection-wide congestion and economic planning studies are conducted by WECC in an open stakeholder process that holds region-wide stakeholder meetings on a regular basis. The WECC planning process is posted on its website (see http://www.wecc.org/Pages/home.aspx). Tri-State participates in the regional planning processes, as appropriate, to ensure data and assumptions are coordinated. Tri-State did not perform any economic studies this cycle nor were any requested by Tri-State stakeholders.

3. *Public Service Economic Study Policies*

Public Service facilitates priority local economic planning studies for its transmission system, pursuant to the procedures in its OATT Attachment R. Regional economic planning studies shall be performed by WECC, pursuant to procedures posted on the WECC website. Public Service did not perform any economic studies this cycle nor were any requested by stakeholders.

2020 CPUC Rule 3627 Appendices

Appendix A: Colorado Transmission Maps

Appendix B: Denver-Metro Transmission Map

Appendix C: Black Hills Energy Transmission Map

Appendix D: Black Hills Energy Projects

Appendix E: Tri-State Generation and Transmission Association Projects

Appendix F: Public Service Company of Colorado Projects

Appendix G: Colorado Springs Utilities Projects

Appendix H: Platte River Power Authority Projects

Appendix I: Western Area Power Administration - RMR Projects

Appendix J: CCPG Stakeholder Process

Appendix K: Responses to Stakeholder Comments

Appendix L: Black Hills Supporting Documents

Appendix M: Tri-State Supporting Documents

Appendix N: Public Service Company Supporting Documents

Attachment Vol II 4-3 Tri-State Transmission Project Information

PUBLIC

Tri-State Generation and Transmission Association

2020-2030 Transmission Plan

Burlington - Burlington (KCEA) Rebuild

Project Sponsor:	Tri-State Generation and Transmission Association
Additional Project Participants:	
Project Description:	Rebuild the existing Burlington - Burlington (KCEA) 115 kV line
Voltage Class:	115 kV
Facility Rating:	118 MVA
Point of Origin/Location:	Burlington
Point of Termination:	Burlington (KCEA)
Intermediate Points:	
Length of Line (in Miles):	2.0
Type of Project:	Transmission Line
Development Status:	Planned
Routing:	
Subregional Planning Group:	CCPG
Purpose of Project:	Increase conductor thermal rating.
Project Driver (Primary):	Reliability
Project Driver (Secondary):	
Estimated Cost (in 2019 Dollars):	$718,000
Schedule:	
Construction Date:	
Planned In-Service Date:	2022
Regulatory Info:	
Regulatory Date:	
Permitting Info:	
Permitting Date:	
Contact Information:	Ryan Hubbard
Email	rhubbard@tristategt.org
Phone	303-254-3025

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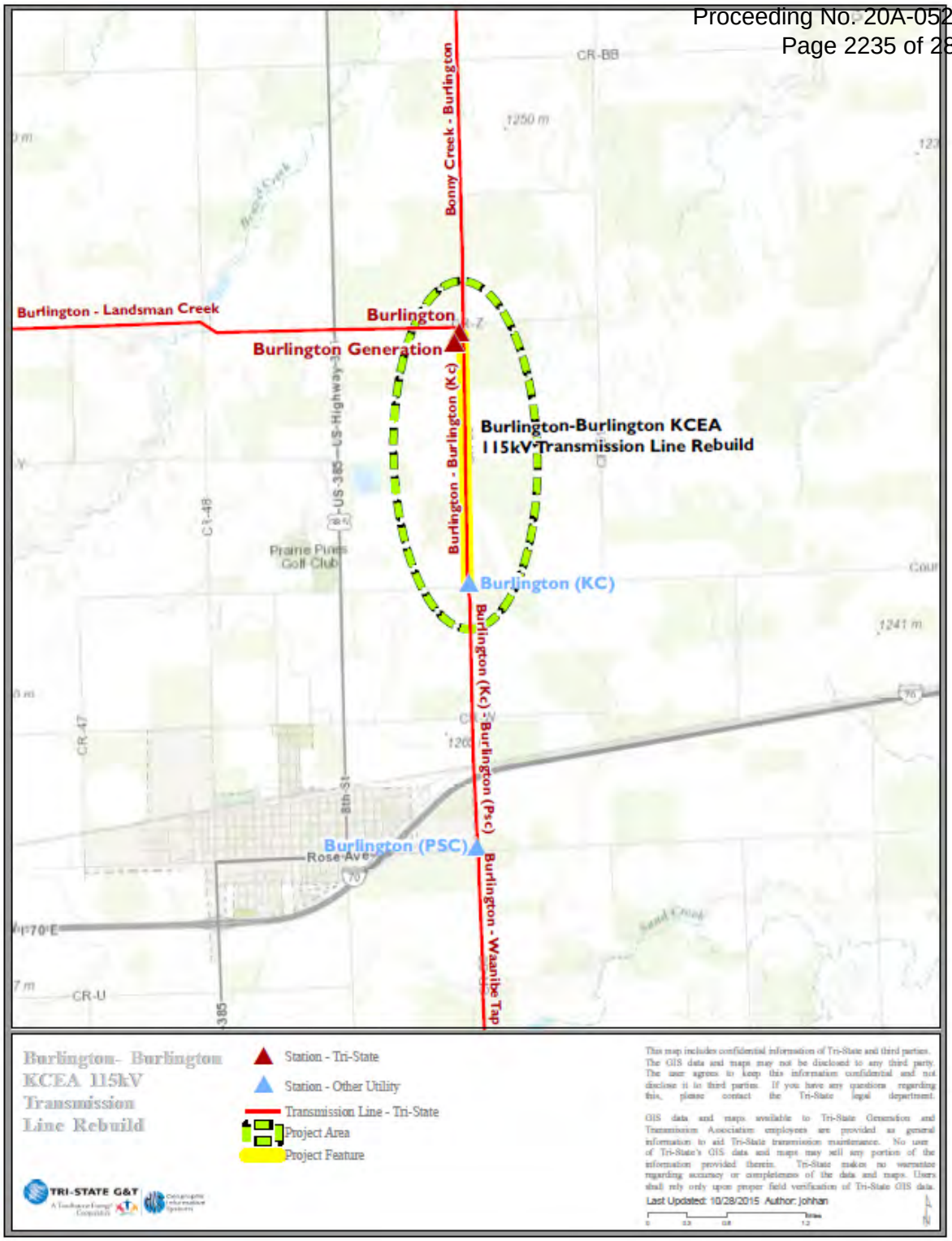
Bonny Creek - Burlington
CR-BB
1250 m
Burlington - Landsman Creek
Burlington
Burlington Generation
Burlington - Burlington (Kc)
Burlington-Burlington KCEA
115kV Transmission Line Rebuild
US-385
C1-48
Prairie Pines
Golf Club
Burlington (KC)
Burlington (Kc) Burlington (Psc)
1241 m
CR-47
8th St
Burlington (PSC)
Rose Ave
70
CR-U
385
Burlington - Waanibe Tap
Burlington- Burlington
KCEA 115kV
Transmission
Line Rebuild
Station - Tri-State
Station - Other Utility
Transmission Line - Tri-State
Project Area
Project Feature
TRI-STATE G&T
This map includes confidential information of Tri-State and third parties. The GIS data and maps may not be disclosed to any third party. The user agrees to keep this information confidential and not disclose it to third parties. If you have any questions regarding this, please contact the Tri-State legal department.
GIS data and maps available to Tri-State Generation and Transmission Association employees are provided as general information to aid Tri-State transmission maintenance. No user of Tri-State's GIS data and maps may sell any portion of the information provided therein. Tri-State makes no warranties regarding accuracy or completeness of the data and maps. Users shall rely only upon proper field verification of Tri-State GIS data.
Last Updated: 10/28/2015 Author: johhan
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Del Camino-Slater 115 kV Line Uprate

Project Sponsor:	Tri-State Generation and Transmission Association
Additional Project Participants:	
Project Description:	Reconductor portions of the existing Del Camino-Slater 115 kV line
Voltage Class:	115 kV
Facility Rating:	131 MVA
Point of Origin/Location:	Del Camino Switch
Point of Termination:	Slater
Intermediate Points:	
Length of Line (in Miles):	3.6
Type of Project:	Transmission Line
Development Status:	Planned
Routing:	
Subregional Planning Group:	CCPG
Purpose of Project:	Increase conductor thermal rating.
Project Driver (Primary):	Reliability
Project Driver (Secondary):	Load Serving
Estimated Cost (in 2019 Dollars):	$1,400,000
Schedule:	
Construction Date:	
Planned In-Service Date:	2021
Regulatory Info:	
Regulatory Date:	
Permitting Info:	
Permitting Date:	
Contact Information:	Ryan Hubbard
Email	rhubbard@tristategt.org
Phone	303-254-3025

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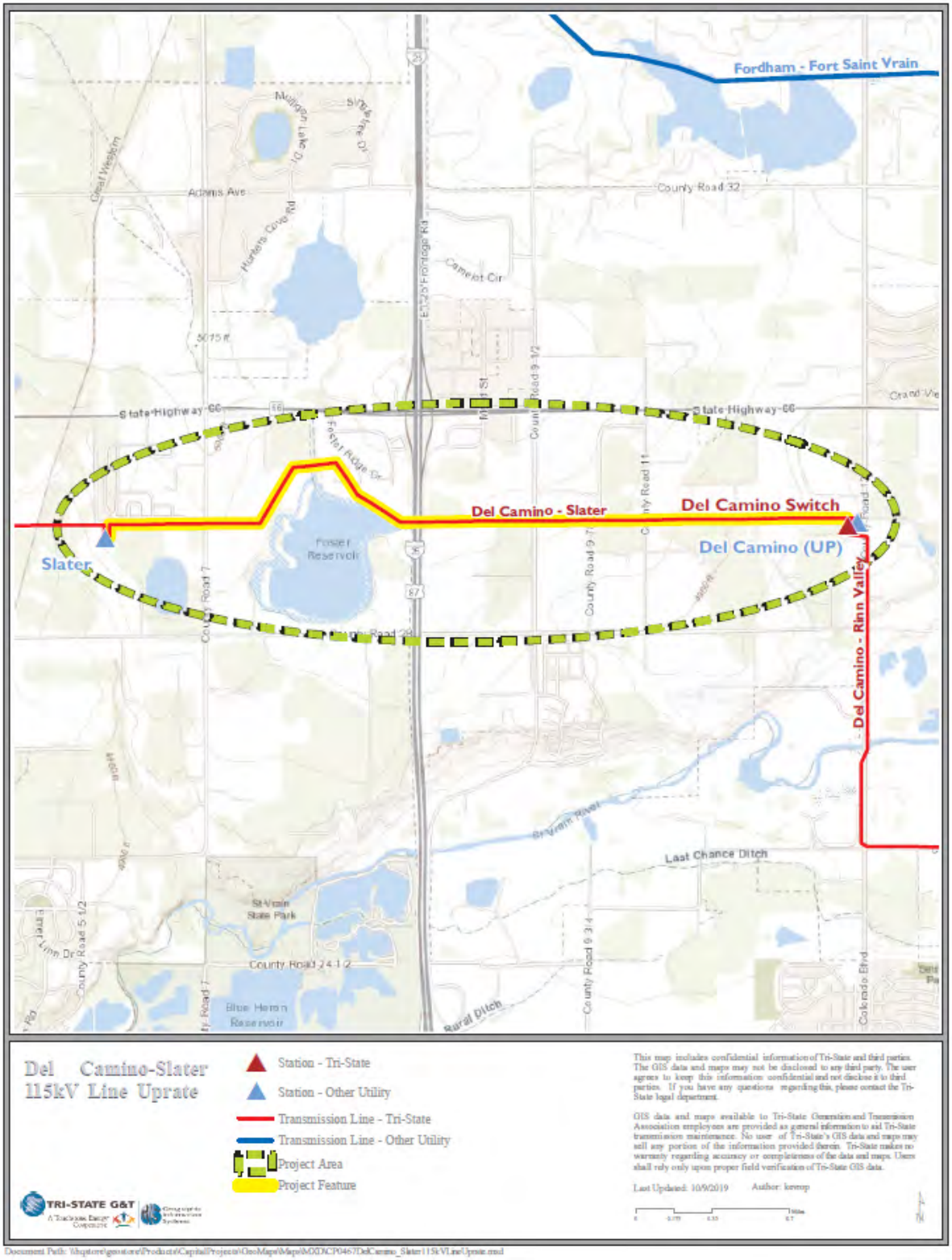
Fordham - Fort Saint Vrain
State Highway 66
Del Camino - Slater
Del Camino Switch
Del Camino (UP)
Slater
Del Camino - Rinn Valley
Last Chance Ditch
St Vrain State Park
Blue Heron Reservoir
Foster Reservoir
County Road 32
County Road 24 1/2
Del Camino-Slater
115kV Line Uprate
Station - Tri-State
Station - Other Utility
Transmission Line - Tri-State
Transmission Line - Other Utility
Project Area
Project Feature
TRI-STATE G&T

Falcon-Midway 115 kV Line Uprate Project

Project Sponsor:	Tri-State Generation and Transmission Association
Additional Project Participants:	
Project Description:	Planned uprate of existing 115 kV line between Falcon and Midway.
Voltage Class:	115 kV
Facility Rating:	145 MVA
Point of Origin/Location:	Falcon
Point of Termination:	Midway
Intermediate Points:	Geesen, Lorson Ranch, Rancho
Length of Line (in Miles):	27.0
Type of Project:	Transmission Line
Development Status:	Planned
Routing:	
Subregional Planning Group:	CCPG
Purpose of Project:	Increase conductor thermal rating.
Project Driver (Primary):	Reliability
Project Driver (Secondary):	
Estimated Cost (in 2019 Dollars):	$3,800,000
Schedule:	
Construction Date:	
Planned In-Service Date:	2022
Regulatory Info:	
Regulatory Date:	
Permitting Info:	
Permitting Date:	
Contact Information:	Ryan Hubbard
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Phone	303-254-3025

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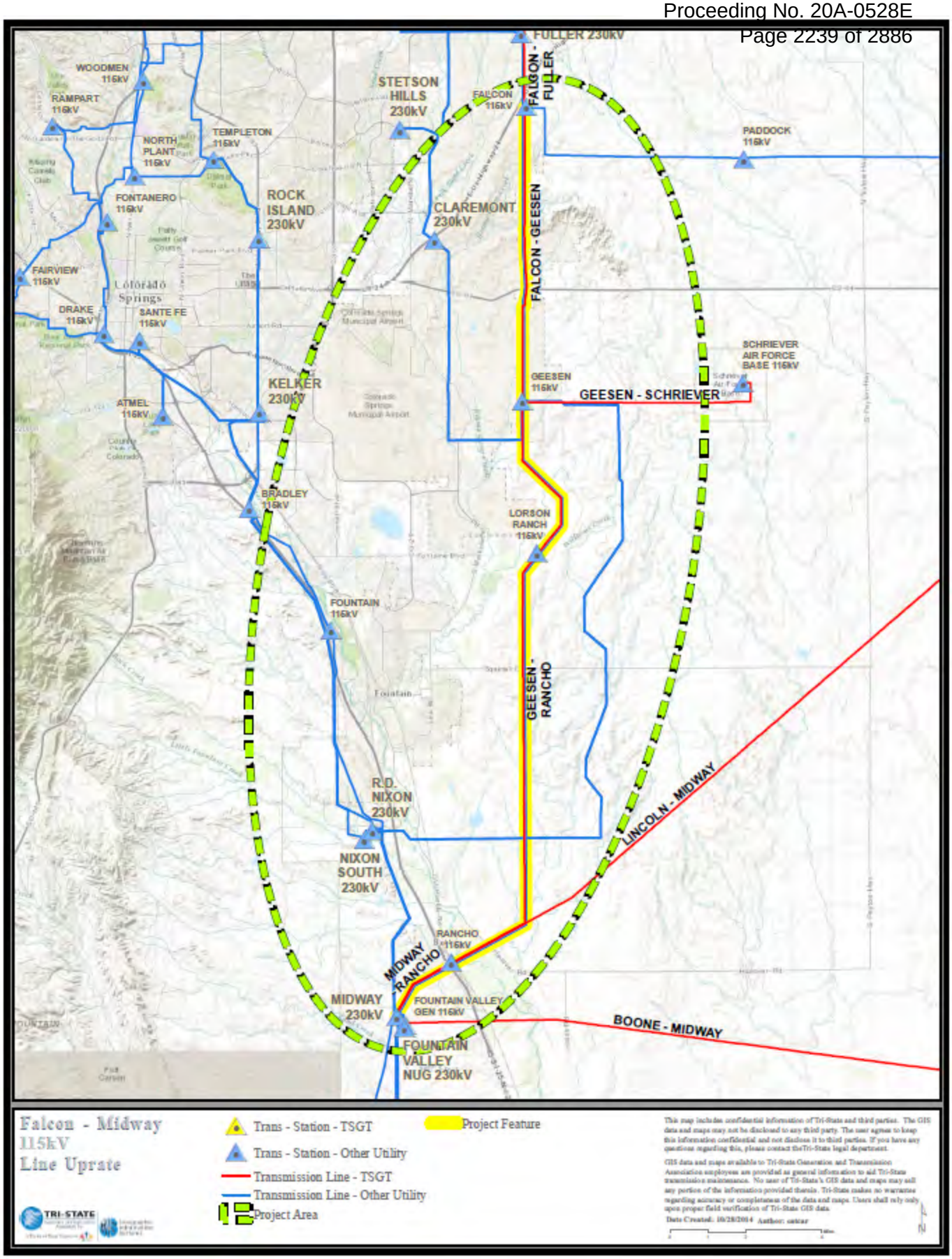
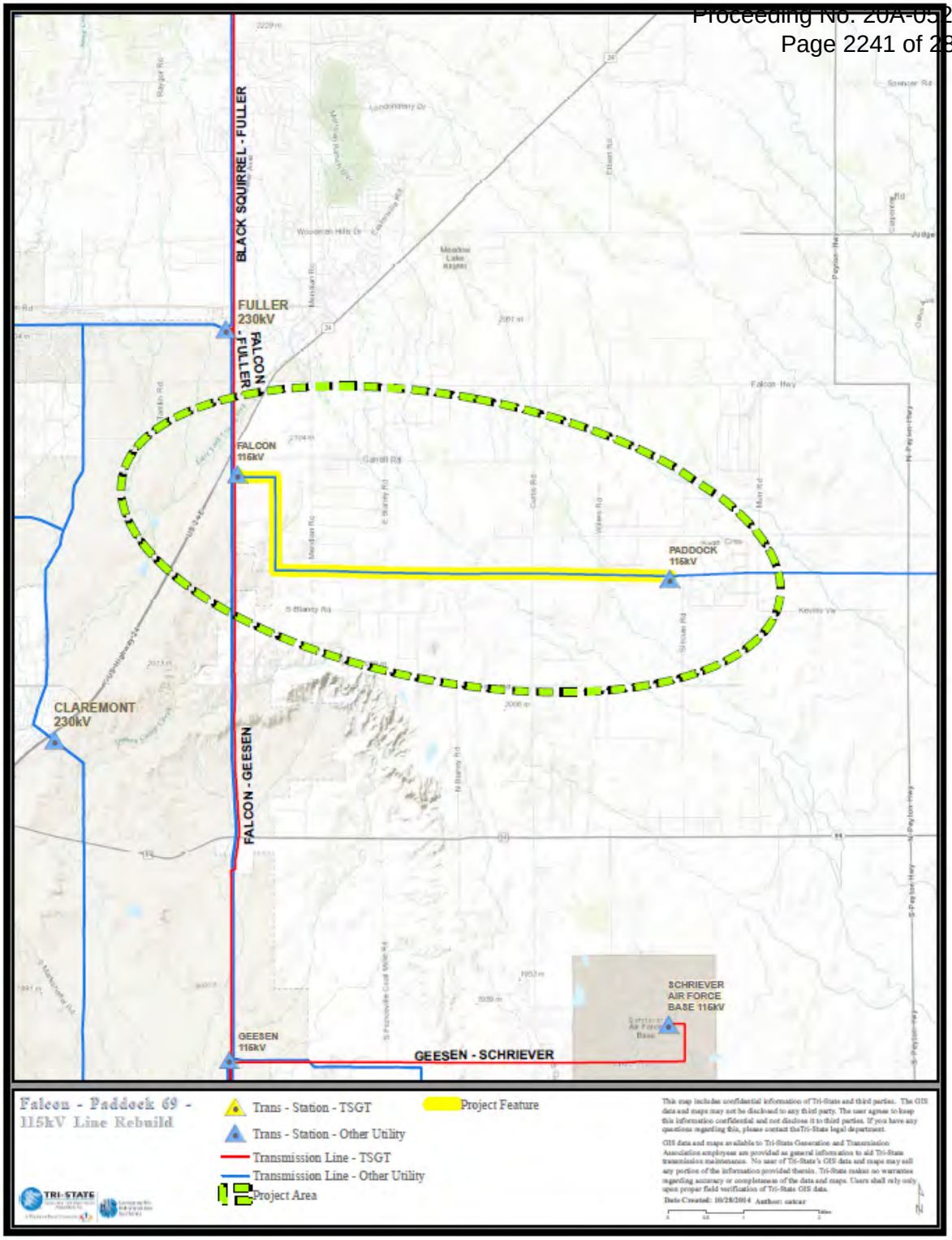
Hearing Exhibit 101
Page 13 of 45



Falcon-Paddock-Calhan 115 kV

Project Sponsor:	Tri-State Generation and Transmission Association
Additional Project Participants:	
Project Description:	Rebuild of existing 69 kV line between Falcon and Calhan.
Voltage Class:	115 kV
Facility Rating:	242 MVA
Point of Origin/Location:	Falcon
Point of Termination:	Calhan
Intermediate Points:	Paddock
Length of Line (in Miles):	25.0
Type of Project:	Transmission Line and Substation
Development Status:	Conceptual
Routing:	
Subregional Planning Group:	CCPG
Purpose of Project:	Increase conductor thermal rating and create 115 kV loop.
Project Driver (Primary):	Reliability
Project Driver (Secondary):	
Estimated Cost (in 2014 Dollars):	$33,400,000
Schedule:	
Construction Date:	
Planned In-Service Date:	TBD
Regulatory Info:	
Regulatory Date:	
Permitting Info:	
Permitting Date:	
Contact Information:	Ryan Hubbard
Email	rhubbard@tristategt.org
Phone	303-254-3028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FULLER
230kV
FULLER - FALCON
FALCON
115kV
PADDOCK
115kV
CLAREMONT
230kV
FALCON - GEESEN
SCHRIEVER
AIR FORCE
BASE 115kV
GEESEN
115kV
GEESEN - SCHRIEVER
Falcon - Paddock 69 - 115kV Line Rebuild
Trans - Station - TSGT
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Transmission Line - TSGT
Transmission Line - Other Utility
Project Area
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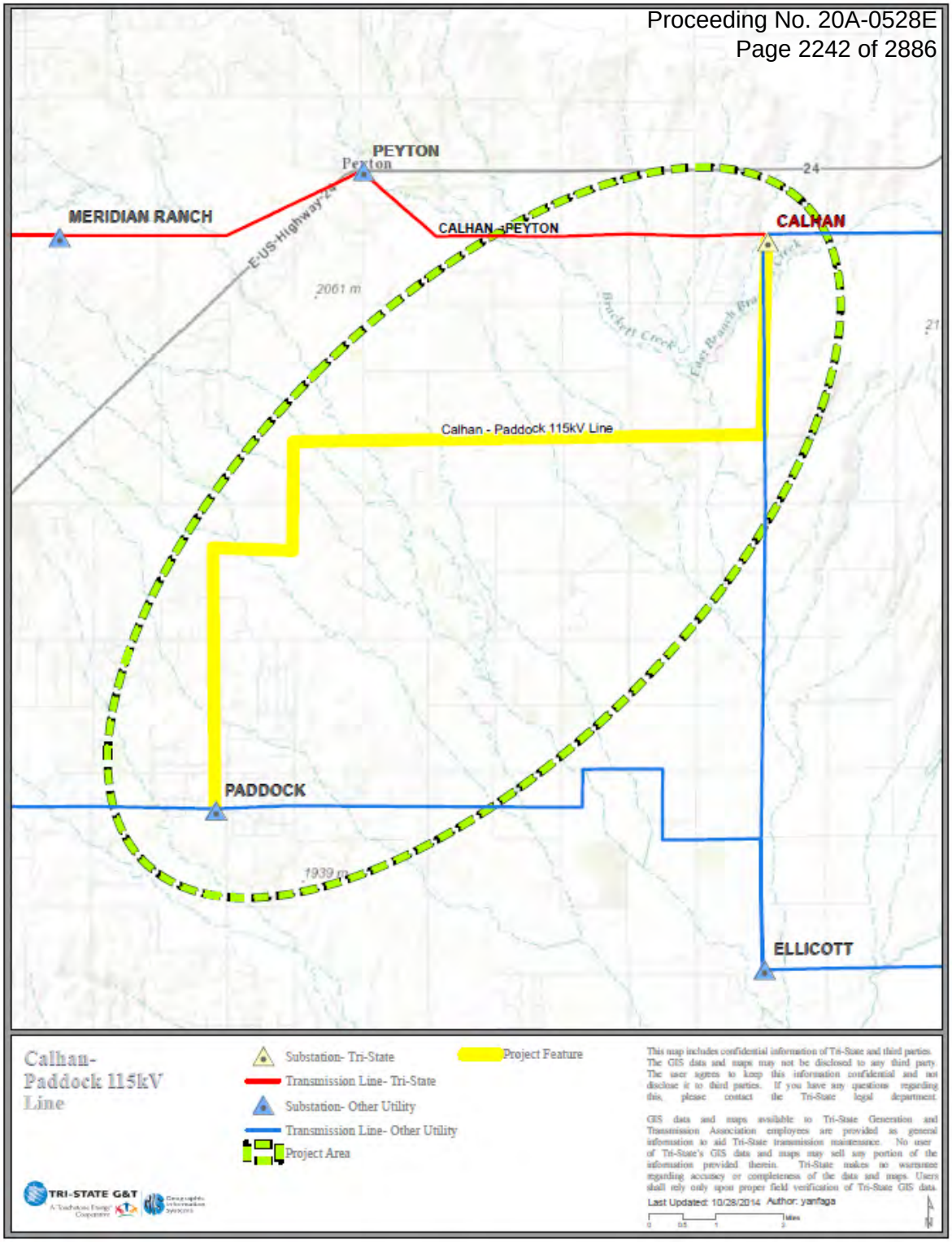
TRI-STATE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Peyton
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CALHAN
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Brockett Creek
East Branch Bra
Calhan - Paddock 115kV Line
PADDOCK
1939 m
ELLICOTT
Calhan-
Paddock 115kV
Line
Substation- Tri-State
Transmission Line- Tri-State
Substation- Other Utility
Transmission Line- Other Utility
Project Area
Project Feature
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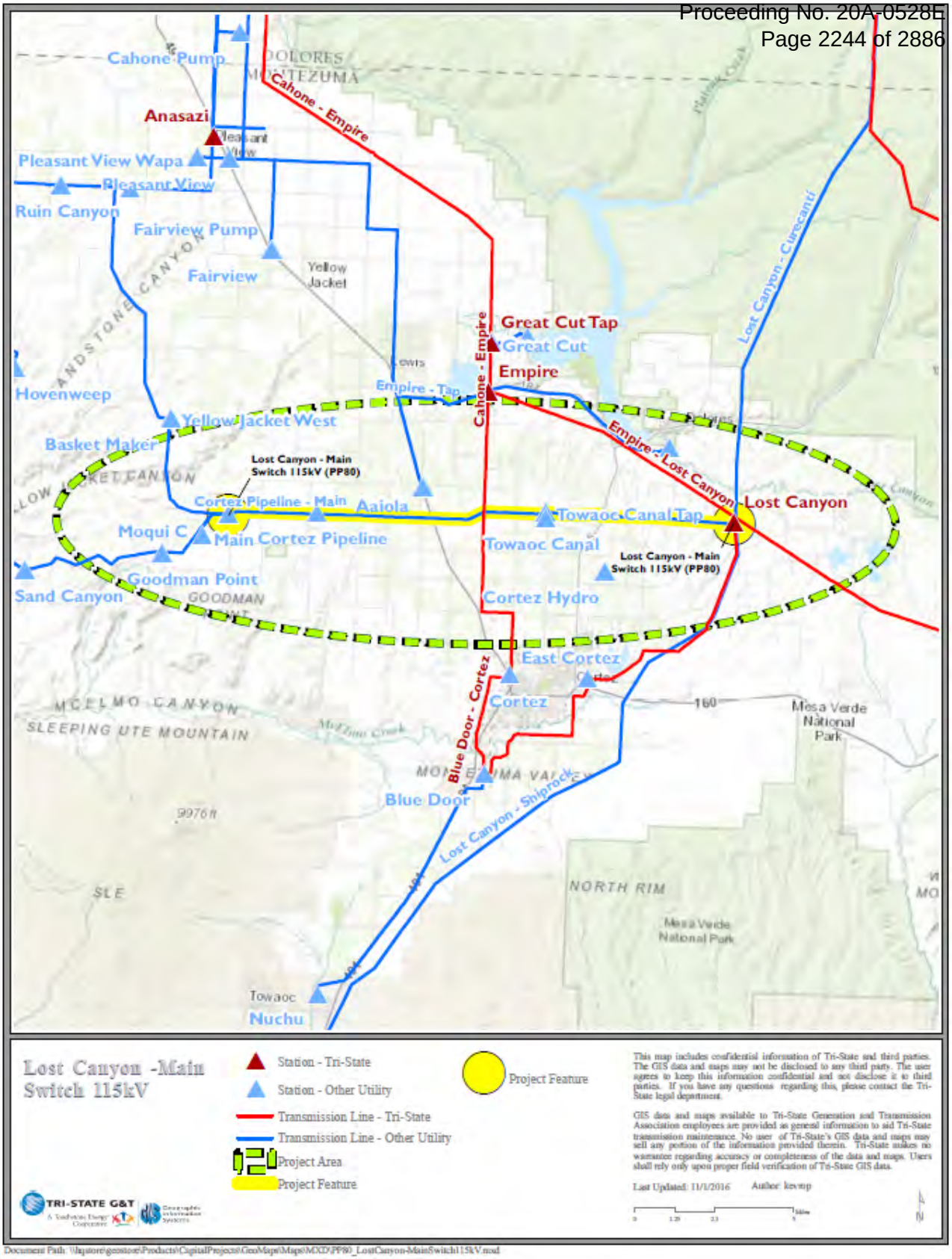
TRI-STATE G&T

Lost Canyon - Main Switch 115 kV Line

Project Sponsor:	Tri-State Generation and Transmission Association
Additional Project Participants:	
Project Description:	New 115 kV transmission line between Lost Canyon and Main Switch Substations.
Voltage Class:	115 kV
Facility Rating:	238 MVA
Point of Origin/Location:	Lost Canyon
Point of Termination:	Main Switch
Intermediate Points:	
Length of Line (in Miles):	16.0
Type of Project:	Transmission Line
Development Status:	Conceptual
Routing:	
Subregional Planning Group:	CCPG
Purpose of Project:	Increase load-serving capability of the CO2 Loop.
Project Driver (Primary):	Load Serving
Project Driver (Secondary):	Reliability
Estimated Cost (in 2019 Dollars):	$22,600,000
Schedule:	
Construction Date:	
Planned In-Service Date:	TBD
Regulatory Info:	
Regulatory Date:	
Permitting Info:	
Permitting Date:	
Contact Information:	Ryan Hubbard
Email	rhubbard@tristategt.org
Phone	303-254-3025



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Sisson Project

Project Sponsor:	Tri-State Generation and Transmission Association
Additional Project Participants:	
Project Description:	Substation addition radially served from Keota substation
Voltage Class:	115 kV
Facility Rating:	244 MVA
Point of Origin/Location:	Keota
Point of Termination:	Lloyd Sisson
Intermediate Points:	
Length of Line (in Miles):	24.0
Type of Project:	Transmission Line and Substation
Development Status:	Planned
Routing:	
Subregional Planning Group:	CCPG
Purpose of Project:	Increase load serving capability.
Project Driver (Primary):	Load Serving
Project Driver (Secondary):	
Estimated Cost (in 2019 Dollars):	$18,800,000
Schedule:	
Construction Date:	
Planned In-Service Date:	2020
Regulatory Info:	
Regulatory Date:	
Permitting Info:	
Permitting Date:	
Contact Information:	Ryan Hubbard
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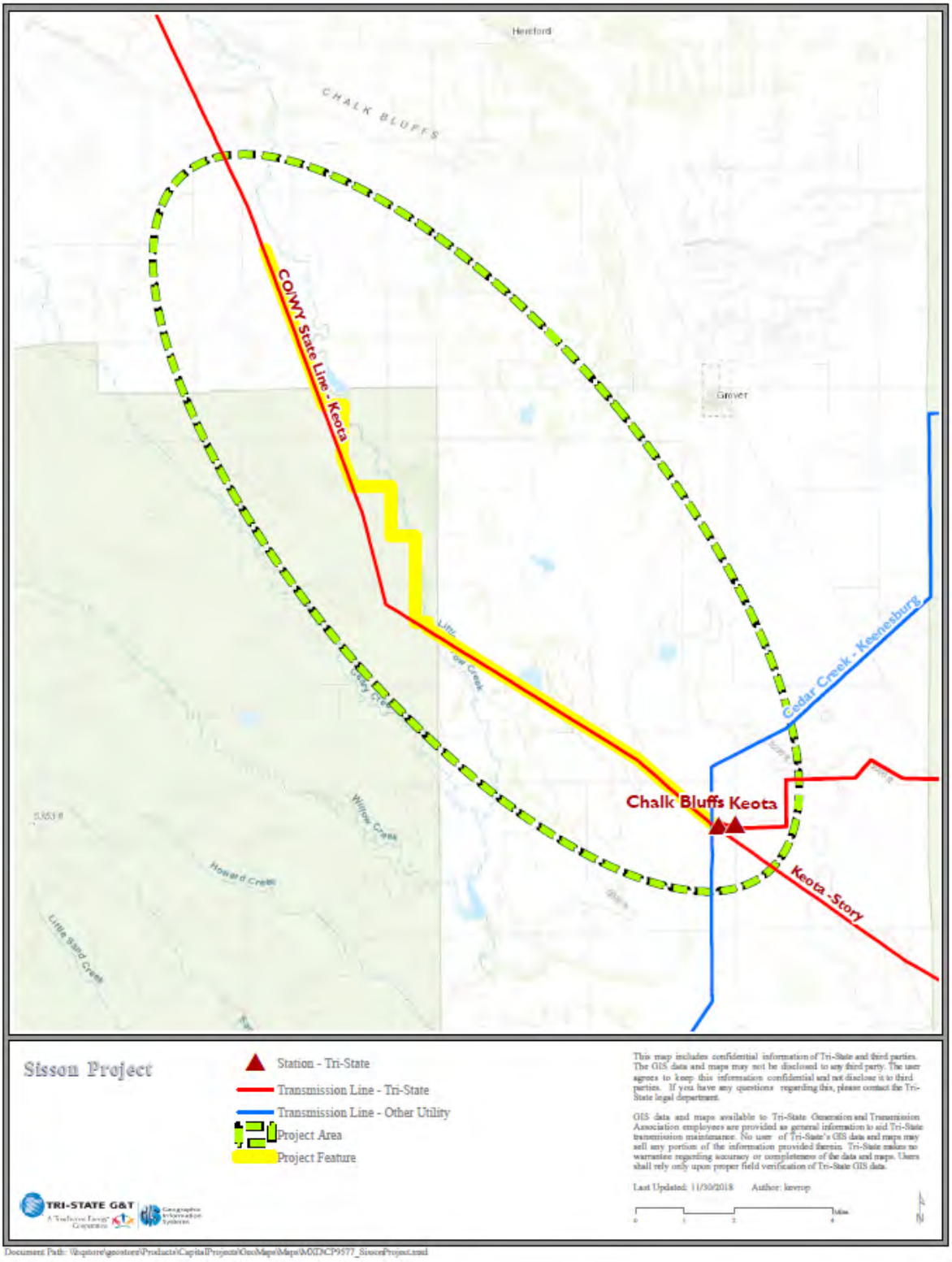
Phone	254-3025



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Tri-State Generation and Transmission Association
2020-2030 Transmission Plan

Vollmer Project

Project Sponsor:	Tri-State Generation and Transmission Association
Additional Project Participants:	
Project Description:	Construct approximately 2 miles of 115 kV transmission to serve the planned Vollmer substation
Voltage Class:	115 kV
Facility Rating:	143 MVA
Point of Origin/Location:	Vollmer
Point of Termination:	Jackson Fuller, Black Squirrel
Intermediate Points:	
Length of Line (in Miles):	2 miles
Type of Project:	Transmission Line and Substation
Development Status:	Planned
Routing:	
Subregional Planning Group:	CCPG
Purpose of Project:	Increase load-serving capability
Project Driver (Primary):	Load Serving
Project Driver (Secondary):	
Estimated Cost (in 2019 Dollars):	$7,100,000
Schedule:	
Construction Date:	
Planned In-Service Date:	2022
Regulatory Info:	
Regulatory Date:	
Permitting Info:	
Permitting Date:	
Contact Information:	Ryan Hubbard
Email	rhubbard@tristategt.org 303-
Phone	254-3025

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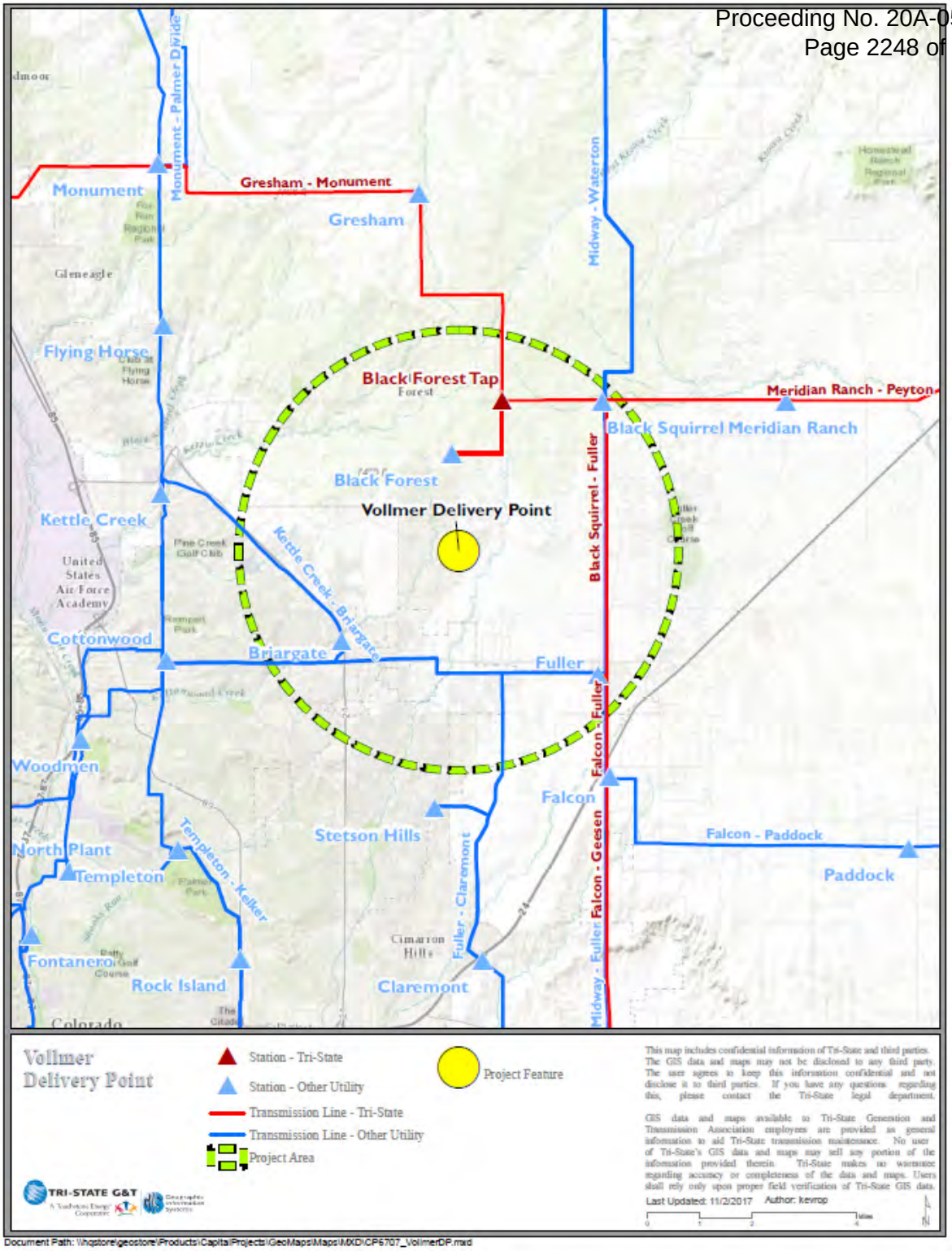
Monument
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Midway - Waterton
Gleneagle
Flying Horse
Black Forest Tap
Forest
Meridian Ranch - Peyton
Black Squirrel Meridian Ranch
Black Forest
Vollmer Delivery Point
Black Squirrel - Fuller
Kettle Creek
Kettle Creek - Briargate
United States Air Force Academy
Cottonwood
Briargate
Fuller
Falcon - Fuller
Woodmen
Falcon
Stetson Hills
Falcon - Paddock
North Plant
Templeton
Templeton - Kelker
Paddock
Fuller - Claremont
Cimarron Hills
Fontanero
Rock Island
Claremont
Midway - Fuller
Falcon - Geesen
Colorado
Vollmer Delivery Point
Station - Tri-State
Station - Other Utility
Transmission Line - Tri-State
Transmission Line - Other Utility
Project Area
Project Feature
TRI-STATE G&T
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Miles
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Western Colorado Transmission Upgrade Project

Project Sponsor:	Tri-State Generation and Transmission Association
Additional Project Participants:	
Project Description:	Rebuild existing transmission line from Montrose Substation to Cahone Substation from 115 kV to 230 kV capable. The transmission line will continue 115 kV operation and be sectionalized at the planned Maverick 115 kV substation, which will be constructed near Nucla substation. The existing Nucla - Norwood 115 kV line will sectionalize at Maverick substation.
Voltage Class:	230 kV
Facility Rating:	239 MVA
Point of Origin/Location:	Montrose
Point of Termination:	Cahone
Intermediate Points:	Maverick
Length of Line (in Miles):	80 Miles
Type of Project:	Transmission Line and Substation
Development Status:	Under Construction
Routing:	
Subregional Planning Group:	CCPG
Purpose of Project:	Reliability - eliminate need for existing Nucla Remedial Action Scheme and replace failing structures.
Project Driver (Primary):	Reliability
Project Driver (Secondary):	
Estimated Cost (in 2019 Dollars):	$57,200,000
Schedule:	
Construction Date:	
Planned In-Service Date:	2020
Regulatory Info:	
Regulatory Date:	
Permitting Info:	
Permitting Date:	
Contact Information:	Ryan Hubbard
Email	rhubbard@tristategt.org
Phone	303-254-3025

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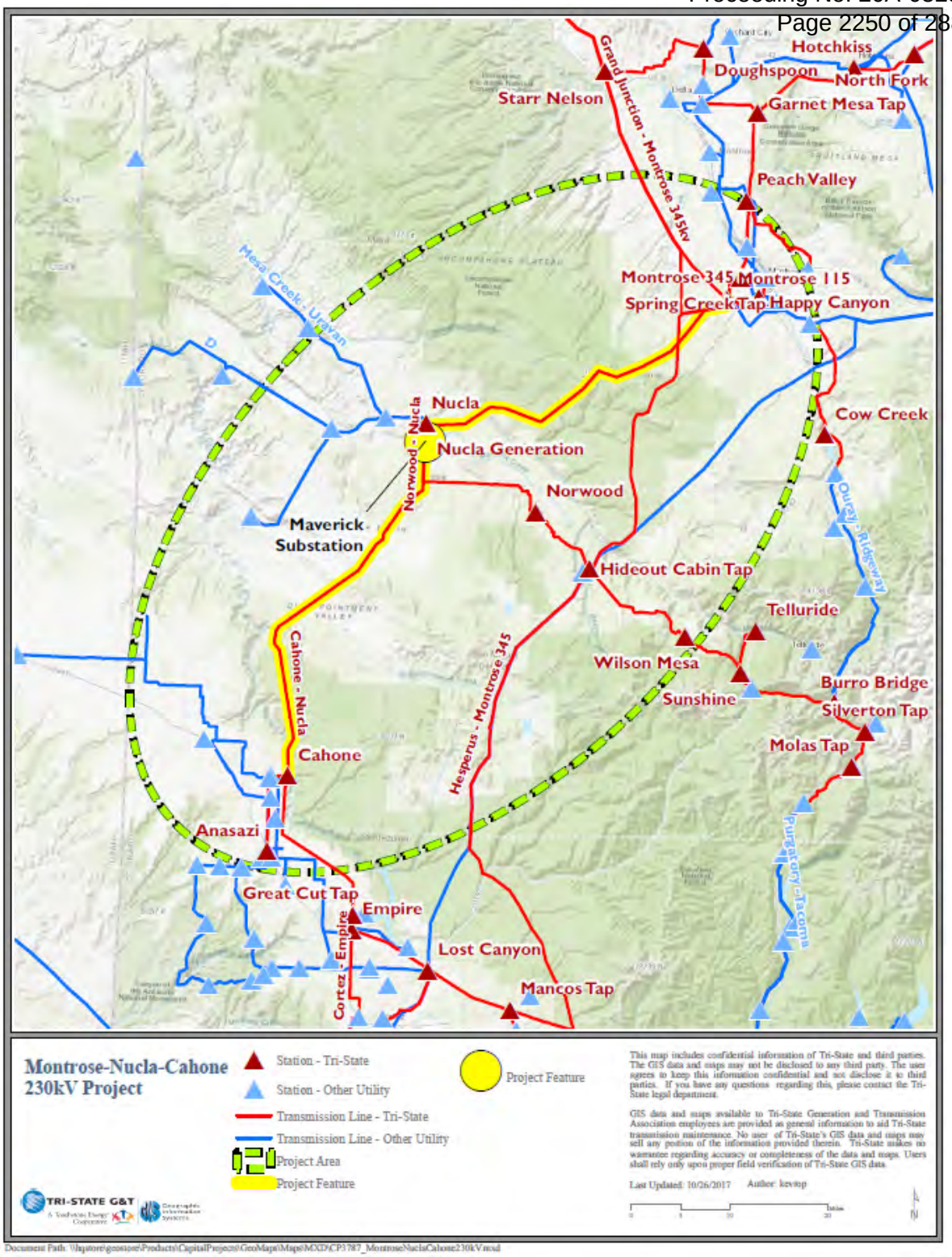

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Attachment Vol II 5-1 Demand Side Management & Energy Efficiency Potential Study

DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY POTENTIAL STUDY

FOR TRI-STATE GENERATION & TRANSMISSION

MAY 8, 2020

Prepared by: Mesa Point Energy & BrightLine Group

TRI-STATE GENERGATION & TRANSMISSION DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY POTENTIAL STUDY

MAY 8, 2020

Prepared For:

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EXECUTIVE SUMMARY

Project Overview

Mesa Point Energy, along with their subcontractor Brightline Group, (collectively the Mesa Point Team or the Team) performed a demand side management potential study in support of Tri-State Generation and Transmission's (Tri-State) resources planning initiatives. The study is intended to assist Tri-State in developing their Integrated Resource Plan (IRP) and Electric Resource Plan (ERP). The Mesa Point Team assessed the available technical, economic, and achievable energy and demand savings potential from energy efficiency (EE), demand response (DR), and behind-the-meter distributed energy resources (DER) from 2021 to 2040 for the electric cooperatives served by Tri-State.

The study focuses on energy efficiency, DR, and DER *achievable* potential; it is not a *program* potential study meaning it does not take into consideration program budget and design constraints. Therefore, the study examines what *could be* (i.e., what savings could accrue from considered cost effective measures) but does not account for structural and organizational limitations inherent and unique to the cooperative utility structure where each member can choose which products and measures to offer.

This Executive Summary presents an overview of the analysis approach, key assumptions, and study findings and the main report report goes into more detail on methods, savings, and findings.

A separate electronic reporting tool serves as an appendix to the report. The tool provides the ability to view findings in greater detail by sector, end-use, and region.

Results by Resource: EE, DR, DER

There are significant opportunities for cost-effective EE and DR savings in the Tri-State service territory. Behind-the-meter DER resources hold significant technical potential but realize limited cost-effective potential based on the analysis framework used for the study.

Given the uncertainty associated with customer adoption of energy-saving technologies, the Mesa Point Team developed achievable scenarios based on four different incentive and program delivery spending levels – from low to maximum levels of program funding.

These scenarios were:

1. Low – assumes incentivizing 25% of incremental cost
2. Moderate – 50% incentive level
3. Aggressive – 75% incentive level
4. Maximum – 100% of incremental cost. Note that maximum funding was assumed to be limited to 100% of the incremental cost to install a measure.

Key findings from each of the three resources assessed, EE, DR, and DER, are summarized below.

Energy Efficiency (EE) Resource

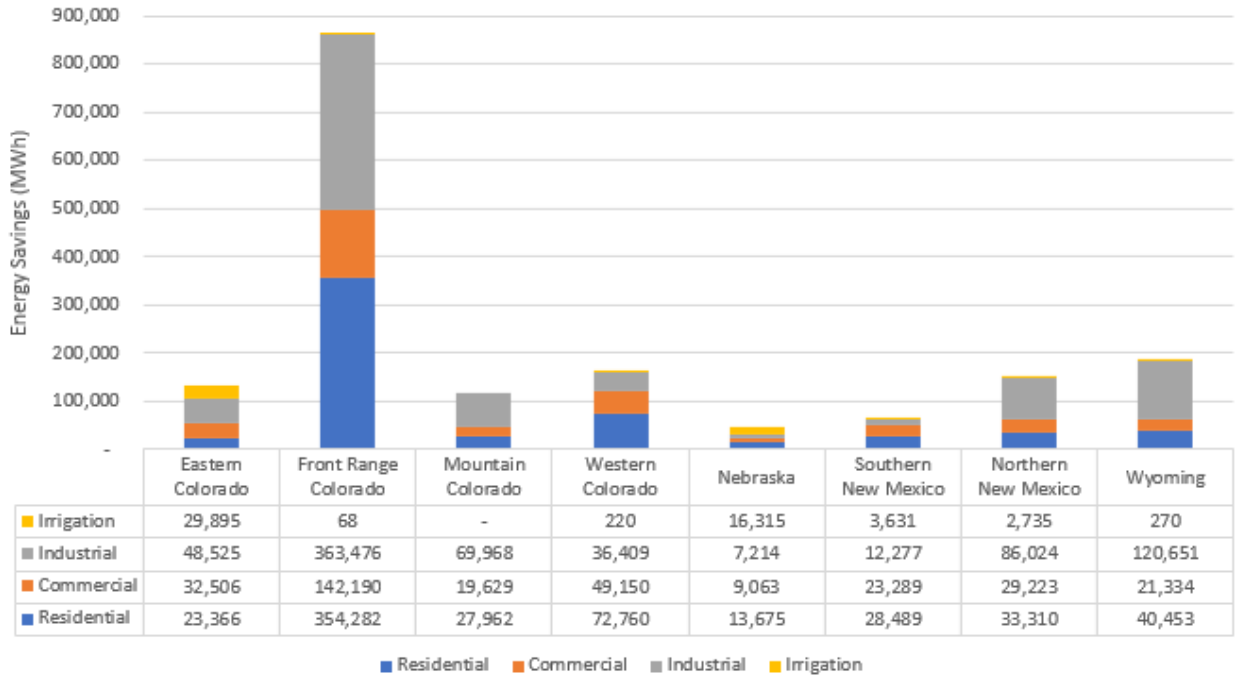
As summarized in Table ES-1, the Mesa Point Team found that the Achievable-moderate scenario would result in approximately 38 GWh (0.25% of sales) of energy efficiency saving in 2021 rising to 1,718 GWh (8.16% of sales) of savings through 2040.

Table ES-1. Portfolio Cumulative Energy Efficiency Savings by Scenario by Time Horizon

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE _MAX	ACHIEVABLE _ AGG	ACHIEVABLE _MOD	ACHIEVABLE _ LOW
Cumulative Energy Savings (MWh)						
2021 (first year)	130,384	98,221	75,523	55,330	38,083	27,043
2025	1,293,033	928,122	539,750	393,656	266,309	179,222
2030	3,868,940	2,851,171	1,372,971	1,062,225	723,605	475,993
2040	9,081,432	6,956,507	2,876,487	2,354,365	1,718,357	1,193,109
% of Baseline Sales						
2021 (first year)	0.85%	0.64%	0.49%	0.36%	0.25%	0.18%
2025	7.88%	5.65%	3.29%	2.40%	1.62%	1.09%
2030	21.74%	16.02%	7.71%	5.97%	4.07%	2.67%
2040	43.14%	33.04%	13.66%	11.18%	8.16%	5.67%

Energy effiency savings potential breakdown shares similarities to energy load in terms of distribution by region and by sector (Figure ES-1 and Figure ES-5). Front Range Colorado has the largest cumulative energy savings potential with 860 GWh. Across all regions, the industrial customer sector has more than 744 GWh of cumulative energy savings potential, followed by the residential sector at just under 600 GWh.

Figure ES-1. 2040 Cumulative Energy Efficiency Savings Potential by Region by Customer Sector (Achievable-Moderate Scenario)



	Eastern Colorado	Front Range Colorado	Mountain Colorado	Western Colorado	Nebraska	Southern New Mexico	Northern New Mexico	Wyoming
Irrigation	29,895	68	-	220	16,315	3,631	2,735	270
Industrial	48,525	363,476	69,968	36,409	7,214	12,277	86,024	120,651
Commercial	32,506	142,190	19,629	49,150	9,063	23,289	29,223	21,334
Residential	23,366	354,282	27,962	72,760	13,675	28,489	33,310	40,453

Table ES-2 summarizes the key cumulative energy efficiency cost metrics across the portfolio at four time horizons under the Achievable-Moderate scenario, as well as 20-year averages across the full study time horizon. It is estimated that over the 20-year study horizon approximately 114 GWh of energy savings is achievable, on average, per year at a cost of $24.3 million for an acquisition cost of $212/MWh. Over the 20 year study horizon, and on a levelized basis, the cost to acquire all energy savings under the Achievable-Moderate scenario is $21.55/MWh.

Table ES-2. Portfolio Energy Efficiency Cost Metrics by Time Horizon (Achievable-Moderate Scenario)

MILESTONE YEAR	TRC RATIO	SUM OF ANNUAL PROGRAM COSTS ($)[1]	SUM OF FIRST YEAR MEASURE SAVINGS (MWH)	FINAL YEAR DEMAND SAVINGS (MW)	ACQUISTION COST ($/MWH)	LEVELIZED COST ($/MWH)
2021	2.08	$6,957,787	38,083	5.28	$182.70	$15.25
2025	1.91	$54,155,251	279,461	9.91	$193.78	$17.41
2030	1.72	$164,148,094	797,374	17.25	$205.86	$20.18
2040	1.64	$486,794,842	2,290,399	23.11	$212.54	$21.55
20-year avg.	**1.64**	**$24,339,742**	**114,520**	13.89	**$212.54**	**$21.55**

Demand Response (DR) Resource

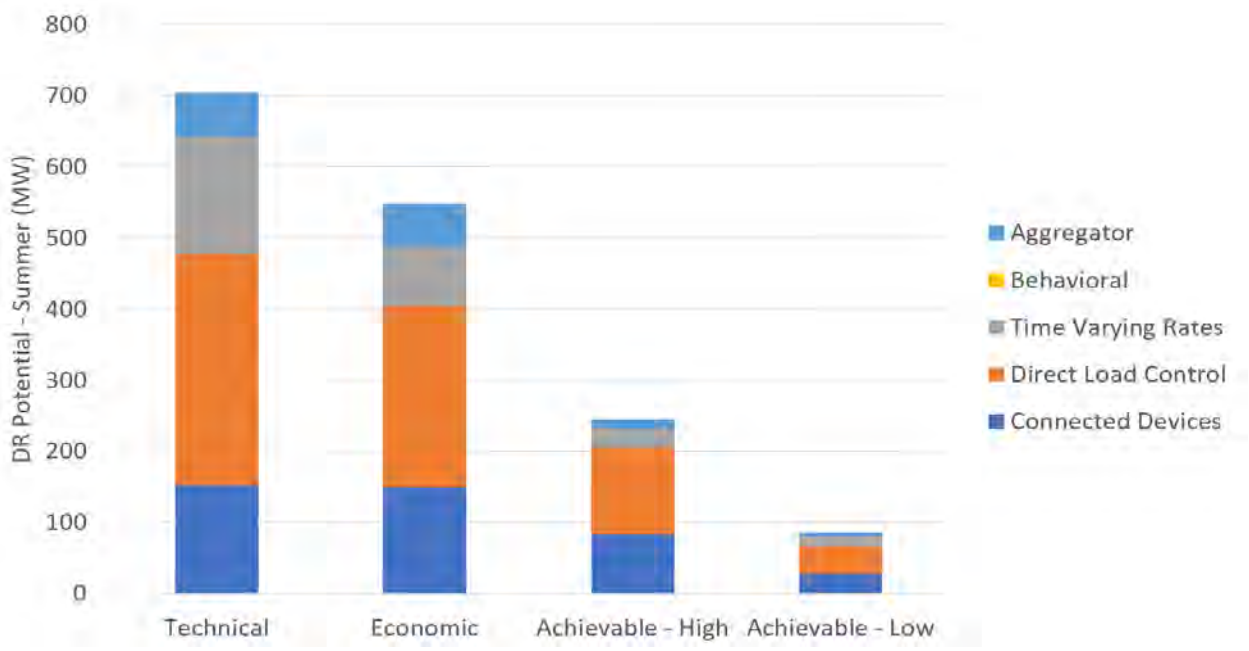
The study considered five different types of DR programs:

1. Aggregator – Capacity bidding programs managed by 3rd party aggregators
2. Behavioral – Personalized communication to customers requesting curtailed usage during peak events
3. Time varying rates – Customer retail electricity rates designed to shift usage by charging more during peak periods
4. Direct load control – Centralized remote control of customer equipment through installation of switches
5. Connected devices – Interaction with and control of internet-connected customer devices through web-based portals (e.g. Bring Your Own Thermostat programs)

Figure ES-2 shows the available DR potential across the portfolio by 2040 by program type. Connected device programs (primarily for Smart Thermostats) and Direct Load Control (DLC) (primarily for irrigation pumping) are the most significant program types.

[1] Includes administrative and incentive costs

Figure ES-2. Portfolio Demand Response Potential by Program Type (2040)



The DR analysis considered two different time-varying rates programs – **Critical Peak Pricing without Enabling Technology** (CPP no tech), and **Time Of Use** (TOU) – in each sector. Because Tri-State does not control customer rates, implementing a CPP or TOU rate demand response programs would require a high level of collaboration with electric cooperatives.

Table ES-3 summarizes the demand response cost metrics across the portfolio at each time horizon under the Achievable-Low scenario. By the end of the 20-year study horizon, the estimated 86 MW of peak demand savings is achievable at a cumulative total cost of $39 million. The Net Present Value TRC ratio of the demand response portfolio is cost effective by the end of the horizon (1.16 TRC), but not cost effective in the more immediate time horizons. This characteristic is largely driven by Tri-State's negligible costs of capacity until 2027.

Table ES-3. Portfolio Demand Response Cost Metrics by Time Horizon (Achievable-Low Scenario)

MILESTONE YEAR	TRC RATIO	CUMULATIVE PROGRAM COST ($)	DR POTENTIAL (MW)
2021	0.02	$5,440,119	5
2025	0.09	$13,818,802	30
2030	0.60	$24,286,062	78
2040	1.16	$39,068,285	86

Distributed Energy Resource (DER)

The Team limited resources for the DER potential study to technologies that are behind-the-meter and owned by the customer; we did not consider market potential for supply-side resources within this assessment. The market potential assessment for DERs focused on solar photovoltaic (PV) systems across Tri-State's region for the period 2021 to 2040. We performed review and preliminary cost screens for other potential DER technologies such as combined heat and power and small wind but ultimately did not find these technologies applicable and/or cost effective.

Overall, solar PV generation has the technical capability of providing over half of Tri-State's sales. However, this value varies considerably by region. Figure ES-3 and Figure ES-4 below illustrate cumulative technically possible PV generation in 2040 compared to cumulative 2040 sales. It is interesting to note that in some areas of New Mexico solar power has the technical potential to produce more energy than is used. New Mexico's PV generation exceeds sales due to a high solar irradiance which improves solar efficiency and relatively low consumption on average.

Figure ES-3. 2040 Technical Potential for Cumulative Residential PV Generation vs Sales by Region

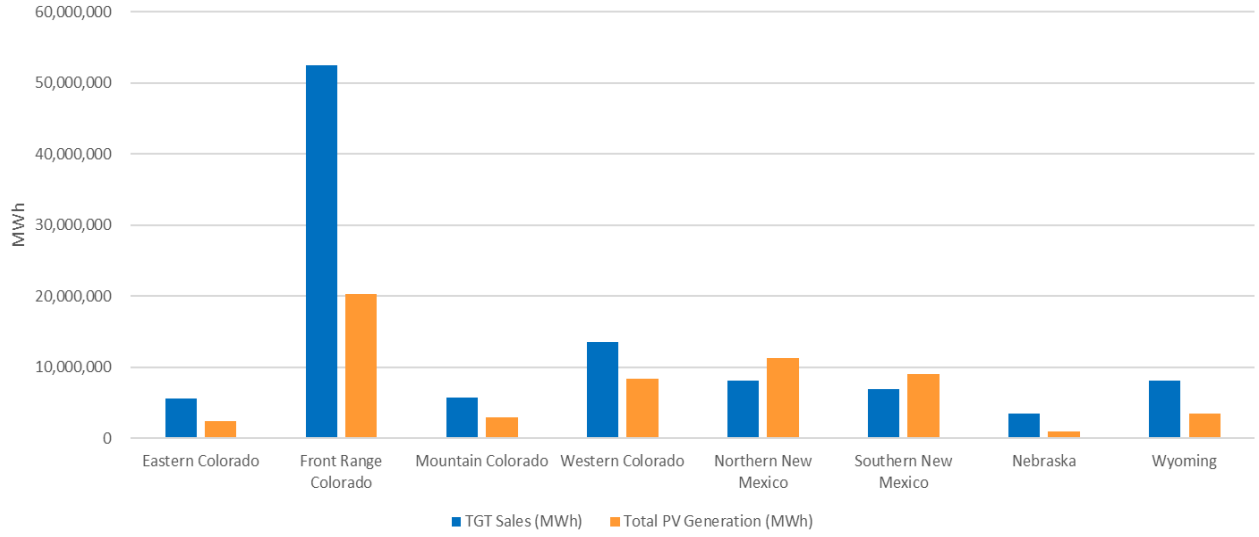
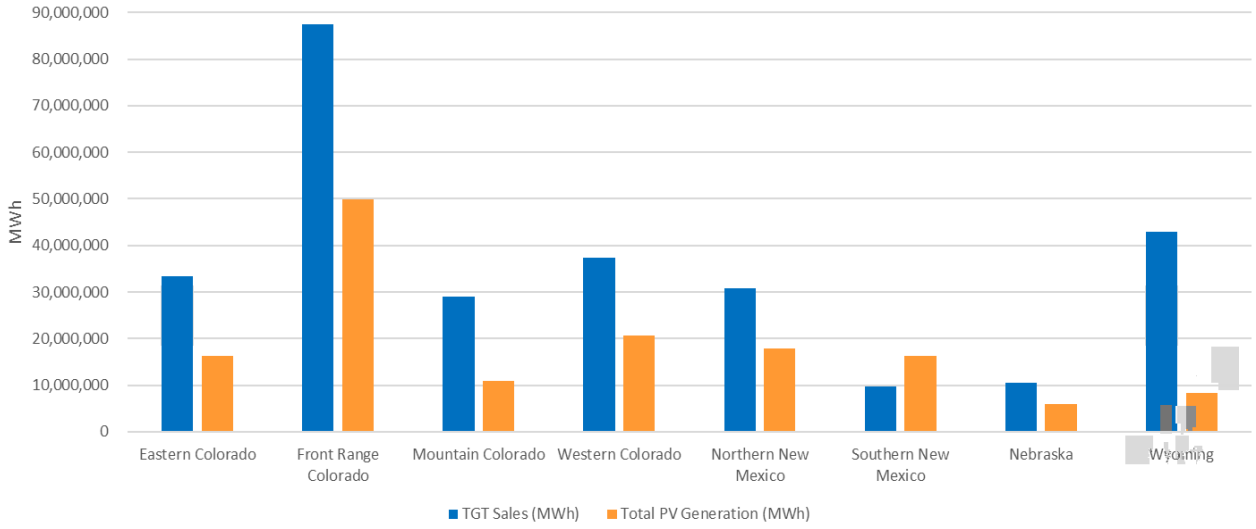
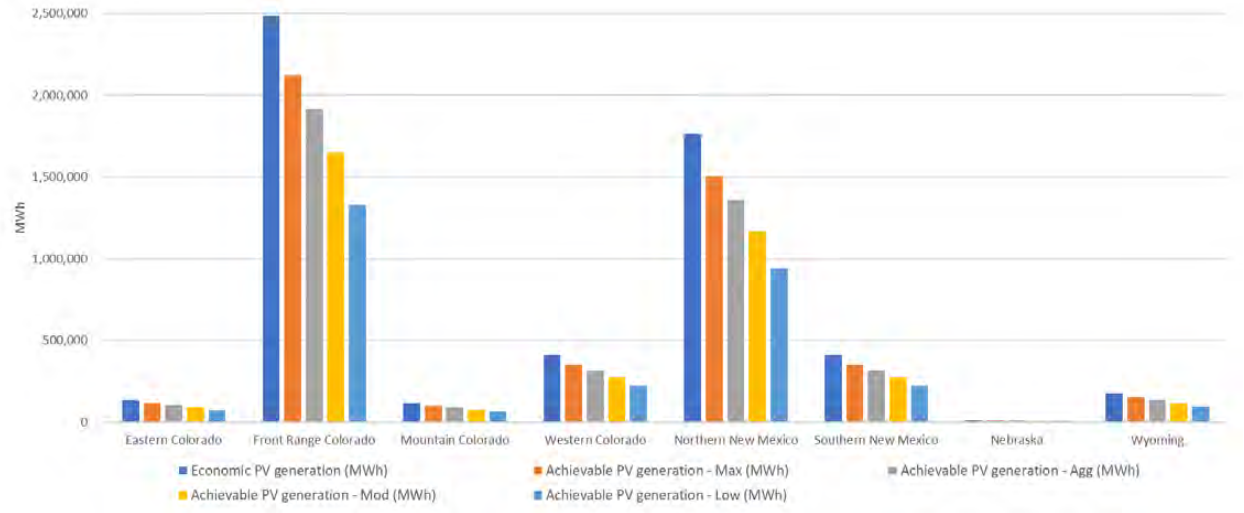


Figure ES-4. 2040 Technical Potential for Cumulative Non-Residential PV Generation vs Sales by Region



The results of the economic and achievable potential analysis are presented below in Figure ES-5. Only non-residential measures passed cost effectiveness, and those cost effective measures comprised just 9% of analyzed measure permutations. Cumulative non-residential economic potential solar PV generation equates to 2.0% of 2040 cumulative sales; achievable potential solar PV generation equates to 1.7% - 1.1% of 2040 cumulative sales. It is noted that while this potential generation reflect the entire Tri-State territory, the cost effective scenario used in this analysis includes CO_2 emission benefits which are not applicable to regions outside of Colorado, as emissions are not a quantifiable benefit at the time of this report publication.

Figure ES-5. 2040 Cumulative Non-Residential Economic and Achievable Potential PV Energy Generation by Region



Results Summary

In summary, Tri-State and its member co-ops could save the following energy and dollars with the corresponding investment, on a levelized basis over the 20-year study period:

Table ES-7. DSM Investment Outlook through 2040 (Achievable-Moderate Scenario)

RESOURCE TYPE	RESULTS
EE	Average annual savings of 114,520 MWH/year and 14 MW at a levelized cost of $15.25/MWH (TRC = 1.64)
DR	86 MW of demand response potential by 2040 at a cumulative cost of $39M (TRC = 1.16)
DER	3,661,295 MWH and 50 MW potential by 2040 at a cumulative administrative cost of $183M (TRC = 1.04)

Market Characterization & Baseline Forecast Results

In order to develop the results presented above, the Team developed a detailed characterization of Tri-Stat's customer base. This section summarizes the market and baseline forecast characterization including Tri-State's energy usage by sector and end use (additional details about customer segment and end use breakdowns within each sector are provided in Section 3). Tri-State's forecasted 2021 electricity sales to member cooperatives is just over 15 TWh, estimated to grow to just over 20 TWh by 2040 (Figure ES-6). In the base year of the analysis industrial is the largest market sector at 44% of load, followed by the residential sector at 30% of load, commercial at 18% and finally irrigation at 8%. These sector load shares remain fairly steady during the study horizon. The distribution of energy load by customer sector varies among the eight regions modeled in this study – for example, Eastern Colorado has a large irrigation sector load share while Mountain Colorado has almost no irrigation energy load (Figure ES-7). Front Range Colorado is the largest region at 5 TWh of energy load; it also has the largest Residential load share.

Figure ES-6. Baseline Load Forecast by Sector by Milestone Year

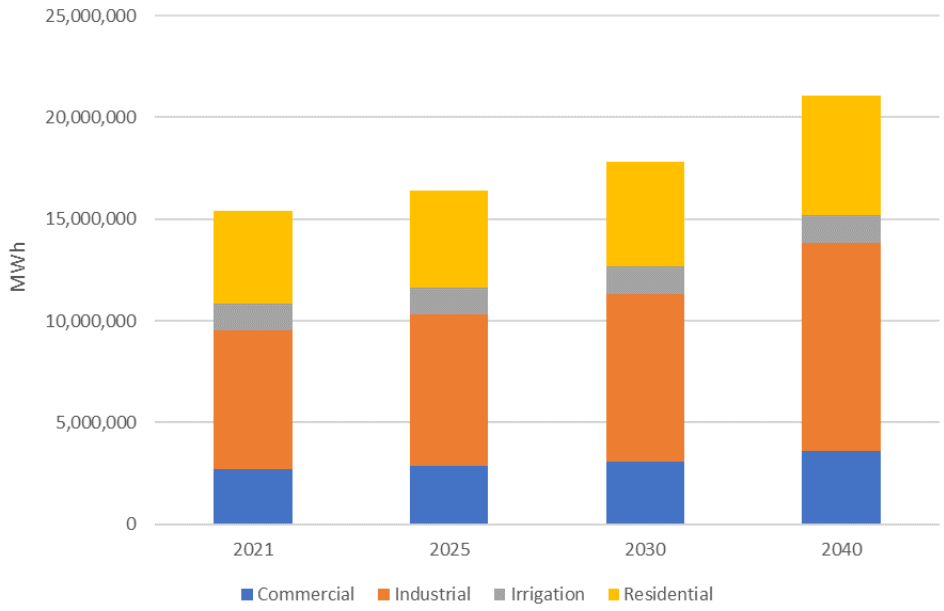
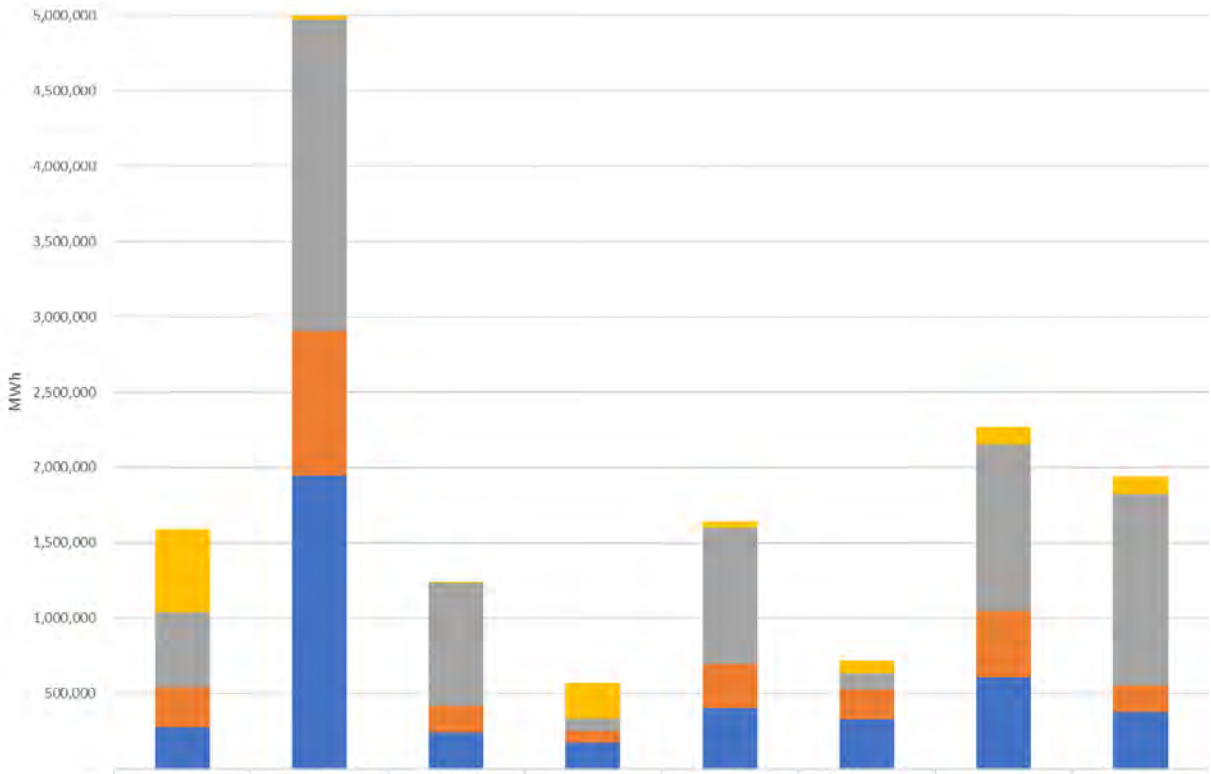


Figure ES-6. 2018 Baseline Energy Load by Customer Sector by Region



	Eastern Colorado	Front Range Colorado	Mountain Colorado	Nebraska	Northern New Mexico	Southern New Mexico	Western Colorado	Wyoming
Irrigation	554,724	31,967	861	237,972	41,763	85,091	116,352	119,890
Industrial	494,719	2,061,346	814,705	79,803	903,438	107,893	1,104,101	1,268,084
Commercial	268,177	964,547	176,453	78,733	289,986	197,934	444,417	173,590
Residential	276,257	1,944,118	241,514	173,762	406,734	328,318	606,582	380,071

Study Approach and Methods

The study approach undertaken to develop the results presented above consists of three main tasks. These tasks are summarized below and discussed in more detail in Section 2 of this report. The tasks include:

- Customer Segmentation and Forecast Disaggregation
- Measure Impact Research
- Modeling and Data Analysis

Segmentation and forecast: For the market segmentation analysis, the Team collected relevant customer and forecast datasets from Tri-State to disaggregate customer energy load by region, sector, building/business type (i.e. segment), and end use for each year in the study's 20-year time horizon. This task identifies the available energy load within the various market and end use sectors available for conversion to higher efficiency or demand reduction technologies.

Measure impacts: With the market segemented and forecast disaggregated across the study horizon, the Team then characterized the universe of efficiency, demand response, and DER measures and their end-use-specific savings, costs, and lifetimes. Measures currently implemented in Tri-State's and Xcel Energy's DSM programs received careful consideration since these measures have a historical record and vendors have proven processes for implementation. Each measure was assigned to the relevant resource, region(s), sector(s), segment(s), and end use(s) for modeling. Each measure permutation was screened for cost effectiveness according the Total Resource Cost (TRC) test with a passing threshold of 0.7 for EE measures (thus allowing some less cost-effective measures to be assessed so long as the portfolio remained above a TRC of 1.0) and a passing threshold of 1.0 for DR and DER resources.

Modeling and data analysis: The Mesa Point Team used industry-standard modeling approaches to estimate the technical, economic, and achievable potential and associated costs for EE, DR and DER resources. Specifically, a discrete model was developed for each resource and potential estimates were developed independent of one-another – for example, each resource used the same baseline disaggregated load forecast and energy efficiency improvements did not reduce the opportunity for demand response potential. The energy savings and associated costs of each resource was forecasted for a 20-year time horizon (2021 – 2040). Two to four achievable potential scenarios were developed for each resource so that varying levels of market opportunities could be assessed given variances in measure incentive levels and aggressiveness of program delivery. Outputs from each resource model were developed at high levels of resolution, showing annual energy savings, lifetimes, and costs for each measure permutation (by region, sector, segment, end use, and vintage) for each year of the study horizon.

1. INTRODUCTION

1.1. Background, Project Scope, and Objectives

Tri-State retained Mesa Point Energy, along with their subcontractor Brightline Group, (collectively the Mesa Point Team or the Team) to perform a demand side management study in support of the company's resources planning initiatives. The primary objective of this study is to assess the available technical, economic, and achievable energy savings potential from energy efficiency (EE), demand response (DR), and behind-the-meter distributed energy resources (DER) from 2021 to 2040 for the electric cooperatives served by Tri-State Generation and Transmission (Tri-State). Measures considered are limited to technologies that are behind-the-meter and owned by the end-user.

The potential study is intended to assist Tri-State in developing their Integrated Resource Plan (IRP) and Electric Resource Plan (ERP). Tri-State will use the results of this market potential study to analyze and incorporate potential EE, DR and DER impacts at various levels of program investment over the planning horizon from 2021 to 2040.

The study focuses on energy efficiency, DR, and DER *achievable* potential. As discussed further in Section 2, the study is not a *program* potential study meaning it does not take into consideration program budget and design constraints. Therefore, this report's conclusions and recommendations do not include program-specific recommendations; rather, the report focuses on identifying market opportunities and costs for EE, DR, and DER.

1.2. Achievable v. Planned Savings

This potential study examines what *could be* (i.e., what savings could accrue from considered cost effective measures) but does not account for structural and organizational limitations to that potential.

Tri-State member cooperatives are responsible for implementing measures and programs on a voluntary basis. Tri-State does not have control over which measures its members choose to offer nor how the measures are bundled into program offerings. Some co-ops may choose not to offer incentive programs, or to incent only a subset of cost-effective measures.

The study only takes into consideration barriers on the market side and does not attempt to predict if and at what levels co-ops will choose to move forward with programs.

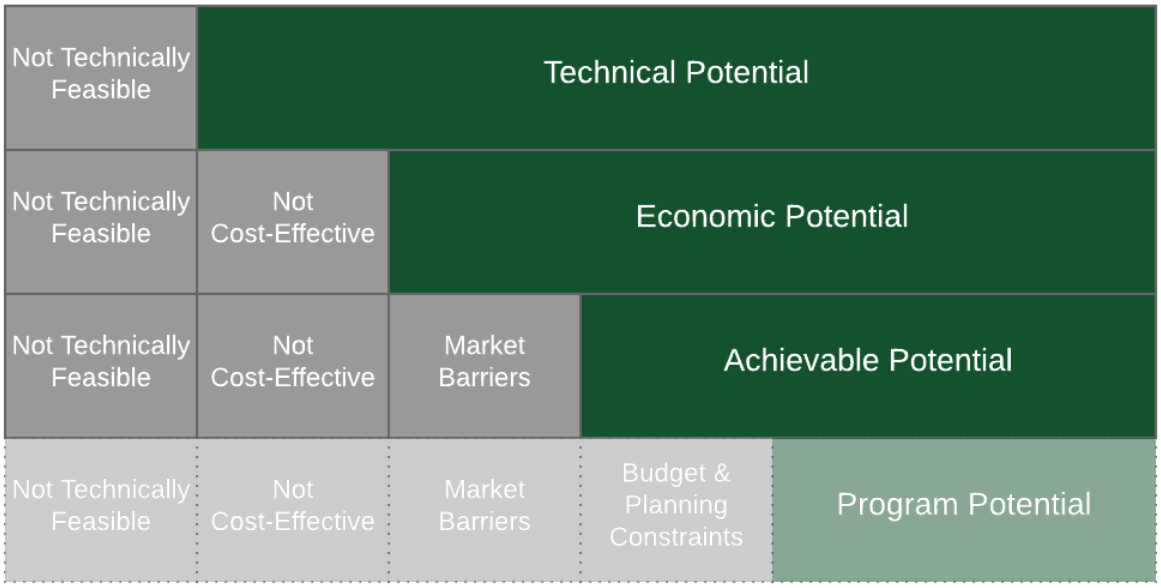
1.3. Study Approach Overview

In accordance with standard industry practice for DSM potential studies, this study considers measures from the perspective of theoretical maximum savings, and then accounts for barriers to estimate actual achievable savings.

Specifically, the study begins with *technical potential*, wherein all technically viable measures are included without regard to costs or other barriers. Knowing the technical potential, *economic potential* is assessed by estimating costs to implement measures, and then applying economic criteria to the measures. Finally, *achievable potential* is calculated by considering non-economic factors affecting DSM measure implementation. Not considered in the report are factors affecting *program potential*.

This analysis approach is based on standard perspectives of DSM resource potential according to the Environmental Protection Agency's (EPA) National Action Plan for Energy Efficiency (NAPEE)[2] as illustrated in Figure 1.

Figure 1: Conceptual Overview of DSM Resource Potential Defintions



- **Technical Potential** is the theoretical maximum amount of energy and capacity that could be displaced by an efficient technology, regardless of cost and other barriers that may prevent the installation or adoption of a measure. Technical potential is only constrained by factors such as technical feasibility and applicability of measures.
- **Economic Potential** is the amount of energy and capacity that could be reduced by measures that pass a cost-effectiveness test. This analysis used the Total Resource Cost (TRC) Test, which estimates the measure costs to both the utility and customer.
- **Achievable Potential** is the energy savings that can feasibly be achieved through program and policy interventions. Achievable potential takes into account barriers that hinder consumer adoption of energy efficiency measures such as financial, political and regulatory barriers, and the capability of programs and administrators to ramp up activity over time.
- **Program Potential** reflects the realistic quantity of energy savings the utility can realize through DSM programs during the horizon defined in the study. Potential delivered by programs is often less than achievable potential due to real-world constraints such as program budgets, effectiveness of outreach, and market delays. Program potential would also incorporate go-to-market considerations, such as practical limitations for Tri-State to deliver programs to

[2] The EPA National Action Plan for Energy Efficiency: http://www.epa.gov/cleanenergy/documents/suca/napee_report.pdf

customers through the rural electric cooperative members. As noted previously and as shown in Figure 1, this study does not address program potential.

1.4. Cost Effectiveness

At the core of DSM potential is the concept of cost-effectiveness. To assess cost effectiveness, the total cost of implementing measures is compared to the cost of business as usual with energy being provided to the baseline energy using equipment and behaviors. A DSM measure is considered cost effective if it is less costly than simply providing energy to baseline systems.

The California Standard Practice Manual (SPM) provides the methodology for estimating cost effectiveness of technologies, bundles, programs, or portfolios based on a series of tests representing the perspectives of the utility, customers, and societal stakeholders. "Low," Moderate ("Mod"), Aggressive ("Agg"), and Maximum ("Max") scenarios vary based on the assumptions for level of incentive, staffing, and marketing investment.

1.5. Presentation of Savings

This report represents savings in several different ways. For the most part, savings across years is presented as cumulative, but there are cases in which the savings may be presented in one of the other ways defined below. Following are the various methods for presenting savings:

- **Annual Incremental**: Energy savings acquired in the year in which measures are installed
- **Cumulative**: Total energy savings acquired over a given time horizon, accounting for measure decay (i.e. retired energy savings after an installed measure reaches the end of its useful life)
- **Sum of Annual Incremental**: Total energy savings acquired over a given time horizon, not accounting for measure decay

1.6. Organization of the Report and Related Deliverables

This report presents a summary of the analysis approach, key assumptions and study findings. Two separate electronic reporting tools serve as an appendices to the report. The tools provide the ability to view findings by sector, end-use, and region from both annual and hourly perspectives. The intent is for Tri-State and stakeholders to make use of both work products depending on the desired level of detail. Figure 2 summarizes the structure for the remainder of this report.

Figure 2. Summary of Report Structure

Section 2

- Describes the study approach and methods.

Section 3

- Discusses the team's efforts to disaggregate and analyze Tri-State's baseline forecast. That work serves as the foundation for the analysis and findings presented in the remainder of the report.

Sections 4-8

- Present sector-level findings for energy efficiency potential.

Section 9

- Presents findings for the demand response potential analysis.

Section 10

- Presents findings from the distributed energy resource (DER) potential analysis.

Section 11

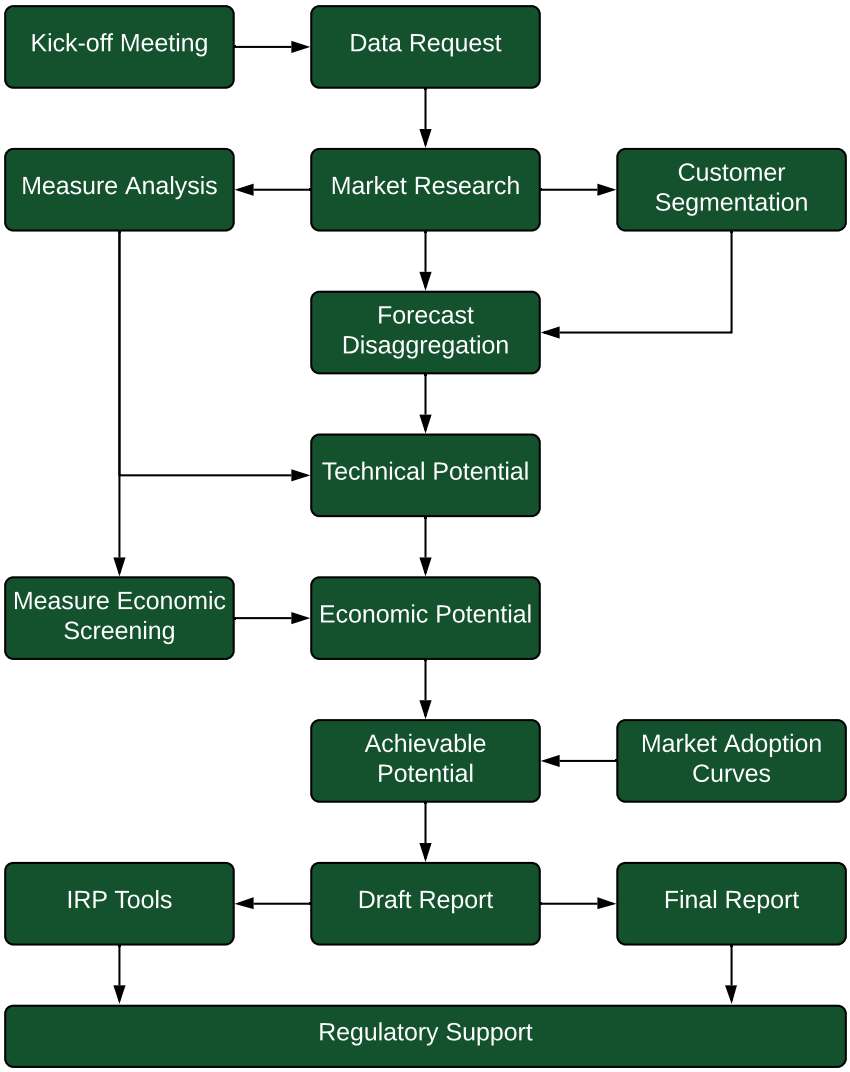
- Presents overall findings and recommendations.

2. STUDY APPROACH AND METHODS

2.1. Overview

The process shown in Figure 3 depicts the steps taken during a market potential study.

Figure 3. Approach for Demand Side Resource Potential Modeling



These steps generally apply to all three demand-side management (DSM) resources considered: energy efficiency, DR, and DER. Each step is described in detail in the sections that follow. Sections 2.2–2.4 generally apply across all three resources. Sections 2.5 and 2.6 provide additional detail for the approach and methods used for the DR and DER analyses.

2.2. Customer Segmentation and Forecast Disaggregation

An accurate assessment of achievable savings potential requires a thorough characterization of the baseline energy usage. This characterization involves the following steps:

- Determine the energy consumption per region, customer class and segment in baseline year.
- Disaggregate customer class loads into end-use loads, such as water heating.
- Analyze and calibrate data to 2018.
- Forecast the 20-year end-use energy consumption through 2040.

To complete these steps the Team relied on a large dataset consisting of:

- Information on Tri-State member cooperative customers
- Historical loads
- Market data including fuel shares, equipment saturations, and structural characteristics
- End-uses including energy use intensities and load shapes
- Measure characteristics including technologies, costs, life, and savings

These data were drawn from a combination of primary and secondary research. An overview of the steps involved in this process follows. The findings of the market characterization is presented in Section 3.

2.2.1.Customer Segmentation

To begin, the Team analyzed the portion of Tri-State's forecasted sales attributable to DSM-ineligible accounts. This included the share of the load that is served by re-sale customer or non-premise accounts. This portion of the load was removed from the load considered eligible for energy efficiency and demand reduction measures.

Next the Team determined energy and demand loads for the appropriate regions, sectors, market segments, vintages, and end-uses as follows:

- **Regions**: Sales for rural electric cooperatives were aggregated into regional definitions; including Front Range Colorado, Nebraska, North New Mexico, Wyoming, etc., as shown in Table 1.
- **Customer Sectors**: Residential, commercial, irrigation, and industrial (including agricultural)
- **Market Segments:**
  - **Commercial**: Typically based on major Commercial Buildings Energy Consumption Study (CBECS) business types.
  - **Industrial**: All major industrial segments in Tri-State service territory using NAICS classification from the Form 345 information.
  - **Residential and Irrigation**: No further segment-level breakdown

- **Vintages:** Existing and New Construction
- **End-uses:** Those shown by sector in Table 2

2.2.1.1. Primary Market Research

Primary market research guided customer segmentation. In 2012, Tri-State distributed a mail-in residential end-use survey requesting information on consumers' residence structure and energy consuming equipment type, age, fuel type, end-uses, and behavior. The survey yielded over 300 customer responses, with each cooperative providing a minimum confidence level of 90% with 10% precision for each surveyed technology at the cooperative level. This data was used to guide the disaggregation of the residential sector load.

The Team also used North American Industry Classification System (NAICS) data that provides business type data on large customers (greater than 250KW) and their associated energy consumption from the Rural Utilities Service (RUS) Form 345. Business type information for energy sales of non-residential customers less than 250KW was not available. Secondary research was necessary to estimate segmentation of business types for customers less than 250KW.

2.2.1.2. Secondary Market Research

The Team utilized secondary resources to complete the customer segmentation. Examples of these resources include the 2010 Tri-State System-Wide Electric Energy Efficiency Potential Study , United States Energy Information Administration (EIA) Residential Energy Consumption Survey (RECS)[3], the EIA Commercial Buildings Energy Consumption Survey (CBECS)[4], 2016 NorthWestern Energy End-Use and Load Profile study[5], the 2015 Platte River Power DSM Potential Study, among other references.

2.2.2.Segmentation of Regions

To accurately characterize Tri-State's large geographic service territory, the Team segmented end-use load profiles and energy efficiency potential by region. Eight (8) regions were defined based on geographic location of the co-ops[6]. Segregating the co-ops by region, instead of producing one set of potential values for all of Tri-State's territory has several advantages:

- Energy efficiency measures more accurately match building codes in each region. For example, envelope construction requirements are different depending on climate zone.

[3] *https://www.eia.gov/consumption/residential/*

[4] https://www.eia.gov/consumption/commercial/

[5] https://www.northwesternenthinkergy.com/docs/default-source/documents/etac/2017/nexant_energy_end_use_and_load_profile_study.pdf

[6] This report and the associated Reporting Tool, described in this report, utilize the regional breakdown characterized here. The Load Shape Tool, also described in this report, utilizes an adapted breakdown to accommodate for member coops that cross certain regional boundaries. This alternative breakdown of potential savings is to allow for more accurate output data for input into Tri-State's resource planning models. The adjustment reflects where coop service territory extends across eastern and western interconnects.

- Regional segmentation captures a higher resolution of equipment end-use saturation and energy intensity. For instance, direct expansion (DX) cooling in the residential sector has a higher saturation and energy intensity in southern New Mexico as compared to northern Wyoming.
- This segmenation accommodates regional cost variances for participant energy efficiency implementation or utility avoided costs.
- Barriers to achievable potential may be regionally specific.

Based on evaluation of climatic impacts, sector segmentation and end-uses, the Team developed the regional electric cooperative groups shown in Table 1.

Table 1: Tri-State Cooperative Regional Groups

EASTERN COLORADO	FRONT RANGE COLORADO	MOUNTAIN COLORADO	WESTERN COLORADO
Highline	Mountain View	Gunn County	Empire
K.C.	Poudre Valley	Mountain Parks	La Plata
Morgan County	San Isabel	White River	San Luis Valley
Southeast	United		San Miguel
Y-W			Sangre De Cristo
NEBRASKA	**SOUTHERN NEW MEXICO**	**NORTHERN NEW MEXICO**	**WYOMING**
Chimney Rock	Central NM	Cont. Divide	Big Horn
Midwest	Columbus	Jemez Mtns	Carbon
Northwest	Otero County	Mor San Miguel	Garland
Panhandle	Sierra	North. Rio Arriba	High Plains
Roosevelt	Socorro	Southwestern	High West
Wheat Belt		Springer	Niobrara
			Wheatland
			Wyrulec

2.3. End-Use Load Classification

To further disaggregate the load the Team established end-use loads within each sector.[7] Table 2 presents a summary of those end-uses.

[7] The irrigation sector is solely composed of the motor end-use.

Table 2: End-Uses for Each Tri-State Sector

RESIDENTIAL	COMMERCIAL	INDUSTRIAL
Central Air Conditioning	Cooking	Lighting
Central Heating	Cooling	HVAC
Clothes Washer	Heat Pump	Motors
Dishwasher	HVAC Aux	Pumps
Electric Cooking	Lighting	Process Heat
Electric Dryer	Plug Load	Process Cool
Freezer	Refrigeration	Pumps
Exterior Plug Load	Space Heating	
HVAC Aux	Water Heating	
Heat Pump		
Lighting		
Plug Load		
Refrigerator		
Second Refrigerator		
Room AC		
Electric Water Heater		

The primary regional inputs needed to model each end-use were the total premise count, fuel shares, end-use Unit Energy Consumption (UEC), and saturation. Expected improvements in building energy code requirements and other general trends were incorporated into the UECs based on data found in the U.S. Energy Information Administration's forecasts. In general these trends showed a decrease in all end-use UECs with the exception of plug loads, which showed an increasing trend.

2.3.1.Codes and Standards

There is uncertainty about future federal standard updates and enforcement. While the study considers current codes and standards, the analysis is not intended to predict how or when energy codes and standards will change over time. As a result, there are only limited known improvements to federal codes and standards to reasonably account for in this analysis.

The primary adjustment made in the Team's methodology impacts residential screw-in lighting. Based on the current Department of Energy final rule that did not trigger the Energy Independence and Security Act (EISA) backstop, the potential analysis does not model Tier II EISA efficiency requirements. However, the study does model the transitioning screw-based lighting market that is rapidly being

saturated with LED technology. The Team modeled this market transition by limiting the future potential for residential lighting starting in 2027. The analysis assumes only a limited number of direct-install screw-based lighting opportunities for standard, specialty, and reflector bulbs over the latter analysis period.

Although not exhaustive, the following list outlines additional key standards the Team considered:

- The baseline efficiency for air source heat pumps (ASHP) is anticipated to improve to 15 SEER/8.8 HSPF.
- The baseline efficiency for split system central AC systems is anticipated to improve to 14 SEER in 2023.
- In July 2019, the DOE makes new standards effective for more efficient furnace fan/motors. The standards are expected to improve the efficiency by approximately 45% over the current baselines. The new standard will create a shift to electronically commutated motors (ECMs).

2.4. Energy Efficiency Potential Modeling

Drawing on outcomes from of the disaggregated the Team modeled first technical, then economic, and finally achievable energy savings potential. Those steps are described in the following sections.

2.4.1. Estimate Technical Potential

Technical potential is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end-users to adopt the efficiency measures. Technical potential is only constrained by factors such as technical feasibility of measures. The model applies the measure-level inputs to the disaggregated baseline sales forecast to estimate technical savings and demand reduction potential over the planning horizon.

As an example, the core equation used in the residential sector energy efficiency technical potential analysis for each individual efficiency measure is shown in Equation 1.

Equation 1. Core Equation for Residential Sector Technical Potential



Where:

Total Number of Households *= Count of customer households in the subject region.*

Base Case Equipment Energy Use Intensity *= the electricity used per customer per year by each base-case technology in each market segment. In other words, the base case*

equipment energy-use intensity is the consumption of the electrical energy using equipment that the efficient technology replaces or affects.

Saturation Share = *the fraction of the end-use electrical energy that is applicable for the efficient technology in a given market segment. For example, for residential water heating, the saturation share would be the fraction of all residential electric customers that have electric water heating in their household.*

Remaining Factor = *the fraction of equipment that is not considered to already be energy efficient. To extend the example above, the fraction of electric water heaters that is not already energy efficient.*

Applicability Factor = *the fraction of the applicable units that is technically feasible for conversion to the most efficient available technology from an engineering perspective—i.e., it may not be possible to install a heat pump water heater in all homes due to space constraints.*

Savings Factor = *the percentage reduction in electricity consumption resulting from the application of the efficient technology*.

2.4.1.1. Measure Definitions

Once the baseline forecast is disaggregated, the next step to assessing technical market potential is to accurately detail the universe of efficiency measures and their end-use-specific savings, costs, and lifetimes. Measures currently implemented in Tri-State's and Xcel Energy's DSM programs received careful consideration since these measures have a historical record and vendors have proven processes for implementation. Additionally, our Team compiled all measures available from such sources as the Pacific NorthWest Regional Technical Forum (RTF), Xcel Energy's Demand Side Management Plan, and technical reference manuals (TRMs) from jurisdictions like the states of New Mexico, Pennsylvania, and Minnesota. The Team also leveraged measure data it has characterized in similar studies. From these regionally relevant databases, the Team selected measures that are commonly available, based on well-understood technology, and applicable to the buildings and end-uses in Tri-State's service territory. The Team also considered measures that show promise for future viability but have not yet gained a foothold in the market.

Energy efficiency measures are characterized in three main vintages:

- **Replace on Burnout:** As equipment replacements are made normally in the market when a piece of equipment is at the end of its effective useful life (also referred to as "turnover").
- **Retrofit:** At any time in the life of the equipment or building (referred to as "early-retirement").
- **New:** When a new home or building is constructed.

Upon finalizing the energy efficiency measure list, the Team collected data on energy savings, costs, lifetime, and applicability to determine potential measure impacts. This work involves a multi-step process described here.

Step 1: Define market classifications for application of measures

The Team established market classifications as a framework for documenting applicability of each measure. These classifications were based on factors including region, fuel type, sector, market segment, and end-use as defined in the disaggregated forecast (Section 2.2). Additionally, the Team further defined permutations for each measure based on the following parameters:

- **Climate Zone:** This measure research includes savings estimates for weather-dependent measures specific to ASHRAE climate zones 4 through climate zone 6
- **Measure Type:** Equipment vs. Non-equipment
- **Vintage:**
  - **Equipment** – Turnover, Retrofit, New
  - **Non**-equipment – Existing, New

Step 2: Screen sectors, segments, and end-uses for eligibility

The Team screened market segments and end-uses for applicability of specific energy efficiency measures. For example, certain commercial end-uses, such as cooking, may not be appropriate for segments such as offices and warehouses and therefore were analyzed only in limited market segments.

Step 3: Develop base case impacts and costs

The Team determined base case equipment and practices for each of the energy efficiency measures on the final list, and developed a description and rationale for each. This included all base case assumptions and data, such as state building codes (the 2012 International Energy Conservation Code (IECC) in most cases) and federal standards. Base case assumptions included projected future adjustments, such as upcoming federal standards.

Step 4: Develop energy efficiency measure impacts and costs

The Team developed a description of all energy efficiency (or "change case") measure equipment and practices, including all measure energy savings assumptions and calculation parameters, such as equivalent full load hours (EFLH). For each measure, the Team estimated energy savings as a percentage of base equipment and/or end-use consumption.

In addition to energy savings, the Team collected incremental measure costs pertinent to Tri-State's service territory from appropriate TRM references and internet retailer data and researched measure life drawing on TRM documentation.

2.4.1.2. Screw-in Lighting

The Team reviewed the residential, commercial, and industrial lighting measures and lighting end-use assumptions to incorporate recent changes to the lighting market. This included reviewing and updating savings, measure cost, saturation, and expected useful life assumptions for each lighting measure. Based on federal policy projections, the Team made the assumption that the EISA "backstop" would not be enacted beginning in 2020. Additionally, the Team characterized the lighting market to transform primarily to an LED baseline for screw-in lighting by the end of the decade.

2.4.2. Estimate Economic Potential

Economic potential represents the savings possible given full adoption of all cost-effective efficiency measures. For this study, the Team utilized the Total Resource Cost (TRC), which is commonly considered the preferred test to assess measure benefits and costs from the perspective of the utility and society as a whole. Equation 2 presents the TRC ratio equation.

The benefits in the TRC test are the net present value of the lifetime avoided energy and capacity costs. The costs in this test are the net present value incremental measure costs.

Equation 2. TRC Ratio

$$\textbf{TRC Ratio} = \textbf{NPV}(\textbf{Avoided Costs})/\textbf{NPV}(\textbf{Incremental Measure Costs})$$

Where*:*

$$\text{Avoided Cost} = \text{NPV}\left(\sum_{\text{year}=1}^{\text{measure life}}\left(\sum_{\text{i}=0}^{\text{i}=8760}(\text{impact}_{\text{i}} \times \text{avoided cost}_{\text{i}})\right)\right)$$

The **benefits** include the net present value of the energy and capacity saved by the measures along with any natural gas or other fossil fuel benefits. The forecast of electric avoided costs of energy and capacity were obtained from Tri-State and represent their most recent forecast of avoided electric benefits. The avoided costs are calculated by applying end-use-specific annual hourly load shapes to measure savings impacts and determine the time-differentiated value of energy and capacity benefits. The annual hourly load shapes were developed from industry-specific energy load profiles, and a peak definition (noon – 22nd hour in weekday summer months) was provided by Tri-State to estimate coincident peak demand.

To accurately value avoided energy savings for Tri-State, the expected losses were estimated from the customers' meters to Tri-State's generation source. These losses were calculated for each climate zone, and reflected the losses from the customer to the co-op and the losses from the co-op to Tri-State. In addition to line losses, a discount rate of 5% was applied to value future avoided costs.

The **costs** are the net present value of all costs to implement those measures. These costs include full incremental costs (both utility and participant contributions), but no incentive payments that offset incremental costs to customers and no lost revenues. The full incremental costs include single upfront costs and operational & maintenance costs where applicable. Incentives are not included, because they are transaction between the utility and customer, thus the costs and benefits negate each other. While non-incentive costs were not included in the measure-level screening of electric energy efficiency potential, they were included in further assessments of potential at the achievable potential level described below.

Additionally the social cost of carbon at $46/ton of carbon dioxide (CO_2) was incorporated as an avoided benefit in the TRC calculations. This value was escalated annually over the study time horizon based on figures provided by Tri-State.

The measure screen from technical potential to economic potential utilized a cost-effectiveness hurdle of 0.7 in order that the sector level TRC test would be closer to 1.0. This reduction in the screening threshold permits non cost-effective measures into the portfolio so that a potential program

intervention is more well-rounded and can include a limited number of non-cost-effective measures. However, the forecasted sector portfolio must have an estimated TRC greater than 1.0 when program administrative costs are included.

2.4.3.Estimate Achievable Potential

Finally, the assessment of realistically achievable energy efficiency potential required estimating, among other parameters, the rate at which cost-effective measures can be adopted over time. The Team incorporated individually developed sets of market penetration curves corresponding to implementation scenarios to account for the fact that program implementation scenarios have a direct influence over such market penetration rates. These scenarios were correlated to differing levels of urgency in program implementation, tolerance for rate impacts, macroeconomic conditions, and other situations.

The following are important components in determining achievable potential:

- **Benchmarking.** The amount of savings expected to be achievable through DSM programs will be informed by the experience of utilities across the region and nation.
- **Customers' willingness to participate.** The likelihood that customers will participate in energy efficiency programs is a function of several factors, most notably incentive level.
- **Uncertainty.** Planning requirements often necessitate a point-estimate of potential, however, this is not an accurate reflection of the reality of DSM programs. We prefer to think of achievable potential as a range, or probability distribution, where the point-estimate is the most likely outcome. This distribution defines the lower and upper bounds of expected savings, as well as the most likely value.

Achievable potential energy efficiency impacts were evaluated based on four incentive scenarios as a function of the incremental costs of efficiency measures:

- 25% "Low"
- 50% Moderate ("Mod")
- 75% Aggressive ("Agg")
- 100% Maximum ("Max")

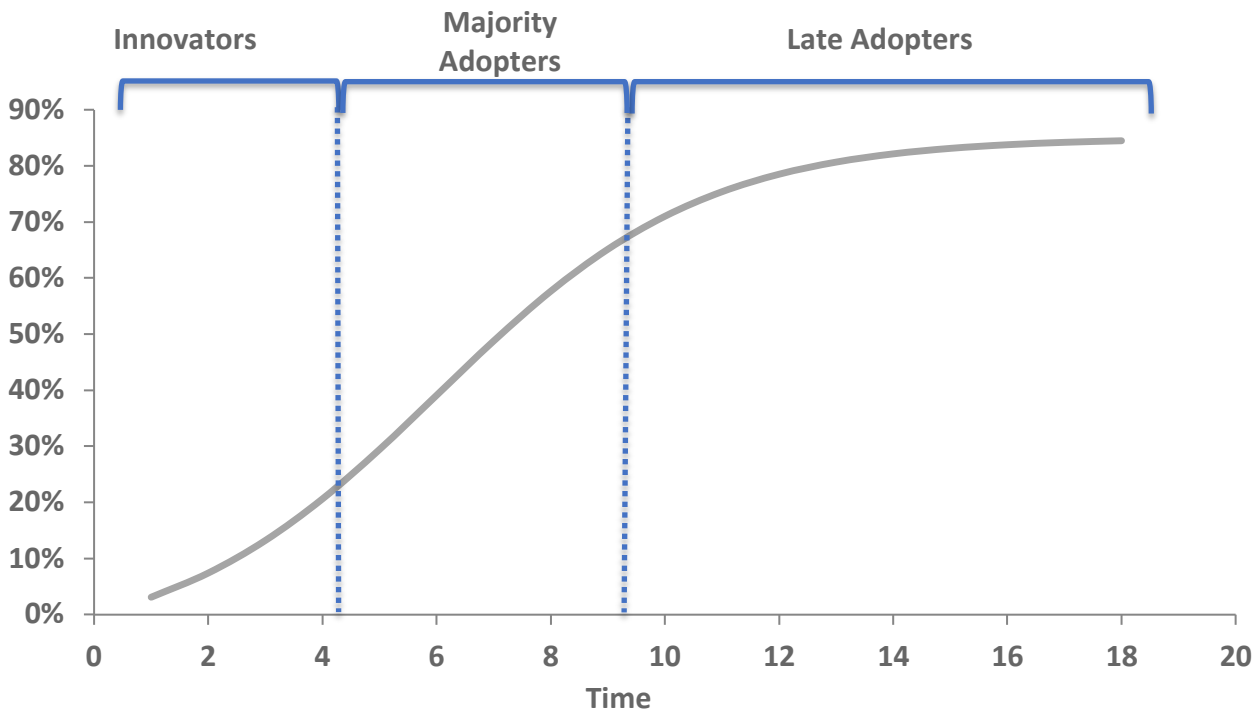
For instance, the moderate scenario approximates the market adoption achievable by incentivizing 50% of the incremental cost of the measure. Results are presented from the perspective of the Achievable Moderate scenario unless otherwise specified. This scenario represents a reasonable progression from Tri-State's current program offerings.

2.4.3.1. Market Adoption Rates

In order to characterize the rate of market adoption for each of the specified scenarios, the Team developed a quantitative approach based on a Bass Diffusion Model. This method relies on scientific theory and historic program participation data based on Tri-State experience and other DSM programs in North America.

The Bass Diffusion Model is a mathematical description of how the rate of product diffusion in a market changes over time. When the product is introduced, there is a slow rate of adoption while customers become familiar with the product. When the market accepts a product, the adoption rate accelerates to relative stability in the middle of the product cycle. The end of the product cycle is characterized by a low adoption rate because fewer customers remain that have yet to adopt the product. This concept of forecasting future adoption rates is illustrated in Figure 4.

Figure 4: Typical Product Diffusion in the Marketplace



The rate of adoption in a discrete time period is determined by external influences on the market, internal market conditions, and the number of previous adopters.

- Initial Year Measure Adoption
  - First year adoption levels were informed by recent Tri-State historical performance where possible.
- Long-Term Market Adoption Rates
  - The final adoption scores that resulted from willingness to pay surveys serve as the point-estimate for the long-term market adoption potential for the realistic achievable scenario.
- Adoption Curve Shape
  - Once the initial year adoption rate (Point A) and long-term adoption rates (Point B) are determined, the remaining step was to determine the rate and duration to get from Point A to Point B.

Unique end-use adoption curves were developed based on the following three parameters:

- **Customer Sector:** Residential, Commercial, and Industrial
- **End-Use**: Lighting, Motors, etc.
- **Incentive Level based on Achievable Scenario**: 25%, 50%, etc.

2.4.3.2. Program Costs

Finally, to capture the full cost of achievable energy efficiency potential, the Team added program non-incentive costs in the overall assessment of cost-effectiveness. Non-incentive program cost categories included: (1) Administration, (2) Marketing, (3) Technical, and (4) Measurement & Verification and Planning. Program non-incentive costs were calculated on a gross $ per first-year kWh saved. Non-incentive costs were developed for each program by sector. The included program cost assumptions are shown in Table 3.

Table 3: Summary of Non-Incentive Program Costs ($/kWh)

SECTOR	ACHIEVABLE LOW	ACHIEVABLE MOD	ACHIEVABLE AGG
Residential	$0.100	$0.115	$0.150
Commercial	$0.050	$0.058	$0.075
Industrial	$0.100	$0.115	$0.150
Irrigation	$0.050	$0.058	$0.075

2.4.4. Data Analysis and Reporting Tool

A set of dynamic analysis tools were developed to provide Tri-State staff access to the data outputs from the modeling efforts. These consist of a Reporting Tool and a Load Shape Tool specifically created for this project. The Reporting Tool summarizes and illustrates the savings potential and associated costs by sector, year, and scenario enabling the user to select results for a specific region or for the entire service territory. The results are depicted in tabular form and in associated charts that update dynamically based on the selected region.

The Load Shape Tool was developed to convert the model's annual energy savings and cost outputs into 8760 hourly load profiles for direct input into Tri-State's ERP planning tool. The tool bundles and maps measures to associated 8760 hourly load profiles to illustrate at what hours during the day and year energy savings are likely to be incurred for each bundle of measures. The tool also shows the associated levelized cost of each bundle of measures on an 8760-hourly basis. The data is represented by sector, interconnect region, scenario, and load shape bundle. This tool will allow Tri-State to compare energy efficiency resource savings and levelized costs and compare them with other supply-side and demand-side resources during its ERP development process.

2.5. Demand Response Potential Assessment

Demand response refers to the reduction of electric demand by way of altering the operation of some piece of technology or equipment. Demand response programs take several forms, but most rely on

direct control of energy-using equipment via communication infrastructure like radio or WiFi or the change in customer behavior from time-based rates.

There are a few important differences between the assessment of demand response programs and other demand-side management options, such as energy efficiency. First, demand response programs require active, ongoing participation by customers. Second, unlike energy efficiency programs, demand response is designed to shift load from peak periods of energy use to non-peak periods, which can affect the availability of service to the customer. These programs use independent concepts and technologies and not 'upgrades' in the sense that energy efficiency measures are upgrades from some similar baseline option. These programs use independent concepts or technologies and are not 'upgrades' in the sense that energy efficiency measures are upgrades from similar baseline options. Thus, demand response technologies have no incremental cost. Finally, demand response depends on a customer's willingness to participate in individual events. This willingness to participate is a function of program design, which includes the number of events, incentive levels, the stipulation of mandatory or voluntary participation, and the existence of penalties for non-compliance. Hence, estimating demand response potential involves in a number of steps. The final potential number is a product of the base peak demand, eligibility rates, technical load impact rates, program participation rates, and event participation rates.

2.5.1.Estimate Peak Demand

Coincident peak demand data was available for each of the eight regions in the Tri-State system. This system-level peak demand was divided to estimate the contributions from each sector (residential, irrigation, commercial, and industrial) by using sector energy use during the peak month relative to the system energy use during the same time period. Per premise demand estimates were generated by dividing by the number of premises in each sector.

2.5.2.Apply Eligibility Rates

Eligibility rates customized to each program were applied to the base peak demand to determine the peak load eligible to participate. For example, a Direct Load Control (DLC) program capturing residential central HVAC load will require premises to have central air conditioners, while a Smart Thermostat DR program would additionally require the residence to have broadband service and a WIFI network. Irrigation load reduction is generally limited to customers with pumping power greater than 75 horsepower. Commercial and industrial customers in a capacity bidding program typically need to have a peak demand of greater than 250 kW.

2.5.3.Estimate Technical DR Potential

Technical potential for demand response is the theoretical maximum level of peak demand that could be curtailed through DR programs. This scenario disregards non-engineering constraints such as cost-effectiveness and willingness of end-users to enroll. All eligible customers are modelled as if enrolled in one or more DR programs and participating in DR events.

In the Technical Potential scenario, care must be taken to avoid double-counting participation in programs that affect the same end-uses. For example, a customer cannot be modelled as curtailing its HVAC load in both a DLC program and a rate program during the same event. We applied a hierarchy of

demand response programs for each sector based on Tri-State's unique market position, as shown in Table 4.

Table 4. Demand Response Programs Applied by Sector

RESIDENTIAL	AGRICULTURAL	COMMERCIAL	INDUSTRIAL
Smart Devices	Direct Load Control	Capacity Bidding	Capacity Bidding
Behavioral	Time Varying Rates	Smart Devices	Time Varying Rates
Direct Load Control		Direct Load Control	
Time Varying Rates		Time Varying Rates	

2.5.4. Estimate Economic DR Potential

Economic potential is a subset of technical potential that is economically cost-effective. A full cost-benefit analysis was conducted for each DR program incorporating Tri-state's avoided energy and capacity costs, program start-up costs, on-going administrative costs, equipment costs for the program and the participant, and discount rates.

Resource acquisition costs fall into one of two categories. Fixed costs include program start-up, infrastructure, maintenance, administration, and data acquisition. Variable costs include hardware costs, which vary by the number of customers, and incentive costs, which can vary by number of customers or kW reduced.

Fixed and variable costs were estimated for each program type according to comparable programs implemented by other utilities or other potential studies. In cases where published cost information could not be found, the Team used assumptions based on other comparable program data points. The Team also incorporated a multiplier of 8 into start-up costs and administration costs, to represent the complexity of managing a program with multiple co-op partners. This analysis assumes a cost of $640,000 or more to start a demand response program. Lower costs were incorporated for time-vary rates programs - $100,000 for start-up and $23,000 per year for administration. Lower costs were also assumed for some commercial programs where commercial participation could be assumed as an addition to an existing residential program. All programs were assumed to require an annual evaluation at a cost of $50,000. Average hardware, communication, and incentive levels were estimated based on published values from other utilities or studies.

Program cost assumptions are summarized in Table 5.

Table 5. Demand Response Program Cost Assumptions

SECTOR	PROGRAM	START-UP	ADMIN	EVAL	MARKETING	EQUIP
Residential	Smart Tstat	$640k	$538k/yr	$50k/yr	$50/signup	$0
	Smart Water Heater	$665k	$543k/yr	$50k/yr	$50/signup	$175
	DLC Central AC	$665k	$543k/yr	$50k/yr	$50/signup	$225
	DLC Room AC	$665k	$543k/yr	$50k/yr	$20/signup	$50
	DLC Pool Pump	$665k	$543k/yr	$50k/yr	$20/signup	$200
	CPP no tech	$100k	$23k/yr	$50k/yr	$25/signup	$200
	Time of Use	$100k	$23k/yr	$50k/yr	$25/signup	$200
	Behavioral	$640k	$7/meter	$50k/yr	$0	$0
Irrig-ation	DLC	$665k	$862k/yr	$50k/yr	$63/premise	$500
	CPP no tech	$100k	$23k/yr	$50k/yr	$25/signup	$200
	Time of Use	$100k	$23k/yr	$50k/yr	$25/signup	$200
Commer-cial	Capacity Bidding	$640k	$184k/yr	$50k/yr	$50/premise	$0
	Smart Tstat	$128k	$107k/yr	$50k/yr	$50/signup	$0
	DLC Water Heater	$128k	$107k/yr	$50k/yr	$50/signup	$175
	DLC Room AC	$665k	$543k/yr	$50k/yr	$20/signup	$50
	CPP no tech	$100k	$23k/yr	$50k/yr	$25/signup	$200
	Time of Use	$100k	$23k/yr	$50k/yr	$25/signup	$200
Indust-rial	Capacity Bidding	$640k	$184k/yr	$50k/yr	$50/premise	$0
	CPP no tech	$100k	$23k/yr	$50k/yr	$25/signup	$200
	Time of Use	$100k	$23k/yr	$50k/yr	$25/signup	$200

2.5.5.Estimate Achievable DR Potential

The Team applied program participation rates to economic potential to incorporate each sector's willingness to participate in demand response programs. This participation rate is expressed as a percentage of eligible customers. As it takes some time for a utility to fully implement a demand response program, program participation rates are assumed to reach a mature participation rate after 10 years.

Combining economic potential with program and event participation rates yields "achievable potential," or the load that can reasonably be reduced during any one event for a certain program. The Team modeled two achievable potential scenarios for demand response to illustrate the impacts of varying incentive levels to drive program participation. Adoption for both scenarios were selected based on achieved participation rates from similar program types in other jurisdictions.

- 'High' scenario represents best-in-class participation for programs with non-mandantory (opt-in) enrollment
- 'Low' scenario represent more typical or 'average' participation rates from the body of similar programs.

Steady-state participation rates are summarized in Table 6 for each achievable scenario.

Table 6. Demand Response Program Achievable Scenario Participation Rates

SECTOR	PROGRAM	ACHIEVABLE HIGH	ACHIEVABLE LOW
Residential	Smart Tstat	59%	20%
	Smart Water Heater	59%	20%
Irrigation	DLC	48%	15%
	CPP no tech	18%	8%
Commercial	Capacity Bidding	20%	10%
	Smart Tstat	20%	8%
	CPP no tech	18%	8%
Industrial	Capacity Bidding	20%	10%
	CPP no tech	18%	8%

The results of the approach described in this section are presented in Section 9.

2.6. Behind-the-Meter Distributed Energy Resource Potential Assessment[8]

For the purposes of this report, distributed energy resources is defined as equipment installed at customer premises behind-the-meter that generates electricity. This study reviewed the potential for end users of Tri-State's electricity to install and operate these types of resources.

The DER potential study followed the same method as energy efficiency potential in that the DER assessment reviews the opportunity for technical, economic, and achievable potential. The analysis limited resources for this potential assessment study to technologies that are behind-the-meter and owned by the customer. The analysis did not consider market potential for supply-side resources within this assessment. The market potential assessment for DERs focused on solar photovoltaic (PV) systems across Tri-State's region for the period 2021 to 2040, because it was the most probable technology to be cost effective and applicable to Tri-State's territory. We performed review and preliminary cost screens for potential DER technologies such as combined heat and power and small wind but did not find these technologies to be applicable and/or cost-effective.

2.6.1. Estimate Technical DER Potential

The technical potential of a DER is the amount of energy that can be generated at a customer's site behind the meter.

Photovoltaic systems utilize solar panels, a packaged collection of photovoltaic cells, to convert sunlight into electricity. A system is constructed with multiple solar panels, a DC/AC inverter(s), a racking system to hold the panels, and electrical system interconnections. These systems are often roof-mounted and face south-west, south, and/or, south-east.

The study analyzed the potential associated with roof-mounted systems installed on residential and non-residential sector buildings. For the non-residential sector, the analysis estimated potential for ground mounted (or covered parking) systems for a few specific business types such as municipal

[8] Actual results for DER analysis are not included in this draft report pending gathering of additional information

facilities, parking enclosures, and some manufacturing facilities. The analysis also included battery storage as an additional configuration with each solar PV system type. This study did not explore the market potential associated utility-scale solar PV installations.

The approach to estimating technical potential required calculating the total square footage of suitable rooftop area within Tri-State's territory and calculating solar PV system generation based on building and regional characteristics. Technical potential is computed using Equation 3.

Equation 3: Solar PV Technical Potential Calculation

$$\boldsymbol{PV\ Technical\ Potential} = \boldsymbol{\Sigma}(\boldsymbol{Suitable\ Rooftop\ Square\ Footage} \times \boldsymbol{PV\ System\ Generation\ per\ Sq.Ft.})$$

The two key parameters in Equation 3 were estimated based on multiple data sources relevant to Tri-State's territory. A discussion of methods for defining these parameters follows.

The Team estimated total rooftop square footage using the forecast disaggregation analysis to characterize the existing and new residential and non-residential building stocks. The building stocks were characterized based on relevant parameters such as number of facilities, average number of floors, average premise consumption, and premise EUI by region. The Team used these parameters to estimate the total rooftop square footage for each Tri-State region.

To estimate the fraction of the total roof area that is suitable for rooftop solar PV, the Team relied on research completed by the National Renewable Energy Laboratory (NREL). NREL has developed estimates of the portion of total rooftops across the country that are suitable for solar PV based on analysis of LIDAR data. NREL criteria for suitable roof area include:

- **Contiguous rooftop area size:** Rooftops with fewer than 10 square meters of contiguous roof area excluded.
- **Rooftop orientation (tilt and azimuth):** Northeast through northwest orientation and roof pitches greater than 60 degrees excluded.
- **Shading:** Roof areas that had a minimum solar exposure of less than 80% relative to an unshaded roof were excluded.

Based on NREL's data, the Team was able to apply unique suitability factors to estimate the total square footage of suitable rooftop for residential and non-residential buildings for each Tri-State region. The Team further adjusted the total suitable rooftop square footage by accounting for existing systems. Data on existing systems was captured from Google's Project Sunroof and applied to the NREL suitability factors.

The second key parameter – PV system generation – was estimated by developing standardized solar PV system configurations. These included system sizes for residential premises ranging from 3 to 20 kW (DC) and 10 to 2,000 kW (DC) for non-residential premises. Additionally, the Team selected battery system sizes for each solar PV system size to dispatch energy for 2-4 hours during low and/or non-generation time periods.

The Team relied on NREL's PVWatts[9] (Version 6) and System Advisor Model (SAM)[10] tools to estimate system generation for both residential and non-residential sited systems. These tools model PV power density based on site specific data from NREL's LIDAR-based NSRDB to estimate total solar irradiance in conjunction with PV system specifications. The PV system simulations were generated for various cities within each Tri-State region. The Team based assumptions for PV system azimuth on rooftop orientation data sourced from Google's Project Sunroof. For the analysis the following assumptions are summarized in Table 7.

Table 7: Key Assumptions in Solar PV Analysis

PARAMETER	ASSUMPTIONS
Residential System Sizes (Nominal DC Capacity)	3 kW, 5 kW, 7.5 kW, 10 kW, 15 kW, 20 kW
Non-Residential System Sizes (Nominal DC Capacity)	10 kW, 15 kW, 20 kW, 25 kW, 50 kW, 100 kW, 250 kW, 500 kW, 1,000 kW, 2,000 kW
System losses	14.1%
Tilt	By region
Azimuth:	By region
DC to AC size ratio	1.2
Inverter efficiency	96% (micro-inverter)
Battery Round-Trip Efficiency	85%
Technology Useful Life	20 years

Based on the simulations and resulting capacity factors for residential and non-residential buildings for each Tri-State region, we applied the capacity factor to the system size and multiplied by 8,760 to estimate annual electricity generation. These system generation values were used to calculate total energy generation per square foot of rooftop and extrapolated based on the total suitable rooftop square footage to estimate overall all technical potential.

2.6.2. Estimate Economic DER Potential

As discussed in Section 2, economic potential represents the savings possible given full adoption of all cost-effective efficiency measures according to the Total Resource Cost (TRC) test or other commonly used tests. For the cost effectiveness analysis on solar PV, the Team set a TRC hurdle of 1.0[11]. To estimate economic potential for solar PV, we gathered pertinent data on system costs along with calculated generation benefits to use in the benefit-cost analysis which we conducted at the system measure level. The Team screened solar PV measures with an assumed program administration cost of $0.05 per kWh generated.

9 PVWatts estimates solar PV energy production and costs. Developed by the National Renewable Energy Laboratory. (NREL) *http://pvwatts.nrel.gov/*

10 SAM estimates houlry solar PV energy production and costs with more detailed inputs and outputs than PVwatts. Developed by the National Renewable Energy Laboratory. (NREL) *http:// https://sam.nrel.gov/*

11 The TRC hurdle is higher than the hurdle used for the energy efficiency study as the solar PV systems have a much more homogenous benefit-cost profile relative to the portfolio of diverse energy efficiency measures that when combined elevated the overall TRC ratio for the portfolio.

The Team relied on multiple data sources to determine the solar PV system costs for the system sizes and configurations mentioned above. We assessed system component costs based on data included in the National Renewable Energy Laboratory's (NREL) Q1 2018 Benchmarking report[12] which provided detailed cost information on modules, inverters (by technology), structural and electrical balance of system, supply chain, permitting-inspection-interconnection, marketing, overhead, and profit. We adjusted cost parameters from a national level to Tri-State region-specific values by using various market data provided by Energy Sage[13] for residential cost estimates and the Lawrence Berkeley National Laboratory Tracking the Sun[14] data for non-residential cost estimates. This analysis produced an estimated installation cost per watt installed which we applied to various system sizes to estimate total installed cost. Additionally, the Team included O&M costs that scale with system size. Finally, we assumed the impact of the federal investment tax credit (ITC) to follow the existing schedule at the time of this report which equates to a 10% tax credit for commercial systems by 2022 and a 0% tax credit for residential systems by 2022.

In addition to modeling solar PV system costs, the Team estimated cost impacts for solar PV systems coupled with battery storage. Because these systems are far less prevalent in both residential and non-residential systems at the time of reporting, fewer published data on battery costs, balance of system costs, and maintenance were available. Moreover, the battery capacity is also variable based on the service need. Ultimately, multiple data sources were used to assume an overall capital cost per kWh based on a 3- or 4-hour battery for various measure permutations. O&M costs were largely defined by a ten-year amortized battery replacement cost.

Table 8: Average Solar PV Installation Cost

SECTOR	SYSTEM COST ($/ DC W)[1]
Residential	$3.22
Residential (Battery)	$4.88
Non-Residential (<250 kW)	$2.73
Non-Residential (<250 kW w/ Battery)	$3.52
Non-Residential (≥250 kW)	$1.50
Non-Residential (≥250 kW w/ Battery)	$1.87
Operations & Maintenance	$10-$15/kw/yr
Operations & Maintenance w/Battery	$24-$76/kw/yr

[1]Costs reflect impact of federal investment tax credit and are averages across regions. Analysis uses region-specific costs.

[12] Fu, R, et. al., U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018. NREL, November 2018.

[13] Energysage Solar Marketplace Intel Report, H2 2018 – H1 2019.

[14] Barbose, G. and Darghouth, N., Tracking the Sun. Lawrence Berkeley National Laboratory. October 2019.

2.6.3. Estimate Achievable DER Potential

The approach to assessing achievable potential for solar PV follows the same logic and methods as outlined in Section 0. Similar to the energy efficiency analysis, the Team defined adoption curves based on a Bass diffusion model. The data informing the adoption curves were based on two key parameter inputs:

- Maximum estimated number of buildings suitable for solar
- Adoption rates based on customer willingness to participate

The Team estimated the first parameter based on the count of buildings suitable for solar PV measures. For example, if a 7.5 kW solar PV measure passed cost effectiveness, the total count of applicable buildings is defined as residential buildings that do not consume more than the total annual generation of the PV system and have sufficient rooftop area to support a system of that size. The second parameter of customer adoption is based on secondary data collected from the Midwest that surveyed residential and non-residential customers' willingness to install solar PV on their home or facility with varying incentive levels. Residential customers were asked their willingness to install based rebate values that covered a percent of the total system cost while non-residential customers were asked their willingness to install based on number of years of payback. With these parameters defined, the Team developed Bass diffusion curves to approximate adoption at various incentive levels. Innovation and imitation coefficients were defined based on state-specific research conducted by NREL[15].

3. MARKET CHARACTERIZATION & BASELINE FORECAST FINDINGS

3.1. Overview

As outlined in Section 2, the analysis of theoretically achievable savings potential requires an accurate characterization of the baseline energy usage and customer characterization. This section summarizes the market and end-use characterization including Tri-State's energy usage by sector, region, and end-use. Tri-State's 2018 electricity sales to member cooperative customers were found to be 14,974 GWh with distribution of sales by customer sector shown in Figure 5, sales by region in Figure 6, and finally with detail conjoined by customer sector and region included in Figure 7.

[15] Sigrin, B, et. al. The Distributed Generation Market Demand Model (dGen): Documentation. National Renewable Energy Laboratory. February 2016.

Figure 5. 2018 Energy Sales by Customer Sector

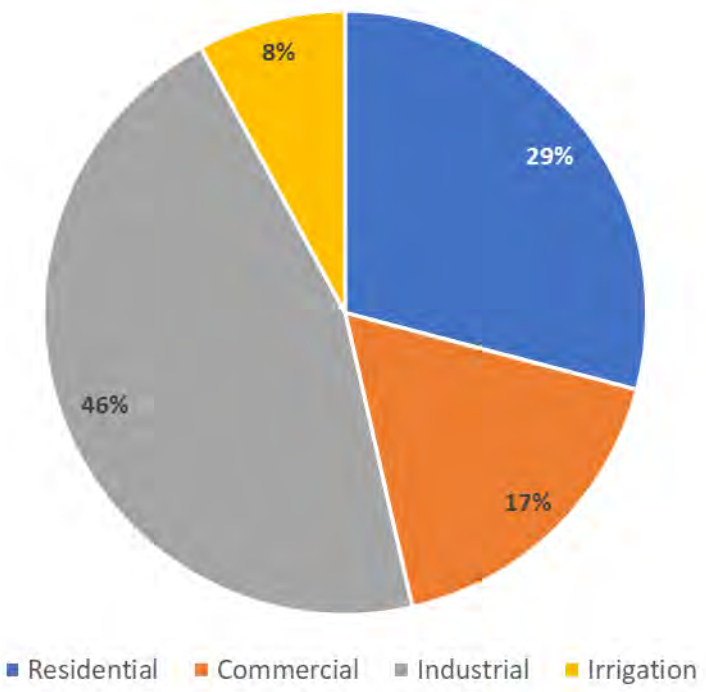


Figure 6. 2018 Energy Sales by Region

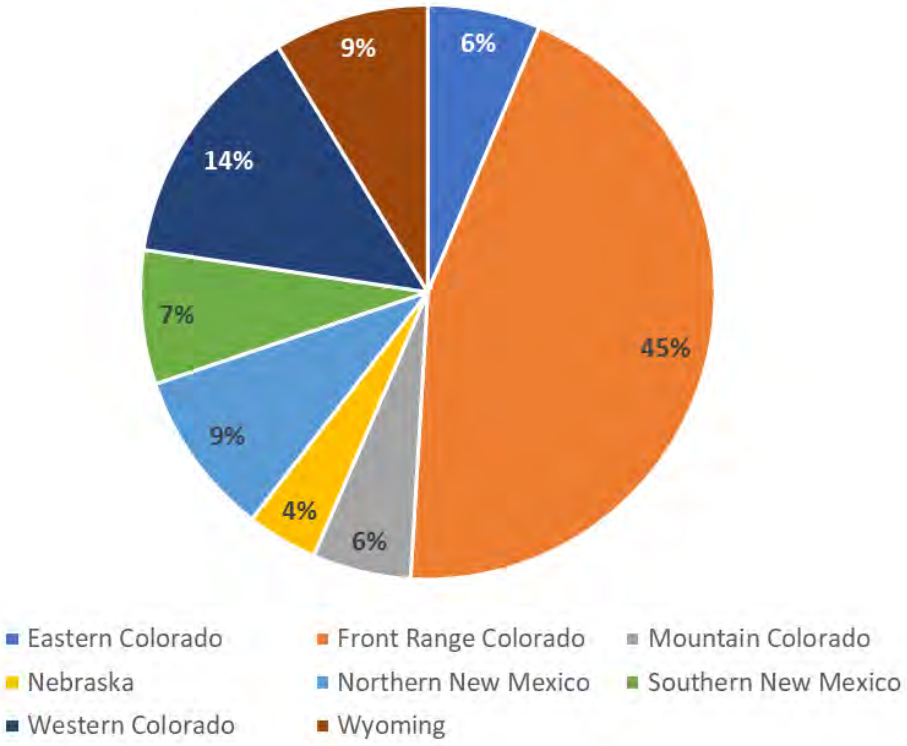
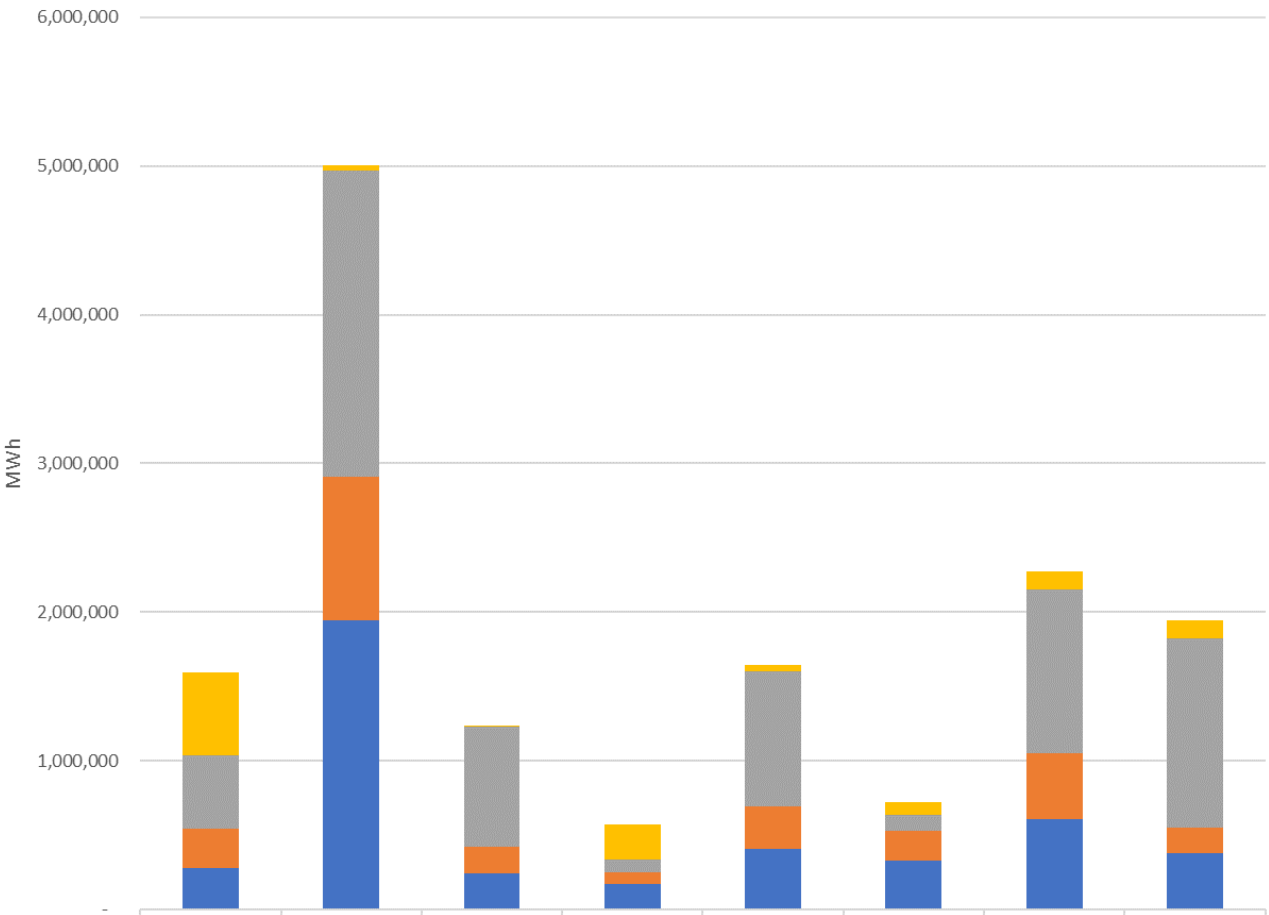


Figure 7. 2018 Energy Sales by Customer Sector and Region



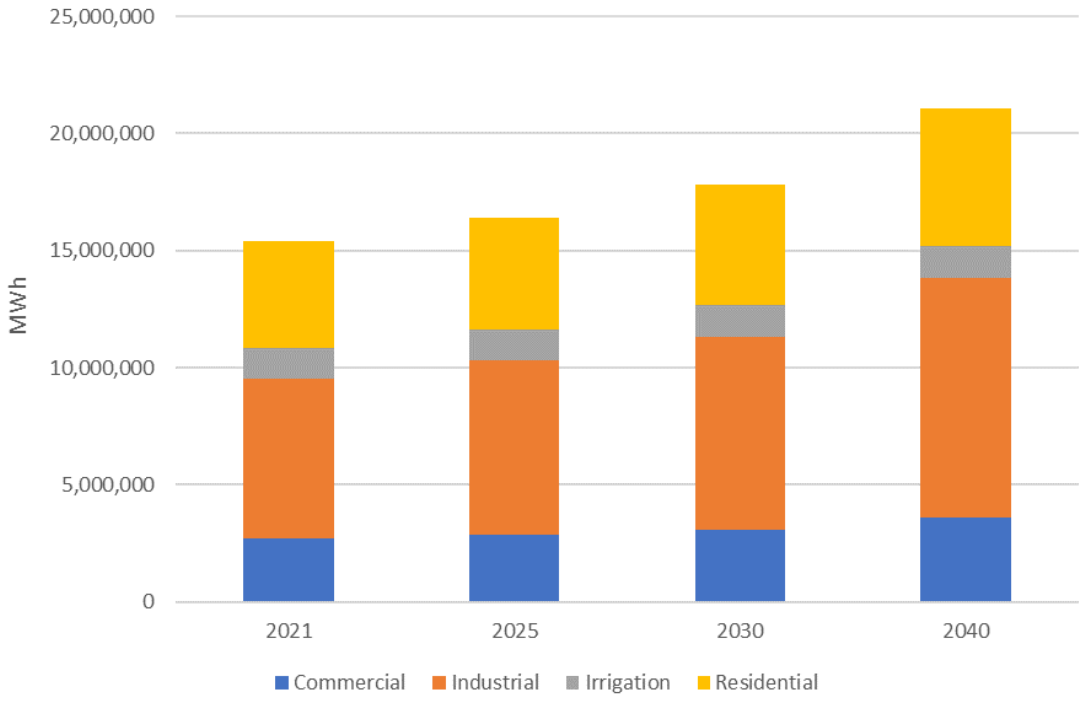
	Eastern Colorado	Front Range Colorado	Mountain Colorado	Nebraska	Northern New Mexico	Southern New Mexico	Western Colorado	Wyoming
Irrigation	554,724	31,967	861	237,972	41,763	85,091	116,352	119,890
Industrial	494,719	2,061,346	814,705	79,803	903,438	107,893	1,104,101	1,268,084
Commercial	268,177	964,547	176,453	78,733	289,986	197,934	444,417	173,590
Residential	276,257	1,944,118	241,514	173,762	406,734	328,318	606,582	380,071

The industrial sector comprises a very large share of the energy load (46%). Energy use in this sector is predominately focused around the oil, gas, and mining industries, as described further in section 4.3. Conversely, the commercial sector share, at 17%, is lower than other electric utilities that serve metropolitan communities and typically have a commercial sector share closer to 40 to 50% of all energy sales. Tri-State's relatively low commercial sector values reflect the fact that many of the member cooperatives do not serve the city and town customers within their service territories. Municipal electric utilities are common for many rural towns within western Nebraska, eastern Colorado, and most of Wyoming. Eastern Colorado and Nebraska regions have significant shares of their overall electricity sales in the irrigation sector.

Figure 8 presents the baseline load forecast at key milestone points during the analysis period. The industrial sector will see the largest amount of load growth, increasing by approximately 50% by 2040.

Commercial and residential sector load will each increase by approximately one-third. The load growth estimate for the irrigation sector is negligible.

Figure 8. Baseline Load Forecast by Sector by Milestone Year

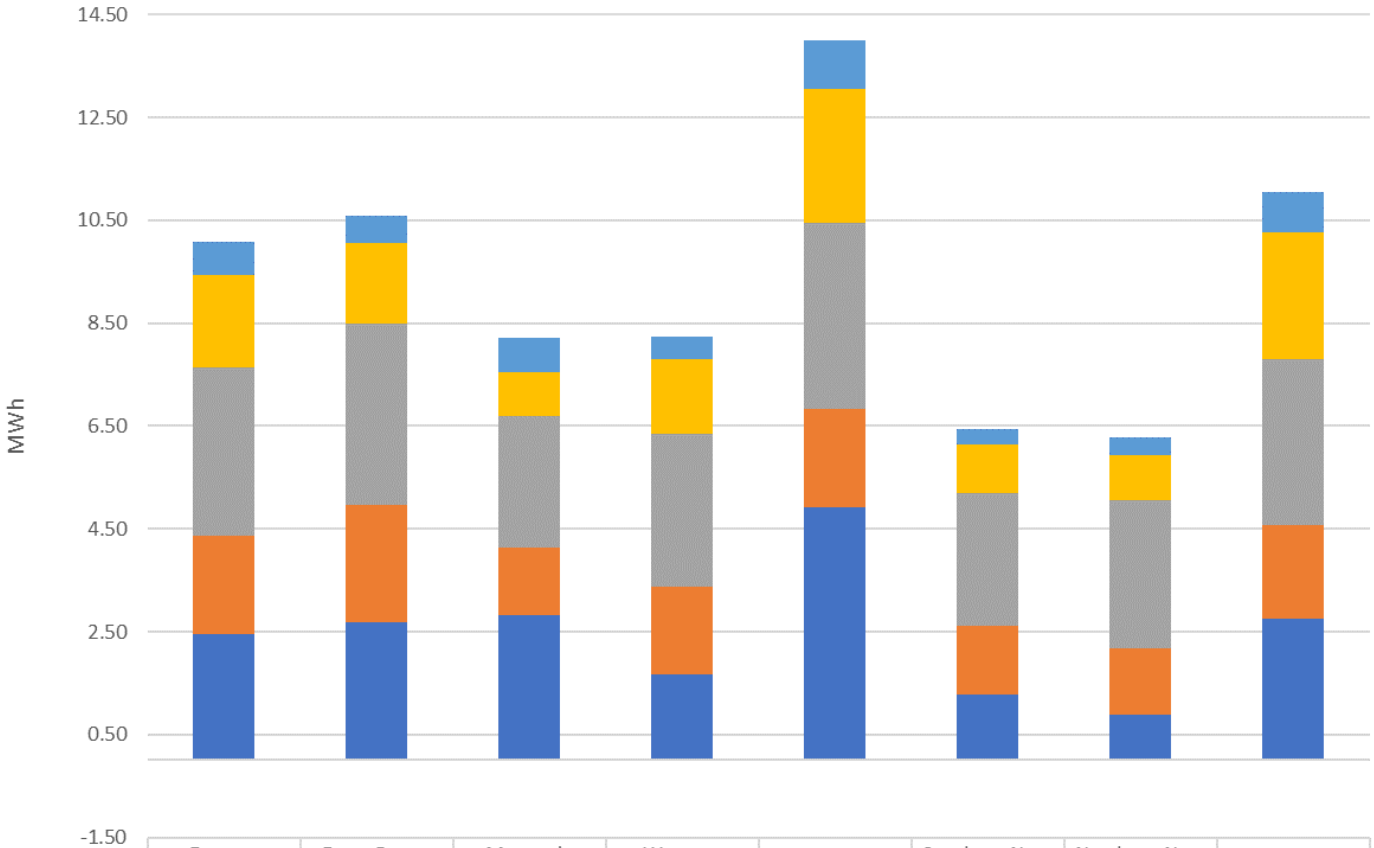


3.2. Residential End-Uses and Loads

The residential sector is responsible for 4,357 GWh of electric consumption, includes approximately 470,000 unique residential dwellings and accounts for 29% of Tri-State's total electricity sales. Average per dwelling energy usage was in line with an annual consumption of 9,260 kWh per home. Based on the limited information available to segment single-family, multi-family, and/or manufactured homes energy use or equipment saturations, it was determined that the existing residential sector should be analyzed in its entirety with no sub-sectors analyzed.

There are notable variations in average home size, average annual energy consumption, and equipment saturations across the different regions as shown in Figure 9.

Figure 9. Average Annual End-Use Consumption per Residence by Region (2018)



	Eastern Colorado	Front Range Colorado	Mountain Colorado	Western Colorado	Nebraska	Southern New Mexico	Northern New Mexico	Wyoming
Water Heat	653	540	668	444	955	298	334	785
Plug Load	1,786	1,569	865	1,441	2,590	948	887	2,478
Appliances	3,279	3,527	2,557	2,972	3,621	2,564	2,868	3,225
Lighting	1,919	2,280	1,308	1,718	1,909	1,356	1,290	1,810
HVAC	2,443	2,674	2,818	1,662	4,928	1,269	890	2,757

The Team utilized the 2012 Tri-State residential end-use survey to compile end-use saturations and average residential premise square footage as in Table 9.

Table 9: Tri-State End-Use Saturations per Region

END-USE	EASTERN COLORADO	FRONT RANGE COLORADO	MOUNTAIN COLORADO	WESTERN COLORADO	NEBRASKA	SOUTHERN NEW MEXICO	NORTHERN NEW MEXICO	WYOMING
Central Heating	13.2%	16.0%	22.7%	15.6%	25.5%	8.4%	6.3%	15.4%
HVAC Aux	67.9%	91.7%	78.3%	78.6%	72.6%	57.5%	39.4%	71.8%
Room AC	18.1%	6.9%	1.8%	5.8%	23.3%	11.3%	11.8%	16.1%
Evap Cooler	12.2%	10.2%	1.6%	17.3%	10.2%	33.4%	10.2%	12.2%
Central Air	44.8%	49.9%	1.4%	7.4%	44.6%	19.7%	12.5%	26.3%
Heat Pump	4.2%	3.9%	0.2%	1.2%	14.4%	2.6%	2.6%	2.0%
Interior Lighting	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Exterior Lighting	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Electric Cooking	56.4%	70.2%	65.8%	54.1%	71.3%	38.8%	71.0%	64.6%
Washer	81.1%	94.0%	79.8%	89.5%	89.6%	82.3%	76.8%	86.2%
Electric Dryer	75.3%	83.7%	67.5%	69.5%	85.6%	67.7%	61.3%	80.8%
Dish Washer	67.9%	91.7%	78.3%	78.6%	72.6%	57.5%	39.4%	71.8%
Electric Water Heater	29.7%	20.3%	40.9%	31.4%	53.7%	25.7%	25.8%	44.7%
Refrigerator	84.5%	96.1%	93.3%	94.3%	91.1%	90.6%	91.5%	89.1%
Second Refrig	23.4%	24.5%	14.1%	14.8%	27.5%	16.6%	14.6%	21.8%
Freezer	69.1%	62.6%	40.6%	54.3%	77.0%	53.6%	58.5%	72.0%
Exterior Plug Loads	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Plug Loads	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

The saturations of 'plug loads' and 'lighting' are both 100% by definition. Therefore, the contribution of these end-uses to the overall energy usage is driven by the unit energy consumption (UEC) and by the prevalence of certain equipment within the end-use category.

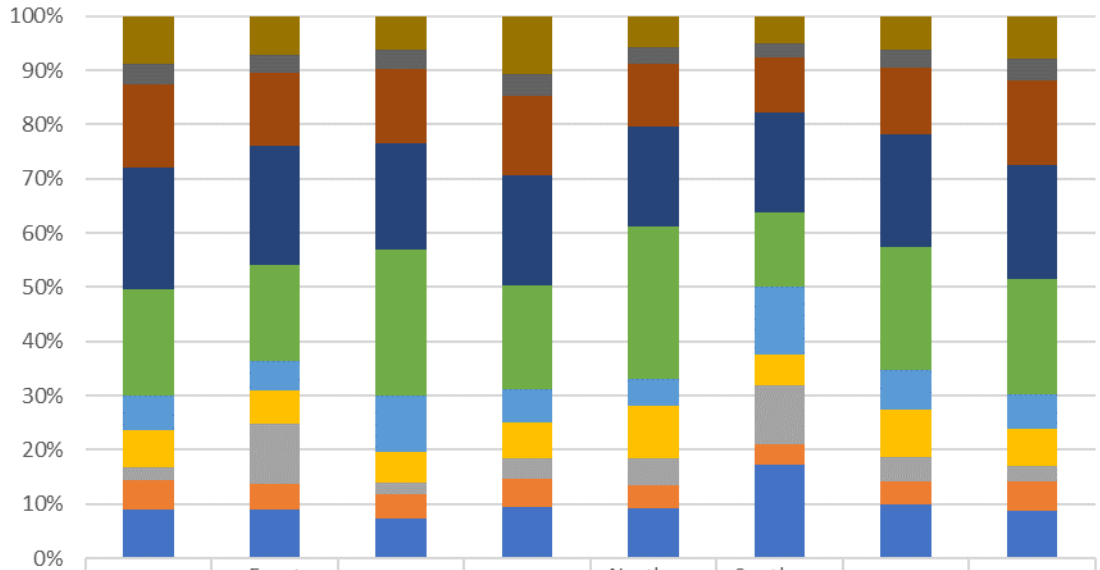
The analysis finds lower appliance saturations and smaller premise square footage for the New Mexico region residences. As expected, there is a higher prevalence of electric space and water heating in the colder climates of mountain Colorado, Nebraska, and Wyoming due to the lack of available natural gas in the rural environment.

3.3. Commercial End-Uses and Loads

The commercial sector is responsible for 2,594 GWh of electric consumption, which accounts for 17% of Tri-State's total electricity sales. In general, the commercial sector covers a large spectrum of customers, usually smaller in size as compared to the remainder of the non-residential customers, with 71% having a peak demand less than 250 kW.

Since the Team only had business type data for large commercial/industrial customers over 250KW, an analysis step was to segment the remainder of customers into distinct commercial business types. Assumptions largely based on secondary data used in this segmentation analysis were checked in the load calibration analysis of the end-use profile.

Figure 10. Commercial Sector Energy Shares by Business Segment and Region (2018)



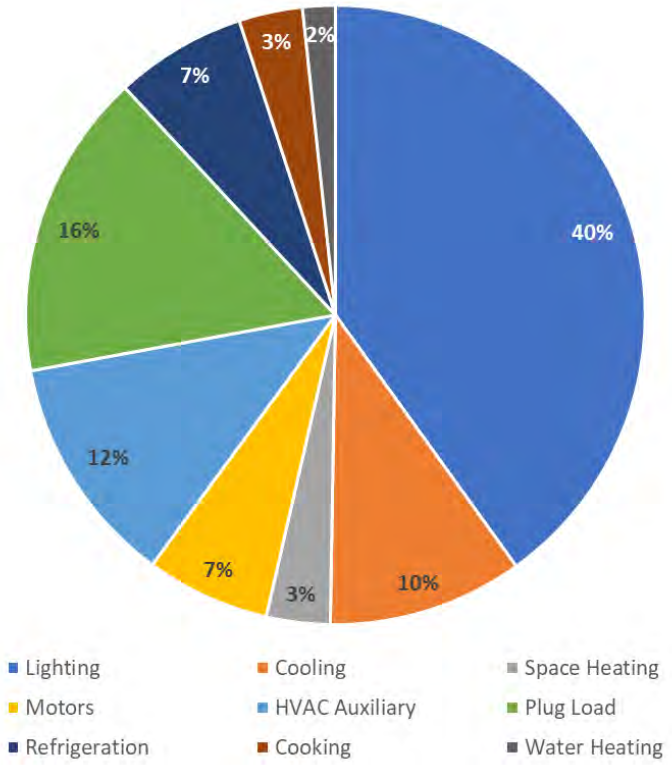
	Eastern Colorado	Front Range Colorado	Mountain Colorado	Nebraska	Northern New Mexico	Southern New Mexico	Western Colorado	Wyoming
Warehouse	9%	7%	6%	11%	6%	5%	6%	8%
Restaurant	4%	3%	3%	4%	3%	3%	3%	4%
Office	15%	13%	14%	15%	12%	10%	12%	15%
Retail	22%	22%	20%	20%	18%	18%	21%	21%
Miscellaneous	20%	18%	27%	19%	28%	14%	23%	21%
Lodging	6%	6%	10%	6%	5%	13%	7%	6%
Health	7%	6%	6%	7%	10%	5%	9%	7%
Government	2%	11%	2%	4%	5%	11%	4%	3%
Grocery	5%	5%	5%	5%	4%	4%	4%	6%
Education	9%	9%	7%	9%	9%	17%	10%	9%

The Team next identified the appropriate energy usage intensity (EUI), or end-use energy consumption per square foot, for each end-use studied. These EUIs were calculated based on other applicable

regional commercial end-use studies, such as those found in Wyoming, Montana, Utah, Colorado, New Mexico, and Iowa. Figure 11 summarizes the energy consumption for each end-use.

Lighting makes up forty-five percent of the total electricity consumption, which is attributable to the fact that this end-use is common in all sub-sectors and does not have any seasonal operation. Lighting is followed by HVAC Auxiliary which included fans, pumps, motors, and electronics used to move or control HVAC air and water systems.

Figure 11. Commercial Energy End-Use Consumption Shares

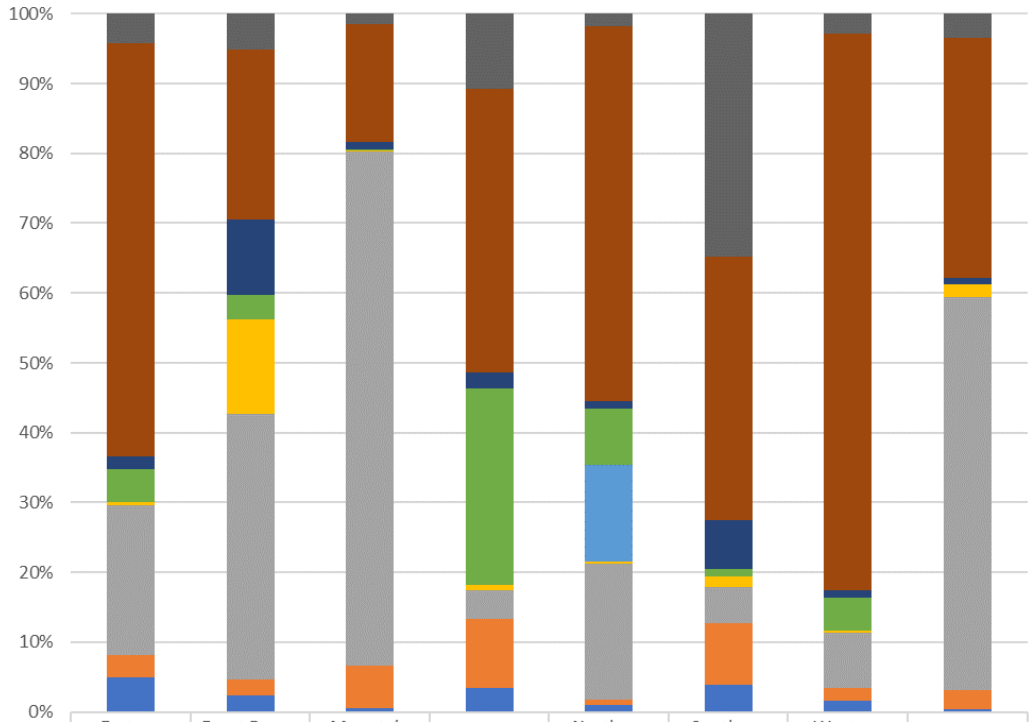


3.4. Industrial End-Uses and Loads

Industrial is the largest sector, accounting for 6,834 GWh of electric consumption and 46% of Tri-State's total electricity sales. In general, Tri-State's industrial sector is unique since approximately 77% of the sector's consumption is from the oil and gas industry and less than 15% is from manufacturing industries (Figure 12).

Since the Team only had business type data for large commercial/industrial customers over 250KW, an analysis step was to segment the remainder of customers into distinct industrial business types. Assumptions used in this segmentation analysis were checked in the load calibration analysis of the end-use profile.

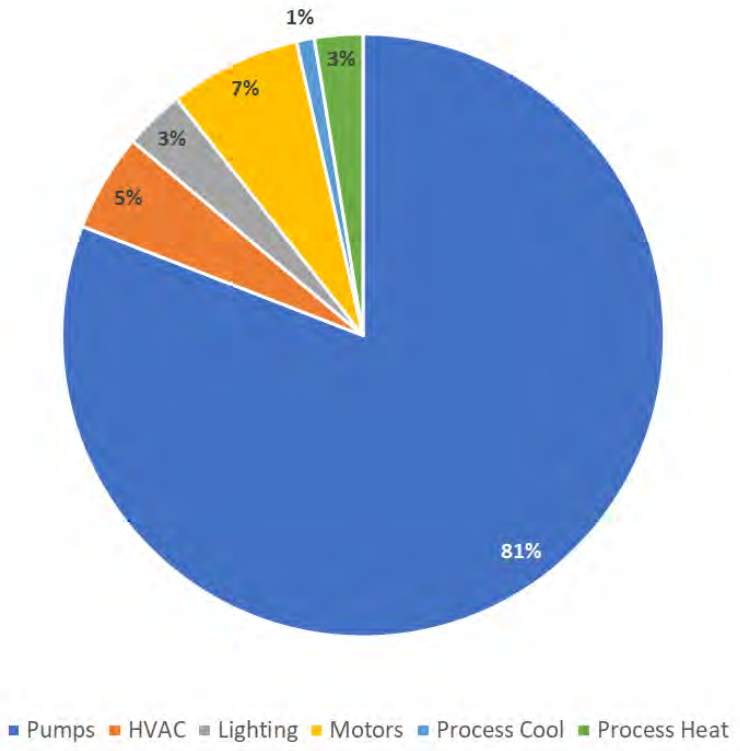
Figure 12. Industrial Sector Energy Shares by Business Segment and Region (2018)



	Eastern Colorado	Front Range Colorado	Mountain Colorado	Nebraska	Northern New Mexico	Southern New Mexico	Western Colorado	Wyoming
TCU	4%	5%	1%	11%	2%	35%	3%	4%
Pipeline Transportation	59%	24%	17%	41%	54%	38%	80%	34%
Mfg - Misc.	2%	11%	1%	2%	1%	7%	1%	1%
Mfg - Chemical	5%	3%	0%	28%	8%	1%	5%	0%
Mfg - Paper	0%	0%	0%	0%	14%	0%	0%	0%
Mfg - Nonmetallic Mineral Product	0%	13%	0%	1%	0%	2%	0%	2%
Liquid Mining (Oil, Gas, and Carbon Dioxide)	22%	38%	74%	4%	19%	5%	8%	56%
Mining	3%	2%	6%	10%	1%	9%	2%	3%
Agriculture	5%	2%	1%	3%	1%	4%	2%	0%

The Team identified the appropriate energy usage fraction for each industrial end-use studied. These energy end-use shares were calculated based on other applicable regional and national industrial end-use studies (Figure 13).

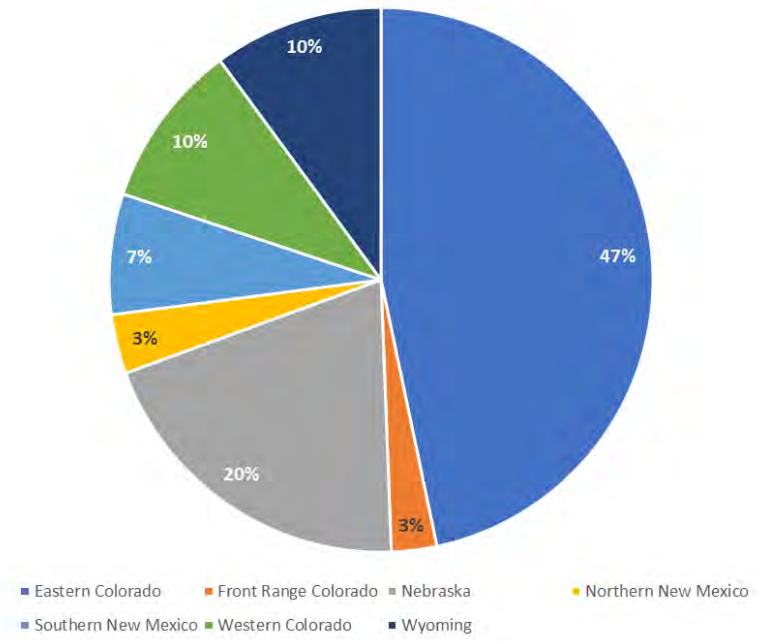
Figure 13. Industrial Sector Energy Shares by End-Use



3.5. Irrigation End-Uses and Loads

Figure 14 summarizes the irrigation energy consumption share for each region analyzed. Eastern Colorado has the largest share of irrigation energy consumption by a wide margin and is followed by the Nebraska region. The Mountain Colorado region has a negligible market share of irrigation sales and is not shown for clarity.

Figure 14: Irrigation Energy Shares by Region



Irrigation energy usage is entirely attributable to electric motors. These motors serve several different purposes, including well lift pumps, supplemental pressure boost pumps, drive motors for center pivots, and gate motors. Based on the Team's experience and research, it was determined that the major application for irrigation electricity is well lift pumps and supplemental pressure boost pumps; consequently, analyses and measures were developed for these end-uses.

3.6. Peak Demand Characterization

This section summarizes the market and end-use characterization of Tri-State's summer peak demand by sector and region. Tri-State's 2018 coincident peak demand used by member cooperatives was 2,887 MW, observed during the month of July. Figure 15 shows the distribution of the coincident peak demand by region. Energy sales by sector were used to estimate coincident peak demand allocation by sector, as described in Section 3. Figure 16 shows the results of this estimation for the Tri-State system as a whole and Figure 17 presents results by region. Notable contributors to the coincident peak demand are the residential and industrial sectors in the Front Range region, as well as the irrigation sector in Eastern Colorado and Nebraska.

Figure 15. 2018 Coincident Peak Demand by Region

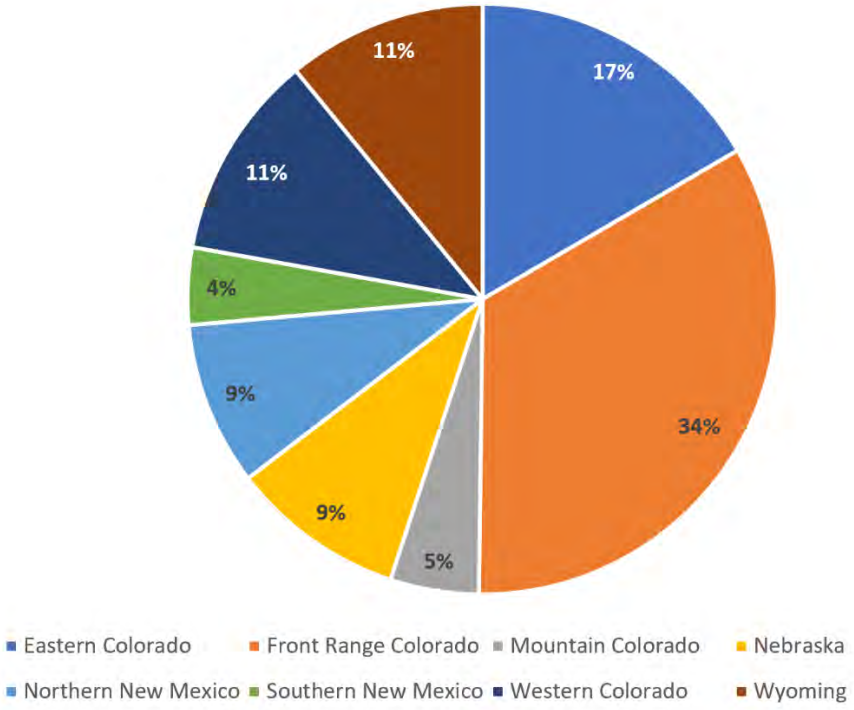


Figure 16. 2018 Coincident Peak Demand by Sector

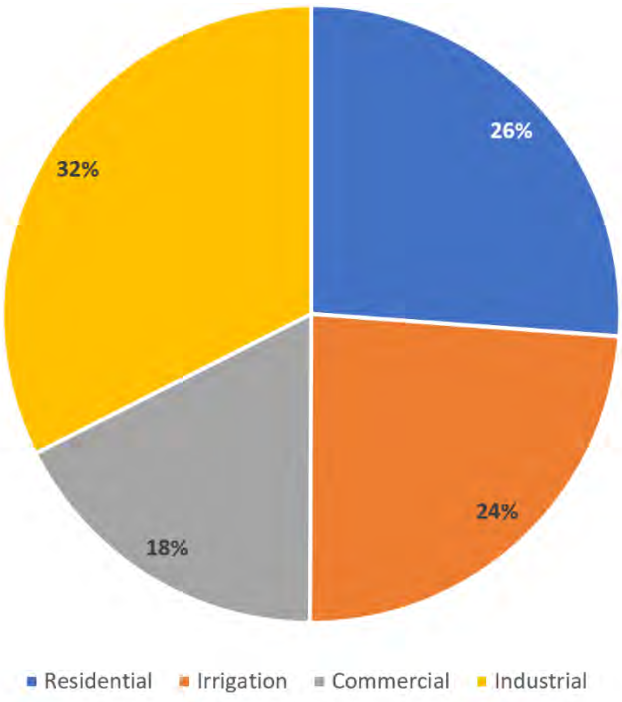
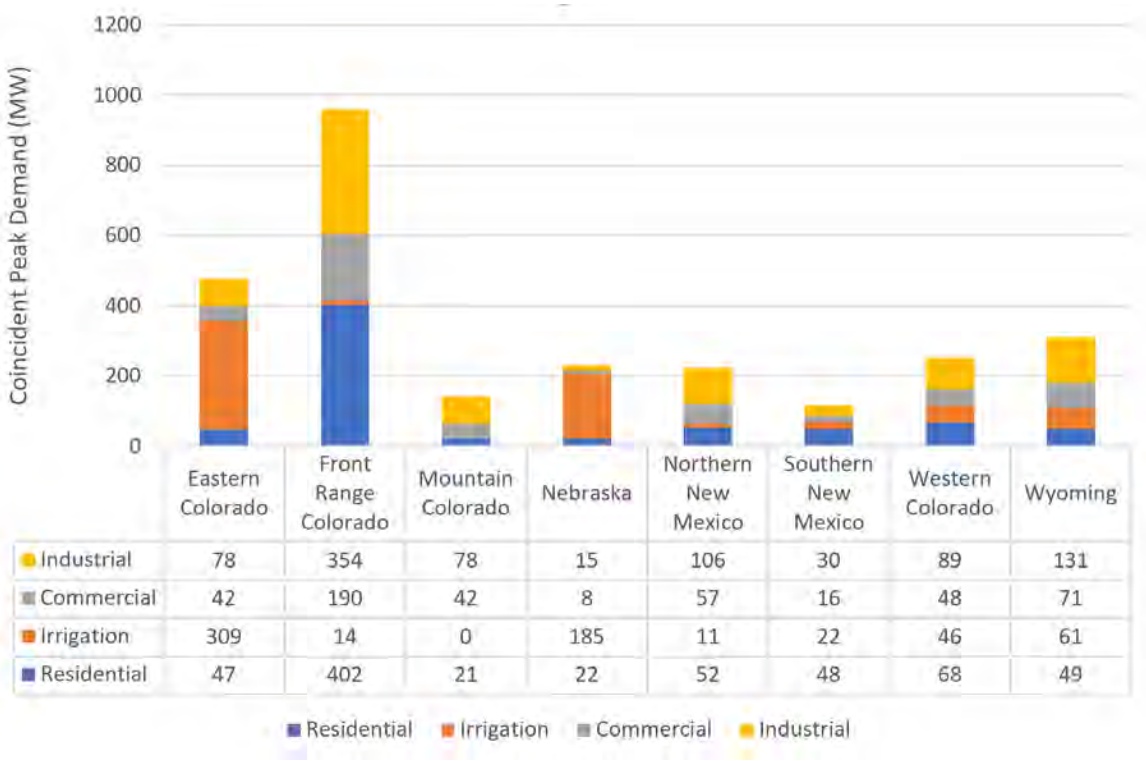


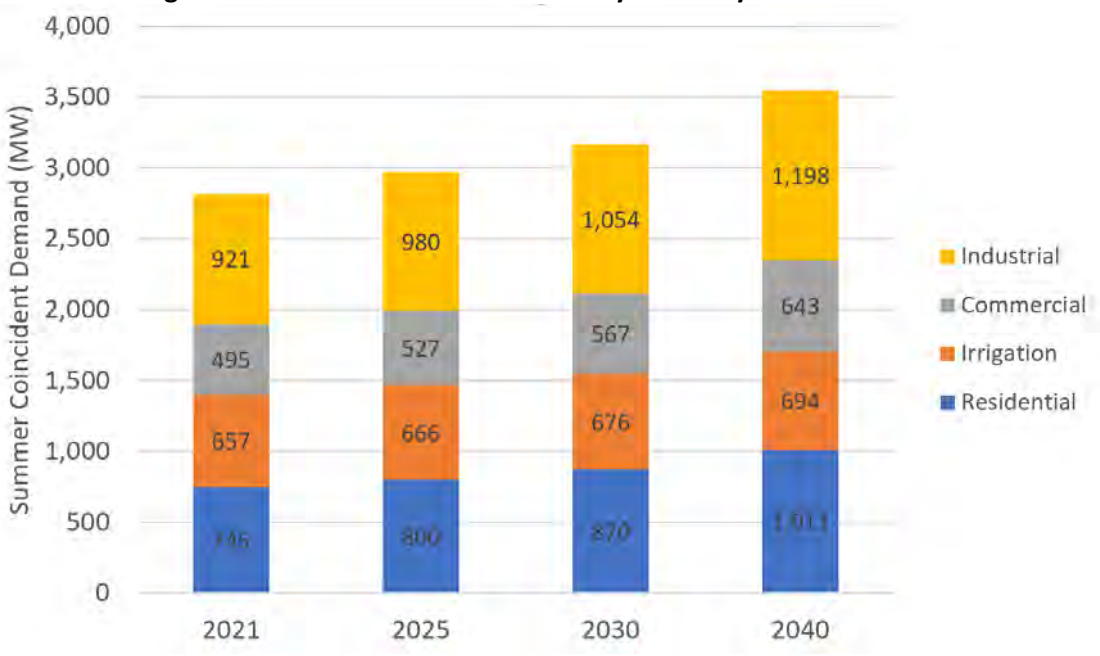
Figure 17. 2018 Coincident Peak Demand by Sector and Region



	Eastern Colorado	Front Range Colorado	Mountain Colorado	Nebraska	Northern New Mexico	Southern New Mexico	Western Colorado	Wyoming
Industrial	78	354	78	15	106	30	89	131
Commercial	42	190	42	8	57	16	48	71
Irrigation	309	14	0	185	11	22	46	61
Residential	47	402	21	22	52	48	68	49

Figure 18 presents the baseline demand forecast at key milestone points during the analysis period. Industrial, commercial, and residential sectors will increase by about 30%. The irrigation sector's coincident peak is not expected to increase significantly.

Figure 18. Baseline Demand Forecast by Sector by Milestone Year



4. PORTFOLIO LEVEL ENERGY EFFICIENCY POTENTIAL

4.1. Overview

The analysis finds that at the portfolio level Tri-State can achieve an average annual savings of 115 GWh from a collection of energy efficiency measures at an average annual cost of $24.3 million during the 20-year time horizon. This includes incentives and administrative costs and equates to an acquisition cost of $0.22/kWh which is in line with industry benchmarks.

4.2. Detailed Results

Table 10 presents portfolio-level energy efficiency savings potential by time horizon and Figure 19 shows the growth in cumulative savings potential through 2040. The Achievable-Moderate scenario estimates 38,083 MWh of savings potential in 2021 rising to 1,718,357 MWh of cumulative savings potential through 2040. Pursuing an aggressive incentive approach (Achievable-Aggressive) could increase cumulative savings potential by approximately 40%. The maximum achievable scenario increases savings potential by approximately 25% over the aggressive scenario, resulting in cumulative savings of approximately 2,876,487 GWh. First-year savings potential for the Achievable-Moderate scenario represents an increase of approximately 19% over Tri-State's 2018 energy efficiency program performance.

Table 10 Cumulative Savings Potential (MWh) by Scenario by Time Horizon

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021	130,384	98,221	75,523	55,330	38,083	27,043

2025	1,293,033	928,122	539,750	393,656	266,309	179,222
2030	3,868,940	2,851,171	1,372,971	1,062,225	723,605	475,993
2040	9,081,432	6,956,507	2,876,487	2,354,365	1,718,357	1,193,109

Figure 19. Portfolio Energy Efficiency Savings Potential by Scenario by Year

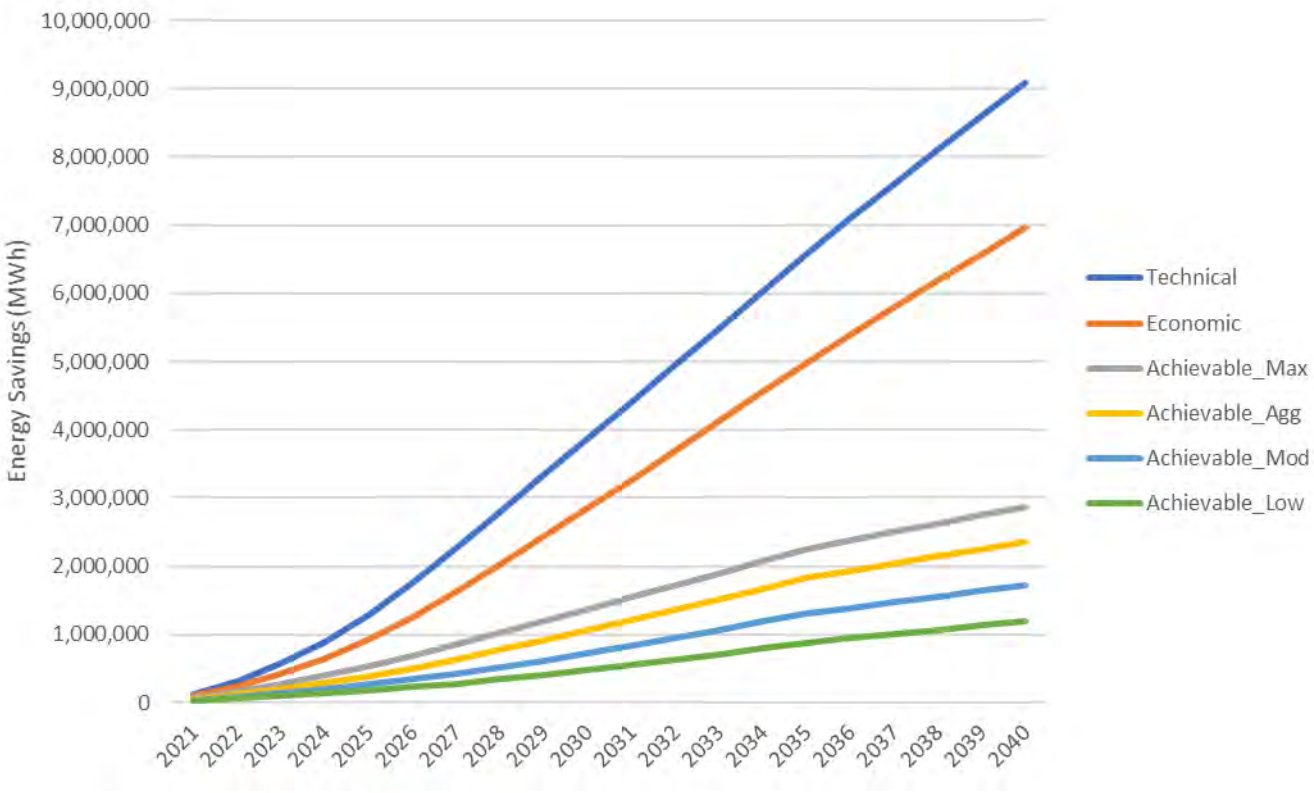


Table 11. shows the impacts of cumulative savings potential on Tri-State's baseline energy consumption forecast. The cumulative savings associated with the Achievable Moderate scenario would decrease Tri-State's baseline forecast consumption by approximately 0.25% in 2021. The reduction in baseline energy consumption would grow to 1.62% by 2025 and ultimately 8% through 2040. The range of potential reduction in baseline consumption across the achievable scenarios spans from 5.7% (Achievable-Low) to 13.7% (Achievable-Max) by 2040.

Table 11. Portfolio Cumulative Savings Potential as % of Baseline Forecast by Sector by Year

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	0.85%	0.64%	0.49%	0.36%	0.25%	0.18%
2025	7.88%	5.65%	3.29%	2.40%	1.62%	1.09%

2030	21.74%	16.02%	7.71%	5.97%	4.07%	2.67%
2040	43.14%	33.04%	13.66%	11.18%	8.16%	5.67%

Figure 20 shows the impact of the modeled scenarios on the baseline forecast. The Achievable-Max scenario would reduce Tri-State's overall load growth significantly, though Tri-State's load will continue a steady growth trajectory under all Achievable scenarios.

Figure 20. Impact of Portfolio Energy Efficiency Savings on Baseline Forecast by Scenario by Year

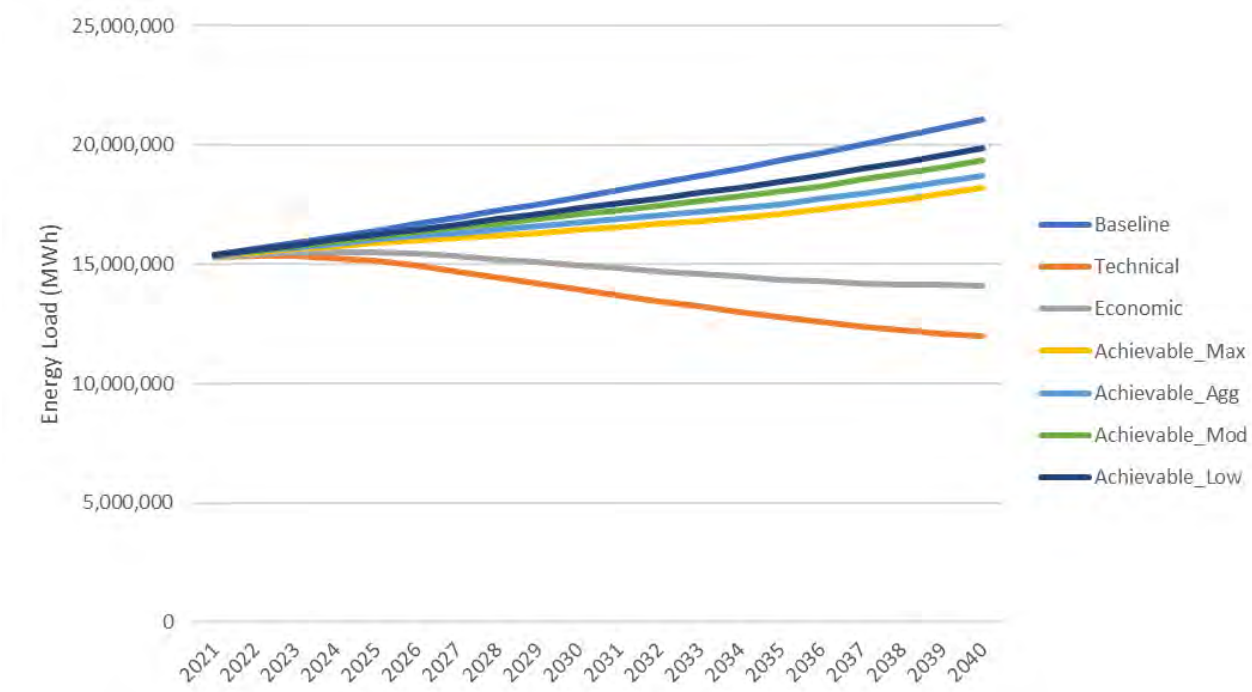
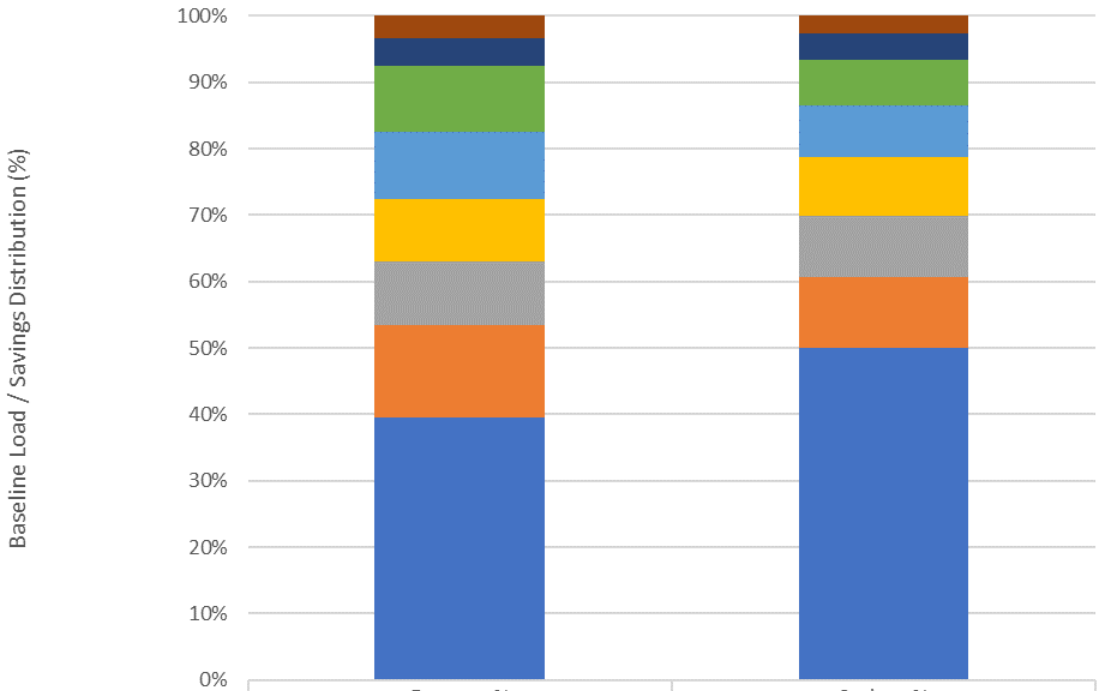


Figure 21 and Table 12 present energy savings potential by region. Front Range Colorado represents the largest share making up half the total. The other regions within Colorado account for nearly one quarter of the remaining savings potential. The two regions within New Mexico together comprise approximately 13% of total savings potential, while Wyoming accounts for approximately 10% of the total. Nebraska's savings potential is much smaller at just 2.7% of the total. This savings potential is generally aligned with the distribution of forecast energy load by region. However, Front Range Colorado's share of energy savings (50%) is larger than its share of forecast baseline energy consumption (39.5%) by a notable margin.

Figure 21. Baseline Forecast and Portfolio Energy Efficiency Savings by Region



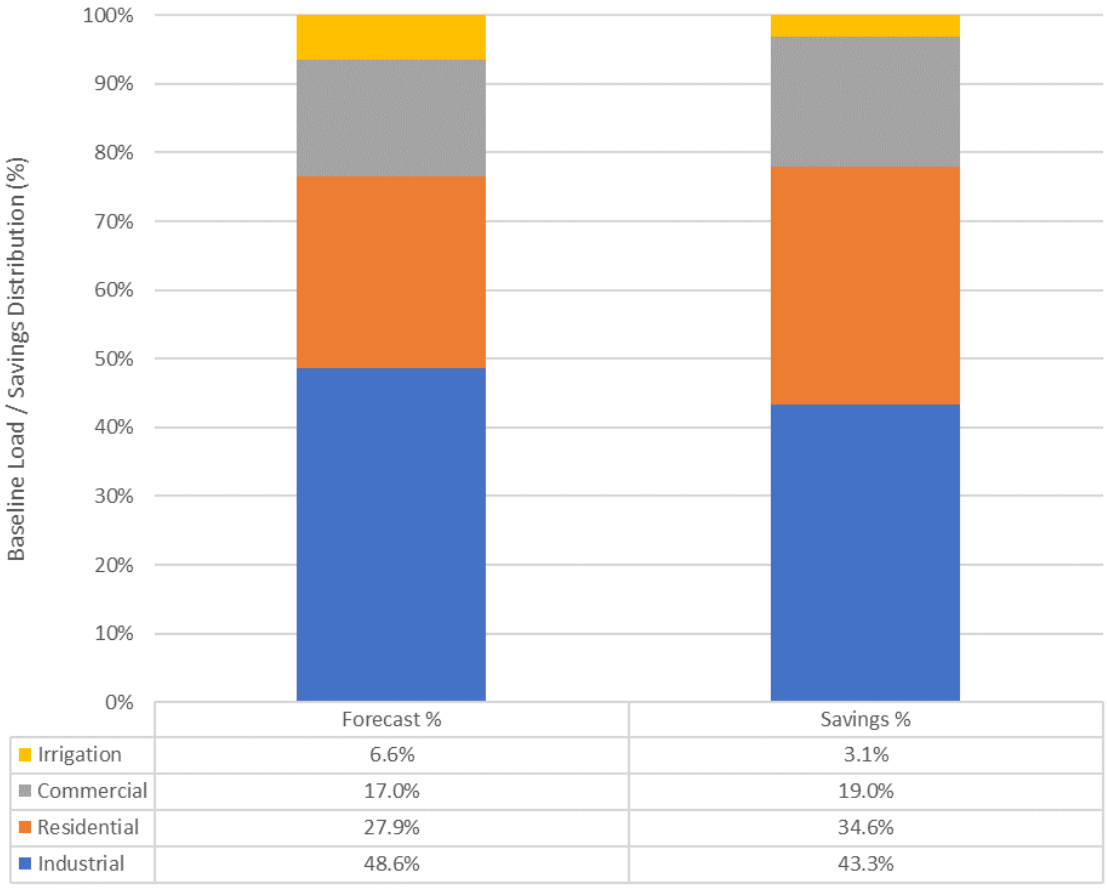
	Forecast %	Savings %
Nebraska	3.4%	2.7%
Southern New Mexico	4.1%	3.9%
Mountain Colorado	9.8%	6.8%
Eastern Colorado	10.2%	7.8%
Northern New Mexico	9.5%	8.8%
Western Colorado	9.6%	9.2%
Wyoming	13.9%	10.6%
Front Range Colorado	39.5%	50.0%

Table 12. Cumulative Savings Potential by Region, Achievable-Moderate Scenario (2040)

STATE / SUB-REGION	POTENTIAL SAVINGS (MWH)
Colorado	1,270,405
Front Range	*860,016*
Western	*158,539*
Mountain	*117,559*
Eastern	*134,292*
Wyoming	182,708
New Mexico	218,977
Northern	*151,292*
Southern	*67,685*
Nebraska	46,267
Total	**1,718,357**

As shown in Figure 22 the industrial and residential sectors represent the largest opportunity for savings. The industrial sector comprises 43% of the total savings potential and its share of the baseline forecast consumption is slightly higher at 49%. This sector's oil and gas-related energy consumption is exceptionally high, and motor-related efficiency improvements can go a long way toward reducing that load, as discussed further in Section 7. The residential sector makes up 35% of the total savings potential, and a slightly smaller portion of the baseline forecast consumption at 28%. Numerous measures are available to reduce residential energy load, with the most substantial savings coming from lighting and central heating, as discussed further in Section 5. The commercial sector also holds substantial potential energy savings at 19% of the total, which is generally in line with its share of the baseline forecast energy consumption. Heavy use of energy for lighting coupled with the availability of numerous lighting efficiency-related measures account for this sector's substantial share of savings potential. The irrigation sector contributes substantially less, both in terms of overall savings potential and in terms of its share of baseline forecast load.

Figure 22. Energy Efficiency Savings Potential by Sector (2040)



The portfolio of energy efficiency measures can achieve a cumulative demand savings of 23 MW by 2040 (Table 13.) under the Achievable-Moderate scenario. The industrial sector accounts for the largest share of demand savings, followed by the residential sector.

Table 13. Portfolio Cumulative Demand Savings Potential by Sector by Year (MW)

MILESTONE YEAR	INDUSTRIAL	RESIDENTIAL	COMMERCIAL	IRRIGATION	**TOTAL**
2021 (first year)	1.8	2.1	1.1	0.12	**5.3**
2025	3.7	3.5	2.3	0.37	**9.9**
2030	6.7	5.8	3.7	1.1	**17.2**
2040	10.3	6.2	4.5	2.1	**23.1**

Table 14 presents cumulative and average annual cost, savings and TRC metrics associated with the Achievable-Moderate scenario. As shown, in the first year Tri-State can achieve 38,083 MWh of energy savings at a cost of approximately $7 million, or $183/MWh. As programs expand and become more established annual costs and savings increase substantially to reach a cumulative program expenditure of nearly $500 million by 2040 and savings of approximately 2,290,400 MWh. The 20-year average annual program costs are approximately $24.3 million and savings are 114,520 MWh.

Table 14. Portfolio Cost Metrics by Time Horizon (Achievable-Moderate Scenario)

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	SUM OF FIRST-YEAR MEASURE SAVINGS (MWH)	ACQUISTION COST ($/MWH)	LEVELIZED COST ($/MWH)
2021	2.08	$6,957,787	38,083	$182.70	$15.25
2025	1.91	$54,155,251	279,461	$193.78	$17.41
2030	1.72	$164,148,094	797,374	$205.86	$20.18
2040	1.64	$486,794,842	2,290,399	$212.54	$21.55
20-year avg.	1.64	$24,339,742	114,520	$212.54	$21.55

5. RESIDENTIAL ENERGY EFFICIENCY POTENTIAL

5.1. Overview

The residential sector accounts for just under one-third of the total baseline forecast energy load, and 35% of energy savings potential. Cumulative savings potential for this sector is approximately 5,880 GWh through 2040 (Achievable-Moderate scenario) with lighting efficiency improvements making up over half the total energy savings potential. Central heating improvements comprise almost one-sixth of the residential sector savings potential.

Notable assumptions for the residential sector analysis include: 1) the speed with which lighting market transformation will occur, and 2) the timing of the roll-out and accrual of demand impacts associated with Home Energy Reports (HERs). With regard to lighting, research indicates that LED lamps will become standard technology within 10 years despite delays in implementing lighting efficiency standards under the Energy Independence and Security Act (EISA) of 2007. Lighting measures commonly account for the largest share of savings for residential energy efficiency programs. However, since residential lighting market transformation is well underway, savings from lighting measures are limited for the second half of the evaluation period.

For the home energy reports measure (HER) the analysis assumes a seven-year implementation delay in order to capture demand benefits associated with this measure. This is because Tri-State is not capacity

constrained during this period and avoided cost of capacity benefits do not apply. The addition of demand benefits along with energy savings benefits allows the HERs measure to achieve cost effectiveness for various measure permutations in varying regions.

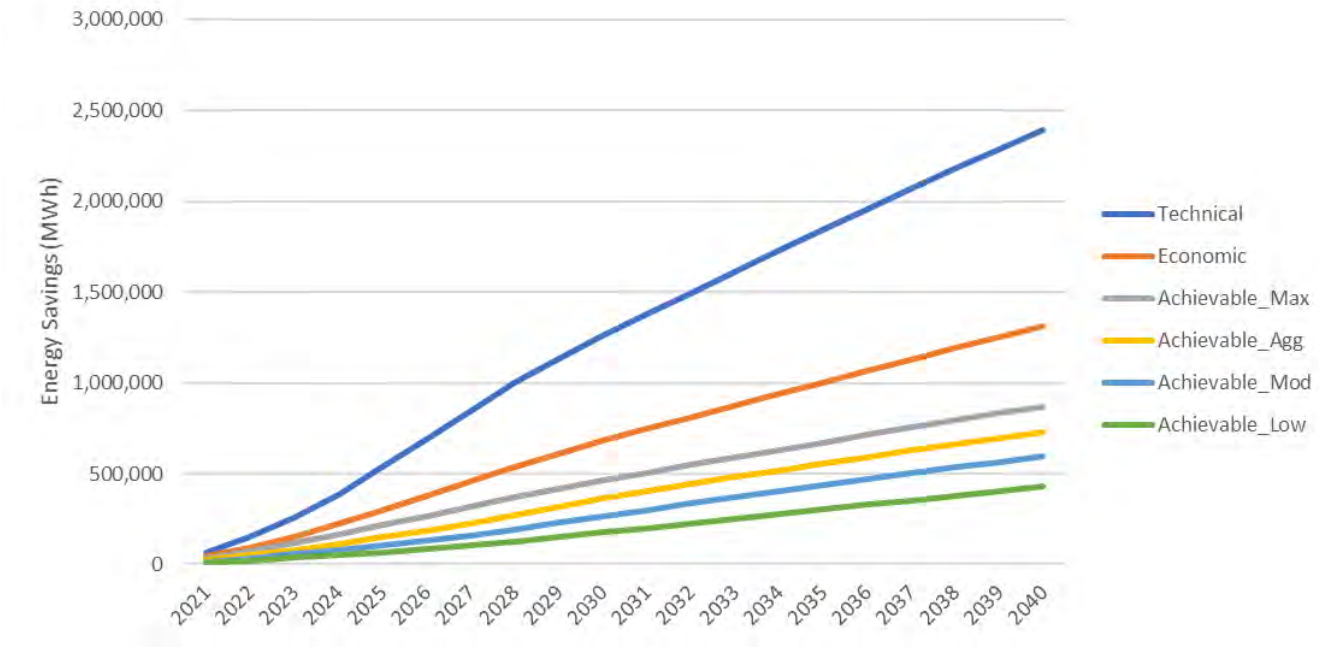
5.2. Detailed Results

Table 15 presents cumulative savings potential for the residential sector by scenario at various milestones in the analysis period and Figure 23 shows the growth in cumulative savings potential through 2040. The Achievable-Moderate scenario estimates 14,649 MWh of savings potential in 2021 rising to 594,298 MWh of cumulative savings potential through 2040. Pursuing an aggressive incentive approach (Achievable-Aggressive scenario) could increase cumulative savings potential by approximately 22%. The maximum achievable scenario estimates savings potential approximately 46% higher than the aggressive scenario, equating to cumulative savings of approximately 870,669 MWh through 2040.

Table 15. Cumulative Residential Savings Potential by Scenario by Time Horizon (MWh)

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	63,817	42,581	34,166	22,384	14,649	9,539
2025	532,961	299,459	214,988	149,245	104,278	68,016
2030	1,257,012	679,699	461,040	361,598	263,762	175,118
2040	2,395,940	1,313,384	870,669	726,771	594,298	427,615

Figure 23. Residential Energy Efficiency Savings Potential by Scenario by Year



The cumulative residential savings potential under the Achievable-Moderate scenario equates to 9.1% of the residential baseline load forecast for 2040 (see Table 16.). The maximum achievable savings would equate to 16.2% of the forecast energy load for this sector.

Table 16. Residential Savings Potential as % of Baseline Forecast by Scenario by Year

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	1.10%	0.75%	0.57%	0.45%	0.32%	0.24%
2025	12.48%	8.63%	4.36%	3.36%	2.25%	1.54%
2030	38.13%	26.76%	10.02%	8.03%	5.53%	3.74%
2040	76.33%	53.93%	16.19%	13.21%	9.14%	6.54%

As shown in Figure 24, lighting accounts for the greatest share of energy savings potential at 55% of the total followed by central heating at approximately 15% of total savings. Plug loads, central air, HVAC auxiliary, and refrigerator/freezer end-uses combined comprise over a quarter of savings potential.

Figure 24. Residential Baseline Energy Load and Cumulative Energy Efficiency Savings Potential by End-Use (2040)

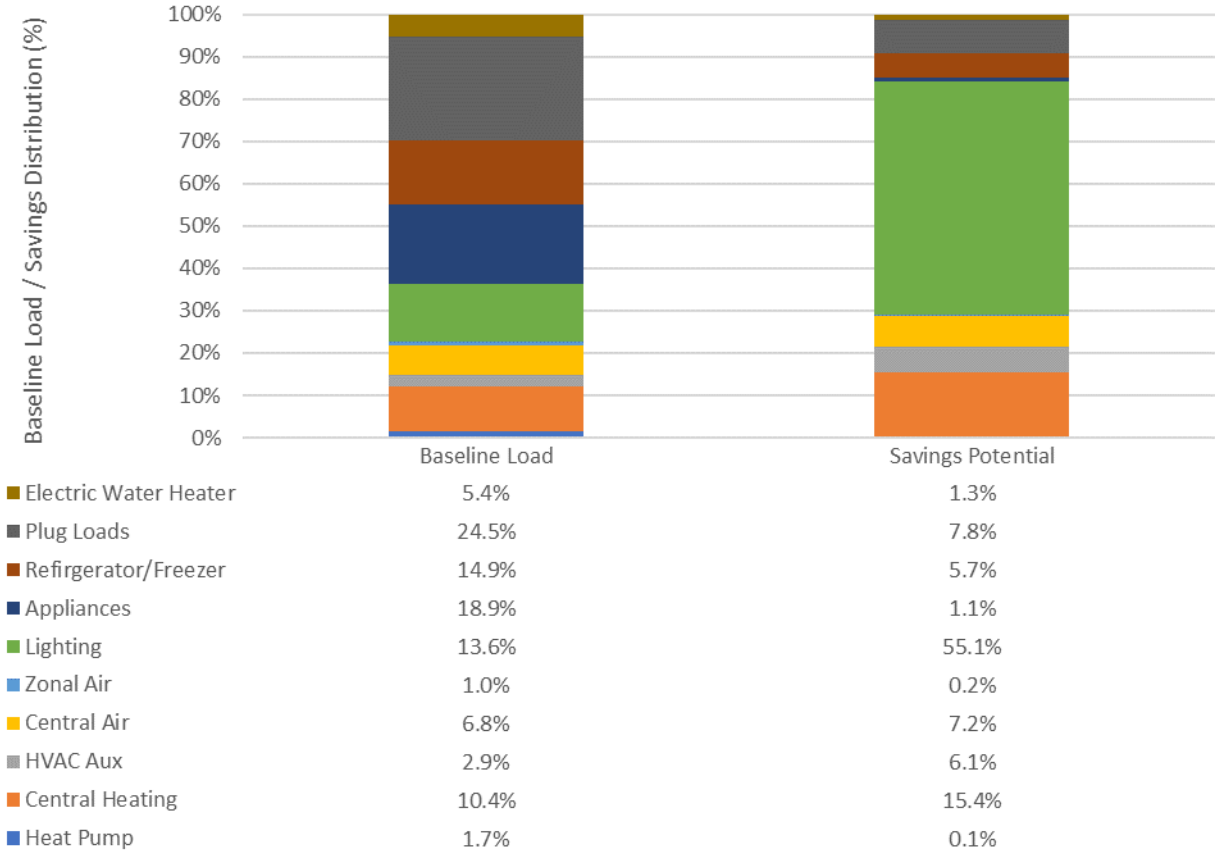


Table 17 presents cumulative residential demand savings by end-use by milestone year. High efficiency lighting is by far the greatest contributor to demand savings from residential energy efficiency measures producing 2,722 kW of cumulative demand savings through 2040. Additional measures with relatively large volumes of demand savings include plug loads and central air.

Table 17. Residential Cumulative Demand Savings Potential by End-Use by Year (MW)

YEAR	HEAT PUMP	CENTRAL HEATING	HVAC AUX	CENTRAL AIR	ZONAL AIR	LIGHTING	APPLIANCES	REFRIG-ERATOR / FREEZER	PLUG LOADS	ELECTRIC WH	TOTAL
2021	0.0002	0.0053	0.0122	0.0951	0.0	1.8303	0.0080	0.0605	0.1238	0.0100	**2.1454**
2025	0.0008	0.0203	0.0538	0.3813	0.0	2.4448	0.0296	0.1921	0.3284	0.0408	**3.4921**
2030	0.0031	0.0505	0.1460	1.5397	0.0806	2.9055	0.0990	0.3152	0.5296	0.1378	**5.8072**

2040	0.0037	0.0440	0.2012	1.7245	0.0829	2.7220	0.1116	0.3383	0.7502	0.1771	**6.1554**

Table 18. presents cumulative program cost metrics by milestone year. As shown, first-year program costs are approximately $3.0 million, rising to a 20-year average annual cost of approximately $8.9 millon. Acquisition costs rise from $206/MWh in 2021 to $251/MWh in 2040. A change in lighting market measures available during the analysis period drives this increase in acquisition costs, as LEDs become the market baseline within ten years. The decline in highly cost-effective lighting measures also has a downward effect on the TRC ratio, as it decreases from 2.15 in 2021 to 1.36 in 2040.

Table 18. Cumulative Residential Cost Metrics by Time Horizon

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	SUM 1st-YEAR MEASURE SAVINGS (MWH)	ACQUISTION COST ($/MWH)	LEVELIZED COST ($/MWH)
2021	2.15	$ 3,013,704	14,649	$ 205.72	$ 14.90
2025	1.84	$ 23,693,929	104,884	$ 225.91	$ 18.61
2030	1.50	$ 68,913,983	280,300	$ 245.86	$ 23.95
2040	1.36	$ 177,217,648	705,466	$ 251.21	$ 26.52
20-year avg.	1.36	$ 8,860,882	35,273	$ 251.21	$ 26.52

6. COMMERCIAL ENERGY EFFICIENCY POTENTIAL

6.1. Overview

The commercial sector accounts for 17% of the total baseline forecast energy load, and 19% of cumulative energy savings potential in 2040. Cumulative savings potential for this sector is approximately 326 GWh through 2040 (Achievable-Moderate scenario) with lighting measures making up 74% of the total energy savings potential. Other end-uses comprising a notable share of savings potential include refrigeration, motors and plug load at 7.5%, 5% and 4% of savings respectively. The retail segment holds the largest opportunity for savings at roughly 27% of the cumulative savings potential in 2040.

6.2. Detailed Results

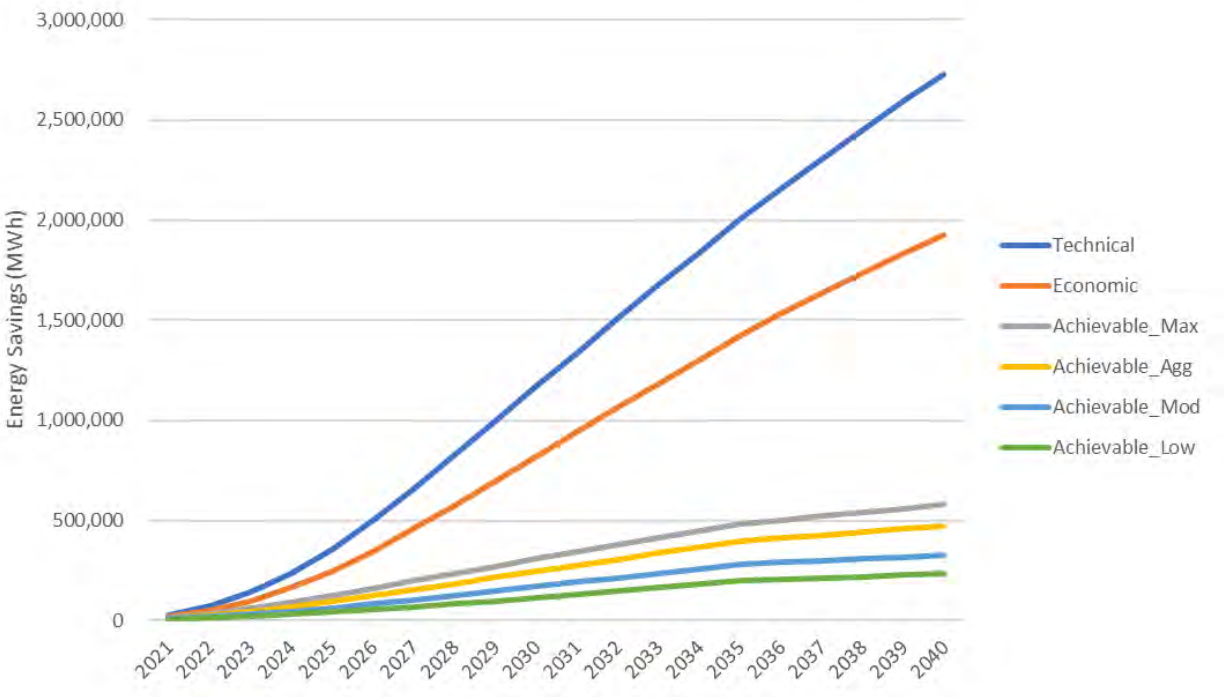
Table 19. presents cumulative savings potential for the commercial sector by scenario at various milestones in the analysis period and Figure 25 shows the growth in cumulative savings potential through 2040. The Achievable-Moderate scenario estimates 8.6 GWh of savings potential in 2021 rising to approximately 326 GWh of cumulative savings potential through 2040. Pursuing an aggressive program-delivery approach (Achievable-Aggressive scenario) could increase cumulative savings potential

by approximately 45% to 472 GWh. A less aggressive program delivery approach (Achievable-Low scenario) would reduce savings by approximately 30% relative to the Achievable-Moderatemoderate scenario.

Table 19. Cumulative Commercial Savings Potential by Scenario by Time Horizon (MWh)

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	29,723	20,331	15,375	12,230	8,626	6,372
2025	356,164	246,342	124,400	95,929	64,202	43,820
2030	1,167,833	819,729	307,053	245,955	169,298	114,633
2040	2,726,737	1,926,747	578,473	472,062	326,383	233,706

Figure 25. Commercial Cumulative Energy Efficiency Savings Potential by Sector by Year



The cumulative commercial savings potential under the Achievable-Moderate scenario equates to a reduction of 0.32% of commercial baseline sales in 2021, a 2.25% reduction by 2025 and a 9.14% reduction by 2040 (see Table 20.). The Mesa Point Energy Team esimates a range in reduction of baseline energy sales for the achievable scenarios from 6.5% (Achievable-Low) to 16.2% (Achievable-Max) by 2040.

Table 20. Commercial Cumulative Savings Potential as % of Baseline Forecast by Sector by Year

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	1.10%	0.75%	0.57%	0.45%	0.32%	0.24%
2025	12.48%	8.63%	4.36%	3.36%	2.25%	1.54%
2030	38.13%	26.76%	10.02%	8.03%	5.53%	3.74%
2040	76.33%	53.93%	16.19%	13.21%	9.14%	6.54%

As shown in Figure 26 lighting makes up a large majority of the commercial sector's energy savings potential at 74%, a significant increase in its baseline load share. Refrigeration, motors and plug loads comprise most of the remaining savings potential for this sector at 7.5%, 5.5% and 4% respectively.

Figure 26. Commercial Baseline Energy Load and Cumulative Energy Efficiency Savings Potential Distribution by End-Use (2040)

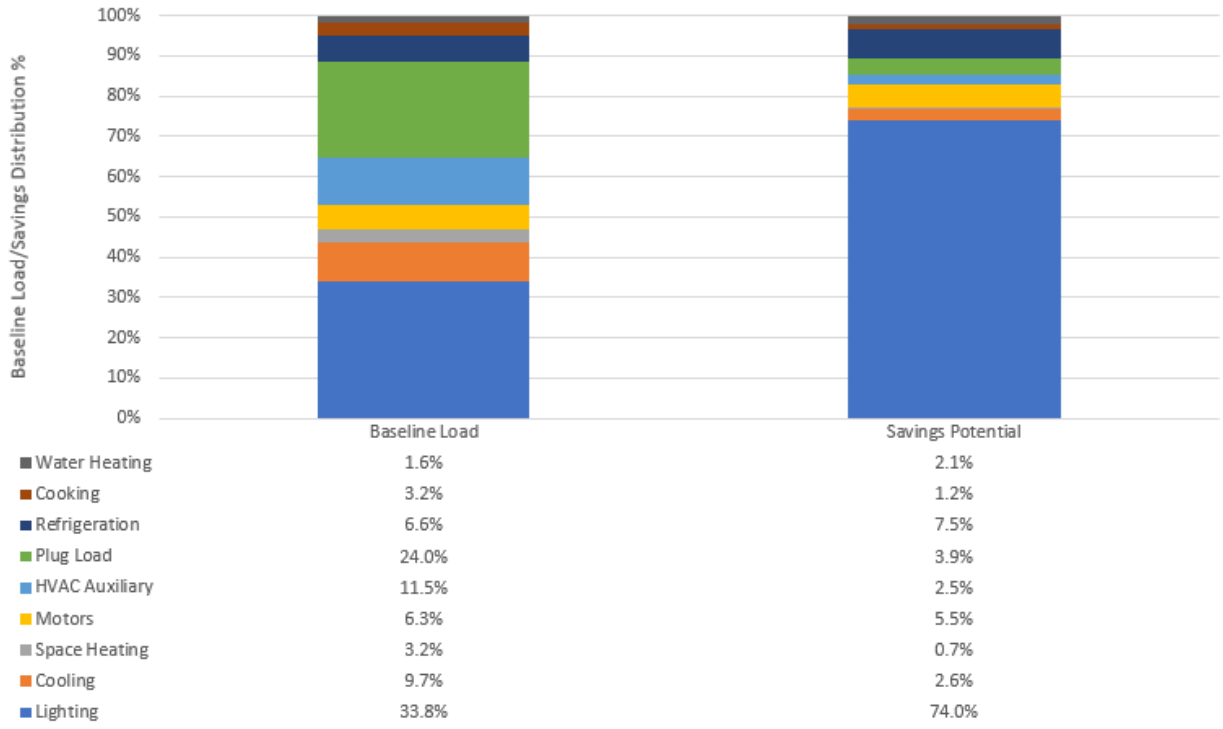


Table 21 presents cumulative commercial demand reductions by end-use by milestone year. Lighting accounts for nearly 55% of demand savings from commercial energy efficiency measures, producing almost 2,500 kW of demand reductions by 2040. Relative to their energy savings, the Cooling and HVAC Auxillary end-uses provide a large demand reduction opportunity at 430 kW and 424 kW respectively.

Table 21. Commercial Cumulative Demand Savings Potential by End-Use by Year (MW)

YEAR	LIGHTING	COOLING	HEATING	MOTORS	HVAC AUX	PLUG LOAD	REFRIGER-ATION	COOKING	DHW	TOTAL
2021 (first year)	0.763	O.054	0.001	0.0251	0.054	0.102	0.108	0.011	0.014	**1.133**
2025	1.526	0.147	0.002	0.0693	0.145	0.161	0.230	0.025	0.039	**2.344**
2030	2.171	0.310	0.004	O.1529	0.305	0.233	0.353	0.041	0.082	**3.653**
2040	2.476	0.430	0.006	0.2206	0.424	0.357	0.434	0.053	0.116	**4.517**

Figure 27 presents baseline energy load and cumulative savings by commercial market segment through 2040. The savings potential for each segment is generally similar to its share of total baseline energy load. The retail segment has the largest share of 2040 cumulative savings potential (27.4%), an increase of just over 7% of its baseline energy load share. This is a result of the large lighting load share in retail buildings. The Miscellaneous and Office segments comprise the next largest opportunities at 17.7% and 10.4% of cumulative savings potential respectively.

Figure 27. Commercial Baseline Load and Cumulative Energy Efficiency Savings Potential Distribution by Segment (2040)

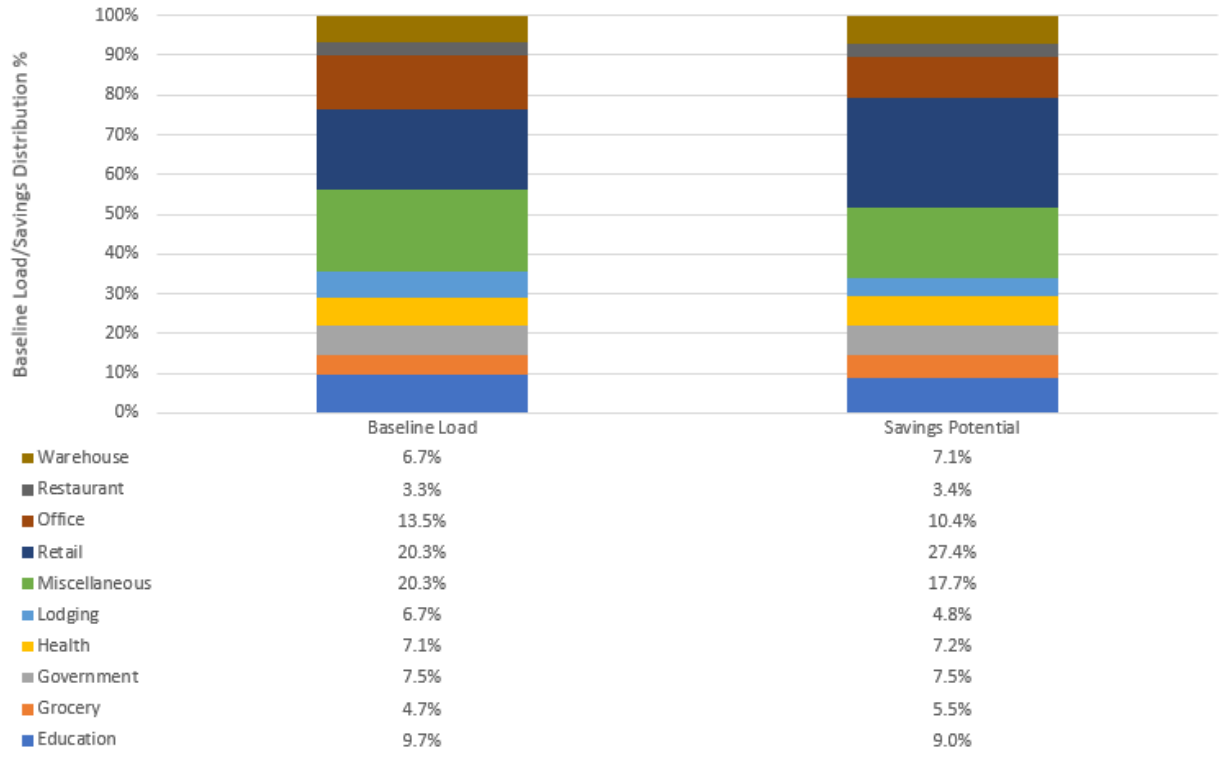


Table 22. summarizes cumulative commercial program cost metrics by milestone year. As shown, first-year program costs are approximately $1.4 million, rising to a 20-year average annual cost of roughly $4.1 millon. Acquisition costs start at $159/MWh during the first year of analysis and see a gradual increase through 2040. The TRC ratio remains solid for the commercial sector starting at 2.11 in 2021 and decreasing modestly to 1.93 in 2040.

Table 22. Commercial Cost Metrics by Time Horizon

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	SUM 1st-YEAR MEASURE SAVINGS (MWH)	ACQUISTION COST ($/MWH)	LEVELIZED COST ($/MWH)
2021	2.11	$ 1,367,761	8,626	$ 158.57	$ 18.87
2025	2.07	$ 10,437,397	64,743	$ 161.21	$19.27
2030	2.01	$ 30,065,223	181,191	$ 165.93	$ 20.13
2040	1.93	$ 82,522,317	481,235	$ 171.48	$ 21.24
20-year avg.	1.93	$ 4,126,116	24,062	$ 171.48	$ 21.24

7. INDUSTRIAL ENERGY EFFICIENCY POTENTIAL

7.1. Overview

The industrial sector makes up roughly one-half of Tri-State's total baseline forecast energy load, and 43% of potential energy savings. Cumulative savings potential for this sector is approximately 745 GWh through 2040 (Achievable-Moderate scenario) with pump-related savings accounting for a majority of potential savings at 58%. Efficiency measures for the oil and gas segment of the market comprise nearly 55% of potential savings for this sector. Manufacturing-related efficiency opportunities account for most of the remaining energy savings potential.

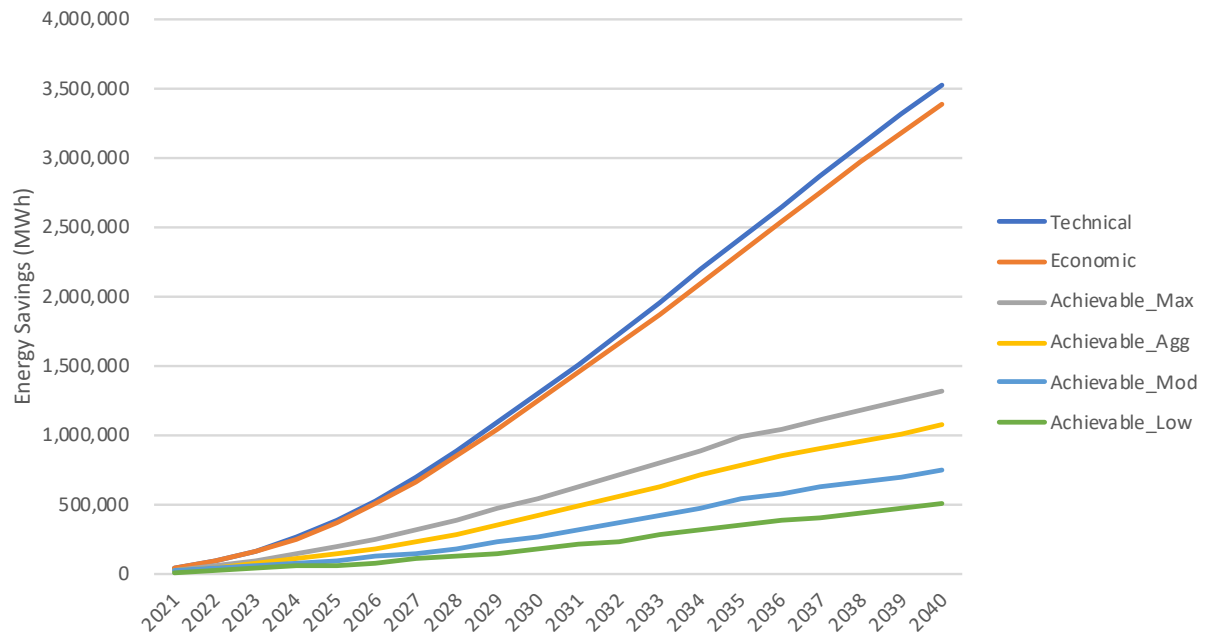
7.2. Detailed Results

Table 23 presents cumulative savings potential for the industrial sector by scenario at various milestones in the analysis period and Figure 28 shows the growth in cumulative savings potential through 2040. The Achievable-Moderate scenario estimates 14 GWh of savings potential in 2021 rising to approximately 745 GWh of cumulative savings potential through 2040. Pursuing an aggressive incentive approach (Achievable-Aggressive scenario) could increase cumulative savings potential by approximately 43%. Savings potential increases by an additional 22% under the maximum achievable scenario, equating to a a cumulative maximum achievable savings of approximately 1,308 GWh through 2040.

Table 23. Cumulative Industrial Savings Potential by Scenario by Time Horizon (MWh)

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	35,303	34,181	24,956	19,902	14,224	10,678
2025	378,791	363,954	186,953	139,453	92,325	63,777
2030	1,294,201	1,240,358	544,166	414,383	268,351	173,960
2040	3,523,534	3,381,672	1,307,552	1,066,805	744,543	502,719

Figure 28. Industrial Energy Efficiency Savings Potential by Scenario by Year



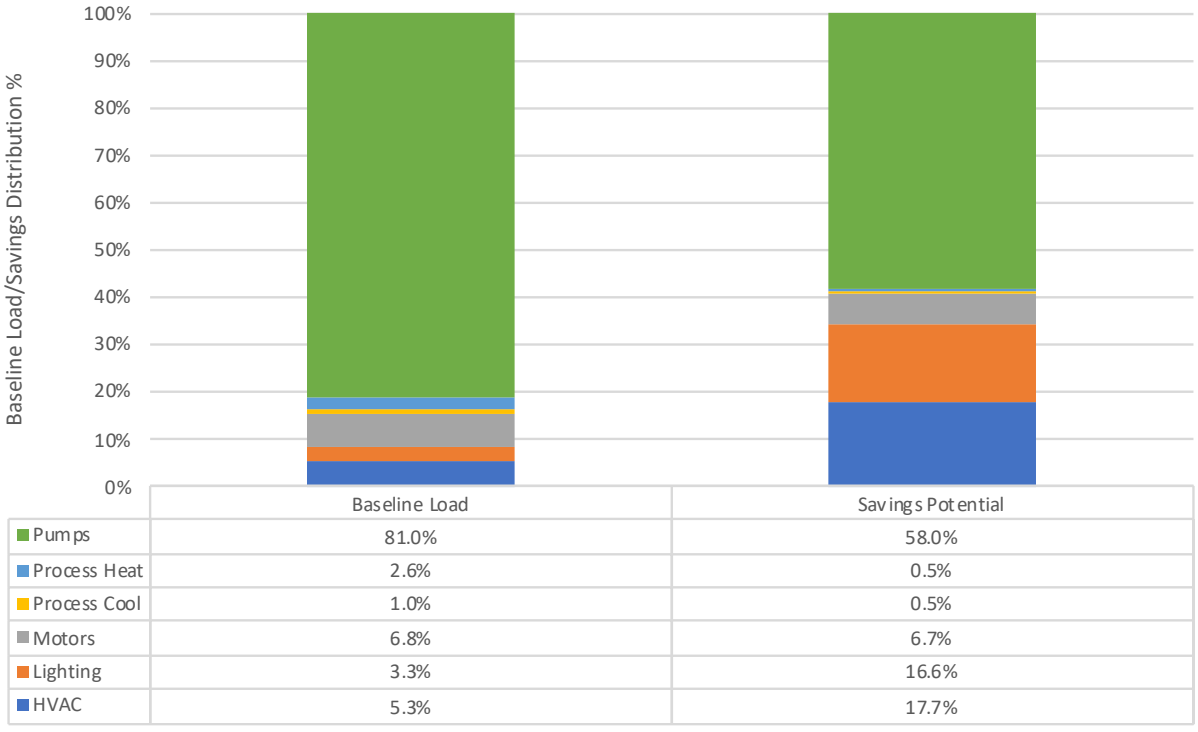
The cumulative industrial savings potential under the Achievable-Moderate scenario equates to a reduction of 0.21% of industrial baseline sales in 2021, a 1.24% reduction by 2025 and a 7.28% reduction by 2040 (see Table 24.). The analysis estimates a range in reduction of baseline energy sales for the achievable scenarios from 4.9% (Achievable-Low) to 12.8% (Achievable-Max) by 2040.

Table 24. Industrial Cumulative Savings Potential as % of Baseline Forecast by Sector by Year

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	0.52%	0.50%	0.36%	0.29%	0.21%	0.16%
2025	5.09%	4.89%	2.51%	1.87%	1.24%	0.86%
2030	15.66%	15.01%	6.58%	5.01%	3.25%	2.10%
2040	34.44%	33.05%	12.78%	10.43%	7.28%	4.91%

As shown in Figure 29 efficient pumps and related measures hold by far the greatest energy savings potential for the industrial sector, accounting for nearly 60% of the total. This is in part due to the fact that pumps account for such a large portion of the industrial sector's forecast baseline energy load (81%). Lighting and HVAC also hold substantial energy savings potential for this sector at 17% and 18% of the total, respectively.

Figure 29. Industrial Baseline Energy Load and Cumulative Energy Efficiency Savings Potential Distribution by End-Use (2040)



	Baseline Load	Savings Potential
Pumps	81.0%	58.0%
Process Heat	2.6%	0.5%
Process Cool	1.0%	0.5%
Motors	6.8%	6.7%
Lighting	3.3%	16.6%
HVAC	5.3%	17.7%

Table 25. presents cumulative industrial demand savings by end-use by milestone year. As with energy savings potential, pumps are also the leader in terms of demand savings potential. Pump-related

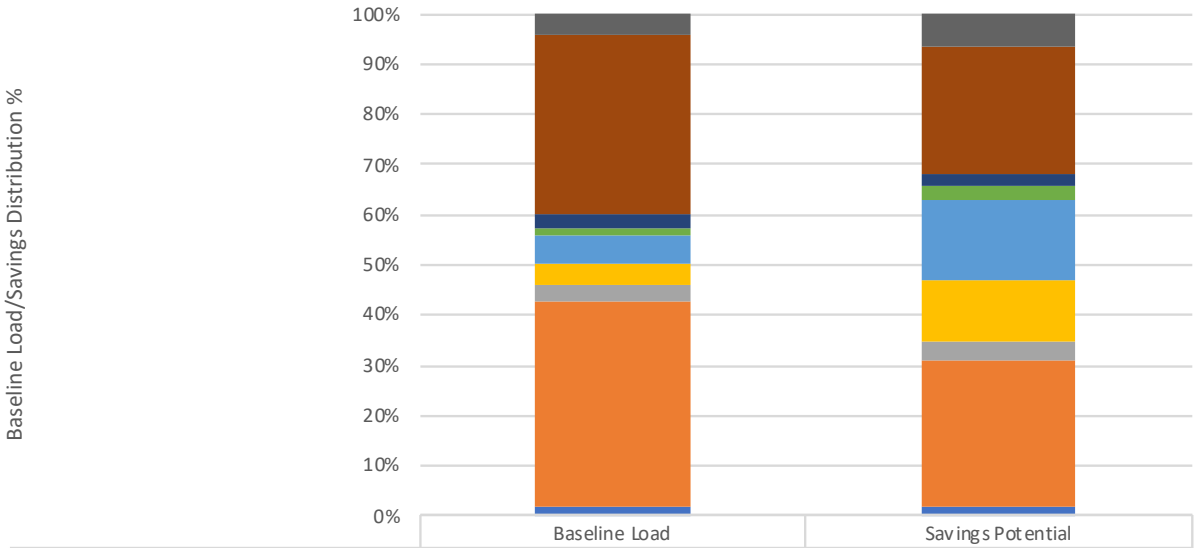
measures contribute nearly 6.6 MW of cumulative demand savings potential. Lighting efficiency measures have the potential to decrease demand by almost 1.3 MW and HVAC by nearly 1.7 MW.

Table 25. Industrial Cumulative Demand Savings Potential by End-Use by Year (MW)

YEAR	HVAC	LIGHTING	MOTORS	PROCESS COOL	PROCESS HEAT	PUMPS	TOTAL
2021 (first year)	0.165	0.201	0.132	0.008	0.008	1.364	**1.878**
2025	0.469	0.496	0.242	0.022	0.020	2.456	**3.705**
2030	1.076	0.898	0.424	0.047	0.037	4.187	**6.669**
2040	1.686	1.258	0.672	0.070	0.052	6.597	**10.335**

Figure 30 shows that liquid mining and pipeline transportation are the two segments of the industrial sector that account for the most energy savings potential, at more than one-quarter of the total for each segement. Together, these two segments account for approximately 55% of the savings potential. Manufacturing-related segments (i.e., non-metallic mineral products, chemical, paper and other manufacturing segments) together make up over one-third of the total energy savings potential.

Figure 30. Industrial Baseline Load and Cumulative Energy Efficiency Savings Potential Distribution by Segment (2040)



	Baseline Load	Savings Potential
TCU	4.2%	6.6%
Pipeline Transportation (Oil, Gas, and CO2)	35.6%	25.5%
Mining	3.0%	2.0%
Mfg - Paper	1.6%	3.2%
Mfg - Nonmetallic Mineral Product	5.3%	15.9%
Mfg - Misc.	4.6%	12.1%
Mfg - Chemical	3.2%	3.9%
Liquid Mining (Oil, Gas, and Carbon Dioxide)	40.8%	29.2%
Agriculture	1.8%	1.7%

Table 26. summarizes cumulative industrial program cost metrics by milestone year. As shown, first-year program costs are approximately $2.4 million, rising to a 20-year average annual cost of roughly $9.6 millon. Acquisition costs start at $168/MWh during the first year of analysis and see only a slight increase through 2040. The TRC ratio remains solid for the industrial sector starting at 2.08 in 2021 and decreasing modestly to 1.92 in 2040.

Table 26. Industrial Cost Metrics by Time Horizon

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	SUM 1st-YEAR MEASURE SAVINGS (MWH)	ACQUISTION COST ($/MWH)	LEVELIZED COST ($/MWH)
2021	2.08	$2,391,009	14,224	$168.09	$11.67
2025	2.02	$18,273,240	104,319	$175.17	$12.80
2030	1.96	$57,536,744	311,837	$184.51	$14.14

2040	1.92	$192,026,153	993,332	$193.32	$15.25
20-year avg.	1.92	$9,601,308	**49,667**	**$193.32**	**$15.25**

8. IRRIGATION EFFICIENCY POTENTIAL

8.1. Overview

Irrigation accounts for a small fraction of energy consumption and savings potential; it represents approximately 8% of Tri-State's total baseline energy load, and 3% of potential energy savings. Cumulative savings potential for this sector is approximately 53,134 MWh through 2040 (Achievable-Moderate scenario). Measures with notable savings potential include high efficiency motors, motor VFDs and base boot gasket improvements, making up approximately 63%, 18% and 17% of total savings potential respectively.

8.2. Detailed Results

Table 27 presents cumulative savings potential for the irrigation sector by scenario at various milestones in the analysis period and Figure 31 shows the growth in cumulative savings potential through 2040. The Achievable-Moderate scenario estimates 584 MWh of savings potential in 2021 rising to approximately 53,134 MWh of cumulative savings potential through 2040. Pursuing an aggressive incentive approach (Achievable-Aggressive scenario) could increase cumulative savings potential by approximately 70%. Savings potential increases by an additionad 39% under the maximum achievable scenario, equating to a a cumulative maximum achievable savings of approximately 119,793 MWh through 2040.

Table 27. Cumulative Irrigation Savings Potential by Scenario by Time Horizon (MWh)

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	1,541	1,128	1,026	814	584	454
2025	25,117	18,368	13,409	9,028	5,504	3,609
2030	149,894	111,385	60,712	40,289	22,193	12,282
2040	435,221	334,704	119,793	88,727	53,134	29,070

Figure 31. Irrigation Energy Efficiency Savings Potential by Scenario by Year

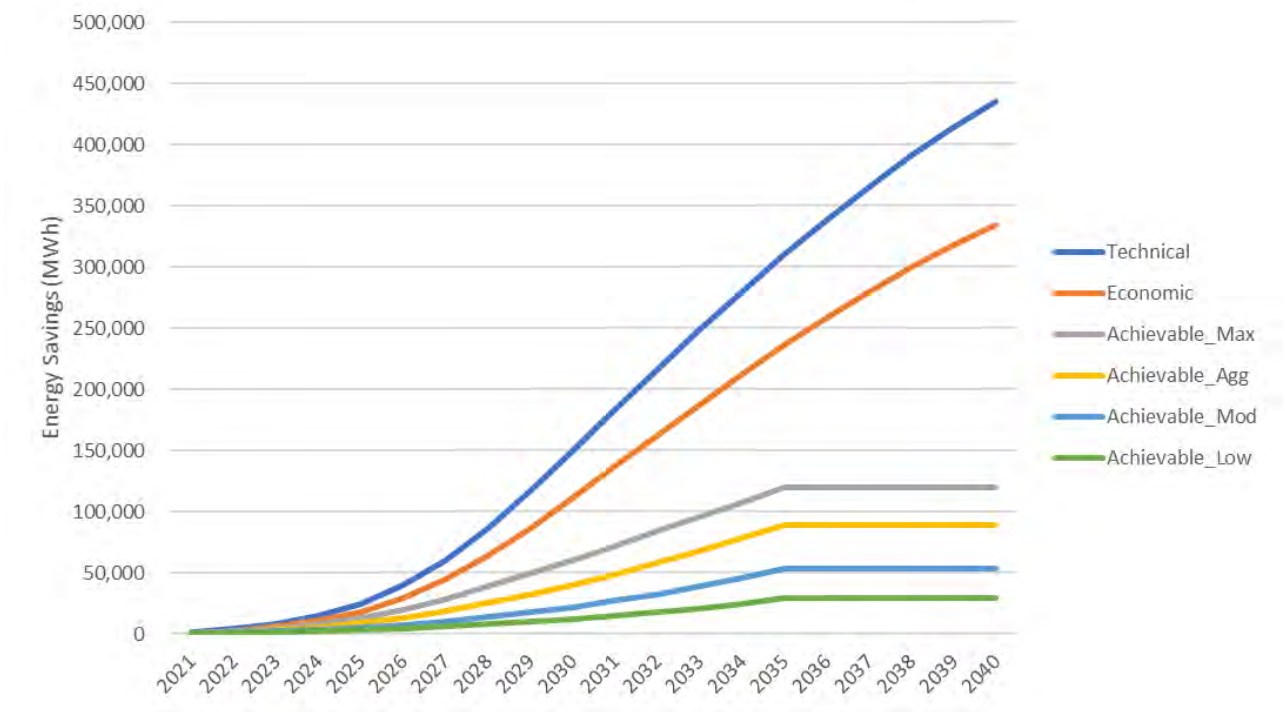


Table 28. shows the percentage impact of cumulative irrigation savings on the baseline forecast by scenario for each milestone year. Under the Achievable-Moderate scenario irrigation measures have the potential to reduce baseline load by nearly 4%. The maximum achievable scenario would more than double those savings to reduce baseline load by approximately 9%.

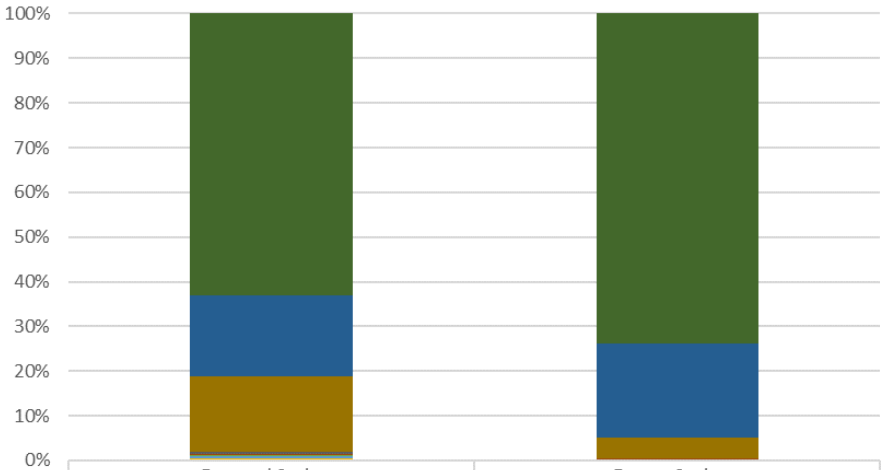
Eastern Colorado accounts for approximately half the irrigation savings potential, followed by Nebraska at approximately 30% of the total. Northern and Southern New Mexico together account for approximately 12% of total irrigation savings potential with the remaining regions making up a nominal share of total irrigation savings potential.

Table 28. Irrigation Cumulative Savings Potential as % of Baseline Forecast by Sector by Year

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	0.12%	0.09%	0.08%	0.06%	0.04%	0.03%
2025	1.90%	1.39%	1.01%	0.68%	0.42%	0.27%
2030	11.17%	8.30%	4.52%	3.00%	1.65%	0.91%
2040	31.51%	24.23%	8.67%	6.42%	3.85%	2.10%

Figure 32 shows the range of measures examined as part of the analysis, as well as the share of total demand and energy savings each measure represents. High efficiency motors comprise by far the largest share of savings at 63% of demand and approximately 74% of energy savings. Motor VFDs and base boot gaskets also represent notable savings opportunities. Other measures, like upgrades to Low Elevation Spray Application (LESA) and Low Energy Precision Application (LEPA) and scheduling-related measures may hold potential for improving customer satisfaction, as they can reduce water use and improve crop yields. However, LESA and LEPA are not found to provide substantial energy savings, and the analysis Team did not explore scheduling-related measures as part of this analysis.

Figure 32. Irrigation Cumulative Demand and Energy Savings by Measure (2040)



	Demand Savings	Energy Savings
HE Motor	63.07%	73.81%
Motor VFD	18.02%	21.18%
Base boot gasket	16.91%	4.52%
Cut and press repair	0.43%	0.12%
Hub gasket	0.25%	0.11%
Upgrade from high pressure to LESA/LEPA/MDI	0.22%	0.10%
Upgrade from high pressure to MESA	0.20%	0.09%
Sprinkler package replacement, high pressure	0.41%	0.03%
Nozzle replacement	0.24%	0.02%
Gaskets	0.15%	0.02%
Drains	0.08%	0.01%
Sprinkler package replacement, MESA	0.02%	0.00%

Table 29. presents cumulative and average annual costs, savings and TRC metrics associated with the Achievable-Moderate scenario for irrigation efficiency measures. As shown, in the first year Tri-State can achieve approximately 584 MWh of energy savings at a cost of approximately $185,313, or a levelized cost of $47.49/MWh. As programs expand and become more established annual costs and savings increase substantially. The 20-year average annual program costs are approximately $1.75 million and savings are 5,518 MWh.

Table 29. Irrigation Cumulative Cost Metrics by Time Horizon

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	SUM OF 1st-YEAR MEASURE SAVINGS (MWH)	ACQUISTION COST ($/MWH)	LEVELIZED COST ($/MWH)
2021	0.99	$185,313	584	$317.40	$47.49
2025	0.99	$1,750,685	5,516	$317.39	$47.50
2030	0.99	$7,632,143	24,046	$317.40	$47.51
2040	0.99	$35,028,723	110,365	$317.39	$47.53
20-year avg.	**0.99**	$1,751,436	5,518	$317.39	$47.53

9. DEMAND RESPONSE POTENTIAL STUDY

9.1. Overview

The analysis finds that a Tri-State portfolio of demand response programs could cost effectively contribute 86 MW of demand curtailment during the summer peak window by the end of the 20-year analysis time horizon. This result (the Achievable-Low scenario) assumes conservative realistic participation rates across Tri-State's territory.

Table 30 presents portfolio-level demand response potential by time horizon. As Tri-State does not currently offer demand response programs, each scenario ramps from zero and then plateaus when the program achieves maturity. The Achievable-Low scenario estimates 86 MW of cumulative summer demand response potential in 2040. Achieving more aggressive participation rates through increased marketing and incentive costs could yield an estimated 245 MW of potential (Achievable-High scenario).

Table 30. Cumulative Demand Response Potential (MW) By Scenario By Time Horizon

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE HIGH	ACHIEVABLE LOW
2021	46	30	12	5
2025	297	196	85	30
2030	647	500	222	78
2040	704	548	245	86

Figure 33. Portfolio Demand Response Potential by Scenario by Year

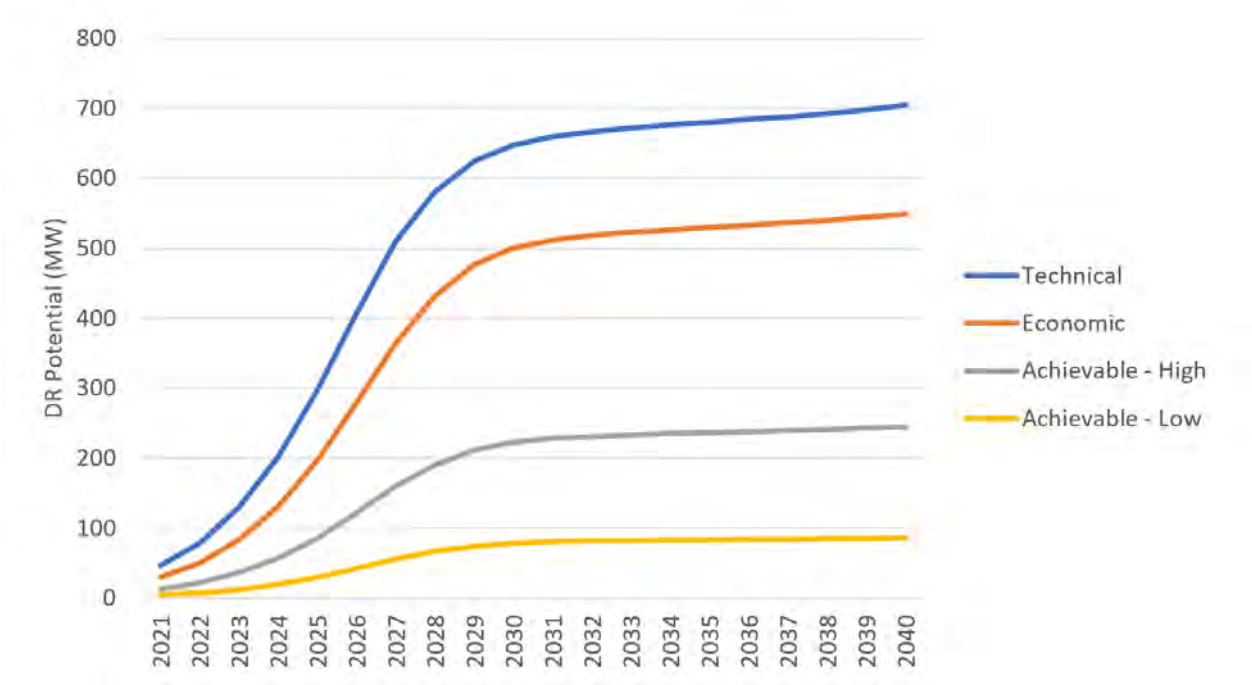


Table 31. shows the impacts of demand response potential relative to Tri-State's baseline demand forecast. The Achievable-High and -Low scenarios represent about 6.90% and 2.43% of forecasted coincident demand in 2040 respectively.

Table 31. Portfolio Demand Response Potential as % of Baseline Forecast by Year

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE HIGH	ACHIEVABLE LOW
2021	1.65%	1.07%	0.48%	0.16%
2025	9.99%	6.61%	2.87%	1.00%
2030	20.43%	15.79%	7.03%	2.47%
2040	19.85%	15.46%	6.90%	2.43%

Figure 34 and Figure 35 show contributions to the portfolio-level demand response potential by sector and by program type respectively. In each scenario, the largest contributors to the demand response potential are the residential and irrigation sectors. Connected device programs, primarily Smart Thermostat programs, and Direct Load Control (DLC), primarily for irrigation pumping, are the most significant program types.

This analysis considered two different time-varying rates programs – **Critical Peak Pricing without Enabling Technology** (CPP no tech), and **Time Of Use** (TOU) – in each sector. As Tri-State does not control customer rates, implementing this type of demand response program would require a high level of collaboration with electric cooperatives.

Figure 34. Portfolio Demand Response Potential by Sector (2040)

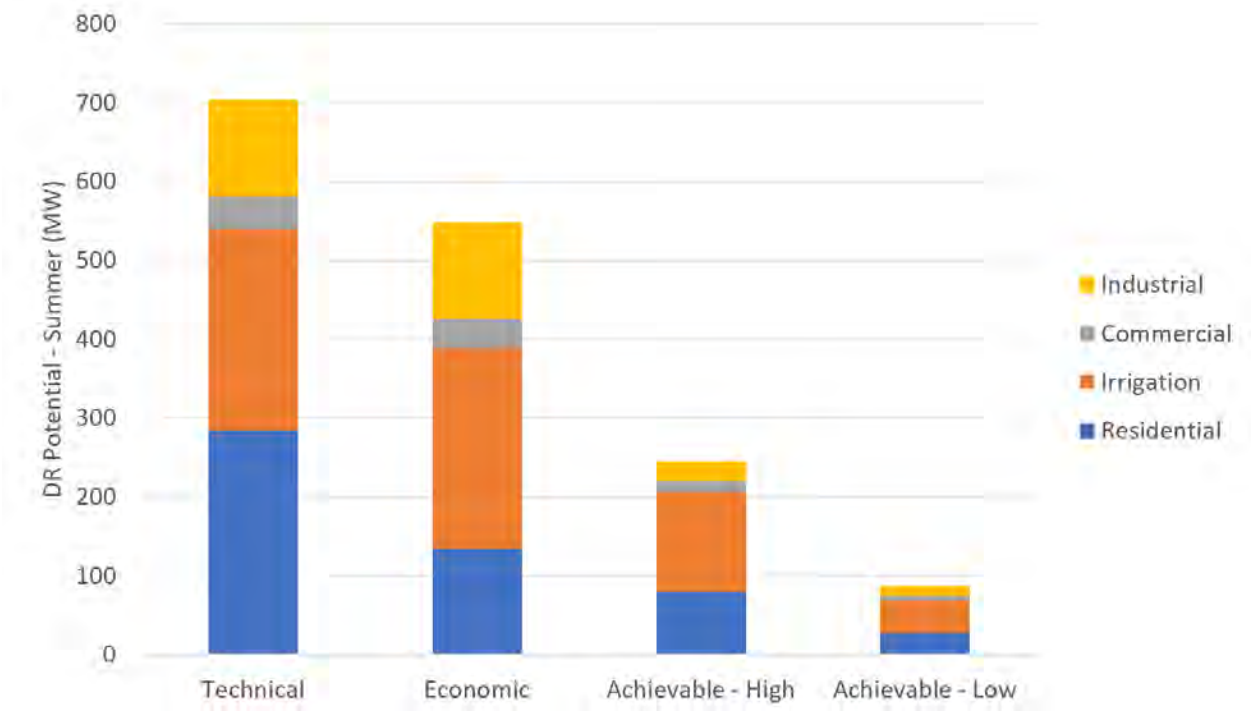
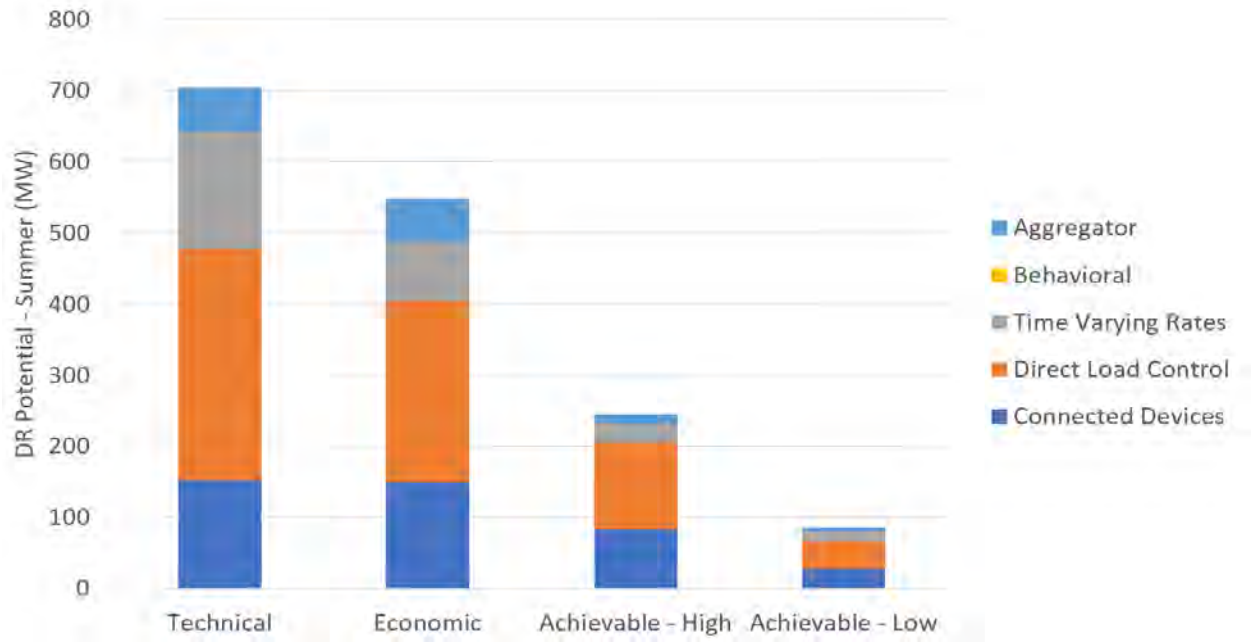


Figure 35. Portfolio Demand Response Potential by Program Type (2040)[16]



[16] Behavioral value is too small to observe.

Table 32 summarizes the demand response cost metrics across the portfolio at each time horizon under the Achievable-Low scenario. By the end of the 20-year study horizon, the estimated 86 MW of peak demand savings is achievable at a cost of $39 million. The Net Present Value TRC ratio of the demand response portfolio is cost effective by the end of the horizon (1.16 TRC), but not cost effective in the more immediate time horizons. This characteristic is largely driven by Tri-State's negligible costs of capacity for 2021 through 2026 with an increase in 2027.

Table 32. Portfolio Demand Response Cost Metrics by Time Horizon (Achievable-Low Scenario)

MILESTONE YEAR	TRC RATIO	CUMULATIVE PROGRAM COST ($)	DR POTENTIAL (MW)
2021	0.02	$5,440,119	5
2025	0.09	$13,818,802	30
2030	0.60	$24,286,062	78
2040	1.16	$39,068,285	86

9.2. Residential Sector Demand Response Potential

Figure 36 shows how demand response potential for residential sector programs grows over the study horizon as program participation increases. Figure 37 shows the contribution from each modeled demand response program for the four considered scenarios in 2040. Two programs were cost effective and thus included in the economic and achievable scenarios – Smart Thermostats and Smart Water Heaters. In the Achievable scenarios, Smart Thermostats achieve the largest share of the demand response potential.

Traditional DLC programs are not cost effective given their higher switch and controller hardware costs. The analysis shows that demand response for residential HVAC unit loads could be more cost effectively managed with a Bring-Your-Own-Thermostat program format utilizing customer-purchased smart thermostat devices. This finding aligns with a nationally observable trend away from the older DLC technology and pager network communications protocols towards programs that use customer-purchased devices and device internet access for communication.

Although a less mature program model, Smart Water heater programs are also increasing in popularity in many jurisdictions nationwide. Some versions of these programs similarly use internet-based communications and would be the most cost effective for Tri-State. Water heaters with built-in grid connection technology are also becoming more widely available, thus eliminating the need for installation of a separate device. As this technology matures, Tri-State could likely develop a successful demand response program to control residential water heaters during peak periods.

Figure 36. Residential Sector Demand Response Potential by Scenario by Year

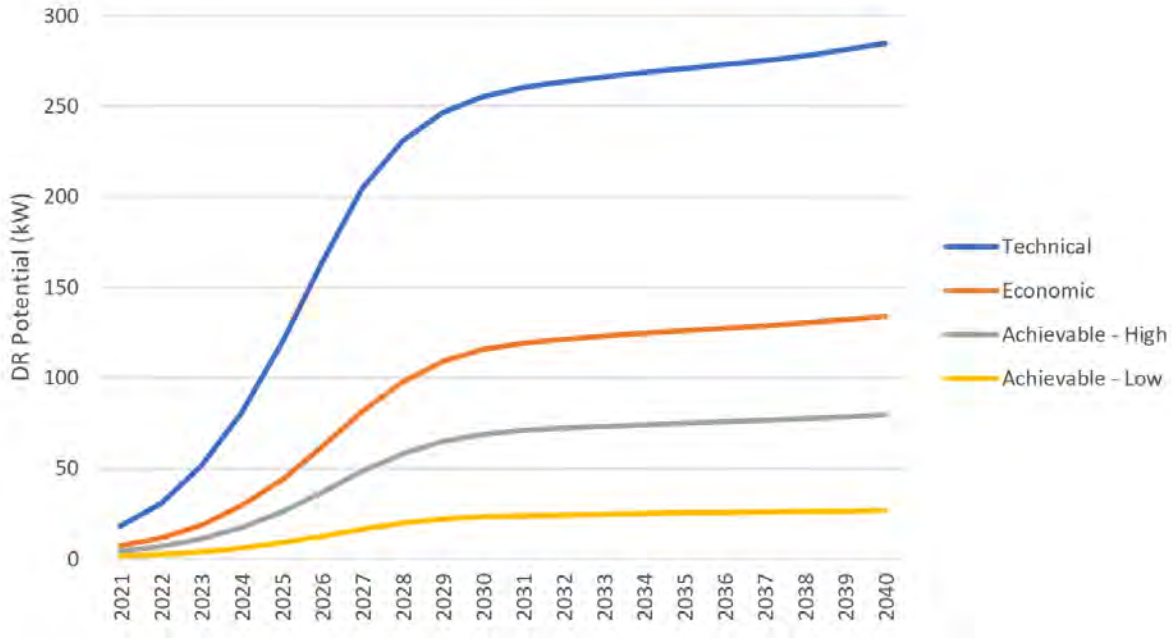
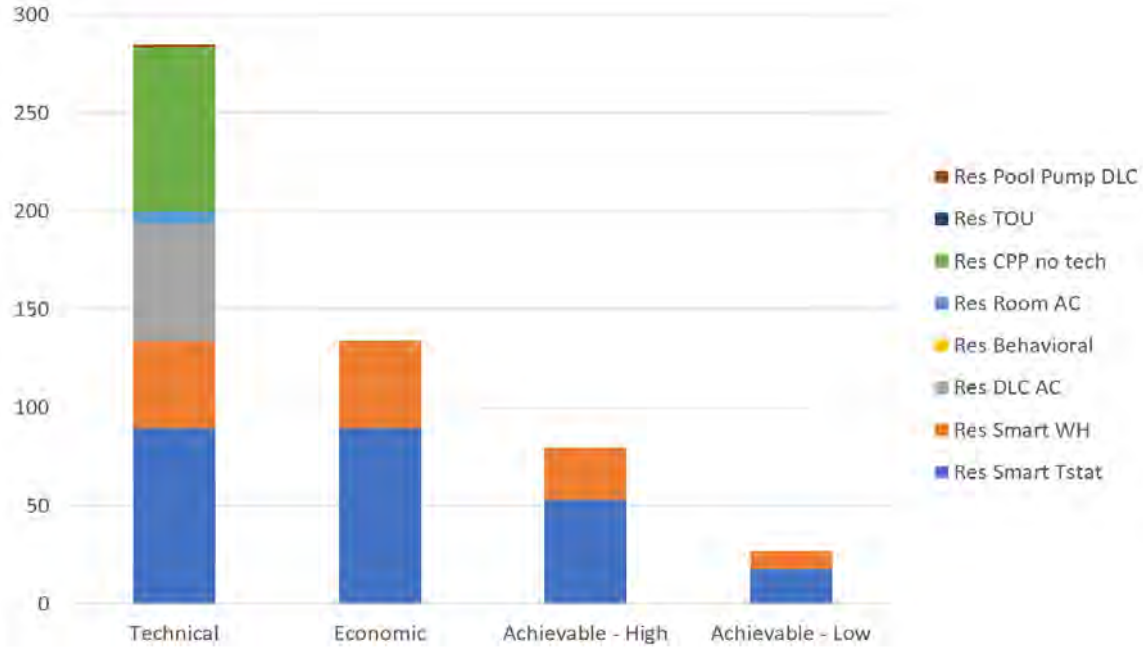


Figure 37. Residential Sector Demand Response Potential by Program (2040)



9.3. Irrigation Sector Demand Response Potential

Figure 38 shows how demand response potential for the irrigation sector programs grows over the study horizon as program participation increases. Figure 39 shows the each modeled demand response program's contribution to the four considered scenarios in 2040. Two programs were cost effective and therefore included in the economic and achievable scenarios – Direct Load Control and Critical Peak Pricing without Enabling Technology. In the Achievable scenarios, Direct Load Control achieves the largest share of the demand response potential.

Successful irrigation DLC programs are currently operational in regions similar to portions of Tri-State's territory, such as Idaho Power's Irrigation Peak Rewards program. That program is designed to target only customers with pumping demand greater than 75 horsepower, thereby focusing economic resources for maximum demand reduction. This analysis included eligibility rates for each region in Tri-State's territory to estimate the regional prevalence of large irrigation pumps. Mountain Colorado, for example, has a 0% eligibility rate because of presumed reliance on lower horsepower pumps for horizontal pumping.

Figure 38. Irrigation Sector Demand Response Potential by Scenario by Year

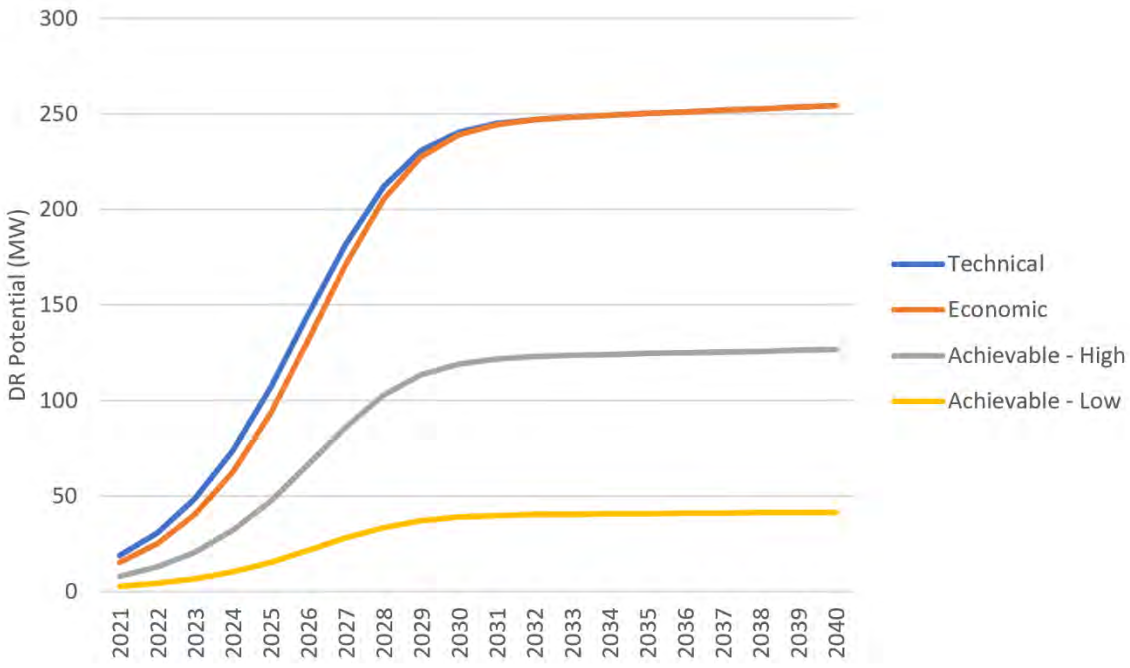
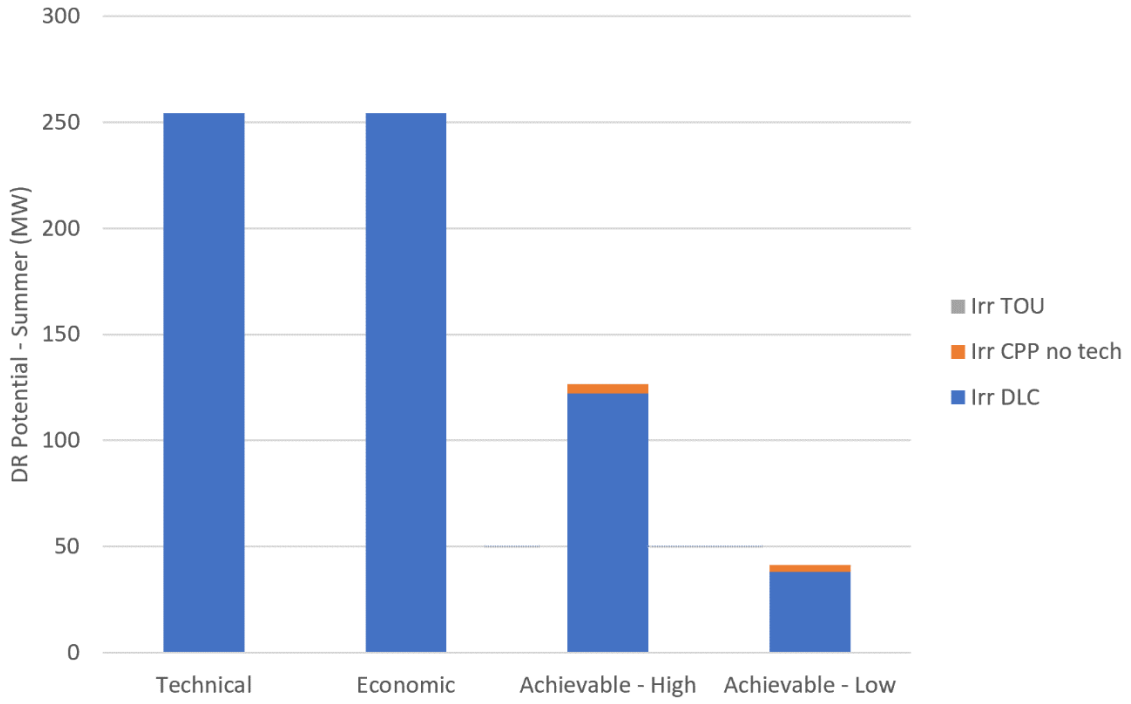


Figure 39. Irrigation Sector Demand Response Potential by Program (2040)



9.4. Commercial Sector Demand Response Potential

Figure 40 shows how demand response potential for irrigation sector programs grows over the study horizon as program participation increases. Figure 41 shows each modeled demand response program's contribution to the four considered scenarios in 2040. Three programs were cost effective and therefore included in the economic and achievable scenarios – Demand Bidding, Smart Thermostats, and Critical Peak Pricing without Enabling Technology. The Smart Thermostats program option was modelled as an extension of the residential Smart Thermostats program and assuming the residential program sector carries a majority of program set-up and administration costs.

Capacity bidding programs offer qualified businesses incentive payments for agreeing to reduce load (for example, lighting, HVAC, escalators/elevators, pumps or some manufacturing equipment) when an event is called. Third-party aggregators often manage these types of programs; thefore, this could be a strategy to overcome Tri-State's lack of direct access to end-users.

Figure 40. Commercial Sector Demand Response Potential by Scenario by Year

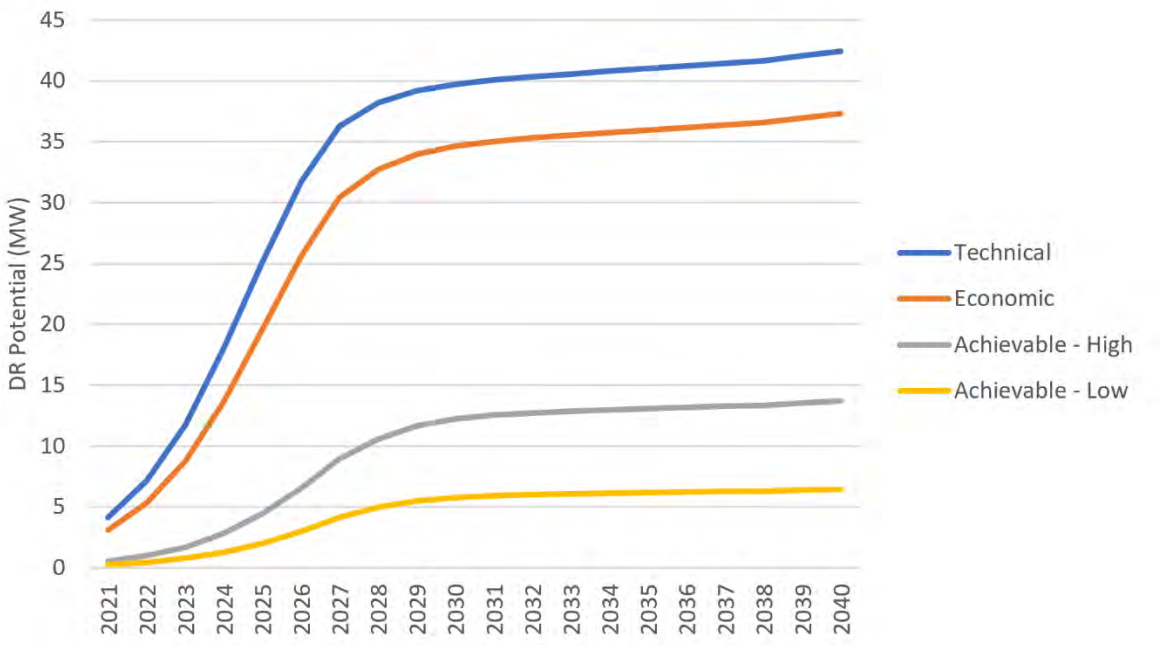
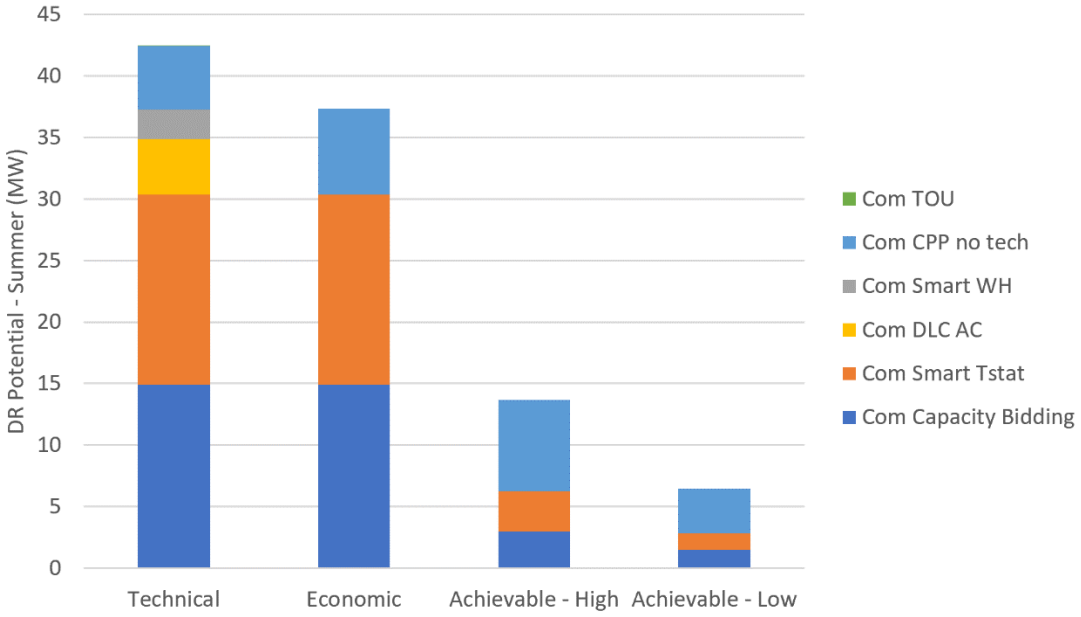


Figure 41. Commercial Sector Demand Response Potential by Program (2040)



9.5. Industrial Sector Demand Response Potential

Figure 42 shows how demand response potential for industrial sector programs grows over the study horizon as program participation increases. Figure 43 shows each modeled demand response program's

contribution to the four considered scenarios in 2040. Two programs are cost effective and therefore included in the economic and achievable scenarios – Capacity Bidding and Critical Peak Pricing without Enabling Technology.

As in the commercial sector, capacity bidding programs offer qualified businesses incentive payments for agreeing to reduce load (for example, lighting, HVAC, escalators/elevators, pumps or some manufacturing equipment) when an event is called. These types of programs are often managed by third-party aggregators, and thus could be a strategy to overcome Tri-State's lack of direct access to end-users.

Figure 42. Industrial Sector Demand Response Potential by Scenario by Year

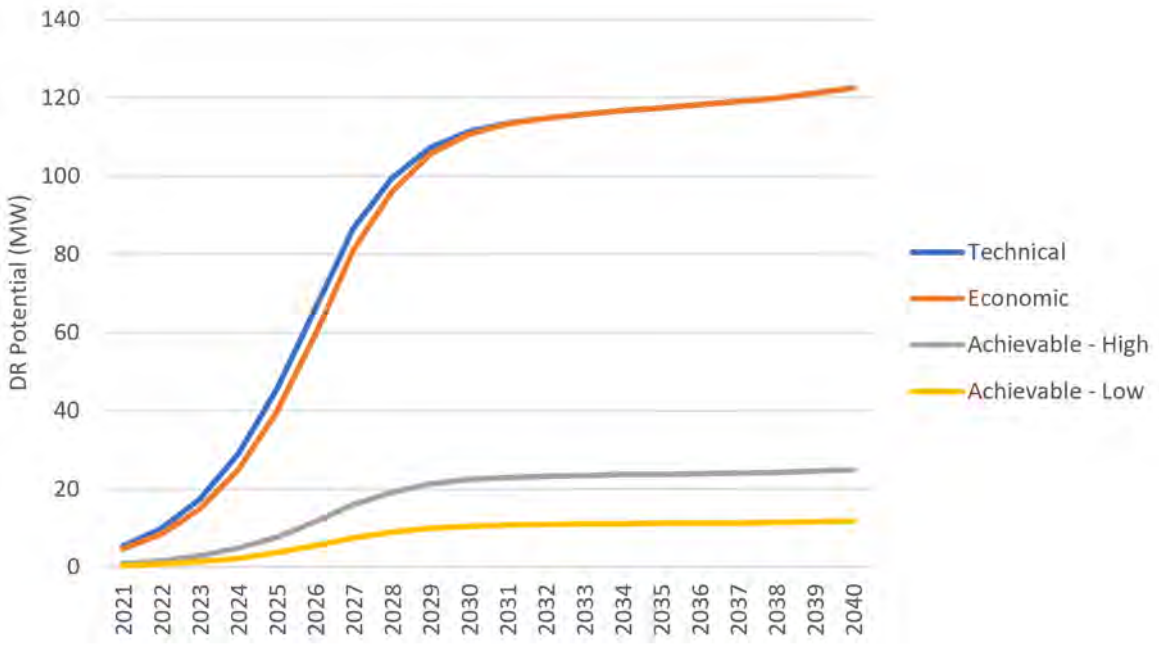
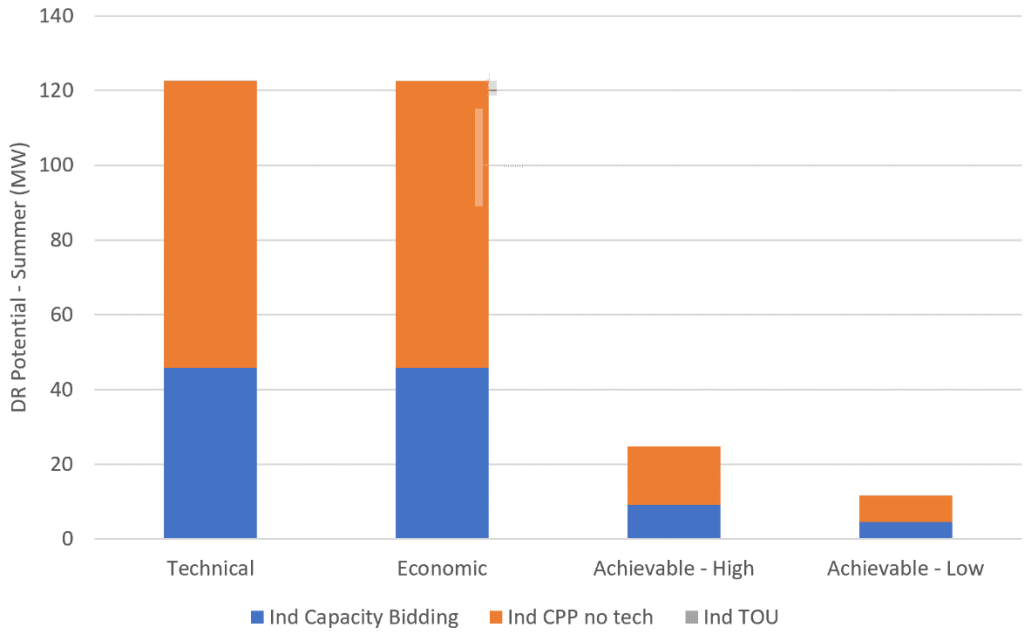


Figure 43. Industrial Sector Demand Response Potential by Program (2040)



10. BEHIND-THE-METER DISTRIBUTED ENERGY RESOURCE POTENTIAL STUDY FINDINGS

10.1. Overview

As discussed in Section 3, the Team assessed rooftop solar PV potential for the residential and non-residential sectors. The technical potential analysis considered the total rooftop area suitable for solar PV within Tri-State's territory and extrapolated potential solar generation based on solar system power density per square foot for each Tri-State region. The Team subsequently screened systems for cost effectiveness and adjusted potential accordingly followed by further adjustments using adoption curves to represent achievable potential.

The Team found no systems to be cost effective for the residential sector under any TRC scenario analyzed. The highest TRC ratio achieved under the residential sector was 0.45 which reflects capacity and CO_2 emissions benefits.

The non-residential sector's very large PV systems are marginally cost effective for specific scenarios. Of these scenarios, the Team found the presence of CO_2 emissions benefits to be crucial as no PV system analyzed surpassed a TRC of 1.0 without inclusion of these benefits.

10.2. Detailed Results

Table 33 and Table 34 summarize the solar PV cumulative annual potential estimated generation for the residential and non-residential sectors, respectively. Electric demand impacts are presented for each sector in Table 35 and Table 36. While technical potential represents 100% adoption for each year, economic and achievable potential reflect applied adoption rates across the study time horizon.

Table 33. Cumulative Residential Generation Potential by Scenario by Time Horizon (MWh)

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE _MAX	ACHIEVABLE _AGG	ACHIEVABLE _MOD	ACHIEVABLE _LOW
2021 (first year)	2,548,130	0	0	0	0	0
2025	13,139,699	0	0	0	0	0
2030	27,290,122	0	0	0	0	0
2040	58,657,889	0	0	0	0	0

Table 34. Cumulative Non-Residential Generation Potential by Scenario by Time Horizon (MWh)

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	6,417,504	10,322	10,310	10,300	10,284	10,256
2025	33,037,716	141,370	139,829	138,809	137,108	134,198
2030	68,427,022	1,011,060	951,078	911,778	851,923	764,606
2040	146,160,272	5,512,777	4,705,933	4,254,001	3,661,295	2,952,911

The demand impacts presented in Table 35 and Table 36 reflect technical capacity based on operational capacity (based on installed nameplate) and coincident peak capacity. Economic and achievable scenarios reflect coincident peak capacity benefits.

Table 35. Summary of Residential Solar PV Electric Demand Market Potential (MW)

MILESTONE YEAR	TECHNICAL DC CAPACITY	TECHNICAL PEAK CAPACITY	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	1,644	400	0	0	0	0	0
2025	1,747	425	0	0	0	0	0
2030	1,878	457	0	0	0	0	0
2040	2,141	521	0	0	0	0	0

Table 36. Summary of Non-Residential Solar PV Electric Demand Market Potential (MW)

MILESTONE YEAR	TECHNICAL DC CAPACITY	TECHNICAL PEAK CAPACITY	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	4,139	1,106	2	2	2	2	2
2025	4,384	1,172	9	9	9	9	9
2030	4,686	1,252	49	45	42	37	31
2040	5,281	1,411	83	69	61	50	39

The cumulative residential generation potential under the technical scenario equates to 57% of the cumulative residential baseline load sales forecast for 2040 (see Table 37). Similarly, the non-residential cumulative generation represents 52% of the cumulative residential baseline load forecast for 2040 (see Table 38). Non-residential economic potential equates to 2.0% of the cumulative residential baseline load forecast for 2040 and ranges from 1.7% to 1.1% under the achievable potential scenarios.

Table 37. Cumulative Residential Generation Potential as % of Baseline Forecast Sales by Year

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	56.1%	0	0	0	0	0
2025	56.3%	0	0	0	0	0
2030	56.4%	0	0	0	0	0
2040	56.5%	0	0	0	0	0

Table 38. Cumulative Non-Residential Generation Potential as % of Baseline Forecast Sales by Year

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	53.9%	0.1%	0.1%	0.1%	0.1%	0.1%
2025	53.4%	0.2%	0.2%	0.2%	0.2%	0.2%
2030	53.1%	0.8%	0.7%	0.7%	0.7%	0.6%
2040	52.0%	2.0%	1.7%	1.5%	1.3%	1.1%

10.3. Technical DER Potential Findings

Overall, solar PV generation has the technical capability of providing over half of Tri-State's sales. However, this value varies considerably by region. Figure 44 and Figure 45 below illustrate cumulative PV generation in 2040 compared to cumulative 2040 sales. For both the residential and non-residential

sectors, PV generation is well below total sales for each region with the exception of Northern New Mexico (for residential) and Southern New Mexico. New Mexico's PV generation exceeds sales due to a high solar irradiance which improves solar efficiency, a relatively high number of buildings, and relatively low energy consumption on average.

Figure 44. 2040 Cumulative Residential PV Generation vs Sales by Region

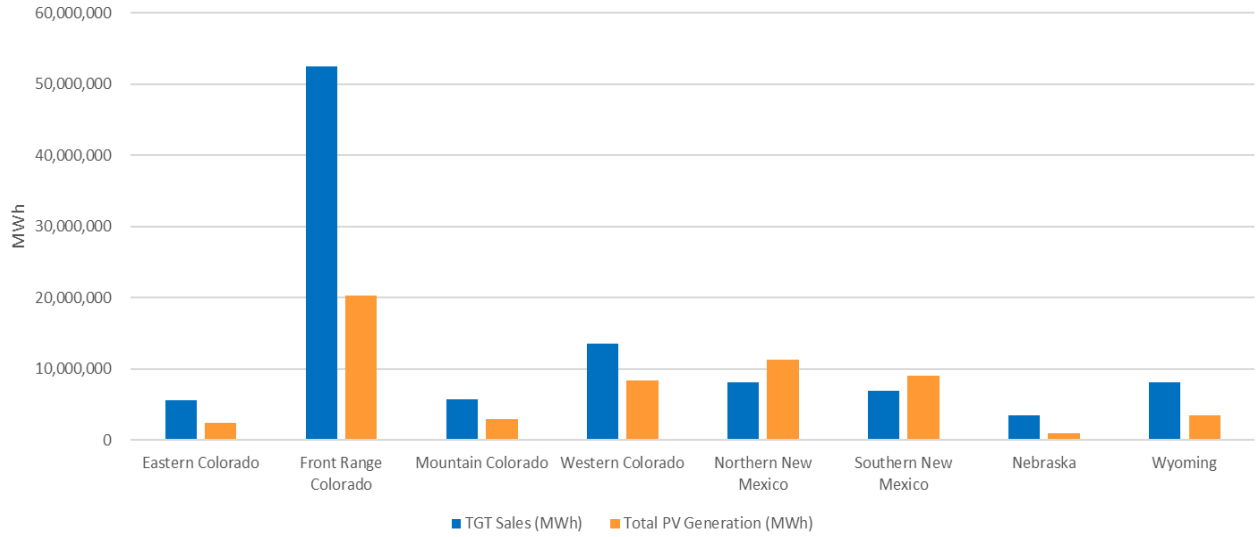
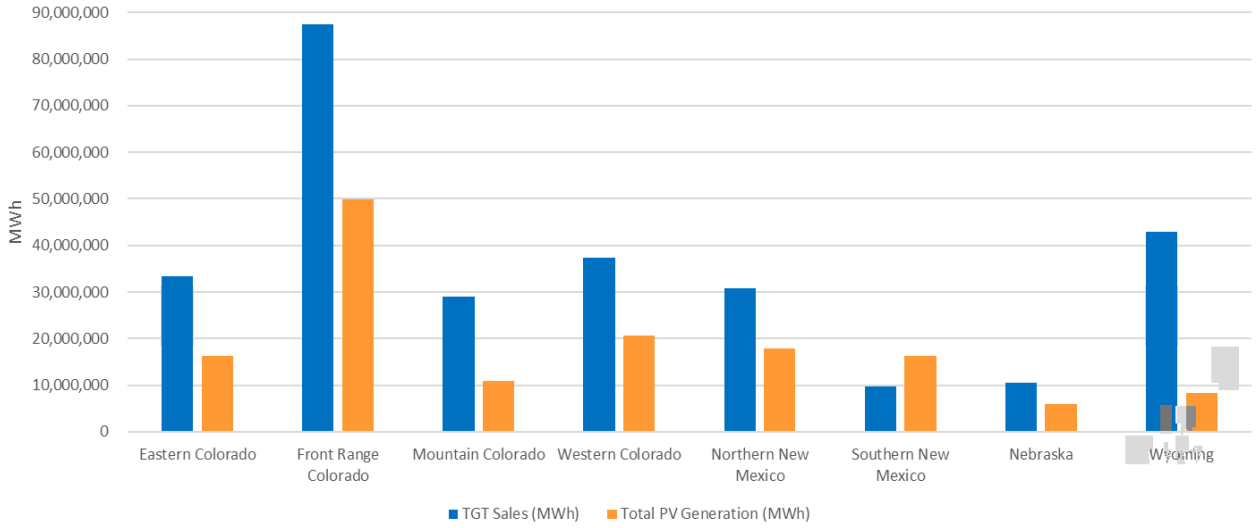


Figure 45. 2040 Cumulative Non-Residential PV Generation vs Sales by Region



10.4. Economic and Achievable DER Potential Findings

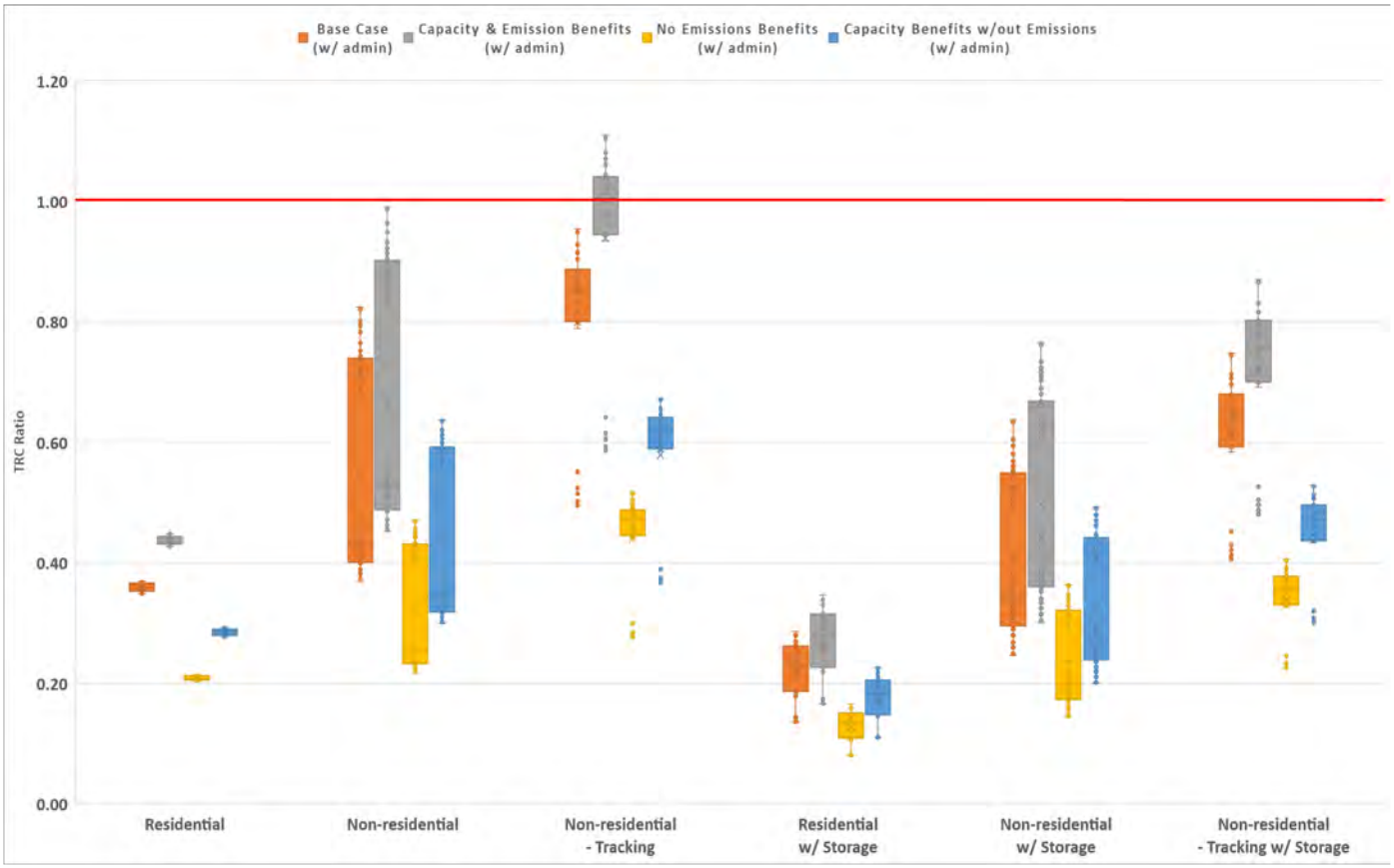
The Team screened economic potential using a TRC hurdle of 1.0 with the inclusion of CO_2 emission benefits based on the social cost of carbon of $46/ton and administrative costs of $0.05/kWh. However,

to understand the sensitivity of various benefit parameters, the team modeled cost effectiveness for multiple scenarios that included various combinations of benefits. Scenarios reviewed included:

- Base case
  - Inclusive of CO_2 emission reduction benefits
- Capacity and emission benefits
  - Base case inclusive of benefits resulting from reduced capacity needs
  - Inclusive of CO_2 emission reduction benefits
- No emissions benefits
  - Base case exclusive of CO_2 emission reduction benefits
- Capacity benefits without emissions benefits
  - Base case inclusive of benefits resulting from reduced capacity needs
  - Exclusive of CO_2 emission reduction benefits

Figure 46 illustrates the results and sensitivities of the solar PV cost effectiveness under each of these scenarios for various categories of solar PV systems included in the potential study. Only one scenario yields TRC ratios that exceed 1.0 – non-residential tracking systems assuming the presence of capacity and CO_2 emission benefits benefits. Also noted is any scenario excluding CO_2 emission benefits results in all solar system configurations analyzed to fail pass cost effectiveness.

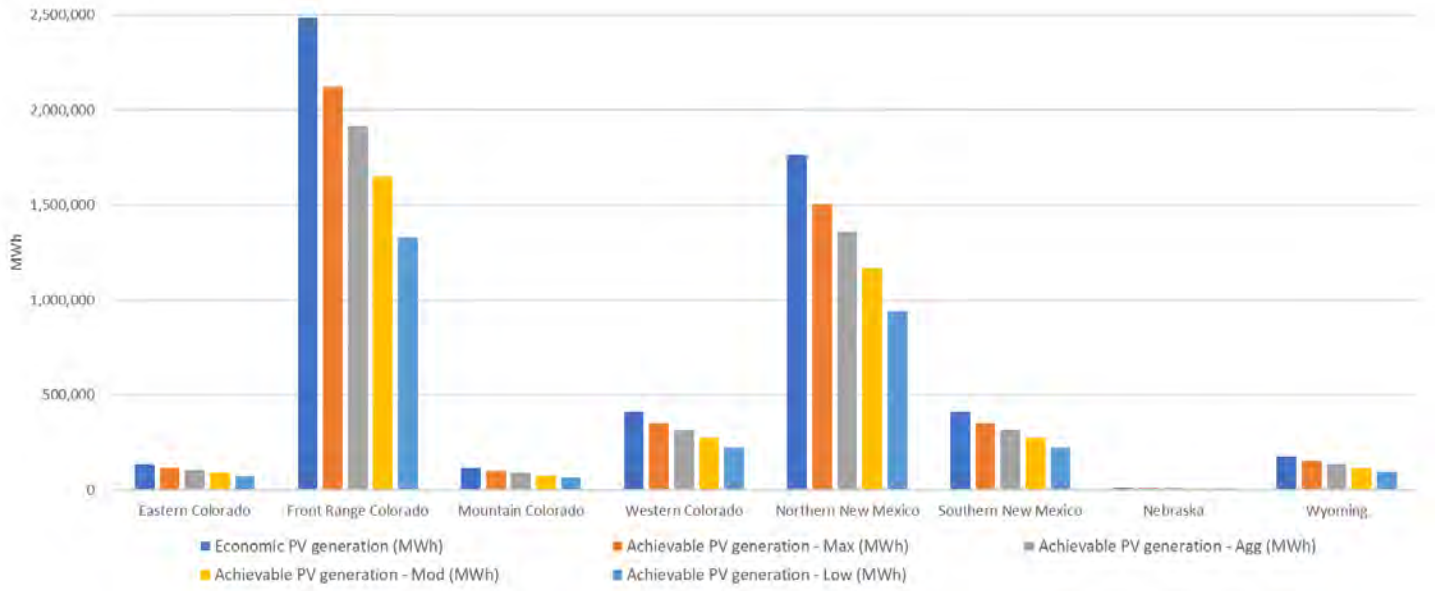
Figure 46. Solar PV TRC Ratios - Multiple Scenarios



Based on the cost effectiveness analysis, the Team modeled economic and achievable potential based on the sole cost effective scenario – non-residential tracking solar systems with capacity and emission benefits. Twenty two solar PV system configurations (9% of all tested measure permutations) passed cost effectiveness including tracking systems varying in size from 250 kW to 2000 kW system capacity. These passing measures have an average TRC of 1.04. This scenario, however, is not applicable throughout the Tri-State territory insofar as capacity constraints are not expected until 2027 (and therefore capacity benefits would not be realized until that time) and carbon benefits are only applicable to Colorado regions (at the time of report publication). Regardless, for the purposes of this report, the Team opted to model economic and achievable potential for all regions in order to inform Tri-State of how solar adoption may occur throughout its territory.

The results of the economic and achievable potential are presented below in Figure 47. Economic and achievable potential is limited due to the small number of solar systems that pass cost effectiveness and due to the physical requirements of these systems – tracking systems are considered ground-mounted for this analysis and therefore are only applicable to sites that are expected to have sufficient land space to host these systems and the system does not generate more energy than the site consumes. Based on these constraints, the team estimated 66 eligible sites across Tri-State's territory for the economic scenario. The number of eligible systems decreases for each achievable potential scenario as solar system payback time increases.

Figure 47. 2040 Cumulative Non-Residential Economic and Achievable Potential by Region



As illustrated in Figure 47, the highest concentration of eligible sites, and thereby the highest potential, are in the Front Range and Northern New Mexico regions. However, as noted earlier, carbon emission benefits at the time of this report publication are not currently a quantifiable benefit in New Mexico, Wyoming, or Nebraska and therefore this reported economic and achievable potential should be considered with that perspective.

11.KEY FINDINGS

At present Tri-State and its member cooperatives deliver some energy efficiency and DR programs, and no DER programs, to their customers. Even with low avoided energy cost benefits for DSM programs within Tri-State's service territory this study identifies significant cost-effective opportunities for energy and demand savings for energy efficiency programs. There are also opportunities for DR programs, but in some cases those program require long term operation to provide cost-effectiveness. DER programs are generally not cost-effective except for larger systems in specific regions. Key findings and observations related to each of these resources is summarized below. It should be noted that the results of this study and the findings presented here are uncertain to a degree and are sensitive customer adoption of DSM intervetions. Furthermore, the dynamic relationship between Tri-State and the member co-ops presents instrinsic challenges to the seamless implementation of DSM programs. These variables should be take into account when considering the results of this study.

11.1. Energy Efficiency

In 2018, Tri-State cooperative members acquired roughly 30 GWh of energy efficiency savings (~0.2% of baseline energy load)[17]. This suggests that Tri-State's members are currently operating programs somewhere between the Achievable-Low and Achievable-Moderate scenarios, which identified energy savings of 27 GWh and 38 GWh respectively in 2021. With coordinated efforts among cooperative members the long-term market opportunity for cost-effective energy efficiency savings in the region served by Tri-State is considerably higher; the average annual savings potential is 115 GWh over the study's 20-year time horizon for the Achievable-Moderate scenario. Additional key findings within the energy efficiency assessment include:

- 20-year average annual energy savings are just under 115 GWh (0.66% of baseline energy load) at a total program cost of $24M per year ($212/MWh acquired).
- 20-year levelized cost of energy to acquire all energy savings is $21.55/MWh.
- While the industrial sector represents the largest market opportunity (43% of 20-year potential), the residential sector represents the biggest opportunity (35% of potential) compared to its load share (28% of load).
- The commercial sector holds the most cost-effective savings opportunities with a TRC of 1.93 and average 20-year acquisition cost of $171/MWh.
- Pumps (primarily within the industrial sector) represent the largest end-use opportunity across the portfolio at 25% of 20-year cumulative energy savings – much of this opportunity resides with several large Liquid Mining and Pipeline Transportation customers.
- Even with rapid market transformation to LEDs for A-lamp bulbs, there is still considerable savings opportunities in the commercial lighting (21% of potential) and Residential lighting (19% of potential) end-uses – these end-uses are also among the most cost effective with acquisition costs of $150/MWh and $200/MWh respectively.

[17] Tri-State Generation and Transmission, Inc. 2018 Annual Report. (p. 12).

- HVAC measures account for 18% of savings potential – though are relatively expensive with an average acquisition cost of roughly $275/MWh.
- With zero capacity benefits in the first seven years, Home Energy Reports did not pass the study's TRC cost-effectiveness screen until 2028; after which the measure becomes a major opportunity contributing to almost 6% of portfolio savings potential.
- High/medium bay linear lamp and fixture conversions to LED technology represents more than 60% of cumulative energy savings potential in the commercial sector by 2040.
- Non-EISA compliant light bulbs contribute more than 45% to cumulative energy savings potential by 2040 in the residential sector.
- Upgrading existing air source heat pumps to higher efficiency models represent more than 6% of cumulative energy savings potential by 2040 in the residential sector.

11.2. Demand Response

The analysis finds that a Tri-State portfolio of demand response programs could cost effectively contribute 86 MW of demand curtailment during the summer peak window by the end of the 20-year time horizon. This result (the Achievable-Low scenario) assumes conservative realistic participation rates across Tri-State's territory. Additional key findings from the demand response potential analysis include:

- High levels of investment in marketing and incentives could yield up to 245 MW of potential (Achievable-High scenario).
- Potential reduction in portfolio-level baseline forecast demand ranges from 2.4% (Achievable-Low) to 6.9% (Achievable-High).
- The residential and irrigation sectors hold the greatest potential for demand response program savings.
- In general, the Direct Load Control program model holds the greatest potential for savings. Among the two Achievable scenarios the most promising program models within each each sector are:
    - Residential: Smart Thermostats and Smart Water Heaters
    - Commercial sector: Critical Peak Pricing and Smart Thermostats
    - Industrial: Critical Peak Pricing
    - Irrigation: Direct Load Control

11.3. Behind-The-Meter Distributed Generation

We analyzed potential for rooftop solar PV across Tri-State's territory for both the residential and non-residential sectors. Ultimately we found rooftop solar PV to not be cost effective for the residential sector. The non-residential sector is cost effective for very large ground-mounted tracking solar arrays when including key benefits of capacity and emission benefits. Additional findings from the distributed energy resource potential analysis include:

- Technical potential solar generation for both residential and non-residential sectors can equate to just over half of total sales.
- No residential solar PV measures pass cost effectiveness under any benefit-cost scenario analyzed in the study.
- The sole cost effective scenario includes both capacity benefits and CO_2 emissions benefits. Just 9% of analyzed measure permutations pass this cost effectiveness scenario and are characterized as non-residential ground-mounted tracking systems varying from 250 kW to 2000 kW system capacity. These system measures have an average TRC of 1.04.
- Cumulative non-residential economic potential solar PV generation equates to 2.0% of 2040 cumulative sales; achievable potential solar PV generation equates to 1.7% - 1.1% of 2040 cumulative sales. It is noted that while these potential savings reflect the entire Tri-State territory, the sole cost effective scenario is not applicable to regions outside of Colorado as emissions are not a quantifiable benefit at the time of this report publication.

Attachment Vol II 5-2 B&V Loss of Load Probability Study

Report on Loss of Load Probability Analysis

BV PROJECT NO. 404347

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PREPARED IN CONSULTATION WITH

Tri-State Generation & Transmission Association

14 October 2020

BLACK & VEATCH

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1.0 Executive Summary

Black & Veatch Management Consulting LLC (Black & Veatch) was retained by Tri-State Generation & Transmission Association (Tri-State) to analyze the potential for loss of load within the Tri-State system. Black & Veatch ("we" or "us") has utilized production cost modeling software and in-house expertise to conduct a probabilistic loss of load probability (LOLP) analysis for the Tri-State system for two forecast years, 2025 and 2030, under four capacity expansion (CE) plans. The four CE plans were provided to us by Tri-State and include varying load forecast and capacity addition assumptions. The four CE plans are as follows:

1. Base: Business as usual scenario without greenhouse gas (GHG) emissions reduction requirements in Colorado using market parameters and unit conditions as of March 2020.
2. MAX: Low load scenario representing a 10 percent reduction in system demand and related energy with corresponding reductions in losses and planning reserve margin.
3. MARS: High distributed generation scenario representing an increase in distributed generation equivalent to 10 percent of system demand.
4. Carbon Reduction: GHG reduction scenario with substantial reduction in GHG emissions by 2030 from 2005 baseline.

A production cost model using PLEXOS software was configured to represent the Tri-State system under each of these alternative future CE plans. Assumptions and forecasts were provided by Tri-State including load forecasts, contract purchases and sales, hydro monthly energy constraints, and generator financial and operational characteristics. Outputs from initial runs of the PLEXOS model were then compared to outputs from Tri-State's prior simulation of the Base CE using its own production cost modeling tool.[1] This was done to confirm the accuracy of the PLEXOS model prior to conducting the LOLP analysis. For each year and each capacity expansion plan, the PLEXOS model was then run 20 times with different risk draws to simulate random forced outages within the Tri-State system. The mean and standard deviation LOLP was calculated from the 20 risk samples. We found that the LOLP for the Base CE and MARS CE plans exceeded the LOLP target of 1 day in 10 years for the year 2030 while all other CE plans met the LOLP target. To compensate for these exceedances, two (2) and three (3) 100 MW 4-hour batteries with 400 MWh of energy storage capability were added to the Base CE and MARS CE plans, respectively. The PLEXOS model was run again, and results showed that the mean LOLP target was met for both the Base and MARS capacity expansion plans.

[1] File "March Base 2020 PO Annual data Confidential.xls" (March 2020 Base)

2.0 Scope

Tri-State retained Black & Veatch to analyze the impacts of increased renewable generation and thermal power plant retirements on reliability of the Tri-State power generation system. Generation reliability is traditionally measured in a "static" fashion by observing the forecast capacity reserve margin which is the surplus of forecast generation capacity above forecast peak load measured on an annual basis. However, in high renewable scenarios a dynamic LOLP analysis is a more appropriate because both renewable energy available to serve load and net peak load (load net of renewable generation behind the meter) are highly variable resulting in a highly variable reserve margin. An LOLP analysis allows consideration of this variable margin and a more rigorous probabilistic analysis of conventional generating unit outages as opposed to forecasted capacity reserve margin alone.

The objective for this analysis was to use a production cost model (PCM) implemented in PLEXOS to replicate Tri-State's various future expansion and operation scenarios and to examine the resulting LOLP. The LOLP is a measure of the likelihood of failing to meet load which is present on the Tri-State system and being forced to curtail load in a period with higher load than generation capability. The resulting LOLP under each scenario should not exceed a rate of 1 day in 10 years which is the typical reliability threshold expected for resource portfolios such as that of Tri-State.

The scope of the LOLP analysis was limited to two forecast years (2025 and 2030) and the four CE plans (Base, MAX, MARS, Carbon Reduction) developed by Tri-State. Therefore, the LOLP was forecast for a total of eight cases using the PLEXOS PCM developed for this analysis.

3.0 Methodology

Black & Veatch used a commercial PCM software package, PLEXOS[2], for this analysis. PLEXOS is a fundamental-based PCM software package that provides an optimal solution to meet a given load with a set of generators subject to constraints such as generator operational constraints, transmission constraints, and policy constraints. PLEXOS is widely used in the industry for long-term planning, including use by the California Independent System Operator (CAISO) for integrated resource planning (IRP) in the Western Electricity Coordinating Council (WECC)[3]. Key features of PLEXOS include capacity expansion planning, unit commitment and dispatch, co-optimization of energy and ancillary service markets, and evaluation of Monte-Carlo stochastic algorithms.

Tri-State provided data relevant to their system to conduct the LOLP analysis, including load forecasts, transmission transfer limits, operating reserve requirements with the Northwest Power Pool (NWPP) and the Southwest Reserve Sharing Group (SRSG), fuel forecasts, and generator financial and operational characteristics such as capacity, minimum stable level, heat rates, variable costs, minimum up/down time, ramp rates, outage rates, hourly renewable generation profiles, and monthly hydro generation. Contract purchases and sales were also provided and included in the model. Once configured, the model was assessed in comparison to the March 2020 Base dispatch profile provided by Tri-State. The evaluation primarily consisted of verifying annual generation quantities for each generator and contract to ensure PLEXOS was properly configured.

Four Tri-State CE plans were analyzed including the Base, MAX, MARS, and Carbon Reduction plans. Each plan has unique resource additions, and the MAX plan had a lower load forecast as compared to the other scenarios as shown in Table 1.

Table 1 Summary of Installed Capacity for Each Capacity Expansion Plan

	2025				2030			
Plan Name	Base	MAX	MARS	Carbon Red.	Base	MAX	MARS	Carbon Red.
Peak Load (MW)	3076	2636	3076	3076	3350	2904	3350	3350
Solar Additions (MW)	0	0	0	200	800	100	500	1300
Wind Additions (MW)	0	0	0	200	0	100	200	400
Battery Additions (MW)	0	0	0	75	0	0	0	750
Thermal Additions (MW)	0	0	0	0	596	410	575	265
Total Capacity Additions (MW)	0	0	0	475	1396	1410	1275	2715
Capacity Retirements (MW)	0	0	0	0	648	648	648	648
Net Capacity Additions (MW)	0	0	0	475	748	762	627	2067

To determine the LOLP in each scenario, we used PLEXOS' Monte-Carlo stochastic algorithms to randomly generate a set of forced outages based on forced outage rate and mean time to repair

[2] https://energyexemplar.com/solutions/plexos/
[3] http://www.caiso.com/Documents/2019-01-31-Comments_ProductionCostModeling-IRPProceeding-R16-02-007.pdf

assumptions (each a “risk draw”). The “short term” module of PLEXOS was utilized. PLEXOS was configured and run to simulate 20 risk draws for each year assessed (2025 and 2030) under each CE plan. Outputs from the simulation included mean and standard deviation of the number of hours with unserved energy (USE) each year. From this, an LOLP was calculated by dividing the USE by the total number of hours in the year. If the resulting LOLP exceeded the 1 day in 10 years maximum allowed, an amount of additional battery storage capacity was added to the capacity expansion plan and the simulation rerun. This was done in an iterative fashion until the target LOLP was achieved.

4.0 Results & Discussion

An LOLP of less than 1 day in 10 years corresponds to an LOLP of less than 0.0274 percent on an annual hour basis. The results of the LOLP analysis, including the mean and standard deviation of unserved energy (USE) hours and LOLP percent for each scenario, are shown in Table 2.

Table 2 Summary of USE and LOLP Prior to Battery Additions

	2025				2030			
CE Plan Name	Base	MAX	MARS	Carbon Red.	Base	MAX	MARS	Carbon Red.
Mean USE (hr)	1.95	0.00	1.95	0.00	9.20	1.45	25.75	0.70
Std. Dev. USE (hr)	2.31	0.00	2.31	0.00	4.77	2.48	6.15	1.30
Mean LOLP (%)	0.02	0.00	0.02	0.00	**0.11**	0.02	**0.29**	0.01
Std. Dev. LOLP (%)	0.03	0.00	0.03	0.00	0.05	0.03	0.07	0.01

Results for the year 2025 show that each CE plan was below the LOLP target on a mean LOLP basis. Results for the MAX CE and Carbon Reduction CE plans had zero mean LOLP. This is due to the MAX CE plan having a lower load forecast as compared to the other CE plans and the Carbon Reduction CE plan having capacity additions which are not present in the other CE plans. The MARS CE plan and the Base CE plan had some unserved load and thus non-zero mean LOLPs. Their LOLPs are identical in 2025 because the CE plans are identical up to that point in time.

Results for the year 2030 show that the LOLPs increased for each CE plan, above the LOLP target for two of them (shown in bold). The Base and MARS CE plans exceeded the LOLP target with mean LOLPs of 0.11% and 0.29% respectively. For the Base CE plan, this was due to load growth and not enough firm capacity growth to maintain LOLP below the target level. For MARS, this was due to the plan having the lowest net capacity additions by 2030 as compared to the other CE plans. While the Max CE plan had a mean LOLP (0.02%) under the target LOLP, the standard deviation was high (0.03%) suggesting certain conditions where the LOLP can be exceeded. For the Carbon Reduction CE plan, the mean LOLP (0.01%) was under the LOLP target by enough that the standard deviation (0.01%) does not suggest likely conditions where the LOLP would be exceeded.

To compensate for the excess LOLP in the Base CE and MARS CE plans, additional capacity was added to the Base CE and MARS CE plans in the year 2030 and the simulations re-run. Given Tri-State's long-term goal of achieving GHG reductions, we added generic new battery storage resources instead of thermal resources. The results of the LOLP analysis for the Base and MARS CE plans following addition of the energy storage are shown in Table 3.

Table 3 Summary of USE and LOLP After Battery Additions

	2025				2030			
Plan Name	Base	MAX	MARS	Carbon Red.	Base	MAX	MARS	Carbon Red.
Mean USE (hr)	1.95	0.00	1.95	0.00	1.7	1.45	0.9	0.70
Std. Dev. USE (hr)	2.31	0.00	2.31	0.00	1.92	2.48	1.17	1.30

	2025				2030			
Mean LOLP (%)	0.02	0.00	0.02	0.00	**0.02**	0.02	**0.01**	0.01
Std. Dev. LOLP (%)	0.03	0.00	0.03	0.00	0.02	0.03	0.01	0.01

Results show that both the Base CE and the MARS CE achieve the LOLP target in 2030 with addition of batteries (shown in bold). We found that for the Base CE, two additional 100 MW 4-hour batteries with 400 MWh of storage capacity are required to achieve the LOLP target. These batteries were added in eastern Colorado and Wyoming. For the MARS CE, three additional 100 MW 4-hour batteries with 400 MWh of capacity are required to meet the LOLP target. These batteries were added in western Colorado. While the Base CE plan had a mean LOLP (0.02%) under the target LOLP, the standard deviation was high (0.02%) suggesting certain conditions where the LOLP can be exceeded. As an additional sensitivity, we added three batteries to the Base CE (one in each of eastern Colorado, western Colorado, and Wyoming) and reran the simulation. Results (not shown here) indicated that the sum of the mean LOLP plus standard deviation LOLP was below the LOLP target.

END OF REPORT

Attachment Vol II 5-3 B&V Modified Effective Load Carrying Capability Study

Report on Effective Load Carrying Capability

BV PROJECT NO. 404347

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PREPARED IN CONSULTATION WITH

Tri-State Generation & Transmission Association

14 October 2020

BLACK & VEATCH

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1.0 Executive Summary

Tri-State Generation & Transmission Association ("Tri-State") forecasts the effective load carrying capability (ELCC) of its existing and planned new solar photovoltaic (PV) and wind resources for the purposes of modeling the long-term resource adequacy of its resource plans as part of the energy resource planning process. Tri-State retained Black & Veatch ("we" or "us") to forecast ELCC Values for the overall system that includes the planned solar and wind resources of a representative expansion plan, specifically (the "Analysis"). This report presents the results of the Analysis.

Results show that the System ELCC, as a percent of installed capacity, is forecast to decline as additional planned solar and wind resources are added to the Tri-State system. Effectively, the solar resources provide capacity during peak daytime hours only. That causes the "net peak" to shift to non-solar generating hours, in effect, causing additional solar to have lower capacity value because the added solar is not reducing the net peak. In contrast, results show that the planned additional wind resources will have relatively good capacity value. The Wind Only ELCC is generally increasing over time which indicates the planned additional wind resources will be generating during the new net peak hours and therefore contribute to System ELCC. It is also worth noting that the expansion plan evaluated has a specific resource mix of expansion plan additions, and as the mix is modified from plan to plan a reiterative process to address impacts to ELCC is required.

2.0 Methodology

The basis for calculating the ELCC Values for photovoltaic and wind power is partly based on the methods published by the U.S. Department of Energy (DOE) in document number PNNL-22117 entitled Capacity Value of PV and Wind Generation in the NV Energy System (the "DOE Paper"). Determining ELCC Values is important for estimating additional load that can be served by new PV and wind installations. Variability in solar and wind generation causes wind and solar generation's contribution to resource adequacy to be determined differently from conventional generation.

Our Analysis used the capacity value method described in Chapter 5 of the DOE Paper (the "Capacity Value Method"). The Capacity Value Method defines capacity value as the equivalent perfectly reliable generation capacity that, when used to replace intermittent renewable generation, the system has the same loss of load expectation (LOLE). The Capacity Value Method is a reasonable approximation to a full ELCC method which relies on calculation of loss of load probability (LOLP) and LOLE in every hour. When demand is very low compared to installed capacity, as it is in most systems, the LOLP in low demand hours is negligible. Since the LOLP in low demand hours is very small, the contribution to the annual LOLE is very small. The LOLE result will probably not be affected much if the LOLP in those low demand hours is ignored; and determination of the ELCC can be reasonably accurate using the top 2.5% Net Peak Load hours by determining the average contribution of the renewable generation to meet load during the top 2.5% Net Peak Load hours, as is done under the Capacity Value Method. The Capacity Value Method approximates the ELCC method and eliminates the need for conventional generation data and the calculation of the system LOLP. The Capacity Value Method yields results that are nearly as accurate as the full ELCC method and the analysis can be performed very quickly. The Capacity Value Method is also an improvement over the Peak Period Capacity Factor (PPCF) method mentioned in the DOE Paper.

3.0 Scope and Assumptions

A working model of the Capacity Value Method was developed for the Tri-State system. The ELCC was determined for the renewable generators defined in Table 1 below and for the hourly demand summarized in Table 2 for the Colorado, New Mexico, and Wyoming regions of the Tri-State system (excludes Nebraska). The aggregated system results assume no transmission constraints on flow between locations.

Table 1 – Summary of Renewable Generation Characteristics

ENTITY	CAPACITY (MW) AC	INSTALLATION DATE	RETIREMENT DATE	LOCATION
Alta Luna Solar	25	1/1/2019	1/31/2042	New Mexico
Carousel Wind	150	1/1/2019	7/31/2041	East Colorado
Colorado Highlands Wind	91	1/1/2019	12/31/2032	East Colorado
Crossing Trails Wind	104	12/1/2020	12/1/2035	East Colorado
Cimarron Solar	30	1/1/2019	11/24/2035	New Mexico
Kit Carson Wind	51	1/1/2019	11/30/2030	East Colorado
San Isabel Solar	30	1/1/2019	12/31/2041	East Colorado
Spanish Peaks Solar	100	11/1/2023	11/30/2038	East Colorado
Twin Buttes Wind	76	1/1/2019	12/31/2042	East Colorado
Axial Basin Solar	145	12/31/2023	12/31/2038	West Colorado
Coyote Gulch Solar	120	12/31/2023	12/31/2038	West Colorado
Dolores Canyon Solar	110	12/31/2023	12/31/2038	West Colorado
Niyol Wind	200	12/31/2021	12/31/2041	East Colorado
Spanish Peaks II Solar	40	12/31/2023	12/31/2038	New Mexico
Escalante Solar	200	11/30/2023	11/30/2040	New Mexico
WCO Tracking Solar Simulated	200	1/1/2028		West Colorado
WCO Tracking Solar Simulated	200	1/1/2029		West Colorado
WCO Tracking Solar Simulated	100	1/1/2032		West Colorado
WCO Tracking Solar Simulated	100	1/1/2034		West Colorado
WCO Tracking Solar Simulated	100	1/1/2035		West Colorado
WCO Tracking Solar Simulated	100	1/1/2036		West Colorado
WCO Tracking Solar Simulated	100	1/1/2037		West Colorado
ECO Tracking Solar Simulated	200	1/1/2030		East Colorado
ECO Tracking Solar Simulated	100	1/1/2036		East Colorado
NM Tracking Solar Simulated	50	1/1/2029		New Mexico
NM Tracking Solar Simulated	50	1/1/2030		New Mexico

NM Fixed Solar Simulated	50	1/1/2029		New Mexico
NM Fixed Solar Simulated	50	1/1/2030		New Mexico
NM Wind Simulated	100	1/1/2039		New Mexico
NM Wind Simulated	200	1/1/2040		New Mexico
WY Wind Simulated	100	1/1/2028		Wyoming
WY Wind Simulated	100	1/1/2029		Wyoming
WY Wind Simulated	100	1/1/2030		Wyoming
ECO Wind Simulated	200	1/1/2040		East Colorado

Table 2 - Summary of Model System Annual Energy and Peak Demands

YEAR	ANNUAL ENERGY DEMAND (GWH)	ANNUAL PEAK DEMAND (MW)	YEAR	ANNUAL ENERGY DEMAND (GWH)	ANNUAL PEAK DEMAND (MW)
2020	16,271	2,643			
2021	16,432	2,751	**2031**	19,406	3,230
2022	16,744	2,773	**2032**	19,725	3,264
2023	17,058	2,817	**2033**	20,036	3,296
2024	17,378	2,919	**2034**	20,357	3,336
2025	17,591	2,930	**2035**	20,681	3,403
2026	17,813	2,959	**2036**	21,012	3,481
2027	18,131	3,016	**2037**	21,330	3,504
2028	18,458	3,039	**2038**	21,654	3,563
2029	18,774	3,103	**2039**	21,977	3,600
2030	19,091	3,191	**2040**	22,300	3,656

4.0 Results & Discussion

Table 3 contains the results of the Analysis for each of the years 2020 through 2040. The Peak MW is the coincident peak demand for each year for the defined system analyzed. The Installed Solar Capacity, Installed Wind Capacity, and Installed Renewable Capacity columns show each year's installed solar, wind, and total wind and solar capacity based on existing and proposed renewable capacity additions.

Table 1 ELCC for Wind, Solar, and Combined Wind and Solar in Tri-State System (exclusive of the Nebraska area)

	Peak	Installed Solar Capacity	Installed Wind Capacity	Installed Renewable Capacity	Solar Only ELCC	Wind Only ELCC	Combined Solar and Wind (System) ELCC	Solar Only ELCC	Wind Only ELCC	System ELCC	Incremental Solar Only ELCC	Incremental Wind Only ELCC
Year	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**% of Installed Capacity**				
2020	2,643	85	368	453	36	120	156	42.5%	32.7%	34.5%	43.7%	27.9%
2021	2,751	85	472	557	37	194	231	43.5%	41.1%	41.4%	41.5%	37.5%
2022	2,773	85	672	757	39	257	296	45.4%	38.3%	39.1%	45.1%	31.8%
2023	2,817	85	672	757	39	260	299	46.2%	38.7%	39.6%	44.1%	30.4%
2024	2,919	800	672	1,472	226	246	473	28.3%	36.6%	32.1%	13.3%	32.8%
2025	2,930	800	672	1,472	226	236	462	28.3%	35.2%	31.4%	15.0%	31.6%
2026	2,959	800	672	1,472	223	252	475	27.9%	37.5%	32.3%	14.5%	34.1%
2027	3,016	800	672	1,472	224	270	494	28.0%	40.2%	33.6%	14.0%	35.1%
2028	3,039	1,000	772	1,772	264	292	557	26.4%	37.8%	31.4%	11.4%	35.3%
2029	3,103	1,300	872	2,172	281	314	595	21.6%	36.0%	27.4%	7.4%	34.8%
2030	3,191	1,600	972	2,572	317	328	646	19.8%	33.8%	25.1%	5.1%	32.2%
2031	3,230	1,600	921	2,521	310	330	640	19.4%	35.8%	25.4%	5.8%	32.9%
2032	3,264	1,700	921	2,621	314	318	632	18.5%	34.5%	24.1%	5.2%	31.8%
2033	3,296	1,700	830	2,530	301	347	649	17.7%	41.8%	25.6%	5.3%	36.6%
2034	3,336	1,800	830	2,630	303	337	641	16.9%	40.7%	24.4%	4.7%	34.8%
2035	3,403	1,900	830	2,730	324	323	646	17.0%	38.9%	23.7%	5.2%	36.7%
2036	3,481	2,070	726	2,796	358	276	634	17.3%	38.1%	22.7%	5.1%	40.6%
2037	3,504	2,170	726	2,896	361	281	642	16.6%	38.7%	22.2%	4.5%	39.0%
2038	3,563	2,170	726	2,896	357	270	627	16.4%	37.2%	21.6%	4.5%	39.3%
2039	3,600	1,655	826	2,481	313	313	626	18.9%	37.9%	25.2%	4.2%	38.1%
2040	3,656	1,655	1,226	2,881	328	433	761	19.8%	35.3%	26.4%	3.6%	34.0%

Although wind and solar ELCCs are not separable per sei, in that for example, not only is the Solar ELCC a function of the amount of solar generation in the system, but also a function of how much wind is in the system; one could remove the wind generation and determine the Solar ELCC in the absence of wind; or conversely, leave the wind in and remove the solar and then determine how much the solar generation was contributing to the total system ELCC by subtracting the wind's contribution from the system ELCC assuming the difference is the solar contribution.

Calculations were performed to determine the ELCC with each of the following three configurations: solar only generation (Solar Only ELCC), wind only generation (Wind Only ELCC), and combined solar and wind generation (System ELCC). The Solar Only ELCC was calculated by removing the wind generation from the system. The Wind Only ELCC was calculated by removing the solar generation from the system. The System ELCC is based on the ELCC calculated with both the wind and solar installed as configured. The Solar Only ELCC MW column shows (in megawatts) the average of the Solar Only ELCC and the difference of the System ELCC and the Wind Only ELCC. The Wind Only ELCC MW column shows the average of the Wind Only ELCC and the difference of the System ELCC and the Solar Only ELCC.

The Solar Only ELCC, Wind Only ELCC and System ELCC are also shown as a percent of installed capacity. The System ELCC as a percent of installed capacity is determined by dividing the System ELCC by the total installed solar and wind capacity. The Wind Only ELCC as a percent of installed capacity is determined by dividing the Wind Only ELCC by the total installed wind capacity. A similar calculation was performed to determine the Solar Only ELCC as a percent of installed capacity.

The last two columns in Table 3, labeled Incremental Solar Only ELCC and Incremental Wind Only ELCC as a percent of installed capacity report the incremental ELCC associated with additional wind and solar capacity additions. The incremental Solar Only ELCC was calculated by increasing the Solar generation by five percent. The increase in the system ELCC divided by the increase in solar installed capacity is the Incremental Solar Only ELCC. The five percent increase is based on increasing the output of all installed solar by five percent. A similar method was used to calculate the Incremental Wind Only ELCC.

END OF REPORT

Attachment Vol II 5-4 B&V Report on Review of Existing Resources

August 3, 2020 Revision

Report on Review of Existing Resources

Executive Summary

As part of the energy resource planning process, Tri-State Generation & Transmission Association ("Tri-State") must establish assumptions concerning the future performance and cost of its existing resources for the purposes of modeling the long-term performance and cost of the resource plan ("Modeled Values"). Tri-State retained Black & Veatch ("we" or "us") to review the Modeled Values and as necessary recommend changes to the Modeled Values to better represent future resource performance and cost (the "Review"). The Modeled Values included capacity, heat rate, availability rate, forced outage rate, emissions, renewable production profiles, variable O&M costs and fixed O&M costs. The existing resources included eighteen (18) coal, gas and oil fired resources) two (2) long-term purchase agreements with Basin Electric and seven (7) renewable (solar and wind) facilities located across the Tri-State system. This Report summarizes the scope, methodology and results of our Review.

Our approach was to compare the Modeled Values against actual performance and cost data provided to us by Tri-State, data collected by federal regulatory agencies and national reliability coordinators, and data reported by other generators for resources of similar technology, size, age and location. In cases where a Modeled Value was significantly different from the values shown in the data sources, and if the data was determined to be of reasonable quality, we then recommended an alternative modeled value for consideration by Tri-State (each a "Recommended Modeled Value").

Our review revealed that some of the Modeled Values were significantly different than those shown in one or more of the data sources. Differences included heat rates for the Burlington resources, fixed O&M costs for the Rifle resource, and NOx emission rates for the Burlington and Rifle resources. They also included SO2 emission rates for the Rifle and Shafer resources, availability factors for the Burlington, Limon, Rifle and Shafer resources, and forced outage factors for the Burlington, Knutson, Limon, Rifle and Shafer plants. For each of these we provided a Recommended Modeled Value for consideration by Tri-State. The Recommended Modeled Values are summarized in the Results section of this Report.

Scope

The scope of our Review was defined by Tri-State and included the resources shown in Table 1 below.

Six (6) of the Existing Resources are coal fired. These include the Craig coal-fired Units 1 through 3 located in western Colorado ("wco"), the Laramie River coal-fired station ("LRS") Units 2 and 3 located in Wyoming ("wyo"), and Springerville coal-fired Unit 3 located in Arizona ("arz"). These resources are either partially owned or partially controlled by Tri-State with the exception of Craig Unit 3 which is wholly owned and Springerville Unit 3 which is wholly leased with 100 MW of the Total Capacity sold to a third party under a tolling agreement through the summer of 2036. The capacity currently controlled by Tri-State is shown as the "Tri-State Modeled Capacity".

Another ten (10) of the Existing Resources are oil or gas fired combustion turbines that are fully owned by Tri-State. These include the Burlington Units 1 and 2, the Knutson Units 1 and 2, the Limon Units 1 and 2 and the Pyramid Units 1 through 4. The Burlington, Knutson and Limon Units are located in eastern Colorado and the Pyramid Units are located in southern New Mexico. All of these resources are fully controlled by Tri-State.

Another two (2) of the Existing Resources are gas-fired combined cycle plants that are fully owned by Tri-State. These include the Rifle plant located in western Colorado and the Shafer plant located in eastern Colorado.

These coal, gas or oil fired resources are referred to collectively as the "thermal" resources.

Another seven (7) resources are solar or wind powered "renewable" resources with output purchased by Tri-State under power purchase agreements ("PPA"). Five (5) of these resources are located in eastern Colorado ("eco") and the remaining two (2) are located in New Mexico. All of the output from these resources is purchased by Tri-State.

The remaining two (2) Existing Resources are long-term contract purchases from Basin Electric Power Cooperative ("Basin"), collectively the "Basin Contracts". The first contract is known as the Western CROD Contract ("Basin West") and the other as the Basin Electrically East Contract ("Basin East"). No specific generating resource is associated with each Basin Contract. Basin has the sole discretion to choose how the Basin West contract is supplied on a day ahead and hour ahead basis. The Basin East contract is supplied via Southwest Power Pool (SPP). The Basin West contract has a set hourly energy profile by month for each year of the contract. The Basin East Contract is a full requirements contract and supply is based on actual energy needs of Tri-State's Utility Member Systems located in the Eastern Interconnection. Tri-State purchases all energy as contracted under the Basin Contracts.

Table 1 – Summary of Resources to be Reviewed

	Plant/Unit	Technology	Type	Location	Nominal Capacity (MW)	Tri-State Modeled Capacity (MW)	Year In Service
1	GC-Craig 1-NW_CO	Steam Turbine - Coal	Owned	wco	427	102	1980
2	GC-Craig 2-NW_CO	Steam Turbine - Coal	Owned	wco	410	98	1979
3	GC-Craig 3-NW_CO	Steam Turbine - Coal	Owned	wco	448	448	1984
4	GC-LRS 2-WY	Steam Turbine - Coal	Owned	wyo	570	231	1981
5	GC-LRS 3-WY	Steam Turbine - Coal	Owned	wyo	570	230	1982
6	GC-SV 3-SPV	Steam Turbine - Coal	Owned	arz	417	317	2006
7	GG-Burlington 1-E_CO	Frame CT - Oil	Owned	eco	55	55	1977

	Plant/Unit	Technology	Type	Location	Nominal Capacity (MW)	Tri-State Modeled Capacity (MW)	Year In Service
8	GG-Burlington 2-E_CO	Frame CT - Oil	Owned	eco	55	55	1977
9	GG-Knutson 1-E_CO	Frame CT - Gas	Owned	eco	70	70	2002
10	GG-Knutson 2-E_CO	Frame CT - Gas	Owned	eco	70	70	2002
11	GG-Limon 1-E_CO	Frame CT - Gas	Owned	eco	70	70	2003
12	GG-Limon 2-E_CO	Frame CT - Gas	Owned	eco	70	70	2003
13	GG-Pyramid 1-S_NM	Aeroderivative CT - Gas	Owned	snm	40	40	2003
14	GG-Pyramid 2-S_NM	Aeroderivative CT - Gas	Owned	snm	40	40	2003
15	GG-Pyramid 3-S_NM	Aeroderivative CT - Gas	Owned	snm	40	40	2003
16	GG-Pyramid 4-S_NM	Aeroderivative CT - Gas	Owned	snm	40	40	2003
17	GG-Rifle-NW_CO	Combined Cycle - Gas	Owned	wco	81	81	1987
18	GG-Shafer-E_CO	Combined Cycle - Gas	Owned	eco	272	272	1994
19	CP-AltaLuna-S_NM	Tracking Array Solar	PPA	nm	25	25	2017
20	CP-SanIsabel-E_CO	Tracking Array Solar	PPA	eco	30	30	2016
21	CP-FirstSolar-N_NM	Fixed Solar	PPA	nm	30	30	2010
22	CP-ColoHighlands-E_CO	Wind	PPA	eco	91	91	2012
23	CP-KitCarson-E_CO	Wind	PPA	eco	51	51	2010
24	CP-TwinButtes-E_CO	Wind	PPA	eco	76	76	2017
25	CP-Carousel-E_CO	Wind	PPA	eco	150	150	2015
26	CP-Basin_West	Basin System	PPA	eco	268	268	2017
27	CP-Basin_East	Basin System	PPA	eco	317	317[1]	2017

The scope of parameters to review for each of these resources was also specified by Tri-State. The parameters included heat rate, variable O&M cost, fixed O&M cost, CO2 emission rate, NOx emission rate, SO2 emission rate, availability rate, forced outage rate, and capacity factor for the renewable resources only (each a "Parameter").

Methodology

Our methodology for the Review was to compare the Modeled Values against historical Parameters from three (3) data sources and base our Recommended Modeled Values on the results of that comparison. The Modeled Values were provided to us by Tri-State and consisted of Parameters for each of the existing resources. The first data source was historical data provided to us by Tri-State for heat rate, availability rate and forced outage rate for the thermal resources ("Tri-State Data"). The second data source was historical data gathered from federal regulators by the S&P Global Market Intelligence

[1] Basin East is a full requirements contract so capacity is not specified in the contract but rather fluctuates with the demand forecast of the members.

service ("S&P")[2] for heat rate, variable O&M cost, fixed O&M cost, CO2 emission rate, NOx emission rate and SO2 emission rate for the thermal resources and capacity factor for the renewable resources ("S&P Data"). The third data source was a compilation of Parameters from S&P and from historical data reported by the North American Reliability Corporation ("NERC") for resources of similar technology, size, age and location to the Tri-State resources but that are owned or controlled by others ("Peer Group Data"). Comparing the Modeled Values against data from these three sources allowed us to evaluate the extent to which the Modeled Values were consistent with the actual historical Parameters of the resource and other similar resources in the market.

A summary of the key features of the Peer Group Data is provided in the table below.

Table 2- Summary of Key Features of the Peer Group Data

-	Plant/Unit	Peer Group	NERC Regions	Capacity	COD	# of Units in GADS	GADS Data	# of Units in S&P	S&P Data
1	GC-Craig 1-NW_CO	Large Coal ST	MRO, WECC and SPP	300 to 500 MW	1980 to 2010	26	2015-2018 Forced Outage Factor (FOF) and Availability Factor (AF)	41	2015-2018 Heat Rate, Non-Fuel O&M Variable Costs ($/MWh), Fixed O&M Costs ($/kw-mo), CO2 Emissions (lb/MMBtu), NOx Emissions (lb/MMBtu), SO Emissions (lb/MMBtu)
2	GC-Craig 2-NW_CO	Large Coal ST	MRO, WECC and SPP	300 to 500 MW	1980 to 2010	26		41	
3	GC-Craig 3-NW_CO	Large Coal ST	MRO, WECC and SPP	300 to 500 MW	1980 to 2010	26		41	
4	GC-LRS 2-WY	Large Coal ST	MRO, WECC and SPP	300 to 500 MW	1980 to 2010	26		41	
5	GC-LRS 3-WY	Large Coal ST	MRO, WECC and SPP	300 to 500 MW	1980 to 2010	26		41	
6	GC-SV 3-SPV	Large Coal ST	MRO, WECC and SPP	300 to 500 MW	1980 to 2010	26		41	
7	GG-Burlington 1-E_CO	Frame CT	MRO, WECC and SPP	60 MW to 80 MW	1970 to 2010	125		49	
8	GG-Burlington 2-E_CO	Frame CT	MRO, WECC and SPP	60 MW to 80 MW	1970 to 2010	125		49	
9	GG-Knutson 1-E_CO	Frame CT	MRO, WECC and SPP	60 MW to 80 MW	1970 to 2010	125		49	
10	GG-Knutson 2-E_CO	Frame CT	MRO, WECC and SPP	60 MW to 80 MW	1970 to 2010	125		49	
11	GG-Limon 1-E_CO	Frame CT	MRO, WECC and SPP	60 MW to 80 MW	1970 to 2010	125		49	
12	GG-Limon 2-E_CO	Frame CT	MRO, WECC and SPP	60 MW to 80 MW	1970 to 2010	125		49	
13	GG-Pyramid 1-S_NM	Aeroderivative CT	MRO, WECC and SPP	40 MW to 60 MW	1998 to 2008	122		95	

[2] https://www.spglobal.com/marketintelligence/en/solutions/market-intelligence-platform

	Plant/Unit	Peer Group	NERC Regions	Capacity	COD	# of Units in GADS	GADS Data	# of Units in S&P	S&P Data
14	GG-Pyramid 2-S_NM	Aeroderivative CT	MRO, WECC and SPP	40 MW to 60 MW	1998 to 2008	122		95	
15	GG-Pyramid 3-S_NM	Aeroderivative CT	MRO, WECC and SPP	40 MW to 60 MW	1998 to 2008	122		95	
16	GG-Pyramid 4-S_NM	Aeroderivative CT	MRO, WECC and SPP	40 MW to 60 MW	1998 to 2008	122		95	
17	GG-Rifle-NW_CO	Small CC	All	50 MW to 100 MW	1980 to 1995	21		88	
18	GG-Shafer-E_CO	Large CC	MRO, WECC and SPP	250 MW to 350 MW	1985 to 2005	17		14	
19	CP-AltaLuna-S_NM	Small Solar CO NM WY	WECC	20 to 100 MW	All	n/a	n/a	12	2015-2018 Capacity Factor, Non-Fuel O&M Variable Costs ($/MWh), Fixed O&M Costs ($/kw-mo)
20	CP-SanIsabel-E_CO	Small Solar CO NM WY	WECC	20 to 100 MW	All	n/a	n/a	12	
21	CP-FirstSolar-N_NM	Small Solar CO NM WY	WECC	20 to 100 MW	All	n/a	n/a	12	
22	CP-ColoHighlands-E_CO	Small Wind CO NM WY	WECC	20 to 100 MW	All	n/a	n/a	26	
23	CP-KitCarson-E_CO	Small Wind CO NM WY	WECC	20 to 100 MW	All	n/a	n/a	26	
24	CP-TwinButtes-E_CO	Small Wind CO NM WY	WECC	20 to 100 MW	All	n/a	n/a	26	
25	CP-Carousel-E_CO	Large Wind CO NM WY	WECC	100 MW +	All	n/a	n/a	25	
26	CP-Basin_West	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	CP-Basin_East	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

For each peer group, the NERC region, capacity range and age range were selected such that the existing resource(s) and a reasonable number of third party resources would fall into the group. The total capacity of the existing resource rather than just the Tri-State share was considered in developing each peer group.

Once the peer groups were established, the associated Tri-State Data, S&P Data and Peer Group Data was acquired. Modeled Values and data were limited for the solar and wind resources. Tri-State has

Modeled Values for only capacity factor and none of the other Parameters (variable O&M, fixed O&M, etc.) since the existing wind and solar resources are not owned by Tri-State. Also, NERC has only recently begun requiring owners of renewable energy resources to submit performance and reliability data and NERC has not yet made the data available. Therefore, capacity factor was the only Parameter considered in Review of the wind and solar resources.

Modeled Values and data were also limited for the Basin Contracts because they are not resource specific. Modeled Values for the Basin Contracts included only CO2, SO2 and NOx emission rates. These Modeled Values were calculated by Tri-State based on historical emission rates for Laramie River Station (LRS2, LRS 3) for Basin West and egrid subregion MRO-W emissions were used for the Basin East. This approach reflects the fact that historically some of the energy from Basin West has likely been generated from coal fired power plants on the Basin system and that Basin East is served by the Southwest Power Pool. Modeled Values for the other Parameters (variable O&M, fixed O&M, etc.) were not available. No Parameters were available in the S&P Data and Peer Group Data because S&P and NERC do not record data for non-resource specific system sales. Therefore CO2, SO2 and NOx emission rates were the only Parameters considered in review of the Basin Contracts. It is also important to note that none of the Parameters reviewed in this report including emissions are specified in the Basin Contracts.

Data analysis began with comparison of each Modeled Value against a four year (2015 – 2018 inclusive) average of the associated Parameter from the Tri-State Data, the S&P Data and the Peer Group Data. Data for the years 2019 and 2020 was excluded because it was either unavailable or incomplete at the time the Review was performed (Spring 2020). Each Modeled Value was then also compared against an average of the three averages (the “Grand Average”). In cases where the Modeled Value was more than 10% greater or less than the Grand Average (5% for the availability factor and forced outage factor Grand Averages), the difference was considered significant and we further examined the data to determine the cause of the difference including whether or not the Grand Average was skewed high or low by the presence of high or low outliers in the underlying data or the underlying data was of poor quality for some other reason. If the Grand Average proved to be of reasonable quality, we then recommended an alternative modeled value for consideration by Tri-State (a "Recommended Modeled Value").

The threshold for significance was only 5% for the availability factor and forced outage factor Grand Averages because the data ranged from only 70% to 100% and therefore, we felt that using a 10% threshold would mask too many significant differences.

Results

Results of the data analysis are summarized in the following tables. Each table summarizes the analysis for one of the Parameters including the relevant Modeled Value, the Tri-State Data value, the S&P Data value, the Peer Group Data value and the Grand Average for each of the existing resources. Grand Averages highlighted in yellow indicate the Grand Average is significantly (+\- 10% or +/- 5%) different than the Modeled Value. Recommended Values highlighted in green indicate Recommended Values different than the Modeled Value.

Heat rate results show that the Grand Average was significantly different than the Modeled Value for several of the resources. However, review of the Grand Average revealed that the underlying Tri-State data and Peer Group data was skewed in most of these cases. For these resources, no change was recommended. The exception are the Burlington combustion turbine Units 1 and 2. A Recommended Modeled Value was therefore provided based on the Grand Average. A heat rate comparison was not applicable to the renewable resources and the Basin Contracts.

Variable O&M cost results show that the Grand Average was significantly different than the Modeled Value for nearly all of the resources. However, review of these Grand Averages revealed that the underlying S&P Data was not actual data (but rather calculated) for the coal-fired units and was skewed by extreme outliers for the combustion turbine units and for the Shafer combined cycle plant. As a result, the Recommended Modeled Values were the same as the Modeled Values for all the resources (no change recommended). A variable O&M Cost comparison was not applicable to the renewable resources and the Basin Contracts.

Fixed O&M cost results show that the Grand Average was significantly different than the Modeled Values for nearly all of the resources. However, the underlying S&P data and Peer Group data was judged to be of poor quality and therefore no changes to the Modeled Values were recommended. The exception was for the Rifle combined cycle plant, where a lower Recommended Modeled Value was provided. The Recommended Modeled Value was also expressed in $000s for convenience since Tri-State models fixed O&M on a dollar basis instead of $/kw-yr. A fixed O&M cost comparison was not applicable to the renewable resources and the Basin Contracts.

CO2 emission rate results show only a few significant differences between the Grand Averages and the Modeled Values. Further investigation into these differences revealed that the S&P Data and Peer Group Data was not actual but rather calculated. As a result, our Recommended Modeled Values were the same as the Modeled Values for all the resources (no change recommended). A CO2 emission comparison was not applicable to the renewable resources. A comparison was not applicable to the Basin Contracts because of the lack of S&P Data and Peer Group Data. As a result, our Recommended Modeled Values were the same as the Modeled Values for the Basin Contracts (no change recommended).

NOx emission rate results show that the Grand Average is significantly different than the Modeled Values for nearly all resources. However, no changes were recommended in most cases due to poor S&P Data and Peer Group Data quality. For Craig 2, no change was recommended because the significant difference is due to NOx emission controls that have been added to the unit. This causes the rate to be much less than Craig 1 as well as the S&P Data and Peer Group Data. Changes were recommended for Burlington Units 1 and 2 and the Rifle combined cycle plant. The Modeled Values are relatively high for these resources. It is possible that the Modeled Values reflect actual emission rates which are relatively high due to use of fuel oil at Burlington or lack of modern emission controls at Rifle. If this is the case, then no change should be made to the Modeled Value. A NOx emission comparison was not applicable to the renewable resources. A comparison was not applicable to the Basin Contracts because of the lack of S&P Data and Peer Group Data. As a result, our Recommended Modeled Values were the same as the Modeled Values for the Basin Contracts (no change recommended).

SO2 emission rate results show that the Grand Average is significantly different than the Modeled Values for all the resources. However, no changes were recommended in most cases due to poor S&P Data quality. The exception is the Rifle and Shafer resources. The Modeled Values are relatively low for these resources and so a higher Recommended Modeled Value is provided. An SO2 emission comparison was not applicable to the renewable resources. A comparison was not applicable to the Basin Contracts because of the lack of S&P Data and Peer Group Data. As a result, our Recommended Modeled Values were the same as the Modeled Values for the Basin Contracts (no change recommended).

Availability factor results show significant differences between the Grand Averages and the Modeled Values for the majority of the resources. However, in some of these cases (Craig Unit 1, Craig Unit 3, Springerville Unit 3, Knutson Unit 2 and Limon Unit 2) no changes were recommended due to the Tri-State data being skewed by low values for the years 2016 or 2018. For the other resources, a Recommended Modeled Value was provided based primarily on the Tri-State Data. The Recommended Modeled Value was also expressed in maintenance outage hours (MOH) for convenience since Tri-State models maintenance outages on an hourly basis instead of a percentage basis. An availability factor comparison was not applicable to the renewable resources and the Basin Contracts.

Forced outage factor results show significant differences between the Grand Averages and the Modeled Values for the majority of the resources. However, in some of these cases (Craig Unit 2, LRS Unit 2) no change was recommended since the Grand Average if rounded would equal the Modeled Value and therefore the Modeled Value was judged to be in a reasonable range. In other cases (Craig Unit 3, Springerville Unit 3) no changes were recommended due to the Tri-State data being skewed by low values for the years 2016, 2017 or 2018. For the other resources, a Recommended Modeled Value was provided based primarily on the Tri-State Data. The Recommended Modeled Value was also expressed in forced outage hours (FOH) for convenience since Tri-State models forced outages on an hourly basis instead of a percentage basis. A forced outage factor comparison was not applicable to the renewable resources and the Basin Contracts.

Renewable capacity factor results show significant differences between the Grand Averages and the Modeled Values for the majority of the resources. However, in some of these cases (San Isabel, Twin Buttes and Carousel) no change was recommended since the Tri-State and S&P data were skewed low due to outlier low values in 2015, 2016 or 2017. In the other cases (Colorado Highlands and Kit Carson) no changes were recommended due to the Peer Group Data being relatively low. A capacity factor comparison was not applicable to the thermal resources and the Basin Contracts.

Table 3 – Results of Review – Heat Rate (Btu/kwh)

	Heat Rate (Btu/kwh)							
Resource	Current Modeled	Tri-State Data	S&P Data	Peer Group Data (S&P)	Avg. Tri-State, S&P, Peer Group Data	Recommendation	Notes	Recommended Modeled
1 GC-Craig 1-NW_CO	10,316	10,176	10,213	10,582	10,324	No change	Within reasonable range	10,316
2 GC-Craig 2-NW_CO	10,219	10,075	10,117	10,582	10,258	No change	Within reasonable range	10,219
3 GC-Craig 3-NW_CO	10,135	10,156	10,227	10,582	10,322	No change	Within reasonable range	10,135
4 GC-LRS 2-WY	9,926	10,035	10,099	10,582	10,239	No change	Within reasonable range	9,926
5 GC-LRS 3-WY	10,286	9,917	10,117	10,582	10,206	No change	Within reasonable range	10,286
6 GC-SV 3-SPV	9,945	13,205	10,183	10,582	11,323	No change	Tri-State data skewed by high 2015 and 2018 values	9,945
7 GG-Burlington 1-E_CO	11,924	14,358	12,999	15,337	14,231	14,000	Tri-State data not skewed, use average.	14,000
8 GG-Burlington 2-E_CO	11,924	13,610	12,999	15,337	13,982	14,000	Tri-State data not skewed, use average.	14,000
9 GG-Knutson 1-E_CO	11,646	16,295	12,270	15,337	14,634	No change	Tri-State and Peer Group data skewed	11,646
10 GG-Knutson 2-E_CO	11,646	15,553	12,515	15,337	14,469	No change	Tri-State and Peer Group data skewed	11,646
11 GG-Limon 1-E_CO	11,646	10,984	12,106	15,337	12,809	No change	Peer group data skewed	11,646
12 GG-Limon 2-E_CO	11,646	11,655	12,504	15,337	13,165	No change	Peer group data skewed	11,646
13 GG-Pyramid 1-S_NM	9,742	9,688	9,908	10,898	10,164	No change	Within reasonable range	9,742
14 GG-Pyramid 2-S_NM	9,742	9,699	10,026	10,898	10,207	No change	Within reasonable range	9,742
15 GG-Pyramid 3-S_NM	9,742	10,069	10,394	10,898	10,453	No change	Within reasonable range	9,742
16 GG-Pyramid 4-S_NM	9,742	9,972	10,230	10,898	10,366	No change	Within reasonable range	9,742
17 GG-Rifle-NW_CO	10,658	6,925	7,672	7,934	7,510	No change	Low Tri-State data from 2015 only, actuals higher due to duct burners.	10,658
18 GG-Shafer-E_CO	9,322	9,021	9,562	7,434	8,672	No change	Within reasonable range	9,322
19 CP-AltaLuna-S_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
20 CP-SanIsabel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
21 CP-FirstSolar-N_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
22 CP-ColoHighlands-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
23 CP-KitCarson-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
24 CP-TwinButtes-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
25 CP-Carousel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
26 CP-Basin_West	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27 CP-Basin_East	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Table 4 – Results of Review – Variable O&M Cost ($/MWh)

	Non-Fuel Variable O&M Costs per MWh							
Resource	Current Modeled	Tri-State Data	S&P Data	Peer Group Data (S&P)	Avg. Tri-State, S&P, Peer Group Data	Recommendation	Notes	Recommended Modeled
1 GC-Craig 1-NW_CO	[redacted]	None	3.37	3.62	3.49	No change	S&P data not actual	[redacted]
2 GC-Craig 2-NW_CO		None	3.37	3.62	3.49	No change	S&P data not actual	
3 GC-Craig 3-NW_CO		None	3.37	3.62	3.49	No change	S&P data not actual	
4 GC-LRS 2-WY		None	2.58	3.62	3.10	No change	S&P data not actual	
5 GC-LRS 3-WY		None	2.58	3.62	3.10	No change	S&P data not actual	
6 GC-SV 3-SPV		None	5.89	3.62	4.75	No change	S&P data not actual	
7 GG-Burlington 1-E_CO		None	88.57	14.97	51.77	No change	S&P data reflects extreme year	
8 GG-Burlington 2-E_CO		None	88.57	14.97	51.77	No change	S&P data reflects extreme year	
9 GG-Knutson 1-E_CO		None	15.26	14.97	15.11	No change	S&P data reflects extreme year	
10 GG-Knutson 2-E_CO		None	15.26	14.97	15.11	No change	S&P data reflects extreme year	
11 GG-Limon 1-E_CO		None	5.67	14.97	10.32	No change	S&P data reflects extreme year	
12 GG-Limon 2-E_CO		None	5.67	14.97	10.32	No change	S&P data reflects extreme year	
13 GG-Pyramid 1-S_NM		None	6.49	8.69	7.59	No change	S&P data not actual	
14 GG-Pyramid 2-S_NM		None	6.49	8.69	7.59	No change	S&P data not actual	
15 GG-Pyramid 3-S_NM		None	6.49	8.69	7.59	No change	S&P data not actual	
16 GG-Pyramid 4-S_NM		None	6.49	8.69	7.59	No change	S&P data not actual	
17 GG-Rifle-NW_CO		None	8.32	3.23	5.77	No change	Within reasonable range	
18 GG-Shafer-E_CO		None	3.75	1.63	2.69	No change	S&P data skewed by 2017 value	
19 CP-AltaLuna-S_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
20 CP-SanIsabel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
21 CP-FirstSolar-N_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
22 CP-ColoHighlands-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
23 CP-KitCarson-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
24 CP-TwinButtes-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
25 CP-Carousel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
26 CP-Basin_West	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27 CP-Basin_East	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Table 5 – Results of Review – Fixed O&M Costs ($/kw-yr)

	Fixed O&M Costs per kW-Year									
Resource	Current Modeled	Tri-State Data	S&P Data	Peer Group Data (S&P)	Avg. Tri-State, S&P, Peer Group Data	Recommendation	Notes	Max Capacity (MW)	Recommended Modeled	Recommended Modeled ($000s)
1 GC-Craig 1-NW_CO	[redacted]	None	42.62	27.77	35.19	No change	S&P data poor quality (duplicative, missing)	102	[redacted]	[redacted]
2 GC-Craig 2-NW_CO		None	42.62	27.77	35.19	No change	S&P data poor quality (duplicative, missing)	98		
3 GC-Craig 3-NW_CO		None	42.62	27.77	35.19	No change	S&P data poor quality (duplicative, missing)	448		
4 GC-LRS 2-WY		None	28.01	27.77	27.89	No change	S&P data poor quality (duplicative, missing)	231		
5 GC-LRS 3-WY		None	28.01	27.77	27.89	No change	S&P data poor quality (duplicative, missing)	230		
6 GC-SV 3-SPV		None	49.73	27.77	38.75	No change	S&P data poor quality (duplicative, missing)	417		
7 GG-Burlington 1-E_CO		None	4.68	3.55	4.12	No change	S&P data poor quality (duplicative, missing)	55		
8 GG-Burlington 2-E_CO		None	4.68	3.55	4.12	No change	S&P data poor quality (duplicative, missing)	55		
9 GG-Knutson 1-E_CO		None	3.62	3.55	3.58	No change	S&P data poor quality (duplicative, missing)	70		
10 GG-Knutson 2-E_CO		None	3.62	3.55	3.58	No change	S&P data poor quality (duplicative, missing)	70		
11 GG-Limon 1-E_CO		None	3.62	3.55	3.58	No change	S&P data poor quality (duplicative, missing)	70		
12 GG-Limon 2-E_CO		None	3.62	3.55	3.58	No change	S&P data poor quality (duplicative, missing)	70		
13 GG-Pyramid 1-S_NM		None	3.51	6.34	4.92	No change	S&P data poor quality (duplicative, missing)	55		
14 GG-Pyramid 2-S_NM		None	3.51	6.34	4.92	No change	S&P data poor quality (duplicative, missing)	55		
15 GG-Pyramid 3-S_NM		None	3.51	6.34	4.92	No change	S&P data poor quality (duplicative, missing)	70		
16 GG-Pyramid 4-S_NM		None	3.51	6.34	4.92	No change	S&P data poor quality (duplicative, missing)	70		
17 GG-Rifle-NW_CO		None	26.68	14.44	20.56	25.00	Current modeled very high	52		
18 GG-Shafer-E_CO		None	14.64	11.08	12.86	No change	Within reasonable range	14		
19 CP-AltaLuna-S_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
20 CP-SanIsabel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
21 CP-FirstSolar-N_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
22 CP-ColoHighlands-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
23 CP-KitCarson-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
24 CP-TwinButtes-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
25 CP-Carousel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
26 CP-Basin_West	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27 CP-Basin_East	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Notes:
Yellow highlight indicates average Tri-State, S&P and Peer Group value is more than 10% above/below current modeled value
Green highlight indicates recommended modeled value different than current modeled value
Grey highlight indicates user entered value

Table 6 – Results of Review – CO2 Emission Rate (lb/MMBtu)

		CO2 Emission Rate (lb/MMBtu)							
	Resource	Current Modeled	Tri-State Data	S&P Data	Peer Group Data (S&P)	Avg. Tri-State, S&P, Peer Group Data	Recommendation	Notes	Recommended Modeled
1	GC-Craig 1-NW_CO	224.80	None	209.76	208.80	209.28	No change	Within reasonable range	224.80
2	GC-Craig 2-NW_CO	229.96	None	209.76	208.80	209.28	No change	Within reasonable range	229.96
3	GC-Craig 3-NW_CO	206.21	None	209.76	208.80	209.28	No change	Within reasonable range	206.21
4	GC-LRS 2-WY	221.94	None	209.76	208.80	209.28	No change	Within reasonable range	221.94
5	GC-LRS 3-WY	234.01	None	209.76	208.80	209.28	No change	S&P data not actual	234.01
6	GC-SV 3-SPV	215.08	None	209.66	208.80	209.23	No change	Within reasonable range	215.08
7	GG-Burlington 1-E_CO	185.51	None	162.22	122.03	142.13	No change	S&P data not actual	185.51
8	GG-Burlington 2-E_CO	174.94	None	162.22	122.03	142.13	No change	S&P data not actual	174.94
9	GG-Knutson 1-E_CO	129.15	None	119.08	122.03	120.56	No change	S&P data not actual	129.15
10	GG-Knutson 2-E_CO	128.80	None	119.07	122.03	120.55	No change	S&P data not actual	128.80
11	GG-Limon 1-E_CO	128.63	None	120.09	122.03	121.06	No change	S&P data not actual	128.63
12	GG-Limon 2-E_CO	128.12	None	119.16	122.03	120.60	No change	S&P data not actual	128.12
13	GG-Pyramid 1-S_NM	127.28	None	120.20	118.98	119.59	No change	Within reasonable range	127.28
14	GG-Pyramid 2-S_NM	126.46	None	121.06	118.98	120.02	No change	Within reasonable range	126.46
15	GG-Pyramid 3-S_NM	128.31	None	122.74	118.98	120.86	No change	Within reasonable range	128.31
16	GG-Pyramid 4-S_NM	127.08	None	120.04	118.98	119.51	No change	Within reasonable range	127.08
17	GG-Rifle-NW_CO	113.15	None	118.40	116.81	117.61	No change	Within reasonable range	113.15
18	GG-Shafer-E_CO	105.24	None	118.86	118.67	118.77	No change	S&P data not actual	105.24
19	CP-AltaLuna-S_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
20	CP-SanIsabel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
21	CP-FirstSolar-N_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
22	CP-ColoHighlands-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
23	CP-KitCarson-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
24	CP-TwinButtes-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
25	CP-Carousel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
26	CP-Basin_West	168.32	n/a	n/a	n/a	n/a	n/a	n/a	168.323
27	CP-Basin_East	123.81	n/a	n/a	n/a	n/a	n/a	n/a	123.805

Notes:
Yellow highlight indicates average Tri-State, S&P and Peer Group value is more than 10% above/below current modeled value
Green highlight indicates recommended modeled value different than current modeled value
Grey highlight indicates user entered value

Table 7 – Results of Review – NOx Emission Rate (lb/MMBtu)

	NOx Emission Rate (lb/MMBtu)							
Resource	Current Modeled	Tri-State Data	S&P Data	Peer Group Data (S&P)	Avg. Tri-State, S&P, Peer Group Data	Recommendation	Notes	Recommended Modeled
1 GC-Craig 1-NW_CO	0.269	None	0.249	0.139	0.194	No change	S&P peer group data suspect	0.27
2 GC-Craig 2-NW_CO	0.066	None	0.197	0.139	0.168	No change	Lower than Craig 1 due to NOx controls	0.07
3 GC-Craig 3-NW_CO	0.222	None	0.275	0.139	0.207	No change	S&P peer group data suspect	0.22
4 GC-LRS 2-WY	0.235	None	0.153	0.139	0.146	No change	S&P peer group data suspect	0.23
5 GC-LRS 3-WY	0.234	None	0.150	0.139	0.145	No change	S&P data, peer group data suspect	0.23
6 GC-SV 3-SPV	0.079	None	0.077	0.139	0.108	No change	S&P peer group data suspect	0.08
7 GG-Burlington 1-E_CO	1.047	None	0.301	0.202	0.252	0.300	Current modeled very high	0.30
8 GG-Burlington 2-E_CO	1.030	None	0.301	0.202	0.252	0.300	Current modeled very high	0.30
9 GG-Knutson 1-E_CO	0.030	None	0.029	0.202	0.115	No change	S&P peer group data suspect	0.03
10 GG-Knutson 2-E_CO	0.029	None	0.030	0.202	0.116	No change	S&P peer group data suspect	0.03
11 GG-Limon 1-E_CO	0.037	None	0.029	0.202	0.116	No change	S&P peer group data suspect	0.04
12 GG-Limon 2-E_CO	0.028	None	0.029	0.202	0.116	No change	S&P peer group data suspect	0.03
13 GG-Pyramid 1-S_NM	0.129	None	0.127	0.057	0.092	No change	S&P peer group data suspect	0.13
14 GG-Pyramid 2-S_NM	0.120	None	0.118	0.057	0.087	No change	S&P peer group data suspect	0.12
15 GG-Pyramid 3-S_NM	0.129	None	0.122	0.057	0.089	No change	S&P peer group data suspect	0.13
16 GG-Pyramid 4-S_NM	0.125	None	0.125	0.057	0.091	No change	S&P peer group data suspect	0.13
17 GG-Rifle-NW_CO	0.245	None	0.020	0.048	0.034	0.030	Current modeled very high	0.03
18 GG-Shafer-E_CO	0.080	None	0.089	0.010	0.050	No change	S&P peer group data suspect	0.08
19 CP-AltaLuna-S_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
20 CP-SanIsabel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
21 CP-FirstSolar-N_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
22 CP-ColoHighlands-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
23 CP-KitCarson-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
24 CP-TwinButtes-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
25 CP-Carousel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
26 CP-Basin_West	0.173	n/a	n/a	n/a	n/a	n/a	n/a	0.173
27 CP-Basin_East	0.099	n/a	n/a	n/a	n/a	n/a	n/a	0.099

Notes:
Yellow highlight indicates average Tri-State, S&P and Peer Group value is more than 10% above/below current modeled value
Green highlight indicates recommended modeled value different than current modeled value
Grey highlight indicates user entered value

Table 8 – Results of Review – SO2 Emission Rate (lb/MMBtu)

	SO2 Emission Rate (lb/MMBtu)							
Resource	Current Modeled	Tri-State Data	S&P Data	Peer Group Data (S&P)	Avg. Tri-State, S&P, Peer Group Data	Recommendation	Notes	Recommended Modeled
GC-Craig 1-NW_CO	0.0366	None	0.042	0.187	0.1148	No change	S&P peer group data suspect	0.0366
GC-Craig 2-NW_CO	0.0338	None	0.043	0.187	0.1151	No change	S&P peer group data suspect	0.0338
GC-Craig 3-NW_CO	0.1291	None	0.131	0.187	0.1592	No change	S&P peer group data suspect	0.1291
GC-LRS 2-WY	0.1109	None	0.098	0.187	0.1427	No change	S&P peer group data suspect	0.1109
GC-LRS 3-WY	0.1772	None	0.112	0.187	0.1496	No change	Modeled rate based on permit. S&P peer group data suspect	0.1772
GC-SV 3-SPV	0.0843	None	0.073	0.187	0.1298	No change	S&P peer group data suspect	0.0843
GG-Burlington 1-E_CO	0.0173	None	0.075	0.014	0.0443	No change	S&P data suspect	0.0173
GG-Burlington 2-E_CO	0.0153	None	0.075	0.014	0.0443	No change	S&P data suspect	0.0153
GG-Knutson 1-E_CO	0.0007	None	0.001	0.014	0.0071	No change	S&P peer group data suspect	0.0007
GG-Knutson 2-E_CO	0.0008	None	0.001	0.014	0.0071	No change	S&P peer group data suspect	0.0008
GG-Limon 1-E_CO	0.0007	None	0.001	0.014	0.0072	No change	S&P peer group data suspect	0.0007
GG-Limon 2-E_CO	0.0007	None	0.001	0.014	0.0071	No change	S&P peer group data suspect	0.0007
GG-Pyramid 1-S_NM	0.0013	None	0.001	0.001	0.0011	No change	S&P peer group data suspect	0.0013
GG-Pyramid 2-S_NM	0.0017	None	0.002	0.001	0.0014	No change	S&P peer group data suspect	0.0017
GG-Pyramid 3-S_NM	0.0012	None	0.003	0.001	0.0017	No change	S&P peer group data suspect	0.0012
GG-Pyramid 4-S_NM	0.0006	None	0.001	0.001	0.0011	No change	S&P peer group data suspect	0.0006
GG-Rifle-NW_CO	0.0001	None	0.001	0.004	0.0026	0.0010	Current modeled data very low	0.0010
GG-Shafer-E_CO	0.0008	None	0.001	0.001	0.0006	0.0010	Current modeled data very low	0.0010
CP-AltaLuna-S_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CP-SanIsabel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CP-FirstSolar-N_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CP-ColoHighlands-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CP-KitCarson-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CP-TwinButtes-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CP-Carousel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CP-Basin_West	0.107	n/a	n/a	n/a	n/a	n/a	n/a	0.107
CP-Basin_East	0.139	n/a	n/a	n/a	n/a	n/a	n/a	0.139

Notes:
Yellow highlight indicates average Tri-State, S&P and Peer Group value is more than 10% above/below current modeled value
Green highlight indicates recommended modeled value different than current modeled value
Grey highlight indicates user entered value

Table 9 – Results of Review – Annual Availability Factor (%)

	Availability Factor (%)								
Resource	Current Modeled	Tri-State Data	S&P Data	Peer Group Data (NERC)	Avg. Tri-State, Peer Group Data (5% Sig.)	Recommendation	Notes	Recommended Modeled	Resulting Modeled MOH
1 GC-Craig 1-NW_CO	95.81	91.63	None	88.83	90.23	No change	Tri-State data skewed by low 2016 value	95.81	367
2 GC-Craig 2-NW_CO	93.70	90.37	None	88.83	89.60	No change	Within reasonable range	93.70	552
3 GC-Craig 3-NW_CO	92.88	78.77	None	88.83	83.80	No change	Tri-State data skewed by low 2016 value	92.88	624
4 GC-LRS 2-WY	91.66	91.28	None	88.83	90.05	No change	Within reasonable range	91.66	731
5 GC-LRS 3-WY	91.93	91.96	None	88.83	90.39	No change	Within reasonable range	91.93	707
6 GC-SV 3-SPV	93.70	87.31	None	88.83	88.07	No change	Tri-State data skewed by low 2016 value	93.70	552
7 GG-Burlington 1-E_CO	99.27	97.74	None	90.23	93.99	98	Current modeled too high	98.00	175
8 GG-Burlington 2-E_CO	99.78	98.65	None	90.23	94.44	99	Current modeled too high	99.00	88
9 GG-Knutson 1-E_CO	99.56	96.46	None	90.23	93.34	96	Current modeled too high	96.00	350
10 GG-Knutson 2-E_CO	99.56	95.32	None	90.23	92.78	No change	Tri-State data skewed by low 2018 value	99.56	38
11 GG-Limon 1-E_CO	99.56	96.39	None	90.23	93.31	96	Current modeled too high	96.00	350
12 GG-Limon 2-E_CO	99.56	91.59	None	90.23	90.91	No change	Tri-State data skewed by low 2018 value	99.56	38
13 GG-Pyramid 1-S_NM	98.55	98.61	None	90.23	94.42	No change	Within reasonable range	98.55	127
14 GG-Pyramid 2-S_NM	98.42	98.69	None	90.23	94.46	No change	Within reasonable range	98.42	139
15 GG-Pyramid 3-S_NM	98.42	98.90	None	90.23	94.57	No change	Within reasonable range	98.42	139
16 GG-Pyramid 4-S_NM	98.55	99.07	None	90.23	94.65	No change	Within reasonable range	98.55	127
17 GG-Rifle-NW_CO	99.74	89.98	None	87.91	88.95	90	Current modeled too high	90.00	876
18 GG-Shafer-E_CO	99.91	89.89	None	86.31	88.10	90	Current modeled too high	90.00	876
19 CP-AltaLuna-S_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
20 CP-SanIsabel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
21 CP-FirstSolar-N_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
22 CP-ColoHighlands-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
23 CP-KitCarson-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
24 CP-TwinButtes-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
25 CP-Carousel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
26 CP-Basin_West	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27 CP-Basin_East	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Notes:
Yellow highlight indicates average Tri-State, S&P and Peer Group value is more than 10% above/below current modeled value
Green highlight indicates recommended modeled value different than current modeled value
Grey highlight indicates user entered value

Table 10 – Results of Review – Annual Forced Outage Factor (%)

	Forced Outage Factor (%)								
Resource	Current Modeled	Tri-State Data	S&P Data	Peer Group Data (NERC)	Avg. Tri-State, Peer Group Data (5% Sig.)	Recommendation	Notes	Recommended Modeled	Resulting Modeled FOH
1 GC-Craig 1-NW_CO	4.00	3.52	None	4.53	4.03	No Change	Within reasonable range	4.00	350
2 GC-Craig 2-NW_CO	4.00	2.70	None	4.53	3.62	No Change	Within reasonable range	4.00	350
3 GC-Craig 3-NW_CO	4.00	15.93	None	4.53	10.23	No Change	Tri-State data skewed by 2018 45%	4.00	350
4 GC-LRS 2-WY	4.00	3.01	None	4.53	3.77	No Change	Within reasonable range	4.00	350
5 GC-LRS 3-WY	4.00	3.53	None	4.53	4.03	No Change	Within reasonable range	4.00	350
6 GC-SV 3-SPV	4.00	10.21	None	4.53	7.37	No Change	Tri-State data skewed by 2016, 2017 15%	4.00	350
7 GG-Burlington 1-E_CO	0.00	1.23	None	3.85	2.54	1.00	Modeled too low. Use Tri-State data.	1.00	88
8 GG-Burlington 2-E_CO	0.22	0.92	None	3.85	2.38	1.00	Modeled too low. Use Tri-State data.	1.00	88
9 GG-Knutson 1-E_CO	0.44	0.51	None	3.85	2.18	1.00	Modeled too low. Use Tri-State data.	1.00	88
10 GG-Knutson 2-E_CO	0.44	0.52	None	3.85	2.18	1.00	Modeled too low. Use Tri-State data.	1.00	88
11 GG-Limon 1-E_CO	0.44	1.00	None	3.85	2.43	1.00	Modeled too low. Use Tri-State data.	1.00	88
12 GG-Limon 2-E_CO	0.44	0.70	None	3.85	2.27	1.00	Modeled too low. Use Tri-State data.	1.00	88
13 GG-Pyramid 1-S_NM	0.44	0.24	None	3.85	2.05	1.00	Modeled too low. Use Tri-State data.	1.00	88
14 GG-Pyramid 2-S_NM	0.44	0.88	None	3.85	2.36	1.00	Modeled too low. Use Tri-State data.	1.00	88
15 GG-Pyramid 3-S_NM	0.44	0.31	None	3.85	2.08	1.00	Modeled too low. Use Tri-State data.	1.00	88
16 GG-Pyramid 4-S_NM	0.44	0.19	None	3.85	2.02	1.00	Modeled too low. Use Tri-State data.	1.00	88
17 GG-Rifle-NW_CO	0.26	3.27	None	4.50	3.89	3.00	Modeled too low. Use Tri-State data.	3.00	263
18 GG-Shafer-E_CO	0.09	2.93	None	3.93	3.43	3.00	Modeled too low. Use Tri-State data.	3.00	263
19 CP-AltaLuna-S_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
20 CP-SanIsabel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
21 CP-FirstSolar-N_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
22 CP-ColoHighlands-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
23 CP-KitCarson-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
24 CP-TwinButtes-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
25 CP-Carousel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
26 CP-Basin_West	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27 CP-Basin_East	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Notes:
Yellow highlight indicates average Tri-State, S&P and Peer Group value is more than 10% above/below current modeled value
Green highlight indicates recommended modeled value different than current modeled value
Grey highlight indicates user entered value

Table 11 – Results of Review – Annual Renewable Capacity Factor

	Renewable Capacity Factor (%)							
Resource	Current Modeled	Tri-State Data	S&P Data	Peer Group Data (S&P)	Avg. Tri-State, Peer Group Data	Recommendation	Notes	Recommended Modeled
1 GC-Craig 1-NW_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2 GC-Craig 2-NW_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
3 GC-Craig 3-NW_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
4 GC-LRS 2-WY	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
5 GC-LRS 3-WY	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
6 GC-SV 3-SPV	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
7 GG-Burlington 1-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
8 GG-Burlington 2-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
9 GG-Knutson 1-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
10 GG-Knutson 2-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
11 GG-Limon 1-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
12 GG-Limon 2-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
13 GG-Pyramid 1-S_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
14 GG-Pyramid 2-S_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
15 GG-Pyramid 3-S_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
16 GG-Pyramid 4-S_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
17 GG-Rifle-NW_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
18 GG-Shafer-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
19 CP-AltaLuna-S_NM	35	33	31	23	29	No Change	Peer group data suspect, very low	35
20 CP-SanIsabel-E_CO	29	19	19	35	29	No Change	Within reasonable range	29
21 CP-FirstSolar-N_NM	22	24	24	29	29	No Change	Peer group data suspect, very high	22
22 CP-ColoHighlands-E_CO	46	45	44	32	41	No Change	Peer group data suspect, very low	46
23 CP-KitCarson-E_CO	42	40	40	32	37	No Change	Peer group data suspect, very low	42
24 CP-TwinButtes-E_CO	45	28	23	32	28	No Change	Tri-State, S&P data skewed by low 2017	45
25 CP-Carousel-E_CO	51	37	37	32	35	No Change	Tri-State, S&P data skewed by low 2015	51
26 CP-Basin_West	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27 CP-Basin_East	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Notes:
Yellow highlight indicates average Tri-State, S&P and Peer Group value is more than 10% above/below current modeled value
Green highlight indicates recommended modeled value different than current modeled value
Grey highlight indicates user entered value

END OF REPORT

Attachment Vol II 5-5 B&V Benchmarking Study

August 3, 2020 Revision

Report on Benchmarking of Existing Resources

Executive Summary

As part of its responsibilities under a recent Energy Resource Planning decision by the Colorado Public Utilities Commission[1], Tri-State Generation & Transmission Association ("Tri-State") must file in support of its Energy Resource Plan (ERP) an assessment of its existing resources including a comparison of the costs and performance of each of its existing resources (utility owned and contracted) to the costs and performance of the generic resources (a "Benchmarking")[2]. Tri-State retained Black & Veatch ("we" or "us") to perform the Benchmarking for the purposes of supporting a filing by Tri-State. Tri-State defined the existing resources to include eighteen (18) of its coal, gas and oil fired resources, two (2) long-term purchase agreements with Basin Electric, and seven (7) of its renewable (solar and wind) facilities totaling twenty seven (27) existing resources ("Existing Resources"). Tri-State did not include its renewable facilities that are under contract but not yet in commercial operation. The generic resources included future potential gas-fired, solar, wind, battery storage, solar plus battery, wind plus battery, and hydroelectric resources located in Colorado, Wyoming and New Mexico totaling sixty one (61) generic resources ("Generic Resources"). This Report summarizes the scope, methodology and results of the Benchmarking.

Our approach was to first identify for each Existing Resource a Generic Resource for comparison based on the type of Existing Resource (thermal or renewable), the location of the Existing Resource, the generating capacity of the Existing Resource, and the annual capacity factor typically expected for a resource of that type. We then forecast the annual energy production and costs of both the Existing Resource and the Generic Resource for the years 2021-2040 assuming each operated at the same capacity factor in isolation from all other resources and under common assumptions for the Colorado social cost of carbon ("Social Cost of Carbon"), fuel costs, interest rates and escalation. Assumptions for heat rate, fixed O&M, variable O&M, capital basis, depreciation, and book life were specific to each resource and were provided by Tri-State. We developed assumptions for a limited number of the Generic Resources where necessary. The forecasts were made on an "equal service life" basis ensuring the Existing Resource and Generic Resource operated for the same years in the study period at the same capacity factor. We then discounted the annual capacity, energy production and annual cost streams to net present values and expressed them as a levelized cost of energy in $/MWh (LCOE) for cases where the capacity factor was relatively high or a levelized cost of capacity in $/kw-yr (LCOC) where the capacity factor was relatively low.

[1] Colorado Public Utilities Decision No. C20-0155 issued March 10, 2020 adopting amendments to the provisions in the rules governing Electric Resource Planning (ERP Rules).

[2] Colorado Department of Regulatory Agencies, Public Utilities Commission, Code of Colorado Regulations (CCR) 723-3, Part 3 Rules Regulating Electric Utilities, Electric Resource Planning, Section 3605 (c)(II).

Results of the Benchmarking show that each coal-fired Existing Resource is more costly than its associated Generic Resource counterpart due primarily to higher Social Cost of Carbon and higher FOM costs. Each oil and gas fired combustion turbine Existing Resource is less costly than its Generic Resource counterpart due primarily to a lower (highly depreciated) capital basis and therefore lower depreciation and interest costs. Each renewable Existing Resource is more costly than its associated Generic Resource counterpart likely due to the fact that the Existing Resources were built in prior years when the cost of solar and wind technology was higher than today and much higher than costs expected in future years (a declining capital cost curve). The Basin West Contract is more costly than its Generic Resources due to an applied social cost of carbon rate, whereas conversely the Basin East Contract is less costly than its Generic Resources due to the need to include a gas-fired peaking resource in the Generic Resources to account for renewable intermittency. Results are shown in the Results section of this Report.

We also performed a supplemental analysis concerning the Existing Resources not located in Colorado to examine how their LCOE and LCOC would change if the Social Cost of Carbon was not applied ("Non-Colorado Benchmarking"). Results of the Non-Colorado Benchmarking revealed that both the Non-Colorado Existing Resources and the Non-Colorado Generic Resources are significantly less costly than under the Benchmarking. Results also revealed that although the Existing Resources are still more costly than the Generic Resources the gap in cost is narrowed significantly. This is particularly true for LRS Units 2 and 3 where the cost difference is narrowed to approximately ten (10) percent.

Scope

The scope of the resources to be Benchmarked was defined by Tri-State and included the Existing Resources shown in Table 1 and the Generic Resources shown in Table 2 below.

Existing Resources

Six (6) of the Existing Resources are coal fired. These include the Craig coal-fired Units 1 through 3 located in western Colorado ("wco"), the Laramie River coal-fired station ("LRS") Units 2 and 3 located in Wyoming ("wyo"), and Springerville coal-fired Unit 3 located in Arizona ("arz"). These resources are either partially owned or partially controlled by Tri-State with the exception of Craig Unit 3 which is wholly owned, and Springerville Unit 3 which is wholly leased with 100 MW of the Total Capacity sold to a third party under a tolling agreement through the summer of 2036. The capacity currently controlled by Tri-State is shown as the "Tri-State Modeled Capacity".

Another ten (10) the Existing Resources are oil or gas fired combustion turbines that are fully owned by Tri-State. These include the Burlington Units 1 and 2, the Knutson Units 1 and 2, and the Limon Units 1 and 2and the Pyramid Units 1 through 4. The Burlington, Knutson and Limon Units are located in eastern Colorado and the Pyramid Units are located in southern New Mexico. All of these resources are fully controlled by Tri-State

Another two (2) of the Existing Resources are gas-fired combined cycle plants that are fully owned by Tri-State. These include the Rifle plant located in western Colorado and the Shafer plant located in eastern Colorado.

These coal, gas or oil fired resources are referred to collectively as the "thermal" resources.

Another seven (7) Existing Resources are solar or wind powered "renewable" resources with output purchased by Tri-State under power purchase agreements ("PPA"). Five (5) of these resources are located in eastern Colorado ("eco") and the remaining two (2) are located in New Mexico. All of the output is purchased by Tri-State.

The remaining two (2) Existing Resources are long-term contract purchases from Basin Electric Power Cooperative ("Basin"), collectively the "Basin Contracts". The first contract is known as the Western CROD Contract ("Basin West") and the other as the Basin Electrically East Contract ("Basin East"). No specific generating resource is associated with each Basin Contract. Basin has the sole discretion to choose how the Basin West contract is supplied on a day ahead and hour ahead basis. The Basin East contract is supplied via Southwest Power Pool (SPP). The Basin West contract has a set hourly energy profile by month for each year of the contract. The Basin East Contract is a full requirements contract and supply is based on actual energy needs of Tri-State's Utility Member Systems located in the Eastern Interconnection. Tri-State purchases all energy as contracted under the Basin Contracts.

Table 1 – Summary of Existing Resources to be Benchmarked

	Plant/Unit	Technology	Type	Location	Nominal Capacity (MW)	Tri-State Modeled Capacity (MW)	Year In Service
1	GC-Craig 1-NW_CO	Steam Turbine - Coal	Owned	wco	427	102	1980
2	GC-Craig 2-NW_CO	Steam Turbine - Coal	Owned	wco	410	98	1979
3	GC-Craig 3-NW_CO	Steam Turbine - Coal	Owned	wco	448	448	1984
4	GC-LRS 2-WY	Steam Turbine - Coal	Owned	wyo	570	231	1981
5	GC-LRS 3-WY	Steam Turbine - Coal	Owned	wyo	570	230	1982
6	GC-SV 3-SPV	Steam Turbine - Coal	Owned	arz	417	317	2006
7	GG-Burlington 1-E_CO	Frame CT - Oil	Owned	eco	55	55	1977
8	GG-Burlington 2-E_CO	Frame CT - Oil	Owned	eco	55	55	1977
9	GG-Knutson 1-E_CO	Frame CT - Gas	Owned	eco	70	70	2002
10	GG-Knutson 2-E_CO	Frame CT - Gas	Owned	eco	70	70	2002
11	GG-Limon 1-E_CO	Frame CT - Gas	Owned	eco	70	70	2003
12	GG-Limon 2-E_CO	Frame CT - Gas	Owned	eco	70	70	2003
13	GG-Pyramid 1-S_NM	Aeroderivative CT - Gas	Owned	snm	40	40	2003
14	GG-Pyramid 2-S_NM	Aeroderivative CT - Gas	Owned	snm	40	40	2003
15	GG-Pyramid 3-S_NM	Aeroderivative CT - Gas	Owned	snm	40	40	2003

	Plant/Unit	Technology	Type	Location	Nominal Capacity (MW)	Tri-State Modeled Capacity (MW)	Year In Service
16	GG-Pyramid 4-S_NM	Aeroderivative CT - Gas	Owned	snm	40	40	2003
17	GG-Rifle-NW_CO	Combined Cycle - Gas	Owned	wco	81	81	1987
18	GG-Shafer-E_CO	Combined Cycle - Gas	Owned	eco	272	272	1994
19	CP-AltaLuna-S_NM	Tracking Array Solar	PPA	nm	25	25	2017
20	CP-SanIsabel-E_CO	Tracking Array Solar	PPA	eco	30	30	2016
21	CP-FirstSolar-N_NM	Fixed Solar	PPA	nm	30	30	2010
22	CP-ColoHighlands-E_CO	Wind	PPA	eco	91	91	2012
23	CP-KitCarson-E_CO	Wind	PPA	eco	51	51	2010
24	CP-TwinButtes-E_CO	Wind	PPA	eco	76	76	2017
25	CP-Carousel-E_CO	Wind	PPA	eco	150	150	2015
26	CP-Basin_West	Basin System	PPA	eco	268	268	2017
27	CP-Basin_East	Basin System	PPA	eco	317	317[3]	2017

Generic Resources

Twenty-eight (28) of the Generic Resources were gas-fired including reciprocating engine ("Recip_Engine"), aeroderivative combustion turbine ("Aeroderivative_CT"), industrial combustion turbine ("Frame_CT") and industrial combined cycle ("Frame_CCCT") technologies that would be located in western Colorado ("wco"), southwestern Colorado ("swco"), northwestern Colorado ("nwco"), northern New Mexico ("nnm") and Wyoming ("wyo"). All of these would be wholly owned by Tri-State with the capacity shown as the "Tri-State Modeled Capacity".

The remaining Generic Resources included:

- Solar PV ("Solar_PV") technologies of various sizes (40, 100, 120, 230 MW) and wind ("Wind") technologies of various sizes (40, 100, 165, 280 MW) to be located in eco, swco, nnm, and wyo either under third party ownership ("PPA") or Tri-State ownership ("Build-Transfer");
- Standalone lithium ion battery storage technology ("Li-Ion Battery") in various combinations of size (25, 100, 500 MW) and duration (4 hour or 8 hour) to be located in eco, swco, wco, nnm, and wyo to be owned ("Owned") by Tri-State;
- 300 MW pumped storage technology located in nnm to be owned by Tri-State;
- 100 MW combined solar PV plus storage ("Solar+Battery") and wind plus storage ("Wind+Battery") technologies to be located in eco, nnm, wyo and swco either under third party ownership or Tri-State ownership

[3] Basin East is a full requirements contract so capacity is not specified in the contract but rather fluctuates with the demand forecast of the members.

Table 2 – Summary of Generic Resources to be Considered in the Benchmarking

	Name	Technology	Type	Location	Modeled Tri-State Capacity (MW)
1	112_18x6RICE_eco	Recip_Engine	Owned	eco	112
2	112_18x6RICE_nnm	Recip_Engine	Owned	nnm	112
3	46_9x5RICE_eco	Recip_Engine	Owned	eco	46
4	46_9x5RICE_nnm	Recip_Engine	Owned	nnm	46
5	46_9x5RICE_swco	Recip_Engine	Owned	swco	46
6	Upd-93_10x9_3ICE_eco	Recip_Engine	Owned	eco	93
7	Upd-93_10x9_3ICE_nnm	Recip_Engine	Owned	nnm	93
8	Upd-93_10x9_3ICE_swco	Recip_Engine	Owned	swco	93
9	Upd-93_10x9_3ICE_wyo	Recip_Engine	Owned	wyo	93
10	40_1x40LM6000_eco	Aeroderivative_CT	Owned	eco	40
11	40_1x40LM6000_nnm	Aeroderivative_CT	Owned	nnm	40
12	40_1x40LM6000_swco	Aeroderivative_CT	Owned	swco	40
13	81_2x40LM6000_eco	Aeroderivative_CT	Owned	eco	81
14	81_2x40LM6000_wyo	Aeroderivative_CT	Owned	wyo	81
15	93_1x100_LMS100_nnm	Aeroderivative_CT	Owned	nnm	93
16	300_1x1_7FA05_eco	Frame_CCCT	Owned	eco	300
17	300_1x1_7FA05_nnm	Frame_CCCT	Owned	nnm	300
18	300_1x1_7FA05_swco	Frame_CCCT	Owned	swco	300
19	300_1x1_7FA05_wyo	Frame_CCCT	Owned	wyo	300
20	287_1x1_M501G_nwco	Frame_CCCT	Owned	nwco	350
21	331_1x1_STG-8000H_nwco	Frame_CCCT	Owned	nwco	375
22	357_1x1_7HA01_nwco	Frame_CCCT	Owned	nwco	357
23	545_1x1_7HA03_nwco	Frame_CCCT	Owned	nwco	545
24	200_1x235_7FA05_eco	Frame_CT	Owned	eco	200
25	200_1x235_7FA05_nnm	Frame_CT	Owned	nnm	200
26	200_1x235_7FA05_swco	Frame_CT	Owned	swco	200
27	CP-1x100PV_eco	Solar_PV	PPA	eco	100
28	CP-1x100PV_nnm	Solar_PV	PPA	nnm	100
29	CP-1x100PV_swco	Solar_PV	PPA	swco	100
30	CP-1x100PV_eco Build-Transfer	Solar_PV	Owned	eco	100
31	CP-1x100PVBatt_eco	Solar+Battery	PPA	eco	100
32	CP-1x100PVBatt_nnm	Solar+Battery	PPA	nnm	100
33	CP-1x100PVBatt_swco	Solar+Battery	PPA	swco	100
34	CP-1x100PVBatt_eco Build-Transfer	Solar+Battery	Owned	eco	100
35	CP-1x100Wind_eco	Wind	PPA	eco	100
36	CP-1x100Wind_nnm	Wind	PPA	nnm	100
37	CP-1x100Wind_wyo	Wind	PPA	wyo	100
38	CP-1x100Wind_eco Build-Transfer	Wind	Owned	eco	100
39	CP-1x100WindBatt_eco	Wind+Battery	PPA	eco	100
40	CP-1x100WindBatt_nnm	Wind+Battery	PPA	nnm	100
41	CP-1x100WindBatt_wyo	Wind+Battery	PPA	wyo	100
42	100MW Li-Ion Battery_eco	Li-Ion_Battery	Owned	eco	100
43	100MW Li-Ion Battery_wco	Li-Ion_Battery	Owned	wco	100
44	100MW Li-Ion Battery_nnm	Li-Ion_Battery	Owned	nnm	100

	Name	Technology	Type	Location	Modeled Tri-State Capacity (MW)
45	25MW Li-Ion Battery_eco	Li-Ion_Battery	Owned	eco	25
46	25MW Li-Ion Battery_nnm	Li-Ion_Battery	Owned	nnm	25
47	25MW Li-Ion Battery_wco	Li-Ion_Battery	Owned	wco	25
48	25MW Li-Ion Battery_wyo	Li-Ion_Battery	Owned	wyo	25
49	50MW 8Hr Li-Ion Battery_eco	Li-Ion_Battery	Owned	eco	50
50	50MW 8Hr Li-Ion Battery_nnm	Li-Ion_Battery	Owned	nnm	50
51	50MW 8Hr Li-Ion Battery_swco	Li-Ion_Battery	Owned	swco	50
52	Pumped Storage - nnm	Hydro	Owned	nnm	300
53	CP-1x130PV-eco	Solar_PV	PPA	eco	130
54	CP-1x165Wind-eco	Wind	PPA	eco	165
55	270_18x6RICE_eco	Recip_Engine	Owned	eco	270
56	CP-1x230PV-eco	Solar_PV	PPA	eco	230
57	CP-1x280Wind-eco	Wind	PPA	eco	280
58	500MW Li-Ion Battery_eco	Li-Ion_Battery	Owned	eco	500
59	CP-1x40PV-eco	Solar_PV	PPA	eco	40
60	CP-1x40Wind-eco	Wind	PPA	eco	40
61	306_18x6RICE_eco	Recip_Engine	Owned	eco	306

Overall Methodology

Our overall methodology for the Benchmarking was to first select for each Existing Resource a Generic Resource for comparison. We identified certain criteria to guide and constrain the selection of the Generic Resource for comparison (the "Selection Criteria"). The Selection Criteria included 1) that the Generic Resource must be of similar technology to the Existing Resource (e.g. a thermal resource could not be compared with a renewable resource), 2) that the Generic Resource must have a similar location as the Existing Resource, 3) that the Generic Resource must have a capacity similar to the Existing Resource and 4) that the Generic Resource must be capable of operating at or above the annual capacity factor typically expected for a resource of that type. Each combination of Existing Resource and its associated Generic Resource for comparison was known as a "Pairing".

The total capacity of the Existing Resource rather than just the Tri-State Modeled Capacity was considered in selecting the Generic Resource for comparison. This was done because the performance and cost of Tri-State's share of the Existing Resource benefits from the economies of scale of the entire Existing Resource (for example, entire resource heat rate, variable O&M cost rate, fixed O&M cost rate) and therefore a Generic Resource of similar size to the entire Existing Resource should be selected for a fair comparison.

Once the Pairings had been made, we then forecast the annual capacity, energy production and annual operating and ownership costs of both the Existing Resource and the Generic Resource for the years 2021-2040 assuming they would operate in isolation from each other and all other resources. Both the Existing Resource and the Generic resource were forecast to operate at a capacity factor consistent with resources of their types and with historical or expected capacity factors for the Existing Resources as reported by Tri-State (the "Common Capacity Factor"). Energy for each Existing Resource was forecast based on the Common Capacity Factor and its Tri-State Modeled Capacity. Energy for each Generic

Resource was forecast to operate based on the Common Capacity Factor but only a portion of the Plant Capacity equal to their Tri-State Modeled Capacity for the Existing Resource (the "Tri-State Share"). This was done so that the forecast energy production for the Existing Resource and the Generic resource were the same, as if Tri-State was to own just a share of the Generic Resource.

Assumptions for fuel cost, heat rate, carbon emission rates, fixed O&M, variable O&M, capital expenditures, capital basis, depreciation, book life and PPA price (for the third party owned renewable resources) were specific to each Existing Resource and Generic Resource. Assumptions for the Existing Resources were provided by Tri-State but reviewed by us and in some cases modified by Tri-State in consultation with us as part of our Existing Resource Review work. Similarly, assumptions for the Generic Resources were provided by Tri-State but reviewed by us and in some cases modified by Tri-State in consultation with us as part of our Generic Resource Review work. Assumptions for a limited number of the Generic Resources were developed by us. Please see the Results section of this report for a more detailed description of these assumptions and the forecasting methodology. The forecasts were made on an "equal service life" basis ensuring the Existing Resource and Generic Resource were modeled to operate for the same years in the study period. Assumptions provided by Tri-State were aligned with those used in their resource capacity expansion modeling software and were not representative of inputs specific to their financial modeling.

We then discounted the annual capacity, energy production and annual cost streams to net present values and used them to calculate a levelized cost in 2020 dollars for both the Existing Resource and Generic Resource. In cases where the Common Capacity Factor was relatively high, we calculated a levelized cost of energy (LCOE) in $/MWh. In cases where the Common Capacity Factor was relatively low, we calculated a levelized cost of capacity (LCOC) in $/kw-yr. We then compared the LCOE or LCOC results for the Existing Resource and the Generic Resource and commented on why they differed.

Expanded Methodology for the Basin Contracts

For the Basin Contracts, a special methodology was necessary because no specific generating resource is associated with either Basin Contract. For the purposes of benchmarking this type of unspecified energy with varying profiles, we expanded the methodology to allow comparison of each Basin Contract against a group of three (3) Generic Resources (a "Generic Composite") instead of just a single Generic Resource. Use of three resources of differing types was judged a reasonable proxy for a system resource for the purposes of benchmarking.

Generic Resources were selected for each Generic Composite based on three general criteria; 1) to maximize the use of renewable resources; 2) to match the forecast delivery profile of the associated Basin Contract as best possible and 3) minimize the overall cost of the Generic Composite. We began the selection process by examining the hourly Basin Contract forecast energy profile for a typical year (8760 hours). We then attempted to replicate the Basin Contract profile with the hourly forecast energy profiles of the various sized solar and wind Generic Resources. Invariably, there were hours in which the combined forecast solar and wind profiles were insufficient to replicate the Basin Contract profile. In these cases, we introduced a forecast hourly profile for a dispatchable resource to fill the gap. The dispatchable resource was either Recip_Engine, Aeroderivative_CT, Frame_CT, Frame_CCCT or Li-Ion

Battery based. For a battery resource, it was assumed to store energy from the selected solar and wind resources only with a certain efficiency "round-trip" loss.

Although specific generating resources are not associated with the Basin Contracts, Tri-State did provide us with carbon emission rates based on how the Basin Contracts primarily have been historically served to apply to the Basin Contracts.

Results

This section includes results of the resource Pairing, a detailed description of the forecasting and costing methodology with detailed results for one of the Pairings, and a summary of the LCOE and LCOC results for all of the Pairings.

Pairings

Table 3 summarizes results of the resource Pairing.

The coal-fired Existing Resources have plant capacities ranging from 410 to 570 MW with relatively high historical capacity factors reported by Tri-State. Therefore, each of these Existing Resources was paired with the large gas-fired combined cycle combustion turbine (545_1x1_7HA03_nwco) Generic Resource. This Pairing satisfies the Selection Criteria except in the case of the Springerville 3 (SV 3) resource and the Laramie River Station (LRS2, LRS 3) resources. With respect to SV 3, the Generic Resource has a northwest Colorado location instead of an Arizona location. However, we judged the pairing as reasonable since no other CCCT Generic Resource is located in Arizona. With respect to LRS 2 and LRS 3, the Generic Resource has a capacity (545 MW) that is smaller than LRS 2 and LRS 3 (570 MW). However, we judged the Pairings as reasonable because no Frame_CCCT Generic Resource has a capacity greater than LRS. The 545_1x1_7HA03_nwco Generic Resource is the largest Frame_CCCT Generic Resource. We also judged the other coal-fired resource Pairings reasonable even though the capacity (545 MW) is much greater than that of the other coal-fired resources (410-448 MW). This is because no other Frame_CCCT Generic Resource has a capacity greater than 375 MW and therefore would not have satisfied the Selection Criteria. We set the Common Capacity Factor for each Pairing equal to eighty (80) percent which is representative for large coal fired resources and large gas-fired combined cycle resources. This capacity factor is also representative of air quality permit limitations for Craig 1 which limits its capacity factor to 80%.

The combustion turbine Existing Resources have plant capacities ranging from 40 to 70 MW and relatively low historical and expected capacity factors reported by Tri-State. Therefore, each of these resources was paired with a small simple cycle combustion turbine (781_2x40LM6000_eco) Generic Resource. This Pairing satisfied the Selection Criteria. We set the Common Capacity Factor for each Pairing equal to fifteen (15) percent which is representative for combustion turbine resources.

The Rifle Existing Resource is relatively small (81 MW) combined cycle plant. Although a combined cycle plant, Rifle has a historical and expected capacity factor reported by Tri-State that is much lower than typical for combined cycle resource and more typical of a combustion turbine resource. Therefore, the Rifle resource was paired with the same small simple cycle combustion turbine (81_2x40LM6000_eco) Generic Resource used for the combustion turbine Existing Resources. This Pairing satisfied the

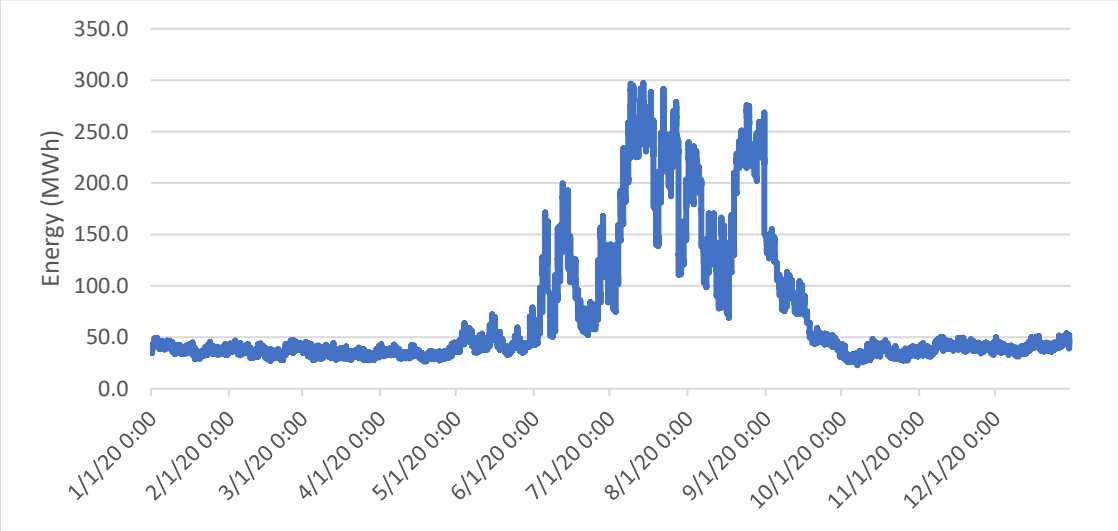
Selection Criteria. We set the Common Capacity Factor for the Pairing equal to fifteen (15) percent which is representative for combustion turbine resources.

The Shafer combined cycle Existing Resource is relatively large (272 MW) with a historical and expected capacity factor reported by Tri-State of approximately thirty five (35) percent. This is relatively low with respect to typical combined cycle resources yet relatively high compared with combustion turbine resources. We decided to pair the Shafer resource with the small gas-fired combined cycle combustion turbine (300_1x1_7FA05_eco) Generic Resource. We felt this was more representative than pairing it with a combustion turbine resource. This Pairing satisfies the Selection Criteria. We set the Common Capacity Factor for the Pairing equal to thirty five (35) percent.

The solar PV Existing Resources were paired with the 100 MW solar PV (CP-1x100PV_eco) Generic Resource. The wind Existing Resources were paired with the 100 MW wind (CP-1x100Wind_eco) Generic Resource. These Pairings satisfy the Selection Criteria, with the exception of the Carousel wind resource. The wind Generic resource has a capacity (100 MW) that is less than the Carousel capacity (150 MW). However, we judged this Pairing reasonable because there is no wind Generic Resource with a capacity greater than 100 MW. We set the Common Capacity Factor for the Pairings equal to the historical capacity factors reported by Tri-State for the Existing Resources.

The Basin West Contract was paired with a Generic Composite consisting of a 230 MW Solar PV resource PPA in eco (CP-1x130PV-eco), a 280 MW Wind resource PPA in eco (CP-1x280Wind-eco) and a 500 MW Li-Ion Battery resource Owned in eco (500MW Li-Ion Battery_eco). The Basin East Contract was paired with a 40 MW Solar PV resource PPA in eco (CP-1x40PV-eco), a 40 MW wind resource PPA in eco (CP-1x40Wind-eco) and a 306 MW RICE resource Owned in eco (306_18x6RICE_eco). It's important to note that a gas-fired dispatchable resource was selected for the Basin East Generic Composite rather than a Li-Ion Battery resource. This was due to the fact that the Basin East Contract energy demand is driven by irrigation loads which are consistently high in the summer and consistently low in the winter (see Figure 1 below). It was judged that a Li-Ion Battery resource with just 4 hours of duration and a relatively high capital cost would have very little utilization over the year and therefore would be less cost-effective than a RICE generating resource with a relatively low capital cost.

Figure 1 – Hourly Energy Profile for the Basin East Contract



Forecasting Methodology and Craig 1 Results

This section provides a detailed description of the methodology used for the forecasting and LCOE and LCOC calculations for Benchmarking of Existing Resources other than the Basin Contracts. As a guide, detailed results for the Craig 1 Pairing are shown below (Table 4 for the Existing Resource and Table 5 for the Generic Resource). Assumptions and results are shown in the upper left portion of the results with the annual cost forecast shown below that. A summary of LCOE and LCOC results for all the Pairings are provided in the subsequent LCOE and LCOC Results section.

Generation for the Existing Resource was forecast to be constant every year based on the Tri-State Modeled Capacity and the Common Capacity Factor for the Existing Resource, and the Tri-State Share and the Common Capacity Factor for the Generic Resource.

For Existing Resources and Generic Resources to be owned by Tri-State, fuel cost was forecast based on the heat rate multiplied by the generation and the first year fuel price (Fuel Cost 2021). For costs in subsequent years the fuel price was escalated at the fuel cost escalation rate which was set equal to the compound annual growth rate of prices observed in the fuel price forecasts provided by Tri-State. Carbon costs were forecast similarly, based on the generation, the carbon emission rate of the resource and the first year Social Cost of Carbon (Social Cost of Carbon 2021) and an escalation rate based on the compound annual growth rate of the Social Cost of Carbon forecast provided by Tri-State. Variable O&M (VOM) was forecast based on generation and the first year variable O&M cost (VOM Cost 2021) and an assumed VOM cost escalation rate. Fuel, carbon and VOM forecasts were not applicable to the resources to be owned by third parties.

For Existing Resources and Generic Resources to be owned by Tri-State, fixed operations and maintenance cost (FOM) and capital expenditures (Capex) were forecast similarly to VOM except in the case of the Existing Resources for which resource-specific forecasts were provided by Tri-State. In order

to ensure equal service lives between the Existing Resource and the Generic Resource, we requested for the purposes of the Benchmarking that Tri-State develop the Existing Resource forecasts assuming that the Existing Resources would operate for the entire study period (through 2040). This ran counter to planned retirement decisions for the Existing Resources, in particular the Craig 1 resource which will be retired by 2025 and Craig 2 and Craig 3 resources which will be retired by 2030, but was necessary to the integrity of the comparison. In addition, Tri-State indicated they would not be expending capex in the final five years of the resource life for the Existing Resources and the Generic Resources. Therefore, the capex costs for the years 2035 through 2040 were assumed to be zero for both the Existing Resources and the Generic Resources. FOM and Capex forecasts were not applicable to the resources to be owned by third parties.

For Existing Resources and Generic Resources to be owned by Tri-State, interest and depreciation were forecast based on the undepreciated capital cost of the resource at the beginning of each year (Capex Balance) multiplied by an assumed debt interest rate and an assumed depreciation rate. The resulting interest and depreciation were deducted from the subsequent year Capex Balance. For the Existing Resources the assumed interest and depreciation rates were provided by Tri-State. For the Generic Resources we assumed the same debt interest rate but a depreciation rate equal to straight line depreciation over a 30 year life. Interest and depreciation forecasts were not applicable to the resources to be owned by third parties.

For Existing Resources and Generic Resources to be owned by Tri-State, we also forecast the liability that Tri-State would incur at the time an Existing Resource owned by Tri-State would reach the end of its depreciation life (the "Accounting Retirement Year"). This liability would occur if and to the extent that the resource is not fully depreciated at the end of the Accounting Retirement Year. We characterized this liability as the "Stranded Cost" of the resource which we set equal to the beginning Capex Balance plus the Capex amount in the year equal to the Accounting Year. The Accounting Year assumption was provided by Tri-State.

For Existing Resources and Generic Resources that are (or would be) owned by third parties, PPA Cost was forecast based on Generation multiplied by a PPA price forecast. For Existing Resources, the PPA price forecast was provided by Tri-State. For Generic Resources, the PPA price forecast was developed by us as part of our Generic Resource Review work.

For calculation of LCOE and LCOC, we first calculated the net present value (NPV) of total costs (Total), fixed costs (Fixed Only), Generation and Capacity by discounting the annual cost values to the year 2020 using a discount rate equal to the debt interest rate. The debt interest rate represents the weighted average cost of capital of Tri-State since Tri-State does not have equity in its capital structure. LCOE was then calculated as the ratio of Total NPV to Generation NPV expressed as $/MWh. LCOC was calculated as the ratio of Fixed Only NPV to Capacity NPV expressed as $/kw-year.

LCOE and LCOC Results

A summary of LCOE and LCOC results for all the Pairings is shown in Table 6. Results broken down by cost component are shown on Figure 2, Figure 3 and Figure 4.

For the coal-fired plant pairings, only LCOE results are relevant. Results show that the Existing Resources are more costly than the Generic Resources due primarily to higher Social Cost of Carbon and higher FOM costs. The difference is greatest for Springerville 3 due to its relatively high interest cost in addition to the Social Cost of carbon and FOM cost differences.

For the Frame CT pairings, only LCOC results are relevant. Results show that the Existing Resources are less costly than the Generic Resources due to lower depreciation, interest, capex and FOM costs. The Existing Resources benefit from very low (highly depreciated) Capex Balance and therefore lower interest and depreciation costs.

For the Shafer Pairing, both the LCOE and LCOC results are relevant. The Common Capacity Factor of 35% is relatively low for a resource that is intended to provide energy (such as a CCCT) and relatively high for a resource that is intended to provide capacity (such as a CT). LCOE results show that Shafer is less costly than the Generic Resource due primarily to very low (highly depreciated) Capex Balance and therefore lower interest and depreciation costs. LCOC results also show Shafer less costly, with the difference due to the same reasons.

For the renewable plant Pairings, only LCOE results are relevant. Results show that the Existing Resources are more costly than the Generic Resources for nearly all the Pairings. This is likely because the Existing Resources were built in prior years when the cost of solar and wind technology was high relative to the costs expected in future years (a declining capital cost curve). The exception is the Twin Buttes wind resource. Its LCOE is less than the Generic Resource. Review of the Twin Buttes PPA price forecast reveals that it has a low price with no escalation which compares favorably to the Generic resource that has a similar first year price but is assumed to escalate at 2% annually thereafter.

For the Basin Contracts, only LCOE results are relevant. Results show that the Basin West Contract is more costly than its Generic Composite. This is primarily because the Basin West Contract has a carbon emission rate and therefore incurs a Social Cost of Carbon whereas the Generic Composite does not (all renewables and battery storage). The impact of the Social Cost of Carbon becomes evident when examining the case where there is no Social Cost of Carbon as described in the Non-Colorado Benchmarking section below. Conversely to the Basin West results, the Basin East Contract results show that the Basin East Contract is less costly than its Generic Composite. The Basin East Contract incurs a Social Cost of Carbon, but so does its Generic Composite along with the relatively high cost of installing and operating a new RICE resource. The net effect is a higher cost for the Generic Composite.

Non-Colorado Benchmarking

In addition to the Benchmarking described above, we also performed a supplemental analysis concerning only the Existing Resources not located in Colorado ("Non-Colorado Resources") to examine how their LCOE and LCOC would change if the Social Cost of Carbon was not applied ("Non-Colorado Benchmarking"). The overall methodology, pairing and forecast methodology was identical to the Benchmarking, except that the Social Cost of Carbon was set to zero for both the Existing Resources and the Generic Resources.

A summary of LCOE and LCOC results for the Non-Colorado Benchmarking is shown in Table 7 below.

LCOE results show that both the Non-Colorado Existing Resources and the Non-Colorado Generic Resources are significantly less costly than under the Benchmarking above. For the thermal resources, although the Existing Resources are still more costly than the Generic Resources the gap in cost is narrowed significantly. This is particularly true for LRS Units 2 and 3 where the cost difference is narrowed to approximately ten (10) percent. LCOE results for the renewable resources are unchanged from the Benchmarking results above since the Social Cost of Carbon does not apply to renewable resources. LCOE results for the Basin Contracts show that each contract is less expensive than its Generic Composite if the Social Cost of Carbon is not applied.

LCOC results are identical to those under the Benchmarking above. This is because the Social Cost of Carbon is a variable cost and therefore is not a component of LCOC which considers fixed costs only.

Table 3 – Results of the Pairings of Existing Resources with Generic Resources for Comparison

	Pairings															
	Existing Resource				Generic Resource 1				Generic Resource 2				Generic Resource 3			
	Name	Type	Plant Capacity (MW)	Tri-State Modeled Capacity (MW)	Name	Type	Capacity	Capacity Factor for Comparison	Name	Type	Capacity	Capacity Factor for Comparison	Name	Type	Capacity	Capacity Factor for Comparison
1	GC-Craig 1-NW_CO	Steam Turbine - Coal	427	102	545_1x1_7HA03_nwco	Frame_CCCT	545	80%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2	GC-Craig 2-NW_CO	Steam Turbine - Coal	410	98	545_1x1_7HA03_nwco	Frame_CCCT	545	80%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
3	GC-Craig 3-NW_CO	Steam Turbine - Coal	448	448	545_1x1_7HA03_nwco	Frame_CCCT	545	80%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
4	GC-LRS 2-WY	Steam Turbine - Coal	570	231	545_1x1_7HA03_nwco	Frame_CCCT	545	80%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
5	GC-LRS 3-WY	Steam Turbine - Coal	570	230	545_1x1_7HA03_nwco	Frame_CCCT	545	80%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
6	GC-SV 3-SPV	Steam Turbine - Coal	417	317	545_1x1_7HA03_nwco	Frame_CCCT	545	80%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
7	GG-Burlington 1-E_CO	Frame CT - Oil	55	55	81_2x40LM6000_eco	Aeroderivative_CT	81	15%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
8	GG-Burlington 2-E_CO	Frame CT - Oil	55	55	81_2x40LM6000_eco	Aeroderivative_CT	81	15%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
9	GG-Knutson 1-E_CO	Frame CT - Gas	70	70	81_2x40LM6000_eco	Aeroderivative_CT	81	15%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
10	GG-Knutson 2-E_CO	Frame CT - Gas	70	70	81_2x40LM6000_eco	Aeroderivative_CT	81	15%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
11	GG-Limon 1-E_CO	Frame CT - Gas	70	70	81_2x40LM6000_eco	Aeroderivative_CT	81	15%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
12	GG-Limon 2-E_CO	Frame CT - Gas	70	70	81_2x40LM6000_eco	Aeroderivative_CT	81	15%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
13	GG-Pyramid 1-S_NM	Aeroderivative CT - Gas	40	40	40_1x40LM6000_nnm	Aeroderivative_CT	40	15%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
14	GG-Pyramid 2-S_NM	Aeroderivative CT - Gas	40	40	40_1x40LM6000_nnm	Aeroderivative_CT	40	15%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
15	GG-Pyramid 3-S_NM	Aeroderivative CT - Gas	40	40	40_1x40LM6000_nnm	Aeroderivative_CT	40	15%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
16	GG-Pyramid 4-S_NM	Aeroderivative CT - Gas	40	40	40_1x40LM6000_nnm	Aeroderivative_CT	40	15%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
17	GG-Rifle-NW_CO	Combined Cycle - Gas	81	81	81_2x40LM6000_eco	Aeroderivative_CT	81	15%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
18	GG-Shafer-E_CO	Combined Cycle - Gas	272	272	300_1x1_7FA05_eco	Frame_CCCT	300	35%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
19	CP-AltaLuna-S_NM	Tracking Array Solar	25	25	CP-1x100PV_nnm	Solar_PV	100	35%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
20	CP-SanIsabel-E_CO	Tracking Array Solar	30	30	CP-1x100PV_eco	Solar_PV	100	29%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
21	CP-FirstSolar-N_NM	Fixed Solar	30	30	CP-1x100PV_nnm	Solar_PV	100	22%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
22	CP-ColoHighlands-E_CO	Wind	91	91	CP-1x100Wind_eco	Wind	100	46%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
23	CP-KitCarson-E_CO	Wind	51	51	CP-1x100Wind_eco	Wind	100	42%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
24	CP-TwinButtes-E_CO	Wind	76	76	CP-1x100Wind_eco	Wind	100	45%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
25	CP-Carousel-E_CO	Wind	150	150	CP-1x100Wind_eco	Wind	100	51%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
26	CP-Basin_West	Basin System	268	268	CP-1x230PV-eco	Solar_PV	230	30%	CP-1x280Wind-eco	Wind	280	43%	500MW Li-Ion Battery_eco	Li-Ion_Battery	500	9%
27	CP-Basin_East	Basin System	317	317	CP-1x40PV-eco	Solar_PV	40	30%	CP-1x40Wind-eco	Wind	40	43%	306_18x6RICE_eco	Recip_Engine	306	16%

Table 4 LCOE and LCOC Calculations for an Existing Resource

LCOE and LCOC (values in 2020 $ million unless stated otherwise)																	
Existing Resource	GC-Craig 1-NW_CO					Calculate LCOE and											
Technology	Steam Turbine - Coal																
Type	Owned																
Basin Contract?	No																
Assumptions	Base	Escalation															
Plant Capacity (MW)	427																
Tri-State Share (MW)	102																
Capacity Factor	80%																
Heat Rate (Btu/kwh)	10,316																
Fuel Cost 2021 ($/MMBtu)	[redacted]	0.2%															
VOM Cost 2021 ($/MWh)		0.0%															
Social Cost of Carbon 2021 ($/MWh)	$46.00	1.8%															
FOM Cost 2021 ($/kw-yr)	See Detail	0.0%															
Capex Cost 2021 Tri-State Share ($ million/yr)	$0.8	3.0%															
Capex Balance 2021 BOY ($ million)	$86																
Debt Interest Rate	2.21%																
Debt Term (Years)	30																
Depreciation Rate	4%																
Accounting Retirement Year	2025																
PPA First Year Energy Price ($/MWh)	n/a	n/a															
PPA First Year Capacity Price ($/kw-mo)	n/a	n/a															
PPA Start Year	n/a																
PPA Term	n/a																
Discount Rate	2.21%																
Results																	
Levelized Cost of Energy (2020 $/MWh)	**$101**																
Levelized Cost of Capacity (2020 $/kw-yr)	**$154**																
Detail							Book										
	Generation (GWh)	Fuel	VOM	Social Cost of Carbon	FOM	Capex Balance	Capex	Interest	Depreciation	Stranded Cost	PPA Cost	Total	Total ($/MWh)	Capacity (MW)	Fixed Only	Total Fixed Only ($/kw-yr)	
NPV	11,455	[redacted]			[redacted]							$1,160.4		1,635	[redacted]		
2021	715			$38.1		$86.3	$0.8	$1.9	$3.7	$0.0	$0.0	$65.7	$92	102			
2022	715			$38.8		$83.5	$1.0	$1.9	$3.6	$0.0	$0.0	$66.4	$93	102			
2023	715			$39.5		$80.9	$1.1	$1.8	$3.5	$0.0	$0.0	$67.1	$94	102			
2024	715			$40.2		$78.6	$1.4	$1.8	$3.4	$0.0	$0.0	$67.9	$95	102			
2025	715			$40.9		$76.6	$1.6	$1.7	$3.3	$78.2	$0.0	$147.0	$206	102			
2026	715			$41.7		$74.9	$2.5	$0.0	$0.0	$0.0	$0.0	$63.6	$89	102			
2027	715			$42.4		$77.4	$2.8	$0.0	$0.0	$0.0	$0.0	$64.6	$90	102			
2028	715			$43.2		$80.2	$3.0	$0.0	$0.0	$0.0	$0.0	$65.6	$92	102			
2029	715			$44.0		$83.2	$3.3	$0.0	$0.0	$0.0	$0.0	$66.6	$93	102			
2030	715			$44.8		$86.5	$2.9	$0.0	$0.0	$0.0	$0.0	$67.1	$94	102			
2031	715			$45.6		$89.3	$3.0	$0.0	$0.0	$0.0	$0.0	$68.0	$95	102			
2032	715			$46.4		$92.3	$3.1	$0.0	$0.0	$0.0	$0.0	$68.9	$96	102			
2033	715			$47.2		$95.4	$3.1	$0.0	$0.0	$0.0	$0.0	$69.9	$98	102			
2034	715			$48.1		$98.5	$3.2	$0.0	$0.0	$0.0	$0.0	$70.8	$99	102			
2035	715			$48.9		$101.7	$0.0	$0.0	$0.0	$0.0	$0.0	$68.5	$96	102			
2036	715			$49.8		$101.7	$0.0	$0.0	$0.0	$0.0	$0.0	$69.4	$97	102			
2037	715			$50.7		$101.7	$0.0	$0.0	$0.0	$0.0	$0.0	$70.3	$98	102			
2038	715			$51.6		$101.7	$0.0	$0.0	$0.0	$0.0	$0.0	$71.2	$100	102			
2039	715			$52.6		$101.7	$0.0	$0.0	$0.0	$0.0	$0.0	$72.2	$101	102			
2040	715			$53.5		$101.7	$0.0	$0.0	$0.0	$0.0	$0.0	$73.2	$102	102			

Table 5 – LCOE and LCOC Calculations for a Generic Resource

LCOE and LCOC (values in 2020 $ million unless stated otherwise)																	
Generic Resource	1																
Resource	545_1x1_7HA03_nwco																
Technology	Frame_CCCT																
Type	Owned																
Assumptions	Base	Escalation															
Plant Capacity (MW)	545																
Tri-State Share (MW)	102																
Capacity Factor	80%																
Heat Rate (Btu/kwh)	6,170																
Fuel Cost 2021 ($/MMBtu)	$1.79	4.5%															
VOM Cost 2021 ($/MWh)	$3.67	0.0%															
Social Cost of Carbon 2021 ($/MWh)	$46.00	1.8%															
FOM Cost 2021 ($/kw-yr)	$10.83	0.0%															
Capex Cost 2021 Tri-State Share ($ million/yr)	$0.5	3.0%															
Installed Cost Tri-State Share ($ million)	$121																
Debt Interest Rate	2.21%																
Debt Term (Years)	30																
Depreciation Rate	3%																
Accounting Retirement Year	2051																
PPA First Year Price ($/MWh)	#N/A	n/a															
PPA Start Year	n/a																
PPA Term	n/a																
Discount Rate	2.21%																
Results																	
Levelized Cost of Energy (2020 $/MWh)	**$52**																
Levelized Cost of Capacity (2020 $/kw-yr)	**$67**																
Detail							Book										
	Generation (GWh)	Fuel	VOM	Social Cost of Carbon	FOM	Capex Balance	Capex	Interest	Depreciation	Stranded Cost	PPA Cost	Total	Total ($/MWh)	Capacity (MW)	Fixed Only	Total Fixed Only ($/kw-yr)	
NPV	11,455											$590.7		1,635	$109.0		
2021	715	$7.9	$2.6	$13.1	$1.1	$121.1	$0.5	$2.7	$4.1	$0.0	$0.0	$31.9	$45	102	$8.3	$81	
2022	715	$8.2	$2.6	$13.4	$1.1	$117.5	$0.5	$2.6	$3.9	$0.0	$0.0	$32.3	$45	102	$8.1	$79	
2023	715	$8.6	$2.6	$13.6	$1.1	$114.1	$0.5	$2.5	$3.8	$0.0	$0.0	$32.8	$46	102	$7.9	$78	
2024	715	$9.0	$2.6	$13.9	$1.1	$110.7	$0.5	$2.5	$3.7	$0.0	$0.0	$33.2	$47	102	$7.8	$76	
2025	715	$9.4	$2.6	$14.1	$1.1	$107.5	$0.5	$2.4	$3.6	$0.0	$0.0	$33.7	$47	102	$7.6	$75	
2026	715	$9.8	$2.6	$14.4	$1.1	$104.4	$0.5	$2.3	$3.5	$0.0	$0.0	$34.3	$48	102	$7.4	$73	
2027	715	$10.3	$2.6	$14.6	$1.1	$101.5	$0.5	$2.2	$3.4	$0.0	$0.0	$34.8	$49	102	$7.3	$72	
2028	715	$10.7	$2.6	$14.9	$1.1	$98.6	$0.6	$2.2	$3.3	$0.0	$0.0	$35.4	$50	102	$7.2	$70	
2029	715	$11.2	$2.6	$15.2	$1.1	$95.8	$0.6	$2.1	$3.2	$0.0	$0.0	$36.0	$50	102	$7.0	$69	
2030	715	$11.7	$2.6	$15.4	$1.1	$93.2	$0.6	$2.1	$3.1	$0.0	$0.0	$36.7	$51	102	$6.9	$68	
2031	715	$12.2	$2.6	$15.7	$1.1	$90.7	$0.6	$2.0	$3.0	$0.0	$0.0	$37.3	$52	102	$6.8	$66	
2032	715	$12.8	$2.6	$16.0	$1.1	$88.2	$0.6	$2.0	$3.0	$0.0	$0.0	$38.1	$53	102	$6.7	$65	
2033	715	$13.4	$2.6	$16.3	$1.1	$85.9	$0.6	$1.9	$2.9	$0.0	$0.0	$38.8	$54	102	$6.5	$64	
2034	715	$14.0	$2.6	$16.6	$1.1	$83.7	$0.7	$1.9	$2.8	$0.0	$0.0	$39.6	$55	102	$6.4	$63	
2035	715	$14.6	$2.6	$16.9	$1.1	$81.5	$0.0	$1.8	$2.7	$0.0	$0.0	$39.7	$56	102	$5.6	$55	
2036	715	$15.3	$2.6	$17.2	$1.1	$78.8	$0.0	$1.7	$2.6	$0.0	$0.0	$40.5	$57	102	$5.5	$54	
2037	715	$16.0	$2.6	$17.5	$1.1	$76.2	$0.0	$1.7	$2.5	$0.0	$0.0	$41.4	$58	102	$5.3	$52	
2038	715	$16.7	$2.6	$17.8	$1.1	$73.6	$0.0	$1.6	$2.5	$0.0	$0.0	$42.3	$59	102	$5.2	$51	
2039	715	$17.4	$2.6	$18.1	$1.1	$71.2	$0.0	$1.6	$2.4	$0.0	$0.0	$43.2	$60	102	$5.0	$49	
2040	715	$18.2	$2.6	$18.4	$1.1	$68.8	$0.0	$1.5	$2.3	$0.0	$0.0	$44.2	$62	102	$4.9	$48	

Table 6 – Summary of LCOE and LCOC Results

	Pairings				Results			
	Existing Resource	Generic Resource 1	Generic Resource 2	Generic Resource 3	LCOE (2020 $/MWh)		LCOC (2020 $/kw-yr)	
	Name	Name	Name	Name	Existing	Generic	Existing	Generic
1	GC-Craig 1-NW_CO	545_1x1_7HA03_nwco	n/a	n/a	$101	$52		
2	GC-Craig 2-NW_CO	545_1x1_7HA03_nwco	n/a	n/a	$109	$52		
3	GC-Craig 3-NW_CO	545_1x1_7HA03_nwco	n/a	n/a	$93	$55		
4	GC-LRS 2-WY	545_1x1_7HA03_nwco	n/a	n/a	$92	$53		
5	GC-LRS 3-WY	545_1x1_7HA03_nwco	n/a	n/a	$98	$53		
6	GC-SV 3-SPV	545_1x1_7HA03_nwco	n/a	n/a	$123	$53		
7	GG-Burlington 1-E_CO	81_2x40LM6000_eco	n/a	n/a			$48	$149
8	GG-Burlington 2-E_CO	81_2x40LM6000_eco	n/a	n/a			$48	$149
9	GG-Knutson 1-E_CO	81_2x40LM6000_eco	n/a	n/a			$42	$159
10	GG-Knutson 2-E_CO	81_2x40LM6000_eco	n/a	n/a			$42	$159
11	GG-Limon 1-E_CO	81_2x40LM6000_eco	n/a	n/a			$54	$159
12	GG-Limon 2-E_CO	81_2x40LM6000_eco	n/a	n/a			$54	$159
13	GG-Pyramid 1-S_NM	40_1x40LM6000_nnm	n/a	n/a			$43	$158
14	GG-Pyramid 2-S_NM	40_1x40LM6000_nnm	n/a	n/a			$43	$158
15	GG-Pyramid 3-S_NM	40_1x40LM6000_nnm	n/a	n/a			$43	$158
16	GG-Pyramid 4-S_NM	40_1x40LM6000_nnm	n/a	n/a			$43	$158
17	GG-Rifle-NW_CO	81_2x40LM6000_eco	n/a	n/a			$63	$167
18	GG-Shafer-E_CO	300_1x1_7FA05_eco	n/a	n/a	[redacted]	$104	$50	$158
19	CP-AltaLuna-S_NM	CP-1x100PV_nnm	n/a	n/a		$33		
20	CP-SanIsabel-E_CO	CP-1x100PV_eco	n/a	n/a		$28		
21	CP-FirstSolar-N_NM	CP-1x100PV_nnm	n/a	n/a		$33		
22	CP-ColoHighlands-E_CO	CP-1x100Wind_eco	n/a	n/a		$30		
23	CP-KitCarson-E_CO	CP-1x100Wind_eco	n/a	n/a		$30		
24	CP-TwinButtes-E_CO	CP-1x100Wind_eco	n/a	n/a		$30		
25	CP-Carousel-E_CO	CP-1x100Wind_eco	n/a	n/a		$30		
26	CP-Basin_West	CP-1x230PV-eco	CP-1x280Wind-eco	500MW Li-Ion Battery_eco		$39		
27	CP-Basin_East	CP-1x40PV-eco	CP-1x40Wind-eco	306_18x6RICE_eco		$112		

Figure 2 – Comparison of LCOE for Thermal Resource Pairings



Figure 3 – Comparison of LCOC for Thermal Resource Pairings

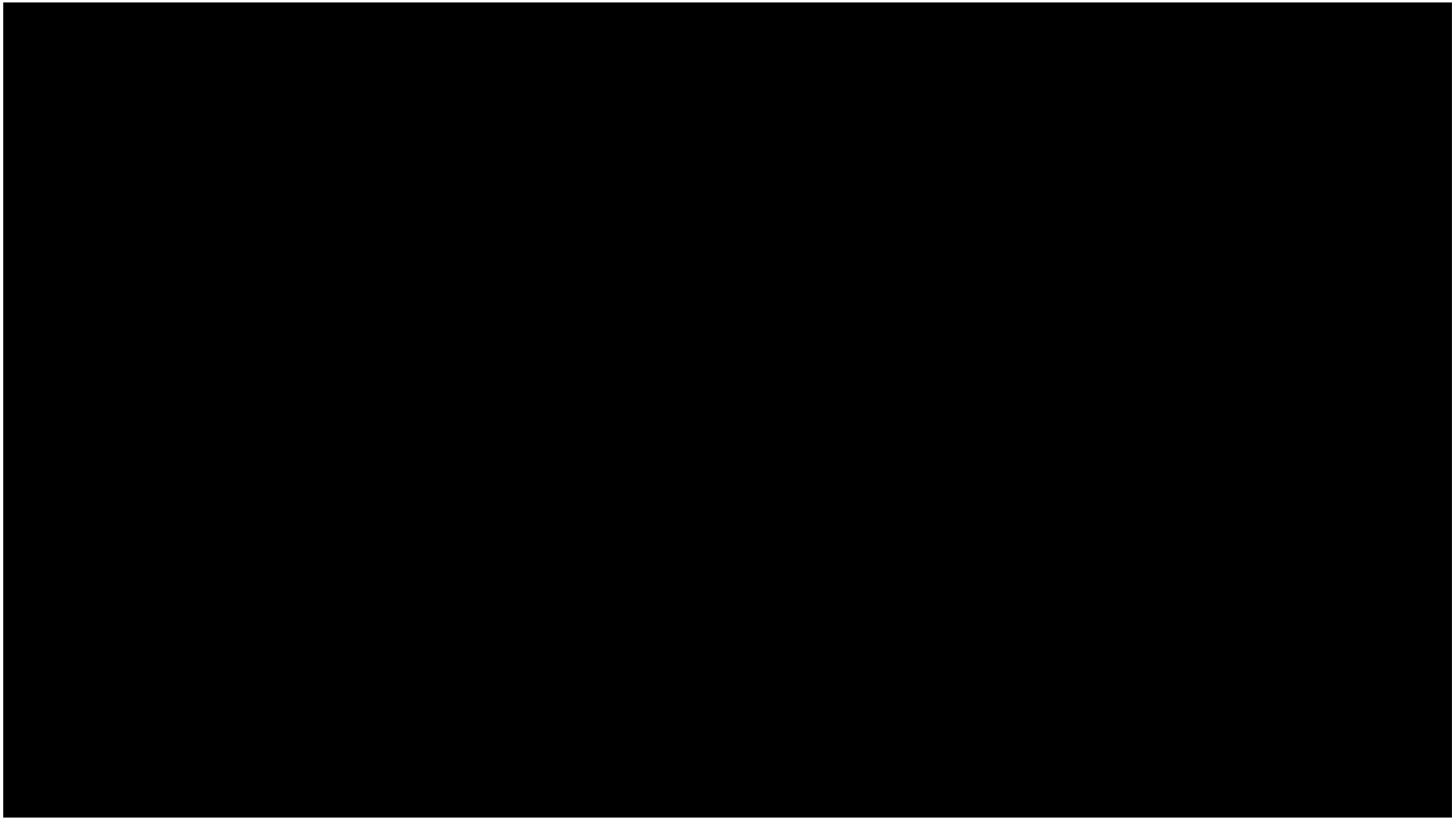


Figure 4 – LCOE Comparison for the Renewable Resource Pairings



Table 7 - Summary of LCOE and LCOC Results for the Non-Colorado Benchmarking

	Pairings				Results - Non-Colorado Benchmarking			
	Existing Resource	Generic Resource 1	Generic Resource 2	Generic Resource 3	LCOE (2020 $/MWh)		LCOC (2020 $/kw-yr)	
	Name	Name	Name	Name	Existing	Generic	Existing	Generic
1	GC-Craig 1-NW_CO	545_1x1_7HA03_nwco	n/a	n/a				
2	GC-Craig 2-NW_CO	545_1x1_7HA03_nwco	n/a	n/a				
3	GC-Craig 3-NW_CO	545_1x1_7HA03_nwco	n/a	n/a				
4	GC-LRS 2-WY	545_1x1_7HA03_nwco	n/a	n/a	$32	$31		
5	GC-LRS 3-WY	545_1x1_7HA03_nwco	n/a	n/a	$33	$31		
6	GC-SV 3-SPV	545_1x1_7HA03_nwco	n/a	n/a	$65	$32		
7	GG-Burlington 1-E_CO	81_2x40LM6000_eco	n/a	n/a				
8	GG-Burlington 2-E_CO	81_2x40LM6000_eco	n/a	n/a				
9	GG-Knutson 1-E_CO	81_2x40LM6000_eco	n/a	n/a				
10	GG-Knutson 2-E_CO	81_2x40LM6000_eco	n/a	n/a				
11	GG-Limon 1-E_CO	81_2x40LM6000_eco	n/a	n/a				
12	GG-Limon 2-E_CO	81_2x40LM6000_eco	n/a	n/a				
13	GG-Pyramid 1-S_NM	40_1x40LM6000_nnm	n/a	n/a			$43	$158
14	GG-Pyramid 2-S_NM	40_1x40LM6000_nnm	n/a	n/a			$43	$158
15	GG-Pyramid 3-S_NM	40_1x40LM6000_nnm	n/a	n/a			$43	$158
16	GG-Pyramid 4-S_NM	40_1x40LM6000_nnm	n/a	n/a			$43	$158
17	GG-Rifle-NW_CO	81_2x40LM6000_eco	n/a	n/a				
18	GG-Shafer-E_CO	300_1x1_7FA05_eco	n/a	n/a				
19	CP-AltaLuna-S_NM	CP-1x100PV_nnm	n/a	n/a	[redacted]	$33		
20	CP-SanIsabel-E_CO	CP-1x100PV_eco	n/a	n/a				
21	CP-FirstSolar-N_NM	CP-1x100PV_nnm	n/a	n/a		$33		
22	CP-ColoHighlands-E_CO	CP-1x100Wind_eco	n/a	n/a				
23	CP-KitCarson-E_CO	CP-1x100Wind_eco	n/a	n/a				
24	CP-TwinButtes-E_CO	CP-1x100Wind_eco	n/a	n/a				
25	CP-Carousel-E_CO	CP-1x100Wind_eco	n/a	n/a				
26	CP-Basin_West	CP-1x230PV-eco	CP-1x280Wind-eco	500MW Li-Ion Battery_eco	[redacted]	$39		
27	CP-Basin_East	CP-1x40PV-eco	CP-1x40Wind-eco	306_18x6RICE_eco		$91		

END OF REPORT

Attachment Vol II 5-6 Ascend Analytics Renewables & Ramping Analysis

Tri-State Generation and Transmission Colorado Energy and Resource Plan Renewables and Ramping Analysis

Summary of work delivered by Ascend Analytics

Overview

Ascend Analytics (Ascend) is pleased to support Tri-State G&T (Tri-State) as it prepares for the 2020 Energy Resource Plan filing with the Colorado Public Utility Commission. Ascend was retained by Tri-State to supplement their in-house modeling capabilities by generating hourly simulation data for renewables and load that capture new market dynamics in the western grid driven by large scale renewable resource deployment. A key limitation of traditional production cost models is the inability to capture weather-driven variability in load and renewable output. A typical approach is to use weather-normalized (e.g. smooth, averaged) input curves for load and renewables. This was not generally a problem when most resources were dispatchable thermal resources. With Tri-State's goal to dramatically increase the amount of variable renewable resources in its portfolio, it becomes critical to capture the inherent variability in loads and resources, because increased volatility drives the need for different types of resources, particularly flexible resources that can provide integration services for system reliability.

Tri-State hired Ascend to use its power system simulation tool PowerSimm to help Tri-State's modeling team better capture the new energy system dynamics with increasing renewable related volatility. This was achieved by providing two deliverables:

1. Simulations of Tri-State member co-op loads and generation of various wind and solar resources between 2021-2030, and
2. An analysis of the effects these variable resources would have on the ramping of system-wide net load.

Tri-State provided historical data on all existing loads and resources for use in training PowerSimm's load and renewable energy simulation modules. Tri-State also provided forecasts of expected future gross load and renewable generation. PowerSimm uses NCDC weather data to generate time-series models that characterize the relationship between weather -> load and weather -> renewable resource behavior. The simulations are internally correlated and consistent within each "sim-rep" or each simulation run of 8760 hours per year over the course of the 10-year study horizon. Ascend delivered 20 such simulated future states. Some or all of these simulated forecasts of Tri-State load and each renewable resource will be input into Tri-State's internal modeling software to solve for resource and portfolio values consistent with an increasingly variable resource portfolio.

Results

Renewable Simulation

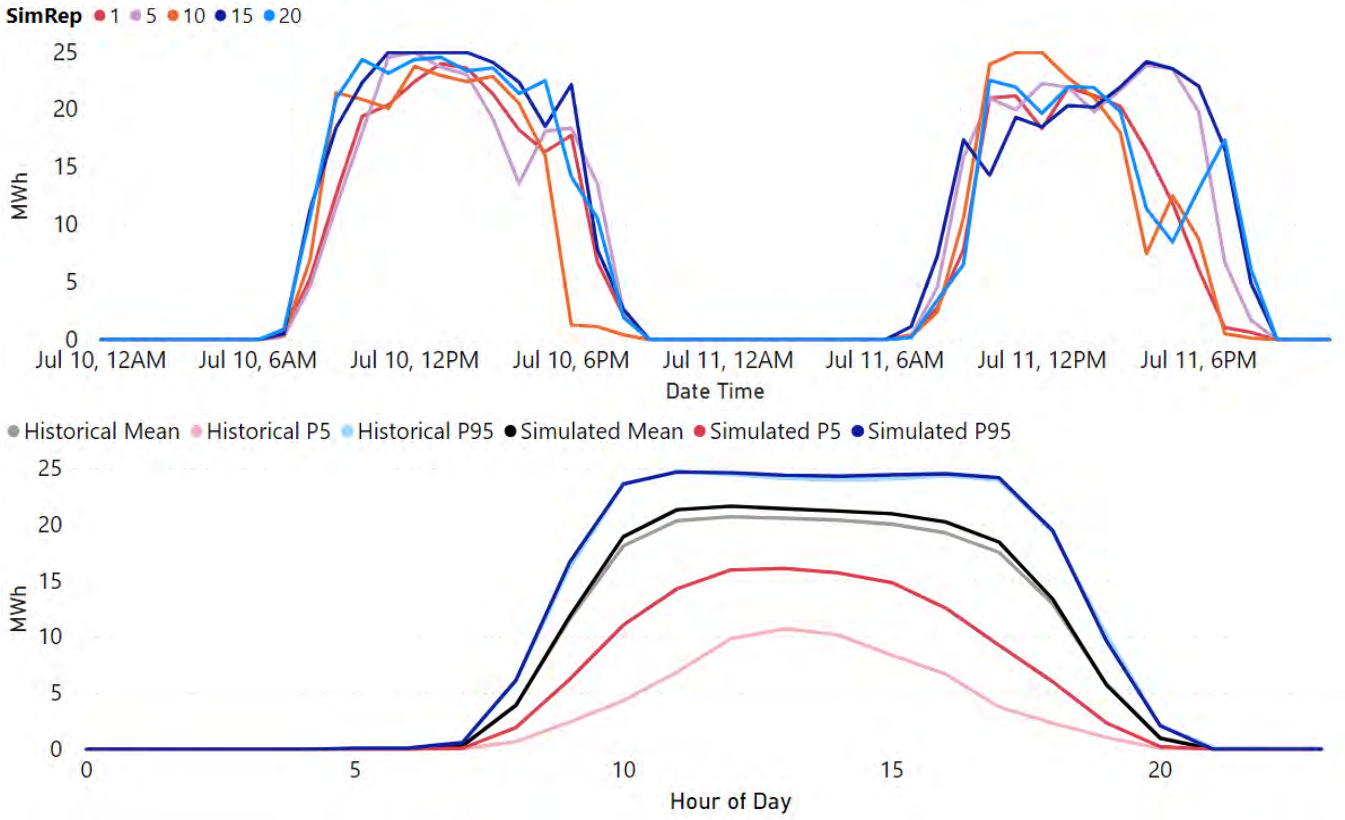
Tri-State provided the following renewable resources to be modeled in PowerSimm:

Resource	Unit Type	Location	State
Alta Luna	Solar	Deming, NM	Existing
Axial	Solar	Moffat County, CO	Under Contract
Carousel	Wind	Burlington, CO	Existing
Cimarron	Solar	Cimarron, NM	Existing
CO Highlands	Wind	Fleming, CO	Existing
Coyote Gulch	Solar	La Plata, CO	Under Contract
Crossing Trails	Wind	Seibert, CO	Under Contract
Dolores	Solar	Dolores County, CO	Under Contract
Kit Carson Wind	Wind	Burlington, CO	Existing
Niyol	Wind	Logan and Washington County, CO	Under Contract
San Isabel Solar	Solar	Trinidad, CO	Existing
Spanish Peaks	Solar	Trinidad, CO	Under Contract
Spanish Peaks Two	Solar	Trinidad, CO	Under Contract
TPE (Escalante)	Solar	McKinley County, NM	Under Contract
Twin Buttes II	Wind	Lamar, CO	Existing

PowerSimm uses historical hourly generation from a resource and correlates that generation against historic weather data to ensure that all behaviors of the resource are captured in the simulation: generation during various meteorological conditions, seasonality, behavior during low-probability weather patterns, etc. Rather than simply repeating historical hourly generation patterns or weather normalized shapes, PowerSimm simulates hourly weather over the modeling time period and uses the historically derived correlations between weather and generation to simulate future hourly generation.

PowerSimm models were set up using historical generation data and expected monthly forecasts provided by Tri-State. The resulting hourly simulations provide statistically robust data on renewable generation across both typical and low-probability conditions, as exemplified in Figure 1 (below) of a sample of five sim-reps (out of 20 simulated) for the Alta Luna solar project.

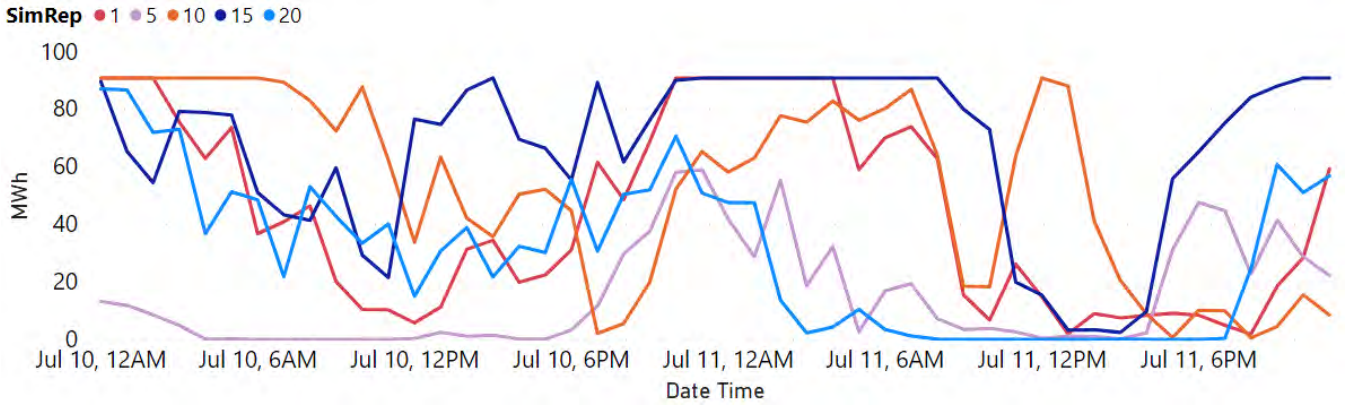
Figure 1: Sample Solar Generation and Validation – Alta Luna

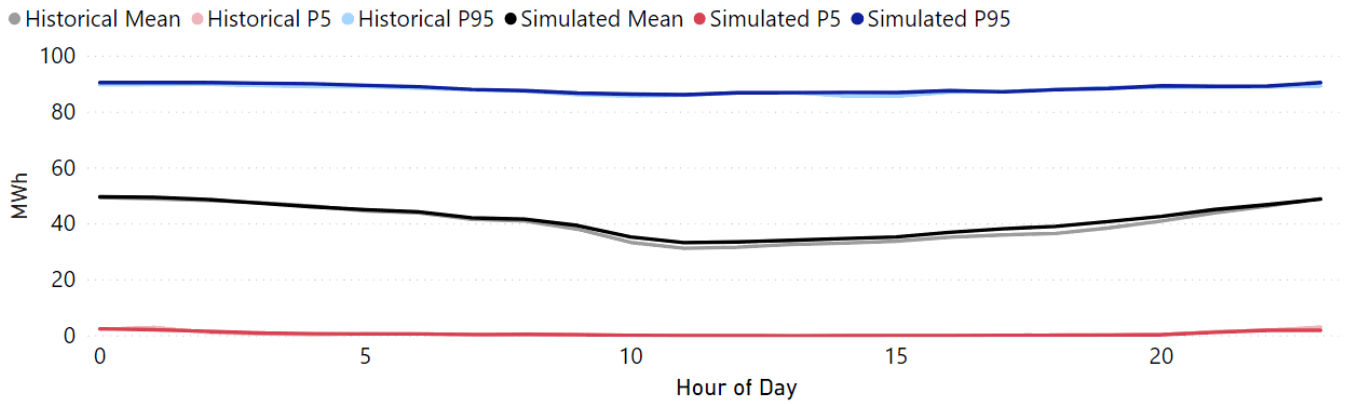


The sim-reps capture a range of variability in the unit's generation. One sim-rep may have max output on one day, while cloud cover on the next day inhibits the unit from outputting at its total capacity as seen in sim-rep 15. For validations (bottom of figure 1) we ensure that the model accurately captures historically observed variations by meeting the mean, P5, and P95 historical observations in the simulations. This approach allows Tri-State to fully understand renewable resource behavior (e.g. wind bursts or droughts, cloudiness, etc.) and risk profiles (e.g. availability during peak load events).

Similarly, Figure 2 shows example generation for five of twenty sim-reps for Tri-States CO Highlands wind unit (top of figure 2).

Figure 2: Sample Wind Generation and Validation – CO Highlands





The sim-reps capture a range of possible variability in the unit's generation. Sim-rep 15 shows generation at max capacity for several hours as the wind resources are plentiful, then a sudden drop off as the wind dies down. Sim-rep 5 demonstrates a different possible weather future where this entire stretch of time shown has relatively low generation. For validations (bottom of figure 2) we ensure that we accurately capture historically present variations by meeting the mean, P5, and P95 historical observations in our simulations.

Load Simulation

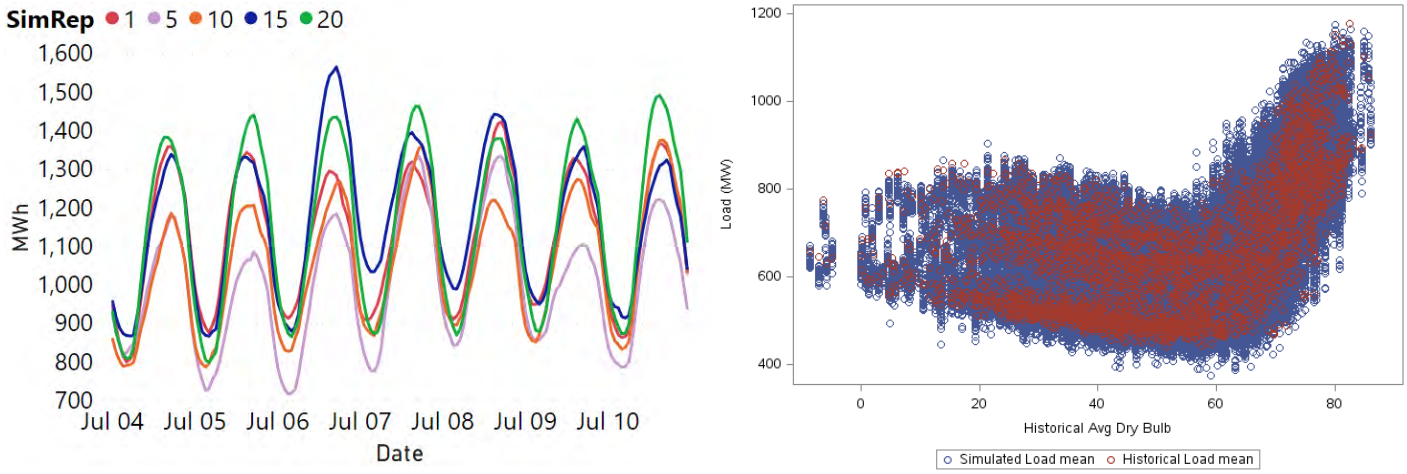
Tri-State provided the following load zones to be modeled in PowerSimm:

Load Zone
East Colorado
Nebraska
New Mexico
West Colorado
Wyoming

The load simulation follows a similar methodology as the renewable simulation. Inputs to the model include hourly historical load volumes as well as a load forecast of expected aggregate growth in demand. The model develops a complex set of correlations based on historical data that considers load, temperature, hour of day, day of week, and time of year. Temporal autocorrelations in the model are also important as each hourly load observation in the simulation is not independent, rather its highly correlated with the observation that came before it.

Figure 3 shows example electric load for five of twenty sim-reps for a week in July (left), showing a variety of possible demand futures. The temporal autocorrelation effects of the model come through, as sim-rep 5 consistently has lower demand than other sim-reps while sim-rep 20 shows consistently higher demand. Weather driven impacts are also visible, as seen in the spike in demand on July 6th for sim-rep 15 indicating a particularly hot day. For load simulations we ensure that we meet the historically present variations by meeting the mean, P5, and P95 historical observations in our simulations. We also ensure that we preserve historically observed temperature-load correlations as shown in the boomerang validation plot to the right. As temperature veers into extreme cold or warm territories we expect load to increase, and we expect our simulations (in blue) to mirror the behavior and cover the full range of historical observations (in red).

Figure 3: Sample Load Simulation and Validation - East Colorado

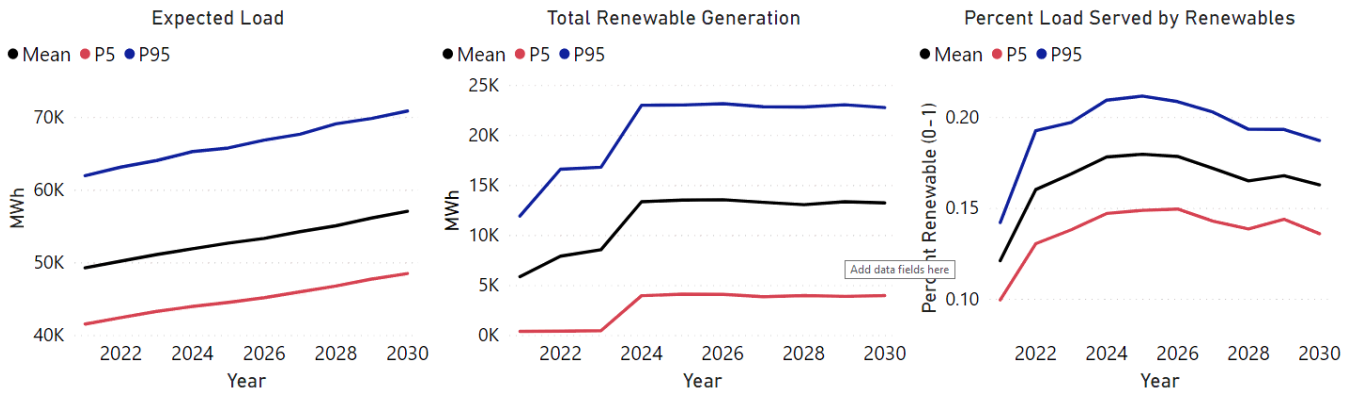


Analysis

Co-simulating Tri-State's load and renewables provides insight on the dynamics in net load, the difference between load and renewable generation, which represents the remaining load to be served by dispatchable resources. Simulating across 20 different possible weather futures, including weather that is considered both "normal" and "extreme," the model captures the interactions of weather, load, and renewable generation and statistically envelopes the most likely future scenario (the mean simulation) while also planning for more extreme possibilities (the P5 and P95 cases).

Figure 4 shows annual trends in load and renewables:

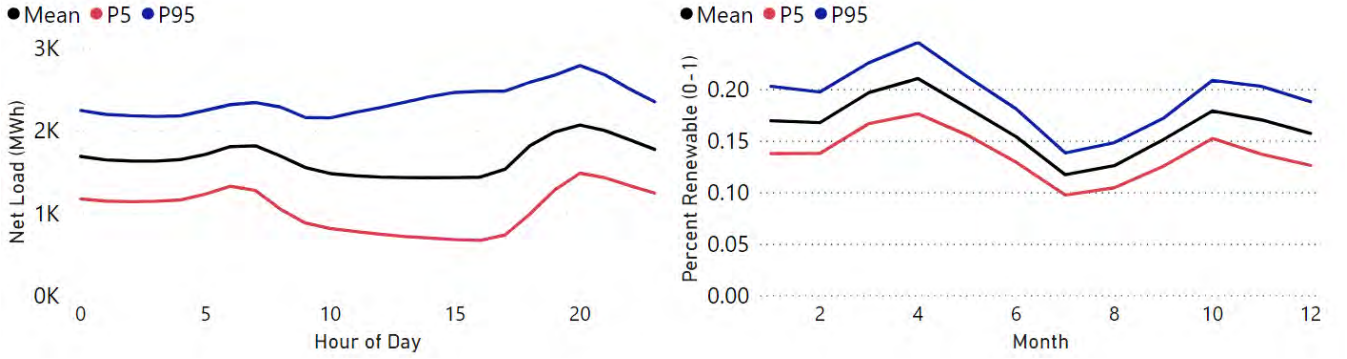
Figure 4: Annual Trends in Load and Renewables



Tri-State's Load (left) across its five load zones grows steadily through time. Renewable generation (middle) grows slowly in the beginning years of the analysis with a big jump in generation in 2024 as new resources come online followed by a leveling out. The resulting percent of load served by renewables (right) grows until 2024 as renewables generation increases followed by a steady decline as the growth in load surpasses the growth in renewable generation.

Figure 5 is a sample of load and renewable generation interaction in 2026.

Figure 5: Net Load (left) and Percent of Load Served by Renewables (right) in 2026



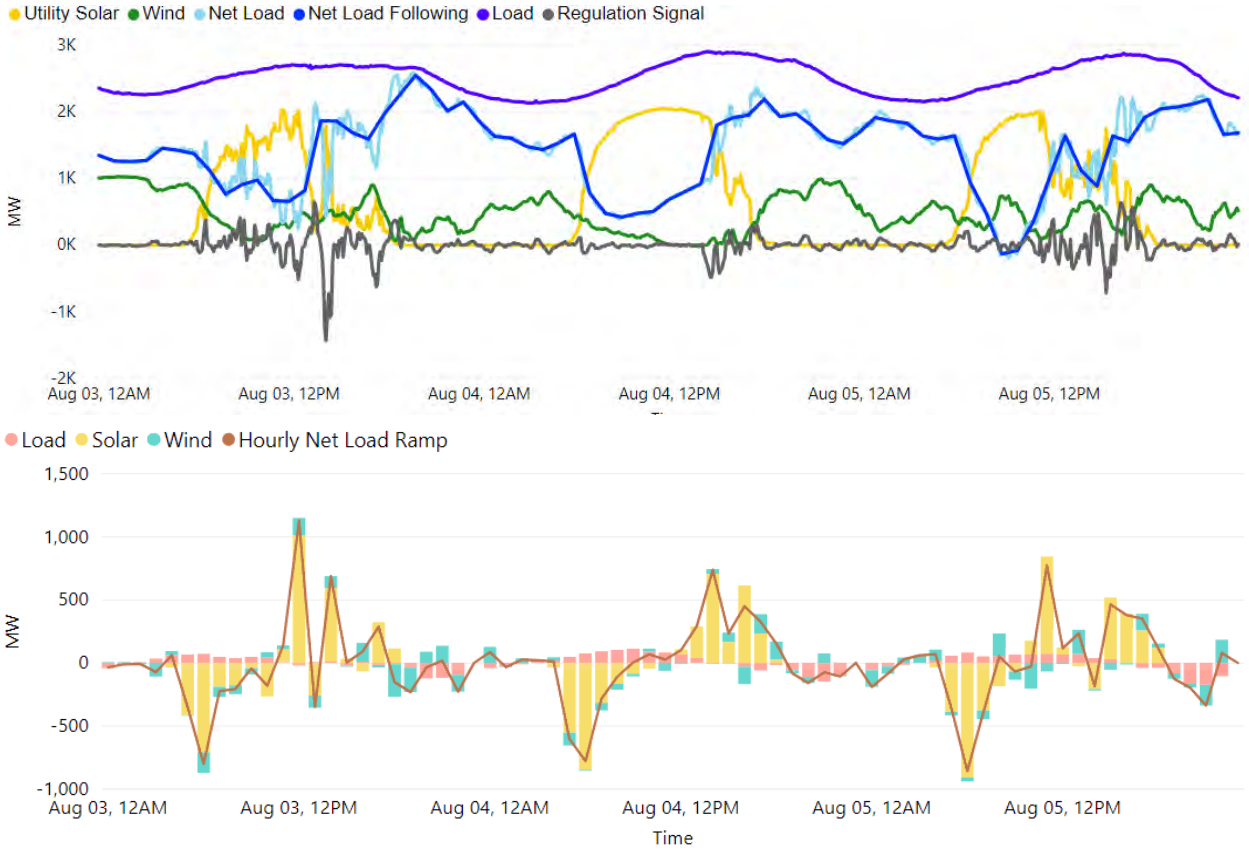
The percent of load served by renewables (right) shows the greatest renewable load share occurs in April and October when loads are low due to moderate temperatures and renewable output tends to peak. Tri-State's solar assets have their peak generation in May, but wind assets have a dual peak in April and October with the April peak being significantly larger. Although there is more solar capacity on the system in 2026 than wind capacity, the wind has a higher capacity factor, more generation, and therefore a stronger influence on total monthly renewable penetration. The hourly weekday Net Load figure (left) shows that Tri-State's net load takes on the "duck" shape, peaking in the morning hours between 6AM and 7AM with a larger peak in the evening at 8PM. Notably, the evening ramp intensity scales inversely with total load with the steepest ramps occurring (on average) during the days with lowest average loads and vice versa.

Ramping Analysis

Ramping analysis was carried out using PowerFlex, an Ascend software tool that analyzes renewable and load behavior on a minute-by-minute timescale to understand the ramping risk of a portfolio on multiple timescales as well as the value of flexible resources and ancillary services required to maintain load balance.

For this study all load and renewable items were input into PowerFlex on a 5-minutely timescale and were scaled up on a yearly basis to match forecasted quantities/capacities. PowerFlex calculated rolling statistics on Net Load (= Load – Total Renewable Generation) to find the largest ramp up and ramp down events in any 5-minute, 15-minute, 30-minute, and 60-minute time period in each month from 2021-2030. Figure 6 below shows a snapshot of the results of this analysis.

Figure 6: Sample PowerFlex Results and Ramping Contributions



The snapshots above shows a sample three-day period of representative load and renewable generation scaled to meet 2030 forecasts; the bottom figure shows the relative ramping contributions of load and renewables. While load takes on a relatively smooth shape, wind and solar profiles have more variability, particularly solar (as seen in the large yellow bars of solar contributions to both positive and negative ramping in the bottom figure). August 3rd shows a very volatile solar generation profile that leads to more dramatic ramping needs mid-day. August 4th has a much smoother solar profile, but we can see from the Ramping Contributions figure (bottom) that even with the smooth profile solar still contributes most to ramping contributions given the nature of solar daily generation patterns.

Table 1 below is a snapshot, based on a typical expansion plan scenario from 2021 to 2030, of what Tri-State's maximum forecasted ramping risk is at different timescales in June throughout the study window.

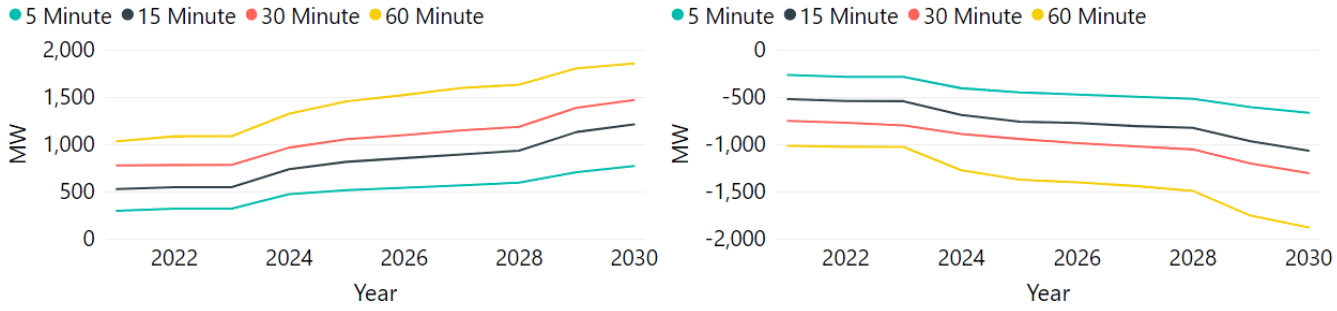
Table 1: June Ramping Risk for Baseline load/renewable forecasts

	Renewable Forecast (MW)		5 Minute Ramps		15 Minute Ramps		30 Minute Ramps		60 Minute Ramps	
Year	**Solar**	**Wind**	**Up**	**Down**	**Up**	**Down**	**Up**	**Down**	**Up**	**Down**
2021	1970	671	79	-83	166	-189	243	-258	326	-378
2022	2007	671	80	-86	170	-188	243	-258	320	-378
2023	2045	671	81	-87	170	-189	244	-258	321	-379
2024	2083	771	164	-178	288	-287	392	-374	563	-502
2025	2109	871	204	-222	355	-362	474	-443	676	-601
2026	2135	971	224	-244	391	-399	525	-489	742	-667
2027	2173	971	244	-267	417	-438	555	-518	801	-705
2028	2212	971	263	-287	452	-464	596	-539	846	-742
2029	2250	971	365	-397	609	-584	795	-709	1104	-928
2030	2288	1071	421	-430	695	-672	914	-811	1269	-1035

Analysis

As Tri-State increases the capacity of renewable resources over time the net ramping risk increases substantially across all timescales, as shown in Figure 7 below.

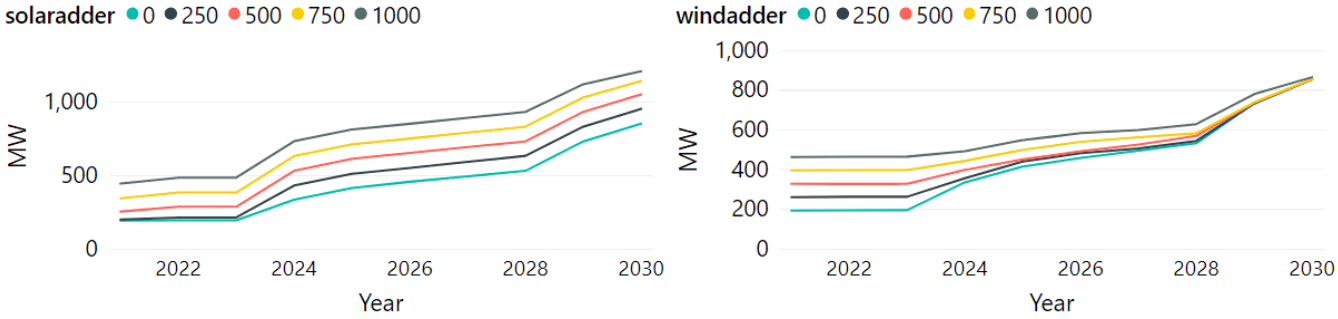
Figure 7: Annual Ramp Up (Left) and Ramp Down (Right) Risk



Ramping requirements grow through time with the ramping requirement increasing more rapidly at longer timescales (e.g. 60-minute ramp risk increases by a larger amount over the 10 year study horizon than 5-minute ramps).

Because of the potential for additional renewables to enter the system that are not currently contracted/planned, Ascend also analyzed ramping risks with solar and wind adders beyond the forecasted quantities to assess the impact of additional intermittent resources on the system. The results of this analysis for an additional 0/250/500/750/1000 MW of added solar/wind capacity (beyond the default forecasted quantity provided by Tri-State) are shown in Figure 8 below.

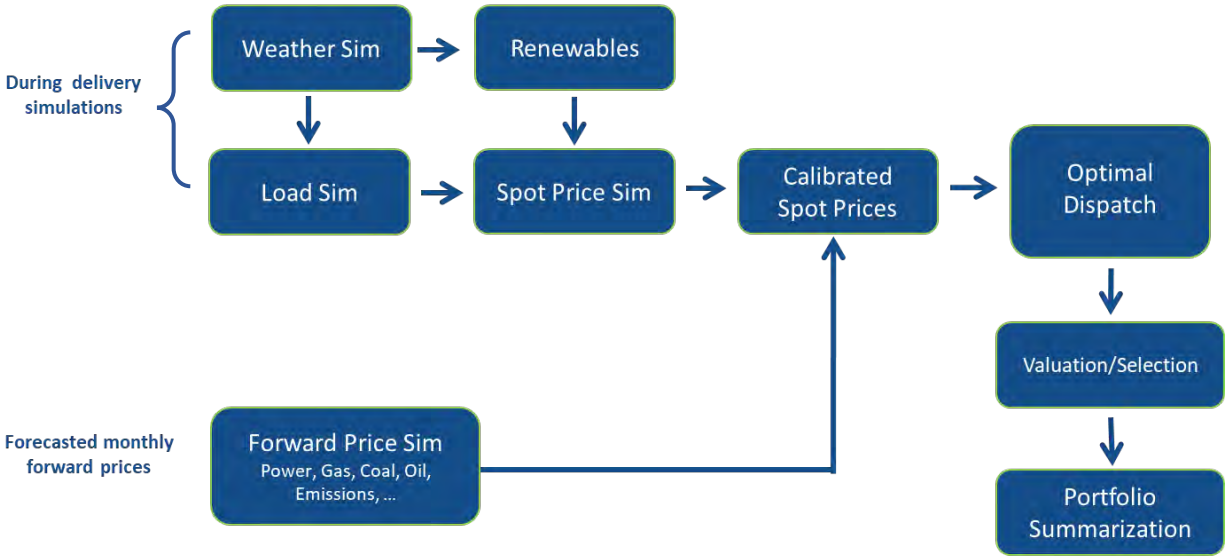
Figure 8: Annual 15 Minute Ramp Up Requirement with Renewable Adders



This analysis suggests that additional solar capacity on the system has a much stronger impact on ramping requirements than additional wind does, which is further supported by the relative ramping contributions of solar shown in Figure 6. Solar has a tendency to be more variable in its generation profile than the wind resources that Tri-State currently has in its portfolio, largely due to the steep ramp-up/ramp-down events that occur daily due to sunrise and sunset and further exaggerated by the effects of clouds and volatile hourly generation.

Appendix: PowerSimm Model Schematic

Figure 7: PowerSimm Modeling Framework



PowerSimm's Sim Engine captures "Meaningful Uncertainty" in weather, load, renewables, and prices

The PowerSimm Resources Planning Suite is a set of software programs consisting of PowerSimm Planner (PowerSimm) production cost model for system operations simulation and PowerFlex for renewable integration planning. The suite is designed and operated by Ascend Analytics for the purposes of Tri-State's2020 ERP. Combined, these tools form a platform for modern resource planning in an era of increasing uncertainty in electricity supply driven by the deployment of renewable generation.

PowerSimm is a dispatch optimization and production cost tool. The tool is comprised of two major elements, the Sim Engine and Dispatch Optimization, that work together to systematically bridge the physical and financial dimensions of electricity provision. PowerSimm uses a simulation-based approach born of the best-in-class techniques to perform decision analysis for portfolio risk management. Managing risk requires characterizing of the volatility in fuel price, power price, renewable generation, and outages. PowerSimm adopts this paradigm into the resource planning context.

The simulation of uncertainty with respect to weather is becoming ever more critical because "weather is the new fuel" in the country's emerging high-renewables system. To capture the changing market dynamics with renewables, PowerSimm simulates weather to capture its effect on renewable output and its effect on energy price formation. We call this "characterizing meaningful uncertainty." It is not simply noise around an arbitrary base scenario, but realistic paths of weather driving renewables, loads, and prices. That means PowerSimm is performing dispatch against system conditions as they really exist, not the idealized system modeled by traditional production cost models with averaged weather patterns, averaged renewable generation profiles, and "expected" load and market conditions. PowerSimm is a stochastic construct and through a multitude of simulations, we probabilistically explore all possible future states through a coherent and appropriately correlated set of data inputs and forecasts. With PowerSimm, resource decision making is supported not only with the mean of the distribution, but also by risk considerations informed by the 5th and 95th percentiles. Therefore, we can solve for the optimal resource portfolio that strikes the best balance between cost and risk.

Attachment Vol II 5-7 Beneficial Electrification Potential Study

BENEFICIAL ELECTRIFICATION POTENTIAL STUDY

FOR TRI-STATE GENERATION & TRANSMISSION

OCTOBER 22, 2020

Prepared by: Mesa Point Energy & BrightLine Group

TRI-STATE GENERGATION & TRANSMISSION
BENEFICIAL ELECTRIFICATION POTENTIAL STUDY

OCTOBER 22, 2020

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EXECUTIVE SUMMARY

Project Overview

Mesa Point Energy, along with their subcontractor Brightline Group, (collectively the Mesa Point Team or the Team) performed a beneficial electrification potential study in support of Tri-State Generation and Transmission's (Tri-State) resources planning initiatives. The study is intended to assist Tri-State in developing future Integrated Resource Plans (IRP) and Electric Resource Plans (ERP). The primary objective of this study is to assess the available technical electrification, beneficial electrification, and achievable electrification potential from a variety of fuel-switching electrification measures from 2021 to 2040 for the electric cooperatives served by Tri-State Generation and Transmission (Tri-State).

For the purposes of this study, electrification can be defined as changing the energy source for an end use from a fossil fuel to electricity. In order to achieve "beneficial" electrification a project must meet one or more of the following conditions without adversely affecting the other three:

1. Saves consumers money over the long run
2. Improves quality of life
3. Enables better grid management
4. Reduces negative environmental impacts

The study focuses on beneficial electrification *achievable* potential. It is not a *program* potential study meaning it does not take into consideration the utility's program-level budget and design constraints. Therefore, the study examines what *could be* (i.e., what impacts could accrue from the qualifying beneficial electrification measures considered in this study) but does not account for structural and organizational limitations inherent and unique to the cooperative utility structure where each member distribution system can choose which products and measures from the overall program to offer to their end-use consumers. The study does not select or evaluate specific programs or their costs.

This Executive Summary presents an overview of the analysis approach, key assumptions, and study findings and the main report goes into more detail on methods, results, and findings.

This report is related in several ways to the recent *Demand Side Management and Energy Efficiency Potential Study* for Tri-State completed in May, 2020. The prior report provides an achievable potential assessment for energy efficiency, demand response, and distributed energy resources, and is referenced in sections of this report.

Two separate electronic Reporting Tools are provided with this report. The tools provide the ability to view findings in greater detail by sector, end-use, and region. More detail on the tools, including how they differ from each other, is provided in the main body of the report.

Results

As summarized in Table ES-1, the Mesa Point Team found that the achievable-moderate scenario[1] would result in approximately 2.5 GWh (0.02 percent of baseline sales) of electric load growth from achievable beneficial electrification in 2021 rising to 653 GWh (3.1 percent of baseline sales) of growth through 2040. Using emissions rates based on a forecast of Tri-State's resource mix, the team estimated a lifetime emissions reduction for measures installed in 2021 of 11,414 tons of CO_2, increasing to a lifetime emissions reduction of nearly half a million tons of CO_2 for measures installed in 2040[2]. Over the 20-year study horizon it is estimated that enough fossil fuel consumption could technically be reduced to more than offset the total on-site natural gas consumption in Tri-State's service territory[3].

[1] Four scenarios were modeled, each of which is described later in this Executive Summary and in the methodology section of the body of the report. Results from the achievable-moderate scenario are presented in most portions of this report. That scenario was selected because it represents a balance between aggressive program approaches and a low level of intervention.

[2] Emissions reductions are calculated based on Tri-State's projected resource mix as provided to MPE in March 2020, which was a non-carbon reduced scenario. The actual changes in resource mix over time will impact the net emissions from electrification measures. Updated resource mix projections could be used in future modeling to refine the estimated emissions benefit of electrification over time.

[3] The estimated cumulative reduction in fossil fuel consumption across all measures and baseline fossil fuel types exceeds 631 million therms by 2040 under the technical potential scenario. The study estimates the total annual natural gas consumption by premise-based (non-vehicle) end uses to be approximately 536 million therms at present.

Table ES-1. Portfolio Cumulative Energy Increase and Annual Emissions Reduction by Scenario by Time Horizon

MILESTONE YEAR	TECHNICAL ELECTRIFICA-TION	BENEFICIAL ELECTRIFICA-TION	ACHIEVABLE _MAX	ACHIEVABLE _ AGG	ACHIEVABLE _MOD	ACHIEVABLE _ LOW
Cumulative Electric Energy Load Growth (MWh)						
2021	52,033	5,487	4,875	3,485	2,524	1,957
2025	417,171	84,088	62,069	43,736	30,905	23,583
2030	1,674,758	474,237	278,910	207,716	144,792	105,867
2040	5,513,285	1,907,671	1,044,310	857,810	652,583	486,764
Increase as % of Baseline Sales						
2021	0.34%	0.04%	0.03%	0.02%	0.02%	0.01%
2025	2.54%	0.51%	0.38%	0.27%	0.19%	0.14%
2030	9.41%	2.66%	1.57%	1.17%	0.81%	0.59%
2040	26.19%	9.06%	4.96%	4.07%	3.10%	2.31%
Annual Net CO_2 Emissions Reduction (tons)						
2021	-152,135	21,155	19,370	14,779	11,414	9,755
2025	90,543	160,778	114,249	85,767	65,253	54,071
2030	1,024,508	749,792	450,864	371,263	290,767	238,362
2040	2,408,393	1,391,801	763,155	620,228	506,031	418,796

Figure ES-1 shows the breakdown of projected load growth by sector. The residential sector makes up nearly half of the potential, owing much of that potential to battery and plug-in hybrid electric vehicles[4] followed by space heating and water heating electrification measures. The commercial sector contributes 35 percent of the potential, having a similar breakdown of end uses with electrification potential. In addition to on-road electric vehicles, the commercial sector also has opportunity for off-road electric vehicles such as forklifts and airport ground support equipment, as well as truckstop electrification measures. These electric vehicles and transportation measures make up over 80 percent of the commercial sector electrification potential with the balance being made up primarily by space heating (heat pump) and water heating (heat pump water heater) measures.

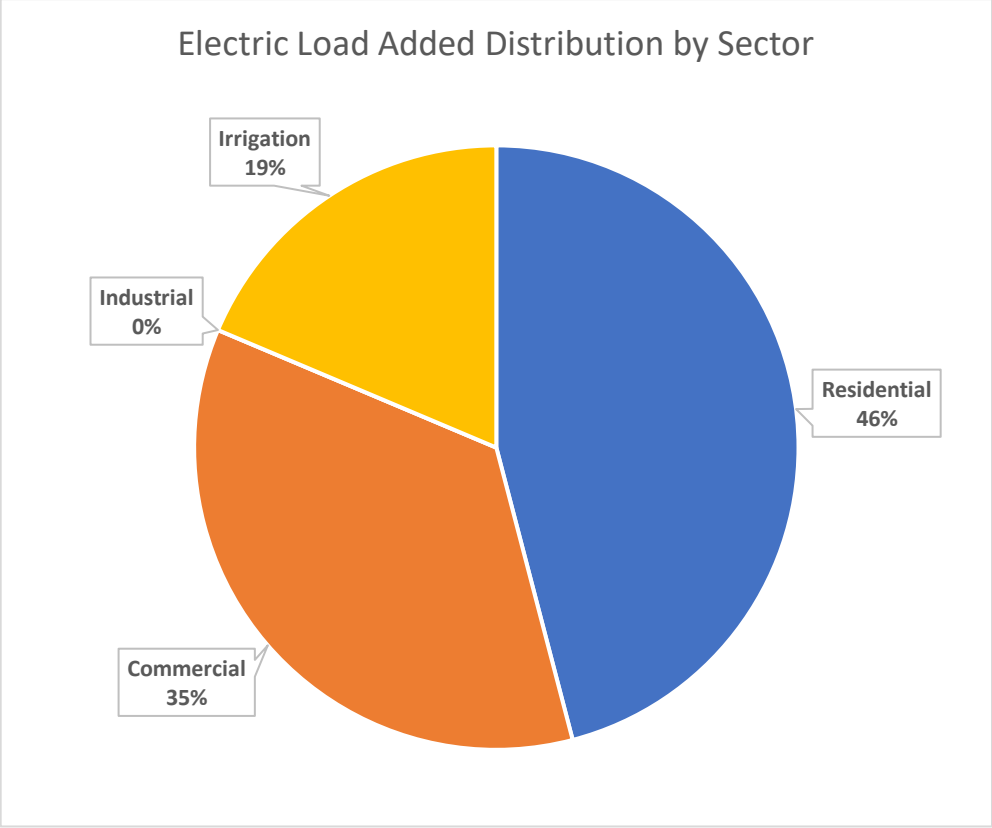
4 As with other electrification measures in this study, electric vehicle potential included in the main body of the report is that directly influenced by Tri-State program activity.

Measures that passed beneficial electrification screening, a process described below and in Section 2.5.2, but contributed a small magnitude towards electrification potential include cooking electrification (electric and induction cooktops) for both the residential and commercial sectors and lawn and garden equipment in the residential sector.

The irrigation sector is estimated to account for nearly 20 percent of the electrification potential in the achievable-moderate scenario by 2040. This potential is made up of the conversion of irrigation pump motors from natural gas, propane, and diesel-driven motors to electric motors.

The industrial sector was shown to have large technical electrification potential from electrification of pipeline compressor stations, but no measure permutation passed the beneficial electrification screening process since each resulted in net emissions increases throughout the 20-year study horizon.

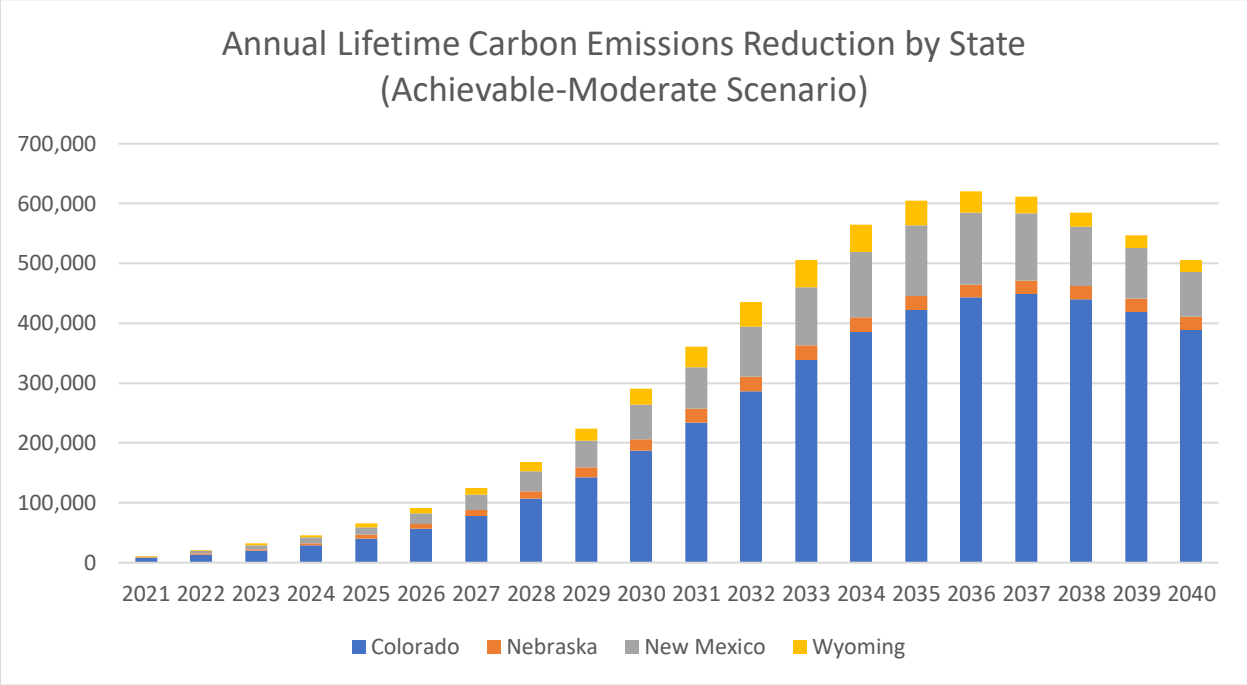
Figure ES-1. Electric Load Added Distribution by Sector (Achievable-Moderate Scenario, 2040)



The estimated emissions reduction associated with beneficial electrification measures under the achievable-moderate scenario, based on Tri-State's forecasted emissions rate as a function of resource mix, is shown in Figure ES-2. The figure represents net emissions expected to be reduced over the lifetime of relevant measures installed in each year of the 20-year study horizon. For some measures analyzed, the net lifetime emissions include both an increase in emissions in the beginning of the measure life and a reduction in emissions later in the life of the measure. This is a function of Tri-State's system-wide emissions rate, measured on a ton/MWh basis, which is expected to decrease over the

study horizon as Tri-State's fuel mix shifts. Other measures represent an immediate emissions reduction in the first year. Figure ES-2 shows the annual carbon emissions reduction estimates broken down by state.

Figure ES-2. Annual Lifetime Carbon Emissions Reduction by State (Achievable-Moderate Scenario)



The commercial sector is expected to make up 58 percent of emissions reduction potential, contributing over 3.7 million tons of CO_2 of the lifetime of measures installed through 2040. The share of emissions reductions as compared to the share of electric load growth potential differs primarily due to energy efficiencies of the baseline and retrofit case equipment. For instance, the commercial sector includes a large portion of emissions reduction from off-road EV measures such as electric forklifts. This type of equipment may contribute a proportionally larger share of emissions reduction potential as compared to its contribution to electric load growth because of the significant efficiency gains realized by switching from internal combustion engines to electric motors.

Table ES-2 summarizes the key cumulative beneficial electrification cost metrics across the portfolio at four time horizons under the achievable-moderate scenario, as well as 20-year averages across the full study time horizon. It is estimated that over the 20-year study horizon approximately 39 GWh of electric load growth is achievable, on average, per year at a cost of $28 million for an acquisition cost of $710/MWh. The 20-year average TRC ratio across the portfolio exceeds 2.0 when considering all achievable measures that pass the beneficial electrification screening.

Table ES-2. Portfolio Electrification Cost Metrics by Time Horizon (Achievable-Moderate Scenario)[5]

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	CUMULATIVE LOAD ADDED (MWH)	ACQUISTION COST ($/MWH)
2021	1.54	$1,941,462	2,524	$769.09
2025	1.61	$25,575,994	30,905	$827.56
2030	1.83	$121,866,050	146,004	$834.68
2040	2.37	$557,671,021	785,329	$710.11
20-year avg.	2.37	$27,883,551	39,266	$710.11

Study Approach and Methods

The study approach undertaken to develop the results presented above consists of three main tasks. These tasks are summarized below and discussed in more detail in Section 2 of this report. The tasks include:

- Customer Segmentation and Forecast Disaggregation
- Measure Impact Research
- Modeling and Data Analysis

Segmentation and forecast: For the market segmentation analysis, the Team first determined the fossil fuel technologies that have an electrical fuel source equivalent, such as water heaters. Next, the Team established the number of fossil fuel technologies per current Tri-State member cooperative customer premise for each customer class and premise segment type. In cases where the electric energy efficiency potential assessment determined the saturations of technologies with an electric fuel source, the saturations of fossil fuel source technologies can be inferred. The study assumes that 100 percent of residential premises have water heating. Using Front Range Colorado as an example, 20 percent of the water heaters have an electric fuel source. This means that 80 percent of the water heaters are fossil fuel based[6]. The final step was to segment fossil fuel technologies into unique fossil fuel types, such as natural gas, propane, diesel, and gasoline. Forecasting this segmentation over the 20-year study horizon followed the forecast developed for the prior DSM potential study, adapting the forecast to estimate fossil fuel segmentation by year instead of electric end use saturation by year.

[5] Program costs are estimates based on several factors and may not align with actual program costs in future years due to structural and organizational limitations that impact portfolio design. This study does not address program design or related drivers of cost.

[6] This breakdown represents Front Range Colorado in year 2020. Each region and year has their own saturation estimates.

Segmentation and forecasting for portions of the electric vehicle beneficial electrification analysis utilized different approaches as some EV technologies cannot be tied to customer premises in a reliable manner. The team used bottom-up and top-down approaches to estimate the forecast for each relevant electric vehicle technology. These methods are described in Section 2 of the report.

Measure impacts: With the market segmentation complete, the Team then characterized a wide variety of electrification measures and their end-use-specific reductions in fossil fuel consumption, added electricity consumption, associated net carbon emissions reduction, costs, and lifetimes. Each measure was assigned to the relevant region(s), sector(s), segment(s), and end use(s) for modeling. Each measure permutation was screened through a four-part beneficial electrification screening process that assessed the measure for customer cost savings, emissions reduction, quality of life, and grid resiliency. The beneficial electrification screening process is described in detail in Section 2.5.2 in the report. The screening involves assessing four criteria of which one or more must exhibit a positive impact while none of the others exhibit a negative impact[7]. The criteria include:

- Saves the customer money
- Reduces emissions
- Improves quality of life
- Fosters grid resiliency

Modeling and data analysis: The Mesa Point Team used industry-standard modeling approaches to estimate the technical electrification, beneficial electrification, and achievable electrification potential and associated costs for the analyzed measures. The projected increase in electricity consumption, reduction in carbon emissions, and associated costs of each measure was forecasted for a 20-year time horizon (2021 – 2040). Four achievable potential scenarios were developed so that varying levels of market opportunities could be assessed given variances in measure incentive levels and aggressiveness of program delivery. Outputs from the modeling were developed to show annual energy load impacts (increase in electric consumption and decrease in fossil fuel consumption), net carbon emission reductions, measure lifetimes, and costs for each measure permutation (by region, sector, segment, end use, and vintage) for each year of the study horizon. It is important to recognize that the carbon emissions reduction estimates are established as a function of Tri-State's forecasted emissions rates (tons of CO_2 per MWh). Tri-State provided the Mesa Point team with a set of projected carbon emissions rates based on projected changes in Tri-State's resource mix. As those projections come to fruition, or change over time, the emissions reduction estimates in this study could be updated to reflect the impacts.

[7] The screening criteria were drawn from the Beneficial Electrification League's definition of BE (https://beneficialelectrification.com).

1. INTRODUCTION

1.1. Background, Project Scope, and Objectives

Tri-State retained Mesa Point Energy, along with their subcontractor Brightline Group, (collectively the Mesa Point Team or the Team) to perform a beneficial electrification (or BE) study in support of the company's resources planning initiatives. The primary objective of this study is to assess the available technical electrification, beneficial electrification, and achievable electrification potential from a variety of measures from 2021 to 2040 for the electric cooperatives served by Tri-State Generation and Transmission (Tri-State).

For the purposes of this study, electrification can be defined as changing the energy source for an end use from a fossil fuel to electricity. For example, electrification could be considered:

- Transportation: Replacement of a gasoline driven vehicle with an electric vehicle
- Space Heating: Replacement of a natural gas fired furnace with a heat pump
- Domestic Water Heating: Replacement of a natural gas water heater with an electric-resistance or heat pump water heater
- Industrial: Use of electrically driven equipment instead of fossil fuel driven equipment in applications such as irrigation pumping and natural gas compressor stations

In order to be "beneficial electrification" a project must meet one or more of the following conditions without adversely affecting the other three:

1. Saves consumers money over the long run
2. Improves quality of life
3. Enables better grid management
4. Reduces negative environmental impacts

In order to *save consumers money*, the electrification measure must reduce the annual cost enough to recover the initial cost of the equipment before the useful life of the electric equipment is reached. *Improved quality of life* may result from enhanced product features, reliability, and other factors. An example of an electrification measure *enabling better grid management* is equipment that allows for some level of demand control by the utility, the customer, or a third-party. An electrification measure *reduces negative environmental impacts* through the elimination of direct emissions in exchange for fewer emissions from the generation of electricity used to power the equipment. This net emissions reduction is examined over the estimated lifetime of the equipment and is based on the projected emissions of the electric generation resources over time.

The beneficial electrification study is intended to assist Tri-State in developing future Integrated Resource Plans (IRP) and Electric Resource Plans (ERP). Tri-State will use the results of this beneficial electrification study to analyze and incorporate potential impacts at various levels of program investment.

The study focuses on beneficial electrification *achievable* potential. As discussed further in Section 2, the study is not a *program* potential study meaning it does not take into consideration program budget and design constraints. Therefore, this report's conclusions and recommendations do not include program-

specific recommendations; rather, the report focuses on identifying market opportunities and costs for electrification initiatives.

Reported emissions reductions in this study rely on information about Tri-State's projected resource mix[8]. Estimated emissions reductions would differ from those presented in this report if Tri-State's generation resource mix forecast changes.

This report is related in several ways to the recent *Demand Side Management and Energy Efficiency Potential Study* for Tri-State completed in May, 2020. The prior report provides an achievable potential assessment for energy efficiency, demand response, and distributed energy resources, and is referenced in sections of this report. Energy efficiency and beneficial electrification are two strategies for achieving demand side management goals. It is important to note that the beneficial nature of electrification measures is substantially impacted by the energy efficiency of the electric equipment being installed. More efficient electric equipment leads to greater emissions reduction over both fossil-fuel equipment and standard electric equipment.

Due to the timing of this report, it is important to note that the assumptions, results, and associated analysis detailed herein do not take into consideration the societal and economic impacts of the COVID-19 virus.

1.2. Achievable v. Planned Potential

This beneficial electrification study examines what *could be* (i.e., what load could be added and emissions reduced from considered beneficial electrification measures) but does not account for structural and organizational limitations to that potential.

Tri-State member cooperatives are responsible for implementing measures and programs on a voluntary basis. Tri-State does not have control over which measures its members choose to offer nor how the measures are bundled into program offerings. Some co-ops may choose not to offer incentive programs, or to incent only a subset of cost-effective measures.

The study only takes into consideration barriers on the market side and does not attempt to predict if and at what levels co-ops will choose to move forward with programs.

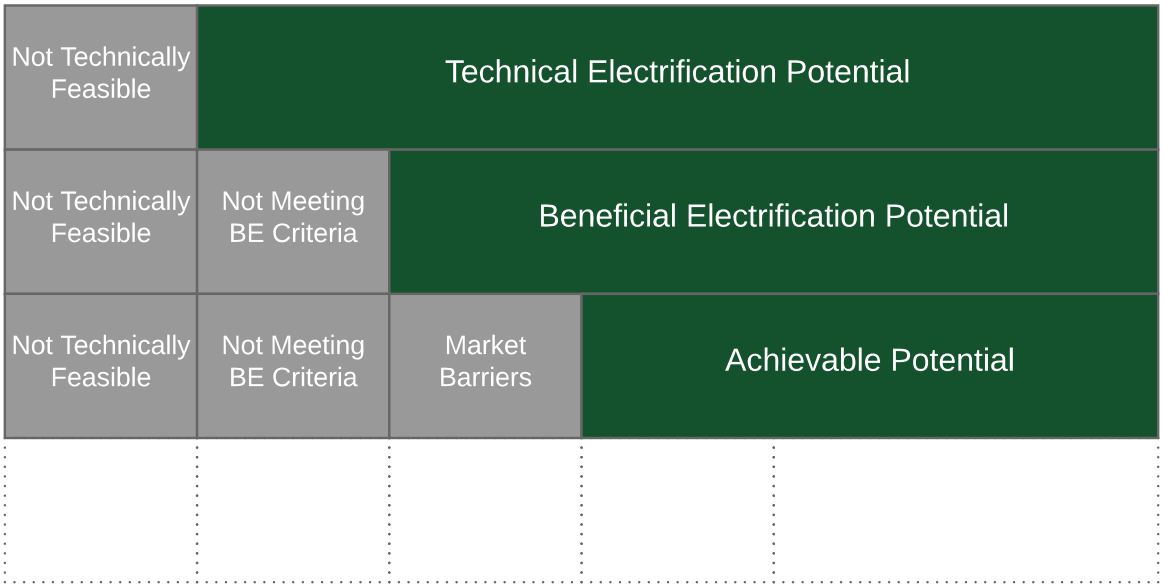
1.3. Study Approach Overview

This study considers measures from the perspective of theoretical maximum benefit, and then accounts for barriers to estimate actual achievable emissions reductions and load growth for the utility.

Specifically, the study begins with *technical electrification potential*, wherein all technically viable measures are included without regard to costs or other barriers. Knowing the technical potential, *beneficial electrification potential* is assessed by estimating costs and reduced emissions associated with implementing measures, and then applying beneficial electrification criteria to the measures. Finally, *achievable potential* is calculated by considering non-economic factors affecting electrification measure implementation. Not considered in the report are factors affecting *program potential*.

[8] Emissions factors were provided by Tri-State based on a resource mix forecast developed in March 2020.

Figure 1: Conceptual Overview of Beneficial Electrification Resource Potential Definitions



- **Technical Electrification Potential** is the theoretical maximum amount of energy load that could be displaced by the replacement of fossil fuel equipment with electric equipment, regardless of cost, emissions impact, and barriers that may prevent the installation or adoption of a measure. Technical electrification potential is only constrained by factors such as technical feasibility and applicability of measures.
- **Beneficial Electrification Potential** represents the amount of emissions reduced, fossil fuel consumption reduced, and associated electric energy and capacity increases that could result from measures that pass beneficial electrification screening criteria. Beneficial electrification screening criteria is described below and in more detail in Section 2.4.2.
- **Achievable Potential** is the energy and emissions impacts that can feasibly be achieved through program and policy interventions. Achievable potential takes into account barriers that hinder consumer adoption of electrification measures such as financial, political and regulatory barriers, and the capability of programs and administrators to ramp up activity over time.
- **Program Potential** reflects the realistic quantity of energy load growth and associated emissions the utility can realize through BE programs during the horizon defined in the study. Potential delivered by programs is often less than achievable potential due to real-world constraints such as program budgets, effectiveness of outreach, and market delays. Program potential would also incorporate go-to-market considerations, such as practical limitations for Tri-State to deliver programs to customers through the rural electric cooperative members. As noted previously and as shown in Figure 1, this study does not address program potential.

1.4. Organization of the Report and Related Deliverables

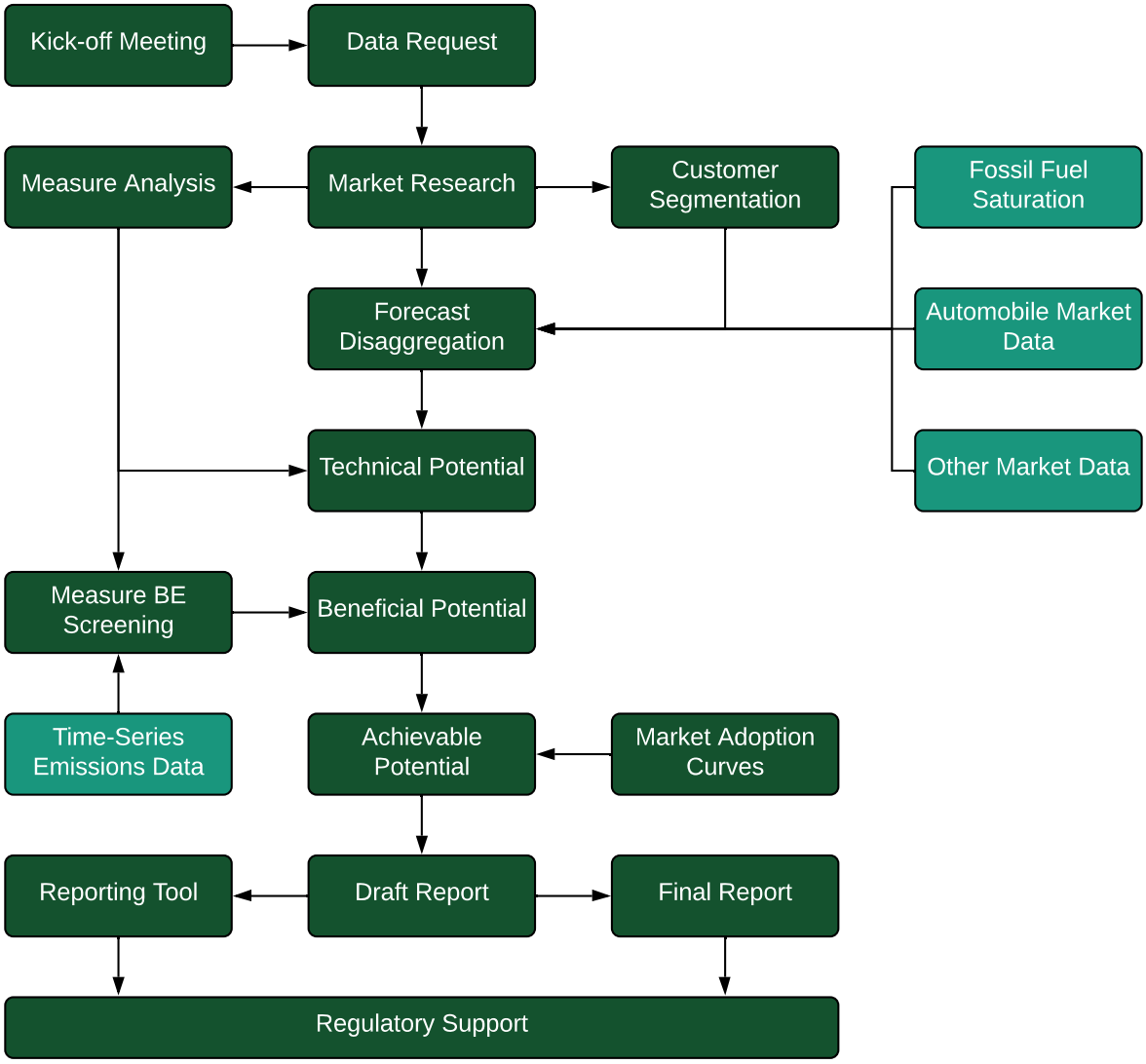
This report presents a summary of the analysis approach, key assumptions, and study findings. Two separate electronic reporting tools are provided with the report, as well as an additional technical appendix spreadsheet that includes select data and input assumptions. The tools provide the ability to view findings by sector, end-use, and region. One reporting tool provides data exclusive of naturally occurring adoption in the EV market, identifying potential that could stem from intervention by Tri-State and its member coops. The main body of this report refers to the results in the version of the tool that excludes naturally occurring adoption. The second reporting tool is inclusive of naturally occurring adoption and is explained further in Appendix C. The intent is for Tri-State and stakeholders to make use of each work product depending on the desired level of detail and perspective.

2. STUDY APPROACH AND METHODS

2.1. Overview

The process shown in Figure 3 depicts the steps taken during a beneficial electrification study.

Figure 2. Approach for Beneficial Electrification Potential Modeling



Each step is described in detail in the sections that follow.

2.2. Customer Segmentation and Forecast Disaggregation

An accurate assessment of achievable beneficial electrification potential requires a thorough characterization of customer technologies. A beneficial electrification study differs from an electric

energy efficiency study as the base forecast represents the technologies that utilize fossil fuels as an energy source and are eligible to switch an electric fuel source. The forecast for a beneficial electrification study differs from an energy efficiency potential assessment forecast, as the BE forecast characterizes the quantity of fossil fuel equipment/technologies eligible for fuel switching and places less importance on the forecast of energy consumption. The forecast characterization of fossil fuel technologies involves the following steps:

- Determine the fossil fuel equipment/technologies that have an electrical fuel source equivalent, such as water heaters.
- Estimate the number of fossil fuel equipment/technologies per current Tri-State member cooperative customer premise for each customer class and premise segment type.
- In cases where the electric energy efficiency potential assessment determined the saturations of technologies with an electric fuel source, the saturations of fossil fuel fuel source technologies can be inferred. For example, if it assumed that 100 percent of residential premises have water heating and 35 percent of the water heaters have an electric fuel source, then it can be assumed that 65 percent of the remaining fuel sources are fossil fuel based.
- Segment fossil fuel equipment/technologies into unique fossil fuel types, such as natural gas, propane, diesel, and gasoline.

To complete these steps the Team relied on a large dataset consisting of:

- The 2020 electric energy efficiency potential study and associated analysis
- Customer forecast from Tri-State member cooperatives
- Market data including fuel shares and equipment saturations
- Technology characteristics including technologies, fuel types, and useful life.

These data were drawn from a combination of primary and secondary research. An overview of the steps involved in forecast characterization process follows.

2.2.1. Customer Segmentation

First, the Team determined the energy and demand loads for each of the geographical regions, sectors, market segments, vintages, and end-uses as follows:

- **Regions**: Sales for rural electric cooperatives were aggregated into regional definitions; including Front Range Colorado, Nebraska, North New Mexico, Wyoming, etc., as shown in Table 1
- **Customer Sectors:** Residential, commercial, irrigation, and industrial (including agricultural)
- **Vintages:** Existing and New Construction
- **End-uses:** Those shown by sector in Table 2

2.2.1.1. Primary Market Research

Primary market research guided the customer segmentation. In 2012, Tri-State distributed a mail-in residential end-use survey requesting information on consumers' residence structure and energy consuming equipment type, age, fuel type, end-uses, and behavior. This data was used to guide the disaggregation of the residential sector load.

The Team also used North American Industry Classification System (NAICS) data that provides business type data on large customers (greater than 250KW) and their associated energy consumption from the Rural Utilities Service (RUS) Form 345. Business type information for energy sales of non-residential customers less than 250KW was not available. Secondary research was necessary to estimate segmentation of business types for customers less than 250KW.

2.2.1.2. Secondary Market Research

The Team utilized secondary resources to complete the customer segmentation, specifically electric versus fossil fuel shares and further segmentation between natural gas and propane. Examples of these resources include the United States Energy Information Administration (EIA) Residential Energy Consumption Survey (RECS) and the EIA Commercial Buildings Energy Consumption Survey (CBECS), among other references, an Environmental Protection Agency-associated technical paper on *National Emissions from Lawn and Garden Equipment*, a U.S. Department of Energy *Energy Storage Technology and Cost Characterization Report*, the U.S. Department of Homeland Security's Homeland Infrastructure Foundation-Level Data (HIFLD) on natural gas compressor stations, among other resources cited throughout this report.

2.2.2. Segmentation of Regions

To accurately characterize Tri-State's large geographic service territory, the Team segmented end-use load profiles and electrification potential by region. Eight (8) regions were defined based on geographic location of the co-ops. Segregating the co-ops by region, instead of producing one set of potential values for all of Tri-State's territory has several advantages:

- Regional segmentation captures variations in equipment end-use saturation and energy intensity. For instance, electric water heater in the residential sector has a higher saturation and energy intensity in Nebraska as compared to Front Range Colorado.
- Barriers to achievable potential may be regionally specific, such as zero emission vehicle encouragement policy within the State of Colorado.

Similar to the electric energy efficiency potential assessment, the Team developed the regional electric cooperative groups shown in Table 1.

Table 1: Tri-State Cooperative Regional Groups

EASTERN COLORADO	FRONT RANGE COLORADO	MOUNTAIN COLORADO	WESTERN COLORADO
Highline	Mountain View	Gunn County	Empire
K.C.	Poudre Valley	Mountain Parks	La Plata
Morgan County	San Isabel	White River	San Luis Valley
Southeast	United		San Miguel
Y-W			Sangre De Cristo
NEBRASKA	**SOUTHERN NEW MEXICO**	**NORTHERN NEW MEXICO**	**WYOMING**
Chimney Rock	Central NM	Cont. Divide	Big Horn
Midwest	Columbus	Jemez Mtns	Carbon
Northwest	Otero County	Mor San Miguel	Garland
Panhandle	Sierra	North. Rio Arriba	High Plains
Roosevelt	Socorro	Southwestern	High West
Wheat Belt		Springer	Niobrara
			Wheatland
			Wyrulec

2.3. End-Use Load Classification

To further disaggregate the load the Team established technology end-use loads within each sector. Table 2 presents a summary of those end-uses.

Table 2: Technology End-Uses for Each Tri-State Sector

RESIDENTIAL	COMMERCIAL	INDUSTRIAL & IRRIGATION
Boilers (Natural Gas Fuel)	Boilers (Natural Gas Fuel)	Pumps (Natural Gas)
Boilers (Propane Fuel)	Boilers (Propane Fuel)	Pumps (Propane)
Furnaces (Natural Gas Fuel)	Furnaces (Natural Gas Fuel)	Pumps (Diesel)
Furnaces (Propane Fuel)	Furnaces (Propane Fuel)	
Water Heating (Natural Gas Fuel)	Water Heating (Natural Gas Fuel)	
Water Heating (Propane Fuel)	Water Heating (Propane Fuel)	
Cooking (Natural Gas Fuel)	Cooking (Natural Gas Fuel)	
Cooking (Propane Fuel)	Fleet Vehicles	
Lawn Equipment	Forklifts	
Garden Equipment	School Buses	
Battery EVs	Transit Buses	
Plug-in Hybrid EVs	Airport Equipment	
	Truck Stop Electrification	

2.4. Electric Vehicle Forecasting

The team used various approaches to estimate the forecast for each relevant electric vehicle technology using both bottom-up and top-down methods of estimation. With the exception of the residential on-road electric vehicle forecast which is derived based on the disaggregated forecast, each technology forecast was constructed outside of the forecasting methods described in this section utilizing the prior DSM potential study as a starting point, as these technologies did not conform with the forecast taxonomy from that study. However, these independent forecasts did follow the same principles and used Tri-State data when applicable. For example, naturally occurring adoption for electric vehicles in Colorado (i.e. adoption independent of Tri-State or member cooperative influence) is expected to be greater relative to non-Colorado regions due to aggressive state policy and funding. This assumption is applied to both the residential on-road forecast and is also carried through to commercial fleets, airport GSE, and forklifts in Colorado, as these are all eligible technologies for Colorado state funding. More detail on forecasting for specific EV technologies is provided in Appendix B.

2.5. Beneficial Electrification Potential Modeling

Drawing on outcomes from the customer segmentation and forecasts the study modeled first technical, then beneficial, and finally achievable electrification potential. Those steps are described in the following sections.

2.5.1. Estimate Technical Electrification Potential

Technical electrification potential is the theoretical maximum amount of energy consumption and capacity added to the grid, along with associated fossil fuel reduction and emissions reduction, associated with electrification measures, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end-users to adopt the electrification measures. Technical electrification potential is only constrained by factors such as technical feasibility of measures and time. The model applies the measure-level inputs to the disaggregated baseline premise count forecast to estimate technical electric load growth potential, as well as net change in emissions, over the planning horizon.

The core equations used in the technical electrification potential analysis for each individual electrification measure are shown in Equation 1 and Equation 2.

Equation 1. Core Equation for Technical Electrification Potential – Electric Growth

Technical Electricity Consumption Growth Potential of Electrification Measures = Total Number of Premises x Saturation Share x Fuel Share x Remaining Factor x Applicability Factor x Proposed Annual Unit Energy Consumption (kWh)

Equation 2. Core Equation for Technical Electrification Potential – Fossil Fuel Reduction

Technical Fossil Fuel Reduction Potential of Elecrification Measures = Total Number of Premises x Saturation Share x Fuel Share x Remaining Factor x Applicability Factor x Baseline Annual Unit Energy Consumption (therms)

Where:

Total Number of Households: *count of customer households in the subject region.*

Saturation Share: *the fraction of households with fossil fuel equipment for a given end-use in a given market segment. For example, for residential water heating, the saturation share would be the fraction of all residential customers that have fossil fuel water heating in their household.*

Fuel Share*: the fraction of fossil fuel equipment for a particular end-use using a specific type of fossil fuel, either natural gas, propane, gasoline, or diesel. For example, for residential water heating, the fuel share of propane would be the fraction of all residential premises with fossil fuel water heating that use propane as a fuel type.*

Remaining Factor: *the fraction of equipment that is not considered to already be converted from fossil fuel to electric. To extend the example above, the fraction of fossil fuel water heaters that is not already converted to electric.*

Applicability Factor: *the fraction of the applicable units that is technically feasible for conversion to electricity from an engineering perspective—i.e., it may not be possible to install a heat pump water heater in all homes due to air circulation constraints.*

Baseline Annual Unit Energy Consumption: *the annual energy consumption, in therms, of the baseline fossil fuel equipment.*

Proposed Annual Unit Energy Consumption*: the annual energy consumption, in kWh, of the proposed electrically-operated equipment.*

2.5.1.1. Measure Definitions

Once the baseline forecast is disaggregated, the next step to assessing technical electrification potential is to accurately detail the various electrification measures under consideration and estimate their end-use-specific energy impacts, costs, and lifetimes. The Team worked with Tri-State to develop a list of electrification measures to analyze. The list of assessed measure types is included in Table 3, and details on the measure permutations and analysis approach for each measure type, is provided in Appendix A.

Table 3: Measure Types Analyzed

RESIDENTIAL	COMMERCIAL	INDUSTRIAL & IRRIGATION
Heat Pump Water Heating	Heat Pump Water Heating	Electric Irrigation Pumps
Heat Pump Space Heating	Heat Pump Space Heating	Pipeline Compressor Station Electrification
Electric Cooking (Electric Resistance and Induction)	Electric Cooking (Electric Resistance and Induction)	
Electric Lawnmowers	Battery Electric Vehicles	
Electric Snow Blowers	Plug-in Hybrid Electric Vehicles	
Electric Leaf Blowers	Electric Forklifts	
Electric Chainsaws	Electric School Busses	
Electric Trimmers, Edgers, Brush Cutters	Electric Transit Busses	
Battery Electric Vehicles	Electric Public Fleet Vehicles	
Plug-in Hybrid Electric Vehicles	Electric Airport Ground Support Vehicles	
	Electric Parking Spaces	
	Electric Transportation Refrigeration Units	

Upon finalizing the electrification measure list, the Team collected data on energy savings and increases, costs, lifetime, and applicability to determine potential measure impacts. This work involves a multi-step process described here.

Step 1: Define market classifications for application of measures

The Team established market classifications as a framework for documenting applicability of each measure. These classifications were based on factors including region, fuel type, sector, market segment, and end-use as defined in the disaggregated forecast (Section 2.2). Additionally, the Team further defined permutations for each measure based on the following parameters:

- **Climate Zone:** This measure research includes estimates for weather-dependent measures specific to ASHRAE climate zones 4 through climate zone 6
- **Vintage:** Turnover, Early Retirement, New
  - **Replace on Burnout:** Convert equipment to electric when a piece of equipment is at the end of its effective useful life (also referred to as “turnover”)
  - **Early Retirement:** Convert equipment to electric at any time during the life of the equipment

- **New:** Install electric equipment instead of fossil fuel equipment when a new home or building is constructed

Step 2: Screen sectors, segments, and end-uses for applicability

The Team screened market segments and end-uses for applicability of specific electrification measures. For example, certain commercial end-uses, such as cooking, may not be appropriate for segments such as warehouses and therefore were analyzed only in limited market segments.

Step 3: Develop base case impacts and costs

The Team determined base case fossil fuel-burning equipment and practices for each of the electrification measures on the final list and developed a description and rationale for each. This included all base case assumptions and data, such as state building codes (the 2012 International Energy Conservation Code (IECC) in most cases) and federal standards. For each measure, the Team estimated fossil fuel energy consumption for the base equipment, as well as the cost to replace the fossil fuel-burning equipment with a new, similar fossil fuel-burning piece of equipment.

Step 4: Develop electrification measure impacts and costs

The Team developed a description of all electrification (or "change case") measure equipment and practices, including all measure energy consumption assumptions and calculation parameters, such as equivalent full load hours (EFLH). For each measure, the Team estimated electric energy consumption of the proposed equipment, as well as the associated cost to purchase and/or install the equipment.

2.5.2. Estimate Beneficial Electrification Potential

Beneficial electrification potential represents the impacts possible given full adoption of all electrification measures considered to be "beneficial electrification" in that the measures must pass the four BE screening criteria explained below.

To determine whether a measure can be considered beneficial electrification, the Team screened all considered electrification measures using a four-part screening process. This process was established based on the Beneficial Electrification League's (BEL)[9] definition of beneficial electrification as "the application of electricity to end-uses where doing so satisfies at least one of the following conditions, without adversely affecting the others:

- Saves consumers money over time;
- Benefits the environment and reduces greenhouse gas emissions;
- Improves product quality or consumer quality of life; and
- Fosters a more robust and resilient grid.

In order to perform this screening process, each measure was assigned a set of four values, each representing one of the four criteria above. The possible values for each criterion are shown in Table 4.

[9] *Beneficial Electrification League*. (2020). Beneficial Electrification League. https://beneficialelectrification.com/

Table 4: Beneficial Electrification Screening Details

SCREENING CRITERIA	EVALUATION METHOD	PASSING VALUE	FAILING VALUE[10]
Saves consumers money over time	Calculate Participant Cost Test (PCT) for each measure	> 1	< 1
Benefits the environment and reduces greenhouse gas emissions	Calculate net CO_2 emissions reduction for each measure (tons)	> 0	< 0
Improves product quality or consumer quality of life	Identify, qualitatively, whether each measure improves (1), has no impact on (0), or negatively impacts (-1) quality of life	0 or 1	-1
Fosters a more robust and resilient grid	Identify, qualitatively, whether each measure could improve (1), has no impact on (0), or negatively impacts (-1) grid resiliency and flexibility	0 or 1	-1

A value for each of the four criteria was calculated for each measure. Subsequently, a beneficial electrification score (BE score) was calculated for each measure using the following logic: The BE score results in a zero value if any one of the four criteria has a failing value assigned to it. If none of the criteria have a failing value assigned to it, and at least one criterion has a passing value assigned to it, the BE score equals 1.

Measures with a passing BE score of 1 are considered beneficial electrification. Measures with a failing BE score of 0 are screened out of modeling in the beneficial electrification potential scenario and all of the achievable potential scenarios.

2.5.2.1. BE Screening Criteria Descriptions

Approaches to assigning or calculating the score for each BE screening criteria are described in the following sections.

2.5.2.1.1. Criterion 1: Saves the Consumer Money over Time

To evaluate the criterion that a measure saves the customer money, the Team performed a participant cost test on each measure using Equation 3. The PCT considers incentives, tax credit, and the net present value of annual savings on utility bills as benefits and the measure incremental costs,

installation costs, and operation and maintenance costs[11], as costs. Utility bill savings[12] in the context of beneficial electrification is the net savings of reduced fossil fuel costs and increased electricity costs. Annual components of the test inputs are taken to a net present value based on measure life.

Equation 3. Participant Cost Test

$$PCT\ Ratio = \frac{Incentives + Tax\ Credit + Fossil\ Fuel\ Cost\ Savings - Added\ Electric\ Bill\ Costs}{Incremental\ Equipment\ Cost + Installation\ Cost + Maintenance\ Cost}$$

2.5.2.1.2. Criterion 2: Benefits the Environment

To pass this screening criterion, the carbon emissions reduction resulting from reduction of fossil fuel use must be greater than the emissions created from the added electric load. Emission reductions for fossil fuel technologies are a function of the annual consumption, its expected life, and the fuel type.

The emission reduction for the fossil fuels includes transportation to the site from the refining facility, whether that is by pipeline, tanker truck, or other method. This allows a comparison to equivalent emissions added from the electric system, which includes the generation resources emissions and line losses, or the "transportation" to the site from the generation resource. The calculation for added emissions is based on a 20-year forecast of hourly (8760) carbon emissions, with greenhouse gas tons per MWh reducing over time as clean generation resources are expected to be introduced. Consequently, the emission reductions for electric technology are a function of the hourly consumption, its expected life, and the installation. Equation 4, calculated for each year of a measure's life, shows the method to calculate net emissions reductions for each measure.

Equation 4. Net Emissions Reduction Test

$$Net\ Emission\ Reduction = Emissions_{fossil\ fuel} - Emissions_{electrified}$$

Or inserting units,

$$Net\ Emission\ Reduction = \left(\frac{BTU}{year} \times \frac{tons\ CO_2}{BTU}\right) - \left(\sum_{i=0}^{i=8760} \left(kWh_i \times \left(\frac{tons\ CO_2}{kWh}\right)_i\right)\right)$$

Factors used to estimate emissions from the fossil fuel baseline equipment are shown in Table 5.

[11] In many cases for Beneficial Electrical technologies, the Operations and Maintenance costs are negative. Even though this may be presented as a benefit, it is applied a credit to costs within the ratio denominator.

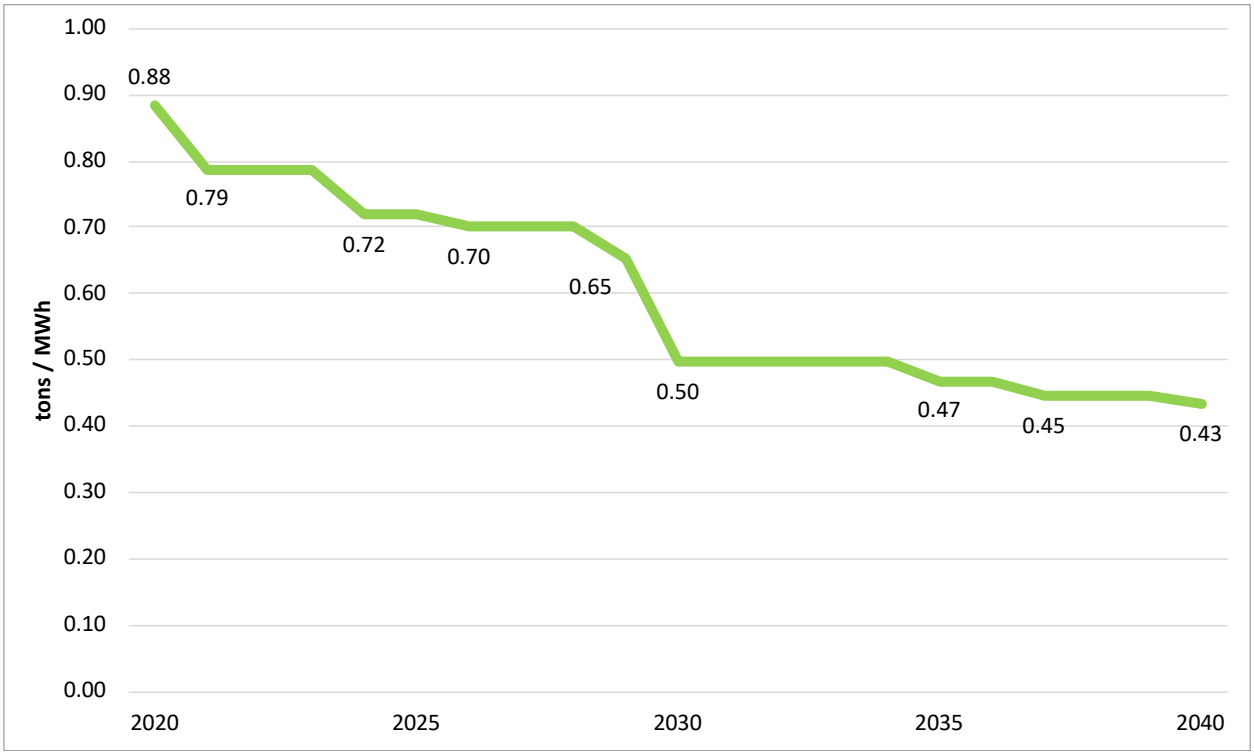
[12] Participant utility bills are based upon the customer rate. Customer rates for this study were generic, not based a specific member cooperative, but were informed by public available, published rates. Generic rates were calculated for each customer segment; residential, commercial, and industrial.

Table 5: Fossil Fuel Carbon Emissions Rates

Fossil Fuel Type	Emissions Rate (tons CO_2/BTU)
Natural Gas	0.00585
Propane	0.00635
Gasoline	0.00971
Diesel	0.00954

Emissions rates used to calculate post/electrified emissions were provided by Tri-State. The rates, measured in tons of CO_2 emissions per megawatt-hour, were provided on an hourly basis for the years 2020 – 2040. The hourly emissions rates were utilized, in conjunction with measure savings and load shape, to calculate the emissions of electrified equipment. The average emissions rates by year are presented in Figure 3, although calculations were done on an hourly basis.

Figure 3: Annual Average Electric Generation Carbon Emission Rates



The emissions rates used in the analysis reflect an individual forecast of Tri-State's resource mix. The forecast could change based on changing regulatory, economic, political, market, and other conditions. Adjustments to Tri-State's resource mix may lead to adjustments in the emissions rates, and therefore adjustments to the emission reduction outcomes. The effects of accelerating or decelerating emissions

rate improvements, or increasing or decreasing the magnitude of the emission rate reductions, would change the post-case emissions and also change which beneficial electrification measures pass the emissions screening criteria.

2.5.2.1.1. Criterion 3: Improves Quality of Life

The Team considered each measure's impact on quality of life in order to assign a value of -1, 0, or 1 to each measure. A value of -1 represents a negative impact, a value of 0 represents no appreciable impact, and a value of 1 represents a positive impact. To assign these values, The Team considered the way in which each measure could improve the quality of life of the customer in terms of comfort, reliability, ease of use, and other aspects. Electrification measures are often associated with these improvements due to the advanced technologies utilized, and reliability of electrically-driven motors, compressors, pumps, etc. Each measures impact on quality of life for the consumer and product quality was carefully considered.

2.5.2.1.2. Criterion 4: Fosters Grid Resiliency

The Team considered whether or not a particular measure may provide an improvement to grid resiliency via potential demand control mechanisms, ability to provide energy storage on the grid, and other aspects. If a particular measure involved a technology that could feasibly provide one of these benefits, the measure received a score of 1 for grid resiliency. If a measure involved a technology that would not feasibly provide these benefits, but would have no negative impact on the grid, the measure received a score of 0 for grid resiliency. If the measure was believed to negatively impact grid resiliency, a score of -1 was assigned to that measure. For example, a heat pump water heater may have the ability to foster grid resiliency by allowing the utility (with customer approval) to adjust the time the unit heats stored water to manipulate the equipment's impact on the system peak demand.

2.5.2.2. Overall Economic Viability

While the beneficial electrification screening process utilized the PCT to screen for cost effectiveness, the Team also assessed the overall economic viability by calculating the Total Resource Cost (TRC) test for each measure. TRC outcomes are presented at the sector and portfolio levels in later sections of this report and at a more granular level in the BE reporting tool. The TRC test is a valuable test to assess measure benefits and costs from the perspective of all the rate payers as a whole. Equation 2 presents the TRC ratio equation.

Equation 5. TRC Ratio

$$TRC\ Ratio = \frac{\left((Avoided\ Electric\ Avoided\ Costs + Avoided\ Fossil\ Fuel\ Costs) \times 10\%\ NEB\ Multiplier\right) + Social\ Cost\ of\ Carbon}{Incremental\ Cost + O\&M\ Costs + Tax\ Credits}$$

The benefits in the TRC test are the net present value of the lifetime avoided energy and capacity costs. The costs in this test are the net present value incremental measure costs.

Specifically, the **benefits** include the net present value of the energy and capacity saved by the measures along with any natural gas or other fossil fuel benefits. The forecast of electric avoided costs of energy

and capacity were obtained from Tri-State[13]. The avoided costs are calculated by applying end-use-specific annual hourly load shapes to measure energy impacts to determine the time-differentiated value of energy and capacity benefits. The annual hourly load shapes were developed from industry-specific energy load profiles, and a peak load window definition of noon to 10 PM during weekday summer months was provided by Tri-State to estimate coincident peak demand.

To accurately value avoided energy impacts for Tri-State, line losses were included. These losses were calculated for each climate zone and reflected the losses from the customer to the co-op and the losses from the co-op to Tri-State. A financial discount rate of 5 percent was applied to value future avoided costs.

Fossil fuel avoided costs were estimated based on various publicly available sources, largely relying upon data contained within natural gas DSM program regulatory filings for the State of Colorado and United State Energy Information Agency (US EIA) annual[14] and short term[15] energy outlooks (AEO) with region adjustments, as available.

The social cost of carbon at $46/ton[16] of CO_2 was incorporated as a benefit of BE in the TRC calculations. This information was provided by Tri-State as a table with values escalated annually over the study time horizon. An additional 10 percent multiplier was applied to the TRC benefits to account for additional non-energy benefits (NEBs) associated with electrification measures such as job creation and societal health benefits. How the NEBs multiplier is calculated is explained in the section below.

The **costs** are the net present value of all costs to implement the measures. These costs include full incremental costs. The full incremental costs include single upfront costs and operational & maintenance costs where applicable. Incentives are not included, because they are transaction between the utility and customer, thus the costs and benefits negate each other. Additionally, state and/or federal tax credits, where applicable were included.

2.5.2.2.1. NEBs Adder

For this study, we used a 10 percent non-energy benefit adder in addition to the monetized cost of carbon to account for health, environmental, and other benefits of electrification. In part, this factor is intended to include the benefit of reduced non-carbon greenhouse gas emissions such as NO_x and SO_x. Additional non-energy benefits to electrification including improved local air quality, improved public and participant health, and compliance (including cost of compliance) with environmental regulations.

To account for benefits beyond cost savings and carbon reduction, some states explicitly monetize the value of health and environmental benefits, while others use a proxy multiplier on the TRC test. This multiplier has the effect of increasing the TRC, potentially allowing for increased BE efforts, inclusion of more measures, and increased program funding.

[13] Because there is added electrical consumption due to beneficial electrification measures, the avoided electric benefits will be **negative**.

[14] *https://www.eia.gov/outlooks/aeo/*

[15] *https://www.eia.gov/outlooks/steo/*

[16] 2020 dollars

Xcel Energy Colorado, in their settlement agreement and DSM plan, uses a TRC modification factor of 20 percent for all non-low income measures and 50 percent for all low income measures, which includes carbon[17].

The BE analysis shows that the monetized cost of carbon increases benefits by about 10 percent. To achieve an overall environmental benefit multiplier of 20 percent, which is in line with Xcel's filings, this analysis adds another 10 percent to account for non-carbon, non-energy benefits.

2.5.3. Estimate of Achievable Potential

The assessment of realistically achievable electrification potential required estimating, among other parameters, the rate at which cost-effective measures can be adopted over time. The Team incorporated individually developed sets of market penetration curves corresponding to implementation scenarios to account for the fact that program implementation scenarios have a direct influence over such market penetration rates. These scenarios were correlated to differing levels of urgency in program implementation, tolerance for rate impacts, macroeconomic conditions, and other situations.

The following are important components in determining achievable potential:

- **Benchmarking.** The amount of participation expected to be achievable through BE programs can be informed by the experience of utilities across the region and nation. For BE measures that have a traditional DSM analog (i.e. heat pump water heaters), program adoption for BE can be informed by traditional DSM program participation rates, adjusting for additional market barriers present for BE measures.
- **Customers' willingness to participate.** The likelihood that customers will participate in electrification programs is a function of several factors, including but not limited to incentive level.
- **Uncertainty.** Planning requirements often necessitate a point-estimate of potential, however, this is not an accurate reflection of the reality of BE programs. The study conceives of achievable potential as a range, or probability distribution, where the point-estimate is the most likely outcome. This distribution defines the lower and upper bounds of expected participation, as well as the most likely value.

Achievable potential electrification impacts were evaluated based on four incentive scenarios as a function of incentive level:

- **Achievable Low**: Incentives below industry standard, with limited administrative expenditures
- **Achievable Moderate**: Incentives and administrative expenditures on par with industry average
- **Achievable Aggressive**: Incentives and administrative expenditures above industry average

[17] Proceeding 17A-0462EG, Xcel Co Settlement Agreement pg 12/34, PSCO DSM plan from Proceeding 18A-0606EG April see pg 333, Proceeding 17A-0462EG decision C18-0417 pg 12 of 45

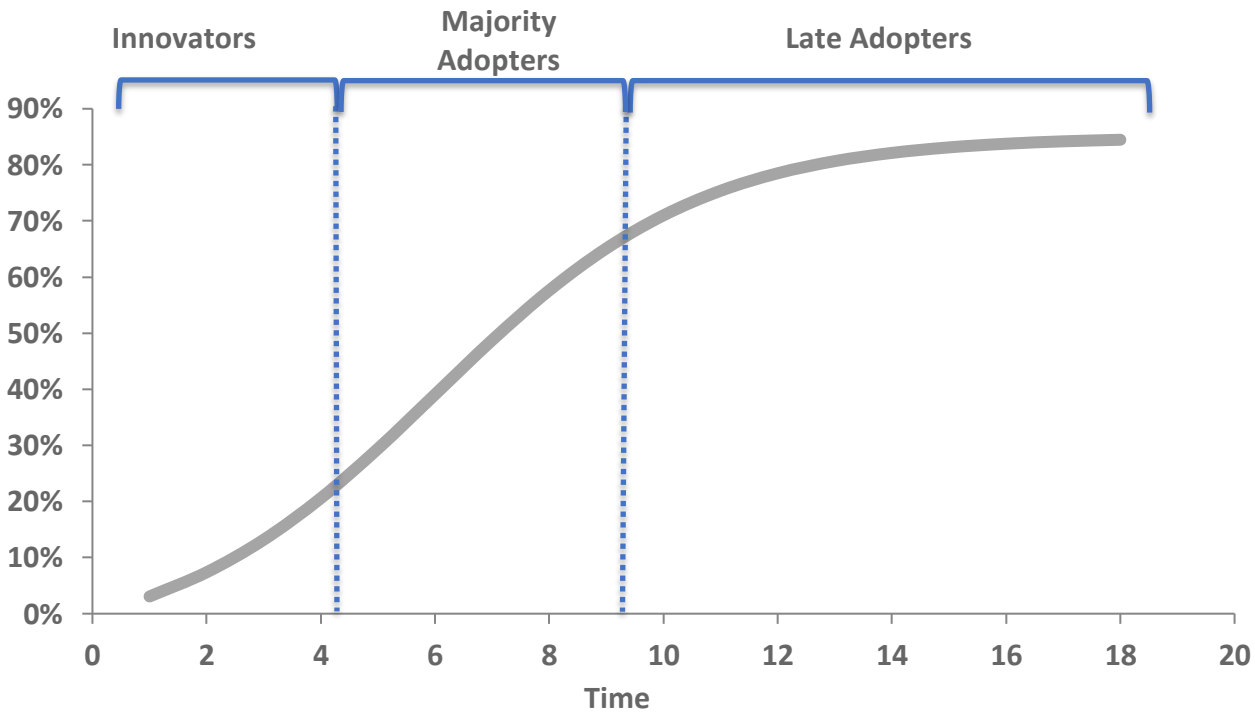
- **Achievable Maximum**: Incentives that cover the full incremental cost of measures, or approximately double industry average, and highly aggressive administrative expenditures

2.5.3.1. Market Adoption Rates

In order to characterize the rate of market adoption for each of the specified scenarios, a quantitative approach was developed based on a Bass Diffusion Model. This method relies on scientific theory and historic program participation data based on Tri-State's experience and other DSM and BE programs in North America.

The Bass Diffusion Model[18] is a mathematical description of how the rate of product diffusion in a market changes over time. When the product is introduced, there is a slow rate of adoption while customers become familiar with the product. When the market accepts a product, the adoption rate accelerates to relative stability in the middle of the product cycle. The end of the product cycle is characterized by a low adoption rate because fewer customers remain that have yet to adopt the product. This concept of forecasting future adoption rates is illustrated in Figure 4.

Figure 4: Typical Product Diffusion in the Marketplace



The rate of adoption in a discrete time period is determined by external influences on the market, internal market conditions, and the number of previous adopters.

[18] Bass, Frank (1969). "A new product growth for model consumer durables". Management Science.

- Initial Year Measure Adoption

First year adoption levels were informed by recent Tri-State historical performance where possible and applicable. For instance, for building-related BE measures, the initial year measure adoption is considered modestly reduced from recent DSM program performance.

- Long-Term Market Adoption Rates

The final adoption scores that resulted from willingness to pay surveys serve as the point-estimate for the long-term market adoption potential for the realistic achievable scenario.

- Adoption Curve Shape

Once the initial year adoption rate (Point A) and long-term adoption rates (Point B) are determined, the remaining step was to determine the rate and duration to get from Point A to Point B.

Unique end-use adoption curves were developed based on the following three parameters:

- **Customer Sector:** Residential, Commercial, and Industrial
- **End-Use Type**: Space Heat, Water Heat, etc.
- **Incentive Level based on Achievable Scenario**: low, moderate, aggressive, maximum

2.5.3.2. Program Costs

To capture the full cost of achievable electrification potential, the Team added program non-incentive costs in the overall assessment of cost-effectiveness. Non-incentive program cost categories included: (1) Administration, (2) Marketing, (3) Technical, and (4) Measurement & Verification and Planning. Program non-incentive costs were calculated on a gross $ per first-year kWh added. Non-incentive costs were developed for each program by sector. The included program cost assumptions are shown in Table 6. These assumed non-incentive costs reflect the same costs used in the recent energy efficiency potential study as program delivery for most BE measures is not expected to take significantly more or less resources to implement.

Table 6: Summary of Non-Incentive Program Costs ($/kWh)

SECTOR	ACHIEVABLE LOW	ACHIEVABLE MOD	ACHIEVABLE AGG
Residential	$0.100	$0.115	$0.150
Commercial	$0.050	$0.058	$0.075
Industrial	$0.100	$0.115	$0.150
Irrigation	$0.050	$0.058	$0.075

For program cost analysis, non-EV incentive costs were developed based on secondary research of existing electrification programs instead of assigning incentives as a percentage of incremental cost. For many electrification measures, the incremental cost is very small or even negative – the electric version of the technology in question costs less than the fossil fuel option. Despite this, incentives or other

motivational elements such as education and outreach, are still required to drive market adoption of BE measures. For the purposes of estimating total program costs, prevailing current incentive amounts were assigned to the achievable-moderate scenario and were scaled up or down in proportion to the incentive level percentages assigned to the other achievable scenarios.

2.5.4. Reporting Tools

A pair of BE Reporting Tools were developed to provide Tri-State staff access to the data outputs from the modeling efforts. The Reporting Tools, presented as Microsoft Excel workbooks, summarize and illustrate the load growth, fossil fuel reduction, and emissions reduction potential and associated costs by sector, year, and scenario enabling the user to select results for a specific region or for the entire service territory. The results are depicted in tabular form and in associated charts that update dynamically based on the selected region. The first of the two files presents results that represent the estimated potential directly associated with interventions by Tri-State and its member coops. The second file presents results that represent estimated potential stemming from both Tri-State's interventions, as well as from naturally occurring adoption. Naturally occurring adoption is expected to be significant in the EV market over the 20-year study horizon. The results presented in the following sections are *exclusive* of naturally occurring adoption. Appendix C provides additional context for the second Reporting Tool that is *inclusive* of naturally occurring adoption in the EV market.

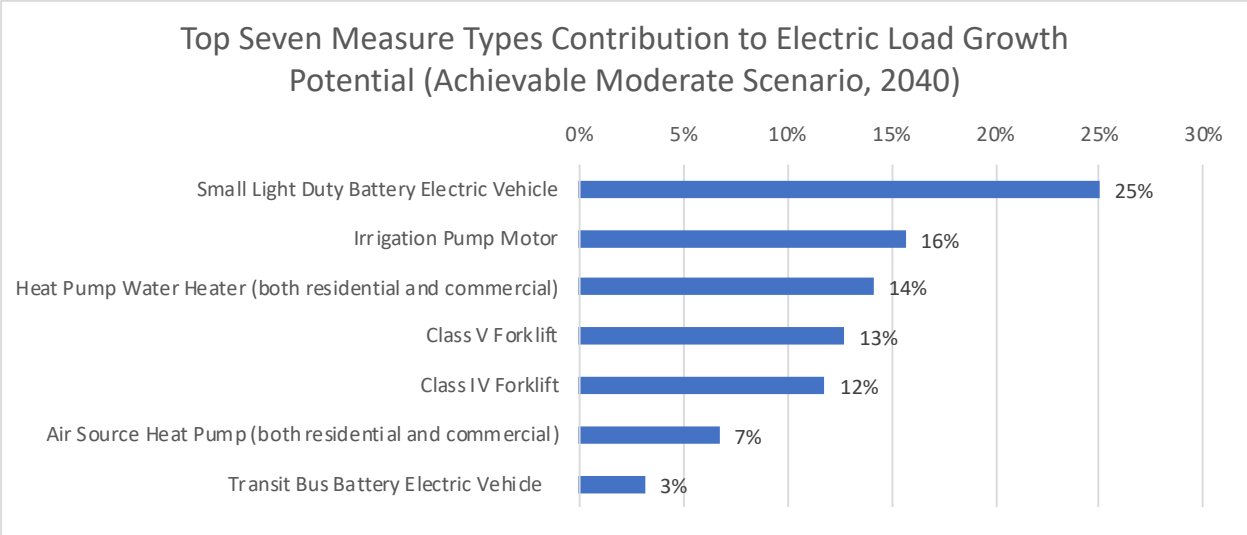
3. PORTFOLIO LEVEL BENEFICIAL ELECTRIFICATION POTENTIAL

3.1. Overview

The study finds that at the portfolio level, in the achievable-moderate scenario, Tri-State can achieve a cumulative reduction of nearly 6.5 million tons CO_2 emissions over the lifetimes of the measures through the electrification of fossil fuel equipment in their service territory. The emissions reduction corresponds to reduction in fossil fuel consumption of nearly 100 million therms (approximately 20 percent of the estimated current on-site natural gas demand in the territory) and an increase in annual electricity consumption of 652,583 MWh, which represents a 3 percent increase in Tri-State's overall load.

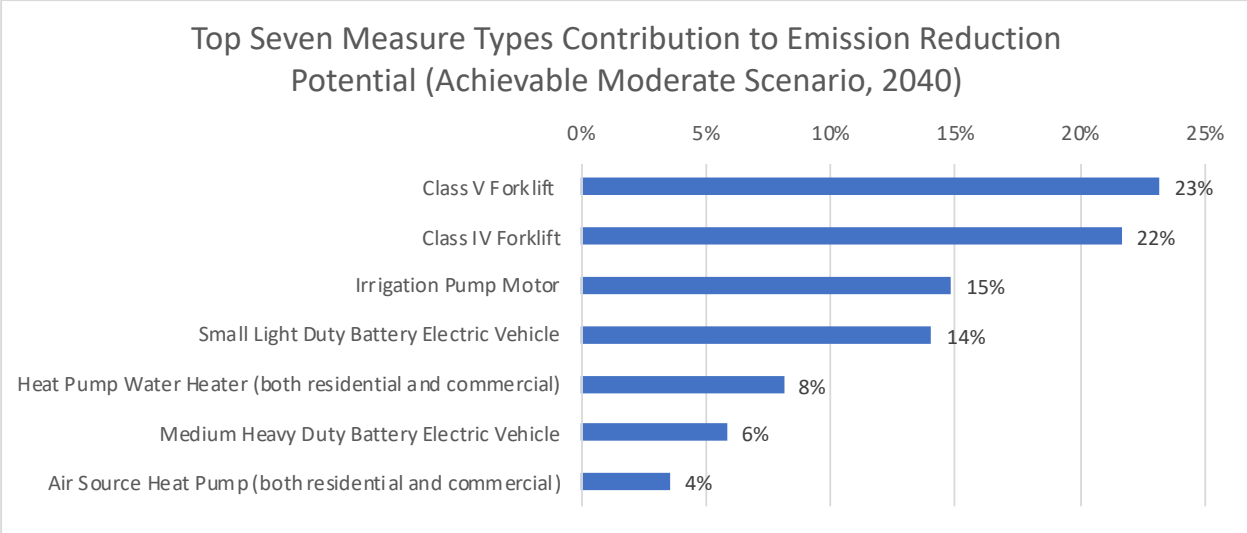
A set of seven measure types constitute nearly 90 percent of the potential load growth from electrification measures. Those seven measures are listed in Figure 5 in order of contribution to electric load growth potential:

Figure 5: Top Seven Measure Types Contribution to Electric Load Growth Potential (Achievable Moderate Scenario, 2040)



A set of seven somewhat overlapping measure types constitute over 90 percent of the cumulative lifetime emissions reduction potential by 2040. Those measure types are listed in Figure 6 in order of contribution to emissions reduction.

Figure 6: Top Seven Measure Types Contribution to Emission Reduction Potential (Achievable Moderate Scenario, 2040)



3.1. Load Growth Potential Results

Table 7 presents portfolio-level potential load growth by time horizon and Figure 7 shows the cumulative growth in electricity consumption potential through 2040. The Achievable-Moderate scenario estimates 2,376 MWh of load growth potential in 2021 rising to 651,520 MWh of cumulative

load growth potential through 2040. Pursuing an aggressive incentive approach (Achievable-Aggressive) could increase cumulative load growth potential by approximately 30 percent. The maximum achievable scenario increases load growth potential by another 23 percent over the aggressive scenario.

Table 7. Cumulative Electric Load Potential (MWh) by Scenario by Time Horizon

MILESTONE YEAR	TECHNICAL ELECTRIFICA-TION	BENEFICIAL ELECTRIFICA-TION	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021	52,033	5,487	4,875	3,485	2,524	1,957
2025	417,171	84,088	62,069	43,736	30,905	23,583
2030	1,674,758	474,237	278,910	207,716	144,792	105,867
2040	5,513,285	1,907,671	1,044,310	857,810	652,583	486,764

Figure 7. Portfolio Electric Load Added by Scenario by Year

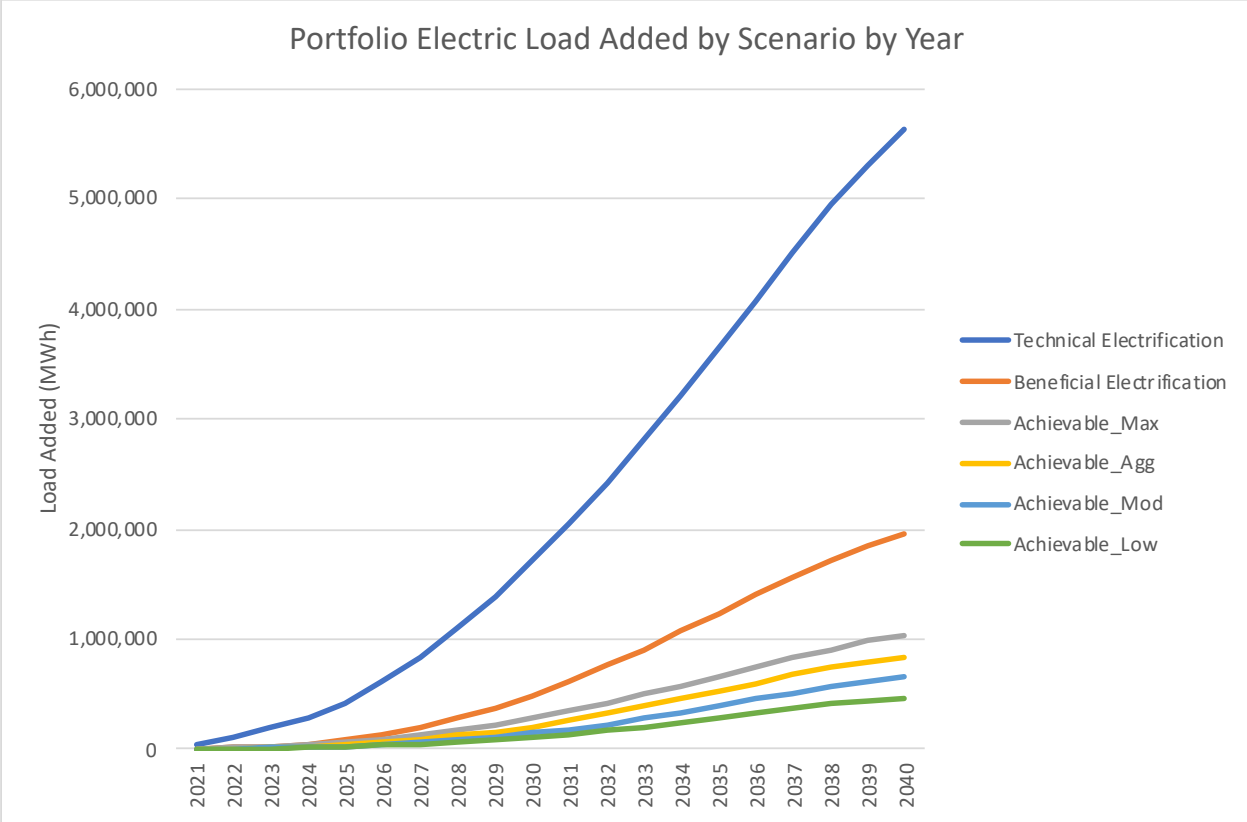


Table 8 shows the impacts of cumulative load growth potential on Tri-State's baseline energy consumption forecast. The cumulative growth associated with the Achievable Moderate scenario would increase Tri-State's baseline forecast consumption by approximately 0.02 percent in 2021. The increase

in baseline energy consumption would grow from 0.19 percent by 2025 to over 3 percent through 2040. The range of potential growth in baseline consumption across the achievable scenarios spans from 2.23 percent (Achievable-Low) to 4.94 percent (Achievable-Max) by 2040.

Table 8. Portfolio Cumulative Load Added as % of Baseline Forecast by Sector by Year

MILESTONE YEAR	TECHNICAL ELECTRIFICA-TION	BENEFICIAL ELECTRIFICA-TION	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	0.34%	0.04%	0.03%	0.02%	0.02%	0.01%
2025	2.54%	0.51%	0.38%	0.27%	0.19%	0.14%
2030	9.41%	2.66%	1.57%	1.17%	0.81%	0.59%
2040	26.19%	9.06%	4.96%	4.07%	3.10%	2.31%

Figure 8 shows the impact of the modeled scenarios on the baseline forecast. Each Achievable scenario would increase Tri-State's overall load growth to some degree. Capturing all technically possible electrification measures considered as part of this study would add over 25 percent to Tri-State's load by 2040.

Figure 8. Impact of Electric Load Added on Baseline Forecast by Scenario by Year

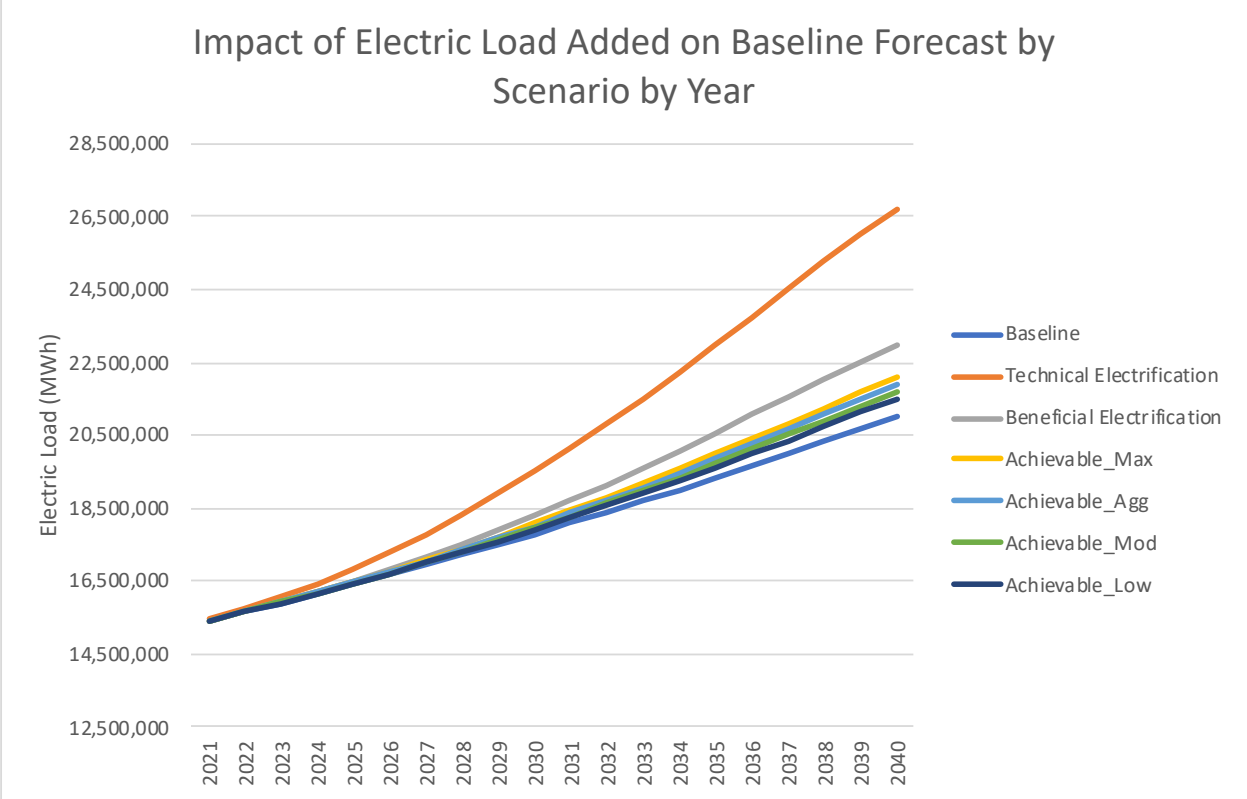


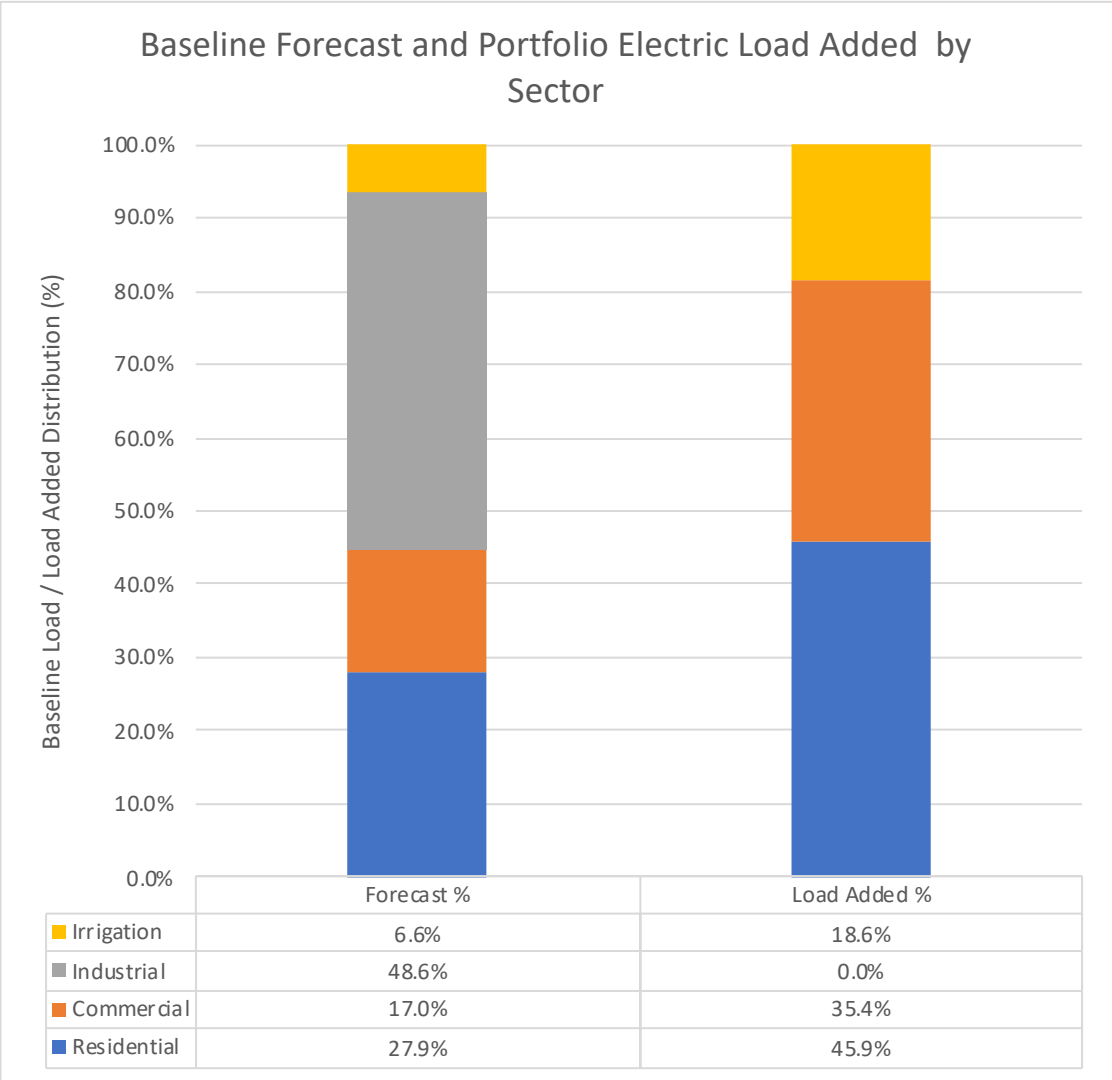
Table 9 presents energy load growth potential by region. Front Range Colorado represents the largest share making up over 42 percent of the total load growth potential. All Colorado regions combined account for nearly three quarters of the load growth potential. The two regions within New Mexico together comprise approximately 15 percent of total potential, while Wyoming accounts for approximately six percent of the total. Nebraska's growth potential is 5 percent of the total. This load growth potential is generally aligned with the distribution of forecast energy load by region. However, Eastern and Western Colorado make up a larger portion of load growth compared to their contribution to the baseline forecast. The outsized contribution to load growth by Eastern Colorado is due, in part, to irrigation pump motor electrification being a highly applicable measure in that region.

Table 9. Cumulative Load Added by Region, Achievable-Moderate Scenario (2040)

STATE / SUB-REGION	POTENTIAL LOAD ADDED (MWH)
Colorado	**460,432**
Eastern	*91,247*
Front Range	*271,902*
Mountain	*32,900*
Western	*64,383*
Wyoming	**38,076**
New Mexico	**118,503**
Northern	*70,475*
Southern	*48,028*
Nebraska	**35,571**
Total	**652,583**

As shown in Figure 9 the residential sector represents the largest opportunity for growth. The residential sector makes up over 45 percent of the total load growth potential, while only accounting for approximately 28 percent of the baseline load. Numerous measures are available to electrify residential energy end uses, with the most substantial growth potential coming from electric vehicles, as discussed further in Section 5. The commercial sector also holds substantial potential load growth at 36 percent of the total growth potential, which is larger than its 17 percent share of the baseline forecast energy consumption. Electric vehicles also contribute a large portion of the growth potential in the commercial sector, at roughly 80 percent of the sector's potential. The irrigation sector contributes less than 20 percent of the achievable electric load growth potential, however that contribution to potential load growth is nearly 3 times the sector's share of the baseline load. Electrification potential in the irrigation sector comes from irrigation pump motor electrification. While the industrial sector comprises nearly 50 percent of the baseline load, the study found no achievable electrification potential for the sector. The study considers pipeline transportation compressor station electrification, which contributes significantly to the technical potential scenario. However, that measure fails the beneficial electrification screen due to increased emissions from electrification over the entire study horizon. More information is presented on the irrigation and industrial sectors in Section 6 and Section 7.

Figure 9. Baseline Forecast and Portfolio Electric Load Added by Sector (2040)



	Forecast %	Load Added %
Irrigation	6.6%	18.6%
Industrial	48.6%	0.0%
Commercial	17.0%	35.4%
Residential	27.9%	45.9%

The portfolio of electrification measures can achieve a cumulative demand growth of 10.6 MW by 2040, as shown in Table 7. The residential sector accounts for the largest share of demand growth, followed by the commercial sector.

Table 10. Portfolio Cumulative Demand Growth Potential by Sector by Year (MW) (Achievable-Moderate Scenario)

MILESTONE YEAR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	IRRIGATION	TOTAL
2021	0.11	0.11	0.00	0.10	**0.31**
2025	0.48	0.44	0.00	0.25	**1.18**
2030	1.76	2.15	0.00	0.71	**4.61**
2040	6.25	2.69	0.00	1.64	**10.58**

Table 11 presents cumulative and average annual cost, added load, and TRC metrics associated with the Achievable-Moderate scenario. As shown, in the first year Tri-State can achieve 2,524 MWh of energy load growth at a cost of approximately $1.9 million, or $769/MWh. As programs expand and become more established annual costs and energy impacts increase substantially to reach a cumulative program expenditure of over $550 million by 2040 and load growth of 785,329 MWh. The 20-year average annual program costs are approximately $28 million and load growth is 39,266 MWh per year.

Table 11. Portfolio Cost Metrics by Time Horizon (Achievable-Moderate Scenario)

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	CUMULATIVE LOAD ADDED (MWH)	ACQUISTION COST ($/MWH)
2021	1.54	$1,941,462	2,524	$769.09
2025	1.61	$25,575,994	30,905	$827.56
2030	1.83	$121,866,050	146,004	$834.68
2040	2.37	$557,671,021	785,329	$710.11
20-year avg.	2.37	$27,883,551	39,266	$710.11

3.2. Emissions Reduction Results

Net lifetime emissions reductions represent the total negative emissions from implementing a measure minus any added emissions, typically in the early years of that measure's lifetime, if applicable. Due to the shift in Tri-State's fuel mix over time, several measures exhibit emissions increases over the associated fossil fuel equipment early in their measures lives and shift to emissions reductions later. An example of this is shown for a residential heat pump water heater measure in Figure 10. For this particular example, installing a new heat pump water heater in place of an existing natural gas water heater in 2021 nets an emissions increase in 2021, 2022, and 2023. Starting in 2024, the measure begins to exhibit an emissions benefit and continues that emissions reduction through its 12-year measure life.

Figure 10. Residential Water Heater Example Annual Emissions by Fuel Type by Year

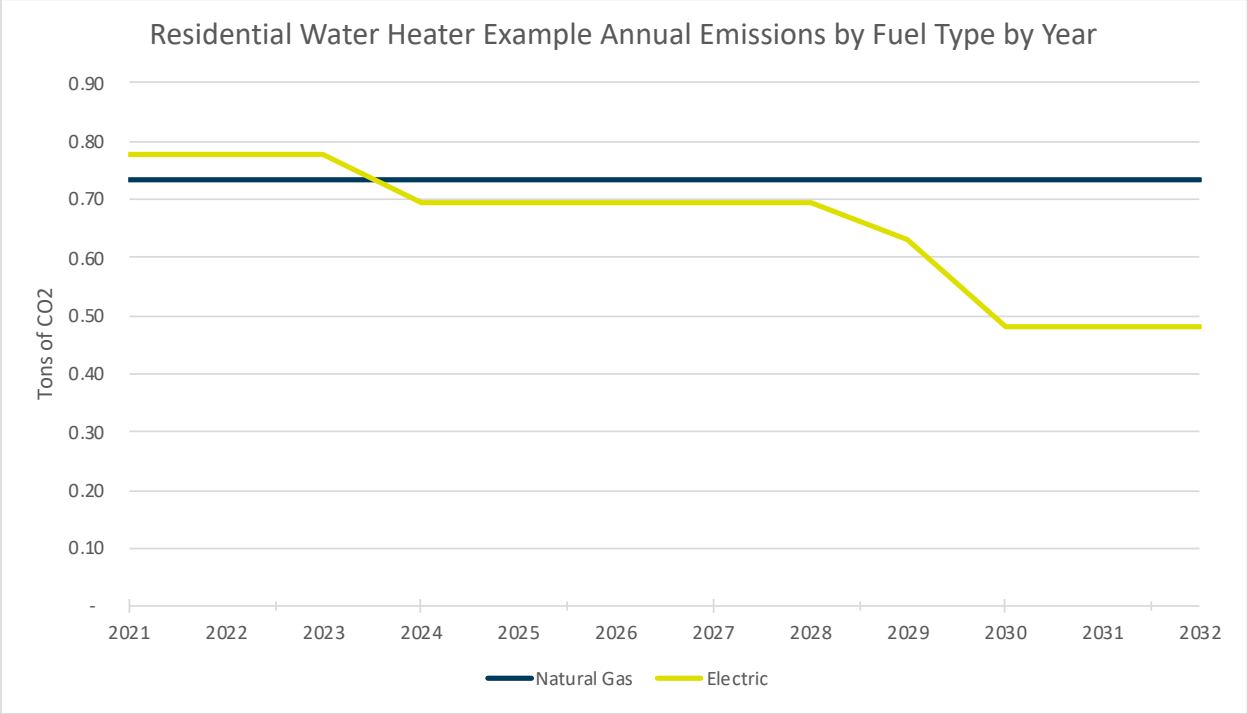


Table 12 shows cumulative net carbon emission reductions by scenario and by time horizon. Since the technical scenario captures all considered electrification measures, that scenario represents measures with lifetime emissions reductions as well as measures that increase emissions.

Table 12. Cumulative Lifetime Carbon Emission Reduction (tons CO_2) by Scenario by Time Horizon

MILESTONE YEAR	TECHNICAL ELECTRIFICA-TION	BENEFICIAL ELECTRIFICA-TION	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021	(152,135)	21,155	19,370	14,779	11,414	9,755
2025	(255,722)	393,851	301,303	227,915	175,668	147,926
2030	2,483,894	2,787,472	1,773,723	1,399,013	1,075,264	882,236
2040	23,254,798	16,006,011	9,489,083	7,811,346	6,417,877	5,389,333

Figure 11 show the contribution by region to cumulative lifetime emissions reduction in 2040. The bulk of emissions reduction potential is in the Front Range Colorado region.

Figure 11. Cumulative Lifetime Portfolio Carbon Emissions Reduction (Tons CO_2) by Region (2040)

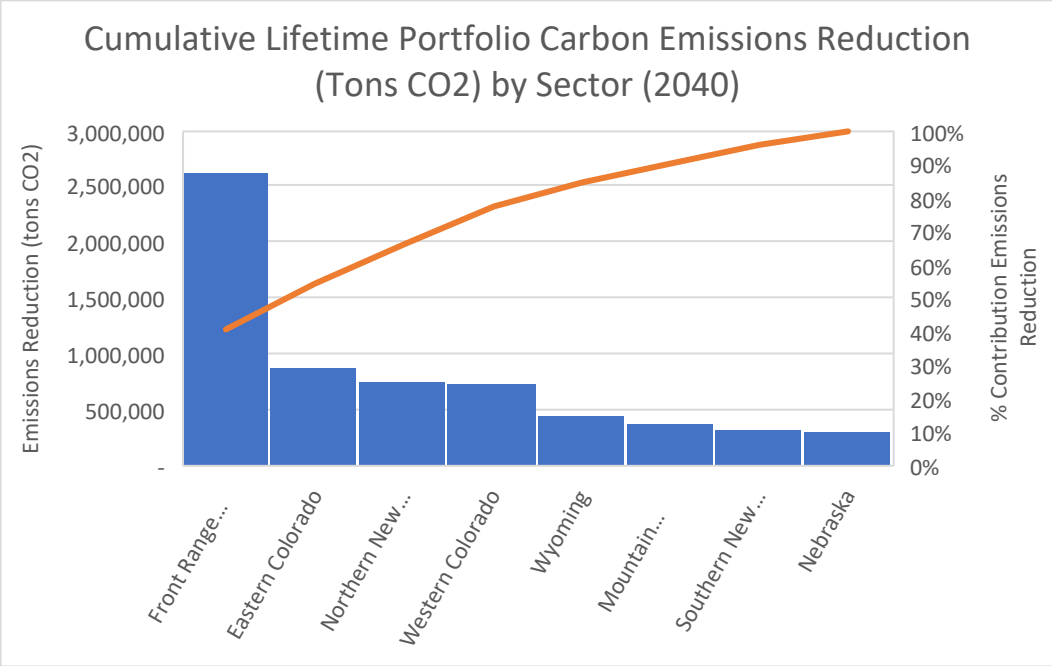
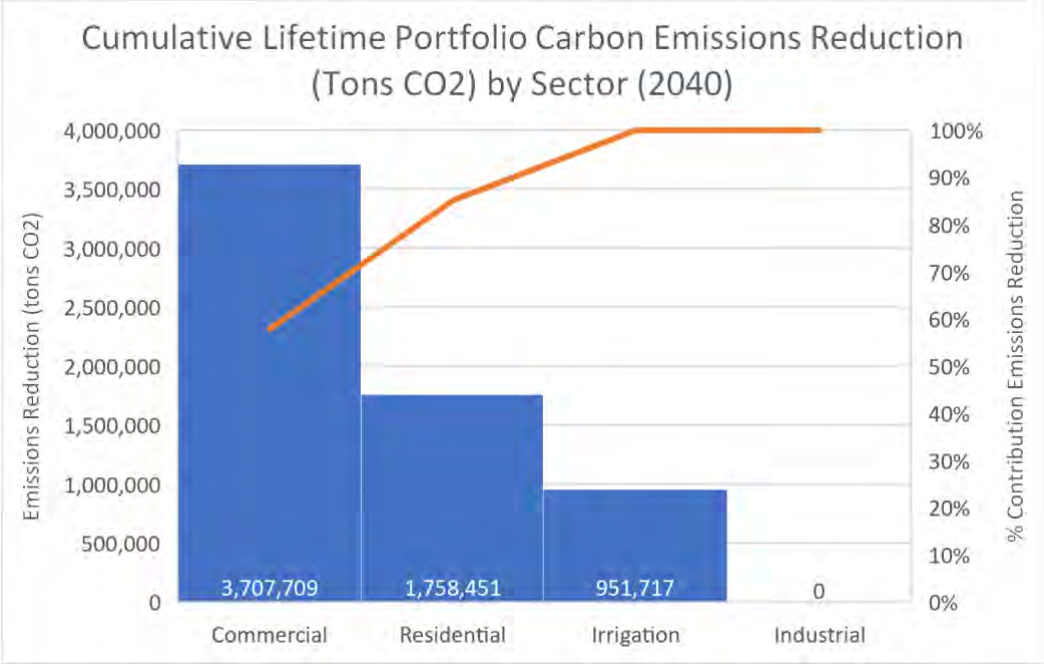


Figure 12 shows the contribution by sector to cumulative lifetime emissions reduction in 2040. The commercial sector makes up over 50 percent of achievable carbon emissions reduction.

Figure 12. Cumulative Lifetime Portfolio Carbon Emissions Reduction (Tons CO_2) by Sector (2040)



4. RESIDENTIAL BENEFICIAL ELECTRIFICATION POTENTIAL

4.1. Overview

The residential sector accounts for just under one-third of the total baseline forecast energy load, 46 percent of load growth potential, and 27 percent of projected cumulative emissions reduction. Cumulative electric load growth potential for this sector is estimated to be 299,757 MWh through 2040 (Achievable-Moderate scenario) with plug-in hybrids (28 percent) and battery electric vehicles (37 percent) making up nearly two-thirds of the total energy load growth potential. Space heating and water heating are also large components of the residential sector growth potential, contributing 12 percent and 21 percent respectively.

4.2. Detailed Results

Table 13 presents cumulative potential impacts for the residential sector by scenario at various milestones in the analysis period and Figure 13 shows the growth in cumulative added energy consumption potential through 2040. The Achievable-Moderate scenario estimates 1,054 MWh of load growth potential in 2021 rising to 299,757 MWh of cumulative load growth potential through 2040. Pursuing an aggressive incentive approach (Achievable-Aggressive scenario) could increase cumulative load growth potential by approximately 35 percent. The maximum achievable scenario estimates load growth potential approximately 20 percent higher than the aggressive scenario, equating to cumulative increase in electric consumption of an estimated 485,799 MWh through 2040. This equates to an increase of over 8 percent of forecasted sector level baseline sales.

In the achievable-moderate scenario, the residential sector is expected to provide a reduction in carbon emissions of nearly 1.8 million tons of CO_2 by 2040. The achievable-maximum scenario increases that number to nearly 3 million tons of CO_2 by 2040.

Table 13. Cumulative Residential Electrification Impacts

MILESTONE YEAR	TECHNICAL ELECTRIFICA-TION	BENEFICIAL ELECTRIFICA-TION	ACHIEVABLE _MAX	ACHIEVABLE _ AGG	ACHIEVABLE _MOD	ACHIEVABLE _ LOW
Cumulative Electric Energy Load Increase (MWh)						
2021	13,979	2,965	2,564	1,567	1,054	742
2025	191,341	41,765	29,152	17,874	11,201	7,562
2030	834,790	215,383	118,945	84,505	54,086	35,248
2040	2,955,794	844,564	485,799	405,492	299,757	209,016
Increase as % of Baseline Sales						
2021	0.31%	0.07%	0.06%	0.03%	0.02%	0.02%
2025	3.99%	0.87%	0.61%	0.37%	0.23%	0.16%
2030	16.28%	4.20%	2.32%	1.65%	1.05%	0.69%
2040	50.38%	14.39%	8.28%	6.91%	5.11%	3.56%
Net CO_2 Emissions Reduction (tons)						
2021	(2,379)	8,492	7,825	4,707	3,185	2,523
2025	146,329	145,341	102,932	62,499	39,652	29,474
2030	1,770,707	933,090	512,420	364,611	237,476	168,946
2040	11,476,214	4,841,494	2,939,543	2,357,711	1,758,451	1,346,869

Figure 13. Residential Annual Electric Consumption Added by Scenario by Year (MWh)

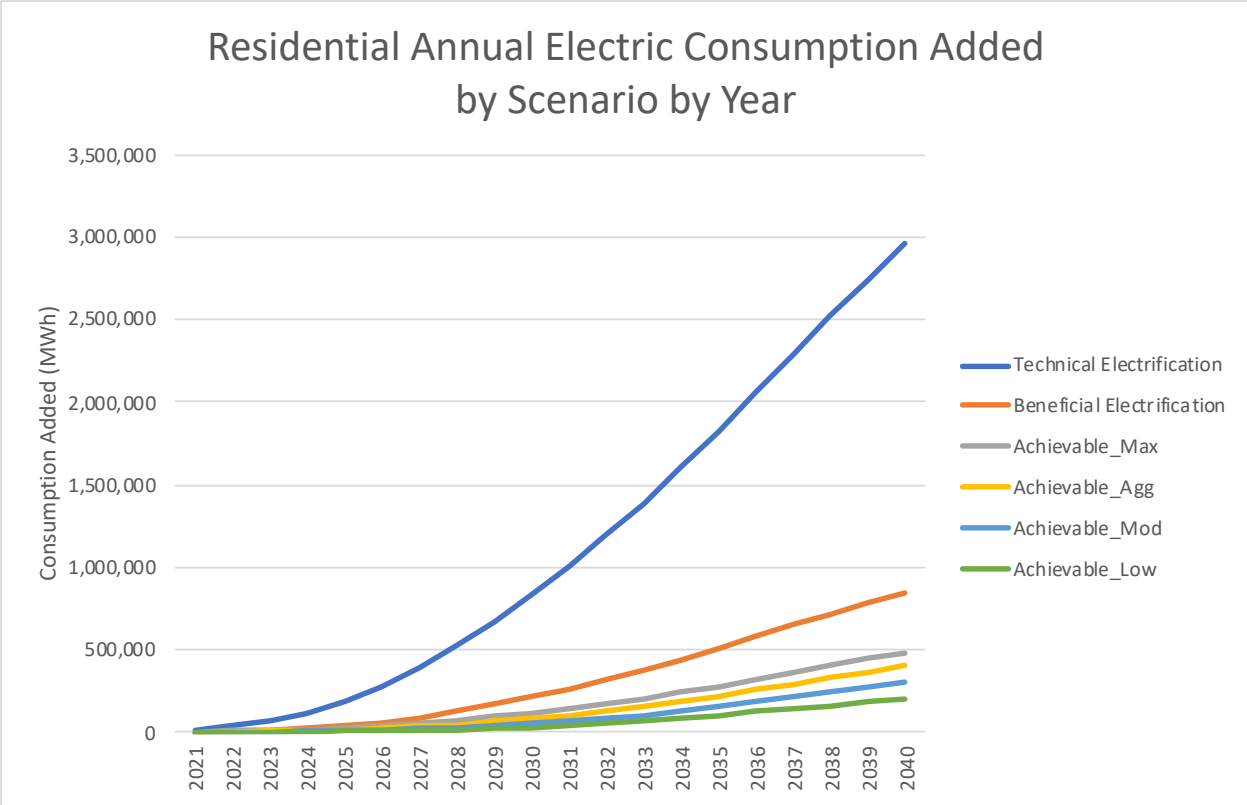
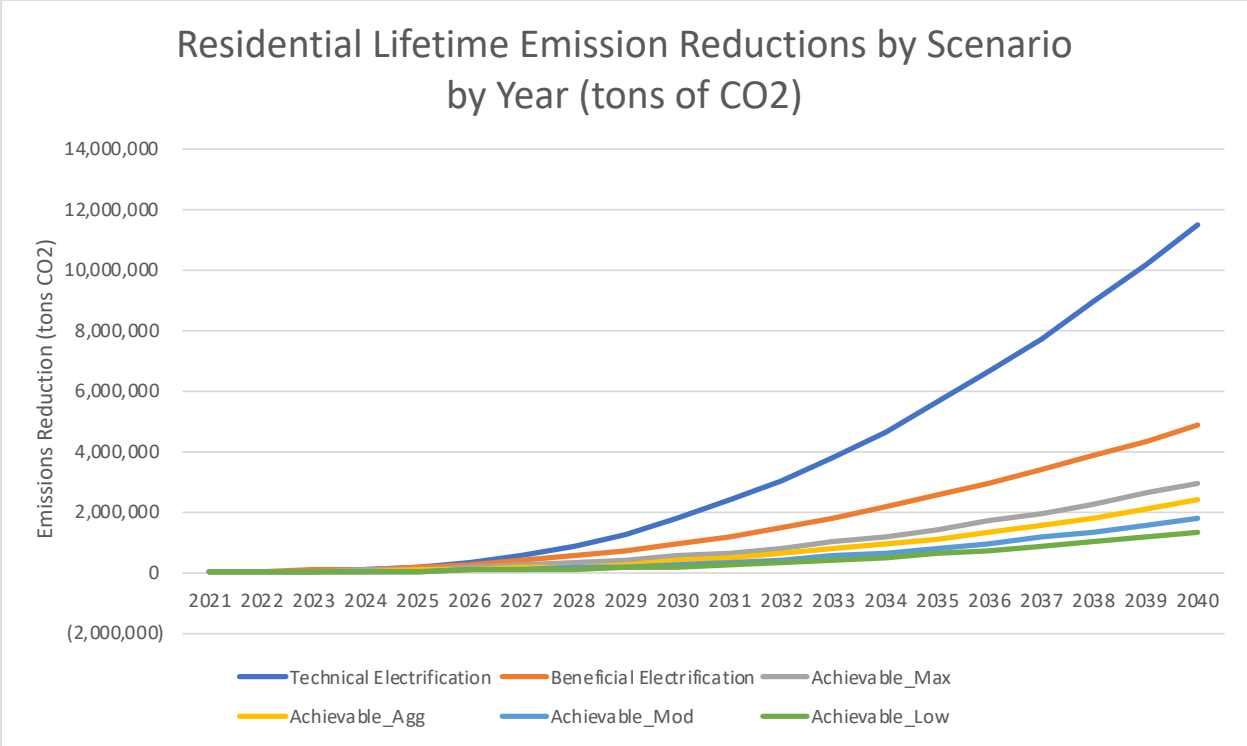


Figure 14 shows the estimated emissions reduction potential by scenario and by year. While in the technical electrification scenario, potential cumulative lifetime emissions reduction is estimated to increase to 11.5 million tons of CO_2 by 2040, the achievable-maximum scenario is estimated to net roughly one-quarter of that amount.

Figure 14. Residential Lifetime Emission Reduction by Scenario by Year (tons of CO_2)



As shown in Figure 15, electric vehicle measures make up approximately two-thirds of the potential electric load growth for the sector. The replacement of fossil fuel space heating equipment (boilers and furnaces) with heat pumps contributes 12 percent to the projected load growth, and heat pump water heaters contribute 21 percent. Less significant measures include electric and induction cooktops and battery-powered electric lawn and garden equipment, together contributing only about 2 percent to the overall project load growth by 2040.

Figure 15. Residential Electric Consumption Added Distribution by End Use

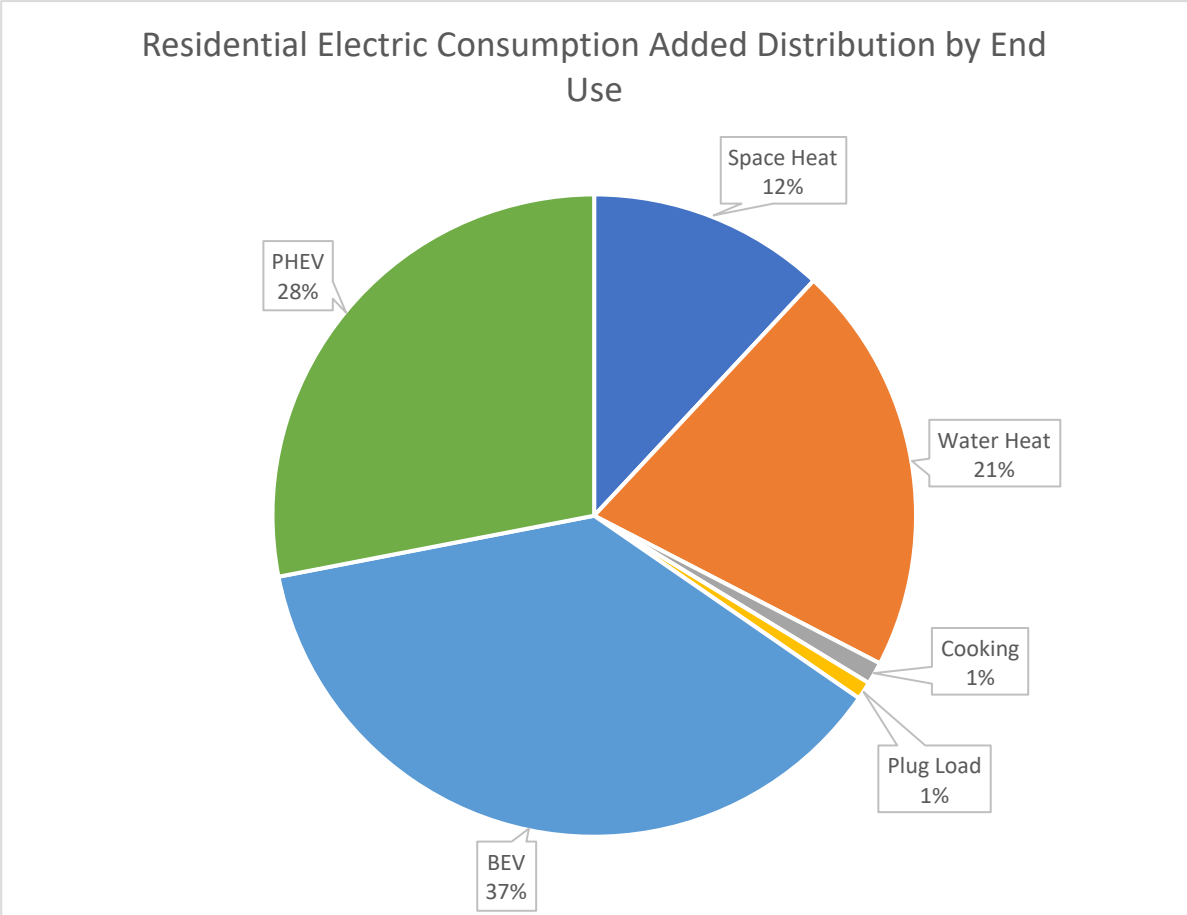


Table 14 presents cumulative program cost metrics by milestone year. As shown, first-year program costs are estimated at $1.4 million, rising to a 20-year average annual cost of approximately $18 million. Acquisition costs decline from $1,370/MWh in 2021 to $1,011/MWh in 2040. At the sector level all residential measures combine to produce TRC ratios of between 1.18 and 1.88 over the study horizon.

Table 14. Residential Sector Electrification Cost Metrics – Achievable-Moderate Scenario

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	CUMULATIVE ADDED CONSUMPTION (MWH)	ACQUISTION COST ($/MWH)
2021	1.18	$1,444,169	1,054	$1,370
2025	1.29	$14,335,776	11,201	$1,280
2030	1.47	$64,035,447	55,246	$1,159
2040	1.88	$368,948,548	365,013	$1,011
20-year avg.	1.88	$18,447,427	18,251	$1,011

5. COMMERCIAL BENEFICIAL ELECTRIFICATION POTENTIAL

5.1. Overview

The commercial sector accounts for 17 percent of the total baseline forecast energy load and accounts for 35 percent of cumulative energy load growth potential and 58 percent of potential emissions reduction by 2040. Cumulative electric load growth potential for this sector is approximately 231 GWh through 2040 (Achievable-Moderate scenario) with battery electric vehicle measures making up over 80 percent of that potential. Space heating and water heating make up the majority of the remaining potential contributing 7 percent and 12 percent of electric load growth, respectively. The Front Range Colorado region has the largest share of load growth potential in the sector at nearly half of the total. Apart from sector-wide EVs, which are applicable across all segments of the commercial sector, other segments with significant potential include restaurants, lodging, and healthcare facilities.

5.2. Detailed Results

Table 15 presents cumulative potential impacts for the commercial sector by scenario at various milestones in the analysis period and Figure 16 shows the growth in cumulative added energy consumption potential through 2040. Figure 17 shows the estimated reduction in carbon emissions by scenario and by year. The Achievable-Moderate scenario estimates 746 MWh of load growth potential in 2021 rising to 231,185 MWh of cumulative load growth potential through 2040. Pursuing an aggressive incentive approach (achievable-aggressive scenario) could increase cumulative load growth potential by approximately 12 percent. The maximum achievable scenario estimates load growth potential approximately 19 percent higher than the aggressive scenario, equating to cumulative increase in electric consumption of an estimated 305,767 MWh through 2040. This equates to an increase of nearly 9 percent of forecasted sector level baseline sales.

In the achievable-moderate scenario, the commercial sector is expected to provide a reduction in carbon emissions of over 3.7 million tons of CO_2 by 2040. The achievable-maximum scenario increases that number to nearly 4.6 million tons of CO_2 by 2040.

Table 15. Cumulative Commercial Electrification Impacts

MILESTONE YEAR	TECHNICAL ELECTRIFICA-TION	BENEFICIAL ELECTRIFICA-TION	ACHIEVABLE _MAX	ACHIEVABLE _ AGG	ACHIEVABLE _MOD	ACHIEVABLE _ LOW
Cumulative Electric Energy Load Increase (MWh)						
2021	1,878	1,179	1,071	917	746	646
2025	30,807	23,337	18,465	15,874	13,449	11,792
2030	186,910	143,038	89,968	77,797	65,650	56,362
2040	890,818	609,836	305,767	258,031	231,185	209,145
Increase as % of Baseline Sales						
2021	0.07%	0.04%	0.04%	0.03%	0.03%	0.02%
2025	1.08%	0.82%	0.65%	0.56%	0.47%	0.41%
2030	6.10%	4.67%	2.94%	2.54%	2.14%	1.84%
2040	24.94%	17.07%	8.56%	7.22%	6.47%	5.85%
Net CO_2 Emissions Reduction (tons)						
2021	7,545	6,302	5,667	5,329	4,798	4,540
2025	145,687	139,370	115,890	108,748	100,753	94,780
2030	1,187,433	1,048,762	780,597	723,429	667,686	617,881
2040	9,731,811	7,653,812	4,594,217	3,941,140	3,707,709	3,504,180

Figure 16. Commercial Annual Electric Consumption Added by Scenario by Year

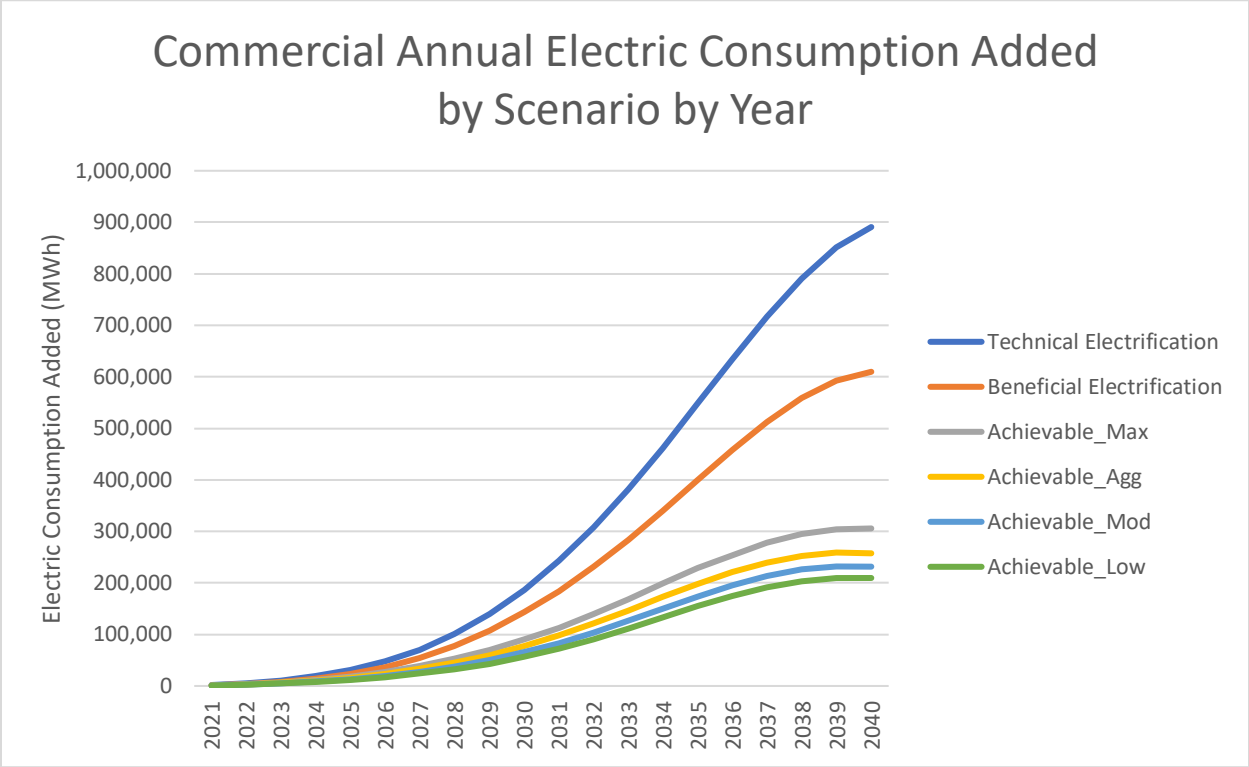
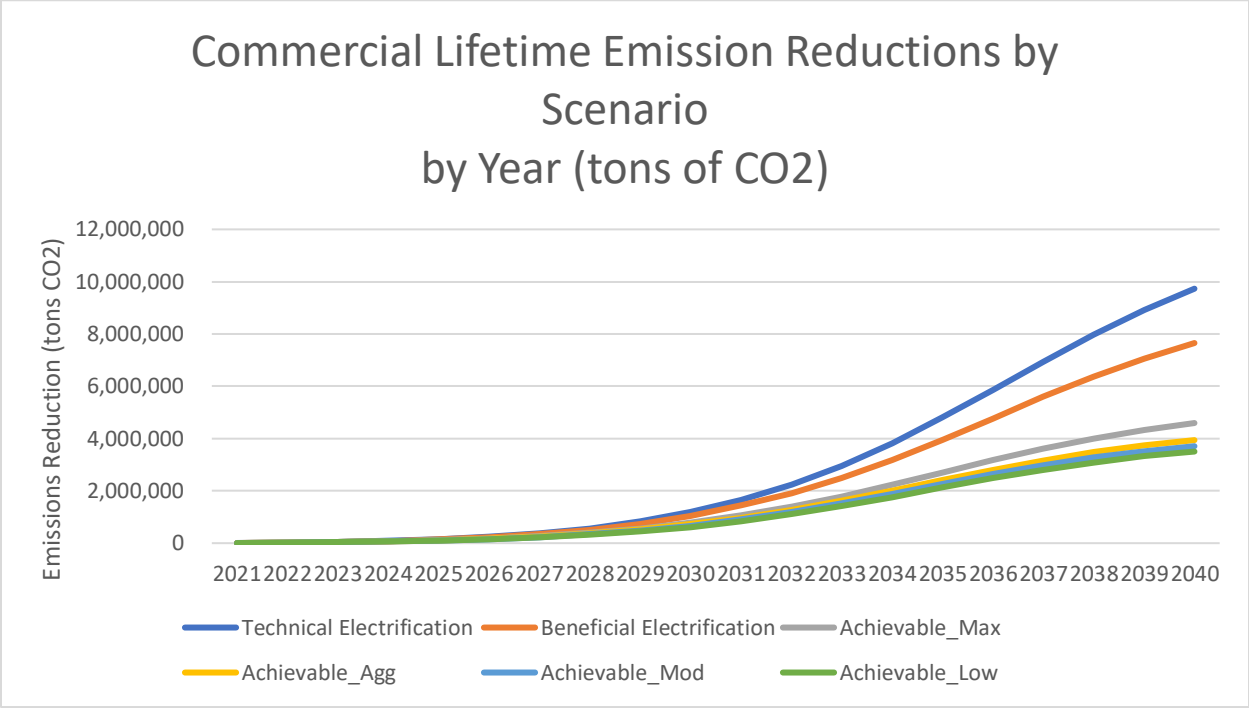


Figure 17. Commercial Lifetime Emission Reductions by Scenario by Year (tons of CO_2)



A large majority of both load growth and emissions reduction (over 80 percent in each case) in the commercial sector is attributable to electric vehicle measures. Figure 18 shows the potential increase in electricity consumption in the commercial sector broken down by end use. Apart from electric vehicles, the remaining 20 percent of load growth potential comes primarily from water heating (12 percent) and space heating (7 percent).

Figure 18. Commercial Electric Consumption Added Distribution by End Use

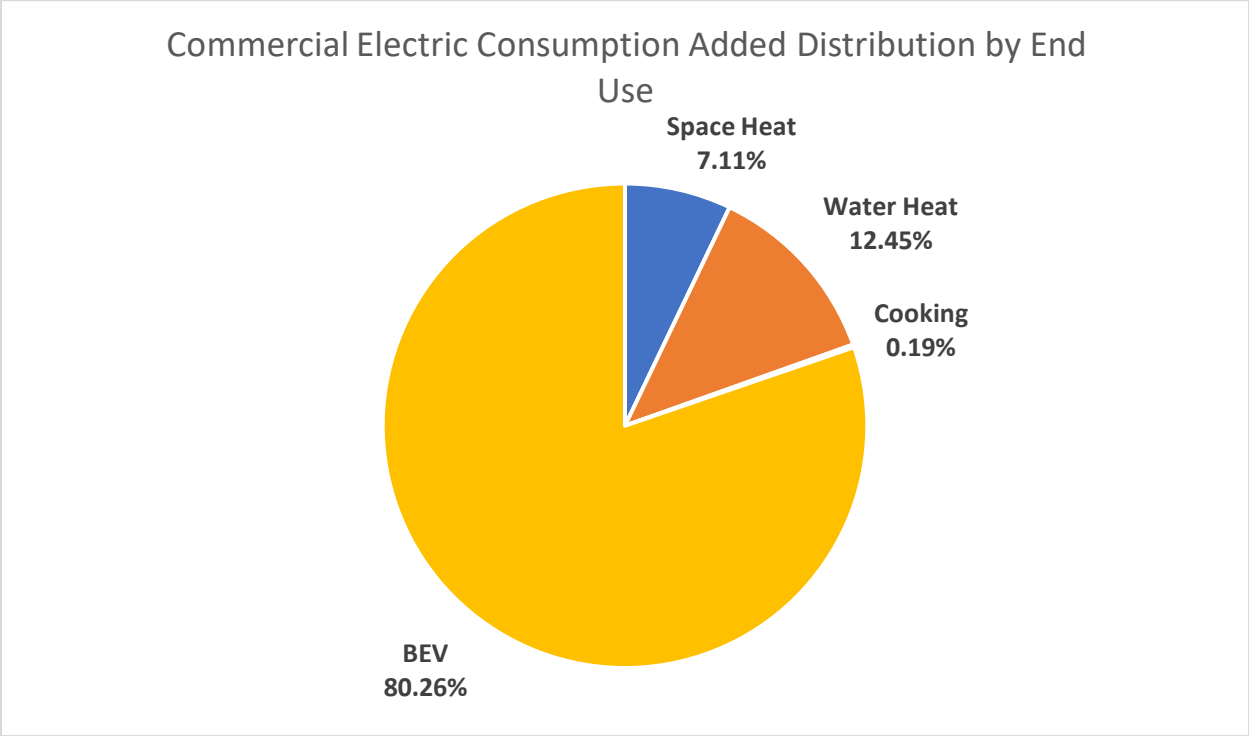


Figure 19 displays the breakdown of electric load growth potential by segment, excluding the sector-wide electric vehicle measures that constitute over 80 percent of the sector's potential. Of the remaining segments, restaurants, lodging, and health facilities contribute the largest shares of load growth potential accounting for 45 percent, 27 percent, and 11 percent of the non-EV potential in the sector, respectively.

Figure 19. Commercial Electric Consumption Added Distribution by Segment (excluding EVs)

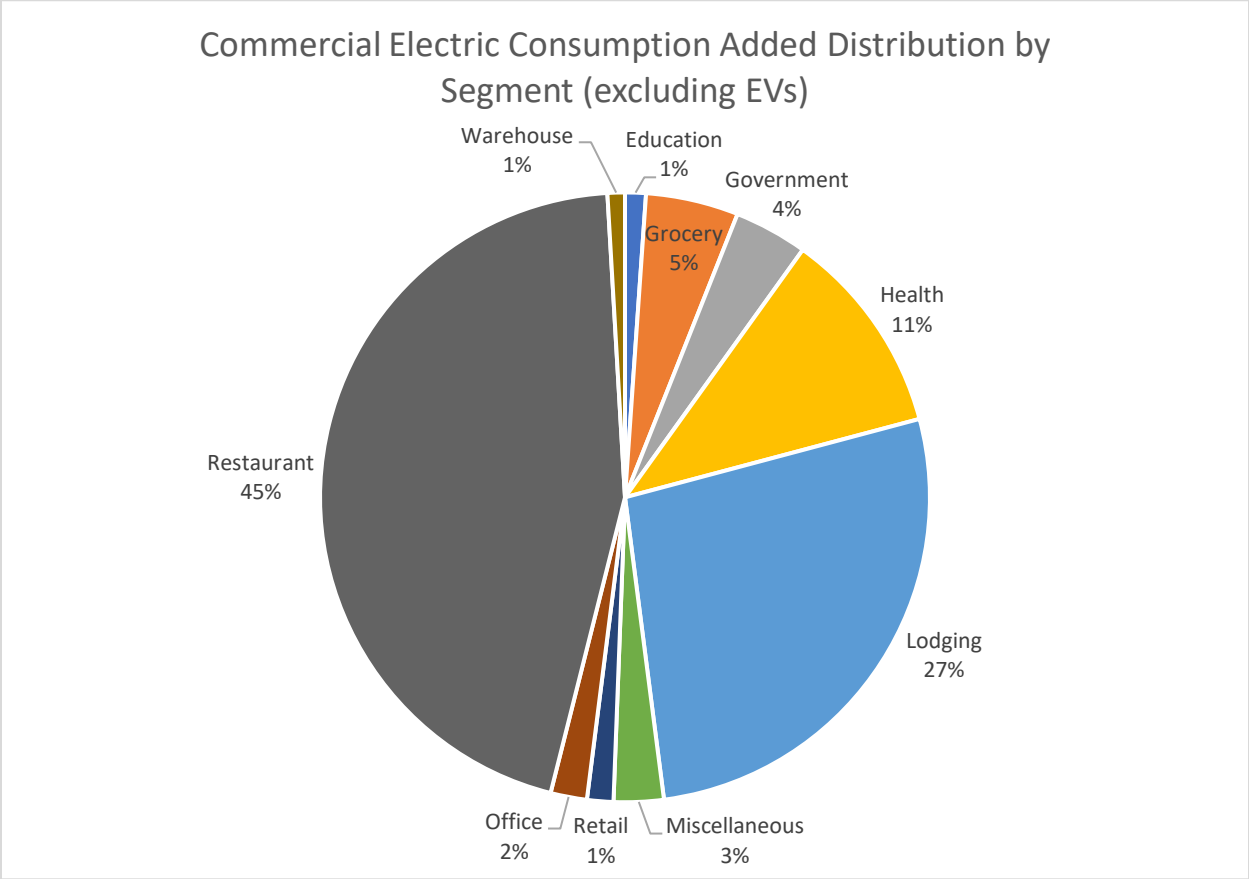


Table 16 presents cumulative program cost metrics by milestone year. As shown, first-year program costs are estimated at $409,700, rising to a 20-year average annual cost of approximately $8.7 million. Acquisition costs shift from $549/MWh in 2021, upward to $834/MWh by 2030, and back down to $585/MWh in 2040. At the sector level all commercial measures combine to produce TRC ratios of between 1.97 and 3.45 over the study horizon.

Table 16. Commercial Sector Electrification Cost Metrics – Achievable-Moderate Scenario

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	CUMULATIVE ADDED CONSUMPTION (MWH)	ACQUISTION COST ($/MWH)
2021	2.71	$409,700	746	$549
2025	1.97	$10,483,573	13,449	$779
2030	2.23	$54,797,334	65,703	$834
2040	3.45	$173,781,926	297,006	$585
20-year avg.	3.45	$8,689,096	14,850	$585

6. INDUSTRIAL BENEFICIAL ELECTRIFICATION POTENTIAL

6.1. Overview

The study analyzed pipeline transportation compressor station electrification to determine the impact of converting natural gas-powered compressor station motors to electric operation. There are estimated to be 68 compressor stations in the Tri-State service territory of which 10 currently operate electrically and 58 use natural gas. These stations have large motors with an average plant horsepower of nearly 15,000 HP. The measure was found to have large technical electrification impacts, having the ability to increase Tri-State's electric sales in the industrial sector by over 11 percent by 2040. This equates to over a 5 percent overall increase in forecasted energy consumption across Tri-State's service territory.

Compressor station electrification failed the BE screening process on the emissions reduction criteria. Many measures analyzed as part of this study passed the emission reduction screen due, in part, to an efficiency gain inherent in the equipment conversion. However, the motor efficiency in a natural gas compressor station represents a relatively small portion of the overall plant efficiency. The conversion from fossil fuel to electric motors improves the motor efficiency significantly, while the other components of compressor station plant efficiency remain unchanged through electrification. The study finds the impact of electrification in this application does not improve emissions reduction over the study horizon.

6.2. Detailed Results

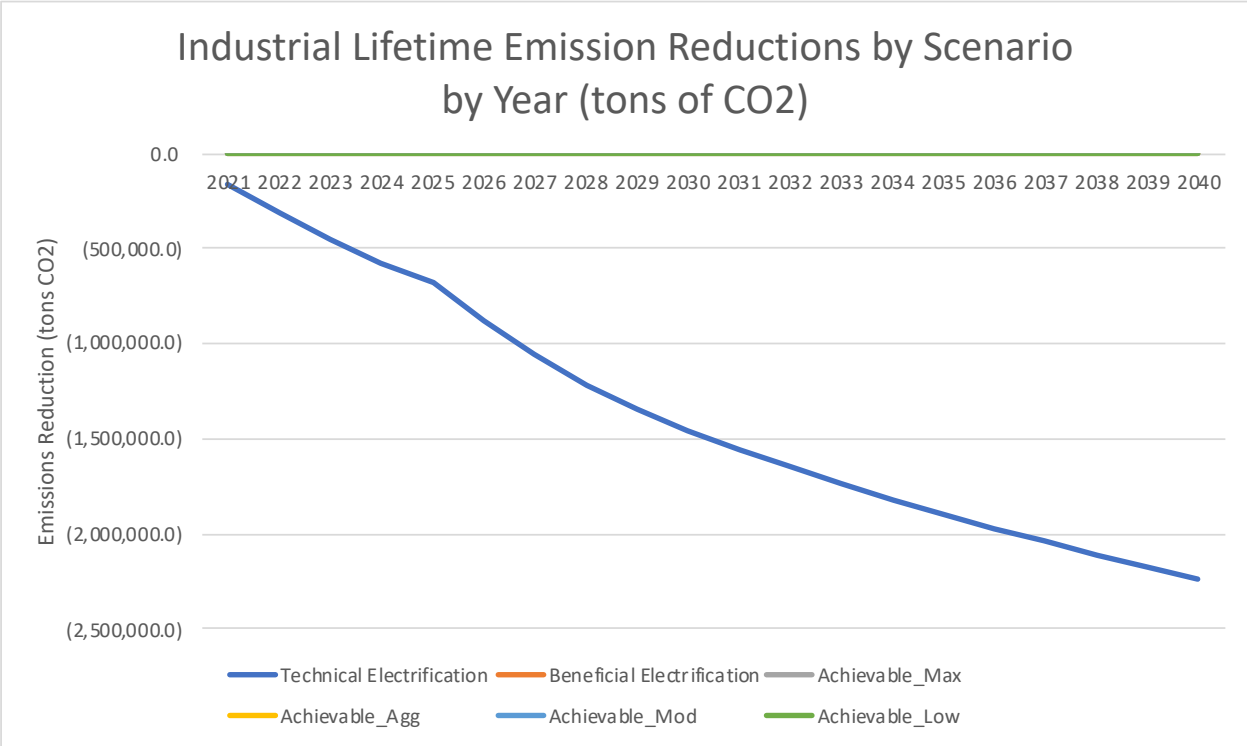
As shown in Table 17, converting natural gas-driven pipeline compressor stations to electrically-driven systems in Tri-State's service territory would add over 1.1 million MWh of cumulative electric consumption by 2040. However, in doing so, an additional 2.2 million tons of CO_2 would be emitted.

Table 17. Cumulative Industrial Electrification Impacts

MILESTONE YEAR	TECHNICAL ELECTRIFICA-TION	BENEFICIAL ELECTRIFICA-TION	ACHIEVABLE _MAX	ACHIEVABLE _ AGG	ACHIEVABLE _MOD	ACHIEVABLE _ LOW
Cumulative Electric Energy Load Increase (MWh)						
2021	34,632	0	0	0	0	0
2025	173,160	0	0	0	0	0
2030	519,480	0	0	0	0	0
2040	1,142,856	0	0	0	0	0
Increase as % of Baseline Sales						
2021	0.51%	0.00%	0.00%	0.00%	0.00%	0.00%
2025	2.33%	0.00%	0.00%	0.00%	0.00%	0.00%
2030	6.29%	0.00%	0.00%	0.00%	0.00%	0.00%
2040	11.17%	0.00%	0.00%	0.00%	0.00%	0.00%
Net CO_2 Emissions Reduction (tons)						
2021	(165,256)	0	0	0	0	0
2025	(682,616)	0	0	0	0	0
2030	(1,460,465)	0	0	0	0	0
2040	(2,238,896)	0	0	0	0	0

Figure 20 shows the negative emissions reduction (i.e. increased emissions) projected over the study horizon for the technical electrification scenario in the industrial sector.

Figure 20. Industrial Lifetime Emission Reductions by Scenario by Year (tons of CO_2)



7. IRRIGATION BENEFICIAL ELECTRIFICATION POTENTIAL

7.1. Overview

The irrigation sector represents approximately 8 percent of Tri-State's total baseline energy load and is projected to contribute nearly 15 percent of potential emissions reduction due to electrification. The study examined the electrification of irrigation pump motors, examining natural gas, propane, diesel, and gasoline baselines. Cumulative electric consumption growth potential for this sector is estimated at 121,641 MWh through 2040 (Achievable-Moderate scenario). Eastern Colorado represents the greatest potential for the sector, contributing nearly half of load growth and emissions reductions.

7.2. Detailed Results

Table 15 presents cumulative electric consumption growth potential for the irrigation sector by scenario at various milestones in the analysis period and Figure 25 shows the growth in cumulative electric consumption potential through 2040. The Achievable-Moderate scenario estimates 724 MWh of added consumption potential in 2021 rising to approximately 121,641 MWh of cumulative consumption growth potential through 2040. Pursuing an aggressive incentive approach (Achievable-Aggressive scenario) could increase cumulative electrification potential by approximately 50 percent. Energy consumption growth potential increases by an additional 30 percent under the maximum achievable

scenario, equating to a cumulative maximum achievable growth of approximately 252,744 MWh through 2040. This represents over 18 percent growth in the sector over the 20 year study horizon.

Table 18. Cumulative Irrigation Electrification Impacts

MILESTONE YEAR	TECHNICAL ELECTRIFICA-TION	BENEFICIAL ELECTRIFICA-TION	ACHIEVABLE _MAX	ACHIEVABLE _ AGG	ACHIEVABLE _MOD	ACHIEVABLE _ LOW
Cumulative Electric Energy Load Increase (MWh)						
2021	1,543	1,342	1,241	1,001	724	568
2025	21,863	18,986	14,452	9,988	6,255	4,229
2030	133,578	115,817	69,996	45,414	25,055	14,258
2040	523,817	453,271	252,744	194,288	121,641	68,604
Increase as % of Baseline Sales						
2021	0.12%	0.10%	0.09%	0.08%	0.06%	0.04%
2025	1.65%	1.43%	1.09%	0.75%	0.47%	0.32%
2030	9.95%	8.63%	5.21%	3.38%	1.87%	1.06%
2040	37.92%	32.82%	18.30%	14.07%	8.81%	4.97%
Net CO_2 Emissions Reduction (tons)						
2021	7,954	6,360	5,878	4,743	3,431	2,693
2025	134,877	109,139	82,480	56,669	35,263	23,671
2030	986,219	805,620	480,705	310,973	170,102	95,409
2040	4,285,669	3,510,706	1,955,323	1,512,496	951,717	538,284

Figure 21. Irrigation Annual Electric Consumption Added by Scenario by Year

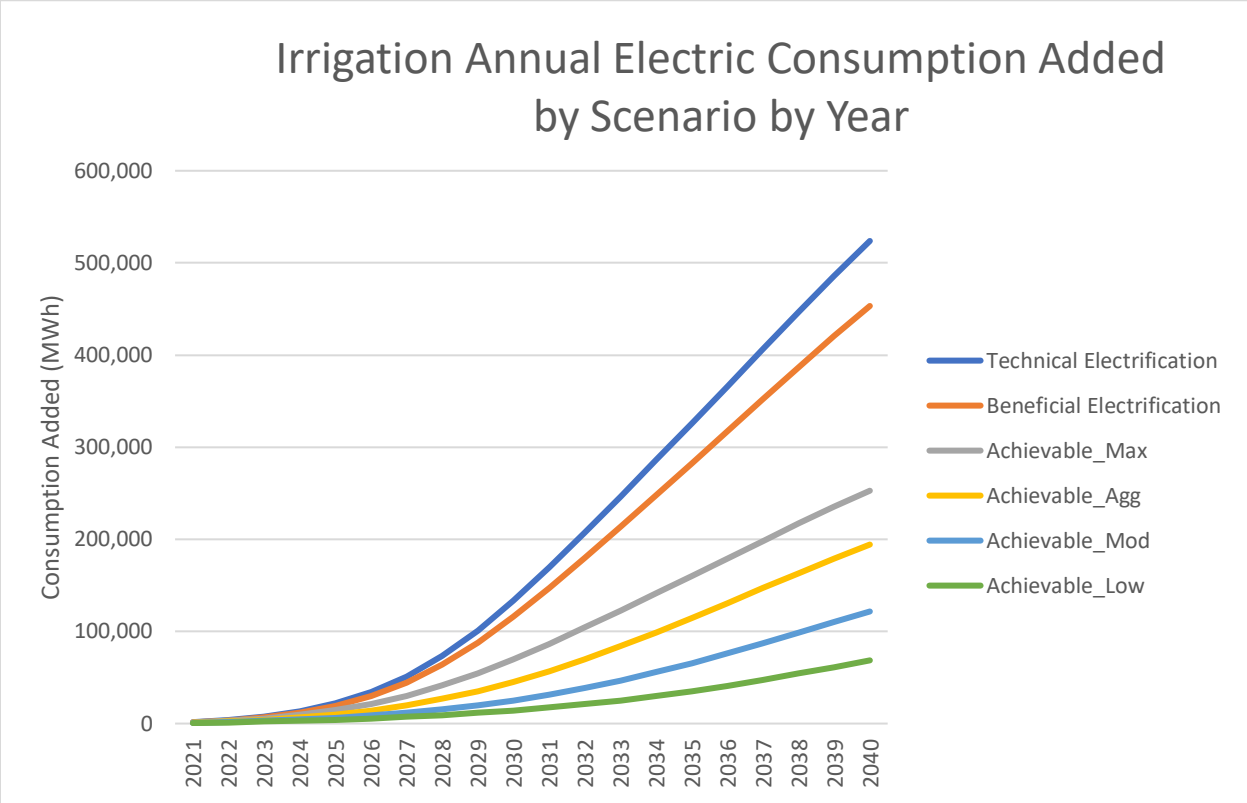


Figure 22 shows the net lifetime emissions reduction potential associated with irrigation electrification. The potential reduction in emissions for the sector approaches 1 million tons of CO_2 by 2040 in the achievable-moderate scenario.

Figure 22. Irrigation Lifetime Emission Reductions by Scenario by Year (tons of CO_2)

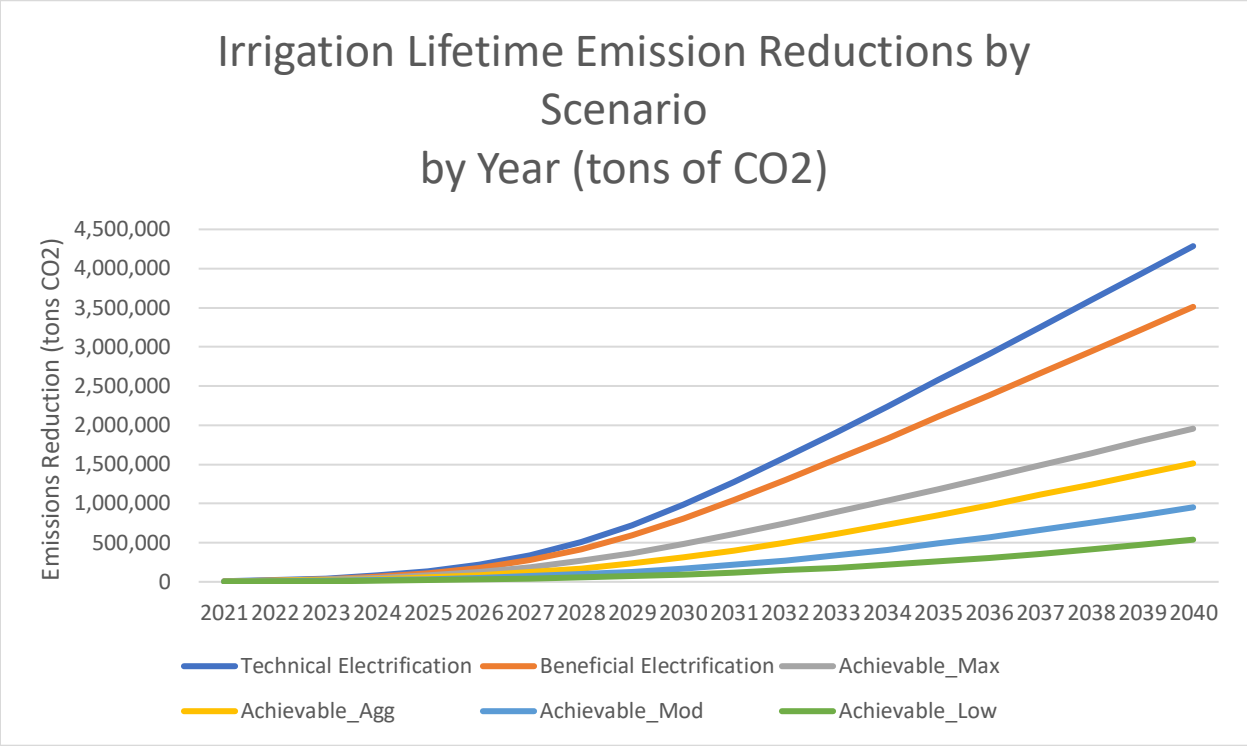


Figure 23 shows the projected breakdown of impacts on electricity consumption in the irrigation sector. Nearly half of the projected load growth is in the Eastern Colorado region, followed by approximately 20 percent contributed by Nebraska and 9 percent by Wyoming.

Figure 24 shows the breakdown of electric consumption impact by segment. In the case of the irrigation sector, and for the purposes of this study, segments refer to the fuel type associated with the baseline irrigation pump motor. The majority of potential comes from converting natural gas pump motors to electric (50 percent). Diesel pump conversions account for 37 percent, while propane pump conversions provide 13 percent of the project electric system growth for the sector.

Figure 23. Irrigation Electric Consumption Added Distribution by Region

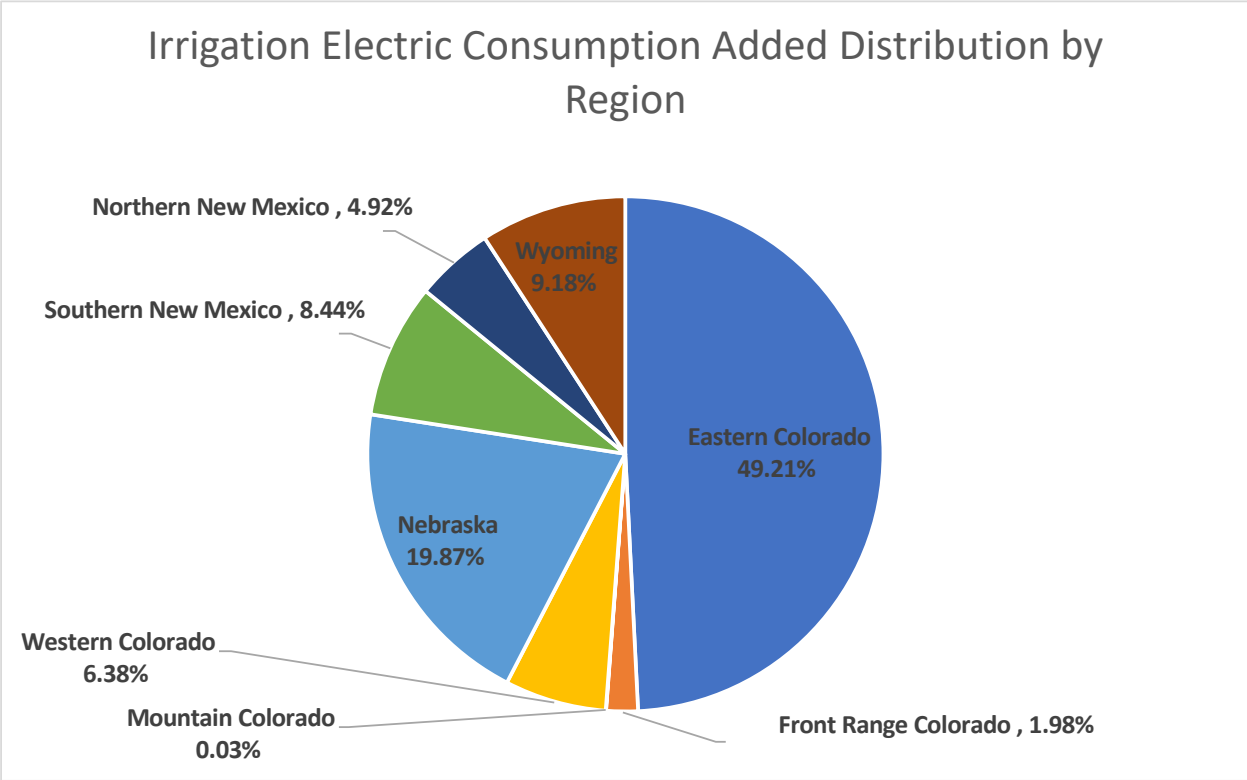


Figure 24. Irrigation Electric Consumption Added Distribution by Segment

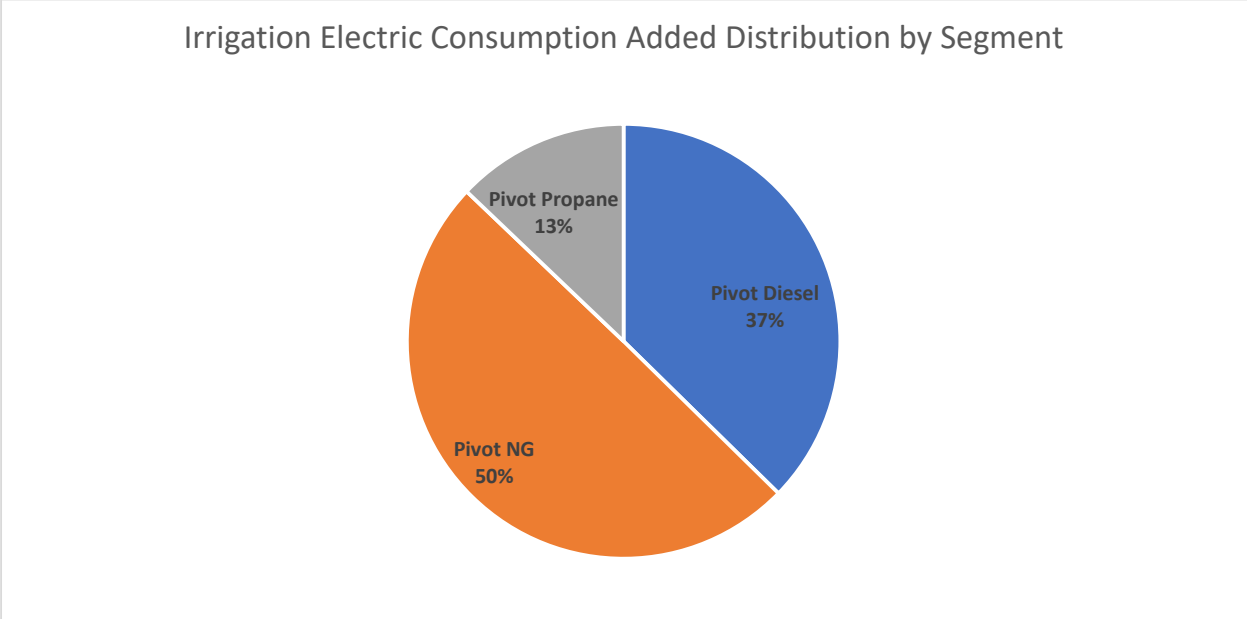


Table 19 presents cumulative and average annual costs, load growth, and TRC metrics associated with the Achievable-Moderate scenario for irrigation electrification measures. As shown, in the first year Tri-State can expect to see an increase in irrigation sector consumption of 724 MWh at a cost of approximately $87,593. As programs expand and become more established annual costs and load impacts increase substantially. The 20-year average annual program costs are approximately $747,027 and the impact on electricity consumption is 6,165 MWh.

Table 19. Irrigation Sector Electrification Cost Metrics – Achievable-Moderate Scenario

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	CUMULATIVE ADDED CONSUMPTION (MWH)	ACQUISTION COST ($/MWH)
2021	1.20	$87,593	724	$120.95
2025	1.19	$756,645	6,255	$120.97
2030	1.18	$3,033,269	25,055	$121.06
2040	1.18	$14,940,547	123,309	$121.16
20-year avg.	1.18	$747,027	6,165	$121.16

8. KEY FINDINGS AND RECOMMENDATIONS

There are several key findings related to this potential opportunity for Tri-State, some of which are detailed below:

- Over the 20-year period analyzed in this study, Tri-State has the opportunity to reduce carbon emissions in its service territory by over 6 million tons of CO_2 by undertaking the achievable moderate approach to beneficial electrification. This would equate to an associated growth in electricity consumption of over 650 GWh annually, over 3 percent of Tri-State's forecasted baseline load, and a reduction in fossil fuel consumption of nearly 100 million therms across all baseline fuel types. The fossil fuel reduction is estimated to be approximately 20 percent of the total on-site natural gas consumption in Tri-State's service territory.
- Low conversion is a challenge. The difference between the beneficial electrification scenario and the maximum achievable scenario is large, suggesting market adoption is a hurdle to BE potential. Tri-State may benefit from studying innovative ways to increase the saturation level of these beneficial electrification technologies such as implementation strategies, marketing techniques, educational programs, and other techniques.
- Because Tri-State's carbon emissions rate is expected to shift substantially over the study horizon, some measures analyzed result in increased emissions in the early years of their measure life, but provide an emission reduction over the fossil fuel baseline in later years. An example is provided in Figure 10 showing the net emissions by year for a residential water heater measure. Examining the same set of measures over different time horizons and with

different forecasted emissions factors would affect the resulting beneficial electrification potential.

- Equipment load side efficiency gains are integral to passing beneficial electrification screening. As end use efficiency improves, the benefits from electrification also increase. For example air-source heat pumps are much more efficient than electric resistance furnaces, and air-source heat pumps pass BE screening, whereas electric resistance furnaces would not pass under current or forecasted conditions.

- As Tri-State's system-wide emissions rate improves, electrification becomes more beneficial from an emissions reduction standpoint. To continue the example above, were the CO_2 emission rate from Tri-State's generation to approach a range between 0.20 and 0.27 tons/MWh, electric resistance space heating measures would begin to exhibit reduced emissions compared to a fossil fuel baseline. Currently, Tri-State's emission rate is projected to be 0.34 tons/MWh at its lowest over the 20-year study horizon.

- Most measures that passed the beneficial electrification screening also had favorable TRC scores. Even including measures that passed the BE screening, but didn't pass the TRC test, the overall TRC at the portfolio level, and at each sector level, passed at a TRC threshold of 1.0.

- At the measure level, a small number of measures passed BE screening but had TRC scores less than 1. These include electric lawnmowers and leaf blowers, airport bag tractors and pushback tractors, and some permutations of on-road electric vehicles. However, the large majority of measures that exhibit a PCT score greater than 1 also exhibited a TRC score greater than 1. These details can be explored at the measure level in the electronic reporting tool associated with this report.

- When designing traditional DSM programs, energy efficiency measure incentives are often established based on a percentage of the estimated incremental cost of the measure. With BE measures, however, the cost of the electric version of a particular technology is often similar to or lower than the fossil fuel option. Because direct customer incentives are a proven method for driving market adoption of a particular technology, alternative approaches to establishing those incentives may be required for certain measures, such as setting incentives at a percentage of the full measure cost. Additional barriers to adoption may include lack of awareness of electric alternatives to fossil fuel technologies or hesitation to adopt an electric alternative due to lack of knowledge of their operation and reliability. Careful consideration should be taken by Tri-State with respect to the balance between direct customer incentive payments and marketing and outreach efforts.

- There is a large amount of usage in natural gas compressor stations and other pipeline pumping operations but these measures do not pass BE screening at any projected emissions rate. Based upon the Team's calculations, the average electricity consumption of compressor station plants (on an energy per horsepower basis) in the service territory does not represent a significant enough improvement over the natural gas consumption (on an energy per horsepower basis) to result in a net emissions reduction.

- Battery electric vehicles and plug-in hybrid electric vehicles represent the largest opportunity for Tri-State to reduce emissions in the service-territory while increasing electric load on the grid.

- Small light-duty battery-powered electric vehicles provide the largest opportunity for load growth for Tri-State and exhibit a TRC score greater than 3. Of the seven largest contributors to load growth potential, forklifts provide the highest TRC score, greater than 7 for both classes of forklifts.

APPENDIX A. MODELED ELECTRIFICATION MEASURES

A variety of measures were analyzed for input into the beneficial electrification potential model. This Appendix provides additional detail on the measure permutations, energy impacts calculation approach, and resources relevant to each measure.

Electric Lawn and Garden Equipment

The study analyzed several residential lawn and garden measures, including battery-powered:

- Lawnmowers
- Leaf blowers
- Snow blowers
- Chainsaws
- Trimmers, edgers, and brush cutters

Average annual fossil fuel energy consumption for these pieces of equipment was calculated using average equipment horsepower, average annual hours of operation, and brake-specific fuel consumption (BSFC) in gallons per horsepower-hour. Electricity consumption from a battery-powered electric analog was calculated using the output energy estimated for the fossil fuel equipment and applying factors to account for DC/DC roundtrip battery efficiency from charge and discharge cycles, as well as power conversion system efficiency to convert AC to DC at the charger.

Information on average run times, horsepower, and BSFC was drawn from a technical paper associated with the Environmental Protection Agency titled *National Emissions from Lawn and Garden Equipment*[19]. Battery efficiency characteristics were sources from a U.S. DOE paper titled *Energy Storage Technology and Cost Characterization Report*[20].

Heat Pump Water Heating

The study analyzed the conversion of natural gas and propane water heaters to electric heat pump water heaters in the residential sector and applicable segments of the commercial sector. Measures included installation in locations with and without DX cooling and considered the interactive effects on space heating and cooling. Baseline fossil fuel and proposed electricity consumption was calculated adapted from methodologies in Xcel Energy's 2019/2020 DSM Plan's Technical Reference Manual

[19] Banks, J. L., PhD, MS, & McConnell, R. (n.d.). *National Emissions from Lawn and Garden Equipment* (Tech.).

[20] U.S. Department of Energy. (2019, July). *Energy Storage Technology and Cost Characterization Report*. https://www.energy.gov/sites/prod/files/2019/07/f65/Storage%20Cost%20and%20Performance%20Characterization%20Report_Final.pdf

appendix[21]. The calculations relied on inputs including average gallons per day of hot water demand, storage temperature, supply water temperature, draw pattern, and energy factor.

Heat Pump Space Heating

The study analyzed the conversion of natural gas and propane furnaces and boilers to air-source heat pumps in the residential sector and applicable segments of the commercial sector. Measures included installation in locations with and without existing DX cooling and with and without existing ductwork (in the case of a fossil fuel boiler baseline). Baseline fossil fuel and proposed electricity consumption was calculated based on methodologies from Xcel Energy's 2019/2020 DSM Plan's Technical Reference Manual appendix[21]. The calculations relied on inputs including system capacity, baseline fossil fuel efficiency, baseline cooling SEER (if applicable), proposed SEER and HSPF, and heating and cooling equivalent full load hours.

For systems being installed where no ductwork currently exists, the full cost of installing ductwork was taken into account for measure cost estimation.

Electric Cooking

Converting natural gas cooktops to electric resistance and induction type cooktops was analyzed for both the residential and applicable segments of the commercial sector. For residential applications, the Team utilized average annual consumption figures drawn from an Electric Power Research Institute (EPRI) white paper, *Induction Cooking Technology Design and Assessment*[22], for gas, electric, and induction type cooktops. For commercial applications, the Team utilized a methodology from the Minnesota Technical Reference Manual, version 3.0 along with inputs from a D.O.E. Building Technologies Office paper[23], *Energy Savings Potential and Research, Development, & Demonstration Opportunities for Commercial Building Appliances*[24].

Oil and Gas Pipeline Transportation Compressor Stations

The study analyzed the electrification potential for natural gas (or other) pipeline transportation compressor stations in the Tri-State territory. The Team drew from an ArcGIS data set published by the Department of Homeland Security to identify counts of natural gas-driven and electrically-driven

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[21] Public Service Company of Colorado. (2019, April 18). *2019/2020 Demand-Side Management Plan Electric and Natural Gas*. Xcel Energy. https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/DSM-Plan.pdf

[22] Electric Power Research Institute (EPRI), Sweeney, M., Dols, J., Fortenbery, B., & Sharp, F. (2014). Induction Cooking Technology Design and Assessment. ACEEE Summer Study on Energy Efficiency in Buildings. https://www.aceee.org/files/proceedings/2014/data/papers/9-702.pdf

[23] Minnesota Commerce Department. (2019, January). State of Minnesota Technical Reference Manual for Energy Conservation Improvement Programs. https://mn.gov/commerce-stat/pdfs/mn-trm-v3.0.pdf

[24] Navigant Consulting, Inc. (2009, December). Energy Savings Potential and RD&D Opportunities for Commercial Building Appliances. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Building Technologies Office. https://www.energy.gov/sites/prod/files/2014/07/f17/commercial_appliance_research_opportunities.pdf

compressor stations in the service territory[25]. There are approximately 68 stations in the region, 10 of which currently operate off of electricity. Data was drawn from the data set to estimate the average annual consumption per horsepower, in natural gas or electricity, for the specific plants in the territory. That data was used, along with average plant total horsepower, to establish the annual consumption by fuel type for these large plants. Cost data was also available from this resource.

Irrigation Pumping Electrification

To identify fossil fuel consumption and electricity consumption for the relevant types of irrigation pump motors, the Team drew from a University of Nebraska report on energy use in irrigation pumping[26]. The resource identified typical water-horsepower-hours per fuel unit which was used to determine average therms of natural gas, propane, diesel, and gasoline per water-horsepower-hour. To determine average pump motor runtime, the Team analyzed Tri-State-specific consumption data for irrigation accounts in each region to determine an average pump run time by region. The therms per water-horsepower-hour values were multiplied by the regional pumping hours figures, as well as by the stipulated horsepower determined by the measure definition, to determine fossil fuel baseline consumption. A kWh per water-horsepower-hour value was used similarly to determine the electricity consumption in the proposed case.

On-road vehicles

The potential study defined on-road vehicle measures based on gross vehicle weight rating (GVWR) according the Federal Highway Administration classification system:

- Light-duty vehicles – GVWR <10,000 pounds
- Medium-duty vehicles – GVWR 10,001 – 26,000 pounds
- Heavy-duty vehicles – GVWR >26,001 pounds

Light-duty vehicles represented the largest sample of analyzed vehicles, and the team stratified light-duty vehicles as small, medium, large passenger vehicles and light-duty trucks. These strata are approximate to vehicle Class 1 (small and medium light-duty vehicles) and Class 2a (large light-duty vehicles and light-duty trucks). Medium-duty vehicles are represented as delivery step vans for the purpose of this potential study. Finally, heavy-duty vehicles are represented as school bus and transit bus vehicles.

[25] U.S. Department of Homeland Security, Homeland Infrastructure Foundation-Level Data (HIFLD). (2019, July 31). Natural Gas Compressor Stations [Dataset]. ArcGIS. https://hifld-geoplatform.opendata.arcgis.com/datasets/natural-gas-compressor-stations/data?selectedAttribute=ELEC_COMPR

[26] University of Nebraska Haskell Agricultural Laboratory, Kranz, W. L., Martin, D. L., Dorn, T. W., Melvin, S. R., & Corr, A. J. (2011, February). Evaluating Energy Use for Pumping Irrigation Water. Proceedings of the 23rd Annual Central Plains Irrigation Conference, Burlington, CO. https://www.ksre.k-state.edu/irrigate/oow/p11/Kranz11a.pdf

Off-road vehicles

Airport Ground Support Equipment

Airports are serviced by various forms of ground support equipment (GSE) to assist in air travel operations. Among the various GSE, the team reviewed the following technologies as opportunities for electrification:

- Pushbacks
- Tow tractors
- Belt loaders

These three GSE are typically operated as ICE vehicles; however, the aviation industry has begun adopting electric counterparts for these GSE over the past decade. The transition has been gradual with market estimates of approximately 10 percent electric GSE market saturation.

Electric Forklifts

Forklifts are categorized based on multiple classes that span Class I through Class VII with each class forklift intended for specific abilities and operation in specific environments. Class IV and V forklifts are most prevalently ICE vehicles. However, research conducted by EPRI[27] on behalf of Tri-State found the market offers electric equivalent forklift models for all class IV forklifts and 80 percent electric equivalent forklift models for class V forklifts. Class IV forklifts are characterized as counterbalanced with cushioned or solid tires designed for indoor usage whereas and Class V forklifts are characterized as counterbalanced with pneumatic tires intended for outdoor usage.

Electric Parking Space Infrastructure: *Truck Stop Electrification*

Electric parking space technologies considered in this analysis included truck stop electrification (TSE) and electric transport refrigeration units (eTRU). These systems allow truck drivers to shut down their diesel engines while at truck stops by relying on electricity rather than the truck's engine to provide power for necessities such as cab plug loads or HVAC as well as cargo refrigeration. For TSE, the team reviewed on-board electrification commonly known as shore power in which truck stops are equipped with parking spaces with electric infrastructure that provides a pedestal providing electric power that the truck is able to connect to via a heavy duty extension plug. A competing TSE technology known as off-board electrification is available and provides amenities to trucks such as cooling, heating, plug load, internet, etc. via a module that connects to the truck's cab side window. However, these systems are less prevalent relative to the shore power option due to higher installation costs, operating costs, and market trends at time of reporting. For these reasons, only shore power TSE technology was considered in the potential analysis.

eTRU technology is broadly defined in this report as trailers that have the ability to be powered by grid-supplied electricity. Various TRU technologies are available on the market; however, for the purposes of

[27]EPRI Electrification Initiative. Tri-State Generation and Transmission Association, Inc. Case Study Report, 2016.

this report, we focus on eTRUs that have the option to be powered via shore power when parked at a truck stop. These eTRUs are connected to pedestals like the TSE described above but provide three phase 480 volt power supply to the eTRU. In doing so, the truck driver is able to rely on the electricity provided through the grid rather than on the eTRU generator powered by the truck's diesel engine.

APPENDIX B. EV POTENTIAL ASSESSMENT APPROACH ADDITIONAL DETAILS

As mentioned several times in the body of the report, the assessment of electrification potential for electric on-road and off-road vehicles and related electric parking infrastructure measures involved alternate approaches to several aspects of the study. EV measures are less related to customer premise counts and forecasts than the other measures analyzed as part of the study which can be readily tied to buildings/premises. Some ways in which the approach to analyzing EV measures differed were identified in the body of this report. Additional details on those methods are described in this Appendix.

Beneficial Electrification Screening

As discussed in Section 2.5.2, the team screened each electric vehicle technology against a set criteria qualifying beneficial electrification including impacts on the environment, quality of life, cost savings for the end user, and grid resiliency. As noted, this screening process is largely qualitative to assess if the beneficial electrification technology can successfully contribute a neutral or positive impact within each category. Similar to building technologies, the team assessed electric vehicles based on greenhouse gas and criteria pollutant net emission impacts, technology capital and O&M costs, as well as the technology's ability to reduce stress on the grid. The findings of this screening exercise are discussed in this section.

Cost Effectiveness Screening

As presented in Section 2.5.2, the team calculated PCT cost effectiveness for each measure based on net cost savings for the customer, tax credits, and incentives (benefits) and incremental cost, installation cost, and maintenance costs (costs). TRC cost effectiveness for each measure was based on benefits including reduced net emissions and net O&M savings, while costs were based on initial incremental capital costs and avoided energy costs. Discussed below are the processes used to estimate incremental costs for each EV technology assessed in this potential study.

Incremental Costs (Capital and O&M)

The team performed cost research on a variety of sources ranging from current market data to literature review of secondary research. Our approach to assessing incremental costs included review of capital costs for the purchase of the electric vehicle and its ICE equivalent as well as the incremental cost of operation and maintenance (O&M) between the two technologies. O&M costs are typically negative as electric vehicles usually have lower fuel costs and reduced maintenance requirements[28]. These parameters informed the cost effectiveness analysis to determine the various benefit-cost ratios.

Of the technologies reviewed, data for on-road vehicles was most prevalent. Incremental capital costs were gleaned primarily from manufacturer websites that had both ICE and equivalent electric vehicle models; however, certain information for measures such as the heavy-duty vehicle were sourced from secondary studies. We additionally developed permutations of on-road vehicles in the residential sector that included and excluded the cost of purchasing and installing charging equipment in a home. The team defined fuel costs for on-road vehicles based on fuel economy rates (both electric and gasoline

[28] Vehicle and/or equipment depreciation was not included as an O&M cost as part of this study.

mileage rates) provided by the Environmental Protection Agency (EPA) and annual vehicle miles travelled (VMT) provided by the Federal Highway Administration (FHA) and the Argonne National Laboratory's Alternative Fuel Life-Cycle Environmental and Economic Transportation (AFLEET) model. Maintenance cost estimates were based on various secondary studies and data that provided information on the lifetime costs associated with repairs and general maintenance for ICE vehicles and their electric counterparts.

We assessed incremental costs for off-road technologies based on the same parameters outlined above for on-road vehicles. Each category of off-road vehicles – forklifts, airport GSE, and TSE – were reviewed using secondary data sources. The team leveraged prior research conducted by EPRI[29] on behalf of Tri-State to develop capital and O&M costs for forklifts and charging equipment. To assess costs for the various airport GSE, the team used the Idaho National Laboratory's GSE Cost Model v1.1 which provides capital and operating costs for ICE and electric bag tractors, belt loaders, pushbacks as well as GSE charging equipment. Finally, TSE costs were defined based on literature reviews of various TSE pilot programs.

Estimate Load Growth Potential

Load growth is characterized as the increased electricity consumption resulting from the replacement of ICE vehicles to electric vehicles. For the purposes of this analysis, the team assumed a one-for-one substitution between the ICE and electric vehicles thereby assuming that each technology operates for the same number of miles driven or hours operated. Load growth estimation begins with understanding the expected forecast of ICE vehicle stock across the study timeframe and estimating the portion of that stock that can and will be converted to electric technology as characterized as technical and achievable potential, respectively. Due to the various electric vehicle technology types, the team completed independent analyses to estimate overall load growth.

Technology Forecasts

The team used various approaches to estimate the forecast for each relevant electric vehicle technology using both bottom-up and top-down methods of estimation. With the exception of the residential on-road electric vehicle forecast which is derived based on the disaggregated forecast, each technology forecast was constructed outside of the forecasting methods described in Section 2.2, as these technologies did not conform with the forecast taxonomy. However, these independent forecasts did follow the same principles described in that section and used Tri-State data when applicable. For example, naturally occurring adoption for electric vehicles in Colorado is expected to be greater relative to non-Colorado regions due to aggressive state policy and funding. This assumption is applied to both the residential on-road forecast and is also carried through to commercial fleets, airport GSE, and forklifts in Colorado, as these are all eligible technologies for Colorado state funding. Forecast methods for each EV technology are described in this section.

[29] EPRI Electrification Initiative. Tri-State Generation and Transmission Association, Inc. Case Study Report, 2016.

On-road Electric Vehicles

The on-road vehicles are comprised of both the residential and commercial sectors. To estimate the residential on-road vehicle stock and forecast, the team was able to leverage the existing residential forecast of households across the Tri-State territory. We applied a multiplier to each household to serve as a proxy for the number of vehicles owned per household. The team assumed an average of 1.9 vehicles per household[30]. After applying the multiplier to estimate the total residential vehicle stock, we extrapolated the forecast based on residential growth rate for each Tri-State region derived from the disaggregated forecast. To calculate the percentage of these stock forecasts that serve as potential for conversion to either plug-in hybrids (PHEV) or battery electric vehicles (BEV), the team applied various electric vehicle sales forecasts by state to estimate the amount of naturally occurring adoption. For the states of New Mexico, Wyoming, and Nebraska, the natural occurring adoption was considered less aggressive due to minimal state policy and was modeled based on the US Energy Information Agency's 2020 Annual Energy Outlook base case sales scenario. Colorado, however, has very aggressive policies oriented at electric vehicle adoption and charging infrastructure build out. To estimate this natural occurring adoption, the team used a Colorado-specific electric vehicle sales forecast which reflects near-term investments planned by the state[31]. The remaining vehicle stock net of natural occurring adoption serves as the basis for the technical and achievable potential analysis for residential on-road electric vehicles.

Unlike the residential vehicle stock, the commercial vehicle stock is considered to be far more heterogeneous insofar as vehicles in the commercial sector serve a wider range of customers and segments. The team narrowed its commercial on-road vehicle forecast analysis to the following vehicle types and categories:

- Public fleets
  - Municipalities, counties, school districts
    - Transit buses, school buses, light-duty vehicles
- Private fleets
  - Company fleets
    - Medium-duty vehicles

To estimate the public fleet forecasts, the team conducted a linear regression analysis based on municipal fleet size relative to the associated population based on various locations throughout Tri-State's Colorado territory. We subsequently applied the regression model to the populations of each non-Colorado cooperative served by Tri-State to estimate public fleet sizes for those locations. As many public fleets are comprised of both vehicles and equipment, we estimated approximately 40 percent of fleet units are vehicles based on select municipal data. Having established the estimated number of public fleet vehicles within each Tri-State region eligible for conversion to electric, the team calculated

[30] US Bureau of Transportation Statistics.

[31] Colorado Energy Office, June 2019.

the fleet forecast based on weighted average growth rates across the residential and commercial sectors derived from the disaggregated forecast discussed in Section 2.2.

The analysis of private fleets focused on medium-duty ground delivery and freight vehicles. To derive the forecast for each vehicle type, our analysis relied on data from private fleets owned by United Parcel Service (UPS) and FedEx. The team located all UPS and FedEx customer centers and shipment centers for ground delivery and service centers for freight in Tri-state's territory based on maps and company inventories. Using a national average number of vehicles per facility, we estimated the total private fleet base size within Tri-State's territory. The forecast across the study timeframe is based on the disaggregated forecast growth rates.

The team estimated the total number of transit buses based on the population locations within Tri-state service area. Our analysis excluded cities and towns with a population fewer than 2,000 with the exception of specific towns that have low populations but high visitation from non-residents which consequently support the presence of a transit bus system. We assumed the average number of buses per 1,000 people as 0.5 to 1.2 based on research provided by the World Bank Group and PPIAF[32]. With these data, we estimated the number of transit buses based on each Tri-State region's population and extrapolated the forecast across the study horizon using weighted residential and commercial growth rates from the disaggregated forecast.

Lastly, school buses were forecasted based on K-12 enrollment in all school districts within Tri-state service area. We assumed 55 percent of students will ride the bus to school[33]. To determine school bus capacity, we classified school districts into urban, rural and small rural designation. School buses in rural districts are assumed to have a smaller capacity as they travel a longer distance compared with those in urban areas. Based on the reported number of students, we estimated the total expected demand for school buses across Tri-State's service territory. The forecast growth rates are based on the residential sector disaggregated forecast.

Each of the above-described forecasts for public and private fleets as well as transit and public buses within the state of Colorado were further adjusted to reflect possible naturally occurring adoption. Specifically, we adjusted the forecast downward based on Colorado's Beneficiary Mitigation Plan[34] which may provide grant funding for the conversion of these vehicles from ICE to electric technology. These funds are expected to be administered from 2021 – 2023 but no indication of the level of funding to cities and towns within Tri-State's territory was available at the time of reporting. The team ultimately applied a conservative adjustment of five percent to each forecast for these three years. However, we do note that future policy and/or funding may further increase naturally occurring adoption such as a zero emissions vehicle standard for medium- and heavy-duty vehicles which was under consideration of adoption by the state of Colorado at the time of reporting.

[32] "Number of Buses per 1,000 Population." Urban Bus Toolkit, ppiaf.org. Accessed 8 July 2020.

[33] "School Bus." *Amalgamated Transit Union*, www.atu.org/work/school. Accessed 8 July 2020.

[34] Colorado Beneficiary Mitigation Plan Volkswagen, Audi, and Prosche Clean Air Act Settlements, September 2019.

Off-road Electric Vehicles

The team used various data sources and approaches to estimate stock forecasts for the off-road vehicle technologies analyzed in the potential study. The categories of off-road vehicles examined did not conform to the potential study's taxonomy described in Section 2.2. Therefore, the team developed custom forecasts similarly to how on-road commercial fleet vehicles were assessed.

Airport GSE reviewed in the analysis include pushbacks, tow tractors, and belt loaders. Our analysis of GSE centered on commercial airports within Tri-State's territory of which five were identified across the Western Colorado and Mountain Colorado regions. The team's approach to estimate the stock of existing GSE used data from each airport to estimate the number of pushbacks and derived ratios of the number of tow tractors and belt loaders to pushbacks based on secondary research. The average forecast growth rate for the GSE is based on the commercial operations forecasts cited in each airport's master plan. The GSE forecast was further adjusted to reflect possible naturally occurring adoption based on Colorado's Beneficiary Mitigation Plan[35] which makes grant funding available through 2023 for converting GSE from ICE to electric technology. Consequently, the forecast from 2021-2023 was adjusted downward by five percent.

Forklift forecasts are based on prior research conducted by EPRI[36] on behalf of Tri-State that provided an estimate of total forklift shipments to facilities within Tri-State's territory for Class I, II, III, IV, and V forklifts. We focused our analysis on Class IV and V forklifts as these technologies are typically built as ICE vehicles and eligible to be converted to electric technology. Leveraging data from the disaggregated forecast, the team allocated total forklift shipments to each state and region based on energy consumption. Growth rates associated with the disaggregated forecast were used to estimate increases in forklift shipments by state through 2040. To estimate total potential stock available for conversion, the team made adjustments to the forklift forecasts to account for technological constraints as well as possible naturally occurring adoption. Based on research completed by EPRI, it is assumed all ICE Class IV forklifts have an electric equivalent while 80 percent of ICE Class V forklifts have an electric equivalent. Therefore, the Class V forecast was reduced to account for this market technological constraint. The Class IV forklift forecast was also adjusted to reflect technical constraints of businesses and facilities that cannot accommodate charging schedules and/or infrastructure within their facility. As noted earlier, we further reduced the Colorado forecast for both classes of forklifts to account for Colorado's Beneficiary Mitigation Plan[37] which has set aside funding for forklift conversion to electric technology. These funds are expected to be administered from 2021 – 2023; the team adjusted the shipment counts for these years accordingly by five percent. These adjusted forecasts provided the basis for the technical potential assessment.

Electric Vehicle Infrastructure

Truck stop electrification (TSE) forecasts are based on prior research conducted by EPRI on behalf of Tri-State and secondary research. As TSE measures analyzed are associated with the availability of

[35] ibid.

[36] EPRI Electrification Initiative. Tri-State Generation and Transmission Association, Inc. Case Study Report, 2016.

[37] Colorado Beneficiary Mitigation Plan Volkswagen, Audi, and Porsche Clean Air Act Settlements, September 2019.

commercial truck stops, the forecasts assess the growth of existing truck stops across the project timeframe. EPRI's research identified all truck stops and associated parking spaces within Tri-State's territory. The team used this research to establish the number of truck stops within each state and Tri-State region. Forecasted growth of truck stops to 2040 was based on secondary research on demand for truck stop capacity[38]. Because there are currently no existing codes or standards nor known policies directly incenting the installation of TSE measures, the team did not adjust the forecast for any natural occurring adoption.

Technical Potential

The beneficial electrification study assessed potential for both load growth resulting from the conversion of transportation technologies to electric as well as the consequent reduction in use of transportation fuels and associated emissions. The team estimated these impacts by analyzing consumption of each measure technology based on various data sources as discussed below.

The on-road measures were comprised of various light-duty, medium-duty, and heavy-duty vehicles. The team calculated energy consumption based on vehicle miles travelled (VMT) and the efficiency of each vehicle based on miles per gallon for ICE technologies and miles per kWh for electric vehicles. The product of the vehicle efficiency and annual VMT determined the annual energy impact for the measure. For example, using the EPA-published miles per gallon and miles per kWh efficiencies for various light-duty vehicles with a GVWR less than 5,000 pounds, the team found an average ICE vehicle miles per gallon of 35.8 and an average kWh per mile of 3.5. Based on an annual VMT of 13,252 miles for the state of New Mexico, the expected avoided annual gasoline consumption was estimated at approximately 370 gallons while estimated electricity consumption was approximately 3,824 kWh. The team applied this approach to each on-road measure.

The team relied on various sources to estimate the impacts for off-road vehicles. Impacts associated with forklifts and TSE/eTRU were estimated based on primary research completed by EPRI[39] on behalf of Tri-State. The EPRI analysis provided data on electricity and fuel usage for these technologies. The team used these data in conjunction with other studies to validate, and if necessary, adjust parameter assumptions used in the EPRI study to estimate the impacts of forklifts and TSE/eTRU equipment. Airport GSE estimates were also based on secondary sources. Specifically, the team used data from an EPRI study (not specific to Tri-State) as well as data from the Idaho National Laboratory's GSE Cost Model (version 1.1) to estimate the electric and fuel impacts for each GSE technology type.

Achievable Potential

The approach to assessing achievable potential for electric vehicles followed the same logic and methods as outlined in Section 2.5.3. Similar to the analysis used for building measures, the Team defined adoption curves based on a Bass diffusion model. The data informing the adoption curves were based on two key parameter inputs:

[38] Estimating the Supply and Demand for Commercial Heavy Truck Parking on Interstate Highways. Virginia Transportation Research Council and Federal Highway Administration, December 2002.

[39] EPRI Electrification Initiative. Tri-State Generation and Transmission Association, Inc. Case Study Report, 2016.

- Maximum estimated number of vehicles and/or units eligible to be converted to electric
- Adoption rates based on customer willingness to participate

The team estimated the first parameter based on the technology forecast, i.e., the summation of units available for conversion to electric after accounting for naturally occurring adoption and any technical constraints. The second parameter of customer adoption is based on secondary data collected from the Midwest that surveyed both residential and non-residential customers. The team used data from residential customers who were asked their willingness to purchase an electric vehicle based on rebate values that covered a percent of the incremental cost. The survey did not ask non-residential customers specifically about converting existing vehicles and equipment to electric; therefore, the team used non-residential customers' response to willingness to install solar PV on their facility based on the number of years of investment payback as a proxy adoption rate. While the team acknowledges the disparity between solar PV and electric vehicles, we assumed this data as a proxy due to the fact that the adoption is based on investment payback which focuses decision making from an economic perspective and that both solar PV and electric vehicles are newer disruptor technologies. Future studies would benefit from primary data collection throughout Tri-State's territory. With these parameters defined, the Team developed Bass diffusion curves to approximate adoption at various incentive levels. Innovation and imitation coefficients were defined based on literature review of electric vehicle adoption models.

Estimate Emissions Reduction

Environmental Life Cycle Analysis

In order to estimate the CO_2 emission impacts resulting from the replacement of ICE vehicles with electric vehicles, the team defined analogous boundaries on the value chain for each energy source. We defined these boundaries beginning at the production of each energy source and ending with the energy consumption. For the fossil fuel-derived energy sources, including gasoline and diesel, the team conducted an environmental life cycle analysis to estimate the emissions associated with all processes beginning with the refining of crude oil to gasoline and/or diesel, delivery to distribution locations and retail stations, and combustion in end user vehicles. Similarly, we estimated emission impacts for the generation of electricity based on Tri-State's generation mix and transmission and distribution to charging infrastructure. No CO_2 emissions are associated with consumption of the electricity after being delivered to the electric vehicle.

The team used data from Argonne National Laboratory's AFLEET model to provide parameter estimates of CO_2 emissions resulting from the production, distribution, and combustion of conventional gasoline and conventional diesel. The AFLEET model provided parameters for upstream emissions (fuel refining and distribution to retail stations) and downstream emissions (combustion in ICE). The team used these data to develop emission factors per gallon of fuel consumed. Upstream CO_2 emissions comprise 16 percent of the total emissions for the value chain. To estimate CO_2 emissions associated with electric vehicles, we applied the hourly emissions forecast data provided by Tri-State (see Section 2.2) to the energy consumption of the electric vehicle inclusive of line losses.

APPENDIX C. NATURALLY OCCURRING ADOPTION OF ELECTRIC VEHICLES

As discussed in Appendix B, the Team reviewed and applied applicable naturally occurring adoption to most of the technologies in the electric vehicle study. Naturally occurring adoption was applied to technology forecasts with the purpose of calculating the total stock available of fossil fueled vehicles that could be converted to electric based on a Tri-State program intervention. The adjustment to the forecast for naturally occurring adoption is a standard process in potential study modeling which effectively isolates the potential opportunity a utility has to achieve its goals above and beyond a business-as-usual scenario. While energy efficiency potential studies typically represent naturally occurring adoption based on codes and standards, this beneficial electrification potential study bases naturally occurring adoption primarily on existing policies that incent uptake of electric vehicles.

While this study presents electric vehicles with naturally occurring adoption removed, the Team also assessed the impacts for electric vehicles inclusive of the vehicle stock that is expected to be converted through naturally occurring adoption. The purpose of this exercise is to present the overall load increase Tri-State could expect beyond any form of program intervention. The naturally occurring adoption adjustments made by the Team applied mostly to the Colorado regions due to significant state-level policies currently in place that provide various incentives for both the residential and commercial sectors to adopt electrified vehicles (conservative natural occurring adoption was also applied to on-road vehicles for non-Colorado regions). To include these impacts, the Team conducted separate model runs based on technology forecasts that did not adjust for naturally occurring adoption. This resulted in a larger available stock for conversion; however, in certain cases, the larger stock requires more years before reaching maximum market adoption. Of the two Reporting Tools provided with this report, and described in Section 2.5.4, one provides results *exclusive* of naturally occurring adoption of EVs and the other provides results *inclusive* of naturally occurring adoption of EVs.

Attachment Vol II 6-1 Annual Emissions and Water Usage

Attachment Vol 2 6-1 Emissions and Water Usage

Base Case

2018 ERP Emissions and Water Usage Rates by Unit

	UNIT	CO_2 lbs per Net MWh	SO_2 lbs per Net MWh	NOx lbs per Net MWh	Hg lbs per Gross MWh	PM lbs per Gross MWh	VOC lbs per Gross MWh	Water Usage (gal/MWh)
	LRS 2	2203	1.101	2.331	0.0000411	0.0953	0.036	528
	LRS 3	2407	1.823	2.410	0.0000468	0.1770	0.036	528
	Craig 1	2319	0.378	2.771	0.000017	0.0421	0.00209	492
	Craig 2	2350	0.345	0.672	0.000014	0.0469	0.00210	492
	Craig 3	2090	1.308	2.248	0.000078	0.0614	0.0304	492
	Springerville 3	2139	0.838	0.787	0.000016	0.0306	0.034	546
	Burlington 1	2212	0.206	12.482	N/A	0.162	0.0054	8.82
	Burlington 2	2086	0.182	12.283	N/A	0.153	0.0051	8.82
	Pyramid 1	1240	0.013	1.253	N/A	0.071	0.021	120
	Pyramid 2	1232	0.017	1.169	N/A	0.072	0.019	120
	Pyramid 3	1250	0.012	1.253	N/A	0.072	0.020	120
	Pyramid 4	1238	0.006	1.218	N/A	0.065	0.020	120
	Rifle	1206	0.00063	2.611	N/A	0.239	0.227	1273
	Limon 1	1498	0.008	0.432	N/A	0.0616	0.0010	57
	Limon 2	1492	0.008	0.324	N/A	0.0625	0.0008	57
	Knutson 1	1504	0.0085	0.345	N/A	0.1237	0.000	21
	Knutson 2	1500	0.0098	0.337	N/A	0.1237	0.000	21
	J. M. Shafer	981	0.0078	0.747	N/A	0.0804	0.0694	348
	Basin Nebraska	1240	1.0332	0.738	N/A	N/A	N/A	N/A
	Basin Electric- Colorado/Wyoming	1280	0.40	0.70	N/A	N/A	N/A	390
	Market Purchases	1280	0.40	0.70	N/A	N/A	N/A	N/A
	Energy Imbalance	1280	0.40	0.70	N/A	N/A	N/A	N/A
Expansion Plan Units*	NM200MWCT	1495	0.01	0.38	N/A	0.0621	0.001	57
	SWCO200MWCT	1495	0.008	0.378	N/A	0.06205	0.0009	57
	SWCO300MWCC	751	0.008	0.747	N/A	0.0804	0.0694	348

GWh Generation

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1937	1597	1918	1777	1661	1897	1907	1686	1880	1884	1644	1883	1855	1616	1859	1853	1670	1860	1870	1671
LRS 3	1639	1712	1870	1448	1898	1861	1646	1870	1654	1867	1871	1666	1837	1831	1645	1835	1857	1646	1853	1851
Craig 1	692	671	685	685	651	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	809	793	681	751	722	762	800	600	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3179	3492	3254	3076	3159	3579	3253	3692	3501	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1969	1693	1896	1784	1923	2252	2436	2384	2557	2728	2450	2790	2778	2631	2819	2730	2410	2535	2565	2554
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	10	22	10	4	26	34	33	37	29	23	31	26	29	33	34	35	41	33	31	25
Pyramid 2	7	22	8	4	26	34	35	38	30	22	31	25	30	31	34	31	40	30	29	20
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	8	21	8	4	25	34	35	38	30	22	31	23	30	31	33	32	39	29	29	20
Rifle	0	0	0	0	14	33	29	25	2	29	27	34	35	39	52	17	14	22	26	26
Limon 1	0	0	0	0	13	24	21	6	0	0	0	1	0	2	0	3	3	7	4	2
Limon 2	0	0	0	0	14	23	19	6	0	0	0	1	0	1	0	3	3	8	6	2
Knutson 1	0	0	0	0	14	23	19	7	0	0	0	0	0	1	0	5	3	7	4	2
Knutson 2	0	0	0	0	14	23	21	7	0	0	0	0	0	1	0	3	4	7	7	2
J. M. Shafer	462	328	390	326	769	627	553	505	367	463	498	481	460	484	520	572	658	627	560	496
Basin Nebraska	680	683	686	689	692	694	698	701	704	707	711	715	718	722	725	729	733	736	740	859
Basin Electric- Colorado/Wyoming	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627
Market Purchases	763	575	498	307	435	254	676	667	894	2464	2496	2214	1897	2027	2109	2337	2770	2528	2263	2128
Energy Imbalance	148	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135
NM200MWCT	0	0	0	0	0	0	0	0	0	162	222	180	224	198	227	211	295	196	176	122
SWCO200MWCT	0	0	0	0	0	0	0	0	0	202	291	262	280	285	299	307	355	359	387	354
SWCO300MWCC	0	0	0	0	0	0	0	0	0	353	399	394	393	405	409	374	425	544	421	373
Total	13932	13374	13667	12617	13818	13916	13944	14030	13411	12689	12465	12456	12327	12098	12529	12840	13084	12937	12733	12269
																		Scenario sum		261136

CO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2133715	1759471	2112345	1956964	1829815	2089160	2100735	1857575	2070520	2075123	1810815	2074035	2043719	1780043	2047718	2041291	1839380	2049123	2059488	1840662
LRS 3	1972795	2060737	2250917	1743262	2284549	2239159	1981423	2249974	1991113	2247123	2252240	2004796	2210457	2203272	1980078	2208294	2235342	1980409	2230467	2227123
Craig 1	801977	778357	793995	794048	754324	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	950206	931310	800735	882535	848521	895647	939458	705022	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3321639	3649324	3400945	3214252	3300872	3740310	3399537	3857679	3658155	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	2105429	1811117	2027598	1908430	2056815	2408387	2605299	2550218	2734457	2917918	2619863	2983488	2971437	2814188	3014901	2919415	2577673	2711432	2743726	2732015
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	6407	13407	6024	2385	16222	21126	20517	23080	18282	14150	19276	15993	17868	20160	21159	21754	25728	20458	19152	15232
Pyramid 2	4477	13394	4864	2421	15830	20976	21409	23270	18493	13316	18850	15178	18334	19207	21225	19290	24693	18173	18054	12579
Pyramid 3	197	197	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	5080	13078	5078	2344	15698	21355	21608	23544	18624	13872	18993	14374	18359	19035	20459	19722	24388	17932	18109	12299
Rifle	0	0	0	0	8302	19832	17324	14810	1274	17705	16455	20282	20913	23410	31217	10048	8338	13288	15748	15681
Limon 1	342	342	0	0	9519	17631	16033	4403	0	0	91	684	0	1134	0	2243	2243	5311	2927	1459
Limon 2	341	341	0	291	10354	17195	14456	4669	0	91	291	581	0	672	191	1943	2375	5820	4387	1262
Knutson 1	343	343	0	0	10627	17008	14565	4915	0	0	0	293	0	485	192	3433	2394	5635	2948	1272
Knutson 2	342	342	0	91	10602	17262	15424	5089	0	0	292	292	0	867	192	2054	2992	5267	4894	1269
J. M. Shafer	226754	161025	191294	160021	377248	307341	271446	247654	180197	227171	244126	235814	225417	237334	254857	280568	322799	307761	274555	243441
Basin Nebraska	421495	423307	425113	427068	428761	430577	432497	434596	436450	438412	440667	443039	445137	447366	449665	452056	454218	456462	458732	532811
Basin Electric- Colorado/Wyoming	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228
Market Purchases	488389	368052	318956	196250	222850	130294	346104	341437	457695	1261490	1278043	1133678	971477	1038035	1079835	1196779	1418120	1294160	1158908	1089349
Energy Imbalance	94493	86656	86656	86656	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325
NM200MWCT	0	0	0	0	0	0	0	0	0	121007	165958	134857	167416	147902	169800	158032	220643	146618	131712	90892
SWCO200MWCT	0	0	0	0	0	0	0	0	0	150784	217839	196095	209509	212753	223664	229840	265670	268428	288992	264805
SWCO300MWCC	0	0	0	0	0	0	0	0	0	132606	149855	147851	147407	152134	153712	140523	159469	204239	157978	140150
Total	13575649	13112030	13465748	12418246	13311462	13503812	13328387	13458489	12695812	10741321	10364206	10531882	10578004	10228549	10579417	10817841	10697018	10621067	10701330	10332855
																		Scenario Sum tons:		235,063,123
																		Scenario lbs/MWh		1800

SO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1066	879	1056	978	914	1044	1050	928	1035	1037	905	1037	1021	890	1023	1020	919	1024	1029	920
LRS 3	1494	1561	1705	1320	1730	1696	1501	1704	1508	1702	1706	1518	1674	1669	1500	1673	1693	1500	1689	1687
Craig 1	131	127	129	129	123	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	139	137	118	130	125	131	138	104	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	2079	2284	2128	2012	2066	2341	2128	2414	2289	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	825	710	794	748	806	944	1021	999	1071	1143	1026	1169	1164	1103	1181	1144	1010	1062	1075	1070
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rifle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	2	1	2	1	3	2	2	2	1	2	2	2	2	2	2	2	3	2	2	2
Basin Nebraska	351	353	354	356	357	359	360	362	364	365	367	369	371	373	375	377	378	380	382	444
Basin Electric- Colorado/Wyoming	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NM200MWCT	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	0
SWCO200MWCT	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	2	1
SWCO300MWCC	0	0	0	0	0	0	0	0	0	1	2	2	2	2	2	1	2	2	2	1
Total	6413	6377	6612	5999	6450	6843	6526	6840	6595	4578	4336	4424	4562	4365	4411	4545	4334	4299	4508	4452

Scenario Sum tons:	107,467
Scenario lbs/MWh	0.82

Nox

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2258	1862	2235	2071	1936	2211	2223	1966	2191	2196	1916	2195	2162	1883	2167	2160	1946	2168	2179	1948
LRS 3	1975	2063	2254	1745	2287	2242	1984	2253	1994	2250	2255	2007	2213	2206	1983	2211	2238	1983	2233	2230
Craig 1	958	930	949	949	901	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	272	266	229	252	243	256	269	202	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3573	3925	3658	3457	3550	4023	3657	4149	3935	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	775	666	746	702	757	886	959	938	1006	1074	964	1098	1093	1035	1109	1074	948	998	1009	1005
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	6	14	6	2	16	21	21	23	18	14	19	16	18	20	21	22	26	21	19	15
Pyramid 2	4	13	5	2	15	20	20	22	18	13	18	14	17	18	20	18	23	17	17	12
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	5	13	5	2	15	21	21	23	18	14	19	14	18	19	20	19	24	18	18	12
Rifle	0	0	0	0	18	43	38	32	3	38	36	44	45	51	68	22	18	29	34	34
Limon 1	0	0	0	0	3	5	5	1	0	0	0	0	0	0	0	1	1	2	1	0
Limon 2	0	0	0	0	2	4	3	1	0	0	0	0	0	0	0	0	1	1	1	0
Knutson 1	0	0	0	0	2	4	3	1	0	0	0	0	0	0	0	1	1	1	1	0
Knutson 2	0	0	0	0	2	4	3	1	0	0	0	0	0	0	0	0	1	1	1	0
J. M. Shafer	173	123	146	122	287	234	207	189	137	173	186	180	172	181	194	214	246	234	209	185
Basin Nebraska	251	252	253	254	255	256	257	259	260	261	262	264	265	266	268	269	270	272	273	317
Basin Electric- Colorado/Wyoming	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NM200MWCT	0	0	0	0	0	0	0	0	0	31	42	34	42	37	43	40	56	37	33	23
SWCO200MWCT	0	0	0	0	0	0	0	0	0	38	55	50	53	54	57	58	67	68	73	67
SWCO300MWCC	0	0	0	0	0	0	0	0	0	132	149	147	147	151	153	140	159	203	157	139
Total	10820	10697	11054	10129	10861	10799	10238	10629	10149	6802	6491	6632	6816	6493	6671	6819	6594	6622	6829	6559

Scenario Sum tons:	168,703
Scenario lbs/MWh	1

Hg

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	0.0428	0.0353	0.0424	0.0393	0.0367	0.0419	0.0422	0.0373	0.0416	0.0417	0.0364	0.0416	0.0410	0.0357	0.0411	0.0410	0.0369	0.0411	0.0413	0.0369
LRS 3	0.0413	0.0431	0.0471	0.0365	0.0478	0.0468	0.0415	0.0471	0.0417	0.0470	0.0471	0.0419	0.0462	0.0461	0.0414	0.0462	0.0468	0.0414	0.0467	0.0466
Craig 1	0.0063	0.0062	0.0063	0.0063	0.0060	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 2	0.0061	0.0060	0.0051	0.0057	0.0054	0.0058	0.0060	0.0045	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 3	0.1336	0.1468	0.1368	0.1293	0.1328	0.1505	0.1368	0.1552	0.1472	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1368
Springerville 3	0.0171	0.0147	0.0165	0.0155	0.0167	0.0196	0.0212	0.0208	0.0223	0.0237	0.0213	0.0243	0.0242	0.0229	0.0245	0.0238	0.0210	0.0221	0.0223	0.0222
Burlington 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Burlington 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Rifle	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
J. M. Shafer	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NM200MWCT	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO200MWCT	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	0.2473	0.2521	0.2542	0.2325	0.2455	0.2646	0.2476	0.2648	0.2526	0.1124	0.1048	0.1079	0.1115	0.1047	0.1071	0.1109	0.1047	0.1046	0.1103	0.1058
																		Scenario Sum tons:		3.446
																		Scenario lbs/MWh		0.000024

PM

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	99	82	98	91	85	97	98	86	96	97	84	97	95	83	95	95	86	95	96	86
LRS 3	156	163	178	138	181	177	157	178	158	178	178	159	175	174	157	175	177	157	176	176
Craig 1	16	15	16	16	15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	20	20	17	19	18	19	20	15	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	105	116	108	102	105	118	108	122	116	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	33	28	32	30	32	37	41	40	43	45	41	46	46	44	47	45	40	42	43	43
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Pyramid 2	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Rifle	0	0	0	0	2	4	3	3	0	4	3	4	4	5	6	2	2	3	3	3
Limon 1	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	19	13	16	13	31	25	22	20	15	19	20	20	19	20	21	23	27	25	23	20
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NM200MWCT	0	0	0	0	0	0	0	0	0	5	7	6	7	6	7	7	9	6	6	4
SWCO200MWCT	0	0	0	0	0	0	0	0	0	6	9	8	9	9	9	10	11	11	12	11
SWCO300MWCC	0	0	0	0	0	0	0	0	0	14	16	16	16	16	17	15	17	22	17	15
Total	449	440	465	409	474	487	456	470	431	370	362	358	374	360	363	376	374	367	380	360
																		Scenario Sum tons:		8,125
																		Scenario lbs/MWh		0.06

Water

Gallons

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1,022,788,531	843,395,797	1,012,544,975	938,063,576	877,115,073	1,001,431,245	1,006,979,548	890,421,623	992,496,132	994,702,434	868,007,512	994,181,028	979,649,435	853,257,173	981,566,223	978,485,578	881,700,105	982,239,418	987,207,939	882,314,790
LRS 3	865,505,411	904,087,546	987,523,402	764,804,568	1,002,278,174	982,364,612	869,290,520	987,109,533	873,541,901	985,858,842	988,103,634	879,544,772	969,772,601	966,620,255	868,700,781	968,823,642	980,690,075	868,845,965	978,551,210	977,084,470
Craig 1	340,295,438	330,273,189	336,908,459	336,930,948	320,075,244	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	397,873,308	389,961,376	335,286,340	369,537,974	355,295,600	375,028,285	393,373,036	295,209,382	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1,563,872,240	1,718,150,728	1,601,210,376	1,513,313,022	1,554,094,750	1,760,988,148	1,600,547,674	1,816,246,784	1,722,308,477	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1,074,861,427	924,609,728	1,035,127,095	974,289,596	1,050,043,053	1,229,527,220	1,330,054,374	1,301,934,784	1,395,992,307	1,489,652,383	1,337,489,655	1,523,126,994	1,516,975,084	1,436,696,217	1,539,163,973	1,490,416,875	1,315,950,869	1,384,237,203	1,400,724,003	1,394,745,306
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1,239,986	2,594,936	1,165,969	461,636	3,139,764	4,088,830	3,971,111	4,467,113	3,538,431	2,738,696	3,730,895	3,095,342	3,458,397	3,901,996	4,095,315	4,210,370	4,979,703	3,959,504	3,706,859	2,948,197
Pyramid 2	872,086	2,609,253	947,441	471,638	3,083,708	4,086,327	4,170,533	4,533,115	3,602,527	2,594,057	3,672,133	2,956,789	3,571,549	3,741,648	4,134,739	3,757,726	4,810,299	3,540,136	3,517,070	2,450,529
Pyramid 3	37,884	37,884	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	984,902	2,535,329	984,439	454,369	3,043,180	4,139,914	4,188,986	4,564,220	3,610,387	2,689,282	3,681,955	2,786,519	3,559,141	3,690,144	3,966,268	3,823,348	4,727,795	3,476,258	3,510,694	2,384,282
Rifle	0	0	0	0	17,527,167	41,867,379	36,572,333	31,266,005	2,689,211	37,377,689	34,738,405	42,817,453	44,150,547	49,421,031	65,902,898	21,212,958	17,601,458	28,051,510	33,246,305	33,104,047
Limon 1	26,020	26,020	0	0	724,411	1,341,740	1,220,155	335,064	0	0	6,925	52,039	0	86,294	0	170,680	170,680	404,176	222,733	111,003
Limon 2	26,020	26,020	0	22,203	791,132	1,313,812	1,104,533	356,780	0	6,925	22,203	44,401	0	51,326	14,563	148,480	181,483	444,727	335,178	96,440
Knutson 1	9,586	9,586	0	0	296,753	474,953	406,730	137,252	0	0	0	8,179	0	13,544	5,365	95,865	66,865	157,348	82,328	35,531
Knutson 2	9,586	9,586	0	2,553	296,856	483,328	431,878	142,481	0	0	8,179	8,179	0	24,276	5,365	57,517	83,788	147,478	137,031	35,531
J. M. Shafer	160,877,259	114,244,268	135,719,454	113,531,974	267,650,241	218,052,033	192,585,505	175,705,405	127,846,000	161,173,669	173,202,489	167,305,657	159,928,559	168,383,721	180,815,767	199,057,633	229,019,626	218,350,088	194,791,582	172,716,429
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NM200MWCT	0	0	0	0	0	0	0	0	0	9,227,286	12,655,01	10,283,40	12,766,16	11,278,12	12,947,93	12,050,63	16,824,93	11,180,266	10,043,595	6,930,915
SWCO200MWCT	0	0	0	0	0	0	0	0	0	11,497,884	16,611,10	14,953,06	15,975,92	16,223,30	17,055,31	17,526,27	20,258,43	20,468,776	22,036,875	20,192,451
SWCO300MWCC	0	0	0	0	0	0	0	0	0	122,894,40	138,879,94	137,022,75	136,611,16	140,992,10	142,454,43	130,232,09	147,790,55	189,281,070	146,407,982	129,885,576

Year	CO2 (tons)	SO2 (tons)	NOx (tons)	Hg (tons)	PM (tons)	Water (gallons)	RES CO	RPS NM (SB489)
2021	13,575,649	6413	10,820	0.2473	449	6,063,231,450	*C*	*C*
2022	13,112,030	6377	10,697	0.2521	440	5,866,523,011	*C*	*C*
2023	13,465,748	6612	11,054	0.2542	465	6,081,369,710	*C*	*C*
2024	12,418,246	5999	10,129	0.2325	409	5,645,835,819	*C*	*C*
2025	13,311,462	6450	10,861	0.2455	474	6,089,406,874	*C*	*C*
2026	13,503,812	6843	10,799	0.2646	487	6,259,139,589	*C*	*C*
2027	13,328,387	6526	10,238	0.2476	456	6,078,848,688	*C*	*C*
2028	13,458,489	6840	10,629	0.2648	470	6,146,381,311	*C*	*C*
2029	12,695,812	6595	10,149	0.2526	431	5,759,577,146	*C*	*C*
2030	10,741,321	4578	6,802	0.1124	370	4,454,365,320	*C*	*C*
2031	10,364,206	4336	6,491	0.1048	362	4,214,761,807	*C*	*C*
2032	10,531,882	4424	6,632	0.1079	358	4,412,138,345	*C*	*C*
2033	10,578,004	4562	6,816	0.1115	374	4,480,370,331	*C*	*C*
2034	10,228,549	4365	6,493	0.1047	360	4,288,332,918	*C*	*C*
2035	10,579,417	4411	6,671	0.1071	363	4,454,780,697	*C*	*C*
2036	10,817,841	4545	6,819	0.1109	376	4,464,021,434	*C*	*C*
2037	10,697,018	4334	6,594	0.1047	374	4,258,808,429	*C*	*C*
2038	10,621,067	4299	6,622	0.1046	367	4,348,735,743	*C*	*C*
2039	10,701,330	4508	6,829	0.1103	380	4,418,473,131	*C*	*C*
2040	10,332,855	4452	6,559	0.1058	360	4,258,987,351	*C*	*C*
Total	235,063,123	107,467	168,703	3.446	8,125	102,044,089,106		
per MWh**	1,197	1	0.86	0.00002	0.04	260		

TS Thermal Gen Emissions & Water per TS Thermal Gen	**CO2 (lbs/net MWH)**	**SO2 (lbs/net MWH)**	**NOx (lbs/net MWH**	**Hg (lbs/gross MWh)***	**PM (lbs gross MWh)**	**Water (gallons/net MWH**
Scenario Average	1800	0.82	1.29	0.000024	0.06	391

*** This is divided by all thermal MWH even though gas does not have a Mercury impact**

TS Thermal Gen Emissions& Water per Member Load Energy	**CO2 (lbs/net MWH)**	**SO2 (lbs/net MWH)**	**NOx (lbs/net MWH**	**Hg (lbs/gross MWh)**	**PM (lbs gross MWh)**	**Water (gallons/net MWH**
Scenario Average	1197	0.55	0.86	0.00002	0.04	260

80pct CR Version 1

2018 ERP Emissions and Water Usage Rates by Unit

	UNIT	CO_2 lbs per Net MWh	SO_2 lbs per Net MWh	NOx lbs per Net MWh	Hg lbs per Gross MWh	PM lbs per Gross MWh	VOC lbs per Gross MWh	Water Usage (gal/MWh)
	LRS 2	2203	1.101	2.331	0.0000411	0.0953	0.036	528
	LRS 3	2407	1.823	2.410	0.0000468	0.1770	0.036	528
	Craig 1	2319	0.378	2.771	0.000017	0.0421	0.00209	492
	Craig 2	2350	0.345	0.672	0.000014	0.0469	0.00210	492
	Craig 3	2090	1.308	2.248	0.000078	0.0614	0.0304	492
	Springerville 3	2139	0.838	0.787	0.000016	0.0306	0.034	546
	Burlington 1	2212	0.206	12.482	N/A	0.162	0.0054	8.82
	Burlington 2	2086	0.182	12.283	N/A	0.153	0.0051	8.82
	Pyramid 1	1240	0.013	1.253	N/A	0.071	0.021	120
	Pyramid 2	1232	0.017	1.169	N/A	0.072	0.019	120
	Pyramid 3	1250	0.012	1.253	N/A	0.072	0.020	120
	Pyramid 4	1238	0.006	1.218	N/A	0.065	0.020	120
	Rifle	1206	0.00063	2.611	N/A	0.239	0.227	1273
	Limon 1	1498	0.008	0.432	N/A	0.0616	0.0010	57
	Limon 2	1492	0.008	0.324	N/A	0.0625	0.0008	57
	Knutson 1	1504	0.0085	0.345	N/A	0.1237	0.000	21
	Knutson 2	1500	0.0098	0.337	N/A	0.1237	0.000	21
	J. M. Shafer	981	0.0078	0.747	N/A	0.0804	0.0694	348
	Basin Nebraska	1240	1.0332	0.738	N/A	N/A	N/A	N/A
	Basin Electric- Colorado/Wyoming	1280	0.40	0.70	N/A	N/A	N/A	390
	Market Purchases	1280	0.40	0.70	N/A	N/A	N/A	N/A
	Energy Imbalance	1280	0.40	0.70	N/A	N/A	N/A	N/A
Expansion Plan Units*	SWCO300MWCC	751	0.008	0.747	N/A	0.0804	0.0694	348

GWh Generation

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1891	1491	1906	1588	1659	1869	1887	1666	1851	1722	1544	1741	1760	1525	1676	1640	1521	1567	1568	1536
LRS 3	1613	1620	1864	1320	1879	1816	1625	1827	1629	1633	1733	1526	152	0	0	0	0	0	0	0
Craig 1	672	758	733	737	609	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	742	780	667	747	651	730	743	321	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	2880	3418	3100	3087	2753	3401	3067	2636	737	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1754	1665	1838	1738	1556	1647	1898	1871	2150	2064	1958	2204	2584	2384	2571	2657	2108	207	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	2	23	10	5	39	28	23	24	23	17	28	23	30	32	35	22	5	43	42	38
Pyramid 2	1	23	9	3	37	28	22	24	25	17	28	22	26	28	32	20	4	43	39	35
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	1	22	9	4	38	28	23	24	24	17	28	21	26	29	33	20	5	43	40	36
Rifle	0	0	0	0	10	8	1	0	37	1	2	0	3	1	1	0	0	0	0	0
Limon 1	0	0	0	0	22	18	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	25	18	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	17	20	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	19	18	3	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	493	321	353	300	739	527	357	255	145	27	35	28	30	38	73	70	52	63	37	35
Basin Nebraska	664	683	686	689	692	694	698	701	704	707	711	715	718	722	725	729	733	736	740	859
Basin Electric- Colorado/Wyoming	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627
Market Purchases	1396	702	596	398	669	210	449	507	1645	1341	1556	1334	1574	1651	1592	1702	1682	2215	2346	2716
Energy Imbalance	148	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135
SWCO300MWCC	0	0	0	0	0	0	0	0	0	679	706	720	719	736	636	628	635	644	653	646
Total	13886	13270	13533	12381	13175	12823	12561	11618	10733	9987	10090	10097	9384	8909	9136	9249	8506	7323	7226	7665
																		Scenario sum		211552

CO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2082842	1642784	2099730	1749148	1827505	2059117	2078391	1834564	2038633	1896825	1701169	1918194	1938936	1680302	1846175	1806047	1674912	1726406	1726891	1691504
LRS 3	1941677	1949508	2242764	1589215	2261738	2185631	1956064	2199254	1961069	1965660	2085214	1836743	182535	0	0	0	0	0	0	0
Craig 1	778917	879364	850358	855027	705738	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	872202	916188	784037	877691	765205	857661	873187	376905	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3009639	3571450	3239200	3226399	2877121	3553838	3204788	2754905	770183	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1876411	1780200	1965846	1858710	1664088	1761622	2029590	2001050	2299042	2206982	2094037	2357577	2763391	2549979	2749300	2841981	2254484	221491	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	51	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1055	13990	6209	2874	23954	17172	14143	15092	14065	10658	17206	14266	18524	19593	21715	13388	3272	26572	25814	23723
Pyramid 2	570	13909	5447	2114	22561	17094	13569	14947	15168	10210	16951	13276	16237	17376	20014	12157	2738	26222	24331	21811
Pyramid 3	197	197	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	505	13880	5657	2356	23733	17304	13932	14586	14756	10459	17076	12896	16214	17787	20219	12226	2851	26773	24639	22402
Rifle	0	0	0	0	6088	4935	372	0	22239	490	1058	196	1512	588	529	0	0	294	0	0
Limon 1	342	342	0	292	16183	13642	675	0	84	0	0	0	0	0	0	0	0	0	0	0
Limon 2	341	341	0	0	18420	13724	2043	0	257	0	0	0	0	91	0	0	0	0	0	0
Knutson 1	343	343	0	293	12952	15029	981	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	342	342	0	292	14605	13248	2045	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	241699	157484	172958	147145	362345	258501	175021	125317	71320	13363	17286	13638	14832	18837	35806	34323	25378	30711	17988	17074
Basin Nebraska	411673	423307	425113	427068	428761	430577	432497	434596	436450	438412	440667	443039	445137	447366	449665	452056	454218	456462	458732	532811
Basin Electric- Colorado/Wyoming	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228
Market Purchases	893648	449335	381479	255030	342362	107584	229926	259364	842441	686591	796589	683021	805924	845520	814900	871345	861030	1133943	1200951	1390815
Energy Imbalance	94493	86656	86656	86656	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325
SWCO300MWCC	0	0	0	0	0	0	0	0	0	254986	265137	270432	269843	276464	238656	235845	238409	241788	245195	242643
Total	13248122	12940848	13306681	12121536	12483909	12437232	12137777	11141134	9596311	8605190	8562944	8673832	7583638	6984456	7307532	7389922	6627845	5001214	4835095	5053335
																		Scenario Sum tons:		186,038,552
																		Scenario lbs/MWh		1759

SO2
short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1041	821	1049	874	913	1029	1039	917	1019	948	850	959	969	840	923	903	837	863	863	845
LRS 3	1471	1477	1699	1204	1713	1655	1481	1666	1485	1489	1579	1391	138	0	0	0	0	0	0	0
Craig 1	127	143	139	139	115	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	128	135	115	129	112	126	128	55	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1884	2235	2027	2019	1801	2224	2006	1724	482	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	735	697	770	728	652	690	795	784	901	865	820	924	1083	999	1077	1113	883	87	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rifle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	2	1	1	1	3	2	1	1	1	0	0	0	0	0	0	0	0	0	0	0
Basin Nebraska	343	353	354	356	357	359	360	362	364	365	367	369	371	373	375	377	378	380	382	444
Basin Electric- Colorado/Wyoming	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	3	3	3	3	3	2	2	2	3	3	3
Total	6056	6188	6480	5776	5993	6412	6137	5835	4577	3995	3946	3971	2890	2540	2703	2721	2427	1659	1574	1618

Scenario Sum tons: 83,497
Scenario lbs/MWh 0.79

Nox
short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2204	1738	2222	1851	1934	2179	2199	1941	2157	2007	1800	2030	2052	1778	1953	1911	1772	1827	1827	1790
LRS 3	1944	1952	2246	1591	2265	2188	1959	2202	1964	1968	2088	1839	183	0	0	0	0	0	0	0
Craig 1	931	1051	1016	1022	843	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	249	262	224	251	219	245	250	108	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3237	3841	3484	3470	3095	3823	3447	2963	828	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	690	655	723	684	612	648	747	736	846	812	770	867	1017	938	1012	1046	829	81	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1	14	6	3	24	17	14	15	14	11	17	14	19	20	22	14	3	27	26	24
Pyramid 2	1	13	5	2	21	16	13	14	14	10	16	13	15	16	19	12	3	25	23	21
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	14	6	2	23	17	14	14	15	10	17	13	16	17	20	12	3	26	24	22
Rifle	0	0	0	0	13	11	1	0	48	1	2	0	3	1	1	0	0	1	0	0
Limon 1	0	0	0	0	5	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	4	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	184	120	132	112	276	197	133	95	54	10	13	10	11	14	27	26	19	23	14	13
Basin Nebraska	245	252	253	254	255	256	257	259	260	261	262	264	265	266	268	269	270	272	273	317
Basin Electric- Colorado/Wyoming	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	254	264	269	268	275	237	235	237	241	244	241
Total	10257	10482	10886	9812	10165	10180	9604	8918	6770	5913	5819	5889	4418	3896	4129	4093	3707	3092	3001	2997

Scenario Sum tons: 134,028
Scenario lbs/MWh 1

Hg
short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	0.0418	0.0330	0.0422	0.0351	0.0367	0.0413	0.0417	0.0368	0.0409	0.0381	0.0341	0.0385	0.0389	0.0337	0.0371	0.0363	0.0336	0.0347	0.0347	0.0340
LRS 3	0.0406	0.0408	0.0469	0.0332	0.0473	0.0457	0.0409	0.0460	0.0410	0.0411	0.0436	0.0384	0.0038	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 1	0.0062	0.0069	0.0067	0.0068	0.0056	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 2	0.0056	0.0059	0.0050	0.0056	0.0049	0.0055	0.0056	0.0024	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 3	0.1211	0.1437	0.1303	0.1298	0.1158	0.1430	0.1289	0.1108	0.0310	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Springerville 3	0.0153	0.0145	0.0160	0.0151	0.0135	0.0143	0.0165	0.0163	0.0187	0.0180	0.0170	0.0192	0.0225	0.0208	0.0224	0.0231	0.0183	0.0018	0.0000	0.0000
Burlington 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Burlington 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Rifle	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
J. M. Shafer	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	0.2305	0.2448	0.2471	0.2257	0.2238	0.2499	0.2337	0.2124	0.1316	0.0972	0.0948	0.0961	0.0652	0.0545	0.0594	0.0594	0.0520	0.0365	0.0347	0.0340

Scenario Sum tons: 2.683
Scenario lbs/MWh 0.000023

PM

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	97	76	98	81	85	96	97	85	95	88	79	89	90	78	86	84	78	80	80	79
LRS 3	154	154	177	126	179	173	155	174	155	156	165	145	14	0	0	0	0	0	0	0
Craig 1	15	17	17	17	14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	19	20	17	19	16	18	19	8	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	95	113	103	102	91	113	101	87	24	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	29	28	31	29	26	27	32	31	36	34	33	37	43	40	43	44	35	3	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	2	1	1
Pyramid 2	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	2	1	1
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	1	1	1
Rifle	0	0	0	0	1	1	0	0	4	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	20	13	14	12	30	21	14	10	6	1	1	1	1	2	3	3	2	3	1	1
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	28	29	29	29	30	26	26	26	26	27	26
Total	429	424	457	387	450	456	421	399	323	309	310	304	181	153	161	159	141	117	113	110

Scenario Sum tons:	5,804
Scenario lbs/MWh	0.05

Water

Gallons

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	998,402,713	787,462,557	1,006,497,937	838,447,519	876,007,804	987,030,333	996,269,237	879,391,726	977,211,345	909,236,085	815,449,346	919,479,288	929,422,072	805,446,404	884,957,025	865,722,203	802,862,779	827,546,307	827,778,937	810,816,102
LRS 3	851,853,147	855,288,853	983,946,420	697,220,943	992,270,663	958,881,055	858,165,393	964,857,489	860,361,110	862,375,296	914,826,103	805,816,714	80,081,798	0	0	0	0	0	0	0
Craig 1	330,510,581	373,132,437	360,824,688	362,805,728	299,459,148	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	365,211,193	383,629,470	328,294,491	367,509,804	320,409,148	359,122,613	365,623,883	157,819,084	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1,416,978,435	1,681,486,422	1,525,058,908	1,519,031,797	1,354,587,004	1,673,194,435	1,508,857,000	1,297,046,170	362,612,481	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	957,943,556	908,825,738	1,003,601,522	948,906,778	849,548,232	899,341,513	1,036,144,334	1,021,574,043	1,173,704,443	1,126,706,119	1,069,045,484	1,203,587,802	1,410,763,583	1,301,812,464	1,403,569,909	1,450,885,003	1,150,956,803	113,075,186	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	430	0	0	0	0	0	0	0	0	0	0
Pyramid 1	204,150	2,707,713	1,201,744	556,237	4,636,163	3,323,648	2,737,297	2,921,038	2,722,225	2,062,781	3,330,110	2,761,178	3,585,251	3,792,224	4,202,808	2,591,307	633,286	5,142,927	4,996,317	4,591,536
Pyramid 2	111,000	2,709,624	1,061,054	411,722	4,394,914	3,329,952	2,643,277	2,911,793	2,954,755	1,988,994	3,302,055	2,586,311	3,163,083	3,384,849	3,898,880	2,368,273	533,325	5,108,103	4,739,794	4,248,838
Pyramid 3	37,884	37,884	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	97,884	2,690,706	1,096,609	456,735	4,600,818	3,354,533	2,700,834	2,827,656	2,860,666	2,027,532	3,310,338	2,500,119	3,143,232	3,448,265	3,919,673	2,370,196	552,778	5,190,236	4,776,602	4,342,809
Rifle	0	0	0	0	12,851,988	10,417,795	786,076	0	46,950,004	1,034,797	2,234,115	413,725	3,192,579	1,241,175	1,117,058	0	0	620,586	0	0
Limon 1	26,020	26,020	0	22,203	1,231,579	1,038,203	51,357	0	6,355	0	0	0	0	0	0	0	0	0	0	0
Limon 2	26,020	26,020	0	0	1,407,433	1,048,626	156,061	0	19,661	0	0	0	0	6,921	0	0	0	0	0	0
Knutson 1	9,586	9,586	0	8,179	361,694	419,680	27,404	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	9,586	9,586	0	8,179	408,940	370,954	57,259	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	171,480,537	111,731,773	122,710,105	104,396,303	257,076,320	183,401,325	124,173,961	88,910,200	50,600,266	9,480,933	12,264,412	9,675,949	10,522,693	13,364,311	25,403,848	24,351,379	18,005,318	21,789,054	12,762,469	12,113,479
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	236,312,262	245,719,822	250,626,332	250,080,759	256,217,417	221,178,010	218,572,752	220,948,766	224,080,826	227,237,644	224,872,751
Total	5726854057	5743726155	5968245238	5473733883	5613203615	5718226438	5532345142	5052210960	4113955505	3785176555	3703433547	3831399175	3327906815	3022665802	3182198961	3200812875	2828444813	1836504994	1716243528	1694937259

Scenario Sum (Gallons):	81,072,225,351
Scenario gallons/MWh	383

Year	CO2 (tons)	SO2 (tons)	NOx (tons)	Hg (tons)	PM (tons)	Water (gallons)	RES CO	RPS NM (SB489)
2021	13,248,122	6056	10,257	0.2305	429	5,726,854,057	*C*	*C*
2022	12,940,848	6188	10,482	0.2448	424	5,743,726,155	*C*	*C*
2023	13,306,681	6480	10,886	0.2471	457	5,968,245,238	*C*	*C*
2024	12,121,536	5776	9,812	0.2257	387	5,473,733,881	*C*	*C*
2025	12,483,909	5993	10,165	0.2238	450	5,613,203,615	*C*	*C*
2026	12,437,232	6412	10,180	0.2499	456	5,718,226,436	*C*	*C*
2027	12,137,777	6137	9,604	0.2337	421	5,532,345,140	*C*	*C*
2028	11,141,134	5835	8,918	0.2124	399	5,052,210,969	*C*	*C*
2029	9,596,311	4577	6,770	0.1316	323	4,113,955,503	*C*	*C*
2030	8,605,190	3995	5,913	0.0972	309	3,785,176,551	*C*	*C*
2031	8,562,944	3946	5,819	0.0948	310	3,703,433,543	*C*	*C*
2032	8,673,832	3971	5,889	0.0961	304	3,831,399,175	*C*	*C*
2033	7,583,638	2890	4,418	0.0652	181	3,327,906,815	*C*	*C*
2034	6,984,456	2540	3,896	0.0545	153	3,022,665,802	*C*	*C*
2035	7,307,532	2703	4,129	0.0594	161	3,182,198,961	*C*	*C*
2036	7,389,922	2721	4,093	0.0594	159	3,200,812,876	*C*	*C*
2037	6,627,845	2427	3,707	0.0520	141	2,828,444,813	*C*	*C*
2038	5,001,214	1659	3,092	0.0365	117	1,836,504,994	*C*	*C*
2039	4,835,095	1574	3,001	0.0347	113	1,716,243,528	*C*	*C*
2040	5,053,335	1618	2,997	0.0340	110	1,694,937,299	*C*	*C*
Total	186,038,552	83,497	134,028	2.683	5,804	81,072,225,351		
per MWh**	947	0.43	0.68	0.00001	0.03	206		

TS Thermal Gen Emissions & Water per TS Thermal Gen	**CO2 (lbs/net MWH)**	**SO2 (lbs/net MWH)**	**NOx (lbs/net MWH**	**Hg (lbs/gross MWh)***	**PM (lbs gross MWh)**	**Water (gallons/net MWH**
Scenario Average	1759	0.79	1.27	0.000023	0.05	383

*** This is divided by all thermal MWH even though gas does not have a Mercury impact**

TS Thermal Gen Emissions& Water per Member Load Energy	**CO2 (lbs/net MWH)**	**SO2 (lbs/net MWH)**	**NOx (lbs/net MWH**	**Hg (lbs/gross MWh)**	**PM (lbs gross MWh)**	**Water (gallons/net MWH**
Scenario Average	947	0.43	0.68	0.00001	0.03	206

80pct CR Version 2

2018 ERP Emissions and Water Usage Rates by Unit

	UNIT	CO_2 lbs per Net MWh	SO_2 lbs per Net MWh	NOx lbs per Net MWh	Hg lbs per Gross MWh	PM lbs per Gross MWh	VOC lbs per Gross MWh	Water Usage (gal/MWh)
	LRS 2	2203	1.101	2.331	0.0000411	0.0953	0.036	528
	LRS 3	2407	1.823	2.410	0.0000468	0.1770	0.036	528
	Craig 1	2319	0.378	2.771	0.000017	0.0421	0.00209	492
	Craig 2	2350	0.345	0.672	0.000014	0.0469	0.00210	492
	Craig 3	2090	1.308	2.248	0.000078	0.0614	0.0304	492
	Springerville 3	2139	0.838	0.787	0.000016	0.0306	0.034	546
	Burlington 1	2212	0.206	12.482	N/A	0.162	0.0054	8.82
	Burlington 2	2086	0.182	12.283	N/A	0.153	0.0051	8.82
	Pyramid 1	1240	0.013	1.253	N/A	0.071	0.021	120
	Pyramid 2	1232	0.017	1.169	N/A	0.072	0.019	120
	Pyramid 3	1250	0.012	1.253	N/A	0.072	0.020	120
	Pyramid 4	1238	0.006	1.218	N/A	0.065	0.020	120
	Rifle	1206	0.00063	2.611	N/A	0.239	0.227	1273
	Limon 1	1498	0.008	0.432	N/A	0.0616	0.0010	57
	Limon 2	1492	0.008	0.324	N/A	0.0625	0.0008	57
	Knutson 1	1504	0.0085	0.345	N/A	0.1237	0.000	21
	Knutson 2	1500	0.0098	0.337	N/A	0.1237	0.000	21
	J. M. Shafer	981	0.0078	0.747	N/A	0.0804	0.0694	348
	Basin Nebraska	1240	1.0332	0.738	N/A	N/A	N/A	N/A
	Basin Electric- Colorado/Wyoming	1280	0.40	0.70	N/A	N/A	N/A	390
	Market Purchases	1280	0.40	0.70	N/A	N/A	N/A	N/A
	Energy Imbalance	1280	0.40	0.70	N/A	N/A	N/A	N/A
Expansion Plan Units*	SWCO300MWCC	751	0.008	0.747	N/A	0.0804	0.0694	348

GWh Generation

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1891	1471	1904	1598	1661	1876	1885	1669	1855	1729	1560	1759	1778	1540	1705	1619	1540	1616	1627	1580
LRS 3	1613	1616	1864	1334	1877	1825	1625	1835	1637	1645	1752	1546	155	0	0	0	0	0	0	0
Craig 1	672	763	741	748	604	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	742	782	673	753	652	731	735	376	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	2880	3450	3144	3141	2720	3440	3037	2555	721	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1754	1669	1848	1747	1643	1787	1910	1928	2280	2082	1875	2291	2530	2400	2617	2756	2347	221	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	2	25	11	5	38	29	26	30	23	20	30	27	33	36	35	22	6	48	49	46
Pyramid 2	1	23	11	5	37	30	27	29	24	19	30	25	31	33	35	21	6	49	51	42
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	1	24	11	5	37	29	27	30	25	18	31	24	31	35	35	20	6	49	51	43
Rifle	0	0	0	0	11	14	4	0	59	0	1	1	1	1	0	0	3	0	1	0
Limon 1	0	0	0	0	23	22	6	0	1	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	27	24	8	0	2	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	18	21	5	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	19	22	5	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	493	338	382	341	773	550	447	296	148	29	33	31	29	35	79	75	58	65	49	44
Basin Nebraska	664	683	686	689	692	694	698	701	704	707	711	715	718	722	725	729	733	736	740	859
Basin Electric- Colorado/Wyoming	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627
Market Purchases	1396	722	620	420	735	212	535	659	1727	1494	1816	1533	1935	2014	2070	2231	2231	2844	3051	3544
Energy Imbalance	148	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135
SWCO300MWCC	0	0	0	0	0	0	0	0	0	734	780	793	810	808	641	632	655	672	654	669
Total	13886	13331	13657	12548	13327	13069	12741	11870	10968	10239	10381	10507	9813	9387	9704	9868	9347	8063	8037	8590
																		Scenario sum		219334

CO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2082842	1620555	2097656	1760013	1829238	2066196	2075993	1838426	2042820	1903965	1718521	1937045	1958357	1696586	1877728	1783033	1696427	1780364	1792538	1740259
LRS 3	1941677	1944812	2243827	1605732	2258576	2196727	1955167	2208491	1970563	1979807	2108347	1860165	187100	0	0	0	0	0	0	0
Craig 1	778917	884559	858945	866819	699891	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	872202	919061	790783	885027	765924	859144	863342	442244	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3009639	3605275	3285479	3282063	2842178	3594365	3173784	2669618	753855	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1876411	1785058	1976004	1868468	1757301	1911628	2042531	2061667	2437945	2226655	2005246	2450127	2705806	2566815	2798600	2947372	2510197	236330	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1055	15423	6771	3154	23744	18270	15918	18330	14347	12291	18901	16848	20424	22622	21981	13361	3975	29805	30492	28696
Pyramid 2	570	14262	6629	2948	22526	18269	16581	17966	14848	11758	18671	15694	19350	20198	21289	13145	3505	30198	31456	25918
Pyramid 3	197	197	0	0	0	0	30	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	505	14755	6602	2951	23024	18175	16696	18793	15258	11326	18962	15002	19161	21372	21627	12565	3622	30209	31700	26439
Rifle	0	0	0	0	6768	8165	2313	0	35810	294	431	750	568	747	0	0	1607	59	901	0
Limon 1	342	342	0	0	16856	16689	4603	0	537	0	0	0	0	73	0	0	0	0	200	0
Limon 2	341	341	0	291	20105	17588	6270	0	1251	0	136	206	62	282	0	0	0	0	0	0
Knutson 1	343	343	0	293	13584	15795	3453	0	145	0	0	0	0	143	0	0	0	0	64	0
Knutson 2	342	342	0	0	14549	16600	3731	0	163	0	0	0	0	71	0	0	0	0	356	0
J. M. Shafer	241699	165878	187553	167193	378935	269863	219271	145266	72374	14056	15978	15308	14082	17331	38927	36793	28505	32061	23965	21615
Basin Nebraska	411673	423307	425113	427068	428761	430577	432497	434596	436450	438412	440667	443039	445137	447366	449665	452056	454218	456462	458732	532811
Basin Electric- Colorado/Wyoming	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228
Market Purchases	893648	462080	396633	268718	376323	108571	274015	337296	884400	765092	929603	784983	990536	1031002	1059940	1142428	1142161	1456149	1561961	1814752
Energy Imbalance	94493	86656	86656	86656	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325
SWCO300MWCC	0	0	0	0	0	0	0	0	0	275495	293049	297638	304183	303350	240528	237400	245975	252437	245620	251207
Total	13248122	12984474	13409879	12268619	12588836	12677176	12216747	11303247	9791318	8749703	8679065	8947358	7775321	7238511	7640839	7748707	7200745	5414627	5288539	5552251
																		Scenario Sum tons:		190,724,082
																		Scenario lbs/MWh		1739

SO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1041	810	1048	880	914	1033	1038	919	1021	952	859	968	979	848	938	891	848	890	896	870
LRS 3	1471	1473	1699	1216	1711	1664	1481	1673	1492	1499	1597	1409	142	0	0	0	0	0	0	0
Craig 1	127	144	140	141	114	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	128	135	116	130	112	126	127	65	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1884	2256	2056	2054	1779	2249	1986	1671	472	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	735	699	774	732	688	749	800	808	955	872	786	960	1060	1006	1096	1155	983	93	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rifle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	2	1	1	1	3	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0
Basin Nebraska	343	353	354	356	357	359	360	362	364	365	367	369	371	373	375	377	378	380	382	444
Basin Electric- Colorado/Wyoming	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	3	3	3	3	3	2	2	3	3	3	3
Total	6056	6197	6515	5836	6005	6508	6120	5824	4630	4017	3938	4035	2881	2556	2738	2751	2538	1692	1607	1643

Scenario Sum tons: 84,087
Scenario lbs/MWh 0.77

Nox

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2204	1715	2220	1862	1936	2186	2197	1945	2162	2015	1818	2050	2072	1795	1987	1887	1795	1884	1897	1841
LRS 3	1944	1947	2247	1608	2261	2199	1958	2211	1973	1982	2111	1862	187	0	0	0	0	0	0	0
Craig 1	931	1057	1026	1036	836	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	249	263	226	253	219	246	247	126	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3237	3878	3534	3530	3057	3866	3414	2871	811	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	690	657	727	687	647	703	752	759	897	819	738	901	996	944	1030	1084	924	87	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1	16	7	3	24	18	16	19	14	12	19	17	21	23	22	14	4	30	31	29
Pyramid 2	1	14	6	3	21	17	16	17	14	11	18	15	18	19	20	12	3	29	30	25
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	15	6	3	23	18	16	18	15	11	19	15	19	21	21	12	4	30	31	26
Rifle	0	0	0	0	15	18	5	0	78	1	1	2	1	2	0	0	3	0	2	0
Limon 1	0	0	0	0	5	5	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	4	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	3	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	3	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	184	126	143	127	289	205	167	111	55	11	12	12	11	13	30	28	22	24	18	16
Basin Nebraska	245	252	253	254	255	256	257	259	260	261	262	264	265	266	268	269	270	272	273	317
Basin Electric- Colorado/Wyoming	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	274	291	296	303	302	239	236	245	251	244	250
Total	10257	10508	10964	9936	10167	10319	9618	8906	6848	5967	5859	6003	4462	3955	4186	4112	3839	3176	3096	3074

Scenario Sum tons: 135,252
Scenario lbs/MWh 1

Hg

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	0.0418	0.0325	0.0421	0.0353	0.0367	0.0415	0.0417	0.0369	0.0410	0.0382	0.0345	0.0389	0.0393	0.0341	0.0377	0.0358	0.0341	0.0357	0.0360	0.0349
LRS 3	0.0406	0.0407	0.0469	0.0336	0.0473	0.0460	0.0409	0.0462	0.0412	0.0414	0.0441	0.0389	0.0039	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 1	0.0062	0.0070	0.0068	0.0069	0.0055	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 2	0.0056	0.0059	0.0051	0.0057	0.0049	0.0055	0.0055	0.0028	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 3	0.1211	0.1450	0.1322	0.1320	0.1143	0.1446	0.1277	0.1074	0.0303	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Springerville 3	0.0153	0.0145	0.0161	0.0152	0.0143	0.0156	0.0166	0.0168	0.0198	0.0181	0.0163	0.0199	0.0220	0.0209	0.0228	0.0240	0.0204	0.0019	0.0000	0.0000
Burlington 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Burlington 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Rifle	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
J. M. Shafer	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	0.2305	0.2457	0.2492	0.2287	0.2231	0.2531	0.2324	0.2101	0.1324	0.0978	0.0949	0.0977	0.0652	0.0549	0.0605	0.0598	0.0545	0.0377	0.0360	0.0349

Scenario Sum tons: 2.699
Scenario lbs/MWh 0.000022

PM

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	97	75	98	82	85	96	97	86	95	89	80	90	91	79	87	83	79	83	83	81
LRS 3	154	154	178	127	179	174	155	175	156	157	167	147	15	0	0	0	0	0	0	0
Craig 1	15	17	17	17	14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	19	20	17	19	16	18	19	10	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	95	114	104	104	90	114	101	85	24	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	29	28	31	29	27	30	32	32	38	35	31	38	42	40	44	46	39	4	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	2	2	2
Pyramid 2	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	2	2	2
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	2	2	1
Rifle	0	0	0	0	1	2	0	0	7	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	20	14	16	14	31	22	18	12	6	1	1	1	1	1	3	3	2	3	2	2
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	30	32	32	33	33	26	26	27	27	27	27
Total	429	425	460	392	452	463	425	402	329	313	314	312	186	157	164	160	148	122	118	115

Scenario Sum tons: 5,884
Scenario lbs/MWh 0.05

Water

Gallons

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	998,402,713	776,807,074	1,005,503,755	843,655,733	876,838,623	990,423,405	995,119,524	881,242,933	979,218,425	912,658,573	823,766,728	928,515,514	938,731,194	813,252,173	900,081,959	854,690,430	813,175,920	853,410,935	859,246,534	834,186,876
LRS 3	851,853,147	853,228,904	984,412,812	704,467,256	990,883,430	963,749,146	857,771,661	968,910,189	864,525,974	868,581,724	924,974,831	816,092,283	82,084,524	0	0	0	0	0	0	0
Craig 1	330,510,581	375,336,854	364,468,311	367,809,167	296,978,394	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	365,211,193	384,832,350	331,119,446	370,581,316	320,710,153	359,743,814	361,501,708	185,177,873	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1,416,978,435	1,697,411,637	1,546,847,621	1,545,239,455	1,338,135,269	1,692,275,160	1,494,260,177	1,256,891,887	354,924,866	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	957,943,556	911,306,087	1,008,787,534	953,888,053	897,135,423	975,922,486	1,042,750,954	1,052,520,219	1,244,617,109	1,136,749,766	1,023,716,001	1,250,836,072	1,381,365,271	1,310,407,506	1,428,738,433	1,504,689,376	1,281,502,879	120,651,134	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	204,150	2,985,102	1,310,464	610,484	4,595,653	3,536,116	3,080,805	3,547,768	2,776,883	2,378,842	3,658,211	3,260,977	3,953,054	4,378,539	4,254,379	2,586,047	769,289	5,768,715	5,901,767	5,554,102
Pyramid 2	111,000	2,778,230	1,291,287	574,232	4,388,278	3,558,952	3,229,983	3,499,900	2,892,379	2,290,485	3,637,265	3,057,238	3,769,547	3,934,767	4,147,302	2,560,737	682,886	5,882,817	6,127,832	5,049,031
Pyramid 3	37,884	37,884	0	0	0	0	5,764	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	97,884	2,860,391	1,279,827	572,054	4,463,394	3,523,380	3,236,611	3,643,222	2,957,854	2,195,602	3,675,911	2,908,268	3,714,536	4,143,165	4,192,643	2,435,919	702,252	5,856,139	6,145,327	5,125,574
Rifle	0	0	0	0	14,288,324	17,236,193	4,881,955	0	75,598,151	620,588	910,196	1,583,948	1,199,805	1,576,676	0	0	3,392,546	124,118	1,903,135	0
Limon 1	26,020	26,020	0	0	1,282,750	1,270,084	350,325	0	40,885	0	0	0	0	5,529	0	0	0	0	15,221	0
Limon 2	26,020	26,020	0	22,203	1,536,143	1,343,843	479,040	0	95,606	0	10,369	15,716	4,769	21,563	0	0	0	0	0	0
Knutson 1	9,586	9,586	0	8,179	379,344	441,093	96,418	0	4,053	0	0	0	0	3,990	0	0	0	0	1,791	0
Knutson 2	9,586	9,586	0	0	407,373	464,812	104,482	0	4,553	0	0	0	0	1,978	0	0	0	0	9,968	0
J. M. Shafer	171,480,537	117,686,970	133,065,134	118,619,870	268,846,974	191,462,411	155,568,309	103,063,249	51,347,661	9,972,185	11,335,898	10,860,871	9,991,157	12,295,705	27,617,965	26,103,568	20,223,654	22,746,667	17,002,807	15,335,239
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	255,318,709	271,587,657	275,840,259	281,906,001	281,134,069	222,912,796	220,014,033	227,961,288	233,949,614	227,632,034	232,809,948
Total	5726854057	5759294460	6012037957	5539999761	5654821295	5838902658	5556389500	5092449011	4212956177	3824718238	3701224831	3926922913	3340671623	3065107428	3225897233	3247031866	2982362473	1882342021	1757938157	1732012501

Scenario Sum (Gallons): 82,079,934,163
Scenario gallons/MWh 374

Year	CO_2 (tons)	SO_2 (tons)	NO_x (tons)	Hg (tons)	PM (tons)	Water (gallons)	RES CO	RPS NM (SB489)
2021	13,248,122	6056	10,257	0.2305	429	5,726,854,057	*C*	*C*
2022	12,984,474	6197	10,508	0.2457	425	5,759,294,460	*C*	*C*
2023	13,409,879	6515	10,964	0.2492	460	6,012,037,957	*C*	*C*
2024	12,268,619	5836	9,936	0.2287	392	5,539,999,761	*C*	*C*
2025	12,588,836	6005	10,167	0.2231	452	5,654,821,299	*C*	*C*
2026	12,677,176	6508	10,319	0.2531	463	5,838,902,658	*C*	*C*
2027	12,216,747	6120	9,618	0.2324	425	5,556,389,500	*C*	*C*
2028	11,303,247	5824	8,906	0.2101	402	5,092,449,011	*C*	*C*
2029	9,791,318	4630	6,848	0.1324	329	4,212,956,177	*C*	*C*
2030	8,749,703	4017	5,967	0.0978	313	3,824,718,238	*C*	*C*
2031	8,679,065	3938	5,859	0.0949	314	3,701,224,831	*C*	*C*
2032	8,947,358	4035	6,003	0.0977	312	3,926,922,913	*C*	*C*
2033	7,775,321	2881	4,462	0.0652	186	3,340,671,623	*C*	*C*
2034	7,238,511	2556	3,955	0.0549	157	3,065,107,428	*C*	*C*
2035	7,640,839	2738	4,186	0.0605	164	3,225,897,233	*C*	*C*
2036	7,748,707	2751	4,112	0.0598	160	3,247,031,866	*C*	*C*
2037	7,200,745	2538	3,839	0.0545	148	2,982,362,473	*C*	*C*
2038	5,414,627	1692	3,176	0.0377	122	1,882,342,021	*C*	*C*
2039	5,288,539	1607	3,096	0.0360	118	1,757,938,157	*C*	*C*
2040	5,552,251	1643	3,074	0.0349	115	1,732,012,501	*C*	*C*
Total	190,724,082	84,087	135,252	2.699	5,884	82,079,934,163		
per MWh**	971	0.43	0.69	0.00001	0.03	209		

TS Thermal Gen Emissions & Water per TS Thermal Gen	CO2 (lbs/net MWH)	SO2 (lbs/net MWH)	NOx (lbs/net MWH	Hg (lbs/gross MWh)*	PM (lbs gross MWh)	Water (gallons/net MWH
Scenario Average	1739	0.77	1.23	0.000022	0.05	374

*** This is divided by all thermal MWH even though gas does not have a Mercury impact**

TS Thermal Gen Emissions& Water per Member Load Energy	CO2 (lbs/net MWH)	SO2 (lbs/net MWH)	NOx (lbs/net MWH	Hg (lbs/gross MWh)	PM (lbs gross MWh)	Water (gallons/net MWH
Scenario Average	971	0.43	0.69	0.00001	0.03	209

80pct CR Version 3

2018 ERP Emissions and Water Usage Rates by Unit

	UNIT	CO_2 lbs per Net MWh	SO_2 lbs per Net MWh	NOx lbs per Net MWh	Hg lbs per Gross MWh	PM lbs per Gross MWh	VOC lbs per Gross MWh	Water Usage (gal/MWh)
	LRS 2	2203	1.101	2.331	0.0000411	0.0953	0.036	528
	LRS 3	2407	1.823	2.410	0.0000468	0.1770	0.036	528
	Craig 1	2319	0.378	2.771	0.000017	0.0421	0.00209	492
	Craig 2	2350	0.345	0.672	0.000014	0.0469	0.00210	492
	Craig 3	2090	1.308	2.248	0.000078	0.0614	0.0304	492
	Springerville 3	2139	0.838	0.787	0.000016	0.0306	0.034	546
	Burlington 1	2212	0.206	12.482	N/A	0.162	0.0054	8.82
	Burlington 2	2086	0.182	12.283	N/A	0.153	0.0051	8.82
	Pyramid 1	1240	0.013	1.253	N/A	0.071	0.021	120
	Pyramid 2	1232	0.017	1.169	N/A	0.072	0.019	120
	Pyramid 3	1250	0.012	1.253	N/A	0.072	0.020	120
	Pyramid 4	1238	0.006	1.218	N/A	0.065	0.020	120
	Rifle	1206	0.00063	2.611	N/A	0.239	0.227	1273
	Limon 1	1498	0.008	0.432	N/A	0.0616	0.0010	57
	Limon 2	1492	0.008	0.324	N/A	0.0625	0.0008	57
	Knutson 1	1504	0.0085	0.345	N/A	0.1237	0.000	21
	Knutson 2	1500	0.0098	0.337	N/A	0.1237	0.000	21
	J. M. Shafer	981	0.0078	0.747	N/A	0.0804	0.0694	348
	Basin Nebraska	1240	1.0332	0.738	N/A	N/A	N/A	N/A
	Basin Electric- Colorado/Wyoming	1280	0.40	0.70	N/A	N/A	N/A	390
	Market Purchases	1280	0.40	0.70	N/A	N/A	N/A	N/A
	Energy Imbalance	1280	0.40	0.70	N/A	N/A	N/A	N/A
Expansion Plan Units*	SWCO300MWCC	751	0.008	0.747	N/A	0.0804	0.0694	348

GWh Generation

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1891	1503	1903	1613	1661	1876	1885	1669	1855	1679	1534	1759	1778	1540	1705	1619	1540	1616	1627	1580
LRS 3	1613	1650	1863	1352	1876	1825	1625	1835	1637	1604	1710	1546	155	0	0	0	0	0	0	0
Craig 1	672	671	680	685	557	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	742	785	675	758	661	731	735	376	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	2880	3473	3191	3169	2730	3440	3037	2555	721	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1754	1675	1849	1746	1560	1787	1910	1928	2280	2070	1962	2291	2530	2400	2617	2756	2347	221	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	2	24	11	5	38	29	26	30	23	19	29	27	33	36	35	22	6	48	49	46
Pyramid 2	1	23	11	5	37	30	27	29	24	19	29	25	31	33	35	21	6	49	51	42
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	1	24	11	5	36	29	27	30	25	18	29	24	31	35	35	20	6	49	51	43
Rifle	0	0	0	0	11	14	4	0	59	1	25	1	1	1	0	0	3	0	1	0
Limon 1	0	0	0	0	25	22	6	0	1	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	29	24	8	0	2	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	22	21	5	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	22	22	5	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	493	333	382	343	766	550	447	296	148	29	32	31	29	35	79	75	58	65	49	44
Basin Nebraska	664	683	686	689	692	694	698	701	704	707	711	715	718	722	725	729	733	736	740	859
Basin Electric- Colorado/Wyoming	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627
Market Purchases	1396	714	627	413	808	212	535	659	1727	1392	1628	1533	1935	2014	2070	2231	2231	2844	3051	3544
Energy Imbalance	148	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135
SWCO300MWCC	0	0	0	0	0	0	0	0	0	730	757	793	810	808	641	632	655	672	654	669
Total	13886	13322	13650	12546	13293	13069	12741	11870	10968	10030	10208	10507	9813	9387	9704	9868	9347	8063	8037	8590
																		Scenario sum		218900

CO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2082842	1655303	2095923	1776784	1829163	2066196	2075993	1838426	2042820	1849376	1690012	1937045	1958357	1696586	1877728	1783033	1696427	1780364	1792538	1740259
LRS 3	1941677	1986209	2242100	1627219	2257199	2196727	1955167	2208491	1970563	1930100	2058133	1860165	187100	0	0	0	0	0	0	0
Craig 1	778917	777981	788170	794713	646235	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	872202	921846	793271	890641	776986	859144	863342	442244	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3009639	3629287	3334168	3311884	2852495	3594365	3173784	2669618	753855	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1876411	1791116	1977786	1867400	1667992	1911628	2042531	2061667	2437945	2214011	2097899	2450127	2705806	2566815	2798600	2947372	2510197	236330	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1055	14937	6791	3249	23752	18270	15918	18330	14347	11581	18108	16848	20424	22622	21981	13361	3975	29805	30492	28696
Pyramid 2	570	14037	6531	2892	22679	18269	16581	17966	14848	11406	17637	15694	19350	20198	21289	13145	3505	30198	31456	25918
Pyramid 3	197	197	0	0	0	0	30	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	505	14939	6712	2912	22547	18175	16696	18793	15258	11203	17748	15002	19161	21372	21627	12565	3622	30209	31700	26439
Rifle	0	0	0	0	6866	8165	2313	0	35810	628	15072	750	568	747	0	0	1607	59	901	0
Limon 1	342	342	0	0	18768	16689	4603	0	537	0	0	0	0	73	0	0	0	0	200	0
Limon 2	341	341	0	0	21715	17588	6270	0	1251	0	0	206	62	282	0	0	0	0	0	0
Knutson 1	343	343	0	293	16225	15795	3453	0	145	0	0	0	0	143	0	0	0	0	64	0
Knutson 2	342	342	0	292	16624	16600	3731	0	163	0	130	0	0	71	0	0	0	0	356	0
J. M. Shafer	241699	163507	187283	168350	375950	269863	219271	145266	72374	14032	15859	15308	14082	17331	38927	36793	28505	32061	23965	21615
Basin Nebraska	411673	423307	425113	427068	428761	430577	432497	434596	436450	438412	440667	443039	445137	447366	449665	452056	454218	456462	458732	532811
Basin Electric- Colorado/Wyoming	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228
Market Purchases	893648	457109	401472	264118	413511	108571	274015	337296	884400	712680	833332	784983	990536	1031002	1059940	1142428	1142161	1456149	1561961	1814752
Energy Imbalance	94493	86656	86656	86656	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325
SWCO300MWCC	0	0	0	0	0	0	0	0	0	219403	227489	238110	243346	242680	192422	189920	196780	201950	196496	200966
Total	13248122	12979028	13393204	12265698	12508020	12677176	12216747	11303247	9791318	8523385	8542638	8887830	7714484	7177841	7592733	7701227	7151550	5364139	5239415	5502009
																		Scenario Sum tons:		189,779,811
																		Scenario lbs/MWh		1734

SO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1041	827	1047	888	914	1033	1038	919	1021	924	845	968	979	848	938	891	848	890	896	870
LRS 3	1471	1504	1698	1232	1710	1664	1481	1673	1492	1462	1559	1409	142	0	0	0	0	0	0	0
Craig 1	127	127	128	130	105	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	128	135	116	131	114	126	127	65	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1884	2271	2087	2073	1785	2249	1986	1671	472	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	735	702	775	732	653	749	800	808	955	867	822	960	1060	1006	1096	1155	983	93	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rifle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	2	1	1	1	3	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0
Basin Nebraska	343	353	354	356	357	359	360	362	364	365	367	369	371	373	375	377	378	380	382	444
Basin Electric- Colorado/Wyoming	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	3	3	3	3	3	2	2	3	3	3	3
Total	6056	6247	6533	5868	5969	6508	6120	5824	4630	3947	3921	4035	2881	2556	2738	2751	2538	1692	1607	1643

Scenario Sum tons: 84,063
Scenario lbs/MWh 0.77

Nox

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2204	1751	2218	1880	1935	2186	2197	1945	2162	1957	1788	2050	2072	1795	1987	1887	1795	1884	1897	1841
LRS 3	1944	1989	2245	1629	2260	2199	1958	2211	1973	1933	2061	1862	187	0	0	0	0	0	0	0
Craig 1	931	930	942	950	772	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	249	264	227	255	222	246	247	126	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3237	3904	3586	3562	3068	3866	3414	2871	811	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	690	659	728	687	614	703	752	759	897	815	772	901	996	944	1030	1084	924	87	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1	15	7	3	24	18	16	19	14	12	18	17	21	23	22	14	4	30	31	29
Pyramid 2	1	13	6	3	22	17	16	17	14	11	17	15	18	19	20	12	3	29	30	25
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	15	7	3	22	18	16	18	15	11	17	15	19	21	21	12	4	30	31	26
Rifle	0	0	0	0	15	18	5	0	78	1	33	2	1	2	0	0	3	0	2	0
Limon 1	0	0	0	0	5	5	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	5	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	4	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	4	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	184	125	143	128	286	205	167	111	55	11	12	12	11	13	30	28	22	24	18	16
Basin Nebraska	245	252	253	254	255	256	257	259	260	261	262	264	265	266	268	269	270	272	273	317
Basin Electric- Colorado/Wyoming	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	273	283	296	303	302	239	236	245	251	244	250
Total	10257	10486	10930	9924	10083	10319	9618	8906	6848	5853	5833	6003	4462	3955	4186	4112	3839	3176	3096	3074

Scenario Sum tons: 134,957
Scenario lbs/MWh 1

Hg

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	0.0418	0.0332	0.0421	0.0357	0.0367	0.0415	0.0417	0.0369	0.0410	0.0371	0.0339	0.0389	0.0393	0.0341	0.0377	0.0358	0.0341	0.0357	0.0360	0.0349
LRS 3	0.0406	0.0416	0.0469	0.0340	0.0472	0.0460	0.0409	0.0462	0.0412	0.0404	0.0431	0.0389	0.0039	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 1	0.0062	0.0061	0.0062	0.0063	0.0051	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 2	0.0056	0.0059	0.0051	0.0057	0.0050	0.0055	0.0055	0.0028	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 3	0.1211	0.1460	0.1341	0.1332	0.1148	0.1446	0.1277	0.1074	0.0303	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Springerville 3	0.0153	0.0146	0.0161	0.0152	0.0136	0.0156	0.0166	0.0168	0.0198	0.0180	0.0171	0.0199	0.0220	0.0209	0.0228	0.0240	0.0204	0.0019	0.0000	0.0000
Burlington 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Burlington 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Rifle	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
J. M. Shafer	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	0.2305	0.2474	0.2505	0.2302	0.2224	0.2531	0.2324	0.2101	0.1324	0.0955	0.0941	0.0977	0.0652	0.0549	0.0605	0.0598	0.0545	0.0377	0.0360	0.0349

Scenario Sum tons: 2.700
Scenario lbs/MWh 0.000022

PM

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	97	77	98	83	85	96	97	86	95	86	79	90	91	79	87	83	79	83	83	81
LRS 3	154	157	177	129	179	174	155	175	156	153	163	147	15	0	0	0	0	0	0	0
Craig 1	15	15	15	16	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	19	20	17	19	17	18	19	10	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	95	115	106	105	90	114	101	85	24	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	29	28	31	29	26	30	32	32	38	34	33	38	42	40	44	46	39	4	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	2	2	2
Pyramid 2	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	2	2	2
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	2	2	1
Rifle	0	0	0	0	1	2	0	0	7	0	3	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	20	14	16	14	31	22	18	12	6	1	1	1	1	1	3	3	2	3	2	2
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWC0300MWCC	0	0	0	0	0	0	0	0	0	30	31	32	33	33	26	26	27	27	27	27
Total	429	428	460	395	450	463	425	402	329	306	312	312	186	157	164	160	148	122	118	115

Scenario Sum tons: 5,879
Scenario lbs/MWh 0.05

Water

Gallons

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	998,402,713	793,463,646	1,004,673,227	851,694,858	876,802,700	990,423,405	995,119,524	881,242,938	979,218,425	886,491,456	810,101,247	928,515,516	938,731,196	813,252,178	900,081,959	854,690,430	813,175,922	853,410,935	859,246,534	834,186,876
LRS 3	851,853,147	871,390,299	983,655,031	713,894,288	990,279,070	963,749,146	857,771,667	968,910,189	864,525,976	846,774,239	902,944,882	816,092,283	82,084,524	0	0	0	0	0	0	0
Craig 1	330,510,581	330,113,561	334,436,758	337,213,266	274,210,876	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	365,211,193	385,998,568	332,161,126	372,932,085	325,342,089	359,743,814	361,501,708	185,177,873	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1,416,978,435	1,708,716,751	1,569,770,951	1,559,279,216	1,342,992,935	1,692,275,160	1,494,260,177	1,256,891,887	354,924,866	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	957,943,556	914,398,777	1,009,696,979	953,342,939	851,541,691	975,922,486	1,042,750,956	1,052,520,219	1,244,617,109	1,130,294,766	1,071,017,058	1,250,836,072	1,381,365,271	1,310,407,506	1,428,738,432	1,504,689,374	1,281,502,878	120,651,134	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	204,150	2,891,098	1,314,466	628,816	4,597,115	3,536,116	3,080,809	3,547,769	2,776,883	2,241,483	3,504,749	3,260,977	3,953,054	4,378,539	4,254,373	2,586,047	769,289	5,768,715	5,901,767	5,554,102
Pyramid 2	111,000	2,734,545	1,272,178	563,419	4,418,047	3,558,952	3,229,983	3,499,900	2,892,379	2,221,898	3,435,773	3,057,238	3,769,547	3,934,767	4,147,302	2,560,737	682,884	5,882,817	6,127,832	5,049,031
Pyramid 3	37,884	37,884	0	0	0	0	5,766	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	97,884	2,896,057	1,301,272	564,535	4,370,920	3,523,380	3,236,615	3,643,222	2,957,854	2,171,827	3,440,601	2,908,268	3,714,536	4,143,165	4,192,641	2,435,919	702,252	5,856,316	6,145,327	5,125,574
Rifle	0	0	0	0	14,495,223	17,236,191	4,881,955	0	75,598,151	1,324,782	31,819,173	1,583,948	1,199,803	1,576,676	0	0	3,392,545	124,118	1,903,135	0
Limon 1	26,020	26,020	0	0	1,428,286	1,270,084	350,329	0	40,885	0	0	0	0	5,529	0	0	0	0	15,221	0
Limon 2	26,020	26,020	0	0	1,659,184	1,343,841	479,040	0	95,606	0	0	15,716	4,769	21,562	0	0	0	0	0	0
Knutson 1	9,586	9,586	0	8,179	453,097	441,095	96,416	0	4,053	0	0	0	0	3,990	0	0	0	0	1,791	0
Knutson 2	9,586	9,586	0	8,179	465,478	464,812	104,482	0	4,557	0	3,647	0	0	1,976	0	0	0	0	9,963	0
J. M. Shafer	171,480,537	116,004,883	132,873,701	119,440,660	266,728,900	191,462,411	155,568,309	103,063,249	51,347,667	9,955,626	11,251,351	10,860,871	9,991,157	12,295,705	27,617,965	26,103,563	20,223,654	22,746,607	17,002,807	15,335,210
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWC0300MWCC	0	0	0	0	0	0	0	0	0	254,168,322	263,535,345	275,840,259	281,906,001	281,134,069	222,912,795	220,014,031	227,961,283	233,949,614	227,632,014	232,809,943
Total	572685057	5762669045	6005107457	5543522205	5593737378	5838902658	5556389500	5092449011	4212956177	3769596165	3735005592	3926922913	3340671623	3065107428	3225897233	3247031866	2982362473	1882342021	1757938157	1732012501

Scenario Sum (Gallons): 81,997,475,457
Scenario gallons/MWh 375

Year	CO_2 (tons)	SO_2 (tons)	NO_x (tons)	Hg (tons)	PM (tons)	Water (gallons)	RES CO	RPS NM (SB489)
2021	13,248,122	6056	10,257	0.2305	429	5,726,854,057	*C*	*C*
2022	12,979,028	6247	10,486	0.2474	428	5,762,669,045	*C*	*C*
2023	13,393,204	6533	10,930	0.2505	460	6,005,107,457	*C*	*C*
2024	12,265,698	5868	9,924	0.2302	395	5,543,522,205	*C*	*C*
2025	12,508,020	5969	10,083	0.2224	450	5,593,737,378	*C*	*C*
2026	12,677,176	6508	10,319	0.2531	463	5,838,902,658	*C*	*C*
2027	12,216,747	6120	9,618	0.2324	425	5,556,389,500	*C*	*C*
2028	11,303,247	5824	8,906	0.2101	402	5,092,449,011	*C*	*C*
2029	9,791,318	4630	6,848	0.1324	329	4,212,956,177	*C*	*C*
2030	8,523,385	3947	5,853	0.0955	306	3,769,596,165	*C*	*C*
2031	8,542,638	3921	5,833	0.0941	312	3,735,005,592	*C*	*C*
2032	8,887,830	4035	6,003	0.0977	312	3,926,922,913	*C*	*C*
2033	7,714,484	2881	4,462	0.0652	186	3,340,671,623	*C*	*C*
2034	7,177,841	2556	3,955	0.0549	157	3,065,107,428	*C*	*C*
2035	7,592,733	2738	4,186	0.0605	164	3,225,897,233	*C*	*C*
2036	7,701,227	2751	4,112	0.0598	160	3,247,031,866	*C*	*C*
2037	7,151,550	2538	3,839	0.0545	148	2,982,362,473	*C*	*C*
2038	5,364,139	1692	3,176	0.0377	122	1,882,342,021	*C*	*C*
2039	5,239,415	1607	3,096	0.0360	118	1,757,938,157	*C*	*C*
2040	5,502,009	1643	3,074	0.0349	115	1,732,012,501	*C*	*C*
Total	189,779,811	84,063	134,957	2.700	5,879	81,997,475,457		
per MWh*	966	0.43	0.69	0.00001	0.03	209		

TS Thermal Gen Emissions & Water per TS Thermal Gen	**CO2 (lbs/net MWH)**	**SO2 (lbs/net MWH)**	**NOx (lbs/net MWH**	**Hg (lbs/gross MWh)***	**PM (lbs gross MWh)**	**Water (gallons/net MWH**
Scenario Average	1734	0.77	1.23	0.000022	0.05	375

*** This is divided by all thermal MWH even though gas does not have a Mercury impact**

TS Thermal Gen Emissions& Water per Member Load Energy	**CO2 (lbs/net MWH)**	**SO2 (lbs/net MWH)**	**NOx (lbs/net MWH**	**Hg (lbs/gross MWh)**	**PM (lbs gross MWh)**	**Water (gallons/net MWH**
Scenario Average	966	0.43	0.69	0.00001	0.03	209

80pct CR Version 4

2018 ERP Emissions and Water Usage Rates by Unit

	UNIT	CO_2 lbs per Net MWh	SO_2 lbs per Net MWh	NOx lbs per Net MWh	Hg lbs per Gross MWh	PM lbs per Gross MWh	VOC lbs per Gross MWh	Water Usage (gal/MWh)
	LRS 2	2203	1.101	2.331	0.0000411	0.0953	0.036	528
	LRS 3	2407	1.823	2.410	0.0000468	0.1770	0.036	528
	Craig 1	2319	0.378	2.771	0.000017	0.0421	0.00209	492
	Craig 2	2350	0.345	0.672	0.000014	0.0469	0.00210	492
	Craig 3	2090	1.308	2.248	0.000078	0.0614	0.0304	492
	Springerville 3	2139	0.838	0.787	0.000016	0.0306	0.034	546
	Burlington 1	2212	0.206	12.482	N/A	0.162	0.0054	8.82
	Burlington 2	2086	0.182	12.283	N/A	0.153	0.0051	8.82
	Pyramid 1	1240	0.013	1.253	N/A	0.071	0.021	120
	Pyramid 2	1232	0.017	1.169	N/A	0.072	0.019	120
	Pyramid 3	1250	0.012	1.253	N/A	0.072	0.020	120
	Pyramid 4	1238	0.006	1.218	N/A	0.065	0.020	120
	Rifle	1206	0.00063	2.611	N/A	0.239	0.227	1273
	Limon 1	1498	0.008	0.432	N/A	0.0616	0.0010	57
	Limon 2	1492	0.008	0.324	N/A	0.0625	0.0008	57
	Knutson 1	1504	0.0085	0.345	N/A	0.1237	0.000	21
	Knutson 2	1500	0.0098	0.337	N/A	0.1237	0.000	21
	J. M. Shafer	981	0.0078	0.747	N/A	0.0804	0.0694	348
	Basin Nebraska	1240	1.0332	0.738	N/A	N/A	N/A	N/A
	Basin Electric- Colorado/Wyoming	1280	0.40	0.70	N/A	N/A	N/A	390
	Market Purchases	1280	0.40	0.70	N/A	N/A	N/A	N/A
	Energy Imbalance	1280	0.40	0.70	N/A	N/A	N/A	N/A
Expansion Plan Units*	SWCO300MWCC	751	0.008	0.747	N/A	0.0804	0.0694	348

GWh Generation

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1891	1503	1903	1613	1661	1876	1885	1669	1855	1718	1553	1750	1770	1535	1703	1644	1534	1619	1626	1578
LRS 3	1613	1650	1863	1352	1876	1825	1625	1835	1637	1646	1743	1536	155	0	0	0	0	0	0	0
Craig 1	672	671	680	685	557	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	742	785	675	758	661	731	735	376	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	2880	3473	3191	3169	2730	3440	3037	2555	721	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1754	1675	1849	1746	1560	1787	1910	1928	2280	2066	1861	2277	2502	2370	2611	2663	2169	220	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	2	24	11	5	38	29	26	30	23	15	31	28	33	36	37	23	6	49	50	45
Pyramid 2	1	23	11	5	37	30	27	29	24	14	31	25	31	33	35	23	6	53	46	40
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	1	24	11	5	36	29	27	30	25	14	30	25	30	34	36	22	5	53	47	41
Rifle	0	0	0	0	11	14	4	0	59	2	1	5	2	3	1	2	2	0	1	0
Limon 1	0	0	0	0	25	22	6	0	1	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	29	24	8	0	2	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	22	21	5	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	22	22	5	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	493	333	382	343	766	550	447	296	148	141	34	31	29	36	80	72	62	65	53	39
Basin Nebraska	664	683	686	689	692	694	698	701	704	707	711	715	718	722	725	729	733	736	740	859
Basin Electric- Colorado/Wyoming	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627
Market Purchases	1396	714	627	413	808	212	535	659	1727	1085	1797	1513	1935	1991	2042	2241	2275	2822	3003	3484
Energy Imbalance	148	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135
SWCO300MWCC	0	0	0	0	0	0	0	0	0	1163	775	787	785	809	639	630	652	668	661	672
Total	13886	13322	13650	12546	13293	13069	12741	11870	10968	10334	10330	10454	9751	9332	9672	9811	9206	8048	7989	8521
																		Scenario sum		218794

CO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2082842	1655303	2095923	1776784	1829163	2066196	2075993	1838426	2042820	1892262	1710673	1927315	1950079	1690960	1876386	1810325	1689619	1783581	1791176	1737849
LRS 3	1941677	1986209	2242100	1627219	2257199	2196727	1955167	2208491	1970563	1981090	2097947	1849016	185956	0	0	0	0	0	0	0
Craig 1	778917	777981	788170	794713	646235	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	872202	921846	793271	890641	776986	859144	863342	442244	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3009639	3629287	3334168	3311884	2852495	3594365	3173784	2669618	753855	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1876411	1791116	1977786	1867400	1667992	1911628	2042531	2061667	2437945	2209991	1990773	2435291	2675991	2534764	2792957	2848025	2319655	235394	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1055	14937	6791	3249	23752	18270	15918	18330	14347	9395	19252	17128	20236	22582	23095	14183	3825	30543	30768	27984
Pyramid 2	570	14037	6531	2892	22679	18269	16581	17966	14848	8734	18967	15558	18854	20029	21529	13958	3437	32808	28604	24777
Pyramid 3	197	197	0	0	0	0	30	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	505	14939	6712	2912	22547	18175	16696	18793	15258	8875	18477	15347	18265	21161	22128	13473	3244	32599	29336	25612
Rifle	0	0	0	0	6866	8165	2313	0	35810	1434	510	2914	1444	2036	745	1254	1097	59	862	0
Limon 1	342	342	0	0	18768	16689	4603	0	537	0	0	0	0	149	0	0	0	0	0	0
Limon 2	341	341	0	0	21715	17588	6270	0	1251	0	132	202	0	282	0	0	0	0	0	0
Knutson 1	343	343	0	293	16225	15795	3453	0	145	0	0	0	0	67	0	0	0	0	0	0
Knutson 2	342	342	0	292	16624	16600	3731	0	163	0	0	0	0	70	0	0	0	0	0	0
J. M. Shafer	241699	163507	187283	168350	375950	269863	219271	145266	72374	68983	16746	15391	14364	17714	39096	35332	30508	31854	25959	19055
Basin Nebraska	411673	423307	425113	427068	428761	430577	432497	434596	436450	438412	440667	443039	445137	447366	449665	452056	454218	456462	458732	532811
Basin Electric- Colorado/Wyoming	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228
Market Purchases	893648	457109	401472	264118	413511	108571	274015	337296	884400	555345	920261	774789	990526	1019439	1045601	1147469	1164610	1445030	1537299	1783770
Energy Imbalance	94493	86656	86656	86656	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325
SWCO300MWCC	0	0	0	0	0	0	0	0	0	436795	290949	295430	294613	303733	239899	236663	244864	250816	248046	252290
Total	13248122	12979028	13393204	12265698	12508020	12677176	12216747	11303247	9791318	8721869	8635907	8901974	7726018	7190904	7621654	7683293	7025629	5409698	5261336	5514701
																		Scenario Sum tons:		190,075,543
																		Scenario lbs/MWh		1737

SO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1041	827	1047	888	914	1033	1038	919	1021	946	855	963	975	845	938	905	844	891	895	869
LRS 3	1471	1504	1698	1232	1710	1664	1481	1673	1492	1500	1589	1400	141	0	0	0	0	0	0	0
Craig 1	127	127	128	130	105	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	128	135	116	131	114	126	127	65	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1884	2271	2087	2073	1785	2249	1986	1671	472	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	735	702	775	732	653	749	800	808	955	866	780	954	1048	993	1094	1116	909	92	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rifle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	2	1	1	1	3	2	2	1	1	1	0	0	0	0	0	0	0	0	0	0
Basin Nebraska	343	353	354	356	357	359	360	362	364	365	367	369	371	373	375	377	378	380	382	444
Basin Electric- Colorado/Wyoming	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	5	3	3	3	3	2	2	3	3	3	3
Total	6056	6247	6533	5868	5969	6508	6120	5824	4630	4008	3920	4016	2864	2540	2735	2726	2460	1693	1606	1641
																		Scenario Sum tons:		83,964
																		Scenario lbs/MWh		0.77

Nox

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2204	1751	2218	1880	1935	2186	2197	1945	2162	2002	1810	2039	2063	1789	1985	1916	1788	1887	1895	1839
LRS 3	1944	1989	2245	1629	2260	2199	1958	2211	1973	1984	2101	1851	186	0	0	0	0	0	0	0
Craig 1	931	930	942	950	772	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	249	264	227	255	222	246	247	126	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3237	3904	3586	3562	3068	3866	3414	2871	811	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	690	659	728	687	614	703	752	759	897	813	732	896	985	933	1028	1048	853	87	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1	15	7	3	24	18	16	19	14	9	19	17	20	23	23	14	4	31	31	28
Pyramid 2	1	13	6	3	22	17	16	17	14	8	18	15	18	19	20	13	3	31	27	24
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	15	7	3	22	18	16	18	15	9	18	15	18	21	22	13	3	32	29	25
Rifle	0	0	0	0	15	18	5	0	78	3	1	6	3	4	2	3	2	0	2	0
Limon 1	0	0	0	0	5	5	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	5	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	4	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	4	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	184	125	143	128	286	205	167	111	55	53	13	12	11	13	30	27	23	24	20	15
Basin Nebraska	245	252	253	254	255	256	257	259	260	261	262	264	265	266	268	269	270	272	273	317
Basin Electric- Colorado/Wyoming	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	434	289	294	293	302	239	235	244	249	247	251
Total	10257	10486	10930	9924	10083	10319	9618	8906	6848	6146	5834	5979	4432	3940	4186	4108	3760	3183	3093	3068
																		Scenario Sum tons:		135,098
																		Scenario lbs/MWh		1

Hg

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	0.0418	0.0332	0.0421	0.0357	0.0367	0.0415	0.0417	0.0369	0.0410	0.0380	0.0343	0.0387	0.0391	0.0339	0.0377	0.0363	0.0339	0.0358	0.0360	0.0349
LRS 3	0.0406	0.0416	0.0469	0.0340	0.0472	0.0460	0.0409	0.0462	0.0412	0.0414	0.0439	0.0387	0.0039	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 1	0.0062	0.0061	0.0062	0.0063	0.0051	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 2	0.0056	0.0059	0.0051	0.0057	0.0050	0.0055	0.0055	0.0028	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 3	0.1211	0.1460	0.1341	0.1332	0.1148	0.1446	0.1277	0.1074	0.0303	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Springerville 3	0.0153	0.0146	0.0161	0.0152	0.0136	0.0156	0.0166	0.0168	0.0198	0.0180	0.0162	0.0198	0.0218	0.0206	0.0227	0.0232	0.0189	0.0019	0.0000	0.0000
Burlington 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Burlington 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Rifle	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
J. M. Shafer	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	0.2305	0.2474	0.2505	0.2302	0.2224	0.2531	0.2324	0.2101	0.1324	0.0974	0.0944	0.0972	0.0648	0.0546	0.0604	0.0595	0.0528	0.0377	0.0360	0.0349
																		Scenario Sum tons:		2.699
																		Scenario lbs/MWh		0.000022

PM
short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	97	77	98	83	85	96	97	86	95	88	80	90	91	79	87	84	79	83	83	81
LRS 3	154	157	177	129	179	174	155	175	156	157	166	146	15	0	0	0	0	0	0	0
Craig 1	15	15	15	16	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	19	20	17	19	17	18	19	10	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	95	115	106	105	90	114	101	85	24	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	29	28	31	29	26	30	32	32	38	34	31	38	42	39	43	44	36	4	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	2	2	2
Pyramid 2	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	2	2	1
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	1	0	0	1	1	1	1	1	0	1	1	1	1	1	1	0	2	2	1
Rifle	0	0	0	0	1	2	0	0	7	0	0	1	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	20	14	16	14	31	22	18	12	6	6	1	1	1	1	3	3	3	3	2	2
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	47	31	32	32	33	26	26	26	27	27	27
Total	429	428	460	395	450	463	425	402	329	334	313	310	184	157	164	160	145	122	118	114

Scenario Sum tons: 5,901
Scenario lbs/MWh 0.05

Water
Gallons

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	998,402,713	793,463,646	1,004,673,227	851,694,858	876,802,700	990,423,405	995,119,524	881,242,938	979,218,427	907,048,653	820,005,082	923,851,239	934,763,209	810,555,277	899,438,908	867,772,875	809,912,849	854,952,926	858,593,546	833,031,544
LRS 3	851,853,147	871,390,299	983,655,033	713,894,288	990,279,070	963,749,146	857,771,661	968,910,189	864,525,976	869,144,662	920,411,964	811,201,199	81,582,767	0	0	0	0	0	0	0
Craig 1	330,510,581	330,113,561	334,436,756	337,213,266	274,210,876	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	365,211,193	385,998,568	332,161,126	372,932,085	325,342,089	359,743,814	361,501,708	185,177,873	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1,416,978,435	1,708,716,753	1,569,770,955	1,559,279,216	1,342,992,930	1,692,275,160	1,494,260,177	1,256,891,887	354,924,866	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	957,943,556	914,398,777	1,009,696,979	953,342,938	851,541,691	975,922,486	1,042,750,954	1,052,520,219	1,244,617,109	1,128,242,134	1,016,327,114	1,243,261,955	1,366,143,974	1,294,045,247	1,425,857,543	1,453,970,787	1,184,227,703	120,173,346	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	204,150	2,891,098	1,314,466	628,816	4,597,115	3,536,116	3,080,809	3,547,768	2,776,883	1,818,403	3,726,273	3,315,087	3,916,634	4,370,709	4,470,007	2,745,149	740,323	5,911,509	5,955,108	5,416,257
Pyramid 2	111,000	2,734,545	1,272,178	563,419	4,418,043	3,558,952	3,229,983	3,499,900	2,892,375	1,701,452	3,694,879	3,030,876	3,672,879	3,901,714	4,194,047	2,719,067	669,536	6,391,168	5,572,268	4,826,735
Pyramid 3	37,884	37,884	0	0	0	5,766	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	97,884	2,896,057	1,301,272	564,539	4,370,920	3,523,288	3,236,615	3,643,222	2,957,854	1,720,613	3,581,947	2,975,277	3,540,839	4,102,223	4,289,677	2,611,986	628,847	6,319,652	5,687,088	4,965,170
Rifle	0	0	0	0	14,495,223	17,236,193	4,881,955	0	75,598,151	3,027,174	1,075,685	6,152,321	3,047,736	4,298,855	1,572,155	2,647,840	2,316,860	124,118	1,820,350	0
Limon 1	26,020	26,020	0	0	1,428,288	1,270,084	350,325	0	40,885	0	0	0	0	11,314	0	0	0	0	0	0
Limon 2	26,020	26,020	0	0	1,659,184	1,343,843	479,040	0	95,606	0	10,083	15,431	0	21,510	0	0	0	0	0	0
Knutson 1	9,586	9,586	0	8,179	453,097	441,099	96,416	0	4,053	0	0	0	0	1,858	0	0	0	0	0	0
Knutson 2	9,586	9,586	0	8,179	465,478	464,812	104,482	0	4,557	0	0	0	0	1,955	0	0	0	0	0	0
J. M. Shafer	171,480,537	116,004,883	132,873,709	119,440,666	266,728,900	191,462,411	155,568,309	103,063,249	51,347,661	48,941,821	11,881,044	10,919,771	10,190,994	12,568,039	27,737,735	25,067,570	21,644,794	22,599,781	18,417,337	13,519,035
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	404,806,141	269,641,053	273,794,344	273,037,187	281,488,988	222,329,541	219,330,802	226,930,871	232,447,176	229,880,488	233,813,203
Total	5726854057	5762669045	6005107457	5543522205	5593737378	5838902658	5556389500	5092449011	4212956177	4000402823	3684306893	3912469252	3313847970	3049319450	3223841371	3210817842	2881023549	1882871435	1759877993	1729523811

Scenario Sum (Gallons): 81,980,889,875
Scenario gallons/MWh 375

Year	CO_2 (tons)	SO_2 (tons)	NO_x (tons)	Hg (tons)	PM (tons)	Water (gallons)	RPS CO	RPS NM (SB489)
2021	13,248,122	6056	10,257	0.2305	429	5,726,854,057	*C*	*C*
2022	12,979,028	6247	10,486	0.2474	428	5,762,669,045	*C*	*C*
2023	13,393,204	6533	10,930	0.2505	460	6,005,107,457	*C*	*C*
2024	12,265,698	5868	9,924	0.2302	395	5,543,522,205	*C*	*C*
2025	12,508,020	5969	10,083	0.2224	450	5,593,737,378	*C*	*C*
2026	12,677,176	6508	10,319	0.2531	463	5,838,902,658	*C*	*C*
2027	12,216,747	6120	9,618	0.2324	425	5,556,389,500	*C*	*C*
2028	11,303,247	5824	8,906	0.2101	402	5,092,449,011	*C*	*C*
2029	9,791,318	4630	6,848	0.1324	329	4,212,956,177	*C*	*C*
2030	8,721,869	4008	6,146	0.0974	334	4,000,402,823	*C*	*C*
2031	8,635,907	3920	5,834	0.0944	313	3,684,306,893	*C*	*C*
2032	8,901,974	4016	5,979	0.0972	310	3,912,469,252	*C*	*C*
2033	7,726,018	2864	4,432	0.0648	184	3,313,847,970	*C*	*C*
2034	7,190,904	2540	3,940	0.0546	157	3,049,319,450	*C*	*C*
2035	7,621,654	2735	4,186	0.0604	164	3,223,841,371	*C*	*C*
2036	7,683,293	2726	4,108	0.0595	160	3,210,817,842	*C*	*C*
2037	7,025,629	2460	3,760	0.0528	145	2,881,023,549	*C*	*C*
2038	5,409,698	1693	3,183	0.0377	122	1,882,871,435	*C*	*C*
2039	5,261,336	1606	3,093	0.0360	118	1,759,877,993	*C*	*C*
2040	5,514,701	1641	3,068	0.0349	114	1,729,523,811	*C*	*C*
Total	190,075,543	83,964	135,098	2.699	5,901	81,980,889,875		
per MWh**	968	0.43	0.69	0.00001	0.03	209		

TS Thermal Gen Emissions & Water per TS Thermal Gen	CO2 (lbs/net MWH)	SO2 (lbs/net MWH)	NOx (lbs/net MWH	Hg (lbs/gross MWh)*	PM (lbs gross MWh)	Water (gallons/net MWH
Scenario Average	1737	0.77	1.23	0.000022	0.05	375

*** This is divided by all thermal MWH even though gas does not have a Mercury impact**

TS Thermal Gen Emissions& Water per Member Load Energy	CO2 (lbs/net MWH)	SO2 (lbs/net MWH)	NOx (lbs/net MWH	Hg (lbs/gross MWh)	PM (lbs gross MWh)	Water (gallons/net MWH
Scenario Average	968	0.43	0.69	0.00001	0.03	209

Low Load 80pct Version 1

2018 ERP Emissions and Water Usage Rates by Unit

UNIT	CO_2 lbs per Net MWh	SO_2 lbs per Net MWh	NOx lbs per Net MWh	Hg lbs per Gross MWh	PM lbs per Gross MWh	VOC lbs per Gross MWh	Water Usage (gal/MWh)
LRS 2	2203	1.101	2.331	0.0000411	0.0953	0.036	528
LRS 3	2407	1.823	2.410	0.0000468	0.1770	0.036	528
Craig 1	2319	0.378	2.771	0.000017	0.0421	0.00209	492
Craig 2	2350	0.345	0.672	0.000014	0.0469	0.00210	492
Craig 3	2090	1.308	2.248	0.000078	0.0614	0.0304	492
Springerville 3	2139	0.838	0.787	0.000016	0.0306	0.034	546
Burlington 1	2212	0.206	12.482	N/A	0.162	0.0054	8.82
Burlington 2	2086	0.182	12.283	N/A	0.153	0.0051	8.82
Pyramid 1	1240	0.013	1.253	N/A	0.071	0.021	120
Pyramid 2	1232	0.017	1.169	N/A	0.072	0.019	120
Pyramid 3	1250	0.012	1.253	N/A	0.072	0.020	120
Pyramid 4	1238	0.006	1.218	N/A	0.065	0.020	120
Rifle	1206	0.00063	2.611	N/A	0.239	0.227	1273
Limon 1	1498	0.008	0.432	N/A	0.0616	0.0010	57
Limon 2	1492	0.008	0.324	N/A	0.0625	0.0008	57
Knutson 1	1504	0.0085	0.345	N/A	0.1237	0.000	21
Knutson 2	1500	0.0098	0.337	N/A	0.1237	0.000	21
J. M. Shafer	981	0.0078	0.747	N/A	0.0804	0.0694	348
Basin Nebraska	1240	1.0332	0.738	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	1280	0.40	0.70	N/A	N/A	N/A	390
Market Purchases	1280	0.40	0.70	N/A	N/A	N/A	N/A
Energy Imbalance	1280	0.40	0.70	N/A	N/A	N/A	N/A
Expansion Plan Units*	SWCO300MWCC	751	0.008	0.747	N/A	0.0804	0.0694	348

GWh Generation

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1891	1506	1862	1577	1658	1869	1892	1694	1888	1771	1553	1744	1761	1566	1764	1735	1609	1739	1789	1661
LRS 3	1613	1508	1792	1246	1880	1804	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	672	709	655	638	560	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	742	740	621	672	600	728	733	343	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	2880	2976	2465	2375	2581	3334	2982	2587	690	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1754	1398	1569	1487	1171	1419	1884	1877	2078	1895	1762	2024	2024	1887	2139	2007	1677	1990	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	2	7	0	0	20	19	20	22	17	12	16	13	14	19	16	12	2	1	31	21
Pyramid 2	1	5	0	0	21	20	22	22	17	12	16	13	13	19	17	12	2	0	28	20
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	1	5	0	0	21	20	22	22	17	13	15	13	13	18	17	12	2	1	28	20
Rifle	0	0	0	0	0	8	1	1	13	0	0	0	0	3	0	0	0	1	0	0
Limon 1	0	0	0	0	3	6	7	0	0	0	0	0	0	1	0	0	0	0	0	0
Limon 2	0	0	0	0	3	7	8	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	3	6	5	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	3	7	5	0	0	0	0	0	0	1	0	0	0	0	0	0
J. M. Shafer	493	133	162	94	610	462	519	304	129	36	46	37	43	47	62	43	44	45	32	29
Basin Nebraska	664	484	471	463	458	455	453	452	452	453	454	455	457	459	461	463	465	467	469	472
Basin Electric- Colorado/Wyoming	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627
Market Purchases	1396	395	301	154	595	96	425	878	1774	1204	1171	895	1086	1169	987	896	1020	819	1793	1990
Energy Imbalance	148	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135
SWCO300MWCC	0	0	0	0	0	0	0	0	0	602	633	599	644	649	618	611	628	624	621	627
Total	13886	11631	11661	10468	11949	12022	10738	9965	8839	7760	7428	7556	7816	7599	7843	7554	7211	7448	6554	6603
																		Scenario sum		182532

CO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2082842	1658380	2050571	1737226	1825881	2059237	2083538	1865405	2079504	1950624	1710514	1920903	1939720	1724678	1943120	1911451	1771967	1914993	1970616	1829077
LRS 3	1941677	1815274	2156102	1499346	2262993	2171577	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	778917	821747	759839	739943	649679	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	872202	869384	729808	789217	704941	855834	860878	403465	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3009639	3110432	2576250	2481839	2697159	3483695	3115946	2703790	721067	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1876411	1495426	1678378	1590274	1252619	1517119	2014514	2007006	2222936	2026212	1884056	2164387	2164774	2018596	2287981	2146789	1793711	2128220	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	84	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	92	0	0	0	0	0	0
Pyramid 1	1055	4214	0	0	12510	11958	12652	13332	10721	7748	10134	8189	8485	11903	9728	7419	1300	363	19046	13329
Pyramid 2	570	3081	0	0	12830	12442	13389	13506	10671	7633	9764	7959	7999	11751	10543	7154	1343	245	17126	12535
Pyramid 3	197	197	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	505	2970	0	0	12922	12245	13348	13803	10360	7953	9530	8129	7799	11425	10625	7374	1136	429	17253	12362
Rifle	0	0	0	0	0	4801	431	588	7566	59	0	0	0	1529	0	0	216	901	0	0
Limon 1	342	342	0	0	2526	4638	5396	0	130	0	0	0	0	484	0	0	0	0	0	0
Limon 2	341	341	0	0	2224	4866	6167	0	130	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	343	343	0	0	2062	4437	3646	0	0	0	0	0	0	82	0	0	0	0	0	0
Knutson 2	342	342	0	0	2616	5468	3531	0	275	0	0	0	0	484	0	0	0	0	0	0
J. M. Shafer	241699	65459	79337	46043	299077	226692	254627	149284	63499	17802	22392	18382	20893	22974	30226	21327	21428	21836	15898	14377
Basin Nebraska	411673	300213	292197	287169	283818	281800	280719	280371	280308	280638	281392	282393	283349	284484	285733	287095	288349	289685	291061	292507
Basin Electric- Colorado/Wyoming	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228
Market Purchases	893648	252721	192812	98471	304454	49083	217704	449752	908187	616403	599739	458216	555785	598303	505478	458554	522146	419131	918222	1019117
Energy Imbalance	94493	86656	86656	86656	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325
SWCO300MWCC	0	0	0	0	0	0	0	0	0	225980	237704	224846	241829	243569	231924	229495	235753	234203	233218	235501
Total	13248122	11528749	11643176	10397412	11438864	11816446	9997041	9010857	7425906	6251603	5875778	6203957	6341186	6040991	6425910	6187211	5747902	6120559	4592993	4539358
																		Scenario Sum tons:		160,834,022
																		Scenario lbs/MWh		1762

SO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1041	829	1025	868	913	1029	1041	932	1039	975	855	960	969	862	971	955	886	957	985	914
LRS 3	1471	1375	1633	1136	1714	1645	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	127	134	124	121	106	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	128	128	107	116	103	126	126	59	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1884	1947	1612	1553	1688	2180	1950	1692	451	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	735	586	658	623	491	594	789	786	871	794	738	848	848	791	896	841	703	834	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rifle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	2	1	1	0	2	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0
Basin Nebraska	343	250	243	239	236	235	234	234	234	234	234	235	236	237	238	239	240	241	243	244
Basin Electric- Colorado/Wyoming	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	2	2	2	3	3	2	2	2	2	2	2
Total	6056	5574	5728	4982	5579	6137	4469	4031	2921	2331	2156	2371	2382	2218	2434	2364	2157	2360	1556	1486
																		Scenario Sum tons:		69,290
																		Scenario lbs/MWh		0.76

Nox

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2204	1755	2170	1838	1932	2179	2205	1974	2200	2064	1810	2033	2052	1825	2056	2023	1875	2026	2085	1935
LRS 3	1944	1818	2159	1501	2266	2174	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	931	982	908	884	776	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	249	249	209	226	202	245	246	115	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3237	3346	2771	2669	2901	3747	3352	2908	776	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	690	550	618	585	461	558	741	738	818	746	693	796	796	743	842	790	660	783	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0
Pyramid 1	1	4	0	0	13	12	13	13	11	8	10	8	9	12	10	7	1	0	19	13
Pyramid 2	1	3	0	0	12	12	13	13	10	7	9	8	8	11	10	7	1	0	16	12
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	3	0	0	13	12	13	14	10	8	9	8	8	11	10	7	1	0	17	12
Rifle	0	0	0	0	0	10	1	1	16	0	0	0	0	3	0	0	0	2	0	0
Limon 1	0	0	0	0	1	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	184	50	60	35	228	173	194	114	48	14	17	14	16	17	23	16	16	17	12	11
Basin Nebraska	245	179	174	171	169	168	167	167	167	167	167	168	169	169	170	171	172	172	173	174
Basin Electric- Colorado/Wyoming	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	225	236	224	241	242	231	228	234	233	232	234
Total	10257	9507	9637	8479	9543	9864	7518	6627	4626	3807	3522	3828	3867	3605	3921	3819	3531	3804	3124	2962
																		Scenario Sum tons:		115,849
																		Scenario lbs/MWh		1

Hg

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	0.0418	0.0333	0.0412	0.0349	0.0367	0.0413	0.0418	0.0374	0.0417	0.0392	0.0343	0.0386	0.0389	0.0346	0.0390	0.0384	0.0356	0.0384	0.0396	0.0367
LRS 3	0.0406	0.0380	0.0451	0.0314	0.0473	0.0454	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 1	0.0062	0.0065	0.0060	0.0058	0.0051	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 2	0.0056	0.0056	0.0047	0.0051	0.0045	0.0055	0.0055	0.0026	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 3	0.1211	0.1251	0.1036	0.0998	0.1085	0.1402	0.1254	0.1088	0.0290	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Springerville 3	0.0153	0.0122	0.0137	0.0129	0.0102	0.0123	0.0164	0.0163	0.0181	0.0165	0.0153	0.0176	0.0176	0.0164	0.0186	0.0175	0.0146	0.0173	0.0000	0.0000
Burlington 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Burlington 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Rifle	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
J. M. Shafer	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	0.2305	0.2207	0.2143	0.1899	0.2124	0.2448	0.1891	0.1651	0.0888	0.0556	0.0497	0.0562	0.0566	0.0510	0.0576	0.0558	0.0502	0.0558	0.0396	0.0367
																		Scenario Sum tons:		2.320
																		Scenario lbs/MWh		0.000023

PM

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	97	77	95	81	85	96	97	87	97	91	80	89	90	80	90	89	82	89	92	85
LRS 3	154	144	171	119	179	172	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	15	16	15	14	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	19	19	16	17	15	18	19	9	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	95	99	82	79	85	110	99	86	23	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	29	23	26	25	19	24	31	31	35	32	29	34	34	31	36	33	28	33	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	0	0	0	1	1	1	1	1	0	1	0	0	1	1	0	0	0	1	1
Pyramid 2	0	0	0	0	1	1	1	1	1	0	1	0	0	1	1	0	0	0	1	1
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	0	0	0	1	1	1	1	1	0	1	0	0	1	1	0	0	0	1	1
Rifle	0	0	0	0	0	1	0	0	2	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	20	5	7	4	25	19	21	12	5	1	2	2	2	2	3	2	2	2	1	1
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	24	26	24	26	26	25	25	25	25	25	25
Total	429	383	411	338	424	443	270	227	163	150	138	150	153	142	155	150	138	150	121	114

Scenario Sum tons: 4,651
Scenario lbs/MWh 0.05

Water

Gallons

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	998,402,713	794,938,201	982,933,504	832,733,045	875,229,422	987,087,923	998,736,325	894,174,911	996,802,683	935,024,384	819,928,731	920,777,869	929,797,726	826,717,939	931,427,348	916,247,250	849,385,875	917,944,819	944,607,636	876,761,459
LRS 3	851,853,147	796,397,538	945,925,796	657,793,523	992,821,273	952,715,063	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	330,510,581	348,684,482	322,415,618	313,973,249	275,672,393	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	365,211,193	364,031,440	305,587,638	330,463,619	295,175,117	358,357,617	360,469,841	168,940,401	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1,416,978,435	1,464,432,976	1,212,933,033	1,168,482,895	1,269,858,433	1,640,170,498	1,467,029,045	1,272,980,772	339,488,164	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	957,943,556	763,443,264	856,843,597	811,864,785	639,485,782	774,518,143	1,028,447,516	1,024,614,749	1,134,850,694	1,034,419,489	961,846,366	1,104,960,752	1,105,157,994	1,030,531,670	1,168,057,511	1,095,976,326	915,723,538	1,086,496,494	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	781	0	0	0	0	0	0
Pyramid 1	204,150	815,548	0	0	2,421,197	2,314,492	2,448,833	2,580,403	2,074,951	1,499,541	1,961,461	1,585,040	1,642,337	2,303,751	1,882,812	1,435,868	251,550	70,321	3,686,400	2,579,847
Pyramid 2	111,000	600,115	0	0	2,499,409	2,423,773	2,608,333	2,631,133	2,078,803	1,486,929	1,901,996	1,550,469	1,558,334	2,289,251	2,053,841	1,393,669	261,675	47,747	3,336,206	2,441,803
Pyramid 3	37,884	37,884	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	97,884	575,859	0	0	2,505,123	2,373,884	2,587,700	2,675,955	2,008,393	1,541,689	1,847,579	1,575,855	1,511,985	2,214,827	2,059,813	1,429,479	220,318	83,052	3,344,775	2,396,602
Rifle	0	0	0	0	0	10,136,263	910,195	1,241,175	15,972,383	124,118	0	0	0	3,227,054	0	0	455,098	1,903,135	0	0
Limon 1	26,020	26,020	0	0	192,229	352,932	410,643	0	9,899	0	0	0	0	36,808	0	0	0	0	0	0
Limon 2	26,020	26,020	0	0	169,939	371,823	471,203	0	9,899	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	9,586	9,586	0	0	57,570	123,910	101,811	0	0	0	0	0	0	2,288	0	0	0	0	0	0
Knutson 2	9,586	9,586	0	0	73,253	153,092	98,879	0	7,699	0	0	0	0	13,559	0	0	0	0	0	0
J. M. Shafer	171,480,537	46,441,857	56,287,721	32,666,880	212,189,212	160,833,190	180,652,985	105,913,982	45,051,470	12,629,824	15,886,401	13,041,344	14,823,053	16,299,570	21,444,459	15,131,000	15,202,405	15,492,271	11,279,148	10,199,961
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	209,430,235	220,295,988	208,378,929	224,118,559	225,731,271	214,938,475	212,687,814	218,487,188	217,051,002	216,137,909	218,254,276
Total	5726854057	5214427141	5316878666	4781929764	5202302115	5525884368	4678925102	4109705244	3172306802	2830107973	2657620282	2885822022	2912561750	2743321204	2975816027	2878253164	2633939407	2873040605	1816343814	1746585719

Scenario Sum (Gallons): 72,682,620,234
Scenario gallons/MWh 398

Year	CO_2 (tons)	SO_2 (tons)	NO_x (tons)	Hg (tons)	PM (tons)	Water (gallons)	RES CO	RPS NM (SB489)
2021	13,248,122	6056	10,257	0.2305	429	5,726,854,057	*C*	*C*
2022	11,528,749	5574	9,507	0.2207	383	5,214,422,141	*C*	*C*
2023	11,643,176	5728	9,637	0.2143	411	5,316,878,666	*C*	*C*
2024	10,397,412	4982	8,479	0.1899	338	4,781,929,764	*C*	*C*
2025	11,438,864	5579	9,543	0.2124	424	5,202,302,115	*C*	*C*
2026	11,816,446	6137	9,864	0.2448	443	5,525,884,368	*C*	*C*
2027	9,997,041	4469	7,518	0.1891	270	4,678,925,102	*C*	*C*
2028	9,010,857	4031	6,627	0.1651	227	4,109,705,244	*C*	*C*
2029	7,425,906	2921	4,626	0.0888	163	3,172,306,802	*C*	*C*
2030	6,251,603	2331	3,807	0.0556	150	2,830,107,973	*C*	*C*
2031	5,875,778	2156	3,522	0.0497	138	2,657,620,281	*C*	*C*
2032	6,203,957	2371	3,828	0.0562	150	2,885,822,021	*C*	*C*
2033	6,341,186	2382	3,867	0.0566	153	2,912,561,758	*C*	*C*
2034	6,040,991	2218	3,605	0.0510	142	2,743,321,204	*C*	*C*
2035	6,425,910	2434	3,921	0.0576	155	2,975,816,027	*C*	*C*
2036	6,187,211	2364	3,819	0.0558	150	2,878,253,164	*C*	*C*
2037	5,747,902	2157	3,531	0.0502	138	2,633,939,407	*C*	*C*
2038	6,120,559	2360	3,804	0.0558	150	2,873,040,605	*C*	*C*
2039	4,592,993	1556	3,124	0.0396	121	1,816,343,814	*C*	*C*
2040	4,539,358	1486	2,962	0.0367	114	1,746,585,719	*C*	*C*
Total	**160,834,022**	**69,290**	**115,849**	**2.320**	**4,651**	**72,682,620,234**		
per MWh**	**975**	**0.42**	**0.70**	**0.00001**	**0.03**	**220**		

TS Thermal Gen Emissions & Water per TS Thermal Gen	**CO2 (lbs/net MWH)**	**SO2 (lbs/net MWH)**	**NOx (lbs/net MWH**	**Hg (lbs/gross MWh)***	**PM (lbs gross MWh)**	**Water (gallons/net MWH**
:enario Averag	1762	0.76	1.27	#######	0.05	398

*** This is divided by all thermal MWH even though gas does not have a Mercury impact**

TS Thermal Gen Emissions& Water per Member Load Energy	**CO2 (lbs/net MWH)**	**SO2 (lbs/net MWH)**	**NOx (lbs/net MWH**	**Hg (lbs/gross MWh)**	**PM (lbs gross MWh)**	**Water (gallons/net MWH**
:enario Averag	975	0.42	0.70	0.00001	0.03	220

Low Load 80pct Version 2

2018 ERP Emissions and Water Usage Rates by Unit

UNIT	CO_2 lbs per Net MWh	SO_2 lbs per Net MWh	NOx lbs per Net MWh	Hg lbs per Gross MWh	PM lbs per Gross MWh	VOC lbs per Gross MWh	Water Usage (gal/MWh)
LRS 2	2203	1.101	2.331	0.0000411	0.0953	0.036	528
LRS 3	2407	1.823	2.410	0.0000468	0.1770	0.036	528
Craig 1	2319	0.378	2.771	0.000017	0.0421	0.00209	492
Craig 2	2350	0.345	0.672	0.000014	0.0469	0.00210	492
Craig 3	2090	1.308	2.248	0.000078	0.0614	0.0304	492
Springerville 3	2139	0.838	0.787	0.000016	0.0306	0.034	546
Burlington 1	2212	0.206	12.482	N/A	0.162	0.0054	8.82
Burlington 2	2086	0.182	12.283	N/A	0.153	0.0051	8.82
Pyramid 1	1240	0.013	1.253	N/A	0.071	0.021	120
Pyramid 2	1232	0.017	1.169	N/A	0.072	0.019	120
Pyramid 3	1250	0.012	1.253	N/A	0.072	0.020	120
Pyramid 4	1238	0.006	1.218	N/A	0.065	0.020	120
Rifle	1206	0.00063	2.611	N/A	0.239	0.227	1273
Limon 1	1498	0.008	0.432	N/A	0.0616	0.0010	57
Limon 2	1492	0.008	0.324	N/A	0.0625	0.0008	57
Knutson 1	1504	0.0085	0.345	N/A	0.1237	0.000	21
Knutson 2	1500	0.0098	0.337	N/A	0.1237	0.000	21
J. M. Shafer	981	0.0078	0.747	N/A	0.0804	0.0694	348
Basin Nebraska	1240	1.0332	0.738	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	1280	0.40	0.70	N/A	N/A	N/A	390
Market Purchases	1280	0.40	0.70	N/A	N/A	N/A	N/A
Energy Imbalance	1280	0.40	0.70	N/A	N/A	N/A	N/A
Expansion Plan Units*	SWCO300MWCC	751	0.008	0.747	N/A	0.0804	0.0694	348

GWh Generation

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1891	1506	1862	1577	1656	1868	1890	1693	1882	1764	1546	1735	1756	1568	1779	1733	1611	1733	1798	1664
LRS 3	1613	1508	1792	1246	1861	1802	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	672	709	655	638	542	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	742	740	621	672	591	729	732	341	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	2880	2976	2465	2375	2601	3334	2998	2592	743	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1754	1398	1569	1487	1220	1526	1884	1878	2074	1906	1761	2015	2101	1885	2262	2181	1689	1915	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	2	7	0	0	20	21	20	21	18	13	19	16	18	20	18	13	2	1	32	23
Pyramid 2	1	5	0	0	20	21	21	22	17	14	17	15	16	19	18	14	2	0	30	21
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	1	5	0	0	20	20	21	22	17	13	18	15	16	19	18	13	2	0	30	21
Rifle	0	0	0	0	0	8	1	1	29	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	1	9	8	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	1	9	8	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	1	8	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	1	8	5	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	493	133	162	94	620	487	507	301	142	49	57	46	55	49	62	46	52	47	30	26
Basin Nebraska	664	484	471	463	458	455	453	452	452	453	454	455	457	459	461	463	465	467	469	472
Basin Electric- Colorado/Wyoming	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627
Market Purchases	1396	395	301	154	578	82	434	915	1779	1283	1281	1002	1198	1275	1076	992	1184	1016	2030	2263
Energy Imbalance	148	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135
SWCO300MWCC	1396	395	301	154	578	82	0	0	0	612	638	630	643	662	624	621	629	642	643	637
Total	15282	12026	11962	10622	12529	12231	10748	9999	8916	7869	7553	7691	8023	7718	8081	7839	7399	7585	6824	6889
																		Scenario sum		187788

CO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2082842	1658380	2050571	1737226	1823746	2058101	2081416	1864626	2073178	1943105	1703070	1911589	1933798	1727444	1959800	1908373	1774804	1909052	1980363	1832797
LRS 3	1941677	1815274	2156102	1499346	2239400	2168638	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	778917	821747	759839	739943	628318	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	872202	869384	729808	789217	694791	856872	859923	400867	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3009639	3110432	2576250	2481839	2718037	3483529	3133017	2708189	776184	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1876411	1495426	1678378	1590274	1305025	1632001	2014893	2008145	2217763	2038546	1883133	2154655	2246553	2016216	2419439	2332682	1806526	2048364	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1055	4214	0	0	12206	13271	12582	12982	10986	8219	11917	9630	11264	12109	10854	8152	1399	378	19796	13994
Pyramid 2	570	3081	0	0	12450	12779	13235	13661	10454	8476	10705	9249	9933	11707	11116	8350	1382	267	18255	13194
Pyramid 3	197	197	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	505	2970	0	0	12398	12568	13136	13764	10745	8216	10896	9052	9936	11797	11268	8222	1166	218	18361	13028
Rifle	0	0	0	0	0	4605	372	588	17211	59	59	0	59	59	0	0	0	59	0	0
Limon 1	342	342	0	0	676	6587	5730	0	197	0	0	0	0	0	0	0	0	0	0	0
Limon 2	341	341	0	0	674	6878	6319	0	278	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	343	343	0	0	394	6342	2445	0	198	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	342	342	0	0	677	5730	4093	0	323	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	241699	65459	79337	46043	304138	239066	248855	147484	69743	23886	28072	22640	27119	23920	30301	22657	25549	23093	14513	12791
Basin Nebraska	411673	300213	292197	287169	283818	281800	280719	280371	280308	280638	281392	282393	283349	284484	285733	287095	288349	289685	291061	292507
Basin Electric- Colorado/Wyoming	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228
Market Purchases	893648	252721	192812	98471	295760	41882	222205	468362	910869	656846	655690	512993	613551	652870	551154	507888	606138	520012	1039616	1158421
Energy Imbalance	94493	86656	86656	86656	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325
SWCO300MWCC	524320	148276	113126	57775	216910	30716	0	0	0	229863	239508	236586	241574	248569	234360	233347	236318	241240	241569	239221
Total	13772442	11677025	11756302	10455187	11659972	11971919	10009492	9029592	7488990	6308408	5934993	6259339	6487689	6099728	6624580	6427319	5852185	6142921	4734087	4686507
																		Scenario Sum tons:		163,378,677
																		Scenario lbs/MWh		1740

SO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1041	829	1025	868	911	1029	1040	932	1036	971	851	955	966	863	979	954	887	954	990	916
LRS 3	1471	1375	1633	1136	1696	1642	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	127	134	124	121	102	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	128	128	107	116	102	126	126	59	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1884	1947	1612	1553	1701	2180	1961	1695	486	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	735	586	658	623	511	639	789	787	869	799	738	844	880	790	948	914	708	802	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rifle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	2	1	1	0	2	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0
Basin Nebraska	343	250	243	239	236	235	234	234	234	234	234	235	236	237	238	239	240	241	243	244
Basin Electric- Colorado/Wyoming	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	5	2	1	1	2	0	0	0	0	2	2	2	3	3	2	2	2	3	3	2
Total	6061	5575	5729	4982	5591	6179	4478	4033	2951	2332	2152	2363	2411	2219	2494	2435	2163	2326	1561	1488
																		Scenario Sum tons:		69,524
																		Scenario lbs/MWh		0.74

Nox

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2204	1755	2170	1838	1930	2178	2202	1973	2194	2056	1802	2023	2046	1828	2074	2019	1878	2020	2095	1939
LRS 3	1944	1818	2159	1501	2242	2171	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	931	982	908	884	751	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	249	249	209	226	199	245	246	115	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3237	3346	2771	2669	2924	3747	3370	2913	835	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	690	550	618	585	480	600	741	739	816	750	693	793	827	742	890	858	665	754	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1	4	0	0	12	13	13	13	11	8	12	10	11	12	11	8	1	0	20	14
Pyramid 2	1	3	0	0	12	12	13	13	10	8	10	9	9	11	11	8	1	0	17	13
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	3	0	0	12	12	13	14	11	8	11	9	10	12	11	8	1	0	18	13
Rifle	0	0	0	0	0	10	1	1	37	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	0	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	184	50	60	35	232	182	189	112	53	18	21	17	21	18	23	17	19	18	11	10
Basin Nebraska	245	179	174	171	169	168	167	167	167	167	167	168	169	169	170	171	172	172	173	174
Basin Electric- Colorado/Wyoming	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	522	147	113	57	216	31	0	0	0	229	238	235	240	247	233	232	235	240	240	238
Total	10778	9655	9750	8537	9748	9945	7529	6629	4703	3814	3524	3833	3902	3609	3992	3891	3542	3774	3145	2970
																		Scenario Sum tons:		117,270
																		Scenario lbs/MWh		1

Hg

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	0.0418	0.0333	0.0412	0.0349	0.0366	0.0413	0.0418	0.0374	0.0416	0.0390	0.0342	0.0384	0.0388	0.0347	0.0393	0.0383	0.0356	0.0383	0.0398	0.0368
LRS 3	0.0406	0.0380	0.0451	0.0314	0.0469	0.0454	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 1	0.0062	0.0065	0.0060	0.0058	0.0050	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 2	0.0056	0.0056	0.0047	0.0051	0.0045	0.0055	0.0055	0.0026	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 3	0.1211	0.1251	0.1036	0.0998	0.1094	0.1401	0.1260	0.1090	0.0312	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Springerville 3	0.0153	0.0122	0.0137	0.0129	0.0106	0.0133	0.0164	0.0163	0.0180	0.0166	0.0153	0.0175	0.0183	0.0164	0.0197	0.0190	0.0147	0.0167	0.0000	0.0000
Burlington 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Burlington 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Rifle	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
J. M. Shafer	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	0.2305	0.2207	0.2143	0.1899	0.2129	0.2456	0.1897	0.1653	0.0909	0.0556	0.0495	0.0559	0.0571	0.0511	0.0590	0.0573	0.0503	0.0550	0.0398	0.0368
																		Scenario Sum tons:		2.327
																		Scenario lbs/MWh		0.000023

PM
short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	97	77	95	81	85	96	97	87	96	90	79	89	90	80	91	89	83	89	92	85
LRS 3	154	144	171	119	177	172	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	15	16	15	14	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	19	19	16	17	15	18	19	9	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	95	99	82	79	86	110	99	86	25	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	29	23	26	25	20	25	31	31	35	32	29	34	35	31	38	36	28	32	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	0	0	0	1	1	1	1	1	0	1	1	1	1	1	0	0	0	1	1
Pyramid 2	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	0	0	0	1	1
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	0	0	0	1	1	1	1	1	0	1	0	1	1	1	0	0	0	1	1
Rifle	0	0	0	0	0	1	0	0	3	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
z	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	20	5	7	4	25	20	21	12	6	2	2	2	2	2	3	2	2	2	1	1
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	57	16	12	6	23	3	0	0	0	25	26	26	26	27	25	25	26	26	26	26
Total	486	400	423	344	447	449	270	227	167	150	139	152	155	143	159	154	139	149	123	115

Scenario Sum tons: 4,788
Scenario lbs/MWh 0.05

Water
Gallons

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	998,402,713	794,938,201	982,933,504	832,733,045	874,206,004	986,542,989	997,719,209	893,801,699	993,770,128	931,420,294	816,360,307	916,313,408	926,959,217	828,044,204	939,423,189	914,771,427	850,745,881	915,096,966	949,279,813	878,544,410
LRS 3	851,853,147	796,397,538	945,925,790	657,793,521	982,470,672	951,425,633	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	330,510,581	348,684,482	322,415,618	313,973,249	266,608,545	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	365,211,193	364,031,440	305,587,638	330,463,619	290,925,408	358,792,540	360,069,796	167,852,207	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1,416,978,435	1,464,432,976	1,212,933,033	1,168,482,895	1,279,688,033	1,640,092,183	1,475,066,259	1,275,051,685	365,437,917	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	957,943,556	763,443,264	856,843,597	811,864,789	666,240,084	833,167,261	1,028,640,904	1,025,196,169	1,132,209,931	1,040,716,419	961,374,961	1,099,992,034	1,146,907,697	1,029,316,247	1,235,169,497	1,190,878,524	922,265,659	1,045,728,826	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	204,150	815,548	0	0	2,362,365	2,568,533	2,435,230	2,512,648	2,126,353	1,590,852	2,306,426	1,863,796	2,180,035	2,343,759	2,100,830	1,577,717	270,870	73,200	3,831,450	2,708,497
Pyramid 2	111,000	600,115	0	0	2,425,375	2,489,456	2,578,274	2,661,142	2,036,572	1,651,152	2,085,377	1,801,798	1,934,931	2,280,495	2,165,480	1,626,580	269,214	52,061	3,556,116	2,570,356
Pyramid 3	37,884	37,884	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	97,884	575,859	0	0	2,403,495	2,436,460	2,546,494	2,668,285	2,082,985	1,592,808	2,112,320	1,754,828	1,926,235	2,287,005	2,184,402	1,593,986	226,106	42,244	3,559,565	2,525,668
Rifle	0	0	0	0	0	9,722,538	786,078	1,241,175	36,333,300	124,118	124,118	0	124,118	124,118	0	0	0	124,118	0	0
Limon 1	26,020	26,020	0	0	51,469	501,269	436,064	0	15,029	0	0	0	0	0	0	0	0	0	0	0
Limon 2	26,020	26,020	0	0	51,469	525,565	482,811	0	21,233	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	9,586	9,586	0	0	10,993	177,104	68,269	0	5,537	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	9,586	9,586	0	0	18,962	160,451	114,593	0	9,051	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	171,480,537	46,441,857	56,287,721	32,666,880	215,780,185	169,612,757	176,557,901	104,637,098	49,481,068	16,946,719	19,916,207	16,062,536	19,240,547	16,970,766	21,498,284	16,075,026	18,126,233	16,383,737	10,296,747	9,075,218
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	485,920,844	137,417,022	104,841,265	53,543,733	201,024,523	28,466,550	0	0	0	213,028,756	221,967,708	219,259,037	223,882,351	230,365,029	217,196,649	216,257,797	219,011,342	223,572,905	223,877,650	221,701,696
Total	6212774902	5351839163	5421719931	4835473497	5418219347	5620633053	4681453646	4109573873	3217480869	2841022883	2660199189	2890999203	2957106895	2745683389	3053690095	2976732821	2644867071	2835025820	1828353105	1751077609

Scenario Sum (Gallons): 74,053,926,362
Scenario gallons/MWh 394

Year	CO_2 (tons)	SO_2 (tons)	NO_x (tons)	Hg (tons)	PM (tons)	Water (gallons)	RES CO	RPS NM (SB489)
2021	13,772,442	6061	10,778	0.2305	486	6,212,774,902	*C*	*C*
2022	11,677,025	5575	9,655	0.2207	400	5,351,839,163	*C*	*C*
2023	11,756,302	5729	9,750	0.2143	423	5,421,719,931	*C*	*C*
2024	10,455,187	4982	8,537	0.1899	344	4,835,473,497	*C*	*C*
2025	11,659,972	5591	9,748	0.2129	447	5,418,219,347	*C*	*C*
2026	11,971,919	6179	9,945	0.2456	449	5,620,633,053	*C*	*C*
2027	10,009,492	4478	7,529	0.1897	270	4,681,453,646	*C*	*C*
2028	9,029,592	4033	6,629	0.1653	227	4,109,573,873	*C*	*C*
2029	7,488,990	2951	4,703	0.0909	167	3,217,480,869	*C*	*C*
2030	6,308,408	2332	3,814	0.0556	150	2,841,022,883	*C*	*C*
2031	5,934,993	2152	3,524	0.0495	139	2,660,199,189	*C*	*C*
2032	6,259,339	2363	3,833	0.0559	152	2,890,999,203	*C*	*C*
2033	6,487,689	2411	3,902	0.0571	155	2,957,106,895	*C*	*C*
2034	6,099,728	2219	3,609	0.0511	143	2,745,683,389	*C*	*C*
2035	6,624,580	2494	3,992	0.0590	159	3,053,690,095	*C*	*C*
2036	6,427,319	2435	3,891	0.0573	154	2,976,732,821	*C*	*C*
2037	5,852,185	2163	3,542	0.0503	139	2,644,867,071	*C*	*C*
2038	6,142,921	2326	3,774	0.0550	149	2,835,025,820	*C*	*C*
2039	4,734,087	1561	3,145	0.0398	123	1,828,353,105	*C*	*C*
2040	4,686,507	1488	2,970	0.0368	115	1,751,077,609	*C*	*C*
Total	163,378,677	69,524	117,270	2.327	4,788	74,053,926,362		
per MWh**	990	0.42	0.71	0.00001	0.03	224		

TS Thermal Gen Emissions & Water per TS Thermal Gen	CO2 (lbs/net MWH)	SO2 (lbs/net MWH)	NOx (lbs/net MWH	Hg (lbs/gross MWh)*	PM (lbs gross MWh)	Water (gallons/net MWH
Scenario Average	1740	0.74	1.25	0.000023	0.05	394

*** This is divided by all thermal MWH even though gas does not have a Mercury impact**

TS Thermal Gen Emissions& Water per Member Load Energy	CO2 (lbs/net MWH)	SO2 (lbs/net MWH)	NOx (lbs/net MWH	Hg (lbs/gross MWh)	PM (lbs gross MWh)	Water (gallons/net MWH
Scenario Average	990	0.42	0.71	0.00001	0.03	224

Social Cost of Carbon

2018 ERP Emissions and Water Usage Rates by Unit

	UNIT	CO_2 lbs per Net MWh	SO_2 lbs per Net MWh	NOx lbs per Net MWh	Hg lbs per Gross MWh	PM lbs per Gross MWh	VOC lbs per Gross MWh	Water Usage (gal/MWh)
	LRS 2	2203	1.101	2.331	0.0000411	0.0953	0.036	528
	LRS 3	2407	1.823	2.410	0.0000468	0.1770	0.036	528
	Craig 1	2319	0.378	2.771	0.000017	0.0421	0.00209	492
	Craig 2	2350	0.345	0.672	0.000014	0.0469	0.00210	492
	Craig 3	2090	1.308	2.248	0.000078	0.0614	0.0304	492
	Springerville 3	2139	0.838	0.787	0.000016	0.0306	0.034	546
	Burlington 1	2212	0.206	12.482	N/A	0.162	0.0054	8.82
	Burlington 2	2086	0.182	12.283	N/A	0.153	0.0051	8.82
	Pyramid 1	1240	0.013	1.253	N/A	0.071	0.021	120
	Pyramid 2	1232	0.017	1.169	N/A	0.072	0.019	120
	Pyramid 3	1250	0.012	1.253	N/A	0.072	0.020	120
	Pyramid 4	1238	0.006	1.218	N/A	0.065	0.020	120
	Rifle	1206	0.00063	2.611	N/A	0.239	0.227	1273
	Limon 1	1498	0.008	0.432	N/A	0.0616	0.0010	57
	Limon 2	1492	0.008	0.324	N/A	0.0625	0.0008	57
	Knutson 1	1504	0.0085	0.345	N/A	0.1237	0.000	21
	Knutson 2	1500	0.0098	0.337	N/A	0.1237	0.000	21
	J. M. Shafer	981	0.0078	0.747	N/A	0.0804	0.0694	348
	Basin Nebraska	1240	1.0332	0.738	N/A	N/A	N/A	N/A
	Basin Electric- Colorado/Wyoming	1280	0.40	0.70	N/A	N/A	N/A	390
	Market Purchases	1280	0.40	0.70	N/A	N/A	N/A	N/A
	Energy Imbalance	1280	0.40	0.70	N/A	N/A	N/A	N/A
Expansion Plan Units*	SWCO300MWCC	751	0.008	0.747	N/A	0.0804	0.0694	348
	SWCO545MWCC	710	0.008	0.747	N/A	0.0804	0.0694	348

GWh Generation

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1891	1538	1904	1626	1646	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRS 3	1613	1678	1863	1356	1835	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	672	671	677	682	640	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	742	788	676	752	698	766	788	580	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	2880	3479	3172	3133	3032	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1754	1654	1840	1728	1830	2500	2558	2413	2650	2534	2157	2613	2606	2467	2660	2616	0	0	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	2	19	8	4	13	53	49	40	36	15	24	18	20	24	24	20	78	80	76	79
Pyramid 2	1	19	7	2	14	54	50	39	33	12	0	0	0	0	0	0	0	0	0	0
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	1	19	7	3	14	55	50	39	34	8	21	16	18	23	22	19	77	79	77	79
Rifle	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	6	66	24	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	4	66	27	1	0	2	2	0	0	0	1	2	2	2	2	1
Knutson 2	0	0	0	0	3	66	25	2	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	493	302	343	294	556	845	721	581	509	0	0	0	0	0	0	0	0	0	0	0
Basin Nebraska	664	683	686	689	692	694	698	701	704	707	711	715	718	722	725	729	733	736	740	859
Basin Electric- Colorado/Wyoming	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627
Market Purchases	1396	677	598	376	370	2017	1942	1785	2155	2328	2167	1752	1821	1859	1697	1716	2472	2387	2294	2546
Energy Imbalance	148	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135
SWCO300MWCC	0	0	0	0	0	0	0	0	0	175	63	101	87	102	131	78	117	131	147	146
SWCO545MWCC	0	0	0	0	0	276	256	178	164	370	329	327	284	354	442	350	447	496	498	560
Total	13886	13290	13543	12409	13122	9221	8951	8122	8047	7913	7236	7303	7316	7313	7464	7293	5688	5672	5595	6033
																		Scenario sum		175418

CO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2082842	1694623	2097310	1791227	1812722	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRS 3	1941677	2019613	2242683	1632416	2208534	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	778917	777969	785226	791159	741596	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	872202	925439	793736	884134	820733	899773	925949	680916	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3009639	3635514	3315051	3274050	3168810	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1876411	1769162	1967351	1848620	1957471	2673365	2735711	2580414	2833846	2710127	2306919	2794159	2787163	2637924	2844614	2798190	0	0	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1055	11511	5120	2202	8100	33045	30511	24708	22343	9225	15073	11132	12176	14964	15011	12469	48232	49335	46815	49268
Pyramid 2	570	11503	4378	1472	8464	33411	31069	23941	20401	7266	0	0	0	0	0	0	0	0	0	0
Pyramid 3	197	197	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	505	11699	4393	1609	8578	33937	30687	24351	21074	5220	12968	9738	11048	14148	13324	11550	47616	48677	47481	48845
Rifle	0	0	0	0	1697	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	342	342	0	0	2530	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	341	341	0	0	4152	49030	18161	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	343	343	0	0	3306	49291	20649	1090	0	1401	1553	0	101	293	696	1392	1694	1392	1483	1019
Knutson 2	342	342	0	0	2622	49777	18648	1781	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	241699	148074	168169	144236	272686	414623	353702	285012	249644	0	0	0	0	0	0	0	0	0	0	0
Basin Nebraska	411673	423307	425113	427068	428761	430577	432497	434596	436450	438412	440667	443039	445137	447366	449665	452056	454218	456462	458732	532811
Basin Electric- Colorado/Wyoming	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228
Market Purchases	893648	433137	382731	240566	189597	1032800	994550	913996	1103340	1191816	1109410	896878	932388	951853	868982	878383	1265871	1222016	1174414	1303447
Energy Imbalance	94493	86656	86656	86656	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325
SWCO300MWCC	0	0	0	0	0	0	0	0	0	65583	23528	37965	32599	38227	49026	29436	43904	49200	55080	54814
SWCO545MWCC	0	0	0	0	0	97932	90934	63312	58067	131364	116844	116213	100967	125670	156909	124418	158745	176108	176967	198830
Total	13248122	12991001	13319145	12166643	12750912	6908114	6793620	6144670	5855718	5670966	5137515	5419677	5432133	5340999	5508779	5418447	3130833	3113742	3071525	3299587
																		Scenario Sum tons:		140,722,148
																		Scenario lbs/MWh		1604

SO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1041	847	1048	895	906	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRS 3	1471	1530	1699	1236	1673	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	127	127	128	129	121	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	128	136	117	130	120	132	136	100	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1884	2275	2075	2049	1983	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	735	693	771	724	767	1047	1072	1011	1110	1062	904	1095	1092	1033	1114	1096	0	0	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	1
Pyramid 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rifle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	2	1	1	1	2	3	3	2	2	0	0	0	0	0	0	0	0	0	0	0
Basin Nebraska	343	353	354	356	357	359	360	362	364	365	367	369	371	373	375	377	378	380	382	444
Basin Electric- Colorado/Wyoming	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	0	0	1	1	1
SWCO545MWCC	0	0	0	0	0	1	1	1	1	1	1	1	1	1	2	1	2	2	2	2
Total	6056	6287	6518	5846	6255	1870	1899	1802	1803	1755	1598	1791	1790	1734	1817	1800	707	709	711	773

Scenario Sum tons: 53,518
Scenario lbs/MWh 0.61

Nox

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2204	1793	2219	1895	1918	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRS 3	1944	2022	2245	1634	2211	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	931	930	938	945	886	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	249	265	227	253	235	257	265	195	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3237	3910	3566	3522	3408	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	690	651	724	680	720	984	1007	949	1043	997	849	1028	1025	971	1047	1030	0	0	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1	12	5	2	8	33	31	25	23	9	15	11	12	15	15	13	49	50	47	50
Pyramid 2	1	11	4	1	8	32	29	23	19	7	0	0	0	0	0	0	0	0	0	0
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	12	4	2	8	33	30	24	21	5	13	10	11	14	13	11	47	48	47	48
Rifle	0	0	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	1	11	4	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	1	11	5	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	1	11	4	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	184	113	128	110	208	316	269	217	190	0	0	0	0	0	0	0	0	0	0	0
Basin Nebraska	245	252	253	254	255	256	257	259	260	261	262	264	265	266	268	269	270	272	273	317
Basin Electric- Colorado/Wyoming	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	65	23	38	32	38	49	29	44	49	55	55
SWCO545MWCC	0	0	0	0	0	103	96	67	61	138	123	122	106	132	165	131	167	185	186	209
Total	10257	10539	10884	9868	10442	2617	2567	2328	2186	2053	1855	2042	2022	2006	2126	2052	1146	1173	1178	1248

Scenario Sum tons: 80,589
Scenario lbs/MWh 1

Hg

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	0.0418	0.0340	0.0421	0.0360	0.0364	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
LRS 3	0.0406	0.0423	0.0469	0.0342	0.0462	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 1	0.0062	0.0061	0.0062	0.0063	0.0059	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 2	0.0056	0.0059	0.0051	0.0057	0.0053	0.0058	0.0059	0.0044	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 3	0.1211	0.1463	0.1334	0.1317	0.1275	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Springerville 3	0.0153	0.0144	0.0160	0.0150	0.0159	0.0218	0.0223	0.0210	0.0231	0.0221	0.0188	0.0227	0.0227	0.0215	0.0232	0.0228	0.0000	0.0000	0.0000	0.0000
Burlington 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Burlington 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Rifle	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
J. M. Shafer	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO545MWCC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	0.2305	0.2490	0.2497	0.2288	0.2371	0.0275	0.0282	0.0254	0.0231	0.0221	0.0188	0.0227	0.0227	0.0215	0.0232	0.0228	0.0000	0.0000	0.0000	0.0000

Scenario Sum tons: 1.453
Scenario lbs/MWh 0.000015

PM
short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	97	79	98	83	84	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRS 3	154	160	177	129	175	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	15	15	15	15	15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	19	20	17	19	18	19	20	15	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	95	115	105	104	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	29	28	31	29	30	42	43	40	44	42	36	43	43	41	44	44	0	0	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	1	0	0	0	2	2	1	1	1	1	1	1	1	1	1	3	3	3	3
Pyramid 2	0	1	0	0	1	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	1	0	0	0	2	2	1	1	0	1	1	1	1	1	1	3	3	3	3
Rifle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	0	4	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	0	4	2	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	20	12	14	12	23	34	29	24	21	0	0	0	0	0	0	0	0	0	0	0
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO545MWCC	0	0	0	0	0	11	10	7	7	15	13	13	12	14	18	14	18	20	20	23
Total	429	431	458	392	447	123	111	90	75	59	51	58	56	57	64	59	24	26	26	28

Scenario Sum tons: 3,063
Scenario lbs/MWh 0.03

Water
Gallons

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	998,402,713	812,311,565	1,005,337,944	858,618,042	868,921,436	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRS 3	851,853,147	886,045,503	983,910,799	716,174,149	968,928,748	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	330,510,581	330,108,532	333,187,727	335,705,312	314,674,744	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	365,211,193	387,502,795	332,355,812	370,207,587	343,660,002	376,755,985	387,716,353	285,115,297	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1,416,978,435	1,711,648,867	1,560,770,248	1,541,466,550	1,491,918,332	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	957,943,556	903,190,647	1,004,370,114	943,755,639	999,326,195	1,364,803,408	1,396,632,421	1,317,350,325	1,446,732,137	1,383,571,039	1,177,725,963	1,426,471,183	1,422,899,716	1,346,710,095	1,452,229,111	1,428,528,780	0	0	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	204,150	2,227,874	991,032	426,119	1,567,744	6,395,825	5,905,361	4,782,169	4,324,433	1,785,444	2,917,343	2,154,585	2,356,679	2,896,251	2,905,279	2,413,356	9,335,211	9,548,672	9,060,876	9,535,824
Pyramid 2	111,000	2,240,819	852,849	286,847	1,648,814	6,508,697	6,052,435	4,663,769	3,974,316	1,415,405	0	0	0	0	0	0	0	0	0	0
Pyramid 3	37,884	37,884	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	97,884	2,268,034	851,578	311,916	1,662,973	6,579,124	5,948,933	4,720,739	4,085,451	1,011,914	2,513,975	1,887,797	2,141,784	2,742,837	2,582,939	2,239,013	9,230,896	9,436,667	9,204,684	9,469,105
Rifle	0	0	0	0	3,581,764	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	26,020	26,020	0	0	192,539	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	26,020	26,020	0	0	317,220	3,746,248	1,387,607	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	9,586	9,586	0	0	92,333	1,376,470	576,622	30,428	0	39,133	43,372	0	2,825	8,179	19,435	38,870	47,302	38,870	41,422	28,447
Knutson 2	9,586	9,586	0	0	73,424	1,393,742	522,154	49,864	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	171,480,537	105,055,846	119,312,833	102,332,352	193,465,413	294,167,112	250,944,293	202,210,542	177,117,444	0	0	0	0	0	0	0	0	0	0	0
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	60,779,798	21,804,548	35,184,469	30,211,586	35,427,700	45,435,253	27,280,619	40,689,079	45,596,403	51,046,238	50,799,737
SWCO545MWCC	0	0	0	0	0	96,001,212	89,140,941	62,063,814	56,921,573	128,773,558	114,540,288	113,921,019	98,975,798	123,191,645	153,815,333	121,964,638	155,614,810	172,635,137	173,477,142	194,905,781
Total	5726854057	5776661343	5975892700	5503236276	5823983444	2791679589	2778778901	2514938704	2327107117	2211328045	1953497247	2213570810	2190540133	2144928469	2290939115	2216417034	848869064	871207757	876782122	898694707

Scenario Sum (Gallons): 57,935,906,637
Scenario gallons/MWh 330

Year	CO2 (tons)	SO2 (tons)	NOx (tons)	Hg (tons)	PM (tons)	Water (gallons)	RES CO	RPS NM (SB489)
2021	13,248,122	6056	10,257	0.2305	429	5,726,854,057	*C*	*C*
2022	12,991,001	6287	10,539	0.2490	431	5,776,661,343	*C*	*C*
2023	13,319,145	6518	10,884	0.2497	458	5,975,892,700	*C*	*C*
2024	12,166,643	5846	9,868	0.2288	392	5,503,236,276	*C*	*C*
2025	12,750,912	6255	10,442	0.2371	447	5,823,983,448	*C*	*C*
2026	6,908,114	1870	2,617	0.0275	123	2,791,679,589	*C*	*C*
2027	6,793,620	1899	2,567	0.0282	111	2,778,778,901	*C*	*C*
2028	6,144,670	1802	2,328	0.0254	90	2,514,938,704	*C*	*C*
2029	5,855,718	1803	2,186	0.0231	75	2,327,107,117	*C*	*C*
2030	5,670,966	1755	2,053	0.0221	59	2,211,328,045	*C*	*C*
2031	5,137,515	1598	1,855	0.0188	51	1,953,497,247	*C*	*C*
2032	5,419,677	1791	2,042	0.0227	58	2,213,570,810	*C*	*C*
2033	5,432,133	1790	2,022	0.0227	56	2,190,540,133	*C*	*C*
2034	5,340,999	1734	2,006	0.0215	57	2,144,928,469	*C*	*C*
2035	5,508,779	1817	2,126	0.0232	64	2,290,939,115	*C*	*C*
2036	5,418,447	1800	2,052	0.0228	59	2,216,417,034	*C*	*C*
2037	3,130,833	707	1,146	0.0000	24	848,869,064	*C*	*C*
2038	3,113,742	709	1,173	0.0000	26	871,207,757	*C*	*C*
2039	3,071,525	711	1,178	0.0000	26	876,782,122	*C*	*C*
2040	3,299,587	773	1,248	0.0000	28	898,694,707	*C*	*C*
Total	140,722,148	53,518	80,589	1.453	3,063	57,935,906,637		
per MWh**	717	0.27	0.41	0.00001	0.02	148		

TS Thermal Gen Emissions & Water per TS Thermal Gen	CO2 (lbs/net MWH)	SO2 (lbs/net MWH)	NOx (lbs/net MWH	Hg (lbs/gross MWh)*	PM (lbs gross MWh)	Water (gallons/net MWH
Scenario Average	1604	0.61	0.92	0.000015	0.03	330

*** This is divided by all thermal MWH even though gas does not have a Mercury impact**

TS Thermal Gen Emissions& Water per Member Load Energy	CO2 (lbs/net MWH)	SO2 (lbs/net MWH)	NOx (lbs/net MWH	Hg (lbs/gross MWh)	PM (lbs gross MWh)	Water (gallons/net MWH
Scenario Average	717	0.27	0.41	0.00001	0.02	148

Attachment Vol II 6-2 RES/RPS

Hyperion Data

Base Case

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,235,474	11,468,302	11,710,122	11,931,568	12,142,495	12,379,349	12,614,855	12,869,179	13,119,887	13,342,451	13,575,587	13,798,708	14,021,025	14,265,209	14,520,163	14,775,306	15,021,402	15,261,838	15,510,303	15,767,501
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,247,095	2,293,660	2,342,024	2,386,314	2,428,499	2,475,870	2,522,971	2,573,836	2,623,977	2,668,490	2,715,117	2,759,742	2,804,205	2,853,042	2,904,033	2,955,061	3,004,280	3,052,368	3,102,061	3,153,500
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	231,363	231,363	231,363	232,138	231,363	231,363	231,363	232,138	231,363	211,775	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,263	461,263	461,263	462,550	461,263	461,263	461,263	462,550	461,263	461,263	461,263	461,250	-	-	-	-	-	-	-	-
Carousel-E.CO	1	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	664,520
San Isabel Solar	1	76,103	75,730	75,370	75,140	74,570	74,160	73,810	73,580	73,020	72,630	72,230	72,020	71,470	71,080	70,700	70,460	69,910	69,550	69,150	69,150
Twin Buttes	1	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430
Spanish Peaks Solar	1	-	-	12,706	267,735	266,395	265,056	263,716	262,377	261,038	259,698	258,359	257,020	255,680	254,341	253,001	251,662	250,323	237,306	-	-
Crossing Trails Wind	1	439,001	439,001	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	421,191	-	-	-	-	-
Niyol Wind	1	-	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712
Axial Basin Solar	1	-	-	-	369,907	368,057	366,207	364,357	362,507	360,657	358,807	356,957	355,107	353,257	351,407	349,557	347,707	345,858	344,089	-	-
Dolores Canyon Solar	1	-	-	-	297,092	295,606	294,121	292,635	291,149	289,663	288,177	286,692	285,206	283,720	282,234	280,748	279,263	277,777	276,359	-	-
Spanish Peaks II Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Coyote Gulch Solar	1	-	-	-	331,082	329,427	327,771	326,115	324,459	322,803	321,148	319,492	317,836	316,180	314,524	312,869	311,130	309,557	307,977	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2																					
Tri-County Hydropower / Ridgway1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	358,064	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,274	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
ECO100MWPV	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWPV2	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWPV3	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWPV4	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWPV5	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND	1	-	-	-	-	-	-	-	-	-	-	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
SWCO100MWPV	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWCO100MWPV2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWCO100MWPV3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
SWCO100MWPV4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
SWCO100MWPV5	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244,648
SWCO100MWPV6	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244,648
SWCO100MWPV7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244,648
WYO100MWWIND	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	394,835	379,717
WYO100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	394,835	379,717
WYO100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	394,835	379,717
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	379,717
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	379,717
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,158,423	4,010,703	4,026,187	5,384,987	5,356,089	5,351,905	5,331,757	5,318,738	6,297,612	6,542,964	7,050,423	7,460,169	8,125,171	8,528,379	8,487,903	8,255,540	8,066,802	8,641,007	9,062,465	10,375,907
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,158,423	4,010,703	4,026,187	5,384,987	5,356,089	5,351,905	5,331,757	5,318,738	6,297,612	6,542,964	7,050,423	7,460,169	8,125,171	8,528,379	8,487,903	8,255,540	8,066,802	8,641,007	9,062,465	10,375,907
Rollover, Vintage -1 year	2,323,881	2,643,797	3,158,423	4,010,703	4,026,187	5,384,987	5,356,089	5,351,905	5,331,757	5,318,738	6,297,612	6,542,964	7,050,423	7,460,169	8,125,171	8,528,379	8,487,903	8,255,540	8,066,802	8,641,007	9,062,465
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,158,423	4,010,703	4,026,187	5,384,987	5,356,089	5,351,905	5,331,757	5,318,738	6,297,612	6,542,964	7,050,423	7,460,169	8,125,171	8,528,379	8,487,903	8,255,540	8,066,802	8,641,007
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,158,423	4,010,703	4,026,187	5,384,987	5,356,089	5,351,905	5,331,757	5,318,738	6,297,612	6,542,964	7,050,423	7,460,169	8,125,171	8,528,379	8,487,903	8,255,540	8,066,802
Rollover, Vintage -4 year	1,596,193	1,455,566	1,321,801	1,303,657	1,561,141	2,291,065	3,825,898	4,026,187	5,384,987	5,356,089	5,351,905	5,331,757	5,318,738	6,297,612	6,542,964	7,050,423	7,460,169	8,125,171	8,528,379	8,487,903	8,255,540
Rollover, Vintage -5 year	133,754	-	-	-	-	-	-	1,302,927	2,755,278	5,384,987	5,356,089	5,351,905	5,331,757	5,318,738	6,297,612	6,542,964	7,050,423	7,460,169	8,125,171	8,528,379	8,487,903
Expiring RECs		-	-	-	-	-	-	-	-	131,301	2,716,497	2,640,972	2,592,163	2,527,552	2,465,696	3,393,580	3,587,902	4,046,143	4,407,801	5,023,111	5,374,879
BALANCE AFTER COMPLIANCE		**11,741,562**	**13,458,605**	**15,142,768**	**18,141,441**	**21,069,032**	**23,945,067**	**26,753,853**	**29,498,756**	**33,041,090**	**34,199,066**	**35,893,400**	**38,001,664**	**40,795,078**	**44,004,719**	**46,195,010**	**47,907,587**	**48,923,966**	**50,104,804**	**51,042,097**	**52,889,625**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
New Mexico Member Load		2,773,756	2,804,086	2,835,823	2,869,044	2,803,594	2,739,229	2,768,895	2,800,445	2,830,124	2,860,568	2,891,298	2,923,241	2,952,642	2,983,400	3,014,802	3,047,239	3,077,495	3,108,543	3,139,854	3,172,211
New Mexico Member Retail Sales6	2%	2,718,281	2,748,005	2,779,106	2,811,664	2,747,523	2,684,445	2,713,517	2,744,436	2,773,522	2,803,357	2,833,472	2,864,776	2,893,589	2,923,732	2,954,506	2,986,294	3,015,945	3,046,372	3,077,056	3,108,767
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		271,828	274,800	277,911	281,166	1,099,009	1,073,778	1,085,407	1,097,775	1,109,409	1,401,678	1,416,736	1,432,388	1,446,795	1,461,866	1,477,253	1,493,147	1,507,972	1,523,186	1,538,528	1,554,384
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	176,813	175,271	173,733	172,195	170,657	169,119	167,580	166,042	164,504	162,965	161,426	159,890	158,351	156,812	144,658	-	-	-	-	-
Alta Luna Solar	1	76,231	75,850	75,471	75,093	74,717	74,089	73,670	73,440	72,880	72,510	72,110	71,900	71,340	70,950	70,570	70,350	69,800	69,410	69,020	69,020
Escalante Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591														
Policy 115	1.2	55,496	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	475	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	-	-	370,943	379,766	392,123	383,262	393,457	385,983	386,783	386,291	387,603	377,201	384,144
Total RECs Generated		831,267	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	1,286,902	1,293,457	1,303,869	1,292,408	1,300,320	1,279,959	1,135,605	1,134,131	1,134,723	1,024,461	1,031,736
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	831,267	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	1,286,902	1,293,457	1,303,869	1,292,408	1,300,320	1,279,959	1,135,605	1,134,131	1,038,837	524,770	2,123
Rollover, Vintage -1 year	258,073	835,623	831,267	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	1,286,902	1,293,457	1,225,115	1,055,657	878,724	665,536	293,169	-	-	-
Rollover, Vintage -2 year	265,817	258,073	835,623	831,267	829,372	827,490	932,886	930,339	927,691	922,797	718,569	220,070	74,584	-	-	-	-	-	-	-	-
Rollover, Vintage -3 year	209,144	203,133	186,406	744,118	831,267	829,372	778,293	625,772	458,336	276,619	-	-	-	-	-	-	-	-	-	-	-
Rollover, Vintage -4 year	-	-	-	-	462,951	195,209	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,128,096**	**2,682,667**	**3,232,247**	**3,883,966**	**3,715,296**	**3,569,209**	**3,406,600**	**3,229,656**	**3,038,485**	**2,923,708**	**2,800,429**	**2,671,910**	**2,517,523**	**2,355,977**	**2,158,683**	**1,801,141**	**1,427,300**	**1,038,837**	**524,770**	**2,123**

Notes:

1 Project is not registered with WREGIS
2 Contract expired
3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.
4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)
5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.
6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

80% Carbon Reduction Version 1

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	11,096,023	11,334,704	11,551,975	11,760,844	11,994,606	12,227,035	12,477,215	12,725,959	12,945,710	13,175,611	13,394,617	13,615,062	13,856,273	14,108,272	14,359,711	14,603,647	14,841,172	15,086,738	15,339,875
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	2,219,205	2,266,941	2,310,395	2,352,169	2,398,921	2,445,407	2,495,443	2,545,192	2,589,142	2,635,122	2,678,923	2,723,012	2,771,255	2,821,654	2,871,942	2,920,729	2,968,234	3,017,348	3,067,975
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	231,363	231,363	231,363	232,138	231,363	231,363	231,363	232,138	231,363	211,775	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,263	461,263	461,263	462,550	461,263	461,263	461,263	462,550	461,263	461,263	461,263	461,250	-	-	-	-	-	-	-	-
Carousel-E.CO	1	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	664,520
San Isabel Solar	1	76,103	75,730	75,370	75,140	74,570	74,160	73,810	73,580	73,020	72,630	72,230	72,020	71,470	71,080	70,700	70,460	69,910	69,550	69,150	69,150
Twin Buttes	1	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430
Spanish Peaks Solar	1	-	-	12,706	267,735	266,395	265,056	263,716	262,377	261,038	259,698	258,359	257,020	255,680	254,341	253,001	251,662	250,323	237,306	-	-
Crossing Trails Wind	1	439,001	439,001	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	421,191	-	-	-	-	-
Niyol Wind	1	-	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712
Axial Basin Solar	1	-	-	-	369,907	368,057	366,207	364,357	362,507	360,657	358,807	356,957	355,107	353,257	351,407	349,557	347,707	345,858	344,089	-	-
Dolores Canyon Solar	1	-	-	-	297,092	295,606	294,121	292,635	291,149	289,663	288,177	286,692	285,206	283,720	282,234	280,748	279,263	277,777	276,359	-	-
Spanish Peaks II Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Coyote Gulch Solar	1	-	-	-	331,082	329,427	327,771	326,115	324,459	322,803	321,148	319,492	317,836	316,180	314,524	312,869	311,130	309,557	307,977	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2																					
Tri-County Hydropower / Ridgway1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
ECO100MWWIND	1	-	-	-	-	396,172	395,541	393,345	361,548	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND	1	-	-	-	-	382,161	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND2	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV2	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV3	1	-	-	-	-	-	-	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND3	1	-	-	-	-	-	-	-	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV4	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV5	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV6	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV7	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV8	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV9	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	-	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
SWC0100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND8	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND9	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
SWC0100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV12	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV13	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
ECO100MWPV	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	8,955,517	10,603,759	10,348,748	10,824,666	11,049,414	11,853,488	12,424,606	12,681,075	12,750,912	13,646,903	13,429,513	13,129,917
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	8,955,517	10,603,759	10,348,748	10,824,666	11,049,414	11,853,488	12,424,606	12,681,075	12,750,912	13,646,903	13,429,513	13,129,917
Rollover, Vintage -1 year	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	8,955,517	10,603,759	10,348,748	10,824,666	11,049,414	11,853,488	12,424,606	12,681,075	12,750,912	13,646,903	13,429,513
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	8,955,517	10,603,759	10,348,748	10,824,666	11,049,414	11,853,488	12,424,606	12,681,075	12,750,912	13,646,903
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	8,955,517	10,603,759	10,348,748	10,824,666	11,049,414	11,853,488	12,424,606	12,681,075	12,750,912
Rollover, Vintage -4 year	1,596,193	1,502,331	1,443,021	1,499,961	1,833,363	2,641,344	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	8,955,517	10,603,759	10,348,748	10,824,666	11,049,414	11,853,488	12,424,606	12,681,075
Rollover, Vintage -5 year	133,754	-	-	-	-	-	242,423	1,807,719	3,338,463	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	8,955,517	10,603,759	10,348,748	10,824,666	11,049,414	11,853,488	12,424,606
Expiring RECs		-	-	-	-	-	-	-	-	793,272	2,795,845	3,499,300	4,342,496	4,503,898	5,356,317	6,133,862	7,731,817	7,428,018	7,856,432	8,032,066	8,785,512
BALANCE AFTER COMPLIANCE		**11,790,054**	**13,581,552**	**15,340,798**	**18,415,391**	**22,197,644**	**26,820,143**	**31,601,646**	**37,233,775**	**42,850,828**	**48,069,599**	**52,283,924**	**56,087,171**	**59,909,674**	**63,635,590**	**67,104,679**	**69,181,996**	**71,584,159**	**74,406,397**	**76,786,497**	**78,062,926**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
New Mexico Member Load		2,612,907	2,747,921	2,779,463	2,812,346	2,746,850	2,682,294	2,711,769	2,742,982	2,772,621	2,802,899	2,833,421	2,865,028	2,894,395	2,924,969	2,956,189	2,988,368	3,018,519	3,049,387	3,080,519	3,112,544
New Mexico Member Retail Sales6	2%	2,560,648	2,692,963	2,723,874	2,756,099	2,691,913	2,628,648	2,657,533	2,688,123	2,717,168	2,746,841	2,776,753	2,807,728	2,836,507	2,866,470	2,897,065	2,928,600	2,958,149	2,988,399	3,018,908	3,050,293
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	269,296	272,387	275,610	1,076,765	1,051,459	1,063,013	1,075,249	1,086,867	1,373,420	1,388,376	1,403,864	1,418,254	1,433,235	1,448,533	1,464,300	1,479,074	1,494,200	1,509,454	1,525,147
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	176,813	175,271	173,733	172,195	170,657	169,119	167,580	166,042	164,504	162,965	161,426	159,890	158,351	156,812	144,658	-	-	-	-	-
Alta Luna Solar	1	76,231	75,850	75,471	75,093	74,717	74,089	73,670	73,440	72,880	72,510	72,110	71,900	71,340	70,950	70,570	70,350	69,800	69,410	69,020	69,020
Escalante Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	387,603	377,201	384,144
Total RECs Generated		830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	906,864	893,977	748,822	1,520,423	1,909,930	1,778,863	1,800,025
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	722,799	168,243	-	41,348	457,079	726,488	1,001,366
Rollover, Vintage -1 year	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	846,533	340,025	-	-	-	-	-	-	-
Rollover, Vintage -2 year	265,817	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	890,887	420,747	-	-	-	-	-	-	-	-	-
Rollover, Vintage -3 year	209,144	218,896	207,673	770,908	830,956	829,372	827,490	724,765	579,854	420,678	-	-	-	-	-	-	-	-	-	-	-
Rollover, Vintage -4 year	-	-	-	-	495,298	249,490	27,403	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,143,548**	**2,703,624**	**3,258,727**	**3,916,002**	**3,769,576**	**3,645,808**	**3,505,592**	**3,351,174**	**3,182,544**	**2,725,082**	**2,250,397**	**1,758,279**	**1,249,171**	**722,799**	**168,243**	**-**	**41,348**	**457,079**	**726,488**	**1,001,366**

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

80% Carbon Reduction Version 2

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	11,096,023	11,334,704	11,551,975	11,760,844	11,994,606	12,227,035	12,477,215	12,725,959	12,945,710	13,175,611	13,394,617	13,615,062	13,856,273	14,108,272	14,359,711	14,603,647	14,841,172	15,086,738	15,339,875
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	2,219,205	2,266,941	2,310,395	2,352,169	2,398,921	2,445,407	2,495,443	2,545,192	2,589,142	2,635,122	2,678,923	2,723,012	2,771,255	2,821,654	2,871,942	2,920,729	2,968,234	3,017,348	3,067,975
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	231,363	231,363	231,363	232,138	231,363	231,363	231,363	232,138	231,363	211,775	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,263	461,263	461,263	462,550	461,263	461,263	461,263	462,550	461,263	461,263	461,263	461,250	-	-	-	-	-	-	-	-
Carousel-E.CO	1	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	664,520
San Isabel Solar	1	76,103	75,730	75,370	75,140	74,570	74,160	73,810	73,580	73,020	72,630	72,230	72,020	71,470	71,080	70,700	70,460	69,910	69,550	69,150	69,150
Twin Buttes	1	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430
Spanish Peaks Solar	1	-	-	12,706	267,735	266,395	265,056	263,716	262,377	261,038	259,698	258,359	257,020	255,680	254,341	253,001	251,662	250,323	237,306	-	-
Crossing Trails Wind	1	439,001	439,001	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	421,191	-	-	-	-	-
Niyol Wind	1	-	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712
Axial Basin Solar	1	-	-	-	369,907	368,057	366,207	364,357	362,507	360,657	358,807	356,957	355,107	353,257	351,407	349,557	347,707	345,858	344,089	-	-
Dolores Canyon Solar	1	-	-	-	297,092	295,606	294,121	292,635	291,149	289,663	288,177	286,692	285,206	283,720	282,234	280,748	279,263	277,777	276,359	-	-
Spanish Peaks II Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Coyote Gulch Solar	1	-	-	-	331,082	329,427	327,771	326,115	324,459	322,803	321,148	319,492	317,836	316,180	314,524	312,869	311,130	309,557	307,977	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2																					
Tri-County Hydropower / Ridgway1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
ECO100MWWIND	1	-	-	-	-	396,172	395,541	393,345	361,548	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND	1	-	-	-	-	382,161	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND2	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV2	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV3	1	-	-	-	-	-	-	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND3	1	-	-	-	-	-	-	-	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV4	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV5	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV6	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV7	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV8	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV9	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND8	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
SWC0100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND9	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
SWC0100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV12	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV13	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
ECO100MWPV	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	10,991,049	10,719,326	11,202,903	11,434,396	12,237,606	12,809,609	13,087,395	13,132,258	14,043,219	13,827,422	13,512,610
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	10,991,049	10,719,326	11,202,903	11,434,396	12,237,606	12,809,609	13,087,395	13,132,258	14,043,219	13,827,422	13,512,610
Rollover, Vintage -1 year	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	10,991,049	10,719,326	11,202,903	11,434,396	12,237,606	12,809,609	13,087,395	13,132,258	14,043,219	13,827,422
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	10,991,049	10,719,326	11,202,903	11,434,396	12,237,606	12,809,609	13,087,395	13,132,258	14,043,219
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	10,991,049	10,719,326	11,202,903	11,434,396	12,237,606	12,809,609	13,087,395	13,132,258
Rollover, Vintage -4 year	1,596,193	1,502,331	1,443,021	1,499,961	1,833,363	2,641,344	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	10,991,049	10,719,326	11,202,903	11,434,396	12,237,606	12,809,609	13,087,395
Rollover, Vintage -5 year	133,754	-	-	-	-	-	242,423	1,807,719	3,338,463	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	10,991,049	10,719,326	11,202,903	11,434,396	12,237,606	12,809,609
Expiring RECs		-	-	-	-	-	-	-	-	793,272	2,795,845	3,499,300	4,342,496	4,503,898	5,356,317	6,531,851	8,119,107	7,798,596	8,234,668	8,417,048	9,169,630
BALANCE AFTER COMPLIANCE		**11,790,054**	**13,581,552**	**15,340,798**	**18,415,391**	**22,197,644**	**26,820,143**	**31,601,646**	**37,233,775**	**43,248,817**	**48,854,878**	**53,439,782**	**57,621,265**	**61,828,750**	**65,938,784**	**69,394,887**	**71,491,233**	**73,904,165**	**76,744,481**	**79,137,508**	**80,412,512**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

Retail Load																					
New Mexico Member Load		2,612,907	2,747,921	2,779,463	2,812,346	2,746,850	2,682,294	2,711,769	2,742,982	2,772,621	2,802,899	2,833,421	2,865,028	2,894,395	2,924,969	2,956,189	2,988,368	3,018,519	3,049,387	3,080,519	3,112,544
New Mexico Member Retail Sales	2%	2,560,648	2,692,963	2,723,874	2,756,099	2,691,913	2,628,648	2,657,533	2,688,123	2,717,168	2,746,841	2,776,753	2,807,728	2,836,507	2,866,470	2,897,065	2,928,600	2,958,149	2,988,399	3,018,908	3,050,293
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	269,296	272,387	275,610	1,076,765	1,051,459	1,063,013	1,075,249	1,086,867	1,373,420	1,388,376	1,403,864	1,418,254	1,433,235	1,448,533	1,464,300	1,479,074	1,494,200	1,509,454	1,525,147
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	176,813	175,271	173,733	172,195	170,657	169,119	167,580	166,042	164,504	162,965	161,426	159,890	158,351	156,812	144,658	-	-	-	-	-
Alta Luna Solar	1	76,231	75,850	75,471	75,093	74,717	74,089	73,670	73,440	72,880	72,510	72,110	71,900	71,340	70,950	70,570	70,350	69,800	69,410	69,020	69,020
Escalante Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	387,603	377,201	384,144
Total RECs Generated		830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	906,864	893,977	748,822	1,520,423	1,909,930	1,778,863	1,800,025
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	722,799	168,243	-	41,348	457,079	726,488	1,001,366
Rollover, Vintage -1 year	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	846,533	340,025	-	-	-	-	-	-	-
Rollover, Vintage -2 year	265,817	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	890,887	420,747	-	-	-	-	-	-	-	-	-
Rollover, Vintage -3 year	209,144	218,896	207,673	770,908	830,956	829,372	827,490	724,765	579,854	420,678	-	-	-	-	-	-	-	-	-	-	-
Rollover, Vintage -4 year	-	-	-	-	495,298	249,490	27,403	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,143,548**	**2,703,624**	**3,258,727**	**3,916,002**	**3,769,576**	**3,645,808**	**3,505,592**	**3,351,174**	**3,182,544**	**2,725,082**	**2,250,397**	**1,758,279**	**1,249,171**	**722,799**	**168,243**	**-**	**41,348**	**457,079**	**726,488**	**1,001,366**

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

80% Carbon Reduction Version 3

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	11,096,023	11,334,704	11,551,975	11,760,844	11,994,606	12,227,035	12,477,215	12,725,959	12,945,710	13,175,611	13,394,617	13,615,062	13,856,273	14,108,272	14,359,711	14,603,647	14,841,172	15,086,738	15,339,875
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	2,219,205	2,266,941	2,310,395	2,352,169	2,398,921	2,445,407	2,495,443	2,545,192	2,589,142	2,635,122	2,678,923	2,723,012	2,771,255	2,821,654	2,871,942	2,920,729	2,968,234	3,017,348	3,067,975
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	231,363	231,363	231,363	232,138	231,363	231,363	231,363	232,138	231,363	211,775	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,263	461,263	461,263	462,550	461,263	461,263	461,263	462,550	461,263	461,263	461,263	461,250	-	-	-	-	-	-	-	-
Carousel-E.CO	1	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	664,520
San Isabel Solar	1	76,103	75,730	75,370	75,140	74,570	74,160	73,810	73,580	73,020	72,630	72,230	72,020	71,470	71,080	70,700	70,460	69,910	69,550	69,150	69,150
Twin Buttes	1	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430
Spanish Peaks Solar	1	-	-	12,706	267,735	266,395	265,056	263,716	262,377	261,038	259,698	258,359	257,020	255,680	254,341	253,001	251,662	250,323	237,306	-	-
Crossing Trails Wind	1	439,001	439,001	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	421,191	-	-	-	-	-
Niyol Wind	1	-	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712
Axial Basin Solar	1	-	-	-	369,907	368,057	366,207	364,357	362,507	360,657	358,807	356,957	355,107	353,257	351,407	349,557	347,707	345,858	344,089	-	-
Dolores Canyon Solar	1	-	-	-	297,092	295,606	294,121	292,635	291,149	289,663	288,177	286,692	285,206	283,720	282,234	280,748	279,263	277,777	276,359	-	-
Spanish Peaks II Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Coyote Gulch Solar	1	-	-	-	331,082	329,427	327,771	326,115	324,459	322,803	321,148	319,492	317,836	316,180	314,524	312,869	311,130	309,557	307,977	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2																					
Tri-County Hydropower / Ridgway1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
ECO100MWWIND	1	-	-	-	-	396,172	395,541	393,345	361,548	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND	1	-	-	-	-	382,161	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND2	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV2	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV3	1	-	-	-	-	-	-	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND3	1	-	-	-	-	-	-	-	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV4	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV5	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV6	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV7	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV8	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV9	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND8	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
SWC0100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND9	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
SWC0100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV12	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV13	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
ECO100MWPV	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,378,340	11,089,904	11,202,903	11,434,396	12,237,606	12,809,609	13,087,395	13,132,258	14,043,219	13,827,422	13,512,610
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,378,340	11,089,904	11,202,903	11,434,396	12,237,606	12,809,609	13,087,395	13,132,258	14,043,219	13,827,422	13,512,610
Rollover, Vintage -1 year	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,378,340	11,089,904	11,202,903	11,434,396	12,237,606	12,809,609	13,087,395	13,132,258	14,043,219	13,827,422
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,378,340	11,089,904	11,202,903	11,434,396	12,237,606	12,809,609	13,087,395	13,132,258	14,043,219
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,378,340	11,089,904	11,202,903	11,434,396	12,237,606	12,809,609	13,087,395	13,132,258
Rollover, Vintage -4 year	1,596,193	1,502,331	1,443,021	1,499,961	1,833,363	2,641,344	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,378,340	11,089,904	11,202,903	11,434,396	12,237,606	12,809,609	13,087,395
Rollover, Vintage -5 year	133,754	-	-	-	-	-	242,423	1,807,719	3,338,463	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,378,340	11,089,904	11,202,903	11,434,396	12,237,606	12,809,609
Expiring RECs		-	-	-	-	-	-	-	-	793,272	2,795,845	3,499,300	4,342,496	4,503,898	5,356,317	6,531,851	8,506,398	8,169,174	8,234,668	8,417,048	9,169,630
BALANCE AFTER COMPLIANCE		**11,790,054**	**13,581,552**	**15,340,798**	**18,415,391**	**22,197,644**	**26,820,143**	**31,601,646**	**37,233,775**	**43,248,817**	**49,242,169**	**54,197,650**	**58,379,133**	**62,586,619**	**66,696,653**	**70,152,756**	**71,861,811**	**73,904,165**	**76,744,481**	**79,137,508**	**80,412,512**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

Retail Load																					
New Mexico Member Load		2,612,907	2,747,921	2,779,463	2,812,346	2,746,850	2,682,294	2,711,769	2,742,982	2,772,621	2,802,899	2,833,421	2,865,028	2,894,395	2,924,969	2,956,189	2,988,368	3,018,519	3,049,387	3,080,519	3,112,544
New Mexico Member Retail Sales6	2%	2,560,648	2,692,963	2,723,874	2,756,099	2,691,913	2,628,648	2,657,533	2,688,123	2,717,168	2,746,841	2,776,753	2,807,728	2,836,507	2,866,470	2,897,065	2,928,600	2,958,149	2,988,399	3,018,908	3,050,293
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	269,296	272,387	275,610	1,076,765	1,051,459	1,063,013	1,075,249	1,086,867	1,373,420	1,388,376	1,403,864	1,418,254	1,433,235	1,448,533	1,464,300	1,479,074	1,494,200	1,509,454	1,525,147
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	176,813	175,271	173,733	172,195	170,657	169,119	167,580	166,042	164,504	162,965	161,426	159,890	158,351	156,812	144,658	-	-	-	-	-
Alta Luna Solar	1	76,231	75,850	75,471	75,093	74,717	74,089	73,670	73,440	72,880	72,510	72,110	71,900	71,340	70,950	70,570	70,350	69,800	69,410	69,020	69,020
Escalante Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	387,603	377,201	384,144
Total RECs Generated		830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	906,864	893,977	748,822	1,520,423	1,909,930	1,778,863	1,800,025
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	722,799	168,243	-	41,348	457,079	726,488	1,001,366
Rollover, Vintage -1 year	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	846,533	340,025	-	-	-	-	-	-	-
Rollover, Vintage -2 year	265,817	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	890,887	420,747	-	-	-	-	-	-	-	-	-
Rollover, Vintage -3 year	209,144	218,896	207,673	770,908	830,956	829,372	827,490	724,765	579,854	420,678	-	-	-	-	-	-	-	-	-	-	-
Rollover, Vintage -4 year	-	-	-	-	495,298	249,490	27,403	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,143,548**	**2,703,624**	**3,258,727**	**3,916,002**	**3,769,576**	**3,645,808**	**3,505,592**	**3,351,174**	**3,182,544**	**2,725,082**	**2,250,397**	**1,758,279**	**1,249,171**	**722,799**	**168,243**	**-**	**41,348**	**457,079**	**726,488**	**1,001,366**

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

80% Carbon Reduction Version 4

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	11,096,023	11,334,704	11,551,975	11,760,844	11,994,606	12,227,035	12,477,215	12,725,959	12,945,710	13,175,611	13,394,617	13,615,062	13,856,273	14,108,272	14,359,711	14,603,647	14,841,172	15,086,738	15,339,875
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	2,219,205	2,266,941	2,310,395	2,352,169	2,398,921	2,445,407	2,495,443	2,545,192	2,589,142	2,635,122	2,678,923	2,723,012	2,771,255	2,821,654	2,871,942	2,920,729	2,968,234	3,017,348	3,067,975
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	231,363	231,363	231,363	232,138	231,363	231,363	231,363	232,138	231,363	211,775	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,263	461,263	461,263	462,550	461,263	461,263	461,263	462,550	461,263	461,263	461,263	461,250	-	-	-	-	-	-	-	-
Carousel-E.CO	1	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	664,520
San Isabel Solar	1	76,103	75,730	75,370	75,140	74,570	74,160	73,810	73,580	73,020	72,630	72,230	72,020	71,470	71,080	70,700	70,460	69,910	69,550	69,150	69,150
Twin Buttes	1	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430
Spanish Peaks Solar	1	-	-	12,706	267,735	266,395	265,056	263,716	262,377	261,038	259,698	258,359	257,020	255,680	254,341	253,001	251,662	250,323	237,306	-	-
Crossing Trails Wind	1	439,001	439,001	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	421,191	-	-	-	-
Niyol Wind	1	-	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712
Axial Basin Solar	1	-	-	-	369,907	368,057	366,207	364,357	362,507	360,657	358,807	356,957	355,107	353,257	351,407	349,557	347,707	345,858	344,089	-	-
Dolores Canyon Solar	1	-	-	-	297,092	295,606	294,121	292,635	291,149	289,663	288,177	286,692	285,206	283,720	282,234	280,748	279,263	277,777	276,359	-	-
Spanish Peaks II Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Coyote Gulch Solar	1	-	-	-	331,082	329,427	327,771	326,115	324,459	322,803	321,148	319,492	317,836	316,180	314,524	312,869	311,130	309,557	307,977	-	-
ECO100MWWIND	1	-	-	-	-	396,172	395,541	393,345	361,548	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2																					
Tri-County Hydropower/Ridgway1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
WYO100MWWIND	1	-	-	-	-	382,161	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND2	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV2	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV3	1	-	-	-	-	-	-	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND3	1	-	-	-	-	-	-	-	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV4	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV5	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV6	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV7	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV8	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV9	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC050MWPV01	1	-	-	-	-	-	-	-	-	-	126,390	124,601	126,329	122,179	125,035	122,578	126,699	126,012	124,663	124,109	122,324
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND8	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
SWC0100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND9	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
SWC0100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV12	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV13	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
ECO100MWPV	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,117,439	10,843,926	11,329,232	11,556,574	12,362,640	12,932,186	13,214,094	13,258,270	14,167,882	13,951,531	13,634,934
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,117,439	10,843,926	11,329,232	11,556,574	12,362,640	12,932,186	13,214,094	13,258,270	14,167,882	13,951,531	13,634,934
Rollover, Vintage -1 year	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,117,439	10,843,926	11,329,232	11,556,574	12,362,640	12,932,186	13,214,094	13,258,270	14,167,882	13,951,531
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,117,439	10,843,926	11,329,232	11,556,574	12,362,640	12,932,186	13,214,094	13,258,270	14,167,882
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,117,439	10,843,926	11,329,232	11,556,574	12,362,640	12,932,186	13,214,094	13,258,270
Rollover, Vintage -4 year	1,596,193	1,502,331	1,443,021	1,499,961	1,833,363	2,641,344	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,117,439	10,843,926	11,329,232	11,556,574	12,362,640	12,932,186	13,214,094
Rollover, Vintage -5 year	133,754	-	-	-	-	-	242,423	1,807,719	3,338,463	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,117,439	10,843,926	11,329,232	11,556,574	12,362,640	12,932,186
Expiring RECs		-	-	-	-	-	-	-	-	793,272	2,795,845	3,499,300	4,342,496	4,503,898	5,356,317	6,531,851	8,245,497	7,923,197	8,360,997	8,539,227	9,294,665
BALANCE AFTER COMPLIANCE		**11,790,054**	**13,581,552**	**15,340,798**	**18,415,391**	**22,197,644**	**26,820,143**	**31,601,646**	**37,233,775**	**43,248,817**	**48,981,268**	**53,690,772**	**57,998,584**	**62,328,248**	**66,563,316**	**70,141,997**	**72,238,652**	**74,652,995**	**77,491,645**	**79,886,602**	**81,158,896**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

Retail Load																					
New Mexico Member Load		2,612,907	2,747,921	2,779,463	2,812,346	2,746,850	2,682,294	2,711,769	2,742,982	2,772,621	2,802,899	2,833,421	2,865,028	2,894,395	2,924,969	2,956,189	2,988,368	3,018,519	3,049,387	3,080,519	3,112,544
New Mexico Member Retail Sales6	2%	2,560,648	2,692,963	2,723,874	2,756,099	2,691,913	2,628,648	2,657,533	2,688,123	2,717,168	2,746,841	2,776,753	2,807,728	2,836,507	2,866,470	2,897,065	2,928,600	2,958,149	2,988,399	3,018,908	3,050,293
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	269,296	272,387	275,610	1,076,765	1,051,459	1,063,013	1,075,249	1,086,867	1,373,420	1,388,376	1,403,864	1,418,254	1,433,235	1,448,533	1,464,300	1,479,074	1,494,200	1,509,454	1,525,147
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	176,813	175,271	173,733	172,195	170,657	169,119	167,580	166,042	164,504	162,965	161,426	159,890	158,351	156,812	144,658	-	-	-	-	-
Alta Luna Solar	1	76,231	75,850	75,471	75,093	74,717	74,089	73,670	73,440	72,880	72,510	72,110	71,900	71,340	70,950	70,570	70,350	69,800	69,410	69,020	69,020
Escalante Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591														
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	387,603	377,201	384,144
NM100MWWind	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
Total RECs Generated		830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	906,864	893,977	748,822	1,520,423	1,909,930	1,778,863	1,800,025
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	722,799	168,243	-	41,348	457,079	726,488	1,001,366
Rollover, Vintage -1 year	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	846,533	340,025	-	-	-	-	-	-	-
Rollover, Vintage -2 year	265,817	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	890,887	420,747	-	-	-	-	-	-	-	-	-
Rollover, Vintage -3 year	209,144	218,896	207,673	770,908	830,956	829,372	827,490	724,765	579,854	420,678	-	-	-	-	-	-	-	-	-	-	-
Rollover, Vintage -4 year	-	-	-	-	495,298	249,490	27,403	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,143,548**	**2,703,624**	**3,258,727**	**3,916,002**	**3,769,576**	**3,645,808**	**3,505,592**	**3,351,174**	**3,182,544**	**2,725,082**	**2,250,397**	**1,758,279**	**1,249,171**	**722,799**	**168,243**	-	**41,348**	**457,079**	**726,488**	**1,001,366**

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

Low Load 80% Carbon Reduction Version 1

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	9,977,192	10,093,076	10,208,551	10,327,548	10,475,126	10,626,864	10,798,057	10,970,948	11,121,149	11,281,911	11,435,692	11,590,367	11,763,379	11,947,079	12,130,590	12,308,499	12,480,739	12,660,788	12,847,891
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	1,995,438	2,018,615	2,041,710	2,065,510	2,095,025	2,125,373	2,159,611	2,194,190	2,224,230	2,256,382	2,287,138	2,318,073	2,352,676	2,389,416	2,426,118	2,461,700	2,496,148	2,532,158	2,569,578
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	231,363	231,363	231,363	232,138	231,363	231,363	231,363	232,138	231,363	211,775	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,263	461,263	461,263	462,550	461,263	461,263	461,263	462,550	461,263	461,263	461,263	461,250	-	-	-	-	-	-	-	-
Carousel-E.CO	1	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	664,520
San Isabel Solar	1	76,103	75,730	75,370	75,140	74,570	74,160	73,810	73,580	73,020	72,630	72,230	72,020	71,470	71,080	70,700	70,460	69,910	69,550	69,150	69,150
Twin Buttes	1	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430
Spanish Peaks Solar	1	-	-	12,706	267,735	266,395	265,056	263,716	262,377	261,038	259,698	258,359	257,020	255,680	254,341	253,001	251,662	250,323	237,306	-	-
Crossing Trails Wind	1	439,001	439,001	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	421,191	-	-	-	-	-
Niyol Wind	1	-	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712
Axial Basin Solar	1	-	-	-	369,907	368,057	366,207	364,357	362,507	360,657	358,807	356,957	355,107	353,257	351,407	349,557	347,707	345,858	344,089	-	-
Dolores Canyon Solar	1	-	-	-	297,092	295,606	294,121	292,635	291,149	289,663	288,177	286,692	285,206	283,720	282,234	280,748	279,263	277,777	276,359	-	-
Spanish Peaks II Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Coyote Gulch Solar	1	-	-	-	331,082	329,427	327,771	326,115	324,459	322,803	321,148	319,492	317,836	316,180	314,524	312,869	311,130	309,557	307,977	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	1.25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2	0																				
Tri-County Hydropower / Ridgway1	1.25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
SWCO100MWPV	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND	1	-	-	-	-	-	-	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV2	1	-	-	-	-	-	-	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND2	1	-	-	-	-	-	-	-	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
ECO100MWWIND	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
SWCO100MWPV3	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND3	1	-	-	-	-	-	-	-	-	-	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV4	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV5	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV6	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV7	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV8	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV9	1	-	-	-	-	-	-	-	-	-	-	-	-	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	388,143	388,184	387,918	379,721	384,936	394,835	379,717
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	396,315	397,909	382,693
SWCO100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
SWCO100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,160,150	4,010,703	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806	11,578,233	11,351,599	11,834,210	11,138,241	10,890,693
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806	11,578,233	11,351,599	11,834,210	11,138,241	10,890,693
Rollover, Vintage -1 year	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806	11,578,233	11,351,599	11,834,210	11,138,241
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806	11,578,233	11,351,599	11,834,210
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806	11,578,233	11,351,599
Rollover, Vintage -4 year	1,596,193	1,502,331	1,666,787	1,972,053	2,574,140	3,160,150	4,010,703	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806	11,578,233
Rollover, Vintage -5 year	133,754	-	-	-	-	508,630	1,573,755	3,459,085	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806
Expiring RECs		-	-	-	-	-	-	-	1,299,474	1,831,997	3,160,758	3,099,707	3,311,348	3,889,119	4,262,322	5,212,562	7,169,739	7,637,847	8,092,749	7,751,673	8,139,605
BALANCE AFTER COMPLIANCE		11,790,054	13,805,318	15,812,890	19,156,167	22,446,747	25,950,209	30,032,029	33,187,941	36,763,732	40,974,601	45,718,058	50,708,468	54,785,106	58,879,291	62,308,119	64,290,495	65,542,548	66,787,861	67,642,272	67,823,782
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

		2,612,907	2,393,217	2,370,000	2,354,020	2,259,751	2,171,703	2,164,869	2,161,203	2,157,825	2,156,149	2,155,679	2,156,870	2,157,195	2,159,045	2,161,937	2,165,998	2,169,058	2,173,008	2,177,489	2,182,861
Retail Load																					
New Mexico Member Load																					
New Mexico Member Retail Sales	2%	2,560,648	2,345,353	2,322,600	2,306,939	2,214,556	2,128,269	2,121,572	2,117,979	2,114,668	2,113,026	2,112,566	2,113,733	2,114,051	2,115,864	2,118,698	2,122,678	2,125,677	2,129,547	2,133,939	2,139,203
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	234,535	232,260	230,694	885,822	851,308	848,629	847,191	845,867	1,056,513	1,056,283	1,056,866	1,057,026	1,057,932	1,059,349	1,061,339	1,062,838	1,064,774	1,066,970	1,069,602
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	176,813	175,271	173,733	172,195	170,657	169,119	167,580	166,042	164,504	162,965	161,426	159,890	158,351	156,812	144,658	-	-	-	-	-
Alta Luna Solar	1	76,231	75,850	75,471	75,093	74,717	74,089	73,670	73,440	72,880	72,510	72,110	71,900	71,340	70,950	70,570	70,350	69,800	69,410	69,020	69,020
Escalante Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	384,144
Total RECs Generated		830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	906,864	893,977	748,822	1,134,131	1,134,723	1,024,461	1,415,881
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	906,864	893,977	748,822	1,134,131	1,134,723	1,024,461	1,415,881
Rollover, Vintage -1 year	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	906,864	893,977	748,822	1,134,131	1,134,723	1,024,461
Rollover, Vintage -2 year	265,817	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	906,864	893,977	748,822	1,111,330	1,134,723
Rollover, Vintage -3 year	209,144	218,896	242,434	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	774,312	622,118	466,144	295,346	-	41,728
Rollover, Vintage -4 year	-	-	-	10,174	615,103	560,237	538,302	517,163	602,857	687,328	558,507	425,021	288,986	150,198	8,224	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		2,143,548	2,738,385	3,333,615	4,035,807	4,080,323	4,156,707	4,230,876	4,304,515	4,376,885	4,236,331	4,093,740	3,948,619	3,800,738	3,649,670	3,484,297	3,171,780	3,243,073	3,313,022	3,270,514	3,616,792

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

Low Load 80% Carbon Reduction Version 2

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	9,977,192	10,093,076	10,208,551	10,327,548	10,475,126	10,626,864	10,798,057	10,970,948	11,121,149	11,281,911	11,435,692	11,590,367	11,763,379	11,947,079	12,130,590	12,308,499	12,480,739	12,660,788	12,847,891
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	1,995,438	2,018,615	2,041,710	2,065,510	2,095,025	2,125,373	2,159,611	2,194,190	2,224,230	2,256,382	2,287,138	2,318,073	2,352,676	2,389,416	2,426,118	2,461,700	2,496,148	2,532,158	2,569,578
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	231,363	231,363	231,363	232,138	231,363	231,363	231,363	232,138	231,363	211,775	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,263	461,263	461,263	462,550	461,263	461,263	461,263	462,550	461,263	461,263	461,263	461,250	-	-	-	-	-	-	-	-
Carousel-E.CO	1	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	664,520
San Isabel Solar	1	76,103	75,730	75,370	75,140	74,570	74,160	73,810	73,580	73,020	72,630	72,230	72,020	71,470	71,080	70,700	70,460	69,910	69,550	69,150	69,150
Twin Buttes	1	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430
Spanish Peaks Solar	1	-	-	12,706	267,735	266,395	265,056	263,716	262,377	261,038	259,698	258,359	257,020	255,680	254,341	253,001	251,662	250,323	237,306	-	-
Crossing Trails Wind	1	439,001	439,001	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	421,191	-	-	-	-	-
Niyol Wind	1	-	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712
Axial Basin Solar	1	-	-	-	369,907	368,057	366,207	364,357	362,507	360,657	358,807	356,957	355,107	353,257	351,407	349,557	347,707	345,858	344,089	-	-
Dolores Canyon Solar	1	-	-	-	297,092	295,606	294,121	292,635	291,149	289,663	288,177	286,692	285,206	283,720	282,234	280,748	279,263	277,777	276,359	-	-
Spanish Peaks II Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Coyote Gulch Solar	1	-	-	-	331,082	329,427	327,771	326,115	324,459	322,803	321,148	319,492	317,836	316,180	314,524	312,869	311,130	309,557	307,977	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	1.25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2	0																				
Tri-County Hydropower / Ridgway1	1.25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
SWCO100MWPV	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND	1	-	-	-	-	-	-	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV2	1	-	-	-	-	-	-	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND2	1	-	-	-	-	-	-	-	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
ECO100MWWIND	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
SWCO100MWPV3	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND3	1	-	-	-	-	-	-	-	-	-	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV4	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV5	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV6	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV7	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV8	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV9	1	-	-	-	-	-	-	-	-	-	-	-	-	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	388,143	388,184	387,918	379,721	384,936	394,835	379,717
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	396,315	397,909	382,693
SWCO100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
SWCO100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,160,150	4,010,703	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806	11,578,233	11,351,599	11,834,210	11,138,241	10,890,693
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806	11,578,233	11,351,599	11,834,210	11,138,241	10,890,693
Rollover, Vintage -1 year	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806	11,578,233	11,351,599	11,834,210	11,138,241
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806	11,578,233	11,351,599	11,834,210
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806	11,578,233	11,351,599
Rollover, Vintage -4 year	1,596,193	1,502,331	1,666,787	1,972,053	2,574,140	3,160,150	4,010,703	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806	11,578,233
Rollover, Vintage -5 year	133,754	-	-	-	-	508,630	1,573,755	3,459,085	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806
Expiring RECs		-	-	-	-	-	-	-	1,299,474	1,831,997	3,160,758	3,099,707	3,311,348	3,889,119	4,262,322	5,212,562	7,169,739	7,637,847	8,092,749	7,751,673	8,139,605
BALANCE AFTER COMPLIANCE		**11,790,054**	**13,805,318**	**15,812,890**	**19,156,167**	**22,446,747**	**25,950,209**	**30,032,029**	**33,187,941**	**36,763,732**	**40,974,601**	**45,718,058**	**50,708,468**	**54,785,106**	**58,879,291**	**62,308,119**	**64,290,495**	**65,542,548**	**66,787,861**	**67,642,272**	**67,823,782**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
New Mexico Member Load		2,612,907	2,393,217	2,370,000	2,354,020	2,259,751	2,171,703	2,164,869	2,161,203	2,157,825	2,156,149	2,155,679	2,156,870	2,157,195	2,159,045	2,161,937	2,165,998	2,169,058	2,173,008	2,177,489	2,182,861
New Mexico Member Retail Sales6	2%	2,560,648	2,345,353	2,322,600	2,306,939	2,214,556	2,128,269	2,121,572	2,117,979	2,114,668	2,113,026	2,112,566	2,113,733	2,114,051	2,115,864	2,118,698	2,122,678	2,125,677	2,129,547	2,133,939	2,139,203
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	234,535	232,260	230,694	885,822	851,308	848,629	847,191	845,867	1,056,513	1,056,283	1,056,866	1,057,026	1,057,932	1,059,349	1,061,339	1,062,838	1,064,774	1,066,970	1,069,602
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	176,813	175,271	173,733	172,195	170,657	169,119	167,580	166,042	164,504	162,965	161,426	159,890	158,351	156,812	144,658	-	-	-	-	-
Alta Luna Solar	1	76,231	75,850	75,471	75,093	74,717	74,089	73,670	73,440	72,880	72,510	72,110	71,900	71,340	70,950	70,570	70,350	69,800	69,410	69,020	69,020
Escalante Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	384,144
Total RECs Generated		830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	906,864	893,977	748,822	1,134,131	1,134,723	1,024,461	1,415,881
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	906,864	893,977	748,822	1,134,131	1,134,723	1,024,461	1,415,881
Rollover, Vintage -1 year	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	906,864	893,977	748,822	1,134,131	1,134,723	1,024,461
Rollover, Vintage -2 year	265,817	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	906,864	893,977	748,822	1,111,330	1,134,723
Rollover, Vintage -3 year	209,144	218,896	242,434	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	774,312	622,118	466,144	295,346	-	41,728
Rollover, Vintage -4 year	-	-	-	10,174	615,103	560,237	538,302	517,163	602,857	687,328	558,507	425,021	288,986	150,198	8,224	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,143,548**	**2,738,385**	**3,333,615**	**4,035,807**	**4,080,323**	**4,156,707**	**4,230,876**	**4,304,515**	**4,376,885**	**4,236,331**	**4,093,740**	**3,948,619**	**3,800,738**	**3,649,670**	**3,484,297**	**3,171,780**	**3,243,073**	**3,313,022**	**3,270,514**	**3,616,792**

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

Social Cost of Carbon

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	11,096,023	11,334,704	11,551,975	11,760,844	11,994,606	12,227,035	12,477,215	12,725,959	12,945,710	13,175,611	13,394,617	13,615,062	13,856,273	14,108,272	14,359,711	14,603,647	14,841,172	15,086,738	15,339,875
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	2,219,205	2,266,941	2,310,395	2,352,169	2,398,921	2,445,407	2,495,443	2,545,192	2,589,142	2,635,122	2,678,923	2,723,012	2,771,255	2,821,654	2,871,942	2,920,729	2,968,234	3,017,348	3,067,975
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	231,363	231,363	231,363	232,138	231,363	231,363	231,363	232,138	231,363	211,775	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,263	461,263	461,263	462,550	461,263	461,263	461,263	462,550	461,263	461,263	461,263	461,250	-	-	-	-	-	-	-	-
Carousel-E.CO	1	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	664,520
San Isabel Solar	1	76,103	75,730	75,370	75,140	74,570	74,160	73,810	73,580	73,020	72,630	72,230	72,020	71,470	71,080	70,700	70,460	69,910	69,550	69,150	69,150
Twin Buttes	1	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430
Spanish Peaks Solar	1	-	-	12,706	267,735	266,395	265,056	263,716	262,377	261,038	259,698	258,359	257,020	255,680	254,341	253,001	251,662	250,323	237,306	-	-
Crossing Trails Wind	1	439,001	439,001	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	421,191	-	-	-	-
Niyol Wind	1	-	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712
Axial Basin Solar	1	-	-	-	369,907	368,057	366,207	364,357	362,507	360,657	358,807	356,957	355,107	353,257	351,407	349,557	347,707	345,858	344,089	-	-
Dolores Canyon Solar	1	-	-	-	297,092	295,606	294,121	292,635	291,149	289,663	288,177	286,692	285,206	283,720	282,234	280,748	279,263	277,777	276,359	-	-
Spanish Peaks II Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Coyote Gulch Solar	1	-	-	-	331,082	329,427	327,771	326,115	324,459	322,803	321,148	319,492	317,836	316,180	314,524	312,869	311,130	309,557	307,977	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2																					
Tri-County Hydropower / Ridgway1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
WYO100MWWIND	1	-	-	-	-	382,161	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND2	1	-	-	-	-	382,161	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND3	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND4	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND5	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND6	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND7	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
ECO100MWWINDBATT01	1	-	-	-	-	-	373,835	373,835	375,540	373,835	373,835	373,835	375,540	373,835	373,835	373,835	375,540	373,835	373,835	373,835	375,540
SWCO100MWPV	1	-	-	-	-	-	246,582	248,928	251,403	248,291	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV2	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND8	1	-	-	-	-	-	-	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND9	1	-	-	-	-	-	-	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
ECO100MWWIND	1	-	-	-	-	-	-	-	361,544	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWPV	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV3	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV4	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWPV2	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWPV3	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV5	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND10	1	-	-	-	-	-	-	-	-	-	-	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV6	1	-	-	-	-	-	-	-	-	-	-	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
SWCO100MWPV7	1	-	-	-	-	-	-	-	-	-	-	-	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
SWCO100MWPV8	1	-	-	-	-	-	-	-	-	-	-	-	-	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV9	1	-	-	-	-	-	-	-	-	-	-	-	-	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
ECO100MWWIND8	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
ECO100MWWIND9	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
SWCO100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWCO100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
ECO100MWWINDBATT02	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	373,835	375,540
ECO100MWWINDBATT03	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	373,835	375,540
SWCO100MWPV12	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
SWCO100MWPV13	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
SWCO100MWPV14	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,160,150	4,010,703	4,026,187	5,384,987	6,120,412	8,951,736	9,599,383	10,631,705	10,724,298	11,460,479	11,912,369	13,050,255	13,333,170	13,381,772	13,689,662	13,877,717	14,764,708	15,402,113	15,729,377	15,389,737
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,120,412	8,951,736	9,599,383	10,631,705	10,724,298	11,460,479	11,912,369	13,050,255	13,333,170	13,381,772	13,689,662	13,877,717	14,764,708	15,402,113	15,729,377	15,389,737
Rollover, Vintage -1 year	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,120,412	8,951,736	9,599,383	10,631,705	10,724,298	11,460,479	11,912,369	13,050,255	13,333,170	13,381,772	13,689,662	13,877,717	14,764,708	15,402,113	15,729,377
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,120,412	8,951,736	9,599,383	10,631,705	10,724,298	11,460,479	11,912,369	13,050,255	13,333,170	13,381,772	13,689,662	13,877,717	14,764,708	15,402,113
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,120,412	8,951,736	9,599,383	10,631,705	10,724,298	11,460,479	11,912,369	13,050,255	13,333,170	13,381,772	13,689,662	13,877,717	14,764,708
Rollover, Vintage -4 year	1,596,193	1,502,331	1,443,021	1,499,961	1,833,363	2,641,344	4,010,703	4,026,187	5,384,987	6,120,412	8,951,736	9,599,383	10,631,705	10,724,298	11,460,479	11,912,369	13,050,255	13,333,170	13,381,772	13,689,662	13,877,717
Rollover, Vintage -5 year	133,754	-	-	-	-	-	242,423	1,807,719	3,338,463	5,384,987	6,120,412	8,951,736	9,599,383	10,631,705	10,724,298	11,460,479	11,912,369	13,050,255	13,333,170	13,381,772	13,689,662
Expiring RECs		-	-	-	-	-	-	-	-	793,272	2,795,845	3,485,290	6,272,812	6,876,370	7,860,450	7,902,644	8,588,537	8,991,640	10,082,021	10,315,822	10,313,797
BALANCE AFTER COMPLIANCE		**11,790,054**	**13,581,552**	**15,340,798**	**18,415,391**	**22,183,634**	**28,736,448**	**35,890,424**	**44,026,685**	**51,412,520**	**57,488,012**	**63,279,970**	**67,378,489**	**71,112,277**	**73,862,344**	**76,827,708**	**79,244,945**	**82,097,284**	**84,449,142**	**86,845,349**	**88,853,314**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
New Mexico Member Load		2,612,907	2,747,921	2,779,463	2,812,346	2,746,850	2,682,294	2,711,769	2,742,982	2,772,621	2,802,899	2,833,421	2,865,028	2,894,395	2,924,969	2,956,189	2,988,368	3,018,519	3,049,387	3,080,519	3,112,544
New Mexico Member Retail Sales6	2%	2,560,648	2,692,963	2,723,874	2,756,099	2,691,913	2,628,648	2,657,533	2,688,123	2,717,168	2,746,841	2,776,753	2,807,728	2,836,507	2,866,470	2,897,065	2,928,600	2,958,149	2,988,399	3,018,908	3,050,293
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	269,296	272,387	275,610	1,076,765	1,051,459	1,063,013	1,075,249	1,086,867	1,373,420	1,388,376	1,403,864	1,418,254	1,433,235	1,448,533	1,464,300	1,479,074	1,494,200	1,509,454	1,525,147
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	176,813	175,271	173,733	172,195	170,657	169,119	167,580	166,042	164,504	162,965	161,426	159,890	158,351	156,812	144,658	-	-	-	-	-
Alta Luna Solar	1	76,231	75,850	75,471	75,093	74,717	74,089	73,670	73,440	72,880	72,510	72,110	71,900	71,340	70,950	70,570	70,350	69,800	69,410	69,020	69,020
Escalante Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	386,965	378,013	370,943	379,766	392,123	383,262	393,457	385,983	386,783	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
Total RECs Generated		830,956	829,372	827,490	932,886	930,339	927,691	922,797	1,307,796	1,296,251	1,286,902	1,293,457	1,303,869	1,292,408	1,300,320	1,279,959	1,135,605	1,520,423	1,522,326	1,401,662	1,415,881
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	1,307,796	1,296,251	1,286,902	1,293,457	1,303,869	1,292,408	1,300,320	1,279,959	1,135,605	1,520,423	1,522,326	1,401,662	1,415,881
Rollover, Vintage -1 year	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	1,307,796	1,296,251	1,286,902	1,293,457	1,303,869	1,292,408	1,300,320	1,279,959	1,135,605	1,457,209	1,470,081	1,346,596
Rollover, Vintage -2 year	265,817	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	1,277,851	1,185,725	1,068,763	943,967	814,601	658,476	494,496	295,381	-	-	-
Rollover, Vintage -3 year	209,144	218,896	207,673	770,908	830,956	829,372	827,490	724,765	579,854	420,678	-	-	-	-	-	-	-	-	-	-	-
Rollover, Vintage -4 year	-	-	-	-	495,298	249,490	27,403	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,143,548**	**2,703,624**	**3,258,727**	**3,916,002**	**3,769,576**	**3,645,808**	**3,505,592**	**3,738,139**	**3,947,522**	**3,861,004**	**3,766,084**	**3,666,089**	**3,540,243**	**3,407,329**	**3,238,755**	**2,910,060**	**2,951,408**	**2,979,535**	**2,871,743**	**2,762,477**

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

PO Data

Base Case

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,235,474	11,468,302	11,710,122	11,931,568	12,142,495	12,379,349	12,614,855	12,869,179	13,119,887	13,342,451	13,575,587	13,798,708	14,021,025	14,265,209	14,520,163	14,775,306	15,021,402	15,261,838	15,510,303	15,767,501
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,247,095	2,293,660	2,342,024	2,386,314	2,428,499	2,475,870	2,522,971	2,573,836	2,623,977	2,668,490	2,715,117	2,759,742	2,804,205	2,853,042	2,904,033	2,955,061	3,004,280	3,052,368	3,102,061	3,153,500
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	229,148	217,782	239,856	223,709	234,134	237,995	228,894	220,305	229,456	207,070	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,352	457,957	464,712	464,805	474,110	455,605	467,680	461,110	458,947	451,773	461,352	463,264	-	-	-	-	-	-	-	-
Carousel-E.CO	1	666,843	648,237	672,506	643,626	639,494	658,276	630,020	665,358	649,569	653,199	637,988	658,407	665,672	627,181	651,272	679,557	654,028	666,149	664,391	650,333
San Isabel Solar	1	71,416	72,000	71,416	70,005	70,097	67,964	68,110	69,242	67,104	67,207	66,599	68,868	68,448	61,991	67,776	67,942	64,638	65,203	63,018	64,757
Twin Buttes	1	307,567	308,270	308,267	309,311	308,177	307,740	307,790	308,827	308,191	307,745	308,151	309,102	307,792	308,336	308,286	308,690	307,454	308,290	307,612	309,840
Spanish Peaks Solar	1	-	-	14,113	248,894	242,914	243,911	245,119	246,209	242,205	244,985	240,271	242,341	233,157	237,357	231,467	238,193	236,903	223,417	-	-
Crossing Trails Wind	1	414,777	404,512	408,546	405,177	412,565	411,480	420,353	403,092	413,927	408,330	406,225	400,442	402,187	414,951	366,722	-	-	-	-	-
Niyol Wind	1	10	896,119	882,203	885,459	896,156	893,988	907,129	892,039	895,011	890,207	896,119	884,163	872,514	899,628	893,988	865,549	887,474	882,726	893,321	860,792
Axial Basin Solar	1	-	-	-	321,943	314,757	315,363	316,550	317,270	312,010	315,286	310,320	312,558	302,518	306,310	300,111	307,916	304,682	300,423	-	-
Dolores Canyon Solar	1	-	-	-	254,843	248,539	249,756	249,772	251,760	246,302	250,291	244,935	247,590	238,872	242,817	237,571	243,392	241,020	237,793	-	-
Spanish Peaks II Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Coyote Gulch Solar	1	-	-	-	284,737	277,322	279,034	279,203	281,148	275,754	279,776	273,785	276,551	266,867	271,253	265,310	271,546	269,304	265,384	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2																					
Tri-County Hydropower / Ridgway1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	358,064	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,274	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
ECO100MWPV	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWPV2	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWPV3	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWPV4	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWPV5	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND	1	-	-	-	-	-	-	-	-	-	-	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
SWCO100MWPV	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWCO100MWPV2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWCO100MWPV3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
SWCO100MWPV4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
SWCO100MWPV5	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244,648
SWCO100MWPV6	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244,648
SWCO100MWPV7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244,648
WYO100MWWIND	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	394,835	379,717
WYO100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	394,835	379,717
WYO100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	394,835	379,717
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	379,717
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	379,717
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,134,857	3,998,561	4,058,444	5,196,675	5,182,850	5,188,992	5,176,348	5,162,218	6,132,614	6,383,839	6,878,246	7,311,578	7,938,840	8,362,440	8,297,969	8,154,149	7,956,831	8,532,314	9,111,994	10,382,817
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,134,857	3,998,561	4,058,444	5,196,675	5,182,850	5,188,992	5,176,348	5,162,218	6,132,614	6,383,839	6,878,246	7,311,578	7,938,840	8,362,440	8,297,969	8,154,149	7,956,831	8,532,314	9,111,994	10,382,817
Rollover, Vintage -1 year	2,323,881	2,643,797	3,134,857	3,998,561	4,058,444	5,196,675	5,182,850	5,188,992	5,176,348	5,162,218	6,132,614	6,383,839	6,878,246	7,311,578	7,938,840	8,362,440	8,297,969	8,154,149	7,956,831	8,532,314	9,111,994
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,134,857	3,998,561	4,058,444	5,196,675	5,182,850	5,188,992	5,176,348	5,162,218	6,132,614	6,383,839	6,878,246	7,311,578	7,938,840	8,362,440	8,297,969	8,154,149	7,956,831	8,532,314
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,134,857	3,998,561	4,058,444	5,196,675	5,182,850	5,188,992	5,176,348	5,162,218	6,132,614	6,383,839	6,878,246	7,311,578	7,938,840	8,362,440	8,297,969	8,154,149	7,956,831
Rollover, Vintage -4 year	1,596,193	1,455,566	1,321,801	1,303,657	1,561,141	2,267,499	3,790,190	4,058,444	5,196,675	5,182,850	5,188,992	5,176,348	5,162,218	6,132,614	6,383,839	6,878,246	7,311,578	7,938,840	8,362,440	8,297,969	8,154,149
Rollover, Vintage -5 year	133,754	-	-	-	-	-	-	1,267,219	2,751,827	5,196,675	5,182,850	5,188,992	5,176,348	5,162,218	6,132,614	6,383,839	6,878,246	7,311,578	7,938,840	8,362,440	8,297,969
Expiring RECs		-	-	-	-	-	-	-	-	127,850	2,528,185	2,467,732	2,429,250	2,372,143	2,309,176	3,228,581	3,428,778	3,873,965	4,259,210	4,836,779	5,208,940
BALANCE AFTER COMPLIANCE		**11,717,996**	**13,422,897**	**15,139,316**	**17,949,678**	**20,704,029**	**23,417,151**	**26,070,528**	**28,658,909**	**32,039,696**	**33,226,860**	**34,922,256**	**37,044,841**	**39,807,333**	**43,007,556**	**45,172,911**	**46,943,222**	**48,021,807**	**49,242,543**	**50,415,698**	**52,436,075**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
New Mexico Member Load		2,773,756	2,804,086	2,835,823	2,869,044	2,803,594	2,739,229	2,768,895	2,800,445	2,830,124	2,860,568	2,891,298	2,923,241	2,952,642	2,983,400	3,014,802	3,047,239	3,077,495	3,108,543	3,139,854	3,172,211
New Mexico Member Retail Sales6	2%	2,718,281	2,748,005	2,779,106	2,811,664	2,747,523	2,684,445	2,713,517	2,744,436	2,773,522	2,803,357	2,833,472	2,864,776	2,893,589	2,923,732	2,954,506	2,986,294	3,015,945	3,046,372	3,077,056	3,108,767
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		271,828	274,800	277,911	281,166	1,099,009	1,073,778	1,085,407	1,097,775	1,109,409	1,401,678	1,416,736	1,432,388	1,446,795	1,461,866	1,477,253	1,493,147	1,507,972	1,523,186	1,538,528	1,554,384
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	183,641	178,584	182,474	178,018	177,813	182,492	176,748	177,520	181,129	177,199	176,727	178,087	173,107	171,650	159,594	-	-	-	-	-
Alta Luna Solar	1	74,710	72,253	73,998	72,825	74,357	74,265	71,143	72,803	72,056	74,707	73,318	72,628	72,242	71,235	72,164	74,249	70,955	72,525	73,144	72,412
Escalante Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591														
Policy 115	1.2	55,496	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	475	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	-	-	370,943	379,766	392,123	383,262	393,457	385,983	386,783	386,291	387,603	377,201	384,144
Total RECs Generated		836,574	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	1,290,498	1,295,696	1,309,896	1,292,674	1,301,928	1,281,779	1,127,092	1,122,898	1,124,701	1,028,585	1,035,128
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	836,574	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	1,290,498	1,295,696	1,309,896	1,292,674	1,301,928	1,281,779	1,127,092	1,122,898	1,005,180	495,237	-
Rollover, Vintage -1 year	258,073	835,623	836,574	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	1,290,498	1,295,696	1,217,534	1,048,342	873,017	661,648	280,767	-	-	-
Rollover, Vintage -2 year	265,817	258,073	835,623	836,574	829,088	834,758	921,804	920,973	925,818	915,327	698,330	200,626	58,736	-	-	-	-	-	-	-	-
Rollover, Vintage -3 year	209,144	203,133	186,406	744,118	836,574	829,088	790,584	626,981	450,180	266,589	-	-	-	-	-	-	-	-	-	-	-
Rollover, Vintage -4 year	-	-	-	-	462,951	200,516	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,133,403**	**2,687,690**	**3,244,538**	**3,885,175**	**3,707,139**	**3,559,178**	**3,389,099**	**3,209,417**	**3,019,040**	**2,907,860**	**2,786,820**	**2,664,328**	**2,510,208**	**2,350,270**	**2,154,795**	**1,788,740**	**1,403,665**	**1,005,180**	**495,237**	-

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

80% Carbon Reduction Version 1

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	11,096,023	11,334,704	11,551,975	11,760,844	11,994,606	12,227,035	12,477,215	12,725,959	12,945,710	13,175,611	13,394,617	13,615,062	13,856,273	14,108,272	14,359,711	14,603,647	14,841,172	15,086,738	15,339,875
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	2,219,205	2,266,941	2,310,395	2,352,169	2,398,921	2,445,407	2,495,443	2,545,192	2,589,142	2,635,122	2,678,923	2,723,012	2,771,255	2,821,654	2,871,942	2,920,729	2,968,234	3,017,348	3,067,975
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	229,148	217,782	239,856	223,709	234,134	237,995	228,894	220,305	229,456	207,070	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,352	457,957	464,712	464,805	474,110	455,605	467,680	461,110	458,947	451,773	461,352	463,264	-	-	-	-	-	-	-	-
Carousel-E.CO	1	666,843	648,237	672,506	643,626	639,494	658,276	630,020	665,358	649,569	653,199	637,988	658,407	665,672	627,181	651,272	679,557	654,028	666,149	664,391	650,333
San Isabel Solar	1	71,416	72,000	71,416	70,005	70,097	67,964	68,110	69,242	67,104	67,207	66,599	68,868	68,448	61,991	67,776	67,942	64,638	65,203	63,018	64,757
Twin Buttes	1	307,567	308,270	308,267	309,311	308,177	307,740	307,790	308,827	308,191	307,745	308,151	309,102	307,792	308,336	308,286	308,690	307,454	308,290	307,612	309,840
Spanish Peaks Solar	1	-	-	14,113	248,894	242,914	243,911	245,119	246,209	242,205	244,985	240,271	242,341	233,157	237,357	231,467	238,193	236,903	223,417	-	-
Crossing Trails Wind	1	414,777	404,512	408,546	405,177	412,565	411,480	420,353	403,092	413,927	408,330	406,225	400,442	402,187	414,951	366,722	-	-	-	-	-
Niyol Wind	1	10	896,119	882,203	885,459	896,156	893,988	907,129	892,039	895,011	890,207	896,119	884,163	872,514	899,628	893,988	865,549	887,474	882,726	893,321	860,792
Axial Basin Solar	1	-	-	-	321,943	314,757	315,363	316,550	317,270	312,010	315,286	310,320	312,558	302,518	306,310	300,111	307,916	304,682	300,423	-	-
Dolores Canyon Solar	1	-	-	-	254,843	248,539	249,756	249,772	251,760	246,302	250,291	244,935	247,590	238,872	242,817	237,571	243,392	241,020	237,793	-	-
Spanish Peaks II Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Coyote Gulch Solar	1	-	-	-	284,737	277,322	279,034	279,203	281,148	275,754	279,776	273,785	276,551	266,867	271,253	265,310	271,546	269,304	265,384	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2																					
Tri-County Hydropower / Ridgway1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
ECO100MWWIND	1	-	-	-	-	396,172	395,541	393,345	361,548	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND	1	-	-	-	-	382,161	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND2	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV2	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV3	1	-	-	-	-	-	-	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND3	1	-	-	-	-	-	-	-	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV4	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV5	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV6	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV7	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV8	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV9	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	-	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
SWC0100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND8	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND9	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
SWC0100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV12	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV13	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
ECO100MWPV	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	8,790,518	10,444,634	10,176,570	10,676,075	10,863,082	11,687,548	12,234,672	12,579,684	12,640,940	13,538,210	13,479,043	13,136,828
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	8,790,518	10,444,634	10,176,570	10,676,075	10,863,082	11,687,548	12,234,672	12,579,684	12,640,940	13,538,210	13,479,043	13,136,828
Rollover, Vintage -1 year	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	8,790,518	10,444,634	10,176,570	10,676,075	10,863,082	11,687,548	12,234,672	12,579,684	12,640,940	13,538,210	13,479,043
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	8,790,518	10,444,634	10,176,570	10,676,075	10,863,082	11,687,548	12,234,672	12,579,684	12,640,940	13,538,210
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	8,790,518	10,444,634	10,176,570	10,676,075	10,863,082	11,687,548	12,234,672	12,579,684	12,640,940
Rollover, Vintage -4 year	1,596,193	1,502,331	1,443,021	1,499,961	1,833,363	2,617,778	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	8,790,518	10,444,634	10,176,570	10,676,075	10,863,082	11,687,548	12,234,672	12,579,684
Rollover, Vintage -5 year	133,754	-	-	-	-	-	218,857	1,772,011	3,335,012	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	8,790,518	10,444,634	10,176,570	10,676,075	10,863,082	11,687,548	12,234,672
Expiring RECs		-	-	-	-	-	-	-	-	789,820	2,607,533	3,326,061	4,179,583	4,348,488	5,199,797	5,968,863	7,572,692	7,255,840	7,707,840	7,845,734	8,619,573
BALANCE AFTER COMPLIANCE		**11,766,487**	**13,545,844**	**15,337,347**	**18,223,627**	**21,832,641**	**26,292,226**	**30,918,320**	**36,393,928**	**41,849,434**	**47,097,393**	**51,312,780**	**55,130,348**	**58,921,929**	**62,638,426**	**66,082,581**	**68,217,631**	**70,682,001**	**73,544,136**	**76,160,097**	**77,609,376**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
New Mexico Member Load		2,612,907	2,747,921	2,779,463	2,812,346	2,746,850	2,682,294	2,711,769	2,742,982	2,772,621	2,802,899	2,833,421	2,865,028	2,894,395	2,924,969	2,956,189	2,988,368	3,018,519	3,049,387	3,080,519	3,112,544
New Mexico Member Retail Sales6	2%	2,560,648	2,692,963	2,723,874	2,756,099	2,691,913	2,628,648	2,657,533	2,688,123	2,717,168	2,746,841	2,776,753	2,807,728	2,836,507	2,866,470	2,897,065	2,928,600	2,958,149	2,988,399	3,018,908	3,050,293
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	269,296	272,387	275,610	1,076,765	1,051,459	1,063,013	1,075,249	1,086,867	1,373,420	1,388,376	1,403,864	1,418,254	1,433,235	1,448,533	1,464,300	1,479,074	1,494,200	1,509,454	1,525,147
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	183,641	178,584	182,474	178,018	177,813	182,492	176,748	177,520	181,129	177,199	176,727	178,087	173,107	171,650	159,594	-	-	-	-	-
Alta Luna Solar	1	74,710	72,253	73,998	72,825	74,357	74,265	71,143	72,803	72,056	74,707	73,318	72,628	72,242	71,235	72,164	74,249	70,955	72,525	73,144	72,412
Escalante Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	387,603	377,201	384,144
Total RECs Generated		836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	908,471	895,796	740,308	1,509,189	1,899,908	1,782,988	1,803,417
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	717,092	164,355	-	30,115	435,823	709,356	987,626
Rollover, Vintage -1 year	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	832,925	332,444	-	-	-	-	-	-	-
Rollover, Vintage -2 year	265,817	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	870,647	401,303	-	-	-	-	-	-	-	-	-
Rollover, Vintage -3 year	209,144	218,896	207,673	770,908	836,264	829,088	834,758	725,974	571,698	410,648	-	-	-	-	-	-	-	-	-	-	-
Rollover, Vintage -4 year	-	-	-	-	495,298	254,797	32,425	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,148,856**	**2,708,647**	**3,271,018**	**3,917,211**	**3,761,419**	**3,635,778**	**3,488,092**	**3,330,935**	**3,163,100**	**2,709,234**	**2,236,788**	**1,750,697**	**1,241,855**	**717,092**	**164,355**	**-**	**30,115**	**435,823**	**709,356**	**987,626**

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

80% Carbon Reduction Version 2

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	11,096,023	11,334,704	11,551,975	11,760,844	11,994,606	12,227,035	12,477,215	12,725,959	12,945,710	13,175,611	13,394,617	13,615,062	13,856,273	14,108,272	14,359,711	14,603,647	14,841,172	15,086,738	15,339,875
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	2,219,205	2,266,941	2,310,395	2,352,169	2,398,921	2,445,407	2,495,443	2,545,192	2,589,142	2,635,122	2,678,923	2,723,012	2,771,255	2,821,654	2,871,942	2,920,729	2,968,234	3,017,348	3,067,975
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	229,148	217,782	239,856	223,709	234,134	237,995	228,894	220,305	229,456	207,070	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,352	457,957	464,712	464,805	474,110	455,605	467,680	461,110	458,947	451,773	461,352	463,264	-	-	-	-	-	-	-	-
Carousel-E.CO	1	666,843	648,237	672,506	643,626	639,494	658,276	630,020	665,358	649,569	653,199	637,988	658,407	665,672	627,181	651,272	679,557	654,028	666,149	664,391	650,333
San Isabel Solar	1	71,416	72,000	71,416	70,005	70,097	67,964	68,110	69,242	67,104	67,207	66,599	68,868	68,448	61,991	67,776	67,942	64,638	65,203	63,018	64,757
Twin Buttes	1	307,567	308,270	308,267	309,311	308,177	307,740	307,790	308,827	308,191	307,745	308,151	309,102	307,792	308,336	308,286	308,690	307,454	308,290	307,612	309,840
Spanish Peaks Solar	1	-	-	14,113	248,894	242,914	243,911	245,119	246,209	242,205	244,985	240,271	242,341	233,157	237,357	231,467	238,193	236,903	223,417	-	-
Crossing Trails Wind	1	414,777	404,512	408,546	405,177	412,565	411,480	420,353	403,092	413,927	408,330	406,225	400,442	402,187	414,951	366,722	-	-	-	-	-
Niyol Wind	1	10	896,119	882,203	885,459	896,156	893,988	907,129	892,039	895,011	890,207	896,119	884,163	872,514	899,628	893,988	865,549	887,474	882,726	893,321	860,792
Axial Basin Solar	1	-	-	-	321,943	314,757	315,363	316,550	317,270	312,010	315,286	310,320	312,558	302,518	306,310	300,111	307,916	304,682	300,423	-	-
Dolores Canyon Solar	1	-	-	-	254,843	248,539	249,756	249,772	251,760	246,302	250,291	244,935	247,590	238,872	242,817	237,571	243,392	241,020	237,793	-	-
Spanish Peaks II Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Coyote Gulch Solar	1	-	-	-	284,737	277,322	279,034	279,203	281,148	275,754	279,776	273,785	276,551	266,867	271,253	265,310	271,546	269,304	265,384	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2																					
Tri-County Hydropower / Ridgway1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
ECO100MWWIND	1	-	-	-	-	396,172	395,541	393,345	361,548	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND	1	-	-	-	-	382,161	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND2	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV2	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV3	1	-	-	-	-	-	-	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND3	1	-	-	-	-	-	-	-	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV4	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV5	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV6	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV7	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV8	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV9	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND8	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
SWC0100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND9	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
SWC0100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV12	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV13	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
ECO100MWPV	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,831,925	10,547,148	11,054,311	11,248,064	12,071,666	12,619,675	12,986,004	13,022,286	13,934,525	13,876,952	13,519,520
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,831,925	10,547,148	11,054,311	11,248,064	12,071,666	12,619,675	12,986,004	13,022,286	13,934,525	13,876,952	13,519,520
Rollover, Vintage -1 year	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,831,925	10,547,148	11,054,311	11,248,064	12,071,666	12,619,675	12,986,004	13,022,286	13,934,525	13,876,952
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,831,925	10,547,148	11,054,311	11,248,064	12,071,666	12,619,675	12,986,004	13,022,286	13,934,525
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,831,925	10,547,148	11,054,311	11,248,064	12,071,666	12,619,675	12,986,004	13,022,286
Rollover, Vintage -4 year	1,596,193	1,502,331	1,443,021	1,499,961	1,833,363	2,617,778	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,831,925	10,547,148	11,054,311	11,248,064	12,071,666	12,619,675	12,986,004
Rollover, Vintage -5 year	133,754	-	-	-	-	-	218,857	1,772,011	3,335,012	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,831,925	10,547,148	11,054,311	11,248,064	12,071,666	12,619,675
Expiring RECs		-	-	-	-	-	-	-	-	789,820	2,607,533	3,326,061	4,179,583	4,348,488	5,199,797	6,366,852	7,959,983	7,626,419	8,086,077	8,230,716	9,003,691
BALANCE AFTER COMPLIANCE		**11,766,487**	**13,545,844**	**15,337,347**	**18,223,627**	**21,832,641**	**26,292,226**	**30,918,320**	**36,393,928**	**42,247,423**	**47,882,672**	**52,468,637**	**56,664,442**	**60,841,006**	**64,941,621**	**68,372,789**	**70,526,868**	**73,002,006**	**75,882,220**	**78,511,108**	**79,958,962**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
New Mexico Member Load		2,612,907	2,747,921	2,779,463	2,812,346	2,746,850	2,682,294	2,711,769	2,742,982	2,772,621	2,802,899	2,833,421	2,865,028	2,894,395	2,924,969	2,956,189	2,988,368	3,018,519	3,049,387	3,080,519	3,112,544
New Mexico Member Retail Sales	2%	2,560,648	2,692,963	2,723,874	2,756,099	2,691,913	2,628,648	2,657,533	2,688,123	2,717,168	2,746,841	2,776,753	2,807,728	2,836,507	2,866,470	2,897,065	2,928,600	2,958,149	2,988,399	3,018,908	3,050,293
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	269,296	272,387	275,610	1,076,765	1,051,459	1,063,013	1,075,249	1,086,867	1,373,420	1,388,376	1,403,864	1,418,254	1,433,235	1,448,533	1,464,300	1,479,074	1,494,200	1,509,454	1,525,147
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	183,641	178,584	182,474	178,018	177,813	182,492	176,748	177,520	181,129	177,199	176,727	178,087	173,107	171,650	159,594	-	-	-	-	-
Alta Luna Solar	1	74,710	72,253	73,998	72,825	74,357	74,265	71,143	72,803	72,056	74,707	73,318	72,628	72,242	71,235	72,164	74,249	70,955	72,525	73,144	72,412
Escalante Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	387,603	377,201	384,144
Total RECs Generated		836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	908,471	895,796	740,308	1,509,189	1,899,908	1,782,988	1,803,417
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	717,092	164,355	-	30,115	435,823	709,356	987,626
Rollover, Vintage -1 year	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	832,925	332,444	-	-	-	-	-	-	-
Rollover, Vintage -2 year	265,817	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	870,647	401,303	-	-	-	-	-	-	-	-	-
Rollover, Vintage -3 year	209,144	218,896	207,673	770,908	836,264	829,088	834,758	725,974	571,698	410,648	-	-	-	-	-	-	-	-	-	-	-
Rollover, Vintage -4 year	-	-	-	-	495,298	254,797	32,425	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expiring RECs																	-				
BALANCE AFTER COMPLIANCE		**2,148,856**	**2,708,647**	**3,271,018**	**3,917,211**	**3,761,419**	**3,635,778**	**3,488,092**	**3,330,935**	**3,163,100**	**2,709,234**	**2,236,788**	**1,750,697**	**1,241,855**	**717,092**	**164,355**	**-**	**30,115**	**435,823**	**709,356**	**987,626**

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

80% Carbon Reduction Version 3

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	11,096,023	11,334,704	11,551,975	11,760,844	11,994,606	12,227,035	12,477,215	12,725,959	12,945,710	13,175,611	13,394,617	13,615,062	13,856,273	14,108,272	14,359,711	14,603,647	14,841,172	15,086,738	15,339,875
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	2,219,205	2,266,941	2,310,395	2,352,169	2,398,921	2,445,407	2,495,443	2,545,192	2,589,142	2,635,122	2,678,923	2,723,012	2,771,255	2,821,654	2,871,942	2,920,729	2,968,234	3,017,348	3,067,975
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	229,148	217,782	239,856	223,709	234,134	237,995	228,894	220,305	229,456	207,070	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,352	457,957	464,712	464,805	474,110	455,605	467,680	461,110	458,947	451,773	461,352	463,264	-	-	-	-	-	-	-	-
Carousel-E.CO	1	666,843	648,237	672,506	643,626	639,494	658,276	630,020	665,358	649,569	653,199	637,988	658,407	665,672	627,181	651,272	679,557	654,028	666,149	664,391	650,333
San Isabel Solar	1	71,416	72,000	71,416	70,005	70,097	67,964	68,110	69,242	67,104	67,207	66,599	68,868	68,448	61,991	67,776	67,942	64,638	65,203	63,018	64,757
Twin Buttes	1	307,567	308,270	308,267	309,311	308,177	307,740	307,790	308,827	308,191	307,745	308,151	309,102	307,792	308,336	308,286	308,690	307,454	308,290	307,612	309,840
Spanish Peaks Solar	1	-	-	14,113	248,894	242,914	243,911	245,119	246,209	242,205	244,985	240,271	242,341	233,157	237,357	231,467	238,193	236,903	223,417	-	-
Crossing Trails Wind	1	414,777	404,512	408,546	405,177	412,565	411,480	420,353	403,092	413,927	408,330	406,225	400,442	402,187	414,951	366,722	-	-	-	-	-
Niyol Wind	1	10	896,119	882,203	885,459	896,156	893,988	907,129	892,039	895,011	890,207	896,119	884,163	872,514	899,628	893,988	865,549	887,474	882,726	893,321	860,792
Axial Basin Solar	1	-	-	-	321,943	314,757	315,363	316,550	317,270	312,010	315,286	310,320	312,558	302,518	306,310	300,111	307,916	304,682	300,423	-	-
Dolores Canyon Solar	1	-	-	-	254,843	248,539	249,756	249,772	251,760	246,302	250,291	244,935	247,590	238,872	242,817	237,571	243,392	241,020	237,793	-	-
Spanish Peaks II Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Coyote Gulch Solar	1	-	-	-	284,737	277,322	279,034	279,203	281,148	275,754	279,776	273,785	276,551	266,867	271,253	265,310	271,546	269,304	265,384	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2																					
Tri-County Hydropower / Ridgway1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
ECO100MWWIND	1	-	-	-	-	396,172	395,541	393,345	361,548	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND	1	-	-	-	-	382,161	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND2	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV2	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV3	1	-	-	-	-	-	-	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND3	1	-	-	-	-	-	-	-	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV4	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV5	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV6	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV7	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV8	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV9	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND8	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
SWC0100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND9	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
SWC0100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV12	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV13	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
ECO100MWPV	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	11,219,215	10,917,726	11,054,311	11,248,064	12,071,666	12,619,675	12,986,004	13,022,286	13,934,525	13,876,952	13,519,520
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	11,219,215	10,917,726	11,054,311	11,248,064	12,071,666	12,619,675	12,986,004	13,022,286	13,934,525	13,876,952	13,519,520
Rollover, Vintage -1 year	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	11,219,215	10,917,726	11,054,311	11,248,064	12,071,666	12,619,675	12,986,004	13,022,286	13,934,525	13,876,952
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	11,219,215	10,917,726	11,054,311	11,248,064	12,071,666	12,619,675	12,986,004	13,022,286	13,934,525
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	11,219,215	10,917,726	11,054,311	11,248,064	12,071,666	12,619,675	12,986,004	13,022,286
Rollover, Vintage -4 year	1,596,193	1,502,331	1,443,021	1,499,961	1,833,363	2,617,778	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	11,219,215	10,917,726	11,054,311	11,248,064	12,071,666	12,619,675	12,986,004
Rollover, Vintage -5 year	133,754	-	-	-	-	-	218,857	1,772,011	3,335,012	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	11,219,215	10,917,726	11,054,311	11,248,064	12,071,666	12,619,675
Expiring RECs		-	-	-	-	-	-	-	-	789,820	2,607,533	3,326,061	4,179,583	4,348,488	5,199,797	6,366,852	8,347,273	7,996,997	8,086,077	8,230,716	9,003,691
BALANCE AFTER COMPLIANCE		**11,766,487**	**13,545,844**	**15,337,347**	**18,223,627**	**21,832,641**	**26,292,226**	**30,918,320**	**36,393,928**	**42,247,423**	**48,269,963**	**53,226,506**	**57,422,311**	**61,598,874**	**65,699,489**	**69,130,657**	**70,897,446**	**73,002,006**	**75,882,220**	**78,511,108**	**79,958,962**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

Retail Load																					
New Mexico Member Load		2,612,907	2,747,921	2,779,463	2,812,346	2,746,850	2,682,294	2,711,769	2,742,982	2,772,621	2,802,899	2,833,421	2,865,028	2,894,395	2,924,969	2,956,189	2,988,368	3,018,519	3,049,387	3,080,519	3,112,544
New Mexico Member Retail Sales6	2%	2,560,648	2,692,963	2,723,874	2,756,099	2,691,913	2,628,648	2,657,533	2,688,123	2,717,168	2,746,841	2,776,753	2,807,728	2,836,507	2,866,470	2,897,065	2,928,600	2,958,149	2,988,399	3,018,908	3,050,293
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	269,296	272,387	275,610	1,076,765	1,051,459	1,063,013	1,075,249	1,086,867	1,373,420	1,388,376	1,403,864	1,418,254	1,433,235	1,448,533	1,464,300	1,479,074	1,494,200	1,509,454	1,525,147
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	183,641	178,584	182,474	178,018	177,813	182,492	176,748	177,520	181,129	177,199	176,727	178,087	173,107	171,650	159,594	-	-	-	-	-
Alta Luna Solar	1	74,710	72,253	73,998	72,825	74,357	74,265	71,143	72,803	72,056	74,707	73,318	72,628	72,242	71,235	72,164	74,249	70,955	72,525	73,144	72,412
Escalante Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	387,603	377,201	384,144
Total RECs Generated		836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	908,471	895,796	740,308	1,509,189	1,899,908	1,782,988	1,803,417
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	717,092	164,355	-	30,115	435,823	709,356	987,626
Rollover, Vintage -1 year	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	832,925	332,444	-	-	-	-	-	-	-
Rollover, Vintage -2 year	265,817	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	870,647	401,303	-	-	-	-	-	-	-	-	-
Rollover, Vintage -3 year	209,144	218,896	207,673	770,908	836,264	829,088	834,758	725,974	571,698	410,648	-	-	-	-	-	-	-	-	-	-	-
Rollover, Vintage -4 year	-	-	-	-	495,298	254,797	32,425	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,148,856**	**2,708,647**	**3,271,018**	**3,917,211**	**3,761,419**	**3,635,778**	**3,488,092**	**3,330,935**	**3,163,100**	**2,709,234**	**2,236,788**	**1,750,697**	**1,241,855**	**717,092**	**164,355**	**-**	**30,115**	**435,823**	**709,356**	**987,626**

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

80% Carbon Reduction Version 4

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	11,096,023	11,334,704	11,551,975	11,760,844	11,994,606	12,227,035	12,477,215	12,725,959	12,945,710	13,175,611	13,394,617	13,615,062	13,856,273	14,108,272	14,359,711	14,603,647	14,841,172	15,086,738	15,339,875
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	2,219,205	2,266,941	2,310,395	2,352,169	2,398,921	2,445,407	2,495,443	2,545,192	2,589,142	2,635,122	2,678,923	2,723,012	2,771,255	2,821,654	2,871,942	2,920,729	2,968,234	3,017,348	3,067,975
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	229,148	217,782	239,856	223,709	234,134	237,995	228,894	220,305	229,456	207,070	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,352	457,957	464,712	464,805	474,110	455,605	467,680	461,110	458,947	451,773	461,352	463,264	-	-	-	-	-	-	-	-
Carousel-E.CO	1	666,843	648,237	672,506	643,626	639,494	658,276	630,020	665,358	649,569	653,199	637,988	658,407	665,672	627,181	651,272	679,557	654,028	666,149	664,391	650,333
San Isabel Solar	1	71,416	72,000	71,416	70,005	70,097	67,964	68,110	69,242	67,104	67,207	66,599	68,868	68,448	61,991	67,776	67,942	64,638	65,203	63,018	64,757
Twin Buttes	1	307,567	308,270	308,267	309,311	308,177	307,740	307,790	308,827	308,191	307,745	308,151	309,102	307,792	308,336	308,286	308,690	307,454	308,290	307,612	309,840
Spanish Peaks Solar	1	-	-	14,113	248,894	242,914	243,911	245,119	246,209	242,205	244,985	240,271	242,341	233,157	237,357	231,467	238,193	236,903	223,417	-	-
Crossing Trails Wind	1	414,777	404,512	408,546	405,177	412,565	411,480	420,353	403,092	413,927	408,330	406,225	400,442	402,187	414,951	366,722	-	-	-	-	-
Niyol Wind	1	10	896,119	882,203	885,459	896,156	893,988	907,129	892,039	895,011	890,207	896,119	884,163	872,514	899,628	893,988	865,549	887,474	882,726	893,321	860,792
Axial Basin Solar	1	-	-	-	321,943	314,757	315,363	316,550	317,270	312,010	315,286	310,320	312,558	302,518	306,310	300,111	307,916	304,682	300,423	-	-
Dolores Canyon Solar	1	-	-	-	254,843	248,539	249,756	249,772	251,760	246,302	250,291	244,935	247,590	238,872	242,817	237,571	243,392	241,020	237,793	-	-
Spanish Peaks II Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Coyote Gulch Solar	1	-	-	-	284,737	277,322	279,034	279,203	281,148	275,754	279,776	273,785	276,551	266,867	271,253	265,310	271,546	269,304	265,384	-	-
ECO100MWWIND	1	-	-	-	-	396,172	395,541	393,345	361,548	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2																					
Tri-County Hydropower/Ridgway1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
WYO100MWWIND	1	-	-	-	-	382,161	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND2	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV2	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV3	1	-	-	-	-	-	-	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND3	1	-	-	-	-	-	-	-	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV4	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV5	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV6	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV7	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV8	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV9	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC050MWPV01	1	-	-	-	-	-	-	-	-	-	126,390	124,601	126,329	122,179	125,035	122,578	126,699	126,012	124,663	124,109	122,324
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND8	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
SWC0100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND9	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
SWC0100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV12	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV13	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
ECO100MWPV	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,958,314	10,671,748	11,180,640	11,370,242	12,196,701	12,742,252	13,112,703	13,148,298	14,059,188	14,001,061	13,641,844
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,958,314	10,671,748	11,180,640	11,370,242	12,196,701	12,742,252	13,112,703	13,148,298	14,059,188	14,001,061	13,641,844
Rollover, Vintage -1 year	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,958,314	10,671,748	11,180,640	11,370,242	12,196,701	12,742,252	13,112,703	13,148,298	14,059,188	14,001,061
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,958,314	10,671,748	11,180,640	11,370,242	12,196,701	12,742,252	13,112,703	13,148,298	14,059,188
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,958,314	10,671,748	11,180,640	11,370,242	12,196,701	12,742,252	13,112,703	13,148,298
Rollover, Vintage -4 year	1,596,193	1,502,331	1,443,021	1,499,961	1,833,363	2,617,778	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,958,314	10,671,748	11,180,640	11,370,242	12,196,701	12,742,252	13,112,703
Rollover, Vintage -5 year	133,754	-	-	-	-	-	218,857	1,772,011	3,335,012	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,958,314	10,671,748	11,180,640	11,370,242	12,196,701	12,742,252
Expiring RECs		-	-	-	-	-	-	-	-	789,820	2,607,533	3,326,061	4,179,583	4,348,488	5,199,797	6,366,852	8,086,372	7,751,019	8,212,406	8,352,895	9,128,726
BALANCE AFTER COMPLIANCE		**11,766,487**	**13,545,844**	**15,337,347**	**18,223,627**	**21,832,641**	**26,292,226**	**30,918,320**	**36,393,928**	**42,247,423**	**48,009,062**	**52,719,627**	**57,041,761**	**61,340,503**	**65,566,153**	**69,119,898**	**71,274,287**	**73,750,836**	**76,629,384**	**79,260,203**	**80,705,346**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
New Mexico Member Load		2,612,907	2,747,921	2,779,463	2,812,346	2,746,850	2,682,294	2,711,769	2,742,982	2,772,621	2,802,899	2,833,421	2,865,028	2,894,395	2,924,969	2,956,189	2,988,368	3,018,519	3,049,387	3,080,519	3,112,544
New Mexico Member Retail Sales6	2%	2,560,648	2,692,963	2,723,874	2,756,099	2,691,913	2,628,648	2,657,533	2,688,123	2,717,168	2,746,841	2,776,753	2,807,728	2,836,507	2,866,470	2,897,065	2,928,600	2,958,149	2,988,399	3,018,908	3,050,293
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	269,296	272,387	275,610	1,076,765	1,051,459	1,063,013	1,075,249	1,086,867	1,373,420	1,388,376	1,403,864	1,418,254	1,433,235	1,448,533	1,464,300	1,479,074	1,494,200	1,509,454	1,525,147
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	183,641	178,584	182,474	178,018	177,813	182,492	176,748	177,520	181,129	177,199	176,727	178,087	173,107	171,650	159,594	-	-	-	-	-
Alta Luna Solar	1	74,710	72,253	73,998	72,825	74,357	74,265	71,143	72,803	72,056	74,707	73,318	72,628	72,242	71,235	72,164	74,249	70,955	72,525	73,144	72,412
Escalante Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591														
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	387,603	377,201	384,144
NM100MWWind	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144	
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144	
Total RECs Generated		836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	908,471	895,796	740,308	1,509,189	1,899,908	1,782,988	1,803,417
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	717,092	164,355	-	30,115	435,823	709,356	987,626
Rollover, Vintage -1 year	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	832,925	332,444	-	-	-	-	-	-	-
Rollover, Vintage -2 year	265,817	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	870,647	401,303	-	-	-	-	-	-	-	-	-
Rollover, Vintage -3 year	209,144	218,896	207,673	770,908	836,264	829,088	834,758	725,974	571,698	410,648	-	-	-	-	-	-	-	-	-	-	-
Rollover, Vintage -4 year	-	-	-	-	495,298	254,797	32,425	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,148,856**	**2,708,647**	**3,271,018**	**3,917,211**	**3,761,419**	**3,635,778**	**3,488,092**	**3,330,935**	**3,163,100**	**2,709,234**	**2,236,788**	**1,750,697**	**1,241,855**	**717,092**	**164,355**	**-**	**30,115**	**435,823**	**709,356**	**987,626**

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

Low Load 80% Carbon Reduction Version 1

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	9,977,192	10,093,076	10,208,551	10,327,548	10,475,126	10,626,864	10,798,057	10,970,948	11,121,149	11,281,911	11,435,692	11,590,367	11,763,379	11,947,079	12,130,590	12,308,499	12,480,739	12,660,788	12,847,891
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	1,995,438	2,018,615	2,041,710	2,065,510	2,095,025	2,125,373	2,159,611	2,194,190	2,224,230	2,256,382	2,287,138	2,318,073	2,352,676	2,389,416	2,426,118	2,461,700	2,496,148	2,532,158	2,569,578
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	229,148	217,782	239,856	223,709	234,134	237,995	228,894	220,305	229,456	207,070	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,352	457,957	464,712	464,805	474,110	455,605	467,680	461,110	458,947	451,773	461,352	463,264	-	-	-	-	-	-	-	-
Carousel-E.CO	1	666,843	648,237	672,506	643,626	639,494	658,276	630,020	665,358	649,569	653,199	637,988	658,407	665,672	627,181	651,272	679,557	654,028	666,149	664,391	650,333
San Isabel Solar	1	71,416	72,000	71,416	70,005	70,097	67,964	68,110	69,242	67,104	67,207	66,599	68,868	68,448	61,991	67,776	67,942	64,638	65,203	63,018	64,757
Twin Buttes	1	307,567	308,270	308,267	309,311	308,177	307,740	307,790	308,827	308,191	307,745	308,151	309,102	307,792	308,336	308,286	308,690	307,454	308,290	307,612	309,840
Spanish Peaks Solar	1	-	-	14,113	248,894	242,914	243,911	245,119	246,209	242,205	244,985	240,271	242,341	233,157	237,357	231,467	238,193	236,903	223,417	-	-
Crossing Trails Wind	1	414,777	404,512	408,546	405,177	412,565	411,480	420,353	403,092	413,927	408,330	406,225	400,442	402,187	414,951	366,722	-	-	-	-	-
Niyol Wind	1	10	896,119	882,203	885,459	896,156	893,988	907,129	892,039	895,011	890,207	896,119	884,163	872,514	899,628	893,988	865,549	887,474	882,726	893,321	860,792
Axial Basin Solar	1	-	-	-	321,943	314,757	315,363	316,550	317,270	312,010	315,286	310,320	312,558	302,518	306,310	300,111	307,916	304,682	300,423	-	-
Dolores Canyon Solar	1	-	-	-	254,843	248,539	249,756	249,772	251,760	246,302	250,291	244,935	247,590	238,872	242,817	237,571	243,392	241,020	237,793	-	-
Spanish Peaks II Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Coyote Gulch Solar	1	-	-	-	284,737	277,322	279,034	279,203	281,148	275,754	279,776	273,785	276,551	266,867	271,253	265,310	271,546	269,304	265,384	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	1.25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2	0																				
Tri-County Hydropower / Ridgway1	1.25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
SWCO100MWPV	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND	1	-	-	-	-	-	-	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV2	1	-	-	-	-	-	-	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND2	1	-	-	-	-	-	-	-	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
ECO100MWWIND	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
SWCO100MWPV3	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND3	1	-	-	-	-	-	-	-	-	-	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV4	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV5	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV6	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV7	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV8	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV9	1	-	-	-	-	-	-	-	-	-	-	-	-	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	388,143	388,184	387,918	379,721	384,936	394,835	379,717
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	396,315	397,909	382,693
SWCO100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
SWCO100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,136,584	3,998,561	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872	11,476,842	11,241,628	11,725,516	11,187,770	10,897,604
	Inventory									**REC Balance after Compliance is Met for the Year, (includes multipliers)**											
Current Year Rollover	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872	11,476,842	11,241,628	11,725,516	11,187,770	10,897,604
Rollover, Vintage -1 year	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872	11,476,842	11,241,628	11,725,516	11,187,770
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872	11,476,842	11,241,628	11,725,516
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872	11,476,842	11,241,628
Rollover, Vintage -4 year	1,596,193	1,502,331	1,666,787	1,972,053	2,574,140	3,136,584	3,998,561	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872	11,476,842
Rollover, Vintage -5 year	133,754	-	-	-	-	508,630	1,550,189	3,423,377	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872
Expiring RECs	-	-	-	-	-	-	-	-	-	1,263,766	1,864,255	2,972,446	2,926,467	3,148,435	3,733,710	4,105,801	5,047,563	7,010,614	7,465,669	7,944,158	7,565,341	7,973,666
BALANCE AFTER COMPLIANCE		11,766,487	13,769,610	15,809,439	18,964,404	22,081,744	25,422,293	29,348,703	32,383,803	35,762,338	40,002,395	44,746,914	49,751,646	53,797,361	57,882,128	61,286,021	63,326,130	64,640,390	65,925,600	67,015,872	67,370,232
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

		2,612,907	2,393,217	2,370,000	2,354,020	2,259,751	2,171,703	2,164,869	2,161,203	2,157,825	2,156,149	2,155,679	2,156,870	2,157,195	2,159,045	2,161,937	2,165,998	2,169,058	2,173,008	2,177,489	2,182,861
Retail Load																					
New Mexico Member Load																					
New Mexico Member Retail Sales	2%	2,560,648	2,345,353	2,322,600	2,306,939	2,214,556	2,128,269	2,121,572	2,117,979	2,114,668	2,113,026	2,112,566	2,113,733	2,114,051	2,115,864	2,118,698	2,122,678	2,125,677	2,129,547	2,133,939	2,139,203
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	234,535	232,260	230,694	885,822	851,308	848,629	847,191	845,867	1,056,513	1,056,283	1,056,866	1,057,026	1,057,932	1,059,349	1,061,339	1,062,838	1,064,774	1,066,970	1,069,602
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	183,641	178,584	182,474	178,018	177,813	182,492	176,748	177,520	181,129	177,199	176,727	178,087	173,107	171,650	159,594	-	-	-	-	-
Alta Luna Solar	1	74,710	72,253	73,998	72,825	74,357	74,265	71,143	72,803	72,056	74,707	73,318	72,628	72,242	71,235	72,164	74,249	70,955	72,525	73,144	72,412
Escalante Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	384,144
Total RECs Generated		836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	908,471	895,796	740,308	1,122,898	1,124,701	1,028,585	1,419,273
	Inventory									**REC Balance after Compliance is Met for the Year, (includes multipliers)**											
Current Year Rollover	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	908,471	895,796	740,308	1,122,898	1,124,701	1,028,585	1,419,273
Rollover, Vintage -1 year	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	908,471	895,796	740,308	1,122,898	1,124,701	1,028,585
Rollover, Vintage -2 year	265,817	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	908,471	895,796	740,308	1,087,694	1,124,701
Rollover, Vintage -3 year	209,144	218,896	242,434	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	908,307	766,730	614,803	460,436	291,458	-	18,093
Rollover, Vintage -4 year	-	-	-	10,174	615,103	565,544	543,324	529,454	604,066	679,171	548,476	407,521	268,746	130,753	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		2,148,856	2,743,408	3,345,906	4,037,016	4,072,166	4,146,676	4,213,375	4,284,276	4,357,441	4,220,483	4,080,131	3,941,037	3,793,423	3,643,962	3,480,409	3,159,379	3,219,438	3,279,365	3,240,981	3,590,651

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

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5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

Low Load 80% Carbon Reduction Version 2

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	9,977,192	10,093,076	10,208,551	10,327,548	10,475,126	10,626,864	10,798,057	10,970,948	11,121,149	11,281,911	11,435,692	11,590,367	11,763,379	11,947,079	12,130,590	12,308,499	12,480,739	12,660,788	12,847,891
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	1,995,438	2,018,615	2,041,710	2,065,510	2,095,025	2,125,373	2,159,611	2,194,190	2,224,230	2,256,382	2,287,138	2,318,073	2,352,676	2,389,416	2,426,118	2,461,700	2,496,148	2,532,158	2,569,578
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	229,148	217,782	239,856	223,709	234,134	237,995	228,894	220,305	229,456	207,070	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,352	457,957	464,712	464,805	474,110	455,605	467,680	461,110	458,947	451,773	461,352	463,264	-	-	-	-	-	-	-	-
Carousel-E.CO	1	666,843	648,237	672,506	643,626	639,494	658,276	630,020	665,358	649,569	653,199	637,988	658,407	665,672	627,181	651,272	679,557	654,028	666,149	664,391	650,333
San Isabel Solar	1	71,416	72,000	71,416	70,005	70,097	67,964	68,110	69,242	67,104	67,207	66,599	68,868	68,448	61,981	67,776	67,942	64,638	65,203	63,018	64,757
Twin Buttes	1	307,567	308,270	308,267	309,311	308,177	307,740	307,790	308,827	308,191	307,745	308,151	309,102	307,792	308,336	308,286	308,690	307,454	308,290	307,612	309,840
Spanish Peaks Solar	1	-	-	14,113	248,894	242,914	243,911	245,119	246,209	242,205	244,985	240,271	242,341	233,157	237,357	231,467	238,193	236,903	223,417	-	-
Crossing Trails Wind	1	414,777	404,512	408,546	405,177	412,565	411,480	420,353	403,092	413,927	408,330	406,225	400,442	402,187	414,951	366,722	-	-	-	-	-
Niyol Wind	1	10	896,119	882,203	885,459	896,156	893,988	907,129	892,039	895,011	890,207	896,119	884,163	872,514	899,628	893,988	865,549	887,474	882,726	893,321	860,792
Axial Basin Solar	1	-	-	-	321,943	314,757	315,363	316,550	317,270	312,010	315,286	310,320	312,558	302,518	306,310	300,111	307,916	304,682	300,423	-	-
Dolores Canyon Solar	1	-	-	-	254,843	248,539	249,756	249,772	251,760	246,302	250,291	244,935	247,590	238,872	242,817	237,571	243,392	241,020	237,793	-	-
Spanish Peaks II Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Coyote Gulch Solar	1	-	-	-	284,737	277,322	279,034	279,203	281,148	275,754	279,776	273,785	276,551	266,867	271,253	265,310	271,546	269,304	265,384	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	1.25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2	0																				
Tri-County Hydropower / Ridgway1	1.25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
SWCO100MWPV	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND	1	-	-	-	-	-	-	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV2	1	-	-	-	-	-	-	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND2	1	-	-	-	-	-	-	-	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
ECO100MWWIND	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
SWCO100MWPV3	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND3	1	-	-	-	-	-	-	-	-	-	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV4	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV5	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV6	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV7	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV8	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV9	1	-	-	-	-	-	-	-	-	-	-	-	-	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	388,143	388,184	387,918	379,721	384,936	394,835	379,717
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	396,315	397,909	382,693
SWCO100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
SWCO100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,136,584	3,998,561	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872	11,476,842	11,241,628	11,725,516	11,187,770	10,897,604
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872	11,476,842	11,241,628	11,725,516	11,187,770	10,897,604
Rollover, Vintage -1 year	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872	11,476,842	11,241,628	11,725,516	11,187,770
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872	11,476,842	11,241,628	11,725,516
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872	11,476,842	11,241,628
Rollover, Vintage -4 year	1,596,193	1,502,331	1,666,787	1,972,053	2,574,140	3,136,584	3,998,561	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872	11,476,842
Rollover, Vintage -5 year	133,754	-	-	-	-	508,630	1,550,189	3,423,377	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872
Expiring RECs	-	-	-	-	-	-	-	-	1,263,766	1,864,255	2,972,446	2,926,467	3,148,435	3,733,710	4,105,801	5,047,563	7,010,614	7,465,669	7,944,158	7,565,341	7,973,666
BALANCE AFTER COMPLIANCE		**11,766,487**	**13,769,610**	**15,809,439**	**18,964,404**	**22,081,744**	**25,422,293**	**29,348,703**	**32,383,803**	**35,762,338**	**40,002,395**	**44,746,914**	**49,751,646**	**53,797,361**	**57,882,128**	**61,286,021**	**63,326,130**	**64,640,390**	**65,925,600**	**67,015,872**	**67,370,232**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
New Mexico Member Load		2,612,907	2,393,217	2,370,000	2,354,020	2,259,751	2,171,703	2,164,869	2,161,203	2,157,825	2,156,149	2,155,679	2,156,870	2,157,195	2,159,045	2,161,937	2,165,998	2,169,058	2,173,008	2,177,489	2,182,861
New Mexico Member Retail Sales6	2%	2,560,648	2,345,353	2,322,600	2,306,939	2,214,556	2,128,269	2,121,572	2,117,979	2,114,668	2,113,026	2,112,566	2,113,733	2,114,051	2,115,864	2,118,698	2,122,678	2,125,677	2,129,547	2,133,939	2,139,203
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	234,535	232,260	230,694	885,822	851,308	848,629	847,191	845,867	1,056,513	1,056,283	1,056,866	1,057,026	1,057,932	1,059,349	1,061,339	1,062,838	1,064,774	1,066,970	1,069,602
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	183,641	178,584	182,474	178,018	177,813	182,492	176,748	177,520	181,129	177,199	176,727	178,087	173,107	171,650	159,594	-	-	-	-	-
Alta Luna Solar	1	74,710	72,253	73,998	72,825	74,357	74,265	71,143	72,803	72,056	74,707	73,318	72,628	72,242	71,235	72,164	74,249	70,955	72,525	73,144	72,412
Escalante Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	384,144
Total RECs Generated		836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	908,471	895,796	740,308	1,122,898	1,124,701	1,028,585	1,419,273
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	908,471	895,796	740,308	1,122,898	1,124,701	1,028,585	1,419,273
Rollover, Vintage -1 year	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	908,471	895,796	740,308	1,122,898	1,124,701	1,028,585
Rollover, Vintage -2 year	265,817	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	908,471	895,796	740,308	1,087,694	1,124,701
Rollover, Vintage -3 year	209,144	218,896	242,434	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	908,307	766,730	614,803	460,436	291,458	-	18,093
Rollover, Vintage -4 year	-	-	-	10,174	615,103	565,544	543,324	529,454	604,066	679,171	548,476	407,521	268,746	130,753	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,148,856**	**2,743,408**	**3,345,906**	**4,037,016**	**4,072,166**	**4,146,676**	**4,213,375**	**4,284,276**	**4,357,441**	**4,220,483**	**4,080,131**	**3,941,037**	**3,793,423**	**3,643,962**	**3,480,409**	**3,159,379**	**3,219,438**	**3,279,365**	**3,240,981**	**3,590,651**

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

Social Cost of Carbon

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	11,096,023	11,334,704	11,551,975	11,760,844	11,994,606	12,227,035	12,477,215	12,725,959	12,945,710	13,175,611	13,394,617	13,615,062	13,856,273	14,108,272	14,359,711	14,603,647	14,841,172	15,086,738	15,339,875
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	2,219,205	2,266,941	2,310,395	2,352,169	2,398,921	2,445,407	2,495,443	2,545,192	2,589,142	2,635,122	2,678,923	2,723,012	2,771,255	2,821,654	2,871,942	2,920,729	2,968,234	3,017,348	3,067,975
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	229,148	217,782	239,856	223,709	234,134	237,995	228,894	220,305	229,456	207,070	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,352	457,957	464,712	464,805	474,110	455,605	467,680	461,110	458,947	451,773	461,352	463,264	-	-	-	-	-	-	-	-
Carousel-E.CO	1	666,843	648,237	672,506	643,626	639,494	658,276	630,020	665,358	649,569	653,199	637,988	658,407	665,672	627,181	651,272	679,557	654,028	666,149	664,391	650,333
San Isabel Solar	1	71,416	72,000	71,416	70,005	70,097	67,964	68,110	69,242	67,104	67,207	66,599	68,868	68,448	61,991	67,776	67,942	64,638	65,203	63,018	64,757
Twin Buttes	1	307,567	308,270	308,267	309,311	308,177	307,740	307,790	308,827	308,191	307,745	308,151	309,102	307,792	308,336	308,286	308,690	307,454	308,290	307,612	309,840
Spanish Peaks Solar	1	-	-	14,113	248,894	242,914	243,911	245,119	246,209	242,205	244,985	240,271	242,341	233,157	237,357	231,467	238,193	236,903	223,417	-	-
Crossing Trails Wind	1	414,777	404,512	408,546	405,177	412,565	411,480	420,353	403,092	413,927	408,330	406,225	400,442	402,187	414,951	366,722	-	-	-	-	-
Niyol Wind	1	10	896,119	882,203	885,459	896,156	893,988	907,129	892,039	895,011	890,207	896,119	884,163	872,514	899,628	893,988	865,549	887,474	882,726	893,321	860,792
Axial Basin Solar	1	-	-	-	321,943	314,757	315,363	316,550	317,270	312,010	315,286	310,320	312,558	302,518	306,310	300,111	307,916	304,682	300,423	-	-
Dolores Canyon Solar	1	-	-	-	254,843	248,539	249,756	249,772	251,760	246,302	250,291	244,935	247,590	238,872	242,817	237,571	243,392	241,020	237,793	-	-
Spanish Peaks II Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Coyote Gulch Solar	1	-	-	-	284,737	277,322	279,034	279,203	281,148	275,754	279,776	273,785	276,551	266,867	271,253	265,310	271,546	269,304	265,384	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2																					
Tri-County Hydropower / Ridgway1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
WYO100MWWIND	1	-	-	-	-	382,161	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND2	1	-	-	-	-	382,161	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND3	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND4	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND5	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND6	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND7	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
ECO100MWWINDBATT01	1	-	-	-	-	-	373,835	373,835	375,540	373,835	373,835	373,835	375,540	373,835	373,835	373,835	375,540	373,835	373,835	373,835	375,540
SWCO100MWPV	1	-	-	-	-	-	246,582	248,928	251,403	248,291	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV2	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND8	1	-	-	-	-	-	-	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND9	1	-	-	-	-	-	-	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
ECO100MWWIND	1	-	-	-	-	-	-	-	361,544	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWPV	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV3	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV4	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWPV2	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWPV3	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV5	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND10	1	-	-	-	-	-	-	-	-	-	-	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV6	1	-	-	-	-	-	-	-	-	-	-	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
SWCO100MWPV7	1	-	-	-	-	-	-	-	-	-	-	-	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
SWCO100MWPV8	1	-	-	-	-	-	-	-	-	-	-	-	-	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV9	1	-	-	-	-	-	-	-	-	-	-	-	-	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
ECO100MWWIND8	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
ECO100MWWIND9	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
SWCO100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWCO100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
ECO100MWWINDBATT02	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	373,835	375,540
ECO100MWWINDBATT03	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	373,835	375,540
SWCO100MWPV12	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
SWCO100MWPV13	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
SWCO100MWPV14	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,136,584	3,998,561	4,058,444	5,196,675	5,947,172	8,788,823	9,443,973	10,475,184	10,559,299	11,301,355	11,740,191	12,901,664	13,146,838	13,215,833	13,499,728	13,776,326	14,654,736	15,293,419	15,778,906	15,396,648
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,947,172	8,788,823	9,443,973	10,475,184	10,559,299	11,301,355	11,740,191	12,901,664	13,146,838	13,215,833	13,499,728	13,776,326	14,654,736	15,293,419	15,778,906	15,396,648
Rollover, Vintage -1 year	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,947,172	8,788,823	9,443,973	10,475,184	10,559,299	11,301,355	11,740,191	12,901,664	13,146,838	13,215,833	13,499,728	13,776,326	14,654,736	15,293,419	15,778,906
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,947,172	8,788,823	9,443,973	10,475,184	10,559,299	11,301,355	11,740,191	12,901,664	13,146,838	13,215,833	13,499,728	13,776,326	14,654,736	15,293,419
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,947,172	8,788,823	9,443,973	10,475,184	10,559,299	11,301,355	11,740,191	12,901,664	13,146,838	13,215,833	13,499,728	13,776,326	14,654,736
Rollover, Vintage -4 year	1,596,193	1,502,331	1,443,021	1,499,961	1,833,363	2,617,778	3,998,561	4,058,444	5,196,675	5,947,172	8,788,823	9,443,973	10,475,184	10,559,299	11,301,355	11,740,191	12,901,664	13,146,838	13,215,833	13,499,728	13,776,326
Rollover, Vintage -5 year	133,754	-	-	-	-	-	218,857	1,772,011	3,335,012	5,196,675	5,947,172	8,788,823	9,443,973	10,475,184	10,559,299	11,301,355	11,740,191	12,901,664	13,146,838	13,215,833	13,499,728
Expiring RECs		-	-	-	-	-	-	-	-	789,820	2,607,533	3,312,050	6,109,899	6,720,961	7,703,929	7,737,645	8,429,413	8,819,462	9,933,430	10,129,490	10,147,858
BALANCE AFTER COMPLIANCE		**11,766,487**	**13,545,844**	**15,337,347**	**18,223,627**	**21,818,631**	**28,208,532**	**35,207,098**	**43,186,839**	**50,411,126**	**56,515,806**	**62,308,825**	**66,421,667**	**70,124,532**	**72,865,180**	**75,805,609**	**78,280,580**	**81,195,125**	**83,586,881**	**86,218,949**	**88,399,764**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
New Mexico Member Load		2,612,907	2,747,921	2,779,463	2,812,346	2,746,850	2,682,294	2,711,769	2,742,982	2,772,621	2,802,899	2,833,421	2,865,028	2,894,395	2,924,969	2,956,189	2,988,368	3,018,519	3,049,387	3,080,519	3,112,544
New Mexico Member Retail Sales6	2%	2,560,648	2,692,963	2,723,874	2,756,099	2,691,913	2,628,648	2,657,533	2,688,123	2,717,168	2,746,841	2,776,753	2,807,728	2,836,507	2,866,470	2,897,065	2,928,600	2,958,149	2,988,399	3,018,908	3,050,293
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	269,296	272,387	275,610	1,076,765	1,051,459	1,063,013	1,075,249	1,086,867	1,373,420	1,388,376	1,403,864	1,418,254	1,433,235	1,448,533	1,464,300	1,479,074	1,494,200	1,509,454	1,525,147
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	183,641	178,584	182,474	178,018	177,813	182,492	176,748	177,520	181,129	177,199	176,727	178,087	173,107	171,650	159,594	-	-	-	-	-
Alta Luna Solar	1	74,710	72,253	73,998	72,825	74,357	74,265	71,143	72,803	72,056	74,707	73,318	72,628	72,242	71,235	72,164	74,249	70,955	72,525	73,144	72,412
Escalante Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100NMWWind	1	-	-	-	-	-	-	-	386,965	378,013	370,943	379,766	392,123	383,262	393,457	385,983	386,783	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
Total RECs Generated		836,264	829,088	834,758	921,804	920,973	925,818	915,327	1,305,057	1,297,046	1,290,498	1,295,696	1,309,896	1,292,674	1,301,928	1,281,779	1,127,092	1,509,189	1,512,304	1,405,786	1,419,273
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	1,305,057	1,297,046	1,290,498	1,295,696	1,309,896	1,292,674	1,301,928	1,281,779	1,127,092	1,509,189	1,512,304	1,405,786	1,419,273
Rollover, Vintage -1 year	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	1,305,057	1,297,046	1,290,498	1,295,696	1,309,896	1,292,674	1,301,928	1,281,779	1,127,092	1,433,573	1,436,424	1,317,063
Rollover, Vintage -2 year	265,817	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	1,257,612	1,166,281	1,052,915	930,358	807,019	651,160	488,788	291,492	-	-	-
Rollover, Vintage -3 year	209,144	218,896	207,673	770,908	836,264	829,088	834,758	725,974	571,698	410,648	-	-	-	-	-	-	-	-	-	-	-
Rollover, Vintage -4 year	-	-	-	-	495,298	254,797	32,425	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,148,856**	**2,708,647**	**3,271,018**	**3,917,211**	**3,761,419**	**3,635,778**	**3,488,092**	**3,717,899**	**3,928,078**	**3,845,155**	**3,752,476**	**3,658,507**	**3,532,928**	**3,401,621**	**3,234,867**	**2,897,659**	**2,927,773**	**2,945,878**	**2,842,210**	**2,736,336**

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

Attachment Vol II 7-1 Phase II All-Source RFP

REQUEST FOR PROPOSALS
FOR
CAPACITY AND ENERGY SUPPLY



Tri-State
Generation and Transmission
Association, Inc.

1100 W. 116th Avenue
Westminster, CO 80234

Issue date: [Date TBD]

Tri-State Generation and Transmission Association, Inc.
Request for Proposals (RFP)

Introduction

Tri-State Generation and Transmission Association, Inc. (Tri-State) is a member-owned rural electric generation & transmission (G&T) cooperative headquartered in Westminster, Colorado. Tri-State provides wholesale power and energy to its 42 utility member electric distribution cooperatives and public power districts that collectively deliver electricity over a 200,000 square mile area to consumers in Colorado, Nebraska, New Mexico and Wyoming.

Purpose and Background

Tri-State is evaluating the procurement of renewable, semi-dispatchable and dispatchable resources as part of an All-Source RFP approved by the Colorado Public Utilities Commission (Commission).

Product Description

This single RFP covers three distinct types of resources as described below. Bidders should clearly indicate which resource type they are submitting a proposal for and be cognizant that there are distinct model contracts and Bidder Response Forms depending on the resource type. This RFP focuses on Power Purchase Agreements (PPA) as the transactional structure and does not focus on utility-build or ownership options.

Renewable Resources
All intermittent renewable and carbon-free resources without co-located storage whose pricing will be offered on an annual energy-only basis. This includes, but is not limited to, wind and solar, hydroelectric, geothermal, biomass and in Colorado, recycled energy or eligible coal-mine methane.

Semi-Dispatchable Resources
All stand-alone energy storage systems or resources coupled with storage systems that are limited in the amount of energy delivered during a particular cycle. This includes, but is not limited to, stand-alone battery systems, pumped hydro, compressed air energy storage systems as well as renewable resources with co-located thermal or battery storage.

Firm-Capacity Resources
New or existing gas generation or any other resource that can be dispatched by Tri-State for a reasonable amount of time without any restriction on duration at the rated maximum capacity threshold. Renewable or carbon-free resources such as hydroelectric, biomass or geothermal capable of this requirement may be bid into this resource type. Resources that include carbon capture technologies may be considered under this category as well.

Quantity, Timing and Term[1]

Tri-State is seeking energy and capacity deliveries from projects with nameplate capacity ratings of greater than 20 MW and up to a maximum of [TBD] MW for delivery in [TBD].

A Resource Acquisition Period through 2030 is required by Commission Rule 3605(a)(IV)(A); however, given changes in technologies, load and various other factors that can change over time, commitments to negotiate agreements for specific projects with commercial operation dates more than [four] years from the date of this RFP may be contingent on future RFPs.

Tri-State will only consider projects sourced from a unit-specific generation asset or from a group of generation assets with a single interconnection point. Tri-State will consider PPA terms between fifteen (15) and twenty-five (25) years.

System Description

Tri-State's 2019 member system peak demand was approximately 3,000 MW. Tri-State's current generation portfolio consists of a combination of owned baseload and peaking power plants that use coal and natural gas as their primary fuels, along with leased and contracted supplies of power that include a significant federal hydroelectric allocation, numerous utility scale wind and solar projects, and several small hydroelectric projects.

Tri-State owns and operates approximately 5,600 miles of transmission lines and is a network transmission service customer of Western Area Power Administration, PacifiCorp, Platte River Power Authority, Public Service Company of New Mexico, Public Service Company of Colorado, and Black Hills/Colorado Electric Utility Co. Tri-State also maintains various firm transmission rights on the Tri-State transmission system and with other transmission providers.

Tri-State dispatches generation owned by or under contract to Tri-State and performs wholesale market-related functions on its own behalf. Tri-State is a member of the Western Electric Coordinating Council (WECC) and the Western Systems Power Pool (WSPP). Tri-State currently meets its contingency reserve requirements through its membership in two regional reserve sharing groups.

Tri-State will be operating in two energy imbalance markets in the near term – the WEIM (Western Energy Imbalance Market) and the WEIS (Western Energy Imbalance Service) and expects the development of fully-organized markets in the western region over the course of this decade.

[1] The scope for new resources to be acquired through an all-source competitive acquisition process is expected to be defined by the Commission's Phase I decision approving and/or modifying Tri-State's ERP application.

Location and Delivery

Tri-State will consider delivery of energy and capacity under this RFP to points of delivery in New Mexico, Colorado, Wyoming or Nebraska in the Western Interconnection. Transmission constraints in several areas of the Tri-State system may require generation curtailment, among other actions, to preserve the safe and reliable operation of the transmission grid as well as compliance with North American Electric Reliability Corporation (NERC) reliability standards applicable in the WECC. Bidder has the obligation to operate its project in a manner that preserves grid reliability and safety, and is solely responsible for any costs associated with such curtailment of its project. Such restrictions may be mitigated or eliminated by Network Upgrades as identified by the transmission provider during the interconnection process for projects located in transmission-constrained areas.

Proposals must identify the project's proposed delivery and interconnection point(s) as well as costs included and not included in the pricing with any and all transmission provider(s) required to provide delivery of the output from the proposed resource(s) to Tri-State.

Bidder will be responsible for meeting transmission provider requirements for interconnection, voltage regulation and associated reactive power capability, voltage ride through, power quality, and other criteria as required by the transmission provider's posted Generator Interconnection Procedures. A generator owner and operator will be required to register as appropriate with WECC and NERC.

Bidder is encouraged to consult each transmission provider's OASIS sites for information on generator interconnection requirements.

If the proposed project is intended to be interconnected with the Tri-State transmission system, Tri-State requests that bidders complete and submit a Voluntary Form of Consent with their proposals to allow Tri-State transmission personnel to communicate non-public, project-specific transmission/interconnection information to Tri-State's merchant function personnel. This document is posted on the RFP website [Link TBD].

Pricing and Total Cost of Power Delivered to Tri-State

Prices shall be quoted in U.S. dollars and shall be binding upon the bidder unless expressly stated otherwise. If the bidder's pricing involves escalation or an index, the escalation terms and conditions, or specific index must be included for evaluation.

Proposals must include the total cost of power at the proposed delivery point(s), including but not limited to losses, transmission charges, and the cost of any other services required to be provided by the bidder or third parties. Bidder must clearly explain the costs and breakdown of the pricing components so that the total cost of power under the terms of the proposal can be evaluated on a stand-alone basis. Bidder should take care to

separately identify and specify any transmission, interconnection and network upgrade costs both included and not included in the pricing on the Bidder Response Forms.

Environmental Attributes

Bidder shall provide and Tri-State will retain all environmental attributes associated with the proposed project's output, including but not limited to, renewable energy credits, green tags, greenhouse gas or carbon credits, and any other emissions attributes.

Financial Stability and Performance Guarantees

Financial capability and stability of the bidder and the demonstrated ability to fulfill its contractual obligations are important to Tri-State and will be an integral part of the bid evaluation process.

A successful bidder must satisfy Tri-State's financial security requirements. Tri-State will require financial security arrangements for PPAs, which may include a letter of credit, cash deposit, or other instrument to secure performance under the PPA that is acceptable to Tri-State. Bidder should describe the proposed credit enhancements or other means proposed to guarantee performance under any contract that might result from this RFP.

Bidder must provide sufficient evidence of financial and operational capability to provide the services outlined in the proposal during the contract term. Bidder, its parent, and any other guarantor of services under the bidder's proposal must provide audited financial statements and annual reports from the previous three years in order to demonstrate financial viability. The financial and operational viability of any third parties relied upon by the bidder for providing service to Tri-State must also be demonstrated. If bidder, its parent, and any other guarantor of services has a credit rating, the most recent ratings reports must also be provided.

Finally, bidder must provide references for any current and/or prior power supply agreements to wholesale customers.

Other Terms and Conditions

Tri-State will require that projects comply with all applicable federal, state, and local laws. All permits, licenses, fees, emissions allowances, and environmental requirements are the responsibility of the bidder. If a project is not in service as of the proposal submittal deadline, a detailed milestone schedule describing major project activities, including a permitting schedule, leading up to the commercial operation date must be provided.

Notice of Intent to Submit Proposal

Each potential bidder should complete and return the **Notice of Intent to Submit Proposal** form included on the RFP website to be included in the RFP process. The form must be submitted by 5:00 PM Mountain Daylight Time on [Date TBD]. Although a notice of intent is not required to submit a bid, only those entities that have provided this notice to Tri-State will be notified of any RFP clarifications or corrections that may occur.

A bidder must use best efforts to provide accurate information about its planned proposal in the completed Notice of Intent to Submit Proposal form; however, bidder will not be bound by the information provided in the completed Notice of Intent to Submit Proposal form.

There is no fee required to submit a Notice of Intent to Submit Proposal form.

Bid Fee

Bidders are required to submit a nonrefundable bid fee of $5,000.00 for each project they submit under this RFP. The funds must be received by Tri-State on or prior to the proposal due date of [Date TBD] and may be sent in the form of a check made out to "Tri-State Generation and Transmission Association, Inc." or via electronic funds transfer. Detailed instructions for sending funds to Tri-State are included on the RFP website. Please provide a reference to the bidding organization/proposal on the form of payment. Failure to submit the required bid fee will result in a proposal being disqualified from further evaluation.

A bid fee is applicable to a single project location and single project technology. A bidder may propose up to three (3) different combinations of pricing, contract term, size, or commercial operation date options for a single project without having to submit an additional fee. The table below provides illustrative examples. Projects that are proposed with additional technology options (i.e., wind + solar or solar + battery storage) or different interconnection points will be considered a different project requiring an additional bid fee.

Bid Examples	**Required Bid Fee**
Project with five different pricing options (could offer six pricing options for the same two bid fees)	Two Bid Fees
2023 and 2024 COD dates with two pricing options for the 2023 date and one for the 2024 data	One Bid Fee
Two different project sizes, each with two pricing options (could add a third pricing option to each size for the same two bid fees)	Two Bid Fees

Proposal Content

Bidder Response Forms

Tri-State requires that all proposals submitted to this RFP contain, at a minimum, a completed set of Bidder Response Forms and requested information as applicable. The Bidder Response Forms are contained in a separate file on the RFP website and a distinct, completed set shall be submitted in Microsoft Excel format to the email below **for each project option**. Tri-State will review and may utilize information, if any, submitted by a bidder which is not specifically requested as a part of the Bidder Response Form. Tri-State may request additional information from a bidder during the proposal evaluation process.

For proposals that contain options for different project sizes and/or pricing options, bidders should submit **a separate set of Bidder Response Forms for each option proposed**.

Narrative Topics

In addition to the Bidder Response Forms, each proposal shall describe the following as they relate to any project.

Executive Summary - Summary of the overall project

Development and Siting Status - Bidders shall provide a thorough description of the development status of its proposed project. The information provided should include status of the following:

- Site, Zoning and Construction Permitting - Include the size of the project in acres and any zoning restrictions that would impact development or use of facility
- Environmental Assessments and Studies
- Emissions and Environmental Permitting
- Regulatory and Governmental Approvals
- Engineering and Design Activities
- Resource Acquisitions (i.e., land, equipment such as wind turbines or solar panels, inverters, fuel supply, waste disposal arrangements, etc.) Proof of equipment supply is viewed favorably
- Construction Status
- Project Schedule and Milestones - Include construction start through commercial operation date
- Project retirement / decommissioning plan

Technical Description and Resource Type Data - Bidders shall provide assurance to Tri-State that the project will be able to meet is projected production estimates for the duration of the project life.

- Wind Resources - Provide a correlation of the long-term wind speed data in the region to the collected resource data at the proposed or existing project site.

Please include a general plot plan showing site location, turbine positions, IEC wind class, annual wind production average capacity factor, minimum operating temperature, proposed wind turbine power curve data, nameplate ratings, and manufacturers of proposed turbine equipment. Wind data provided should also include projections by month and hourly patterns to the extent the data is available. Forecasting information should include projections or guarantees of forecasting accuracy as a function of time of delivery. Please include any turbine blade shadowing studies for light and radio wave impacts, any avian (bird or bat) impact studies performed for the project site and confirmation that the site does not conflict with any training area requirements of the US armed services. Bidder should also include any droop response for wind generation.

- Solar Resources - Please describe the proposed solar generation equipment specifications including brand, model, nameplate ratings, size, type and capabilities, modules, inverters, and tracking equipment, and all UL and IEEE equipment compliance information. Water consumption requirements should be included. If applicable, all energy storage devices should be identified. Provide a guaranteed minimum output performance level on an annual basis and detail the design of the specific proposed solar generation system including array configuration, overall system efficiency and total energy output. Please also include a general plot plan showing site location, equipment positions, pertinent meteorological data, annual solar energy production, expected panel degradation and average capacity factor.
- Biomass or Biogas Resources - For proposals that include resources that use a combustion or digester process (such as biomass, biogas or other renewable waste product), the bidder shall provide information describing applicable gas quality, fuel types, fuel sources, fuel contracts, fuel procurement/transportation plans, fuel price risk and availability risk issues. Proposals involving combustion type resources shall also include combustion process by-product emission rates, including SOX, NOX, CO_2, methane, nitrous oxide, CFCs, HCFCs, heavy metals, halides, unburned hydrocarbons and other emissions in gaseous or liquid form, dissolved in another liquid or mixed with a solid for offsite disposal. Describe the quantity and type of all environmental permits for air and water compliance required to develop the project, and if such permits and approvals are not already in the bidder's possession, provide information regarding the plan to acquire such permits and associated approvals. Proposals should also include gas production forecasts for resources identified, including decay rate of gas production from landfill or digester processes for closed or active sources, and forecast for future sources planned.
- Geothermal Resources - Please provide a summary of all collected geothermal data for the proposed or existing site and characterize the geothermal resource quality, quantity and proposed production levels. Describe land lease and rights issues and describe and test drilling performed (if applicable). Provide a table or graph that illustrates the annual and monthly projection of geothermal resources.
- Hydro Resources (including pumped hydro) - Provide a description and map of the project area and any information about the project's water rights and any ongoing or anticipated disputes, legal challenges or regulations affecting those

water rights. Identify if the project is run-of-river or has storage/pondage capability. Identify the volume of the storage and any hourly, daily or seasonal restrictions to the use of the storage for power production. Provide an estimate of the average firm generation expected over the life of the project. Identify anticipated generation by month during an average water year and a low water year. Provide monthly flow duration curves based upon daily stream flow records.

- Energy Storage Systems - For co-located or stand-alone energy storage systems, please provide the type of storage facility, describe any system limitations such as the number of discharges per day, per year and over the contract term as well any limitations on the depth of discharges. Also, please discuss any expected degradation or potential of adding capacity during the contract term. Further, specifically for battery systems, please provide information on the ability to charge from the grid and about the battery chemistry selected.
- Other Resources - Provide a description of the fuel source and identify its thermal (heat content), delivery and storage characteristics. Provide an estimate of the average generation expected from the fuel source over the life of the project. Describe the methodology and the in-house or consulting expertise used to arrive at the generation estimates.

Pricing Methodology - Please describe the pricing structure. Tables to list prices are provided in the Bidder Response Forms, however, Tri-State is interested in the methodology used by all bidders to ensure pricing includes all applicable charges. Examples of items to discuss, as applicable, are: demand charges versus energy charges. Are there start up charges, or start-up fuel costs? If there is a separate demand component, describe the methodology for calculating the kW billing demand determinant. Is pricing fixed or subject to change? Is pricing dependent upon certain subsidies or credits? Is there a separate transmission charge component?

Transmission & Interconnection - Please indicate the transmission provider for which you have applied for interconnection and describe the timing and status of the interconnection and/or transmission application and results.

Best Value Employment Metrics – Please provide information on the following as they relate to the bid project.

- Availability, cost and duration of training programs including training through apprenticeship programs register with the United States Department of Labor Office of Apprenticeship and Training.
- Estimates of the number of man-hours worked by Colorado workers as compared to total man-hours for each job classification.
- Long-term career opportunities for each job classification
- Wages and fringe benefits (healthcare, pension and other compensation) by job classification.

Financing and Credit - Describe proposed financing arrangements including potential sources of funding, contingencies, and interest during construction.

- Is financing required to fund the transmission and/or generation facilities? If yes, have financing arrangements been made prior to submitting this proposal?
- Describe any financial instruments the bidder will use to guarantee the financial security requirements described in the indicative term sheet.
- If company is rated by S&P, Moody's and/or Fitch, please provide latest credit report from (if responding company is not rated, then please provide for parent company and/or any other guarantor).
- Please include the most recent SEC form 10K and most recent SEC Form 10Q Report
- Please include the most recent Annual Report

References - Please list client references who may be contacted and for whom services have been rendered in the last 24 months. Include names, titles, address, phone numbers and e-mail addresses.

Project Team – Please describe the company and personnel to be involved as follows:

- Please provide a bidder profile, including office location, age of company, average number of employees over the past 5 years, and any ownership interests.
- Description of the bidder's pertinent experience for all power projects, projects of similar technology, and projects located in the same state as proposed for this project. The bidder should designate if the experience is in (1) development, (2) construction, (3) ownership and/or (4) operation and maintenance of the projects.
- State whether there is any current litigation regarding any power supply matter involving the bidder and any of its subsidiaries or off-balance sheet companies in which it has an interest. If there is any current litigation, provide a discussion of the current litigation.
- Provide a bidder organization chart and identify qualifications of key staff.

Model Contracts

Model contracts are posted on the RFP website. Each bidder is required to review the applicable model contract depending on resource type and identify any modifications or objections and include this mark-up with its proposal(s). It is expected that bidders offer meaningful input, comments such as "will be discussed" is not considered meaningful.

Proposal Submittal

All proposals must be received by Tri-State by no later than 5:00 PM Mountain Daylight Time on [Date TBD]. All proposals must be sent via email and a single hard copy delivered by this deadline. Emailed proposals must be sent to the email address listed below. Hard copies may be submitted by U.S. mail, overnight or courier service, or hand delivery. A hard copy submittal must include a signed original. If there is a discrepancy between the electronic and hard copies, the hard copy will prevail.

Proposals received after the deadline will not be considered unless Tri-State determines in its sole discretion that extenuating circumstances led to late delivery.
Proposal submittals should be directed to Tri-State's RFP administrator as follows:

Origination Manager
Tri-State Generation and Transmission Association, Inc.
1100 W. 116th Avenue
Westminster, CO 80234

E-mail: renewablerfp@tristategt.org

Proposal Checklist

To assist bidders in ensuring their proposals are complete and eligible for evaluation by Tri-State, a checklist of required and optional items is listed below:

	Item	Due Date
	Notice of Intent to Bid	[Date TBD] by 5:00 PM MDT
	Bidder Response Forms	[Date TBD] by 5:00 PM MDT
	Narrative Topics	[Date TBD] by 5:00 PM MDT
	Model Contract comments	[Date TBD] by 5:00 PM MDT
	Bid Fee	[Date TBD] by 5:00 PM MDT
	Form of Voluntary Consent	[Date TBD] by 5:00 PM MDT

Tentative RFP Schedule*

RFP Release Date	[Date TBD]
Notice of Intent to Submit a Proposal due	[Date TBD]
Proposals Due	[Date TBD]
Identify Short-listed Proposals	[Date TBD]
Execute Project Agreements**	[Date TBD]

** Tri-State will make a concerted effort to maintain the tentative schedule but reserves the right to revise the schedule to accommodate changing circumstances.*
***Contingent on Commission Phase II decision*

Proposal Duration

All proposals must be valid through the Phase II evaluation period and short-listed and back-up bids must remain valid through the subsequent negotiation period following the issuance of a final Phase II Commission Decision.

Project Agreements

Tri-State's selection of bidders for project agreement negotiations does not create an implicit contract between Tri-State and the bidder, nor is the selection process, including negotiations, a guarantee of contract between Tri-State and the bidder as a result of this RFP.

Collusion

By submitting a proposal to Tri-State under this RFP, bidder certifies that it has not divulged, discussed or compared its proposal with other bidders and has not colluded whatsoever with any other bidder or parties with respect to this proposal.

Bid Evaluation Criteria

Bidders to this solicitation should provide all relevant financial and operational information necessary to allow Tri-State to conduct a thorough analysis of their proposals. Proposals will be analyzed over a range of scenarios defined by price and non-price variables.

An initial economic analysis will be conducted where the Levelized Cost of Energy (LCoE) for each project option is calculated using the discount rate approved by the Commission in its Phase I decision. The LCoE will be calculated by determining the "all in" Net Present Value (NPV) of the average annual costs divided by the NPV of the average annual energy.

The projects will then be reviewed with respect to non-price factors. These will include:

- Best Value Employment Metrics
- Contribution to meeting GHG reduction goals of Colorado
- Location in a Tri-State utility member system service territory
- Financial viability of the bidder, including its parent or any other guarantor of services under the bidder's proposal
- Bidder's prior experience with project development
- Certainty of outside funding sources (i.e. tax credits or government subsidies)
- Compliance with all applicable local, state and federal laws, rules and orders
- Renewal and purchase options at the end of PPA
- Project retirement / decommissioning plan
- Legal, engineering and other costs required to implement the proposed project
- Forecasting capability

Each of these factors is important to the addition of a new capacity and/or energy supply resource to Tri-State's existing resource portfolio. Tri-State reserves the right to consider any other factors that it deems to be relevant to its supply portfolio needs.

Bids will then be evaluated with respect to transmission interconnection and network upgrade costs. It is expected that any electric interconnection network upgrades, firm transmission and/or wheeling costs necessary to deliver a project's output to a system where Tri-State is a network transmission customer are included in the pricing. Potential bidders should review and clearly understand Tri-State's Transmission Provider function's interconnection process.

While, at a minimum, having initiated an LGIP application can better define a project's potential viability, it is not required for bids proposing to connect to the Tri-State transmission system. Projects that have only just submitted interconnection requests or have not begun the LGIP with Tri-State should still include estimates of these costs and assumptions in the pricing offered and provide the specific amounts in the bid forms. Tri-State's Transmission Provider function will then review estimated transmission costs based on existing interconnection studies. This evaluation is not a substitute for the LGIP and does not guarantee the viability of a project. Projects utilizing incremental transmission capacity resulting from network upgrades that have received a CPCN will not be assessed costs associated with those upgrades.

Projects connecting to other transmission systems will be required to provide network upgrade and interconnection costs developed through an LGIP application (and associated studies) or an equivalent independent study. In addition, any bidder connecting a project to a system where Tri-State does not hold network transmission rights must be able to provide a transmission service request and system impact study demonstrating the availability of firm transmission service to a system where Tri-State does hold network transmission rights and include these costs along with any wheeling, losses and other costs associated with such services in its bid pricing.

Inquiries and Other Communications

For information and inquiries relating to the RFP, an e-mail address has been established at renewablerfp@tristategt.org. This e-mail address will be the primary means of communication for all inquiries, responses to questions, updates and clarifications. Bidders are asked not to contact the RFP administrator or any other Tri-State employee directly.

In order to facilitate a clear and timely response to critical inquiries, all bidders are encouraged to submit questions via e-mail on or prior to [DATA TBD]. Questions and responses to specific questions and general information, clarification of items, etc. will be posted on the RFP website, without bidder identification or attribution.

Confidentiality and Disclosure

Bidders may identify any information in their proposals that they consider to be confidential or proprietary. Nonetheless, Tri-State reserves the right to release all or a portion of the proposals to its affiliates and members and their agents, advisors and consultants for purposes of proposal evaluation. Tri-State will, to the extent required by law, advise each member, agent, advisor or consultant that receives such claimed confidential information of its obligations to protect such information. In addition, Tri-State reserves the right to release and disclose, without any obligation of confidentiality and at any time, (a) the general location or generation technology type of any of proposals submitted to Tri-State provided it does not identify the individual bidders and (b) aggregated bid pricing information that does not identify particular bids or bidders. Furthermore, all information, regardless of its confidential or proprietary nature, will be subject to review by the Commission and other governmental authorities and courts with jurisdiction, and may be subject to legal discovery. It is not Tri-State's intent to enter into any separate confidentiality, nondisclosure, or similar agreements as a condition to receiving a bidder's proposal.

Notwithstanding the above paragraph, a reasonable number of attorneys and a reasonable number of subject matter experts representing a party to the Tri-State's 2020 ERP proceeding may, upon the execution of the appropriate nondisclosure agreement, request and receive access to all bid information provided in response to this RFP regardless of a bidder's claim of confidentiality or propriety. In addition, upon completion of the competitive acquisition process, Tri-State is required by Commission Rule 3605(h)(IV), to post on its website and thereby make publicly available the following information from all bids: bidder name; bid price and utility cost; generation technology type; size of facility; contract duration or expected useful life of facility for utility proposals; and whether the proposed PPA includes an option for the utility to purchase the bid facility during or at the end of the contract term.

Acceptance of Proposals

Tri-State reserves the right, without qualification, to select or reject any or all proposals and to waive any formality, technicality, requirement, or irregularity in the proposals received. A bidder who submits a proposal does so without recourse against Tri-State for either rejection by Tri-State or failure to execute an agreement for purchase of capacity and/or energy for any reason. Additionally, Tri-State reserves the right to accept proposals other than the lowest cost proposal and bidders should recognize that factors other than cost, as described above, will be considered during the proposal evaluation process. Tri-State will not reimburse any bidders for any cost incurred in preparing and submitting a proposal or any subsequent contract negotiations or the bid fee. Under no circumstances will Tri-State be contractually bound by the terms of any bidder's proposal until a fully-executed agreement has been entered into between the parties.

Tri-State Board of Directors and Regulatory Approval

The projects offered in this RFP will be evaluated as described above and ultimately be presented as portfolios of resources in an ERP Implementation Report to be filed for approval with the Commission. It is expected that the Commission will issue a decision approving, modifying or denying any of the portfolios within 90 days. Depending on the outcome of the decision, preliminary contract negotiations may be initiated but Tri-State cannot fully move forward without Commission approval. Once there is a final Commission decision in place, Tri-State can commence or finalize preliminary contract negotiations with the ability to commit to specific projects.

Any contracts that may be considered as a result of this RFP or subsequent negotiations will be subject to Tri-State Board of Directors approval and inclusion in the resource portfolio approved by the Commission as part of the Electric Resource Planning process and may be subject to other regulatory approvals.

Thank you for your interest.

Attachment Vol II 7-2 Bidder Highly Confidential Non-Disclosure Agreement

Commission Confidentiality Order

BIDDER HIGHLY CONFIDENTIAL NONDISCLOSURE AGREEMENT

I, _____, state that I am employed by a bidder in Tri-State's 2021 All-Source RFP.

For purposes of this highly confidential nondisclosure agreement "Potential Resources" means the new or existing resource of the bidder by which I am employed.

For purposes of this highly confidential nondisclosure agreement "Highly Confidential Information" means highly confidential modeling inputs and assumptions that reasonably relate to the Potential Resource or to the transmission of electricity from that Potential Resource to Tri-State.

I understand that I may obtain Highly Confidential Information for the sole purpose of assisting the bidder to identify modeling errors or omissions concerning its Potential Resource so that the modeling errors or omissions may be corrected before the competitive acquisition process is completed.

I hereby state that I have read the protective provisions relating to confidential information contained in 4 Code of Colorado Regulations 723-1-1100 through 1104. With respect to all Highly Confidential information that may be provided to me, I agree to be bound by the terms of the protective provisions contained in 4 Code of Colorado Regulations 723-1-1100.

I hereby state that I will properly implement and maintain extraordinary confidentiality provisions for the Highly Confidential Information I receive.

I hereby state that I will not disclose or disseminate any Highly Confidential Information I receive to any third party other than to those who are specifically authorized to review such Highly Confidential Information and who have signed a highly confidential nondisclosure agreement. At the conclusion of the 2021 All-Source RFP competitive acquisition process, I agree to return all Highly Confidential Information to Tri-State Generation and Transmission Association, Inc.

_____

Name

_____

Title

_____

Employer or Firm

_____

Business Address

_____

Bidder Represented

_____

Date

_____

Signature

Attachment Vol II 7-3 Dispatchable PPA

Tri-State 11/19/2020
Model Dispatchable PPA
TS-XX-XXXX

POWER PURCHASE AGREEMENT FOR THE _____ PROJECT

BETWEEN

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

AND

_____

- [date] -

TS-XX-XXXX

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POWER PURCHASE AGREEMENT FOR THE _____ PROJECT
BETWEEN
TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.
AND
_____

This Power Purchase Agreement for the _____ Project (this "PPA") is made this ____ day of _____, 20__, by and between (i) _____ ("Seller"), a _____ and (ii) Tri-State Generation and Transmission Association, Inc. ("Tri-State"), a Colorado cooperative corporation. Seller and Tri-State are hereinafter referred to individually as a "Party" and collectively as the "Parties."

WHEREAS, Seller desires to develop, design, construct, interconnect, own, operate, and maintain a **_insert generation technology_** electric generating facility consisting of _____(__) _____ with an expected total nameplate capacity of ___ (the "Expected Nameplate Capacity Rating"), and which is further defined below as the "Facility"; and

WHEREAS, Seller has secured an approximately _____ (__,000) acre site in _____ County, _____ where it intends to locate the Facility and interconnect the Facility **[**to Interconnection Provider's existing _____ transmission line in the vicinity of the Site**][**at the Interconnection Provider's _____ Substation**]**; and

WHEREAS, Seller desires to sell and deliver to Tri-State at the Point of Delivery the electric power and energy produced by the Facility and all associated Environmental Attributes, and Tri-State desires to buy the same from Seller.

NOW, THEREFORE, in consideration of the mutual covenants herein contained, the sufficiency and adequacy of which are hereby acknowledged, the Parties agree to the following:

Article 1
Definitions and Rules of Interpretation

1.1 Rules of Construction.

The capitalized terms used in this PPA shall have the meaning set forth in this Article 1 or as otherwise defined in this PPA, whether in the singular or the plural or in the present or past tense. Words not otherwise defined herein shall have meanings as commonly used in the English language and, where applicable, in Prudent Utility Practice. Words not otherwise defined herein that have well known and generally accepted technical or trade meanings are used herein in accordance with such recognized meanings. In addition, the following rules of interpretation shall apply:

(A) References to "Articles," "Sections," or "Exhibits" shall be to articles, sections, or exhibits of this PPA.

(B) The Exhibits attached hereto are incorporated in and are intended to be a part of this PPA; *provided* that in the event of a conflict between the terms of any Exhibit and the terms of this PPA, the terms of this PPA shall take precedence.

(C) This PPA was negotiated and prepared by both Parties with the advice and participation of counsel. The Parties have agreed to the wording of this PPA and none of the provisions hereof shall be construed against one Party on the ground that such Party is the author of this PPA or any part hereof.

(D) The Parties shall act reasonably and in accordance with the principles of good faith and fair dealing in the performance of this PPA. Unless expressly provided otherwise in this PPA, (i) where this PPA requires the consent, approval, or similar action by a Party, such consent or approval shall not be unreasonably withheld, conditioned or delayed, and (ii) wherever this PPA gives a Party a right to determine, require, specify or take similar action with respect to a matter, such determination, requirement, specification or similar action shall be reasonable.

(E) Use of the words "include" or "including" or similar words shall be interpreted as "including, but not limited to" or "including, without limitation."

(F) The words "hereof," "herein," and "hereunder" and words of similar import when used in this PPA shall refer to this PPA as a whole and not to any particular provision of this PPA.

(G) Numerical amounts will be rounded to the nearest cent with respect to Dollars, one (1) decimal point for MW and MWh, three (3) decimal points for percentages, which is to the nearest tenth of a percent, and otherwise to two (2) decimal points.

(H) Tri-State's technical review, comments or inspection of the Facility, any designs, testing procedures, reports, or other documents or monitoring of any events shall not be construed as endorsing such nor as any express or implied warranty of performance, safety, durability, or reliability of the Facility or waiver of its rights under this PPA.

1.2 Interpretation with Interconnection Agreement.

The Parties recognize that Seller will enter into a separate Interconnection Agreement with the Interconnection Provider. The Parties acknowledge and agree that:

(A) the Interconnection Agreement shall be a separate and free-standing contract and that the terms of this PPA are not binding upon the Interconnection Provider.

(B) this PPA does not provide Seller authorization to interconnect the Facility to the Interconnection Provider or inject power into the Transmission System.

(C) notwithstanding any other provision in this PPA, nothing in the Interconnection Agreement shall alter or modify Seller's or Tri-State's rights, duties and obligations under this PPA. This PPA shall not be construed to create any rights between Seller and the Interconnection Provider.

(D) for purposes of this PPA, the Interconnection Provider shall be deemed to be a separate entity and separate contracting party whether or not the Interconnection Agreement is entered into with Tri-State or an Affiliate of Tri-State.

1.3 Interpretation of Arrangements for Power Supply to the Facility.

This PPA does not provide for the supply of retail electric power to the Facility ("House Energy"). Seller shall arrange with the local utility in whose retail service territory the Facility is located ("Local Provider") for the supply of House Energy. Subject to Seller's right to self-generate and consume energy concurrently generated by the Facility, Seller shall obtain House Energy exclusively from the Local Provider.

1.4 Definitions.

The following terms shall have the meanings set forth herein:

"Abandonment" means (i) the relinquishment of all possession and control of the Facility by Seller, other than a transfer permitted under this PPA, or (ii) if prior to the Commercial Operation Date, complete cessation of the development, design, construction, testing or inspection of the Facility for thirty (30) consecutive Days by Seller and/or Seller's contractors, but only if such relinquishment or cessation is not caused by or attributable to an Event of Default of, or requested by, Tri-State, or a Force Majeure Event.

"Affiliate" of any named Person means any other Person that Controls, is under the Control of, or is under common Control with, the named Person.

"AGC" means the equipment and capability of an electric generation facility to automatically adjust the generation quantity within the applicable Balancing Authority Area with the purpose of interchange balancing and specifically, the Facility's capability to accept an AGC Set-Point electronically, and the automatic adjustment and regulation of the Facility's energy production via the SCADA system.

"AGC Set-Point" means the Tri-State-generated analog or digital signal sent by the SCADA system to the Facility, representing the quantity of Contract Capacity and Contract Energy to be generated by the Facility. The RDD will communicate the AGC Set-Point to the Facility via the SCADA system.

"Applicable Law" means, collectively, all applicable laws, statutes, treaties, codes, ordinances, regulations, certificates, orders, licenses and permits of any Governmental Authority, now in effect or hereafter enacted, amendments to any of the foregoing, interpretations of any of the foregoing by a Governmental Authority having jurisdiction over the Parties or the Facility, and all applicable judicial, administrative, arbitration and regulatory decrees, judgments, injunctions, writs, orders, awards or like actions (including those relating to human health, safety, the natural environment or otherwise).

"Back-Up Metering" shall have the meaning set forth in Section 5.3(B).

"Balancing Authority" means _____ or any successor entity or another responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.

"Balancing Authority Area" means the collection of generation, transmission and loads within the metered boundaries of the Balancing Authority.

"Business Day" means any Day that is not a Saturday, a Sunday, or a NERC-holiday, or state- and/or federal-recognized holiday where banks in Denver, Colorado are required or authorized to close.

"Capacity Availability Factor" or "CAF" equals (AE + SME) ÷ PE

Where:

AE = Available Energy, stated in MWh, means the amount of Contract Energy that is available from the Facility for dispatch and receipt by Tri-State, regardless of the extent to which Tri-State actually dispatches the Facility, during such period. For purposes of calculating AE:

- The Facility shall be derated for Forced Outages (regardless of whether caused by Force Majeure Event) and ambient conditions.
- Contract Capacity that is unavailable for dispatch by Tri-State nevertheless shall be considered to be available for the purposes of determining Available Energy when (and only when):

(i) the Facility is disconnected from the Transmission System pursuant to the Interconnection Agreement, and the disconnection is not caused by actions of Seller or problems with the Facility;

(ii) the Contract Capacity and associated Contract Energy cannot be delivered by Seller or received by Tri-State due to an Emergency Condition or Force Majeure Event affecting the Transmission System at or beyond the Point of Delivery;

(iii) Tri-State has contracted for non-firm transmission service, and the Contract Capacity and associated Contract Energy cannot be received at the Point of Delivery due to transmission constraints affecting the Transmission System; and/or

(iv) [if any – generation technology, project specific- the Facility cannot operate because its emissions have exhausted the annual limits of its Permits but the Facility has generated the Planned Permitted Energy for such year].

SME = Scheduled Maintenance Energy for any period, stated in MWh, means the amount of Energy that is not available from the Facility for dispatch and receipt by Tri-State during such period, due to Scheduled Maintenance Outages not to exceed **_insert – generation technology and project specific-** MWhs.

PE = Period Energy for any period, stated in MWh, means the product of the Expected Capacity Rating and the total number of hours in such period.

"Change of Control" of a specified Person means any sale or series of sales or other transactions, whether voluntary or by operation of law, following which the previously existing Ultimate Parent does not Control such Person.

"Commercial Operation" means the operation of the Facility beginning on the Commercial Operation Date and continuing through the Term of this PPA.

"Commercial Operation Date" or "COD" for the Facility means the date set forth in Seller's COD notice that Seller has satisfied all of the conditions for Commercial Operation listed in Section 4.9, subject to confirmation by Tri-State.

"Commercial Operation Milestone" means the milestone for Commercial Operation as set forth in Exhibit A.

"Commercial Operation Year" means, for the first Commercial Operation Year, the period starting at 12:01 a.m. MPT on the COD and ending at 11:59 p.m. MPT on the last Day of the Month in which the first anniversary of COD occurs, and each successive "Commercial Operation Year" shall mean the twelve (12) Month period following the prior Commercial Operation Year.

"Conditions" shall have the meaning set forth in Section 4.9.

"Construction Milestone" means the result specified by Seller as set forth in Exhibit A which Seller shall achieve by the Construction Milestone Date, including the Commercial Operation Milestone.

"Construction Milestone Date" means the date set forth in Exhibit A by which Seller shall achieve the corresponding result specified for such date, including the Commercial Operation Milestone.

"Contract Capacity" means all net generating capacity including any and all capacity attributes and all net generating capacity available from the Facility, including uncommitted and undispatched capacity, not exceeding the Nameplate Capacity Rating.

"Contract Energy" means all net electric Energy generated by the Contract Capacity as dispatched by Tri-State from time to time, and any other attributes resulting from the generation or the output of the Facility or produced by the Facility and delivered to the Point of Delivery as measured by the Electric Metering Devices installed pursuant to Section 5.3. Contract Energy shall include any Test Energy.

"Capacity Payment" means the payment specified in Section 7.1.

"Contract Energy Payment" means the payment specified in Section 7.2.

"Control" means the ownership of fifty percent (50%) or more of the voting interests of the entity, or the possession, directly or indirectly, of the power to direct or cause the direction of the management policies of the entity, whether through ownership of voting securities, by contract or otherwise. "Controls," "Controlling," and "common Control" shall have correlative meanings when used in this PPA.

"Day" means a calendar day.

"Default Rate" shall have the meaning set forth in Section 8.3(C).

"Delay Damages" shall have the meaning set forth in Section 4.3(D).

"Delivery Excuse" means an event solely or substantially due to actions or omissions by Tri-State which prevents or delays delivery of Contract Capacity and/or Contract Energy.

"Designation Approval Date" shall have the meaning set forth in Section 2.2(A).

"Dispute Notice" shall have the meaning set forth in Section 13.9(A).

"Dollars" means the lawful currency of the United States of America.

"Effective Date" means the date first written above.

"Electric Interconnection Point" means the physical point at which electrical interconnection is made between the Interconnection Facilities and the Transmission System, pursuant to the Interconnection Agreement.

"Electric Metering Device(s)" means all metering and data processing equipment used to measure, record, or transmit data relating to the power and Energy produced by the Facility. Electric Metering Devices include the metering current transformers (CTs) and the metering voltage transformers (VTs).

"Emergency Condition" means any emergency condition or similar situation as defined under the Interconnection Agreement or any abnormal interconnection or system condition that requires automatic or immediate manual action to prevent or limit loss of load or generation supply (including Tri-State's load or generation), that could adversely affect the reliability of the interconnected system, or that could otherwise pose a threat to public safety.

"Energy" means three-phase, 60-cycle alternating current electric energy, expressed in MWh.

"Environmental Attributes" means any and all present and future environmental benefits characteristics, or credits that are attributable to Contract Energy, Contract Capacity, and/or the Facility including credits towards achieving local, national or international emission reduction requirements or renewable portfolio standards; green tags, greenhouse gas or emissions reductions or avoidances, credits, offset, allowances or benefits; any avoided emissions of pollutants to the air, soil, or water, including sulfur oxides (SO2), nitrogen oxides (NOx), carbon dioxide (CO2), carbon monoxide (CO), methane (CH4), carbon, volatile organic compounds (VOC), mercury (Hg), hydro fluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF6), and other emissions avoided; and any and all other green energy or other environmental benefits associated with the generation from the Facility (regardless of how any present or future law or regulation attributes or allocates such characteristics). Environmental Attributes do not include Tax Credits.

"Environmental Contamination" means the introduction or presence of Regulated Materials at the Site at such levels, quantities or location, or of such form or character, as to constitute a violation of Applicable Laws, or present a material risk under Applicable Laws that the Facility will not be available or usable, whether in whole or in

part, to sell Contract Capacity and/or Contract Energy to Tri-State as contemplated by this PPA.

"EPC Contract" means the turnkey engineering, procurement and construction contract(s) to be entered into between Seller and the EPC Contractor in relation to the engineering, procurement and construction of the Facility.

"EPC Contractor" means the engineering, procurement and construction contractor(s) retained and paid for by Seller, which contractor(s) shall be acceptable to Tri-State.

"Equipment Supply Agreement" means the agreement under which Seller has purchased or has rights to purchase the **_insert – generation technology and project specific-** and related equipment for the Facility.

"Event of Default" shall have the meaning set forth in Article 12.

"Expected Nameplate Capacity Rating" shall have the meaning set forth in the recitals to this PPA.

"Facility" means Seller's **_insert generation technology_** electric generating facility and Seller's Interconnection Facilities, as identified and described in Article 3 and Exhibit B, including all of the following, the purpose of which is to produce electricity and deliver such electricity to the Electric Interconnection Point: Seller's equipment, buildings, all of the generation facilities, including turbines, step-up transformers, fuel piping systems, equipment and software necessary to receive, accept and respond to an AGC Set-Point signal from Tri-State, output breakers, monitoring hardware, facilities necessary to connect to the Electric Interconnection Point, protective and associated equipment, improvements, and other tangible assets, contract rights, easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation, and maintenance of such electric generating facility. The term "Facility" includes the **_insert – generation technology and project specific-**, and generator step up transformer.

"Facility Site Documents" means the deeds, leases, easements, rights of way, land use agreement and other agreements or instruments reasonably necessary for the construction, operation and maintenance of the Facility and that evidence Seller's ownership or control of the Site.

"FERC" means the Federal Energy Regulatory Commission, or any successor agency.

"Financing" means the obligations of Seller or its Affiliates to any Financing Parties pursuant to the Financing Documents, including principal of and premium and interest on, indebtedness, fees, expenses or penalties, amounts due upon acceleration,

prepayment or restructuring, swap or interest rate hedging breakage costs and any claims or interest due with respect to any of the foregoing.

"Financing Documents" means the loan and credit agreements, notes, bonds, indentures, security agreements, lease financing agreements, mortgages, deeds of trust, interest rate exchanges, swap agreements, equity purchase agreements, purchase option agreements and other documents relating to the development, bridge, construction and/or permanent debt and/or equity financing for the Facility, including any credit enhancement, credit support, working capital financing, or refinancing documents, and any and all amendments, modifications, or supplements to the foregoing that may be entered into from time to time at the discretion of Seller subject to any required approvals, whether in this PPA, or otherwise, in connection with development, construction, ownership, leasing, operation or maintenance of the Facility.

"Financing Parties" means, collectively, any lender(s), lessor(s) or tax equity investor(s) and other parties providing any Financing and any successor(s) or assigns thereto.

"Force Majeure Event" shall have the meaning set forth in Article 14.

"Forced Outage" means a reduction of, or cessation in the delivery of, or inability to deliver, Energy that is not the result of (i) a Scheduled Maintenance Outage, (ii) a Force Majeure Event, (iii) a Delivery Excuse, or (iv) an Emergency Condition.

"Governmental Approval" means any authorization, consent, permission, approval, license, ruling, permit (including land use, air quality, and emissions control), exemption, variance, order, judgment, instruction, condition, direction, directive, decree, declaration of, or regulation by, any Governmental Authority relating to the construction, development, ownership, occupation, start-up, Testing, operation or maintenance of the Facility or to the execution, delivery or performance of this PPA or the purchase of power and energy from the Facility.

"Governmental Authority" means any federal, state, tribal, local or municipal governmental body; any governmental, quasi-governmental, regulatory or administrative agency, commission, body or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory or taxing authority or power, including a Reliability Coordinator, Balancing Authority or other governmental or quasi-governmental body administering energy, capacity, ancillary service, energy imbalance market or other Organized Markets, and PUC, FERC, NERC, WECC or other NERC regional entities; or any court or governmental tribunal.

"Guaranty" means the payment and performance guaranty provided by a Qualified Guarantor or Superior Guarantor, as appropriate, to Tri-State in the form set forth in Exhibit J.

"House Energy" shall have the meaning set forth in Section 1.3.

"Independent Engineer" means an independent engineering firm of national repute and appropriate expertise in electric generation relative to the configuration of the Facility under this PPA, appointed by Financing Parties under any Financing Documents, or if no such Financing Documents exist, by Seller after consultation with, and upon the prior written consent of, Tri-State.

"Interconnection Agreement" means the separate agreement between Seller and the Interconnection Provider for interconnection of the Facility to the Transmission System, as such agreement may be amended from time to time.

"Interconnection Facilities" means the facilities required to connect the Facility to the Transmission Provider's Transmission System and shall include the Interconnection Provider's Interconnection Facilities and Seller's Interconnection Facilities.

"Interconnection Provider" means _____ in its capacity as the owner of the Interconnection Provider's Interconnection Facilities, or any successor entity owner.

"Interconnection Provider's Interconnection Facilities" means the facilities necessary to connect Seller's Interconnection Facilities to the Transmission System at the Electric Interconnection Point as described in the Interconnection Agreement, including breakers, bus work, bus relays, and associated equipment installed by or for the Interconnection Provider for the direct purpose of interconnecting the Facility to the Transmission System at the Electric Interconnection Point, along with any easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of such facilities. Arrangements for the installation and operation of the Interconnection Provider's Interconnection Facilities shall be governed by the Interconnection Agreement.

"Issuer" means a U.S. commercial bank or a licensed U.S. branch of a foreign bank, with such bank having an unsecured bond rating equivalent to A- or better as determined by at least two (2) rating agencies, one of which must be either Standard & Poor's or Moody's, and an asset value of at least thirty billion Dollars ($30,000,000,000), or a Person otherwise approved by Tri-State in its sole discretion. An Issuer cannot be an Affiliate of Seller.

"kW" means kilowatt.

"Letter(s) of Credit" means an unconditional, irrevocable, standby letter of credit from an Issuer in substantially the form set forth in Exhibit K, *provided, however,* that such form may be modified by the Issuer as long as such modifications are customary, commercially reasonable, and acceptable to Tri-State. Costs of a Letter of Credit shall be borne by Seller.

"Minimum Loading" means the minimum capacity of the Facility that can be scheduled for continuous operation consistent with Prudent Utility Practices, including equipment manufacturer's warranties and performance standards.

“Month” means a calendar month.

“Moody’s” means Moody’s Investors Services, Inc., or any successor thereto.

“MPT” means, during any period of determination, the time in effect as of such period determination in the Mountain Time Zone of the United States of America, whether Mountain Standard Time or Mountain Daylight Savings Time.

“MW” means megawatt.

“MWh” means megawatt hours.

“Nameplate Capacity Rating” means the maximum installed instantaneous generation capacity of the completed Facility, expressed in MW, when operated in compliance with the Interconnection Agreement and consistent with the Facility manufacturer’s recommended power factor and operating parameters, as set forth in a notice from Seller to Tri-State delivered prior to or on the Commercial Operation Date (but shall be deemed to be zero (0) MW if no such notice is provided). The Nameplate Capacity Rating of the Facility shall not exceed **Insert the Expected Nameplate Capacity Rating** MW.

“NERC” means the North American Electric Reliability Corporation, or any successor organization.

“O&M Records” shall have the meaning set forth in Section 13.7.

“Operating Committee” means one representative each from Tri-State and Seller, appointed pursuant to Section 9.9(A).

“Operating Procedures” means those procedures developed pursuant to Section 9.9(B).

“Operating Records” means all agreements, records and other data associated with the construction, operation or maintenance of the Facility, including O&M Records, Project Contracts, blueprints for construction, operating manuals, all warranties on equipment, and all documents, whether in printed or electronic format, that Seller uses or maintains for the operation of the Facility.

“Operating Reserve” means the undispatched portion of the Contract Capacity, which is maintained to respond to system needs as determined by Tri-State.

“Operating Requirements and Restrictions” means the operating requirements, parameters and restrictions set forth in Exhibit G.

"Operation and Maintenance Agreement" means that certain operation and maintenance agreement between Seller and the Operation and Maintenance Contractor with respect to the Facility.

"Operation and Maintenance Contractor" means the operation and maintenance contractor retained and paid for by Seller, which contractor shall be a Qualified Operator and acceptable to Tri-State.

"Organized Market" means a regional transmission organization, independent system operator, energy imbalance market, or any other organized market.

"Party" and "Parties" shall have the meaning set forth in the recitals to this PPA.

"Party Representative" or "Parties' Representatives" shall have the meaning set forth in Section 13.9(A).

"Person" means any natural person, corporation, limited liability company, general partnership, limited partnership, proprietorship, other business organization, trust, union, association or Governmental Authority.

[if any – generation technology, project specific- "Planned Permitted Energy" means **Insert – generation technology and project specific-** MWh per calendar year of Contract Energy authorized or expected to be authorized to be generated in accordance with Seller required Governmental Approvals.]

"Point of Delivery" means the electric system point at which Seller makes available to Tri-State the Contract Capacity and Contract Energy, which shall be on the high side of the step-up transformer **[**at the Electric Interconnection Point**]** and as specified in Exhibit B.

"PPA" means this Power Purchase Agreement between Seller and Tri-State, including the Exhibits attached hereto, as the same may be amended from time to time in accordance with the provisions hereof.

"Project Contracts" means the EPC Contract, the Equipment Supply Agreement, the Interconnection Agreement, the Facility Site Documents and the Operation and Maintenance Agreement, and any such other material agreements related to the development, construction, ownership, operation and maintenance of the Facility, a list of which agreements is set forth in Exhibit E.

"Project Entity" means (a) Seller, and (b) any entity that Controls Seller if the Facility and assets related thereto constitute all or substantially all of the assets of such entity (determined on a consolidated basis with all other Persons that are Controlled by such entity).

"Prudent Utility Practice(s)" means the practices, methods, standards, and acts of a significant portion of the electric power generation industry (including, where applicable, the practices, methods, standards, and acts engaged in or approved by a significant portion of the electric generation industry operating facilities of a similar type, size and location in the United States of America), WECC and/or NERC, that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with Applicable Laws, codes, standards, equipment manufacturer's recommendations, reliability, safety, environmental protection, economy, and expedition. With respect to the Facility, Prudent Utility Practice(s) includes taking reasonable steps to ensure that:

(A) equipment, materials, resources, and supplies, including spare parts inventories, are available to meet the Facility's needs;

(B) sufficient operating personnel are available at all times and are adequately experienced and trained and licensed as necessary to operate the Facility properly, efficiently, and in coordination with Tri-State and are capable of responding to reasonably foreseeable Emergency Conditions;

(C) preventive, routine, and non-routine maintenance and repairs are performed on a basis that ensures reliable, long-term and safe operation, and are performed by knowledgeable, trained, and experienced personnel utilizing proper equipment and tools;

(D) appropriate monitoring and testing are performed to ensure equipment is functioning as designed;

(E) equipment is not operated in a reckless manner, in violation of manufacturers' guidelines or in a manner unsafe to workers, the general public, or the interconnected system or contrary to environmental laws, permits or regulations or without regard to defined limitations such as, steam pressure, temperature, chemical content of make-up water, flood conditions, safety inspection requirements, operating voltage, current, volt-ampere reactive (VAR) loading, frequency, rotational speed, polarity, synchronization, and/or control system limits;

(F) equipment and components meet or exceed the standard of durability that is generally used for electric generation operations in the region and will function properly over the full range of ambient temperature and weather conditions reasonably expected to occur at the Site under both normal and Emergency Conditions; and

(G) equipment, components, and processes are appropriately permitted with any Governmental Authority and are operated and maintained in accordance with Applicable Laws.

"PUC" means the _____ Commission, or any successor agency.

"PUC Approval" means any written order of the PUC necessary for Tri-State to effectuate the purposes of this PPA.

"Qualified Guarantor" means a Person having an issuer credit rating of (A) Baa2 or higher by Moody's and (B) BBB or higher by Standard & Poor's, or a Person otherwise approved by Tri-State in its sole discretion.

"Qualified Operator" means an operation and maintenance contractor that (i) has operated, for a period of at least five (5) years, multiple electric energy generating facilities of a similar type, size in North America having, collectively, an aggregate nameplate capacity of at least 500 MW, and (ii) maintains an operating staff consisting of personnel with comparable experience in the operation and maintenance of power generation facilities similar to the Facility.

"RDD" means Tri-State's resource dispatch desk representative(s) who are responsible for dispatch of generating units, including the Facility.

"Regulated Materials" means any substance, material, gas, or particulate matter that is regulated by any Governmental Authority, as an environmental pollutant or dangerous to public health, public welfare, or the natural environment, including protection of non-human forms of life, land, water, groundwater, and air, including any material or substance that is (i) defined as "toxic," "polluting," "hazardous waste," "hazardous material," "hazardous substance," "extremely hazardous waste," "solid waste" or "restricted hazardous waste" under any provision of local, state, or federal law; (ii) petroleum, including any fraction, derivative or additive; (iii) asbestos; (iv) polychlorinated biphenyls; (v) radioactive material; (vi) designated as a "hazardous substance" pursuant to the Clean Water Act, 33 U.S.C. §1251 *et seq.* (33 U.S.C. §1251); (vii) defined as a "hazardous waste" pursuant to the Resource Conservation and Recovery Act, 42 U.S.C. §6901 *et seq.* (42 U.S.C. §6901); (viii) defined as a "hazardous substance" pursuant to the Comprehensive Environmental Response, Compensation, and Liability Act, 42 U.S.C. §9601 *et seq.* (42 U.S.C. §9601); (ix) defined as a "chemical substance" under the Toxic Substances Control Act, 15 U.S.C. §2601 *et seq.* (15 U.S.C. §2601); or (x) defined as a "pesticide" under the Federal Insecticide, Fungicide, and Rodenticide Act, 7 U.S.C. §136 *et seq.* (7 U.S.C. §136).

"Reliability Coordinator" shall have the meaning as set forth in NERC's Glossary of Terms Used in NERC Reliability Standards as modified from time to time.

"Replacement Cost(s)" means the costs incurred and reasonably forecasted to be incurred by Tri-State for the Energy, capacity, ancillary services and Enviromental Attributes which are necessary to replace that which Seller, in accordance with this PPA, is required to produce at the Facility and deliver to Tri-State, but will fail to so

provide, less the sum of any payments from Tri-State to Seller, under this PPA, which are eliminated as a result of such failure. Replacement Costs include the amounts incurred and reasonably forecasted to be incurred by Tri-State for replacement ancillary services, transmission and directly associated transaction costs (including reasonable attorneys' fees suffered as result of Seller's failure to perform). Additional costs may include replacement capacity costs applicable to a resource and any penalties incurred as a result of Seller's non-performance.

"RTU" shall have the meaning set forth in Section 3.3(A).

"SCADA" means supervisory control and data acquisition.

"Scheduled Maintenance Outage" means a time period during which all or a portion of the Facility is shut down, derated, or its output reduced to undergo scheduled maintenance in accordance with this PPA, or as otherwise agreed by Seller and Tri-State.

"Security" shall have the meaning set forth in Article 11.

"Security Party" shall have the meaning set forth in Section 19.1(B).

"Seller" shall have the meaning set forth in the preamble to this PPA.

"Seller's Interconnection Facilities" means the facilities and equipment owned by Seller related to the interconnection of the Facility with the Interconnection Provider's Interconnection Facilities along with any easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of such facilities. On the low side of the step-up transformer, it includes Seller's metering, relays, and load control equipment as provided for in the Interconnection Agreement.

"Site" means the parcel(s) of real property on which the Facility will be constructed and located, including any easements, rights of way, land use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of the Facility. The Site is more specifically described in Section 3.2 and Exhibit B.

"Standard & Poor's" means Standard & Poor's Global Ratings, or any successor thereto.

"Successful Start" means, in response to a request from Tri-State to start the Facility, Seller's start and operation of the Facility that:

(A) achieves the Minimum Loading level for the requested operating configuration within **_ Insert – generation technology and project specific-** minutes after the time Tri-State requests the Facility start to begin, and

(B) upon achieving such Minimum Loading level, generates continuously for a period of not less than one hour while synchronized to the Transmission System at or above such Minimum Loading level without experiencing any abnormal operating conditions.

"Superior Guarantor" means any Person having an issuer credit rating of (A) Baa1 or higher by Moody's and (B) BBB+ or higher by Standard & Poor's, or a Person otherwise approved by Tri-State in its sole discretion.

"Tariff" shall have the meaning set forth in Section 5.1(B).

"Taxes" means all taxes, fees, levies, licenses or charges imposed by any Governmental Authority, other than taxes, levies, licenses or charges based upon net income or net worth, together with any interest and penalties thereon.

"Term" means the period of time during which this PPA shall remain in full force and effect, and which is further defined in Section 2.1.

"Test" or "Testing" means those tests, evaluations and measurements of the Facility's output capability that are undertaken prior to and in connection with preparing the Facility for Commercial Operation pursuant to Section 9.2, which shall include such tests as are consistent with Prudent Utility Practices.

"Test Date" means the date on which Seller shall commence Testing of the Facility and shall be the date falling at least sixty (60) Days prior to the Commercial Operation Milestone or such other date as Seller and Tri-State may agree in writing.

"Test Energy" means the net electric Energy that is produced by the Facility, including any and all associated ancillary services delivered to Tri-State at the Point of Delivery, prior to Commercial Operation.

"Test Energy Payment" means the payment specified in Section 7.6.

"TP Approvals" shall have the meaning set forth in Section 2.2.

"Transfer" means any sale, transfer or other disposition.

"Transmission Provider" means the owner or operator of the Transmission System responsible for providing transmission service.

"Transmission System" means the contiguously interconnected electric transmission and sub-transmission facilities over which the Transmission Provider has rights (by ownership or contract) to provide bulk transmission of capacity and energy from the Electric Interconnection Point.

"Tri-State" shall have the meaning set forth in the preamble to this PPA.

"Ultimate Parent" means _____ or such other Person that Controls Seller and is not controlled by any other Person.

"WECC" means the Western Electricity Coordinating Council, a NERC regional entity, or any successor organization.

"Year" means a calendar year consisting of 365 Days (or 366 Days if a leap year), beginning on January 1 and ending on December 31.

Article 2
Term

2.1 PPA Term and Delivery Term.

This PPA shall become effective as of the Effective Date, and shall remain in full force and effect until 11:59 p.m. MPT on the last Day of the Month during which occurs the [___th] anniversary of the Commercial Operation Date, subject to early termination as set forth herein (the "Term").

2.2 Conditions Precedent.

(A) Network Resource. Tri-State's obligation to accept and pay for Contract Capacity and Contract Energy is subject to approval by the Transmission Providers of Tri-State's application for designation of the Facility as a network resource for Tri-State's native load customers and the associated reservation of firm network transmission service on the Transmission Provider's Transmission System, all without conditions materially unsatisfactory to Tri-State or requirements of material transmission upgrades (collectively, the "TP Approvals"). Tri-State shall (i) no later than fifteen (15) Business Days after the Effective Date, make a written request for all TP Approvals and (ii) thereafter use commercially reasonable efforts to obtain such TP Approvals from the Transmission Providers within one hundred fifty (150) Days from the Effective Date ("Designation Approval Date") and shall provide Seller prompt written notice upon receipt of all such TP Approvals. If any or all of the TP Approvals are not received by the Designation Approvals Date or any TP Approval would require conditions materially unsatisfactory to Tri-State or material transmission upgrades, (y) Tri-State shall promptly provide Seller written notice notifying Seller that Tri-State elects to terminate this PPA, upon which the Parties shall have no obligations or liabilities to each other hereunder, subject to Tri-State's obligation to return the Security to Seller in full, or (z) if no such notice is received by Seller within ten (10) Days following the Designation Approval Date, Tri-State shall be deemed to have elected to proceed with this PPA despite not receiving such TP Approvals, upon which the condition provided in this Section 2.2(A) shall be deemed to have been satisfied.

(B) PUC Approvals. Tri-State's obligation to accept and pay for Contract Capacity and Contract Energy is subject to PUC Approvals. Tri-State shall

(i) no later than sixty (60) Days after the Effective Date apply to the PUC for any necessary PUC Approvals and (ii) thereafter use commercially reasonable efforts to obtain such PUC Approvals as soon as reasonably practicable. Seller shall cooperate with Tri-State's efforts to obtain PUC Approvals and provide such additional documentation and information as reasonably requested by Tri-State or the PUC. Tri-State shall have the right to terminate this PPA, upon which the Parties shall have no obligations or liabilities to each other hereunder as a result of such termination, by written notice to Seller: (a) at any time within thirty (30) Days following issuance of a written order by the PUC rejecting PUC Approvals or granting PUC Approvals with conditions unacceptable to Tri-State in its sole discretion, (b) at any time between the 180th and 215th Day following Tri-State's application for PUC Approval, if prior to the date of such termination the PUC has not issued the PUC Approvals, (c) at any time within 30 Days following timely request for reconsideration (in whole or in any material part) by any third party, of the PUC Approvals, and/or (d) at any time within thirty (30) Days following timely appeal by any party, of the PUC Approvals. If Tri-State elects to terminate this PPA, Tri-State shall return the Security to Seller in full. If Tri-State is eligible to terminate this PPA, but fails to terminate this PPA by the applicable date, Tri-State shall be deemed to have elected to proceed with this PPA despite not receiving such PUC Approvals, upon which the condition provided in this Section 2.2(B) shall be deemed to have been satisfied.

(C) Other Tri-State CPs. [if any].

(D) Seller CPs. [if any – project specific].

2.3 Survivability.

Applicable provisions of this PPA shall continue in effect after termination, including early termination, to the extent necessary to enforce or complete the duties, obligations or responsibilities of the Parties arising prior to termination and, as applicable, to provide for: final billings and adjustments related to the period prior to termination, repayment of any money due and owing to either Party pursuant to this PPA, and the indemnifications specified in this PPA. All remedies in this PPA shall survive termination or cancellation of this PPA.

Article 3
Facility Description

3.1 Summary Description.

Seller shall develop, design, construct, interconnect, own, operate, and maintain the Facility, which consists of _____ and associated equipment having a designed aggregate nameplate electric energy generating capacity of **Insert the Expected Nameplate Capacity Rating**. Exhibit B provides a detailed description of the Facility,

including identification of the major equipment and components that will make up the Facility.

3.2 Location.

The Facility shall be located on the Site and shall be identified as the "**Insert Project Name**" or such other name as agreed to by the Parties. The latitude and longitude of the Site are _____. A scaled map that identifies the Site and the location of the Facility on the Site and a drawing identifying the location of the Electric Interconnection Point, the Point of Delivery, important ancillary facilities and Interconnection Facilities, is included in Exhibit B.

3.3 General Design of the Facility.

Seller shall develop, design and construct the Facility according to Prudent Utility Practice(s), this PPA and the Interconnection Agreement, as applicable. In addition to the requirements of the Interconnection Agreement, the Facility shall at all times, and at Seller's expense:

(A) have the required electronic plant interfaces and communications interfaces for meter recording devices, 125vDC battery supplied voltage for meter recording devices, remote terminal unit ("RTU"), telemetering equipment and communications equipment. Seller is responsible for providing appropriate panel space and maintaining ambient conditions suitable for electronic equipment. Seller is responsible for establishing appropriate access control to the electronic equipment;

(B) use communication circuits from the Facility to Tri-State's RDD for the purpose of telemetering, supervisory control/data acquisition, voice communications as required by Tri-State for AGC, and dial-in access by Tri-State to remotely interrogate the Electric Metering Devices;

(C) have the required equipment and software necessary to receive, accept and respond to an AGC Set-Point signal from Tri-State; and

(D) meet the Operating Requirements and Restrictions.

Article 4
Commercial Operation

4.1 Commercial Operation.

Seller shall cause the Facility to achieve Commercial Operation no later than the Commercial Operation Milestone. The Facility shall be fully capable of reliably producing and delivering the Contract Capacity and Contract Energy to be provided under this PPA to Tri-State at the Point of Delivery, no later than the Commercial Operation Milestone; provided, that Seller shall not be obligated to establish a

Commercial Operation Date under this PPA that is earlier than the Commercial Operation Milestone, and Tri-State shall not be obligated to acknowledge a Commercial Operation Date under this PPA that is earlier than thirty (30) Days prior to the Commercial Operation Milestone.

4.2 Construction Milestone.

In order to achieve the Commercial Operation Date of the Facility by the Commercial Operation Milestone, Seller shall meet the Construction Milestones set forth in Exhibit A.

4.3 Delay Damages.

(A) If Seller fails to achieve any Construction Milestones (excluding the Commercial Operation Milestone) by the applicable Construction Milestone Date, (i) Seller shall provide Tri-State within ten (10) Days of the missed milestone with a detailed written report indicating the reason for such failure and Seller's proposed course of action to maintain the overall construction and commercial operation schedule, including any required expediting actions, and (ii) Tri-State shall be entitled to delay damages, as liquidated damages and not a penalty, in an amount equal to Two Thousand Five Hundred Dollars ($2,500) per Day for each Day following the Construction Milestone Date until the date the Construction Milestone is achieved; *provided, however,* that if Commercial Operation is achieved on or before the Commercial Operation Milestone, any liquidated damages amounts paid by, or on behalf of, Seller pursuant to this Section 4.3(A) shall be refunded by Tri-State to Seller without interest.

(B) If the Facility fails to achieve Commercial Operation by the Commercial Operation Milestone, (i) Seller shall provide Tri-State within ten (10) Days of the missed milestone with a detailed written report indicating the reason for such failure and Seller's proposed course of action to achieve Commercial Operation, including any required expediting actions, and (ii) Tri-State shall be entitled to delay damages, as liquidated damages and not a penalty, in an amount equal to Two Hundred Fifty Dollars ($250) per Day per MW for each MW of nameplate capacity not installed, operating and capable of generating Test Energy below the Expected Nameplate Capacity Rating until the earlier to occur of (x) the date Commercial Operation is achieved, and (y) the date, if any, on which this PPA is terminated by Tri-State as permitted hereunder.

(C) All Delay Damages shall begin to accrue on the Day after the applicable missed Construction Milestone and shall continue to accrue until the result specified for such Construction Milestone is achieved. Delay Damages shall be payable in lieu of actual damages accrued for the period during which Delay Damages are assessed; provided, that nothing in this Section shall be construed to preclude Tri-State from terminating this PPA for an Event of Default under Section 12.1 or Tri-

State's entitlement to Replacement Costs upon termination of this PPA. All Delay Damages shall be cumulative.

(D) Each Party agrees and acknowledges that (i) the damages that Tri-State would incur due to Seller's delay or failure in achieving any Construction Milestone (collectively, "Delay Damages") would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the Delay Damages as agreed to by the Parties set forth herein are a fair and reasonable calculation of such damages.

(E) Following the end of the Month in which Delay Damages begin to accrue, Tri-State shall promptly deliver to Seller an invoice setting forth the amount due Tri-State in respect thereof for the preceding Month. The amount of Delay Damages shall be due and payable by Seller in accordance with Section 8.3(A).

4.4 Site Report.

(A) Within ninety (90) Days of the Effective Date, Seller shall conduct a Phase I environmental investigation of the Site and shall provide Tri-State with a copy of the report summarizing such investigation, together with any data or information generated pursuant to such investigation. To the extent the Phase I investigation identifies the need for further environmental audits or investigations, Seller shall also provide to Tri-State, any related further reports. Seller shall provide to Tri-State, with such report, confirmation from an environmental engineer that the Site has been inspected for Environmental Contamination and that the Site complies, in all respects, with all Applicable Law relating to environmental or occupational health and safety matters and Regulated Materials. Such report shall include a confirmation that, based upon such investigation and to the best of Seller's knowledge, no conditions involving Environmental Contamination exist at or under the Site.

(B) During the Term, Seller shall promptly:

(1) disclose to Tri-State and remediate, at Seller's sole cost and expense, any Environmental Contamination identified at the Site;

(2) provide to Tri-State copies of any reports summarizing any further environmental assessments or investigations, together with any data or information generated pursuant to such investigation; and

(3) disclose to Tri-State the existence of any enforcement, legal, or regulatory action or proceeding relating to any alleged presence of Environmental Contamination and/or the alleged violation of any Applicable Law related to the protection of endangered, migratory or other protected species.

4.5 Project Contracts.

Promptly after the execution of each of the Project Contracts or amendment thereto, Seller shall deliver to Tri-State copies of each of the fully executed Project Contracts. Upon reasonable notice and request by Tri-State, Seller shall provide Tri-State with other Facility design and construction documents and drawings, including as-built and other major engineering drawings. Seller shall be permitted to redact from the copies of the Project Contracts provided to Tri-State any pricing information which Seller considers confidential.

4.6 Governmental Approvals.

Seller shall timely and lawfully procure and maintain in good standing, at its own cost and expense, all Seller required Governmental Approvals, and shall timely and properly pay its charges and fees in connection therewith. Tri-State shall have the right to inspect and obtain copies of all Seller required Governmental Approvals (and related applications) obtained or applied for by Seller. Exhibit F sets forth a list of Seller's required Governmental Approvals, which Seller shall update from time to time, as appropriate, to add additional Seller required Governmental Approvals prior to Commercial Operation.

4.7 Construction Progress Reports.

Seller shall provide Tri-State with written progress reports in a form reasonably acceptable to Tri-State: (A) on a quarterly basis commencing with the Effective Date and continuing until the commencement of physical construction of the Facility within twenty (20) Days following the end of each calendar quarter; and (B) on a monthly basis commencing on the commencement of physical construction of the Facility and continuing until Commercial Operation, on or before the twentieth (20th) Day of each Month for the preceding Month. Such written progress reports shall evaluate the progress on development, design, and construction of the Facility, which reports shall include (i) a project master schedule, with appropriate bar charts and status reports; (ii) updated engineering and procurement schedules; (iii) an updated testing, commissioning and start-up schedule; and (iv) reports from engineers and other Persons involved in the engineering, procurement and construction of the Facility. Seller shall, from time to time, upon reasonable advance request from Tri-State, meet with Tri-State to discuss the progress of the construction of the Facility and make the EPC Contractor available to discuss and answer questions of Tri-State regarding the Facility and Construction Milestone progress in order to keep Tri-State informed on the status of the engineering, procurement and construction for the Facility and to consider Tri-State's comments in good faith. None of the foregoing shall be deemed to be in lieu of, or in substitution for, the general record and reporting obligations attendant to Seller in accordance with Article 13.

4.8 Tri-State's Rights During Construction.

Tri-State shall have the right to monitor the construction, start-up and Testing of the Facility, and Seller shall comply with all requests of Tri-State with respect to the monitoring of these events. Seller shall cooperate in such physical inspections of the Facility as may be requested by Tri-State during and after completion of construction. All persons visiting the Facility on behalf of Tri-State shall comply with all of Seller's applicable reasonable safety and health rules and requirements that have been provided to Tri-State in writing prior to its visit.

4.9 Conditions to Commercial Operation.

Seller shall notify Tri-State in writing when Seller has satisfied all of the Conditions for Commercial Operation. Such notice shall specify the Commercial Operation Date. The Commercial Operation Date is contingent upon verification by Tri-State, including Seller providing evidence acceptable to Tri-State of the satisfaction or occurrence of all of the Conditions set forth below. Review and approval of such Conditions may occur on an ongoing and incremental basis, pending resolution of any dispute, as such Conditions are satisfied. Conditions shall be satisfied at Seller's sole cost and expense. Conditions to be fulfilled by Seller prior to Commercial Operation, to the satisfaction of, or waived in writing by, Tri-State are ("Conditions"):

(A) Seller having delivered to Tri-State copies of fully executed Project Contracts, pursuant to Section 4.5(A);

(B) if applicable, Seller having entered into Financing Documents and having achieved or obtained waivers with respect to all conditions precedent to the initial availability for disbursement of funds under the Financing Documents;

(C) Seller having delivered to Tri-State (i) a copy of its constitutional documents (certified by the Secretary of State of the State of _____) and (ii) a copy of a resolution approving the terms of this PPA and authorizing one or more individuals to execute this PPA on its behalf (such copy to have been certified by its authorized officer as true, complete and current);

(D) the Facility having achieved initial synchronization with the Transmission System and having demonstrated the reliability of its communications systems and communications with Tri-State's RDD;

(E) the Independent Engineer having certified that the Facility has been completed in all material respects (excepting punch list items that do not adversely affect the ability of the Facility to operate as intended hereunder) and the Facility is ready for the delivery of Contract Capacity and Contract Energy and commencement of Commercial Operation;

(F) all arrangements for the supply of required House Energy to the Facility have been completed by Seller, are in effect, and are available for the supply of such House Energy to the Facility;

(G) the Security meeting the requirements set forth in Section 11.1 having been established in the amount required after the Commercial Operation Date pursuant to Section 11.1;

(H) certificates of insurance evidencing the coverages required in Exhibit D having been obtained and submitted to Tri-State;

(I) Seller having submitted to Tri-State a certificate of an officer of Seller familiar with the Facility after due inquiry stating that:

(1) all applicable Seller required Governmental Approvals (including those set forth in Exhibit F) have been obtained and are in full force and effect, except for minor Governmental Approvals that are expected by such officer to be obtained in the ordinary course, the failure of which to obtain would not adversely affect the construction and/or operation of the Facility;

(2) Seller is in compliance with the terms and conditions of this PPA;

(3) the Facility is in compliance with all national and regional reliability standards, including standards set by WECC, NERC, FERC, the PUC and is compliance with all applicable terms and conditions of applicable Tariffs;

(4) Seller has good title to the Facility and all Facility Site Documents reasonably necessary for the operation and maintenance of the Facility are in full force and effect;

(5) Seller has registered (and attaching with such certificate documentation setting forth that it has registered) (i) with NERC as a generator owner and generator operator, and (ii) the Facility with any Governmental Authority or other Person as requested by Tri-State pursuant to Section 10.2(A);

(6) Seller having successfully completed Testing of the Facility that may be required by the Financing Documents, applicable Seller required Governmental Approvals, any Project Contracts, manufacturers' specifications and warranties for the commencement of Commercial Operation, and in accordance with Section 9.2 at an installed capacity of the Expected Nameplate Capacity Rating;

(7) (i) Seller is in compliance with the Interconnection Agreement, (ii) the interconnection of the Facility to the Interconnection Provider's Interconnection Facilities has been completed in accordance with the Interconnection Agreement, (iii) the Facility has operated at a generation level acceptable to the

Interconnection Provider, without experiencing any abnormal or unsafe operating conditions on any interconnected system, and (iv) any other testing of the Facility and/or Seller's interconnection Facilities required by the Interconnection Agreement to interconnect and deliver energy has been completed satisfactorily;

(8) the Nameplate Capacity Rating of the Facility at the time of Commercial Operation is **Insert the Expected Nameplate Capacity Rating** MW; and

(9) Seller shall have demonstrated that it is a Qualified Operator or that Seller has engaged a Qualified Operator to operate and maintain the Facility;

(J) the Facility has achieved at least two Successful Starts, without experiencing any abnormal operating conditions and the Facility has demonstrated the ability to meet the Operating Requirements and Restrictions;

(K) generation technology specific- the Facility has generated continuously for a period not less than **_insert – generation technology and project specific-** consecutive hours, at an output level not less than **_insert – generation technology and project specific-** % of Expected Nameplate Capacity (adjusted for ambient conditions), without experiencing any abnormal operating conditions; and

(L) the Facility is configured and available for operation in a manner to permit accreditation of the Facility as a Capacity Resource, in an amount substantially equal to the Expected Nameplate Capacity Rating.

4.10 Financial Ability.

Within ninety (90) Days of the Effective Date, Seller shall provide to Tri-State copies of applicable funding agreements, financing documents or other documents and agreements, as such may be updated from time to time, which reasonably establish that Seller has or will have sufficient funding to complete the construction of the Facility and achieve Commercial Operation.

4.11 Test Energy.

Seller shall coordinate the production and delivery of Test Energy with Tri-State, with such prior notice as Tri-State may request. Tri-State shall cooperate with Seller to facilitate Testing, shall accept delivery of all Test Energy, and shall accept and purchase all such Test Energy in accordance with this PPA, so long as the Facility is interconnected in accordance with the Interconnection Agreement and Seller is otherwise in compliance with this PPA.

Article 5
Delivery, Metering and Fuel Supply

5.1 Delivery Arrangements.

(A) Seller shall be responsible for all interconnection arrangements and costs required to deliver the Contract Capacity and Contract Energy. Seller shall execute, deliver, and perform its obligations under the Interconnection Agreement.

(B) Seller is solely responsible for meeting its obligations as an interconnection customer under the Interconnection Provider's open access transmission tariff (the "Tariff") and the requirements of the Balancing Authority. All costs and obligations associated with Interconnection Facilities required to accomplish and operate the Interconnection Facilities is the responsibility of Seller. Seller shall satisfy any concerns of Tri-State regarding viability of the interconnection (timing and status of the generator interconnection request); *provided, however,* that any and all costs associated with this Section 5.1(B) shall be at the sole cost and expense of Seller.

(C) Seller is responsible for all electric losses, transmission and ancillary service arrangements and costs required to deliver Contract Capacity and Contract Energy to Tri-State at the Point of Delivery.

(D) Tri-State shall be responsible for all electric losses, transmission and ancillary service arrangements and costs required to deliver Contract Capacity and Contract Energy beyond the Point of Delivery. Subject to the provisions of this PPA, Tri-State may elect, at Tri-State's sole option, whether to obtain and utilize firm transmission service, non-firm transmission service or network integration transmission service for the delivery of Contract Capacity and Contract Energy from the Point of Delivery.

5.2 Availability Reporting.

Within thirty (30) Days after the end of each Commercial Operation Year, Seller shall provide Tri-State with an operating report detailing events such as maintenance outages, [_____] trips and the causes of such trips, Facility failures and the diagnosis of such failures, status of repairs as well as statistical performance summaries and operational trends for the previous Commercial Operation Year.

5.3 Electric Metering Devices.

(A) All Electric Metering Devices used to measure the Contract Capacity and Contract Energy and to monitor and coordinate operation of the Facility shall be owned, installed, and maintained in accordance with the Interconnection Agreement. If Electric Metering Devices are not installed at the Point of Delivery, meters or meter readings shall be adjusted to reflect losses from the Electric Metering

Devices to the Point of Delivery. All Electric Metering Devices used to provide data for the computation of payments shall be sealed and only the Interconnection Provider shall break the seal when such Electric Metering Devices are to be inspected and tested or adjusted in accordance with this Article 5.

(B) Seller and/or Tri-State may elect to install and maintain, at its own expense, backup metering devices ("Back-Up Metering") in addition to those installed and maintained pursuant to the Interconnection Agreement, which installation and maintenance shall be performed in a manner acceptable to Tri-State. The Party installing the Back-Up Metering shall, at its own expense, inspect and test the Back-Up Metering upon installation and periodically thereafter. The Party installing the Back-Up Metering shall provide the other Party with reasonable advance notice of, and permit a representative of the other Party to witness and verify, such inspections and tests; provided, however, that the other Party shall not unreasonably interfere with or disrupt the activities of the Party installing the Back-Up Metering and shall comply with all of such Party's safety standards. Upon request from the other Party, the Party installing the Back-Up Metering shall perform additional inspections or tests of its Back-Up Metering and shall permit a qualified representative of the other Party to inspect or witness the testing of the Back-Up Metering, provided, however, that the other Party shall not unreasonably interfere with or disrupt the activities of the Party installing the Back-Up Metering and shall comply with all of such Party's safety standards. The actual expense of any such requested additional inspection or testing by the non-installing Party shall be borne by the non-installing Party; *provided, however*, that the expense of the requested additional inspection or testing shall be borne by the Party installing if the Back-Up Metering is found to be inaccurate by more than the allowable limits established in this Article 5. If requested in writing, the Party installing the Back-Up Metering shall provide copies of any inspection or testing reports to other Party.

(C) If any Electric Metering Device, or Back-Up Metering, are found to be defective or inaccurate outside the bounds of the selected device's manufacturer's performance standards, they shall be adjusted, repaired, replaced, and/or recalibrated as near as practicable to a condition of zero error by the Party owning such defective or inaccurate device and at that Party's expense.

(D) Seller shall be responsible for the design, installation, operation and maintenance of site data historian systems at the Facility, which are linked on a real-time basis and interoperable with the RDD subject to prior written approval of such systems by Tri-State.

5.4 Adjustment for Inaccurate Meters.

If an Electric Metering Device, or Back-Up Metering, fails to register, or if the measurement made by an Electric Metering Device, or Back-Up Metering, is found upon testing to be inaccurate by more than one percent (1.0%), an adjustment shall be made

correcting all measurements by the inaccurate or defective Electric Metering Device, or Back-Up Metering, for both the amount of the inaccuracy and the period of the inaccuracy, in the following manner:

(A) In the event that the Electric Metering Device is found to be defective or inaccurate, the Parties shall use Tri-State's Back-up Metering, if installed, to determine the amount of such inaccuracy; *provided,* however, that Tri-State's Back-Up Metering has been tested and maintained in accordance with the provisions of this Article 5. If Tri-State's Back-Up Metering is installed on the low side of Seller's step-up transformer, Tri-State's Back-Up Metering data shall be adjusted for losses. In the event that Tri-State did not install Back-Up Metering, or Tri-State's Back-Up Metering is also found to be inaccurate by more than one percent (1.0%), the Parties shall use Seller's Back-up Metering, if installed, to determine the amount of such inaccuracy; provided, however, that Seller's Back-Up Metering has been tested and maintained in accordance with the provisions of this Article 5. If Seller's Back-Up Metering is installed on the low side of Seller's step-up transformer, Seller's Back-Up Metering data shall be adjusted for losses. In the event that Seller did not install Back-Up Metering, or Seller's Back-Up Metering is also found to be inaccurate by more than one percent (1.0%), the Parties shall estimate the amount of the necessary adjustment on the basis of deliveries of Contract Capacity and Contract Energy during periods of similar operating conditions when the Electric Metering Device was registering accurately. The adjustment shall be made for the period during which inaccurate measurements were made.

(B) In the event that the Parties cannot agree on the actual period during which the inaccurate measurements were made, the period during which the measurements are to be adjusted shall be the shorter of (i) the last one-half of the period from the last previous test of the Electric Metering Device to the test that found the Electric Metering Device to be defective or inaccurate, or (ii) the one hundred eighty (180) Days immediately preceding the test that found the Electric Metering Device to be defective or inaccurate.

(C) To the extent that the adjustment period covers a period of deliveries for which payment has already been made by Tri-State, Tri-State shall use the corrected measurements as determined in accordance with this Article 5 to recompute the amount due for the period of the inaccuracy and shall subtract the previous payments by Tri-State for this period from such re-computed amount. If the difference is a positive number, the difference shall be paid by Tri-State to Seller; if the difference is a negative number, the difference shall be paid by Seller to Tri-State, or at the discretion of Tri-State, may take the form of an offset to payments due Seller by Tri-State. Payment of such difference by the owing Party shall be made not later than thirty (30) Days after the owing Party receives notice of the amount due, unless Tri-State elects payment via an offset.

5.5 Fuel Supply

(A) generation technology specific- Seller shall be solely responsible for all fuel interconnection, transportation, delivery and metering arrangements, and all associated costs, required to receive fuel to operate the Facility. Seller shall, at its sole expense, construct, operate and maintain the pipelines, compressors, meters, heaters, filter/separation equipment, electronics, and other necessary equipment, of sufficient capacity and industrial specifications to receive, regulate, meter and transport fuel to the Facility, to allow for full operation of the Facility over the Term.

(B) generation technology specific- Seller shall procure and pay for all fuel for the generation of Contract Capacity and Contract Energy. The cost of fuel is included in applicable price set forth in Article 7.

Article 6
Contract Capacity and Energy

6.1 Sale and Purchase.

Beginning on the Commercial Operation Date, Seller shall generate from the Facility, deliver to the Point of Delivery, and sell to Tri-State, and Tri-State shall purchase from Seller, at the applicable price set forth in Article 7, all Contract Capacity and Contract Energy and all other products and services required by this PPA; *provided* that, notwithstanding anything in this PPA to the contrary, Tri-State shall have no obligation (i) to pay for any capacity or Energy that has not actually been generated by the Facility, measured by the Electric Metering Device(s), and delivered to Tri-State at the Point of Delivery or (ii) to pay for any Energy generated by the Facility to the extent the instantaneous output exceeds **Insert the Expected Nameplate Capacity Rating** MW. Seller shall be responsible for, and shall reimburse Tri-State for, any charges, fees, fines or penalties assessed to Tri-State by the Transmission Provider, Balancing Authority, or an Organized Market as a result of the instantaneous output exceeding **Insert the Expected Nameplate Capacity Rating** MW. Seller shall not curtail or interrupt deliveries of Contract Capacity and/or Contract Energy to Tri-State for economic reasons of any type.

6.2 Title and Risk of Loss.

As between Seller and Tri-State, Seller shall be deemed to be in control of the Contract Capacity and Contract Energy up to and including delivery and receipt at the Point of Delivery and Tri-State shall be deemed to be in control of Contract Capacity and Contract Energy after delivery and receipt at the Point of Delivery. Title and risk of loss related to the Contract Capacity and Contract Energy shall transfer from Seller to Tri-State at the Point of Delivery.

6.3 Reactive Power

Tri-State shall have access to the full reactive output capability of the generating facility limited by the generator capability curves. Tri-State will notify Seller of required reactive power dispatch as a normal part of the generation dispatch process, or via a schedule of VAR output as a function of MW output.

6.4 Dispatch

Tri-State's RDD shall have dispatch control of the Facility, including the start-ups, shutdowns and generation (MW and MVar) loading levels associated with Contract Capacity and Contract Energy, subject to the Operating Requirements and Restrictions. Tri-State will not dispatch the Facility below Minimum Load. Subject to the Operating Requirements and Restrictions, at least thirty (30) Days prior to the Commercial Operation Date, Seller shall notify Tri-State of the Minimum Load. Thereafter, any changes to the Minimum Load shall be in accordance with the Operating Procedures. For any Facility trip, Seller shall restart the Facility in coordination with RDD and in accordance with Prudent Utility Practices. Tri-State shall make reasonable efforts to provide Seller at least day-ahead notice of the generation levels anticipated by Tri-State from the Facility, provided that such notice shall be subject to and may be pre-empted by real-time operating conditions on Tri-State's electric system, including, but not limited to, Emergency Condition, reliability, stability and economic conditions.

6.5 Operating Reserve.

All Operating Reserve, if any, associated with the Contract Capacity shall be deemed to have been purchased by Tri-State, and shall be made available to Tri-State, consistent with the terms of this PPA. Seller shall use reasonable commercial efforts to maximize the Operating Reserve available to Tri-State from the Contract Capacity, consistent with and subject to the Operating Requirements and Restrictions and Prudent Utility Practice.

6.6 Forced Outages and Emergency Conditions.

Seller shall notify the RDD by telephone call or other automated means acceptable to Tri-State as promptly as possible upon discovering that the Facility is unable to deliver all or part of any scheduled quantity of Contract Capacity and/or Contract Energy due to a Forced Outage or Emergency Condition resulting in a capacity reduction of more than ten (10) MW and, as soon as reasonably practicable, but within no more than ten (10) minutes, following such discovery, shall notify the RDD of its best estimate of the expected duration of such Forced Outage or Emergency Condition. Such estimate by Seller shall be based on the best information available to it. Should Seller expect any further changes in the duration of any such Forced Outage or Emergency Condition, it shall as soon as reasonably practicable, but within no more than ten (10) minutes, of such change notify the RDD of the same.

In addition to the foregoing notification, for any Forced Outage, shutdown or derating of the Facility of more than ten (10) MW, Seller shall conduct a root cause analysis, immediately provide the root cause analysis to Tri-State, and take corrective action to prevent reoccurrences as soon as practicable thereafter, at Seller's sole expense. Such corrective action includes weather protective modifications to the Facility, additional operating or maintenance procedures and other appropriate preventative measures in accordance with Prudent Utility Practices. Seller shall diligently complete such analysis and corrective actions as soon as possible and provide to Tri-State a written report containing such analysis and a summary of the corrective action taken or to be taken as soon as diligently possible.

6.7 Organized Market.

(A) If at any time during the Term, the Interconnection Provider changes or the facilities at the Point of Delivery cease to be subject to the Interconnection Provider's Tariff, Tri-State and Seller shall cooperate and take all necessary actions to facilitate the delivery of Contract Capacity and Contract Energy from the Point of Delivery to Tri-State's load, at the least possible cost to the Parties, consistent with this PPA.

(B) If at any time during the Term, (i) the Interconnection Provider, the Transmission Provider, the Balancing Authority, or Tri-State elects to join or participate in an Organized Market, or (ii) WECC, NERC, FERC or any other Governmental Authority institutes an Organized Market and such action requires changes to this PPA or changes the manner in which the Facility is scheduled and dispatched, the Parties shall cooperate in good faith to change their protocols for operation and scheduling of the Facility and to amend this PPA to comply with such changes accordingly, at the least possible cost to the Parties, consistent with this PPA. The Parties shall negotiate and allocate the costs associated with these changes between the Parties in a fair and reasonable manner.

6.8 Permit Limitations.

[if any – generation technology, project specific-

(A) Neither Party shall take any action that would create a restriction under any Seller required Governmental Approvals that would preclude or limit the generation or delivery of Contract Capacity or Contract Energy to Tri-State.

(B) Seller covenants that Seller has, or will receive prior to, the generation of Contract Capacity or Contract Energy authority under Applicable Law, and obtain the applicable Governmental Approvals, to generate and deliver Contract Capacity and Contract Energy to Tri-State. Seller accepts the risk that its Governmental Approvals or other Applicable Law will preclude or limit its legal authority to generate and deliver all of the Planned Permitted Energy.

(C) Upon request by Tri-State from time to time, Seller shall provide to Tri-State such detailed data regarding emissions from the Facility, as Tri-State may reasonably request.]

Article 7
Payment Calculations

7.1 Contract Capacity Payment

Except as otherwise provided in this PPA, commencing on the Commercial Operation Date, Tri-State shall pay Seller a monthly payment for Contract Capacity ("Capacity Payment") based on the following formula set forth in Exhibit C.

7.2 Contract Energy Payment.

(A) Contract Energy Payment. Except as otherwise provided in this PPA, commencing on the Commercial Operation Date, Tri-State shall pay Seller an energy payment for Contract Energy delivered each Month (the "Contract Energy Payment") determined by the formula set forth in Exhibit C.

7.3 Adjustments to Payments.

[if any – generation technology, project and payment formula specific]

7.4 Testing of Facility.

[if any – generation technology, project and payment formula specific]

7.5 Payment for Facility Starts

[if any – generation technology, project specific- Except as otherwise provided in this PPA, commencing on the Commercial Operation Date, Tri-State shall pay Seller for the number of successful start of the Facility requested by Tri-State in the monthly billing period. The monthly " Start Payment" shall be determined by the formula set forth in Exhibit C.]

7.6 Test Energy Payment.

During Testing, Tri-State shall pay Seller an energy payment for Test Energy delivered each Month (the "Test Energy Payment") determined by the formula set forth in Exhibit C.

Article 8
Billing and Payment Procedures

8.1 Billing Invoices.

No later than ten (10) Business Days after the end of each Month, Seller shall provide to Tri-State an invoice for the amount due to Seller by Tri-State for the services provided by Seller and purchased by Tri-State under this PPA during the previous calendar month billing period. Seller's invoice shall show metered Energy from the Facility, all billing parameters, rates and factors, and any other data reasonably pertinent to the calculation of monthly payments due to Seller. If Tri-State disputes any portion of the invoice, Tri-State shall provide to Seller an explanation of the items in dispute. Billing disputes shall be resolved in accordance with Section 8.4.

8.2 Metered Billing Data.

All billing data based on metered deliveries to Tri-State shall be collected by the Electric Metering Device(s) in accordance with Article 5.

8.3 Payments and Late Payments.

(A) Payment Due to Tri-State. Unless otherwise specified herein, payments due to Tri-State under or in connection with this PPA shall be due and payable by electronic funds transfer, as designated by Tri-State, on or before the fifth (5th) Business Day following receipt of the billing invoice. Any failure to make full payment within such time period shall constitute an Event of Default of Seller upon its occurrence but shall be subject to cure within three (3) Business Days after the date of written notice from Tri-State to Seller. This Section shall not limit Tri-State's right to draw any such amounts due from the Security in accordance with Section 11.1(E).

(B) Payments due to Seller. Unless otherwise specified herein, payments due to Seller under or in connection with this PPA shall be due and payable by electronic funds transfer, as designated by Seller, on or before the twentieth (20th) Business Day following receipt of the billing invoice. Any failure to make full payment within such time period shall constitute an Event of Default of Tri-State upon its occurrence but shall be subject to cure within ten (10) Business Days after the date of written notice from Seller to Tri-State.

(C) Late Payment Charges. If the undisputed amount due is not paid on or before the due date, a late payment charge shall be applied to the unpaid balance and shall be added to the next billing statement. Such late payment charge shall be calculated based on the lower of (i) an annual interest rate equal to two percent (2%) plus the prime interest rate, as published on the date of the invoice in *The Wall Street Journal* (or, if *The Wall Street Journal* is not published on that Day, the next succeeding date of publication) and (ii) the maximum interest rate allowed by Applicable Law

("Default Rate"). If the due date occurs on Day that is not a Business Day, the late payment charge shall begin to accrue on the next succeeding Business Day.

(D) Offset. Tri-State at any time may offset against amounts owed to Seller, any liquidated amounts, accrued damages and other payments, and undisputed billing errors and adjustments, which are owed by Seller to Tri-State.

8.4 Billing Disputes.

Either Party may dispute invoiced amounts, but shall pay to the other Party at least the undisputed portion of invoiced amounts on or before the invoice due date. To resolve billing disputes, the Parties shall use the procedures set forth in Section 13.9(A). When the billing dispute is resolved, the Party owing shall pay the amount owed within five (5) Business Days of the date of such resolution, with late payment interest charges calculated on the amount owed in accordance with the provisions of Section 8.3 if payment is not received within the five (5) Business Days. Undisputed amounts invoiced under this PPA shall be paid on or before the due date or shall be subject to the late payment interest charges set forth in Section 8.3(C).

8.5 Statement Errors.

In the event that either Party becomes aware of any error in any statement, such Party shall, promptly upon discovery of the error, notify in writing the other Party of such error and shall rectify such error (whether in the form of an underpayment or overpayment) within thirty (30) Days of such notification. If a Party does not notify the other Party of any error (regardless of actual knowledge of such error) within three hundred sixty five (365) Days of such error, any payment associated with such error older than three hundred sixty five (365) Days shall be waived. Except for adjustments in the billing and payment for defective or inaccurate Electric Metering Devices as provided in Section 5.4, if Seller fails to invoice for Contract Capacity or Contract Energy within one hundred eighty (180) Days of delivery of such Contract Capacity or Contract Energy, payment for such shall be waived.

8.6 Taxes.

(A) Tax Responsibility. Seller shall be responsible for, and shall pay when due, all income, gross receipts, sales, *ad valorem*, personal property or real property or other similar taxes and any and all franchise fees or similar fees assessed against Seller or the Facility due to generation of Energy and providing capacity from the Facility, the construction, ownership, leasing, operation or maintenance of the Facility, or any components or appurtenances thereof, including all taxes, fees, allowances, trading credits and other offsets and impositions for wastes and emissions (including carbon-based compounds, oxides of nitrogen and sulfur, mercury and other Regulated Materials) produced by the Facility. Seller's prices under Article 7 are inclusive of such Taxes, allowances and credits during the Term. If Tri-State is

assessed any Taxes or associated fees as a result of the improvement of the Site due to the existence of the Facility on the Site, Tri-State shall promptly notify Seller. Tri-State and Seller shall cooperate in contesting such assessment; *provided, however,* that Tri-State may pay such Taxes to avoid any penalties on such assessments subject to reimbursement by Seller. If, after resolution of the matter, Taxes are imposed on Tri-State as a result of the improvement of the Site due to the existence of the Facility on the Site, Seller shall reimburse Tri-State for such Taxes. Seller shall not be obligated to pay or reimburse Tri-State for Taxes imposed on or measured by the Tri-State's overall revenues or income.

(B) Reimbursement. If a Party is required to remit or pay Taxes that are the other Party's responsibility hereunder, such Party shall promptly reimburse the other Party for such Taxes.

(C) Information. The Parties shall provide each other, upon written request, with copies of any documentation that may be reasonably necessary in the ordinary course of any inter-governmental, state, local, municipal or other political subdivision tax audit inquiry or investigation.

(D) Cooperation. Consistent with Applicable Law, the Parties shall cooperate to minimize Taxes; *provided, however,* that no Party shall be obligated to incur any extraordinary financial burden to reduce Taxes for which the other Party is responsible hereunder.

(E) Failure to Qualify for Tax Credits. Seller's failure to qualify for the Tax Credits for any reason including Delivery Excuse, Force Majeure Event, the acts or inaction of the Interconnection Provider or of any third party, or any Event of Default, shall not release Seller of its obligations to comply with this PPA, give rise to any damages payable by Tri-State or an increase in the price set forth in this PPA.

Article 9
Testing, Operations and Maintenance

9.1 Modification of the Facility.

Seller shall not modify the Facility in any way that would increase or decrease the electric energy generating capacity of the Facility or the output of Contract Capacity and/or Contract Energy to be delivered to Tri-State under this PPA without Tri-State's prior written consent, which may be withheld in its sole discretion.

9.2 Facility Tests Prior to Commercial Operation.

Seller shall give Tri-State at least three (3) Months prior notice of (i) the approximate Test Date, (ii) the proposed Tests scheduled relating to the commissioning of the Facility, and (iii) a draft of the Testing procedures and requirements. Tri-State

shall review and provide any comments on the Testing procedures and requirements within thirty (30) Days of receipt. Representatives of Tri-State shall have the right to be present at all such Testing. Seller shall promptly notify Tri-State of any changes to the Test Date or the date of any Tests relating to the Facility in order that Tri-State may arrange for its respective representatives to attend.

9.3 Operation and Maintenance of the Facility.

Seller shall staff, control, operate, maintain, and repair the Facility or cause the same to be staffed, controlled, operated, maintained, and repaired at all times in accordance with manufacturers' recommendations, Prudent Utility Practices, and Exhibit G and otherwise in accordance with this PPA. Seller shall procure and maintain a Qualified Operator to operate and maintain the Facility. generation technology specific- Personnel of Seller capable of starting, operating, and stopping the Facility shall be physically present at the Facility 24x7 during Commercial Operation.

9.4 Replacement of Facility Equipment.

Seller shall, consistent with Prudent Utility Practices, repair and replace all necessary equipment at the Facility required to deliver Contract Capacity and Contract Energy for the Term.

9.5 Disposal of Facility Equipment.

Upon the cessation of operations or the replacement of equipment, Seller shall, at its sole expense and cost, dispose of all Facility equipment no longer in use in accordance with Applicable Law and Prudent Utility Practices, and all requirements under the Facility Site Documents.

9.6 Scheduled Maintenance.

(A) Three (3) Months prior to the Commercial Operation Date and, thereafter, by August 1 of each Year, Seller shall deliver to Tri-State (i) the Scheduled Maintenance Outages (including the date, start time and expected duration of the outage), for the subsequent Year and (ii) the projected long-term Scheduled Maintenance Outages encompassing the following four Years or the remainder of the Term, whichever period of time is shorter. Within thirty (30) days of receipt of the maintenance schedule, Tri-State may reasonably change the annual maintenance schedule proposed by Seller by written notification to Seller. Seller shall notify Tri-State of any changes to the Scheduled Maintenance Outage, including start date, as follows:

Scheduled Outage Expected Duration	Advance Notice to Tri-State
(1) Less than 2 Days	at least 24 hours

(2) 2 to 5 Days — at least 7 days

(3) Major overhauls (over 5 Days) — at least 90 days

(B) In the event a Scheduled Maintenance Outage is extended, Seller shall notify Tri-State as soon as practicable of such extension and the expected end date of such Scheduled Maintenance Outage. Scheduled Maintenance Outages may not be scheduled during the Months of January, June, July, August, September, or December unless agreed to in writing by Tri-State at its sole discretion.

9.7 Access to and Inspection of Facility.

(A) Seller shall provide Tri-State and its authorized employees, agents and inspectors with reasonable access to the Facility (including Tri-State's equipment, if any) for the purposes set forth herein. Tri-State acknowledges that such access does not provide Tri-State with the right to direct or modify the operation of the Facility in any way and further acknowledges that any exercise by Tri-State of its rights under this Section 9.7 shall be at its own risk and expense.

(B) No inspections of the Facility, whether by Tri-State or otherwise, shall relieve Seller of its obligation to maintain the Facility and operate the same in accordance with Prudent Utility Practices. In no event shall any statement, representation, or lack thereof by Tri-State, either express or implied, relieve Seller of its exclusive responsibility for the Facility.

9.8 Operating Parameters.

(A) Seller shall operate, maintain or procure the operation and maintenance of the Facility in accordance with Prudent Utility Practices and Applicable Law. Subject to compliance with Prudent Utility Practices and Applicable Law, Seller shall operate the Facility in such a manner that Contract Capacity and Contract Energy shall meet all requirements required by the Interconnection Provider and the Transmission Provider.

(B) Seller shall operate the Facility such that all system protective equipment is in service whenever the Facility is connected to, or is operated in parallel with, the Transmission System, except for normal testing and repair. Seller shall provide adequate system protection and control devices to ensure safe and protected operation of all energized equipment during normal testing and repair. The Facility's protective equipment shall meet Institute of Electrical and Electronic Engineers and all other applicable industry standards. Seller shall have qualified personnel test, calibrate and certify in writing the proper functioning of all protective equipment in accordance with the intervals and maintenance activities for each component as established by the appropriate reliability standards. All of the foregoing shall be conducted in accordance with Prudent Utility Practices.

9.9 Operating Committee and Operating Procedures.

(A) Representative. Tri-State and Seller shall each appoint one (1) representative and one (1) alternate representative to act in matters relating to the Parties' performance obligations under this PPA and to develop operating arrangements for the generation, delivery and receipt of Contract Capacity and Contract Energy hereunder. Such representatives shall constitute the Operating Committee, and shall be specified in Exhibit H. Each Party shall notify the other Party in writing of any changes to their representative and provide the other Party an updated Exhibit H. The Operating Committee shall have no authority to amend or waive any terms or conditions of this PPA.

(B) Operating Procedures. Prior to the Commercial Operation Date, the Operating Committee shall develop mutually agreeable written Operating Procedures which shall include methods of day-to-day communications; metering, telemetering, telecommunications, and data acquisition procedures; key personnel list for applicable Tri-State and Seller operating centers; operations and maintenance scheduling and reporting; changes in the Minimum Load, Contract Capacity deration reports; Contract Energy reports; unit operations log; and such other matters as may be mutually agreed upon by the Parties.

Article 10
Environmental Attributes

10.1 Ownership of Environmental Attributes.

(A) Ownership of Environmental Attributes. The prices set forth in Article 7 include the consideration for the assignment, purchase and ownership of, and the right to market and sell, all Environmental Attributes associated with the services provided by Seller and purchased by Tri-State under this PPA, including Contract Energy and Contract Capacity. Title to the Environmental Attributes shall irrevocably pass from Seller to Tri-State immediately upon the generation of Contract Energy and/or Contract Capacity at the Facility that gives rise to such Environmental Attributes or the creation of the Environmental Attributes, as applicable. Environmental Attributes shall be transferred to Tri-State free of all liens and encumbrances.

(B) Duration. Environmental Attributes associated with the Facility, Contract Energy and Contract Capacity are owned by Tri-State and Tri-State shall have the right to own and to use such Environmental Attributes for any purpose, including any Environmental Attributes that are reserved or "banked" during the Term of this PPA but not used, sold, assigned or otherwise transferred during the Term of this PPA. Tri-State may assign its rights, title and interest in and to any Environmental Attributes associated with Contract Energy to one or more third parties under any transaction.

10.2 Registration of Environmental Attributes.

(A) Seller Registration. Upon request from Tri-State, Seller shall, at its expense, register and/or certify the Facility with Governmental Authorities or such other Persons requested by Tri-State in order to qualify the Facility or qualify the Contract Energy, Contract Capacity and/or Environmental Attributes with such Governmental Authority or such other Persons and maintain such registration/certification for the Term for Tri-State to obtain the full benefit of the Environmental Attributes.

(B) Tri-State Registration. Upon request from Tri-State in lieu of Seller registering as provided above, Seller hereby irrevocably assigns to Tri-State all rights, title and authority for Tri-State to register the Facility and own, hold and manage the Environmental Attributes associated with the Facility in Tri-State's own name and to Tri-State's account, including any rights associated with any reporting or tracking system that exists or may be established with regard to monitoring, registering, tracking, certifying, and/or trading such Environmental Attributes. Seller hereby authorizes Tri-State to act as its agent for the purposes of registering the Facility and tracking, certifying, registering and reporting such Environmental Attributes. Seller grants to Tri-State full authority to hold, use, sell and/or trade such Environmental Attributes for its own account in all applicable reporting or tracking systems.

(C) Attestations. Upon request from Tri-State, Seller shall, at its expense, (i) deliver or cause to be delivered to Tri-State appropriate attestations/certifications of Environmental Attributes, and (ii) cooperate with tracking, registration, reporting and certification of Environmental Attributes.

Article 11
Security

11.1 Seller Security Form and Amount.

(A) Form. As security for its obligations hereunder, Seller shall, within ten (10) Days after the Effective Date, post and maintain in favor of Tri-State (i) one or more unconditional, irrevocable, standby Letter(s) of Credit from an Issuer, (ii) a cash escrow account established with an Issuer in favor of Tri-State pursuant to an escrow agreement acceptable to Tri-State, or (iii) any combination of the foregoing (i) and (ii) (the "Security"); *provided* that a Guaranty may be posted to satisfy part of or all of the Security amount set forth in Section 11.1(B) in lieu of Letter(s) of Credit or a cash escrow account, subject to the following conditions: (x) any Guaranty provided by a Superior Guarantor shall not exceed Ten Million Dollars ($10,000,000), (y) any Guaranty provided by a Qualified Guarantor shall not exceed Five Million Dollars ($5,000,000), and (z) the total aggregate amount of guaranteed obligations of any such Guaranty and any other guaranties of payment or performance related to or provided by Seller, the Qualified Guarantor, the Superior Guarantor or any of their Affiliates to Tri-State shall not exceed an aggregate of Five Million Dollars

($5,000,000) if provided by a Qualified Guarantor or Ten Million Dollars ($10,000,000) if provided by a Superior Guarantor, unless agreed to in writing by Tri-State at its sole discretion.

(B) Amount. The Security shall be in the amount of: (i) **Insert $100*Expected Nameplate Capacity Rating in kw** Dollars ($_____,000) for the period beginning with the Effective Date until the Commercial Operation Date; and (ii) **Insert $125*Expected Nameplate Capacity Rating in kw** Dollars ($_____,000) thereafter.

(C) Duration. The Security shall remain in place for the entire Term (except to the extent drawn upon as provided herein). To the extent the Security consists of Letter(s) of Credit expiring before the end of the Term, Seller shall cause their renewal or extension for additional consecutive terms of three hundred sixty (360) Days or more (or, if shorter, the remainder of the Term) no later than thirty (30) Days prior to each expiration date of such Letter(s) of Credit and written proof of such renewal shall be provided to Tri-State as soon as practicable thereafter, but in no event later than fifteen (15) Days prior to the expiration of the same. If the Letter of Credit(s) is not renewed or extended as required herein, Tri-State shall have the right to demand payment under the Guaranty or draw immediately upon the entire amount of the Letter of Credit and to place the amounts so drawn, at Seller's cost and with Seller's funds, in an account controlled by Tri-State until and unless Seller provides a substitute Letter of Credit(s) meeting the requirements of this Article 11.

(D) Downgrades. Upon the occurrence of a downgrade event, such that the Person providing the Security in the form of a Letter of Credit or Guaranty no longer meets the requirements of an Issuer, Qualified Guarantor, or Superior Guarantor, as applicable, Seller shall within three (3) Business Days of such downgrade event, provide replacement security satisfying the requirements of this Article 11. If such replacement security is not provided within three (3) Business Days, Tri-State shall have the right to draw immediately upon the entire amount of the Letter of Credit or demand payment under the Guaranty, as applicable, and to place the amounts so drawn, at Seller's cost and with Seller's funds, in an account controlled by Tri-State until and unless Seller provides a substitute security meeting the requirements of this Article 11. Except as provided in this Section 11.1(D), Seller may change the form of Security at any time and from time-to-time upon thirty (30) Days' prior written notice to Tri-State; *provided* that the Security shall satisfy the requirements of this Article 11 at all times.

(E) Draw on Security. Without notice to Seller, Tri-State may demand payment under or draw on the Security during the Term for Seller's failure to meet any of its obligations under this PPA, including Delay Damages, the damages provided in Section 12.3 and Replacement Costs. Tri-State may draw or demand payment of all or any part of the appropriate amounts due to it from any form of Security to the extent available pursuant to this Article 11, and from all such forms, and in any sequence Tri-

State may select; *provided* that any failure to draw upon the Security for any damages or other amounts due to Tri-State shall not prejudice Tri-State's rights to recover such damages or amounts in any other manner to the extent provided in this PPA. Tri-State shall notify Seller within five (5) Business Days following any draw on the Security by Tri-State, including the amount thereof and the basis therefor.

(F) Release of Security. Within thirty (30) Days following the expiration or termination of this PPA and the satisfaction of all of Seller's obligations hereunder, Tri-State shall release any remaining balance of the Security to Seller without interest.

(G) Replenishment. In the event Tri-State draws upon the Security pursuant to this Article 11, Seller shall replenish the Security to the amount required by Section 11.1 within ten (10) Days of such draw.

(H) Expenses. Seller shall reimburse Tri-State for its expenses, including internal costs and expenses and reasonable attorneys' fees, incurred by Tri-State in connection with the preparation, negotiation, execution and/or release (including making a draw of funds) of the Security under this Article 11.

Article 12
Default and Remedies

12.1 Events of Default of Seller.

(A) Seller Defaults (No Cure). Any of the following shall constitute an Event of Default of Seller upon its occurrence and no cure period shall be applicable unless otherwise stated:

(1) Seller's dissolution or liquidation;

(2) Seller makes a general assignment for the benefit of its creditors;

(3) Seller's authorization or filing of a petition in voluntary bankruptcy or insolvency or for reorganization or arrangement under the bankruptcy laws of the United States or under any insolvency law of any state, or Seller voluntarily taking advantage of any such law by answer or otherwise;

(4) The sale by Seller to a third party, or diversion by Seller for any use, of Contract Capacity and/or Contract Energy committed to Tri-State by Seller other than in mitigation of damages for any breach by Tri-State of this PPA;

(5) Seller's failure to establish, and maintain, the Security in accordance with Article 11;

(6) Seller's failure to achieve Commercial Operation by the date that is ninety (90) Days following the Commercial Operation Milestone;

(7) A persistent pattern of willful misconduct by Seller resulting in a failure by Seller to provide Contract Capacity and Contract Energy to Tri-State in accordance with this PPA;

(8) Seller's actual fraud or tampering with Tri-State owned facilities or other material misrepresentation or intentional misconduct in connection with this PPA or the operation of the Facility; and/or

(9) Seller's failure to make any payment due to Tri-State under this PPA in accordance with Article 8 (subject to cure by Seller as provided therein).

(B) Seller Defaults (30 Day Cure). Any of the following shall constitute an Event of Default of Seller upon its occurrence but shall be subject to cure within thirty (30) Days after the date of written notice from Tri-State to Seller:

(1) Seller's Abandonment;

(2) Seller's failure to maintain in effect any agreements required to deliver Contract Capacity and/or Contract Energy to the Point of Delivery pursuant to Section 5.1, including the Interconnection Agreement;

(3) Seller's failure to comply with the requirements of Section 10.2;

(4) Seller's breach of or failure to perform or comply with any material term of this PPA not otherwise specified in this Section 12.1; and/or

(5) Seller's failure to achieve any Construction Milestone, excluding the Commercial Operation Milestone, by the date that is ninety (90) Days following the date specified for such milestone.

(C) Seller Defaults (60 Day Cure). Any of the following shall constitute an Event of Default of Seller upon its occurrence but shall be subject to cure within sixty (60) Days after the date of written notice from Tri-State to Seller:

(1) Seller's assignment of this PPA, or any Change of Control of Seller, or Seller's sale or transfer of its interest, or any part thereof, in the Facility, except as permitted in accordance with Article 19;

(2) Any representation or warranty made by Seller in this PPA shall prove to have been false or misleading in any material respect when made; and/or

(3) The filing of an involuntary case in bankruptcy or any proceeding under any other insolvency law against Seller.

(D) Seller Default (Delivery Shortfall). Beginning on the Second Commercial Operation Year, Seller's failure to maintain a CAF of at least eighty-five percent (85%) on a twelve (12) month rolling average basis shall constitute an Event of Default of Seller upon its occurrence; *provided* that to the extent such failure of performance is attributable to Force Majeure Event, the contribution of such Force Majeure Event shall be eliminated from the CAF calculation for the purposes of, and only for the purposes of, establishing an Event of Default of Seller pursuant to this this Section 12.1(D); *provided further* that this Event of Default shall be curable and deemed cured if (i) within thirty (30) Days following the Event of Default, Seller cures the reason(s) for such default (or, if such cure cannot reasonably be effected within thirty (30) Days, Seller commences to cure such default within thirty (30) Days and then diligently pursues such cure to completion as soon as practicable thereafter), and (ii) as a result of such efforts, during the next Commercial Operation Year subsequent to such Default, the CAF (again with periods of Force Majeure Event excluded from the calculation) equals or exceeds ninety percent (90%).

Seller shall keep Tri-State apprised at least monthly of Seller's cure efforts under this Section 12.1(D). If the CAF fails to equal or exceed ninety percent (90%) for the Commercial Operation Year following the Event of Default as described in this Section 12.1(D), Tri-State shall have the right to terminate this PPA for default upon delivery of written notice.

12.2 Events of Default of Tri-State.

(A) Tri-State Defaults (No Cure). Any of the following shall constitute an Event of Default of Tri-State upon its occurrence and no cure period shall be applicable, unless otherwise stated:

(1) Tri-State's dissolution or liquidation, *provided, however,* that division of Tri-State into multiple entities shall not constitute dissolution or liquidation;

(2) Tri-State makes a general assignment for the benefit of creditors;

(3) Tri-State's authorization or filing of a voluntary petition in bankruptcy or insolvency or for reorganization or arrangement under the bankruptcy laws of the United States or under any insolvency law of any State, or Tri-State voluntarily taking advantage of any such law by answer or otherwise; and/or

(4) Tri-State's failure to make any payment due to Seller under this PPA in accordance with Article 8 (subject to cure by Tri-State as provided therein).

(B) Tri-State Defaults (30 Day Cure). Tri-State's failure to comply with any material obligation under this PPA not otherwise specified in this Section 12.2 shall constitute an Event of Default of Tri-State if not cured within thirty (30) Days after the date of written notice from Seller to Tri-State.

(C) Tri-State Defaults (60 Day Cure). Any of the following shall constitute an Event of Default of Tri-State upon its occurrence but subject to cure sixty (60) Days after the date of written notice from Seller to Tri-State:

(1) The filing of an involuntary case in bankruptcy or any proceeding under any other insolvency law against Tri-State;

(2) Tri-State's assignment of this PPA, except as permitted in accordance with Article 19; and/or

(3) Any representation or warranty made by Tri-State in this PPA shall prove to have been false or misleading in any material respect when made.

12.3 Damages Prior to Termination.

Upon the occurrence of an Event of Default, the non-defaulting Party shall have the right to collect damages accruing prior to the termination of this PPA from the defaulting Party as set forth below, and the payment of any such damages accruing prior to the cure of an Event of Default shall constitute an element of any respective cure. For all Events of Default (including failure to achieve the Commercial Operation Milestone) the non-defaulting Party shall be entitled to receive from the defaulting Party all of the direct damages incurred by the non-defaulting Party in connection with such Event of Default. The Parties agree that the damages recoverable by Tri-State hereunder on account of an Event of Default of Seller prior to termination of this PPA shall include any Replacement Costs incurred and Tri-State may draw the appropriate amounts from the Security. Each Party agrees and acknowledges that (i) the damages that Tri-State would incur at such time prior to termination of this PPA due to Seller's failure to perform would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the liquidated damages as agreed to by the Parties set forth in this Section 12.3 are a fair and reasonable calculation of such damages.

12.4 Termination.

Upon the occurrence of an Event of Default that has not been cured within the applicable time period, if any, the non-defaulting Party shall have the right to declare a date, which shall be between fifteen (15) and thirty (30) Days after the notice thereof, upon which this PPA shall terminate. Neither Party shall have the right to terminate this PPA except as provided for upon the occurrence of an Event of Default as described above or as otherwise may be explicitly provided for in this PPA. Upon the termination

of this PPA under this Section 12.4, the non-defaulting Party shall be entitled to receive from the defaulting Party, all of the direct damages incurred by the non-defaulting Party related to such Event of Default, including, if Seller is the defaulting Party, the value of future Replacement Costs, however, that, if the Replacement Costs amount is negative, the Replacement Costs shall be deemed to be zero.

12.5 Operation by Tri-State Following Event of Default of Seller.

(A) Subject to the rights of the Financing Parties, on occasion of an Event of Default and after the expiration of the cure period provided in respect thereof, if any, and prior to any termination of this PPA as a result thereof, Tri-State shall have the right, but not the obligation, to possess, assume control of, and operate the Facility as agent for Seller (in accordance with Seller's rights, obligations, and interest under this PPA) during the period provided for herein. Seller shall not grant any Person, other than the Financing Parties, a right to possess, assume control of, and operate the Facility that is equal to or superior to Tri-State's right under this Section 12.5.

(B) Tri-State shall give Seller and the Financing Parties ten (10) Days' prior notice of the contemplated exercise of Tri-State's rights under this Section 12.5. Upon such notice, Seller shall collect and have available at a convenient, central location at the Facility all documents, contracts, books, manuals, reports, and records required to construct, operate, and maintain the Facility in accordance with Prudent Utility Practice, including all Operating Records. Upon such notice, Tri-State, its employees, contractors, or designated third parties shall have the unrestricted right to enter the Site and Facility for the purpose of constructing and/or operating the Facility.

(C) Tri-State shall be entitled to immediately draw upon the Security to cover any expenses incurred by Tri-State in exercising its rights under this Section 12.5.

(D) During any period that Tri-State is in possession of and constructing and/or operating the Facility pursuant to this Section 12.5, Tri-State shall perform and comply with all of the obligations of Seller under this PPA and shall use the proceeds from the sale of electricity generated by the Facility to first, reimburse Tri-State for any and all expenses reasonably incurred by Tri-State in taking possession of and operating the Facility, and to second, remit any remaining proceeds to Seller.

(E) During any period that Tri-State is in possession of and operating the Facility, Seller shall retain legal title to and ownership of the Facility and Tri-State shall assume possession, operation, and control solely as agent for Seller.

(1) In the event that Tri-State is in possession and control of the Facility for an interim period, Seller may resume operation and Tri-State shall relinquish its right to operate when Seller demonstrates to Tri-State's satisfaction that it will

remove those grounds that originally gave rise to Tri-State's right to operate the Facility, as provided above, in that Seller (i) will resume operation of the Facility in accordance with the provisions of this PPA, and (ii) has cured any Events of Default of Seller that allowed Tri-State to exercise its rights under this Section 12.5 (or, if the Event of Default is of such a nature that it cannot be cured by Seller without possession of the Facility, reasonable assurance that Seller will cure such Event of Default promptly following resumption of possession).

(2) In the event that Tri-State is in possession and control of the Facility for an interim period, the Financing Parties, or any nominee or transferee thereof, may foreclose and take possession of and operate the Facility and Tri-State shall relinquish its right to operate when the Financing Parties or any nominee or transferee thereof, requests such relinquishment.

(F) Tri-State's exercise of its rights hereunder to possess and operate the Facility shall not be deemed an assumption by Tri-State of any liability attributable to Seller. If at any time after exercising its rights to take possession of and operate the Facility Tri-State elects to return such possession and operation to Seller, Tri-State shall provide Seller with at least fifteen (15) Days' prior notice of the date Tri-State intends to return such possession and operation, and upon receipt of such notice Seller shall take all measures necessary to resume possession and operation of the Facility on such date.

(G) In the event Tri-State assumes operation of the Facility under this Section 12.5, Tri-State shall operate the Facility in accordance with Prudent Utility Practice.

12.6 Replacement Costs.

Upon termination for an Event of Default, subject to Section 12.11, Tri-State shall be entitled to Replacement Costs for the balance of the Term had this PPA not been terminated, and Tri-State may draw the appropriate amounts from the Security.

12.7 Specific Performance.

In addition to the other remedies specified in this Article 12, in the event that any Event of Default of Seller is not cured within the applicable cure period set forth herein, Tri-State shall have the right to specific performance. The Parties agree that in the event Tri-State seeks injunctive relief in connection with the foregoing, that such action may be taken without the necessity of posting of a bond or other security as would otherwise be required under Applicable Law.

12.8 Remedies Cumulative.

Each right or remedy of the Parties provided for in this PPA shall be cumulative of and shall be in addition to every other right or remedy provided for in this PPA, and

the exercise, or the beginning of the exercise, by a Party of any one or more or the rights or remedies provided for herein shall not preclude the simultaneous or later exercise by such Party of any or all other rights or remedies provided for herein.

12.9 Forward Contracts.

The Parties agree that this PPA is a "forward contract" for purposes of the U. S. Bankruptcy Code; all payments made or to be made by one Party to the other Party pursuant to this PPA are "settlement payments" within the meaning of the U.S. Bankruptcy Code; and all transfers of Security by Seller to Tri-State under this PPA are "margin payments" within the meaning of the U.S. Bankruptcy Code.

12.10 Waiver and Exclusion of Other Damages.

NEITHER PARTY SHALL BE LIABLE TO THE OTHER PARTY FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES BY STATUTE, IN TORT OR CONTRACT (EXCEPT TO THE EXTENT EXPRESSLY PROVIDED HEREIN); *PROVIDED* THAT IF EITHER PARTY IS HELD LIABLE TO A THIRD PARTY FOR SUCH DAMAGES AND THE PARTY HELD LIABLE FOR SUCH DAMAGES IS ENTITLED TO INDEMNIFICATION THEREFOR FROM THE OTHER PARTY, THE INDEMNIFYING PARTY SHALL BE LIABLE FOR, AND OBLIGATED TO REIMBURSE THE INDEMNIFIED PARTY FOR, SUCH DAMAGES, ALL IN ACCORDANCE WITH THE INDEMNIFICATION PROVISIONS OF ARTICLE 17.

12.11 Duty to Mitigate.

Each Party (i) has a general duty to mitigate all damages hereunder (other than Delay Damages) and (ii) shall use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance of this PPA.

12.12 Limitation of Liability.

Except as otherwise provided in this Section 12.12, Seller's aggregate financial liability to Tri-State for Delay Damages pursuant to Section 4.3, shall not exceed an amount equal to **Insert $100*Expected Nameplate Capacity Rating in kw** Dollars ($_____,000) and Seller's aggregate financial liability to Tri-State for Replacement Costs and other damages, excluding Delay Damages, shall not exceed **Insert $250*Expected Nameplate Capacity Rating in kw** Dollars ($_____,000). If at any time during the Term, Tri-State incurs damages in excess of the limitations set forth above which Seller does not agree to pay when billed by Tri-State, Tri-State shall have the right to declare a termination of this PPA under Section 12.1, unless such damages are disputed in good faith. The limitations on damages set forth in this Section 12.12 shall not apply to damages arising out of any of the following events:

(A) damage or tampering with Tri-State owned facilities caused by negligence, breach of this PPA or other misconduct by Seller, its directors, officers, employees and agents;

(B) the sale by Seller to a third party, or diversion by Seller for any use, of Contract Capacity and Contract Energy committed to Tri-State under this PPA other than in mitigation of damages for any breach by Tri-State of this PPA;

(C) Seller's intentional misrepresentation or intentional misconduct in connection with this PPA or the operation of the Facility;

(D) Seller's failure (i) to maintain insurance coverages in the types and amounts required by this PPA or (ii) to apply any insurance proceeds to reconstruct the Facility following a casualty;

(E) any claim for indemnification herein;

(F) any Environmental Contamination; or

(G) damages incurred by Tri-State in connection with any bankruptcy or insolvency proceeding involving Seller, including Tri-State's loss of the benefit of its bargain due to rejection or other termination of this PPA in such proceeding.

Article 13
Contract Administration and Notices

13.1 Notices in Writing.

Notices required by this PPA shall be addressed to the other Party, including the other Party's representative on the Operating Committee, at the addresses specified in Exhibit I, as either Party updates them from time to time by written notice to the other Party. Any notice, request, consent, or other communication required or authorized under this PPA to be given by one Party to the other Party shall be in writing. It shall either be hand delivered or delivered by electronic mail with a copy mailed via overnight service with signature required upon receipt, to the representative of said other Party. Any such notice, request, consent, or other communication shall be deemed to have been received by the close of the Business Day on which it was hand delivered or transmitted electronically (unless hand delivered or transmitted after such close in which case it shall be deemed received at the close of the next Business Day). Real-time or routine communications concerning Facility operations shall be exempt from this Section 13.1.

13.2 Representative for Notices.

Each Party shall maintain a designated representative to receive notices. Such representative may, at the option of each Party, be the same person as that Party's

representative or alternate representative on the Operating Committee, or a different person. Either Party may, by written notice to the other Party, change the representative or the address to which such notices and communications are to be sent and shall provide the other Party an updated Exhibit I.

13.3 Authority of Representatives.

The Parties' designated representatives shall have authority to act for its respective principals in all technical matters relating to performance of this PPA and to attempt to resolve disputes or potential disputes. However, in their capacity as representatives, they shall not have the authority to amend or waive any provision of this PPA.

13.4 Operating Records.

Originals or copies of all Operating Records shall be maintained at the Facility or such other location in the State in which the Facility is located as may be specified by Seller from time to time. Tri-State may examine and make copies of such Operating Records from time to time upon request, during normal business hours.

13.5 Books and Records.

Seller and Tri-State shall each keep complete and accurate records and all other data required by each of them for the purposes of proper administration of this PPA, including metering, billing and payment records, and such records as may be required by Governmental Authorities in the prescribed format.

13.6 Audit Rights.

During the Term and for a period of three (3) years after the Term, Tri-State shall have the right, at its sole expense, with reasonable advance written notice and during normal working hours, to examine the records of Seller to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this PPA.

13.7 Operating Log.

Seller shall maintain an accurate and up-to-date hourly operating log, in electronic format, at the Facility, that identifies real-time operating information for the Facility, including levels of capacity availability; energy production; changes in operating status; Forced Outages; Scheduled Maintenance Outages; information required by Governmental Authorities in the prescribed format; and other information reasonably requested by Tri-State (the "O&M Records"). Within thirty (30) Days after the end of each quarter of the Year, Seller shall submit to Tri-State, in a mutually agreeable format, a copy of the O&M Records for the prior quarter.

Seller shall deliver to Tri-State information on Facility performance during each calendar month within five Business Days after the end of the month. Using definitions provided by (or consistent with) the NERC Generation Availability Data System ("GADS") Manual, or any successor document, the data reported shall include planned and unplanned derated hours, average derated kW from the Nameplate Capacity Rating during the derated hours, scheduled maintenance hours, average derated kW during scheduled maintenance hours, the number of successful and unsuccessful starts, hours on-control, hours on-line, and the monthly operating log of the Facility.

13.8 Availability Reporting.

(A) Seller shall provide accurate and timely updates to Tri-State on the current availability of the Contract Capacity ("Reported Availability"), adjusted for ambient conditions, via such electronic means as may be reasonably specified by Tri-State. The amount of Contract Capacity available for any individual hour shall be integrated over the hour, on a prorated basis, to reflect any updates in Seller's Reported Availability made effective during such hour.

(B) Tri-State may verify Seller's then-current Reported Availability at any time, without prior notice to Seller, by dispatching the Facility to the level of Reported Availability. Tri-State shall notify Seller as soon as possible by telephone and thereafter in writing whenever Tri-State identifies an issue with Reported Availability.

13.9 Dispute Resolution.

(A) The Parties agree that it is in the best interest of both Parties to attempt to resolve disputes that arise under this PPA in a quick and inexpensive manner. To that end, the Parties commit to use their best efforts to resolve disputes informally. For all disputes that arise pursuant to this PPA, the Parties immediately, through their designated representatives selected in the sole discretion of each Party (individually, the "Party Representative", together, the "Parties' Representatives"), shall negotiate with one another in good faith in order to reach resolution of the dispute. Such negotiation shall commence within fourteen (14) Days of the date of the letter from one Party Representative notifying the other Party Representative of the nature of the dispute. In the event that the Parties' Representatives cannot agree to a resolution of the dispute within thirty (30) Days after the commencement of negotiations, written notice of the dispute (the "Dispute Notice"), together with a statement describing the issues or claims, shall be delivered, within seventy-two (72) hours after the expiration of such thirty (30) Day period, by each of the Parties' Representatives to its respective senior manager or official (such senior manager or official to be selected by each of the Party Representatives in his or her sole discretion, *provided* such senior manager or official has authority to bind the respective Party). Within three (3) Business Days after receipt of the Dispute Notice, the senior manager or officials for both Parties shall negotiate in good faith to resolve

the dispute. If the Parties are unable to resolve the dispute within fourteen (14) Days of receipt of the Dispute Notice by the senior manager or officials, either Party may seek available legal remedies.

(B) SELLER AND TRI-STATE EACH HEREBY KNOWINGLY, VOLUNTARILY AND INTENTIONALLY WAIVE ANY RIGHTS THEY MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY LITIGATION BASED HEREON, OR ARISING OUT OF, UNDER, OR IN CONNECTION WITH, THIS PPA OR ANY COURSE OF CONDUCT, COURSE OF DEALING, STATEMENTS (WHETHER ORAL OR WRITTEN) OR ACTIONS OF SELLER AND TRI-STATE RELATED HERETO.

Article 14
Force Majeure

14.1 Definition of Force Majeure Event.

(A) A "Force Majeure Event" shall mean (i) an event or circumstance that is not reasonably foreseeable, (ii) is beyond the reasonable control of, and is not caused by, the negligence or lack of due diligence of the affected Party or its contractors or suppliers and (iii) adversely affects the performance by that Party of its obligations under or pursuant to this PPA. Such events or circumstances may include: actions or inactions of civil or military authority (including courts and governmental or administrative agencies), acts of God, war, riot or insurrection, terrorism, blockades, embargoes, sabotage (including arson and vandalism), epidemics, explosions and fires not originating in the Facility or caused by its operation, hurricanes, floods, strikes, lockouts or other labor disputes (not caused by the failure of the affected Party to comply with the terms of a collective bargaining agreement).

(B) The failure of a transmission line or element due to a Force Majeure Event that prevents Tri-State from delivering Contract Capacity and Contract Energy from the Point of Delivery is considered a Force Majeure Event.

(C) Equipment breakdown or the inability of Seller to use equipment due to its design, construction, operation, maintenance, the inability of Seller to meet regulatory standards, or failure by Seller to obtain on a timely basis and maintain a necessary permit or other regulatory approval, is not considered a Force Majeure Event.

(D) Notwithstanding the foregoing, the term "Force Majeure Event" does not include any of the following (i) inability by Seller to procure any equipment or parts for the Facility for any reason (the risk of which is assumed by Seller) or any increase in the price to procure any equipment or any parts for the Facility, including due to changes in any import or export duties or tariffs, (ii) any other acts or omissions of any third party, including any vendor, materialman, customer, or supplier of Seller,

unless such acts or omissions are themselves excused by reason of a Force Majeure Event under Section 14.1(A); (iii) any full or partial curtailment in the electric output of the Facility that is caused by or arises from a mechanical or equipment breakdown or other mishaps, events or conditions attributable to normal wear and tear or flaws, except as caused by a Force Majeure Event under Section 14.1(A), (iv) failure of Seller to abide by Prudent Utility Practices, (v) changes in market conditions that affect the cost of supplies, or that affect demand or price for power and/or Environmental Attributes; (vi) any labor strikes, slow downs or stoppages, or other labor disruptions against Seller's contractors, subcontractors, vendors, or suppliers; (vii) changes in Applicable Laws; (viii) failure of Seller or the Facility to qualify or be eligible for any Tax Credit, including any federal, state, or local tax credits or exemptions; (ix) any delay or inability of Seller to construct or install any required interconnection or transmission facilities required to be constructed and installed in order for Seller to meet its obligations hereunder, including any delays of the Interconnection Provider; (x) Seller's failure to timely apply for, or diligently pursue, any of the Governmental Approvals set forth in Exhibit F; (xi) [if any – generation technology, project specific-restriction in any Seller required Governmental Approvals that precludes or limits the generation or delivery of Contract Energy below the Planned Permitted Energy]; or (xii) weather events or sudden actions of the natural elements within twenty (20) year normal weather patterns.

(E) In the event that any delay or failure of performance (including a significant reduction in the delivery of Contract Capacity and Contract Energy) caused by a Force Majeure Event affecting Seller continues for an uninterrupted period of sixty (60) Days from its inception, the Term of this PPA shall be extended on a day for day basis for the duration of the Force Majeure Event (including the initial sixty (60) Days from its inception) with a maximum extension of the Term of this PPA for all Force Majeure Events not to exceed four (4) years; *provided that* the Commercial Operation Year for purposes of determining the applicable Contract Capacity Rate, Contract Energy Rate and Expected Contract Energy shall be tolled on a day for day basis for the duration of the Force Majeure Event.

(F) In the event that any delay or failure of performance (including a significant reduction in the delivery of Contract Capacity and/or Contract Energy) caused by a Force Majeure Event affecting Seller continues for an uninterrupted period of ninety (90) Days from its inception (with respect to a Force Majeure Event occurring prior to COD) or three hundred sixty-five (365) Days from its inception (with respect to a Force Majeure Event occurring after COD), the Party not claiming a Force Majeure Event may, at any time following the end of such period, terminate this PPA upon written notice to the affected Party, without further obligation by either Party except as to costs and balances incurred prior to the effective date of such termination.

(G) Except as otherwise provided in this PPA, and subject to compliance with the notice, mitigation and other requirements of this Article 14, each

Party shall be excused from performance when non-performance was caused, directly or indirectly, by a Force Majeure Event but only and to the extent thereof.

14.2 Notification Obligations.

In the event of any delay or nonperformance resulting from a Force Majeure Event, the Party claiming that a Force Majeure Event has occurred shall notify the other Party immediately by telephonic communication and in writing, within five (5) Days of such occurrence, of the nature, cause, date of commencement thereof and the anticipated duration, and shall indicate whether any deadlines or date(s) imposed hereunder may be affected thereby. The suspension of performance shall be of no greater scope and of no greater duration than the cure for the Force Majeure Event requires. A Party claiming that a Force Majeure Event has occurred shall not be entitled to any relief therefor unless and until confirming notice is provided. The Party claiming that a Force Majeure Event has occurred shall notify the other Party of the cessation of the Force Majeure Event or of the conclusion of the affected Party's cure for the Force Majeure Event, in either case within two (2) Business Days thereof.

14.3 Duty to Mitigate.

The Party claiming that a Force Majeure Event has occurred shall use commercially reasonable efforts to cure the cause(s) preventing its performance of this PPA; *provided, however,* that the settlement of strikes, lockouts and other labor disputes shall be entirely within the discretion of the affected Party and such Party shall not be required to settle such strikes, lockouts or other labor disputes by acceding to demands which such Party deems to be unreasonable.

14.4 Delay Caused by Force Majeure Event.

Upon the occurrence and during the continuance of a Force Majeure Event and the effects thereof, to the extent that a Force Majeure Event affects the ability of Tri-State, Interconnection Provider or Transmission Provider to accept Energy from the Facility or to the extent that a Force Majeure Event affects the ability of Seller to Test pursuant to Section 9.2 or to deliver Energy from the Facility, then the hours during which the Force Majeure Event occurs shall be excluded from the payment calculations as set forth in Section 7.1.

Article 15
Representations and Warranties

15.1 Seller's Representations and Warranties.

Seller hereby represents and warrants as of the date hereof as follows:

(A) Seller is a _____, duly organized, validly existing and in good standing under the laws of the state of _____. Seller is qualified to do business

in _____ and in each other jurisdiction where the failure to so qualify would have a material adverse effect on the business or financial condition of Seller. Seller has all requisite power and authority to conduct its business, to own its properties, and to execute, deliver, and perform its obligations under this PPA.

(B) The execution, delivery, and performance of its obligations under this PPA by Seller have been duly authorized by all necessary corporate action, and do not and will not:

(1) require any consent or approval by any governing body of Seller, other than that which has been obtained and is in full force and effect (evidence of which shall be delivered to Tri-State upon execution of this PPA);

(2) violate any Applicable Law, the violation of which could have a material adverse effect on the ability of Seller to perform its obligations under this PPA;

(3) result in a breach or constitute a default under Seller's organizational documents or bylaws, or any indenture or loan or credit agreement, or any other agreement, lease, or instrument to which Seller is a party or by which Seller or its properties or assets may be bound or affected, or any judgment, order, statute, or regulation that is applicable to Seller or the Facility; or

(4) result in, or require the creation or imposition of any mortgage, deed of trust, pledge, lien, security interest, or other charge or encumbrance of any nature (other than as may be contemplated by this PPA) upon or with respect to any of the assets or properties of Seller now owned or hereafter acquired.

(C) The obligations of Seller under this PPA are valid and binding obligations of Seller, enforceable against it in accordance with its terms, except as the enforceability hereof may be limited by general principles of equity or bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies.

(D) The individual of Seller executing this PPA is authorized to do so and is authorized to bind Seller to the obligations under this PPA.

(E) The execution and performance of this PPA shall not conflict with or constitute a breach or default under any contract or agreement of any kind to which Seller is a party.

(F) Except for those permits, consents, approvals, licenses and authorizations identified in Exhibit F, which Seller anticipates will be obtained by Seller in the ordinary course of business, all Governmental Approvals necessary for Seller's execution, delivery and performance of this PPA have been duly obtained and are in full force and effect.

(G) That it has arranged for sufficient financing and other funding required to complete the construction of the Facility in accordance with this PPA and to achieve Commercial Operation on or before the Commercial Operation Milestone.

(H) Within the meaning of the U.S. Bankruptcy Code, Seller is a "forward contract merchant."

15.2 Tri-State's Representations and Warranties.

Tri-State hereby represents and warrants as of the date hereof as follows:

(A) Tri-State is a cooperative corporation duly organized, validly existing and in good standing under the laws of the state of Colorado and is qualified in each other jurisdiction where the failure to so qualify would have a material adverse effect upon the business or financial condition of Tri-State. Tri-State has all requisite power and authority to conduct its business, to own its properties, and to execute, deliver, and perform its obligations under this PPA.

(B) The execution, delivery, and performance of its obligations under this PPA by Tri-State have been duly authorized by all necessary corporate action, and do not and will not:

(1) require any consent or approval of Tri-State's members;

(2) violate any Applicable Law, the violation of which could have a material adverse effect on the ability of Tri-State to perform its obligations under this PPA;

(3) result in a breach or constitute a default under Tri-State's corporate charter or bylaws, or under any agreement relating to the management or affairs of Tri-State, or any indenture or loan or credit agreement, or any other agreement, lease, or instrument to which Tri-State is a party or by which Tri-State or its properties or assets may be bound or affected, the breach or default of which could reasonably be expected to have a material adverse effect on the ability of Tri-State to perform its obligations under this PPA; or

(4) result in, or require the creation or imposition of, any mortgage, deed of trust, pledge, lien, security interest, or other charge or encumbrance of any nature (other than as may be contemplated by this PPA) upon or with respect to any of the assets or properties of Tri-State now owned or hereafter acquired, the creation or imposition of which could reasonably be expected to have a material adverse effect on the ability of Tri-State to perform its obligations under this PPA.

(C) This PPA is a valid and binding obligation of Tri-State, enforceable against it in accordance with its terms, except as the enforceability hereof may be limited by general principles of equity or bankruptcy, insolvency, bank

moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies.

(D) The individual of Tri-State executing this PPA is authorized to do so and is authorized to bind Tri-State to the obligations under this PPA.

(E) The execution and performance of this PPA shall not conflict with or constitute a breach or default under any contract or agreement of any kind to which Tri-State is a party or any judgment, order, statute, or regulation that is applicable to Tri-State.

(F) Within the meaning of the U.S. Bankruptcy Code, Tri-State is a "forward contract merchant."

Article 16
Insurance

16.1 Evidence of Insurance.

Seller shall, upon execution of this PPA and promptly after the renewal of each policy of insurance coverage required in Exhibit D, provide Tri-State with one copy of insurance certificates or other evidence in a form acceptable to Tri-State evidencing the insurance coverages required to be maintained in accordance with Exhibit D to this PPA. Such certificates shall (i) include Tri-State as an additional insured (except worker's compensation); (ii) provide that the applicable insurer shall endeavor to provide Tri-State with thirty (30) Days' prior written notice of non-renewal or cancellation of the policies required in Exhibit D (except that such notice shall be ten (10) Days for non-payment of premiums); and (iii) provide a waiver of any rights of subrogation against Tri-State, its Affiliates and their officers, directors, agents, subcontractors, and employees. Insurance carriers providing the coverages required in Exhibit D, must have a policy holders rating of "A-" or better, and a financial size of "Class VII" or better as published in the most recent edition of Best's Insurance Reports. Any policy of insurance furnished hereunder shall be written by an insurer authorized to write such coverage in the state where the Facility is located. All policies shall be written on an occurrence basis, except as provided in Section 16.2. All policies shall include language providing that Seller's policy shall be primary in all instances regardless of like coverages, if any, carried by Tri-State. Seller's liability under this PPA is not limited to the amount of insurance coverage required herein. Seller shall notify Tri-State immediately should the policies required in Exhibit D be cancelled before the expiration date, if the insureds receive a non-renewal notice from its carrier, or if there is any material adverse change of coverage.

16.2 Term and Modification of Insurance.

(A) All insurance required under this PPA shall cover occurrences during the Term and for a period of two (2) years after the Term. In the event that any insurance as required herein is commercially available only on a "claims-made" basis, such insurance shall provide for a retroactive date not later than the later of (i) the Effective Date, or (ii) the cancellation date of any occurrence basis policies that such insurance has replaced.

(B) Tri-State shall have the right to request modification of the insurance minimum limits specified in Exhibit D in order to maintain reasonable coverage amounts. Seller shall make all commercially reasonable efforts to comply with any such request. Tri-State shall reimburse Seller for all premium increases and other costs incurred by Seller in complying with any such Tri-State request for modification of the insurance minimum limits specified in Exhibit D.

16.3 Application of Proceeds.

Seller shall apply any insurance proceeds to reconstruction of the Facility following a casualty.

Article 17
Indemnity

17.1 Indemnification.

Each Party (the "Indemnifying Party") shall, to the extent permitted by Applicable Law, indemnify, pay, defend and hold harmless the other Party (the "Indemnified Party") and its officers, directors, employees, agents and contractors from and against any and all claims or demands of a third party, costs or expenses (including reasonable attorneys' fees) for loss, damages, or injury to persons or property of the Indemnified Party (or to third parties) (collectively, "Losses") caused by, arising out of, or resulting from:

(A) a breach by the Indemnifying Party of its covenants, representations, and warranties or obligations hereunder;

(B) a violation or alleged violation of Applicable Laws by the Indemnifying Party;

(C) any act or omission by the Indemnifying Party or its contractors, agents, servants or employees in connection with the installation, testing, inspection, or operation or maintenance of its respective facilities or equipment;

(D) any defect in, failure of, or fault related to, the Indemnifying Party's facilities or equipment; or

(E) the negligence or intentional acts or other misconduct of the Indemnifying Party or its contractors, agents, servants, employees or any authorized persons acting on behalf of such Indemnifying Party.

17.2 Indemnification for Fines and Penalties.

Any fines or other penalties incurred by a Party (other than fines or penalties due to the negligence or intentional acts or other misconduct of the other Party) for non-compliance with any Applicable Laws shall be the sole responsibility of the non-complying Party.

17.3 Limitations

(A) The foregoing indemnification obligations shall apply notwithstanding any contributory misconduct of the Indemnified Party, but the Indemnifying Party's liability to indemnify the Indemnified Party shall be reduced in proportion to the percentage by which the Indemnified Party's misconduct caused the damages.

(B) Neither Party shall be indemnified for Losses resulting from the sole negligence or intentional acts or misconduct of the directors, officers, employees, or agents of such Party

17.4 Notice of Proceedings.

Each Party shall promptly notify the other Party of any loss or proceeding in respect of which such notifying Party is or may be entitled to indemnification pursuant to Section 17.1. Such notice shall be given as soon as reasonably practicable after the relevant Party becomes aware of the loss or proceeding and that such loss or proceeding may give rise to an indemnification, but in any event no later than seven (7) Days after the receipt by the Party seeking indemnification of notice of the commencement of any action for which indemnity may be sought. The delay or failure of such Indemnified Party to provide the notice required pursuant to this Section 17.4 to the other Party shall not release the other Party from any indemnification obligation which it may have to such Indemnified Party except (i) to the extent that such failure or delay materially and adversely affected the Indemnifying Party's ability to defend such action or increased the amount of the loss, and (ii) that the Indemnifying Party shall not be liable for any costs or expenses of the Indemnified Party in the defense of the claim, suit, action or proceeding during such period of failure or delay.

17.5 Defense of Claims.

(A) Whether or not acknowledging in writing its obligation to indemnify an Indemnified Party to the extent required pursuant to this Section 17.5, the Indemnifying Party shall be entitled, at its option, to assume and control the defense of

such claim, action, suit or proceeding at its expense with counsel of its selection, subject to the prior approval of the Indemnified Party.

(B) Unless and until the Indemnifying Party acknowledges in writing its obligation to indemnify the Indemnified Party to the extent required pursuant to this Section 17.5 and assumes control of the defense of a claim, suit, action or proceeding in accordance with paragraph (A) above, the Indemnified Party shall have the right, but not the obligation, to contest, defend and litigate, with counsel of its own selection, any claim, action, suit or proceeding by any third party alleged or asserted against such Party in respect of, resulting from, related to or arising out of any matter for which it is entitled to be indemnified hereunder, and the reasonable costs and expenses thereof shall be subject to the indemnification obligations of the Indemnifying Party hereunder.

(C) Neither the Indemnifying Party nor the Indemnified Party shall be entitled to settle or compromise any such claim, action, suit or proceeding without the prior consent of the other; *provided, however,* that after agreeing in writing to indemnify the Indemnified Party, the Indemnifying Party may, subject to paragraph (D) below, settle or compromise any claim without the approval of such Indemnified Party. Except where such consent is unreasonably withheld, if an Indemnified Party settles or compromises any claim, action, suit or proceeding in respect of which it would otherwise be entitled to be indemnified without the prior consent of the Indemnifying Party, the Indemnifying Party shall be excused from any indemnification obligation in respect of such settlement or compromise.

(D) Following the acknowledgement of the indemnification and the assumption of the defense by the Indemnifying Party pursuant to paragraph (A) above, the Indemnified Party shall have the right to employ its own counsel and such counsel may participate in such action, but the fees and expenses of such counsel shall be at the expense of the Indemnified Party, when and as incurred, unless: (i) the employment of counsel by the Indemnified Party has been authorized in writing by the Indemnifying Party; (ii) the Indemnified Party shall have reasonably concluded and specifically notified the Indemnifying Party that there may be a conflict of interest between the Indemnifying Party and the Indemnified Party in the conduct of the defense of such action; (iii) the Indemnifying Party shall not in fact have employed independent counsel reasonably satisfactory to the Indemnified Party to assume the defense of such action and shall have been so notified by the Indemnified Party; or (iv) the Indemnified Party shall have reasonably concluded and specifically notified the Indemnifying Party that there may be specific defenses available to it which are different from or additional to those available to the Indemnifying Party, or that such claim, action, suit or proceeding involves or could have a material adverse effect upon the Indemnified Party beyond the scope of this PPA. If clause (ii), (iii) or (iv) of the preceding sentence shall be applicable, then counsel for the Indemnified Party shall have the right to direct the defense of such claim, action, suit or proceeding on behalf

of the Indemnified Party and the reasonable fees and disbursements of such counsel shall constitute reimbursable legal or other expenses hereunder.

Article 18
Legal and Regulatory Compliance

18.1 Applicable Law.

Each Party shall at all times comply with all Applicable Law related to its obligations under this PPA, except for any non-compliance which, individually or in the aggregate, could not reasonably be expected to have a material adverse effect on the business or financial condition of the Party or its ability to fulfill its commitments under this PPA. Seller shall promptly notify Tri-State of any investigation, notices or findings of violations of Applicable Law from any Governmental Authority, including any audit, notification, inspection or inquiry that has been commenced by any Governmental Authority in respect of a potential or possible violation of Applicable Law. Except as otherwise expressly provided herein, each Party assumes the risk of changes in Applicable Laws following the date hereof, that affect such Party's costs of ownership and operation of its assets, and its performance of this PPA, except as otherwise specifically set forth herein.

18.2 Compliance with Governmental Approvals.

Seller shall comply with and cause the Facility to comply with all applicable Governmental Approvals. Seller shall promptly notify Tri-State of any inspections by any Governmental Authority with respect to any material Governmental Approval and will promptly provide Tri-State with copies of any notices of violation or non-compliance with respect to any material Governmental Approval. Upon permanent cessation of generation of Energy from the Facility, Seller, at its sole cost and expense, shall decommission the Facility, dismantle the Facility, remediate the Site and submit and obtain any Governmental Approvals with respect thereto.

18.3 Compliance Information.

(A) Each Party shall, for the purpose of gathering information and/or providing verbal or written reports, testimony, affidavits or other submissions relevant to any Governmental Approvals, Applicable Laws or in connection with any litigation, arbitration or administrative proceeding before any authority of competent jurisdiction: (i) deliver or cause to be delivered to the other Party any necessary or required certificates of its officers, accountants, engineers or agents; and/or (ii) make available necessary personnel with knowledge as to such matters.

(B) To the full extent authorized by FERC regulations and the FERC standards of conduct, Seller hereby authorizes Tri-State to contact and obtain information concerning the Facility and Interconnection Facilities directly from the

Interconnection Provider and the Transmission Provider and, to the extent necessary, Seller shall provide written notice to the Interconnection Provider and the Transmission Provider confirming such authorization.

18.4 Reliability Standards.

In the event that new reliability standards are promulgated by WECC, NERC, FERC, or PUC, or any successor agencies, any and all costs incurred as a result of actions required for compliance with the new reliability standards shall be borne by Seller. To the extent that Seller contributes in whole or in part to actions which result in monetary penalties being assessed to Tri-State by WECC, NERC, FERC or PUC, or any successor agencies, for lack of compliance with reliability standards (except to the extent that Seller acted at the direction of Tri-State), Seller shall reimburse Tri-State for its share of such monetary penalties.

18.5 Financial Accounting Standards.

Under accounting principles generally accepted in the United States of America ("GAAP"), Tri-State may be required to consolidate an entity with which Tri-State has entered into a long-term power purchase agreement. Seller shall provide all information needed by Tri-State in order for Tri-State to determine whether or not Seller must be consolidated by Tri-State under GAAP. If Tri-State determines in its discretion that Tri-State is required to consolidate Seller in its financial statements, Seller shall provide reasonable access to any records and personnel, as requested by Tri-State, in connection with such consolidation and also so that Tri-State's independent auditors can conduct financial statement audits in accordance with generally accepted audit standards, as well as internal controls review. Seller shall have adequate controls over financial information.

Article 19
Assignment and Other Transfer Restrictions

19.1 Assignment of PPA.

(A) Except as expressly permitted by this Section 19.1 or in connection with a Transfer of the Facility that is expressly permitted by Section 19.4, neither Party shall assign this PPA, or any portion thereof, without the prior written consent of the other Party. Any purported assignment of this PPA or any portion thereof in violation of the foregoing shall be null and void and shall constitute an Event of Default.

(B) Notwithstanding Section 19.1(A) but subject to Section 19.1(C), without the prior written consent of the other Party:

(1) Either Party shall have the right at any time and from time to time to mortgage, create or provide for a security interest in, convey in trust, or collaterally assign its respective rights, titles and interests in this PPA to any lender, collateral agent, mortgagee, or trustee as security for its present or future indebtedness (including, in the case of such an assignment by Seller, any Financing Party) (each, a "Security Party"), without such Security Party assuming or becoming in any respect obligated to perform any of the obligations of the Parties.

(2) Any Security Party may foreclose upon or, in lieu thereof, otherwise succeed to and acquire all the rights, titles and interests of such Party in this PPA.

(3) Either Party may assign this PPA to any Affiliate thereof that has the financial capability to fulfill its obligations hereunder as demonstrated by a credit rating of equal to or better than the assigning Party.

(C) No assignment of or other succession to a Party's interest in this PPA shall be permitted pursuant to this PPA (other than Section 19.1(B)(1)) unless and until: (i) the successor assumes and agrees, in writing in form and substance reasonably acceptable to the other Party, to fully perform and discharge all of the obligations hereunder of such Party, and (ii) in the case of Seller's interest in this PPA, the successor (1) succeeds to and acquires all rights, title and interest of Seller in the Facility and (2) provides to Tri-State all Security then required to be maintained by Seller hereunder.

(D) Any successor to a Party's interest in this PPA shall notify the other Party promptly in writing of such succession, and shall furnish to the other Party evidence of such succession.

19.2 Change of Operator.

(A) Except as expressly permitted by this Section 19.2, Seller shall not replace the Operation and Maintenance Contractor (which for purposes of this Section 19.2 shall include replacement of any subcontractor or other Person providing operation management or other significant operation or maintenance services) without the prior written consent of Tri-State. The replacement of the Operation and Maintenance Contractor in violation of the foregoing shall constitute an Event of Default.

(B) Notwithstanding Section 19.2(A), Seller can replace the Operation and Maintenance Contractor without the prior written consent of Tri-State if:

(1) Seller provides to Tri-State reasonable advance written notice of such replacement (which, absent extraordinary circumstances affecting the

safe and reliable operation of the Facility, shall not be less than ninety (90) Days prior to such replacement); and

(2) Seller reasonably demonstrates to Tri-State that the replacement operator is a Qualified Operator.

19.3 Change of Control.

(A) Except as expressly permitted by this Section 19.3, Seller shall not permit a Change of Control of Seller to occur without the prior written consent of Tri-State. The occurrence of a Change of Control of Seller in violation of the foregoing shall constitute an Event of Default.

(B) Notwithstanding Section 19.3(A) but subject to Section 19.3(C), without the prior written consent of Tri-State:

(1) Any direct or indirect owner of Seller shall have the right at any time and from time to time to mortgage, grant a security interest in, convey in trust, or pledge to any Security Party any equity or ownership interest in Seller or in any Person that Controls Seller.

(2) Any Security Party may foreclose upon or, in lieu thereof, otherwise succeed to and acquire any such equity or ownership interests in Seller or in any Person that Controls Seller.

(C) No Change of Control of Seller shall be permitted under this PPA unless all obligations of Seller hereunder with respect to maintaining Security are satisfied immediately following such Change of Control.

(D) Seller shall notify Tri-State promptly in writing of any Change of Control of Seller.

19.4 Transfer of Facility.

(A) Except as expressly permitted by this Section 19.4, Seller shall not Transfer all or any portion of the Facility without the prior written consent of Tri-State. The Transfer of all or any portion of the Facility in violation of the foregoing shall constitute an Event of Default.

(B) Notwithstanding Section 19.4(A) but subject to Section 19.4(C), without the prior written consent of Tri-State:

(1) Seller shall have the right at any time and from time to time to mortgage, convey in trust, or grant to any Security Party a security interest in the Facility or any portion thereof.

(2) Any Security Party may foreclose upon or, in lieu thereof, otherwise succeed to and acquire the Facility or any portion thereof.

(3) Seller may, and shall be obligated to, Transfer the Facility to any Affiliate to which Seller assigns the PPA in compliance with the provisions of Section 19.1.

(C) No Transfer of the Facility or any portion thereof shall be permitted pursuant to this PPA (other than Section 19.4(B)(1)) unless and until the successor (i) succeeds to and acquires all rights, title and interest of Seller in this PPA, (ii) assumes and agrees in writing, in form and substance reasonably acceptable to Tri-State, to fully perform and discharge all of the obligations of Seller hereunder, and (iii) provides to Tri-State all Security then required to be maintained by Seller hereunder.

(D) Seller shall notify Tri-State promptly in writing of any Transfer of the Facility or any portion thereof, and shall furnish to Tri-State evidence of such Transfer.

19.5 Reimbursement of Tri-State's Costs.

In the event Seller proposes to or does assign or transfer an interest in the Facility or this PPA, undergo a Change of Control, or replace the Operation and Maintenance Contractor, as such transactions are described in this Article 19, Seller shall reimburse Tri-State for its expenses, including internal costs and expenses and reasonable attorneys' fees, incurred by Tri-State in connection with the evaluation of such proposed transaction and the preparation, negotiation, and execution of any consent and any other documents associated with such proposed transaction.

Article 20
Change in Law

[if any – generation technology and project specific]

Article 21
Miscellaneous

21.1 Waiver.

The delay or failure of either Party to enforce or insist upon compliance with or strict performance of any of the terms or conditions of this PPA, or to exercise or take advantage of any of its rights, including any right to terminate this PPA, shall not constitute a waiver or relinquishment of any such terms, conditions, or rights, but the same shall be and remain at all times in full force and effect.

21.2 Fines and Penalties.

(A) Seller shall pay when due all fees, fines, penalties or costs incurred by Seller or its agents, employees or contractors for noncompliance by Seller or the Facility, its employees, or subcontractors with any provision of this PPA, or any contractual obligation, permit or requirements of Applicable Law except for such fines, penalties and costs that are being actively contested in good faith and with due diligence by Seller and for which adequate financial reserves have been set aside to pay such fines, penalties or costs in the event of an adverse determination.

(B) If fees, fines, liens, penalties, or costs are claimed or assessed against Tri-State by any Governmental Authority due to noncompliance by Seller or the Facility with this PPA, any requirements of Applicable Law, any permit or contractual obligation, or, if the work of Seller or any of its contractors or subcontractors is delayed or stopped by order of any Governmental Authority due to Seller's noncompliance with any requirements of Applicable Law, permit, or contractual obligation, Seller shall indemnify and hold Tri-State harmless against any and all losses, liabilities, damages, and claims suffered or incurred by Tri-State, including claims for indemnity or contribution made by third parties against Tri-State, except to the extent Tri-State recovers any such losses, liabilities or damages through other provisions of this PPA.

21.3 Disclaimer of Third Party Beneficiary Rights.

In executing this PPA, Tri-State does not, nor should it be construed to, extend its credit or financial support for the benefit of any third parties lending money to or having other transactions with Seller. Nothing in this PPA shall be construed to create any duty to, or standard of care with reference to, or any liability to, any Person not a party to this PPA.

21.4 Relationship of the Parties.

(A) This PPA shall not be interpreted to create an association, joint venture, or partnership between the Parties nor to impose any partnership obligation or liability upon either Party. Except as specifically provided in Section 12.5, neither Party shall have any right, power, or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as an agent or representative of, the other Party.

(B) Seller shall be solely liable for the payment of all wages, taxes, and other costs related to the employment of Persons to perform Seller's obligations under this PPA, including all federal, state, and local income, social security, payroll, and employment taxes and statutorily mandated workers' compensation coverage. None of the Persons employed by Seller shall be considered employees of Tri-State

for any purpose; nor shall Seller represent to any Person that he or she is or shall become a Tri-State employee.

21.5 Severability.

In the event any of the terms, covenants, or conditions of this PPA, its Exhibits, or the application of any such terms, covenants, or conditions, shall be held invalid, illegal, or unenforceable by any court or administrative body having jurisdiction, all other terms, covenants, and conditions of this PPA and their application not adversely affected thereby shall remain in force and effect; *provided, however,* that Tri-State and Seller shall negotiate in good faith to attempt to implement an equitable adjustment in the provisions of this PPA with a view toward effecting the purposes of this PPA by replacing the provision that is held invalid, illegal, or unenforceable with a valid provision the economic effect of which comes as close as possible to that of the provision that has been found to be invalid, illegal or unenforceable.

21.6 Complete Agreement; Amendments.

The terms and provisions contained in this PPA constitute the entire agreement between Tri-State and Seller with respect to the Facility and shall supersede all previous communications, representations, or agreements, either verbal or written, between Tri-State and Seller with respect to the sale of Contract Capacity and Contract Energy. This PPA may be amended, changed, modified, or altered, *provided* that such amendment, change, modification, or alteration shall be in writing and signed by both Parties.

21.7 Binding Effect.

This PPA, as it may be amended from time to time pursuant to this Article 21, shall be binding upon and inure to the benefit of the Parties and their respective successors-in-interest, legal representatives, and assigns permitted hereunder.

21.8 Headings.

The table of contents, captions and headings used in this PPA are for ease of reference only and do not constitute a part of this PPA.

21.9 Counterparts.

This PPA may be executed in any number of counterparts, and each executed counterpart shall have the same force and effect as an original instrument.

21.10 Governing Law.

The interpretation and performance of this PPA and each of its provisions shall be governed and construed in accordance with the laws of the State of Colorado. The

Parties hereby submit to the exclusive jurisdiction in the federal and state courts of the State of Colorado, and venue is hereby stipulated as Denver, Colorado.

21.11 Mobile-Sierra

Notwithstanding any other provision of this PPA to the contrary, neither Party shall seek, nor shall they support any third party seeking, to prospectively or retroactively revise the rates, terms or conditions of service of this PPA through application or complaint to FERC pursuant to the provisions of Section 205, 206 or 306 of the Federal Power Act, or any other provisions of the Federal Power Act, absent prior written agreement of the Parties. Further, absent the prior written agreement in writing by both Parties, the standard of review for changes to the rates, terms or conditions of service of this PPA proposed by a Party shall be the "public interest" standard of review set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956) and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956), as interpreted in *Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. 1,* 128 S. Ct. 2733 (2008). Changes proposed by a non-Party or FERC acting *sua sponte* shall be subject to the most stringent standard permissible under Applicable Law.

[Signature Page Follows]

IN WITNESS WHEREOF, the Parties have executed this PPA as of the date first written above.

Seller:

_____

By: _____

Printed Name: _____

Title:_____

Tri-State:

Tri-State Generation and Transmission Association, Inc.

By: _____

Printed Name:

Title: Chief Executive Officer

EXHIBIT A

PROJECT MILESTONES

Date	**Construction Milestones**
10 Days after the Effective Date	Seller shall have established the Security in accordance with Article 11.
[ ]	Seller shall have delivered a fully executed EPC Contract to Tri-State.
[ ]	Seller shall have provided Tri-State with documentation that all Seller required Governmental Approvals have been obtained or will be obtained by the time needed to meet all Construction Milestones.
[ ]	Seller shall have entered into Financing Documents and having achieved or obtained waivers with respect to all conditions precedent to the initial availability for disbursement of funds under the Financing Documents.
[ ]	Seller shall have commenced construction of the Facility (all Seller required Governmental Approvals required to construct Facility shall have been obtained and are in full force and effect, except for minor Seller required Governmental Approvals that are expected to be obtained in the ordinary course, the failure of which to obtain would not adversely affect the construction and/or operation of the Facility).
[ ]	Delivery of major components to the Site shall have commenced.
[ ]	Seller shall have provided Tri-State with copies of the executed Operation and Maintenance Agreement, if applicable
[ ]	The step-up transformer shall have been delivered to the Site.
[ ]	Seller shall have completed construction of Seller's Interconnection Facilities and such facilities are capable of being energized.
[ ]	Start-up testing of the Facility shall have commenced.

Commercial Operation Milestone

[_____] The Facility shall have achieved Commercial Operation.

EXHIBIT B

FACILITY DESCRIPTION AND SITE MAPS

Required Items:

Location of Electric Interconnection Point (see definition of Point of Delivery)

A detailed description of the Facility, including identification of the major equipment and components that will make up the Facility (see Section 3.1)

A scaled map that identifies the Site and the location of the Facility on the Site and a drawing identifying the location of the Electric Interconnection Point, the Point of Delivery, important ancillary facilities and Interconnection Facilities (See Section 3.2)

EXHIBIT C

PRICING

Contract Capacity Formula

TBD – project specific

Contract Energy Payment Formula

TBD – project specific

Start Payment Formula

TBD – project specific

Test Energy Payment Formula

TBD – project specific

EXHIBIT D

INSURANCE COVERAGE

Type of Insurance	**Minimum Limits of Coverage**
1. Commercial General Liability ("CGL") and commercial umbrella	$15,000,000 per occurrence and aggregate. If CGL insurance contains a general aggregate limit, it shall apply separately to the Facility.

CGL insurance shall be written on ISO occurrence form CG 00 01 01 96 (or a substitute form providing similar coverage) and shall cover liability arising from premises, operations, independent contractors, products/completed operations, contracts, property damage, personal injury and advertising injury, and liability assumed under an insured contract (including the tort liability of another assumed in a business contract). There shall be no endorsement or modification limiting coverage for liability assumed under an insured contract. There shall be no endorsement or modification of the CGL insurance limiting the scope of coverage for liability arising from explosion, collapse, or underground property damage.

Tri-State shall be included as an additional insured under the CGL policy, using ISO additional insured endorsement CG 20 10 (or a substitute providing similar coverage), and under the commercial umbrella insurance. The commercial umbrella insurance shall provide coverage over the top of the CGL insurance, the Business Automobile Liability insurance.

The CGL and commercial umbrella insurance to be obtained by or on behalf of Seller shall be:

> primary as respects any claims, losses, damages, expenses, or liabilities arising out of this PPA.

2 Environmental/Pollution Liability insurance either stand alone or as part of the CGL/commercial umbrella	At least $5,000,000 each occurrence

Environmental/Pollution Liability insurance shall protect against bodily injury and property damage claims arising out of pollution. The policy through its language or by endorsement, shall include coverage for contractual liability.

3. Business Automobile Liability	$1,000,000 combined single limit (each accident), including Non-Owned and Hired Autos.

Business Automobile Liability insurance shall be written on ISO form CA 00 01, CA 00 05, CA 00 12, CA 00 20, or a substitute form providing similar liability coverage. If necessary, the policy shall be endorsed to provide contractual liability coverage equivalent to that provided in the 1990 and later editions of CA 00 01. If transporting hazardous waste/materials from the Site, an appropriate MCS-90 Endorsement must be attached with $10,000,000 limits of liability.

4. Workers' Compensation	Statutory Requirements. Seller may comply with these requirements through its project operator.

EXHIBIT D

INSURANCE COVERAGE

Type of Insurance	**Minimum Limits of Coverage**
5. Employers' Liability, if Seller maintains employees (or a certification from Seller that is maintains no employees)	Bodily Injury by Accident, $1,000,000 each accident Bodily Injury by Disease, $1,000,000 policy limit Bodily Injury by Disease, $1,000,000 each employee

6. Builders All Risk insurance coverage	For the full value of Facility.

Builders All Risk insurance shall include coverage carried by either Seller or the EPC Contractor, without limitation against the perils of fire and physical loss or damage including, without duplication of coverage, theft, vandalism, malicious mischief, collapse, water, falsework, testing and startup, for entire period of construction, which shall cover the interests of Indemnified Parties until the Commercial Operation Date, and insurance coverage as set forth in 7 below is provided. A certificate of Builders Risk insurance shall be provided to Tri-State regardless of who procures coverage.

7. All-Risk Property insurance covering physical loss or damage to the Facility	Full Replacement Value of the Facility. A deductible may be carried, which deductible shall be the absolute responsibility of Seller.

All-Risk Property insurance shall include: (i) coverage for fire, flood, wind and storm, tornado and earthquake; (ii) Boiler and Machinery insurance covering all objects customarily subject to such insurance, including boilers and engines, and (iii) business interruption to cover loss of providing Energy to Tri-State should Seller not be able to produce or provide electrical energy as agreed to herein. Tri-State shall be named as a loss payee as to its interests under this PPA.

Seller shall require its contractors and subcontractors to purchase and maintain commercial general liability including environmental coverage within or as a separate policy in an amount commensurate with type of work to be performed and automobile, workers' compensation and employers liability insurance of the types and amounts specified above. If requested by Tri-State, Seller shall furnish copies of certificates of insurance evidencing such coverage.

EXHIBIT E

PROJECT CONTRACTS

[Seller to Provide]

1. Generator Interconnection Agreement

2.

EXHIBIT F

SELLER'S REQUIRED GOVERNMENTAL APPROVALS

[Seller to Provide]

EXHIBIT G

OPERATING REQUIREMENTS AND RESTRICTIONS

TBD - generation technology and project specific

EXHIBIT H

OPERATING COMMITTEE REPRESENTATIVES

Tri-State	Seller
Primary Representative: Origination Manager Tri-State Generation and Transmission Association, Inc. 1100 W. 116th Avenue Westminster, CO 80234 Phone: (303) 254-_____ Email: _____@tristategt.org	**Primary Representative:**
Alternative Representative: Senior Manager, Energy Resources Tri-State Generation and Transmission Association, Inc. 1100 W. 116th Avenue Westminster, CO 80234 Phone: (303) 254-_____ Email: _____@tristategt.org	**Alternative Representative:**

EXHIBIT I

NOTICE ADDRESSES

Tri-State	Seller
Notices: Chief Executive Officer Tri-State Generation and Transmission Association, Inc. 1100 W. 116th Avenue Westminster, CO 80234 Telephone: (303) 452-6111 with a copy to (at the same address): Senior Vice President and General Counsel	**Notice**:

EXHIBIT J

FORM OF GUARANTY

This Guaranty is executed and delivered as of this _____ day of _____, 20__ by _____, a _____ ("Guarantor"), in favor of Tri-State Generation and Transmission Association, Inc. ("Company"), in connection with the performance by _____, a _____ _____ ("Seller") of that certain Power Purchase Agreement for the _____, dated _____, 20__, TS-__-____, by and between Seller and Company (the "PPA"). Capitalized terms used but not defined herein shall have the meanings set forth in the PPA.

RECITALS

A. Seller is planning to develop, design, construct, own, operate, and maintain a _____ electric generating facility having an Expected Nameplate Capacity Rating of _____ MW to be located in _____ County, _____ (the "Facility").

B. Seller and Company have entered into the PPA for the purchase and sale of capacity and electrical energy from the Facility on the terms and conditions set forth therein.

C. This Guaranty is delivered to the Company pursuant to Section 11.1(A) of the PPA.

D. To induce Company to enter into the PPA and consummate the purchase and sale of electrical energy contemplated by the PPA, Guarantor has agreed to guarantee the obligations of Seller as provided in this Guaranty.

NOW, THEREFORE, in consideration of the foregoing and for good and valuable consideration, Guarantor hereby agrees as follows:

AGREEMENT

1. Guaranty. Subject to the provisions of this Guaranty, Guarantor hereby absolutely, irrevocably, unconditionally, and fully guarantees to Company the due, prompt, and complete observance, performance, and discharge of each and every payment obligation of Seller under the PPA, whether incurred before or after the date of delivery of this Guaranty (the "Obligations"). This is a guaranty of payment, not of collection, and as such, Company shall not be required to institute, pursue, or exhaust any remedies against Seller before instituting suit, obtaining judgment, and executing thereon against Guarantor under this Guaranty. In furtherance of the foregoing and without limiting the generality thereof, Guarantor agrees as follows:

a. The liability of Guarantor under this Guaranty is not conditional or contingent upon the genuineness, validity, regularity or enforceability of the PPA or the pursuit by Company of any remedies which it now has or may hereafter have under the PPA;
b. Company may enforce this Guaranty upon the occurrence of a default by Seller under the PPA notwithstanding the existence of a dispute between Company and Seller with respect to the existence of the default;
c. The obligations of Guarantor under this Guaranty are independent of the obligations of Seller under the PPA and a separate action or actions may be brought and prosecuted against Guarantor whether or not any action is brought against Seller or any other guarantors and whether or not Seller is joined in any such action or actions;
d. Company may, at its election, foreclose on any security held by Company, or exercise any other right or remedy available to Company without affecting or impairing in any way the liability of Guarantor under this Guaranty, except to the extent the amount(s) owed to Company by Seller have been paid;
e. Guarantor shall continue to be liable under this Guaranty and the provisions hereof shall remain in full force and effect notwithstanding: (i) any modification, amendment, supplement, extension, agreement or stipulation between Seller and Company or their respective successors and assigns, with respect to the PPA or the obligations encompassed thereby; (ii) Company's waiver of or failure to enforce any of the terms, covenants or conditions contained in the PPA; (iii) any release of Seller or any other guarantor from any liability with respect to the Obligations or any portion thereof; (iv) any release, compromise or subordination of any real or personal property then held by Company as security for the performance of the Obligations or any portion thereof, or any substitution with respect thereto; (v) without in any way limiting the generality of the foregoing, if Company is awarded a judgment in any suit brought to enforce a portion of the Obligations, such judgment is not deemed to release Guarantor from its covenant to pay that portion of the Obligations which is not the subject of such suit; (vi) Company's acceptance and/or enforcement of, or failure to enforce, any other guaranties or any portion of this Guaranty; (vii) Company's exercise of any other rights available to it under the PPA; (viii) Company's consent to the change, reorganization or termination of the corporate structure or existence of the Seller and to any corresponding restructuring of the Obligations; (ix) any failure to perfect or continue perfection of a security interest in any collateral that secures the Obligations; and (x) any other act or thing or omission, or delay to do any other act or thing that might in any manner or to any extent vary the risk of Guarantor as an obligor with respect to the Obligations; and

f. Guarantor agrees that upon a demand for payment under this Guaranty, Guarantor shall pay such Obligations as are included in such demand notwithstanding any defenses, setoffs or counterclaims that Seller may allege or assert against Company with respect to the Obligations, including, without limitation, statute of frauds and accord and satisfaction; provided that Guarantor reserves the right to assert any defenses, setoffs or counterclaims that Seller may allege or assert against Company (except for such defenses, setoffs or counterclaims as are expressly waived under other provisions of this Guaranty) in a subsequent action for recoupment, restitution or reimbursement.

2. Maximum Liability. Notwithstanding anything herein to the contrary, Guarantor's maximum liability under this Guaranty shall be limited to _____ ($_____), plus costs of collection with respect to any valid claim(s) made by Company hereunder that are incurred in the enforcement or protection of the rights of Company.

3. Rights of Company. Guarantor hereby grants to Company, in Company's discretion and without the need to notify or obtain any consent from Guarantor, and without termination, impairment, or any other effect upon Guarantor's duties hereunder, the power and authority from time to time:

   a. to renew, compromise, extend, accelerate, or otherwise change, substitute, supersede, or terminate the terms of performance of any of the Obligations, in each case in accordance with the PPA;
   b. to grant any indulgences, forbearances, and waivers, on one or more occasions, for any length of time, with respect to Seller's performance of any of the Obligations; and
   c. to accept collateral, further guaranties, and/or other security for the Obligations, and, if so accepted, then to impair, exhaust, exchange, enforce, waive, or release any such security.

4. Performance; Payment. If any of the Obligations are not performed according to the tenor thereof, and any applicable notice and cure period provided by the PPA has expired ("Default"), Guarantor shall immediately (but in no event later than three (3) Business Days) upon receipt of written demand by Company (a) perform or cause Seller to perform the Obligation in Default, and (b) pay, reimburse, and indemnify Company against any liabilities, damages, and related costs (including attorneys' fees) incurred by Company as a result thereof, all in such manner and at such times as Company may reasonably direct. All sums payable by Guarantor hereunder shall be made in immediately available funds in U.S. Dollars.

5. Term; Satisfaction.
    a. This Guaranty shall continue in full force and effect until the earlier to occur of: (i) the substitution of an alternative form of Security in accordance with the PPA; (ii) the satisfaction of all Obligations of Seller under the PPA; or (iii) the payment by Guarantor, without reservation of rights, of an aggregate amount equal to the maximum liability set forth in Section 2, together with any other amounts required to be paid by Guarantor pursuant to Section 10 hereof.
    b. Satisfaction by Guarantor of any duty hereunder incident to a particular Default or the occurrence of any other Default shall not discharge Guarantor except with respect to the Default satisfied, it being the intent of Guarantor that this Guaranty be continuing until such time as all of the Obligations have irrevocably been discharged in full.

6. Bankruptcy. So long as any Obligations remain outstanding, Guarantor may not, without the prior written consent of Company, commence or join with any other person in commencing any bankruptcy, reorganization or insolvency proceedings of or against Seller. The obligations of Guarantor under this Guaranty may not be reduced, limited, impaired, discharged, deferred, suspended or terminated by any proceeding, voluntary or involuntary, involving the bankruptcy, insolvency, receivership, reorganization, liquidation or arrangement of the Seller or by any defense which Seller may have by reason of the order, decree or decision of any court or administrative body resulting from any such proceeding. If at any time the performance of any Obligation by Seller or Guarantor is rescinded or voided under the federal Bankruptcy Code or otherwise, then Guarantor's duties hereunder shall continue and be deemed to have been automatically reinstated, restored, and continued with respect to that Obligation, as though the performance of that Obligation had never occurred, regardless of whether this Guaranty otherwise had terminated or would have been terminated following or as a result of that performance.

7. Waivers by Guarantor. Guarantor hereby waives and agrees not to assert or take advantage of:

    a. all set-offs, counterclaims, withholdings or deductions and all presentments, demands for performance, notices of non-performance, protests, and notices of every kind that may be required by Applicable Laws;
    b. any right to require Company to proceed against Seller or any other person, or to require Company first to exhaust any remedies against Seller or any other person, before proceeding against Guarantor hereunder;
    c. any defense based upon an election of remedies by Company;
    d. any duty of Company to protect or not impair any security for the Obligations;

e. any defense based upon promptness, diligence, and any requirement that Company protect, secure, perfect or insure any security interest or lien or any property subject thereto;
f. the benefit of any laws limiting the liability of a surety or any other circumstance that limits the liability of or exonerates a guarantor generally or provides any legal or equitable discharge of Guarantor's obligations hereunder;
g. other than demand for payment, any requirement of notices between Company and Seller including, without limitation, with respect to the PPA and this Guaranty, notice of acceptance of this Guaranty, any notice of credits extended and sales made by Seller to Company, any information regarding Seller's financial condition, and all other notices whatsoever;
h. any duty of Company to disclose to Guarantor any facts concerning Seller, the PPA or the Facility, or any other circumstances, that would or allegedly would increase the risk to Guarantor under this Guaranty, whether now known or hereafter learned by Company, it being understood that Guarantor is capable of and assumes the responsibility for being and remaining informed as to all such facts and circumstances; and
i. until all Obligations in Default have been fully paid and/or performed, any rights of subrogation, contribution, reimbursement, indemnification, or other rights of payment or recovery for any payment or performance by it hereunder. For the avoidance of doubt, if any amount is paid to Guarantor in violation of this provision, such amount shall be held by Guarantor for the benefit of, and promptly paid to, Company.

8. Cumulative Remedies. The rights and remedies of Company hereunder shall be cumulative and not alternative to any other rights, powers, and remedies that Company may have at law, in equity, or under the PPA. The obligations of Guarantor hereunder are independent of those of Seller and shall survive unaffected by the bankruptcy of Seller. Company need not join Seller in any action against Guarantor to preserve its rights set forth herein.

9. Representations and Warranties. Guarantor represents and warrants to Company as follows:

a. Guarantor is a [corporation], duly organized, validly existing, and in good standing under the laws of the state of its [incorporation]. Seller is a direct or indirect wholly-owned subsidiary of Guarantor. Guarantor has all necessary corporate power and authority to execute and deliver this Guaranty and to perform its obligations hereunder.
b. The execution, delivery and performance of this Guaranty has been duly and validly authorized by all corporate proceedings of Guarantor and is not in violation of any law, judgment of court or government agency . This Guaranty has been duly and validly executed and delivered by Guarantor

and constitutes a legal, valid and binding obligation of Guarantor, enforceable against Guarantor in accordance with its terms.

10. Collection Costs. Guarantor hereby agrees to pay to Company, upon demand, and in addition to the maximum liability set forth in Section 2 hereof, all reasonable attorneys' fees and other expenses which Company may expend or incur in enforcing the Obligations against Seller and/or enforcing this Guaranty against Guarantor, whether or not suit is filed, including, without limitation, all attorneys' fees, and other expenses incurred by Company in connection with any insolvency, bankruptcy, reorganization, arrangement, or other similar proceedings involving Seller that in any way affect the exercise by Company of its rights and remedies hereunder.

11. Severability. Should any one or more provisions of this Guaranty be determined to be illegal or unenforceable, all other provisions nevertheless shall be effective.

12. Waiver or Amendment. No provision of this Guaranty or right of Company hereunder can be waived, nor can Guarantor be released from Guarantor's duties hereunder, except by a writing duly executed by Company. This Guaranty may not be modified, amended, revised, revoked, terminated, changed, or varied in any way whatsoever except by the express terms of a writing duly executed by Company.

13. Successors and Assigns. This Guaranty shall inure to the benefit of and bind the successors and assigns of Company and Guarantor. Guarantor shall have no right to assign this Guaranty or its obligations hereunder without the prior written consent of Company, which consent may be withheld in its sole discretion. Company shall have the right to assign this Guaranty to any person or entity without the prior written consent of Guarantor; *provided*, *however*, that no such assignment shall be binding upon Guarantor until it receives written notice of such assignment from Company.

14. Governing Law. This Guaranty shall be governed by and construed in accordance with the law of the State of Colorado without regard to the principles of conflicts of law thereof. Guarantor hereby submits to the exclusive jurisdiction in the federal and state courts of the State of Colorado, and venue is hereby stipulated as Denver, Colorado. Guarantor waives any claim or defense that such action or proceeding brought in any such court is an inconvenient forum, any objection to venue with respect to such action or proceeding, and any right of jurisdiction on the account of the place of residence or domicile of the Guarantor.

15. Notices. All notices, requests, claims, demands, and other communications hereunder shall be in writing and shall be given (and shall be deemed to have

been duly given upon receipt) by delivery in the manner contemplated by the PPA, addressed as follows:

if to Company: Tri-State Generation and Transmission Association, Inc.
1100 W. 116th Avenue
Westminster, CO 80234
Attn: Senior Vice President and Chief Financial Officer
Phone: (303) 452-6111

if to Guarantor: _____
_____
_____
Attn:
Phone: (___) _____

or to such other address(es) as the person to whom notice is given may have previously furnished to the others in writing in the manner set forth above.

IN WITNESS WHEREOF, Guarantor has caused this Guaranty to be duly executed and delivered to Company as of the day and year first above written.

[Name of Guarantor]

By:_____
Name:
Title:

STATE OF_____)
) ss.
COUNTY OF _____)

The foregoing instrument was acknowledged before me this _____ day of _____, 20__, by _____, as _____ of _____.

Witness my hand and official seal.

My commission expires:_____.

_____
Notary Public

(S E A L)

EXHIBIT K

FORM OF LETTER OF CREDIT

[LETTERHEAD OF ISSUING BANK]

IRREVOCABLE LETTER OF CREDIT NO _____

DATE OF ISSUANCE: _____

INITIAL EXPIRATION DATE: [Must be at least ONE YEAR after Date of Issuance]

BENEFICIARY:
TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

APPLICANT:
[NAME OF APPLICANT]

ATTN: CREDIT RISK ADMINISTRATOR
1100 W. 116TH AVENUE
WESTMINSTER, CO 80234

[APPLICANT ADDRESS]

1. AS THE ISSUING BANK ("ISSUER"), WE, [NAME OF ISSUING BANK], HEREBY ESTABLISH AND ISSUE THIS IRREVOCABLE STANDBY LETTER OF CREDIT NO. _____ IN FAVOR OF THE ABOVE-NAMED BENEFICIARY ("BENEFICIARY") FOR THE ACCOUNT OF THE ABOVE-NAMED APPLICANT ("APPLICANT") IN THE MAXIMUM AGGREGATE AMOUNT OF USD $_____ (_____ U.S. DOLLARS).

2. ISSUER UNDERTAKES TO BENEFICIARY TO PAY BENEFICIARY'S DEMAND FOR PAYMENT OF AN AMOUNT AVAILABLE UNDER THIS LETTER OF CREDIT, UPON PRESENTATION OF A DEMAND FOR PAYMENT SUBSTANTIALLY IN THE FORM OF EXHIBIT "A," ATTACHED HERETO, DULY COMPLETED AS INDICATED, AT THE FOLLOWING PLACE FOR PRESENTATION: [ADDRESS OF PLACE FOR PRESENTATION], AT ANY TIME ON OR BEFORE 5:00 PM (_____ TIME) ON THE EXPIRATION DATE.

DEMAND FOR PAYMENT MAY ALSO BE PRESENTED BY FACSIMILE ("FAX") TO FAX NO._____ PROVIDED THAT SUCH FAX PRESENTATION IS MADE AT ANY TIME ON OR BEFORE 5:00 PM (_____ TIME) ON THE EXPIRATION DATE. ISSUER WILL ACKNOWLEDGE RECEIPT OF BENEFICIARY'S PRESENTMENT WITHIN FOUR (4) BUSINESS HOURS TO THE EMAIL ADDRESS PROVIDED TO ISSUER IN THE FAX DRAW CERTIFICATE.

IF THE AMOUNT IN THE DRAW CERTIFICATE EXCEEDS THE AMOUNT AVAILABLE, BUT THE PRESENTATION OTHERWISE COMPLIES, ISSUER UNDERTAKES TO PAY THE AMOUNT AVAILABLE.

NO OTHER DOCUMENTS WILL BE REQUIRED TO BE PRESENTED. PAYMENT MADE HEREUNDER SHALL BE MADE IN U.S. DOLLARS IN IMMEDIATELY AVAILABLE FUNDS.

3. PARTIAL AND MULTIPLE DRAWS AND PRESENTATIONS ARE PERMITTED, PROVIDED THAT THE AVAILABLE AMOUNT OF THIS LETTER OF CREDIT SHALL BE PERMANENTLY REDUCED BY THE AMOUNT OF EACH SUCH DRAW.

4. THIS LETTER OF CREDIT IS ISSUED PURSUANT TO THE PROVISIONS OF THAT CERTAIN POWER PURCHASE AGREEMENT BETWEEN THE BENEFICIARY AND THE APPLICANT DATED AS OF _____, 20__ (AS THE SAME MAY HAVE BEEN OR MAY BE AMENDED FROM TIME TO TIME, THE "PPA"). NOTWITHSTANDING ANY REFERENCE IN THIS LETTER OF CREDIT TO THE PPA OR ANY OTHER DOCUMENTS, INSTRUMENTS OR AGREEMENTS, OR REFERENCES IN THE PPA OR ANY OTHER DOCUMENTS, INSTRUMENTS OR AGREEMENTS TO THIS LETTER OF CREDIT, THIS LETTER OF CREDIT CONTAINS THE ENTIRE AGREEMENT BETWEEN BENEFICIARY AND ISSUER RELATING TO THE OBLIGATIONS OF ISSUER HEREUNDER.

5. THIS LETTER OF CREDIT WILL BE AUTOMATICALLY EXTENDED EACH YEAR WITHOUT AMENDMENT FOR A PERIOD OF ONE YEAR FROM THE EXPIRATION DATE HEREOF, AS EXTENDED, UNLESS AT LEAST FORTY-FIVE (45) DAYS PRIOR TO THE EXPIRATION DATE, ISSUER NOTIFIES BENEFICIARY AND APPLICANT BY A NATIONALLY RECOGNIZED OVERNIGHT COURIER OR CERTIFIED MAIL THAT IT ELECTS NOT TO EXTEND THIS LETTER OF CREDIT FOR SUCH ADDITIONAL PERIOD (THE PRESENT OR ANY FUTURE EXPIRATION DATE AS AFORESAID IS REFERRED TO HEREIN AS THE "EXPIRATION DATE"). NOTICE OF NON-EXTENSION WILL BE GIVEN BY ISSUER TO BENEFICIARY AT BENEFICIARY'S ADDRESS SET FORTH HEREIN OR AT SUCH OTHER ADDRESS AS BENEFICIARY MAY DESIGNATE TO ISSUER IN WRITING AT ISSUER'S LETTERHEAD ADDRESS.

6. ISSUER UNDERTAKES TO MAKE PAYMENT AGAINST A COMPLYING PRESENTATION WITHIN THREE BUSINESS DAYS AFTER PRESENTATION. THE BENEFICIARY SHALL RECEIVE PAYMENT BY WIRE TRANSFER TO A BANK ACCOUNT OF THE BENEFICIARY. FOR THE PURPOSES HEREOF, "BUSINESS DAY" SHALL MEAN ANY DAY ON WHICH COMMERCIAL BANKS IN COLORADO ARE NOT AUTHORIZED OR REQUIRED TO CLOSE.

7. THIS LETTER OF CREDIT IS FREELY TRANSFERABLE TO AN ASSIGNEE AND THE NUMBER OF TRANSFERS IS UNLIMITED. SUBJECT TO COMPLIANCE WITH APPLICABLE LAWS, ISSUER AGREES THAT IT WILL EFFECT ANY TRANSFERS IMMEDIATELY UPON PRESENTATION TO ISSUER OF THIS LETTER OF CREDIT AND A COMPLETED WRITTEN TRANSFER REQUEST SUBSTANTIALLY IN THE FORM OF EXHIBIT "B," ATTACHED HERETO, DULY COMPLETED AS INDICATED. SUCH TRANSFER WILL BE EFFECTED AT NO COST TO BENEFICIARY. ANY TRANSFER FEES ASSESSED BY ISSUER WILL BE PAYABLE SOLELY BY APPLICANT, AND THE PAYMENT OF ANY TRANSFER FEES WILL NOT BE A CONDITION TO THE VALIDITY OR EFFECTIVENESS OF THE TRANSFER OR THIS LETTER OF CREDIT.

8. THIS LETTER OF CREDIT IS SUBJECT TO THE INTERNATIONAL STANDBY PRACTICES 1998 ("ISP98") (INTERNATIONAL CHAMBER OF COMMERCE PUBLICATION NO. 590), EXCEPT TO THE EXTENT THAT THE TERMS HEREOF ARE INCONSISTENT WITH THE PROVISIONS OF THE ISP98. AS TO MATTERS NOT COVERED BY THE ISP98, THIS

LETTER OF CREDIT SHALL BE GOVERNED AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF COLORADO, WITHOUT REGARD FOR THE PRINCIPLES OF CONFLICTS OF LAWS THEREUNDER.

9. ISSUER'S CHARGES AND FEES FOR ISSUING, AMENDING, OR HONORING THIS LETTER OF CREDIT ARE FOR APPLICANT'S ACCOUNT AND SHALL NOT BE DEDUCTED FROM ANY PAYMENT ISSUER MAKES UNDER THIS LETTER OF CREDIT.

ISSUER:

By: _____
AUTHORIZED SIGNATURE
Its:_____

EXHIBIT "A"
(TO LETTER OF CREDIT)

FORM OF DEMAND FOR PAYMENT

[ISSUING BANK NAME] DATE:
[ISSUING BANK ADDRESS]

LADIES AND GENTLEMEN:

THIS DEMAND FOR PAYMENT IS PRESENTED BY THE UNDERSIGNED BENEFICIARY UNDER THE IRREVOCABLE LETTER OF CREDIT NO. _____, DATED _____ (THE "LETTER OF CREDIT"), ISSUED BY _____ ("ISSUER") FOR THE AMOUNT OF U.S. DOLLARS _____ AND ____/100THS (U.S.$_____), WHICH CONSTITUTES A PAYMENT OF THE FUNDS AVAILABLE TO THE BENEFICIARY UNDER THE LETTER OF CREDIT.

1. UNDER THIS DEMAND FOR PAYMENT, THE BENEFICIARY STATES [CHECK APPLICABLE]:

   [___] BENEFICIARY IS OWED BY APPLICANT THE AMOUNT DEMANDED UNDER THE AGREEMENT BETWEEN BENEFICIARY AND APPLICANT TITLED _____ AND DATED _____, WHICH AMOUNT REMAINS DUE AS OF THE DATE OF THIS DEMAND FOR PAYMENT.

   [___] THE ISSUER HAS GIVEN WRITTEN NOTICE PURSUANT TO THE LETTER OF CREDIT OF ITS INTENT NOT TO EXTEND THE LETTER OF CREDIT FOLLOWING THE PRESENT EXPIRATION DATE THEREOF AND THE CURRENT EXPIRY DATE OF THIS LETTER OF CREDIT IS WITHIN THIRTY (30) DAYS AND THE AMOUNT DEMANDED IS REQUIRED TO SECURE THE OBLIGATIONS OF APPLICANT UNDER THE AGREEMENT BETWEEN BENEFICIARY AND APPLICANT TITLED _____ AND DATED _____.

2. BENEFICIARY REQUESTS THE AMOUNT DEMANDED HEREUNDER BE TRANSFERRED TO BENEFICIARY BY WIRE TRANSFER TO THE FOLLOWING BANK ACCOUNT OF THE BENEFICIARY:

   _____
   _____
   _____

[3. ISSUER ACKNOWLEDGEMENT OF BENEFICIARY'S PRESENTMENT BY FAX SHALL BE SENT TO BENEFICIARY AT _____@TRISTATEGT.ORG.]

BENEFICIARY:

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

BY: _____
NAME: _____
TITLE: _____

EXHIBIT "B"
(TO LETTER OF CREDIT)

FORM OF TRANSFER REQUEST

IRREVOCABLE LETTER OF CREDIT NO: _____

CURRENT BENEFICIARY:

APPLICANT:

TO: [NAME OF ISSUING BANK]

THE UNDERSIGNED, AS THE CURRENT "BENEFICIARY" OF THE ABOVE REFERENCED LETTER OF CREDIT, HEREBY REQUESTS THAT YOU REISSUE THE LETTER OF CREDIT IN FAVOR OF THE TRANSFEREE NAMED BELOW [INSERT TRANSFEREE NAME AND ADDRESS BELOW]:

FROM AND AFTER THE DATE THIS TRANSFER REQUEST IS DELIVERED TO THE ISSUER, THE TRANSFEREE SHALL BE THE "BENEFICIARY" UNDER THE LETTER OF CREDIT FOR ALL PURPOSES AND SHALL BE ENTITLED TO EXERCISE AND ENJOY ALL OF THE RIGHTS, PRIVILEGES AND BENEFITS THEREOF.

DATED: _____

[NAME OF BENEFICIARY]

By:
Name:
Title:

Attachment Vol II 7-4 Semi-Dispatchable PPA

Tri-State 11/19/2020
Model Semi-Dispatchable PPA
TS-XX-XXXX

[WIND] [SOLAR] AND STORAGE ENERGY PURCHASE AGREEMENT FOR THE _____ PROJECT

BETWEEN

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

AND

_____

- [date] -

TS-XX-XXXX

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[WIND] [SOLAR] AND STORAGE ENERGY PURCHASE AGREEMENT FOR THE _____ PROJECT
BETWEEN
TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.
AND
_____

This [Wind][Solar] and Storage Energy Purchase Agreement for the _____ Project (this "PPA") is made this ____ day of _____, 20__, by and between (i) _____ ("Seller"), a _____ and (ii) Tri-State Generation and Transmission Association, Inc. ("Tri-State"), a Colorado cooperative corporation. Seller and Tri-State are hereinafter referred to individually as a "Party" and collectively as the "Parties."

WHEREAS, Seller desires to develop, design, construct, interconnect, own, operate, and maintain a _____ -powered electric energy generating facility consisting of _____(__) _____ [wind turbines][solar panels] (each, a "Generating Unit" and collectively, the "Generating Units") with an expected total nameplate capacity of ___ MW [*solar only-* AC] (the "Expected Nameplate Capacity Rating"), plus an energy storage facility consisting of _____(__) _____ (each, a "Storage Unit" and collectively, the "Storage Units") with an expected storage capacity ___ MW (the "Expected Energy Storage Capacity"), which is collectively further defined below as the "Facility"; and

WHEREAS, Seller has secured an approximately _____ (__,000) acre site in _____ County, _____ where it intends to locate the Facility and interconnect the Facility [to Interconnection Provider's existing _____ transmission line in the vicinity of the Site][at the Interconnection Provider's _____ Substation]; and

WHEREAS, Seller desires to sell and deliver to Tri-State at the Point of Delivery the electric energy produced and/or stored by the Facility and all associated Environmental Attributes, and Tri-State desires to buy the same from Seller.

NOW, THEREFORE, in consideration of the mutual covenants herein contained, the sufficiency and adequacy of which are hereby acknowledged, the Parties agree to the following:

Article 1
Definitions and Rules of Interpretation

1.1 Rules of Construction.

The capitalized terms used in this PPA shall have the meaning set forth in this Article 1 or as otherwise defined in this PPA, whether in the singular or the plural or in the present or past tense. Words not otherwise defined herein shall have meanings as

commonly used in the English language and, where applicable, in Prudent Utility Practice. Words not otherwise defined herein that have well known and generally accepted technical or trade meanings are used herein in accordance with such recognized meanings. In addition, the following rules of interpretation shall apply:

(A) References to "Articles," "Sections," or "Exhibits" shall be to articles, sections, or exhibits of this PPA.

(B) The Exhibits attached hereto are incorporated in and are intended to be a part of this PPA; *provided* that in the event of a conflict between the terms of any Exhibit and the terms of this PPA, the terms of this PPA shall take precedence.

(C) This PPA was negotiated and prepared by both Parties with the advice and participation of counsel. The Parties have agreed to the wording of this PPA and none of the provisions hereof shall be construed against one Party on the ground that such Party is the author of this PPA or any part hereof.

(D) The Parties shall act reasonably and in accordance with the principles of good faith and fair dealing in the performance of this PPA. Unless expressly provided otherwise in this PPA, (i) where this PPA requires the consent, approval, or similar action by a Party, such consent or approval shall not be unreasonably withheld, conditioned or delayed, and (ii) wherever this PPA gives a Party a right to determine, require, specify or take similar action with respect to a matter, such determination, requirement, specification or similar action shall be reasonable.

(E) Use of the words "include" or "including" or similar words shall be interpreted as "including, but not limited to" or "including, without limitation."

(F) The words "hereof," "herein," and "hereunder" and words of similar import when used in this PPA shall refer to this PPA as a whole and not to any particular provision of this PPA.

(G) Numerical amounts will be rounded to the nearest cent with respect to Dollars, one (1) decimal point for MW and MWh, three (3) decimal points for percentages, which is to the nearest tenth of a percent, and otherwise to two (2) decimal points.

(H) Tri-State's technical review, comments or inspection of the Facility, any designs, testing procedures, reports, or other documents or monitoring of any events shall not be construed as endorsing such nor as any express or implied warranty of performance, safety, durability, or reliability of the Facility or waiver of its rights under this PPA.

1.2 Interpretation with Interconnection Agreement.

The Parties recognize that Seller will enter into a separate Interconnection Agreement with the Interconnection Provider. The Parties acknowledge and agree that:

(A) the Interconnection Agreement shall be a separate and free-standing contract and that the terms of this PPA are not binding upon the Interconnection Provider.

(B) this PPA does not provide Seller authorization to interconnect the Facility to the Interconnection Provider or inject power into the Transmission System.

(C) notwithstanding any other provision in this PPA, nothing in the Interconnection Agreement shall alter or modify Seller's or Tri-State's rights, duties and obligations under this PPA. This PPA shall not be construed to create any rights between Seller and the Interconnection Provider.

(D) for purposes of this PPA, the Interconnection Provider shall be deemed to be a separate entity and separate contracting party whether or not the Interconnection Agreement is entered into with Tri-State or an Affiliate of Tri-State.

1.3 Interpretation of Arrangements for Power Supply to the Facility.

This PPA does not provide for the supply of retail electric power to the Facility ("House Energy"). Seller shall arrange with the local utility in whose retail service territory the Facility is located ("Local Provider") for the supply of House Energy. Subject to Seller's right to self-generate and consume energy concurrently generated by the Facility, Seller shall obtain House Energy exclusively from the Local Provider.

1.4 Definitions.

The following terms shall have the meanings set forth herein:

"Abandonment" means (i) the relinquishment of all possession and control of the Facility by Seller, other than a transfer permitted under this PPA, or (ii) if prior to the Commercial Operation Date, complete cessation of the development, design, construction, testing or inspection of the Facility for thirty (30) consecutive Days by Seller and/or Seller's contractors, but only if such relinquishment or cessation is not caused by or attributable to an Event of Default of, or requested by, Tri-State, or a Force Majeure Event.

[solar only- "AC" means alternating electric current.*]*

"Additional Tax Benefits" means any new Tax Benefits or changes to, extensions of, or qualification for existing Tax Benefits which become available to Seller or the Facility during the Term, from and after the Effective Date, and which provide an overall net increase in the Tax Benefits attributable to the Facility.

"Additional Tax Benefit Amount" means an amount equal to (i) the aggregate amount of all Tax Benefits received by or on behalf of Seller with respect to any Additional Tax Benefits, minus (ii) the aggregate amount of all Additional Tax Benefit

Costs with respect to such Additional Tax Benefits. For the avoidance of doubt, if the Additional Tax Benefit Amount is a negative amount, it shall be deemed to be zero.

"Additional Tax Benefit Costs" means all additional costs, if any, incurred by Seller resulting directly from production, qualification, or verification of an Additional Tax Benefit.

"Additional Maintenance Outages" shall have the meaning set forth in Section 9.7.

"Affiliate" of any named Person means any other Person that Controls, is under the Control of, or is under common Control with, the named Person.

"AGC" means the equipment and capability of an electric generation facility to automatically adjust the generation quantity within the applicable Balancing Authority Area with the purpose of interchange balancing and specifically, the Facility's capability to accept an AGC Set-Point electronically, and the automatic adjustment and regulation of the Facility's energy production and storage via the SCADA system.

"AGC Set-Point" means the Tri-State-generated analog or digital signal sent by the SCADA system to the Facility, representing the quantity of Contract Energy to be generated by the Facility or stored/discharged by the Storage System. The RDD will communicate the AGC Set-Point to the Facility via the SCADA system.

"Allowable Curtailment" means the amount of otherwise compensable Curtailed Contract Energy in any Commercial Operation Year to be applied at the election of Tri-State at any time during a Commercial Operation Year, which amount equals (i) one percent (1%) in MWh of the Expected Contract Energy for that Commercial Operation Year plus (ii) any unused Allowable Curtailment from prior Commercial Operation Years. Any unused Allowable Curtailment from a Commercial Operation Year does not expire at the end of a Commercial Operation Year and is carried forward to future Commercial Operation Years.

"Applicable Law" means, collectively, all applicable laws, statutes, treaties, codes, ordinances, regulations, certificates, orders, licenses and permits of any Governmental Authority, now in effect or hereafter enacted, amendments to any of the foregoing, interpretations of any of the foregoing by a Governmental Authority having jurisdiction over the Parties or the Facility, and all applicable judicial, administrative, arbitration and regulatory decrees, judgments, injunctions, writs, orders, awards or like actions (including those relating to human health, safety, the natural environment or otherwise).

"Back-Up Metering" shall have the meaning set forth in Section 5.3(D).

"Balancing Authority" means _____ or any successor entity or another responsible entity that integrates resource plans ahead of time, maintains load-

interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.

"Balancing Authority Area" means the collection of generation, transmission and loads within the metered boundaries of the Balancing Authority.

"Business Day" means any Day that is not a Saturday, a Sunday, or a NERC-holiday, or state- and/or federal-recognized holiday where banks in Denver, Colorado are required or authorized to close.

"Change of Control" of a specified Person means any sale or series of sales or other transactions, whether voluntary or by operation of law, following which the previously existing Ultimate Parent does not Control such Person.

"Charging Energy" means all Energy applied to the Storage System for the purpose of supplying Discharging Energy at a later time per the terms of this PPA. Charging Energy does not include House Energy.

"Commercial Operation" means the operation of the Facility beginning on the Commercial Operation Date and continuing through the Term of this PPA.

"Commercial Operation Date" or "COD" for the Facility means the date set forth in Seller's COD notice that Seller has satisfied all of the conditions for Commercial Operation listed in Section 4.9, subject to confirmation by Tri-State.

"Commercial Operation Milestone" means the milestone for Commercial Operation as set forth in Exhibit A.

"Commercial Operation Year" means, for the first Commercial Operation Year, the period starting at 12:01 a.m. MPT on the COD and ending at 11:59 p.m. MPT on the last Day of the Month in which the first anniversary of COD occurs, and each successive "Commercial Operation Year" shall mean the twelve (12) Month period following the prior Commercial Operation Year.

"Conditions" shall have the meaning set forth in Section 4.9.

"Construction Milestone" means the result specified by Seller as set forth in Exhibit A which Seller shall achieve by the Construction Milestone Date, including the Commercial Operation Milestone.

"Construction Milestone Date" means the date set forth in Exhibit A by which Seller shall achieve the corresponding result specified for such date, including the Commercial Operation Milestone.

"Contract Energy" means all net electric Energy including any and all associated capacity attributes, ancillary services, all associated Environmental Attributes, and any other attributes resulting from the generation or the output of the Generating Facility or

produced by the Generating Facility and delivered to the Point of Delivery as measured by the Electric Metering Devices installed pursuant to Section 5.3. Contract Energy shall include any Test Energy and any Excess Contract Energy.

"Contract Energy Payment" means the payment specified in Section 7.1(A).

"Contract Energy Rate" means _____ and __/100 Dollars per MWh ($_____/MWh)**[**, escalating at a rate of ___ (__) percent per year on the anniversary of each Commercial Operation Year and as further set forth in Exhibit C**]**.

"Control" means the ownership of fifty percent (50%) or more of the voting interests of the entity, or the possession, directly or indirectly, of the power to direct or cause the direction of the management policies of the entity, whether through ownership of voting securities, by contract or otherwise. "Controls," "Controlling," and "common Control" shall have correlative meanings when used in this PPA.

"Curtailed Contract Energy" shall have the meaning set forth in Section 7.2(A).

"Curtailed Contract Energy Payment" shall have the meaning set forth in Section 7.2(A).

[wind only - "Cut-Out Event" means the temporary shutting down of Generating Units where the output from the Generating Facility decreases by an aggregate of thirty (30) MW or greater during a five (5) minute interval due to wind speeds in excess of operating parameters specified by the Generating Unit manufacturer.]

"Day" means a calendar day.

"Default Rate" shall have the meaning set forth in Section 8.3(C).

"Deficiency MWhs" means the amount of Energy in MWh, if a positive number, for any Month, equal to (i) ninety percent (90%) of the product of the Expected Contract Energy multiplied by the monthly production percentage for the applicable Month specified on Exhibit G less (ii) the actual amount of Contract Energy during the same period.

"Delay Damages" shall have the meaning set forth in Section 4.3(D).

"Delivery Excuse" means an event solely or substantially due to actions or omissions by Tri-State which prevents or delays delivery of Contract Energy.

"Designation Approval Date" shall have the meaning set forth in Section 2.2.

"Discharging Energy" means all Contract Energy discharged by the Storage System, less transformation and transmission losses, if any, and delivered to the Point of Delivery.

"Dispute Notice" shall have the meaning set forth in Section 13.9(A).

"Dollars" means the lawful currency of the United States of America.

"Effective Date" means the date first written above.

"Electric Interconnection Point" means the physical point at which electrical interconnection is made between the Interconnection Facilities and the Transmission System, pursuant to the Interconnection Agreement.

"Electric Metering Device(s)" means all revenue quality metering and data processing equipment used to measure, record, or transmit data relating to the Energy produced by the Facility. Electric Metering Devices include the metering current transformers (CTs) and the metering voltage transformers (VTs). Electric Metering Devices shall include Storage System Electric Metering Devices.

"Emergency Condition" means any emergency condition or similar situation as defined under the Interconnection Agreement or any abnormal interconnection or system condition that requires automatic or immediate manual action to prevent or limit loss of load or generation supply (including Tri-State's load or generation), that could adversely affect the reliability of the interconnected system, or that could otherwise pose a threat to public safety.

"Energy" means three-phase, 60-cycle alternating current electric energy, expressed in MWh.

"Environmental Attributes" means any and all present and future environmental benefits characteristics, or credits that are attributable to renewable energy, Contract Energy, or the Facility including credits towards achieving local, national or international emission reduction requirements or renewable portfolio standards; green tags, RECs; greenhouse gas or emissions reductions or avoidances, credits, offset, allowances or benefits; any avoided emissions of pollutants to the air, soil, or water, including sulfur oxides (SO2), nitrogen oxides (NOx), carbon dioxide (CO2), carbon monoxide (CO), methane (CH4), carbon, volatile organic compounds (VOC), mercury (Hg), hydro fluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF6), and other emissions avoided; and any and all other green energy or other environmental benefits associated with the generation of renewable energy (regardless of how any present or future law or regulation attributes or allocates such characteristics). Environmental Attributes do not include Tax Credits.

"Environmental Contamination" means the introduction or presence of Regulated Materials at the Site at such levels, quantities or location, or of such form or character, as to constitute a violation of Applicable Laws, or present a material risk under Applicable Laws that the Facility will not be available or usable, whether in whole or in part, to sell Contract Energy to Tri-State as contemplated by this PPA.

"EPC Contract" means the turnkey engineering, procurement and construction contract(s) to be entered into between Seller and the EPC Contractor in relation to the engineering, procurement and construction of the Facility.

"EPC Contractor" means the engineering, procurement and construction contractor(s) retained and paid for by Seller, which contractor(s) shall be acceptable to Tri-State.

"Equipment Supply Agreement" means the agreement under which Seller has purchased or has rights to purchase the Generating Units and Storage Units and related equipment for the Facility.

"Event of Default" shall have the meaning set forth in Article 12.

"Excess Contract Energy" means that amount of Contract Energy in excess of one hundred ten percent (110%) of the Expected Contract Energy.

"Excess Contract Energy Payment" means the payment specified in Section 7.1(C).

"Excess Contract Energy Rate" means fifty percent (50%) of the Contract Energy Rate.

"Expansion Right" shall have the meaning set forth in Section 20.2(A).

"Expected Contract Energy" means _____ MWh of Contract Energy in any given Commercial Operation Year.

"Expected Energy Storage Capacity" shall have the meaning set forth in the recitals to this PPA.

"Expected Nameplate Capacity Rating" shall have the meaning set forth in the recitals to this PPA.

"Facility" means the Generating Facility, Storage System, and Seller's Interconnection Facilities, as identified and described in Article 3 and Exhibit B, including all of the following, the purpose of which is to produce and store electricity and deliver such electricity to the Electric Interconnection Point: Seller's equipment, buildings, all of the generation facilities, including Generating Units, Storage Units, step-up transformers, equipment and software necessary to receive, accept and respond to an AGC Set-Point signal from Tri-State, output breakers, monitoring hardware, weather station hardware, facilities necessary to connect to the Electric Interconnection Point, protective and associated equipment, improvements, and other tangible assets, contract rights, easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation, and maintenance of such capacity and energy subject to this PPA.

"Facility Assets" shall have the meaning set forth in Section 20.3(B).

"Facility Site Documents" means the deeds, leases, easements, rights of way, land use agreement and other agreements or instruments reasonably necessary for the construction, operation and maintenance of the Facility and that evidence Seller's ownership or control of the Site.

"FERC" means the Federal Energy Regulatory Commission, or any successor agency.

"Financing" means the obligations of Seller or its Affiliates to any Financing Parties pursuant to the Financing Documents, including principal of and premium and interest on, indebtedness, fees, expenses or penalties, amounts due upon acceleration, prepayment or restructuring, swap or interest rate hedging breakage costs and any claims or interest due with respect to any of the foregoing.

"Financing Documents" means the loan and credit agreements, notes, bonds, indentures, security agreements, lease financing agreements, mortgages, deeds of trust, interest rate exchanges, swap agreements, equity purchase agreements, purchase option agreements and other documents relating to the development, bridge, construction and/or permanent debt and/or equity financing for the Facility, including any credit enhancement, credit support, working capital financing, or refinancing documents, and any and all amendments, modifications, or supplements to the foregoing that may be entered into from time to time at the discretion of Seller subject to any required approvals, whether in this PPA, or otherwise, in connection with development, construction, ownership, leasing, operation or maintenance of the Facility.

"Financing Parties" means, collectively, any lender(s), lessor(s) or tax equity investor(s) and other parties providing any Financing and any successor(s) or assigns thereto.

"Force Majeure Event" shall have the meaning set forth in Article 14.

"Forced Outage" means a reduction of, or cessation in the delivery of, or inability to deliver or store, Energy that is not the result of (i) a Scheduled Maintenance Outage, (ii) a Force Majeure Event, (iii) a Delivery Excuse, (iv) an Emergency Condition, or (v) a curtailment as set forth in Section 6.3(A).

"Generating Facility" means the portion of the Facility that is used to generate Contract Energy using the Generating Units, as identified and described in Article 3 and Exhibit B, including all of the following, generators, step-up transformers, facilities necessary to connect to the Electric Interconnection Point, protective and associated equipment, improvements, and other tangible assets, contract rights, easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation, and maintenance of the foregoing.

"Generating Unit" shall have the meaning set forth in the recitals to this PPA.

"Governmental Approval" means any authorization, consent, permission, approval, license, ruling, permit, exemption, variance, order, judgment, instruction, condition, direction, directive, decree, declaration of, or regulation by, any Governmental Authority relating to the construction, development, ownership, occupation, start-up, Testing, operation or maintenance of the Facility or to the execution, delivery or performance of this PPA.

"Governmental Authority" means any federal, state, tribal, local or municipal governmental body; any governmental, quasi-governmental, regulatory or administrative agency, commission, body or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory or taxing authority or power, including a Reliability Coordinator, Balancing Authority or other governmental or quasi-governmental body administering energy, capacity, ancillary service, energy imbalance market or other Organized Markets, and PUC, FERC, NERC, WECC or other NERC regional entities; or any court or governmental tribunal.

"Guaranteed Energy Production" means that amount of Contract Energy equal to ninety percent (90%) of the Expected Contract Energy.

"Guaranty" means the payment and performance guaranty provided by a Qualified Guarantor or Superior Guarantor, as appropriate, to Tri-State in the form set forth in Exhibit L.

"House Energy" shall have the meaning set forth in Section 1.3.

"Independent Engineer" means an independent engineering firm of national repute and appropriate expertise in [wind][solar]-power electric generation with energy storage relative to the configuration of the Facility under this PPA, appointed by Financing Parties under any Financing Documents, or if no such Financing Documents exist, by Seller after consultation with, and upon the prior written consent of, Tri-State.

"Interconnection Agreement" means the separate agreement between Seller and the Interconnection Provider for interconnection of the Facility to the Transmission System, as such agreement may be amended from time to time.

"Interconnection Facilities" means the facilities required to connect the Facility to the Transmission Provider's Transmission System and shall include the Interconnection Provider's Interconnection Facilities and Seller's Interconnection Facilities.

"Interconnection Provider" means _____ in its capacity as the owner of the Interconnection Provider's Interconnection Facilities, or any successor entity owner.

"Interconnection Provider's Interconnection Facilities" means the facilities necessary to connect Seller's Interconnection Facilities to the Transmission System at the Electric Interconnection Point as described in the Interconnection Agreement, including breakers, bus work, bus relays, and associated equipment installed by or for the Interconnection Provider for the direct purpose of interconnecting the Facility to the

Transmission System at the Electric Interconnection Point, along with any easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of such facilities. Arrangements for the installation and operation of the Interconnection Provider's Interconnection Facilities shall be governed by the Interconnection Agreement.

"Issuer" means a U.S. commercial bank or a licensed U.S. branch of a foreign bank, with such bank having an unsecured bond rating equivalent to A- or better as determined by at least two (2) rating agencies, one of which must be either Standard & Poor's or Moody's, and an asset value of at least thirty billion Dollars ($30,000,000,000), or a Person otherwise approved by Tri-State in its sole discretion. An Issuer cannot be an Affiliate of Seller.

"kW" means kilowatt.

"Letter(s) of Credit" means an unconditional, irrevocable, standby letter of credit from an Issuer in substantially the form set forth in Exhibit K, *provided, however,* that such form may be modified by the Issuer as long as such modifications are customary, commercially reasonable, and acceptable to Tri-State. Costs of a Letter of Credit shall be borne by Seller.

"Mean Absolute Percent Error" or "MAPE" equals:

$$\frac{1}{n}\sum_{t=1}^{n}\left|\frac{A_{t-}F_t}{NC}\right|$$

Where:

n = number of hours in the quarter of the Year;

A_t = actual value of Contract Energy deliveries in MWh for the forecast hour;

F_t = hour-ahead forecasted value in MWh for the forecast hour, as provided by Seller in accordance with Section 6.4(E); provided if no hour-ahead forecast was provided for such hour, the amount of the forecast for that hour will be zero; and

NC = Nameplate Capacity Rating.

"Month" means a calendar month.

"Moody's" means Moody's Investors Services, Inc., or any successor thereto.

"MPT" means, during any period of determination, the time in effect as of such period determination in the Mountain Time Zone of the United States of America, whether Mountain Standard Time or Mountain Daylight Savings Time.

"MW" means megawatt.

"MWh" means megawatt hours.

"Nameplate Capacity Rating" means the maximum installed instantaneous generation capacity of the completed Generating Facility, expressed in MW [*solar only-* AC], when operated in compliance with the Interconnection Agreement and consistent with the Generating Unit manufacturer's recommended power factor and operating parameters, as set forth in a notice from Seller to Tri-State delivered prior to or on the Commercial Operation Date (but shall be deemed to be zero (0) MW if no such notice is provided). The Nameplate Capacity Rating of the Generating Facility shall not exceed **Insert the Expected Nameplate Capacity Rating** MW [*solar only-* AC].

"NERC" means the North American Electric Reliability Corporation, or any successor organization.

"Notice of Intent to Purchase" shall have the meaning set forth in Section 20.3(D).

"O&M Records" shall have the meaning set forth in Section 13.7.

"Offered Assets Notice" shall have the meaning set forth in Section 20.1(A).

"Operating Committee" means one representative each from Tri-State and Seller, appointed pursuant to Section 9.10(A).

"Operating Procedures" means those procedures developed pursuant to Section 9.10(B), and also the Storage Operating Procedures.

"Operating Records" means all agreements, records and other data associated with the construction, operation or maintenance of the Facility, including O&M Records, Project Contracts, blueprints for construction, operating manuals, all warranties on equipment, and all documents, whether in printed or electronic format, that Seller uses or maintains for the operation of the Facility.

"Operation and Maintenance Agreement" means that certain operation and maintenance agreement between Seller and the Operation and Maintenance Contractor with respect to the Facility.

"Operation and Maintenance Contractor" means the operation and maintenance contractor retained and paid for by Seller, which contractor shall be a Qualified Operator and acceptable to Tri-State.

"Organized Market" means a regional transmission organization, independent system operator, energy imbalance market, or any other organized market.

"Party" and "Parties" shall have the meaning set forth in the recitals to this PPA.

"Party Representative" or "Parties' Representatives" shall have the meaning set forth in Section 13.9(A).

"Person" means any natural person, corporation, limited liability company, general partnership, limited partnership, proprietorship, other business organization, trust, union, association or Governmental Authority.

"Point of Delivery" means the electric system point at which Seller makes available to Tri-State the Contract Energy, which shall be on the high side of the step-up transformer **[**at the Electric Interconnection Point**]** and as specified in Exhibit B.

"PPA" means this [Wind][Solar] and Storage Energy Purchase Agreement between Seller and Tri-State, including the Exhibits attached hereto, as the same may be amended from time to time in accordance with the provisions hereof.

[*wind only-* "Production Tax Credit" mean the production tax credits applicable to electricity produced from certain renewable resources under Section 45 of the Internal Revenue Code of 1986 or any substantially similar federal tax credits under Applicable Law that provides Seller with a tax credit based on energy production from the Facility.]

"Project Contracts" means the EPC Contract, the Equipment Supply Agreement, the Interconnection Agreement, the Facility Site Documents and the Operation and Maintenance Agreement, and any such other material agreements related to the development, construction, ownership, operation and maintenance of the Facility, a list of which agreements is set forth in Exhibit E.

"Project Entity" means (a) Seller, and (b) any entity that Controls Seller if the Facility and assets related thereto constitute all or substantially all of the assets of such entity (determined on a consolidated basis with all other Persons that are Controlled by such entity).

"Prudent Utility Practice(s)" means the practices, methods, standards, and acts of a significant portion of the electric power generation industry (including, where applicable, the practices, methods, standards, and acts engaged in or approved by a significant portion of the [wind][solar]-power electric generation industry operating facilities of a similar type, size and location in the United States of America), WECC and/or NERC, that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with Applicable Laws, codes, standards, equipment manufacturer's recommendations, reliability, safety, environmental protection, economy, and

expedition. With respect to the Facility, Prudent Utility Practice(s) includes taking reasonable steps to ensure that:

(A) equipment, materials, resources, and supplies, including spare parts inventories, are available to meet the Facility's needs;

(B) sufficient operating personnel are available at all times and are adequately experienced and trained and licensed as necessary to operate the Facility properly, efficiently, and in coordination with Tri-State and are capable of responding to reasonably foreseeable Emergency Conditions;

(C) preventive, routine, and non-routine maintenance and repairs are performed on a basis that ensures reliable, long-term and safe operation, and are performed by knowledgeable, trained, and experienced personnel utilizing proper equipment and tools;

(D) appropriate monitoring and testing are performed to ensure equipment is functioning as designed;

(E) equipment is not operated in a reckless manner, in violation of manufacturers' guidelines or in a manner unsafe to workers, the general public, or the interconnected system or contrary to environmental laws, permits or regulations or without regard to defined limitations such as, flood conditions, safety inspection requirements, operating voltage, current, volt-ampere reactive (VAR) loading, frequency, polarity, synchronization, and/or control system limits;

(F) equipment and components meet or exceed the standard of durability that is generally used for electric generation operations in the region and will function properly over the full range of ambient temperature and weather conditions reasonably expected to occur at the Site under both normal and Emergency Conditions; and

(G) equipment, components, and processes are appropriately permitted with any Governmental Authority and are operated and maintained in accordance with Applicable Laws.

"PUC" means the _____ Commission, or any successor agency.

"PUC Approval" means any written order of the PUC necessary for Tri-State to effectuate the purposes of this PPA.

"Purchase Notice" shall have the meaning set forth in Section 20.3(I).

"Purchase Option" shall have the meaning set forth in Section 20.3(A).

"Qualified Guarantor" means a Person having an issuer credit rating of (A) Baa2 or higher by Moody's and (B) BBB or higher by Standard & Poor's, or a Person otherwise approved by Tri-State in its sole discretion.

"Qualified Operator" means an operation and maintenance contractor that (a) (i) has operated, for a period of at least five (5) years, multiple utility-scale [wind][solar]-powered electric energy generating facilities in North America having, collectively, an aggregate nameplate capacity of at least 500 MW, and (ii) maintains an operating staff consisting of personnel with comparable experience in the operation and maintenance of power generation facilities similar to the Generating Facility and (b) (y) has operated, for a period of at least two (2) years, multiple [_____] energy storage facilities in North America, of at least 20 MW and 40 MWh of energy storage capacity in aggregate with at least one facility that has at least 5 MW and 10 MWh of [_____] energy storage capacity and (z) maintains an operating staff consisting of personnel with comparable experience in the operation and maintenance of energy storage facilities similar to the Storage System .

"RDD" means Tri-State's resource dispatch desk representative(s) who are responsible for dispatch of generating units, including the Facility.

"Regulated Materials" means any substance, material, gas, or particulate matter that is regulated by any Governmental Authority, as an environmental pollutant or dangerous to public health, public welfare, or the natural environment, including protection of non-human forms of life, land, water, groundwater, and air, including any material or substance that is (i) defined as "toxic," "polluting," "hazardous waste," "hazardous material," "hazardous substance," "extremely hazardous waste," "solid waste" or "restricted hazardous waste" under any provision of local, state, or federal law; (ii) petroleum, including any fraction, derivative or additive; (iii) asbestos; (iv) polychlorinated biphenyls; (v) radioactive material; (vi) designated as a "hazardous substance" pursuant to the Clean Water Act, 33 U.S.C. §1251 *et seq.* (33 U.S.C. §1251); (vii) defined as a "hazardous waste" pursuant to the Resource Conservation and Recovery Act, 42 U.S.C. §6901 *et seq.* (42 U.S.C. §6901); (viii) defined as a "hazardous substance" pursuant to the Comprehensive Environmental Response, Compensation, and Liability Act, 42 U.S.C. §9601 *et seq.* (42 U.S.C. §9601); (ix) defined as a "chemical substance" under the Toxic Substances Control Act, 15 U.S.C. §2601 *et seq.* (15 U.S.C. §2601); or (x) defined as a "pesticide" under the Federal Insecticide, Fungicide, and Rodenticide Act, 7 U.S.C. §136 *et seq.* (7 U.S.C. §136).

"RECs" means renewable energy credits or certificates representing all right, title and interest in and to all Environmental Attributes associated with each MWh of energy from a generation facility in the specific period, including title to and claim over such Environmental Attributes, reporting and all other rights arising therefrom or connected therewith under Applicable Law.

"Reliability Coordinator" shall have the meaning as set forth in NERC's Glossary of Terms Used in NERC Reliability Standards as modified from time to time.

"Replacement Cost(s)" means the costs incurred and reasonably forecasted to be incurred by Tri-State to replace the products and services which Seller was required to provide under this PPA, including Energy, storage capability, ancillary services and Environmental Attributes, but has or will fail to so provide, less the sum of any payments from Tri-State to Seller, under this PPA, which are eliminated as a result of such failure. Replacement Costs include the amounts incurred and reasonably forecasted to be incurred by Tri-State for replacement renewable energy, replacement energy storage capabilities, ancillary services, transmission and directly associated transaction costs (including reasonable attorneys' fees suffered as result of Seller's failure to perform). Additional costs may include replacement capacity costs applicable to a [wind][solar] resource with storage and any penalties incurred as a result of Seller's non-performance.

"ROFO Transfer" shall have the meaning set forth in Section 20.1(A).

"RTU" shall have the meaning set forth in Section 3.3(A).

"SCADA" means supervisory control and data acquisition.

"Scheduled Maintenance Outage" means a time period during which all or a portion of the Facility is shut down or its output reduced to undergo scheduled maintenance in accordance with this PPA, or as otherwise agreed by Seller and Tri-State, including any Storage System Planned Outage.

"Security" shall have the meaning set forth in Article 11.

"Security Party" shall have the meaning set forth in Section 19.1(B).

"Seller" shall have the meaning set forth in the preamble to this PPA.

"Seller's Interconnection Facilities" means the facilities and equipment owned by Seller related to the interconnection of the Facility with the Interconnection Provider's Interconnection Facilities along with any easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of such facilities. On the low side of the step-up transformer, it includes Seller's metering, relays, and load control equipment as provided for in the Interconnection Agreement.

"Seller's WREGIS Account" shall have the meaning set forth in Section 10.2(D).

"Shortfall MWh" means the amount of Energy in MWh, for any period of determination, equal to the Guaranteed Energy Production less the actual amount of Contract Energy during the same period.

"Site" means the parcel(s) of real property on which the Facility will be constructed and located, including any easements, rights of way, land use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of the Facility. The Site is more specifically described in Section 3.2 and Exhibit B.

"Standard & Poor's" means Standard & Poor's Global Ratings, or any successor thereto.

"Storage Availability" means total hours during each Month during a Commercial Operation Year that the Storage System is fully operational and is calculated as follows: (Hours – Total Forced Outage Hours – Total Planned Outage Hours) / (Hours – Total Planned Outage Hours)

Where:

"Hours" means, for each Month during the Commercial Operation Year, the total number of hours in such Month.

"Total Forced Outage Hours" means the sum of the number of hours during Storage System Forced Outages during the applicable Month.

"Total Planned Outage Hours" means the sum of the number of hours during Storage System Planned Outages during the applicable Month.

"Storage Operating Day" means any Day during Commercial Operation on which the Storage System operates.

"Storage Operation Test" means the commercial operation test described in Exhibit N.

"Storage System" means the portion of the Facility that is used to store Energy using the Storage Units, as identified and described in Article 3 and Exhibit B, including, without limitation, step-up transformers, output breakers, facilities necessary to connect to the Electric Interconnection Point, protective and associated equipment, improvements, and other tangible and intangible assets, contract rights, easements, rights of way, surface use agreements and other interests or rights in real estate, owned or used for construction, operation, maintenance, storage, and delivery of the foregoing.

"Storage System Electric Metering Devices" means revenue quality meters and data processing equipment used to measure, record or transmit data related to the Charging Energy delivered to and the Discharging Energy delivered from the Storage System. Storage System Electric Metering Devices include the metering current transformers (CTs) and the metering voltage transformers (VTs). All Charging Energy and Discharging Energy values measured by the Storage System Electric Metering

Devices will be normalized for electrical losses between the Storage System Electric Metering Devices and the Point of Delivery.

"Storage System Excused Outage" means any Storage System Outage of the Storage System resulting from (i) a Storage System Planned Outage, (ii) a Force Majeure Event, (iii) an Emergency Conditions, or (iv) any event solely or substantially due to actions or omissions by Tri-State which causes an Outage.

"Storage System Forced Outage" means any Storage System Outage of the Storage System that is not a Storage System Excused Outage.

"Storage System Nameplate Capacity" means the designed maximum capacity of the completed Storage System, expressed in MW and calculated by dividing the MWhs of energy the Storage System is designed to store, divided by the number of hours the Storage System is designed to discharge at full output, when operated in compliance with the Interconnection Agreement and as designed by the manufacture, as measured at the Point of Delivery. The Storage System Nameplate Capacity Rating of the Facility shall not exceed **Insert the Expected Energy Storage Capacity** MW.

"Storage System Operating Procedures" means those procedures applicable to the operation of the Storage System, as developed by the Operating Committee, in accordance with and subject to the Storage Requirements.

"Storage System Outage" means any period during which the capacity of the Storage System is unavailable for any reason as reported in accordance with the Operating Procedures.

"Storage System Planned Outage" means a planned removal from service of the Storage System, or some part thereof constituting not less than ten percent (10%) of the Storage System Nameplate Capacity, that is required for inspection, or routine, preventive or corrective maintenance; provided that Storage System Planned Outages during any Commercial Operation Year may not exceed **project specific** hours.

"Storage Requirements" means those requirements applicable to the Storage System and set forth in Exhibit M.

"Storage Test" shall have the meaning set forth in Exhibit N.

"Storage Unit" shall have the meaning set forth in the recitals to this PPA.

"Superior Guarantor" means any Person having an issuer credit rating of (A) Baa1 or higher by Moody's and (B) BBB+ or higher by Standard & Poor's, or a Person otherwise approved by Tri-State in its sole discretion.

"Tariff" shall have the meaning set forth in Section 5.1(B).

"Taxes" means all taxes, fees, levies, licenses or charges imposed by any Governmental Authority, other than taxes, levies, licenses or charges based upon net income or net worth, together with any interest and penalties thereon.

"Tax Credit" means (i) [*wind only*-the Production Tax Credit][*solar only*- the tax credit for "energy property" under Section 48(a)(3)(A)(i) of the Internal Revenue Code of 1986 or any similar tax credits under Applicable Law, as it may be amended, supplemented, extended or replaced from time to time.], (ii) any other local, state or federal tax credits providing a tax benefit to Seller based on ownership of the Facility or energy production therefrom, and (iii) depreciation and other tax benefits arising from ownership or operation of the Facility.

"Term" means the period of time during which this PPA shall remain in full force and effect, and which is further defined in Section 2.1.

"Test" or "Testing" means those tests, evaluations and measurements of the Facility's output capability that are undertaken in connection with preparing the Facility for Commercial Operation pursuant to Section 9.2 and Section 9.11(A), which shall include such tests as are consistent with Prudent Utility Practices.

"Test Date" means the date on which Seller shall commence Testing of the Facility and shall be the date falling at least sixty (60) Days prior to the Commercial Operation Milestone or such other date as Seller and Tri-State may agree in writing.

"Test Energy" means the net electric Energy that is produced by the Facility, including any and all associated ancillary services and all Environmental Attributes and delivered to Tri-State at the Point of Delivery, prior to Commercial Operation.

"Test Energy Payment" means the payment specified in Section 7.1(B).

"Test Energy Rate" means an amount equal to fifty percent (50%) of the Contract Energy Rate.

"TP Approvals" shall have the meaning set forth in Section 2.2.

"Transfer" means any sale, transfer or other disposition.

"Transmission Provider" means the owner or operator of the Transmission System responsible for providing transmission service.

"Transmission System" means the contiguously interconnected electric transmission and sub-transmission facilities over which the Transmission Provider has rights (by ownership or contract) to provide bulk transmission of capacity and energy from the Electric Interconnection Point.

"Tri-State" shall have the meaning set forth in the preamble to this PPA.

"Tri-State's WREGIS Account" shall have the meaning set forth in Section 10.2(D).

"Ultimate Parent" means _____ or such other Person that Controls Seller and is not controlled by any other Person.

"WECC" means the Western Electricity Coordinating Council, a NERC regional entity, or any successor organization.

"WREGIS" means the Western Renewable Energy Generation Information System, or any successor organization that Tri-State uses to track Environmental Attributes.

"Year" means a calendar year consisting of 365 Days (or 366 Days if a leap year), beginning on January 1 and ending on December 31.

Article 2
Term

2.1 PPA Term and Delivery Term.

This PPA shall become effective as of the Effective Date, and shall remain in full force and effect until 11:59 p.m. MPT on the last Day of the Month during which occurs the [___th] anniversary of the Commercial Operation Date, subject to early termination as set forth herein (the "Term").

2.2 Conditions Precedent.

(A) Network Resource. Tri-State's obligation to accept and pay for Contract Energy is subject to approval by the Transmission Providers of Tri-State's application for designation of the Facility as a network resource for Tri-State's native load customers and the associated reservation of firm network transmission service on the Transmission Provider's Transmission System, all without conditions materially unsatisfactory to Tri-State or requirements of material transmission upgrades (collectively, the "TP Approvals"). Tri-State shall (i) no later than fifteen (15) Business Days after the Effective Date, make a written request for all TP Approvals and (ii) thereafter use commercially reasonable efforts to obtain such TP Approvals from the Transmission Providers within one hundred fifty (150) Days from the Effective Date ("Designation Approval Date") and shall provide Seller prompt written notice upon receipt of all such TP Approvals. If any or all of the TP Approvals are not received by the Designation Approvals Date or any TP Approval would require conditions materially unsatisfactory to Tri-State or material transmission upgrades, (y) Tri-State shall promptly provide Seller written notice notifying Seller that Tri-State elects to terminate this PPA, upon which the Parties shall have no obligations or liabilities to each other hereunder, subject to Tri-State's obligation to return the Security to Seller in full, or (z) if no such notice is received by Seller within ten (10) Days following the Designation Approval Date, Tri-State shall be deemed to have elected to proceed with this PPA

despite not receiving such TP Approvals, upon which the condition provided in this Section 2.2(A) shall be deemed to have been satisfied.

(B) PUC Approvals. Tri-State's obligation to accept and pay for Contract Energy is subject to PUC Approvals. Tri-State shall (i) no later than sixty (60) Days after the Effective Date apply to the PUC for any necessary PUC Approvals and (ii) thereafter use commercially reasonable efforts to obtain such PUC Approvals as soon as reasonably practicable. Seller shall cooperate with Tri-State's efforts to obtain PUC Approvals and provide such additional documentation and information as reasonably requested by Tri-State or the PUC. Tri-State shall have the right to terminate this PPA, upon which the Parties shall have no obligations or liabilities to each other hereunder as a result of such termination, by written notice to Seller: (a) at any time within thirty (30) Days following issuance of a written order by the PUC rejecting PUC Approvals or granting PUC Approvals with conditions unacceptable to Tri-State in its sole discretion, (b) at any time between the 180th and 215th Day following Tri-State's application for PUC Approval, if prior to the date of such termination the PUC has not issued the PUC Approvals, (c) at any time within 30 Days following timely request for reconsideration (in whole or in any material part) by any third party, of the PUC Approvals, and/or (d) at any time within thirty (30) Days following timely appeal by any party, of the PUC Approvals. If Tri-State elects to terminate this PPA, Tri-State shall return the Security to Seller in full. If Tri-State is eligible to terminate this PPA, but fails to terminate this PPA by the applicable date, Tri-State shall be deemed to have elected to proceed with this PPA despite not receiving such PUC Approvals, upon which the condition provided in this Section 2.2(B) shall be deemed to have been satisfied.

(C) Other Tri-State CPs. [if any].

(D) Seller CPs. [if any – project specific].

2.3 Survivability.

Applicable provisions of this PPA shall continue in effect after termination, including early termination, to the extent necessary to enforce or complete the duties, obligations or responsibilities of the Parties arising prior to termination and, as applicable, to provide for: final billings and adjustments related to the period prior to termination, repayment of any money due and owing to either Party pursuant to this PPA, and the indemnifications specified in this PPA. All remedies in this PPA shall survive termination or cancellation of this PPA.

Article 3
Facility Description

3.1 Summary Description.

Seller shall develop, design, construct, interconnect, own, operate, and maintain the Facility, which consists of (i) _____ (__) _____ [wind turbines][solar panels] and associated equipment having a designed aggregate nameplate electric energy generating capacity of **Insert the Expected Nameplate Capacity Rating** and (ii) _____ (__) _____ and associated equipment having a designed aggregate electric storage capacity of **Insert the Expected Energy Storage Capacity**. Exhibit B provides a detailed description of the Facility, including identification of the major equipment and components that will make up the Facility.

3.2 Location.

The Facility shall be located on the Site and shall be identified as the "**Insert Project Name**" or such other name as agreed to by the Parties. The latitude and longitude of the Site are _____. A scaled map that identifies the Site and the location of the Generating Units and Storage Units on the Site and a drawing identifying the location of the Electric Interconnection Point, the Point of Delivery, important ancillary facilities and Interconnection Facilities, is included in Exhibit B.

3.3 General Design of the Facility.

Seller shall develop, design and construct the Facility according to Prudent Utility Practice(s), this PPA and the Interconnection Agreement, as applicable. In addition to the requirements of the Interconnection Agreement, the Facility shall at all times, and at Seller's expense:

(A) have the required electronic plant interfaces and communications interfaces for meter recording devices, 125vDC battery supplied voltage for meter recording devices, remote terminal unit ("RTU"), telemetering equipment and communications equipment. Seller is responsible for providing appropriate panel space and maintaining ambient conditions suitable for electronic equipment. Seller is responsible for establishing appropriate access control to the electronic equipment;

(B) use communication circuits from the Facility to Tri-State's RDD for the purpose of telemetering, supervisory control/data acquisition, voice communications as required by Tri-State, and dial-in access by Tri-State to remotely interrogate the Electric Metering Devices;

(C) [solar only- have suitable solar irradiation meters and other instrumentation necessary to measure the available resource and ambient temperature and to estimate the quantity of Contract Energy expected to be generated;]

(D) meet the Storage Requirements;

(E) include one full data circuit as required to transmit to Tri-State real-time weather data, including [wind speed, wind direction][solar irradiance], humidity and temperature collected by Seller's monitoring equipment on its meteorological data acquisition equipment located at the Facility; and

(F) have the required equipment and software necessary to receive, accept and respond to an AGC Set-Point signal from Tri-State.

Article 4
Commercial Operation

4.1 Commercial Operation.

Seller shall cause the Facility to achieve Commercial Operation no later than the Commercial Operation Milestone. The Facility shall be fully capable of reliably producing, storing and delivering the Contract Energy to be provided under this PPA to Tri-State at the Point of Delivery, no later than the Commercial Operation Milestone; provided, that Seller shall not be obligated to establish a Commercial Operation Date under this PPA that is earlier than the Commercial Operation Milestone, and Tri-State shall not be obligated to acknowledge a Commercial Operation Date under this PPA that is earlier than thirty (30) Days prior to the Commercial Operation Milestone.

4.2 Construction Milestone.

In order to achieve the Commercial Operation Date of the Facility by the Commercial Operation Milestone, Seller shall meet the Construction Milestones set forth in Exhibit A.

4.3 Delay Damages.

(A) If Seller fails to achieve any Construction Milestones (excluding the Commercial Operation Milestone) by the applicable Construction Milestone Date, (i) Seller shall provide Tri-State within ten (10) Days of the missed milestone with a detailed written report indicating the reason for such failure and Seller's proposed course of action to maintain the overall construction and commercial operation schedule, including any required expediting actions, and (ii) Tri-State shall be entitled to delay damages, as liquidated damages and not a penalty, in an amount equal to Two Thousand Five Hundred Dollars ($2,500) per Day for each Day following the Construction Milestone Date until the date the Construction Milestone is achieved; *provided, however,* that if Commercial Operation is achieved on or before the Commercial Operation Milestone, any liquidated damages amounts paid by, or on behalf of, Seller pursuant to this Section 4.3(A) shall be refunded by Tri-State to Seller without interest.

(B) If the Facility fails to achieve Commercial Operation by the Commercial Operation Milestone, (i) Seller shall provide Tri-State within ten (10) Days

of the missed milestone with a detailed written report indicating the reason for such failure and Seller's proposed course of action to achieve Commercial Operation, including any required expediting actions, and (ii) Tri-State shall be entitled to delay damages, as liquidated damages and not a penalty, in an amount equal to Two Hundred Fifty Dollars ($250) per Day per MW for each MW of nameplate capacity not installed, operating and capable of generating and storing Test Energy, as applicable, below the Expected Nameplate Capacity Rating and the Expected Energy Storage Capacity, as applicable, until the earlier to occur of (x) the date Commercial Operation is achieved, and (y) the date, if any, on which this PPA is terminated by Tri-State as permitted hereunder.

(C) All Delay Damages shall begin to accrue on the Day after the applicable missed Construction Milestone and shall continue to accrue until the result specified for such Construction Milestone is achieved. Delay Damages shall be payable in lieu of actual damages accrued for the period during which Delay Damages are assessed; provided, that nothing in this Section shall be construed to preclude Tri-State from terminating this PPA for an Event of Default under Section 12.1 or Tri-State's entitlement to Replacement Costs upon termination of this PPA. All Delay Damages shall be cumulative.

(D) Each Party agrees and acknowledges that (i) the damages that Tri-State would incur due to Seller's delay or failure in achieving any Construction Milestone (collectively, "Delay Damages") would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the Delay Damages as agreed to by the Parties set forth herein are a fair and reasonable calculation of such damages.

(E) Following the end of the Month in which Delay Damages begin to accrue, Tri-State shall promptly deliver to Seller an invoice setting forth the amount due Tri-State in respect thereof for the preceding Month. The amount of Delay Damages shall be due and payable by Seller in accordance with Section 8.3(A).

4.4 Site Report.

(A) Within ninety (90) Days of the Effective Date, Seller shall conduct a Phase I environmental investigation of the Site and shall provide Tri-State with a copy of the report summarizing such investigation, together with any data or information generated pursuant to such investigation. To the extent the Phase I investigation identifies the need for further environmental audits or investigations, Seller shall also provide to Tri-State, any related further reports. Seller shall provide to Tri-State, with such report, confirmation from an environmental engineer that the Site has been inspected for Environmental Contamination and that the Site complies, in all respects, with all Applicable Law relating to environmental or occupational health and safety matters and Regulated Materials. Such report shall include a confirmation that, based upon such investigation and to the best of Seller's knowledge, no conditions involving Environmental Contamination exist at or under the Site.

(B) During the Term, Seller shall promptly:

(1) disclose to Tri-State and remediate, at Seller's sole cost and expense, any Environmental Contamination identified at the Site;

(2) provide to Tri-State copies of any reports summarizing any further environmental assessments or investigations, together with any data or information generated pursuant to such investigation; and

(3) disclose to Tri-State the existence of any enforcement, legal, or regulatory action or proceeding relating to any alleged presence of Environmental Contamination and/or the alleged violation of any Applicable Law related to the protection of endangered, migratory or other protected species.

4.5 Project Contracts.

(A) Promptly after the execution of each of the Project Contracts or amendment thereto, Seller shall deliver to Tri-State copies of each of the fully executed Project Contracts. Upon reasonable notice and request by Tri-State, Seller shall provide Tri-State with other Facility design and construction documents and drawings, including as-built and other major engineering drawings. Seller shall be permitted to redact from the copies of the Project Contracts provided to Tri-State any pricing information which Seller considers confidential.

(B) Within ten (10) Days after the Effective Date, Seller shall deliver to Tri-State a copy of any existing [wind][solar] energy or [wind][solar] resource assessment report related to the Site or the Generating Facility. Furthermore, promptly following its issuance to Seller or development by Seller, Seller shall deliver to Tri-State a copy of any new or updated [wind][solar] energy or [wind][solar] resource assessment report related to the Site or the Generating Facility.

4.6 Governmental Approvals.

Seller shall timely and lawfully procure and maintain in good standing, at its own cost and expense, all Seller required Governmental Approvals, and shall timely and properly pay its charges and fees in connection therewith. Tri-State shall have the right to inspect and obtain copies of all Seller required Governmental Approvals (and related applications) obtained or applied for by Seller. Exhibit F sets forth a list of Seller's required Governmental Approvals, which Seller shall update from time to time, as appropriate, to add additional Seller required Governmental Approvals prior to Commercial Operation.

4.7 Construction Progress Reports.

Seller shall provide Tri-State with written progress reports in a form reasonably acceptable to Tri-State: (A) on a quarterly basis commencing with the Effective Date and continuing until the commencement of physical construction of the Facility within

twenty (20) Days following the end of each calendar quarter; and (B) on a monthly basis commencing on the commencement of physical construction of the Facility and continuing until Commercial Operation, on or before the twentieth (20th) Day of each Month for the preceding Month. Such written progress reports shall evaluate the progress on development, design, and construction of the Facility, which reports shall include (i) a project master schedule, with appropriate bar charts and status reports; (ii) updated engineering and procurement schedules; (iii) an updated testing, commissioning and start-up schedule; and (iv) reports from engineers and other Persons involved in the engineering, procurement and construction of the Facility. Seller shall, from time to time, upon reasonable advance request from Tri-State, meet with Tri-State to discuss the progress of the construction of the Facility and make the EPC Contractor available to discuss and answer questions of Tri-State regarding the Facility and Construction Milestone progress in order to keep Tri-State informed on the status of the engineering, procurement and construction for the Facility and to consider Tri-State's comments in good faith. None of the foregoing shall be deemed to be in lieu of, or in substitution for, the general record and reporting obligations attendant to Seller in accordance with Article 13.

4.8 Tri-State's Rights During Construction.

Tri-State shall have the right to monitor the construction, start-up and Testing of the Facility, and Seller shall comply with all requests of Tri-State with respect to the monitoring of these events. Seller shall cooperate in such physical inspections of the Facility as may be requested by Tri-State during and after completion of construction. All persons visiting the Facility on behalf of Tri-State shall comply with all of Seller's applicable reasonable safety and health rules and requirements that have been provided to Tri-State in writing prior to its visit.

4.9 Conditions to Commercial Operation.

Seller shall notify Tri-State in writing when Seller has satisfied all of the Conditions for Commercial Operation. Such notice shall specify the Commercial Operation Date. The Commercial Operation Date is contingent upon verification by Tri-State, including Seller providing evidence acceptable to Tri-State of the satisfaction or occurrence of all of the Conditions set forth below. Review and approval of such Conditions may occur on an ongoing and incremental basis, pending resolution of any dispute, as such Conditions are satisfied. Conditions shall be satisfied at Seller's sole cost and expense. Conditions to be fulfilled by Seller prior to Commercial Operation, to the satisfaction of, or waived in writing by, Tri-State are ("Conditions"):

(A) Seller having delivered to Tri-State copies of fully executed Project Contracts, pursuant to Section 4.5(A);

(B) if applicable, Seller having entered into Financing Documents and having achieved or obtained waivers with respect to all conditions precedent to the initial availability for disbursement of funds under the Financing Documents;

(C) Seller having delivered to Tri-State (i) a copy of its constitutional documents (certified by the Secretary of State of the State of _____) and (ii) a copy of a resolution approving the terms of this PPA and authorizing one or more individuals to execute this PPA on its behalf (such copy to have been certified by its authorized officer as true, complete and current);

(D) the Facility having achieved initial synchronization with the Transmission System and having demonstrated the reliability of its communications systems and communications with Tri-State's RDD;

(E) the Independent Engineer having certified that the Facility has been completed in all material respects (excepting punch list items that do not adversely affect the ability of the Facility to operate as intended hereunder) and the Facility is ready for the delivery and storage of Contract Energy and commencement of Commercial Operation;

(F) all arrangements for the supply of required House Energy to the Facility have been completed by Seller, are in effect, and are available for the supply of such House Energy to the Facility;

(G) the Security meeting the requirements set forth in Section 11.1 having been established in the amount required after the Commercial Operation Date pursuant to Section 11.1;

(H) certificates of insurance evidencing the coverages required in Exhibit D having been obtained and submitted to Tri-State;

(I) Seller has successfully completed a Storage Operation Test in accordance with Section 9.11(A) and Exhibit N;

(J) Seller having submitted to Tri-State a certificate of an officer of Seller familiar with the Facility after due inquiry stating that:

(1) all applicable Seller required Governmental Approvals (including those set forth in Exhibit F) have been obtained and are in full force and effect, except for minor Governmental Approvals that are expected by such officer to be obtained in the ordinary course, the failure of which to obtain would not adversely affect the construction and/or operation of the Facility;

(2) Seller is in compliance with the terms and conditions of this PPA;

(3) the Facility is in compliance with all national and regional reliability standards, including standards set by WECC, NERC, FERC, the PUC and is compliance with all applicable terms and conditions of applicable Tariffs;

(4) Seller has good title to the Facility and all Facility Site Documents reasonably necessary for the operation and maintenance of the Facility are in full force and effect;

(5) Seller has registered (and attaching with such certificate documentation setting forth that it has registered) (i) with NERC as a generator owner and generator operator, and (ii) the Facility as a generating unit and itself as an account holder with WREGIS;

(6) Seller having successfully completed (i) Testing of the Facility that may be required by the Financing Documents, applicable Seller required Governmental Approvals, any Project Contracts, manufacturers' specifications and warranties for the commencement of Commercial Operation, and in accordance with Section 9.2 at an installed capacity of the Expected Nameplate Capacity Rating and the Storage Operation Test in accordance with Section 9.11;

(7) (i) Seller is in compliance with the Interconnection Agreement, (ii) the interconnection of the Facility to the Interconnection Provider's Interconnection Facilities has been completed in accordance with the Interconnection Agreement, (iii) the Facility has operated in a manner acceptable to the Interconnection Provider, without experiencing any abnormal or unsafe operating conditions on any interconnected system, and (iv) any other testing of the Facility and/or Seller's interconnection Facilities required by the Interconnection Agreement to interconnect and deliver energy has been completed satisfactorily;

(8) the Nameplate Capacity Rating of the Generating Facility at the time of Commercial Operation is **Insert the Expected Nameplate Capacity Rating** MW [*solar only-* AC] and the Storage System Nameplate Capacity at the time of Commercial Operation is **Insert the Expected Energy Storage Capacity** MW; and

(9) Seller shall have demonstrated that it is a Qualified Operator or that Seller has engaged a Qualified Operator to operate and maintain the Facility.

4.10 Financial Ability.

Within ninety (90) Days of the Effective Date, Seller shall provide to Tri-State copies of applicable funding agreements, financing documents or other documents and agreements, as such may be updated from time to time, which reasonably establish that Seller has or will have sufficient funding to complete the construction of the Facility and achieve Commercial Operation.

4.11 Test Energy.

Seller shall coordinate the production and delivery of Test Energy with Tri-State, with such prior notice as Tri-State may request. Tri-State shall cooperate with Seller to facilitate Testing, shall accept delivery of all Test Energy, and shall accept and purchase

all such Test Energy at the Test Energy Rate, so long as the Facility is interconnected in accordance with the Interconnection Agreement and Seller is otherwise in compliance with this PPA.

Article 5
Delivery and Metering

5.1 Delivery Arrangements.

(A) Seller shall be responsible for all interconnection arrangements and costs required to deliver the Contract Energy. Seller shall execute, deliver, and perform its obligations under the Interconnection Agreement.

(B) Seller is solely responsible for meeting its obligations as an interconnection customer under the Interconnection Provider's open access transmission tariff (the "Tariff") and the requirements of the Balancing Authority. All costs and obligations associated with Interconnection Facilities required to accomplish and operate the Interconnection Facilities is the responsibility of Seller. Seller shall satisfy any concerns of Tri-State regarding viability of the interconnection (timing and status of the generator interconnection request); *provided, however,* that any and all costs associated with this Section 5.1(B) shall be at the sole cost and expense of Seller.

(C) Seller is responsible for all electric losses, transmission and ancillary service arrangements and costs required to deliver Contract Energy to Tri-State at the Point of Delivery.

(D) Tri-State shall be responsible for all electric losses, transmission and ancillary service arrangements and costs required to deliver Contract Energy beyond the Point of Delivery. Subject to the provisions of this PPA, Tri-State may elect, at Tri-State's sole option, whether to obtain and utilize firm transmission service, non-firm transmission service or network integration transmission service for the delivery of Contract Energy from the Point of Delivery.

5.2 Availability Reporting.

Within thirty (30) Days after the end of each Commercial Operation Year, Seller shall provide Tri-State with an operating report detailing events such as maintenance outages, [Generating Unit][feeder breaker] trips and the causes of such trips, Generating Unit and Storage Unit failures and the diagnosis of such failures, status of repairs as well as statistical performance summaries and operational trends for the previous Commercial Operation Year.

5.3 Electric Metering Devices.

(A) All Electric Metering Devices used to measure the Contract Energy and to monitor and coordinate operation of the Facility shall be owned, installed, and maintained in accordance with the Interconnection Agreement. If Electric Metering

Devices are not installed at the Point of Delivery, meters or meter readings shall be adjusted to reflect losses from the Electric Metering Devices to the Point of Delivery. All Electric Metering Devices used to provide data for the computation of payments shall be sealed and only the Interconnection Provider shall break the seal when such Electric Metering Devices are to be inspected and tested or adjusted in accordance with this Article 5.

(B) Seller shall configure Electric Metering Devices in a manner that enables separate, bi-directional (as applicable) meter reading for all Energy transmitted between, or at, the following points as set forth in Exhibit B:

(1) Facility and the Point of Delivery

(2) To and from the Storage System Electric Metering Devices; and

(3) Generating Units and the Point of Delivery.

(C) Seller shall separately configure Electric Metering Devices, installed in accordance with the Local Provider's electric system and tariff requirements, as necessary, to separately account for all House Power.

(D) Seller and/or Tri-State may elect to install and maintain, at its own expense, backup metering devices ("Back-Up Metering") in addition to those installed and maintained pursuant to the Interconnection Agreement, which installation and maintenance shall be performed in a manner acceptable to Tri-State. The Party installing the Back-Up Metering shall, at its own expense, inspect and test the Back-Up Metering upon installation and periodically thereafter. The Party installing the Back-Up Metering shall provide the other Party with reasonable advance notice of, and permit a representative of the other Party to witness and verify, such inspections and tests; provided, however, that the other Party shall not unreasonably interfere with or disrupt the activities of the Party installing the Back-Up Metering and shall comply with all of such Party's safety standards. Upon request from the other Party, the Party installing the Back-Up Metering shall perform additional inspections or tests of its Back-Up Metering and shall permit a qualified representative of the other Party to inspect or witness the testing of the Back-Up Metering, provided, however, that the other Party shall not unreasonably interfere with or disrupt the activities of the Party installing the Back-Up Metering and shall comply with all of such Party's safety standards. The actual expense of any such requested additional inspection or testing by the non-installing Party shall be borne by the non-installing Party; *provided, however*, that the expense of the requested additional inspection or testing shall be borne by the Party installing if the Back-Up Metering is found to be inaccurate by more than the allowable limits established in this Article 5. If requested in writing, the Party installing the Back-Up Metering shall provide copies of any inspection or testing reports to other Party.

(E) If any Electric Metering Device, or Back-Up Metering, are found to be defective or inaccurate outside the bounds of the selected device's manufacturer's performance standards, they shall be adjusted, repaired, replaced, and/or recalibrated as near as practicable to a condition of zero error by the Party owning such defective or inaccurate device and at that Party's expense.

(F) Seller shall be responsible for the design, installation, operation and maintenance of site data historian systems at the Facility, which are linked on a real-time basis and interoperable with the RDD subject to prior written approval of such systems by Tri-State.

5.4 Adjustment for Inaccurate Meters.

If an Electric Metering Device, or Back-Up Metering, fails to register, or if the measurement made by an Electric Metering Device, or Back-Up Metering, is found upon testing to be inaccurate by more than one percent (1.0%), an adjustment shall be made correcting all measurements by the inaccurate or defective Electric Metering Device, or Back-Up Metering, for both the amount of the inaccuracy and the period of the inaccuracy, in the following manner:

(A) In the event that the Electric Metering Device is found to be defective or inaccurate, the Parties shall use Tri-State's Back-up Metering, if installed, to determine the amount of such inaccuracy; *provided,* however, that Tri-State's Back-Up Metering has been tested and maintained in accordance with the provisions of this Article 5. If Tri-State's Back-Up Metering is installed on the low side of Seller's step-up transformer, Tri-State's Back-Up Metering data shall be adjusted for losses. In the event that Tri-State did not install Back-Up Metering, or Tri-State's Back-Up Metering is also found to be inaccurate by more than one percent (1.0%), the Parties shall use Seller's Back-up Metering, if installed, to determine the amount of such inaccuracy; provided, however, that Seller's Back-Up Metering has been tested and maintained in accordance with the provisions of this Article 5. If Seller's Back-Up Metering is installed on the low side of Seller's step-up transformer, Seller's Back-Up Metering data shall be adjusted for losses. In the event that Seller did not install Back-Up Metering, or Seller's Back-Up Metering is also found to be inaccurate by more than one percent (1.0%), the Parties shall estimate the amount of the necessary adjustment on the basis of deliveries of Contract Energy during periods of similar operating conditions when the Electric Metering Device was registering accurately. The adjustment shall be made for the period during which inaccurate measurements were made.

(B) In the event that the Parties cannot agree on the actual period during which the inaccurate measurements were made, the period during which the measurements are to be adjusted shall be the shorter of (i) the last one-half of the period from the last previous test of the Electric Metering Device to the test that found the Electric Metering Device to be defective or inaccurate, or (ii) the one hundred eighty (180) Days immediately preceding the test that found the Electric Metering Device to be defective or inaccurate.

(C) To the extent that the adjustment period covers a period of deliveries for which payment has already been made by Tri-State, Tri-State shall use the corrected measurements as determined in accordance with this Article 5 to recompute the amount due for the period of the inaccuracy and shall subtract the previous payments by Tri-State for this period from such re-computed amount. If the difference is a positive number, the difference shall be paid by Tri-State to Seller; if the difference is a negative number, the difference shall be paid by Seller to Tri-State, or at the discretion of Tri-State, may take the form of an offset to payments due Seller by Tri-State. Payment of such difference by the owing Party shall be made not later than thirty (30) Days after the owing Party receives notice of the amount due, unless Tri-State elects payment via an offset.

5.5 WREGIS Metering.

Seller shall cause the Facility to implement all necessary generation information communications required by WREGIS, and report generation information to WREGIS pursuant to a WREGIS-approved meter that is dedicated to the Facility.

5.6 Charging Requirements

Tri-State shall be responsible for scheduling all of the Charging Energy for the Storage System in accordance with Section 6.9 and the Storage System Operating Procedures. Seller shall be responsible for delivering all Charging Energy from the Generating Facility to the Storage System. Seller shall be responsible for delivering all Discharging Energy up to and including delivery and receipt at the Point of Delivery. Tri-State shall be responsible for all Discharging Energy after delivery and receipt at the Point of Delivery. Seller shall take any and all action necessary to allow the delivery of Charging Energy to the Storage System in order to deliver Energy in accordance with the terms of this PPA, including maintenance, repair or replacement of equipment in Seller's possession or control used to deliver the Charging Energy to the Storage System and to delivery Discharging Energy at the Point of Delivery. Seller is responsible for any and all costs associated with charging the Storage System.

Article 6
Sale and Purchase of Contract Energy

6.1 Sale and Purchase.

Beginning on the Commercial Operation Date, Seller shall generate from the Generating Facility, store in the Storage System, and deliver to the Point of Delivery, and sell to Tri-State, and Tri-State shall purchase from Seller, at the applicable price set forth in Article 7, all Contract Energy and other products and services required by this PPA; *provided* that, notwithstanding anything in this PPA to the contrary, Tri-State shall have no obligation (i) to pay for any Energy that has not actually been generated by the Generating Facility, measured by the Electric Metering Device(s), and delivered to Tri-State at the Point of Delivery except for payments of Curtailed Contract Energy as set

forth in Section 7.2 or (ii) to pay for any Energy generated by the Facility to the extent the instantaneous output exceeds **Insert the Expected Nameplate Capacity Rating** MW. Seller shall be responsible for, and shall reimburse Tri-State for, any charges, fees, fines or penalties assessed to Tri-State by the Transmission Provider, Balancing Authority, or an Organized Market as a result of the instantaneous output exceeding **Insert the Expected Nameplate Capacity Rating** MW. Seller shall not curtail or interrupt deliveries of Contract Energy to Tri-State for economic reasons of any type.

6.2 Title and Risk of Loss.

As between Seller and Tri-State, Seller shall be deemed to be in control of the Contract Energy up to and including delivery and receipt at the Point of Delivery and Tri-State shall be deemed to be in control of Contract Energy after delivery and receipt at the Point of Delivery. Title and risk of loss related to the Contract Energy shall transfer from Seller to Tri-State at the Point of Delivery.

6.3 Right to Curtail Energy.

(A) Tri-State shall have the right at any time to notify Seller, by telephonic communication from the RDD or by the AGC system, to curtail the delivery of Contract Energy, in whole or in part, to Tri-State from the Facility to the Point of Delivery, and Seller shall as soon as reasonably practicable, but within no more than ten (10) minutes, comply with such notification consistent with Prudent Utility Practices. Tri-State may provide such notification for any reason and in its sole discretion. Any payments for such curtailed Contract Energy shall be in accordance with Section 7.2. Such curtailment rights do not provide Tri-State with any rights to direct the operation of the Facility.

(B) In the event the Transmission Provider, Interconnection Provider, Balancing Authority, Reliability Coordinator, an Organized Market, NERC, WECC, FERC or any other Governmental Authority either directs Tri-State to notify Seller or notifies Seller directly, by any method established by such Person, to curtail the delivery of Contract Energy, in whole or in part, to Tri-State from the Facility, Seller shall as soon as reasonably practicable, but within no more than ten (10) minutes, comply with such notification consistent with Prudent Utility Practices.

(C) Seller shall be responsible for, and shall reimburse Tri-State to the extent Tri-State is charged and pays for any damages, fines or penalties as a result of Seller failing to comply with such curtailment instructions described in this Section 6.3.

6.4 Scheduling.

(A) Seller shall be responsible for providing the forecast of Contract Energy deliveries during the Term in accordance with the mutually-developed Operating Procedures described in Section 9.10(B).

(B) No later than ninety (90) Days before the start of Testing and by August 1 of each Year thereafter, Seller shall provide, or cause to be provided, to Tri-State, in a format acceptable to Tri-State, a forecast of each Month's average-day deliveries of Contract Energy, by hour, for the following Year.

(C) No later than thirty (30) Days before the start of Testing and at least ten (10) Business Days before the beginning of each Month thereafter, Seller shall provide, or cause to be provided, to Tri-State, in a format acceptable to Tri-State, a forecast of each Day's average deliveries of Contract Energy, by hour, for the following Month.

(D) Seller shall provide, or cause to be provided to Tri-State, by 6:00 a.m. MPT on each Day, in a format acceptable to Tri-State, a forecast of the hourly quantities of Contract Energy to be delivered to Tri-State for the immediately succeeding Day or for multiple Days as may be required by the parameters of the WECC prescheduling calendar.

(E) Seller shall provide, or cause to be provided to Tri-State, thirty (30) minutes before the start of every hour, in a format acceptable to Tri-State, a forecast of the hourly quantity of Contract Energy to be delivered to Tri-State for the next scheduling hour. As an example, Seller shall provide to Tri-State by 6:30 a.m. MPT, a forecast of the hourly quantity of Contract Energy to be delivered to Tri-State beginning 8:00 a.m. MPT and ending 9:00 a.m. MPT.

(F) If, at any time following submission of a forecast as described in Sections 6.4(B), (C), (D) and (E), Seller becomes aware of any change that alters the values previously provided to Tri-State, Seller shall promptly notify Tri-State no later than sixty (60) minutes before the next scheduling hour of such change or predicted change and if such change reduces the forecasted availability of the Facility more than ten (10) MW, such reduction shall be communicated to the RDD as soon as reasonably practicable, but within no more than ten (10) minutes.

(G) Tri-State and Seller shall agree upon reasonable changes to the requirements and procedures set forth above from time to time, as necessary to comply with changes to the Tariff or other requirements set forth by Tri-State, the Interconnection Provider, the Balancing Authority, the Transmission Provider, or an Organized Market, to accommodate changes to their respective generation technology and organizational structure and address changes in the operation and scheduling procedures of Tri-State, the Interconnection Provider, the Balancing Authority, the Transmission Provider, or the Organized Market, including more frequent reporting and automated forecast and outage submissions.

(H) Within fifteen (15) Days after the end of each quarter of the Year commencing with the first full quarter of the Year after the Commercial Operation Date, Seller shall calculate the aggregate MAPE for the prior quarter and provide such percentage, together with reasonable documentation supporting such calculation, to Tri-

State. Such percentage of MAPE amount is subject to verification by Tri-State. If the aggregate MAPE for any quarter exceeds [*wind only-* twelve percent (12%)][*solar only-* seven percent (7%)], Seller shall pay Tri-State, as liquidated damages and not a penalty, within ten (10) Days after delivering such calculation to Tri-State **Insert $2000*Expected Nameplate Capacity Rating** for each one percent (1.0%) above such amount, adjusted pro-rata for any partial percentage. Each Party agrees and acknowledges that (i) the damages that Tri-State would incur due to Seller's forecasting inaccuracies would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the liquidated damages as agreed to by the Parties set forth in this Section 6.4(H) are a fair and reasonable calculation of such damages.

6.5 Forced Outages and Emergency Conditions.

Seller shall notify the RDD by telephone call or other automated means acceptable to Tri-State as promptly as possible upon discovering that the Facility is unable to deliver all or part of any scheduled quantity of Contract Energy due to a Forced Outage, Storage System Forced Outage, or Emergency Condition resulting in a Generating Facility capacity reduction of more than ten (10) MW or Storage System capacity reduction of more than ten percent (10%) and, as soon as reasonably practicable, but within no more than ten (10) minutes, following such discovery, shall notify the RDD of its best estimate of the expected duration of such Storage System Forced Outage, Forced Outage or Emergency Condition. Such estimate by Seller shall be based on the best information available to it. Should Seller expect any further changes in the duration of any such Storage System Forced Outage, Forced Outage or Emergency Condition, it shall as soon as reasonably practicable, but within no more than ten (10) minutes, of such change notify the RDD of the same.

6.6 *[wind only-*Cut-Out Events.

In the event of a Cut-Out Event, Seller shall coordinate with Tri-State's RDD the ramp-up rate of the Facility back to full production after such event.]

6.7 Guaranteed Energy Production.

(A) During each Commercial Operation Year, Seller is required to deliver to Tri-State at least the Guaranteed Energy Production; *provided* that the Facility shall be deemed to have generated Contract Energy during such Commercial Operation Year to the extent it was capable of delivering Contract Energy but failed to deliver such Contract Energy due to a (i) Delivery Excuse, (ii) Force Majeure Event, (iii) Emergency Condition, or (iv) a curtailment pursuant to Section 6.3 (except for a curtailment caused by a Forced Outage or otherwise covered by Section 7.2(B)(9) through (11)) with such deemed quantity to be determined using the factors set forth in Section 7.2(A).

(B) In the event Seller delivers less than the Guaranteed Energy Production in any Commercial Operation Year, Tri-State shall promptly invoice Seller for

an amount equal to the Shortfall MWh multiplied by the Contract Energy Rate during such Commercial Operation Year. Invoiced amounts shall be payable in accordance with Section 8.3(A); *provided* that this Section shall not limit Tri-State's rights and remedies under Article 12 with respect to Deficiency MWhs upon the occurrence of and during an Event of Default or Replacement Costs upon termination of this PPA. Each Party agrees and acknowledges that (i) the damages that Tri-State would incur due to Seller's failure in achieving the Guaranteed Energy Production would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the liquidated damages as agreed to by the Parties set forth in this Section 6.7 are a fair and reasonable calculation of such damages and not a penalty.

6.8 Organized Market.

(A) If at any time during the Term, the Interconnection Provider changes or the facilities at the Point of Delivery cease to be subject to the Interconnection Provider's Tariff, Tri-State and Seller shall cooperate and take all necessary actions to facilitate the delivery of Contract Energy from the Point of Delivery to Tri-State's load, at the least possible cost to the Parties, consistent with this PPA.

(B) If at any time during the Term, (i) the Interconnection Provider, the Transmission Provider, the Balancing Authority, or Tri-State elects to join or participate in an Organized Market, or (ii) WECC, NERC, FERC or any other Governmental Authority institutes an Organized Market and such action requires changes to this PPA or changes the manner in which the Facility is scheduled and dispatched, the Parties shall cooperate in good faith to change their protocols for operation and scheduling of the Facility and to amend this PPA to comply with such changes accordingly, at the least possible cost to the Parties, consistent with this PPA. The Parties shall negotiate and allocate the costs associated with these changes between the Parties in a fair and reasonable manner.

6.9 Storage System Dispatch

(A) Every Storage Operating Day, Tri-State's RDD shall have the exclusive right to dispatch the Storage System, twenty-four (24) hours per Day, by communicating with Seller electronically in accordance to the requirements and limitations set forth in this PPA, including the Storage System Operating Procedures. Seller shall abide with all directives from Tri-State, subject only to Prudent Utility Practices.

(B) For each Storage Operating Day, Seller shall provide to Tri-State an hourly schedule of the expected availability of the Storage System for such Storage Operating Day, no later than two (2) Business Days before such Storage Operating Day (the "Availability Notice"). Seller must update Tri-State immediately, unless an event or circumstance makes it unsafe to do so, then as soon as practicable the availability of the Storage System for dispatch by Tri-State changes. Seller shall accommodate Tri-

State's reasonable requests for changes in the time or form of delivery of the Availability Notices.

Article 7
Payment Calculations

7.1 Contract Energy Payment.

(A) Contract Energy Payment. Except as otherwise provided in this PPA, commencing on the Commercial Operation Date, Tri-State shall pay Seller an energy payment for each Month (the "Contract Energy Payment") equal to the product of (i) the applicable Contract Energy Rate; and (ii) the aggregate amount of Contract Energy (other than Test Energy and Excess Contract Energy) delivered to Tri-State. The Contract Energy Payment for each Month during the Term shall be paid in accordance with the invoicing procedures set forth in Section 8.1.

(B) Test Energy Payment. Tri-State shall pay for all Test Energy at the Test Energy Rate. Test Energy Payments shall be equal to the product of (i) the Test Energy Rate; and (ii) the aggregate amount of Test Energy delivered by Seller to Tri-State during such Month. The Test Energy Payment for each Month during the Term shall be paid in accordance with the invoicing procedures set forth in Section 8.1.

(C) Excess Contract Energy Payment. Except as otherwise provided in this PPA, Tri-State shall pay for all Excess Contract Energy, if any, generated and delivered in each Commercial Operation Year, during the Term at the Excess Contract Energy Rate. Excess Contract Energy Payments shall be equal to the product of (i) the applicable Excess Contract Energy Rate for such Month, and (ii) the aggregate amount of Excess Contract Energy delivered by Seller to Tri-State. The Excess Contract Energy Payment, if any, for each Month during the Term shall be paid in accordance with the invoicing procedures set forth in Section 8.1.

7.2 Curtailed Contract Energy Payment.

(A) Determination of Curtailed Contract Energy. On and after the Commercial Operation Date, if delivery of Contract Energy is curtailed by Tri-State pursuant to Section 6.3(A), then:

(1) The Parties shall determine the quantity of Contract Energy that would have been generated by the Facility and delivered to the Point of Delivery during the period of curtailment had its generation not been so curtailed by Tri-State ("Curtailed Contract Energy") by using the best available data obtained through commercially reasonable methods in accordance with the Operating Procedures; and shall be dependent upon measured [wind speed and wind direction][solar irradiance] gathered from appropriate [*wind only-* Generating Units anemometers][*solar only-* pyranometers] and meteorological towers at the Facility during those hours in which Tri-State curtailed its receipt of Contract Energy, as such process may be further described

in the Operating Procedures, and any other adjustments necessary to accurately reflect the Facility's capacity to generate and deliver Energy to the Point of Delivery including applicable losses and manufacturers' warranted power curves (a copy of which shall be provided to Tri-State) for all operational Generating Units whose output was curtailed. The methodology utilized to measure Curtailed Contract Energy shall be reviewed and adjusted, as necessary, by the Operating Committee, at least once every five (5) years after the Commercial Operation Date.

(2) Tri-State shall pay to Seller for such Curtailed Contract Energy all amounts that Seller would have received from Tri-State under this PPA for the corresponding Contract Energy had delivery not been so curtailed by Tri-State (and at the applicable rates set out in Section 7.1) [wind only -plus an amount per MWh that equals (a) the Production Tax Credit to the extent Seller would have been entitled to receive such Production Tax Credit plus (b) a gross up amount to take into account the federal, state and local income tax to Seller or its Affiliates or tax investors on such payment in lieu of the Production Tax Credit, calculated in accordance with the following formula] (the "Curtailed Contract Energy Payment"):

[wind only -

$$\text{Amount of Payment in lieu of Production Tax Credit} \times \frac{1}{\text{1-applicable aggregate tax rate}}$$

For the avoidance of doubt, Seller shall not be entitled to recover any of the above referenced tax benefits to the extent Seller would not have been entitled to receive the Production Tax Credit had the Curtailed Contract Energy actually been delivered.]

(3) In the event Tri-State is obligated to pay for Curtailed Contract Energy under this Section 7.2(A), Seller shall provide on the applicable monthly invoice detailed calculations of the Curtailed Contract Energy and the Curtailed Contract Energy Payment due Seller.

(B) Restriction on Curtailment Payments. Notwithstanding anything in this Section 7.2 to the contrary, no payment shall be due to Seller from Tri-State under paragraph (A) above for curtailments of delivery of Contract Energy resulting from:

(1) an Emergency Condition, Force Majeure Event, Storage System Forced Outage, or Forced Outage;

(2) the failure of Seller's Interconnection Facilities or any action taken by the Interconnection Provider in accordance with its rights under the Interconnection Agreement and not due to Seller's default;

(3) any restriction, reduction, or curtailment of firm transmission service or network integration transmission service by the applicable Transmission Provider, arranged by either Party, to provide transmission of Contract Energy to or from the Point of Delivery;

(4) any restriction, reduction, or curtailment of non-firm transmission service by the applicable Transmission Provider, arranged by either Party, to provide transmission of Contract Energy to or from the Point of Delivery to the extent such restriction, reduction, or curtailment would also have been imposed even if firm transmission service had been in place;

(5) maintenance outages, whether planned or unplanned, of any part of the Transmission System or any testing of the Transmission System;

(6) Allowable Curtailment;

(7) [*wind only-* Cut-Out Events; provided that Tri-State shall compensate Seller for any curtailment of Contract Energy up to one (1) hour for the first Cut-Out Event per quarter of any Year];

(8) any notification from the Balancing Authority requiring Seller to curtail or cease deliveries of Contract Energy to achieve load balancing in the Balancing Authority Area or any notifications from the Reliability Coordinator requiring Seller to curtail or cease deliveries of Contract Energy;

(9) any curtailment arising from Seller's failure to obtain and/or maintain in full force and effect any Governmental Approval or WREGIS registration, or failure to comply with applicable NERC reliability standards;

(10) any action taken by the Interconnection Provider pursuant to Seller's default under the Interconnection Agreement; or

(11) Seller fails or refuses to respond to AGC instructions from the SCADA system, Seller fails or refuses to respond, or Seller refuses or fails to respond to a curtailment instruction from Tri-State, the RDD, the Transmission Provider, Interconnection Provider, Balancing Authority, Reliability Coordinator, an Organized Market, NERC, WECC, FERC or any other Governmental Authority pursuant to Section 6.3 including if the Interconnection Provider trips the breaker at the Electric Interconnection Point, due to Seller's failure or refusal.

7.3 Adjustments to Payments/Storage Payment.

[if any –project and payment formula specific]

Article 8
Billing and Payment Procedures

8.1 Billing Invoices.

No later than ten (10) Business Days after the end of each Month, Seller shall provide to Tri-State an invoice for the amount due to Seller by Tri-State for Contract Energy delivered by Seller to Tri-State and the Curtailed Contract Energy, if any, determined pursuant to Section 7.2 for such Month. Seller's invoice shall show metered Energy from the Facility, all billing parameters, rates and factors, and any other data reasonably pertinent to the calculation of monthly payments due to Seller. If Tri-State disputes any portion of the invoice, Tri-State shall provide to Seller an explanation of the items in dispute. Billing disputes shall be resolved in accordance with Section 8.4.

8.2 Metered Billing Data.

All billing data based on metered deliveries to Tri-State shall be collected by the Electric Metering Device(s) in accordance with Article 5.

8.3 Payments and Late Payments.

(A) Payment Due to Tri-State. Unless otherwise specified herein, payments due to Tri-State under or in connection with this PPA shall be due and payable by electronic funds transfer, as designated by Tri-State, on or before the fifth (5th) Business Day following receipt of the billing invoice. Any failure to make full payment within such time period shall constitute an Event of Default of Seller upon its occurrence but shall be subject to cure within three (3) Business Days after the date of written notice from Tri-State to Seller. This Section shall not limit Tri-State's right to draw any such amounts due from the Security in accordance with Section 11.1(E).

(B) Payments due to Seller. Unless otherwise specified herein, payments due to Seller under or in connection with this PPA shall be due and payable by electronic funds transfer, as designated by Seller, on or before the twentieth (20th) Business Day following receipt of the billing invoice. Any failure to make full payment within such time period shall constitute an Event of Default of Tri-State upon its occurrence but shall be subject to cure within ten (10) Business Days after the date of written notice from Seller to Tri-State.

(C) Late Payment Charges. If the undisputed amount due is not paid on or before the due date, a late payment charge shall be applied to the unpaid balance and shall be added to the next billing statement. Such late payment charge shall be calculated based on the lower of (i) an annual interest rate equal to two percent (2%) plus the prime interest rate, as published on the date of the invoice in *The Wall Street Journal* (or, if *The Wall Street Journal* is not published on that Day, the next succeeding date of publication) and (ii) the maximum interest rate allowed by Applicable Law

("Default Rate"). If the due date occurs on Day that is not a Business Day, the late payment charge shall begin to accrue on the next succeeding Business Day.

(D) Offset. Tri-State at any time may offset against amounts owed to Seller, any liquidated amounts, accrued damages and other payments, and undisputed billing errors and adjustments, which are owed by Seller to Tri-State.

8.4 Billing Disputes.

Either Party may dispute invoiced amounts, but shall pay to the other Party at least the undisputed portion of invoiced amounts on or before the invoice due date. To resolve billing disputes, the Parties shall use the procedures set forth in Section 13.9(A). When the billing dispute is resolved, the Party owing shall pay the amount owed within five (5) Business Days of the date of such resolution, with late payment interest charges calculated on the amount owed in accordance with the provisions of Section 8.3 if payment is not received within the five (5) Business Days. Undisputed amounts invoiced under this PPA shall be paid on or before the due date or shall be subject to the late payment interest charges set forth in Section 8.3(C).

8.5 Statement Errors.

In the event that either Party becomes aware of any error in any statement, such Party shall, promptly upon discovery of the error, notify in writing the other Party of such error and shall rectify such error (whether in the form of an underpayment or overpayment) within thirty (30) Days of such notification. If a Party does not notify the other Party of any error (regardless of actual knowledge of such error) within three hundred sixty five (365) Days of such error, any payment associated with such error older than three hundred sixty five (365) Days shall be waived. Except for adjustments in the billing and payment for defective or inaccurate Electric Metering Devices as provided in Section 5.4, if Seller fails to invoice for Contract Energy or Curtailed Contract Energy within one hundred eighty (180) Days of delivery of such Contract Energy or curtailment of Contract Energy, payment for such shall be waived.

8.6 Taxes.

(A) Tax Responsibility. Seller shall be responsible for, and shall pay when due, all income, gross receipts, sales, *ad valorem*, personal property or real property or other similar taxes and any and all franchise fees or similar fees assessed against Seller or the Facility due to generation of Energy from the Facility, the construction, ownership, leasing, operation or maintenance of the Facility, or any components or appurtenances thereof, including all taxes, fees, allowances, trading credits and other offsets and impositions for wastes and emissions (including carbon-based compounds, oxides of nitrogen and sulfur, mercury and other Regulated Materials) produced by the Facility. Seller's prices under Article 7 are inclusive of such Taxes, allowances and credits during the Term. If Tri-State is assessed any Taxes or associated fees as a result of the improvement of the Site due to the existence of the

Facility on the Site, Tri-State shall promptly notify Seller. Tri-State and Seller shall cooperate in contesting such assessment; *provided, however,* that Tri-State may pay such Taxes to avoid any penalties on such assessments subject to reimbursement by Seller. If, after resolution of the matter, Taxes are imposed on Tri-State as a result of the improvement of the Site due to the existence of the Facility on the Site, Seller shall reimburse Tri-State for such Taxes. Seller shall not be obligated to pay or reimburse Tri-State for Taxes imposed on or measured by the Tri-State's overall revenues or income.

(B) Reimbursement. If a Party is required to remit or pay Taxes that are the other Party's responsibility hereunder, such Party shall promptly reimburse the other Party for such Taxes.

(C) Information. The Parties shall provide each other, upon written request, with copies of any documentation that may be reasonably necessary in the ordinary course of any inter-governmental, state, local, municipal or other political subdivision tax audit inquiry or investigation.

(D) Cooperation. Consistent with Applicable Law, the Parties shall cooperate to minimize Taxes; *provided, however,* that no Party shall be obligated to incur any extraordinary financial burden to reduce Taxes for which the other Party is responsible hereunder.

(E) Failure to Qualify for Tax Credits. Seller's failure to qualify for the Tax Credits or Additional Tax Benefits for any reason including Delivery Excuse, Force Majeure Event, the acts or inaction of the Interconnection Provider or of any third party, or any Event of Default, shall not release Seller of its obligations to comply with this PPA, give rise to any damages payable by Tri-State or an increase in the price for Contract Energy.

(F) Additional Tax Benefits. From and after the Effective Date and throughout the Term, in the event that Seller or the Facility qualifies for and receives or is subject to Additional Tax Benefits, Seller and Tri-State shall share on a 50/50 basis the Additional Tax Benefit Amount associated with such Additional Tax Benefits by making an adjustment to the Contract Energy Rate for the Term of the PPA to account for such Additional Tax Benefit Amount. For the avoidance of doubt, Additional Tax Benefits may not result in an increase to the Contract Energy Rate. The Contract Energy Rate shall be adjusted in the first month following the effective date of the Applicable Law, which may be in the form of new or revised guidance or interpretations by a Governmental Authority having jurisdiction related to such Applicable Law, pursuant to which such Additional Tax Benefit is enacted. Seller shall at all times retain all right, title and interest in any Additional Tax Benefits. Seller shall provide Tri-State with written notice upon its receipt of Additional Tax Benefits, and along with such notice provide to Tri-State commercially reasonable documentation describing: (i) the Additional Tax Benefit Amount, (ii) the effective date of the Applicable Law, including guidance or interpretations by a Governmental Authority, (iii) reasonable accounting of

the Additional Tax Benefit Costs associated therewith, verified by an independent national accounting firm selected by Seller at Seller's expense, subject to further verification by Tri-State, and (iv) a calculation of the reduction to the Contract Energy Rate.

Article 9
Testing, Operations and Maintenance

9.1 Modification of the Facility.

Seller shall not modify the Facility in any way that would increase or decrease the electric energy generating capacity or storage capacity of the Facility or the output of Contract Energy to be delivered to Tri-State under this PPA without Tri-State's prior written consent, which may be withheld in its sole discretion.

9.2 Facility Tests Prior to Commercial Operation.

Seller shall give Tri-State at least three (3) Months prior notice of (i) the approximate Test Date, (ii) the proposed Tests scheduled relating to the commissioning of the Facility, and (iii) a draft of the Testing procedures and requirements. Tri-State shall review and provide any comments on the Testing procedures and requirements within thirty (30) Days of receipt. Representatives of Tri-State shall have the right to be present at all such Testing. Seller shall promptly notify Tri-State of any changes to the Test Date or the date of any Tests relating to the Facility in order that Tri-State may arrange for its respective representatives to attend.

9.3 Operation and Maintenance of the Facility.

Seller shall staff, control, operate, maintain, and repair the Facility or cause the same to be staffed, controlled, operated, maintained, and repaired at all times in accordance with manufacturers' recommendations and Prudent Utility Practices and otherwise in accordance with this PPA. Seller shall procure and maintain a Qualified Operator to operate and maintain the Facility. Personnel (i) capable of remotely starting, operating and stopping the Facility shall be continuously available and reachable by phone, and (ii) shall be capable of being at the Facility on no more than sixty (60) minutes' notice, weather conditions permitting.

9.4 Replacement of Facility Equipment.

Seller shall, consistent with Prudent Utility Practices, repair and replace all necessary equipment at the Facility required to deliver and store Contract Energy for the Term.

9.5 Disposal of Facility Equipment.

Upon the cessation of operations or the replacement of equipment, Seller shall, at its sole expense and cost, dispose of all Facility equipment no longer in use in accordance with Applicable Law and Prudent Utility Practices, and all requirements under the Facility Site Documents.

9.6 Scheduled Maintenance.

Three (3) Months prior to the Commercial Operation Date and, thereafter, by August 1 of each Year, Seller shall deliver to Tri-State the projected schedule of Scheduled Maintenance Outages, for the subsequent Year or the remainder of the Term, whichever period of time is shorter. Seller shall notify Tri-State of a Scheduled Maintenance Outage and any changes to such no later than sixty (60) Days prior to the start date of a Scheduled Maintenance Outage. In the event a Scheduled Maintenance Outage is extended, Seller shall notify Tri-State as soon as practicable of such extension and the expected end date of such Scheduled Maintenance Outage. Scheduled Maintenance Outages and/or Additional Maintenance Outages may not be scheduled during the Months of January, June, July, August, September, or December unless agreed to in writing by Tri-State at its sole discretion.

9.7 Additional Maintenance Outages.

Before Seller conducts further maintenance on the Facility which would result in greater than ten (10) MW of the Nameplate Capacity Rating of the Generating Facility being taken out of service, greater than ten percent (10%) of the Storage System Nameplate Capacity Rating being taken out of service, or Seller's Interconnection Facilities being taken out of service in addition to the Scheduled Maintenance Outages conducted pursuant to Section 9.6 ("Additional Maintenance Outages"), Seller shall notify Tri-State of such required maintenance, together with proposed dates for carrying out such additional maintenance and the estimated duration of the work to be carried out. To the extent possible, such notification to Tri-State shall be provided no later than sixty (60) Days prior to the start date of an Additional Maintenance Outage. Unless deferral of such maintenance would cause an Emergency Condition, Seller and Tri-State shall negotiate in good faith a reasonable schedule during which such Additional Maintenance Outages shall take place. In the event an Additional Maintenance Outage is extended, Seller shall notify Tri-State as soon as practicable of such extension and the expected end date of such Additional Maintenance Outage.

9.8 Access to and Inspection of Facility.

(A) Seller shall provide Tri-State and its authorized employees, agents and inspectors with reasonable access to the Facility (including Tri-State's equipment, if any) for the purposes set forth herein. Tri-State acknowledges that such access does not provide Tri-State with the right to direct or modify the operation of the Facility in any

way and further acknowledges that any exercise by Tri-State of its rights under this Section 9.8 shall be at its own risk and expense.

(B) No inspections of the Facility, whether by Tri-State or otherwise, shall relieve Seller of its obligation to maintain the Facility and operate the same in accordance with Prudent Utility Practices. In no event shall any statement, representation, or lack thereof by Tri-State, either express or implied, relieve Seller of its exclusive responsibility for the Facility.

9.9 Operating Parameters.

(A) Seller shall operate, maintain or procure the operation and maintenance of the Facility in accordance with the Storage Requirements, Prudent Utility Practices and Applicable Law. Subject to compliance with Prudent Utility Practices and Applicable Law, Seller shall operate the Facility in such a manner that Contract Energy shall meet all requirements required by the Interconnection Provider and the Transmission Provider.

(B) Seller shall operate the Facility such that all system protective equipment is in service whenever the Facility is connected to, or is operated in parallel with, the Transmission System, except for normal testing and repair. Seller shall provide adequate system protection and control devices to ensure safe and protected operation of all energized equipment during normal testing and repair. The Facility's protective equipment shall meet Institute of Electrical and Electronic Engineers and all other applicable industry standards. Seller shall have qualified personnel test, calibrate and certify in writing the proper functioning of all protective equipment in accordance with the intervals and maintenance activities for each component as established by the appropriate reliability standards. All of the foregoing shall be conducted in accordance with Prudent Utility Practices.

9.10 Operating Committee and Operating Procedures.

(A) Representative. Tri-State and Seller shall each appoint one (1) representative and one (1) alternate representative to act in matters relating to the Parties' performance obligations under this PPA and to develop operating arrangements for the generation, delivery and receipt of Contract Energy hereunder. Such representatives shall constitute the Operating Committee, and shall be specified in Exhibit H. Each Party shall notify the other Party in writing of any changes to their representative and provide the other Party an updated Exhibit H. The Operating Committee shall have no authority to amend or waive any terms or conditions of this PPA.

(B) Operating Procedures. Prior to the Commercial Operation Date, the Operating Committee shall develop mutually agreeable written Operating Procedures which shall include methods of day-to-day communications; metering, telemetering, telecommunications, and data acquisition procedures; key personnel list

for applicable Tri-State and Seller operating centers; operations and maintenance scheduling and reporting; Contract Energy reports; measurement of Curtailed Contract Energy; unit operations log; charging and dispatch of the Storage System, and such other matters as may be mutually agreed upon by the Parties.

9.11 Storage System Testing

(A) Prior to the Commercial Operation Date, Seller shall schedule and successfully complete a "Storage Operation Test" in accordance with Exhibit N and provide the results of such to Tri-State.

(B) On an annual basis during Commercial Operation, upon seven (7) days prior notice to Tri-State, Seller shall schedule and complete a "Storage Periodic Test" in accordance with Exhibit N and provide the results of such to Tri-State. In addition, either Party shall have the right to require a retest at any time if such Party reasonably believes that the performance of the Storage System has varied materially from the results of the most recent Storage Test. Such retest shall be scheduled as soon as is reasonably practicable for the Parties consistent with Prudent Utility Practice.

(C) If Seller fails a Storage Periodic Test, then Seller shall be required to commence repairs in accordance with Section 9.12.

9.12 Storage System Repair Obligations

In the event that any equipment failure with respect to the Storage System results in the Storage System failing a Storage Test, then Seller shall repair the Storage System in accordance with Prudent Utility Practices. Within fourteen (14) Days of such failure, Seller shall demonstrate such remedy to Tri-State's satisfaction or present to Tri-State a description of the reason for the failure and a plan and schedule for the repair. Seller shall diligently and expeditiously implement such repair plan and repair the Storage System.

Article 10
Environmental Attributes

10.1 Ownership of Environmental Attributes.

(A) Ownership of Environmental Attributes. Payment of each of the Contract Energy Rate, Test Energy Rate and the Excess Contract Energy Rate to Seller by Tri-State includes the consideration for the purchase and ownership of, and the right to market and sell, all Environmental Attributes associated with the generation of Contract Energy, Test Energy and Excess Contract Energy, respectively.

(B) Duration. Environmental Attributes associated with the Contract Energy are owned by Tri-State and Tri-State shall have the right to own and to use such Environmental Attributes for any purpose, including any Environmental Attributes that are reserved or "banked" during the Term of this PPA but not used, sold, assigned or

otherwise transferred during the Term of this PPA. Tri-State may assign its rights, title and interest in and to any Environmental Attributes associated with Contract Energy to one or more third parties under any transaction.

10.2 Transfer of Title to Environmental Attributes; Documentation of Environmental Attributes Transfers.

(A) Title. Title to the Environmental Attributes shall irrevocably pass from Seller to Tri-State immediately upon the generation of Contract Energy at the Facility that gives rise to such Environmental Attributes.

(B) Bill of Sale. Upon request from Tri-State, Seller shall deliver to Tri-State an Attestation and Bill of Sale in the form attached as Exhibit J for all Environmental Attributes delivered to Tri-State during the time period requested by Tri-State.

(C) WREGIS Compliance. Seller shall, at its sole expense, use WREGIS to provide and convey to Tri-State the Environmental Attributes associated with the generation of Contract Energy. Such Environmental Attributes shall be conveyed in a manner consistent with the WREGIS provision below promptly upon WREGIS certificates relating to the Facility being credited to Seller's WREGIS account.

(D) WREGIS Account. Prior to Testing, Seller shall register the Facility with WREGIS and establish an account with WREGIS ("Seller's WREGIS Account"), which Seller shall maintain through the Term. Seller shall transfer the WREGIS certificates using "Forward Certificate Transfers" (as described in the WREGIS Operating Rules) from Seller's WREGIS Account to the WREGIS account(s) of Tri-State or the account(s) of a designee that Tri-State identifies by written notice ("Tri-State's WREGIS Account"). Seller shall be responsible for all expenses associated with registering the Facility with WREGIS, establishing and maintaining Seller's WREGIS Account, paying WREGIS certificate issuance and transfer fees, and transferring WREGIS certificates from Seller's WREGIS Account to Tri-State's WREGIS Account.

(E) Qualified Reporting Entity. Seller shall procure and maintain a Person to act as a qualified reporting entity and provide qualified reporting services for the Facility as required by WREGIS.

(F) Reporting Compliance. Seller, at its own cost and expense, shall comply with all reporting and other requirements of WREGIS relating to the Facility or Environmental Attributes.

(G) No Liens or Encumbrances. Environmental Attributes shall be transferred to Tri-State free of all liens and encumbrances.

(H) Additional Certification. Upon request from Tri-State, Seller shall, at its expense, register and/or certify the Facility with Governmental Authorities

requested by Tri-State in order to qualify the Facility as a renewable resource or qualify the Contract Energy and/or Environmental Attributes with such Governmental Authority and maintain such registration/certification for the Term.

Article 11
Security

11.1 Seller Security Form and Amount.

(A) Form. As security for its obligations hereunder, Seller shall, within ten (10) Days after the Effective Date, post and maintain in favor of Tri-State (i) one or more unconditional, irrevocable, standby Letter(s) of Credit from an Issuer, (ii) a cash escrow account established with an Issuer in favor of Tri-State pursuant to an escrow agreement acceptable to Tri-State, or (iii) any combination of the foregoing (i) and (ii) (the "Security"); provided that a Guaranty may be posted to satisfy part of or all of the Security amount set forth in Section 11.1(B) in lieu of Letter(s) of Credit or a cash escrow account, subject to the following conditions (x) any Guaranty provided by a Superior Guarantor shall not exceed Ten Million Dollars ($10,000,000), (y) any Guaranty provided by a Qualified Guarantor shall not exceed Five Million Dollars ($5,000,000), and (z) the total aggregate amount of guaranteed obligations of any such Guaranty and any other guaranties of payment or performance related to or provided by the Seller, the Qualified Guarantor, the Superior Guarantor or any of their Affiliates to Tri-State shall not exceed an aggregate of Five Million Dollars ($5,000,000) if provided by a Qualified Guarantor or Ten Million Dollars ($10,000,000) if provided by a Superior Guarantor, unless agreed to in writing by Tri-State at its sole discretion.

(B) Amount. The Security shall be in the amount of: (i) **Insert $100*(Expected Nameplate Capacity Rating in kw + Expected Energy Storage Capacity in kw)** Dollars ($_____,000) for the period beginning with the Effective Date and continuing thereafter.

(C) Duration. The Security shall remain in place for the entire Term (except to the extent drawn upon as provided herein). To the extent the Security consists of Letter(s) of Credit expiring before the end of the Term, Seller shall cause their renewal or extension for additional consecutive terms of three hundred sixty (360) Days or more (or, if shorter, the remainder of the Term) no later than thirty (30) Days prior to each expiration date of such Letter(s) of Credit and written proof of such renewal shall be provided to Tri-State as soon as practicable thereafter, but in no event later than fifteen (15) Days prior to the expiration of the same. If the Letter of Credit(s) is not renewed or extended as required herein, Tri-State shall have the right to demand payment under the Guaranty or draw immediately upon the entire amount of the Letter of Credit and to place the amounts so drawn, at Seller's cost and with Seller's funds, in an account controlled by Tri-State until and unless Seller provides a substitute Letter of Credit(s) meeting the requirements of this Article 11.

(D) Downgrades. Upon the occurrence of a downgrade event, such that the Person providing the Security in the form of a Letter of Credit or Guaranty no longer meets the requirements of an Issuer, Qualified Guarantor, or Superior Guarantor, as applicable, Seller shall within three (3) Business Days of such downgrade event, provide replacement security satisfying the requirements of this Article 11. If such replacement security is not provided within three (3) Business Days, Tri-State shall have the right to draw immediately upon the entire amount of the Letter of Credit or demand payment under the Guaranty, as applicable, and to place the amounts so drawn, at Seller's cost and with Seller's funds, in an account controlled by Tri-State until and unless Seller provides a substitute security meeting the requirements of this Article 11. Except as provided in this Section 11.1(D), Seller may change the form of Security at any time and from time-to-time upon thirty (30) Days' prior written notice to Tri-State; *provided* that the Security shall satisfy the requirements of this Article 11 at all times.

(E) Draw on Security. Without notice to Seller, Tri-State may demand payment under or draw on the Security during the Term for Seller's failure to meet any of its obligations under this PPA, including Delay Damages, the damages provided in Section 6.4(H), Section 6.7 and Section 12.3, and Replacement Costs. Tri-State may draw or demand payment of all or any part of the appropriate amounts due to it from any form of Security to the extent available pursuant to this Article 11, and from all such forms, and in any sequence Tri-State may select; *provided* that any failure to draw upon the Security for any damages or other amounts due to Tri-State shall not prejudice Tri-State's rights to recover such damages or amounts in any other manner to the extent provided in this PPA. Tri-State shall notify Seller within five (5) Business Days following any draw on the Security by Tri-State, including the amount thereof and the basis therefor.

(F) Release of Security. Within thirty (30) Days following the expiration or termination of this PPA and the satisfaction of all of Seller's obligations hereunder, Tri-State shall release any remaining balance of the Security to Seller without interest.

(G) Replenishment. In the event Tri-State draws upon the Security pursuant to this Article 11, Seller shall replenish the Security to the amount required by Section 11.1 within ten (10) Days of such draw.

(H) Expenses. Seller shall reimburse Tri-State for its expenses, including internal costs and expenses and reasonable attorneys' fees, incurred by Tri-State in connection with the preparation, negotiation, execution and/or release (including making a draw of funds) of the Security under this Article 11.

Article 12
Default and Remedies

12.1 Events of Default of Seller.

(A) Seller Defaults (No Cure). Any of the following shall constitute an Event of Default of Seller upon its occurrence and no cure period shall be applicable unless otherwise stated:

(1) Seller's dissolution or liquidation;

(2) Seller makes a general assignment for the benefit of its creditors;

(3) Seller's authorization or filing of a petition in voluntary bankruptcy or insolvency or for reorganization or arrangement under the bankruptcy laws of the United States or under any insolvency law of any state, or Seller voluntarily taking advantage of any such law by answer or otherwise;

(4) The sale by Seller to a third party, or diversion by Seller for any use, of Contract Energy committed to Tri-State by Seller other than in mitigation of damages for any breach by Tri-State of this PPA;

(5) Seller starts-up, operates, charges, or discharges or permits or causes any third party (including Seller's designated operator) to start-up, operate, charge or discharge the Storage System other than as specifically permitted under this PPA;

(6) Seller intentionally or knowingly delivers, or attempts to deliver, Energy for sale under this PPA that was not associated with or stored by the Facility;

(7) Seller's failure to establish, and maintain, the Security in accordance with Article 11;

(8) Seller's failure to achieve Commercial Operation by the date that is ninety (90) Days following the Commercial Operation Milestone;

(9) Seller's actual fraud or tampering with Tri-State owned facilities or other material misrepresentation or intentional misconduct in connection with this PPA or the operation of the Facility; and/or

(10) Seller's failure to make any payment due to Tri-State under this PPA in accordance with Article 8 (subject to cure by Seller as provided therein).

(B) Seller Defaults (30 Day Cure). Any of the following shall constitute an Event of Default of Seller upon its occurrence but shall be subject to cure within thirty (30) Days after the date of written notice from Tri-State to Seller:

(1) Seller's Abandonment;

(2) Seller's failure to maintain in effect any agreements required to deliver Contract Energy to the Point of Delivery pursuant to Section 5.1, including the Interconnection Agreement;

(3) Seller's failure to comply with the requirements of Section 10.2;

(4) Seller's breach of or failure to perform or comply with any material term of this PPA not otherwise specified in this Section 12.1; and/or

(5) Seller's failure to achieve any Construction Milestone, excluding the Commercial Operation Milestone, by the date that is ninety (90) Days following the date specified for such milestone.

(C) Seller Defaults (60 Day Cure). Any of the following shall constitute an Event of Default of Seller upon its occurrence but shall be subject to cure within sixty (60) Days after the date of written notice from Tri-State to Seller:

(1) Seller's assignment of this PPA, or any Change of Control of Seller, or Seller's sale or transfer of its interest, or any part thereof, in the Facility, except as permitted in accordance with Article 19;

(2) Any representation or warranty made by Seller in this PPA shall prove to have been false or misleading in any material respect when made; and/or

(3) The filing of an involuntary case in bankruptcy or any proceeding under any other insolvency law against Seller.

(D) Seller Default (Delivery Shortfall). Seller's failure to deliver at least eighty percent (80%) of the Expected Contract Energy in a Commercial Operation Year shall constitute an Event of Default of Seller upon its occurrence; *provided* that the Facility shall be deemed to have generated Contract Energy during such period as specified in Section 6.7 with such quantity to be determined using the factors set forth in Section 7.2(A); *provided further* that this Event of Default shall be curable and deemed cured if (i) within thirty (30) Days following the end of the energy deficient Commercial Operation Year, Seller cures the reason(s) for such default (or, if such cure cannot reasonably be effected within thirty (30) Days, Seller commences to cure such default within thirty (30) Days and then diligently pursues such cure to completion as soon as practicable thereafter), and (ii) as a result of such efforts, during the next Commercial Operation Year subsequent to such Default, the production of Contract Energy by the

Facility equals or exceeds ninety-five percent (95%) of the Expected Contract Energy for such period.

Subject at all times to the limitation set forth in Section 6.1, Seller shall be permitted to add and/or replace Generating Units if and to the extent reasonably required to cure Seller's default under this Section 12.1(D). Seller shall keep Tri-State apprised at least monthly of Seller's cure efforts under this Section 12.1(D). If the production of Contract Energy fails to equal or exceed ninety-five percent (95%) of the Expected Contract Energy for the Commercial Operation Year following the Event of Default as described in this Section 12.1(D), Tri-State shall have the right to terminate this PPA for default upon delivery of written notice.

(E) Storage Unavailability. Seller's failure to maintain a Storage Availability of at least ninety percent (90%) on average for a Commercial Operation Year shall constitute an Event of Default of Seller upon its occurrence; *provided* that this Event of Default shall be curable and deemed cured if (i) within thirty (30) Days following the Event of Default, Seller cures the reason(s) for such default (or, if such cure cannot reasonably be effected within thirty (30) Days, Seller commences to cure such default within thirty (30) Days and then diligently pursues such cure to completion as soon as practicable thereafter), and (ii) as a result of such efforts, during the next Commercial Operation Year subsequent to such Default, the Storage Availability equals or exceeds ninety percent (90%).

Seller shall keep Tri-State apprised at least monthly of Seller's cure efforts under this Section 12.1(E). If the Storage Availability fails to equal or exceed ninety percent (90%) for the Commercial Operation Year following the Event of Default as described in this Section 12.1(E), Tri-State shall have the right to terminate this PPA for default upon delivery of written notice.

12.2 Events of Default of Tri-State.

(A) Tri-State Defaults (No Cure). Any of the following shall constitute an Event of Default of Tri-State upon its occurrence and no cure period shall be applicable, unless otherwise stated:

(1) Tri-State's dissolution or liquidation, *provided, however,* that division of Tri-State into multiple entities shall not constitute dissolution or liquidation;

(2) Tri-State makes a general assignment for the benefit of creditors;

(3) Tri-State's authorization or filing of a voluntary petition in bankruptcy or insolvency or for reorganization or arrangement under the bankruptcy laws of the United States or under any insolvency law of any State, or Tri-State voluntarily taking advantage of any such law by answer or otherwise; and/or

(4) Tri-State's failure to make any payment due to Seller under this PPA in accordance with Article 8 (subject to cure by Tri-State as provided therein).

(B) Tri-State Defaults (30 Day Cure). Tri-State's failure to comply with any material obligation under this PPA not otherwise specified in this Section 12.2 shall constitute an Event of Default of Tri-State if not cured within thirty (30) Days after the date of written notice from Seller to Tri-State.

(C) Tri-State Defaults (60 Day Cure). Any of the following shall constitute an Event of Default of Tri-State upon its occurrence but subject to cure sixty (60) Days after the date of written notice from Seller to Tri-State:

(1) The filing of an involuntary case in bankruptcy or any proceeding under any other insolvency law against Tri-State;

(2) Tri-State's assignment of this PPA, except as permitted in accordance with Article 19; and/or

(3) Any representation or warranty made by Tri-State in this PPA shall prove to have been false or misleading in any material respect when made.

12.3 Damages Prior to Termination.

Upon the occurrence of an Event of Default, the non-defaulting Party shall have the right to collect damages accruing prior to the termination of this PPA from the defaulting Party as set forth below, and the payment of any such damages accruing prior to the cure of an Event of Default shall constitute an element of any respective cure. For all Events of Default (including failure to achieve the Commercial Operation Milestone) the non-defaulting Party shall be entitled to receive from the defaulting Party all of the direct damages incurred by the non-defaulting Party in connection with such Event of Default. The Parties agree that the damages recoverable by Tri-State hereunder on account of an Event of Default of Seller prior to termination of this PPA shall include an amount calculated at the end of each Month during an Event of Default equal to the Deficiency MWhs multiplied by the applicable Contract Energy Rate during such Commercial Operation Year and Tri-State may draw the appropriate amounts from the Security. Each Party agrees and acknowledges that (i) the damages that Tri-State would incur at such time prior to termination of this PPA due to Seller's failure to perform would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the liquidated damages as agreed to by the Parties set forth in this Section 12.3 are a fair and reasonable calculation of such damages.

12.4 Termination.

Upon the occurrence of an Event of Default that has not been cured within the applicable time period, if any, the non-defaulting Party shall have the right to declare a date, which shall be between fifteen (15) and thirty (30) Days after the notice thereof,

upon which this PPA shall terminate. Neither Party shall have the right to terminate this PPA except as provided for upon the occurrence of an Event of Default as described above or as otherwise may be explicitly provided for in this PPA. Upon the termination of this PPA under this Section 12.4, the non-defaulting Party shall be entitled to receive from the defaulting Party, all of the direct damages incurred by the non-defaulting Party related to such Event of Default, including, if Seller is the defaulting Party, the value of future Replacement Costs for the then remaining Term based upon, in the case of Energy, the amount of Expected Contract Energy that should have been delivered provided, however, that, if the Replacement Costs amount is negative, the Replacement Costs shall be deemed to be zero.

12.5 Operation by Tri-State Following Event of Default of Seller.

(A) Subject to the rights of the Financing Parties, on occasion of an Event of Default and after the expiration of the cure period provided in respect thereof, if any, and prior to any termination of this PPA as a result thereof, Tri-State shall have the right, but not the obligation, to possess, assume control of, and operate the Facility as agent for Seller (in accordance with Seller's rights, obligations, and interest under this PPA) during the period provided for herein. Seller shall not grant any Person, other than the Financing Parties, a right to possess, assume control of, and operate the Facility that is equal to or superior to Tri-State's right under this Section 12.5.

(B) Tri-State shall give Seller and the Financing Parties ten (10) Days' prior notice of the contemplated exercise of Tri-State's rights under this Section 12.5. Upon such notice, Seller shall collect and have available at a convenient, central location at the Facility all documents, contracts, books, manuals, reports, and records required to construct, operate, and maintain the Facility in accordance with Prudent Utility Practice, including all Operating Records. Upon such notice, Tri-State, its employees, contractors, or designated third parties shall have the unrestricted right to enter the Site and Facility for the purpose of constructing and/or operating the Facility.

(C) Tri-State shall be entitled to immediately draw upon the Security to cover any expenses incurred by Tri-State in exercising its rights under this Section 12.5.

(D) During any period that Tri-State is in possession of and constructing and/or operating the Facility pursuant to this Section 12.5, Tri-State shall perform and comply with all of the obligations of Seller under this PPA and shall use the proceeds from the sale of electricity generated by the Facility to first, reimburse Tri-State for any and all expenses reasonably incurred by Tri-State in taking possession of and operating the Facility, and to second, remit any remaining proceeds to Seller.

(E) During any period that Tri-State is in possession of and operating the Facility, Seller shall retain legal title to and ownership of the Facility and Tri-State shall assume possession, operation, and control solely as agent for Seller.

(1) In the event that Tri-State is in possession and control of the Facility for an interim period, Seller may resume operation and Tri-State shall relinquish its right to operate when Seller demonstrates to Tri-State's satisfaction that it will remove those grounds that originally gave rise to Tri-State's right to operate the Facility, as provided above, in that Seller (i) will resume operation of the Facility in accordance with the provisions of this PPA, and (ii) has cured any Events of Default of Seller that allowed Tri-State to exercise its rights under this Section 12.5 (or, if the Event of Default is of such a nature that it cannot be cured by Seller without possession of the Facility, reasonable assurance that Seller will cure such Event of Default promptly following resumption of possession).

(2) In the event that Tri-State is in possession and control of the Facility for an interim period, the Financing Parties, or any nominee or transferee thereof, may foreclose and take possession of and operate the Facility and Tri-State shall relinquish its right to operate when the Financing Parties or any nominee or transferee thereof, requests such relinquishment.

(F) Tri-State's exercise of its rights hereunder to possess and operate the Facility shall not be deemed an assumption by Tri-State of any liability attributable to Seller. If at any time after exercising its rights to take possession of and operate the Facility Tri-State elects to return such possession and operation to Seller, Tri-State shall provide Seller with at least fifteen (15) Days' prior notice of the date Tri-State intends to return such possession and operation, and upon receipt of such notice Seller shall take all measures necessary to resume possession and operation of the Facility on such date.

(G) In the event Tri-State assumes operation of the Facility under this Section 12.5, Tri-State shall operate the Facility in accordance with Prudent Utility Practice.

12.6 Replacement Costs.

Upon termination for an Event of Default, subject to Section 12.11, Tri-State shall be entitled to Replacement Costs for the balance of the Term (based upon, in the case of Energy, the amount of Expected Contract Energy) had this PPA not been terminated, and Tri-State may draw the appropriate amounts from the Security.

12.7 Specific Performance.

In addition to the other remedies specified in this Article 12, in the event that any Event of Default of Seller is not cured within the applicable cure period set forth herein, Tri-State shall have the right to specific performance. The Parties agree that in the event Tri-State seeks injunctive relief in connection with the foregoing, that such action may be taken without the necessity of posting of a bond or other security as would otherwise be required under Applicable Law.

12.8 Remedies Cumulative.

Each right or remedy of the Parties provided for in this PPA shall be cumulative of and shall be in addition to every other right or remedy provided for in this PPA, and the exercise, or the beginning of the exercise, by a Party of any one or more or the rights or remedies provided for herein shall not preclude the simultaneous or later exercise by such Party of any or all other rights or remedies provided for herein.

12.9 Forward Contracts.

The Parties agree that this PPA is a "forward contract" for purposes of the U. S. Bankruptcy Code; all payments made or to be made by one Party to the other Party pursuant to this PPA are "settlement payments" within the meaning of the U.S. Bankruptcy Code; and all transfers of Security by Seller to Tri-State under this PPA are "margin payments" within the meaning of the U.S. Bankruptcy Code.

12.10 Waiver and Exclusion of Other Damages.

NEITHER PARTY SHALL BE LIABLE TO THE OTHER PARTY FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES BY STATUTE, IN TORT OR CONTRACT (EXCEPT TO THE EXTENT EXPRESSLY PROVIDED HEREIN); *PROVIDED* THAT IF EITHER PARTY IS HELD LIABLE TO A THIRD PARTY FOR SUCH DAMAGES AND THE PARTY HELD LIABLE FOR SUCH DAMAGES IS ENTITLED TO INDEMNIFICATION THEREFOR FROM THE OTHER PARTY, THE INDEMNIFYING PARTY SHALL BE LIABLE FOR, AND OBLIGATED TO REIMBURSE THE INDEMNIFIED PARTY FOR, SUCH DAMAGES, ALL IN ACCORDANCE WITH THE INDEMNIFICATION PROVISIONS OF ARTICLE 17.

12.11 Duty to Mitigate.

Each Party (i) has a general duty to mitigate all damages hereunder (other than Delay Damages, or the damages provided in Section 6.4(H), Section 6.7 and Section 12.3) and (ii) shall use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance of this PPA.

12.12 Limitation of Liability.

Except as otherwise provided in this Section 12.12, Seller's aggregate financial liability to Tri-State for Delay Damages pursuant to Section 4.3, shall not exceed an amount equal to **Insert $100*(Expected Nameplate Capacity Rating in kw + Expected Energy Storage Capacity in kw)** Dollars ($_____,000) and Seller's aggregate financial liability to Tri-State for Replacement Costs and other damages, excluding Delay Damages, shall not exceed **Insert $250*(Expected Nameplate Capacity Rating in kw + Expected Energy Storage Capacity in kw)** Dollars ($_____,000). If at any time during the Term, Tri-State incurs damages in excess of

the limitations set forth above which Seller does not agree to pay when billed by Tri-State, Tri-State shall have the right to declare a termination of this PPA under Section 12.1, unless such damages are disputed in good faith. The limitations on damages set forth in this Section 12.12 shall not apply to damages arising out of any of the following events:

(A) damage or tampering with Tri-State owned facilities caused by negligence, breach of this PPA or other misconduct by Seller, its directors, officers, employees and agents;

(B) the sale by Seller to a third party, or diversion by Seller for any use, of Contract Energy committed to Tri-State under this PPA, including use, operation, charging or discharging of the Storage System, other than in mitigation of damages for any breach by Tri-State of this PPA;

(C) Seller's intentional misrepresentation or intentional misconduct in connection with this PPA or the operation of the Facility;

(D) Seller's failure (i) to maintain insurance coverages in the types and amounts required by this PPA or (ii) to apply any insurance proceeds to reconstruct the Facility following a casualty;

(E) any claim for indemnification herein;

(F) any Environmental Contamination; or

(G) damages incurred by Tri-State in connection with any bankruptcy or insolvency proceeding involving Seller, including Tri-State's loss of the benefit of its bargain due to rejection or other termination of this PPA in such proceeding.

Article 13
Contract Administration and Notices

13.1 Notices in Writing.

Notices required by this PPA shall be addressed to the other Party, including the other Party's representative on the Operating Committee, at the addresses specified in Exhibit I, as either Party updates them from time to time by written notice to the other Party. Any notice, request, consent, or other communication required or authorized under this PPA to be given by one Party to the other Party shall be in writing. It shall either be hand delivered or delivered by electronic mail with a copy mailed via overnight service with signature required upon receipt, to the representative of said other Party. Any such notice, request, consent, or other communication shall be deemed to have been received by the close of the Business Day on which it was hand delivered or transmitted electronically (unless hand delivered or transmitted after such close in which case it shall be deemed received at the close of the next Business Day). Real-time or

routine communications concerning Facility operations shall be exempt from this Section 13.1.

13.2 Representative for Notices.

Each Party shall maintain a designated representative to receive notices. Such representative may, at the option of each Party, be the same person as that Party's representative or alternate representative on the Operating Committee, or a different person. Either Party may, by written notice to the other Party, change the representative or the address to which such notices and communications are to be sent and shall provide the other Party an updated Exhibit I.

13.3 Authority of Representatives.

The Parties' designated representatives shall have authority to act for its respective principals in all technical matters relating to performance of this PPA and to attempt to resolve disputes or potential disputes. However, in their capacity as representatives, they shall not have the authority to amend or waive any provision of this PPA.

13.4 Operating Records.

Originals or copies of all Operating Records shall be maintained at the Facility or such other location in the State in which the Facility is located as may be specified by Seller from time to time. Tri-State may examine and make copies of such Operating Records from time to time upon request, during normal business hours.

13.5 Books and Records.

Seller and Tri-State shall each keep complete and accurate records and all other data required by each of them for the purposes of proper administration of this PPA, including metering, billing and payment records, and such records as may be required by Governmental Authorities in the prescribed format.

13.6 Audit Rights.

During the Term and for a period of three (3) years after the Term, Tri-State shall have the right, at its sole expense, with reasonable advance written notice and during normal working hours, to examine the records of Seller to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this PPA.

13.7 Operating Log.

Seller shall maintain an accurate and up-to-date operating log, in electronic format, at the Facility with records of energy production and storage (by individual block or Generating Unit and Storage Unit); changes in operating status; meteorological data;

maintenance; Storage System Forced Outage and Forced Outages (the "O&M Records"). Within thirty (30) Days after the end of each quarter of the Year, Seller shall submit to Tri-State, in a mutually agreeable format, a copy of the O&M Records for the prior quarter.

13.8 Provision of Real Time Data.

Seller shall, at least five (5) Business Days prior to the delivery of Test Energy and continuing through the Term, make the following data available to Tri-State on a real-time basis, at the Tri-State RTU:

(1) production of Energy in MW and MWh;

(2) [in-service status for each Generating Unit][feeder level breaker status] and Storage Unit;

(3) [Generating Unit MW output][inverter availability and generation in kW] and Storage Unit output;

(4) Storage Unit Energy available for discharge;

(5) [wind speed and direction at each Generating Unit][solar irradiance as measured by the pyranometers at the Facility];

(6) ambient temperature [solar only- and solar panel temperature];

(7) [solar only- stow indication][wind only- icing indication and overspeed indication for each Generating Unit];

(8) humidity; and

(9) barometric pressure.

13.9 Dispute Resolution.

(A) The Parties agree that it is in the best interest of both Parties to attempt to resolve disputes that arise under this PPA in a quick and inexpensive manner. To that end, the Parties commit to use their best efforts to resolve disputes informally. For all disputes that arise pursuant to this PPA, the Parties immediately, through their designated representatives selected in the sole discretion of each Party (individually, the "Party Representative", together, the "Parties' Representatives"), shall negotiate with one another in good faith in order to reach resolution of the dispute. Such negotiation shall commence within fourteen (14) Days of the date of the letter from one Party Representative notifying the other Party Representative of the nature of the dispute. In the event that the Parties' Representatives cannot agree to a resolution of the dispute within thirty (30) Days after the commencement of negotiations, written

notice of the dispute (the "Dispute Notice"), together with a statement describing the issues or claims, shall be delivered, within seventy-two (72) hours after the expiration of such thirty (30) Day period, by each of the Parties' Representatives to its respective senior manager or official (such senior manager or official to be selected by each of the Party Representatives in his or her sole discretion, *provided* such senior manager or official has authority to bind the respective Party). Within three (3) Business Days after receipt of the Dispute Notice, the senior manager or officials for both Parties shall negotiate in good faith to resolve the dispute. If the Parties are unable to resolve the dispute within fourteen (14) Days of receipt of the Dispute Notice by the senior manager or officials, either Party may seek available legal remedies.

(B) SELLER AND TRI-STATE EACH HEREBY KNOWINGLY, VOLUNTARILY AND INTENTIONALLY WAIVE ANY RIGHTS THEY MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY LITIGATION BASED HEREON, OR ARISING OUT OF, UNDER, OR IN CONNECTION WITH, THIS PPA OR ANY COURSE OF CONDUCT, COURSE OF DEALING, STATEMENTS (WHETHER ORAL OR WRITTEN) OR ACTIONS OF SELLER AND TRI-STATE RELATED HERETO.

Article 14
Force Majeure

14.1 Definition of Force Majeure Event.

(A) A "Force Majeure Event" shall mean (i) an event or circumstance that is not reasonably foreseeable, (ii) is beyond the reasonable control of, and is not caused by, the negligence or lack of due diligence of the affected Party or its contractors or suppliers and (iii) adversely affects the performance by that Party of its obligations under or pursuant to this PPA. Such events or circumstances may include: actions or inactions of civil or military authority (including courts and governmental or administrative agencies), acts of God, war, riot or insurrection, terrorism, blockades, embargoes, sabotage (including arson and vandalism), epidemics, explosions and fires not originating in the Facility or caused by its operation, hurricanes, floods, strikes, lockouts or other labor disputes (not caused by the failure of the affected Party to comply with the terms of a collective bargaining agreement).

(B) The failure of a transmission line or element due to a Force Majeure Event that prevents Tri-State from delivering Contract Energy from the Point of Delivery is considered a Force Majeure Event.

(C) Equipment breakdown or the inability of Seller to use equipment due to its design, construction, operation, maintenance, the inability of Seller to meet regulatory standards, or failure by Seller to obtain on a timely basis and maintain a necessary permit or other regulatory approval, is not considered a Force Majeure Event.

(D) Notwithstanding the foregoing, the term "Force Majeure Event" does not include any of the following (i) inability by Seller to procure the Generating

Units, Storage Units, or any component parts therefor, or any associated equipment for the Facility for any reason (the risk of which is assumed by Seller) or any increase in the price to procure the Generating Units, Storage Units or any component parts therefor, including due to changes in any import or export duties or tariffs, (ii) any other acts or omissions of any third party, including any vendor, materialman, customer, or supplier of Seller, unless such acts or omissions are themselves excused by reason of a Force Majeure Event under Section 14.1(A); (iii) any full or partial curtailment in the electric output of the Facility that is caused by or arises from a mechanical or equipment breakdown or other mishaps, events or conditions attributable to normal wear and tear or flaws, except as caused by a Force Majeure Event under Section 14.1(A), (iv) failure of Seller to abide by Prudent Utility Practices, (v) changes in market conditions that affect the cost of supplies, or that affect demand or price for power and/or Environmental Attributes; (vi) any labor strikes, slow downs or stoppages, or other labor disruptions against Seller's contractors, subcontractors, vendors, or suppliers; (vii) changes in Applicable Laws; (viii) failure of Seller or the Facility to qualify or be eligible for any Tax Credit or Additional Tax Benefits, including any federal, state, or local tax credits or exemptions; (ix) any delay or inability of Seller to construct or install any required interconnection or transmission facilities required to be constructed and installed in order for Seller to meet its obligations hereunder, including any delays of the Interconnection Provider; (x) Seller's failure to timely apply for, or diligently pursue, any of the Governmental Approvals set forth in Exhibit F; or (xi) weather events or sudden actions of the natural elements within twenty (20) year normal weather patterns.

(E) In the event that any delay or failure of performance (including a significant reduction in the delivery of Contract Energy) caused by a Force Majeure Event affecting Seller continues for an uninterrupted period of sixty (60) Days from its inception, the Term of this PPA shall be extended on a day for day basis for the duration of the Force Majeure Event (including the initial sixty (60) Days from its inception) with a maximum extension of the Term of this PPA for all Force Majeure Events not to exceed four (4) years; *provided that* the Commercial Operation Year for purposes of determining the applicable Contract Energy Rate and Expected Contract Energy shall be tolled on a day for day basis for the duration of the Force Majeure Event.

(F) In the event that any delay or failure of performance (including a significant reduction in the delivery of Contract Energy) caused by a Force Majeure Event affecting Seller continues for an uninterrupted period of ninety (90) Days from its inception (with respect to a Force Majeure Event occurring prior to COD) or three hundred sixty-five (365) Days from its inception (with respect to a Force Majeure Event occurring after COD), the Party not claiming a Force Majeure Event may, at any time following the end of such period, terminate this PPA upon written notice to the affected Party, without further obligation by either Party except as to costs and balances incurred prior to the effective date of such termination.

(G) Except as otherwise provided in this PPA, and subject to compliance with the notice, mitigation and other requirements of this Article 14, each

Party shall be excused from performance when non-performance was caused, directly or indirectly, by a Force Majeure Event but only and to the extent thereof.

14.2 Notification Obligations.

In the event of any delay or nonperformance resulting from a Force Majeure Event, the Party claiming that a Force Majeure Event has occurred shall notify the other Party immediately by telephonic communication and in writing, within five (5) Days of such occurrence, of the nature, cause, date of commencement thereof and the anticipated duration, and shall indicate whether any deadlines or date(s) imposed hereunder may be affected thereby. The suspension of performance shall be of no greater scope and of no greater duration than the cure for the Force Majeure Event requires. A Party claiming that a Force Majeure Event has occurred shall not be entitled to any relief therefor unless and until confirming notice is provided. The Party claiming that a Force Majeure Event has occurred shall notify the other Party of the cessation of the Force Majeure Event or of the conclusion of the affected Party's cure for the Force Majeure Event, in either case within two (2) Business Days thereof.

14.3 Duty to Mitigate.

The Party claiming that a Force Majeure Event has occurred shall use commercially reasonable efforts to cure the cause(s) preventing its performance of this PPA; *provided, however,* that the settlement of strikes, lockouts and other labor disputes shall be entirely within the discretion of the affected Party and such Party shall not be required to settle such strikes, lockouts or other labor disputes by acceding to demands which such Party deems to be unreasonable.

14.4 Delay Caused by Force Majeure Event.

Upon the occurrence and during the continuance of a Force Majeure Event and the effects thereof, to the extent that a Force Majeure Event affects the ability of Tri-State, Interconnection Provider or Transmission Provider to accept Energy from the Facility or to the extent that a Force Majeure Event affects the ability of Seller to Test pursuant to Section 9.2 or to deliver Energy from the Facility, then the hours during which the Force Majeure Event occurs shall be excluded from the payment calculations as set forth in Article 7.

Article 15
Representations and Warranties

15.1 Seller's Representations and Warranties.

Seller hereby represents and warrants as of the date hereof as follows:

(A) Seller is a _____, duly organized, validly existing and in good standing under the laws of the state of _____. Seller is qualified to do business in _____ and in each other jurisdiction where the failure to so qualify would have a

material adverse effect on the business or financial condition of Seller. Seller has all requisite power and authority to conduct its business, to own its properties, and to execute, deliver, and perform its obligations under this PPA.

(B) The execution, delivery, and performance of its obligations under this PPA by Seller have been duly authorized by all necessary corporate action, and do not and will not:

(1) require any consent or approval by any governing body of Seller, other than that which has been obtained and is in full force and effect (evidence of which shall be delivered to Tri-State upon execution of this PPA);

(2) violate any Applicable Law, the violation of which could have a material adverse effect on the ability of Seller to perform its obligations under this PPA;

(3) result in a breach or constitute a default under Seller's organizational documents or bylaws, or any indenture or loan or credit agreement, or any other agreement, lease, or instrument to which Seller is a party or by which Seller or its properties or assets may be bound or affected, or any judgment, order, statute, or regulation that is applicable to Seller or the Facility; or

(4) result in, or require the creation or imposition of any mortgage, deed of trust, pledge, lien, security interest, or other charge or encumbrance of any nature (other than as may be contemplated by this PPA) upon or with respect to any of the assets or properties of Seller now owned or hereafter acquired.

(C) The obligations of Seller under this PPA are valid and binding obligations of Seller, enforceable against it in accordance with its terms, except as the enforceability hereof may be limited by general principles of equity or bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies.

(D) The individual of Seller executing this PPA is authorized to do so and is authorized to bind Seller to the obligations under this PPA.

(E) The execution and performance of this PPA shall not conflict with or constitute a breach or default under any contract or agreement of any kind to which Seller is a party.

(F) Except for those permits, consents, approvals, licenses and authorizations identified in Exhibit F, which Seller anticipates will be obtained by Seller in the ordinary course of business, all Governmental Approvals necessary for Seller's execution, delivery and performance of this PPA have been duly obtained and are in full force and effect.

(G) That it has arranged for sufficient financing and other funding required to complete the construction of the Facility in accordance with this PPA and to achieve Commercial Operation on or before the Commercial Operation Milestone.

(H) That the Environmental Attributes, as to which right and title is to be transferred to Tri-State under this PPA are, or will be: (1) compliant with the definitions of local, state, or federal renewable portfolio standard rules and requirements, (2) free and clear of any liens, encumbrances and/or defects of title; and (3) shall not otherwise been, nor will be sold, retired, claimed, or represented as part of electricity output or sales, or used to satisfy obligations in any other jurisdiction.

(I) Within the meaning of the U.S. Bankruptcy Code, Seller is a "forward contract merchant."

15.2 Tri-State's Representations and Warranties.

Tri-State hereby represents and warrants as of the date hereof as follows:

(A) Tri-State is a cooperative corporation duly organized, validly existing and in good standing under the laws of the state of Colorado and is qualified in each other jurisdiction where the failure to so qualify would have a material adverse effect upon the business or financial condition of Tri-State. Tri-State has all requisite power and authority to conduct its business, to own its properties, and to execute, deliver, and perform its obligations under this PPA.

(B) The execution, delivery, and performance of its obligations under this PPA by Tri-State have been duly authorized by all necessary corporate action, and do not and will not:

(1) require any consent or approval of Tri-State's members;

(2) violate any Applicable Law, the violation of which could have a material adverse effect on the ability of Tri-State to perform its obligations under this PPA;

(3) result in a breach or constitute a default under Tri-State's corporate charter or bylaws, or under any agreement relating to the management or affairs of Tri-State, or any indenture or loan or credit agreement, or any other agreement, lease, or instrument to which Tri-State is a party or by which Tri-State or its properties or assets may be bound or affected, the breach or default of which could reasonably be expected to have a material adverse effect on the ability of Tri-State to perform its obligations under this PPA; or

(4) result in, or require the creation or imposition of, any mortgage, deed of trust, pledge, lien, security interest, or other charge or encumbrance of any nature (other than as may be contemplated by this PPA) upon or with respect to any of the assets or properties of Tri-State now owned or hereafter acquired, the

creation or imposition of which could reasonably be expected to have a material adverse effect on the ability of Tri-State to perform its obligations under this PPA.

(C) This PPA is a valid and binding obligation of Tri-State, enforceable against it in accordance with its terms, except as the enforceability hereof may be limited by general principles of equity or bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies.

(D) The individual of Tri-State executing this PPA is authorized to do so and is authorized to bind Tri-State to the obligations under this PPA.

(E) The execution and performance of this PPA shall not conflict with or constitute a breach or default under any contract or agreement of any kind to which Tri-State is a party or any judgment, order, statute, or regulation that is applicable to Tri-State.

(F) Within the meaning of the U.S. Bankruptcy Code, Tri-State is a "forward contract merchant."

Article 16
Insurance

16.1 Evidence of Insurance.

Seller shall, upon execution of this PPA and promptly after the renewal of each policy of insurance coverage required in Exhibit D, provide Tri-State with one copy of insurance certificates or other evidence in a form acceptable to Tri-State evidencing the insurance coverages required to be maintained in accordance with Exhibit D to this PPA. Such certificates shall (i) include Tri-State as an additional insured (except worker's compensation); (ii) provide that the applicable insurer shall endeavor to provide Tri-State with thirty (30) Days' prior written notice of non-renewal or cancellation of the policies required in Exhibit D (except that such notice shall be ten (10) Days for non-payment of premiums); and (iii) provide a waiver of any rights of subrogation against Tri-State, its Affiliates and their officers, directors, agents, subcontractors, and employees. Insurance carriers providing the coverages required in Exhibit D, must have a policy holders rating of "A-" or better, and a financial size of "Class VII" or better as published in the most recent edition of Best's Insurance Reports. Any policy of insurance furnished hereunder shall be written by an insurer authorized to write such coverage in the state where the Facility is located. All policies shall be written on an occurrence basis, except as provided in Section 16.2. All policies shall include language providing that Seller's policy shall be primary in all instances regardless of like coverages, if any, carried by Tri-State. Seller's liability under this PPA is not limited to the amount of insurance coverage required herein. Seller shall notify Tri-State immediately should the policies required in Exhibit D be cancelled before the expiration

date, if the insureds receive a non-renewal notice from its carrier, or if there is any material adverse change of coverage.

16.2 Term and Modification of Insurance.

(A) All insurance required under this PPA shall cover occurrences during the Term and for a period of two (2) years after the Term. In the event that any insurance as required herein is commercially available only on a "claims-made" basis, such insurance shall provide for a retroactive date not later than the later of (i) the Effective Date, or (ii) the cancellation date of any occurrence basis policies that such insurance has replaced.

(B) Tri-State shall have the right to request modification of the insurance minimum limits specified in Exhibit D in order to maintain reasonable coverage amounts. Seller shall make all commercially reasonable efforts to comply with any such request. Tri-State shall reimburse Seller for all premium increases and other costs incurred by Seller in complying with any such Tri-State request for modification of the insurance minimum limits specified in Exhibit D.

16.3 Application of Proceeds.

Seller shall apply any insurance proceeds to reconstruction of the Facility following a casualty.

Article 17
Indemnity

17.1 Indemnification.

Each Party (the "Indemnifying Party") shall, to the extent permitted by Applicable Law, indemnify, pay, defend and hold harmless the other Party (the "Indemnified Party") and its officers, directors, employees, agents and contractors from and against any and all claims or demands of a third party, costs or expenses (including reasonable attorneys' fees) for loss, damages, or injury to persons or property of the Indemnified Party (or to third parties) (collectively, "Losses") caused by, arising out of, or resulting from:

(A) a breach by the Indemnifying Party of its covenants, representations, and warranties or obligations hereunder;

(B) a violation or alleged violation of Applicable Laws by the Indemnifying Party;

(C) any act or omission by the Indemnifying Party or its contractors, agents, servants or employees in connection with the installation, testing, inspection, or operation or maintenance of its respective facilities or equipment;

(D) any defect in, failure of, or fault related to, the Indemnifying Party's facilities or equipment; or

(E) the negligence or intentional acts or other misconduct of the Indemnifying Party or its contractors, agents, servants, employees or any authorized persons acting on behalf of such Indemnifying Party.

17.2 Indemnification for Fines and Penalties.

Any fines or other penalties incurred by a Party (other than fines or penalties due to the negligence or intentional acts or other misconduct of the other Party) for non-compliance with any Applicable Laws shall be the sole responsibility of the non-complying Party.

17.3 Limitations

(A) The foregoing indemnification obligations shall apply notwithstanding any contributory misconduct of the Indemnified Party, but the Indemnifying Party's liability to indemnify the Indemnified Party shall be reduced in proportion to the percentage by which the Indemnified Party's misconduct caused the damages.

(B) Neither Party shall be indemnified for Losses resulting from the sole negligence or intentional acts or misconduct of the directors, officers, employees, or agents of such Party

17.4 Notice of Proceedings.

Each Party shall promptly notify the other Party of any loss or proceeding in respect of which such notifying Party is or may be entitled to indemnification pursuant to Section 17.1. Such notice shall be given as soon as reasonably practicable after the relevant Party becomes aware of the loss or proceeding and that such loss or proceeding may give rise to an indemnification, but in any event no later than seven (7) Days after the receipt by the Party seeking indemnification of notice of the commencement of any action for which indemnity may be sought. The delay or failure of such Indemnified Party to provide the notice required pursuant to this Section 17.4 to the other Party shall not release the other Party from any indemnification obligation which it may have to such Indemnified Party except (i) to the extent that such failure or delay materially and adversely affected the Indemnifying Party's ability to defend such action or increased the amount of the loss, and (ii) that the Indemnifying Party shall not be liable for any costs or expenses of the Indemnified Party in the defense of the claim, suit, action or proceeding during such period of failure or delay.

17.5 Defense of Claims.

(A) Whether or not acknowledging in writing its obligation to indemnify an Indemnified Party to the extent required pursuant to this Section 17.5, the

Indemnifying Party shall be entitled, at its option, to assume and control the defense of such claim, action, suit or proceeding at its expense with counsel of its selection, subject to the prior approval of the Indemnified Party.

(B) Unless and until the Indemnifying Party acknowledges in writing its obligation to indemnify the Indemnified Party to the extent required pursuant to this Section 17.5 and assumes control of the defense of a claim, suit, action or proceeding in accordance with paragraph (A) above, the Indemnified Party shall have the right, but not the obligation, to contest, defend and litigate, with counsel of its own selection, any claim, action, suit or proceeding by any third party alleged or asserted against such Party in respect of, resulting from, related to or arising out of any matter for which it is entitled to be indemnified hereunder, and the reasonable costs and expenses thereof shall be subject to the indemnification obligations of the Indemnifying Party hereunder.

(C) Neither the Indemnifying Party nor the Indemnified Party shall be entitled to settle or compromise any such claim, action, suit or proceeding without the prior consent of the other; *provided, however,* that after agreeing in writing to indemnify the Indemnified Party, the Indemnifying Party may, subject to paragraph (D) below, settle or compromise any claim without the approval of such Indemnified Party. Except where such consent is unreasonably withheld, if an Indemnified Party settles or compromises any claim, action, suit or proceeding in respect of which it would otherwise be entitled to be indemnified without the prior consent of the Indemnifying Party, the Indemnifying Party shall be excused from any indemnification obligation in respect of such settlement or compromise.

(D) Following the acknowledgement of the indemnification and the assumption of the defense by the Indemnifying Party pursuant to paragraph (A) above, the Indemnified Party shall have the right to employ its own counsel and such counsel may participate in such action, but the fees and expenses of such counsel shall be at the expense of the Indemnified Party, when and as incurred, unless: (i) the employment of counsel by the Indemnified Party has been authorized in writing by the Indemnifying Party; (ii) the Indemnified Party shall have reasonably concluded and specifically notified the Indemnifying Party that there may be a conflict of interest between the Indemnifying Party and the Indemnified Party in the conduct of the defense of such action; (iii) the Indemnifying Party shall not in fact have employed independent counsel reasonably satisfactory to the Indemnified Party to assume the defense of such action and shall have been so notified by the Indemnified Party; or (iv) the Indemnified Party shall have reasonably concluded and specifically notified the Indemnifying Party that there may be specific defenses available to it which are different from or additional to those available to the Indemnifying Party, or that such claim, action, suit or proceeding involves or could have a material adverse effect upon the Indemnified Party beyond the scope of this PPA. If clause (ii), (iii) or (iv) of the preceding sentence shall be applicable, then counsel for the Indemnified Party shall have the right to direct the defense of such claim, action, suit or proceeding on behalf of the Indemnified Party and the reasonable fees and disbursements of such counsel shall constitute reimbursable legal or other expenses hereunder.

Article 18
Legal and Regulatory Compliance

18.1 Applicable Law.

Each Party shall at all times comply with all Applicable Law related to its obligations under this PPA, except for any non-compliance which, individually or in the aggregate, could not reasonably be expected to have a material adverse effect on the business or financial condition of the Party or its ability to fulfill its commitments under this PPA. Seller shall promptly notify Tri-State of any investigation, notices or findings of violations of Applicable Law from any Governmental Authority, including any audit, notification, inspection or inquiry that has been commenced by any Governmental Authority in respect of a potential or possible violation of Applicable Law. Except as otherwise expressly provided herein, each Party assumes the risk of changes in Applicable Laws following the date hereof, that affect such Party's costs of ownership and operation of its assets, and its performance of this PPA, except as otherwise specifically set forth herein.

18.2 Compliance with Governmental Approvals.

Seller shall comply with and cause the Facility to comply with all applicable Governmental Approvals. Seller shall promptly notify Tri-State of any inspections by any Governmental Authority with respect to any material Governmental Approval and will promptly provide Tri-State with copies of any notices of violation or non-compliance with respect to any material Governmental Approval. Upon permanent cessation of generation of Energy from the Facility, Seller, at its sole cost and expense, shall decommission the Facility, dismantle the Facility, remediate the Site and submit and obtain any Governmental Approvals with respect thereto.

18.3 Compliance Information.

(A) Each Party shall, for the purpose of gathering information and/or providing verbal or written reports, testimony, affidavits or other submissions relevant to any Governmental Approvals, Applicable Laws or in connection with any litigation, arbitration or administrative proceeding before any authority of competent jurisdiction: (i) deliver or cause to be delivered to the other Party any necessary or required certificates of its officers, accountants, engineers or agents; and/or (ii) make available necessary personnel with knowledge as to such matters.

(B) To the full extent authorized by FERC regulations and the FERC standards of conduct, Seller hereby authorizes Tri-State to contact and obtain information concerning the Facility and Interconnection Facilities directly from the Interconnection Provider and the Transmission Provider and, to the extent necessary, Seller shall provide written notice to the Interconnection Provider and the Transmission Provider confirming such authorization.

18.4 Reliability Standards.

In the event that new reliability standards are promulgated by WECC, NERC, FERC, or PUC, or any successor agencies, any and all costs incurred as a result of actions required for compliance with the new reliability standards shall be borne by Seller. To the extent that Seller contributes in whole or in part to actions which result in monetary penalties being assessed to Tri-State by WECC, NERC, FERC or PUC, or any successor agencies, for lack of compliance with reliability standards (except to the extent that Seller acted at the direction of Tri-State), Seller shall reimburse Tri-State for its share of such monetary penalties.

18.5 Financial Accounting Standards.

Under accounting principles generally accepted in the United States of America ("GAAP"), Tri-State may be required to consolidate an entity with which Tri-State has entered into a long-term power purchase agreement. Seller shall provide all information needed by Tri-State in order for Tri-State to determine whether or not Seller must be consolidated by Tri-State under GAAP. If Tri-State determines in its discretion that Tri-State is required to consolidate Seller in its financial statements, Seller shall provide reasonable access to any records and personnel, as requested by Tri-State, in connection with such consolidation and also so that Tri-State's independent auditors can conduct financial statement audits in accordance with generally accepted audit standards, as well as internal controls review. Seller shall have adequate controls over financial information.

Article 19
Assignment and Other Transfer Restrictions

19.1 Assignment of PPA.

(A) Except as expressly permitted by this Section 19.1 or in connection with a Transfer of the Facility that is expressly permitted by Section 19.4, neither Party shall assign this PPA, or any portion thereof, without the prior written consent of the other Party. Any purported assignment of this PPA or any portion thereof in violation of the foregoing shall be null and void and shall constitute an Event of Default.

(B) Notwithstanding Section 19.1(A) but subject to Section 19.1(C), without the prior written consent of the other Party:

(1) Either Party shall have the right at any time and from time to time to mortgage, create or provide for a security interest in, convey in trust, or collaterally assign its respective rights, titles and interests in this PPA to any lender, collateral agent, mortgagee, or trustee as security for its present or future indebtedness (including, in the case of such an assignment by Seller, any Financing Party) (each, a

"Security Party"), without such Security Party assuming or becoming in any respect obligated to perform any of the obligations of the Parties.

(2) Any Security Party may foreclose upon or, in lieu thereof, otherwise succeed to and acquire all the rights, titles and interests of such Party in this PPA.

(3) Either Party may assign this PPA to any Affiliate thereof that has the financial capability to fulfill its obligations hereunder as demonstrated by a credit rating of equal to or better than the assigning Party.

(C) No assignment of or other succession to a Party's interest in this PPA shall be permitted pursuant to this PPA (other than Section 19.1(B)(1)) unless and until: (i) the successor assumes and agrees, in writing in form and substance reasonably acceptable to the other Party, to fully perform and discharge all of the obligations hereunder of such Party, and (ii) in the case of Seller's interest in this PPA, the successor (1) succeeds to and acquires all rights, title and interest of Seller in the Facility and (2) provides to Tri-State all Security then required to be maintained by Seller hereunder.

(D) Any successor to a Party's interest in this PPA shall notify the other Party promptly in writing of such succession, and shall furnish to the other Party evidence of such succession.

19.2 Change of Operator.

(A) Except as expressly permitted by this Section 19.2, Seller shall not replace the Operation and Maintenance Contractor (which for purposes of this Section 19.2 shall include replacement of any subcontractor or other Person providing operation management or other significant operation or maintenance services) without the prior written consent of Tri-State. The replacement of the Operation and Maintenance Contractor in violation of the foregoing shall constitute an Event of Default.

(B) Notwithstanding Section 19.2(A), Seller can replace the Operation and Maintenance Contractor without the prior written consent of Tri-State if:

(1) Seller provides to Tri-State reasonable advance written notice of such replacement (which, absent extraordinary circumstances affecting the safe and reliable operation of the Facility, shall not be less than ninety (90) Days prior to such replacement); and

(2) Seller reasonably demonstrates to Tri-State that the replacement operator is a Qualified Operator.

19.3 Change of Control.

(A) Except as expressly permitted by this Section 19.3, Seller shall not permit a Change of Control of Seller to occur without the prior written consent of Tri-State. The occurrence of a Change of Control of Seller in violation of the foregoing shall constitute an Event of Default.

(B) Notwithstanding Section 19.3(A) but subject to Section 19.3(C), without the prior written consent of Tri-State:

(1) Any direct or indirect owner of Seller shall have the right at any time and from time to time to mortgage, grant a security interest in, convey in trust, or pledge to any Security Party any equity or ownership interest in Seller or in any Person that Controls Seller.

(2) Any Security Party may foreclose upon or, in lieu thereof, otherwise succeed to and acquire any such equity or ownership interests in Seller or in any Person that Controls Seller.

(C) No Change of Control of Seller shall be permitted under this PPA unless all obligations of Seller hereunder with respect to maintaining Security are satisfied immediately following such Change of Control.

(D) Seller shall notify Tri-State promptly in writing of any Change of Control of Seller.

19.4 Transfer of Facility.

(A) Except as expressly permitted by this Section 19.4, Seller shall not Transfer all or any portion of the Facility without the prior written consent of Tri-State. The Transfer of all or any portion of the Facility in violation of the foregoing shall constitute an Event of Default.

(B) Notwithstanding Section 19.4(A) but subject to Section 19.4(C), without the prior written consent of Tri-State:

(1) Seller shall have the right at any time and from time to time to mortgage, convey in trust, or grant to any Security Party a security interest in the Facility or any portion thereof.

(2) Any Security Party may foreclose upon or, in lieu thereof, otherwise succeed to and acquire the Facility or any portion thereof.

(3) Seller may, and shall be obligated to, Transfer the Facility to any Affiliate to which Seller assigns the PPA in compliance with the provisions of Section 19.1.

(C) No Transfer of the Facility or any portion thereof shall be permitted pursuant to this PPA (other than Section 19.4(B)(1)) unless and until the successor (i) succeeds to and acquires all rights, title and interest of Seller in this PPA, (ii) assumes and agrees in writing, in form and substance reasonably acceptable to Tri-State, to fully perform and discharge all of the obligations of Seller hereunder, and (iii) provides to Tri-State all Security then required to be maintained by Seller hereunder.

(D) Seller shall notify Tri-State promptly in writing of any Transfer of the Facility or any portion thereof, and shall furnish to Tri-State evidence of such Transfer.

19.5 Reimbursement of Tri-State's Costs.

In the event Seller proposes to or does assign or transfer an interest in the Facility or this PPA, undergo a Change of Control, or replace the Operation and Maintenance Contractor, as such transactions are described in this Article 19, Seller shall reimburse Tri-State for its expenses, including internal costs and expenses and reasonable attorneys' fees, incurred by Tri-State in connection with the evaluation of such proposed transaction and the preparation, negotiation, and execution of any consent and any other documents associated with such proposed transaction.

Article 20
Purchase Option

20.1 Right of First Offer of Sale of the Facility.

(A) Except for Transfers expressly permitted by Section 19.3(B) or Section 19.4(B), Seller shall not, and shall cause each direct and indirect owner of Seller not to, at any time during the Term, consummate or enter into any agreement for the consummation of any of the following (each, a "ROFO Transfer"):

(1) any Transfer by Seller of the Facility or any part of the Facility to one or more Persons that are not Affiliates of Seller; or

(2) any Transfer by any Person, in one or more transactions to one or more other Persons that are not Affiliates of such Person, of equity or other ownership interests in one or more Project Entities that (individually or in the aggregate) constitute a direct or indirect Controlling interest in Seller;

unless Seller has first offered to Transfer the Facility, or such direct or indirect owner has first offered to Transfer such direct or indirect equity interests in Seller, as applicable, to Tri-State pursuant to a written offer (in each case, an "Offered Assets Notice") and otherwise complies with this Section 20.1 and Article 19.

(B) Any Offered Assets Notice shall set forth in reasonable detail all material terms and conditions of the offer, including the minimum price and terms of payment, liabilities and obligations to be directly or indirectly assumed, all other financial terms, all material conditions to closing, a period of no less than 180 days

following execution of the purchase agreement for the parties to obtain any approvals or other authorizations of any Governmental Authority or third party that are required by such party in connection with such Transfer, and all material representations, warranties, rights to indemnification, limitations thereon, and credit support for any of the foregoing. Following Tri-State's receipt of the Offered Assets Notice, Tri-State shall have ninety (90) Days to investigate the proposed transaction and conduct due diligence. Seller (i) shall promptly answer any questions that Tri-State may have concerning the Facility, any applicable liabilities and obligations, and the offered terms and conditions, (ii) shall meet with Tri-State to discuss the offer, and (iii) shall provide all documents and information requested by Tri-State that are reasonably available to Seller.

(C) If Tri-State does not provide Seller notice that it accepts the offered terms and conditions to purchase the Facility or the specified equity interests (as applicable) within ninety (90) Days after receiving the Offered Assets Notice, Seller shall have the right to sell the Facility (or Seller's relevant parent shall have the right to sell the specified equity interests, as applicable) to a third party on terms and conditions that are not more favorable in the aggregate to the third party than those included in the Offered Assets Notice, at any time within the twelve-month period following issuance of the Offered Assets Notice, and to enter into any agreement therefor. If Seller or its relevant parent wishes to enter into an agreement for or consummate a ROFO Transfer with a third party on terms and conditions that in the aggregate are more favorable to the third party than those previously offered to Tri-State in the Offered Assets Notice, or on a date that is more than twelve months following delivery of the applicable Offered Assets Notice, such ROFO Transfer shall again be subject to this Section 20.1 and Seller or its relevant parent shall again first offer the revised terms and conditions to Tri-State pursuant to a new Offered Assets Notice.

(D) If Tri-State accepts an offer made by Seller under Section 20.1(B), the Parties shall within a further ninety (90) Days enter into a purchase agreement that, except to the extent otherwise agreement by Seller and Tri-State, incorporates the terms and conditions in the Offered Assets Notice.

20.2 Right of First Offer on Facility Expansion.

(A) If, at any time during the Term, Seller or any Affiliate of Seller intends to install or modify any energy generation or storage equipment on the Site or on any location within a five (5) mile radius of the boundary of the Site, the effect of which, if deemed part of the Facility, would be to increase the Nameplate Capacity Rating of the Generating Facility and/or Storage System Nameplate Capacity of the Storage System, Seller shall first offer the Energy (and Environmental Attributes) and/or storage capacity resulting from such installation or modification ("Expansion Right") to Tri-State. Such offer shall set forth in reasonable detail the proposed transaction and the terms and conditions of the offer, including the price. Following Tri-State's receipt of such notice, Tri-State shall have ninety (90) Days to investigate the proposed transaction and conduct due diligence. Seller shall promptly answer any question that

Tri-State may have concerning the offered terms and conditions, shall meet with Tri-State to discuss the offer, and shall provide requested documents and information requested by Tri-State.

(B) If Tri-State does not provide Seller notice that it accepts the offered terms and conditions within ninety (90) Days after receiving the offer, Seller or the Affiliate of Seller may enter into an agreement to sell the Expansion Right to a third party on terms and conditions no more favorable in the aggregate to the third party than those offered to Tri-State. If Seller or the Affiliate of Seller wishes to enter into an agreement with a third party on terms and conditions more favorable to the third party than those previously offered to Tri-State under Section 20.2(A), Seller or the Affiliate of Seller shall first offer such revised terms and conditions to Tri-State pursuant to Section 20.2(B).

(C) If Tri-State accepts an offer made by Seller under Section 20.2(A), the Parties shall within a further ninety (90) Days enter into an energy and storage purchase agreement in substantially the same form as this PPA for the purchase and sale of Expansion Right and associated Environmental Attributes (with the Security requirement set forth in Article 11, Contract Energy delivery requirements set forth in Section 6.1, the damage payment in Section 6.4(H) and Expected Contract Energy to be adjusted on a pro rata basis to account for the size of the proposed expansion relative to the Expected Nameplate Capacity Rating and/or Storage System Nameplate Capacity), but incorporating such changes as are expressly identified in the terms and conditions offered by Seller.

20.3 Option to Purchase.

(A) Seller hereby gives and grants to Tri-State the exclusive and irrevocable right and option to purchase the Facility Assets, at the times and upon the terms and conditions set forth in this Section 20.3, for a price equal to the Fair Market Value of the Facility, as determined pursuant to this Section 20.3 ("Purchase Option").

(B) As used herein, "Facility Assets" means the Facility, all interest of Seller or any of its Affiliates in, to or under this PPA, and any and all tangible or intangible assets that are reasonably necessary for the ownership, operation and maintenance of the Facility, including (i) all drawings, specifications, operations and maintenance records, and performance data of or related to the Facility; (ii) all warranties, equipment service and maintenance agreements, and similar agreements related to the Facility, any portion thereof, or any related equipment or facilities; (iii) non-exclusive, irrevocable and royalty-free licenses to use software and other intellectual property necessary for the ownership, operation or maintenance of the Facility; (iv) all Governmental Approvals related to the ownership, operation or maintenance of the Facility, to the extent assignable; (v) the Interconnection Agreement and utility services agreements, (vi) the Facility Site Documents, and all other interests or rights in real estate reasonably necessary for the operation and maintenance of the Facility, and (vii) all rights to future Energy, Environmental Attributes, and tax benefits.

(C) Facility Assets do not include (without limitation) (i) any liabilities of Seller or any of its Affiliates, contingent or otherwise, other than future performance obligations under contracts and Governmental Approvals that, in any case, are reasonably necessary for the ownership, operation or maintenance of the Facility and are assigned to Tri-State; (ii) any agreement or instrument evidencing indebtedness for borrowed money; (iii) any contracts or agreements for the sale of Energy, storage of Energy, Environmental Attributes, or other products, other than this PPA; or (iv) any contract or agreement for asset management, operations, or other services not specifically included in the Facility Assets.

(D) As a condition to any exercise of the Purchase Option, Tri-State must give non-binding written notice (a "Notice of Intent to Purchase") either (i) within ninety (90) days prior to any of [solar only: the sixth (6th) anniversary of the Commercial Operation Date,] the eleventh (11th) anniversary of the Commercial Operation Date, the fifteenth (15th) anniversary of the Commercial Operation Date, the twentieth (20th) anniversary of the Commercial Operation Date, or the expiration of the Term, or (ii) within ninety (90) days following any termination of this PPA by Tri-State, following the [solar: sixth (6th)][wind: fifteenth (15th)] anniversary of the Commercial Operation Date, due to an Event of Default by Seller.

(E) For a period of sixty (60) days following the date of the Notice of Intent to Purchase, the Parties will meet to discuss and negotiate in good faith to determine and agree upon the Fair Market Value, and shall use commercially reasonable efforts to agree upon the terms and conditions of a purchase and sale agreement with respect to the Facility Assets. For the avoidance of doubt, neither agreement upon Fair Market Value and such terms and conditions, nor execution of a purchase and sale agreement, shall be conditions to the closing of a purchase and sale of the Facility Assets pursuant to exercise of the Purchase Option.

(F) For purposes of this Section 20.3, "Fair Market Value" means the fair market value of the Facility Assets as agreed by the Parties; provided, however, that in the event the Parties cannot agree upon Fair Market Value within sixty (60) Days following the delivery of the Notice of Intent to Purchase, the Parties shall retain an independent nationally recognized appraiser experienced in appraising [wind][solar]-powered electric energy generation facilities and storage systems selected by Tri-State (and certified as so qualified by Seller), in which case Fair Market Value shall be as determined by such appraiser. The Parties shall share equally all fees and costs of the third appraiser, if required, retained to determine Fair Market Value.

(G) The appraiser shall consider the following factors in its determination of Fair Market Value:

(1) the expected annual generating output and storage capacity of the Facility over the remainder of its assumed useful life determined in a manner consistent with Prudent Utility Practices, taking into account the expected degradation of the Facility over such period;

(2) the net present value of the after-tax cash flows over the remainder of its assumed useful life (determined in a manner consistent with Prudent Utility Practices, and taking into account the expected degradation), applying a discount rate that is reasonable under then-current market conditions as agreed by the Parties, and if not so agreed within thirty (30) Days, then as determined by such appraiser;

(3) the general condition of the Facility at the time of the expected closing following exercise of the Purchase Option determined by inspection and, if applicable, testing;

(4) any restrictions on use of the Site or any portion thereof;

(5) any rights or obligations of Seller to dismantle and remove the Facility and restore the Site (whenever arising);

(6) any restrictions upon or obligations or liabilities associated with any of the Facility Assets or the operation of the Facility prior to the closing pursuant to the Purchase Option that could adversely affect the operation of the Facility, or for which Tri-State could be responsible or have any liability, following the closing pursuant to the Purchase Option, including due to any Environmental Contamination, any accrued liabilities (contingent or non-contingent) under the Interconnection Agreement, any Facility Site Documents, or any other contract included in the Facility Assets, any accrued and unpaid property tax liabilities, and any failure to comply with any Governmental Approval or Applicable Law;

(7) the terms and conditions of this PPA, including the encumbrance of any obligations and liabilities on an assignee thereof with respect to delivery of Contract Energy to Tri-State for the remainder of the Term, the expected market price of Energy following the expiration of this PPA, transmission costs and constraints and other limitations on the marketability of power generated from the Facility;

(8) any terms and conditions (if any) that will apply to the sale and purchase of the Facility Assets;

(9) an appropriate discount to the extent that (i) Seller fails to provide to Tri-State and the appraiser any material information related to the Facility Assets or Site, or (ii) the representations, warranties, indemnification obligations and other terms and conditions (if any) that will apply to the sale and purchase of the Facility Assets materially deviate from customary terms and conditions for the sale and purchase of facilities similar to the Facility; and

(10) such other factors as the independent appraiser deems relevant.

(H) Following delivery of a Notice of Intent to Purchase, Seller shall promptly provide to Tri-State (and, if applicable, the appraiser) all information regarding the Facility Assets and Site as may be requested thereby, that is reasonably available to Seller, and Tri-State (and, if applicable, the appraiser) shall be provided with access to the Site and Facility in order to conduct an inspection and witness any testing. All inspections and testing, and access to the Site and Facility, shall be conducted in accordance with all of Seller's applicable reasonable safety and health rules and requirements that have been provided to Tri-State (and, if applicable, the appraiser), and shall be conducted in a manner so as to minimize disruption in the operation and the maintenance of the Facility and in such a manner so as to avoid any adverse economic impacts to Seller under this PPA.

(I) To definitively exercise the Purchase Option, Tri-State must deliver written notice (a "Purchase Notice") to Seller within sixty (60) days following determination of Fair Market Value pursuant to this Section 20.3. Once the Purchase Notice has been delivered, the Purchase Option shall be irrevocable.

(J) The closing for purchase and sale of the Facility Assets shall occur on the later of the thirtieth (30th) day following the date of the Purchase Notice and the fifth (5th) Business Day after the receipt of all required consents and approvals of Governmental Authorities. At the closing:

(1) Seller shall convey to Tri-State good and marketable title to all of the Facility Assets, free and clear of all liens and encumbrances (other than those arising under the terms of the Facility Site Documents and Governmental Approvals), and with such other representations and warranties as may be agreed by the Parties; and

(2) Tri-State shall pay to Seller, in full consideration thereof, an amount in cash equal to the Fair Market Value.

Article 21
Miscellaneous

21.1 Waiver.

The delay or failure of either Party to enforce or insist upon compliance with or strict performance of any of the terms or conditions of this PPA, or to exercise or take advantage of any of its rights, including any right to terminate this PPA, shall not constitute a waiver or relinquishment of any such terms, conditions, or rights, but the same shall be and remain at all times in full force and effect.

21.2 Fines and Penalties.

(A) Seller shall pay when due all fees, fines, penalties or costs incurred by Seller or its agents, employees or contractors for noncompliance by Seller or the Facility, its employees, or subcontractors with any provision of this PPA, or any

contractual obligation, permit or requirements of Applicable Law except for such fines, penalties and costs that are being actively contested in good faith and with due diligence by Seller and for which adequate financial reserves have been set aside to pay such fines, penalties or costs in the event of an adverse determination.

(B) If fees, fines, liens, penalties, or costs are claimed or assessed against Tri-State by any Governmental Authority due to noncompliance by Seller or the Facility with this PPA, any requirements of Applicable Law, any permit or contractual obligation, or, if the work of Seller or any of its contractors or subcontractors is delayed or stopped by order of any Governmental Authority due to Seller's noncompliance with any requirements of Applicable Law, permit, or contractual obligation, Seller shall indemnify and hold Tri-State harmless against any and all losses, liabilities, damages, and claims suffered or incurred by Tri-State, including claims for indemnity or contribution made by third parties against Tri-State, except to the extent Tri-State recovers any such losses, liabilities or damages through other provisions of this PPA.

21.3 Disclaimer of Third Party Beneficiary Rights.

In executing this PPA, Tri-State does not, nor should it be construed to, extend its credit or financial support for the benefit of any third parties lending money to or having other transactions with Seller. Nothing in this PPA shall be construed to create any duty to, or standard of care with reference to, or any liability to, any Person not a party to this PPA.

21.4 Relationship of the Parties.

(A) This PPA shall not be interpreted to create an association, joint venture, or partnership between the Parties nor to impose any partnership obligation or liability upon either Party. Except as specifically provided in Section 12.5, neither Party shall have any right, power, or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as an agent or representative of, the other Party.

(B) Seller shall be solely liable for the payment of all wages, taxes, and other costs related to the employment of Persons to perform Seller's obligations under this PPA, including all federal, state, and local income, social security, payroll, and employment taxes and statutorily mandated workers' compensation coverage. None of the Persons employed by Seller shall be considered employees of Tri-State for any purpose; nor shall Seller represent to any Person that he or she is or shall become a Tri-State employee.

21.5 Severability.

In the event any of the terms, covenants, or conditions of this PPA, its Exhibits, or the application of any such terms, covenants, or conditions, shall be held invalid, illegal, or unenforceable by any court or administrative body having jurisdiction, all other terms, covenants, and conditions of this PPA and their application not adversely

affected thereby shall remain in force and effect; *provided, however,* that Tri-State and Seller shall negotiate in good faith to attempt to implement an equitable adjustment in the provisions of this PPA with a view toward effecting the purposes of this PPA by replacing the provision that is held invalid, illegal, or unenforceable with a valid provision the economic effect of which comes as close as possible to that of the provision that has been found to be invalid, illegal or unenforceable.

21.6 Complete Agreement; Amendments.

The terms and provisions contained in this PPA constitute the entire agreement between Tri-State and Seller with respect to the Facility and shall supersede all previous communications, representations, or agreements, either verbal or written, between Tri-State and Seller with respect to the sale of Contract Energy. This PPA may be amended, changed, modified, or altered, *provided* that such amendment, change, modification, or alteration shall be in writing and signed by both Parties.

21.7 Binding Effect.

This PPA, as it may be amended from time to time pursuant to this Article 21, shall be binding upon and inure to the benefit of the Parties and their respective successors-in-interest, legal representatives, and assigns permitted hereunder.

21.8 Headings.

The table of contents, captions and headings used in this PPA are for ease of reference only and do not constitute a part of this PPA.

21.9 Counterparts.

This PPA may be executed in any number of counterparts, and each executed counterpart shall have the same force and effect as an original instrument.

21.10 Governing Law.

The interpretation and performance of this PPA and each of its provisions shall be governed and construed in accordance with the laws of the State of Colorado. The Parties hereby submit to the exclusive jurisdiction in the federal and state courts of the State of Colorado, and venue is hereby stipulated as Denver, Colorado.

21.11 Mobile-Sierra.

Notwithstanding any other provision of this PPA to the contrary, neither Party shall seek, nor shall they support any third party seeking, to prospectively or retroactively revise the rates, terms or conditions of service of this PPA through application or complaint to FERC pursuant to the provisions of Section 205, 206 or 306 of the Federal Power Act, or any other provisions of the Federal Power Act, absent prior written agreement of the Parties. Further, absent the prior written agreement in writing

by both Parties, the standard of review for changes to the rates, terms or conditions of service of this PPA proposed by a Party shall be the "public interest" standard of review set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956) and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956), as interpreted in *Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. 1,* 128 S. Ct. 2733 (2008). Changes proposed by a non-Party or FERC acting *sua sponte* shall be subject to the most stringent standard permissible under Applicable Law.

[Signature Page Follows]

IN WITNESS WHEREOF, the Parties have executed this PPA as of the date first written above.

Seller:

_____

By: _____

Printed Name: _____

Title:_____

Tri-State:

Tri-State Generation and Transmission Association, Inc.

By: _____

Printed Name:

Title: Chief Executive Officer

EXHIBIT A

PROJECT MILESTONES

Date	**Construction Milestones**
10 Days after the Effective Date	Seller shall have established the Security in accordance with Article 11.
[_____]	Seller shall have delivered a fully executed EPC Contract to Tri-State.
[_____]	[*wind only-* Seller shall have provided Tri-State with copies of Determinations of No Hazard from the Federal Aviation Administration for the Generating Units.]
[_____]	Seller shall have provided Tri-State with documentation that all Seller required Governmental Approvals have been obtained or will be obtained by the time needed to meet all Construction Milestones.
[_____]	Seller shall have entered into Financing Documents and having achieved or obtained waivers with respect to all conditions precedent to the initial availability for disbursement of funds under the Financing Documents.
[_____]	Seller shall have commenced construction of the Facility (all Seller required Governmental Approvals required to construct Facility shall have been obtained and are in full force and effect, except for minor Seller required Governmental Approvals that are expected to be obtained in the ordinary course, the failure of which to obtain would not adversely affect the construction and/or operation of the Facility).
[_____]	Delivery of major components to the Site shall have commenced.
[_____]	Seller shall have provided Tri-State with copies of the executed Operation and Maintenance Agreement, if applicable
[_____]	The step-up transformer shall have been delivered to the Site.
[_____]	Seller shall have completed construction of Seller's Interconnection Facilities and such facilities are capable of being energized.

[_____] Start-up testing of the Generating Units and Storage Units shall have commenced.

Commercial Operation Milestone

[_____] The Facility shall have achieved Commercial Operation.

EXHIBIT B

FACILITY DESCRIPTION AND SITE MAPS

Required Items:

Location of Electric Interconnection Point (see definition of Point of Delivery)

A detailed description of the Facility, including identification of the major equipment and components that will make up the Facility (see Section 3.1)

A scaled map that identifies the Site and the location of the Generating Units and Storage Units on the Site and a drawing identifying the location of the Electric Interconnection Point, the Point of Delivery, important ancillary facilities and Interconnection Facilities (See Section 3.2)

EXHIBIT C

CONTRACT ENERGY RATE

EXHIBIT D

INSURANCE COVERAGE

Type of Insurance	Minimum Limits of Coverage
1. Commercial General Liability ("CGL") and commercial umbrella	$15,000,000 per occurrence and aggregate. If CGL insurance contains a general aggregate limit, it shall apply separately to the Facility.

CGL insurance shall be written on ISO occurrence form CG 00 01 01 96 (or a substitute form providing similar coverage) and shall cover liability arising from premises, operations, independent contractors, products/completed operations, contracts, property damage, personal injury and advertising injury, and liability assumed under an insured contract (including the tort liability of another assumed in a business contract). There shall be no endorsement or modification limiting coverage for liability assumed under an insured contract. There shall be no endorsement or modification of the CGL insurance limiting the scope of coverage for liability arising from explosion, collapse, or underground property damage.

Tri-State shall be included as an additional insured under the CGL policy, using ISO additional insured endorsement CG 20 10 (or a substitute providing similar coverage), and under the commercial umbrella insurance. The commercial umbrella insurance shall provide coverage over the top of the CGL insurance, the Business Automobile Liability insurance.

The CGL and commercial umbrella insurance to be obtained by or on behalf of Seller shall be:

primary as respects any claims, losses, damages, expenses, or liabilities arising out of this PPA.

2 Environmental/Pollution Liability insurance either stand alone or as part of the CGL/commercial umbrella	At least $5,000,000 each occurrence

Environmental/Pollution Liability insurance shall protect against bodily injury and property damage claims arising out of pollution. The policy through its language or by endorsement, shall include coverage for contractual liability.

3. Business Automobile Liability	$1,000,000 combined single limit (each accident), including Non-Owned and Hired Autos.

Business Automobile Liability insurance shall be written on ISO form CA 00 01, CA 00 05, CA 00 12, CA 00 20, or a substitute form providing similar liability coverage. If necessary, the policy shall be endorsed to provide contractual liability coverage equivalent to that provided in the 1990 and later editions of CA 00 01. If transporting hazardous waste/materials from the Site, an appropriate MCS-90 Endorsement must be attached with $10,000,000 limits of liability.

4. Workers' Compensation	Statutory Requirements. Seller may comply with these requirements through its project operator.

EXHIBIT D

INSURANCE COVERAGE

Type of Insurance	**Minimum Limits of Coverage**
5. Employers' Liability, if Seller maintains employees (or a certification from Seller that is maintains no employees)	Bodily Injury by Accident, $1,000,000 each accident Bodily Injury by Disease, $1,000,000 policy limit Bodily Injury by Disease, $1,000,000 each employee

6. Builders All Risk insurance coverage	For the full value of Facility.

Builders All Risk insurance shall include coverage carried by either Seller or the EPC Contractor, without limitation against the perils of fire and physical loss or damage including, without duplication of coverage, theft, vandalism, malicious mischief, collapse, water, falsework, testing and startup, for entire period of construction, which shall cover the interests of Indemnified Parties until the Commercial Operation Date, and insurance coverage as set forth in 7 below is provided. A certificate of Builders Risk insurance shall be provided to Tri-State regardless of who procures coverage.

7. All-Risk Property insurance covering physical loss or damage to the Facility	Full Replacement Value of the Facility. A deductible may be carried, which deductible shall be the absolute responsibility of Seller.

All-Risk Property insurance shall include: (i) coverage for fire, flood, wind and storm, tornado and earthquake; (ii) Boiler and Machinery insurance covering all objects customarily subject to such insurance, including boilers and engines, and (iii) business interruption to cover loss of providing Energy to Tri-State should Seller not be able to produce or provide electrical energy as agreed to herein. Tri-State shall be named as a loss payee as to its interests under this PPA.

Seller shall require its contractors and subcontractors to purchase and maintain commercial general liability including environmental coverage within or as a separate policy in an amount commensurate with type of work to be performed and automobile, workers' compensation and employers liability insurance of the types and amounts specified above. If requested by Tri-State, Seller shall furnish copies of certificates of insurance evidencing such coverage.

EXHIBIT E

PROJECT CONTRACTS

[Seller to Provide]

1. Generator Interconnection Agreement

2.

EXHIBIT F

SELLER'S REQUIRED GOVERNMENTAL APPROVALS

[Seller to Provide]

EXHIBIT G

MONTHLY PRODUCTION PERCENTAGE OF EXPECTED CONTRACT ENERGY

Calendar Month	Monthly Production %
January	
February	
March	
April	
May	
June	
July	
August	
September	
October	
November	
December	

EXHIBIT H

OPERATING COMMITTEE REPRESENTATIVES

Tri-State	Seller
Primary Representative: Origination Manager Tri-State Generation and Transmission Association, Inc. 1100 W. 116th Avenue Westminster, CO 80234 Phone: (303) 254-_____ Email: _____@tristategt.org	**Primary Representative:**
Alternative Representative: Senior Manager, Energy Resources Tri-State Generation and Transmission Association, Inc. 1100 W. 116th Avenue Westminster, CO 80234 Phone: (303) 254-_____ Email: _____@tristategt.org	**Alternative Representative:**

EXHIBIT I

NOTICE ADDRESSES

Tri-State	Seller
Notices: Chief Executive Officer Tri-State Generation and Transmission Association, Inc. 1100 W. 116th Avenue Westminster, CO 80234 Telephone: (303) 452-6111 with a copy to (at the same address): Senior Vice President and General Counsel	**Notice**:

EXHIBIT J

FORM OF ATTESTATION AND BILL OF SALE

_____ ("Seller") hereby sells, transfers and delivers to Tri-State Generation and Transmission Association, Inc. ("Tri-State") the Environmental Attributes associated with the generation of Contract Energy, as detailed in the [Wind][Solar] and Storage Energy Purchase Agreement for the _____ Project between the Parties, dated _____ (the "Agreement"). Terms used, but not defined herein, shall have the meaning set forth in the Agreement.

_____
Name of Renewable Energy Facility

_____	_____	_____
Type/Resource	Nameplate Capacity Rating (MW)	Commercial Operation Date

_____ - _____ (from) (to)
Dates

_____
MWh generated

One (1) REC represents the REC and Environmental Attributes reporting rights associated with one (1) MWh generated from the Facility.

Seller further attests, warrants and represents as follows:

i) each REC and Environmental Attribute is free and clear of any liens, encumbrances and/or defects of title;

ii) none of the RECs or Environmental Attributes has been retired, claimed or represented as part of electricity output or sales by Seller, or used to satisfy obligations in any other jurisdiction;

iii) its sale to Tri-State is its one and only sale of the RECs and Environmental Attributes with respect to the Contract Energy referenced herein, after due inquiry, no third party has claimed nor can claim any interest in such RECs or Environmental Attributes;

iv) the Facility identified above produced the number of MWh above during the period indicated above;

v) Seller has title to and ownership of the RECs and Environmental Attributes sold hereunder; and

vi) Seller owns the _____.
Name of the Renewable Energy Facility

This serves as a bill of sale, transferring from Seller to Tri-State all of Seller's right, title and interest in and to the RECs and Environmental Attributes associated with the generation of the above referenced Contract Energy.

Contact Person: _____

phone: _____; fax: _____

[Seller]

Signed: _____

Name: _____

Title: _____

Date: _____

EXHIBIT K

FORM OF LETTER OF CREDIT

[LETTERHEAD OF ISSUING BANK]

IRREVOCABLE LETTER OF CREDIT NO _____

DATE OF ISSUANCE: _____

INITIAL EXPIRATION DATE: [Must be at least ONE YEAR after Date of Issuance]

BENEFICIARY:
TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

APPLICANT:
[NAME OF APPLICANT]

ATTN: CREDIT RISK ADMINISTRATOR
1100 W. 116TH AVENUE
WESTMINSTER, CO 80234

[APPLICANT ADDRESS]

1. AS THE ISSUING BANK ("ISSUER"), WE, [NAME OF ISSUING BANK], HEREBY ESTABLISH AND ISSUE THIS IRREVOCABLE STANDBY LETTER OF CREDIT NO. _____ IN FAVOR OF THE ABOVE-NAMED BENEFICIARY ("BENEFICIARY") FOR THE ACCOUNT OF THE ABOVE-NAMED APPLICANT ("APPLICANT") IN THE MAXIMUM AGGREGATE AMOUNT OF USD $_____ (_____ U.S. DOLLARS).

2. ISSUER UNDERTAKES TO BENEFICIARY TO PAY BENEFICIARY'S DEMAND FOR PAYMENT OF AN AMOUNT AVAILABLE UNDER THIS LETTER OF CREDIT, UPON PRESENTATION OF A DEMAND FOR PAYMENT SUBSTANTIALLY IN THE FORM OF EXHIBIT "A," ATTACHED HERETO, DULY COMPLETED AS INDICATED, AT THE FOLLOWING PLACE FOR PRESENTATION: [ADDRESS OF PLACE FOR PRESENTATION], AT ANY TIME ON OR BEFORE 5:00 PM (_____ TIME) ON THE EXPIRATION DATE.

DEMAND FOR PAYMENT MAY ALSO BE PRESENTED BY FACSIMILE ("FAX") TO FAX NO._____ PROVIDED THAT SUCH FAX PRESENTATION IS MADE AT ANY TIME ON OR BEFORE 5:00 PM (_____ TIME) ON THE EXPIRATION DATE. ISSUER WILL ACKNOWLEDGE RECEIPT OF BENEFICIARY'S PRESENTMENT WITHIN FOUR (4) BUSINESS HOURS TO THE EMAIL ADDRESS PROVIDED TO ISSUER IN THE FAX DRAW CERTIFICATE.

IF THE AMOUNT IN THE DRAW CERTIFICATE EXCEEDS THE AMOUNT AVAILABLE, BUT THE PRESENTATION OTHERWISE COMPLIES, ISSUER UNDERTAKES TO PAY THE AMOUNT AVAILABLE.

NO OTHER DOCUMENTS WILL BE REQUIRED TO BE PRESENTED. PAYMENT MADE HEREUNDER SHALL BE MADE IN U.S. DOLLARS IN IMMEDIATELY AVAILABLE FUNDS.

3. PARTIAL AND MULTIPLE DRAWS AND PRESENTATIONS ARE PERMITTED, PROVIDED THAT THE AVAILABLE AMOUNT OF THIS LETTER OF CREDIT SHALL BE PERMANENTLY REDUCED BY THE AMOUNT OF EACH SUCH DRAW.

4. THIS LETTER OF CREDIT IS ISSUED PURSUANT TO THE PROVISIONS OF THAT CERTAIN _____ AND STORAGE ENERGY PURCHASE AGREEMENT BETWEEN THE BENEFICIARY AND THE APPLICANT DATED AS OF _____, 20__ (AS THE SAME MAY HAVE BEEN OR MAY BE AMENDED FROM TIME TO TIME, THE "PPA"). NOTWITHSTANDING ANY REFERENCE IN THIS LETTER OF CREDIT TO THE PPA OR ANY OTHER DOCUMENTS, INSTRUMENTS OR AGREEMENTS, OR REFERENCES IN THE PPA OR ANY OTHER DOCUMENTS, INSTRUMENTS OR AGREEMENTS TO THIS LETTER OF CREDIT, THIS LETTER OF CREDIT CONTAINS THE ENTIRE AGREEMENT BETWEEN BENEFICIARY AND ISSUER RELATING TO THE OBLIGATIONS OF ISSUER HEREUNDER.

5. THIS LETTER OF CREDIT WILL BE AUTOMATICALLY EXTENDED EACH YEAR WITHOUT AMENDMENT FOR A PERIOD OF ONE YEAR FROM THE EXPIRATION DATE HEREOF, AS EXTENDED, UNLESS AT LEAST FORTY-FIVE (45) DAYS PRIOR TO THE EXPIRATION DATE, ISSUER NOTIFIES BENEFICIARY AND APPLICANT BY A NATIONALLY RECOGNIZED OVERNIGHT COURIER OR CERTIFIED MAIL THAT IT ELECTS NOT TO EXTEND THIS LETTER OF CREDIT FOR SUCH ADDITIONAL PERIOD (THE PRESENT OR ANY FUTURE EXPIRATION DATE AS AFORESAID IS REFERRED TO HEREIN AS THE "EXPIRATION DATE"). NOTICE OF NON-EXTENSION WILL BE GIVEN BY ISSUER TO BENEFICIARY AT BENEFICIARY'S ADDRESS SET FORTH HEREIN OR AT SUCH OTHER ADDRESS AS BENEFICIARY MAY DESIGNATE TO ISSUER IN WRITING AT ISSUER'S LETTERHEAD ADDRESS.

6. ISSUER UNDERTAKES TO MAKE PAYMENT AGAINST A COMPLYING PRESENTATION WITHIN THREE BUSINESS DAYS AFTER PRESENTATION. THE BENEFICIARY SHALL RECEIVE PAYMENT BY WIRE TRANSFER TO A BANK ACCOUNT OF THE BENEFICIARY. FOR THE PURPOSES HEREOF, "BUSINESS DAY" SHALL MEAN ANY DAY ON WHICH COMMERCIAL BANKS IN COLORADO ARE NOT AUTHORIZED OR REQUIRED TO CLOSE.

7. THIS LETTER OF CREDIT IS FREELY TRANSFERABLE TO AN ASSIGNEE AND THE NUMBER OF TRANSFERS IS UNLIMITED. SUBJECT TO COMPLIANCE WITH APPLICABLE LAWS, ISSUER AGREES THAT IT WILL EFFECT ANY TRANSFERS IMMEDIATELY UPON PRESENTATION TO ISSUER OF THIS LETTER OF CREDIT AND A COMPLETED WRITTEN TRANSFER REQUEST SUBSTANTIALLY IN THE FORM OF EXHIBIT "B," ATTACHED HERETO, DULY COMPLETED AS INDICATED. SUCH TRANSFER WILL BE EFFECTED AT NO COST TO BENEFICIARY. ANY TRANSFER FEES ASSESSED BY ISSUER WILL BE PAYABLE SOLELY BY APPLICANT, AND THE PAYMENT OF ANY TRANSFER FEES WILL NOT BE A CONDITION TO THE VALIDITY OR EFFECTIVENESS OF THE TRANSFER OR THIS LETTER OF CREDIT.

8. THIS LETTER OF CREDIT IS SUBJECT TO THE INTERNATIONAL STANDBY PRACTICES 1998 ("ISP98") (INTERNATIONAL CHAMBER OF COMMERCE PUBLICATION NO. 590), EXCEPT TO THE EXTENT THAT THE TERMS HEREOF ARE INCONSISTENT WITH THE PROVISIONS OF THE ISP98. AS TO MATTERS NOT COVERED BY THE ISP98, THIS LETTER OF CREDIT SHALL BE GOVERNED AND CONSTRUED IN ACCORDANCE WITH

THE LAWS OF THE STATE OF COLORADO, WITHOUT REGARD FOR THE PRINCIPLES OF CONFLICTS OF LAWS THEREUNDER.

9. ISSUER'S CHARGES AND FEES FOR ISSUING, AMENDING, OR HONORING THIS LETTER OF CREDIT ARE FOR APPLICANT'S ACCOUNT AND SHALL NOT BE DEDUCTED FROM ANY PAYMENT ISSUER MAKES UNDER THIS LETTER OF CREDIT.

ISSUER:

By: _____
AUTHORIZED SIGNATURE
Its:_____

EXHIBIT "A"
(TO LETTER OF CREDIT)

FORM OF DEMAND FOR PAYMENT

[ISSUING BANK NAME] DATE:
[ISSUING BANK ADDRESS]

LADIES AND GENTLEMEN:

THIS DEMAND FOR PAYMENT IS PRESENTED BY THE UNDERSIGNED BENEFICIARY UNDER THE IRREVOCABLE LETTER OF CREDIT NO. _____, DATED _____ (THE "LETTER OF CREDIT"), ISSUED BY _____ ("ISSUER") FOR THE AMOUNT OF U.S. DOLLARS _____ AND ____/100THS (U.S.$_____), WHICH CONSTITUTES A PAYMENT OF THE FUNDS AVAILABLE TO THE BENEFICIARY UNDER THE LETTER OF CREDIT.

1. UNDER THIS DEMAND FOR PAYMENT, THE BENEFICIARY STATES [CHECK APPLICABLE]:

   [___] BENEFICIARY IS OWED BY APPLICANT THE AMOUNT DEMANDED UNDER THE AGREEMENT BETWEEN BENEFICIARY AND APPLICANT TITLED _____ AND DATED _____, WHICH AMOUNT REMAINS DUE AS OF THE DATE OF THIS DEMAND FOR PAYMENT.

   [___] THE ISSUER HAS GIVEN WRITTEN NOTICE PURSUANT TO THE LETTER OF CREDIT OF ITS INTENT NOT TO EXTEND THE LETTER OF CREDIT FOLLOWING THE PRESENT EXPIRATION DATE THEREOF AND THE CURRENT EXPIRY DATE OF THIS LETTER OF CREDIT IS WITHIN THIRTY (30) DAYS AND THE AMOUNT DEMANDED IS REQUIRED TO SECURE THE OBLIGATIONS OF APPLICANT UNDER THE AGREEMENT BETWEEN BENEFICIARY AND APPLICANT TITLED _____ AND DATED _____.

2. BENEFICIARY REQUESTS THE AMOUNT DEMANDED HEREUNDER BE TRANSFERRED TO BENEFICIARY BY WIRE TRANSFER TO THE FOLLOWING BANK ACCOUNT OF THE BENEFICIARY:

   _____
   _____
   _____

[3. ISSUER ACKNOWLEDGEMENT OF BENEFICIARY'S PRESENTMENT BY FAX SHALL BE SENT TO BENEFICIARY AT _____@TRISTATEGT.ORG.]

BENEFICIARY:

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

BY: _____
NAME: _____
TITLE: _____

EXHIBIT "B"
(TO LETTER OF CREDIT)

FORM OF TRANSFER REQUEST

IRREVOCABLE LETTER OF CREDIT NO: _____

CURRENT BENEFICIARY:

APPLICANT:

TO: [NAME OF ISSUING BANK]

THE UNDERSIGNED, AS THE CURRENT "BENEFICIARY" OF THE ABOVE REFERENCED LETTER OF CREDIT, HEREBY REQUESTS THAT YOU REISSUE THE LETTER OF CREDIT IN FAVOR OF THE TRANSFEREE NAMED BELOW [INSERT TRANSFEREE NAME AND ADDRESS BELOW]:

FROM AND AFTER THE DATE THIS TRANSFER REQUEST IS DELIVERED TO THE ISSUER, THE TRANSFEREE SHALL BE THE "BENEFICIARY" UNDER THE LETTER OF CREDIT FOR ALL PURPOSES AND SHALL BE ENTITLED TO EXERCISE AND ENJOY ALL OF THE RIGHTS, PRIVILEGES AND BENEFITS THEREOF.

DATED: _____

[NAME OF BENEFICIARY]

By:
Name:
Title:

EXHIBIT L

FORM OF GUARANTY

This Guaranty is executed and delivered as of this _____ day of _____, 20__ by _____, a _____ ("Guarantor"), in favor of Tri-State Generation and Transmission Association, Inc. ("Company"), in connection with the performance by _____, a _____ _____ ("Seller") of that certain [Wind][Solar] and Storage Energy Purchase Agreement for the _____, dated _____, 20__, TS-__-____, by and between Seller and Company (the "PPA"). Capitalized terms used but not defined herein shall have the meanings set forth in the PPA.

RECITALS

A. Seller is planning to develop, design, construct, own, operate, and maintain a _____-powered electric energy generating facility having an Expected Nameplate Capacity Rating of _____ MW AC and energy storage facility having an Expected Energy Storage Capacity of _____ MW to be located in _____ County, _____ (the "Facility").

B. Seller and Company have entered into the PPA for the purchase and sale of capacity and electrical energy and storage from the Facility on the terms and conditions set forth therein.

C. This Guaranty is delivered to the Company pursuant to Section 11.1(A) of the PPA.

D. To induce Company to enter into the PPA and consummate the purchase and sale of electrical energy contemplated by the PPA, Guarantor has agreed to guarantee the obligations of Seller as provided in this Guaranty.

NOW, THEREFORE, in consideration of the foregoing and for good and valuable consideration, Guarantor hereby agrees as follows:

AGREEMENT

1. Guaranty. Subject to the provisions of this Guaranty, Guarantor hereby absolutely, irrevocably, unconditionally, and fully guarantees to Company the due, prompt, and complete observance, performance, and discharge of each and every payment obligation of Seller under the PPA, whether incurred before or after the date of delivery of this Guaranty (the "Obligations"). This is a guaranty of payment, not of collection, and as such, Company shall not be required to institute, pursue, or exhaust any remedies against Seller before instituting suit, obtaining judgment, and executing thereon against Guarantor under this

Guaranty. In furtherance of the foregoing and without limiting the generality thereof, Guarantor agrees as follows:

a. The liability of Guarantor under this Guaranty is not conditional or contingent upon the genuineness, validity, regularity or enforceability of the PPA or the pursuit by Company of any remedies which it now has or may hereafter have under the PPA;
b. Company may enforce this Guaranty upon the occurrence of a default by Seller under the PPA notwithstanding the existence of a dispute between Company and Seller with respect to the existence of the default;
c. The obligations of Guarantor under this Guaranty are independent of the obligations of Seller under the PPA and a separate action or actions may be brought and prosecuted against Guarantor whether or not any action is brought against Seller or any other guarantors and whether or not Seller is joined in any such action or actions;
d. Company may, at its election, foreclose on any security held by Company, or exercise any other right or remedy available to Company without affecting or impairing in any way the liability of Guarantor under this Guaranty, except to the extent the amount(s) owed to Company by Seller have been paid;
e. Guarantor shall continue to be liable under this Guaranty and the provisions hereof shall remain in full force and effect notwithstanding: (i) any modification, amendment, supplement, extension, agreement or stipulation between Seller and Company or their respective successors and assigns, with respect to the PPA or the obligations encompassed thereby; (ii) Company's waiver of or failure to enforce any of the terms, covenants or conditions contained in the PPA; (iii) any release of Seller or any other guarantor from any liability with respect to the Obligations or any portion thereof; (iv) any release, compromise or subordination of any real or personal property then held by Company as security for the performance of the Obligations or any portion thereof, or any substitution with respect thereto; (v) without in any way limiting the generality of the foregoing, if Company is awarded a judgment in any suit brought to enforce a portion of the Obligations, such judgment is not deemed to release Guarantor from its covenant to pay that portion of the Obligations which is not the subject of such suit; (vi) Company's acceptance and/or enforcement of, or failure to enforce, any other guaranties or any portion of this Guaranty; (vii) Company's exercise of any other rights available to it under the PPA; (viii) Company's consent to the change, reorganization or termination of the corporate structure or existence of the Seller and to any corresponding restructuring of the Obligations; (ix) any failure to perfect or continue perfection of a security interest in any collateral that secures the Obligations; and (x) any other act or thing or omission, or delay to do any other act or thing that might in any manner or to any

extent vary the risk of Guarantor as an obligor with respect to the Obligations; and

f. Guarantor agrees that upon a demand for payment under this Guaranty, Guarantor shall pay such Obligations as are included in such demand notwithstanding any defenses, setoffs or counterclaims that Seller may allege or assert against Company with respect to the Obligations, including, without limitation, statute of frauds and accord and satisfaction; provided that Guarantor reserves the right to assert any defenses, setoffs or counterclaims that Seller may allege or assert against Company (except for such defenses, setoffs or counterclaims as are expressly waived under other provisions of this Guaranty) in a subsequent action for recoupment, restitution or reimbursement.

2. Maximum Liability. Notwithstanding anything herein to the contrary, Guarantor's maximum liability under this Guaranty shall be limited to _____ ($_____), plus costs of collection with respect to any valid claim(s) made by Company hereunder that are incurred in the enforcement or protection of the rights of Company.

3. Rights of Company. Guarantor hereby grants to Company, in Company's discretion and without the need to notify or obtain any consent from Guarantor, and without termination, impairment, or any other effect upon Guarantor's duties hereunder, the power and authority from time to time:

   a. to renew, compromise, extend, accelerate, or otherwise change, substitute, supersede, or terminate the terms of performance of any of the Obligations, in each case in accordance with the PPA;
   b. to grant any indulgences, forbearances, and waivers, on one or more occasions, for any length of time, with respect to Seller's performance of any of the Obligations; and
   c. to accept collateral, further guaranties, and/or other security for the Obligations, and, if so accepted, then to impair, exhaust, exchange, enforce, waive, or release any such security.

4. Performance; Payment. If any of the Obligations are not performed according to the tenor thereof, and any applicable notice and cure period provided by the PPA has expired ("Default"), Guarantor shall immediately (but in no event later than three (3) Business Days) upon receipt of written demand by Company (a) perform or cause Seller to perform the Obligation in Default, and (b) pay, reimburse, and indemnify Company against any liabilities, damages, and related costs (including attorneys' fees) incurred by Company as a result thereof, all in such manner and at such times as Company may reasonably direct. All sums payable by Guarantor hereunder shall be made in immediately available funds in U.S. Dollars.

5. Term; Satisfaction.

a. This Guaranty shall continue in full force and effect until the earlier to occur of: (i) the substitution of an alternative form of Security in accordance with the PPA; (ii) the satisfaction of all Obligations of Seller under the PPA; or (iii) the payment by Guarantor, without reservation of rights, of an aggregate amount equal to the maximum liability set forth in Section 2, together with any other amounts required to be paid by Guarantor pursuant to Section 10 hereof.
b. Satisfaction by Guarantor of any duty hereunder incident to a particular Default or the occurrence of any other Default shall not discharge Guarantor except with respect to the Default satisfied, it being the intent of Guarantor that this Guaranty be continuing until such time as all of the Obligations have irrevocably been discharged in full.

6. Bankruptcy. So long as any Obligations remain outstanding, Guarantor may not, without the prior written consent of Company, commence or join with any other person in commencing any bankruptcy, reorganization or insolvency proceedings of or against Seller. The obligations of Guarantor under this Guaranty may not be reduced, limited, impaired, discharged, deferred, suspended or terminated by any proceeding, voluntary or involuntary, involving the bankruptcy, insolvency, receivership, reorganization, liquidation or arrangement of the Seller or by any defense which Seller may have by reason of the order, decree or decision of any court or administrative body resulting from any such proceeding. If at any time the performance of any Obligation by Seller or Guarantor is rescinded or voided under the federal Bankruptcy Code or otherwise, then Guarantor's duties hereunder shall continue and be deemed to have been automatically reinstated, restored, and continued with respect to that Obligation, as though the performance of that Obligation had never occurred, regardless of whether this Guaranty otherwise had terminated or would have been terminated following or as a result of that performance.

7. Waivers by Guarantor. Guarantor hereby waives and agrees not to assert or take advantage of:

a. all set-offs, counterclaims, withholdings or deductions and all presentments, demands for performance, notices of non-performance, protests, and notices of every kind that may be required by Applicable Laws;
b. any right to require Company to proceed against Seller or any other person, or to require Company first to exhaust any remedies against Seller or any other person, before proceeding against Guarantor hereunder;
c. any defense based upon an election of remedies by Company;
d. any duty of Company to protect or not impair any security for the Obligations;

e. any defense based upon promptness, diligence, and any requirement that Company protect, secure, perfect or insure any security interest or lien or any property subject thereto;
f. the benefit of any laws limiting the liability of a surety or any other circumstance that limits the liability of or exonerates a guarantor generally or provides any legal or equitable discharge of Guarantor's obligations hereunder;
g. other than demand for payment, any requirement of notices between Company and Seller including, without limitation, with respect to the PPA and this Guaranty, notice of acceptance of this Guaranty, any notice of credits extended and sales made by Seller to Company, any information regarding Seller's financial condition, and all other notices whatsoever;
h. any duty of Company to disclose to Guarantor any facts concerning Seller, the PPA or the Facility, or any other circumstances, that would or allegedly would increase the risk to Guarantor under this Guaranty, whether now known or hereafter learned by Company, it being understood that Guarantor is capable of and assumes the responsibility for being and remaining informed as to all such facts and circumstances; and
i. until all Obligations in Default have been fully paid and/or performed, any rights of subrogation, contribution, reimbursement, indemnification, or other rights of payment or recovery for any payment or performance by it hereunder. For the avoidance of doubt, if any amount is paid to Guarantor in violation of this provision, such amount shall be held by Guarantor for the benefit of, and promptly paid to, Company.

8. Cumulative Remedies. The rights and remedies of Company hereunder shall be cumulative and not alternative to any other rights, powers, and remedies that Company may have at law, in equity, or under the PPA. The obligations of Guarantor hereunder are independent of those of Seller and shall survive unaffected by the bankruptcy of Seller. Company need not join Seller in any action against Guarantor to preserve its rights set forth herein.

9. Representations and Warranties. Guarantor represents and warrants to Company as follows:

a. Guarantor is a [corporation], duly organized, validly existing, and in good standing under the laws of the state of its [incorporation]. Seller is a direct or indirect wholly-owned subsidiary of Guarantor. Guarantor has all necessary corporate power and authority to execute and deliver this Guaranty and to perform its obligations hereunder.
b. The execution, delivery and performance of this Guaranty has been duly and validly authorized by all corporate proceedings of Guarantor and is not in violation of any law, judgment of court or government agency . This Guaranty has been duly and validly executed and delivered by Guarantor

and constitutes a legal, valid and binding obligation of Guarantor, enforceable against Guarantor in accordance with its terms.

10. Collection Costs. Guarantor hereby agrees to pay to Company, upon demand, and in addition to the maximum liability set forth in Section 2 hereof, all reasonable attorneys' fees and other expenses which Company may expend or incur in enforcing the Obligations against Seller and/or enforcing this Guaranty against Guarantor, whether or not suit is filed, including, without limitation, all attorneys' fees, and other expenses incurred by Company in connection with any insolvency, bankruptcy, reorganization, arrangement, or other similar proceedings involving Seller that in any way affect the exercise by Company of its rights and remedies hereunder.

11. Severability. Should any one or more provisions of this Guaranty be determined to be illegal or unenforceable, all other provisions nevertheless shall be effective.

12. Waiver or Amendment. No provision of this Guaranty or right of Company hereunder can be waived, nor can Guarantor be released from Guarantor's duties hereunder, except by a writing duly executed by Company. This Guaranty may not be modified, amended, revised, revoked, terminated, changed, or varied in any way whatsoever except by the express terms of a writing duly executed by Company.

13. Successors and Assigns. This Guaranty shall inure to the benefit of and bind the successors and assigns of Company and Guarantor. Guarantor shall have no right to assign this Guaranty or its obligations hereunder without the prior written consent of Company, which consent may be withheld in its sole discretion. Company shall have the right to assign this Guaranty to any person or entity without the prior written consent of Guarantor; *provided*, *however*, that no such assignment shall be binding upon Guarantor until it receives written notice of such assignment from Company.

14. Governing Law. This Guaranty shall be governed by and construed in accordance with the law of the State of Colorado without regard to the principles of conflicts of law thereof. Guarantor hereby submits to the exclusive jurisdiction in the federal and state courts of the State of Colorado, and venue is hereby stipulated as Denver, Colorado. Guarantor waives any claim or defense that such action or proceeding brought in any such court is an inconvenient forum, any objection to venue with respect to such action or proceeding, and any right of jurisdiction on the account of the place of residence or domicile of the Guarantor.

15. Notices. All notices, requests, claims, demands, and other communications hereunder shall be in writing and shall be given (and shall be deemed to have been duly given upon receipt) by delivery in the manner contemplated by the PPA, addressed as follows:

if to Company: Tri-State Generation and Transmission Association, Inc.
1100 W. 116th Avenue
Westminster, CO 80234
Attn: Senior Vice President and Chief Financial Officer
Phone: (303) 452-6111

if to Guarantor: _____
_____
_____
Attn:
Phone: (___) _____

or to such other address(es) as the person to whom notice is given may have previously furnished to the others in writing in the manner set forth above.

IN WITNESS WHEREOF, Guarantor has caused this Guaranty to be duly executed and delivered to Company as of the day and year first above written.

[Name of Guarantor]

By:_____
Name:
Title:

STATE OF_____)
) ss.
COUNTY OF _____)

The foregoing instrument was acknowledged before me this _____ day of _____, 20__, by _____, as _____ of _____.

Witness my hand and official seal.

My commission expires:_____.

_____
Notary Public

(S E A L)

EXHIBIT M

STORAGE REQUIREMENTS

TBD - generation technology and project specific

EXHIBIT N

STORAGE TEST

TBD - generation technology and project specific

Storage Operation Test

Storage Periodic Test

Attachment Vol II 7-5 Renewable PPA

Tri-State 11/19/2020
Model Renewable PPA
TS-XX-XXXX

[WIND] [SOLAR] ENERGY PURCHASE AGREEMENT FOR THE _____ PROJECT

BETWEEN

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

AND

_____

- [date] -

TS-XX-XXXX

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[WIND] [SOLAR] ENERGY PURCHASE AGREEMENT FOR THE _____ PROJECT
BETWEEN
TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.
AND
_____

This [Wind][Solar] Energy Purchase Agreement for the _____ Project (this "PPA") is made this ____ day of _____, 20__, by and between (i) _____ ("Seller"), a _____ and (ii) Tri-State Generation and Transmission Association, Inc. ("Tri-State"), a Colorado cooperative corporation. Seller and Tri-State are hereinafter referred to individually as a "Party" and collectively as the "Parties."

WHEREAS, Seller desires to develop, design, construct, interconnect, own, operate, and maintain a _____ -powered electric energy generating facility consisting of _____(__) _____ [wind turbines][solar panels] (each, a "Unit" and collectively, the "Units") with an expected total nameplate capacity of ____ MW [*solar only-* AC] (the "Expected Nameplate Capacity Rating"), and which is further defined below as the "Facility"; and

WHEREAS, Seller has secured an approximately _____ (__,000) acre site in _____ County, _____ where it intends to locate the Facility and interconnect the Facility **[**to Interconnection Provider's existing _____ transmission line in the vicinity of the Site**][**at the Interconnection Provider's _____ Substation**]**; and

WHEREAS, Seller desires to sell and deliver to Tri-State at the Point of Delivery the electric energy produced by the Facility and all associated Environmental Attributes, and Tri-State desires to buy the same from Seller.

NOW, THEREFORE, in consideration of the mutual covenants herein contained, the sufficiency and adequacy of which are hereby acknowledged, the Parties agree to the following:

Article 1
Definitions and Rules of Interpretation

1.1 Rules of Construction.

The capitalized terms used in this PPA shall have the meaning set forth in this Article 1 or as otherwise defined in this PPA, whether in the singular or the plural or in the present or past tense. Words not otherwise defined herein shall have meanings as commonly used in the English language and, where applicable, in Prudent Utility Practice. Words not otherwise defined herein that have well known and generally accepted technical or trade meanings are used herein in accordance with such recognized meanings. In addition, the following rules of interpretation shall apply:

(A) References to "Articles," "Sections," or "Exhibits" shall be to articles, sections, or exhibits of this PPA.

(B) The Exhibits attached hereto are incorporated in and are intended to be a part of this PPA; *provided* that in the event of a conflict between the terms of any Exhibit and the terms of this PPA, the terms of this PPA shall take precedence.

(C) This PPA was negotiated and prepared by both Parties with the advice and participation of counsel. The Parties have agreed to the wording of this PPA and none of the provisions hereof shall be construed against one Party on the ground that such Party is the author of this PPA or any part hereof.

(D) The Parties shall act reasonably and in accordance with the principles of good faith and fair dealing in the performance of this PPA. Unless expressly provided otherwise in this PPA, (i) where this PPA requires the consent, approval, or similar action by a Party, such consent or approval shall not be unreasonably withheld, conditioned or delayed, and (ii) wherever this PPA gives a Party a right to determine, require, specify or take similar action with respect to a matter, such determination, requirement, specification or similar action shall be reasonable.

(E) Use of the words "include" or "including" or similar words shall be interpreted as "including, but not limited to" or "including, without limitation."

(F) The words "hereof," "herein," and "hereunder" and words of similar import when used in this PPA shall refer to this PPA as a whole and not to any particular provision of this PPA.

(G) Numerical amounts will be rounded to the nearest cent with respect to Dollars, one (1) decimal point for MW and MWh, three (3) decimal points for percentages, which is to the nearest tenth of a percent, and otherwise to two (2) decimal points.

(H) Tri-State's technical review, comments or inspection of the Facility, any designs, testing procedures, reports, or other documents or monitoring of any events shall not be construed as endorsing such nor as any express or implied warranty of performance, safety, durability, or reliability of the Facility or waiver of its rights under this PPA.

1.2 Interpretation with Interconnection Agreement.

The Parties recognize that Seller will enter into a separate Interconnection Agreement with the Interconnection Provider. The Parties acknowledge and agree that:

(A) the Interconnection Agreement shall be a separate and free-standing contract and that the terms of this PPA are not binding upon the Interconnection Provider.

(B) this PPA does not provide Seller authorization to interconnect the Facility to the Interconnection Provider or inject power into the Transmission System.

(C) notwithstanding any other provision in this PPA, nothing in the Interconnection Agreement shall alter or modify Seller's or Tri-State's rights, duties and obligations under this PPA. This PPA shall not be construed to create any rights between Seller and the Interconnection Provider.

(D) for purposes of this PPA, the Interconnection Provider shall be deemed to be a separate entity and separate contracting party whether or not the Interconnection Agreement is entered into with Tri-State or an Affiliate of Tri-State.

1.3 Interpretation of Arrangements for Power Supply to the Facility.

This PPA does not provide for the supply of retail electric power to the Facility ("House Energy"). Seller shall arrange with the local utility in whose retail service territory the Facility is located ("Local Provider") for the supply of House Energy. Subject to Seller's right to self-generate and consume energy concurrently generated by the Facility, Seller shall obtain House Energy exclusively from the Local Provider.

1.4 Definitions.

The following terms shall have the meanings set forth herein:

"Abandonment" means (i) the relinquishment of all possession and control of the Facility by Seller, other than a transfer permitted under this PPA, or (ii) if prior to the Commercial Operation Date, complete cessation of the development, design, construction, testing or inspection of the Facility for thirty (30) consecutive Days by Seller and/or Seller's contractors, but only if such relinquishment or cessation is not caused by or attributable to an Event of Default of, or requested by, Tri-State, or a Force Majeure Event.

[solar only- "AC" means alternating electric current.*]*

"Additional Tax Benefits" means any new Tax Benefits or changes to, extensions of, or qualification for existing Tax Benefits which become available to Seller or the Facility during the Term, from and after the Effective Date, and which provide an overall net increase in the Tax Benefits attributable to the Facility.

"Additional Tax Benefit Amount" means an amount equal to (i) the aggregate amount of all Tax Benefits received by or on behalf of Seller with respect to any Additional Tax Benefits, minus (ii) the aggregate amount of all Additional Tax Benefit Costs with respect to such Additional Tax Benefits. For the avoidance of doubt, if the Additional Tax Benefit Amount is a negative amount, it shall be deemed to be zero.

"Additional Tax Benefit Costs" means all additional costs, if any, incurred by Seller resulting directly from production, qualification, or verification of an Additional Tax Benefit.

"Additional Maintenance Outages" shall have the meaning set forth in Section 9.7.

"Affiliate" of any named Person means any other Person that Controls, is under the Control of, or is under common Control with, the named Person.

"AGC" means the equipment and capability of an electric generation facility to automatically adjust the generation quantity within the applicable Balancing Authority Area with the purpose of interchange balancing and specifically, the Facility's capability to accept an AGC Set-Point electronically, and the automatic adjustment and regulation of the Facility's energy production via the SCADA system.

"AGC Set-Point" means the Tri-State-generated analog or digital signal sent by the SCADA system to the Facility, representing the quantity of Contract Energy to be generated by the Facility. The RDD will communicate the AGC Set-Point to the Facility via the SCADA system.

"Allowable Curtailment" means the amount of otherwise compensable Curtailed Contract Energy in any Commercial Operation Year to be applied at the election of Tri-State at any time during a Commercial Operation Year, which amount equals (i) one percent (1%) in MWh of the Expected Contract Energy for that Commercial Operation Year plus (ii) any unused Allowable Curtailment from prior Commercial Operation Years. Any unused Allowable Curtailment from a Commercial Operation Year does not expire at the end of a Commercial Operation Year and is carried forward to future Commercial Operation Years.

"Applicable Law" means, collectively, all applicable laws, statutes, treaties, codes, ordinances, regulations, certificates, orders, licenses and permits of any Governmental Authority, now in effect or hereafter enacted, amendments to any of the foregoing, interpretations of any of the foregoing by a Governmental Authority having jurisdiction over the Parties or the Facility, and all applicable judicial, administrative, arbitration and regulatory decrees, judgments, injunctions, writs, orders, awards or like actions (including those relating to human health, safety, the natural environment or otherwise).

"Back-Up Metering" shall have the meaning set forth in Section 5.3(B).

"Balancing Authority" means _____ or any successor entity or another responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.

"Balancing Authority Area" means the collection of generation, transmission and loads within the metered boundaries of the Balancing Authority.

"Business Day" means any Day that is not a Saturday, a Sunday, or a NERC-holiday, or state- and/or federal-recognized holiday where banks in Denver, Colorado are required or authorized to close.

"Change of Control" of a specified Person means any sale or series of sales or other transactions, whether voluntary or by operation of law, following which the previously existing Ultimate Parent does not Control such Person.

"Commercial Operation" means the operation of the Facility beginning on the Commercial Operation Date and continuing through the Term of this PPA.

"Commercial Operation Date" or "COD" for the Facility means the date set forth in Seller's COD notice that Seller has satisfied all of the conditions for Commercial Operation listed in Section 4.9, subject to confirmation by Tri-State.

"Commercial Operation Milestone" means the milestone for Commercial Operation as set forth in Exhibit A.

"Commercial Operation Year" means, for the first Commercial Operation Year, the period starting at 12:01 a.m. MPT on the COD and ending at 11:59 p.m. MPT on the last Day of the Month in which the first anniversary of COD occurs, and each successive "Commercial Operation Year" shall mean the twelve (12) Month period following the prior Commercial Operation Year.

"Conditions" shall have the meaning set forth in Section 4.9.

"Construction Milestone" means the result specified by Seller as set forth in Exhibit A which Seller shall achieve by the Construction Milestone Date, including the Commercial Operation Milestone.

"Construction Milestone Date" means the date set forth in Exhibit A by which Seller shall achieve the corresponding result specified for such date, including the Commercial Operation Milestone.

"Contract Energy" means all net electric Energy including any and all associated capacity attributes, ancillary services, all associated Environmental Attributes, and any other attributes resulting from the generation or the output of the Facility or produced by the Facility and delivered to the Point of Delivery as measured by the Electric Metering Devices installed pursuant to Section 5.3. Contract Energy shall include any Test Energy and any Excess Contract Energy.

"Contract Energy Payment" means the payment specified in Section 7.1(A).

"Contract Energy Rate" means _____ and __/100 Dollars per MWh ($_____/MWh)**[**, escalating at a rate of ___ (__) percent per year on the anniversary of each Commercial Operation Year and as further set forth in Exhibit C**]**.

"Control" means the ownership of fifty percent (50%) or more of the voting interests of the entity, or the possession, directly or indirectly, of the power to direct or cause the direction of the management policies of the entity, whether through ownership of voting securities, by contract or otherwise. "Controls," "Controlling," and "common Control" shall have correlative meanings when used in this PPA.

"Curtailed Contract Energy" shall have the meaning set forth in Section 7.2(A).

"Curtailed Contract Energy Payment" shall have the meaning set forth in Section 7.2(A).

[wind only - "Cut-Out Event" means the temporary shutting down of Units where the output from the Facility decreases by an aggregate of thirty (30) MW or greater during a five (5) minute interval due to wind speeds in excess of operating parameters specified by the Unit manufacturer.]

"Day" means a calendar day.

"Default Rate" shall have the meaning set forth in Section 8.3(C).

"Deficiency MWhs" means the amount of Energy in MWh, if a positive number, for any Month, equal to (i) ninety percent (90%) of the product of the Expected Contract Energy multiplied by the monthly production percentage for the applicable Month specified on Exhibit G less (ii) the actual amount of Contract Energy during the same period.

"Delay Damages" shall have the meaning set forth in Section 4.3(D).

"Delivery Excuse" means an event solely or substantially due to actions or omissions by Tri-State which prevents or delays delivery of Contract Energy.

"Designation Approval Date" shall have the meaning set forth in Section 2.2.

"Dispute Notice" shall have the meaning set forth in Section 13.9(A).

"Dollars" means the lawful currency of the United States of America.

"Effective Date" means the date first written above.

"Electric Interconnection Point" means the physical point at which electrical interconnection is made between the Interconnection Facilities and the Transmission System, pursuant to the Interconnection Agreement.

"Electric Metering Device(s)" means all metering and data processing equipment used to measure, record, or transmit data relating to the Energy produced by the Facility. Electric Metering Devices include the metering current transformers (CTs) and the metering voltage transformers (VTs).

"Emergency Condition" means any emergency condition or similar situation as defined under the Interconnection Agreement or any abnormal interconnection or system condition that requires automatic or immediate manual action to prevent or limit loss of load or generation supply (including Tri-State's load or generation), that could adversely affect the reliability of the interconnected system, or that could otherwise pose a threat to public safety.

"Energy" means three-phase, 60-cycle alternating current electric energy, expressed in MWh.

"Environmental Attributes" means any and all present and future environmental benefits characteristics, or credits that are attributable to renewable energy, Contract Energy, or the Facility including credits towards achieving local, national or international emission reduction requirements or renewable portfolio standards; green tags, RECs; greenhouse gas or emissions reductions or avoidances, credits, offset, allowances or benefits; any avoided emissions of pollutants to the air, soil, or water, including sulfur oxides (SO2), nitrogen oxides (NOx), carbon dioxide (CO2), carbon monoxide (CO), methane (CH4), carbon, volatile organic compounds (VOC), mercury (Hg), hydro fluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF6), and other emissions avoided; and any and all other green energy or other environmental benefits associated with the generation of renewable energy (regardless of how any present or future law or regulation attributes or allocates such characteristics). Environmental Attributes do not include Tax Credits.

"Environmental Contamination" means the introduction or presence of Regulated Materials at the Site at such levels, quantities or location, or of such form or character, as to constitute a violation of Applicable Laws, or present a material risk under Applicable Laws that the Facility will not be available or usable, whether in whole or in part, to sell Contract Energy to Tri-State as contemplated by this PPA.

"EPC Contract" means the turnkey engineering, procurement and construction contract(s) to be entered into between Seller and the EPC Contractor in relation to the engineering, procurement and construction of the Facility.

"EPC Contractor" means the engineering, procurement and construction contractor(s) retained and paid for by Seller, which contractor(s) shall be acceptable to Tri-State.

"Equipment Supply Agreement" means the agreement under which Seller has purchased or has rights to purchase the Units and related equipment for the Facility.

"Event of Default" shall have the meaning set forth in Article 12.

"Excess Contract Energy" means that amount of Contract Energy in excess of one hundred ten percent (110%) of the Expected Contract Energy.

"Excess Contract Energy Payment" means the payment specified in Section 7.1(C).

"Excess Contract Energy Rate" means fifty percent (50%) of the Contract Energy Rate.

"Expansion Energy" shall have the meaning set forth in Section 20.2(A).

"Expected Contract Energy" means _____ MWh of Contract Energy in any given Commercial Operation Year.

"Expected Nameplate Capacity Rating" shall have the meaning set forth in the recitals to this PPA.

"Facility" means Seller's [wind][solar]-powered electric energy generating facility and Seller's Interconnection Facilities, as identified and described in Article 3 and Exhibit B, including all of the following, the purpose of which is to produce electricity and deliver such electricity to the Electric Interconnection Point: Seller's equipment, buildings, all of the generation facilities, including Units, step-up transformers, equipment and software necessary to receive, accept and respond to an AGC Set-Point signal from Tri-State, output breakers, monitoring hardware, weather station hardware, facilities necessary to connect to the Electric Interconnection Point, protective and associated equipment, improvements, and other tangible assets, contract rights, easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation, and maintenance of such [wind][solar]-powered electric energy generating facility.

"Facility Assets" shall have the meaning set forth in Section 20.3(B).

"Facility Site Documents" means the deeds, leases, easements, rights of way, land use agreement and other agreements or instruments reasonably necessary for the construction, operation and maintenance of the Facility and that evidence Seller's ownership or control of the Site.

"FERC" means the Federal Energy Regulatory Commission, or any successor agency.

"Financing" means the obligations of Seller or its Affiliates to any Financing Parties pursuant to the Financing Documents, including principal of and premium and interest on, indebtedness, fees, expenses or penalties, amounts due upon acceleration, prepayment or restructuring, swap or interest rate hedging breakage costs and any claims or interest due with respect to any of the foregoing.

"Financing Documents" means the loan and credit agreements, notes, bonds, indentures, security agreements, lease financing agreements, mortgages, deeds of trust, interest rate exchanges, swap agreements, equity purchase agreements, purchase option agreements and other documents relating to the development, bridge, construction and/or permanent debt and/or equity financing for the Facility, including any credit enhancement, credit support, working capital financing, or refinancing documents, and any and all amendments, modifications, or supplements to the foregoing that may be entered into from time to time at the discretion of Seller subject to any required approvals, whether in this PPA, or otherwise, in connection with development, construction, ownership, leasing, operation or maintenance of the Facility.

"Financing Parties" means, collectively, any lender(s), lessor(s) or tax equity investor(s) and other parties providing any Financing and any successor(s) or assigns thereto.

"Force Majeure Event" shall have the meaning set forth in Article 14.

"Forced Outage" means a reduction of, or cessation in the delivery of, or inability to deliver, Energy that is not the result of (i) a Scheduled Maintenance Outage, (ii) a Force Majeure Event, (iii) a Delivery Excuse, (iv) an Emergency Condition, or (v) a curtailment as set forth in Section 6.3(A).

"Governmental Approval" means any authorization, consent, permission, approval, license, ruling, permit, exemption, variance, order, judgment, instruction, condition, direction, directive, decree, declaration of, or regulation by, any Governmental Authority relating to the construction, development, ownership, occupation, start-up, Testing, operation or maintenance of the Facility or to the execution, delivery or performance of this PPA.

"Governmental Authority" means any federal, state, tribal, local or municipal governmental body; any governmental, quasi-governmental, regulatory or administrative agency, commission, body or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory or taxing authority or power, including a Reliability Coordinator, Balancing Authority or other governmental or quasi-governmental body administering energy, capacity, ancillary service, energy imbalance market or other Organized Markets, and PUC, FERC, NERC, WECC or other NERC regional entities; or any court or governmental tribunal.

"Guaranteed Energy Production" means that amount of Contract Energy equal to ninety percent (90%) of the Expected Contract Energy.

"Guaranty" means the payment and performance guaranty provided by a Qualified Guarantor or Superior Guarantor, as appropriate, to Tri-State in the form set forth in Exhibit L.

"House Energy" shall have the meaning set forth in Section 1.3.

"Independent Engineer" means an independent engineering firm of national repute and appropriate expertise in [wind][solar]-power electric generation relative to the configuration of the Facility under this PPA, appointed by Financing Parties under any Financing Documents, or if no such Financing Documents exist, by Seller after consultation with, and upon the prior written consent of, Tri-State.

"Interconnection Agreement" means the separate agreement between Seller and the Interconnection Provider for interconnection of the Facility to the Transmission System, as such agreement may be amended from time to time.

"Interconnection Facilities" means the facilities required to connect the Facility to the Transmission Provider's Transmission System and shall include the Interconnection Provider's Interconnection Facilities and Seller's Interconnection Facilities.

"Interconnection Provider" means _____ in its capacity as the owner of the Interconnection Provider's Interconnection Facilities, or any successor entity owner.

"Interconnection Provider's Interconnection Facilities" means the facilities necessary to connect Seller's Interconnection Facilities to the Transmission System at the Electric Interconnection Point as described in the Interconnection Agreement, including breakers, bus work, bus relays, and associated equipment installed by or for the Interconnection Provider for the direct purpose of interconnecting the Facility to the Transmission System at the Electric Interconnection Point, along with any easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of such facilities. Arrangements for the installation and operation of the Interconnection Provider's Interconnection Facilities shall be governed by the Interconnection Agreement.

"Issuer" means a U.S. commercial bank or a licensed U.S. branch of a foreign bank, with such bank having an unsecured bond rating equivalent to A- or better as determined by at least two (2) rating agencies, one of which must be either Standard & Poor's or Moody's, and an asset value of at least thirty billion Dollars ($30,000,000,000), or a Person otherwise approved by Tri-State in its sole discretion. An Issuer cannot be an Affiliate of Seller.

"kW" means kilowatt.

"Letter(s) of Credit" means an unconditional, irrevocable, standby letter of credit from an Issuer in substantially the form set forth in Exhibit K, *provided, however,* that such form may be modified by the Issuer as long as such modifications are customary, commercially reasonable, and acceptable to Tri-State. Costs of a Letter of Credit shall be borne by Seller.

"Mean Absolute Percent Error" or "MAPE" equals:

$$\frac{1}{n}\sum_{t=1}^{n}\left|\frac{A_{t-}F_t}{NC}\right|$$

Where:

n = number of hours in the quarter of the Year;

A_t = actual value of Contract Energy deliveries in MWh for the forecast hour;

F_t = hour-ahead forecasted value in MWh for the forecast hour, as provided by Seller in accordance with Section 6.4(E); provided if no hour-ahead forecast was provided for such hour, the amount of the forecast for that hour will be zero; and

NC = Nameplate Capacity Rating.

"Month" means a calendar month.

"Moody's" means Moody's Investors Services, Inc., or any successor thereto.

"MPT" means, during any period of determination, the time in effect as of such period determination in the Mountain Time Zone of the United States of America, whether Mountain Standard Time or Mountain Daylight Savings Time.

"MW" means megawatt.

"MWh" means megawatt hours.

"Nameplate Capacity Rating" means the maximum installed instantaneous generation capacity of the completed Facility, expressed in MW [*solar only-* AC], when operated in compliance with the Interconnection Agreement and consistent with the Unit manufacturer's recommended power factor and operating parameters, as set forth in a notice from Seller to Tri-State delivered prior to or on the Commercial Operation Date (but shall be deemed to be zero (0) MW if no such notice is provided). The Nameplate Capacity Rating of the Facility shall not exceed **Insert the Expected Nameplate Capacity Rating** MW [*solar only-* AC].

"NERC" means the North American Electric Reliability Corporation, or any successor organization.

"Notice of Intent to Purchase" shall have the meaning set forth in Section 20.3(D).

"O&M Records" shall have the meaning set forth in Section 13.7.

"Offered Assets Notice" shall have the meaning set forth in Section 20.1(A).

"Operating Committee" means one representative each from Tri-State and Seller, appointed pursuant to Section 9.10(A).

"Operating Procedures" means those procedures developed pursuant to Section 9.10(B).

"Operating Records" means all agreements, records and other data associated with the construction, operation or maintenance of the Facility, including O&M Records, Project Contracts, blueprints for construction, operating manuals, all warranties on equipment, and all documents, whether in printed or electronic format, that Seller uses or maintains for the operation of the Facility.

"Operation and Maintenance Agreement" means that certain operation and maintenance agreement between Seller and the Operation and Maintenance Contractor with respect to the Facility.

"Operation and Maintenance Contractor" means the operation and maintenance contractor retained and paid for by Seller, which contractor shall be a Qualified Operator and acceptable to Tri-State.

"Organized Market" means a regional transmission organization, independent system operator, energy imbalance market, or any other organized market.

"Party" and "Parties" shall have the meaning set forth in the recitals to this PPA.

"Party Representative" or "Parties' Representatives" shall have the meaning set forth in Section 13.9(A).

"Person" means any natural person, corporation, limited liability company, general partnership, limited partnership, proprietorship, other business organization, trust, union, association or Governmental Authority.

"Point of Delivery" means the electric system point at which Seller makes available to Tri-State the Contract Energy, which shall be on the high side of the step-up transformer **[**at the Electric Interconnection Point**]** and as specified in Exhibit B.

"PPA" means this Energy Purchase Agreement between Seller and Tri-State, including the Exhibits attached hereto, as the same may be amended from time to time in accordance with the provisions hereof.

[*wind only-* "Production Tax Credit" mean the production tax credits applicable to electricity produced from certain renewable resources under Section 45 of the Internal Revenue Code of 1986 or any substantially similar federal tax credits under Applicable Law that provides Seller with a tax credit based on energy production from the Facility.]

"Project Contracts" means the EPC Contract, the Equipment Supply Agreement, the Interconnection Agreement, the Facility Site Documents and the Operation and Maintenance Agreement, and any such other material agreements related to the development, construction, ownership, operation and maintenance of the Facility, a list of which agreements is set forth in Exhibit E.

"Project Entity" means (a) Seller, and (b) any entity that Controls Seller if the Facility and assets related thereto constitute all or substantially all of the assets of such entity (determined on a consolidated basis with all other Persons that are Controlled by such entity).

"Prudent Utility Practice(s)" means the practices, methods, standards, and acts of a significant portion of the electric power generation industry (including, where applicable, the practices, methods, standards, and acts engaged in or approved by a significant portion of the [wind][solar]-power electric generation industry operating facilities of a similar type, size and location in the United States of America), WECC and/or NERC, that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with Applicable Laws, codes, standards, equipment manufacturer's recommendations, reliability, safety, environmental protection, economy, and expedition. With respect to the Facility, Prudent Utility Practice(s) includes taking reasonable steps to ensure that:

(A) equipment, materials, resources, and supplies, including spare parts inventories, are available to meet the Facility's needs;

(B) sufficient operating personnel are available at all times and are adequately experienced and trained and licensed as necessary to operate the Facility properly, efficiently, and in coordination with Tri-State and are capable of responding to reasonably foreseeable Emergency Conditions;

(C) preventive, routine, and non-routine maintenance and repairs are performed on a basis that ensures reliable, long-term and safe operation, and are performed by knowledgeable, trained, and experienced personnel utilizing proper equipment and tools;

(D) appropriate monitoring and testing are performed to ensure equipment is functioning as designed;

(E) equipment is not operated in a reckless manner, in violation of manufacturers' guidelines or in a manner unsafe to workers, the general public, or the interconnected system or contrary to environmental laws, permits or regulations or without regard to defined limitations such as, flood conditions, safety inspection requirements, operating voltage, current, volt-ampere reactive (VAR) loading, frequency, polarity, synchronization, and/or control system limits;

(F) equipment and components meet or exceed the standard of durability that is generally used for electric generation operations in the region and will function properly over the full range of ambient temperature and weather conditions reasonably expected to occur at the Site under both normal and Emergency Conditions; and

(G) equipment, components, and processes are appropriately permitted with any Governmental Authority and are operated and maintained in accordance with Applicable Laws.

"PUC" means the _____ Commission, or any successor agency.

"PUC Approval" means any written order of the PUC necessary for Tri-State to effectuate the purposes of this PPA.

"Purchase Notice" shall have the meaning set forth in Section 20.3(I).

"Purchase Option" shall have the meaning set forth in Section 20.3(A).

"Qualified Guarantor" means a Person having an issuer credit rating of (A) Baa2 or higher by Moody's and (B) BBB or higher by Standard & Poor's, or a Person otherwise approved by Tri-State in its sole discretion.

"Qualified Operator" means an operation and maintenance contractor that (i) has operated, for a period of at least five (5) years, multiple utility-scale [wind][solar]-powered electric energy generating facilities in North America having, collectively, an aggregate nameplate capacity of at least 500 MW, and (ii) maintains an operating staff consisting of personnel with comparable experience in the operation and maintenance of power generation facilities similar to the Facility.

"RDD" means Tri-State's resource dispatch desk representative(s) who are responsible for dispatch of generating units, including the Facility.

"Regulated Materials" means any substance, material, gas, or particulate matter that is regulated by any Governmental Authority, as an environmental pollutant or dangerous to public health, public welfare, or the natural environment, including protection of non-human forms of life, land, water, groundwater, and air, including any material or substance that is (i) defined as "toxic," "polluting," "hazardous waste," "hazardous material," "hazardous substance," "extremely hazardous waste," "solid waste" or "restricted hazardous waste" under any provision of local, state, or federal law; (ii) petroleum, including any fraction, derivative or additive; (iii) asbestos; (iv) polychlorinated biphenyls; (v) radioactive material; (vi) designated as a "hazardous substance" pursuant to the Clean Water Act, 33 U.S.C. §1251 *et seq.* (33 U.S.C. §1251); (vii) defined as a "hazardous waste" pursuant to the Resource Conservation and Recovery Act, 42 U.S.C. §6901 *et seq.* (42 U.S.C. §6901); (viii) defined as a "hazardous substance" pursuant to the Comprehensive Environmental Response, Compensation, and Liability Act, 42 U.S.C. §9601 *et seq.* (42 U.S.C. §9601);

(ix) defined as a "chemical substance" under the Toxic Substances Control Act, 15 U.S.C. §2601 *et seq.* (15 U.S.C. §2601); or (x) defined as a "pesticide" under the Federal Insecticide, Fungicide, and Rodenticide Act, 7 U.S.C. §136 *et seq.* (7 U.S.C. §136).

"RECs" means renewable energy credits or certificates representing all right, title and interest in and to all Environmental Attributes associated with each MWh of energy from a generation facility in the specific period, including title to and claim over such Environmental Attributes, reporting and all other rights arising therefrom or connected therewith under Applicable Law.

"Reliability Coordinator" shall have the meaning as set forth in NERC's Glossary of Terms Used in NERC Reliability Standards as modified from time to time.

"Replacement Cost(s)" means the costs incurred and reasonably forecasted to be incurred by Tri-State for the Energy, ancillary services and Environmental Attributes which are necessary to replace that which Seller, in accordance with this PPA, is required to produce at the Facility and deliver to Tri-State, but will fail to so provide, less the sum of any payments from Tri-State to Seller, under this PPA, which are eliminated as a result of such failure. Replacement Costs include the amounts incurred and reasonably forecasted to be incurred by Tri-State for replacement renewable energy, ancillary services, transmission and directly associated transaction costs (including reasonable attorneys' fees suffered as result of Seller's failure to perform). Additional costs may include replacement capacity costs applicable to a [wind][solar] resource and any penalties incurred as a result of Seller's non-performance.

"ROFO Transfer" shall have the meaning set forth in Section 20.1(A).

"RTU" shall have the meaning set forth in Section 3.3(A).

"SCADA" means supervisory control and data acquisition.

"Scheduled Maintenance Outage" means a time period during which all or a portion of the Facility is shut down or its output reduced to undergo scheduled maintenance in accordance with this PPA, or as otherwise agreed by Seller and Tri-State.

"Security" shall have the meaning set forth in Article 11.

"Security Party" shall have the meaning set forth in Section 19.1(B).

"Seller" shall have the meaning set forth in the preamble to this PPA.

"Seller's Interconnection Facilities" means the facilities and equipment owned by Seller related to the interconnection of the Facility with the Interconnection Provider's Interconnection Facilities along with any easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the

construction, operation and maintenance of such facilities. On the low side of the step-up transformer, it includes Seller's metering, relays, and load control equipment as provided for in the Interconnection Agreement.

"Seller's WREGIS Account" shall have the meaning set forth in Section 10.2(D).

"Shortfall MWh" means the amount of Energy in MWh, for any period of determination, equal to the Guaranteed Energy Production less the actual amount of Contract Energy during the same period.

"Site" means the parcel(s) of real property on which the Facility will be constructed and located, including any easements, rights of way, land use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of the Facility. The Site is more specifically described in Section 3.2 and Exhibit B.

"Standard & Poor's" means Standard & Poor's Global Ratings, or any successor thereto.

"Superior Guarantor" means any Person having an issuer credit rating of (A) Baa1 or higher by Moody's and (B) BBB+ or higher by Standard & Poor's, or a Person otherwise approved by Tri-State in its sole discretion.

"Tariff" shall have the meaning set forth in Section 5.1(B).

"Taxes" means all taxes, fees, levies, licenses or charges imposed by any Governmental Authority, other than taxes, levies, licenses or charges based upon net income or net worth, together with any interest and penalties thereon.

"Tax Credit" means (i) [*wind only*-the Production Tax Credit][*solar only*- the tax credit for "energy property" under Section 48(a)(3)(A)(i) of the Internal Revenue Code of 1986 or any similar tax credits under Applicable Law, as it may be amended, supplemented, extended or replaced from time to time.], (ii) any other local, state or federal tax credits providing a tax benefit to Seller based on ownership of the Facility or energy production therefrom, and (iii) depreciation and other tax benefits arising from ownership or operation of the Facility.

"Term" means the period of time during which this PPA shall remain in full force and effect, and which is further defined in Section 2.1.

"Test" or "Testing" means those tests, evaluations and measurements of the Facility's output capability that are undertaken in connection with preparing the Facility for Commercial Operation pursuant to Section 9.2, which shall include such tests as are consistent with Prudent Utility Practices.

"Test Date" means the date on which Seller shall commence Testing of the Facility and shall be the date falling at least sixty (60) Days prior to the Commercial Operation Milestone or such other date as Seller and Tri-State may agree in writing.

"Test Energy" means the net electric Energy that is produced by the Facility, including any and all associated ancillary services and all Environmental Attributes and delivered to Tri-State at the Point of Delivery, prior to Commercial Operation.

"Test Energy Payment" means the payment specified in Section 7.1(B).

"Test Energy Rate" means an amount equal to fifty percent (50%) of the Contract Energy Rate.

"TP Approvals" shall have the meaning set forth in Section 2.2.

"Transfer" means any sale, transfer or other disposition.

"Transmission Provider" means the owner or operator of the Transmission System responsible for providing transmission service.

"Transmission System" means the contiguously interconnected electric transmission and sub-transmission facilities over which the Transmission Provider has rights (by ownership or contract) to provide bulk transmission of capacity and energy from the Electric Interconnection Point.

"Tri-State" shall have the meaning set forth in the preamble to this PPA.

"Tri-State's WREGIS Account" shall have the meaning set forth in Section 10.2(D).

"Ultimate Parent" means _____ or such other Person that Controls Seller and is not controlled by any other Person.

"Unit" shall have the meaning set forth in the recitals to this PPA.

"WECC" means the Western Electricity Coordinating Council, a NERC regional entity, or any successor organization.

"WREGIS" means the Western Renewable Energy Generation Information System, or any successor organization that Tri-State uses to track Environmental Attributes.

"Year" means a calendar year consisting of 365 Days (or 366 Days if a leap year), beginning on January 1 and ending on December 31.

Article 2
Term

2.1 PPA Term and Delivery Term.

This PPA shall become effective as of the Effective Date, and shall remain in full force and effect until 11:59 p.m. MPT on the last Day of the Month during which occurs the [___th] anniversary of the Commercial Operation Date, subject to early termination as set forth herein (the "Term").

2.2 Conditions Precedent.

(A) Network Resource. Tri-State's obligation to accept and pay for Contract Energy is subject to approval by the Transmission Providers of Tri-State's application for designation of the Facility as a network resource for Tri-State's native load customers and the associated reservation of firm network transmission service on the Transmission Provider's Transmission System, all without conditions materially unsatisfactory to Tri-State or requirements of material transmission upgrades (collectively, the "TP Approvals"). Tri-State shall (i) no later than fifteen (15) Business Days after the Effective Date, make a written request for all TP Approvals and (ii) thereafter use commercially reasonable efforts to obtain such TP Approvals from the Transmission Providers within one hundred fifty (150) Days from the Effective Date ("Designation Approval Date") and shall provide Seller prompt written notice upon receipt of all such TP Approvals. If any or all of the TP Approvals are not received by the Designation Approvals Date or any TP Approval would require conditions materially unsatisfactory to Tri-State or material transmission upgrades, (y) Tri-State shall promptly provide Seller written notice notifying Seller that Tri-State elects to terminate this PPA, upon which the Parties shall have no obligations or liabilities to each other hereunder, subject to Tri-State's obligation to return the Security to Seller in full, or (z) if no such notice is received by Seller within ten (10) Days following the Designation Approval Date, Tri-State shall be deemed to have elected to proceed with this PPA despite not receiving such TP Approvals, upon which the condition provided in this Section 2.2(A) shall be deemed to have been satisfied.

(B) PUC Approvals. Tri-State's obligation to accept and pay for Contract Energy is subject to PUC Approvals. Tri-State shall (i) no later than sixty (60) Days after the Effective Date apply to the PUC for any necessary PUC Approvals and (ii) thereafter use commercially reasonable efforts to obtain such PUC Approvals as soon as reasonably practicable. Seller shall cooperate with Tri-State's efforts to obtain PUC Approvals and provide such additional documentation and information as reasonably requested by Tri-State or the PUC. Tri-State shall have the right to terminate this PPA, upon which the Parties shall have no obligations or liabilities to each other hereunder as a result of such termination, by written notice to Seller: (a) at any time within thirty (30) Days following issuance of a written order by the PUC rejecting PUC Approvals or granting PUC Approvals with conditions unacceptable to Tri-State in its sole discretion, (b) at any time between the 180th and 215th Day following Tri-State's

application for PUC Approval, if prior to the date of such termination the PUC has not issued the PUC Approvals, (c) at any time within 30 Days following timely request for reconsideration (in whole or in any material part) by any third party, of the PUC Approvals, and/or (d) at any time within thirty (30) Days following timely appeal by any party, of the PUC Approvals. If Tri-State elects to terminate this PPA, Tri-State shall return the Security to Seller in full. If Tri-State is eligible to terminate this PPA, but fails to terminate this PPA by the applicable date, Tri-State shall be deemed to have elected to proceed with this PPA despite not receiving such PUC Approvals, upon which the condition provided in this Section 2.2(B) shall be deemed to have been satisfied.

(C) Other Tri-State CPs. [if any].

(D) Seller CPs. [if any – project specific].

2.3 Survivability.

Applicable provisions of this PPA shall continue in effect after termination, including early termination, to the extent necessary to enforce or complete the duties, obligations or responsibilities of the Parties arising prior to termination and, as applicable, to provide for: final billings and adjustments related to the period prior to termination, repayment of any money due and owing to either Party pursuant to this PPA, and the indemnifications specified in this PPA. All remedies in this PPA shall survive termination or cancellation of this PPA.

Article 3
Facility Description

3.1 Summary Description.

Seller shall develop, design, construct, interconnect, own, operate, and maintain the Facility, which consists of _____ (__) _____ [wind turbines][solar panels] and associated equipment having a designed aggregate nameplate electric energy generating capacity of **Insert the Expected Nameplate Capacity Rating**. Exhibit B provides a detailed description of the Facility, including identification of the major equipment and components that will make up the Facility.

3.2 Location.

The Facility shall be located on the Site and shall be identified as the "**Insert Project Name**" or such other name as agreed to by the Parties. The latitude and longitude of the Site are _____. A scaled map that identifies the Site and the location of the Units on the Site and a drawing identifying the location of the Electric Interconnection Point, the Point of Delivery, important ancillary facilities and Interconnection Facilities, is included in Exhibit B.

3.3 General Design of the Facility.

Seller shall develop, design and construct the Facility according to Prudent Utility Practice(s), this PPA and the Interconnection Agreement, as applicable. In addition to the requirements of the Interconnection Agreement, the Facility shall at all times, and at Seller's expense:

(A) have the required electronic plant interfaces and communications interfaces for meter recording devices, 125vDC battery supplied voltage for meter recording devices, remote terminal unit ("RTU"), telemetering equipment and communications equipment. Seller is responsible for providing appropriate panel space and maintaining ambient conditions suitable for electronic equipment. Seller is responsible for establishing appropriate access control to the electronic equipment;

(B) use communication circuits from the Facility to Tri-State's RDD for the purpose of telemetering, supervisory control/data acquisition, voice communications as required by Tri-State, and dial-in access by Tri-State to remotely interrogate the Electric Metering Devices;

(C) [solar only- have suitable solar irradiation meters and other instrumentation necessary to measure the available resource and ambient temperature and to estimate the quantity of Contract Energy expected to be generated;]

(D) include one full data circuit as required to transmit to Tri-State real-time weather data, including [wind speed, wind direction][solar irradiance], humidity and temperature collected by Seller's monitoring equipment on its meteorological data acquisition equipment located at the Facility; and

(E) have the required equipment and software necessary to receive, accept and respond to an AGC Set-Point signal from Tri-State.

Article 4
Commercial Operation

4.1 Commercial Operation.

Seller shall cause the Facility to achieve Commercial Operation no later than the Commercial Operation Milestone. The Facility shall be fully capable of reliably producing and delivering the Contract Energy to be provided under this PPA to Tri-State at the Point of Delivery, no later than the Commercial Operation Milestone; provided, that Seller shall not be obligated to establish a Commercial Operation Date under this PPA that is earlier than the Commercial Operation Milestone, and Tri-State shall not be obligated to acknowledge a Commercial Operation Date under this PPA that is earlier than thirty (30) Days prior to the Commercial Operation Milestone.

4.2 Construction Milestone.

In order to achieve the Commercial Operation Date of the Facility by the Commercial Operation Milestone, Seller shall meet the Construction Milestones set forth in Exhibit A.

4.3 Delay Damages.

(A) If Seller fails to achieve any Construction Milestones (excluding the Commercial Operation Milestone) by the applicable Construction Milestone Date, (i) Seller shall provide Tri-State within ten (10) Days of the missed milestone with a detailed written report indicating the reason for such failure and Seller's proposed course of action to maintain the overall construction and commercial operation schedule, including any required expediting actions, and (ii) Tri-State shall be entitled to delay damages, as liquidated damages and not a penalty, in an amount equal to Two Thousand Five Hundred Dollars ($2,500) per Day for each Day following the Construction Milestone Date until the date the Construction Milestone is achieved; *provided, however,* that if Commercial Operation is achieved on or before the Commercial Operation Milestone, any liquidated damages amounts paid by, or on behalf of, Seller pursuant to this Section 4.3(A) shall be refunded by Tri-State to Seller without interest.

(B) If the Facility fails to achieve Commercial Operation by the Commercial Operation Milestone, (i) Seller shall provide Tri-State within ten (10) Days of the missed milestone with a detailed written report indicating the reason for such failure and Seller's proposed course of action to achieve Commercial Operation, including any required expediting actions, and (ii) Tri-State shall be entitled to delay damages, as liquidated damages and not a penalty, in an amount equal to Two Hundred Fifty Dollars ($250) per Day per MW for each MW [*solar only-* AC] of nameplate capacity not installed, operating and capable of generating Test Energy below the Expected Nameplate Capacity Rating until the earlier to occur of (x) the date Commercial Operation is achieved, and (y) the date, if any, on which this PPA is terminated by Tri-State as permitted hereunder.

(C) All Delay Damages shall begin to accrue on the Day after the applicable missed Construction Milestone and shall continue to accrue until the result specified for such Construction Milestone is achieved. Delay Damages shall be payable in lieu of actual damages accrued for the period during which Delay Damages are assessed; provided, that nothing in this Section shall be construed to preclude Tri-State from terminating this PPA for an Event of Default under Section 12.1 or Tri-State's entitlement to Replacement Costs upon termination of this PPA. All Delay Damages shall be cumulative.

(D) Each Party agrees and acknowledges that (i) the damages that Tri-State would incur due to Seller's delay or failure in achieving any Construction Milestone (collectively, "Delay Damages") would be difficult or impossible to predict with

certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the Delay Damages as agreed to by the Parties set forth herein are a fair and reasonable calculation of such damages.

(E) Following the end of the Month in which Delay Damages begin to accrue, Tri-State shall promptly deliver to Seller an invoice setting forth the amount due Tri-State in respect thereof for the preceding Month. The amount of Delay Damages shall be due and payable by Seller in accordance with Section 8.3(A).

4.4 Site Report.

(A) Within ninety (90) Days of the Effective Date, Seller shall conduct a Phase I environmental investigation of the Site and shall provide Tri-State with a copy of the report summarizing such investigation, together with any data or information generated pursuant to such investigation. To the extent the Phase I investigation identifies the need for further environmental audits or investigations, Seller shall also provide to Tri-State, any related further reports. Seller shall provide to Tri-State, with such report, confirmation from an environmental engineer that the Site has been inspected for Environmental Contamination and that the Site complies, in all respects, with all Applicable Law relating to environmental or occupational health and safety matters and Regulated Materials. Such report shall include a confirmation that, based upon such investigation and to the best of Seller's knowledge, no conditions involving Environmental Contamination exist at or under the Site.

(B) During the Term, Seller shall promptly:

(1) disclose to Tri-State and remediate, at Seller's sole cost and expense, any Environmental Contamination identified at the Site;

(2) provide to Tri-State copies of any reports summarizing any further environmental assessments or investigations, together with any data or information generated pursuant to such investigation; and

(3) disclose to Tri-State the existence of any enforcement, legal, or regulatory action or proceeding relating to any alleged presence of Environmental Contamination and/or the alleged violation of any Applicable Law related to the protection of endangered, migratory or other protected species.

4.5 Project Contracts.

(A) Promptly after the execution of each of the Project Contracts or amendment thereto, Seller shall deliver to Tri-State copies of each of the fully executed Project Contracts. Upon reasonable notice and request by Tri-State, Seller shall provide Tri-State with other Facility design and construction documents and drawings, including as-built and other major engineering drawings. Seller shall be permitted to redact from the copies of the Project Contracts provided to Tri-State any pricing information which Seller considers confidential.

(B) Within ten (10) Days after the Effective Date, Seller shall deliver to Tri-State a copy of any existing [wind][solar] energy or [wind][solar] resource assessment report related to the Site or the Facility. Furthermore, promptly following its issuance to Seller or development by Seller, Seller shall deliver to Tri-State a copy of any new or updated [wind][solar] energy or [wind][solar] resource assessment report related to the Site or the Facility.

4.6 Governmental Approvals.

Seller shall timely and lawfully procure and maintain in good standing, at its own cost and expense, all Seller required Governmental Approvals, and shall timely and properly pay its charges and fees in connection therewith. Tri-State shall have the right to inspect and obtain copies of all Seller required Governmental Approvals (and related applications) obtained or applied for by Seller. Exhibit F sets forth a list of Seller's required Governmental Approvals, which Seller shall update from time to time, as appropriate, to add additional Seller required Governmental Approvals prior to Commercial Operation.

4.7 Construction Progress Reports.

Seller shall provide Tri-State with written progress reports in a form reasonably acceptable to Tri-State: (A) on a quarterly basis commencing with the Effective Date and continuing until the commencement of physical construction of the Facility within twenty (20) Days following the end of each calendar quarter; and (B) on a monthly basis commencing on the commencement of physical construction of the Facility and continuing until Commercial Operation, on or before the twentieth (20th) Day of each Month for the preceding Month. Such written progress reports shall evaluate the progress on development, design, and construction of the Facility, which reports shall include (i) a project master schedule, with appropriate bar charts and status reports; (ii) updated engineering and procurement schedules; (iii) an updated testing, commissioning and start-up schedule; and (iv) reports from engineers and other Persons involved in the engineering, procurement and construction of the Facility. Seller shall, from time to time, upon reasonable advance request from Tri-State, meet with Tri-State to discuss the progress of the construction of the Facility and make the EPC Contractor available to discuss and answer questions of Tri-State regarding the Facility and Construction Milestone progress in order to keep Tri-State informed on the status of the engineering, procurement and construction for the Facility and to consider Tri-State's comments in good faith. None of the foregoing shall be deemed to be in lieu of, or in substitution for, the general record and reporting obligations attendant to Seller in accordance with Article 13.

4.8 Tri-State's Rights During Construction.

Tri-State shall have the right to monitor the construction, start-up and Testing of the Facility, and Seller shall comply with all requests of Tri-State with respect to the monitoring of these events. Seller shall cooperate in such physical inspections of the

Facility as may be requested by Tri-State during and after completion of construction. All persons visiting the Facility on behalf of Tri-State shall comply with all of Seller's applicable reasonable safety and health rules and requirements that have been provided to Tri-State in writing prior to its visit.

4.9 Conditions to Commercial Operation.

Seller shall notify Tri-State in writing when Seller has satisfied all of the Conditions for Commercial Operation. Such notice shall specify the Commercial Operation Date. The Commercial Operation Date is contingent upon verification by Tri-State, including Seller providing evidence acceptable to Tri-State of the satisfaction or occurrence of all of the Conditions set forth below. Review and approval of such Conditions may occur on an ongoing and incremental basis, pending resolution of any dispute, as such Conditions are satisfied. Conditions shall be satisfied at Seller's sole cost and expense. Conditions to be fulfilled by Seller prior to Commercial Operation, to the satisfaction of, or waived in writing by, Tri-State are ("Conditions"):

(A) Seller having delivered to Tri-State copies of fully executed Project Contracts, pursuant to Section 4.5(A);

(B) if applicable, Seller having entered into Financing Documents and having achieved or obtained waivers with respect to all conditions precedent to the initial availability for disbursement of funds under the Financing Documents;

(C) Seller having delivered to Tri-State (i) a copy of its constitutional documents (certified by the Secretary of State of the State of _____) and (ii) a copy of a resolution approving the terms of this PPA and authorizing one or more individuals to execute this PPA on its behalf (such copy to have been certified by its authorized officer as true, complete and current);

(D) the Facility having achieved initial synchronization with the Transmission System and having demonstrated the reliability of its communications systems and communications with Tri-State's RDD;

(E) the Independent Engineer having certified that the Facility has been completed in all material respects (excepting punch list items that do not adversely affect the ability of the Facility to operate as intended hereunder) and the Facility is ready for the delivery of Contract Energy and commencement of Commercial Operation;

(F) all arrangements for the supply of required House Energy to the Facility have been completed by Seller, are in effect, and are available for the supply of such House Energy to the Facility;

(G) the Security meeting the requirements set forth in Section 11.1 having been established in the amount required after the Commercial Operation Date pursuant to Section 11.1;

(H) certificates of insurance evidencing the coverages required in Exhibit D having been obtained and submitted to Tri-State;

(I) Seller having submitted to Tri-State a certificate of an officer of Seller familiar with the Facility after due inquiry stating that:

(1) all applicable Seller required Governmental Approvals (including those set forth in Exhibit F) have been obtained and are in full force and effect, except for minor Governmental Approvals that are expected by such officer to be obtained in the ordinary course, the failure of which to obtain would not adversely affect the construction and/or operation of the Facility;

(2) Seller is in compliance with the terms and conditions of this PPA;

(3) the Facility is in compliance with all national and regional reliability standards, including standards set by WECC, NERC, FERC, the PUC and is compliance with all applicable terms and conditions of applicable Tariffs;

(4) Seller has good title to the Facility and all Facility Site Documents reasonably necessary for the operation and maintenance of the Facility are in full force and effect;

(5) Seller has registered (and attaching with such certificate documentation setting forth that it has registered) (i) with NERC as a generator owner and generator operator, and (ii) the Facility as a generating unit and itself as an account holder with WREGIS;

(6) Seller having successfully completed Testing of the Facility that may be required by the Financing Documents, applicable Seller required Governmental Approvals, any Project Contracts, manufacturers' specifications and warranties for the commencement of Commercial Operation, and in accordance with Section 9.2 at an installed capacity of the Expected Nameplate Capacity Rating;

(7) (i) Seller is in compliance with the Interconnection Agreement, (ii) the interconnection of the Facility to the Interconnection Provider's Interconnection Facilities has been completed in accordance with the Interconnection Agreement, (iii) the Facility has operated at a generation level acceptable to the Interconnection Provider, without experiencing any abnormal or unsafe operating conditions on any interconnected system, and (iv) any other testing of the Facility and/or Seller's interconnection Facilities required by the Interconnection Agreement to interconnect and deliver energy has been completed satisfactorily;

(8) the Nameplate Capacity Rating of the Facility at the time of Commercial Operation is **Insert the Expected Nameplate Capacity Rating** MW [*solar only-* AC]; and

(9) Seller shall have demonstrated that it is a Qualified Operator or that Seller has engaged a Qualified Operator to operate and maintain the Facility.

4.10 Financial Ability.

Within ninety (90) Days of the Effective Date, Seller shall provide to Tri-State copies of applicable funding agreements, financing documents or other documents and agreements, as such may be updated from time to time, which reasonably establish that Seller has or will have sufficient funding to complete the construction of the Facility and achieve Commercial Operation.

4.11 Test Energy.

Seller shall coordinate the production and delivery of Test Energy with Tri-State, with such prior notice as Tri-State may request. Tri-State shall cooperate with Seller to facilitate Testing, shall accept delivery of all Test Energy, and shall accept and purchase all such Test Energy at the Test Energy Rate, so long as the Facility is interconnected in accordance with the Interconnection Agreement and Seller is otherwise in compliance with this PPA.

Article 5
Delivery and Metering

5.1 Delivery Arrangements.

(A) Seller shall be responsible for all interconnection arrangements and costs required to deliver the Contract Energy. Seller shall execute, deliver, and perform its obligations under the Interconnection Agreement.

(B) Seller is solely responsible for meeting its obligations as an interconnection customer under the Interconnection Provider's open access transmission tariff (the "Tariff") and the requirements of the Balancing Authority. All costs and obligations associated with Interconnection Facilities required to accomplish and operate the Interconnection Facilities is the responsibility of Seller. Seller shall satisfy any concerns of Tri-State regarding viability of the interconnection (timing and status of the generator interconnection request); *provided, however,* that any and all costs associated with this Section 5.1(B) shall be at the sole cost and expense of Seller.

(C) Seller is responsible for all electric losses, transmission and ancillary service arrangements and costs required to deliver Contract Energy to Tri-State at the Point of Delivery.

(D) Tri-State shall be responsible for all electric losses, transmission and ancillary service arrangements and costs required to deliver Contract Energy beyond the Point of Delivery. Subject to the provisions of this PPA, Tri-State may elect, at Tri-State's sole option, whether to obtain and utilize firm transmission service, non-

firm transmission service or network integration transmission service for the delivery of Contract Energy from the Point of Delivery.

5.2 Availability Reporting.

Within thirty (30) Days after the end of each Commercial Operation Year, Seller shall provide Tri-State with an operating report detailing events such as maintenance outages, [Unit][feeder breaker] trips and the causes of such trips, Unit failures and the diagnosis of such failures, status of repairs as well as statistical performance summaries and operational trends for the previous Commercial Operation Year.

5.3 Electric Metering Devices.

(A) All Electric Metering Devices used to measure the Contract Energy and to monitor and coordinate operation of the Facility shall be owned, installed, and maintained in accordance with the Interconnection Agreement. If Electric Metering Devices are not installed at the Point of Delivery, meters or meter readings shall be adjusted to reflect losses from the Electric Metering Devices to the Point of Delivery. All Electric Metering Devices used to provide data for the computation of payments shall be sealed and only the Interconnection Provider shall break the seal when such Electric Metering Devices are to be inspected and tested or adjusted in accordance with this Article 5.

(B) Seller and/or Tri-State may elect to install and maintain, at its own expense, backup metering devices ("Back-Up Metering") in addition to those installed and maintained pursuant to the Interconnection Agreement, which installation and maintenance shall be performed in a manner acceptable to Tri-State. The Party installing the Back-Up Metering shall, at its own expense, inspect and test the Back-Up Metering upon installation and periodically thereafter. The Party installing the Back-Up Metering shall provide the other Party with reasonable advance notice of, and permit a representative of the other Party to witness and verify, such inspections and tests; provided, however, that the other Party shall not unreasonably interfere with or disrupt the activities of the Party installing the Back-Up Metering and shall comply with all of such Party's safety standards. Upon request from the other Party, the Party installing the Back-Up Metering shall perform additional inspections or tests of its Back-Up Metering and shall permit a qualified representative of the other Party to inspect or witness the testing of the Back-Up Metering, provided, however, that the other Party shall not unreasonably interfere with or disrupt the activities of the Party installing the Back-Up Metering and shall comply with all of such Party's safety standards. The actual expense of any such requested additional inspection or testing by the non-installing Party shall be borne by the non-installing Party; *provided, however*, that the expense of the requested additional inspection or testing shall be borne by the Party installing if the Back-Up Metering is found to be inaccurate by more than the allowable limits established in this Article 5. If requested in writing, the Party installing the Back-Up Metering shall provide copies of any inspection or testing reports to other Party.

(C) If any Electric Metering Device, or Back-Up Metering, are found to be defective or inaccurate outside the bounds of the selected device's manufacturer's performance standards, they shall be adjusted, repaired, replaced, and/or recalibrated as near as practicable to a condition of zero error by the Party owning such defective or inaccurate device and at that Party's expense.

(D) Seller shall be responsible for the design, installation, operation and maintenance of site data historian systems at the Facility, which are linked on a real-time basis and interoperable with the RDD subject to prior written approval of such systems by Tri-State.

5.4 Adjustment for Inaccurate Meters.

If an Electric Metering Device, or Back-Up Metering, fails to register, or if the measurement made by an Electric Metering Device, or Back-Up Metering, is found upon testing to be inaccurate by more than one percent (1.0%), an adjustment shall be made correcting all measurements by the inaccurate or defective Electric Metering Device, or Back-Up Metering, for both the amount of the inaccuracy and the period of the inaccuracy, in the following manner:

(A) In the event that the Electric Metering Device is found to be defective or inaccurate, the Parties shall use Tri-State's Back-up Metering, if installed, to determine the amount of such inaccuracy; *provided,* however, that Tri-State's Back-Up Metering has been tested and maintained in accordance with the provisions of this Article 5. If Tri-State's Back-Up Metering is installed on the low side of Seller's step-up transformer, Tri-State's Back-Up Metering data shall be adjusted for losses. In the event that Tri-State did not install Back-Up Metering, or Tri-State's Back-Up Metering is also found to be inaccurate by more than one percent (1.0%), the Parties shall use Seller's Back-up Metering, if installed, to determine the amount of such inaccuracy; provided, however, that Seller's Back-Up Metering has been tested and maintained in accordance with the provisions of this Article 5. If Seller's Back-Up Metering is installed on the low side of Seller's step-up transformer, Seller's Back-Up Metering data shall be adjusted for losses. In the event that Seller did not install Back-Up Metering, or Seller's Back-Up Metering is also found to be inaccurate by more than one percent (1.0%), the Parties shall estimate the amount of the necessary adjustment on the basis of deliveries of Contract Energy during periods of similar operating conditions when the Electric Metering Device was registering accurately. The adjustment shall be made for the period during which inaccurate measurements were made.

(B) In the event that the Parties cannot agree on the actual period during which the inaccurate measurements were made, the period during which the measurements are to be adjusted shall be the shorter of (i) the last one-half of the period from the last previous test of the Electric Metering Device to the test that found the Electric Metering Device to be defective or inaccurate, or (ii) the one hundred eighty (180) Days immediately preceding the test that found the Electric Metering Device to be defective or inaccurate.

(C) To the extent that the adjustment period covers a period of deliveries for which payment has already been made by Tri-State, Tri-State shall use the corrected measurements as determined in accordance with this Article 5 to recompute the amount due for the period of the inaccuracy and shall subtract the previous payments by Tri-State for this period from such re-computed amount. If the difference is a positive number, the difference shall be paid by Tri-State to Seller; if the difference is a negative number, the difference shall be paid by Seller to Tri-State, or at the discretion of Tri-State, may take the form of an offset to payments due Seller by Tri-State. Payment of such difference by the owing Party shall be made not later than thirty (30) Days after the owing Party receives notice of the amount due, unless Tri-State elects payment via an offset.

5.5 WREGIS Metering.

Seller shall cause the Facility to implement all necessary generation information communications required by WREGIS, and report generation information to WREGIS pursuant to a WREGIS-approved meter that is dedicated to the Facility.

Article 6
Sale and Purchase of Contract Energy

6.1 Sale and Purchase.

Beginning on the Commercial Operation Date, Seller shall generate from the Facility, deliver to the Point of Delivery, and sell to Tri-State, and Tri-State shall purchase from Seller, at the applicable price set forth in Article 7, all Contract Energy; *provided* that, notwithstanding anything in this PPA to the contrary, Tri-State shall have no obligation (i) to pay for any Energy that has not actually been generated by the Facility, measured by the Electric Metering Device(s), and delivered to Tri-State at the Point of Delivery except for payments of Curtailed Contract Energy as set forth in Section 7.2 or (ii) to pay for any Energy generated by the Facility to the extent the instantaneous output exceeds **Insert the Expected Nameplate Capacity Rating** MW. Seller shall be responsible for, and shall reimburse Tri-State for, any charges, fees, fines or penalties assessed to Tri-State by the Transmission Provider, Balancing Authority, or an Organized Market as a result of the instantaneous output exceeding **Insert the Expected Nameplate Capacity Rating** MW. Seller shall not curtail or interrupt deliveries of Contract Energy to Tri-State for economic reasons of any type.

6.2 Title and Risk of Loss.

As between Seller and Tri-State, Seller shall be deemed to be in control of the Contract Energy up to and including delivery and receipt at the Point of Delivery and Tri-State shall be deemed to be in control of Contract Energy after delivery and receipt at the Point of Delivery. Title and risk of loss related to the Contract Energy shall transfer from Seller to Tri-State at the Point of Delivery.

6.3 Right to Curtail Energy.

(A) Tri-State shall have the right at any time to notify Seller, by telephonic communication from the RDD or by the AGC system, to curtail the delivery of Contract Energy, in whole or in part, to Tri-State from the Facility to the Point of Delivery, and Seller shall as soon as reasonably practicable, but within no more than ten (10) minutes, comply with such notification consistent with Prudent Utility Practices. Tri-State may provide such notification for any reason and in its sole discretion. Any payments for such curtailed Contract Energy shall be in accordance with Section 7.2. Such curtailment rights do not provide Tri-State with any rights to direct the operation of the Facility.

(B) In the event the Transmission Provider, Interconnection Provider, Balancing Authority, Reliability Coordinator, an Organized Market, NERC, WECC, FERC or any other Governmental Authority either directs Tri-State to notify Seller or notifies Seller directly, by any method established by such Person, to curtail the delivery of Contract Energy, in whole or in part, to Tri-State from the Facility, Seller shall as soon as reasonably practicable, but within no more than ten (10) minutes, comply with such notification consistent with Prudent Utility Practices.

(C) Seller shall be responsible for, and shall reimburse Tri-State to the extent Tri-State is charged and pays for any damages, fines or penalties as a result of Seller failing to comply with such curtailment instructions described in this Section 6.3.

6.4 Scheduling.

(A) Seller shall be responsible for providing the forecast of Contract Energy deliveries during the Term in accordance with the mutually-developed Operating Procedures described in Section 9.10(B).

(B) No later than ninety (90) Days before the start of Testing and by August 1 of each Year thereafter, Seller shall provide, or cause to be provided, to Tri-State, in a format acceptable to Tri-State, a forecast of each Month's average-day deliveries of Contract Energy, by hour, for the following Year.

(C) No later than thirty (30) Days before the start of Testing and at least ten (10) Business Days before the beginning of each Month thereafter, Seller shall provide, or cause to be provided, to Tri-State, in a format acceptable to Tri-State, a forecast of each Day's average deliveries of Contract Energy, by hour, for the following Month.

(D) Seller shall provide, or cause to be provided to Tri-State, by 6:00 a.m. MPT on each Day, in a format acceptable to Tri-State, a forecast of the hourly quantities of Contract Energy to be delivered to Tri-State for the immediately succeeding Day or for multiple Days as may be required by the parameters of the WECC prescheduling calendar.

(E) Seller shall provide, or cause to be provided to Tri-State, thirty (30) minutes before the start of every hour, in a format acceptable to Tri-State, a forecast of the hourly quantity of Contract Energy to be delivered to Tri-State for the next scheduling hour. As an example, Seller shall provide to Tri-State by 6:30 a.m. MPT, a forecast of the hourly quantity of Contract Energy to be delivered to Tri-State beginning 8:00 a.m. MPT and ending 9:00 a.m. MPT.

(F) If, at any time following submission of a forecast as described in Sections 6.4(B), (C), (D) and (E), Seller becomes aware of any change that alters the values previously provided to Tri-State, Seller shall promptly notify Tri-State no later than sixty (60) minutes before the next scheduling hour of such change or predicted change and if such change reduces the forecasted availability of the Facility more than ten (10) MW, such reduction shall be communicated to the RDD as soon as reasonably practicable, but within no more than ten (10) minutes.

(G) Tri-State and Seller shall agree upon reasonable changes to the requirements and procedures set forth above from time to time, as necessary to comply with changes to the Tariff or other requirements set forth by Tri-State, the Interconnection Provider, the Balancing Authority, the Transmission Provider, or an Organized Market, to accommodate changes to their respective generation technology and organizational structure and address changes in the operation and scheduling procedures of Tri-State, the Interconnection Provider, the Balancing Authority, the Transmission Provider, or the Organized Market, including more frequent reporting and automated forecast and outage submissions.

(H) Within fifteen (15) Days after the end of each quarter of the Year commencing with the first full quarter of the Year after the Commercial Operation Date, Seller shall calculate the aggregate MAPE for the prior quarter and provide such percentage, together with reasonable documentation supporting such calculation, to Tri-State. Such percentage of MAPE amount is subject to verification by Tri-State. If the aggregate MAPE for any quarter exceeds [*wind only-* twelve percent (12%)][*solar only-* seven percent (7%)], Seller shall pay Tri-State, as liquidated damages and not a penalty, within ten (10) Days after delivering such calculation to Tri-State **Insert $2000*Expected Nameplate Capacity Rating** for each one percent (1.0%) above such amount, adjusted pro-rata for any partial percentage. Each Party agrees and acknowledges that (i) the damages that Tri-State would incur due to Seller's forecasting inaccuracies would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the liquidated damages as agreed to by the Parties set forth in this Section 6.4(H) are a fair and reasonable calculation of such damages.

6.5 Forced Outages and Emergency Conditions.

Seller shall notify the RDD by telephone call or other automated means acceptable to Tri-State as promptly as possible upon discovering that the Facility is unable to deliver all or part of any scheduled quantity of Contract Energy due to a

Forced Outage or Emergency Condition resulting in a capacity reduction of more than ten (10) MW and, as soon as reasonably practicable, but within no more than ten (10) minutes, following such discovery, shall notify the RDD of its best estimate of the expected duration of such Forced Outage or Emergency Condition. Such estimate by Seller shall be based on the best information available to it. Should Seller expect any further changes in the duration of any such Forced Outage or Emergency Condition, it shall as soon as reasonably practicable, but within no more than ten (10) minutes, of such change notify the RDD of the same.

6.6 *[wind only-*Cut-Out Events.

In the event of a Cut-Out Event, Seller shall coordinate with Tri-State's RDD the ramp-up rate of the Facility back to full production after such event.]

6.7 Guaranteed Energy Production.

(A) During each Commercial Operation Year, Seller is required to deliver to Tri-State at least the Guaranteed Energy Production; *provided* that the Facility shall be deemed to have generated Contract Energy during such Commercial Operation Year to the extent it was capable of delivering Contract Energy but failed to deliver such Contract Energy due to a (i) Delivery Excuse, (ii) Force Majeure Event, (iii) Emergency Condition, or (iv) a curtailment pursuant to Section 6.3 (except for a curtailment caused by a Forced Outage or otherwise covered by Section 7.2(B)(9) through (11)) with such deemed quantity to be determined using the factors set forth in Section 7.2(A).

(B) In the event Seller delivers less than the Guaranteed Energy Production in any Commercial Operation Year, Tri-State shall promptly invoice Seller for an amount equal to the Shortfall MWh multiplied by the Contract Energy Rate during such Commercial Operation Year. Invoiced amounts shall be payable in accordance with Section 8.3(A); *provided* that this Section shall not limit Tri-State's rights and remedies under Article 12 with respect to Deficiency MWhs upon the occurrence of and during an Event of Default or Replacement Costs upon termination of this PPA. Each Party agrees and acknowledges that (i) the damages that Tri-State would incur due to Seller's failure in achieving the Guaranteed Energy Production would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the liquidated damages as agreed to by the Parties set forth in this Section 6.7 are a fair and reasonable calculation of such damages and not a penalty.

6.8 Organized Market.

(A) If at any time during the Term, the Interconnection Provider changes or the facilities at the Point of Delivery cease to be subject to the Interconnection Provider's Tariff, Tri-State and Seller shall cooperate and take all necessary actions to facilitate the delivery of Contract Energy from the Point of Delivery to Tri-State's load, at the least possible cost to the Parties, consistent with this PPA.

(B) If at any time during the Term, (i) the Interconnection Provider, the Transmission Provider, the Balancing Authority, or Tri-State elects to join or participate in an Organized Market, or (ii) WECC, NERC, FERC or any other Governmental Authority institutes an Organized Market and such action requires changes to this PPA or changes the manner in which the Facility is scheduled and dispatched, the Parties shall cooperate in good faith to change their protocols for operation and scheduling of the Facility and to amend this PPA to comply with such changes accordingly, at the least possible cost to the Parties, consistent with this PPA. The Parties shall negotiate and allocate the costs associated with these changes between the Parties in a fair and reasonable manner.

Article 7
Payment Calculations

7.1 Contract Energy Payment.

(A) Contract Energy Payment. Except as otherwise provided in this PPA, commencing on the Commercial Operation Date, Tri-State shall pay Seller an energy payment for each Month (the "Contract Energy Payment") equal to the product of (i) the applicable Contract Energy Rate; and (ii) the aggregate amount of Contract Energy (other than Test Energy and Excess Contract Energy) delivered to Tri-State. The Contract Energy Payment for each Month during the Term shall be paid in accordance with the invoicing procedures set forth in Section 8.1.

(B) Test Energy Payment. Tri-State shall pay for all Test Energy at the Test Energy Rate. Test Energy Payments shall be equal to the product of (i) the Test Energy Rate; and (ii) the aggregate amount of Test Energy delivered by Seller to Tri-State during such Month. The Test Energy Payment for each Month during the Term shall be paid in accordance with the invoicing procedures set forth in Section 8.1.

(C) Excess Contract Energy Payment. Except as otherwise provided in this PPA, Tri-State shall pay for all Excess Contract Energy, if any, generated and delivered in each Commercial Operation Year, during the Term at the Excess Contract Energy Rate. Excess Contract Energy Payments shall be equal to the product of (i) the applicable Excess Contract Energy Rate for such Month, and (ii) the aggregate amount of Excess Contract Energy delivered by Seller to Tri-State. The Excess Contract Energy Payment, if any, for each Month during the Term shall be paid in accordance with the invoicing procedures set forth in Section 8.1.

7.2 Curtailed Contract Energy Payment.

(A) Determination of Curtailed Contract Energy. On and after the Commercial Operation Date, if delivery of Contract Energy is curtailed by Tri-State pursuant to Section 6.3(A), then:

(1) The Parties shall determine the quantity of Contract Energy that would have been generated by the Facility and delivered to the Point of Delivery during the period of curtailment had its generation not been so curtailed by Tri-State ("Curtailed Contract Energy") by using the best available data obtained through commercially reasonable methods in accordance with the Operating Procedures; and shall be dependent upon measured [wind speed and wind direction][solar irradiance] gathered from appropriate [*wind only-* Units anemometers][*solar only-* pyranometers] and meteorological towers at the Facility during those hours in which Tri-State curtailed its receipt of Contract Energy, as such process may be further described in the Operating Procedures, and any other adjustments necessary to accurately reflect the Facility's capacity to generate and deliver Energy to the Point of Delivery including applicable losses and manufacturers' warranted power curves (a copy of which shall be provided to Tri-State) for all operational Units whose output was curtailed. The methodology utilized to measure Curtailed Contract Energy shall be reviewed and adjusted, as necessary, by the Operating Committee, at least once every five (5) years after the Commercial Operation Date.

(2) Tri-State shall pay to Seller for such Curtailed Contract Energy all amounts that Seller would have received from Tri-State under this PPA for the corresponding Contract Energy had delivery not been so curtailed by Tri-State (and at the applicable rates set out in Section 7.1) [wind only -plus an amount per MWh that equals (a) the Production Tax Credit to the extent Seller would have been entitled to receive such Production Tax Credit plus (b) a gross up amount to take into account the federal, state and local income tax to Seller or its Affiliates or tax investors on such payment in lieu of the Production Tax Credit, calculated in accordance with the following formula] (the "Curtailed Contract Energy Payment"):

[wind only -

$$\text{Amount of Payment in lieu of Production Tax Credit} \times \frac{1}{1\text{-applicable aggregate tax rate}}$$

For the avoidance of doubt, Seller shall not be entitled to recover any of the above referenced tax benefits to the extent Seller would not have been entitled to receive the Production Tax Credit had the Curtailed Contract Energy actually been delivered.]

(3) In the event Tri-State is obligated to pay for Curtailed Contract Energy under this Section 7.2(A), Seller shall provide on the applicable monthly invoice detailed calculations of the Curtailed Contract Energy and the Curtailed Contract Energy Payment due Seller.

(B) Restriction on Curtailment Payments. Notwithstanding anything in this Section 7.2 to the contrary, no payment shall be due to Seller from Tri-State under paragraph (A) above for curtailments of delivery of Contract Energy resulting from:

(1) an Emergency Condition, Force Majeure Event, or Forced Outage;

(2) the failure of Seller's Interconnection Facilities or any action taken by the Interconnection Provider in accordance with its rights under the Interconnection Agreement and not due to Seller's default;

(3) any restriction, reduction, or curtailment of firm transmission service or network integration transmission service by the applicable Transmission Provider, arranged by either Party, to provide transmission of Contract Energy to or from the Point of Delivery;

(4) any restriction, reduction, or curtailment of non-firm transmission service by the applicable Transmission Provider, arranged by either Party, to provide transmission of Contract Energy to or from the Point of Delivery to the extent such restriction, reduction, or curtailment would also have been imposed even if firm transmission service had been in place;

(5) maintenance outages, whether planned or unplanned, of any part of the Transmission System or any testing of the Transmission System;

(6) Allowable Curtailment;

(7) [*wind only-* Cut-Out Events; provided that Tri-State shall compensate Seller for any curtailment of Contract Energy up to one (1) hour for the first Cut-Out Event per quarter of any Year];

(8) any notification from the Balancing Authority requiring Seller to curtail or cease deliveries of Contract Energy to achieve load balancing in the Balancing Authority Area or any notifications from the Reliability Coordinator requiring Seller to curtail or cease deliveries of Contract Energy;

(9) any curtailment arising from Seller's failure to obtain and/or maintain in full force and effect any Governmental Approval or WREGIS registration, or failure to comply with applicable NERC reliability standards;

(10) any action taken by the Interconnection Provider pursuant to Seller's default under the Interconnection Agreement; or

(11) Seller fails or refuses to respond to AGC instructions from the SCADA system, Seller fails or refuses to respond, or Seller refuses or fails to respond to a curtailment instruction from Tri-State, the RDD, the Transmission Provider, Interconnection Provider, Balancing Authority, Reliability Coordinator, an Organized

Market, NERC, WECC, FERC or any other Governmental Authority pursuant to Section 6.3 including if the Interconnection Provider trips the breaker at the Electric Interconnection Point, due to Seller's failure or refusal.

Article 8
Billing and Payment Procedures

8.1 Billing Invoices.

No later than ten (10) Business Days after the end of each Month, Seller shall provide to Tri-State an invoice for the amount due to Seller by Tri-State for Contract Energy delivered by Seller to Tri-State and the Curtailed Contract Energy, if any, determined pursuant to Section 7.2 for such Month. Seller's invoice shall show metered Energy from the Facility, all billing parameters, rates and factors, and any other data reasonably pertinent to the calculation of monthly payments due to Seller. If Tri-State disputes any portion of the invoice, Tri-State shall provide to Seller an explanation of the items in dispute. Billing disputes shall be resolved in accordance with Section 8.4.

8.2 Metered Billing Data.

All billing data based on metered deliveries to Tri-State shall be collected by the Electric Metering Device(s) in accordance with Article 5.

8.3 Payments and Late Payments.

(A) Payment Due to Tri-State. Unless otherwise specified herein, payments due to Tri-State under or in connection with this PPA shall be due and payable by electronic funds transfer, as designated by Tri-State, on or before the fifth (5th) Business Day following receipt of the billing invoice. Any failure to make full payment within such time period shall constitute an Event of Default of Seller upon its occurrence but shall be subject to cure within three (3) Business Days after the date of written notice from Tri-State to Seller. This Section shall not limit Tri-State's right to draw any such amounts due from the Security in accordance with Section 11.1(E).

(B) Payments due to Seller. Unless otherwise specified herein, payments due to Seller under or in connection with this PPA shall be due and payable by electronic funds transfer, as designated by Seller, on or before the twentieth (20th) Business Day following receipt of the billing invoice. Any failure to make full payment within such time period shall constitute an Event of Default of Tri-State upon its occurrence but shall be subject to cure within ten (10) Business Days after the date of written notice from Seller to Tri-State.

(C) Late Payment Charges. If the undisputed amount due is not paid on or before the due date, a late payment charge shall be applied to the unpaid balance and shall be added to the next billing statement. Such late payment charge shall be calculated based on the lower of (i) an annual interest rate equal to two percent (2%) plus the prime interest rate, as published on the date of the invoice in *The Wall Street*

Journal (or, if *The Wall Street Journal* is not published on that Day, the next succeeding date of publication) and (ii) the maximum interest rate allowed by Applicable Law ("Default Rate"). If the due date occurs on Day that is not a Business Day, the late payment charge shall begin to accrue on the next succeeding Business Day.

(D) Offset. Tri-State at any time may offset against amounts owed to Seller, any liquidated amounts, accrued damages and other payments, and undisputed billing errors and adjustments, which are owed by Seller to Tri-State.

8.4 Billing Disputes.

Either Party may dispute invoiced amounts, but shall pay to the other Party at least the undisputed portion of invoiced amounts on or before the invoice due date. To resolve billing disputes, the Parties shall use the procedures set forth in Section 13.9(A). When the billing dispute is resolved, the Party owing shall pay the amount owed within five (5) Business Days of the date of such resolution, with late payment interest charges calculated on the amount owed in accordance with the provisions of Section 8.3 if payment is not received within the five (5) Business Days. Undisputed amounts invoiced under this PPA shall be paid on or before the due date or shall be subject to the late payment interest charges set forth in Section 8.3(C).

8.5 Statement Errors.

In the event that either Party becomes aware of any error in any statement, such Party shall, promptly upon discovery of the error, notify in writing the other Party of such error and shall rectify such error (whether in the form of an underpayment or overpayment) within thirty (30) Days of such notification. If a Party does not notify the other Party of any error (regardless of actual knowledge of such error) within three hundred sixty five (365) Days of such error, any payment associated with such error older than three hundred sixty five (365) Days shall be waived. Except for adjustments in the billing and payment for defective or inaccurate Electric Metering Devices as provided in Section 5.4, if Seller fails to invoice for Contract Energy or Curtailed Contract Energy within one hundred eighty (180) Days of delivery of such Contract Energy or curtailment of Contract Energy, payment for such shall be waived.

8.6 Taxes.

(A) Tax Responsibility. Seller shall be responsible for, and shall pay when due, all income, gross receipts, sales, *ad valorem*, personal property or real property or other similar taxes and any and all franchise fees or similar fees assessed against Seller or the Facility due to generation of Energy from the Facility, the construction, ownership, leasing, operation or maintenance of the Facility, or any components or appurtenances thereof, including all taxes, fees, allowances, trading credits and other offsets and impositions for wastes and emissions (including carbon-based compounds, oxides of nitrogen and sulfur, mercury and other Regulated Materials) produced by the Facility. Seller's prices under Article 7 are inclusive of such

Taxes, allowances and credits during the Term. If Tri-State is assessed any Taxes or associated fees as a result of the improvement of the Site due to the existence of the Facility on the Site, Tri-State shall promptly notify Seller. Tri-State and Seller shall cooperate in contesting such assessment; *provided, however,* that Tri-State may pay such Taxes to avoid any penalties on such assessments subject to reimbursement by Seller. If, after resolution of the matter, Taxes are imposed on Tri-State as a result of the improvement of the Site due to the existence of the Facility on the Site, Seller shall reimburse Tri-State for such Taxes. Seller shall not be obligated to pay or reimburse Tri-State for Taxes imposed on or measured by the Tri-State's overall revenues or income.

(B) Reimbursement. If a Party is required to remit or pay Taxes that are the other Party's responsibility hereunder, such Party shall promptly reimburse the other Party for such Taxes.

(C) Information. The Parties shall provide each other, upon written request, with copies of any documentation that may be reasonably necessary in the ordinary course of any inter-governmental, state, local, municipal or other political subdivision tax audit inquiry or investigation.

(D) Cooperation. Consistent with Applicable Law, the Parties shall cooperate to minimize Taxes; *provided, however,* that no Party shall be obligated to incur any extraordinary financial burden to reduce Taxes for which the other Party is responsible hereunder.

(E) Failure to Qualify for Tax Credits. Seller's failure to qualify for the Tax Credits or Additional Tax Benefits for any reason including Delivery Excuse, Force Majeure Event, the acts or inaction of the Interconnection Provider or of any third party, or any Event of Default, shall not release Seller of its obligations to comply with this PPA, give rise to any damages payable by Tri-State or an increase in the price for Contract Energy.

(F) Additional Tax Benefits. From and after the Effective Date and throughout the Term, in the event that Seller or the Facility qualifies for and receives or is subject to Additional Tax Benefits, Seller and Tri-State shall share on a 50/50 basis the Additional Tax Benefit Amount associated with such Additional Tax Benefits by making an adjustment to the Contract Energy Rate for the Term of the PPA to account for such Additional Tax Benefit Amount. For the avoidance of doubt, Additional Tax Benefits may not result in an increase to the Contract Energy Rate. The Contract Energy Rate shall be adjusted in the first month following the effective date of the Applicable Law, which may be in the form of new or revised guidance or interpretations by a Governmental Authority having jurisdiction related to such Applicable Law, pursuant to which such Additional Tax Benefit is enacted. Seller shall at all times retain all right, title and interest in any Additional Tax Benefits. Seller shall provide Tri-State with written notice upon its receipt of Additional Tax Benefits, and along with such notice provide to Tri-State commercially reasonable documentation describing: (i) the

Additional Tax Benefit Amount, (ii) the effective date of the Applicable Law, including guidance or interpretations by a Governmental Authority, (iii) reasonable accounting of the Additional Tax Benefit Costs associated therewith, verified by an independent national accounting firm selected by Seller at Seller's expense, subject to further verification by Tri-State, and (iv) a calculation of the reduction to the Contract Energy Rate.

Article 9
Testing, Operations and Maintenance

9.1 Modification of the Facility.

Seller shall not modify the Facility in any way that would increase or decrease the electric energy generating capacity of the Facility or the output of Contract Energy to be delivered to Tri-State under this PPA without Tri-State's prior written consent, which may be withheld in its sole discretion.

9.2 Facility Tests Prior to Commercial Operation.

Seller shall give Tri-State at least three (3) Months prior notice of (i) the approximate Test Date, (ii) the proposed Tests scheduled relating to the commissioning of the Facility, and (iii) a draft of the Testing procedures and requirements. Tri-State shall review and provide any comments on the Testing procedures and requirements within thirty (30) Days of receipt. Representatives of Tri-State shall have the right to be present at all such Testing. Seller shall promptly notify Tri-State of any changes to the Test Date or the date of any Tests relating to the Facility in order that Tri-State may arrange for its respective representatives to attend.

9.3 Operation and Maintenance of the Facility.

Seller shall staff, control, operate, maintain, and repair the Facility or cause the same to be staffed, controlled, operated, maintained, and repaired at all times in accordance with manufacturers' recommendations and Prudent Utility Practices and otherwise in accordance with this PPA. Seller shall procure and maintain a Qualified Operator to operate and maintain the Facility. Personnel (i) capable of remotely starting, operating and stopping the Facility shall be continuously available and reachable by phone, and (ii) shall be capable of being at the Facility on no more than sixty (60) minutes' notice, weather conditions permitting.

9.4 Replacement of Facility Equipment.

Seller shall, consistent with Prudent Utility Practices, repair and replace all necessary equipment at the Facility required to deliver Contract Energy for the Term.

9.5 Disposal of Facility Equipment.

Upon the cessation of operations or the replacement of equipment, Seller shall, at its sole expense and cost, dispose of all Facility equipment no longer in use in accordance with Applicable Law and Prudent Utility Practices, and all requirements under the Facility Site Documents.

9.6 Scheduled Maintenance.

Three (3) Months prior to the Commercial Operation Date and, thereafter, by August 1 of each Year, Seller shall deliver to Tri-State the projected schedule of Scheduled Maintenance Outages, for the subsequent Year or the remainder of the Term, whichever period of time is shorter. Seller shall notify Tri-State of a Scheduled Maintenance Outage and any changes to such no later than sixty (60) Days prior to the start date of a Scheduled Maintenance Outage. In the event a Scheduled Maintenance Outage is extended, Seller shall notify Tri-State as soon as practicable of such extension and the expected end date of such Scheduled Maintenance Outage. Scheduled Maintenance Outages and/or Additional Maintenance Outages may not be scheduled during the Months of January, June, July, August, September, or December unless agreed to in writing by Tri-State at its sole discretion.

9.7 Additional Maintenance Outages.

Before Seller conducts further maintenance on the Facility which would result in greater than ten (10) MW of the Nameplate Capacity Rating of the Facility being taken out of service or Seller's Interconnection Facilities being taken out of service in addition to the Scheduled Maintenance Outages conducted pursuant to Section 9.6 ("Additional Maintenance Outages"), Seller shall notify Tri-State of such required maintenance, together with proposed dates for carrying out such additional maintenance and the estimated duration of the work to be carried out. To the extent possible, such notification to Tri-State shall be provided no later than sixty (60) Days prior to the start date of an Additional Maintenance Outage. Unless deferral of such maintenance would cause an Emergency Condition, Seller and Tri-State shall negotiate in good faith a reasonable schedule during which such Additional Maintenance Outages shall take place. In the event an Additional Maintenance Outage is extended, Seller shall notify Tri-State as soon as practicable of such extension and the expected end date of such Additional Maintenance Outage.

9.8 Access to and Inspection of Facility.

(A) Seller shall provide Tri-State and its authorized employees, agents and inspectors with reasonable access to the Facility (including Tri-State's equipment, if any) for the purposes set forth herein. Tri-State acknowledges that such access does not provide Tri-State with the right to direct or modify the operation of the Facility in any way and further acknowledges that any exercise by Tri-State of its rights under this Section 9.8 shall be at its own risk and expense.

(B) No inspections of the Facility, whether by Tri-State or otherwise, shall relieve Seller of its obligation to maintain the Facility and operate the same in accordance with Prudent Utility Practices. In no event shall any statement, representation, or lack thereof by Tri-State, either express or implied, relieve Seller of its exclusive responsibility for the Facility.

9.9 Operating Parameters.

(A) Seller shall operate, maintain or procure the operation and maintenance of the Facility in accordance with Prudent Utility Practices and Applicable Law. Subject to compliance with Prudent Utility Practices and Applicable Law, Seller shall operate the Facility in such a manner that Contract Energy shall meet all requirements required by the Interconnection Provider and the Transmission Provider.

(B) Seller shall operate the Facility such that all system protective equipment is in service whenever the Facility is connected to, or is operated in parallel with, the Transmission System, except for normal testing and repair. Seller shall provide adequate system protection and control devices to ensure safe and protected operation of all energized equipment during normal testing and repair. The Facility's protective equipment shall meet Institute of Electrical and Electronic Engineers and all other applicable industry standards. Seller shall have qualified personnel test, calibrate and certify in writing the proper functioning of all protective equipment in accordance with the intervals and maintenance activities for each component as established by the appropriate reliability standards. All of the foregoing shall be conducted in accordance with Prudent Utility Practices.

9.10 Operating Committee and Operating Procedures.

(A) Representative. Tri-State and Seller shall each appoint one (1) representative and one (1) alternate representative to act in matters relating to the Parties' performance obligations under this PPA and to develop operating arrangements for the generation, delivery and receipt of Contract Energy hereunder. Such representatives shall constitute the Operating Committee, and shall be specified in Exhibit H. Each Party shall notify the other Party in writing of any changes to their representative and provide the other Party an updated Exhibit H. The Operating Committee shall have no authority to amend or waive any terms or conditions of this PPA.

(B) Operating Procedures. Prior to the Commercial Operation Date, the Operating Committee shall develop mutually agreeable written Operating Procedures which shall include methods of day-to-day communications; metering, telemetering, telecommunications, and data acquisition procedures; key personnel list for applicable Tri-State and Seller operating centers; operations and maintenance scheduling and reporting; Contract Energy reports; measurement of Curtailed Contract Energy; unit operations log; and such other matters as may be mutually agreed upon by the Parties.

Article 10
Environmental Attributes

10.1 Ownership of Environmental Attributes.

(A) Ownership of Environmental Attributes. Payment of each of the Contract Energy Rate, Test Energy Rate and the Excess Contract Energy Rate to Seller by Tri-State includes the consideration for the purchase and ownership of, and the right to market and sell, all Environmental Attributes associated with the generation of Contract Energy, Test Energy and Excess Contract Energy, respectively.

(B) Duration. Environmental Attributes associated with the Contract Energy are owned by Tri-State and Tri-State shall have the right to own and to use such Environmental Attributes for any purpose, including any Environmental Attributes that are reserved or "banked" during the Term of this PPA but not used, sold, assigned or otherwise transferred during the Term of this PPA. Tri-State may assign its rights, title and interest in and to any Environmental Attributes associated with Contract Energy to one or more third parties under any transaction.

10.2 Transfer of Title to Environmental Attributes; Documentation of Environmental Attributes Transfers.

(A) Title. Title to the Environmental Attributes shall irrevocably pass from Seller to Tri-State immediately upon the generation of Contract Energy at the Facility that gives rise to such Environmental Attributes.

(B) Bill of Sale. Upon request from Tri-State, Seller shall deliver to Tri-State an Attestation and Bill of Sale in the form attached as Exhibit J for all Environmental Attributes delivered to Tri-State during the time period requested by Tri-State.

(C) WREGIS Compliance. Seller shall, at its sole expense, use WREGIS to provide and convey to Tri-State the Environmental Attributes associated with the generation of Contract Energy. Such Environmental Attributes shall be conveyed in a manner consistent with the WREGIS provision below promptly upon WREGIS certificates relating to the Facility being credited to Seller's WREGIS account.

(D) WREGIS Account. Prior to Testing, Seller shall register the Facility with WREGIS and establish an account with WREGIS ("Seller's WREGIS Account"), which Seller shall maintain through the Term. Seller shall transfer the WREGIS certificates using "Forward Certificate Transfers" (as described in the WREGIS Operating Rules) from Seller's WREGIS Account to the WREGIS account(s) of Tri-State or the account(s) of a designee that Tri-State identifies by written notice ("Tri-State's WREGIS Account"). Seller shall be responsible for all expenses associated with registering the Facility with WREGIS, establishing and maintaining Seller's WREGIS

Account, paying WREGIS certificate issuance and transfer fees, and transferring WREGIS certificates from Seller's WREGIS Account to Tri-State's WREGIS Account.

(E) Qualified Reporting Entity. Seller shall procure and maintain a Person to act as a qualified reporting entity and provide qualified reporting services for the Facility as required by WREGIS.

(F) Reporting Compliance. Seller, at its own cost and expense, shall comply with all reporting and other requirements of WREGIS relating to the Facility or Environmental Attributes.

(G) No Liens or Encumbrances. Environmental Attributes shall be transferred to Tri-State free of all liens and encumbrances.

(H) Additional Certification. Upon request from Tri-State, Seller shall, at its expense, register and/or certify the Facility with Governmental Authorities requested by Tri-State in order to qualify the Facility as a renewable resource or qualify the Contract Energy and/or Environmental Attributes with such Governmental Authority and maintain such registration/certification for the Term.

Article 11
Security

11.1 Seller Security Form and Amount.

(A) Form. As security for its obligations hereunder, Seller shall, within ten (10) Days after the Effective Date, post and maintain in favor of Tri-State (i) one or more unconditional, irrevocable, standby Letter(s) of Credit from an Issuer, (ii) a cash escrow account established with an Issuer in favor of Tri-State pursuant to an escrow agreement acceptable to Tri-State, or (iii) any combination of the foregoing (i) and (ii) (the "Security"); provided that a Guaranty may be posted to satisfy part of or all of the Security amount set forth in Section 11.1(B) in lieu of Letter(s) of Credit or a cash escrow account, subject to the following conditions (x) any Guaranty provided by a Superior Guarantor shall not exceed Ten Million Dollars ($10,000,000), (y) any Guaranty provided by a Qualified Guarantor shall not exceed Five Million Dollars ($5,000,000), and (z) the total aggregate amount of guaranteed obligations of any such Guaranty and any other guaranties of payment or performance related to or provided by the Seller, the Qualified Guarantor, the Superior Guarantor or any of their Affiliates to Tri-State shall not exceed an aggregate of Five Million Dollars ($5,000,000) if provided by a Qualified Guarantor or Ten Million Dollars ($10,000,000) if provided by a Superior Guarantor, unless agreed to in writing by Tri-State at its sole discretion.

(B) Amount. The Security shall be in the amount of: (i) **Insert $100*Expected Nameplate Capacity Rating in kw** Dollars ($_____,000) for the period beginning with the Effective Date and continuing thereafter.

(C) Duration. The Security shall remain in place for the entire Term (except to the extent drawn upon as provided herein). To the extent the Security consists of Letter(s) of Credit expiring before the end of the Term, Seller shall cause their renewal or extension for additional consecutive terms of three hundred sixty (360) Days or more (or, if shorter, the remainder of the Term) no later than thirty (30) Days prior to each expiration date of such Letter(s) of Credit and written proof of such renewal shall be provided to Tri-State as soon as practicable thereafter, but in no event later than fifteen (15) Days prior to the expiration of the same. If the Letter of Credit(s) is not renewed or extended as required herein, Tri-State shall have the right to demand payment under the Guaranty or draw immediately upon the entire amount of the Letter of Credit and to place the amounts so drawn, at Seller's cost and with Seller's funds, in an account controlled by Tri-State until and unless Seller provides a substitute Letter of Credit(s) meeting the requirements of this Article 11.

(D) Downgrades. Upon the occurrence of a downgrade event, such that the Person providing the Security in the form of a Letter of Credit or Guaranty no longer meets the requirements of an Issuer, Qualified Guarantor, or Superior Guarantor, as applicable, Seller shall within three (3) Business Days of such downgrade event, provide replacement security satisfying the requirements of this Article 11. If such replacement security is not provided within three (3) Business Days, Tri-State shall have the right to draw immediately upon the entire amount of the Letter of Credit or demand payment under the Guaranty, as applicable, and to place the amounts so drawn, at Seller's cost and with Seller's funds, in an account controlled by Tri-State until and unless Seller provides a substitute security meeting the requirements of this Article 11. Except as provided in this Section 11.1(D), Seller may change the form of Security at any time and from time-to-time upon thirty (30) Days' prior written notice to Tri-State; *provided* that the Security shall satisfy the requirements of this Article 11 at all times.

(E) Draw on Security. Without notice to Seller, Tri-State may demand payment under or draw on the Security during the Term for Seller's failure to meet any of its obligations under this PPA, including Delay Damages, the damages provided in Section 6.4(H), Section 6.7 and Section 12.3, and Replacement Costs. Tri-State may draw or demand payment of all or any part of the appropriate amounts due to it from any form of Security to the extent available pursuant to this Article 11, and from all such forms, and in any sequence Tri-State may select; *provided* that any failure to draw upon the Security for any damages or other amounts due to Tri-State shall not prejudice Tri-State's rights to recover such damages or amounts in any other manner to the extent provided in this PPA. Tri-State shall notify Seller within five (5) Business Days following any draw on the Security by Tri-State, including the amount thereof and the basis therefor.

(F) Release of Security. Within thirty (30) Days following the expiration or termination of this PPA and the satisfaction of all of Seller's obligations hereunder, Tri-State shall release any remaining balance of the Security to Seller without interest.

(G) Replenishment. In the event Tri-State draws upon the Security pursuant to this Article 11, Seller shall replenish the Security to the amount required by Section 11.1 within ten (10) Days of such draw.

(H) Expenses. Seller shall reimburse Tri-State for its expenses, including internal costs and expenses and reasonable attorneys' fees, incurred by Tri-State in connection with the preparation, negotiation, execution and/or release (including making a draw of funds) of the Security under this Article 11.

Article 12
Default and Remedies

12.1 Events of Default of Seller.

(A) Seller Defaults (No Cure). Any of the following shall constitute an Event of Default of Seller upon its occurrence and no cure period shall be applicable unless otherwise stated:

(1) Seller's dissolution or liquidation;

(2) Seller makes a general assignment for the benefit of its creditors;

(3) Seller's authorization or filing of a petition in voluntary bankruptcy or insolvency or for reorganization or arrangement under the bankruptcy laws of the United States or under any insolvency law of any state, or Seller voluntarily taking advantage of any such law by answer or otherwise;

(4) The sale by Seller to a third party, or diversion by Seller for any use, of Contract Energy committed to Tri-State by Seller other than in mitigation of damages for any breach by Tri-State of this PPA;

(5) Seller's failure to establish, and maintain, the Security in accordance with Article 11;

(6) Seller's failure to achieve Commercial Operation by the date that is ninety (90) Days following the Commercial Operation Milestone;

(7) Seller's actual fraud or tampering with Tri-State owned facilities or other material misrepresentation or intentional misconduct in connection with this PPA or the operation of the Facility; and/or

(8) Seller's failure to make any payment due to Tri-State under this PPA in accordance with Article 8 (subject to cure by Seller as provided therein).

(B) Seller Defaults (30 Day Cure). Any of the following shall constitute an Event of Default of Seller upon its occurrence but shall be subject to cure within thirty (30) Days after the date of written notice from Tri-State to Seller:

(1) Seller's Abandonment;

(2) Seller's failure to maintain in effect any agreements required to deliver Contract Energy to the Point of Delivery pursuant to Section 5.1, including the Interconnection Agreement;

(3) Seller's failure to comply with the requirements of Section 10.2;

(4) Seller's breach of or failure to perform or comply with any material term of this PPA not otherwise specified in this Section 12.1; and/or

(5) Seller's failure to achieve any Construction Milestone, excluding the Commercial Operation Milestone, by the date that is ninety (90) Days following the date specified for such milestone.

(C) Seller Defaults (60 Day Cure). Any of the following shall constitute an Event of Default of Seller upon its occurrence but shall be subject to cure within sixty (60) Days after the date of written notice from Tri-State to Seller:

(1) Seller's assignment of this PPA, or any Change of Control of Seller, or Seller's sale or transfer of its interest, or any part thereof, in the Facility, except as permitted in accordance with Article 19;

(2) Any representation or warranty made by Seller in this PPA shall prove to have been false or misleading in any material respect when made; and/or

(3) The filing of an involuntary case in bankruptcy or any proceeding under any other insolvency law against Seller.

(D) Seller Default (Delivery Shortfall). Seller's failure to deliver at least eighty percent (80%) of the Expected Contract Energy in a Commercial Operation Year shall constitute an Event of Default of Seller upon its occurrence; *provided* that the Facility shall be deemed to have generated Contract Energy during such period as specified in Section 6.7 with such quantity to be determined using the factors set forth in Section 7.2(A); *provided further* that this Event of Default shall be curable and deemed cured if (i) within thirty (30) Days following the end of the energy deficient Commercial Operation Year, Seller cures the reason(s) for such default (or, if such cure cannot reasonably be effected within thirty (30) Days, Seller commences to cure such default within thirty (30) Days and then diligently pursues such cure to completion as soon as practicable thereafter), and (ii) as a result of such efforts, during the next Commercial Operation Year subsequent to such Default, the production of Contract Energy by the

Facility equals or exceeds ninety-five percent (95%) of the Expected Contract Energy for such period.

Subject at all times to the limitation set forth in Section 6.1, Seller shall be permitted to add and/or replace Units if and to the extent reasonably required to cure Seller's default under this Section 12.1(D). Seller shall keep Tri-State apprised at least monthly of Seller's cure efforts under this Section 12.1(D). If the production of Contract Energy fails to equal or exceed ninety-five percent (95%) of the Expected Contract Energy for the Commercial Operation Year following the Event of Default as described in this Section 12.1(D), Tri-State shall have the right to terminate this PPA for default upon delivery of written notice.

12.2 Events of Default of Tri-State.

(A) Tri-State Defaults (No Cure). Any of the following shall constitute an Event of Default of Tri-State upon its occurrence and no cure period shall be applicable, unless otherwise stated:

(1) Tri-State's dissolution or liquidation, *provided, however,* that division of Tri-State into multiple entities shall not constitute dissolution or liquidation;

(2) Tri-State makes a general assignment for the benefit of creditors;

(3) Tri-State's authorization or filing of a voluntary petition in bankruptcy or insolvency or for reorganization or arrangement under the bankruptcy laws of the United States or under any insolvency law of any State, or Tri-State voluntarily taking advantage of any such law by answer or otherwise; and/or

(4) Tri-State's failure to make any payment due to Seller under this PPA in accordance with Article 8 (subject to cure by Tri-State as provided therein).

(B) Tri-State Defaults (30 Day Cure). Tri-State's failure to comply with any material obligation under this PPA not otherwise specified in this Section 12.2 shall constitute an Event of Default of Tri-State if not cured within thirty (30) Days after the date of written notice from Seller to Tri-State.

(C) Tri-State Defaults (60 Day Cure). Any of the following shall constitute an Event of Default of Tri-State upon its occurrence but subject to cure sixty (60) Days after the date of written notice from Seller to Tri-State:

(1) The filing of an involuntary case in bankruptcy or any proceeding under any other insolvency law against Tri-State;

(2) Tri-State's assignment of this PPA, except as permitted in accordance with Article 19; and/or

(3) Any representation or warranty made by Tri-State in this PPA shall prove to have been false or misleading in any material respect when made.

12.3 Damages Prior to Termination.

Upon the occurrence of an Event of Default, the non-defaulting Party shall have the right to collect damages accruing prior to the termination of this PPA from the defaulting Party as set forth below, and the payment of any such damages accruing prior to the cure of an Event of Default shall constitute an element of any respective cure. For all Events of Default (including failure to achieve the Commercial Operation Milestone) the non-defaulting Party shall be entitled to receive from the defaulting Party all of the direct damages incurred by the non-defaulting Party in connection with such Event of Default. The Parties agree that the damages recoverable by Tri-State hereunder on account of an Event of Default of Seller prior to termination of this PPA shall include an amount calculated at the end of each Month during an Event of Default equal to the Deficiency MWhs multiplied by the applicable Contract Energy Rate during such Commercial Operation Year and Tri-State may draw the appropriate amounts from the Security. Each Party agrees and acknowledges that (i) the damages that Tri-State would incur at such time prior to termination of this PPA due to Seller's failure to perform would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the liquidated damages as agreed to by the Parties set forth in this Section 12.3 are a fair and reasonable calculation of such damages.

12.4 Termination.

Upon the occurrence of an Event of Default that has not been cured within the applicable time period, if any, the non-defaulting Party shall have the right to declare a date, which shall be between fifteen (15) and thirty (30) Days after the notice thereof, upon which this PPA shall terminate. Neither Party shall have the right to terminate this PPA except as provided for upon the occurrence of an Event of Default as described above or as otherwise may be explicitly provided for in this PPA. Upon the termination of this PPA under this Section 12.4, the non-defaulting Party shall be entitled to receive from the defaulting Party, all of the direct damages incurred by the non-defaulting Party related to such Event of Default, including, if Seller is the defaulting Party, the value of future Replacement Costs for the then remaining Term based upon the amount of Expected Contract Energy that should have been delivered provided, however, that, if the Replacement Costs amount is negative, the Replacement Costs shall be deemed to be zero.

12.5 Operation by Tri-State Following Event of Default of Seller.

(A) Subject to the rights of the Financing Parties, on occasion of an Event of Default and after the expiration of the cure period provided in respect thereof, if any, and prior to any termination of this PPA as a result thereof, Tri-State shall have the right, but not the obligation, to possess, assume control of, and operate the Facility as

agent for Seller (in accordance with Seller's rights, obligations, and interest under this PPA) during the period provided for herein. Seller shall not grant any Person, other than the Financing Parties, a right to possess, assume control of, and operate the Facility that is equal to or superior to Tri-State's right under this Section 12.5.

(B) Tri-State shall give Seller and the Financing Parties ten (10) Days' prior notice of the contemplated exercise of Tri-State's rights under this Section 12.5. Upon such notice, Seller shall collect and have available at a convenient, central location at the Facility all documents, contracts, books, manuals, reports, and records required to construct, operate, and maintain the Facility in accordance with Prudent Utility Practice, including all Operating Records. Upon such notice, Tri-State, its employees, contractors, or designated third parties shall have the unrestricted right to enter the Site and Facility for the purpose of constructing and/or operating the Facility.

(C) Tri-State shall be entitled to immediately draw upon the Security to cover any expenses incurred by Tri-State in exercising its rights under this Section 12.5.

(D) During any period that Tri-State is in possession of and constructing and/or operating the Facility pursuant to this Section 12.5, Tri-State shall perform and comply with all of the obligations of Seller under this PPA and shall use the proceeds from the sale of electricity generated by the Facility to first, reimburse Tri-State for any and all expenses reasonably incurred by Tri-State in taking possession of and operating the Facility, and to second, remit any remaining proceeds to Seller.

(E) During any period that Tri-State is in possession of and operating the Facility, Seller shall retain legal title to and ownership of the Facility and Tri-State shall assume possession, operation, and control solely as agent for Seller.

(1) In the event that Tri-State is in possession and control of the Facility for an interim period, Seller may resume operation and Tri-State shall relinquish its right to operate when Seller demonstrates to Tri-State's satisfaction that it will remove those grounds that originally gave rise to Tri-State's right to operate the Facility, as provided above, in that Seller (i) will resume operation of the Facility in accordance with the provisions of this PPA, and (ii) has cured any Events of Default of Seller that allowed Tri-State to exercise its rights under this Section 12.5 (or, if the Event of Default is of such a nature that it cannot be cured by Seller without possession of the Facility, reasonable assurance that Seller will cure such Event of Default promptly following resumption of possession).

(2) In the event that Tri-State is in possession and control of the Facility for an interim period, the Financing Parties, or any nominee or transferee thereof, may foreclose and take possession of and operate the Facility and Tri-State shall relinquish its right to operate when the Financing Parties or any nominee or transferee thereof, requests such relinquishment.

(F) Tri-State's exercise of its rights hereunder to possess and operate the Facility shall not be deemed an assumption by Tri-State of any liability attributable to Seller. If at any time after exercising its rights to take possession of and operate the Facility Tri-State elects to return such possession and operation to Seller, Tri-State shall provide Seller with at least fifteen (15) Days' prior notice of the date Tri-State intends to return such possession and operation, and upon receipt of such notice Seller shall take all measures necessary to resume possession and operation of the Facility on such date.

(G) In the event Tri-State assumes operation of the Facility under this Section 12.5, Tri-State shall operate the Facility in accordance with Prudent Utility Practice.

12.6 Replacement Costs.

Upon termination for an Event of Default, subject to Section 12.11, Tri-State shall be entitled to Replacement Costs for the balance of the Term (based upon the amount of Expected Contract Energy) had this PPA not been terminated, and Tri-State may draw the appropriate amounts from the Security.

12.7 Specific Performance.

In addition to the other remedies specified in this Article 12, in the event that any Event of Default of Seller is not cured within the applicable cure period set forth herein, Tri-State shall have the right to specific performance. The Parties agree that in the event Tri-State seeks injunctive relief in connection with the foregoing, that such action may be taken without the necessity of posting of a bond or other security as would otherwise be required under Applicable Law.

12.8 Remedies Cumulative.

Each right or remedy of the Parties provided for in this PPA shall be cumulative of and shall be in addition to every other right or remedy provided for in this PPA, and the exercise, or the beginning of the exercise, by a Party of any one or more or the rights or remedies provided for herein shall not preclude the simultaneous or later exercise by such Party of any or all other rights or remedies provided for herein.

12.9 Forward Contracts.

The Parties agree that this PPA is a "forward contract" for purposes of the U. S. Bankruptcy Code; all payments made or to be made by one Party to the other Party pursuant to this PPA are "settlement payments" within the meaning of the U.S. Bankruptcy Code; and all transfers of Security by Seller to Tri-State under this PPA are "margin payments" within the meaning of the U.S. Bankruptcy Code.

12.10 Waiver and Exclusion of Other Damages.

NEITHER PARTY SHALL BE LIABLE TO THE OTHER PARTY FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES BY STATUTE, IN TORT OR CONTRACT (EXCEPT TO THE EXTENT EXPRESSLY PROVIDED HEREIN); *PROVIDED* THAT IF EITHER PARTY IS HELD LIABLE TO A THIRD PARTY FOR SUCH DAMAGES AND THE PARTY HELD LIABLE FOR SUCH DAMAGES IS ENTITLED TO INDEMNIFICATION THEREFOR FROM THE OTHER PARTY, THE INDEMNIFYING PARTY SHALL BE LIABLE FOR, AND OBLIGATED TO REIMBURSE THE INDEMNIFIED PARTY FOR, SUCH DAMAGES, ALL IN ACCORDANCE WITH THE INDEMNIFICATION PROVISIONS OF ARTICLE 17.

12.11 Duty to Mitigate.

Each Party (i) has a general duty to mitigate all damages hereunder (other than Delay Damages, or the damages provided in Section 6.4(H), Section 6.7 and Section 12.3) and (ii) shall use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance of this PPA.

12.12 Limitation of Liability.

Except as otherwise provided in this Section 12.12, Seller's aggregate financial liability to Tri-State for Delay Damages pursuant to Section 4.3, shall not exceed an amount equal to **Insert $100*Expected Nameplate Capacity Rating in kw** Dollars ($_____,000) and Seller's aggregate financial liability to Tri-State for Replacement Costs and other damages, excluding Delay Damages, shall not exceed **Insert $250*Expected Nameplate Capacity Rating in kw** Dollars ($_____,000). If at any time during the Term, Tri-State incurs damages in excess of the limitations set forth above which Seller does not agree to pay when billed by Tri-State, Tri-State shall have the right to declare a termination of this PPA under Section 12.1, unless such damages are disputed in good faith. The limitations on damages set forth in this Section 12.12 shall not apply to damages arising out of any of the following events:

(A) damage or tampering with Tri-State owned facilities caused by negligence, breach of this PPA or other misconduct by Seller, its directors, officers, employees and agents;

(B) the sale by Seller to a third party, or diversion by Seller for any use, of Contract Energy committed to Tri-State under this PPA other than in mitigation of damages for any breach by Tri-State of this PPA;

(C) Seller's intentional misrepresentation or intentional misconduct in connection with this PPA or the operation of the Facility;

(D) Seller's failure (i) to maintain insurance coverages in the types and amounts required by this PPA or (ii) to apply any insurance proceeds to reconstruct the Facility following a casualty;

(E) any claim for indemnification herein;

(F) any Environmental Contamination; or

(G) damages incurred by Tri-State in connection with any bankruptcy or insolvency proceeding involving Seller, including Tri-State's loss of the benefit of its bargain due to rejection or other termination of this PPA in such proceeding.

Article 13
Contract Administration and Notices

13.1 Notices in Writing.

Notices required by this PPA shall be addressed to the other Party, including the other Party's representative on the Operating Committee, at the addresses specified in Exhibit I, as either Party updates them from time to time by written notice to the other Party. Any notice, request, consent, or other communication required or authorized under this PPA to be given by one Party to the other Party shall be in writing. It shall either be hand delivered or delivered by electronic mail with a copy mailed via overnight service with signature required upon receipt, to the representative of said other Party. Any such notice, request, consent, or other communication shall be deemed to have been received by the close of the Business Day on which it was hand delivered or transmitted electronically (unless hand delivered or transmitted after such close in which case it shall be deemed received at the close of the next Business Day). Real-time or routine communications concerning Facility operations shall be exempt from this Section 13.1.

13.2 Representative for Notices.

Each Party shall maintain a designated representative to receive notices. Such representative may, at the option of each Party, be the same person as that Party's representative or alternate representative on the Operating Committee, or a different person. Either Party may, by written notice to the other Party, change the representative or the address to which such notices and communications are to be sent and shall provide the other Party an updated Exhibit I.

13.3 Authority of Representatives.

The Parties' designated representatives shall have authority to act for its respective principals in all technical matters relating to performance of this PPA and to attempt to resolve disputes or potential disputes. However, in their capacity as representatives, they shall not have the authority to amend or waive any provision of this PPA.

13.4 Operating Records.

Originals or copies of all Operating Records shall be maintained at the Facility or such other location in the State in which the Facility is located as may be specified by Seller from time to time. Tri-State may examine and make copies of such Operating Records from time to time upon request, during normal business hours.

13.5 Books and Records.

Seller and Tri-State shall each keep complete and accurate records and all other data required by each of them for the purposes of proper administration of this PPA, including metering, billing and payment records, and such records as may be required by Governmental Authorities in the prescribed format.

13.6 Audit Rights.

During the Term and for a period of three (3) years after the Term, Tri-State shall have the right, at its sole expense, with reasonable advance written notice and during normal working hours, to examine the records of Seller to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this PPA.

13.7 Operating Log.

Seller shall maintain an accurate and up-to-date operating log, in electronic format, at the Facility with records of energy production (by individual block or Unit); changes in operating status; meteorological data; maintenance; and Forced Outages (the "O&M Records"). Within thirty (30) Days after the end of each quarter of the Year, Seller shall submit to Tri-State, in a mutually agreeable format, a copy of the O&M Records for the prior quarter.

13.8 Provision of Real Time Data.

Seller shall, at least five (5) Business Days prior to the delivery of Test Energy and continuing through the Term, make the following data available to Tri-State on a real-time basis, at the Tri-State RTU:

(1) production of Energy in MW and MWh;

(2) [in-service status for each Unit][feeder level breaker status];

(3) [Unit MW output][inverter availability and generation in kW];

(4) [wind speed and direction at each Unit][solar irradiance as measured by the pyranometers at the Facility];

(5) ambient temperature [solar only- and solar panel temperature];

(6) [solar only- stow indication][wind only- icing indication and overspeed indication for each Unit];

(7) humidity; and

(8) barometric pressure.

13.9 Dispute Resolution.

(A) The Parties agree that it is in the best interest of both Parties to attempt to resolve disputes that arise under this PPA in a quick and inexpensive manner. To that end, the Parties commit to use their best efforts to resolve disputes informally. For all disputes that arise pursuant to this PPA, the Parties immediately, through their designated representatives selected in the sole discretion of each Party (individually, the "Party Representative", together, the "Parties' Representatives"), shall negotiate with one another in good faith in order to reach resolution of the dispute. Such negotiation shall commence within fourteen (14) Days of the date of the letter from one Party Representative notifying the other Party Representative of the nature of the dispute. In the event that the Parties' Representatives cannot agree to a resolution of the dispute within thirty (30) Days after the commencement of negotiations, written notice of the dispute (the "Dispute Notice"), together with a statement describing the issues or claims, shall be delivered, within seventy-two (72) hours after the expiration of such thirty (30) Day period, by each of the Parties' Representatives to its respective senior manager or official (such senior manager or official to be selected by each of the Party Representatives in his or her sole discretion, *provided* such senior manager or official has authority to bind the respective Party). Within three (3) Business Days after receipt of the Dispute Notice, the senior manager or officials for both Parties shall negotiate in good faith to resolve the dispute. If the Parties are unable to resolve the dispute within fourteen (14) Days of receipt of the Dispute Notice by the senior manager or officials, either Party may seek available legal remedies.

(B) SELLER AND TRI-STATE EACH HEREBY KNOWINGLY, VOLUNTARILY AND INTENTIONALLY WAIVE ANY RIGHTS THEY MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY LITIGATION BASED HEREON, OR ARISING OUT OF, UNDER, OR IN CONNECTION WITH, THIS PPA OR ANY COURSE OF CONDUCT, COURSE OF DEALING, STATEMENTS (WHETHER ORAL OR WRITTEN) OR ACTIONS OF SELLER AND TRI-STATE RELATED HERETO.

Article 14
Force Majeure

14.1 Definition of Force Majeure Event.

(A) A "Force Majeure Event" shall mean (i) an event or circumstance that is not reasonably foreseeable, (ii) is beyond the reasonable control of, and is not caused by, the negligence or lack of due diligence of the affected Party or its contractors or suppliers and (iii) adversely affects the performance by that Party of its obligations under or pursuant to this PPA. Such events or circumstances may include: actions or inactions of civil or military authority (including courts and governmental or administrative agencies), acts of God, war, riot or insurrection, terrorism, blockades, embargoes, sabotage (including arson and vandalism), epidemics, explosions and fires not originating in the Facility or caused by its operation, hurricanes, floods, strikes, lockouts or other labor disputes (not caused by the failure of the affected Party to comply with the terms of a collective bargaining agreement).

(B) The failure of a transmission line or element due to a Force Majeure Event that prevents Tri-State from delivering Contract Energy from the Point of Delivery is considered a Force Majeure Event.

(C) Equipment breakdown or the inability of Seller to use equipment due to its design, construction, operation, maintenance, the inability of Seller to meet regulatory standards, or failure by Seller to obtain on a timely basis and maintain a necessary permit or other regulatory approval, is not considered a Force Majeure Event.

(D) Notwithstanding the foregoing, the term "Force Majeure Event" does not include any of the following (i) inability by Seller to procure the Units or any component parts therefor, or any associated equipment for the Facility for any reason (the risk of which is assumed by Seller) or any increase in the price to procure the Units or any component parts therefor, including due to changes in any import or export duties or tariffs, (ii) any other acts or omissions of any third party, including any vendor, materialman, customer, or supplier of Seller, unless such acts or omissions are themselves excused by reason of a Force Majeure Event under Section 14.1(A); (iii) any full or partial curtailment in the electric output of the Facility that is caused by or arises from a mechanical or equipment breakdown or other mishaps, events or conditions attributable to normal wear and tear or flaws, except as caused by a Force Majeure Event under Section 14.1(A), (iv) failure of Seller to abide by Prudent Utility Practices, (v) changes in market conditions that affect the cost of supplies, or that affect demand or price for power and/or Environmental Attributes; (vi) any labor strikes, slow downs or stoppages, or other labor disruptions against Seller's contractors, subcontractors, vendors, or suppliers; (vii) changes in Applicable Laws; (viii) failure of Seller or the Facility to qualify or be eligible for any Tax Credit or Additional Tax Benefits, including any federal, state, or local tax credits or exemptions; (ix) any delay or inability of Seller to construct or install any required interconnection or transmission facilities required to be constructed and installed in order for Seller to meet its

obligations hereunder, including any delays of the Interconnection Provider; (x) Seller's failure to timely apply for, or diligently pursue, any of the Governmental Approvals set forth in Exhibit F; or (xi) weather events or sudden actions of the natural elements within twenty (20) year normal weather patterns.

(E) In the event that any delay or failure of performance (including a significant reduction in the delivery of Contract Energy) caused by a Force Majeure Event affecting Seller continues for an uninterrupted period of sixty (60) Days from its inception, the Term of this PPA shall be extended on a day for day basis for the duration of the Force Majeure Event (including the initial sixty (60) Days from its inception) with a maximum extension of the Term of this PPA for all Force Majeure Events not to exceed four (4) years; *provided that* the Commercial Operation Year for purposes of determining the applicable Contract Energy Rate and Expected Contract Energy shall be tolled on a day for day basis for the duration of the Force Majeure Event.

(F) In the event that any delay or failure of performance (including a significant reduction in the delivery of Contract Energy) caused by a Force Majeure Event affecting Seller continues for an uninterrupted period of ninety (90) Days from its inception (with respect to a Force Majeure Event occurring prior to COD) or three hundred sixty-five (365) Days from its inception (with respect to a Force Majeure Event occurring after COD), the Party not claiming a Force Majeure Event may, at any time following the end of such period, terminate this PPA upon written notice to the affected Party, without further obligation by either Party except as to costs and balances incurred prior to the effective date of such termination.

(G) Except as otherwise provided in this PPA, and subject to compliance with the notice, mitigation and other requirements of this Article 14, each Party shall be excused from performance when non-performance was caused, directly or indirectly, by a Force Majeure Event but only and to the extent thereof.

14.2 Notification Obligations.

In the event of any delay or nonperformance resulting from a Force Majeure Event, the Party claiming that a Force Majeure Event has occurred shall notify the other Party immediately by telephonic communication and in writing, within five (5) Days of such occurrence, of the nature, cause, date of commencement thereof and the anticipated duration, and shall indicate whether any deadlines or date(s) imposed hereunder may be affected thereby. The suspension of performance shall be of no greater scope and of no greater duration than the cure for the Force Majeure Event requires. A Party claiming that a Force Majeure Event has occurred shall not be entitled to any relief therefor unless and until confirming notice is provided. The Party claiming that a Force Majeure Event has occurred shall notify the other Party of the cessation of the Force Majeure Event or of the conclusion of the affected Party's cure for the Force Majeure Event, in either case within two (2) Business Days thereof.

14.3 Duty to Mitigate.

The Party claiming that a Force Majeure Event has occurred shall use commercially reasonable efforts to cure the cause(s) preventing its performance of this PPA; *provided, however,* that the settlement of strikes, lockouts and other labor disputes shall be entirely within the discretion of the affected Party and such Party shall not be required to settle such strikes, lockouts or other labor disputes by acceding to demands which such Party deems to be unreasonable.

14.4 Delay Caused by Force Majeure Event.

Upon the occurrence and during the continuance of a Force Majeure Event and the effects thereof, to the extent that a Force Majeure Event affects the ability of Tri-State, Interconnection Provider or Transmission Provider to accept Energy from the Facility or to the extent that a Force Majeure Event affects the ability of Seller to Test pursuant to Section 9.2 or to deliver Energy from the Facility, then the hours during which the Force Majeure Event occurs shall be excluded from the payment calculations as set forth in Section 7.1.

Article 15
Representations and Warranties

15.1 Seller's Representations and Warranties.

Seller hereby represents and warrants as of the date hereof as follows:

(A) Seller is a _____, duly organized, validly existing and in good standing under the laws of the state of _____. Seller is qualified to do business in _____ and in each other jurisdiction where the failure to so qualify would have a material adverse effect on the business or financial condition of Seller. Seller has all requisite power and authority to conduct its business, to own its properties, and to execute, deliver, and perform its obligations under this PPA.

(B) The execution, delivery, and performance of its obligations under this PPA by Seller have been duly authorized by all necessary corporate action, and do not and will not:

(1) require any consent or approval by any governing body of Seller, other than that which has been obtained and is in full force and effect (evidence of which shall be delivered to Tri-State upon execution of this PPA);

(2) violate any Applicable Law, the violation of which could have a material adverse effect on the ability of Seller to perform its obligations under this PPA;

(3) result in a breach or constitute a default under Seller's organizational documents or bylaws, or any indenture or loan or credit agreement, or

any other agreement, lease, or instrument to which Seller is a party or by which Seller or its properties or assets may be bound or affected, or any judgment, order, statute, or regulation that is applicable to Seller or the Facility; or

(4) result in, or require the creation or imposition of any mortgage, deed of trust, pledge, lien, security interest, or other charge or encumbrance of any nature (other than as may be contemplated by this PPA) upon or with respect to any of the assets or properties of Seller now owned or hereafter acquired.

(C) The obligations of Seller under this PPA are valid and binding obligations of Seller, enforceable against it in accordance with its terms, except as the enforceability hereof may be limited by general principles of equity or bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies.

(D) The individual of Seller executing this PPA is authorized to do so and is authorized to bind Seller to the obligations under this PPA.

(E) The execution and performance of this PPA shall not conflict with or constitute a breach or default under any contract or agreement of any kind to which Seller is a party.

(F) Except for those permits, consents, approvals, licenses and authorizations identified in Exhibit F, which Seller anticipates will be obtained by Seller in the ordinary course of business, all Governmental Approvals necessary for Seller's execution, delivery and performance of this PPA have been duly obtained and are in full force and effect.

(G) That it has arranged for sufficient financing and other funding required to complete the construction of the Facility in accordance with this PPA and to achieve Commercial Operation on or before the Commercial Operation Milestone.

(H) That the Environmental Attributes, as to which right and title is to be transferred to Tri-State under this PPA are, or will be: (1) compliant with the definitions of local, state, or federal renewable portfolio standard rules and requirements, (2) free and clear of any liens, encumbrances and/or defects of title; and (3) shall not otherwise been, nor will be sold, retired, claimed, or represented as part of electricity output or sales, or used to satisfy obligations in any other jurisdiction.

(I) Within the meaning of the U.S. Bankruptcy Code, Seller is a "forward contract merchant."

15.2 Tri-State's Representations and Warranties.

Tri-State hereby represents and warrants as of the date hereof as follows:

(A) Tri-State is a cooperative corporation duly organized, validly existing and in good standing under the laws of the state of Colorado and is qualified in each other jurisdiction where the failure to so qualify would have a material adverse effect upon the business or financial condition of Tri-State. Tri-State has all requisite power and authority to conduct its business, to own its properties, and to execute, deliver, and perform its obligations under this PPA.

(B) The execution, delivery, and performance of its obligations under this PPA by Tri-State have been duly authorized by all necessary corporate action, and do not and will not:

(1) require any consent or approval of Tri-State's members;

(2) violate any Applicable Law, the violation of which could have a material adverse effect on the ability of Tri-State to perform its obligations under this PPA;

(3) result in a breach or constitute a default under Tri-State's corporate charter or bylaws, or under any agreement relating to the management or affairs of Tri-State, or any indenture or loan or credit agreement, or any other agreement, lease, or instrument to which Tri-State is a party or by which Tri-State or its properties or assets may be bound or affected, the breach or default of which could reasonably be expected to have a material adverse effect on the ability of Tri-State to perform its obligations under this PPA; or

(4) result in, or require the creation or imposition of, any mortgage, deed of trust, pledge, lien, security interest, or other charge or encumbrance of any nature (other than as may be contemplated by this PPA) upon or with respect to any of the assets or properties of Tri-State now owned or hereafter acquired, the creation or imposition of which could reasonably be expected to have a material adverse effect on the ability of Tri-State to perform its obligations under this PPA.

(C) This PPA is a valid and binding obligation of Tri-State, enforceable against it in accordance with its terms, except as the enforceability hereof may be limited by general principles of equity or bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies.

(D) The individual of Tri-State executing this PPA is authorized to do so and is authorized to bind Tri-State to the obligations under this PPA.

(E) The execution and performance of this PPA shall not conflict with or constitute a breach or default under any contract or agreement of any kind to which Tri-State is a party or any judgment, order, statute, or regulation that is applicable to Tri-State.

(F) Within the meaning of the U.S. Bankruptcy Code, Tri-State is a "forward contract merchant."

Article 16
Insurance

16.1 Evidence of Insurance.

Seller shall, upon execution of this PPA and promptly after the renewal of each policy of insurance coverage required in Exhibit D, provide Tri-State with one copy of insurance certificates or other evidence in a form acceptable to Tri-State evidencing the insurance coverages required to be maintained in accordance with Exhibit D to this PPA. Such certificates shall (i) include Tri-State as an additional insured (except worker's compensation); (ii) provide that the applicable insurer shall endeavor to provide Tri-State with thirty (30) Days' prior written notice of non-renewal or cancellation of the policies required in Exhibit D (except that such notice shall be ten (10) Days for non-payment of premiums); and (iii) provide a waiver of any rights of subrogation against Tri-State, its Affiliates and their officers, directors, agents, subcontractors, and employees. Insurance carriers providing the coverages required in Exhibit D, must have a policy holders rating of "A-" or better, and a financial size of "Class VII" or better as published in the most recent edition of Best's Insurance Reports. Any policy of insurance furnished hereunder shall be written by an insurer authorized to write such coverage in the state where the Facility is located. All policies shall be written on an occurrence basis, except as provided in Section 16.2. All policies shall include language providing that Seller's policy shall be primary in all instances regardless of like coverages, if any, carried by Tri-State. Seller's liability under this PPA is not limited to the amount of insurance coverage required herein. Seller shall notify Tri-State immediately should the policies required in Exhibit D be cancelled before the expiration date, if the insureds receive a non-renewal notice from its carrier, or if there is any material adverse change of coverage.

16.2 Term and Modification of Insurance.

(A) All insurance required under this PPA shall cover occurrences during the Term and for a period of two (2) years after the Term. In the event that any insurance as required herein is commercially available only on a "claims-made" basis, such insurance shall provide for a retroactive date not later than the later of (i) the Effective Date, or (ii) the cancellation date of any occurrence basis policies that such insurance has replaced.

(B) Tri-State shall have the right to request modification of the insurance minimum limits specified in Exhibit D in order to maintain reasonable coverage amounts. Seller shall make all commercially reasonable efforts to comply with any such request. Tri-State shall reimburse Seller for all premium increases and other costs incurred by Seller in complying with any such Tri-State request for modification of the insurance minimum limits specified in Exhibit D.

16.3 Application of Proceeds.

Seller shall apply any insurance proceeds to reconstruction of the Facility following a casualty.

Article 17
Indemnity

17.1 Indemnification.

Each Party (the "Indemnifying Party") shall, to the extent permitted by Applicable Law, indemnify, pay, defend and hold harmless the other Party (the "Indemnified Party") and its officers, directors, employees, agents and contractors from and against any and all claims or demands of a third party, costs or expenses (including reasonable attorneys' fees) for loss, damages, or injury to persons or property of the Indemnified Party (or to third parties) (collectively, "Losses") caused by, arising out of, or resulting from:

(A) a breach by the Indemnifying Party of its covenants, representations, and warranties or obligations hereunder;

(B) a violation or alleged violation of Applicable Laws by the Indemnifying Party;

(C) any act or omission by the Indemnifying Party or its contractors, agents, servants or employees in connection with the installation, testing, inspection, or operation or maintenance of its respective facilities or equipment;

(D) any defect in, failure of, or fault related to, the Indemnifying Party's facilities or equipment; or

(E) the negligence or intentional acts or other misconduct of the Indemnifying Party or its contractors, agents, servants, employees or any authorized persons acting on behalf of such Indemnifying Party.

17.2 Indemnification for Fines and Penalties.

Any fines or other penalties incurred by a Party (other than fines or penalties due to the negligence or intentional acts or other misconduct of the other Party) for non-compliance with any Applicable Laws shall be the sole responsibility of the non-complying Party.

17.3 Limitations

(A) The foregoing indemnification obligations shall apply notwithstanding any contributory misconduct of the Indemnified Party, but the Indemnifying Party's liability to indemnify the Indemnified Party shall be reduced in

proportion to the percentage by which the Indemnified Party's misconduct caused the damages.

(B) Neither Party shall be indemnified for Losses resulting from the sole negligence or intentional acts or misconduct of the directors, officers, employees, or agents of such Party

17.4 Notice of Proceedings.

Each Party shall promptly notify the other Party of any loss or proceeding in respect of which such notifying Party is or may be entitled to indemnification pursuant to Section 17.1. Such notice shall be given as soon as reasonably practicable after the relevant Party becomes aware of the loss or proceeding and that such loss or proceeding may give rise to an indemnification, but in any event no later than seven (7) Days after the receipt by the Party seeking indemnification of notice of the commencement of any action for which indemnity may be sought. The delay or failure of such Indemnified Party to provide the notice required pursuant to this Section 17.4 to the other Party shall not release the other Party from any indemnification obligation which it may have to such Indemnified Party except (i) to the extent that such failure or delay materially and adversely affected the Indemnifying Party's ability to defend such action or increased the amount of the loss, and (ii) that the Indemnifying Party shall not be liable for any costs or expenses of the Indemnified Party in the defense of the claim, suit, action or proceeding during such period of failure or delay.

17.5 Defense of Claims.

(A) Whether or not acknowledging in writing its obligation to indemnify an Indemnified Party to the extent required pursuant to this Section 17.5, the Indemnifying Party shall be entitled, at its option, to assume and control the defense of such claim, action, suit or proceeding at its expense with counsel of its selection, subject to the prior approval of the Indemnified Party.

(B) Unless and until the Indemnifying Party acknowledges in writing its obligation to indemnify the Indemnified Party to the extent required pursuant to this Section 17.5 and assumes control of the defense of a claim, suit, action or proceeding in accordance with paragraph (A) above, the Indemnified Party shall have the right, but not the obligation, to contest, defend and litigate, with counsel of its own selection, any claim, action, suit or proceeding by any third party alleged or asserted against such Party in respect of, resulting from, related to or arising out of any matter for which it is entitled to be indemnified hereunder, and the reasonable costs and expenses thereof shall be subject to the indemnification obligations of the Indemnifying Party hereunder.

(C) Neither the Indemnifying Party nor the Indemnified Party shall be entitled to settle or compromise any such claim, action, suit or proceeding without the prior consent of the other; *provided, however,* that after agreeing in writing to indemnify the Indemnified Party, the Indemnifying Party may, subject to paragraph (D) below,

settle or compromise any claim without the approval of such Indemnified Party. Except where such consent is unreasonably withheld, if an Indemnified Party settles or compromises any claim, action, suit or proceeding in respect of which it would otherwise be entitled to be indemnified without the prior consent of the Indemnifying Party, the Indemnifying Party shall be excused from any indemnification obligation in respect of such settlement or compromise.

(D) Following the acknowledgement of the indemnification and the assumption of the defense by the Indemnifying Party pursuant to paragraph (A) above, the Indemnified Party shall have the right to employ its own counsel and such counsel may participate in such action, but the fees and expenses of such counsel shall be at the expense of the Indemnified Party, when and as incurred, unless: (i) the employment of counsel by the Indemnified Party has been authorized in writing by the Indemnifying Party; (ii) the Indemnified Party shall have reasonably concluded and specifically notified the Indemnifying Party that there may be a conflict of interest between the Indemnifying Party and the Indemnified Party in the conduct of the defense of such action; (iii) the Indemnifying Party shall not in fact have employed independent counsel reasonably satisfactory to the Indemnified Party to assume the defense of such action and shall have been so notified by the Indemnified Party; or (iv) the Indemnified Party shall have reasonably concluded and specifically notified the Indemnifying Party that there may be specific defenses available to it which are different from or additional to those available to the Indemnifying Party, or that such claim, action, suit or proceeding involves or could have a material adverse effect upon the Indemnified Party beyond the scope of this PPA. If clause (ii), (iii) or (iv) of the preceding sentence shall be applicable, then counsel for the Indemnified Party shall have the right to direct the defense of such claim, action, suit or proceeding on behalf of the Indemnified Party and the reasonable fees and disbursements of such counsel shall constitute reimbursable legal or other expenses hereunder.

Article 18
Legal and Regulatory Compliance

18.1 Applicable Law.

Each Party shall at all times comply with all Applicable Law related to its obligations under this PPA, except for any non-compliance which, individually or in the aggregate, could not reasonably be expected to have a material adverse effect on the business or financial condition of the Party or its ability to fulfill its commitments under this PPA. Seller shall promptly notify Tri-State of any investigation, notices or findings of violations of Applicable Law from any Governmental Authority, including any audit, notification, inspection or inquiry that has been commenced by any Governmental Authority in respect of a potential or possible violation of Applicable Law. Except as otherwise expressly provided herein, each Party assumes the risk of changes in Applicable Laws following the date hereof, that affect such Party's costs of ownership and operation of its assets, and its performance of this PPA, except as otherwise specifically set forth herein.

18.2 Compliance with Governmental Approvals.

Seller shall comply with and cause the Facility to comply with all applicable Governmental Approvals. Seller shall promptly notify Tri-State of any inspections by any Governmental Authority with respect to any material Governmental Approval and will promptly provide Tri-State with copies of any notices of violation or non-compliance with respect to any material Governmental Approval. Upon permanent cessation of generation of Energy from the Facility, Seller, at its sole cost and expense, shall decommission the Facility, dismantle the Facility, remediate the Site and submit and obtain any Governmental Approvals with respect thereto.

18.3 Compliance Information.

(A) Each Party shall, for the purpose of gathering information and/or providing verbal or written reports, testimony, affidavits or other submissions relevant to any Governmental Approvals, Applicable Laws or in connection with any litigation, arbitration or administrative proceeding before any authority of competent jurisdiction: (i) deliver or cause to be delivered to the other Party any necessary or required certificates of its officers, accountants, engineers or agents; and/or (ii) make available necessary personnel with knowledge as to such matters.

(B) To the full extent authorized by FERC regulations and the FERC standards of conduct, Seller hereby authorizes Tri-State to contact and obtain information concerning the Facility and Interconnection Facilities directly from the Interconnection Provider and the Transmission Provider and, to the extent necessary, Seller shall provide written notice to the Interconnection Provider and the Transmission Provider confirming such authorization.

18.4 Reliability Standards.

In the event that new reliability standards are promulgated by WECC, NERC, FERC, or PUC, or any successor agencies, any and all costs incurred as a result of actions required for compliance with the new reliability standards shall be borne by Seller. To the extent that Seller contributes in whole or in part to actions which result in monetary penalties being assessed to Tri-State by WECC, NERC, FERC or PUC, or any successor agencies, for lack of compliance with reliability standards (except to the extent that Seller acted at the direction of Tri-State), Seller shall reimburse Tri-State for its share of such monetary penalties.

18.5 Financial Accounting Standards.

Under accounting principles generally accepted in the United States of America ("GAAP"), Tri-State may be required to consolidate an entity with which Tri-State has entered into a long-term power purchase agreement. Seller shall provide all information needed by Tri-State in order for Tri-State to determine whether or not Seller must be consolidated by Tri-State under GAAP. If Tri-State determines in its discretion that Tri-

State is required to consolidate Seller in its financial statements, Seller shall provide reasonable access to any records and personnel, as requested by Tri-State, in connection with such consolidation and also so that Tri-State's independent auditors can conduct financial statement audits in accordance with generally accepted audit standards, as well as internal controls review. Seller shall have adequate controls over financial information.

Article 19
Assignment and Other Transfer Restrictions

19.1 Assignment of PPA.

(A) Except as expressly permitted by this Section 19.1 or in connection with a Transfer of the Facility that is expressly permitted by Section 19.4, neither Party shall assign this PPA, or any portion thereof, without the prior written consent of the other Party. Any purported assignment of this PPA or any portion thereof in violation of the foregoing shall be null and void and shall constitute an Event of Default.

(B) Notwithstanding Section 19.1(A) but subject to Section 19.1(C), without the prior written consent of the other Party:

(1) Either Party shall have the right at any time and from time to time to mortgage, create or provide for a security interest in, convey in trust, or collaterally assign its respective rights, titles and interests in this PPA to any lender, collateral agent, mortgagee, or trustee as security for its present or future indebtedness (including, in the case of such an assignment by Seller, any Financing Party) (each, a "Security Party"), without such Security Party assuming or becoming in any respect obligated to perform any of the obligations of the Parties.

(2) Any Security Party may foreclose upon or, in lieu thereof, otherwise succeed to and acquire all the rights, titles and interests of such Party in this PPA.

(3) Either Party may assign this PPA to any Affiliate thereof that has the financial capability to fulfill its obligations hereunder as demonstrated by a credit rating of equal to or better than the assigning Party.

(C) No assignment of or other succession to a Party's interest in this PPA shall be permitted pursuant to this PPA (other than Section 19.1(B)(1)) unless and until: (i) the successor assumes and agrees, in writing in form and substance reasonably acceptable to the other Party, to fully perform and discharge all of the obligations hereunder of such Party, and (ii) in the case of Seller's interest in this PPA, the successor (1) succeeds to and acquires all rights, title and interest of Seller in the Facility and (2) provides to Tri-State all Security then required to be maintained by Seller hereunder.

(D) Any successor to a Party's interest in this PPA shall notify the other Party promptly in writing of such succession, and shall furnish to the other Party evidence of such succession.

19.2 Change of Operator.

(A) Except as expressly permitted by this Section 19.2, Seller shall not replace the Operation and Maintenance Contractor (which for purposes of this Section 19.2 shall include replacement of any subcontractor or other Person providing operation management or other significant operation or maintenance services) without the prior written consent of Tri-State. The replacement of the Operation and Maintenance Contractor in violation of the foregoing shall constitute an Event of Default.

(B) Notwithstanding Section 19.2(A), Seller can replace the Operation and Maintenance Contractor without the prior written consent of Tri-State if:

(1) Seller provides to Tri-State reasonable advance written notice of such replacement (which, absent extraordinary circumstances affecting the safe and reliable operation of the Facility, shall not be less than ninety (90) Days prior to such replacement); and

(2) Seller reasonably demonstrates to Tri-State that the replacement operator is a Qualified Operator.

19.3 Change of Control.

(A) Except as expressly permitted by this Section 19.3, Seller shall not permit a Change of Control of Seller to occur without the prior written consent of Tri-State. The occurrence of a Change of Control of Seller in violation of the foregoing shall constitute an Event of Default.

(B) Notwithstanding Section 19.3(A) but subject to Section 19.3(C), without the prior written consent of Tri-State:

(1) Any direct or indirect owner of Seller shall have the right at any time and from time to time to mortgage, grant a security interest in, convey in trust, or pledge to any Security Party any equity or ownership interest in Seller or in any Person that Controls Seller.

(2) Any Security Party may foreclose upon or, in lieu thereof, otherwise succeed to and acquire any such equity or ownership interests in Seller or in any Person that Controls Seller.

(C) No Change of Control of Seller shall be permitted under this PPA unless all obligations of Seller hereunder with respect to maintaining Security are satisfied immediately following such Change of Control.

(D) Seller shall notify Tri-State promptly in writing of any Change of Control of Seller.

19.4 Transfer of Facility.

(A) Except as expressly permitted by this Section 19.4, Seller shall not Transfer all or any portion of the Facility without the prior written consent of Tri-State. The Transfer of all or any portion of the Facility in violation of the foregoing shall constitute an Event of Default.

(B) Notwithstanding Section 19.4(A) but subject to Section 19.4(C), without the prior written consent of Tri-State:

(1) Seller shall have the right at any time and from time to time to mortgage, convey in trust, or grant to any Security Party a security interest in the Facility or any portion thereof.

(2) Any Security Party may foreclose upon or, in lieu thereof, otherwise succeed to and acquire the Facility or any portion thereof.

(3) Seller may, and shall be obligated to, Transfer the Facility to any Affiliate to which Seller assigns the PPA in compliance with the provisions of Section 19.1.

(C) No Transfer of the Facility or any portion thereof shall be permitted pursuant to this PPA (other than Section 19.4(B)(1)) unless and until the successor (i) succeeds to and acquires all rights, title and interest of Seller in this PPA, (ii) assumes and agrees in writing, in form and substance reasonably acceptable to Tri-State, to fully perform and discharge all of the obligations of Seller hereunder, and (iii) provides to Tri-State all Security then required to be maintained by Seller hereunder.

(D) Seller shall notify Tri-State promptly in writing of any Transfer of the Facility or any portion thereof, and shall furnish to Tri-State evidence of such Transfer.

19.5 Reimbursement of Tri-State's Costs.

In the event Seller proposes to or does assign or transfer an interest in the Facility or this PPA, undergo a Change of Control, or replace the Operation and Maintenance Contractor, as such transactions are described in this Article 19, Seller shall reimburse Tri-State for its expenses, including internal costs and expenses and reasonable attorneys' fees, incurred by Tri-State in connection with the evaluation of such proposed transaction and the preparation, negotiation, and execution of any consent and any other documents associated with such proposed transaction.

Article 20
Purchase Option

20.1 Right of First Offer of Sale of the Facility.

(A) Except for Transfers expressly permitted by Section 19.3(B) or Section 19.4(B), Seller shall not, and shall cause each direct and indirect owner of Seller not to, at any time during the Term, consummate or enter into any agreement for the consummation of any of the following (each, a "ROFO Transfer"):

(1) any Transfer by Seller of the Facility or any part of the Facility to one or more Persons that are not Affiliates of Seller; or

(2) any Transfer by any Person, in one or more transactions to one or more other Persons that are not Affiliates of such Person, of equity or other ownership interests in one or more Project Entities that (individually or in the aggregate) constitute a direct or indirect Controlling interest in Seller;

unless Seller has first offered to Transfer the Facility, or such direct or indirect owner has first offered to Transfer such direct or indirect equity interests in Seller, as applicable, to Tri-State pursuant to a written offer (in each case, an "Offered Assets Notice") and otherwise complies with this Section 20.1 and Article 19.

(B) Any Offered Assets Notice shall set forth in reasonable detail all material terms and conditions of the offer, including the minimum price and terms of payment, liabilities and obligations to be directly or indirectly assumed, all other financial terms, all material conditions to closing, a period of no less than 180 days following execution of the purchase agreement for the parties to obtain any approvals or other authorizations of any Governmental Authority or third party that are required by such party in connection with such Transfer, and all material representations, warranties, rights to indemnification, limitations thereon, and credit support for any of the foregoing. Following Tri-State's receipt of the Offered Assets Notice, Tri-State shall have ninety (90) Days to investigate the proposed transaction and conduct due diligence. Seller (i) shall promptly answer any questions that Tri-State may have concerning the Facility, any applicable liabilities and obligations, and the offered terms and conditions, (ii) shall meet with Tri-State to discuss the offer, and (iii) shall provide all documents and information requested by Tri-State that are reasonably available to Seller.

(C) If Tri-State does not provide Seller notice that it accepts the offered terms and conditions to purchase the Facility or the specified equity interests (as applicable) within ninety (90) Days after receiving the Offered Assets Notice, Seller shall have the right to sell the Facility (or Seller's relevant parent shall have the right to sell the specified equity interests, as applicable) to a third party on terms and conditions that are not more favorable in the aggregate to the third party than those included in the Offered Assets Notice, at any time within the twelve-month period following issuance of

the Offered Assets Notice, and to enter into any agreement therefor. If Seller or its relevant parent wishes to enter into an agreement for or consummate a ROFO Transfer with a third party on terms and conditions that in the aggregate are more favorable to the third party than those previously offered to Tri-State in the Offered Assets Notice, or on a date that is more than twelve months following delivery of the applicable Offered Assets Notice, such ROFO Transfer shall again be subject to this Section 20.1 and Seller or its relevant parent shall again first offer the revised terms and conditions to Tri-State pursuant to a new Offered Assets Notice.

(D) If Tri-State accepts an offer made by Seller under Section 20.1(B), the Parties shall within a further ninety (90) Days enter into a purchase agreement that, except to the extent otherwise agreement by Seller and Tri-State, incorporates the terms and conditions in the Offered Assets Notice.

20.2 Right of First Offer on Facility Expansion.

(A) If, at any time during the Term, Seller or any Affiliate of Seller intends to install or modify any energy generation or storage equipment on the Site or on any location within a five (5) mile radius of the boundary of the Site, the effect of which, if deemed part of the Facility, would be to increase the Nameplate Capacity Rating of the Facility, Seller shall first offer the Energy (and Environmental Attributes) resulting from such installation or modification ("Expansion Energy") to Tri-State. Such offer shall set forth in reasonable detail the proposed transaction and the terms and conditions of the offer, including the price. Following Tri-State's receipt of such notice, Tri-State shall have ninety (90) Days to investigate the proposed transaction and conduct due diligence. Seller shall promptly answer any question that Tri-State may have concerning the offered terms and conditions, shall meet with Tri-State to discuss the offer, and shall provide requested documents and information requested by Tri-State.

(B) If Tri-State does not provide Seller notice that it accepts the offered terms and conditions within ninety (90) Days after receiving the offer, Seller or the Affiliate of Seller may enter into an agreement to sell the Expansion Energy to a third party on terms and conditions no more favorable in the aggregate to the third party than those offered to Tri-State. If Seller or the Affiliate of Seller wishes to enter into an agreement with a third party on terms and conditions more favorable to the third party than those previously offered to Tri-State under Section 20.2(A), Seller or the Affiliate of Seller shall first offer such revised terms and conditions to Tri-State pursuant to Section 20.2(B).

(C) If Tri-State accepts an offer made by Seller under Section 20.2(A), the Parties shall within a further ninety (90) Days enter into an energy purchase agreement in substantially the same form as this PPA for the purchase and sale of Expansion Energy and associated Environmental Attributes (with the Security requirement set forth in Article 11, Contract Energy delivery requirements set forth in Section 6.1, the damage payment in Section 6.4(H) and Expected Contract Energy to

be adjusted on a pro rata basis to account for the size of the proposed expansion relative to the Expected Nameplate Capacity Rating), but incorporating such changes as are expressly identified in the terms and conditions offered by Seller.

20.3 Option to Purchase.

(A) Seller hereby gives and grants to Tri-State the exclusive and irrevocable right and option to purchase the Facility Assets, at the times and upon the terms and conditions set forth in this Section 20.3, for a price equal to the Fair Market Value of the Facility, as determined pursuant to this Section 20.3 ("Purchase Option").

(B) As used herein, "Facility Assets" means the Facility, all interest of Seller or any of its Affiliates in, to or under this PPA, and any and all tangible or intangible assets that are reasonably necessary for the ownership, operation and maintenance of the Facility, including (i) all drawings, specifications, operations and maintenance records, and performance data of or related to the Facility; (ii) all warranties, equipment service and maintenance agreements, and similar agreements related to the Facility, any portion thereof, or any related equipment or facilities; (iii) non-exclusive, irrevocable and royalty-free licenses to use software and other intellectual property necessary for the ownership, operation or maintenance of the Facility; (iv) all Governmental Approvals related to the ownership, operation or maintenance of the Facility, to the extent assignable; (v) the Interconnection Agreement and utility services agreements, (vi) the Facility Site Documents, and all other interests or rights in real estate reasonably necessary for the operation and maintenance of the Facility, and (vii) all rights to future Energy, Environmental Attributes, and tax benefits.

(C) Facility Assets do not include (without limitation) (i) any liabilities of Seller or any of its Affiliates, contingent or otherwise, other than future performance obligations under contracts and Governmental Approvals that, in any case, are reasonably necessary for the ownership, operation or maintenance of the Facility and are assigned to Tri-State; (ii) any agreement or instrument evidencing indebtedness for borrowed money; (iii) any contracts or agreements for the sale of Energy, Environmental Attributes, or other products, other than this PPA; or (iv) any contract or agreement for asset management, operations, or other services not specifically included in the Facility Assets.

(D) As a condition to any exercise of the Purchase Option, Tri-State must give non-binding written notice (a "Notice of Intent to Purchase") either (i) within ninety (90) days prior to any of [solar only: the sixth (6th) anniversary of the Commercial Operation Date,] the eleventh (11th) anniversary of the Commercial Operation Date, the fifteenth (15th) anniversary of the Commercial Operation Date, the twentieth (20th) anniversary of the Commercial Operation Date, or the expiration of the Term, or (ii) within ninety (90) days following any termination of this PPA by Tri-State, following the [solar: sixth (6th)][wind: fifteenth (15th)] anniversary of the Commercial Operation Date, due to an Event of Default by Seller.

(E) For a period of sixty (60) days following the date of the Notice of Intent to Purchase, the Parties will meet to discuss and negotiate in good faith to determine and agree upon the Fair Market Value, and shall use commercially reasonable efforts to agree upon the terms and conditions of a purchase and sale agreement with respect to the Facility Assets. For the avoidance of doubt, neither agreement upon Fair Market Value and such terms and conditions, nor execution of a purchase and sale agreement, shall be conditions to the closing of a purchase and sale of the Facility Assets pursuant to exercise of the Purchase Option.

(F) For purposes of this Section 20.3, "Fair Market Value" means the fair market value of the Facility Assets as agreed by the Parties; provided, however, that in the event the Parties cannot agree upon Fair Market Value within sixty (60) Days following the delivery of the Notice of Intent to Purchase, the Parties shall retain an independent nationally recognized appraiser experienced in appraising [wind][solar]-powered electric energy generation facilities selected by Tri-State (and certified as so qualified by Seller), in which case Fair Market Value shall be as determined by such appraiser. The Parties shall share equally all fees and costs of the third appraiser, if required, retained to determine Fair Market Value.

(G) The appraiser shall consider the following factors in its determination of Fair Market Value:

(1) the expected annual generating output of the Facility over the remainder of its assumed useful life determined in a manner consistent with Prudent Utility Practices, taking into account the expected degradation of the Facility over such period;

(2) the net present value of the after-tax cash flows over the remainder of its assumed useful life (determined in a manner consistent with Prudent Utility Practices, and taking into account the expected degradation), applying a discount rate that is reasonable under then-current market conditions as agreed by the Parties, and if not so agreed within thirty (30) Days, then as determined by such appraiser;

(3) the general condition of the Facility at the time of the expected closing following exercise of the Purchase Option determined by inspection and, if applicable, testing;

(4) any restrictions on use of the Site or any portion thereof;

(5) any rights or obligations of Seller to dismantle and remove the Facility and restore the Site (whenever arising);

(6) any restrictions upon or obligations or liabilities associated with any of the Facility Assets or the operation of the Facility prior to the closing pursuant to the Purchase Option that could adversely affect the operation of the

Facility, or for which Tri-State could be responsible or have any liability, following the closing pursuant to the Purchase Option, including due to any Environmental Contamination, any accrued liabilities (contingent or non-contingent) under the Interconnection Agreement, any Facility Site Documents, or any other contract included in the Facility Assets, any accrued and unpaid property tax liabilities, and any failure to comply with any Governmental Approval or Applicable Law;

(7) the terms and conditions of this PPA, including the encumbrance of any obligations and liabilities on an assignee thereof with respect to delivery of Contract Energy to Tri-State for the remainder of the Term, the expected market price of Energy following the expiration of this PPA, transmission costs and constraints and other limitations on the marketability of power generated from the Facility;

(8) any terms and conditions (if any) that will apply to the sale and purchase of the Facility Assets;

(9) an appropriate discount to the extent that (i) Seller fails to provide to Tri-State and the appraiser any material information related to the Facility Assets or Site, or (ii) the representations, warranties, indemnification obligations and other terms and conditions (if any) that will apply to the sale and purchase of the Facility Assets materially deviate from customary terms and conditions for the sale and purchase of facilities similar to the Facility; and

(10) such other factors as the independent appraiser deems relevant.

(H) Following delivery of a Notice of Intent to Purchase, Seller shall promptly provide to Tri-State (and, if applicable, the appraiser) all information regarding the Facility Assets and Site as may be requested thereby, that is reasonably available to Seller, and Tri-State (and, if applicable, the appraiser) shall be provided with access to the Site and Facility in order to conduct an inspection and witness any testing. All inspections and testing, and access to the Site and Facility, shall be conducted in accordance with all of Seller's applicable reasonable safety and health rules and requirements that have been provided to Tri-State (and, if applicable, the appraiser), and shall be conducted in a manner so as to minimize disruption in the operation and the maintenance of the Facility and in such a manner so as to avoid any adverse economic impacts to Seller under this PPA.

(I) To definitively exercise the Purchase Option, Tri-State must deliver written notice (a "Purchase Notice") to Seller within sixty (60) days following determination of Fair Market Value pursuant to this Section 20.3. Once the Purchase Notice has been delivered, the Purchase Option shall be irrevocable.

(J) The closing for purchase and sale of the Facility Assets shall occur on the later of the thirtieth (30th) day following the date of the Purchase Notice and the

fifth (5th) Business Day after the receipt of all required consents and approvals of Governmental Authorities. At the closing:

(1) Seller shall convey to Tri-State good and marketable title to all of the Facility Assets, free and clear of all liens and encumbrances (other than those arising under the terms of the Facility Site Documents and Governmental Approvals), and with such other representations and warranties as may be agreed by the Parties; and

(2) Tri-State shall pay to Seller, in full consideration thereof, an amount in cash equal to the Fair Market Value.

Article 21
Miscellaneous

21.1 Waiver.

The delay or failure of either Party to enforce or insist upon compliance with or strict performance of any of the terms or conditions of this PPA, or to exercise or take advantage of any of its rights, including any right to terminate this PPA, shall not constitute a waiver or relinquishment of any such terms, conditions, or rights, but the same shall be and remain at all times in full force and effect.

21.2 Fines and Penalties.

(A) Seller shall pay when due all fees, fines, penalties or costs incurred by Seller or its agents, employees or contractors for noncompliance by Seller or the Facility, its employees, or subcontractors with any provision of this PPA, or any contractual obligation, permit or requirements of Applicable Law except for such fines, penalties and costs that are being actively contested in good faith and with due diligence by Seller and for which adequate financial reserves have been set aside to pay such fines, penalties or costs in the event of an adverse determination.

(B) If fees, fines, liens, penalties, or costs are claimed or assessed against Tri-State by any Governmental Authority due to noncompliance by Seller or the Facility with this PPA, any requirements of Applicable Law, any permit or contractual obligation, or, if the work of Seller or any of its contractors or subcontractors is delayed or stopped by order of any Governmental Authority due to Seller's noncompliance with any requirements of Applicable Law, permit, or contractual obligation, Seller shall indemnify and hold Tri-State harmless against any and all losses, liabilities, damages, and claims suffered or incurred by Tri-State, including claims for indemnity or contribution made by third parties against Tri-State, except to the extent Tri-State recovers any such losses, liabilities or damages through other provisions of this PPA.

21.3 Disclaimer of Third Party Beneficiary Rights.

In executing this PPA, Tri-State does not, nor should it be construed to, extend its credit or financial support for the benefit of any third parties lending money to or having other transactions with Seller. Nothing in this PPA shall be construed to create any duty to, or standard of care with reference to, or any liability to, any Person not a party to this PPA.

21.4 Relationship of the Parties.

(A) This PPA shall not be interpreted to create an association, joint venture, or partnership between the Parties nor to impose any partnership obligation or liability upon either Party. Except as specifically provided in Section 12.5, neither Party shall have any right, power, or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as an agent or representative of, the other Party.

(B) Seller shall be solely liable for the payment of all wages, taxes, and other costs related to the employment of Persons to perform Seller's obligations under this PPA, including all federal, state, and local income, social security, payroll, and employment taxes and statutorily mandated workers' compensation coverage. None of the Persons employed by Seller shall be considered employees of Tri-State for any purpose; nor shall Seller represent to any Person that he or she is or shall become a Tri-State employee.

21.5 Severability.

In the event any of the terms, covenants, or conditions of this PPA, its Exhibits, or the application of any such terms, covenants, or conditions, shall be held invalid, illegal, or unenforceable by any court or administrative body having jurisdiction, all other terms, covenants, and conditions of this PPA and their application not adversely affected thereby shall remain in force and effect; *provided, however,* that Tri-State and Seller shall negotiate in good faith to attempt to implement an equitable adjustment in the provisions of this PPA with a view toward effecting the purposes of this PPA by replacing the provision that is held invalid, illegal, or unenforceable with a valid provision the economic effect of which comes as close as possible to that of the provision that has been found to be invalid, illegal or unenforceable.

21.6 Complete Agreement; Amendments.

The terms and provisions contained in this PPA constitute the entire agreement between Tri-State and Seller with respect to the Facility and shall supersede all previous communications, representations, or agreements, either verbal or written, between Tri-State and Seller with respect to the sale of Contract Energy. This PPA may be amended, changed, modified, or altered, *provided* that such amendment, change, modification, or alteration shall be in writing and signed by both Parties.

21.7 Binding Effect.

This PPA, as it may be amended from time to time pursuant to this Article 21, shall be binding upon and inure to the benefit of the Parties and their respective successors-in-interest, legal representatives, and assigns permitted hereunder.

21.8 Headings.

The table of contents, captions and headings used in this PPA are for ease of reference only and do not constitute a part of this PPA.

21.9 Counterparts.

This PPA may be executed in any number of counterparts, and each executed counterpart shall have the same force and effect as an original instrument.

21.10 Governing Law.

The interpretation and performance of this PPA and each of its provisions shall be governed and construed in accordance with the laws of the State of Colorado. The Parties hereby submit to the exclusive jurisdiction in the federal and state courts of the State of Colorado, and venue is hereby stipulated as Denver, Colorado.

21.11 Mobile-Sierra.

Notwithstanding any other provision of this PPA to the contrary, neither Party shall seek, nor shall they support any third party seeking, to prospectively or retroactively revise the rates, terms or conditions of service of this PPA through application or complaint to FERC pursuant to the provisions of Section 205, 206 or 306 of the Federal Power Act, or any other provisions of the Federal Power Act, absent prior written agreement of the Parties. Further, absent the prior written agreement in writing by both Parties, the standard of review for changes to the rates, terms or conditions of service of this PPA proposed by a Party shall be the "public interest" standard of review set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956) and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956), as interpreted in *Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. 1,* 128 S. Ct. 2733 (2008). Changes proposed by a non-Party or FERC acting *sua sponte* shall be subject to the most stringent standard permissible under Applicable Law.

[Signature Page Follows]

IN WITNESS WHEREOF, the Parties have executed this PPA as of the date first written above.

Seller:

_____

By: _____

Printed Name: _____

Title:_____

Tri-State:

Tri-State Generation and Transmission Association, Inc.

By: _____

Printed Name:

Title: Chief Executive Officer

EXHIBIT A

PROJECT MILESTONES

Date	**Construction Milestones**
10 Days after the Effective Date	Seller shall have established the Security in accordance with Article 11.
[_____]	Seller shall have delivered a fully executed EPC Contract to Tri-State.
[_____]	[*wind only-* Seller shall have provided Tri-State with copies of Determinations of No Hazard from the Federal Aviation Administration for the Units.]
[_____]	Seller shall have provided Tri-State with documentation that all Seller required Governmental Approvals have been obtained or will be obtained by the time needed to meet all Construction Milestones.
[_____]	Seller shall have entered into Financing Documents and having achieved or obtained waivers with respect to all conditions precedent to the initial availability for disbursement of funds under the Financing Documents.
[_____]	Seller shall have commenced construction of the Facility (all Seller required Governmental Approvals required to construct Facility shall have been obtained and are in full force and effect, except for minor Seller required Governmental Approvals that are expected to be obtained in the ordinary course, the failure of which to obtain would not adversely affect the construction and/or operation of the Facility).
[_____]	Delivery of major components to the Site shall have commenced.
[_____]	Seller shall have provided Tri-State with copies of the executed Operation and Maintenance Agreement, if applicable
[_____]	The step-up transformer shall have been delivered to the Site.
[_____]	Seller shall have completed construction of Seller's Interconnection Facilities and such facilities are capable of being energized.
[_____]	Start-up testing of the Units shall have commenced.

Commercial Operation Milestone

[_____] The Facility shall have achieved Commercial Operation.

EXHIBIT B

FACILITY DESCRIPTION AND SITE MAPS

Required Items:

Location of Electric Interconnection Point (see definition of Point of Delivery)

A detailed description of the Facility, including identification of the major equipment and components that will make up the Facility (see Section 3.1)

A scaled map that identifies the Site and the location of the Units on the Site and a drawing identifying the location of the Electric Interconnection Point, the Point of Delivery, important ancillary facilities and Interconnection Facilities (See Section 3.2)

EXHIBIT C

CONTRACT ENERGY RATE

EXHIBIT D

INSURANCE COVERAGE

Type of Insurance	Minimum Limits of Coverage
1. Commercial General Liability ("CGL") and commercial umbrella	$15,000,000 per occurrence and aggregate. If CGL insurance contains a general aggregate limit, it shall apply separately to the Facility.

CGL insurance shall be written on ISO occurrence form CG 00 01 01 96 (or a substitute form providing similar coverage) and shall cover liability arising from premises, operations, independent contractors, products/completed operations, contracts, property damage, personal injury and advertising injury, and liability assumed under an insured contract (including the tort liability of another assumed in a business contract). There shall be no endorsement or modification limiting coverage for liability assumed under an insured contract. There shall be no endorsement or modification of the CGL insurance limiting the scope of coverage for liability arising from explosion, collapse, or underground property damage.

Tri-State shall be included as an additional insured under the CGL policy, using ISO additional insured endorsement CG 20 10 (or a substitute providing similar coverage), and under the commercial umbrella insurance. The commercial umbrella insurance shall provide coverage over the top of the CGL insurance, the Business Automobile Liability insurance.

The CGL and commercial umbrella insurance to be obtained by or on behalf of Seller shall be:

primary as respects any claims, losses, damages, expenses, or liabilities arising out of this PPA.

2 Environmental/Pollution Liability insurance either stand alone or as part of the CGL/commercial umbrella	At least $5,000,000 each occurrence

Environmental/Pollution Liability insurance shall protect against bodily injury and property damage claims arising out of pollution. The policy through its language or by endorsement, shall include coverage for contractual liability.

3. Business Automobile Liability	$1,000,000 combined single limit (each accident), including Non-Owned and Hired Autos.

Business Automobile Liability insurance shall be written on ISO form CA 00 01, CA 00 05, CA 00 12, CA 00 20, or a substitute form providing similar liability coverage. If necessary, the policy shall be endorsed to provide contractual liability coverage equivalent to that provided in the 1990 and later editions of CA 00 01. If transporting hazardous waste/materials from the Site, an appropriate MCS-90 Endorsement must be attached with $10,000,000 limits of liability.

4. Workers' Compensation	Statutory Requirements. Seller may comply with these requirements through its project operator.

EXHIBIT D

INSURANCE COVERAGE

Type of Insurance	**Minimum Limits of Coverage**
5. Employers' Liability, if Seller maintains employees (or a certification from Seller that is maintains no employees)	Bodily Injury by Accident, $1,000,000 each accident Bodily Injury by Disease, $1,000,000 policy limit Bodily Injury by Disease, $1,000,000 each employee

6. Builders All Risk insurance coverage	For the full value of Facility.

Builders All Risk insurance shall include coverage carried by either Seller or the EPC Contractor, without limitation against the perils of fire and physical loss or damage including, without duplication of coverage, theft, vandalism, malicious mischief, collapse, water, falsework, testing and startup, for entire period of construction, which shall cover the interests of Indemnified Parties until the Commercial Operation Date, and insurance coverage as set forth in 7 below is provided. A certificate of Builders Risk insurance shall be provided to Tri-State regardless of who procures coverage.

7. All-Risk Property insurance covering physical loss or damage to the Facility	Full Replacement Value of the Facility. A deductible may be carried, which deductible shall be the absolute responsibility of Seller.

All-Risk Property insurance shall include: (i) coverage for fire, flood, wind and storm, tornado and earthquake; (ii) Boiler and Machinery insurance covering all objects customarily subject to such insurance, including boilers and engines, and (iii) business interruption to cover loss of providing Energy to Tri-State should Seller not be able to produce or provide electrical energy as agreed to herein. Tri-State shall be named as a loss payee as to its interests under this PPA.

Seller shall require its contractors and subcontractors to purchase and maintain commercial general liability including environmental coverage within or as a separate policy in an amount commensurate with type of work to be performed and automobile, workers' compensation and employers liability insurance of the types and amounts specified above. If requested by Tri-State, Seller shall furnish copies of certificates of insurance evidencing such coverage.

EXHIBIT E

PROJECT CONTRACTS

[Seller to Provide]

1. Generator Interconnection Agreement

2.

EXHIBIT F

SELLER'S REQUIRED GOVERNMENTAL APPROVALS

[Seller to Provide]

Tri-State 11/19/2020
Model Renewable PPA

EXHIBIT G

MONTHLY PRODUCTION PERCENTAGE OF EXPECTED CONTRACT ENERGY

Calendar Month	Monthly Production %
January	
February	
March	
April	
May	
June	
July	
August	
September	
October	
November	
December	

EXHIBIT H

OPERATING COMMITTEE REPRESENTATIVES

Tri-State	Seller
Primary Representative: Origination Manager Tri-State Generation and Transmission Association, Inc. 1100 W. 116th Avenue Westminster, CO 80234 Phone: (303) 254-_____ Email: _____@tristategt.org	**Primary Representative:**
Alternative Representative: Senior Manager, Energy Resources Tri-State Generation and Transmission Association, Inc. 1100 W. 116th Avenue Westminster, CO 80234 Phone: (303) 254-_____ Email: _____@tristategt.org	**Alternative Representative:**

Tri-State 11/19/2020 Model Renewable PPA

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EXHIBIT I

NOTICE ADDRESSES

Tri-State	Seller
Notices: Chief Executive Officer Tri-State Generation and Transmission Association, Inc. 1100 W. 116th Avenue Westminster, CO 80234 Telephone: (303) 452-6111 with a copy to (at the same address): Senior Vice President and General Counsel	**Notice**:

EXHIBIT J

FORM OF ATTESTATION AND BILL OF SALE

_____ ("Seller") hereby sells, transfers and delivers to Tri-State Generation and Transmission Association, Inc. ("Tri-State") the Environmental Attributes associated with the generation of Contract Energy, as detailed in the Energy Purchase Agreement for the _____ Project between the Parties, dated _____ (the "Agreement"). Terms used, but not defined herein, shall have the meaning set forth in the Agreement.

_____
Name of Renewable Energy Facility

_____	_____	_____
Type/Resource	Nameplate Capacity Rating (MW)	Commercial Operation Date

_____ - _____ (from) (to)
Dates

_____
MWh generated

One (1) REC represents the REC and Environmental Attributes reporting rights associated with one (1) MWh generated from the Facility.

Seller further attests, warrants and represents as follows:

i) each REC and Environmental Attribute is free and clear of any liens, encumbrances and/or defects of title;

ii) none of the RECs or Environmental Attributes has been retired, claimed or represented as part of electricity output or sales by Seller, or used to satisfy obligations in any other jurisdiction;

iii) its sale to Tri-State is its one and only sale of the RECs and Environmental Attributes with respect to the Contract Energy referenced herein, after due inquiry, no third party has claimed nor can claim any interest in such RECs or Environmental Attributes;

iv) the Facility identified above produced the number of MWh above during the period indicated above;

v) Seller has title to and ownership of the RECs and Environmental Attributes sold hereunder; and

vi) Seller owns the _____.
Name of the Renewable Energy Facility

This serves as a bill of sale, transferring from Seller to Tri-State all of Seller's right, title and interest in and to the RECs and Environmental Attributes associated with the generation of the above referenced Contract Energy.

Contact Person: _____

phone: _____; fax: _____

[Seller]

Signed: _____

Name: _____

Title: _____

Date: _____

EXHIBIT K

FORM OF LETTER OF CREDIT

[LETTERHEAD OF ISSUING BANK]

IRREVOCABLE LETTER OF CREDIT NO _____

DATE OF ISSUANCE: _____

INITIAL EXPIRATION DATE: [Must be at least ONE YEAR after Date of Issuance]

BENEFICIARY:
TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

APPLICANT:
[NAME OF APPLICANT]

ATTN: CREDIT RISK ADMINISTRATOR
1100 W. 116TH AVENUE
WESTMINSTER, CO 80234

[APPLICANT ADDRESS]

1. AS THE ISSUING BANK ("ISSUER"), WE, [NAME OF ISSUING BANK], HEREBY ESTABLISH AND ISSUE THIS IRREVOCABLE STANDBY LETTER OF CREDIT NO. _____ IN FAVOR OF THE ABOVE-NAMED BENEFICIARY ("BENEFICIARY") FOR THE ACCOUNT OF THE ABOVE-NAMED APPLICANT ("APPLICANT") IN THE MAXIMUM AGGREGATE AMOUNT OF USD $_____ (_____ U.S. DOLLARS).

2. ISSUER UNDERTAKES TO BENEFICIARY TO PAY BENEFICIARY'S DEMAND FOR PAYMENT OF AN AMOUNT AVAILABLE UNDER THIS LETTER OF CREDIT, UPON PRESENTATION OF A DEMAND FOR PAYMENT SUBSTANTIALLY IN THE FORM OF EXHIBIT "A," ATTACHED HERETO, DULY COMPLETED AS INDICATED, AT THE FOLLOWING PLACE FOR PRESENTATION: [ADDRESS OF PLACE FOR PRESENTATION], AT ANY TIME ON OR BEFORE 5:00 PM (_____ TIME) ON THE EXPIRATION DATE.

DEMAND FOR PAYMENT MAY ALSO BE PRESENTED BY FACSIMILE ("FAX") TO FAX NO._____ PROVIDED THAT SUCH FAX PRESENTATION IS MADE AT ANY TIME ON OR BEFORE 5:00 PM (_____ TIME) ON THE EXPIRATION DATE. ISSUER WILL ACKNOWLEDGE RECEIPT OF BENEFICIARY'S PRESENTMENT WITHIN FOUR (4) BUSINESS HOURS TO THE EMAIL ADDRESS PROVIDED TO ISSUER IN THE FAX DRAW CERTIFICATE.

IF THE AMOUNT IN THE DRAW CERTIFICATE EXCEEDS THE AMOUNT AVAILABLE, BUT THE PRESENTATION OTHERWISE COMPLIES, ISSUER UNDERTAKES TO PAY THE AMOUNT AVAILABLE.

NO OTHER DOCUMENTS WILL BE REQUIRED TO BE PRESENTED. PAYMENT MADE HEREUNDER SHALL BE MADE IN U.S. DOLLARS IN IMMEDIATELY AVAILABLE FUNDS.

3. PARTIAL AND MULTIPLE DRAWS AND PRESENTATIONS ARE PERMITTED, PROVIDED THAT THE AVAILABLE AMOUNT OF THIS LETTER OF CREDIT SHALL BE PERMANENTLY REDUCED BY THE AMOUNT OF EACH SUCH DRAW.

4. THIS LETTER OF CREDIT IS ISSUED PURSUANT TO THE PROVISIONS OF THAT CERTAIN ENERGY PURCHASE AGREEMENT BETWEEN THE BENEFICIARY AND THE APPLICANT DATED AS OF _____, 20__ (AS THE SAME MAY HAVE BEEN OR MAY BE AMENDED FROM TIME TO TIME, THE "PPA"). NOTWITHSTANDING ANY REFERENCE IN THIS LETTER OF CREDIT TO THE PPA OR ANY OTHER DOCUMENTS, INSTRUMENTS OR AGREEMENTS, OR REFERENCES IN THE PPA OR ANY OTHER DOCUMENTS, INSTRUMENTS OR AGREEMENTS TO THIS LETTER OF CREDIT, THIS LETTER OF CREDIT CONTAINS THE ENTIRE AGREEMENT BETWEEN BENEFICIARY AND ISSUER RELATING TO THE OBLIGATIONS OF ISSUER HEREUNDER.

5. THIS LETTER OF CREDIT WILL BE AUTOMATICALLY EXTENDED EACH YEAR WITHOUT AMENDMENT FOR A PERIOD OF ONE YEAR FROM THE EXPIRATION DATE HEREOF, AS EXTENDED, UNLESS AT LEAST FORTY-FIVE (45) DAYS PRIOR TO THE EXPIRATION DATE, ISSUER NOTIFIES BENEFICIARY AND APPLICANT BY A NATIONALLY RECOGNIZED OVERNIGHT COURIER OR CERTIFIED MAIL THAT IT ELECTS NOT TO EXTEND THIS LETTER OF CREDIT FOR SUCH ADDITIONAL PERIOD (THE PRESENT OR ANY FUTURE EXPIRATION DATE AS AFORESAID IS REFERRED TO HEREIN AS THE "EXPIRATION DATE"). NOTICE OF NON-EXTENSION WILL BE GIVEN BY ISSUER TO BENEFICIARY AT BENEFICIARY'S ADDRESS SET FORTH HEREIN OR AT SUCH OTHER ADDRESS AS BENEFICIARY MAY DESIGNATE TO ISSUER IN WRITING AT ISSUER'S LETTERHEAD ADDRESS.

6. ISSUER UNDERTAKES TO MAKE PAYMENT AGAINST A COMPLYING PRESENTATION WITHIN THREE BUSINESS DAYS AFTER PRESENTATION. THE BENEFICIARY SHALL RECEIVE PAYMENT BY WIRE TRANSFER TO A BANK ACCOUNT OF THE BENEFICIARY. FOR THE PURPOSES HEREOF, "BUSINESS DAY" SHALL MEAN ANY DAY ON WHICH COMMERCIAL BANKS IN COLORADO ARE NOT AUTHORIZED OR REQUIRED TO CLOSE.

7. THIS LETTER OF CREDIT IS FREELY TRANSFERABLE TO AN ASSIGNEE AND THE NUMBER OF TRANSFERS IS UNLIMITED. SUBJECT TO COMPLIANCE WITH APPLICABLE LAWS, ISSUER AGREES THAT IT WILL EFFECT ANY TRANSFERS IMMEDIATELY UPON PRESENTATION TO ISSUER OF THIS LETTER OF CREDIT AND A COMPLETED WRITTEN TRANSFER REQUEST SUBSTANTIALLY IN THE FORM OF EXHIBIT "B," ATTACHED HERETO, DULY COMPLETED AS INDICATED. SUCH TRANSFER WILL BE EFFECTED AT NO COST TO BENEFICIARY. ANY TRANSFER FEES ASSESSED BY ISSUER WILL BE PAYABLE SOLELY BY APPLICANT, AND THE PAYMENT OF ANY TRANSFER FEES WILL NOT BE A CONDITION TO THE VALIDITY OR EFFECTIVENESS OF THE TRANSFER OR THIS LETTER OF CREDIT.

8. THIS LETTER OF CREDIT IS SUBJECT TO THE INTERNATIONAL STANDBY PRACTICES 1998 ("ISP98") (INTERNATIONAL CHAMBER OF COMMERCE PUBLICATION NO. 590), EXCEPT TO THE EXTENT THAT THE TERMS HEREOF ARE INCONSISTENT WITH THE PROVISIONS OF THE ISP98. AS TO MATTERS NOT COVERED BY THE ISP98, THIS LETTER OF CREDIT SHALL BE GOVERNED AND CONSTRUED IN ACCORDANCE WITH

THE LAWS OF THE STATE OF COLORADO, WITHOUT REGARD FOR THE PRINCIPLES OF CONFLICTS OF LAWS THEREUNDER.

9. ISSUER'S CHARGES AND FEES FOR ISSUING, AMENDING, OR HONORING THIS LETTER OF CREDIT ARE FOR APPLICANT'S ACCOUNT AND SHALL NOT BE DEDUCTED FROM ANY PAYMENT ISSUER MAKES UNDER THIS LETTER OF CREDIT.

ISSUER:

By: _____
AUTHORIZED SIGNATURE
Its:_____

EXHIBIT "A"
(TO LETTER OF CREDIT)

FORM OF DEMAND FOR PAYMENT

[ISSUING BANK NAME] DATE:
[ISSUING BANK ADDRESS]

LADIES AND GENTLEMEN:

THIS DEMAND FOR PAYMENT IS PRESENTED BY THE UNDERSIGNED BENEFICIARY UNDER THE IRREVOCABLE LETTER OF CREDIT NO. _____, DATED _____ (THE "LETTER OF CREDIT"), ISSUED BY _____ ("ISSUER") FOR THE AMOUNT OF U.S. DOLLARS _____ AND ____/100THS (U.S.$_____), WHICH CONSTITUTES A PAYMENT OF THE FUNDS AVAILABLE TO THE BENEFICIARY UNDER THE LETTER OF CREDIT.

1. UNDER THIS DEMAND FOR PAYMENT, THE BENEFICIARY STATES [CHECK APPLICABLE]:

   [___] BENEFICIARY IS OWED BY APPLICANT THE AMOUNT DEMANDED UNDER THE AGREEMENT BETWEEN BENEFICIARY AND APPLICANT TITLED _____ AND DATED _____, WHICH AMOUNT REMAINS DUE AS OF THE DATE OF THIS DEMAND FOR PAYMENT.

   [___] THE ISSUER HAS GIVEN WRITTEN NOTICE PURSUANT TO THE LETTER OF CREDIT OF ITS INTENT NOT TO EXTEND THE LETTER OF CREDIT FOLLOWING THE PRESENT EXPIRATION DATE THEREOF AND THE CURRENT EXPIRY DATE OF THIS LETTER OF CREDIT IS WITHIN THIRTY (30) DAYS AND THE AMOUNT DEMANDED IS REQUIRED TO SECURE THE OBLIGATIONS OF APPLICANT UNDER THE AGREEMENT BETWEEN BENEFICIARY AND APPLICANT TITLED _____ AND DATED _____.

2. BENEFICIARY REQUESTS THE AMOUNT DEMANDED HEREUNDER BE TRANSFERRED TO BENEFICIARY BY WIRE TRANSFER TO THE FOLLOWING BANK ACCOUNT OF THE BENEFICIARY:

   _____
   _____
   _____

[3. ISSUER ACKNOWLEDGEMENT OF BENEFICIARY'S PRESENTMENT BY FAX SHALL BE SENT TO BENEFICIARY AT _____@TRISTATEGT.ORG.]

BENEFICIARY:

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

BY: _____
NAME: _____
TITLE: _____

EXHIBIT "B"
(TO LETTER OF CREDIT)

FORM OF TRANSFER REQUEST

IRREVOCABLE LETTER OF CREDIT NO: _____

CURRENT BENEFICIARY:

APPLICANT:

TO: [NAME OF ISSUING BANK]

THE UNDERSIGNED, AS THE CURRENT "BENEFICIARY" OF THE ABOVE REFERENCED LETTER OF CREDIT, HEREBY REQUESTS THAT YOU REISSUE THE LETTER OF CREDIT IN FAVOR OF THE TRANSFEREE NAMED BELOW [INSERT TRANSFEREE NAME AND ADDRESS BELOW]:

FROM AND AFTER THE DATE THIS TRANSFER REQUEST IS DELIVERED TO THE ISSUER, THE TRANSFEREE SHALL BE THE "BENEFICIARY" UNDER THE LETTER OF CREDIT FOR ALL PURPOSES AND SHALL BE ENTITLED TO EXERCISE AND ENJOY ALL OF THE RIGHTS, PRIVILEGES AND BENEFITS THEREOF.

DATED: _____

[NAME OF BENEFICIARY]

By:
Name:
Title:

EXHIBIT L

FORM OF GUARANTY

This Guaranty is executed and delivered as of this _____ day of _____, 20__ by _____, a _____ ("Guarantor"), in favor of Tri-State Generation and Transmission Association, Inc. ("Company"), in connection with the performance by _____, a _____ _____ ("Seller") of that certain Energy Purchase Agreement for the _____, dated _____, 20__, TS-__-____, by and between Seller and Company (the "PPA"). Capitalized terms used but not defined herein shall have the meanings set forth in the PPA.

RECITALS

A. Seller is planning to develop, design, construct, own, operate, and maintain a _____-powered electric energy generating facility having an Expected Nameplate Capacity Rating of _____ MW AC to be located in _____ County, _____ (the "Facility").

B. Seller and Company have entered into the PPA for the purchase and sale of capacity and electrical energy from the Facility on the terms and conditions set forth therein.

C. This Guaranty is delivered to the Company pursuant to Section 11.1(A) of the PPA.

D. To induce Company to enter into the PPA and consummate the purchase and sale of electrical energy contemplated by the PPA, Guarantor has agreed to guarantee the obligations of Seller as provided in this Guaranty.

NOW, THEREFORE, in consideration of the foregoing and for good and valuable consideration, Guarantor hereby agrees as follows:

AGREEMENT

1. Guaranty. Subject to the provisions of this Guaranty, Guarantor hereby absolutely, irrevocably, unconditionally, and fully guarantees to Company the due, prompt, and complete observance, performance, and discharge of each and every payment obligation of Seller under the PPA, whether incurred before or after the date of delivery of this Guaranty (the "Obligations"). This is a guaranty of payment, not of collection, and as such, Company shall not be required to institute, pursue, or exhaust any remedies against Seller before instituting suit, obtaining judgment, and executing thereon against Guarantor under this

Guaranty. In furtherance of the foregoing and without limiting the generality thereof, Guarantor agrees as follows:

a. The liability of Guarantor under this Guaranty is not conditional or contingent upon the genuineness, validity, regularity or enforceability of the PPA or the pursuit by Company of any remedies which it now has or may hereafter have under the PPA;
b. Company may enforce this Guaranty upon the occurrence of a default by Seller under the PPA notwithstanding the existence of a dispute between Company and Seller with respect to the existence of the default;
c. The obligations of Guarantor under this Guaranty are independent of the obligations of Seller under the PPA and a separate action or actions may be brought and prosecuted against Guarantor whether or not any action is brought against Seller or any other guarantors and whether or not Seller is joined in any such action or actions;
d. Company may, at its election, foreclose on any security held by Company, or exercise any other right or remedy available to Company without affecting or impairing in any way the liability of Guarantor under this Guaranty, except to the extent the amount(s) owed to Company by Seller have been paid;
e. Guarantor shall continue to be liable under this Guaranty and the provisions hereof shall remain in full force and effect notwithstanding: (i) any modification, amendment, supplement, extension, agreement or stipulation between Seller and Company or their respective successors and assigns, with respect to the PPA or the obligations encompassed thereby; (ii) Company's waiver of or failure to enforce any of the terms, covenants or conditions contained in the PPA; (iii) any release of Seller or any other guarantor from any liability with respect to the Obligations or any portion thereof; (iv) any release, compromise or subordination of any real or personal property then held by Company as security for the performance of the Obligations or any portion thereof, or any substitution with respect thereto; (v) without in any way limiting the generality of the foregoing, if Company is awarded a judgment in any suit brought to enforce a portion of the Obligations, such judgment is not deemed to release Guarantor from its covenant to pay that portion of the Obligations which is not the subject of such suit; (vi) Company's acceptance and/or enforcement of, or failure to enforce, any other guaranties or any portion of this Guaranty; (vii) Company's exercise of any other rights available to it under the PPA; (viii) Company's consent to the change, reorganization or termination of the corporate structure or existence of the Seller and to any corresponding restructuring of the Obligations; (ix) any failure to perfect or continue perfection of a security interest in any collateral that secures the Obligations; and (x) any other act or thing or omission, or delay to do any other act or thing that might in any manner or to any

extent vary the risk of Guarantor as an obligor with respect to the Obligations; and

f. Guarantor agrees that upon a demand for payment under this Guaranty, Guarantor shall pay such Obligations as are included in such demand notwithstanding any defenses, setoffs or counterclaims that Seller may allege or assert against Company with respect to the Obligations, including, without limitation, statute of frauds and accord and satisfaction; provided that Guarantor reserves the right to assert any defenses, setoffs or counterclaims that Seller may allege or assert against Company (except for such defenses, setoffs or counterclaims as are expressly waived under other provisions of this Guaranty) in a subsequent action for recoupment, restitution or reimbursement.

2. Maximum Liability. Notwithstanding anything herein to the contrary, Guarantor's maximum liability under this Guaranty shall be limited to _____ ($_____), plus costs of collection with respect to any valid claim(s) made by Company hereunder that are incurred in the enforcement or protection of the rights of Company.

3. Rights of Company. Guarantor hereby grants to Company, in Company's discretion and without the need to notify or obtain any consent from Guarantor, and without termination, impairment, or any other effect upon Guarantor's duties hereunder, the power and authority from time to time:

   a. to renew, compromise, extend, accelerate, or otherwise change, substitute, supersede, or terminate the terms of performance of any of the Obligations, in each case in accordance with the PPA;
   b. to grant any indulgences, forbearances, and waivers, on one or more occasions, for any length of time, with respect to Seller's performance of any of the Obligations; and
   c. to accept collateral, further guaranties, and/or other security for the Obligations, and, if so accepted, then to impair, exhaust, exchange, enforce, waive, or release any such security.

4. Performance; Payment. If any of the Obligations are not performed according to the tenor thereof, and any applicable notice and cure period provided by the PPA has expired ("Default"), Guarantor shall immediately (but in no event later than three (3) Business Days) upon receipt of written demand by Company (a) perform or cause Seller to perform the Obligation in Default, and (b) pay, reimburse, and indemnify Company against any liabilities, damages, and related costs (including attorneys' fees) incurred by Company as a result thereof, all in such manner and at such times as Company may reasonably direct. All sums payable by Guarantor hereunder shall be made in immediately available funds in U.S. Dollars.

5. Term; Satisfaction.

a. This Guaranty shall continue in full force and effect until the earlier to occur of: (i) the substitution of an alternative form of Security in accordance with the PPA; (ii) the satisfaction of all Obligations of Seller under the PPA; or (iii) the payment by Guarantor, without reservation of rights, of an aggregate amount equal to the maximum liability set forth in Section 2, together with any other amounts required to be paid by Guarantor pursuant to Section 10 hereof.
b. Satisfaction by Guarantor of any duty hereunder incident to a particular Default or the occurrence of any other Default shall not discharge Guarantor except with respect to the Default satisfied, it being the intent of Guarantor that this Guaranty be continuing until such time as all of the Obligations have irrevocably been discharged in full.

6. Bankruptcy. So long as any Obligations remain outstanding, Guarantor may not, without the prior written consent of Company, commence or join with any other person in commencing any bankruptcy, reorganization or insolvency proceedings of or against Seller. The obligations of Guarantor under this Guaranty may not be reduced, limited, impaired, discharged, deferred, suspended or terminated by any proceeding, voluntary or involuntary, involving the bankruptcy, insolvency, receivership, reorganization, liquidation or arrangement of the Seller or by any defense which Seller may have by reason of the order, decree or decision of any court or administrative body resulting from any such proceeding. If at any time the performance of any Obligation by Seller or Guarantor is rescinded or voided under the federal Bankruptcy Code or otherwise, then Guarantor's duties hereunder shall continue and be deemed to have been automatically reinstated, restored, and continued with respect to that Obligation, as though the performance of that Obligation had never occurred, regardless of whether this Guaranty otherwise had terminated or would have been terminated following or as a result of that performance.

7. Waivers by Guarantor. Guarantor hereby waives and agrees not to assert or take advantage of:

a. all set-offs, counterclaims, withholdings or deductions and all presentments, demands for performance, notices of non-performance, protests, and notices of every kind that may be required by Applicable Laws;
b. any right to require Company to proceed against Seller or any other person, or to require Company first to exhaust any remedies against Seller or any other person, before proceeding against Guarantor hereunder;
c. any defense based upon an election of remedies by Company;
d. any duty of Company to protect or not impair any security for the Obligations;

e. any defense based upon promptness, diligence, and any requirement that Company protect, secure, perfect or insure any security interest or lien or any property subject thereto;
f. the benefit of any laws limiting the liability of a surety or any other circumstance that limits the liability of or exonerates a guarantor generally or provides any legal or equitable discharge of Guarantor's obligations hereunder;
g. other than demand for payment, any requirement of notices between Company and Seller including, without limitation, with respect to the PPA and this Guaranty, notice of acceptance of this Guaranty, any notice of credits extended and sales made by Seller to Company, any information regarding Seller's financial condition, and all other notices whatsoever;
h. any duty of Company to disclose to Guarantor any facts concerning Seller, the PPA or the Facility, or any other circumstances, that would or allegedly would increase the risk to Guarantor under this Guaranty, whether now known or hereafter learned by Company, it being understood that Guarantor is capable of and assumes the responsibility for being and remaining informed as to all such facts and circumstances; and
i. until all Obligations in Default have been fully paid and/or performed, any rights of subrogation, contribution, reimbursement, indemnification, or other rights of payment or recovery for any payment or performance by it hereunder. For the avoidance of doubt, if any amount is paid to Guarantor in violation of this provision, such amount shall be held by Guarantor for the benefit of, and promptly paid to, Company.

8. Cumulative Remedies. The rights and remedies of Company hereunder shall be cumulative and not alternative to any other rights, powers, and remedies that Company may have at law, in equity, or under the PPA. The obligations of Guarantor hereunder are independent of those of Seller and shall survive unaffected by the bankruptcy of Seller. Company need not join Seller in any action against Guarantor to preserve its rights set forth herein.

9. Representations and Warranties. Guarantor represents and warrants to Company as follows:

a. Guarantor is a [corporation], duly organized, validly existing, and in good standing under the laws of the state of its [incorporation]. Seller is a direct or indirect wholly-owned subsidiary of Guarantor. Guarantor has all necessary corporate power and authority to execute and deliver this Guaranty and to perform its obligations hereunder.
b. The execution, delivery and performance of this Guaranty has been duly and validly authorized by all corporate proceedings of Guarantor and is not in violation of any law, judgment of court or government agency . This Guaranty has been duly and validly executed and delivered by Guarantor

and constitutes a legal, valid and binding obligation of Guarantor, enforceable against Guarantor in accordance with its terms.

10. Collection Costs. Guarantor hereby agrees to pay to Company, upon demand, and in addition to the maximum liability set forth in Section 2 hereof, all reasonable attorneys' fees and other expenses which Company may expend or incur in enforcing the Obligations against Seller and/or enforcing this Guaranty against Guarantor, whether or not suit is filed, including, without limitation, all attorneys' fees, and other expenses incurred by Company in connection with any insolvency, bankruptcy, reorganization, arrangement, or other similar proceedings involving Seller that in any way affect the exercise by Company of its rights and remedies hereunder.

11. Severability. Should any one or more provisions of this Guaranty be determined to be illegal or unenforceable, all other provisions nevertheless shall be effective.

12. Waiver or Amendment. No provision of this Guaranty or right of Company hereunder can be waived, nor can Guarantor be released from Guarantor's duties hereunder, except by a writing duly executed by Company. This Guaranty may not be modified, amended, revised, revoked, terminated, changed, or varied in any way whatsoever except by the express terms of a writing duly executed by Company.

13. Successors and Assigns. This Guaranty shall inure to the benefit of and bind the successors and assigns of Company and Guarantor. Guarantor shall have no right to assign this Guaranty or its obligations hereunder without the prior written consent of Company, which consent may be withheld in its sole discretion. Company shall have the right to assign this Guaranty to any person or entity without the prior written consent of Guarantor; *provided*, *however*, that no such assignment shall be binding upon Guarantor until it receives written notice of such assignment from Company.

14. Governing Law. This Guaranty shall be governed by and construed in accordance with the law of the State of Colorado without regard to the principles of conflicts of law thereof. Guarantor hereby submits to the exclusive jurisdiction in the federal and state courts of the State of Colorado, and venue is hereby stipulated as Denver, Colorado. Guarantor waives any claim or defense that such action or proceeding brought in any such court is an inconvenient forum, any objection to venue with respect to such action or proceeding, and any right of jurisdiction on the account of the place of residence or domicile of the Guarantor.

15. Notices. All notices, requests, claims, demands, and other communications hereunder shall be in writing and shall be given (and shall be deemed to have been duly given upon receipt) by delivery in the manner contemplated by the PPA, addressed as follows:

if to Company: Tri-State Generation and Transmission Association, Inc.
1100 W. 116th Avenue
Westminster, CO 80234
Attn: Senior Vice President and Chief Financial Officer
Phone: (303) 452-6111

if to Guarantor: _____
_____
_____
Attn:
Phone: (___) _____

or to such other address(es) as the person to whom notice is given may have previously furnished to the others in writing in the manner set forth above.

IN WITNESS WHEREOF, Guarantor has caused this Guaranty to be duly executed and delivered to Company as of the day and year first above written.

[Name of Guarantor]

By:_____
Name:
Title:

STATE OF_____)
) ss.
COUNTY OF _____)

The foregoing instrument was acknowledged before me this _____ day of _____, 20__, by _____, as _____ of _____.

Witness my hand and official seal.

My commission expires:_____.

_____
Notary Public

(S E A L)

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit G: CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Attachment BN-1
(Tri-State, *Responsible Energy Plan* (Jan. 2020)

Released January 2020

TRI-STATE

RESPONSIBLE ENERGY PLAN

RESPONSIBLE TO OUR EMPLOYEES, OUR MEMBERS, OUR COMMUNITIES, AND OUR ENVIRONMENT

Cooperative power. Transformed.

Colorado PUC E-Filings System



To learn more about our Responsible Energy Plan, visit **www.tristate.coop**

A Touchstone Energy® Cooperative

TRI-STATE

Tri-State Generation and Transmission Association Responsible Energy Plan

Responsible to our employees, our members, our communities, and our environment

At Tri-State, we're implementing a clean energy transition that will expand renewable generation and reduce greenhouse gas emissions while ensuring reliable, affordable, responsible electricity for our member cooperatives and public power districts, and for the communities they serve. Our Responsible Energy Plan (REP) is based on a vision for the future in which the benefits of an economy-wide energy transition – from cleaner air to economic opportunity to a greener grid – are shared with everyone.

As a cooperative, we're owned and governed by our members, and we're accountable to them and their retail consumers. Our member-comprised board of directors established in July 2019 that our cooperative would pursue a transition to a cleaner energy portfolio by developing a Responsible Energy Plan. The board set a goal for our cooperative to comply with all applicable environmental and renewable energy requirements while striving to reduce members' rates, preserve electricity reliability and affordability, and maintain financial strength. We've been working together since then to develop a REP that reflects this direction. Our plan is also informed by input from a collaboration with an external advisory group – convened and facilitated by Colorado Governor Bill Ritter and the Center for the New Energy Economy – composed of stakeholders gathered from across the region and across interests.

Our Responsible Energy Plan allows Tri-State to work toward the commitments and goals that follow and be responsible to our employees, our members, our communities, and our environment.

While this energy transition comes with challenges, we are confident that by working together and maintaining our commitment to our mission — to provide reliable, affordable, responsible power to our members — we can make it a success.

Tri-State's Responsible Energy Plan outlines an energy transition that makes it possible for us to deliver on our mission while achieving compliance with state and federal regulations. It will ensure significant emission reductions while maintaining our strong financial position and competitive rates in all four states we serve. As a cooperative wholesale electricity provider serving, owned by and governed by members in Colorado, Nebraska, New Mexico, and Wyoming, this regional view was a key consideration as we developed this plan and determined how we would accomplish the commitments and goals we identified.

REDUCING EMISSIONS

We're eliminating 100% of emissions from our New Mexico coal facilities by closing Escalante Station by the end of 2020, and we're eliminating 100% of emissions from our Colorado coal facilities by closing Craig Station and the Colowyo Mine by 2030.

INCREASING CLEAN ENERGY

By 2024, we're bringing over 1 gigawatt of wind and solar resources online, meaning 50% of the energy our cooperative consumes will come from renewables.

INCREASING MEMBER FLEXIBILITY

Our members are working together to increase contract flexibility and options to develop more local renewable generation.

EXTENDING THE BENEFITS OF A CLEAN GRID

We're helping consumers save money and reduce emissions.

COMMITTING TO COMMUNITY AND EMPLOYEES

We're committed to supporting employee and community transition.

LOOKING FORWARD TO A BRIGHTER FUTURE

We're working together to bring this bright future and clean grid in reach.

Tri-State Generation and Transmission Association is a not-for-profit wholesale electric cooperative association of 45 members, including 42 electric distribution cooperatives and public power districts across Colorado, Nebraska, New Mexico, and Wyoming.

Tri-State and our members power more than a million predominantly rural consumers across nearly 200,000 square miles of the West — an area greater than California.

Our mission is to provide our member systems a reliable, affordable and responsible supply of electricity in accordance with cooperative principles.

REDUCING EMISSIONS

In New Mexico, we're committing to a 100% reduction in emissions from coal generation by closing Escalante Station by the end of 2020, in support of New Mexico's SB19-489 zero carbon by 2050 goal

In Colorado, we're committing to a 100% reduction in emissions from coal generation by closing Craig Station and the Colowyo Mine by 2030, in support of Colorado's HB19-1261 emission reduction goals

In Colorado, we anticipate working with the General Assembly to achieve, by 2030 and relative to 2005 levels:

- **A 90% reduction in CO_2 emissions across the generation facilities we own or operate in Colorado, and**
- **A 70% reduction in CO_2 emissions associated with Colorado wholesale electric sales**

We're committing not to add more coal to our system

Our cooperative is working to shift our generation portfolio to cleaner energy sources to meet member demand, comply with environmental regulations in Colorado and New Mexico, and in response to a changing energy landscape. We believe it is possible to provide reliable, affordable, responsible power to our members while implementing these emission reduction steps to meet broader public policy goals. With engagement and support from partners like the Colorado General Assembly and other natural resource stakeholders, we can achieve an efficient, cost-effective and equitable transition.



KEY STEPS:

- **Retire Escalante Generating Station by the end of 2020**
- **Retire Craig Station Unit 1 by the end of 2025**
- **Retire Craig Station Units 2 & 3 and the Colowyo Mine by 2030**
- **Cancel the Holcomb Station coal expansion project**

ADVISORY GROUP

To develop our REP commitments, we collaborated with a diverse advisory group, facilitated by Colorado State University's Center for the New Energy Economy (CNEE) and Colorado Governor Bill Ritter, on key elements regarding emission reductions. This group included representatives from across the states Tri-State serves from academic, agricultural, cooperative, electric industry, environmental, rural, and state and local government groups. These advisors gathered to learn with us, share with us, challenge us, and roll up their sleeves to work with us on some of the details that will make our energy transition vision a reality. We are grateful to Governor Ritter and the CNEE advisory group participants for their good-faith contributions and efforts to find common ground in the pursuit of ambitious but actionable commitments and challenging but attainable goals, as reflected here.

CNEE ADVISORY GROUP INVITEES

- Dan Arvizu, New Mexico State University
- Kim Christiansen, Nebraska Rural Electric Association
- Bob Easton, Western Area Power Administration (retired)
- Howard Geller, Southwest Energy Efficiency Project
- Megan Gilman, Holy Cross Energy Board
- Keven Groenewold, New Mexico Rural Electric Cooperative Association
- Renny MacKay, Wyoming Governor's Office
- Jim Macy, Nebraska Department of Environment & Energy
- John Nielsen, Western Resource Advocates
- Sarah Cottrell Propst, New Mexico Department of Energy, Minerals & Natural Resources
- John Putnam, Colorado Department of Public Health & Environment
- Kent Singer, Colorado Rural Electric Association
- John Stulp, Agriculture & Rural Communities Representative
- John Swartout, Colorado Counties, Inc.
- Shawn Taylor, Wyoming Rural Electric Association
- Will Toor, Colorado Energy Office
- Colorado Public Utilities Commission (PUC) observed

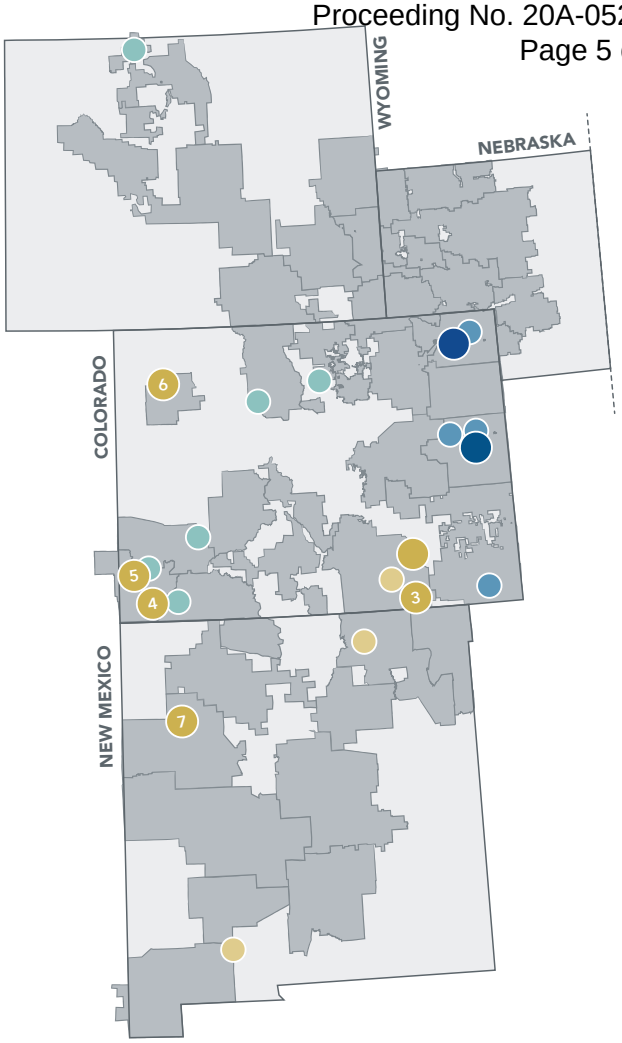
INCREASING CLEAN ENERGY

By 2024, 50% of the energy our cooperative consumes will come from renewable resources

Our members have asked for more renewable resources, so as we accelerate retirement of our coal generation, we're replacing it with clean energy in locations across our members' service territories. To start, we're adding six utility-scale solar projects and two utility-scale wind projects, bringing our system up to over 2 gigawatts of renewables by 2024. This will include the most solar of any cooperative in the nation.

KEY STEPS

- **Bring over 1 gigawatt of additional utility-scale renewable wind and solar projects online by 2024 in seven of our members' service territories — enough to power nearly 850,000 homes**



Projects coming online by 2024

1. Niyol Wind, 200 MW
2. Crossing Trails Wind, 104 MW
3. Spanish Peaks II Solar, 40 MW
4. Coyote Gulch Solar, 120 MW
5. Dolores Canyon Solar, 110 MW
6. Axial Basin Solar, 145 MW
7. Escalante Solar, 200 MW
8. Spanish Peaks Solar, 100 MW

Existing Wind
367 MW total

Existing Solar
85 MW total

Existing Hydro
26.56 MW small hydro total, plus WAPA allocations

INCREASING MEMBER FLEXIBILITY

Our members are working together to develop a more flexible contract structure so they can self-generate more renewable energy than ever before

We're making it more affordable for members that choose to self-generate to take advantage of that opportunity

In April 2019, our members voted to pursue changes to their contracts with Tri-State and each other to make it possible to locally generate more than 5% of their energy, as previously agreed. By the end of 2019, we implemented a provision so members have the option to build community solar to serve an additional 2 megawatts or 2% of their consumption.

In April 2020, we expect the member-comprised contract committee that has been reviewing flexible contract and self-generation options to make their recommendations to the Tri-State Board of Directors so they can vote on their preferred changes and we can implement those adjustments.

KEY STEPS

- **Implement the board's decision regarding partial-requirements contracts and additional self-generation**
- **Partner with a solar and energy services provider to make local renewables easier and more affordable to build**

EXTENDING THE BENEFITS OF A CLEAN GRID

We're committing nearly $2 million to extend the electric vehicle (EV) charging network across our members' service territories and are otherwise promoting EVs and EV solutions in rural areas

We're expanding programs to help consumers save money and energy while cutting emissions through energy efficiency (EE), beneficial electrification (BE) and other initiatives

As we rapidly transition to power the grid with clean energy, there are more and more opportunities to power products with low-cost, reduced-emission electricity. These are some of the exciting benefits of the energy transition, but not all of them are readily available to the rural communities we serve. An electric vehicle (EV), for example, will only take you as far as there's a place to charge it, and there aren't any charging stations in a lot of rural areas. That's why we're working with our members to expand the regional EV charging network by allocating each member $45,000 to install charging stations in their service territories. Access to these charging facilities will give rural consumers the option to choose EVs the next time they buy vehicles by making charging available in their communities. It will also substantially expand the regional and state EV charging networks for everyone to use.

We're committing to expand more of the benefits of a clean grid than just access to EVs and charging. We know beneficial electrification (BE) can save consumers money at the same time that it lowers emissions. We know energy efficiency (EE) can lower energy bills and energy use, and demand-side management (DSM) can lower the total amount of energy we all use so we don't need as many resources to meet our



combined power needs. Together, this suite of tools can make it possible for all of us to enjoy energy savings – on our power bills through lower costs and out on the grid through lower demand and emissions. Tri-State is studying how much those savings might be, and how we can share more of them.

KEY STEPS

- **Allocate $45,000 per member — nearly $2 million in total — to install EV charging stations in their service territories, and promote solutions to increase rural EV usage and equity**
- **Promote BE, EE and DSM and study opportunities to bolster programs, like through support of the Beneficial Electrification League of Colorado and other state chapters**
- **In Colorado, study potential emissions reductions associated with BE**

COMMITTING TO COMMUNITY AND EMPLOYEES

We're providing retraining and transition support for employees affected by these changes

We're committed to working with impacted communities to find meaningful economic development opportunities

We're working with local, state and federal leaders to support a truly just transition from coal

Our REP will change Tri-State as a cooperative, including by directly impacting nearly half of our employees and many of the communities in which they live and work. After their commitment to keeping the lights on for all of us, Tri-State is committing to help them better-manage the challenges of the transition.

KEY STEPS

- For Escalante employees, offer generous severance packages, options to apply to positions at other Tri-State facilities, assistance for financial planning and education, and supplemental funding for health benefits
- For the Escalante area, contribute a $5 million financial package to invest in community development and execute a new $200 million solar project on Escalante Station property
- For Craig Station, the Colowyo Mine and the surrounding areas, work with employees and community members to develop and begin to implement economic development, retraining and other strategies to ease the transition over time, including executing a new solar project on the Colowyo Mine property
- Work with local, state, federal, and industry leaders to develop, fund and implement retraining, educational and economic development solutions in addition to those we provide

LOOKING FORWARD TO A BRIGHTER FUTURE

We're striving for 100% clean energy in Colorado by 2040, and will outline steps for 2030-2040 reflecting our effort to achieve that goal in our 2024 resource plan for the Colorado PUC

We're striving to maintain or reduce rates for members in all states we serve as we implement the REP

We're promoting a western Regional Transmission Organization (RTO) to efficiently and cost-effectively integrate more renewables into the grid

Our REP, like the broader energy transition, is dynamic. Expectations and goals, not to mention technologies and costs, are always changing, and we expect that our REP will change, too. While we work to accomplish the initiatives outlined here, we know we will add more in our pursuit of delivering on our mission: to provide reliable, affordable and responsible power to our members.

We all use electricity, and we are all part of the energy transition. How we all work together to achieve this transition is what will make the difference to the people who provide electricity for us all to use. We will all enjoy the benefits of this energy transition. Imagine what we can accomplish if we all work together to lessen its negative impacts.

We are energized by the potential of this transition, even as we work to manage the challenges that remain. To be able to efficiently, cost-effectively and equitably implement this REP and a broader energy transition, there's an immediate need to work together on solutions that achieve:



- **Dedicated and meaningful support for transitioning communities,** so communities that lose employment, tax and royalty payments, and other benefits associated with existing generation and production facilities don't have to carry the weight of the transition alone.
- **Treatment for cooperative debt and stranded assets,** so cooperative associations can retire coal generation and add renewables in accordance with state regulations without endangering financial stability.
- **The formation of an RTO,** to secure electricity reliability and affordability while transitioning to a clean grid in a cost-effective and efficient manner.
- **Streamlined siting and permitting for necessary infrastructure,** to be able to build transmission and generation infrastructure that meets the time and cost expectations of the clean energy transition.

The REP will have regional impacts, and consideration of these impacts is paramount to Tri-State because our 42 utility members serve more than a million consumers across four states, and this plan changes our cooperative. It will directly impact almost half of our employees. It will require significant investment and disinvestment decisions. If we work together it will also ensure significant emission reductions, a strong financial position, predictable flat to reduced member rates in all states, and create as much time as possible for us, our employees and communities to plan for the future.



Balancing these impacts will not be an easy task, but it is a necessary one, and Tri-State is committed to working with our employees, their communities and others across the region to smooth the effects of this transition. As a cooperative, we believe that if we work together, a bright future and clean grid is in reach.

Cooperative power. Transformed.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit H: Salt River Project, *2023 Integrated Systems Plan*

Delivering water and power®

2023 INTEGRATED SYSTEM PLAN

2023 INTEGRATED SYSTEM PLANNING CONTENTS

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SECTION 1

Executive Summary



Salt River Project (SRP) is a community-based, not-for-profit organization with a mission to provide reliable, affordable and sustainable water and energy to more than 2 million people in central Arizona. To ensure we can continue to carry out this mission as we have for over a century, we regularly perform long-term power and water planning to anticipate and meet future needs. Recently, we completed an Integrated System Plan (ISP), an industry-leading, multidisciplinary effort to identify strategies to help guide our power system planning through 2035.[1]

The world is changing in dramatic ways that will directly and indirectly impact the power system. Key forces of change that are reshaping our industry include:

- Growing electricity demand driven by migration to the region, increasing levels of large customers such as manufacturers and data centers, and the rapid adoption of electric vehicles (EVs), which is also exacerbated by the increasing and prolonged severity of extreme heat due to climate change and urban heat effects;
- Rising costs and extended development timelines for new infrastructure projects as a result of the lingering effects of inflation and supply chain disruptions that began during the COVID-19 pandemic;
- The anticipation that the Inflation Reduction Act will encourage deployment of clean energy resources and accelerate research and development of innovative technologies;

[1]The ISP focuses exclusively on power system planning. SRP plans the water system through separate processes.

- Increasing momentum behind decarbonization efforts, including customer demand for sustainable energy, retirement of coal plants and expansion of renewable and storage resources throughout the West, and electrification of transportation and buildings; and
- Growing tightness in regional electricity markets as significant quantities of aging baseload generators receive additional regulatory scrutiny and approach the end of their operating lifetimes.

The past several years provide a powerful reminder of how suddenly — and unexpectedly — change can occur. In such a dynamic environment, we must plan for a range of potential outcomes in order to develop effective strategies that can stand up to the pressure of unanticipated changes while allowing for flexibility and adaptation.

Simply put, SRP's customers expect the same quality of service from us despite the changing and increasingly complex landscape. Meeting customers' needs over the next decade will require a complete transformation of our power system, including:

- How, when and where we generate and store electricity
- How we deliver electricity over our transmission and distribution systems
- How we engage with our customers through rate design and customer programs

Successfully transforming our power system and achieving our 2035 Sustainability Goals depends on our ability to plan in an integrated fashion, allowing for close coordination and collaboration among groups to identify the best systemwide solutions for customers. By planning together, we can best meet customers' needs and ultimately ensure a more reliable, affordable and sustainable future despite the challenges and uncertainties ahead.

The primary outcome of our first ISP is a set of seven interdependent **System Strategies**. These strategies will guide the actions of our planning teams and help establish a common vision for how we plan the system of the future. They will also help our teams ensure that their specific near-term actions — including siting, engineering, permitting, procurement, development, construction, operations, workforce development, etc. — are consistent with the common strategic vision.

Based on the System Strategies, SRP has already identified some of these near-term actions — the **ISP Actions** — which are summarized later in this section. While the System Strategies provide direction for planning the system, they are also developed with flexibility in mind. Because the future is difficult to predict, SRP cannot lock in all decisions through 2035 today. However, we can adapt and respond to these changing conditions while using the System Strategies to guide us.

Significant changes to SRP's power system are already underway. By the mid 2020s, we will add more than 2,000 megawatts (MW) of solar projects and more than 1,000 MW of battery storage. By 2032, we will retire more than 1,300 MW of capacity at four coal plants, replacing this capacity with new lower-carbon-emitting resources. We are also actively exploring regional market initiatives and have already committed to joining the Western Resource Adequacy Program (WRAP), a regional program designed to ensure there is enough resource capacity to maintain system reliability.

Need for Integrated System Planning

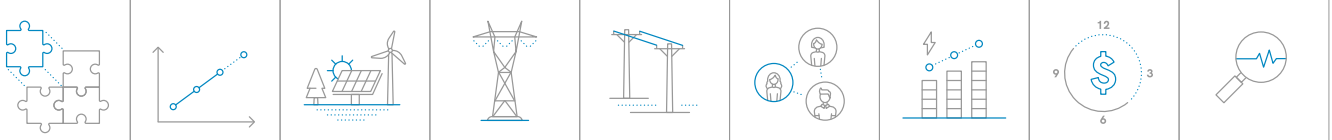
Historically, many of the planning functions that have existed within power utilities have operated independently from one another. While planning processes for generation, transmission, distribution and customer programs have relied on some common data sets and exchanged some information, planning cycles are often asynchronous, focus on different objectives and planning horizons, and lack direct visibility into how quickly other parts of the system are changing. The most prominent of these planning processes, the utility Integrated Resource Plan, has traditionally focused on future generation choices with limited insight into how those choices might impact all parts of the system.

Given the rapid pace of disruptive change in the power sector, planning decisions across the system must be coordinated from end to end to identify the best path forward for customers. For example:

- Adoption of EVs will increase electricity demand, requiring additional investments in new power generation and delivery infrastructure. But if SRP can provide pricing signals to customers that encourage them to charge their vehicles during periods that are more advantageous for the overall system, this can limit the amount of new infrastructure investment needed.
- Many of the new large-scale generation resources that SRP will consider — particularly renewables — will be located in areas where the existing transmission system may not be able to accommodate their delivery. Studying how the location of these new resources will impact the transmission system will provide a leading indicator of where new investment may be needed and may also allow for proactive siting of transmission and renewable resources.
- As the share of solar generation in SRP's portfolio increases over time, daytime energy will become increasingly abundant and lower the value of conservation during this period. This will have direct impacts on how we think about the value of future customer programs and the design of our future time-of-use price plans.

With this first ISP, we have transitioned to a holistic and collaborative framework that includes all of SRP's key planning areas. By planning for the entire power system within one process, we are positioning ourselves to answer the most difficult multidisciplinary and advanced engineering questions that will confront utilities in the coming decade. It will also help us ensure that the solutions we identify are robust given the many uncertainties for the future. A more in-depth overview of SRP's current system and the forces driving the need for an ISP is provided in Section 2.

KEY CONTRIBUTING DEPARTMENTS



Integrated System Planning & Support	Forecasting & Load Research	Resource Planning & Development	Transmission Planning, Strategy & Development	Distribution Planning & Strategy	Customer Programs	Financial Planning & Analysis	Pricing	Strategic Research & Insights

Our Planning Objectives

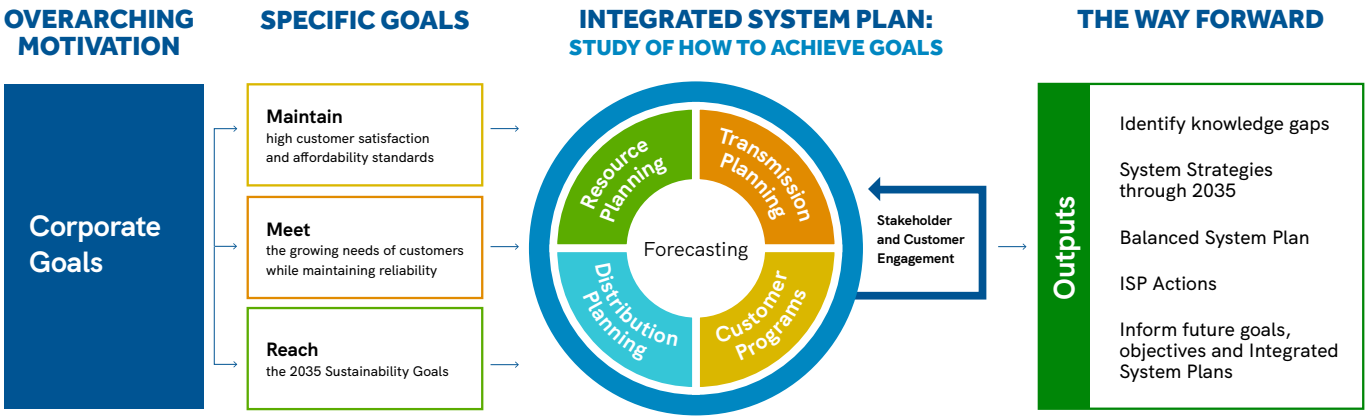
Reliability, affordability and sustainability are the cornerstones of SRP's 2035 goals, which in turn guide our planning efforts. Each of these is essential to upholding our mission and commitment to our customers.

Reliability: We are committed to maintaining electric reliability for our customers who depend on uninterrupted service, especially on the hottest days of the year.

Affordability: We recognize that electric bills represent a large cost to households and businesses. As many of our customers are facing mounting financial hardship and rising prices elsewhere in the economy, it is imperative that we strive to limit future increases to the cost of service.

Sustainability: We understand that our actions today will have far-reaching consequences for generations to come and recognize the importance of environmental stewardship to our community. These priorities are reflected in our comprehensive set of 2035 goals for minimizing our environmental footprint.

In the ISP, our teams performed rigorous systemwide modeling to identify viable pathways through 2035 to meet these goals. In addition to modeling, we engaged with customers and community stakeholders to inform and gather feedback on the ISP, while also building support for the ISP outcomes. The key deliverables of the ISP included the System Strategies approved by the Board, the Balanced System Plan and the ISP Actions. This first ISP also helped us identify opportunities to improve planning in future iterations. A more in-depth overview of the ISP process is provided in Section 3.



Stakeholder & Customer Engagement

A core component of the ISP effort included engaging our customers and stakeholders throughout the entire process, including study design, review of key findings, and development of strategies and actions. Since SRP delivers power to diverse communities, individuals and organizations, we took great care to ensure that we heard varying perspectives on how to design a first-of-its-kind ISP and how we should chart a path forward in planning the power system.

To engage our customers and stakeholders, we created an Advisory Group, which included 32 representatives from 23 different community organizations. This group met 18 times over the course of two years and provided feedback on all aspects of the ISP. We co-developed the ISP study design with the Advisory Group based on their feedback on how the future could unfold, how SRP could consider planning choices, and what aspects of planning the future power system were most important to capture. We also convened a Large Stakeholder Group, including over 140 organizations, eight times to inform a wider group of stakeholders and to receive feedback at key junctures throughout the process. In addition to engaging stakeholders, SRP convened groups of industry experts through four Technical Working Sessions to gather diverse industry perspectives on several key topics that are emerging in the industry. Through these three engagement tracks, customers, stakeholders and industry experts provided incredibly valuable feedback and played a key role in shaping the ISP study process and the final outcomes of the ISP. SRP greatly appreciates their participation and contributions throughout the entire process.

ISP PLANNING PROCESS **FAST FACTS**

NUMBER OF ADVISORY GROUP MEMBERS:

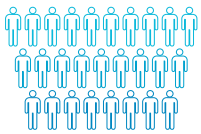


32
community representatives



from **23** organizations

NUMBER OF LARGE STAKEHOLDER GROUP MEMBERS:



250
community representatives from
143
organizations



1,349
SLIDES PRESENTED

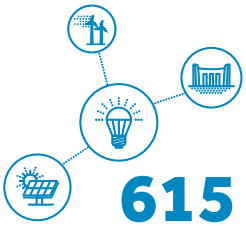
NUMBER OF MEETINGS:



31 stakeholder meetings



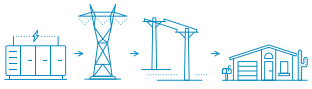
totaling over **62.5** hours of content



615
POINTS OF FEEDBACK COLLECTED AND INTEGRATED INTO THE ISP

1,411
RESIDENTIAL CUSTOMER SURVEYS CONDUCTED





42
SYSTEM PLANS CROSS-FUNCTIONALLY ANALYZED



4 **90-MINUTE RESIDENTIAL FOCUS GROUPS CONDUCTED**

STAKEHOLDER QUESTIONS ANSWERED:
588



In addition to convening stakeholders, SRP performed research in partnership with external research consultants to better understand the perspectives of residential customers. Residential customers have a diverse range of preferences, and it is challenging to capture these perspectives through a stakeholder meeting process given the time commitment required for those customers to meaningfully participate. To make sure that these diverse preferences were considered adequately within the ISP, we performed residential customer research. This customer research consisted of several focus groups and surveys of over 1,400 SRP customers, which SRP and its consultants ensured was a representative sample of residential customers based on demographics. Along with the stakeholder group meetings, this additional information provided us with a more complete picture of customers' desires and how the power system can help satisfy them.

Transparency was essential in the development of the ISP. To ensure visibility for interested SRP stakeholders and customers, we posted all ISP stakeholder engagement materials publicly, including pre-reads, agendas, presentations and meeting summary reports, throughout the process. These can be found on our ISP webpage at srp.net/isp.

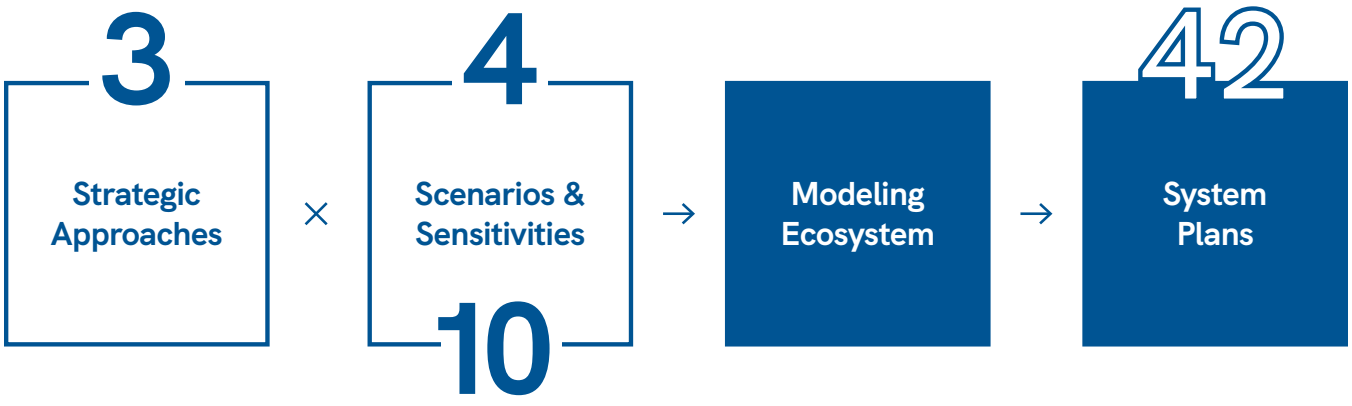
An Integrated Modeling Ecosystem

One of the principal challenges we encountered in implementing an ISP was designing an analytical framework with the appropriate level of detail to represent all parts of the system — from our biggest power plant to an individual customer's meter and every point in between. As the largest machine ever built by humans, the electric power system is incredibly complex. There is no single planning model with the capability to analyze the entirety of the electric power system as it undergoes transformative change over a long period of time. Instead, we sought to harmonize the models and tools currently used by each of our planning functions by utilizing common scenario definitions and consistent input assumptions. Additionally, we worked to improve the linkages between the models in such a way that information flowed fluidly between different analysis platforms. The result of these efforts is SRP's ISP modeling ecosystem that relies on common planning assumptions and connects tools used by each planning function with an unprecedented level of cohesion. This allows us to develop and analyze plans for the entire system.

Scenario-Based Analysis Framework

To identify solutions that benefit our customers across a wide range of uncertainties, we employed a scenario-based planning framework in the ISP. The planning framework included three key elements: scenarios, sensitivities and strategic approaches. A **scenario** represents a plausible future state of the world around us, reflecting societal, technological, economic, environmental and political trends and conditions — generally, factors that are outside of SRP's control. A **sensitivity** modifies one assumption in a scenario to isolate the impact of that assumption. A **strategic approach** represents a decision or set of decisions that are within SRP's control as we develop the power system of the future. A detailed description of the scenarios, sensitivities and strategic approaches is provided in Section 4.

Studying each strategic approach under a range of scenarios and sensitivities provided a framework for understanding how different decisions stand up against the uncertainty of the future. The ISP analyzed three strategic approaches across four scenarios and 10 sensitivities, producing a total of 42 unique system plans. The methodology employed to develop these system plans is discussed in Section 5.



Each of the 42 system plans comprised specific plans for customer programs, distribution investments, transmission investments, and generation additions and retirements from 2025 to 2035. Additionally, for each system plan, SRP evaluated a variety of metrics that measured impacts to reliability, affordability, sustainability and customer value. Assessing strategic approaches across a variety of futures allowed us to identify strategies that work well across various scenarios and helps mitigate future risks. This also allows us to take advantage of potential opportunities, thereby creating a plan that is adaptive yet resilient to the forces of change.

Key Findings from Analysis

SRP gained new insights from performing systemwide analyses of the 42 system plans. This ISP showed how customer needs, infrastructure buildout and operations could evolve under a wide range of future scenarios and uncertainties. We also learned how our actions can influence reliability, affordability and sustainability while also helping to manage future risks and uncertainties. SRP distilled these insights into a list of key findings below. A detailed description of the analysis results is provided in Section 6 of the report.

Customer Programs and Pricing Plans

- SRP will need to evolve programs and price plans to encourage shifts in consumer behavior and further educate customers on when to consume and when to conserve energy.
- Electrification of end uses, including transportation and heating demand, creates new opportunities to shift energy usage to mid-day hours to help integrate more renewable energy and maximize carbon reduction impacts.
- Changes in how our customers use energy will require continued innovation and flexibility in planning.

Infrastructure

- Customers' energy demand is expected to increase rapidly through 2035 in most scenarios, even with significant expansion of customer programs and customer-sited generation.
- Significant investments in new transmission infrastructure are needed over the next decade to connect new resources and customers, while also achieving reliability and sustainability goals. These investments will need to be strategically located and timed.

- Load growth will drive new distribution infrastructure needs while changes in how our customers use energy will require innovation and flexibility.
- SRP will likely need to double or triple resource capacity at an unprecedented pace in the next decade to serve customers while achieving reliability and sustainability goals.
- New renewables and firm capacity are part of a least-cost portfolio, even under a wide range of gas price and technology cost sensitivities.
- When paired with firm capacity, solar and wind contribute to a least-cost portfolio while helping SRP reduce carbon emissions and water usage. If the U.S. government enacted a mandate for 85% CO_2 reductions by 2035 (Strong Climate Policy), further acceleration of renewable and storage deployment would be required.
- Hundreds of miles of new or upgraded transmission lines and nearly double the number of 500/230-kilovolt (kV) transformers could be needed relative to today.
- Location of generation matters and plays a significant role in the buildout of the 500 kV and 230 kV transmission system.

Operations

- Without new firm generation capacity, the system cannot satisfy reliability requirements under a high load growth scenario. In other load growth scenarios, the system can satisfy reliability requirements without new firm generation capacity but requires significant additions of renewable and energy storage resources.
- The reduction in coal generation and expansion of carbon-free resources over time allow SRP to meet, and in many cases exceed, SRP's 2035 goals for carbon emission reductions and water resiliency.
- A future system that relies more on variable renewable resources presents new challenges and will require new operating practices to ensure sufficient flexibility, reduce wear and tear on existing assets and maximize benefits to customers.

Partnerships to Meet the Pace of Transformation

- With the amount of future infrastructure and resources needed, internal and external partnerships are going to be essential to build the future system and maintain high customer value.
- To meet infrastructure needs, supply chain and development solutions are essential to managing costs and to meeting the needed pace of transformation.

These key findings from the analysis underscore the tremendous transformation of SRP's power system over the next 10-plus years. Making this transformation a reality will be a significant undertaking requiring additional planning beyond the ISP to ensure there are detailed, sound engineering and operational plans in place for any additional infrastructure or changes to the system. It will also require making decisions on specific investments, procurements, workforce development, information technology systems, etc.

While the analysis provides insights into how to plan the future power system and tradeoffs for different approaches, SRP ultimately needs a plan that is specific enough for our planning groups,

communities and stakeholders to plan the power system. The plan also needs to be flexible, given uncertainties about the future and the potential for innovation. The plan should include strategies that are no-regrets across all futures, while also making tradeoffs between different objectives and identifying strategies that achieve an appropriate balance between reliability, affordability and sustainability. The next sections describe SRP's vision for how to plan the future power system, including System Strategies, an illustrative Balanced System Plan and ISP Actions.

System Strategies

SRP developed seven interdependent **System Strategies**, representing long-term strategies for planning and operating all parts of the power system, including customer programs, distribution, transmission, generating resources, pricing and system operations. The strategies were approved by SRP's Board on Oct. 2, 2023, and will guide planning through 2035 and beyond. Each strategy is anchored to key findings from the ISP and relies on the other strategies also being in place to ensure success and achievability. To develop these strategies, we synthesized a range of metrics and outputs across scenarios, sensitivities and strategic approaches. We also incorporated feedback from the ISP Advisory Group before finalizing and receiving Board approval.

Each strategy will require that we take action today. Some will take longer than others to implement, but the execution of all strategies together will enable us to meet evolving customer needs, achieve our 2035 goals and beyond, manage costs for customers, achieve an adequate and reliable power system, and adapt toward a more sustainable future regardless of what that may be in 2035. The System Strategies are summarized below, and a full description is provided in Section 7.

Energy Investments
Invest in renewable resources and storage to manage fuel consumption and drive carbon and water reductions.

Capacity Investments
Invest in firm generation, including natural gas, to support reliability and manage affordability, while also supporting advancement of emerging firm technologies.

Proactive Transmission
Proactively plan to expand transmission infrastructure to enable generator interconnections and load growth.

Distribution Innovation
Ensure distribution grid readiness to maintain reliability and enable customer innovations to drive carbon reductions.

Partnerships & Suppliers
Explore partnerships and supply chain and development solutions that manage cost and availability to meet the pace of transformation.

Evolution of Customer Programs & Pricing
Evolve pricing and customer programs to improve economy-wide carbon reductions and pace infrastructure development, while recognizing customers' diverse needs.

Strategic Investment & Reinforcement of Existing Assets
Reinforce and maximize value of existing infrastructure with strategic investments to manage affordability and ensure future performance, grid security and resilience.



Balanced System Plan

The System Strategies set the direction for SRP's planning efforts through 2035. To provide an illustration of how the system could look in 2035, following implementation of the System Strategies, SRP developed a **Balanced System Plan**. The Balanced System Plan provides an illustration of power generation, transmission, distribution and customer program plans, as well as reliability, affordability, sustainability and customer focus metrics, through 2035. To develop this plan, we drew upon the key findings from the analysis and residential customer research and built out a system plan consistent with the System Strategies.

The Balanced System Plan adds a significant quantity of resources, more than doubling SRP's total installed capacity by 2035 relative to today. This includes adding:[2]

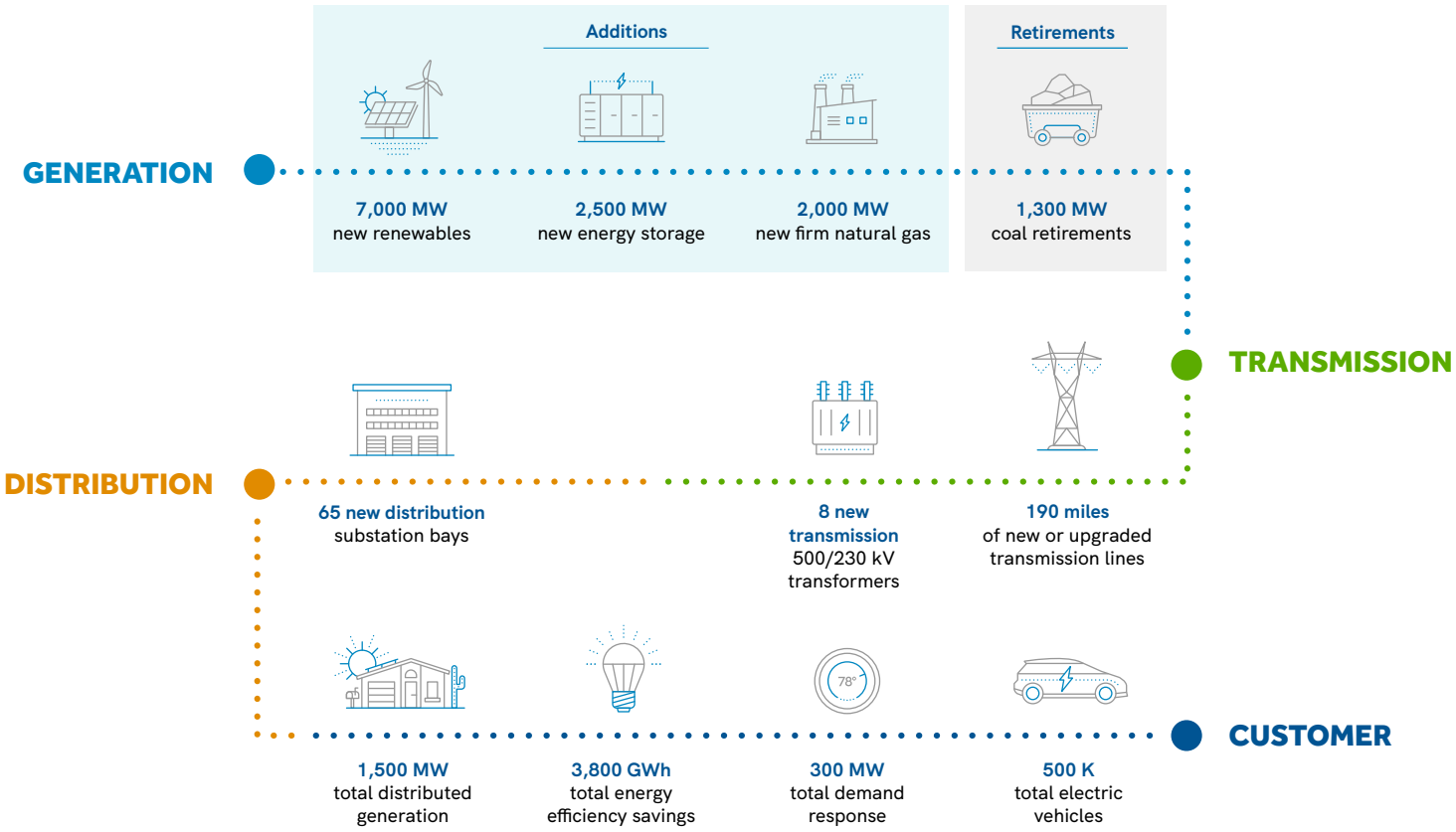
- 7,000 MW of new renewables
- 1,000 MW of new long-duration pumped hydro energy storage
- 1,500 MW of new battery storage
- 2,000 MW of new firm natural gas

This additional capacity, along with resources that are already contracted and planned to come online in the next few years, makes up for the loss of 1,300 MW of retired coal capacity and a retiring agreement with a natural gas plant. It also helps SRP keep pace with a greater than 40% growth in energy demand by 2035 and marks a significant increase of clean energy resources in the future power supply.

To deliver generation from these new resources and to accommodate the increase in energy demand, the plan includes more than 190 miles of new or upgraded high-voltage transmission lines, as well as eight 500/230 kV transformers. This infrastructure can take several years to site, engineer, permit, construct and energize, so it is crucial that SRP takes a proactive approach to ensure transmission is in place to enable future growth. The plan also includes more than 65 new distribution substation bays across existing and new distribution substations which is necessary to accommodate increasing energy demand.

Customers play a significant role in the transformation of the system in the Balanced System Plan. Customers' total energy demand is expected to increase significantly due to new large industrial customers, migration to the Valley and the growing popularity of EVs. However, this growth is mitigated to an extent due to customer adoption of distributed generation, like solar and batteries, and customer participation in SRP's energy efficiency and demand response programs. Moreover, as the power system evolves, we believe that customers can play a central role in achieving that transition through participation in future time-of-use price plans, electric vehicle managed charging programs and other offerings that have yet to be rolled out. The graphic on the next page shows the key elements of the Balanced System Plan, including power generation, transmission, distribution and customer program components.

[2] MW additions reflect the mix of resources determined to best balance reliability, affordability and sustainability needs. However, actual additions may change over time as external conditions change, such as load growth and technology costs.



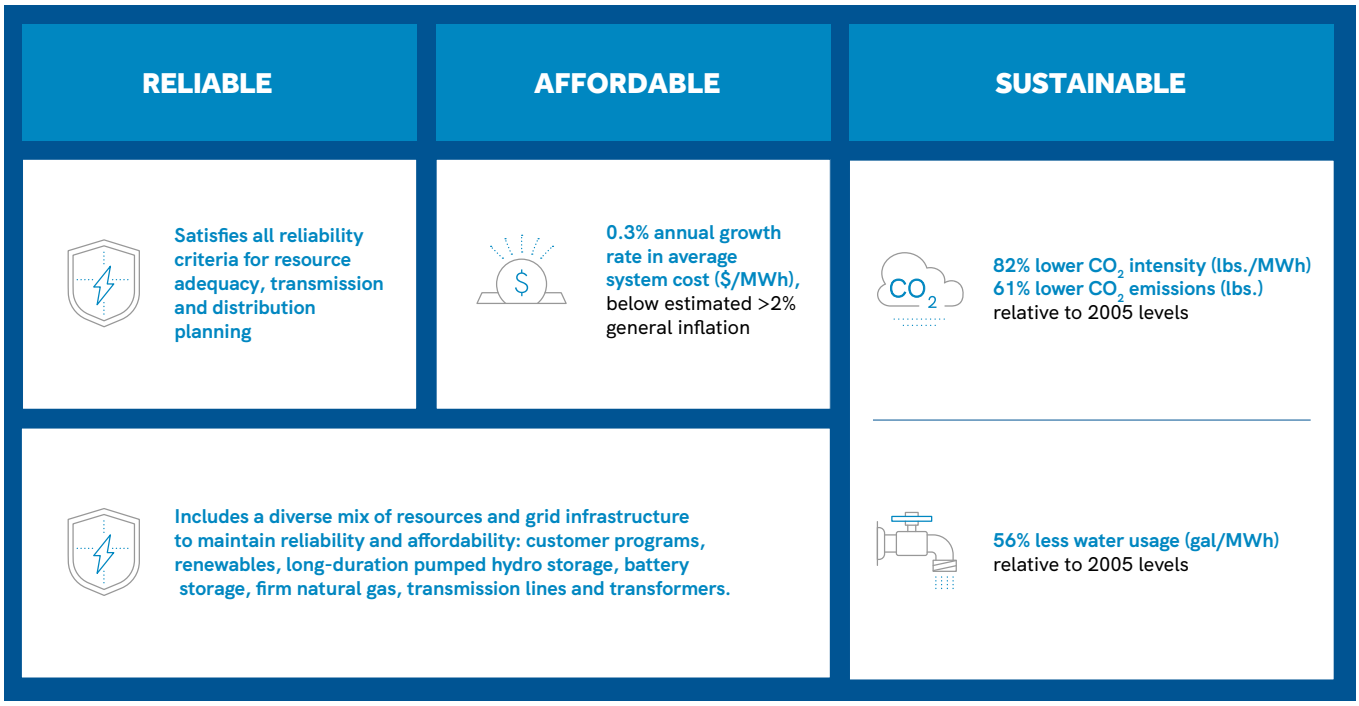
As mentioned earlier, the Balanced System Plan allows SRP to achieve important goals related to reliability, affordability and sustainability.

Reliability: By investing across the system — including new firm generation, long-duration and short-duration storage, renewables, transmission, distribution and customer programs — SRP will ensure strong reliability performance across the system.

Affordability: Due to the diverse mix of investments and programs, average system costs for this plan are projected to increase by less than 0.3% per year, well below projected general inflation. Ultimately, the driving force behind our plan is to meet customers' future energy needs at the best overall value. We believe this plan delivers on that goal.

Sustainability: As SRP retires coal capacity and adds significant amounts of clean energy resources, CO_2 emissions intensity is projected to decline by 82% (relative to 2005) and water usage intensity is projected to decline by 56% (relative to 2005), in both cases surpassing SRP's 2035 Sustainability Goals.

We are excited by the performance of this plan. However, as mentioned earlier, this illustration supports a common vision of what the future may look like based on what is known today. As expectations change — such as economic development forecasts, technology cost projections, or the implementation of new laws and regulations — the system plan will need to adapt and evolve accordingly. The Balanced System Plan is described in more detail in Section 8.



ISP Actions

Our planning processes do not stop with the ISP. In many ways, the conclusion of the ISP represents new beginnings as our teams start to execute the System Strategies. As a first step, SRP has defined 10 **ISP Actions**, which we have already started to implement. The ISP Actions will also help enhance our planning capabilities, establish a roadmap to implement the System Strategies and further our progress toward meeting our 2035 goals. The ISP Actions are summarized below, and a full description is provided in Section 9.

ISP Action #1: Residential Time-of-Use Pilot: Execute a residential time-of-use price plan pilot and perform customer research to evaluate customer response to new time-of-use peak periods and a super off-peak period in the middle of the day, which will inform SRP's load forecast for long-term system planning and SRP's price process.

ISP Action #2: Time-of-Use Evolution: Engage commercial, small business, large industrial and residential customers and stakeholders to inform them of how the evolving grid will impact time-of-use periods. Develop a roadmap for implementing new time-of-use periods, including the following elements: undertake a pricing process informed by the ISP as to how time-of-use plans need to evolve and develop a communication plan for all customer types and segments to educate them about any new time-of-use price plans.

ISP Action #3: Customer Programs: Continuously refresh program plans and drive participation in customer programs at levels consistent with those planned for in the ISP, representing a meaningful increase from SRP's initial 2035 Sustainability Goal for energy efficiency.

ISP Action #4: EV Management: Develop a roadmap by evaluating customer needs and system impacts and assessing viable pathways for managing EV charging through price plans, customer programs and educational efforts to align with time periods that are lower-cost and minimize additional infrastructure needs.

ISP Action #5: Electrification: Analyze the benefits and costs of non-EV electrification within SRP's service area, including effects on SRP operations and economywide emissions. Assess options for expanding E-Tech program offerings related to residential and commercial electrification.

ISP Action #6: Distribution Enablement Roadmap: Continue implementing SRP's Distribution Enablement (DE) Roadmap, including the following elements: deploy the Advanced Distribution Management System (ADMS) and Distributed Energy Resources Management System (DERMS) in 2024; continue implementing advanced locational planning tools; advance the interconnection process; execute the Distribution Enablement Research & Development plan; and share the Distribution Enablement Strategy with external stakeholders.

ISP Action #7: Resource Selection: Issue all-source requests for proposals (RFPs) or requests for information (RFIs) at least once every two years to compare with self-build options and ensure that SRP can agnostically select resource technologies that minimize total system costs while meeting SRP's reliability and 2035 Sustainability Goals.

ISP Action #8: Coal Transition Action Plan: Develop a coal repurposing action plan, including the following elements: coordinate with co-owners to develop a path forward for the Springerville Generating Station; prepare a plan or plans for repurposing the Coronado Generating Station site; develop solutions that preserve transmission following the retirement of coal plants; and test strategies for minimizing emissions from coal power plants.

ISP Action #9: Proactive Siting: Develop and initiate collaborative community engagement, land, resources and transmission siting research to proactively identify, prepare and preserve options for feasible future system infrastructure sites.

ISP Action #10: Regional Transmission: Pursue transmission projects that would enable SRP to access diverse renewable resource options beyond solar, such as wind and geothermal, and engage with project developers as appropriate.

The completion of the ISP Actions will significantly advance SRP's planning and development of the future power system. The ISP Actions related to time-of-use price plans, customer programs, EV management, electrification and the Distribution Enablement Roadmap will ensure that SRP continues to provide customers with the best options for managing their energy costs, adopting clean energy technologies and helping SRP achieve the future transformation of the power system. The ISP Actions related to resource selection, the coal transition action plan, proactive siting and regional transmission will ensure that SRP takes a proactive approach to managing the transition of existing coal assets, maintaining a reliable power grid, accessing the best available resource options and driving improved sustainability. Like the System Strategies, these ISP Actions work together to help SRP achieve its reliability, affordability and sustainability goals. To keep SRP's Board, customers and stakeholders informed on progress made toward the ISP Actions, SRP will provide annual updates.

Beyond the First ISP

SRP is excited to have completed this first ISP. It was a first-of-its-kind effort that required creative thinking in how to plan the entire system in a coordinated manner and led to a comprehensive set of System Strategies and ISP Actions that will allow us to take concrete steps to transform our power system. Given that this effort was trailblazing in many regards, there were challenges in doing end-to-end modeling of the entire system across so many different futures. However, upon reflecting on this effort, we are more confident than ever that an integrated system planning framework is the best way to plan the future power system. By planning for the entire power system within one process, we can identify solutions across the entire system and how those solutions must work together to allow us to achieve reliability, affordability and sustainability goals at the best value to our customers.

The first ISP is just a starting point. SRP has learned a lot about how to perform systemwide planning through this effort and plans to continue to improve upon it in future iterations of the ISP. This will provide us with opportunities to update scenarios as new information becomes available and consider any adjustments to strategies, a balanced plan and actions based on updated systemwide analysis. In the meantime, we will use findings from the ISP to support other ongoing efforts at SRP, including annual planning activities, procurement of new resources through all-source requests for proposals (RFPs), and our 2035 Sustainability Goals update process.

SECTION 2

SRP Overview and Background

About SRP

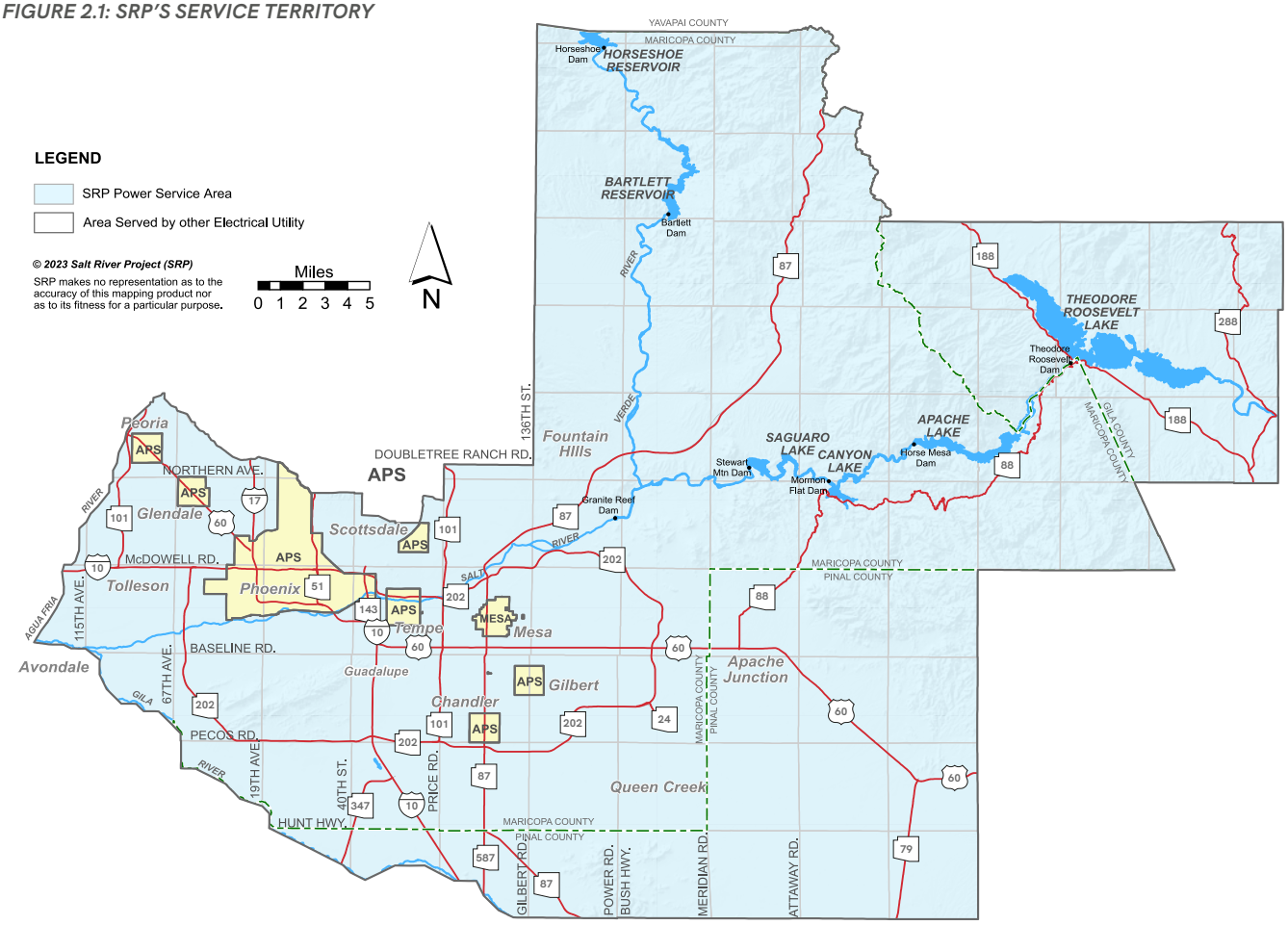
Salt River Project (SRP) is the oldest multipurpose federal reclamation project in the United States and one of the nation's largest public power utilities. As a community-based not-for-profit organization, SRP's mission is to serve our customers and communities by providing reliable, affordable and sustainable water and energy. Our long history, beginning in 1903, predates Arizona's statehood.

SRP comprises two separate organizations: the "Association," a private water corporation founded in 1903, and the "District," an electricity provider formed as an agricultural improvement district and a political subdivision of the State of Arizona in 1937.

SRP has helped and will continue to help the Phoenix metropolitan area develop and thrive by providing these essential water and power resources. Our guiding principles have remained the same since our founding: to act in the best interest of the people we serve and strive to help build a better future for Arizona.

For over a century, SRP has focused on building strategic partnerships and innovative solutions to meet the Phoenix metropolitan area's ever-changing needs. In the years ahead, we will continue to lead the way by applying a forward-thinking approach and new technologies to address energy supply challenges.

FIGURE 2.1: SRP'S SERVICE TERRITORY



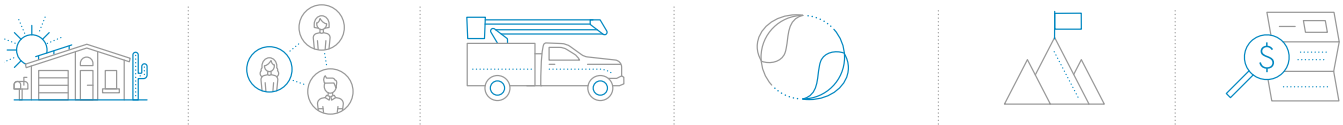
Electric Customers

SRP takes great pride in serving over 1 million electric residential, municipal, large commercial, industrial and small business customers. Residential customers are households that use electricity for their daily needs, such as lighting, heating and cooling. Municipal customers are local governments that use electricity to power public facilities, such as streetlights, traffic signals and water treatment plants. Small business customers are businesses that consume a relatively small amount of electricity, such as small shops and restaurants. Large commercial customers, such as shopping malls, hospitals and universities, consume a significant amount of electricity. Industrial customers are businesses that use electricity to power heavy machinery and equipment, such as factories and manufacturing plants.

J.D. Power recently ranked SRP highest in customer satisfaction in the western United States among large electric utilities for the 22nd time in the 23 years that J.D. Power has been surveying residential electric customers — and the 20th year in a row. Among large electric utilities (500,000-plus households), customers ranked SRP as the top-performing large electric provider in the West in all six customer satisfaction factors: power quality and reliability, price, billing and payment, corporate citizenship, communications, and customer service.

SRP's 2035 Goals

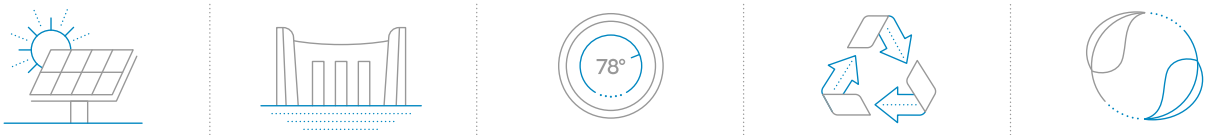
For over 120 years, SRP has fulfilled its mission to deliver reliable, affordable and sustainable water and energy. Our 2035 Corporate Goals define what we want to achieve over the long term in order to continue delivering on our mission. The categories for our corporate goals are shown below. These goals provide us with a purposeful structure for planning strategically as a company. They also allow us to anticipate and respond to the many ways in which our customers' expectations are changing, new technologies are emerging and advancing, and the energy sector is transforming.



CUSTOMERS | **COMMUNITY** | **WORKFORCE** | **SUSTAINABILITY** | **LEADERSHIP** | **FINANCES**

A subset of goals within the 2035 Corporate Goals are sustainability targets that impact SRP's future resource and customer program planning. They include Carbon Footprint and Water Resiliency Goals related to generating resources and Customer and Grid Enablement Goals related to customer programs.

SRP SUSTAINABILITY GOALS



Carbon Footprint | **Water Resiliency** | **Customer & Grid Enablement** | **Supply Chain & Waste Reduction** | **Customer, Community & Employee Engagement**

Carbon Footprint & Water Resiliency Goals:

- Reduce carbon emissions from generation intensity reaching 65% reduction by 2035 and 90% by 2050.
- Achieve a 20% reduction in generation-related water use intensity across all water types.
- Eliminate or offset power generation groundwater use in Active Management Areas (AMAs).

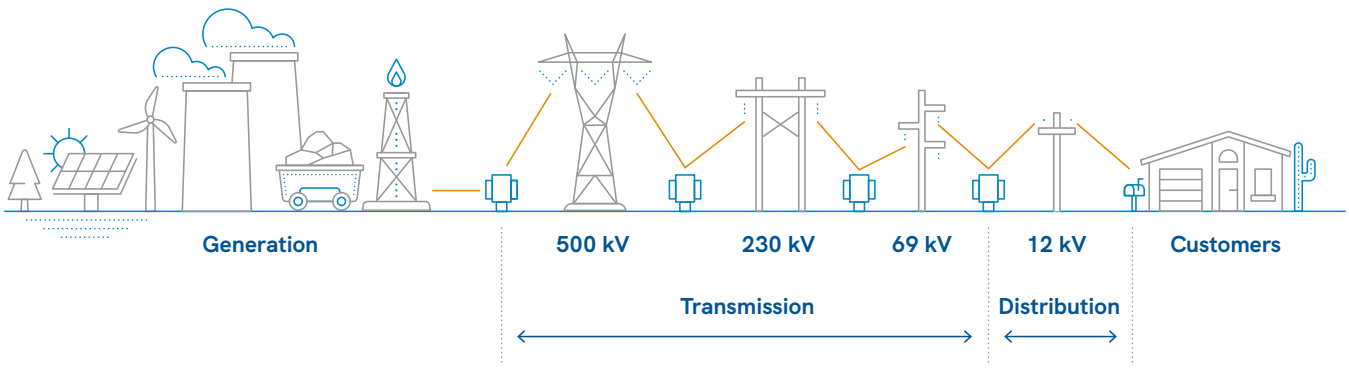
Customer & Grid Enablement Goals:

- **Energy Efficiency:** Deliver over 3 million megawatt-hours (MWh) of annual aggregate energy savings.
- **Demand Response:** Deliver at least 300 megawatts (MW) of dispatchable demand response and load management programs.
- **Electric Transportation:** Support the enablement of 500,000 electric vehicles (EVs) in SRP's service territory and manage 90% of EV charging through price plans, dispatchable load management, original equipment manufacturer integration, connected smart homes, behavioral and other emerging programs.
- **Electric Technologies:** Expand the electric technology (non-EVs) program portfolio to deliver 300,000 MWh of annual aggregate energy impact.
- **Grid Enablement:** Enable the interconnection of all customer-sided resources, including solar photovoltaic (PV) and battery storage, without technical constraints while ensuring current grid integrity and customer satisfaction.

The 2035 Sustainability Goals are being refreshed in 2024 in collaboration with community stakeholders. To learn more about SRP's 2035 Sustainability Goals, visit srp.net/2035.

Existing Power System

SRP is a vertically integrated utility that owns and plans for all-electric energy supply chain levels, including generation, transmission, distribution and customer programs. As a vertically integrated utility, SRP owns and controls the electricity supply chain's generation, transmission and distribution components. We are responsible for producing, transmitting and distributing electricity to our customers. We also design customer programs and pricing to ensure we meet customers' evolving needs and signal customers when to use electricity.



Being a vertically integrated utility, SRP has some advantages when planning, including greater flexibility in designing and implementing customer programs and pricing plans that meet the specific needs of our customers and our system. We can use our oversight of the entire electricity supply chain to ensure that our customer programs are integrated with our operations. This can help improve the reliability and efficiency of SRP's operations, ultimately benefiting customers by reducing costs and improving service quality.

Historically, many of the planning functions that have existed within vertically integrated utilities like SRP have operated independently from one another. While planning processes for generation, transmission, distribution and customer programs have relied on some common data sets and exchanged some information, planning cycles are often asynchronous, focus on different objectives and planning horizons, and lack direct visibility into how quickly other parts of the system are changing.

Generation Overview

Resource planning at SRP determines what generation resources we need to add to our system to maintain reliability and achieve SRP's 2035 Sustainability Goals. SRP's generation resources can be viewed as capacity or energy sources. Capacity is the maximum output a generating resource can physically produce or export at a single point in time, measured in megawatts (MW). This output helps serve high peak demand hours and when the system has critical needs. Not all resources have the same capability to produce power at full capacity for all hours of the day and year. Demand resources, such as Demand Response and Energy Efficiency, are measured by their capacity to reduce demand, also in MW.

Energy is the amount of electricity a generator produces over a specific period of time, measured in MWh. Many generators do not operate at their full capacity all the time. A generator's output may vary according to conditions at the power plant, the availability of fuel, variability of wind and sun, or dispatch instructions from the utility due to changes in fuel costs or market prices. To maintain a balanced grid, SRP must constantly match demand with supply at any given instant.



Think of capacity like the lanes on a freeway and the maximum number of vehicles it can allow. Commuters need enough lanes to accommodate the number of vehicles during rush hour traffic. This means several of the lanes may be empty during lighter traffic times of the day, but the additional lanes are necessary for vehicles during a peak traffic time. Think of the energy as the flow and number of vehicles traveling on the freeway over a given period of time.

ANALOGY

Capacity: Maximum number of cars that can fit on an interstate during rush hour.

Energy: Number of cars per year traveling on that same interstate.





Previously, SRP used an Integrated Resource Plan (IRP) to determine the generation resources needed to meet our forecasted demand. Using this IRP process, SRP could understand how different resource choices and energy portfolios performed in various scenarios and future business environments. Our past IRPs aimed to analyze possible critical uncertainties and the generation of resources available to navigate them. This process involved evaluating current and future energy needs and developing a resource plan to meet those needs in a cost-effective, sustainable and reliable manner. The IRP process included a variety of analyses, such as load forecasting, resource planning and economic analysis. The IRP process aimed to ensure that the utility can provide reliable and affordable electricity to its customers while minimizing environmental impacts.

Once the IRP was completed, SRP would then develop specific plans linearly based on annual load forecasts, starting with a resource plan, then transmission, distribution, and customer programs and pricing. The resource plan was based on the resulting strategic directions from the IRP process, inclusive of annual load growth projections. Then, each subsequent plan was developed and designed to meet SRP sustainability and corporate goals. On an annual basis, between IRP cycles, we monitored and evaluated our operations and adjusted individual planning area plans to ensure that we met our goals and continued providing reliable, affordable and sustainable electricity to our customers.

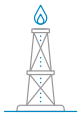
The overall objective of the IRP was to incorporate a flexible resource plan that could embrace the challenges, uncertainties and growing energy requirements of tomorrow's world. The following are the concluding strategic directions from the 2017-2018 IRP.



Coal Generation: Reduce the amount of energy in SRP's portfolio produced by coal generation.



Nuclear Generation: Preserve option for new nuclear generation in the mid-to-late 2030s with a focus on small modular technology.



Natural Gas Generation: Develop flexible natural gas generation options to meet peak demand and integrate renewables.



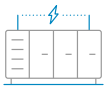
Customer Programs: Continue the promotion of energy efficiency programs and technologies that help customers save energy and money.



Renewable Energy: Grow SRP's renewables portfolio to reduce CO_2 intensity and manage costs; expand opportunities for customer-dedicated projects.



Market Resources: Implement Energy Imbalance Market participation as planned and seek opportunities to expand participation in other regional markets.



Energy Storage: Add cost-effective energy storage to support additional renewable energy integration.



New Technologies: Pursue pilot projects and research and development efforts for innovative applications of new power generation, load management, energy storage and electrification.

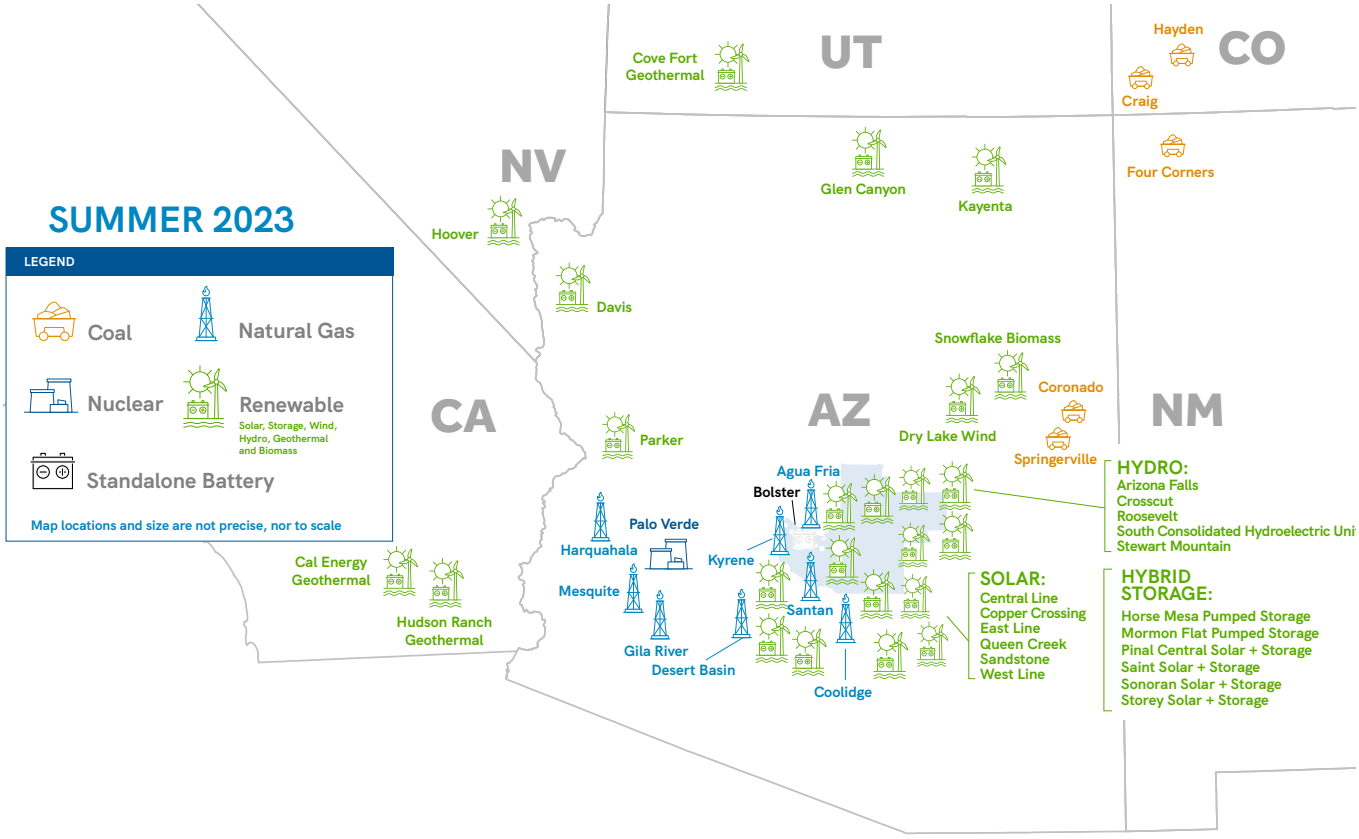
Featured in the next section are brief overviews of each planning area, where they are today and what we must consider when planning for the future.

SRP's Generation Sources Today

Over the past few years, SRP's service area has been experiencing significant and unprecedented growth in demand. In 2023, SRP served a multiday record peak for electricity demand. On several days, power demand reached over 8,000 MW, and SRP served its highest peak demand of 8,163 MW on July 18, 2023. The 2023 peak was 7% higher than last summer.

Where Does SRP Power Come From?

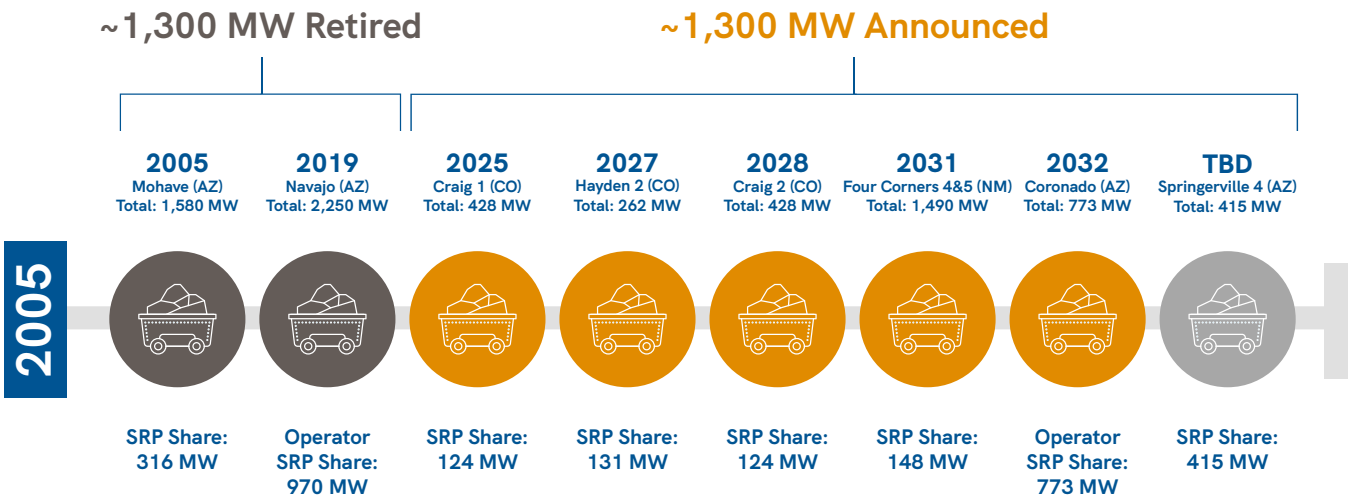
SRP generates electricity from renewable, traditional fossil fuel and carbon-free sources. The renewable sources include solar, geothermal, biomass, wind and hydropower. Traditional fossil fuel sources include coal and natural gas, and carbon-free sources include nuclear generation. Below is a graphic that displays what and where SRP generation sources are today.



To address growing demand and enable the achievement of our 2035 carbon reduction goals, SRP has been positioning its resource portfolio in alignment with the IRP strategic directions that would allow for a lower-carbon future by retiring coal plants, adding new renewable resources, integrating storage, adding flexible natural gas and acquiring existing zero-carbon nuclear resources.

Progress in Reducing Coal

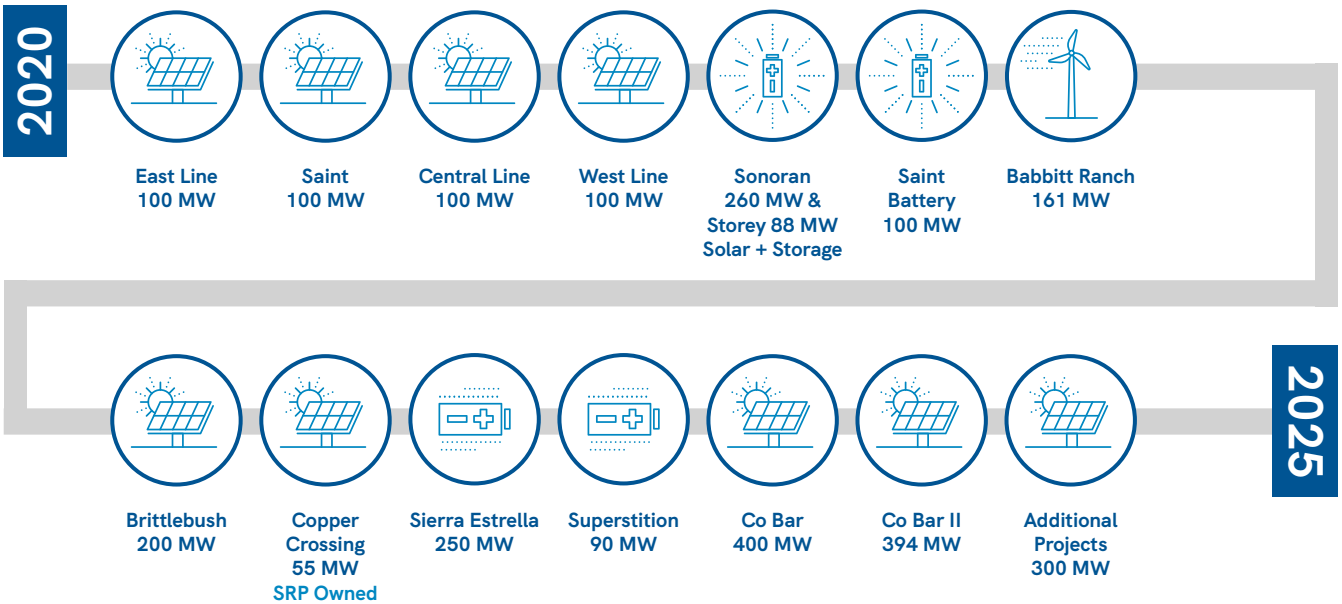
Since 2005, SRP has taken action to retire approximately 1,300 MW of coal generation. By 2032, SRP will retire an additional 1,300 MW from four coal plants already announced for retirement that will be replaced with new lower-carbon resources.



Increase carbon-free resources

In fiscal year 2023 (FY23), SRP added 104 MW of carbon-free generation from Palo Verde and has contracted an additional 10 MW in 2024 for a total of 114 MW. With this purchase, SRP increases the carbon-free energy delivered to our customers by up to 1,000,000 MWh annually, over 2.5% of our annual retail electricity.

SRP also prioritized additional renewable resources by adding 400 MW of new solar and has contracts in place for an additional 1,697 MW and continues to work with developers to implement 1,088 MW of storage and 161 MW of wind under contract.



Develop long-lead carbon-free resources

We have made great efforts to develop the capability to effectively integrate utility-scale storage technologies into our system to provide the optimal value to SRP and our customers, improve our ability to decarbonize with greater amounts of low-cost intermittent renewable resources, and potentially avoid or defer adding conventional generation or power delivery infrastructure while mitigating life-cycle environmental impacts. In addition to new lithium-ion storage technology, we have initiated early development of a Pumped Hydro Storage Project for up to 2,000 MW with a 10-hour duration. Pumped storage can provide utility-scale storage resource diversity and is a proven technology that SRP has had decades of experience owning and operating.

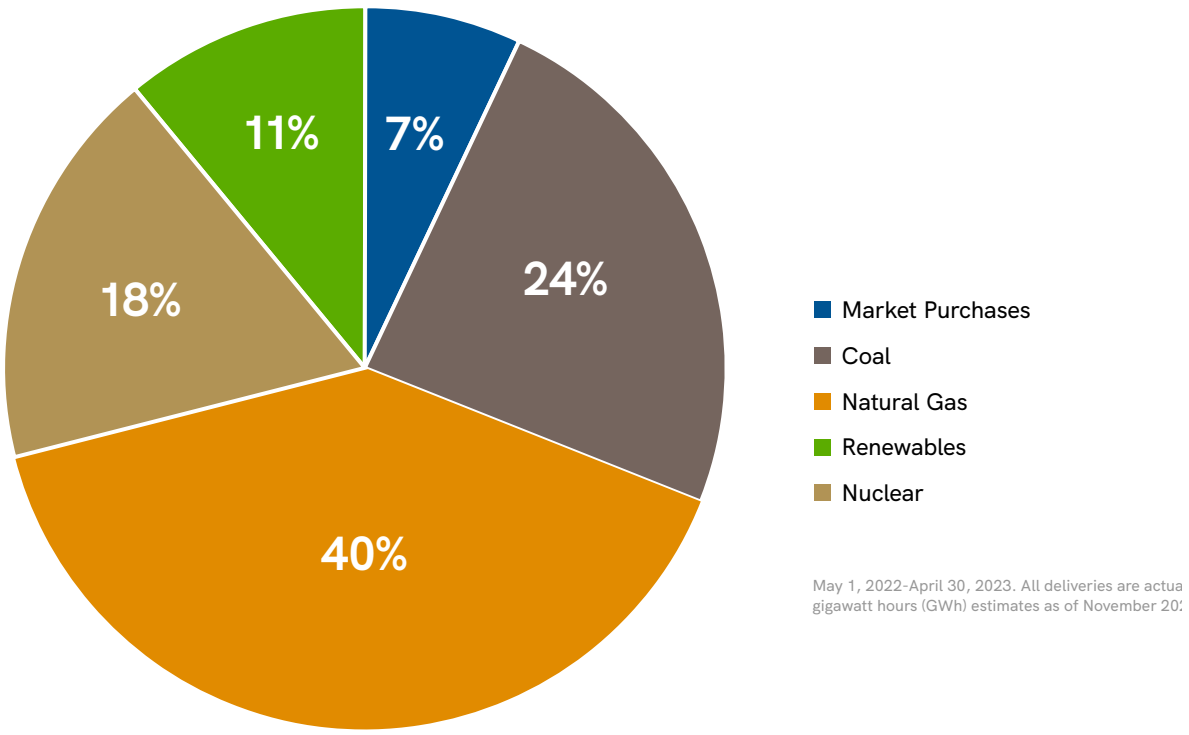
Adding flexible firm resources for future renewable integration and reliability

Without sufficient generation resources and power system stability, SRP customers may experience power shortages. Firm resources are sources of electricity (generation resources) that the utility can dispatch to meet system needs. Characteristics of a firm resource include reliable capacity in all seasons and over long durations. Natural gas is a firm resource that provides flexibility to balance ramps caused by intermittent resources (such as solar and wind) and fast response during emergencies. In 2023, we obtained an Amended Certificate of Environmental Compliance (CEC) authorizing SRP to build the natural gas peaking Coolidge Expansion Project to help integrate intermittent renewable resources.

SRP's Energy Mix

SRP's resource mix is constantly evolving to meet growing customer demands. The chart in Figure 2.2 summarizes SRP's latest energy mix delivered to customers from FY23.

FIGURE 2.2: ENERGY DELIVERED TO CUSTOMERS



May 1, 2022-April 30, 2023. All deliveries are actua
gigawatt hours (GWh) estimates as of November 20

Transmission System Overview

Transmission and distribution refer to the various stages of delivering electricity, from generating resources to a "load" such as a home or a business. The primary distinction between transmission and distribution is the voltage level at which electricity moves. At SRP, transmission refers to energized facilities at 69 kilovolts (kV) (69,000 volts) or higher.



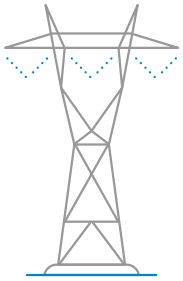
The transmission system is like the "interstate highway" of electricity delivery. It comprises three primary components: substations, switchyards and transmission lines. Both substations and switchyards are connection points where two or more transmission lines connect to form an "intersection."

The transmission lines are responsible for getting large quantities of electricity from the generation resources over long distances to the distribution system to deliver to customers. In some instances, larger energy customers connect directly to the transmission system.

SRP's transmission system is also part of a more extensive transmission network called the Western Interconnection, which ties SRP to other regional utilities and allows SRP to participate in wholesale power markets. The SRP transmission system is just a portion of this more extensive system with solely owned and co-owned lines with neighboring utilities. Being part of the Western Interconnection enables utilities to share generating resources to help balance the region's needs. Transmission Planning at SRP determines what new transmission infrastructure is needed to deliver energy reliably to SRP's service territory.

Transmission System Today

As of April 2023, SRP owns and/or operates and maintains about 3,333 circuit miles of three-phase power lines at 69 kV–525 kV voltages. Of these power lines, SRP owns approximately 955 miles of 69 kV, 263 miles of 115 kV, 493 miles of 230 kV and 361 miles of 525 kV. SRP jointly owns about 36 miles of 230 kV and 1,103 miles of 525 kV. These power lines and additional equipment, including over 1,200 circuit breakers and 72 transformers, make up the SRP transmission system today.



3,333 CIRCUIT MILES

Transmission Planning for the Future

As the demand for electricity in the Phoenix metropolitan area continues to grow, the need for new and upgraded transmission infrastructure also increases. Transmission infrastructure is planned to construct facilities and place them in service before they are needed. One of the significant challenges with planning the transmission system is the uncertainty around the location of the new electric demand and future generation resources. SRP proactively identifies and develops effective transmission solutions for current and future electric customers.

SRP is integrating low-carbon resources, such as solar, to meet our customers' growing electricity demand and replace retiring generation assets. This shift in our resource mix also impacts the transmission system. Some of the transmission-related challenges facing utilities are system voltage control, greater fluctuations in frequency, and increased risk of interruption due to forest fires. To best prepare for these transmission-related issues, we are shifting our planning practices to integrate consideration for all key planning areas. These new efforts will aid in developing plans to address grid needs across all of our planning areas holistically. This move also bolsters our efforts to achieve our 2035 Corporate Goals.

Distribution System Overview

The distribution electrical system includes the distribution substations and the infrastructure required to bring power safely and reliably to SRP customers. Distribution Planning is responsible for ensuring that we can serve the energy needs of current and future customers safely and reliably. This is accomplished by developing short- and long-term load growth plans and designing a highly configurable, robust looped system, allowing us to serve customers by multiple paths. If service from one path gets interrupted, we can still serve the customer from a secondary path. This configuration also allows us to reconfigure the system for optimal use of existing capacity.

This commitment to providing reliable power is why SRP has been ranked highest in customer satisfaction in the western United States among large electric utilities 22 times in the past 23 years that J.D. Power has been surveying residential electric customers.



Distribution System Today

As of 2023, SRP provides power to more than 1.1 million customers in a 2,900-square-mile service area. More than 1,198,000 advanced meters are serving SRP customers. Some of our customers are becoming increasingly involved with their energy future now more than ever by taking more of a prosumer role of consuming as well as producing electricity. In total, 51,287 customer-owned distributed energy resources (DERs) are interconnected with the SRP grid, including standalone solar generation, solar paired with battery storage, and standalone battery storage. Of those DERs, 50,468 are residential and 819 are commercial. These DERs provide a total generation capacity of 472 MW and a battery storage capacity of almost 16 MW.

Most of SRP's distribution system is looped, meaning there is more than one path that electricity can travel to serve a customer, but only one path at a time. SRP operates and maintains 21,736 circuit miles of lines that comprise the SRP distribution system, which entails 1,428 distribution circuits.

SRP operates and maintains 286 substations, including 191 distribution substations that transform power to the 12 kV voltage level to serve neighborhoods and other customers. A substation can accommodate one to four transformers, each serving 2,000–3,000 customers, depending on load requirements.

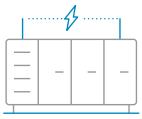
SRP is committed to providing reliable power, which is why we have ranked in the top 10 in the nation for our low System Average Interruption Duration Index (SAIDI) among all electric utilities with more than 500,000 customers every year for at least the past 10 years. This metric tracks the number of minutes customers are without power for more than five minutes averaged over all SRP retail customers. This includes any loss of customer load, planned or unplanned. SAIDI is an industry metric commonly used to assess overall power reliability.

1.1 MILLION+ CUSTOMERS

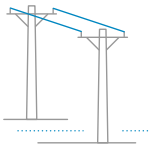


2,900-SQUARE-MILE SERVICE AREA

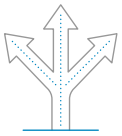
16 MW
DER BATTERY STORAGE CAPACITY



21,736
CIRCUIT MILES



286
SUBSTATIONS



Distribution Planning for the Future

The SRP distribution system is experiencing unprecedented growth due to a wide variety of new and expanding customers, including tech firms and advanced manufacturing. As more DERs, including solar generation and battery storage, are added to the distribution system, the possibility of voltage issues increases. The system is also experiencing an increase in electrification (EV adoption, smart appliances, etc.) that draws more of the load.

When we consider these factors, it becomes clear that we need to enhance our projection models of the distribution system and increase our ability to collect and analyze data. These efforts to plan for the changing grid will enable distribution planning to work collaboratively with other planning areas at SRP through an improved planning process.

Customer Programs Overview

Providing customers with reliable, affordable and sustainable service includes helping them understand and manage their energy usage through energy efficiency, demand response, electrification, EV and grid enablement programs. Customer programs enable us to effectively limit power plant emissions, lower costs, manage current demand and plan for future growth.



SRP has developed and fielded innovative customer programs and price plans to meet changing patterns in electricity use and customer needs. Demand Response (DR) programs such as smart thermostat and EV-focused programs and price plans encourage customers to shift energy usage to times energy is abundant and affordable. Looking to the future, we must evolve our programs to match the changing grid. Distributed energy programs enable the interconnection of thousands of customer-owned solar and battery systems each year. For customers unable to invest in their own renewable energy projects, SRP has invested heavily in system-scale solar and battery storage projects to offer unique solar energy programs that take advantage of economies of scale to help customers large and small achieve their individual sustainability goals. Customer programs will continue to meet evolving customer needs while spurring the transition to low-carbon energy for all customers.

Forecasting SRP customers' future energy demand (load) is one of the most important considerations for any long-term planning. We need to understand our customers' unique needs in order to plan for and maintain the reliability of SRP's transmission and distribution systems and have enough generating resources online to meet that load.

Customer Programs Today

For fiscal year 2023, SRP maintains a robust and comprehensive portfolio of customer programs; SRP's energy efficiency (EE) portfolio remains one of the largest and most cost-effective in the Southwest and across the country. For the 10th consecutive year, SRP was awarded the EPA's 2023 ENERGY STAR® Partner of the Year award with Sustained Excellence in recognition of outstanding delivery of Energy Efficiency programs.

Aside from EE and DR, SRP's growing Transportation Electrification programs are working to support the adoption of EVs and tackle the challenge of managing EV charging demands to avoid future on-peak hours. Electric Technology programs further support the electrification of fossil fuel-served loads today. In contrast, Distributed Energy programs support customer access to

utility-scale renewable energy projects and the interconnection of customer-owned solar and battery systems. SRP has also committed to developing programs like the Sustainable Energy Offering and others to partner with large customers with sustainability goals to reduce carbon emissions on a grand scale.

In fiscal year 2023, SRP's programs helped customers:

- Save 616,847 MWh — enough to power 37,000 homes annually — by:
    - Completing 70,000-plus residential efficiency upgrades and 1,200-plus commercial efficiency projects
    - Moving into 15,000-plus new, efficient homes and commercial spaces
    - Learning more about efficient, cost-saving behaviors (94,000 SRP Energy Scorecard™ and 148,000 SRP M-Power® participants)
    - Planting 5,300-plus drought-tolerant shade trees
- Develop 128 MW of dispatchable demand response capacity by:
    - Subscribing 87 MW of capacity through 76,143 smart thermostats in the residential SRP Bring Your Own Thermostat Program™
    - Enrolling more than 500 business customer facilities to deliver 41 MW of DR capacity
- Adopt 40,585 EVs within SRP's service territory and:
    - Install Level 2 or better charging for 3,300-plus EVs (581 business ports, 2,020 residential ports and 763 EV-ready homes)
- Electrify 15,897 MWh of business equipment load
- Achieve renewable energy goals by:
    - Commissioning 11,925 solar PV or PV+battery storage systems
    - Matching 100% of the electricity needs for 33 large commercial customers with 300 MW of dedicated solar energy through SRP's Sustainable Energy Offering (trimming carbon pollution in Arizona by 1.6 million tons)
    - Connecting 6,544 residential and small business customers to system-scale solar through the SRP Solar Choice™ program
- Avoid the consumption of 250 million-plus gallons of water through avoided generation and water efficiency embedded in the programs

Cutting carbon emissions by 1.6 million tons is equivalent to taking 300,000 cars off the road for a year!

SRP is committed to delivering programs and price plans that continually evolve to align with customer needs while maintaining a reliable, affordable and increasingly sustainable system. Despite recent achievements, there is a future need for even more energy efficiency to help maintain affordability by reducing customer energy consumption and pacing infrastructure investments. SRP has committed to accelerating its energy efficiency plans and goals while expanding demand response initiatives to help achieve established 2035 DR targets.

Customer Programs of the Future

As the population of SRP's service territory expands, we remain committed to meeting the growing needs of the communities we serve while staying focused on our 2035 Sustainability Goals. During our transition to a more sustainable future, the types and availability of low-cost resources will change with the increased adoption of renewables. As these changes occur, we will remain focused on striking the right balance of reliable, affordable and sustainable power for our customers. SRP continues to adapt its customer programs to meet changing patterns in electricity

use and needs by maintaining the acceleration of Energy Efficiency and Demand Response program plans to help address the significant load growth and capacity constraints SRP faces over the next several years.

As we plan further into the future, we must maintain affordability for our customers by continuing to leverage the existing infrastructure upgrades and expansion of customer program strategies to help reduce the need for costly new capital investments to meet near-term capacity needs. We must monitor how customers' energy usage and needs evolve and change as the digital economy drives how and when customers use power. Lastly, we must ensure customer programs will continue to help SRP cost-effectively meet growing customer needs while helping to address load growth and reliability challenges.

Uncertainties Facing SRP Today

While SRP's power system is transforming, other external factors also impact our planning efforts, including explosive load growth in SRP's service territory, evolving customer needs, supply chain volatility, regulatory policy uncertainties and resource adequacy uncertainty in the West. This section covers the significant drivers and trends we observed during our ISP planning efforts.

Explosive Load Growth & Evolving Customer Needs

The Phoenix metropolitan area continues to rank high in population growth nationally. For SRP, this growth means more customers, higher energy demand and increased peak demand. This demand is coming rapidly, putting pressure on us to develop solutions quickly. Demand has increased by 1.7% per year during the last decade, and these trends are expected to continue. While the SRP service area experienced extraordinary residential growth in the early mid-2000s, SRP is now experiencing unprecedented growth in the commercial and industrial sectors, including high-energy users such as semiconductor manufacturing, data centers and other high-tech industries.

Additionally, customers' energy usage and needs continue to evolve and change as the digital economy drives an evolution in how and when customers use power. These new customers not only need 24/7 power but also have specific power quality needs and an increased need for reliable power delivery. Large and small business customers are also driving renewable energy development needs for SRP, with an increased desire for partnership opportunities to help them achieve their sustainability goals.

Supply Chain Volatility

Volatility within the global supply chain impacts each group involved in SRP's integrated system planning process. COVID-19 exposed how quickly the interconnectedness of the global supply chain can lead to fewer suppliers, longer lead times, higher prices, material shortages and logistics challenges. Russia's war with Ukraine further exacerbated the disruptions to an already taxed supply chain and added to the uncertainty. Additionally, as inflation continues to rise, we can expect it to play a significant role in pricing in the future. Supply chain uncertainties are an essential factor in future planning and budgeting, as collectively or individually they can change the direction of our planning. Continuing to work jointly with our Supply Chain organization will enable us to find the flexible solutions needed to support our customers.

Regulatory Policy Uncertainty

Shifts in regulatory policies make it more difficult for SRP to make decisions because it is difficult to assign probabilities to possible future states confidently. Two policy developments that have a high potential impact on SRP's long-term planning efforts are the Inflation Reduction Act and the proposed EPA 111(b) and 111(d) rules.

Inflation Reduction Act

The Inflation Reduction Act of 2022 (IRA) was passed by Congress and signed into law by President Biden. SRP has traditionally contracted for renewable and energy storage projects through power purchase agreements (PPAs) with developers who could take advantage of previous tax credits. The IRA now provides SRP and other public power entities with access to direct pay credits for the first time, which may create the opportunity for SRP to receive federal incentives for self-built renewable and energy storage resources. The IRA could provide several potential benefits to power utilities; however, there are uncertainties about how the domestic supply chain will ramp up to meet increasing demand and what specific requirements must be met to qualify for IRA credits, given implementation guidance has not yet been issued.

Proposed EPA 111(b) and 111(d) rules

In May 2023, the EPA released its proposed carbon pollution standards for new, modified, reconstructed and existing power plants under sections 111(b) and 111(d) of the Clean Air Act. The regulatory package proposed standards for new gas-fired combustion turbines, existing coal and gas-fired steam plants, and certain large and frequently used existing gas-fired combustion turbines. The proposed standards are based on control methods and technologies (e.g., limited capacity factor, combusting hydrogen and installing carbon capture) that can be applied directly at electric generating units. If finalized, the 111(b) and 111(d) rules could help decarbonize the energy sector. Still, uncertainty remains regarding the availability and timing of the control technologies that the EPA relies on to reduce emissions.

Resource Adequacy in the West and the Impacts of Climate Change

SRP must maintain the ability to meet customers' energy demands at all times of the day and across a variety of system conditions. This resource adequacy requirement is becoming more complex as the utility industry transitions from conventional generating technology to renewables and storage. Reliable electricity supply is also becoming increasingly important to society as recent extreme weather events triggered regional outages that impacted customers and communities across the electric system. SRP routinely monitors the current trends affecting the desert Southwest region to understand better how to plan our investments and resources amidst uncertainty.

Because SRP is connected to an extensive grid system that includes neighboring utilities, the entire regional grid is at risk when one area or utility is not resource-adequate. Extreme temperatures also put pressure on utilities to maintain reliability by driving up customers' demand for more energy and fueling natural disasters such as wildfires that can damage the transmission system and limit utilities' ability to move power where their customers need it. The climate change impacts experienced over the last few years are expected to continue.

In light of the dramatic transition in the utility industry and the importance of regional resource adequacy, the SRP Board in January 2023 approved SRP's participation in the Western Resource Adequacy Program (WRAP), which is the first regional program of its kind in the history of the West. WRAP will deliver a regionwide approach to assessing and addressing resource adequacy. It will help ensure that entities use consistent planning approaches as utilities become increasingly reliant on variable resources like solar, wind and battery storage.

Technology Advancements

To achieve continued decarbonization while maintaining a highly reliable grid, SRP is monitoring, developing and deploying advanced low- and zero-carbon firm technologies such as clean hydrogen, long-duration storage and small modular nuclear. Accelerating the deployment of firm low-carbon energy solutions is required to continue to provide reliable and sustainable energy for SRP customers. Significant progress is being made around new nuclear technologies and long-duration storage that could provide reliable, safe and carbon-free generation in the future. Unfortunately, the current development timeline for some of these resources is over a decade. While today's market is experiencing some obstacles, a combination of new technologies, efficiencies in permitting and lower financial risk during construction may provide a compelling option for these resources in the future. Therefore, it is important for SRP to continue to pursue activities that preserve varying resource options, such as potential site locating and early permitting.

Planning for the Future

The electric power industry has undergone a dramatic transformation in recent years, and that transformation is expected to accelerate, driven by a variety of factors mentioned above, including:

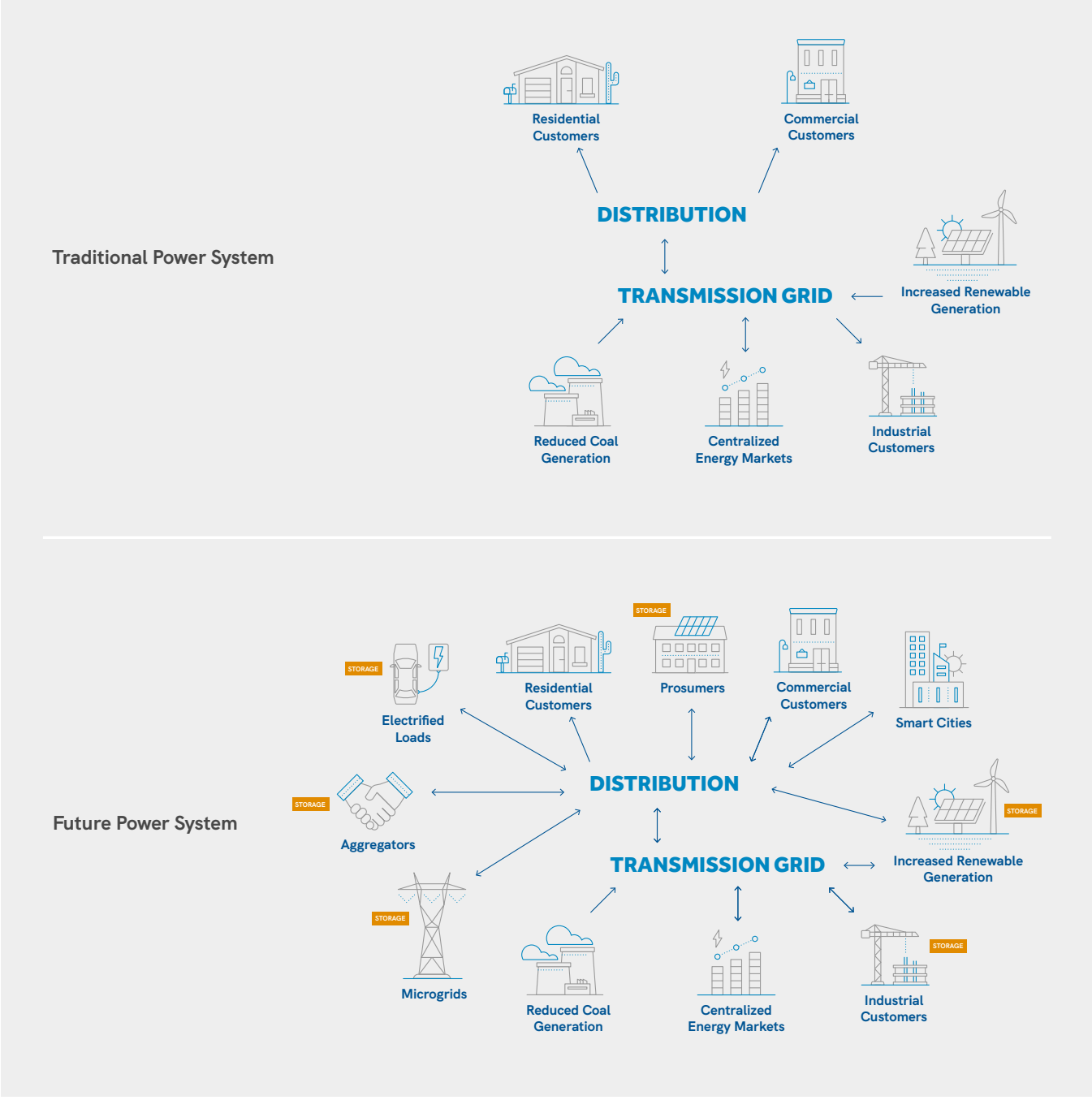
- Rapid deployment of large-scale variable energy resources (VERs) such as solar and wind
- The growth of distributed energy resources (DERs) like rooftop solar and residential battery storage
- Dramatic advances in digital energy and communications technologies
- Persistent low natural gas prices
- Increased reliance on just-in-time delivery of natural gas to support gas-fired generation
- Growing awareness of the electric sector's potential role in achieving environmental goals

While all of these external factors are changing, SRP is also evolving by integrating a significant number of low-carbon resources, such as solar, to meet our customers' growing electricity demand and replace retiring generation assets. This shift in our resource mix also impacts operations and the grid. Some of the transmission-related challenges facing utilities are system voltage control, more significant fluctuations in frequency, and increased risk of interruption due to forest fires. With these changes, traditional planning methods are increasingly insufficient to optimally develop a safe, reliable, affordable and environmentally responsible power system. Meeting our customers' needs over the next decade will require a complete transformation of the power system that touches all aspects of our business: how, when and where we generate and store electricity; how we deliver electricity over our transmission and distribution systems; and how we engage with our customers through rate design and customer programs. Our success

in this transformation depends on our ability to plan the system in an integrated fashion, allowing for close coordination and collaboration to identify the best solutions for our customers.

Integrated Resource Planning to Integrated System Planning

In the past, Integrated Resource Plans guided SRP's ability to plan long-term generation resource decisions by conducting structured analyses assessing risk and uncertainty. Given the many ongoing changes in the power sector, we must adapt these traditional planning methods to optimally develop a safe, reliable, affordable and environmentally responsible power system.



To best prepare for these impacts, SRP has transitioned from a conventional Integrated Resource Plan (IRP) solely focused on resource planning to a more holistic and comprehensive Integrated System Plan (ISP), including forecasting, resources, transmission, distribution and customer programs, to achieve our 2035 Corporate Goals.

An integrated system planning approach is necessary to meet changing customer needs, such as enabling two-way power flow for rooftop solar additions, managing charging of EVs, and anticipating the power system transition to a lower-carbon, increasingly complex grid. Given the effort needed to implement a holistic ISP, we focused on the period from 2025–2035 for our first-ever ISP, which will be covered in more detail in the next section.

SECTION 3

ISP Overview and Process

Why Integrated System Planning?

Historically, many of the planning functions that have existed within utilities have operated independently from one another. While planning processes for generation, transmission, distribution and customer programs have relied on some common data sets and exchanged some information, planning cycles are often asynchronous, focus on different objectives and planning horizons, and lack direct visibility into how quickly other parts of the system are changing. The most prominent of these planning processes, the utility Integrated Resource Plan (IRP), has traditionally focused exclusively or primarily on future generation choices with limited insight into the implications of those choices for other aspects of the utility's systems.

Given the rapid pace of change in the power sector, we identified a need to integrate planning within a single process — the Integrated System Plan (ISP) — to optimally develop a safe, reliable, affordable and sustainable power system. Planning decisions across the system must be coordinated to identify the best path forward for customers. For example:

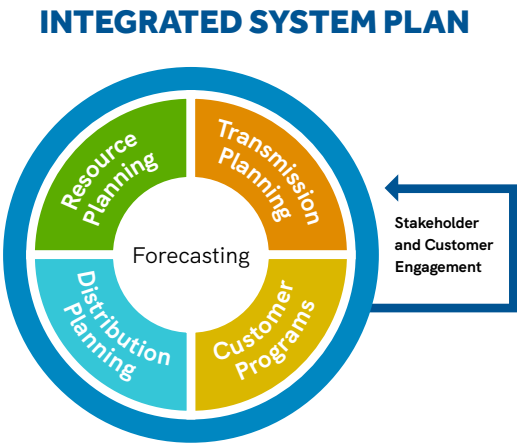
- Adoption of electric vehicles (EVs) will increase electricity demand, requiring additional investments in new power generation and delivery infrastructure. But if we can provide pricing signals to customers that encourage them to charge their vehicles during periods that are more advantageous for the overall system, we can limit the amount of new infrastructure investment needed. The most advantageous periods for charging will depend on future resource, transmission and distribution needs.
- Many of the new large-scale generation resources that we will consider — particularly renewables — will be located in areas where the existing transmission system may not be able to accommodate their delivery. Studying how the location of these new resources will impact the transmission system will provide a leading indicator of where new investment may be needed and may also allow for proactive siting of renewable resources to take advantage of transmission opportunities.
- As the share of solar generation in our portfolio increases over time, daytime energy will become increasingly abundant and lower the value of conservation during this period. This will have direct impacts on how we think about the value of future customer programs and the design of our future time-of-use price plans.

With this first ISP, we have transitioned to a holistic and collaborative planning framework that includes all key planning areas at SRP. By planning for the entire power system within one process, we are positioning ourselves to answer the most difficult multidisciplinary questions that will confront utilities in the coming years.

What is the Integrated System Plan?

SRP's ISP is a holistic power system roadmap that considers evolving customer needs for reliability, affordability and sustainability while achieving our 2035 Corporate Goals. The ISP includes all elements of meeting future customer demand: forecasting, power generation, transmission, distribution and customer programs. The ISP will help SRP plan for a future power system while maintaining a high standard of customer service from 2025 to 2035.

Before initiating the objective setting phase of the ISP, SRP retained Energy and Environmental Economics (E3), an energy consulting firm that works with utilities, regulators, policymakers, developers and investors to tackle the most pressing, difficult questions facing the electric industry. In our ISP — one of the first comprehensive efforts in the industry to initiate a systemwide planning process — E3's combination of broad experience, technical expertise and creative problem-solving made their support invaluable to our success. Further, having worked with each of Arizona's three largest utilities in support of integrated resource planning processes, E3 brought an understanding of our state's unique utility planning landscape that made their advice throughout the process germane and direct. At every step of the process, E3 was a vital partner for SRP, providing full-service support in the following areas: scoping the planning process; designing the analytical and stakeholder engagement frameworks; overseeing analysis and validation; and providing modeling support for the ISP process.



Objectives for the ISP

In April 2021, the SRP ISP project team and E3 concluded the objectives phase of the ISP after conducting many interviews and holding alignment workshops with SRP leadership. Through this process, the ISP project team received direction from senior leaders on the vision and objectives of the first ISP and received approval to develop a more detailed study plan.

ISP Vision Statement and Objectives

This vision, the goals and SRP's 2035 Corporate Goals guided the development of the ISP vision statement and objectives below.

"An ISP is a data-driven, collaboratively developed plan for generation, transmission, distribution and customer-sided resources to meet SRP's 2035 Corporate Goals and prepare for SRP's 2050 ambitions and system needs."

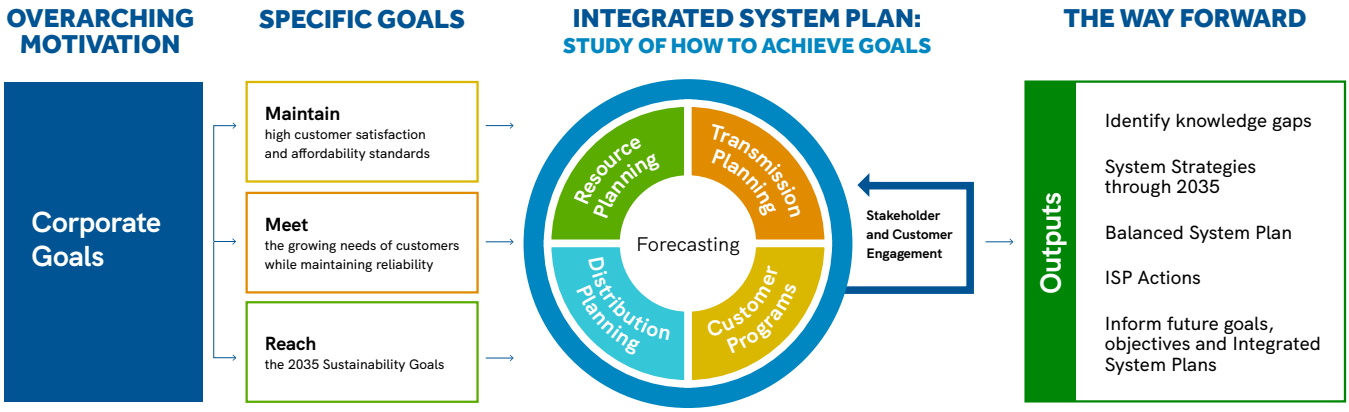
ISP objectives are to identify:

- Viable pathways for achieving SRP's 2035 Corporate Goals
- Costs, risks and trade-offs of these different pathways
- System solutions that are valuable across different pathways
- New capabilities or tools required to plan and operate as the system evolves effectively
- Activities SRP should undertake in the next six years to plan for these system solutions

SRP's 2035 Corporate Goals have been updated. The ISP leveraged goals established in 2019 and was completed prior to the 2024 updates.

Process for the ISP Development

The ISP process begins with SRP's Corporate Goals which establish the specific performance objectives of SRP and the motivation for the ISP. The ISP objectives relate to reliability, affordability and sustainability ("the what"), and the ISP determines how best to meet those objectives ("the how"). The ISP analytical process then combines the power system planning functions into an integrated planning framework to ensure that investments across the functional areas contribute together to support the corporate goals and objectives. In addition to the analysis, the ISP process included a comprehensive engagement process with customers and stakeholders to inform and gather input on the ISP and build support for the ISP outcomes. Key outputs of the ISP include a set of ISP Actions and longer-term System Strategies that help guide the development of SRP's power system through 2035.



The ISP analytical process, or "framework," was developed as part of the ISP objective setting process and involves conducting scenario analysis across the system functions to evaluate the cost and performance trade-offs and risks in achieving SRP's Corporate Goals. The process steps included:

1. Establishing an appropriate set of scenarios that evaluate key drivers of uncertainty outside of SRP's control.
2. Evaluating system needs for each scenario, subject to minimum reliability planning criteria.
3. Developing alternative solutions to meet the system needs for each scenario that consider key SRP decisions.
4. Synthesizing the scenario analysis to develop an illustrative Balanced System Plan that depicts the execution of ISP outputs, including System Strategies and ISP Actions, considering costs, performance and risk trade-offs metrics.

The objective development phase also included a stakeholder and customer engagement approach. SRP obtained the services of Kearns & West, a collaboration and strategic communications firm with experience in similar projects for other power utilities and an impartial approach to outcomes. Kearns & West offered input on establishing stakeholder groups and engagement methods, facilitated and documented meetings with stakeholders, and provided feedback on other aspects of stakeholder engagement. SRP, E3 and Kearns & West established a communications team, closely collaborating to create this approach. The communications team designed and executed all ISP stakeholder engagements, including scheduling, material

preparation and coordinating discussions with stakeholders internally and externally. The process included a review of best practices and lessons learned at SRP and other utilities. The effort also reviewed how other utilities capture residential and small commercial viewpoints in planning activities and consulted with SRP's Community, Communications and Marketing (CCM) organization to identify existing research resources and explore future approaches for gaining residential and small commercial customer input. Finally, the team consulted the CCM organization on best practices and options for stakeholder information sharing and regularly consulted SRP's 2017 IRP and Sustainability 2035 leads.

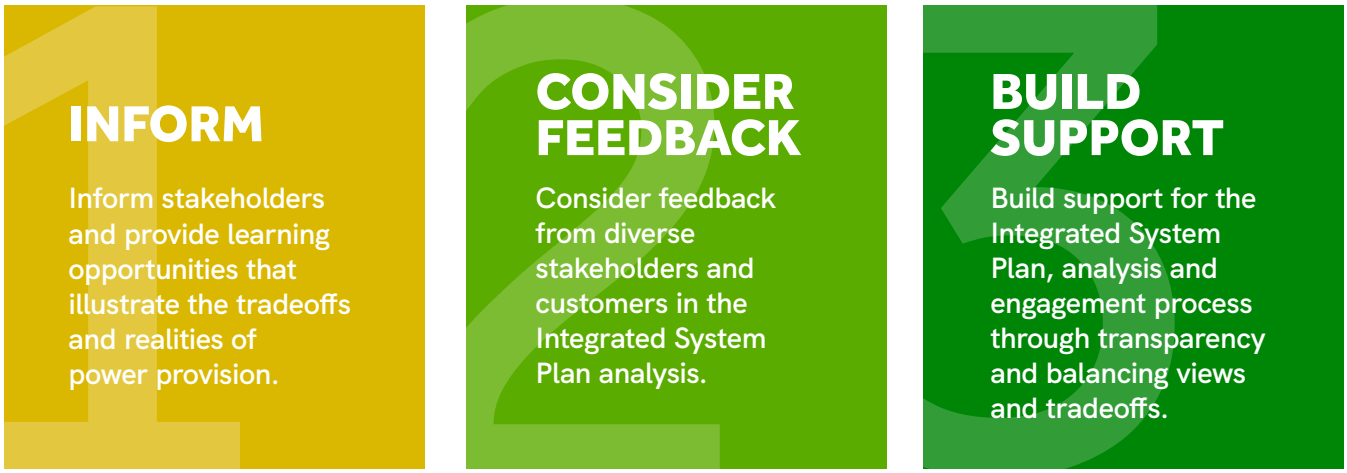
The stakeholder groups and customer engagement approaches are depicted below. SRP, E3 and Kearns & West also worked together to develop the details of the engagement approaches, including stakeholder group membership, roles, meeting topics and information sharing.

Stakeholder Group	Engagement Method
Advisory Group	• Focused engagement from a smaller diverse group • Regular meetings • ~20 representatives from diverse organizations • Role(s): Inform, Consult and Involve
Large Stakeholder Group	• Large-scale public platform • Eight meetings • Over 140 organizations • Role(s): Inform and Consult
Technical Working Sessions	• Small groups convened on specific topics with topical experts • Single sessions scheduled as needed around topics of interest • Role(s): Consult
Customer Research	• Multipronged approach to include the customer's voice • Surveys, customer preference elicitation, focus groups • Role(s): Consult

Role of the ISP Stakeholder Groups

A vital aspect of the ISP is developing and implementing a robust plan to actively engage customers and external stakeholders. SRP delivers power to diverse communities, individuals and organizations, and these stakeholders may hold varying views of the future and preferences for SRP's path forward. Providing information to stakeholders about the challenges SRP faces and collecting feedback on these challenges helped us roadmap a viable path forward. Inclusive, transparent and proactive dialogue with SRP stakeholders helped build support for the ISP process underlying SRP's strategic decisions. Much of the stakeholder and customer engagement efforts were planned to interact with the development of the ISP at specific touchpoints. These engagement efforts had the following three Global Goals:

FIGURE 3.1: ISP ENGAGEMENT GLOBAL GOALS



Transparency was essential in the development of the ISP. We designed the process to engage customers and other stakeholders and be responsive to their questions and input. In our best effort to keep transparency with all interested SRP stakeholders and customers, we posted all ISP stakeholder engagement materials publicly, including pre-reads, agendas, presentations and meeting summary reports, throughout the entirety of the project. These can be found on our ISP webpage at srp.net/isp.

Where We Needed Stakeholder Input for the ISP Process

Through the engagement tools described in the section below, SRP obtained input from stakeholders, including residential customers, regarding the questions proposed below. Their input helped shape all elements in the ISP study plan and informed the design on the final ISP outputs.

- Looking to 2035, what are Arizona's major sources of uncertainty relative to electricity generation, delivery, consumption and affordability?
- What system options should SRP include in its planning analyses for the future power system through 2035?
- What does success look like from your perspective when evaluating reliability, affordability and sustainability?

- What is the scope of the first ISP and which topics of interest should be considered for further research and future ISPs?
- What are the methods for balancing the trade-offs between reliability, affordability and sustainability?
- How might SRP improve our approach to stakeholder engagement for future ISP processes?

Stakeholder and Customer Engagement Tools

The ISP included customer research, technical working groups, large stakeholder group meetings, one-on-one discussions with interested stakeholders and the formation of an Advisory Group. This portfolio of engagement tools helped to achieve all three Global Goals described in Figure 3.1 on the previous page. Some groups focused more on bilateral dialogue, considering feedback and building support, whereas others focused on providing information to stakeholders and the public. The objectives and a brief description of each tool are given below.

The **Advisory Group** is made up of over 20 diverse community organizations and over 30 customer interest representatives. The group contributed wide-ranging expertise and perspectives to the ISP, which helped SRP produce a plan that reflects the diverse interests and values of the customers and communities we serve. Below are the mission and objectives of the ISP Advisory Group. For more information, please reference SRP's ISP Advisory Group Charter.

Mission Statement

The charge of the Advisory Group is to contribute wide-ranging expertise and perspectives to the ISP, resulting in an end product that integrates the diverse interests and values of the customers and communities SRP serves.

Objectives

- Create a dialogue around the ISP.
- Include diverse perspectives as input, guidance and review for the ISP.
- Provide a forum for deep and technical discussion of the trade-offs in energy system planning and the various perspectives to build support around the strategic directions and resource, transmission, distribution and customer program action plans.
- Focus communication for the Large Stakeholder Group.

Choosing a balanced and diverse group of stakeholders for the Advisory Group was critical to ensure that all perspectives were represented and that a single viewpoint was not dominant. To maintain balance, SRP chose members that were representative of one or more of the following stakeholder categories:

Local or special interest groups

- Community Advocates
- Equity Representatives
- Native American Interests
- Environmental Advocates
- SRP Resource Communities
- Public Interest Groups

Customer groups

- Commercial Customers
- Residential Customers
- Small Business Customers

Industry groups

- Energy Efficiency Industry Representatives
- Electric Vehicle Industry Representatives
- Renewable Energy Industry Representatives

Advisory Group Modeling Subgroups – Modeling subgroups were arranged as needed during the ISP process. Advisory Group members who were intensely interested in diving deeper into the ISP analysis self-selected into these subgroups. Efforts were made to include Advisory Group members who span stakeholder interests. Subgroup meeting discussions were reported in subsequent Advisory Group meetings. The Advisory Group's input, questions, ideas and concerns guided and initiated modeling subgroup meetings. If more than 50% of Advisory Group members were interested in participating in a specific subgroup, SRP would consider integrating the subgroup discussion content into the regular Advisory Group meeting series.

Large Stakeholder Group – This group of over 140 organizations was invited to eight meetings throughout the process. The meetings addressed informing stakeholders and considering feedback.

Mission Statement

To provide transparent communication to stakeholders regarding SRP's planning initiatives and allow for stakeholders to ask questions and provide feedback.

Objectives

- Keep stakeholders informed of SRP's planning initiatives in a transparent and proactive way.
- Build understanding of the trade-offs SRP faces and emerging trends in energy markets, regulations and technology.
- Provide opportunities for stakeholders to ask questions and receive answers from SRP experts.
- Provide feedback opportunities for stakeholders and consider their perspectives when balancing trade-offs while developing the ISP.

The Large Stakeholder Group was made up of over 140 organizations and 200 individuals, including representatives from SRP's customers and communities; 120 organizations were initially invited based on their existing relationships with SRP, standing within the Arizona community and diversity of perspectives. Types of organizations also included local and special interest groups, customer groups and industry groups. Throughout the process, SRP received many requests from individuals and entities to join the ISP Large Stakeholder Group outside of the initial organizations invited. They were all accepted and integrated into the process, resulting in a total of over 140 organizations at the end of the process. SRP strove to maintain inclusivity and representativeness within the Large Stakeholder Group so that the group reflected the diverse interests and values of the customers and communities SRP serves.

Technical Working Sessions – These sessions addressed specific technical topics of interest that arose throughout the ISP process and were attended by both external and internal SRP experts. The sessions leveraged external technical expertise for advice on the analytical methods used in

the ISP. The objectives of the Technical Working Sessions addressed considering feedback and building support and were to:

- Create a structured forum for external experts to give deep technical input to the most complex challenges in future planning.
- Build support around the ISP methodologies by leveraging external best practices.

Customer Research – This was a multipronged research approach that focused on understanding the preferences and perspectives of residential customers with the overarching goal of reflecting diverse customer voices and perspectives in the ISP. Customer focus groups and surveys were conducted to collect the preferences of SRP customers on balancing reliability, affordability and sustainability in potential energy futures. This data allowed SRP to consider the customer's perspective when choosing the best path forward. Customer research addressed bilateral dialogue, considering feedback and building support from our residential customers through the achievement of the specific following objectives:

- Co-create learning opportunities about the ISP and SRP's strategies, decisions and initiatives with customer input.
- Understand the energy/utility programs customers participate in and why.
- Understand customers' concerns about the future of Arizona, the economy and the United States.
- Align how customers plan for their futures and how secure they feel in their lot with the process and messaging of the ISP.
- Understand customer perspectives on power, reliability and potential trade-offs with sustainability.
- Understand the diverse perspectives and opinions on SRP's route to sustainability and how these opinions evolve.
- Include customer input into the ISP analysis and the balancing of trade-offs.

Guiding ISP Principles

These principles were developed in collaboration with ISP team and ISP Advisory Group members. The purpose of the Guiding ISP Principles was to balance all important considerations in developing an ISP. SRP strove to understand the inherent trade-offs between reliability, affordability and sustainability for the principles and sought to establish an ISP in accordance with these Guiding ISP Principles.

Integrated Long-Term View

Develop a holistic view, including resources, transmission, distribution and customer program perspectives, for meeting evolving customer needs and achieving our Corporate Goals for 2035 and beyond. The long-term view ensures that SRP is making the right decisions today to support its customers and stakeholders in the future.

Transparency

Engage customers and other stakeholders in a system planning process that is responsive to questions and input.

Measure Success Through the Eyes of Our Customers

Maintain industry-leading customer satisfaction by responding to evolving customer needs by providing safe, reliable, affordable and sustainable power while equitably recognizing the different needs, challenges and perspectives of our customers.

Manage Costs

Deliver exceptional system and energy value by minimizing impacts from additional grid needs and future uncertainties to average retail prices while maximizing customer value through diligent long-term-oriented cost management.

Build an Adequate and Reliable Power System

Meet (and in some cases exceed) industry standards to provide a dependable supply of electricity to all SRP customers. Provide a reliable grid that is able to prepare for and recover from both anticipated and unanticipated disruptions to ensure energy availability.

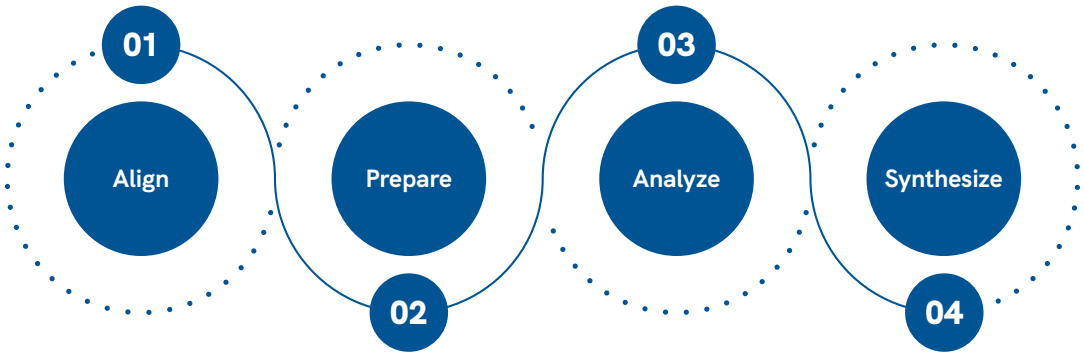
Adapt Toward a More Sustainable Future[1]

Meaningfully reduce carbon emissions and generation water usage to achieve SRP's 2035 Sustainability Goals to help address climate change and create less waste.

ISP Stakeholder Engagement Overview

Below is a summary of the stakeholder engagement process in the ISP and how we gathered and used internal and external stakeholder input to inform this first-of-its-kind planning effort in accordance with the above Guiding ISP Principles.

FIGURE 3.2: SRP ISP ROADMAP - STAKEHOLDER ENGAGEMENT



SRP ISP ROADMAP

Stakeholder Engagement

Align on Objectives of the first ISP

Collaboratively develop Study Plan:

Scenarios & Sensitivities Strategic Approaches Metrics

Gather input data

Perform system analysis

Validate and share results

Recommend new SRP system strategies

Recommend near-term actions

[1]The 2035 Sustainability Goals are being revised in 2024 in collaboration with community stakeholders. The next iteration of the ISP will focus on achieving and exceeding those revised goals.

Advisory and Large Stakeholder Group Engagements

For the initial Align Phase of the ISP depicted in Figure 3.2 on the previous page, SRP hosted four Large Stakeholder Group meetings over the summer of 2021. The SRP Summer Stakeholder Series was an opportunity to update, educate and engage with valued community stakeholders regarding SRP's efforts to transition from a traditional generation resource-focused Integrated Resource Plan (IRP) to a more holistic, comprehensive ISP inclusive of forecasting, customer programs, resource, transmission and distribution planning.

As shown in Figure 3.2, the Prepare Phase of the ISP stakeholder engagement strategy focused on creating a bilateral dialogue with stakeholders where they could comment, provide feedback and contribute their perspectives to the ISP analysis. This phase included customer research, one-on-one discussions with interested stakeholders, technical working groups, Large Stakeholder Group meetings and forming an Advisory Group. Together with community stakeholders, SRP set up a study plan that incorporated principles of scenario planning. This looked at how the future might unfold by analyzing key drivers, as well as the policy choices SRP could make and how those might perform in the future. We presented the co-created study plan for SRP's first-ever ISP to the Large Stakeholder Group on April 29, 2022.

Following along with the Figure 3.2 ISP Roadmap, at the end of April 2022, SRP kicked off the Analyze Phase of the ISP and conducted modeling through 2023. During this phase, SRP provided regular updates on ISP analysis to the Advisory Group as well as a final key findings presentation on April 21, 2023. Final key findings were presented to the Large Stakeholder Group on May 12, 2023.

As indicated in Figure 3.2, the final phase of the ISP was the Synthesize Phase, where SRP discussed with stakeholders and answered questions on viable pathways for meeting growing customer needs and achieving our 2035 Corporate Goals. SRP provided information to stakeholders about the trade-offs SRP faces, and collecting feedback helped SRP design a pathway moving forward. Inclusive, transparent and proactive dialogue with SRP stakeholders helped to build support for the first-ever ISP that will help guide major SRP strategy decisions.

Technical Working Sessions

In response to stakeholder feedback received throughout the objectives setting phase of the project, SRP developed Technical Working Sessions around topics of interest that stakeholders wanted to explore further. Starting in January 2021, SRP hosted four Technical Working Session webinars where experts from SRP and from around the country explored special topics. During 2022, SRP surveyed stakeholders to gauge their interest in different technical topics to help inform the topics for these sessions. The four sessions included the Inflation Reduction Act, inverter-based resources, regional market developments, and evolving time-of-day use programs.

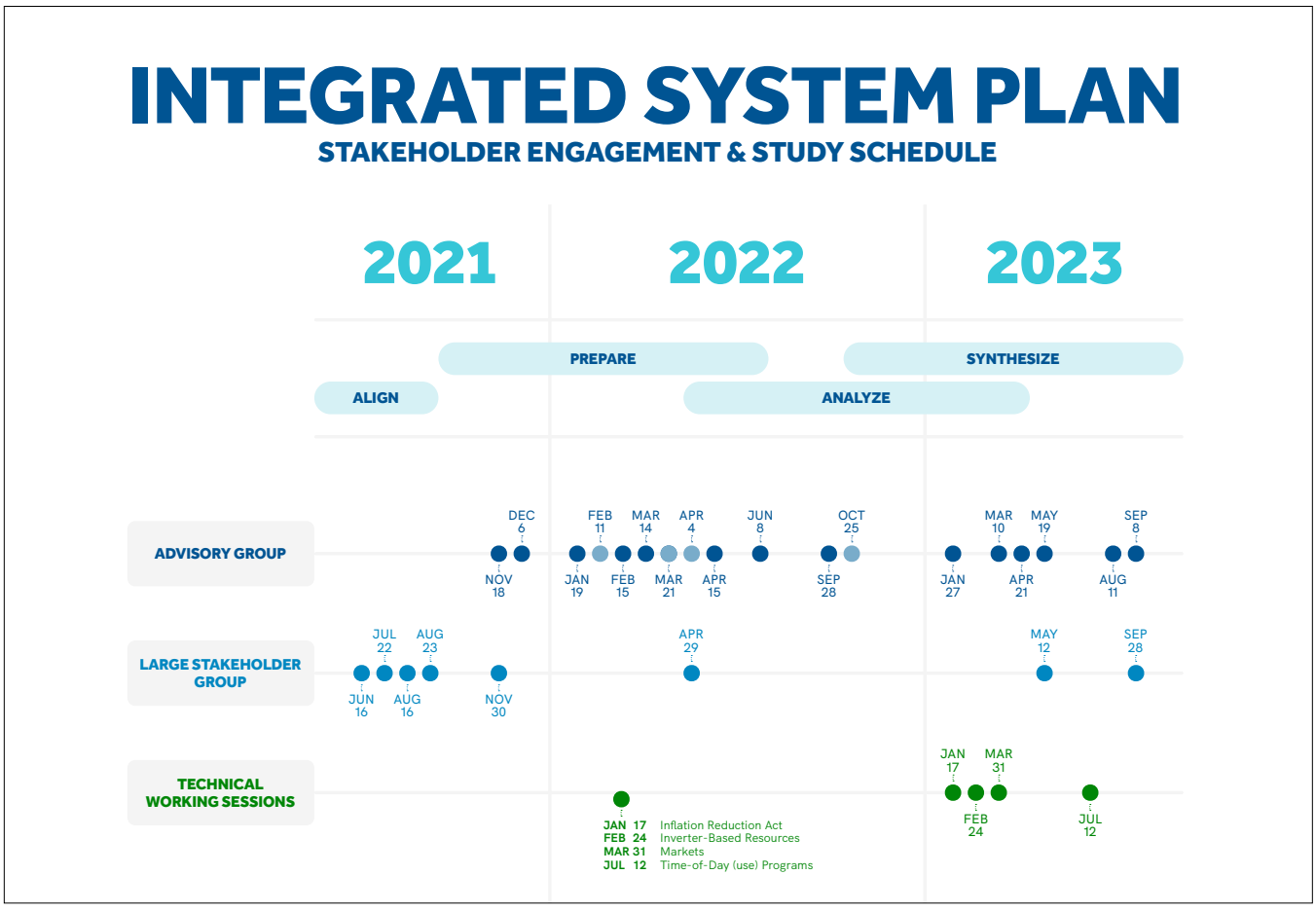
During these sessions, SRP shared work that has been done to date by our team in relevant areas. Each Technical Working Session featured a moderated panel discussion where external experts in relevant areas from around the country were invited to share leading industry experience and discuss potential enhancements SRP could undertake in future planning activities. Through these webinars, we had the opportunity to learn alongside stakeholders, gather input from these stakeholders, collect expert opinions in relevant topical areas and discuss potential enhancements applicable to SRP's system.

Customer Research

Throughout the process, SRP partnered with research consultant Bellomy Market Intelligence to execute the effort to bring the voice of SRP's residential customers into planning the future power system. Bellomy is a full-service market research firm that partners with healthcare, retail, financial, energy and consumer product companies to identify insights and strategic business implications derived from those insights. Having been immersed in the industry for over 25 years, Bellomy understands utility and energy clients' unique needs in regulated and deregulated landscapes. The customer research was a three-phased approach that started with phase 1, virtual focus groups (December 2021), followed by phase 2, quantitative confirmation survey (March 2022). The first two phases of research results were provided to Advisory Group members for consideration in designing the ISP study plan elements. Finally, for phase 3, a choice exercise was executed (May 2023). This research was designed to understand how customers think about reliability, affordability and sustainability related to power provision and gauge their reactions to a potential energy plan. All customers included in the research were SRP residential customers who were considered to be energy decision-makers and who did not work for a competing industry and were over 18 years old.

By using these engagement tools, SRP effectively collaborated with stakeholders and customers to build support for a shared vision for the future of the power system with 31 stakeholder meeting engagements executed and a multipronged residential customer research effort throughout the process, depicted in the timeline below.

FIGURE 3.3: ISP ENGAGEMENT TIMELINE



Transparent and Engaging ISP Process

SRP considered customers and community stakeholders essential partners in building a reliable, affordable and sustainable future power system. The holistic study plan was developed with input from SRP subject matter expert, customer and stakeholder feedback. The SRP project team, consisting of representatives from Forecasting, Resource Planning, Transmission Planning, Distribution Planning, and Customer Programs, performed a first-of-its-kind systemwide scenario analysis that allowed SRP to test strategies for building the future power system across a wide range of futures. Based on learnings from that analysis, the project team developed and shared with stakeholders the ISP key findings that identified costs, risks and trade-offs to consider when planning the future power system.

ISP PLANNING PROCESS FAST FACTS

NUMBER OF ADVISORY GROUP MEMBERS:

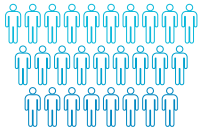


32
community representatives



from **23** organizations

NUMBER OF LARGE STAKEHOLDER GROUP MEMBERS:



250
community representatives from
143
organizations



SLIDES PRESENTED

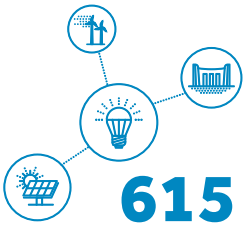
NUMBER OF MEETINGS:



31 stakeholder meetings



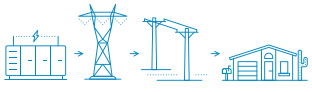
totaling over **62.5** hours of content



615
POINTS OF FEEDBACK COLLECTED AND INTEGRATED INTO THE ISP

1,411
RESIDENTIAL CUSTOMER SURVEYS CONDUCTED



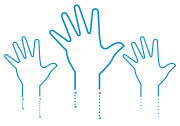


42
SYSTEM PLANS CROSS-FUNCTIONALLY ANALYZED



4
90-MINUTE RESIDENTIAL FOCUS GROUPS CONDUCTED

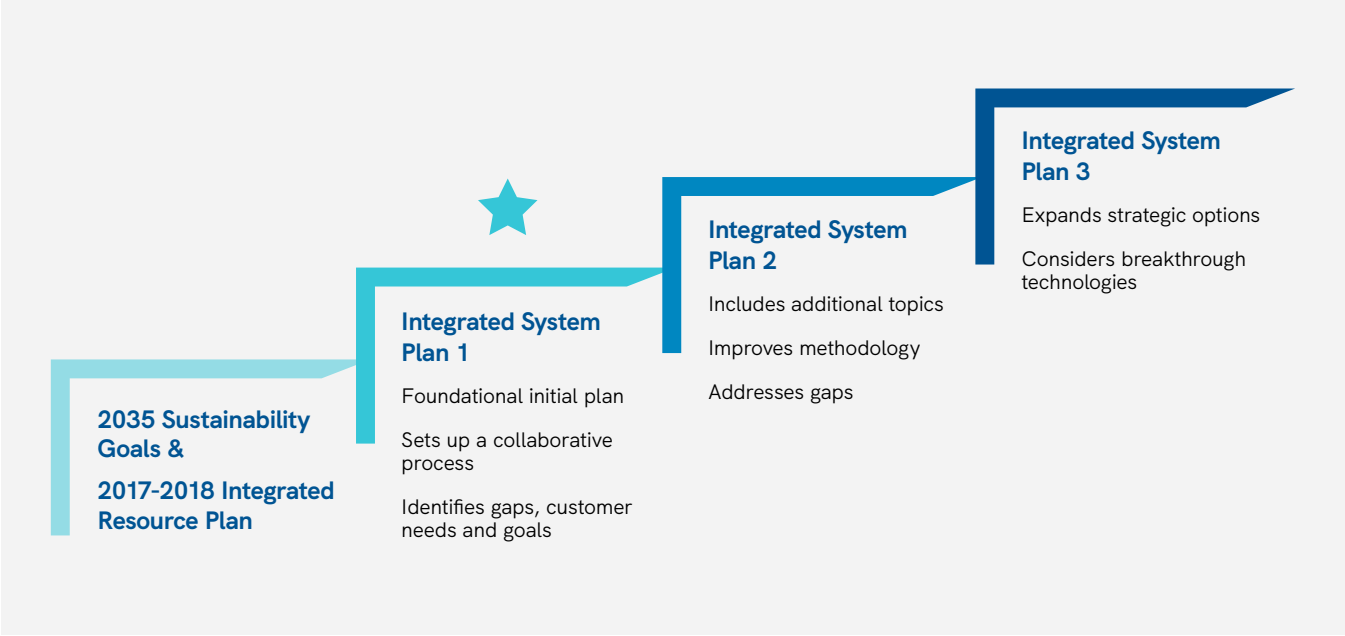
STAKEHOLDER QUESTIONS ANSWERED:
588



ISP Evolution

The scope of the ISP will evolve as SRP's planning groups gain experience and develop new capabilities. Participants in the objective development phase explored and discussed both the long-term vision and initial scope of ISP. Planning groups aligned on the importance of tackling a reasonable scope for the first ISP and building toward a long-term vision over time. One vision for what that evolution could look like is depicted below in Figure 3.4.

FIGURE 3.4: ISP LONG-TERM VISION



The initial ISP, or ISP 1, includes three key enhancements to current planning practices agreed to by the ISP team. The enhancements include consistent scenario and sensitivity analysis across the planning areas, incorporating transmission capacity headroom and expansion costs with supply-side resource planning, and expanding and enhancing the avoided cost framework to better evaluate customer programs. The process could evolve in future ISPs as new capabilities and tools are developed to be more cyclical. The pace and scale of ISP evolution will largely be determined by the experiences and lessons learned with ISP 1 and continued SRP exploration. The ISP enhancements for ISP 2 and ISP 3 in Figure 3.4 are illustrative and reflect stepwise progress of the potential elements identified in the long-term ISP vision.

Lastly, as part of the objective development engagement, the ISP team began a preliminary exploration of how the existing planning and sustainability processes might integrate with the ISP process in the future and the related issue of the cadence or frequency of the ISP. Consistent with the measured approach to the scope of ISP 1, the group generally agreed that gaining experience through ISP 1 would be helpful to inform future discussion on these topics.

The remainder of the report will describe the ISP 1 methodology, analytical framework, modeling results and critical findings that helped shape the concluding ISP deliverables, including System Strategies, ISP Actions and an illustrative Balanced System Plan.

SECTION 4

Scenarios, Sensitivities and Strategic Approaches

Scenario Framework

The decisions SRP makes today must withstand the risks and uncertainties of any future. Therefore, we utilized a scenario planning framework to test how different strategic decisions perform in an uncertain future.

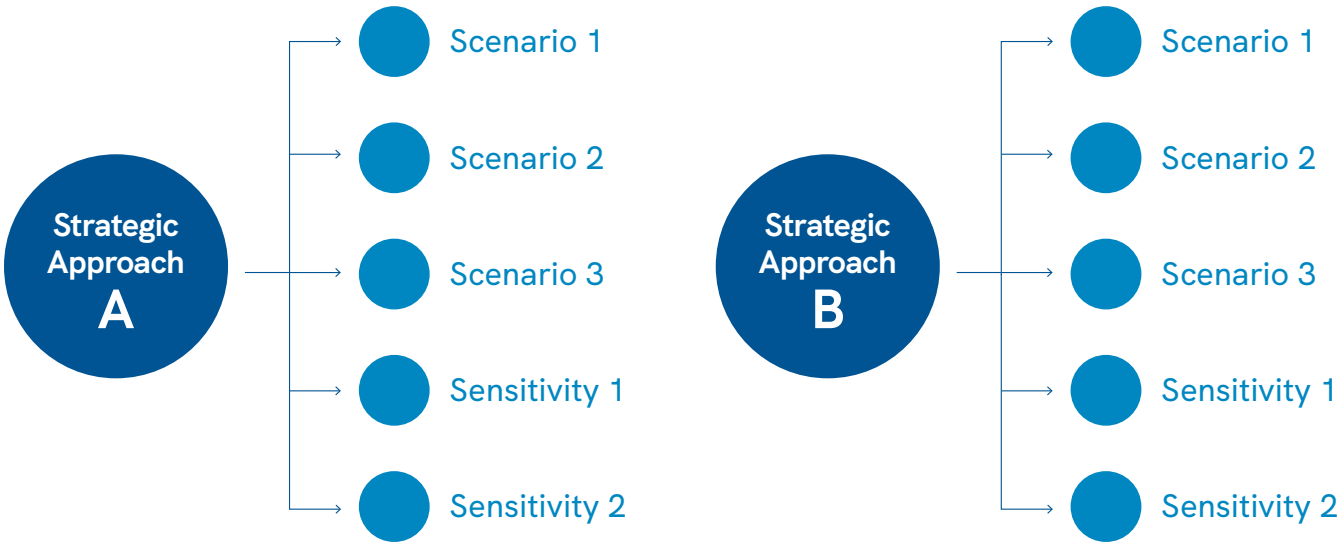
The scenario planning framework used for the Integrated System Plan included three key elements: scenarios, sensitivities and strategic approaches. Scenarios defined plausible future states of the world around us, reflecting societal, technological, economic, environmental and political trends and conditions. These factors are outside of our control and reflect the unpredictable nature of the future that needs to be accounted for in SRP's planning activities. Sensitivities, like scenarios, capture future states of the world around us but vary a single planning assumption. Finally, strategic approaches represented possible decisions that we could make in planning the future power system. These decisions are fully within our direct control.

FIGURE 4.1: SCENARIO DESIGN FRAMEWORK



In the Integrated System Plan, each strategic approach was tested against each of the future scenarios and sensitivities. This allowed us to examine the performance of each strategic approach under different futures and identify the components that best achieved SRP's goals, supporting the development of a robust system plan that positions SRP to take advantage of opportunities and react quickly as changes occur.

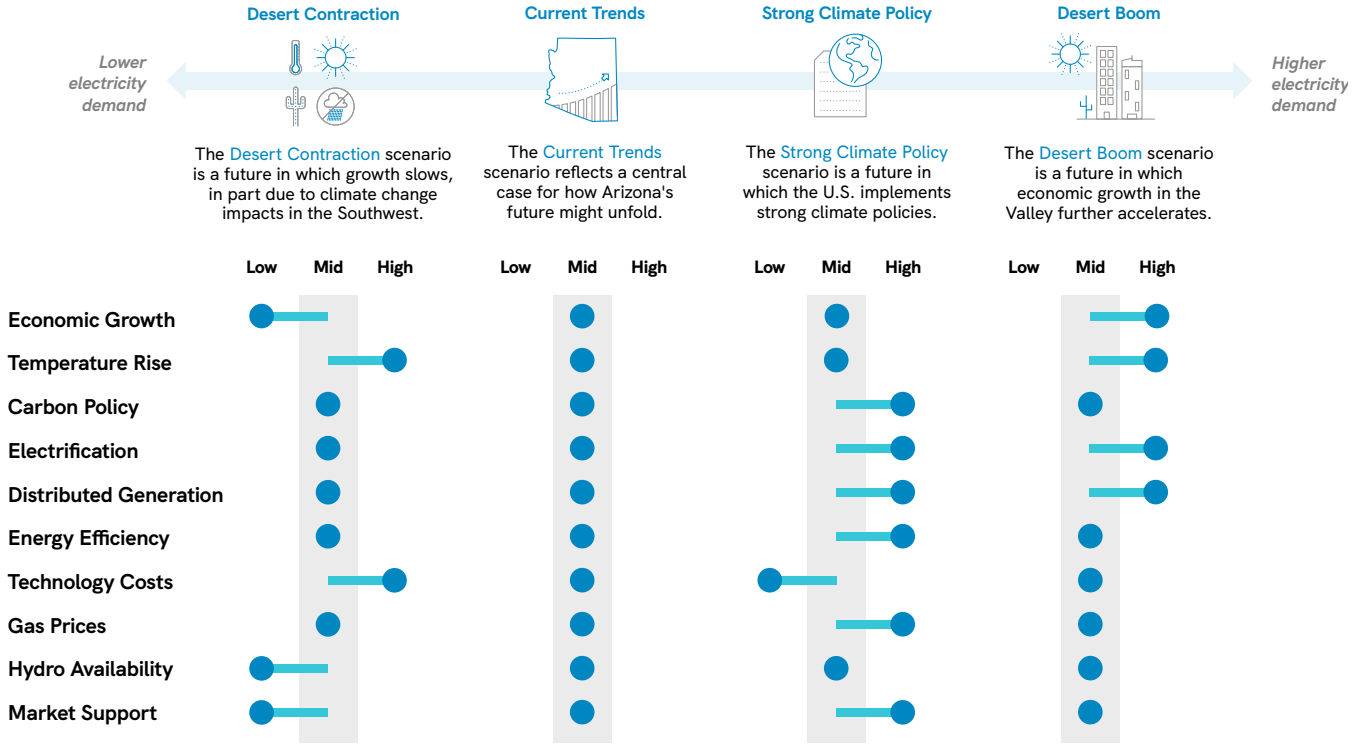
FIGURE 4.2: SCENARIO ANALYSIS



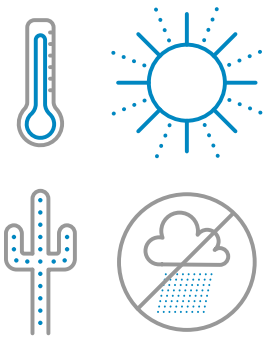
Scenarios

In collaboration with community stakeholders and based on results from customer research efforts, we developed four scenarios to analyze in the first Integrated System Plan: Desert Contraction, Current Trends, Strong Climate Policy and Desert Boom. The four scenarios considered many of the different external factors that can affect SRP's business environment and were designed to reflect a range of diverse yet plausible futures. Figure 4.3 below shows the four scenarios including how each external driver changed across the scenarios.

FIGURE 4.3: SCENARIOS



The following subsections describe each scenario in more detail and the key drivers associated with each scenario.

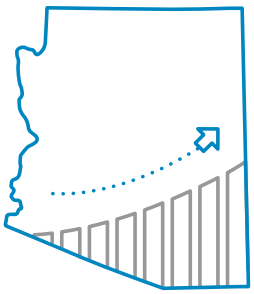


Scenario: Desert Contraction

The Desert Contraction scenario envisions a future where Arizona becomes a less desirable place for people and businesses due to a slowing economy and worsening climate conditions, which negatively impact residential and commercial growth. Additionally, global competition and consolidation initiates an exodus of large industry from the Valley, creating a cascading effect for the state's population. As a result, electricity demand in SRP's service area falls well short of current projections. Climate change also affects the region's watersheds, as declining rainfall throughout the West leads to lower reservoir levels along the Colorado River.[1] The corresponding reductions in generating capacity at large hydroelectric power plants significantly stress power markets, especially during peak demand periods.

[1]The Salt and Verde watersheds are more resilient to climate change and are unaffected in this scenario.

Key Drivers	Descriptions
Economic Growth	Higher summer temperatures and water supply issues stifle growth in the Southwest, limiting new migration and reversing expected growth trends. Large commercial and industrial customers emigrate out of Arizona and population growth levels off over time.
Climate Change	The Southwest experiences accelerated temperature rise consistent with the Intergovernmental Panel on Climate Change's (IPCC's) pessimistic Representative Concentration Pathway (RCP) 8.5 scenario, resulting in warming to the region that is more severe (0.91°F increase per decade). These conditions exacerbate current regional drought conditions, resulting in Lake Powell dropping below minimum power production levels for hydrogeneration from Glen Canyon Dam starting in 2025.
Policy	A worsening climate and intense global competition increase economic pressure on governments, resulting in a failure around the globe to adopt more consistent and aggressive carbon emission reduction regulations. While SRP remains committed to its 2035 Sustainability Goals, no federal or state sustainability policies are passed that supersede these goals.
Customer Participation (EE, DG, electrification)	Spurred by the worsening impacts of climate change and the lack of cohesive federal climate action, more and more Arizonans prioritize sustainability. Therefore, adoption rates for electric vehicles (EVs), heat pumps, and distributed solar and batteries increase. Growing adoption rates for these customer-sided technologies are tempered by lower overall population growth.
Technology	Increased global market competition, prolonged supply chain issues and stagnant economic growth in the Southwest raise material and labor costs, slowing the decline of renewable and storage costs. Tax credits provided through the Inflation Reduction Act help to reduce costs, although a stretched labor market makes qualifying for such credits expensive.
Market Dynamics	Extreme heat waves, wildfires and the loss of power capacity at Glen Canyon Dam as well as other hydrogeneration in the West lead to constrained regional markets that cannot be relied upon during peak periods.

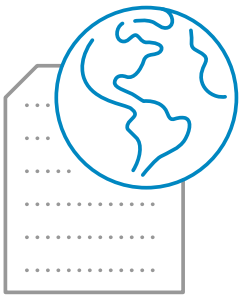


Scenario: Current Trends

The Current Trends scenario presumes that the large-scale changes currently underway in society, the region and the utility sector continue, resulting in substantial changes for SRP and Arizonans by 2035. Population in the Valley grows at a steady pace as the affordable cost of living and pleasant weather most of the year in the Phoenix area continue to attract new residents from California and surrounding states. With land availability, a competitive workforce, a geographical location in the middle of large markets (including California, Texas and Mexico), and with local and federal support of industries such as domestic semiconductor manufacturing, Phoenix becomes increasingly attractive to large commercial and industrial businesses. Data centers and manufacturing companies continue to move into the Valley, creating more jobs and bringing even more growth for Arizona. Some of these companies have significant load requirements measured in the hundreds of megawatts, much larger than those seen in the past. EVs gain popularity due to the broadening availability of vehicle models and improving charging infrastructure across the nation.

Key Drivers	Descriptions
Economic Growth	Continued growth is sustained in the greater Phoenix area, driven by continued migration and expansion in commercial and industrial business activities.
Climate Change	Climate change impacts are consistent with the projected RCP 4.5 scenario modeled by the IPCC, which envisions global emissions dropping below 2005 levels by 2100. Temperatures increase moderately (0.67°F per decade), while current drought conditions in the West persist but do not worsen throughout the study period.
Policy	While the Inflation Reduction Act provides a strong, sustained economic stimulus to support clean energy development, further federal action on climate policy is limited: Partisan politics continue to create a gridlock that prevents adoption of any comprehensive federal climate policy. In the absence of federal policy, state governments, utilities and corporations continue to drive advancements toward clean energy and sustainability goals. Like many other utilities in the region, SRP continues its independent efforts to meet voluntary sustainability goals.

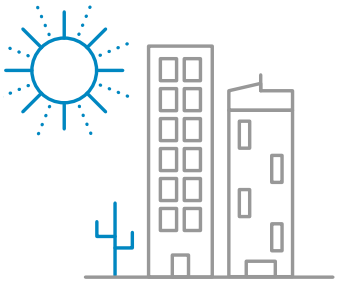
Customer Participation (EE, DG, electrification)	SRP continues to be a regional leader in offering energy efficiency and demand response programs to customers. The number of light-duty EVs increases significantly by 2035, benefiting from strong federal policy support provided in the Infrastructure Investment and Jobs Act, and consistent with SRP's current 2035 Sustainability Goals. Cost declines of distributed solar and batteries drive increased adoption by residential and commercial customers.
Technology	Renewable and storage technologies continue to advance over time, leading to sustained cost declines. Tax credits provided through the Inflation Reduction Act make carbon-free resources even more competitive, but the cost reductions are partially offset by continued supply chain constraints driven by a large spike in demand. Emerging technologies such as small modular reactors, natural gas power plants equipped with carbon capture and green hydrogen production become commercially available in the 2030s.
Market Dynamics	Diversity in load and generation resources across different Balancing Authority Areas in the Southwest allows SRP to rely on market purchases to meet part of its electricity demand when necessary and economical. Natural gas prices increase moderately over time, reflecting increased demand.



Scenario: Strong Climate Policy

The Strong Climate Policy scenario reflects a future where political consensus is reached on the need for swift and decisive action to combat climate change, resulting in several new policies and measures at the U.S. federal level. These policies are guided by an economywide net-zero emissions target by the year 2050, resulting in mass-based emissions reductions targets for electric utilities throughout the country by 2035. Decarbonization policies also impact demand: The pace of electrification in the building and transportation sectors accelerates, causing demand for electricity to increase, and government support for energy efficiency measures results in improvements in efficacy, reduction in cost and more widespread adoption. These two effects are offsetting but change the patterns and timing of electricity consumption. Extensive research and development support of clean energy resources advances power companies' operational learning curves and accelerates cost declines. Such cost declines also impact distributed generation on the customer side and create favorable conditions for the adoption of solar and storage systems. A Regional Transmission Organization (RTO) or a regional resource adequacy program would be established in the Southwest, allowing power companies to better take advantage of load and resource diversity in the region.

Key Drivers	Descriptions
Economic Growth	Growth is sustained as large commercial and industrial customers continue to migrate to the Valley. Furthermore, electricity demand is accelerated by rapid electrification of the building and transportation sectors.
Climate Change	Through 2035, temperatures in the Southwest remain consistent with the IPCC's RCP 4.5 scenario. Temperature increases moderately (0.67°F per decade), while current drought conditions in the West continue throughout the study period.
Policy	The U.S. federal government implements a suite of comprehensive policies to address climate change. These policies are designed around an economywide net-zero emissions target by 2050.
Customer Participation (EE, DG, electrification)	Stronger federal codes, standards and incentives lead to high energy efficiency growth. Technology improvements and rapid cost declines drive accelerated distributed solar and battery adoption among SRP's residential and commercial customers. The number of light-duty, medium-duty and heavy-duty EVs as well as heat pumps increases significantly, with federal support for these technologies.
Technology	Additional federal tax incentives, research and development investments, and increased deployment of clean energy resources advance learning curves, driving significant cost declines for renewables and storage and accelerating the commercialization of emerging technologies. Domestic manufacturing is able to keep up with demand, and no price increases from supply chain constraints are expected.
Market Dynamics	Federal policy support, incentives and subsidies drive increased transmission buildout across the nation. An RTO or a regional resource adequacy program would be established in the Southwest region, and system planning is conducted at a regional level. The regional planning paradigm and operational coordination allow the Balancing Authority Areas in the region to better take advantage of regional load and resource diversity, lowering the planning reserve margin SRP requires. More aggressive policies related to the natural gas supply chain increase natural gas prices.



Scenario: Desert Boom

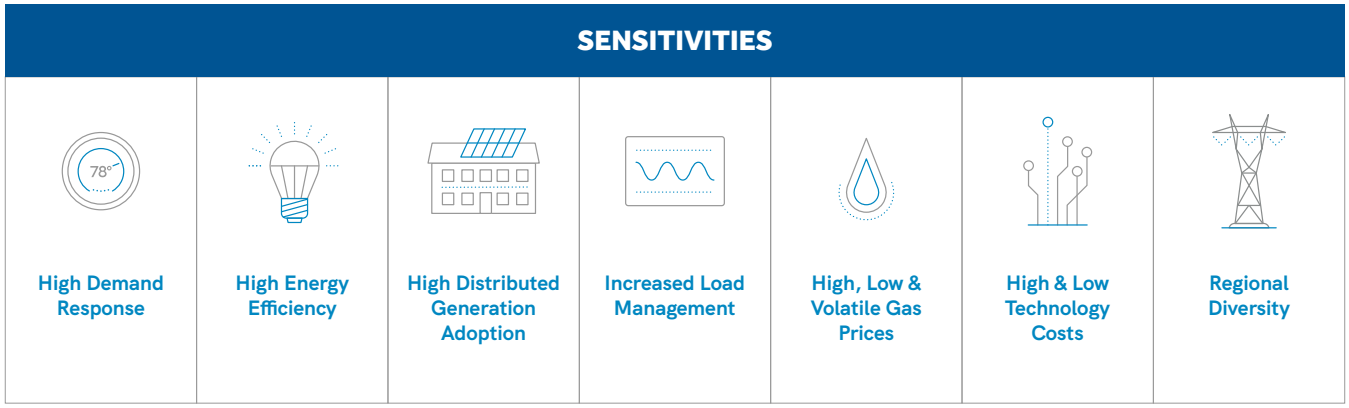
The Desert Boom scenario is characterized by explosive growth in SRP's service territory. Arizona becomes a regional energy, technology and manufacturing hub, creating a second "Silicon Valley" in the Phoenix metropolitan area. Economic growth in the Phoenix metropolitan area accelerates far beyond current projections and is led by a strong global technology industry and a supportive environment in Arizona. Electricity demand increases significantly with accelerated economic activity, growth in energy-intensive businesses and increased energy exports. Arizona's central location, affordable cost of living and skilled workforce attract an influx of people and businesses to the area. Strong economic growth supports accelerated EV and heat pump adoption, adding more electrification loads to the grid. Increased availability of distributed solar and battery technology helps mitigate system demand but not at the scale needed to provide full grid backup.

Key Drivers	Descriptions
Economic Growth	Growth accelerates significantly as Arizona becomes a regional energy, technology and manufacturing hub.
Climate Change	Climate change accelerates around the globe due to both climate policy inaction and strong global economic activity. Greater temperature rise occurs (0.91°F per decade) consistent with the Intergovernmental Panel on Climate Change (IPCC)'s pessimistic Representative Concentration Pathway (RCP) 8.5 scenario while current drought conditions in the West continue throughout the study period.
Policy	Governments around the globe prioritize economic growth over carbon emission reductions in the midst of an economic boom. SRP is committed to its 2035 Sustainability Goals, and no federal or state sustainability policies are passed that supersede these goals.
Customer Participation (EE, DG, electrification)	Population growth and higher incomes accelerate adoption of light-duty EVs, heat pumps, and distributed solar and batteries.

Technology	Renewable and storage technologies continue to advance over time, leading to sustained cost declines. Tax credits through the Inflation Reduction Act make carbon-free resources even more competitive, but the cost reductions are partially offset by continued supply chain constraints driven by a large spike in demand. Emerging technologies such as small modular reactors, natural gas power plants equipped with carbon capture, and green hydrogen production become commercially available in the 2030s.
Market Dynamics	Diversity in load and generation resources across different Balancing Authority Areas in the Southwest allows SRP to rely on market purchases to meet part of its electricity demand when necessary and economical. Natural gas prices increase moderately over time, reflecting continued demand growth and declining supply.

Sensitivities

In addition to the scenarios, SRP also analyzed 10 sensitivities under the Current Trends scenario. A **sensitivity** varied a single assumption in the Current Trends scenario, allowing SRP to understand the impact of the assumption on the overall system plan. Sensitivities were analyzed under the Current Trends scenario to assess the impact of varying individual assumptions on the system plan at a central case of potential future load growth. Details on the assumptions used for each sensitivity are included in Section 5: Methodology.



In the graphic above, the "High, Low & Volatile Gas Prices" icon encompasses three sensitivities, including High Gas Prices, Low Gas Prices and Volatile Gas Prices. The "High & Low Technology Costs" icon encompasses two sensitivities, including High Technology Costs and Low Technology Costs.

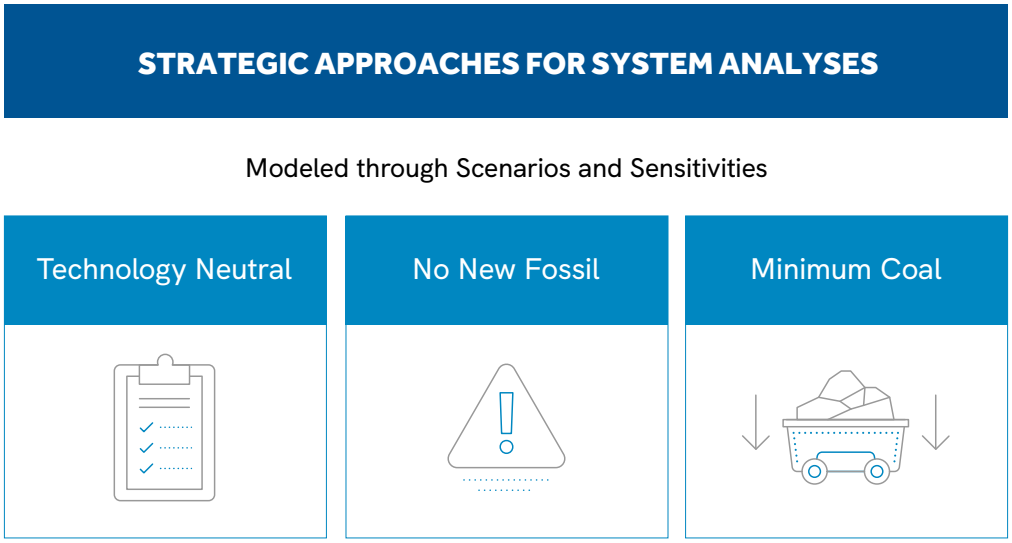
Strategic Approaches

SRP developed three strategic approaches to analyze in the Integrated System Plan. The three strategic approaches were analyzed across each of the scenarios and sensitivities described above.

The **Technology Neutral** strategic approach aims to develop future system plans on a least-cost basis to meet reliability and sustainability goals without any preferences for or restrictions upon the specific technologies included in the portfolio.

The **No New Fossil** strategic approach seeks to meet future system needs with exclusively carbon-free resources, excluding investment in new natural gas resources from consideration. Existing natural gas units remain in service and are still used to meet customer needs. Further, no changes to planned coal retirement dates are included in this strategic approach.

The **Minimum Coal** strategic approach aims to reduce power generation from coal in SRP's system by testing operational changes to SRP's coal resources, including seasonal operations and the full retirement of coal by 2035. This strategic approach builds upon the No New Fossil approach described above, meaning that all new generation resources must not rely on fossil fuel technologies.

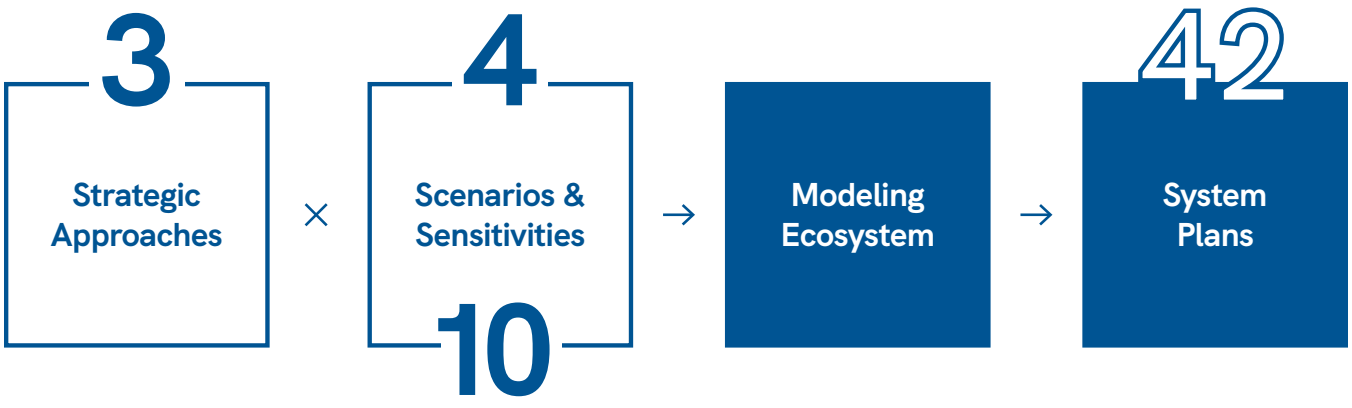


SECTION 5

Methodology

Methodology Overview

As discussed in Section 4, the ISP tested three strategic approaches across four scenarios and 10 sensitivities to evaluate 42 different planning cases. For each of these planning cases, SRP developed a system plan for the years 2025–2035 which included customer programs, distribution investments, transmission investments and resource additions.



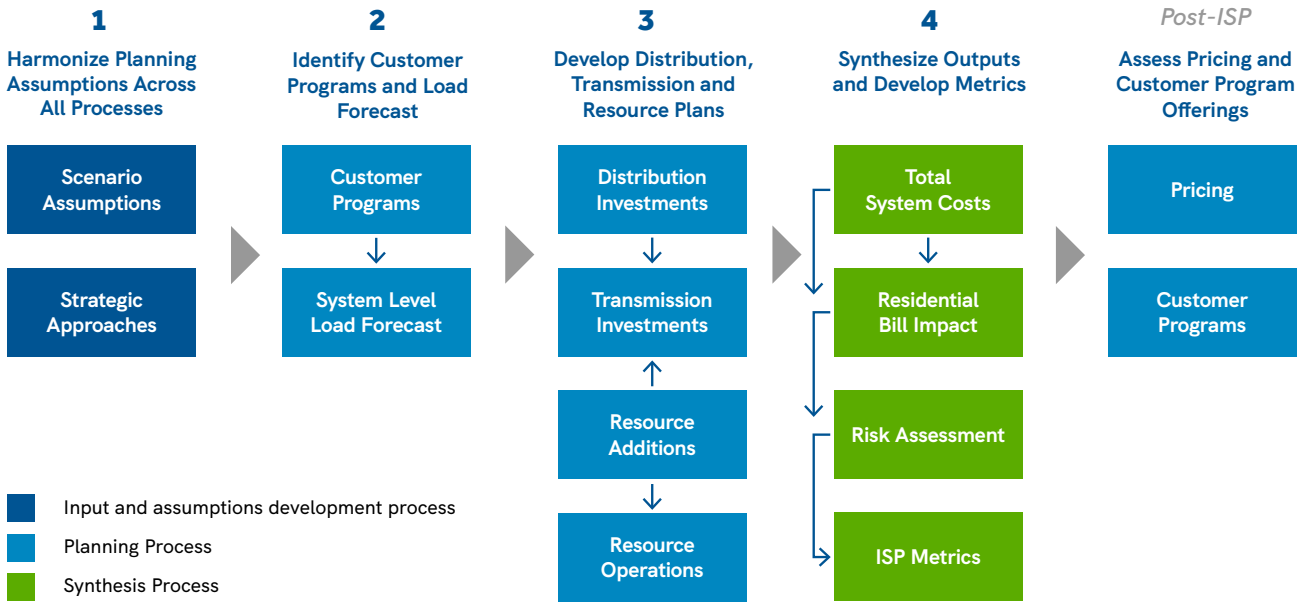
Our team evaluated and compared these plans by developing metrics to understand how each strategic approach performs across different futures and to identify the system components that could help SRP deliver a reliable, affordable and sustainable future power system. While we cannot know what the future will hold, assessing system plans across a variety of potential futures allowed us to identify strategies to mitigate future risks and take advantage of potential opportunities. This section describes the modeling ecosystem, key modeling inputs and metrics that we utilized to develop and evaluate each of the system plans.

Modeling Ecosystem

This first-of-its-kind ISP required a new approach to perform comprehensive system planning. Because there was no single planning model available that we could use to analyze all parts of the system simultaneously, we needed to develop an analytical ecosystem that included multiple planning processes, each with its own model(s). Each planning process utilizes the same planning assumptions, and then results from one planning process feed into other planning processes to help us create integrated system plans. An overview of this modeling ecosystem is shown in Figure 5.1.



FIGURE 5.1: MODELING ECOSYSTEM OVERVIEW



For a given planning case, we utilized the same scenario and strategic approaches across all planning processes (Step 1). We then forecasted energy demand during all times of the year, including the adoption of customer programs and customer-sited generation (Step 2). We next identified distribution investments, transmission investments and resource additions to meet future needs through 2035 (Step 3). The Distribution Investments planning process identified where the load would grow on the distribution system and the distribution infrastructure required, while the Resource Additions planning process identified which resources would be added. These results fed into the Transmission Investments planning process, which determined what transmission investments would be needed on SRP's system to connect large-scale resources to serve customers' energy demand. In addition, the Resource Operations process simulated how the future system could operate. We then leveraged all of these outputs to develop reliability, affordability, sustainability and customer-focused metrics (Step 4).

We will use this information to inform the design of customer programs and pricing plan offerings following the first ISP. These planning processes and metrics are described further in the following sections.

Due to time constraints, we could not perform every modeling process for all 42 planning cases. For the Transmission Investments, Residential Bill Impact and Risk Assessment processes, we performed modeling for a subset of the 42 planning cases, as detailed further below. We quantified all metrics for the 12 "core system plans" (three strategic approaches evaluated against four scenarios) and assessed all 42 system plans when developing key findings, as discussed in Section 6.

Customer Programs and End-Use Technologies

We developed customer program and end-use technology forecasts for energy efficiency, demand response, electrification (transportation and other technologies) and distributed

generation — including distributed solar and distributed batteries — for scenarios and sensitivities. These forecasts served as inputs into the load forecasts, which subsequently served as key inputs for each of the planning processes. The demand response forecast served as a direct input for the Resource Additions process.

Methodology Overview

To meet customers' diverse needs and the overall system needs, we developed a cost-effective portfolio of programs that achieve SRP's 2035 Sustainability Goals for energy efficiency, demand response, transportation electrification and electric technologies. In addition, we developed forecasts for customer adoption of other end-use technologies, including distributed generation in alignment with SRP's 2035 Sustainability Goal for grid enablement.

We developed customer program and end-use technology forecasts for the following scenarios and sensitivities:

- Current Trends
- Desert Boom
- Desert Contraction
- Strong Climate Policy
- High Energy Efficiency (sensitivity)
- High Demand Response (sensitivity)
- High Distributed Generation Adoption (sensitivity)

Across these scenarios and sensitivities, we assumed that external factors drive customer adoption differences relative to the Current Trends scenario. For example, in the Strong Climate Policy scenario, we assumed that increased federal support for decarbonization efforts drives an expansion in energy efficiency, electric vehicles, building electrification and distributed generation.

Key Inputs

Key inputs for the customer programs and end-use technologies planning process included SRP's 2035 Sustainability Goals, assumptions for specific measures and programs, and market drivers.

2035 Sustainability Goals

SRP has established 2035 Sustainability Goals for various customer program offerings. In all ISP cases, we included customer program projections that met or exceeded these levels by 2035. *Note: SRP's 2035 Sustainability Goals are being refreshed in 2024 in collaboration with community stakeholders.*

- Energy efficiency: 3 million MWh
- Demand response: 300 MW
- Transportation electrification: 500,000 EVs
- Electric technologies: 300,000 MWh
- Grid enablement: Enable all distributed energy resources that customers choose to install

SRP Customer Program Planning Assumptions

SRP offers customer programs for energy efficiency, demand response, transportation electrification and electric technologies. The assumptions for these programs reflect the suite of customer program opportunities available to SRP, as well as their performance and costs.

SRP has implemented a continuous improvement process over many years to refine planning assumptions for specific measures for energy efficiency, demand response and electric technology programs. SRP's Measurement & Evaluation team and third-party consultant Guidehouse formally evaluate a subset of programs each year to continually refine assumptions for the measures included in each program. Based on this process, we have defined planning assumptions for each of the following measures:

- Reduction in energy demand during peak hours (kW)
- Reduction in energy demand during the entire year (kWh)
- Timing of energy demand reduction on an hourly basis
- Useful life over which SRP can expect energy savings
- Incremental cost, which serves as the basis for rebate design

Market Research

SRP regularly performs market research to understand the market activity and customer willingness to participate in different programs and to adopt various end-use technologies. In addition to speaking with customers, SRP gathers information from implementation partners, trade allies and third-party research. To develop the distributed generation forecast, we relied on historic and recent trends for distributed generation installations within SRP's power system area as well as advanced metering infrastructure data for the historic and recent generation of the systems already installed. To develop the electric vehicle forecast, we relied on information from the Electric Power Research Institute (EPRI) related to feasible EV adoption rates and supplemented this with internal research on EV load impacts within SRP's service area. We then leveraged this market research information, along with historical trends, to inform the forecast of future customer participation in SRP programs and adoption of end-use technologies.

Key Outputs

Below are the key outputs from this planning process.

Output	Description	Output Units
Energy Efficiency and Electrification Impacts on Annual Load	Forecast of energy efficiency and electrification (transportation and other technologies)	MWh

Demand Response Capacity	Forecast of the amount of capacity on the system that is available to provide demand response services	MW
Distributed Generation Adoption	Forecast of customer-sited solar and batteries	MW
Customer Program Costs	Forecast of program costs for SRP customer programs	$

Load Forecast

In the load forecasting process, we forecasted customer energy demand on an hourly basis through 2035. The forecast reflects typical patterns in energy demand throughout the year and across the hours within a given day, including during peak energy demand periods. This information served as a key input for determining future system needs in the ISP.

Methodology Overview

First, our team created a baseline forecast for the Current Trends scenario. We then employed the Statistically Adjusted End-Use (SAE) model (developed by Itron) to forecast electricity demand from customer end uses. We updated this model to align with inputs related to economic growth, end-use saturation and efficiency trends, adoption of customer programs, adoption of distributed generation, adoption of electric vehicles, and temperature trends. Finally, we used the outputs of this model to determine the hourly energy demand through 2035.

To develop additional forecasts for each of the four planning scenarios and two of the sensitivity cases, we modified one or more key assumptions. We developed load forecasts for the following scenarios and sensitivities:

- Current Trends
- Desert Boom
- Desert Contraction
- Strong Climate Policy
- High Energy Efficiency (sensitivity)
- High Distributed Generation Adoption (sensitivity)

Key Inputs

The following sections describe the key inputs for the Load Forecast process, including economic growth and temperature increase. In addition to these inputs, we factored in changes in customer energy usage from energy efficiency, electrification and adoption of distributed generation. These inputs are the results of the Customer Programs and End-Use Technologies process and are discussed in Section 6.

Economic Growth

We developed economic growth projections for all four scenarios to determine key inputs, such as change in population and growth in energy demand from large customers. To do so, we developed an economic outlook for the Phoenix metro area by creating a composite forecast from a variety of external economic forecast providers, including University of Arizona, Arizona State University, Moody's, Woods & Poole Economics, and R.L. Brown Construction. We also developed an outlook for large customer growth by leveraging information from a variety of sources, including SRP's Strategic Energy Managers, SRP Economic Development, the Greater Phoenix Economic Council, state and local commerce authorities, and observed historical trends.

Figures 5.2 and 5.3 show the population and incremental large customer load growth forecasts for the four scenarios. In the Current Trends and Strong Climate Policy scenarios, the population and new industrial loads increase markedly, consistent with recent trends in migration and expansion of business activity. In the Desert Boom scenario, there is even greater growth as Arizona develops further as a regional energy, technology and manufacturing hub. In the Desert Contraction scenario, there is limited new migration and a significant slowing of large customer growth trends.

FIGURE 5.2: PHOENIX METRO POPULATION

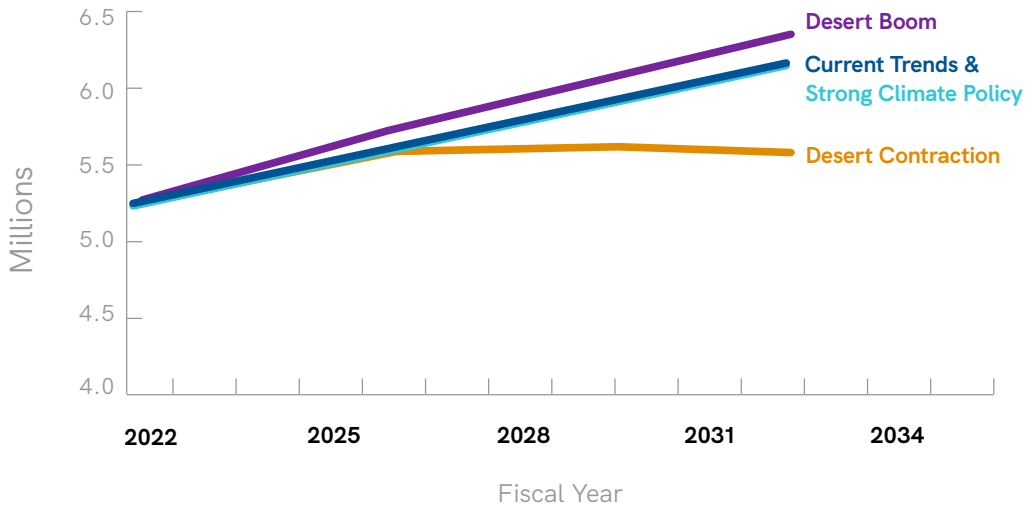
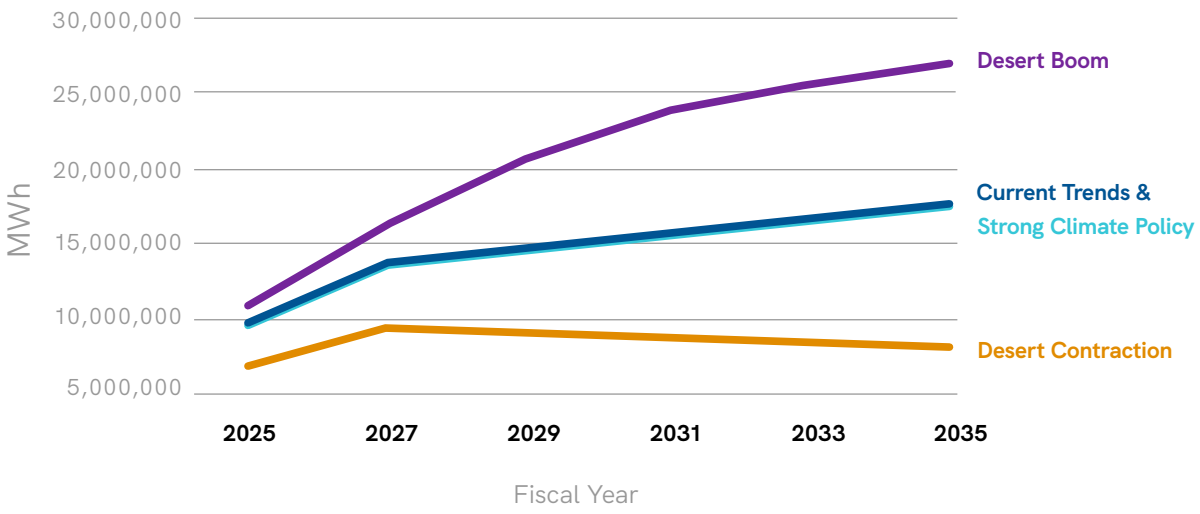


FIGURE 5.3 INCREMENTAL LARGE CUSTOMER LOAD GROWTH



Temperature Increases

In all scenarios, we considered the impacts of global warming. To characterize the future temperature increases, we relied on data from the Intergovernmental Panel on Climate Change (IPCC). For the Current Trends and Strong Climate Policy scenarios, we used the Representative Concentration Pathway (RCP) 4.5 trajectory, which corresponds to a temperature increase of 0.67°F per decade. For the Desert Boom and Desert Contraction scenarios, we used the RCP 8.5 trajectory, which corresponds to an even greater temperature increase of 0.91°F per decade. We then translated these changes in temperature into changes in cooling degree hours and heating degree hours (see figures 5.4 and 5.5), which are metrics that are correlated with energy demand from cooling and heating buildings.

FIGURE 5.4: COOLING AND HEATING DEGREE HOURS

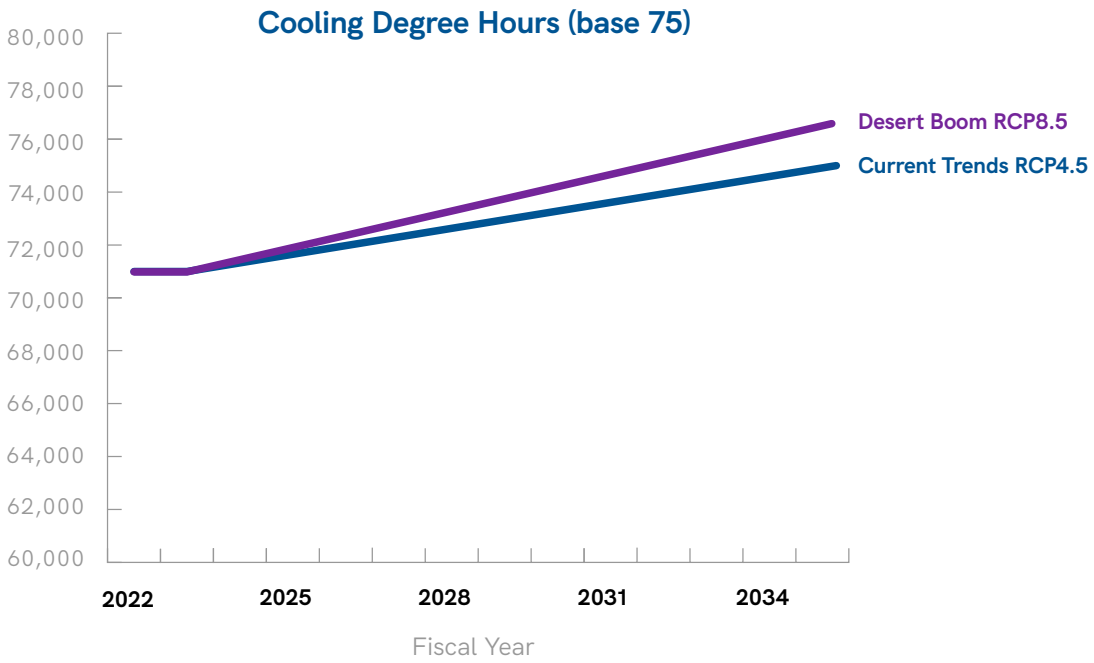
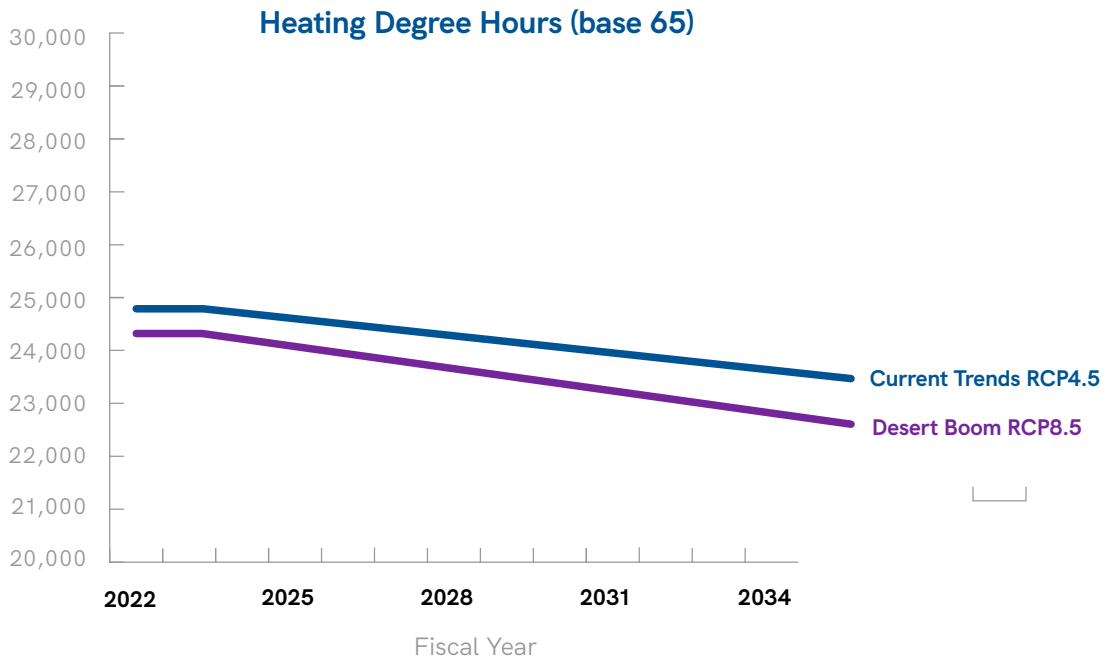


FIGURE 5.5: COOLING AND HEATING DEGREE HOURS



Key Outputs

SRP developed the following outputs, which served as inputs for other planning processes.

Output	Description	Output Units
System Load Forecast	System peak load and hourly energy demand forecast	MW
Transmission-Level Forecast	Peak load forecast for customers that connect directly to the high-voltage transmission system	MW
Distribution-Level Forecast	Peak load forecast for customers that connect to the lower-voltage distribution system	MW

Distribution Investments

In the Distribution Investments planning process, we determined which investments are needed on the distribution system to accommodate growth in customer energy demand, including the impacts from adoption of electric vehicles and customer-sited generation, while ensuring reliability.

Methodology Overview

First, we allocated the system-level load forecast (described in the Load Forecast section) to granular localized levels of the distribution system. We utilized LoadSEER (developed by Integral Analytics), which is a distribution forecasting and planning tool that allocates the system-level load to individual substations based on geographic, economic and historical customer usage data. This resulted in a peak load forecast for each substation, allowing us to understand where customer demand is changing and how the system may need to adapt.

After we allocated the system-level load forecast to the localized levels of the distribution system, SRP analyzed capacity-constrained locations and evaluated applicable infrastructure solutions to alleviate these constraints. Due to modeling limitations and time constraints, we focused on substation equipment and did not evaluate individual distribution lines that connect to the substations. We utilized the following reliability planning criteria, consistent with SRP's distribution planning practices:

- A distribution substation bay may not exceed 85% of its emergency rating.
- The total distribution system load should not exceed 70% of the total distribution system capacity.

One way we addressed an overloaded substation was by shifting loads to adjacent substations, which was possible if the neighboring substation had available capacity. This ensured the existing distribution infrastructure was used efficiently. In areas that were significantly capacity-constrained and existing distribution infrastructure could not be utilized, SRP strategically placed new substations, adding capacity to an area to address as many overloads as possible.

We performed this analysis for the following scenarios and sensitivities, which covered all planning futures in which load and customer programs change and could impact distribution investment needs:

- Current Trends
- Desert Boom
- Desert Contraction
- Strong Climate Policy
- High Energy Efficiency (sensitivity)
- High Distributed Generation Adoption (sensitivity)

For the two sensitivity analyses, the team estimated the required number of substation bay additions through interpolation by calculating the relationship between forecasted load and

resultant substations required in the four major scenarios. This relationship was then applied to the forecasted load for the two sensitivity cases. This process resulted in a high-level estimate of substation bay addition requirements for each sensitivity case, and it assumes that these technologies are adopted evenly throughout the service territory.

Key Outputs

The modeling process resulted in a plan detailing the location of each substation addition for each year as well as the load for each substation in each year.

Output	Description	Output Units
Substation Load Forecast	Projects addition of new substations and allocation of load between substations.	MW
Distribution Investments	Specification of substation additions or upgrades to meet system requirements, as well as associated costs.	$

Resource Additions

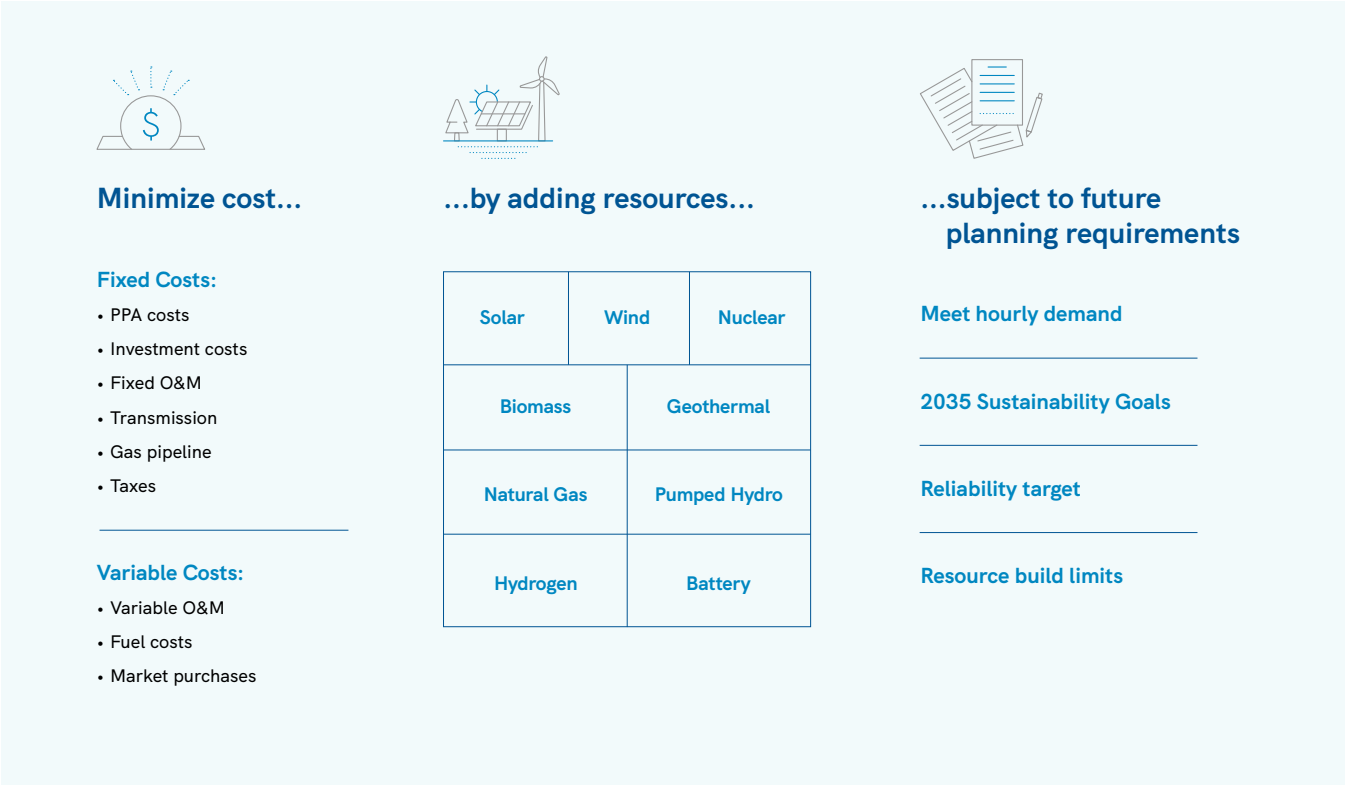
In the Resource Additions planning process, we determined the least-cost resource additions needed to meet future energy demand while ensuring reliability and meeting SRP's 2035 Sustainability Goals related to carbon dioxide emissions and water usage.

Methodology Overview

During this process, our team assessed future resource additions through a resource portfolio optimization analysis that identified the least-cost long-term combination of generation investments subject to reliability, policy and technical constraints.

To perform the analysis, we engaged Energy and Environmental Economics Inc. (E3) to deploy a long-term capacity expansion model, PLEXOS (developed by Energy Exemplar), which we had not leveraged in prior resource planning efforts. PLEXOS considers investment costs, fixed costs and production costs to simultaneously select new resources and simulate system operations over a long planning horizon (see Figure 5.6).

FIGURE 5.6: OVERVIEW OF THE RESOURCE ADDITIONS MODELING FRAMEWORK



E3 produced optimized resource portfolios for all cases presented in the ISP, except for the volatile gas price sensitivities[1], totaling 39 cases. Each portfolio identified resource additions through 2035.

Key Inputs

The key inputs for this analysis included the system load forecast (see Load Forecast section), resource options, resource and transmission costs, reserve margin requirements, fuel prices, reliability requirements and sustainability requirements.

Resource Options

The ISP considered a wide range of resource options to meet future needs, including renewable, storage and thermal resources.

Renewable Resource Options

The ISP considered several renewable resource options, including biomass, geothermal, solar and various wind options that vary by location and transmission path.

[1]The volatile gas price sensitivities are intended to evaluate the impact of gas prices unexpectedly changing over short time periods without SRP being able to change decisions around resource additions. Therefore, SRP evaluated the volatile gas price sensitivities in the Resource Operations analysis, using the same resource additions as in the Current Trends scenario.

FIGURE 5.7: RENEWABLE RESOURCE OPTIONS

Resource	State	First Available Year	Capacity Factor[2]
Biomass	Arizona	2025	Varies
Bioenergy with Carbon Capture and Storage	Arizona	2035	Varies
Geothermal	California	2031	90%
Solar	Arizona	2025	32.2%
Wind – Existing SRP Transmission	Arizona	2033	31.3%
Wind – Existing non-SRP Transmission	Arizona	2025	31.3%
Wind – New Transmission	Arizona	2031	31.3%
Wind – New Transmission	New Mexico	2026	45.5%
Wind – New Transmission	Wyoming	2029	55.4%
Wind – Existing Transmission	Wyoming	2029	55.4%

To ensure that the resource additions identified reflect realistic plans that SRP can execute, the ISP included build limits for the renewable resource options to reflect development limitations in being able to bring such new resources online. Below are the total build limits by 2035 for each resource:

- **Biomass –** SRP assumed up to 150 MW of new additions, based on the amount of fuel that SRP assumed could be made available from forest-thinning projects such as those in the SRP Healthy Forest Initiative™.
- **Bioenergy with Carbon Capture and Storage (BECCS) –** SRP assumed up to 100 MW of new additions, given that the CCS component of this resource is not widely commercialized today and has a certain degree of uncertainty in terms of availability and cost.

[2]Capacity factor is a measure of resource utilization and is expressed as a ratio of the actual output over a given period of time compared to the theoretical continuous maximum output over that period.

- **Geothermal –** SRP assumed up to 1,000 MW of new additions. Based on SRP's assessment of regional transmission, SRP expects that access to new geothermal resources in the Salton Sea area in California — which has high-quality geothermal energy — would require development of new long-distance transmission between the Salton Sea area and the Phoenix metropolitan area. SRP assumed that new transmission could be put in service as early as 2031 and that this would allow SRP to access up to 1,000 MW of geothermal resources. For details on the cost of this transmission, see the Transmission Costs section. In the Strong Climate Policy scenario, SRP assumed that increased federal support for regional transmission could accelerate the availability of this resource from 2029 to 2031.
- **Solar –** SRP effectively did not limit solar additions. In total, the model could add up to 20,000 MW of solar by 2035, but that threshold was never constraining.
- **Wind –** For wind, assumptions varied according to current and potential transmission availability. For more details on the cost of transmission, see the Transmission Costs section.
    - **Wind (AZ), Existing SRP Transmission —** SRP estimated that 800 MW of transmission would become available in 2033 following the retirement of the Coronado Generating Station and an additional 450 MW in 2034 in the Minimum Coal strategic approach following the retirement of the Springerville Generating Station.
    - **Wind (AZ), Existing Non-SRP Transmission —** SRP estimated that 50 MW of non-SRP transmission is currently available for new wind generation in Arizona.
    - **Wind (AZ), New Transmission —** SRP assumed a new transmission line could be added from eastern Arizona by 2035, which would provide access to approximately 500 MW of wind generation.
    - **Wind (NM), New Transmission —** SRP assumed new transmission could be added between a region in New Mexico with high-quality wind and the Valley by 2035. SRP assumed this transmission would enable SRP to access up to 1,500 MW of wind generation.
    - **Wind (WY), Existing Transmission —** SRP estimated that 100 MW of transmission could become available in 2029 following the retirement of the Craig and Hayden coal plants in Colorado.
    - **Wind (WY), New Transmission —** SRP assumed one or more new transmission lines could be added between Wyoming and southern Nevada by 2025, and that SRP could then utilize approximately 300 MW of existing transmission to deliver wind in Wyoming to the Phoenix metropolitan area.

For solar and wind resources, we developed hourly generation profiles by using the System Advisor Model (SAM) developed by the National Renewable Energy Laboratory (NREL). The solar profile reflects a project with single-axis tracking in Arizona, while the wind profiles reflect differences in generation profiles across the different states.

Storage Resource Options

The ISP also considered energy storage resources, including lithium-ion batteries and pumped hydro storage, which can help integrate renewable resources on the system. For battery storage, the ISP considered both stand-alone storage and hybrid storage that is co-located with solar.

FIGURE 5.8: STORAGE RESOURCE OPTIONS

Resource	First Available Year	Duration (hours)	Round-Trip Efficiency
Battery	2025	4	85%
Pumped Hydro	2033	10	80%

As was done for renewable resources, SRP included build limits for storage resources to reflect development limitations in being able to bring new resources online. Below are the total build limits by 2035 for each resource:

- **Battery –** SRP assumed up to 8,500 MW of new additions, above and beyond the battery storage resources that are already contracted.
- **Pumped Hydro –** SRP assumed up to 1,150 MW of new additions, which corresponds to one large new project.

Thermal Resource Options

In addition to renewable and storage resources, the ISP considered several thermal resource technologies. We modeled conventional natural gas technologies, including combined cycle, combustion turbine (both frame and aeroderivative) and reciprocating engine technologies. We also modeled a few emerging technologies, including combined cycle with carbon capture and storage (CCS), combustion turbine that burns 100% green hydrogen (Hydrogen 100),[3] combustion turbine that burns a blend of natural gas and an increasing share of hydrogen (Hydrogen Transition), and nuclear small modular reactors (SMR). The ISP also considered biomass and geothermal as thermal resource options. Those resources are discussed in the Renewable Resource Options section above.

FIGURE 5.9: THERMAL RESOURCE OPTIONS

Resource	First Available Year	Fuel
Combined Cycle (1x1)	2028	Natural Gas
Combined Cycle (2x1)	2028	Natural Gas
Combustion Turbine (Frame)	2027	Natural Gas
Combustion Turbine (Aero)	2025	Natural Gas

[3] Green hydrogen is produced from 100% renewable energy.

Reciprocating Engine	2025	Natural Gas
Hydrogen Transition	2030	Blend (Green Hydrogen and Natural Gas)
Combined Cycle with CCS	2030 or 2035 depending on scenario	Natural Gas
Hydrogen 100	2034 or post-2035 depending on scenario	Green Hydrogen
Nuclear SMR	2034 or post-2035 depending on scenario	Uranium

The resource availability assumptions reflect the time required to site, permit and construct resources. For emerging technologies, including combined cycle with CCS, hydrogen and nuclear SMR resources, we considered the uncertainty of when these resources would become available, given that they have not yet reached widespread commercialization. See Figure 5.10 for the availability assumptions for emerging technologies. We excluded these resources from consideration within the planning horizon under most scenarios. However, to test an alternative scenario in which these technologies progress more rapidly following government support, we accelerated SRP's availability in the Strong Climate Policy scenario.

FIGURE 5.10: FIRST YEAR AVAILABLE FOR EMERGING TECHNOLOGIES

Resource	Strong Climate Policy Scenario	Other Scenarios
Combined Cycle w/ CCS	2030	2035
Hydrogen 100	2034	Post-2035
Nuclear SMR	2034	Post-2035

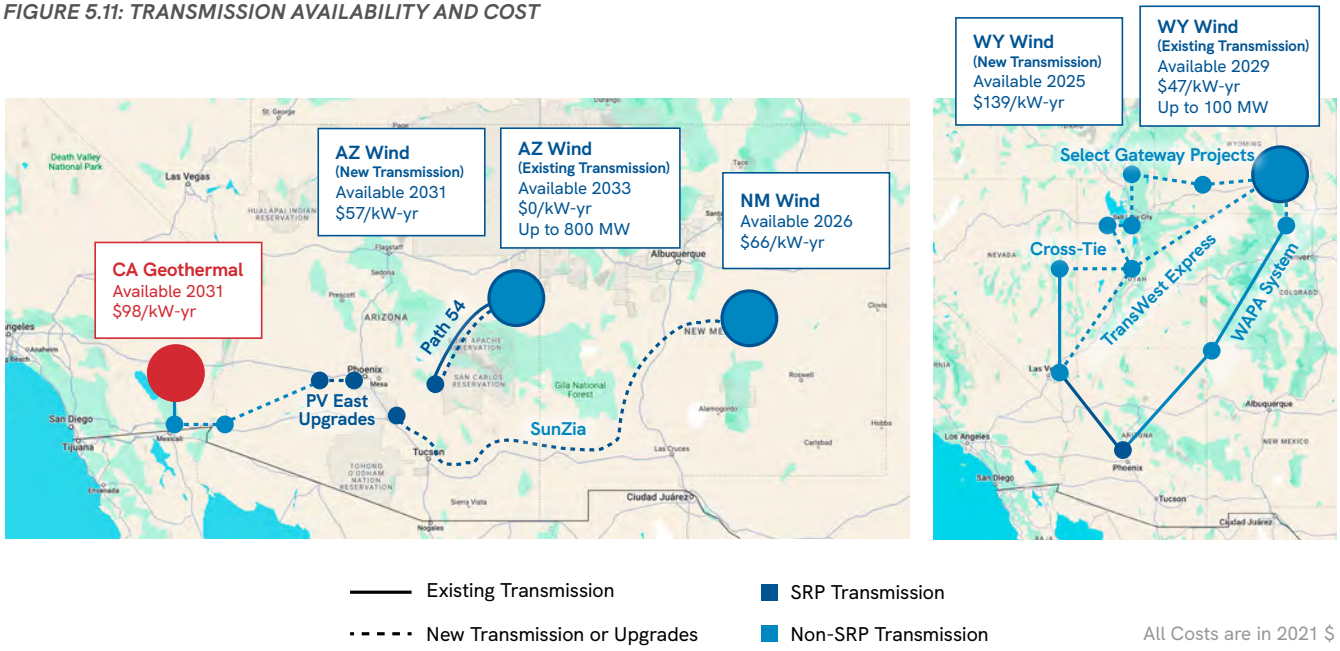
Transmission Costs

Several wind resource options, as well as the geothermal resource option, required consideration of transmission availability and costs of potential transmission expansion or upgrades. The Resource Additions planning process considered this availability and cost information when determining which resources to add.

See Figure 5.11 for the transmission availability and transmission cost adder for each resource option. For transmission paths that would require new or upgrades to transmission, we estimated the cost of this transmission and levelized the cost over the life of the transmission to determine

the transmission cost adder for those wind and geothermal resources. For existing transmission, we estimated how much transmission capacity would be available without further upgrades.

FIGURE 5.11: TRANSMISSION AVAILABILITY AND COST



Resource Costs

Our team forecasted future resource costs under different scenarios by relying on public data. We leveraged the 2022 NREL Annual Technology Baseline (ATB) for renewable and storage resource costs and the Energy Information Administration (EIA) 2022 Annual Energy Outlook (AEO) for thermal resource costs.

The fixed costs for resources included the following components: upfront capital, interconnection, property taxes, transmission (for remote resources, described in previous section), gas transportation (for gas resources), and fixed operations and maintenance costs. For upfront costs, we levelized these costs over the useful lifetime of each resource.[4] The variable costs for resources included fuel expense and variable operations and maintenance costs. This subsection focuses on the fixed costs, which don't vary with operations, while the Fuel Prices section below discusses fuel prices.

In August 2022, as our team was partway through the ISP analysis, Congress passed the Inflation Reduction Act (IRA), which provided an unprecedented federal investment in clean energy and created new federal tax credits for clean energy resources. Because of the significant nature of the IRA, we revised the cost of new resources to reflect these tax credits in all ISP scenarios and used these updated assumptions for the final ISP modeling. These revised costs were in part informed by the Technical Working Session SRP held with a group of industry experts on Jan. 17, 2023, to better understand the IRA.

[4]SRP utilized a lifetime of 15 years for battery storage resources, which was different from the NREL 2022 ATB but is consistent with the NREL 2023 ATB. SRP established this assumption based on experience with contracting for storage resources and after having conversations with members of the NREL ATB team to understand the underlying assumptions for battery lifetimes.

TECHNICAL WORKING SESSION ON THE INFLATION REDUCTION ACT

On 1/17/23, SRP held a Technical Working Session to better understand the impacts and uncertainties of the Inflation Reduction Act (IRA) and how to incorporate this into SRP's planning. Given the significant complexity of the IRA, SRP convened a group of experts with a wide range of viewpoints:

- Christine Turner, Solar Energy Manufacturers for America Coalition
- Mitch Rapaport, Nixon Peabody LLP
- Michael Mace, Public Financial Management (PFM)
- Hanson Wood, EDF Renewables North America

The experts highlighted a few ways in which the IRA could spur significant new clean energy investment:

- Provides significant incentives to grow domestic manufacturing, which could mitigate impacts from supply chain challenges experienced in recent years.
- Provides longer certainty for clean energy credits, through at least 2032 and likely longer.
- Expands eligibility of tax credits to a wider range of technologies, including standalone storage, nuclear, carbon capture and storage, and hydrogen.
- Creates an option for tax credit bonuses for domestic content and location within an Energy Community.
- Allows public power utilities like SRP to take advantage of tax credits via direct pay provisions, increasing feasibility of public power project ownership.

The experts also highlighted a few sources of risk and uncertainty:

- Greater guidance and certainty are needed from the Internal Revenue Service (IRS) for many of the IRA provisions to mitigate risks.
- Public power utilities like SRP must meet domestic content provisions to qualify for a direct pay credit.
- It is too early to tell whether projects will qualify for bonus tax credits, how much it will cost to monetize tax credits, and how tax credit savings will be split between developers and offtakers.
- Increased demand for clean energy demand could put increased pressure on supply chains in the near-term.
- Lack of support for new transmission in the IRA may lead to increased congestion, curtailment, and limitations in renewable resource growth.

Figure 5.12 shows the resource cost forecasts for the Current Trends and Desert Boom scenarios for renewable and nuclear resources in terms of levelized cost of energy (LCOE).[5] The LCOE metric expresses the levelized annual cost of a resource relative to its expected annual generation. One caveat in interpreting this metric is that it only reflects the cost of a resource and does not reflect the value that a resource provides to the system, nor does it reflect any renewable curtailment, which would increase the LCOE.

[5]Resource cost assumptions for the other scenarios and sensitivities are provided in Appendix A: [ASSUMPTIONS USED IN SCENARIOS, SENSITIVITIES AND STRATEGIC APPROACHES].

FIGURE 5.12: RENEWABLE RESOURCE COSTS (2023 $/MWH)

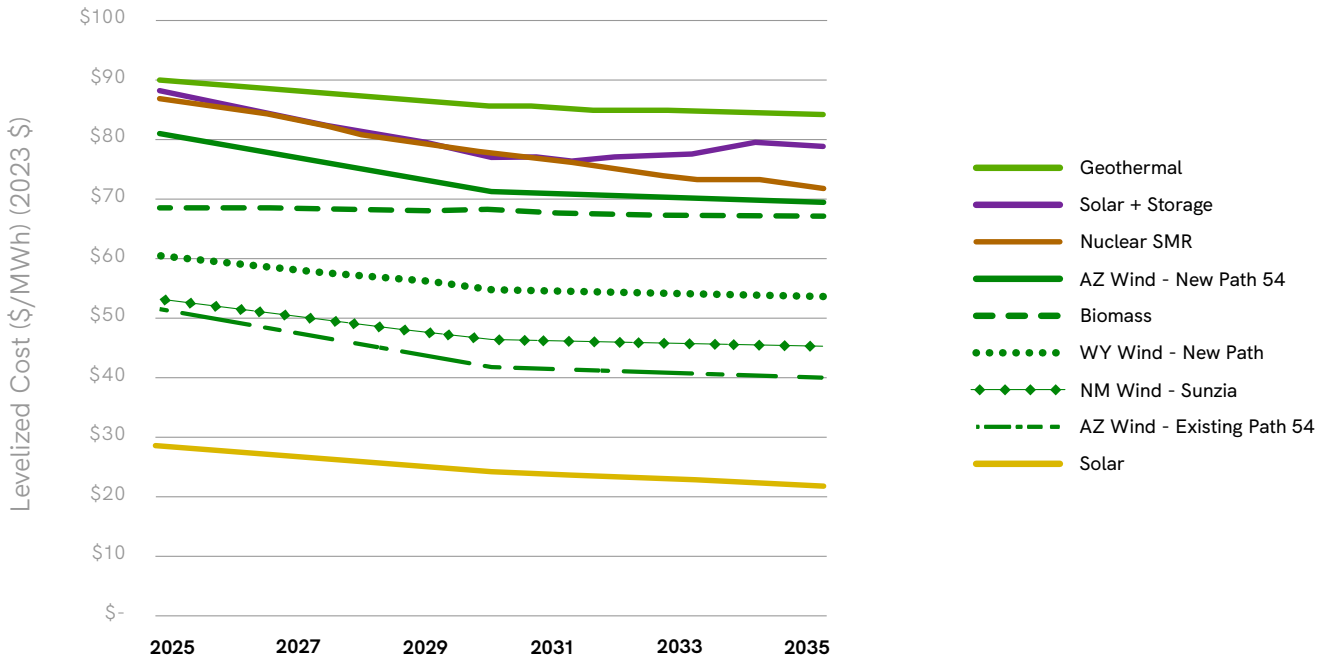
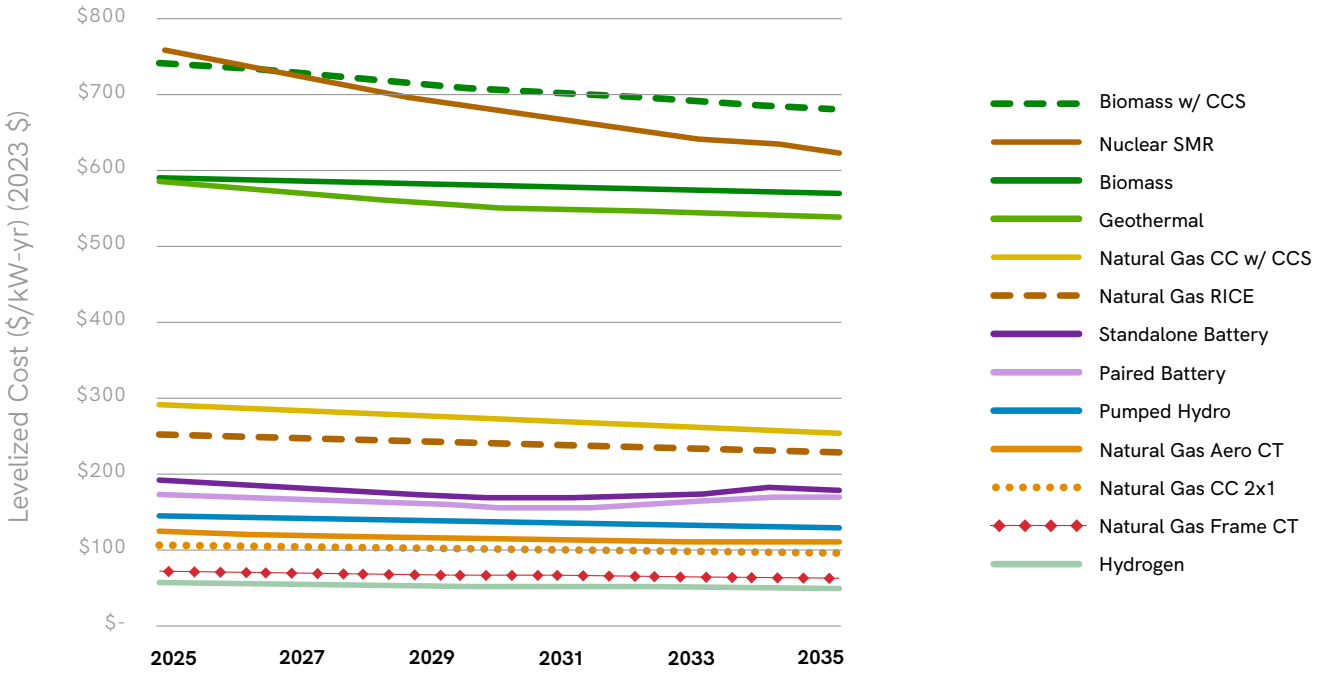


Figure 5.13 shows the resource cost forecasts for the Current Trends and Desert Boom scenarios for thermal and storage resources in terms of levelized fixed cost. Note that the LCOE metric used above is not commonly used for thermal and storage resources because the annual utilization of these resources can vary widely from one scenario to another or even year to year, while the LCOE metric assumes a fixed annual utilization.

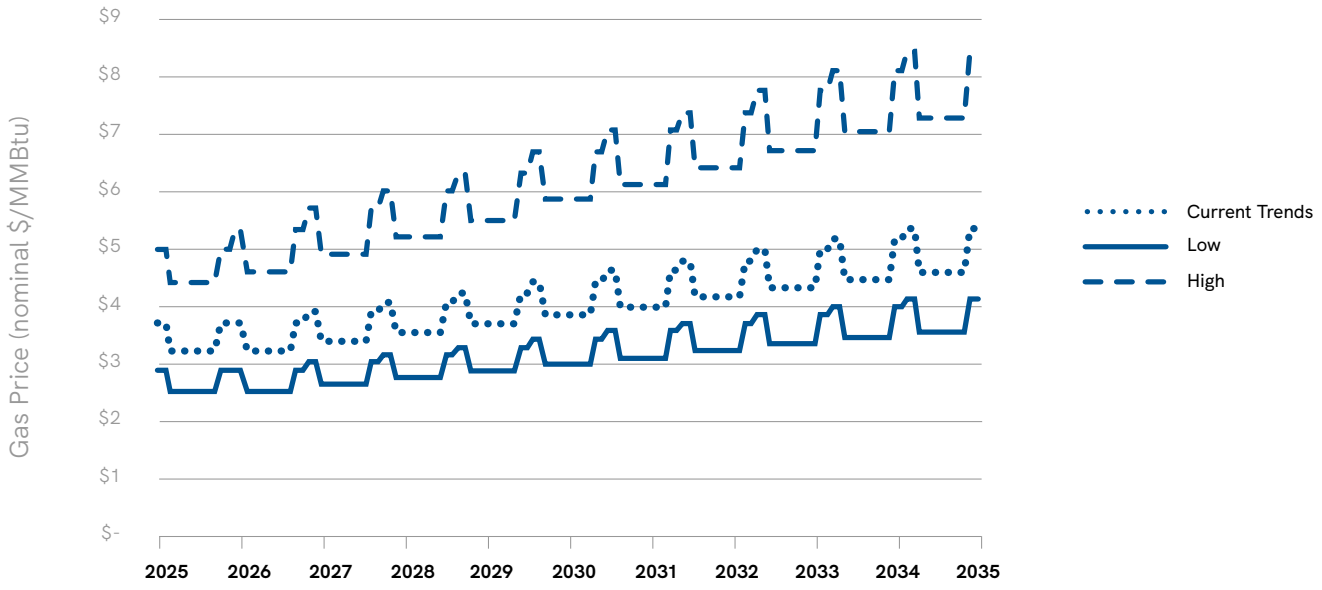
FIGURE 5.13: DISPATCHABLE RESOURCE COSTS



Fuel Prices

Fuel prices for the ISP were derived from several data sources. Natural gas forecasts were derived from the EIA 2022 AEO, with certain scenario trajectories regionalized based on SRP's gas supply. The gas price forecast varies by scenario and across the gas price sensitivities, reflecting low, mid, high and volatile trajectories. The low case reflects AEO's High Oil & Gas Supply Case; the mid case reflects AEO's Reference Case; the high case reflects AEO's Low Oil & Gas Supply Case; and the volatile gas case reflects observed volatility from 2000–2010 for the 2025–2035 analysis period. Figure 5.14 shows the Low, Current Trends (Mid) and High monthly forecasts through the 2025–2035 period.

FIGURE 5.14: GAS PRICE FORECASTS



Green hydrogen price forecasts were developed by E3, assuming electrolysis of hydrogen using an alkaline electrolyzer that is powered by solar energy (with solar resource costs as defined in this report). Hydrogen electrolyzer costs are derived from the California Energy Commission (CEC) publication on hydrogen production costs.[6] Hydrogen storage costs are derived from Department of Energy (DOE) project ST-001 costs.[7] Hydrogen transport costs are derived using Argonne National Laboratory's Hydrogen Delivery Scenario Analysis Model (HDSAM).[8] A $3/kg Production Tax Credit (PTC) is applied to all hydrogen produced through 2032. Market resource costs are derived and provided by internal SRP forecasts.

Reliability

To ensure system reliability, SRP must procure sufficient capacity to exceed annual peak demand over the entire planning horizon. In addition to serving the peak, a planning reserve margin (PRM) must be added to the amount of firm capacity on the system to ensure resource adequacy and avoid loss-of-load events while accounting for the potential for exceptional extreme loads, resource forced outages, uncertainties in load forecasting, and the operator's need to maintain a margin of operating reserves.

[6] https://www.energy.ca.gov/sites/default/files/2021-06/CEC-500-2019-055-F.pdf
[7] https://www.hydrogen.energy.gov/pdfs/review22/st001_ahluwalia_2022_p.pdf
[8] https://hdsam.es.anl.gov/index.php?content=hdsam

In most ISP cases, SRP applies a PRM of 16%, meaning that in each year of the planning horizon, SRP must have reliable capacity in an amount equal to or greater than 116% of forecast peak demand. In the Strong Climate Policy scenario and Regional Diversity sensitivity, the PRM is reduced to 13% as a proxy to represent the assumption that expanded transmission and regional coordination allows for increased resource and load diversity.

Due to high cooling loads, SRP has a summer-peaking system. Thermal generators are assumed to provide a PRM contribution (firm capacity value) equal to their summer monthly rating. Wind and pumped hydro storage resources contribute a fixed percentage of capacity (18% and 80%, respectively) to the PRM. Battery resource contributions to PRM decline with increasing battery penetration. New stand-alone solar resources are assumed to provide no firm capacity to SRP's system, but solar storage resources do contribute to the PRM due to the storage component.

CO_2 Emissions Target

SRP has established a goal of reducing carbon emissions intensity (lbs./MWh) by 65% by 2035 and by 90% by 2050, relative to 2005 levels. The carbon emissions intensity is the amount of carbon dioxide emissions (in pounds) from emitting power plants expressed relative to the amount of total generation (in megawatt-hours) across all power plants. In 2005, SRP's emissions rate was 1,576 lbs./MWh. In 2035, the CO_2 emissions target is 550 lbs./MWh. The ISP analysis capped CO_2 emissions to ensure that the future resource additions and operations are consistent with SRP satisfying its 2035 Sustainability Goals. *Note: SRP's 2035 Sustainability Goals are being refreshed in 2024 in collaboration with community stakeholders.*

Key Outputs

The following table reports the key outputs of the Resource Additions analysis:

Output	Description	Output Units
Resource Installed Capacity	Installed capacity of the generator, including new investments.	MW
Resource Contribution to Reliability	Firm capacity of the generator. For renewable resources options, this will equal the effective load carrying capability (ELCC) times the installed capacity.	MW
Resource Fixed Costs	Total fixed costs, including annualized build costs, fixed O&M and fixed charge (pipeline and/or fuel deliverability) costs.	$
Reliance on Emerging Technologies	Installed capacity and firm capacity for emerging technologies.	MW

Resource Operations

In the Resource Operations planning process, we simulated generating resource operations. For each future year, we simulated resource operations in each hour to understand how resources operate to meet total system demand and to understand the implications for cost, emissions, water usage and interactions with the regional power market. This information helped us evaluate the trade-offs between different system plans. This modeling process is sometimes referred to as production cost simulation in the industry.

Methodology Overview

Although the Resource Additions planning process considered resource operations when determining which resources to add in the future, that planning process did not have the same level of granularity as the Resource Operations planning process. In this planning process, SRP modeled every hour of the year (rather than a representative sample) and factored in more detailed operating characteristics for generators, which can influence operations. This refinement allowed SRP to say with more confidence how resource operations could evolve over time and what that would mean for affordability and sustainability metrics.

During this process, our team performed modeling for all 42 system plans. We used the Aurora model (developed by Energy Exemplar) to simulate future system operations, including existing resources and any new resources selected through the Resource Additions planning process. For the Volatile Gas Prices sensitivity cases, which did not vary the resource additions relative to the corresponding Current Trends cases, we only modified the gas prices and market prices over time to understand the impact of a volatile fuel price environment on system operations, affordability metrics and sustainability metrics.

Key Inputs

For this modeling process, we leveraged most of the same inputs utilized in the Resource Additions modeling process. Whereas the Resource Additions modeling process determined which resources to add to the system, the Resource Operations modeling process took the resource additions as fixed and then simulated future system operations. Therefore, this modeling process did not utilize the inputs related to resource additions or reliability given the system already had sufficient resources to meet future reliability needs. The Resource Operations process utilized the resource addition results as inputs and then leveraged the same data for these inputs:

- Load forecast
- Renewable generation profiles
- Variable operations and maintenance costs
- Fuel price forecast
- Market price forecast
- CO_2 emissions target

Because the Resource Operations modeling process simulated future system operations in a more granular manner, it also incorporated additional key inputs:

- Detailed operating characteristics for thermal generators
    - Minimum stable operating level
    - Startup time
    - Ramp rate
    - Minimum runtime
    - Minimum downtime
- Startup and shutdown costs for thermal generators
- Operating reserve requirements

Key Outputs

This planning process generated detailed system operations data for all 42 system plans. The table below summarizes the key outputs:

Output	Description	Output Units
Fuel, Operations and Maintenance Costs	Hourly fuel use, operations and maintenance costs	$
Market Purchase Costs	Costs of procuring external electricity generation outside of SRP	$
SRP Carbon Emissions (Mass)	Carbon emissions from generating resources during the planning period	Tons CO_2
SRP Carbon Emissions (Intensity)	Carbon emissions per MWh generation emitted during the planning period	Lbs. CO_2 per MWh
Carbon-Free Generation (%)	Percentage of total generation that was carbon-free	%
Water Use	Total water use during resource operation	Gallons
Criteria Pollutants (NO_x, SO_2, PM, VOC)	Criteria pollutant emissions from generation during the planning period	Tons
Thermal Plant Capacity Factor	Capacity factors for thermal plants during resource operation	%

Transmission Investments

In the Transmission Investments planning process, we studied the forecasted load and resource additions, determined future transmission needs and identified transmission investments to meet those needs. For the year 2035, we simulated transmission operations under different load and resource assumptions to understand which transmission investments were needed and at what cost.

Methodology Overview

For the ISP, we analyzed the portion of the transmission system rated 115 kV and above. We focused on this part of the transmission system for two reasons. First, transmission investments at these higher voltages require longer lead times for siting, engineering, permitting and construction, so there is more value in identifying investment needs for these assets through 2035. Second, analyzing the 69 kV system was not feasible due to limited resources over this study period. While we did not analyze the 69 kV system, we did estimate investment costs for the 69 kV system based on the number of new distribution substations.

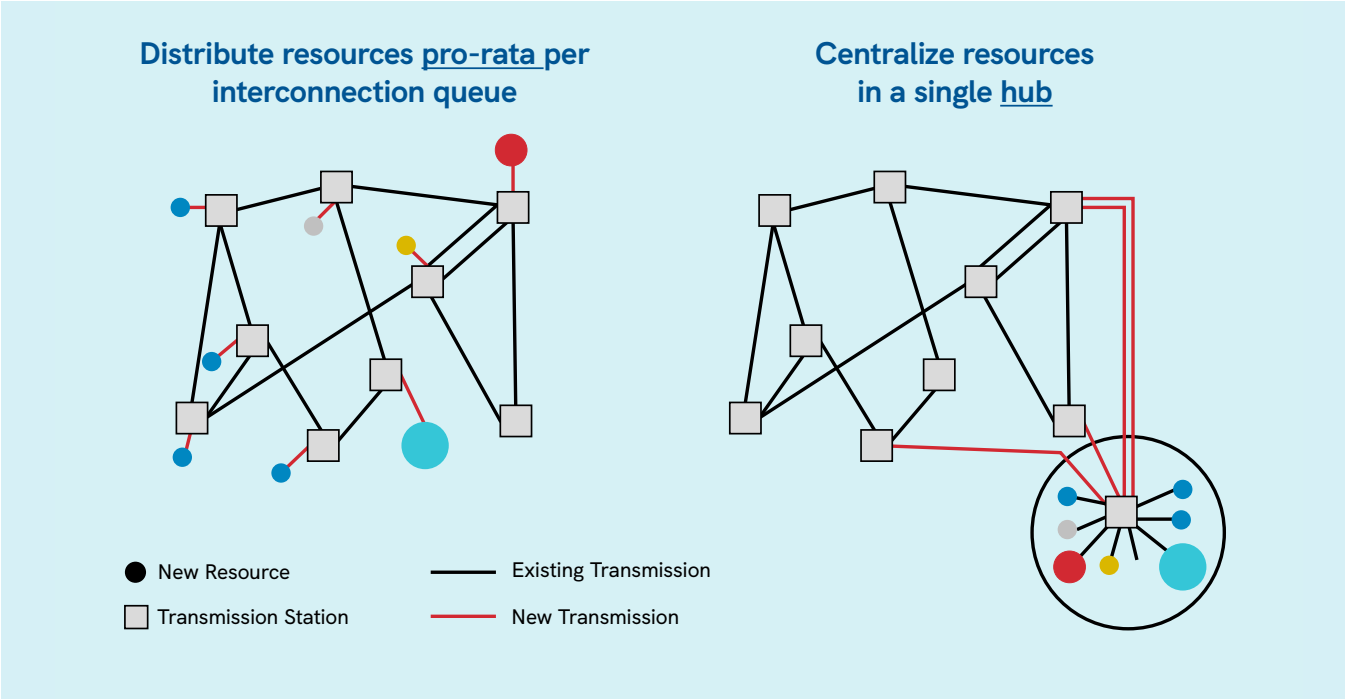
During this process, our team performed power flow analysis for the year 2035 to understand how power would flow across the transmission system and how the voltage would respond under certain conditions. We evaluated whether any element of the transmission system would be overloaded or be outside its acceptable voltage range. We also evaluated whether any element of the transmission system would be overloaded or fall outside its acceptable voltage range if other transmission elements were unavailable. We then identified transmission investments to mitigate the identified issues until none remained.

We studied two different operation hours for each case analyzed: the summer peak load hour, during which energy demand is greatest, and a summer peak renewables hour in which generation from solar, wind and other renewable resources are at maximum output. By studying these two conditions, we confirmed that the transmission system could meet the peak energy demand and accommodate renewable generation during peak production periods. For each case analyzed, we identified transmission investments that mitigated all issues across both operating conditions.

One of the key uncertainties in transmission planning is the location of future resources. Currently, developers decide where to site projects, submit interconnection requests and bid to provide energy to SRP or other utilities. As a result, we do not know where future resources will interconnect. The location of these resources can have a significant impact on the need for new transmission projects.

In the ISP, we chose to evaluate two resource location options: Pro-Rata and Hub (see Figure 5.15). The Pro-Rata option envisions new solar and battery resources being added across the system in proportion to the resources currently in SRP's interconnection queue. The interconnection queue served as a proxy for where developers would site future projects. With the Hub option, SRP would develop a new 500 kV switchyard southeast of the Valley and would encourage development of new gas, solar and battery storage resources at the hub. The Pro-Rata option represents a continuation of current practices in which developers locate throughout SRP's system, while the Hub option represents a potential alternative in which SRP concentrates development of resources in one location and connects that location to the rest of the system.

FIGURE 5.15: RESOURCE LOCATION OPTIONS



Our team identified transmission investments for the following cases under both the Pro-Rata and SRP Hub options. Due to time constraints through the ISP analysis, we could not perform detailed transmission analysis on all cases. Instead, we chose to analyze the following cases because they represent a wide range in both load growth and resource additions.

- Technology Neutral, Current Trends
- Technology Neutral, Desert Boom
- Minimum Coal, Current Trends

Key Inputs

For this modeling process, our team leveraged outputs from different planning processes, including Load Forecasting, Distribution Investments, Resource Additions and Resource Operations. As the transmission system acts as the link between utility-scale resources and customers, inputs related to loads and resources from these other planning processes were key inputs in determining transmission investment needs.

Because SRP's system is connected to other power systems in the Western Interconnection, we utilized models that represent the entire Western Interconnection. On an annual basis, SRP coordinates with neighboring utilities to develop "heavy summer" transmission models for up to 10 years into the future. For the ISP, we adapted the "2032 heavy summer" model to perform analysis for the different transmission cases through 2035.

Energy Demand

The projected energy demand at different locations on the transmission system came from two sources. First, the Load Forecasting modeling process identified the future energy demand for customers that connect directly to the transmission system. Second, the Distribution Investments modeling process identified the energy demand at each existing and new distribution substation to represent those customers connected to the distribution system. These inputs allowed SRP to identify the energy demand for each location on the transmission system.

Resource Locations

Figure 5.16 shows the location assumption for each new resource in the Pro-Rata and Hub options. For natural gas resources under the Pro-Rata option, we identified five potential locations based on preliminary gas siting screening efforts that were recently performed. For solar and battery storage resources under the Pro-Rata option, we allocated them to different substations in proportion to the interconnection queue. For the Hub option, we located new natural gas, solar and battery storage resources at the hub. The locations for other resources did not vary between the Pro-Rata and Hub options because the locations were already determined by the location of the underlying resource. The locations for wind and geothermal resources are discussed above in the Resource Additions section.

FIGURE 5:16: NEW RESOURCE LOCATIONS IN THE PRO-RATA AND HUB OPTIONS

New Resource	Pro-Rata	Hub
Natural Gas	Split across five locations	Placed at hub
Solar	Pro-rata allocation	Placed at hub
Battery Storage	Pro-rata allocation	Placed at hub
Pumped Hydro	Northeast of SRP service territory	
Wind	Varies by resource	
Geothermal	California, wheeled to Arizona, and injected at Hassayampa	
Biomass	Coronado	

Resource Operations

For the resource operations, our team identified the expected generation from all existing and planned resources for the peak load hour, so the transmission peak hour models reflected the planned resource outputs. This also included an economic dispatch order that was used to develop the peak renewable output hour scenarios.

Key Outputs

This planning process determined transmission investments. The table below summarizes the key outputs:

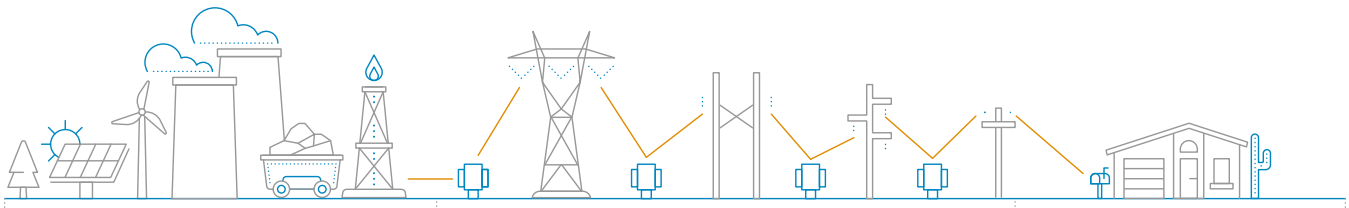
Output	Description	Output Units
Transmission Investments	Transmission projects to meet system requirements and associated upfront investment costs	$

Total System Cost

In this process, we performed simplified financial modeling to develop an annual total system cost metric for every case analyzed in the ISP. The purpose of this analysis was to provide indicative affordability metrics to compare system plans to one another and understand trade-offs between different system strategies. While the total system cost metric is helpful for these comparisons, it is not intended to provide a forecast of future rates for SRP customers or reflect SRP's financial outlook.

See Figure 5.17 below. We developed the total system cost by estimating system costs for generation, transmission, distribution, customer programs and other costs. These costs included costs of existing investments, new investments, operations and an estimate of system costs not modeled explicitly in the ISP. Many of these costs were outputs from the other modeling processes in the ISP.

FIGURE 5.17: COSTS INCLUDED IN TOTAL SYSTEM COST



Generation

Fuel

Market purchases and sales

Power purchase agreements

Existing and new investments

Operations and maintenance

Non-SRP transmission cost

Transmission & Distribution

Existing and new investments

Operations and maintenance

Customer Programs

Program and market enablement costs

Other

General & Administrative

Customer systems (metering, billing, customer service, etc.)

Telecom

Taxes

Assumed constant across all cases

Methodology Overview

For this methodology, our team first established a set of "base" costs that do not change across system plans. We forecasted the costs associated with existing generation, transmission and distribution assets, including the recovery of investment and maintenance costs. In addition, we forecasted other costs that do not relate to generation, transmission, distribution and customer programs, such as general and administrative costs. We held all of these "base" costs constant across cases.

We then determined the costs for investments that differed across the system plans and leveraged the outputs from the different planning processes to determine any incremental investments. To determine the annual costs for these investments, we applied straight-line depreciation and assumed a cost of capital consistent with SRP's weighted average cost of capital. SRP also estimated property taxes for these investments based on previously observed tax rates. Lastly, we leveraged the outputs from the planning processes to forecast operating expenses.

Generation

The Resource Additions process identified incremental generation investments, operation and maintenance fixed costs, and power purchase agreement costs. The Resource Operations process identified all variable operating costs associated with generation, including fuel expense, net market purchase costs, and variable operations and maintenance costs.

Transmission

The Transmission Investments process identified any incremental transmission system investments for the three cases analyzed. SRP further differentiated these costs by investments that are generation-driven versus load-driven to estimate costs in other cases. Using the three transmission cases analyzed, we calculated a linear relationship between (1) generation-driven costs and interconnected capacity additions, and (2) load-driven costs and peak load growth. We then applied those relationships to interconnected capacity additions and peak load growth observed in each of the remaining cases.

Distribution

The Distribution Investments process identified incremental distribution system investments, including transformers to serve new customers, new substations and substation upgrades. SRP identified these investments for each scenario as well as the high distributed generation and high energy efficiency sensitivities. The investment types and estimated costs remained consistent across the three strategic approaches.

Customer Programs

The Customer Programs process identified the incremental customer program operating costs. These costs reflected the cost of Energy Efficiency and Demand Response programs.

Key Outputs

The Total System Cost process generated annual cost estimates for all 42 system plans. The table below summarizes the key outputs. These outputs served as key inputs in calculating residential bill impacts across cases (see the Residential Bill Impact section below).

Output	Description	Output Units
Total System Cost	Total system costs across generation, transmission, distribution and other	$
Average System Cost	Total system cost divided by retail sales	$/MWh

Residential Bill Impact

In this process, we applied a simplified method to estimate the bill impacts over time for residential customers. While the Total System Cost process estimated how total costs could evolve over time, this process estimated how these changes could impact residential customers specifically and developed a residential bill impact metric.

This bill impact analysis does not necessarily reflect how future costs may be allocated and recovered from customers and therefore should not be considered as a projection of customer rates. SRP will carry out pricing processes in the future to determine future cost allocation and rates. Nevertheless, this metric provides a means for comparing cases to understand relative differences.

Methodology Overview

We leveraged information from our most recent Cost Allocation Study (CAS) to allocate costs in the ISP to residential customers. The CAS determined how the energy usage of residential customers differed from other customer classes (e.g., commercial and industrial) and developed cost allocators for different system cost components (e.g., generation and fuel). Because different system cost components are driven by different factors (e.g., total annual energy use, peak hour energy usage), the cost allocators differ by system cost component. This ensures that each customer class pays its fair share of system costs, based on the cost of serving those customers.

Below is the methodology we used in the ISP to allocate costs for different system components to residential customers:

- **Generation –** Generation-related costs, including operations and maintenance (O&M) costs, power purchase agreement (PPA) costs and recovery of investment costs, are allocated based on a blend of two factors: the share of annual delivered energy (in kWh) and the share of energy demand (in MW) during overall system peak periods.

- **Fuel –** Fuel costs, including natural gas, coal and (in some ISP cases) hydrogen fuel costs, are allocated based on the share of total annual energy demand (in kWh), calculated as the total annual delivered energy less any energy exported to the grid.
- **Transmission –** Transmission costs, including O&M costs and recovery of investment costs, are allocated based on the share of energy demand (in MW) during overall system peak periods.
- **Distribution –** Distribution costs, including O&M costs and recovery of investment costs, are allocated based on the peak hourly energy demand of the customer class (in MW) — not necessarily during the overall system peak period — relative to the peak hourly energy demands of other customer classes.
- **Customer Service, Billing and Metering –** Customer service, billing and metering costs are allocated based on the share of the total number of customers served by SRP.
- **Other Costs –** Other costs, including net market purchase expenses and any other costs not described above, are allocated according to the share of total generation, transmission and distribution costs.

To determine the average residential customer cost (in ¢/kWh), SRP divided the total costs allocated to residential customers by the total annual energy demand (in kWh). SRP then compared these average residential costs to the actual costs for residential customers in November 2022 to show the change through 2035.

Key Outputs

The key output of this process is the average residential bill impact:

Output	Description	Output Units
Average Residential Customer Cost	Average residential customer cost for each ISP case.	¢/kWh

Development and Operational Risk Assessments

Our team evaluated the development and operational risk factors for different system plans. While the various planning processes identified future infrastructure additions based on least-cost optimization analysis, as well as future operations based on simulations, there are many real-world risks to consider that could impact SRP's ability to develop and operate these system plans.

There are risks and challenges in developing new infrastructure, including risks related to permitting, siting, constructing and acquiring new infrastructure. As we have observed over the last few years, third-party projects can be delayed or even cancelled due to supply chain challenges. Supply chain issues have also led to increased timelines for acquiring new transmission and distribution infrastructure. There are also risks in developing large new infrastructure projects, which may depend on multiple regulatory approvals and therefore come with uncertainty. Because each of the ISP system plans requires significant development

of new resources, we performed a qualitative risk assessment to better understand the risks and challenges in building out these future power systems.

There are also risks and challenges in operating the power system in new ways. While the production cost model simulated future operations based on hourly optimization analysis, many real-world risks cannot be captured fully in that analysis and could potentially impact SRP's operations. There are risks related to more variable system operations, fuel availability, wear and tear on generating resources, etc. Because each of the ISP system plans requires a meaningful shift in the future operations of the system, we performed a qualitative risk assessment to better understand the risks and challenges in operating these future power systems.

Methodology Overview

Our team developed qualitative development and operational risk ratings for each system plan to understand the relative risks between different system plans. This approach is used to assess uncertainty in factors where it is not easily quantified and is known as the expert opinion method.

First, because the ISP assessed many planning cases, and some of the resulting system plans were relatively similar across cases, we clustered some plans together when performing the risk assessment.[9] The clustered system plans were representative of the 12 core system plans (three strategic approaches evaluated against four scenarios). We then convened an internal group of subject matter experts from various departments to assess the development and operational risks for each of the system plans. After the group assessed the different system plans independently, SRP held a joint workshop during which the group discussed findings, identified risks, discussed mitigation factors and developed risk ratings.

To develop a quantitative risk rating, each participant rated each cluster of system plans on a scale from 1 to 5, with 1 being lowest risk and 5 being highest risk. We identified a reference plan (Tech Neutral, Current Trends) to correspond to a risk rating of 3 to calibrate a point of reference. The participants rated each cluster of system plans based on how the risk factors for that plan compared to the risk factors identified for the reference plan, and SRP averaged these ratings to develop a final risk rating for each system plan.

Development Risk Assessment

To evaluate the development risks for different system plans, we convened an internal group of subject matter experts from the following groups within SRP:

- **Resource Planning, Acquisition and Development**, consisting of engineers and analysts responsible for acquiring and developing power generation resources (renewable and thermal) to meet system needs
- **Distribution Planning**, consisting of engineers who plan distribution infrastructure
- **Innovation & Development**, consisting of engineers who support research into emerging generation technologies (e.g., hydrogen, nuclear small modular reactors, and carbon capture and storage)

[9] For the development risk assessment, SRP clustered system plans based on resource additions across different technologies. For the operational risk assessment, SRP clustered system plans based on multi-hour ramping needs, natural gas fuel consumption, market purchases, solar additions, wind additions, battery storage additions, and curtailment.

- **Power Delivery**, consisting of engineers and planners who support generation interconnection and plan, site and build necessary transmission infrastructure
- **Land**, consisting of analysts responsible for acquiring necessary land for new projects
- **Supply Chain Management**, consisting of analysts managing procurement of long-lead-time equipment
- **Supply and Trading & Fuels**, consisting of power and natural gas traders and analysts focused on market operations
- **Customer Programs**, consisting of analysts who develop and manage customer programs (e.g., energy efficiency, electrification)
- **Environmental Services**, consisting of engineers and scientists who support site permitting and ensure compliance with environmental regulations
- **Community Partnerships**, consisting of community strategists who work with and support the communities that SRP operates within

We provided each of these groups with the outputs for different system plans and then tasked them with evaluating the system plans based on the following development risk factors:

- Permitting, siting and land acquisition
- Supply chain challenges
- Long lead times to develop infrastructure
- Interconnection of new resources
- Natural gas pipeline development
- Reliance on emerging technologies
- Reliance on customer adoption of end-use programs (such as energy efficiency and distributed generation)

Operational Risk Assessment

For the operational risk assessment, we followed a process similar to that used for the development risk assessment. To evaluate the operational risks for different system plans, we convened an internal group of subject matter experts from the following groups within SRP:

- **Supply and Trading & Fuels**, consisting of electricity and natural gas traders and analysts focused on markets and operations
- **Operations Planning**, consisting of analysts focused on modeling the market, optimal dispatch and maintenance planning
- **Transmission & Generation Operations**, consisting of real-time power dispatchers
- **Operational Readiness**, consisting of engineers leading the processes for enabling additional solar and batteries onto SRP's system
- **Generation Engineering**, consisting of engineers analyzing the maintenance needs of generation plants

We provided each of these groups with the outputs for different system plans and then tasked them with evaluating the system plans based on the following operational risk factors:

- System ramping needs and capabilities
- Renewable curtailment
- Thermal unit operations (capacity factor, starts and hours of operation)
- Reliance on market purchases for electricity
- Natural gas hourly and daily consumption

Key Outputs

Output	Description	Output Units
Development Risk Rating	Risk rating summarizing the degree of development risks associated with a given system plan	Likert Scale (1 = lowest risk, 5 = highest risk)
Operational Risk Rating	Risk rating summarizing the degree of operational risks associated with a given system plan	Likert Scale (1 = lowest risk, 5 = highest risk)

Metrics

We developed metrics for ISP cases to evaluate the performance of each strategic approach across scenarios and sensitivities, provide information to customers and other stakeholders, and to inform the ISP residential customer research. Figure 5.18 lists the metrics we developed to evaluate the performance of different system plans, which include reliability, affordability, sustainability and customer focus metrics.

FIGURE 5.18: ISP METRICS



Reliability

Resource Contribution to Reliability

Reliance on Emerging Technologies

Qualitative Risk Ratings (Development Risk and Operational Risk)

Planning Reserve Margin

Affordability

Total System Costs

Average System Costs

Average Residential Price Impact

Sustainability

CO_2 Reductions

Water Use

Carbon-Free Generation

Capacity Factor for Gas Fleet

Direct Air Emissions (NOx, SO_2, PM, VOC)

Customer Focus

Customer Preference Rating

CO_2 reductions from energy efficiency, distributed generation and electrification

We developed most of these metrics through the modeling processes described above. The Total System Cost and Residential Price Impact processes produced the affordability metrics. The Resource Operations process produced the sustainability metrics. And lastly, the Resource Additions, Development Risk Assessment and Operational Risk Assessment processes produced the reliability metrics.

For the Customer Focus metrics, we completed additional analysis separate from the modeling processes described above. To develop the Customer Preference Rating, SRP engaged Bellomy Market Intelligence to complete the ISP residential customer research. The goal of Bellomy's research was to bring the voice of SRP's residential customers into the planning of the future power system. More specifically, this research was designed to gain an understanding of how customers view and value sustainability, affordability and reliability related to their electricity service from SRP and gauge their reactions to potential energy systems being analyzed in the ISP. A choice-based methodology known as a conjoint exercise was utilized to understand customer preference for potential future energy systems being analyzed in the ISP and ultimately develop the Customer Preference Rating. More details on the specific methodology are included in appendices B and C, which contain reports from all phases of the ISP residential customer research effort.

To develop the CO_2 Reductions metric for various customer programs (including energy efficiency, distributed generation, demand response and electrification), we estimated the amount by which additional amounts of these programs could decrease economywide greenhouse gas emissions. For energy efficiency and distributed generation, we evaluated how much annual emissions would decrease in each planning case if customer adoption increased slightly. For electrification measures (including electric vehicles and heat pumps), we estimated how much annual emissions from electricity generation would increase from customers adopting these measures and increasing energy demand. In addition, we estimated how much emissions would decrease from displaced fossil fuel consumption (in vehicles or home heating systems) to arrive at an estimate for net decrease in economywide emissions for adoption of electrification measures.

Ultimately, planning a future energy system involves trade-offs between different planning goals for the system. No single system plan performed the best in every metric that we quantified. We utilized this suite of metrics to evaluate trade-offs between different strategic approaches and to understand how planning would need to adapt under future planning uncertainties.

SECTION 6

Results

This section presents the modeling results and key findings from the ISP analysis. The analytical results are presented for each planning process described in Section 5, including Customer Programs and End-Use Technologies, Load Forecast, Distribution Investments, Resource Additions, Resource Operations, Transmission Investments, Total System Cost, Residential Bill Impact, Development and Operational Risk Assessment, and Residential Customer Research. Several ISP key findings are highlighted in callout boxes throughout and then summarized at the end of this section.

Results

Customer Programs and End-Use Technologies

Customer programs play an important role in managing SRP's load and are a key input to the load forecast used in the ISP. Also, customer adoption of end-use technologies, such as electric vehicles and distributed generation, have an increasing impact on the load forecast over time. This section presents the forecasts through 2035 for annual energy efficiency savings, demand response capacity, additional electrification load, and customer adoption of distributed generation across each scenario.

Figure 6.1 shows the incremental new energy efficiency savings. Under Current Trends, Desert Boom and Desert Contraction, there is continued expansion in energy efficiency over time, reaching 3,236 GWh of new energy efficiency savings by 2035. Under Strong Climate Policy, expansions to federal codes, standards and incentives lead to even higher energy efficiency growth, reaching 3,896 GWh of total energy efficiency savings by 2035.

Figure 6.2 shows the cumulative demand response capacity through 2035. Under all scenarios, SRP doubles demand response capacity, reaching 300 MW of total demand response by 2035.

FIGURE 6.1: ANNUAL NEW ENERGY EFFICIENCY ASSUMPTIONS

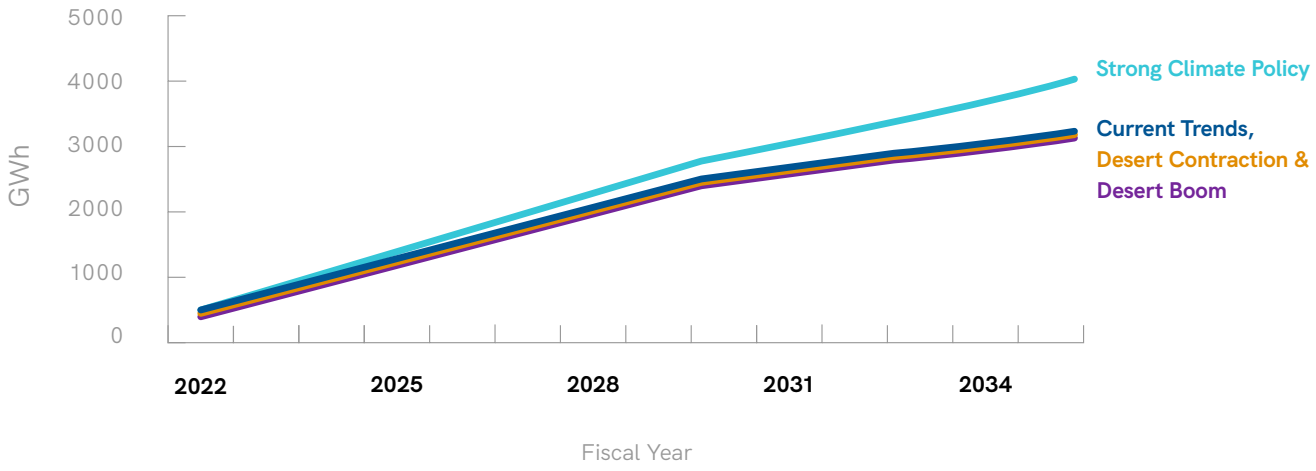
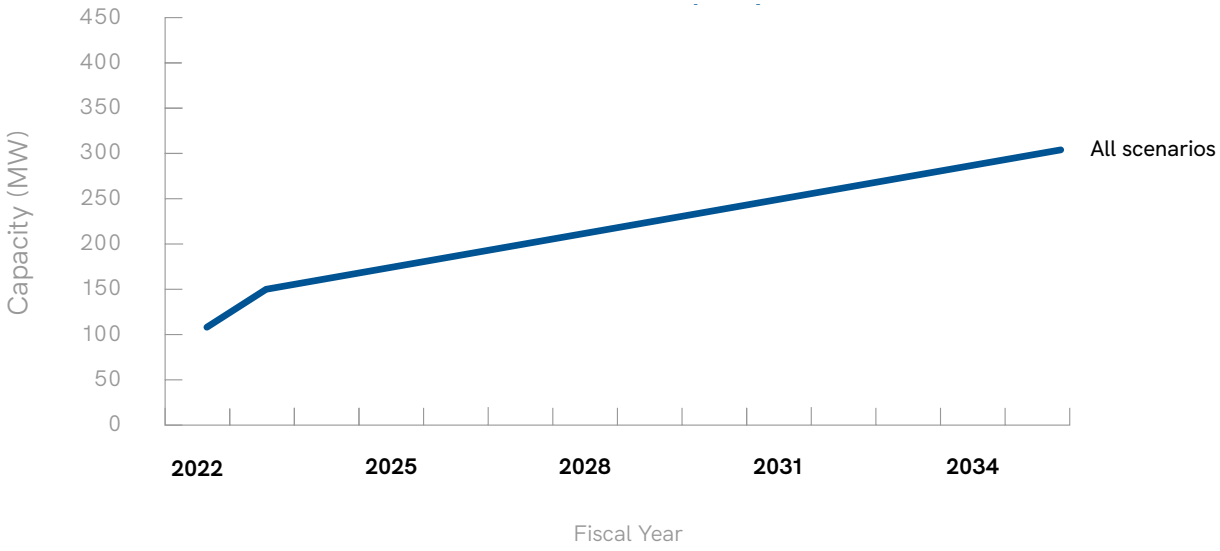


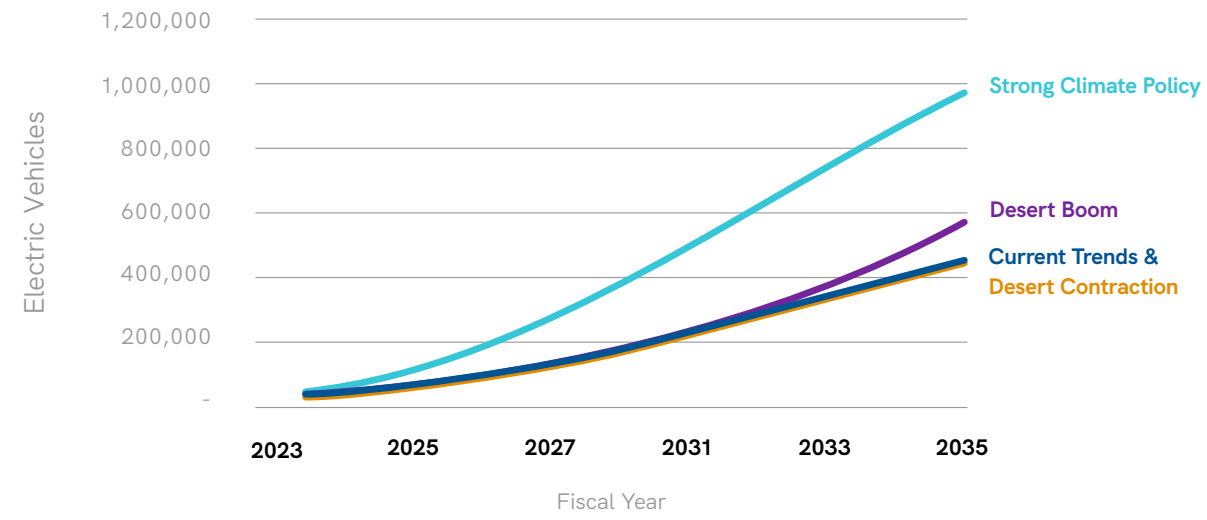
FIGURE 6.2: CUMULATIVE DEMAND RESPONSE CAPACITY ASSUMPTIONS



In addition to the energy efficiency and demand response programs, SRP's electric technologies programs, which serve commercial and industrial customers, grow meaningfully over time. The load impact from these programs grows from approximately 50,000 MWh today to levels consistent with SRP's goal of 300,000 MWh by 2035. The programs are varied and include electrification of material handling equipment (forklifts, scissor lifts, boom lifts, scrubbers, sweepers, etc.), truck stop and truck refrigeration equipment, industrial heating processes (melting, curing, steam, etc.), space and water heating processes, and commercial cooking equipment.

Figure 6.3 shows projected customer adoption of electric vehicles through 2035. Under the Current Trends and Desert Contraction scenarios, customers adopt 500,000 electric vehicles by 2035, consistent with SRP's 2035 goal for electric vehicle adoption. Under the Desert Boom scenario, customers adopt more electric vehicles due to increased economic and population growth. Under the Strong Climate Policy scenario, SRP assumed that increased federal support will result in greater customer adoption of electric vehicles at levels consistent with reaching net-zero economywide emissions by 2050.

FIGURE 6.3: ELECTRIC VEHICLE ADOPTION FORECAST



In addition to customer energy demand, customer adoption of generating resources also impacts the overall forecast for future energy demand. SRP forecasts customer adoption of rooftop solar and batteries to grow, reducing future energy demand (see figures 6.4 and 6.5).

In the Current Trends and Desert Contraction scenarios, rooftop solar and battery adoption increase steadily, reaching 1,296 MW and 75 MW, respectively, by 2035. In the Desert Boom scenario, an increased population and economic growth lead to stronger rooftop solar and battery adoption, reaching 1,804 MW and 157 MW, respectively, by 2035. In the Strong Climate Policy scenario, rooftop solar and battery adoption increase the most due to accelerated technology improvements and cost declines assumed in this scenario. By 2035, solar and battery adoption reach 2,257 MW and 250 MW, respectively, in the Strong Climate Policy scenario.

FIGURE 6.4: ROOFTOP SOLAR ADOPTION NAMEPLATE CAPACITY (MW) FORECAST

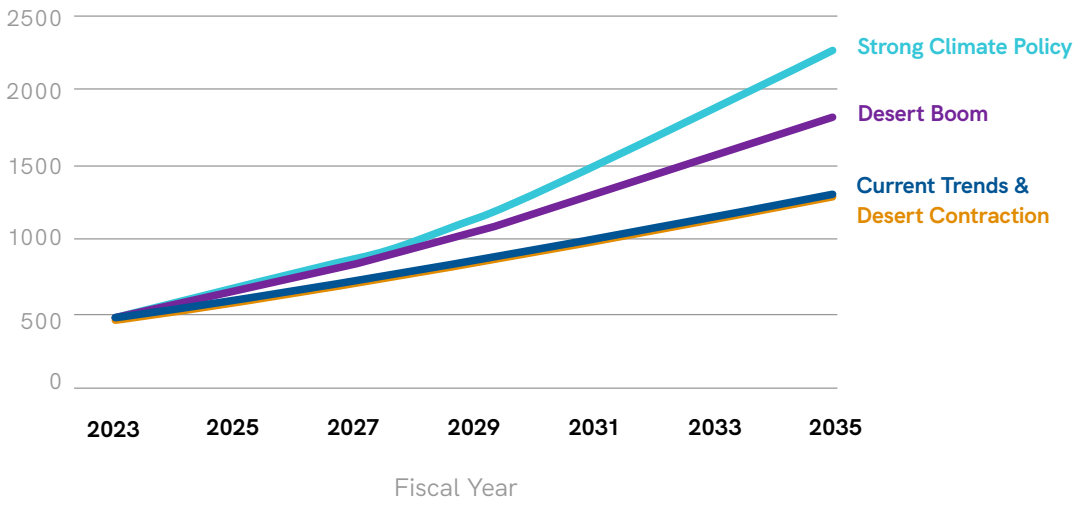
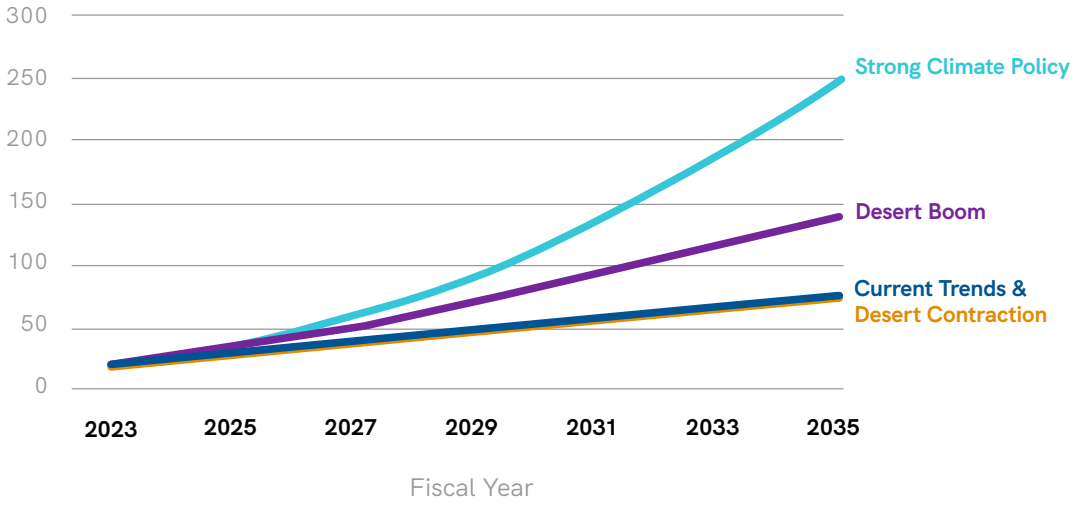


FIGURE 6.5: CUSTOMER-OWNED BATTERY ADOPTION NAMEPLATE CAPACITY (MW) FORECAST



Load Forecast

The load forecast is a key input to all the planning processes, as it is a main driver of future investment needs. This section presents the peak load and annual energy demand forecasts through 2035 for the four scenarios.

KEY FINDING

Customers' energy demand is expected to increase rapidly through 2035 in most scenarios, even with significant expansion of customer programs and customer-sited generation.

Figures 6.6 and 6.7 show peak load and energy demand forecasts for the four scenarios. SRP forecasts rapid load growth in the Current Trends, Desert Boom and Strong Climate Policy scenarios. In the Current Trends scenario, high economic and population growth lead to a substantial increase in both peak load and energy demand. In the Desert Boom scenario, accelerated migration into the Phoenix metropolitan area and increased economic development lead to even higher loads. In the Strong Climate Policy scenario, load growth from rapid electrification is offset by increased customer programs, resulting in a similar, but slightly lower, load forecast as for Current Trends. Across these three scenarios, between 2023 and 2035, peak load grows annually by 2.9%–4.0%, and annual energy demand grows annually by 3.1%–4.8%. The Desert Contraction scenario initially follows a rapid growth trajectory, but then peak load levels off and annual energy demand declines, reflecting a reversal of recent trends in migration and economic growth. Altogether, these load forecasts represent a wide range of future outcomes, from little to no growth in Desert Contraction to accelerated growth in Desert Boom.

FIGURE 6.6: PEAK LOAD (MW) FORECASTS BY SCENARIO

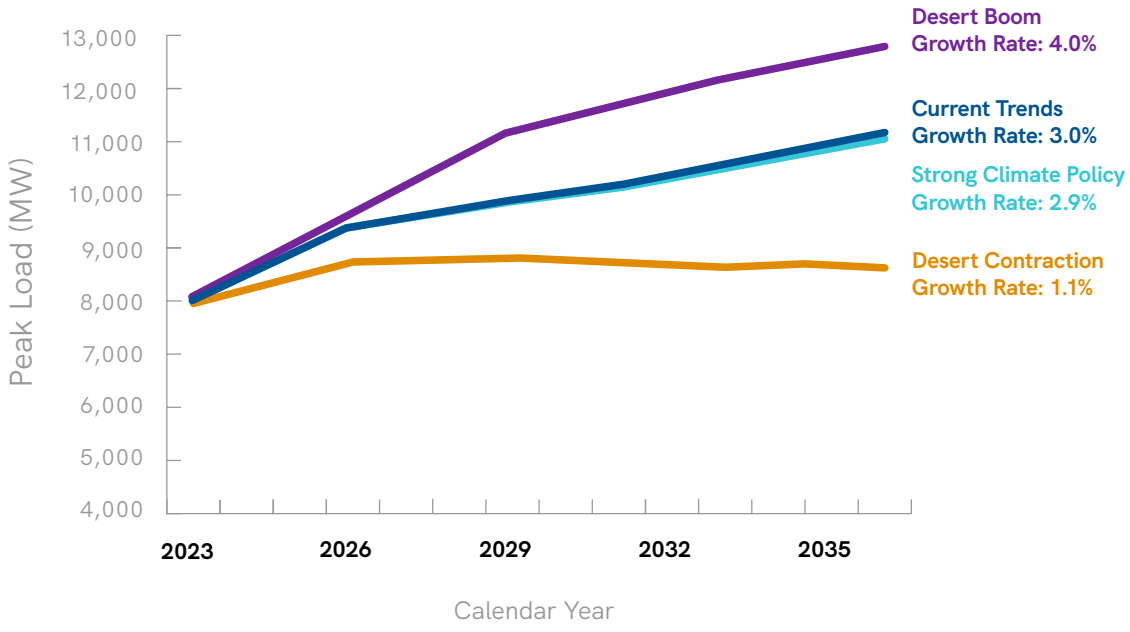
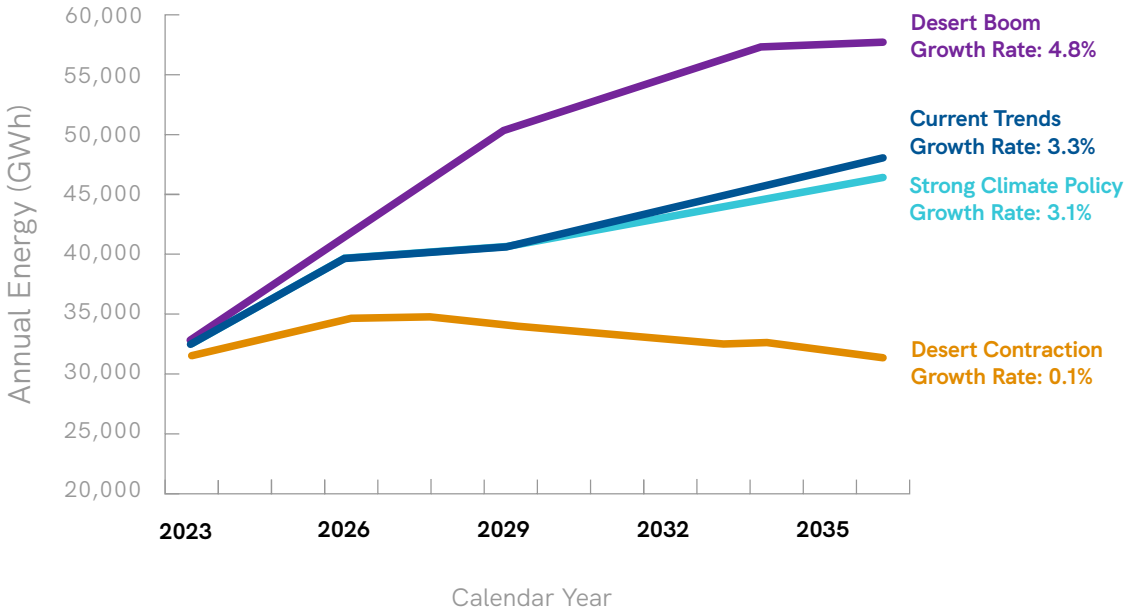


FIGURE 6.7: ENERGY DEMAND (GWH) FORECASTS BY SCENARIO



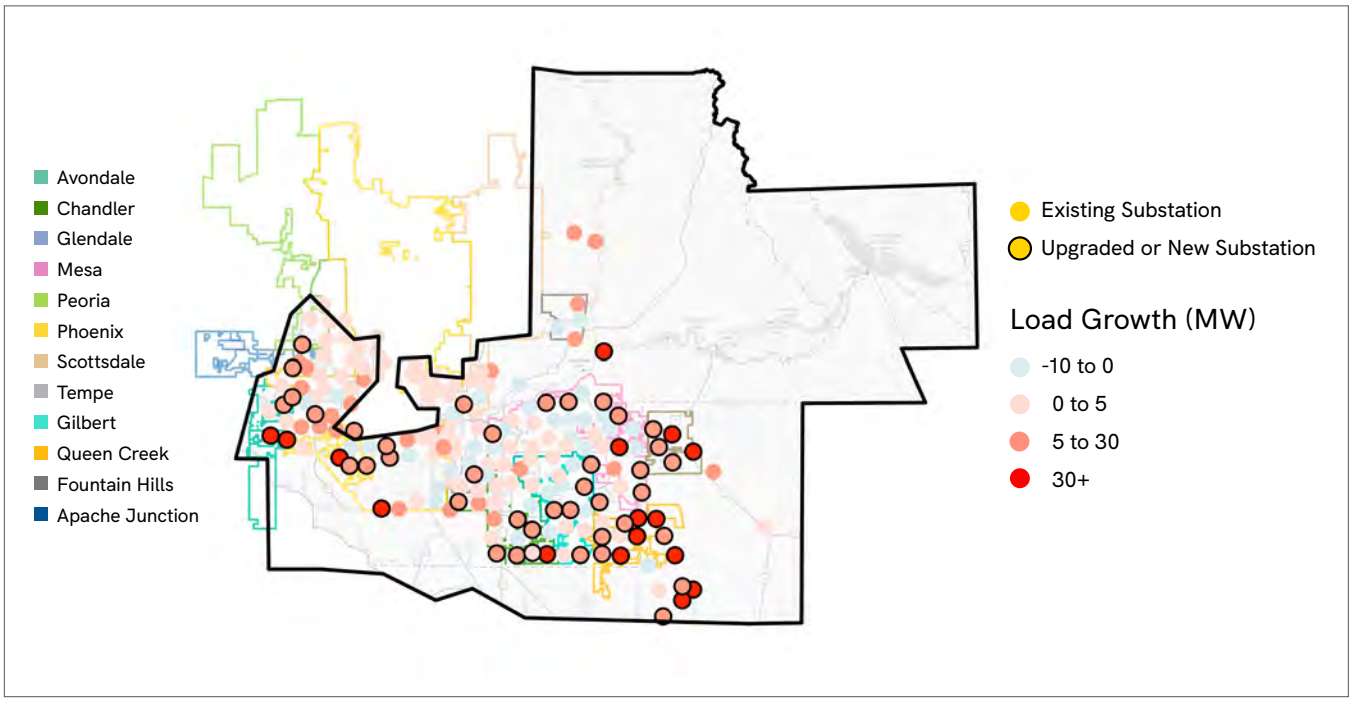
Distribution Investments

Future load growth and customer adoption of new technology increases the demand requirements on SRP's distribution system. SRP adapts to these changes through upgrades to existing infrastructure and investments in new infrastructure, such as distribution substations to serve new loads. This section describes the estimated distribution investments required to reliably serve customers across each scenario.

Figure 6.8 illustrates load growth changes in megawatts (MW) by distribution substation between 2022 and 2035 under the Current Trends scenario, highlighting new substation additions as well as upgrades required at existing substations (i.e., new substation bays added). Load growth and investment needs vary across SRP's service area. The Current Trends scenario results shown below are representative of the other scenarios' results and indicate the most significant load growth would occur in the Southeast Valley, requiring greater investments in that planning region. Additionally, the southwest portion of SRP's service territory sees relatively high load growth, requiring more investments. While these patterns are consistent across scenarios, the level of investments and upgrades needed by 2035 varies with load growth in each scenario, with more investments needed in the Desert Boom scenario and fewer investments needed in the Desert Contraction scenario.



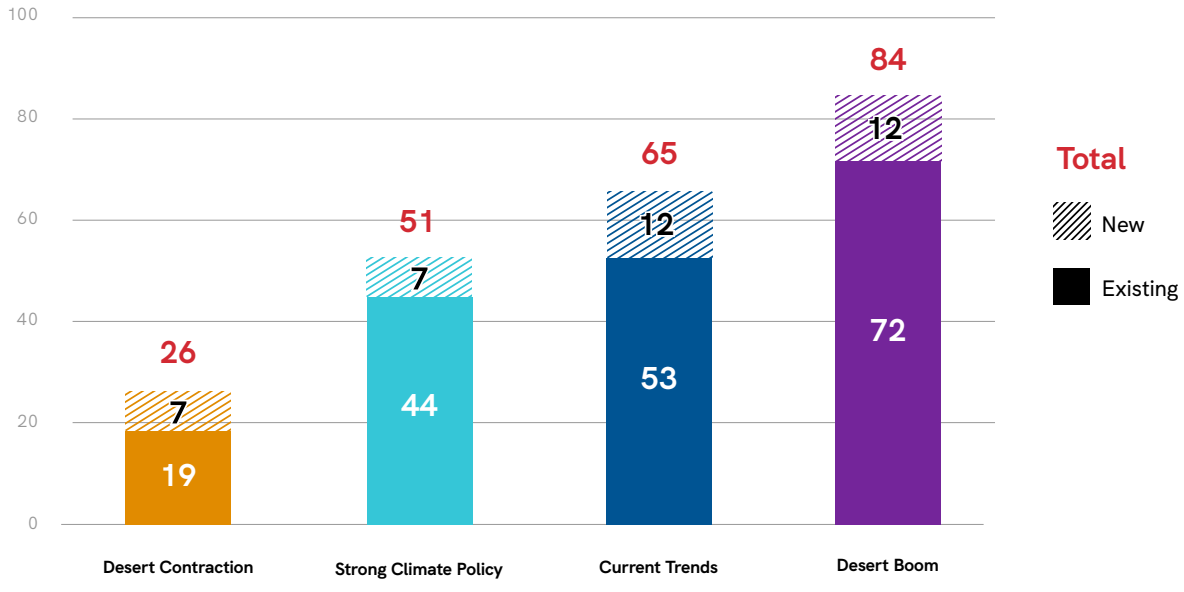
FIGURE 6.8: LOAD GROWTH BY DISTRIBUTION SUBSTATION THROUGH 2035 UNDER CURRENT TRENDS



See Figure 6.9 for the substation bay additions needed through 2035 across each of the scenarios and sensitivities. Across the scenarios, between 26 and 84 new substation bays are needed. A greater need for new distribution infrastructure is correlated with higher load growth across the scenarios. For example, substation bay additions more than triple in the Desert Boom scenario compared to what is required in the Desert Contraction scenario.

As electricity demand continues to grow in SRP's service territory, SRP will need to invest in the distribution system to enable this growth. The level of investments required will depend heavily on the rate of load growth.

FIGURE 6.9: SUBSTATION BAY ADDITIONS AT NEW AND EXISTING DISTRIBUTION SUBSTATIONS BY 2035

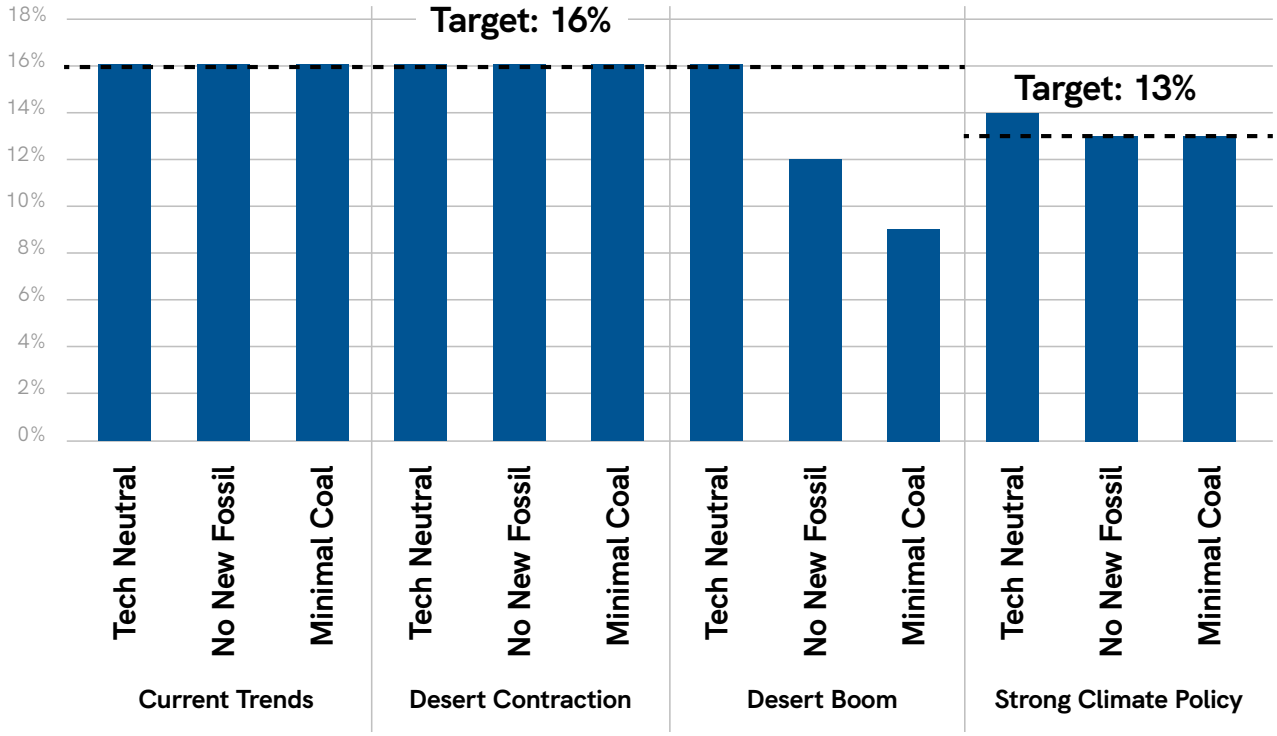


Resource Additions

SRP must add new resources to meet future energy demand, maintain system reliability, and meet the 2035 goals for carbon reduction and water resiliency. This section discusses the least-cost portfolios of generating resources selected by the long-term capacity expansion model across all scenarios and strategic approaches, as well as key reliability metrics.

For SRP to reliably serve customers across a wide range of system conditions, we must build sufficient resources to meet the planning reserve margin (PRM). The PRM is calculated using the load forecast and adding additional capacity to account for contingencies. This is a key metric because a plan that does not meet the PRM requirement is not reliable. Figure 6.10 shows the achieved PRM in 2035 across scenarios and strategic approaches compared with the requirement in each case. SRP's PRM requirement is 16% in all scenarios except for the Strong Climate Policy, where the PRM was reduced to 13% as a proxy to represent the potential benefits from expanded regional markets contributing to reliability.

FIGURE 6.10: ACHIEVED PLANNING RESERVE MARGIN IN 2035



All cases studied satisfy the PRM except for the No New Fossil and Minimum Coal strategic approaches in the Desert Boom scenario. Utilizing these two strategic approaches where firm resource options are limited[1], the accelerated load growth in Desert Boom compromises reliability as early as 2028. In these cases, there is insufficient capacity despite maximizing all available resource options. The third

KEY FINDING

Without new firm generation capacity, the system cannot satisfy reliability requirements under a high load growth scenario. In other load growth scenarios, the system can satisfy reliability requirements without new firm generation capacity but requires significant additions of renewable and energy storage resources.

[1] Firm resources include resources that can generate at sustained output for long periods of time. Firm resources studied in the ISP include natural gas, geothermal, biomass, natural gas with carbon capture and storage (CCS), biomass with CCS, nuclear small modular reactors (SMR), hydrogen and existing coal resources.

case, using a Technology Neutral strategic approach, is reliable in this scenario because it utilizes natural gas technology which was not an option in the No New Fossil and Minimum Coal strategic approaches. Because the No New Fossil and Minimum Coal cases do not meet SRP's reliability requirement, they are not viable in a Desert Boom scenario and were not evaluated further.

Figure 6.11 shows capacity additions through 2035 for all scenarios and strategic approaches. Customer programs, including energy efficiency, demand response and distributed generation, grow in all cases and offset the need for resource additions. Across all cases, renewable and energy storage resources make up a significant share of resource additions. In the Technology Neutral strategic approach, natural gas also accounts for a significant share of additions. In the No New Fossil and Minimum Coal strategic approaches, substantially more capacity is added as renewable and storage because these cases do not allow natural gas. This is because not all technology types contribute to reliability equally. Nearly all the capacity of a firm resource is counted toward the PRM while non-firm resources contribute a smaller portion. With fewer firm generation options, more total resources are needed to ensure reliability.

KEY FINDING

New renewables and firm capacity are part of a least-cost portfolio.

Due to differences in load growth, the Desert Contraction cases require fewer resources than Current Trends, while the Desert Boom cases require more resources. The Strong Climate Policy cases add significant amounts of renewable and storage resources to meet the stringent federal emissions target in this scenario.

KEY FINDING

If the U.S. government enacted a mandate for 85% CO_2 reductions by 2035 (Strong Climate Policy), SRP would need to significantly accelerate renewable and storage deployment.

FIGURE 6.11: CAPACITY ADDITIONS (MW) SELECTED BY MODEL BETWEEN 2025 AND 2035 UNDER ALL SCENARIOS

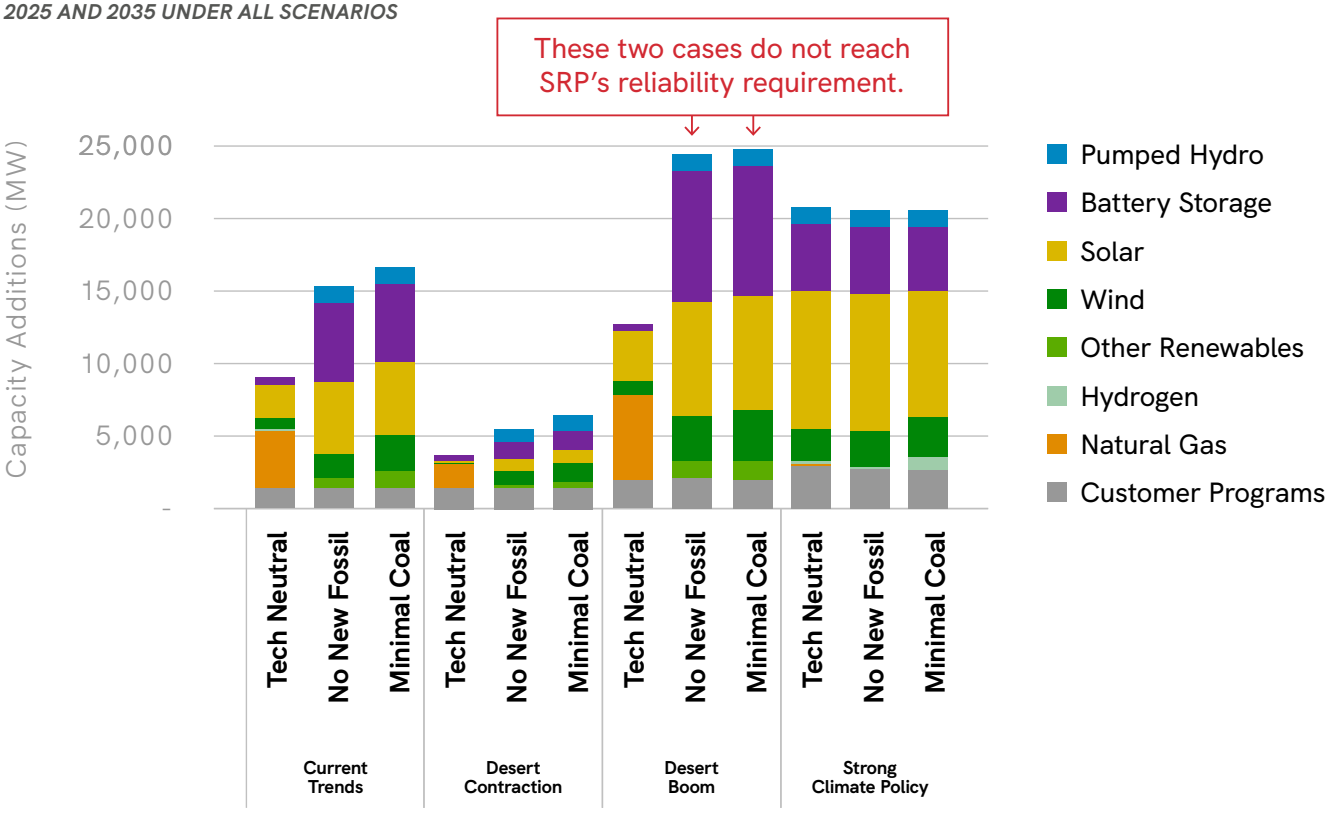


Figure 6.12 shows total installed capacity in 2035 for all scenarios and strategic approaches, as well as installed capacity in 2023 for reference. In the Technology Neutral and No New Fossil cases, more than 1,300 MW of coal capacity will be retired by 2035, with remaining coal capacity making up a small fraction of total capacity in 2035. In the Minimum Coal cases, all coal capacity retires by 2035. Looking across the system plans, there is a significant increase in total capacity between 2023 and 2035. Even the Desert Contraction scenario results in thousands of additional megawatts of capacity, while the other scenarios add more than 10,000 MW of capacity in many cases. Based on these results, SRP will likely need to double or triple its resource capacity in the next decade to serve customers to achieve reliability and sustainability goals, which marks an unprecedented rate of resource additions.

KEY FINDING

SRP will likely need to double or triple resource capacity in the next decade to serve customers while achieving reliability and sustainability goals. This will be at an unprecedented pace.

FIGURE 6.12: TOTAL INSTALLED CAPACITY (MW) IN 2023 AND IN 2035 UNDER ALL SCENARIOS

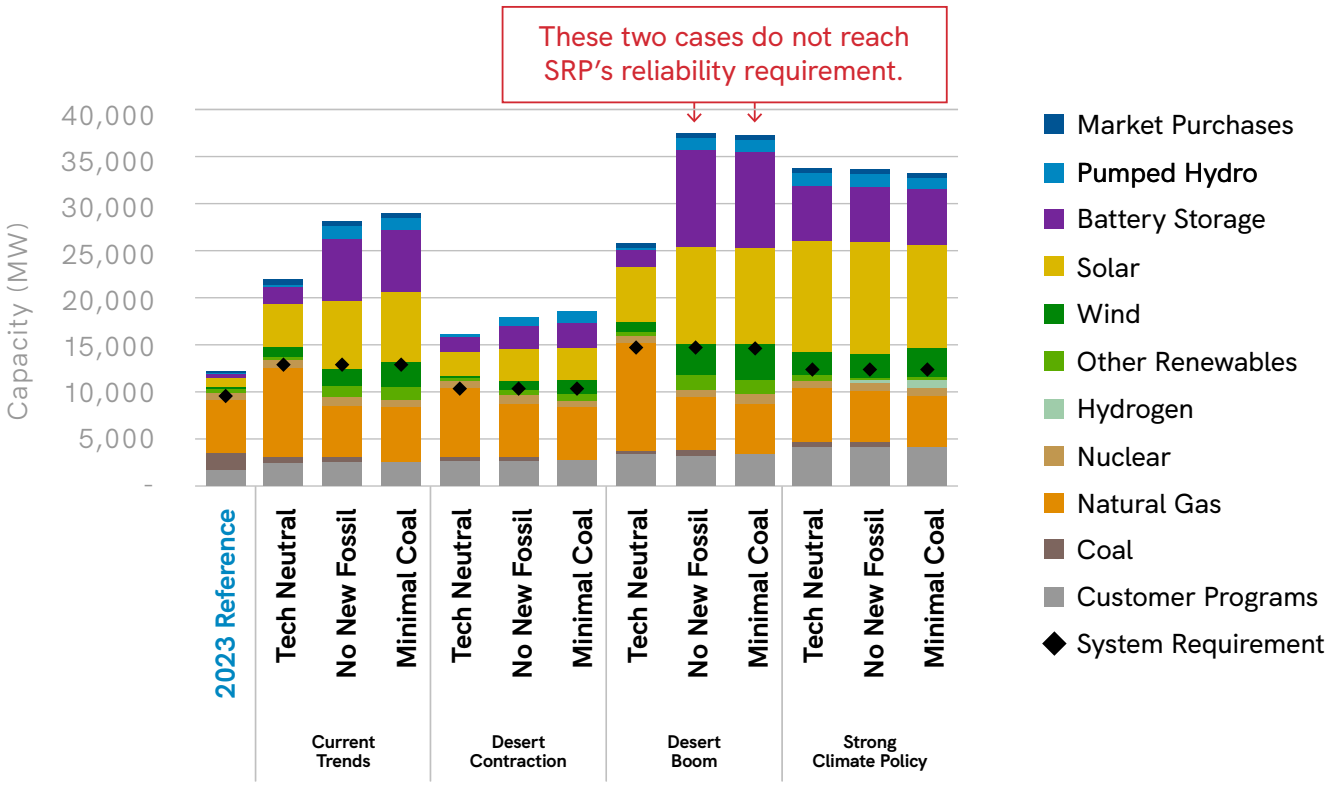
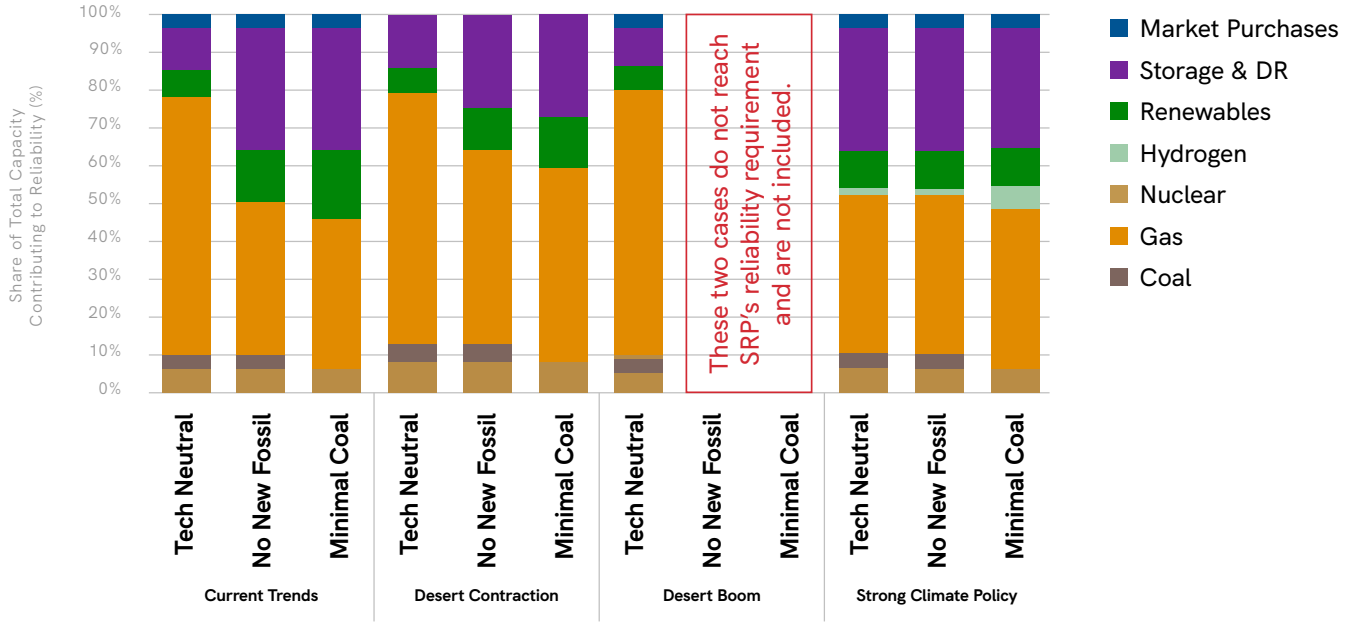


Figure 6.13 shows the contribution share of different resources toward satisfying the PRM requirement in each case. Firm resources are key to maintaining reliability; across all plans, firm resources (nuclear, coal, natural gas, geothermal, biomass and hydrogen) meet at least 55% of reliability needs in 2035, and more so in the Technology Neutral strategic approach. As noted previously, without new firm resources, reliability is compromised by 2028 in the Desert Boom scenario. New renewable and storage resources help contribute to reliability in all cases, and more so in the No New Fossil, Minimum Coal and Strong Climate Policy cases. Lastly, new firm capacity resources (natural gas or hydrogen), when included as an option per the scenario and strategic approach assumptions, are selected to help meet reliability needs at lower cost.

FIGURE 6.13: RESOURCE CONTRIBUTION TO RELIABILITY (RELIABILITY MIX) IN 2035



Note: Renewables includes solar, wind, geothermal, biomass and hydro. Storage & DR includes battery storage, pumped hydro and demand response (DR).

Relying on emerging technology can pose a risk in meeting future customer needs. Figure 6.14 shows the emerging technology selections across cases. The Strong Climate Policy scenario assumes accelerated availability of emerging technologies due to increased government support. Under this scenario, almost 200 MW of hydrogen are added in the Technology Neutral and No New Fossil cases and almost 800 MW in the Minimum Coal case, making up for lost capacity from the early retirement of Springerville Generating Station. This highlights again the value of a firm generation resource option and the potential for emerging technologies like hydrogen to provide firm generation. SRP acknowledges that to deploy 800 MW of hydrogen capacity, significant developments are needed in supply, storage and transportation infrastructure, which would require further advancements in the industry. While the ISP considers carbon capture and storage (CCS) and small modular reactor (SMR) options, these resources are not selected by the model in any of the cases by 2035.

FIGURE 6.14: RELIANCE ON EMERGING TECHNOLOGIES

	STRATEGIC APPROACH		
SCENARIO	Tech Neutral	No New Fossil	Minimum Coal
Current Trends	**No Emerging Technology Additions** Green hydrogen and nuclear SMR not available by 2035 CCS only available by 2035 in Tech Neutral		
Desert Contraction			
Desert Boom			
Strong Climate Policy	**178 MW** Green Hydrogen	**195 MW** Green Hydrogen	**790 MW** Green Hydrogen

Resource Operations

The changes in resource mix from coal retirements and new resource additions have significant implications for resource operations. This section describes the resource operations across cases as modeled in the production cost model, as well as key sustainability metrics.

Figure 6.15 shows the generation mix in 2035 across each scenario and strategic approach, including total generation in megawatt-hours (MWh) as well as the share of total generation for each resource type (%). Coal generation decreases significantly across all cases and only makes up a small share of generation in 2035. Customer programs and renewable generation increase across all cases. The total amounts of renewable and natural gas generation vary most significantly across cases and are explored further below.

FIGURE 6.15: TOTAL GENERATION (GWH) AND GENERATION MIX (%) IN 2035

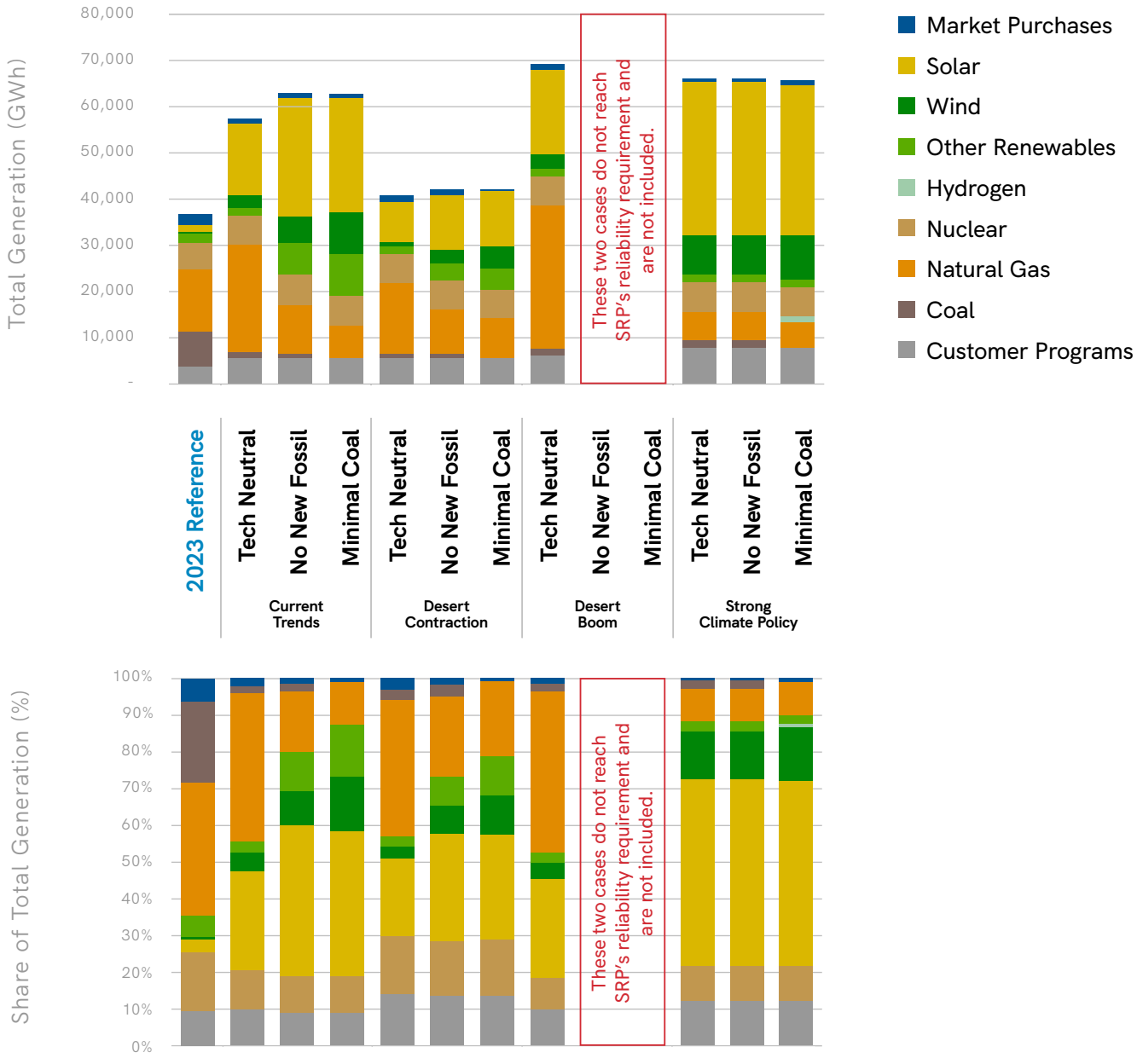
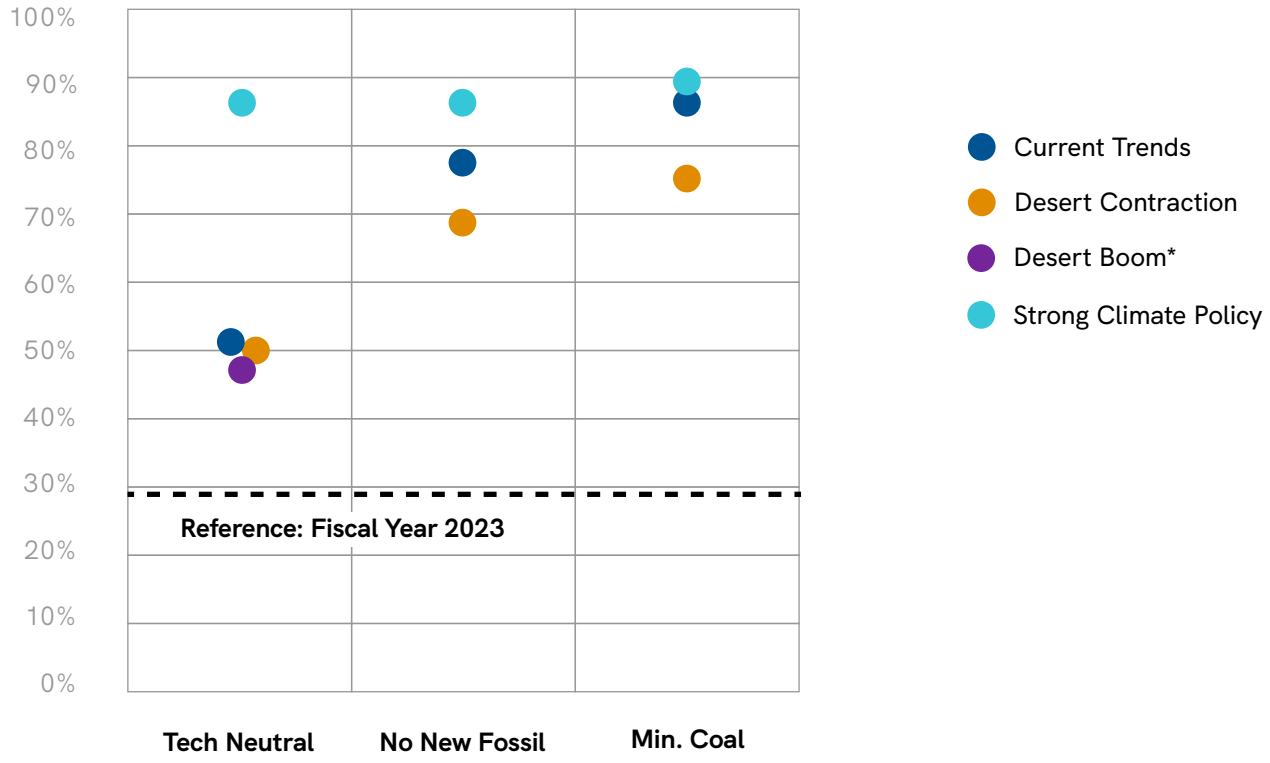


Figure 6.16 shows the percentage of generation coming from carbon-free resources, including nuclear, solar, wind, hydro, geothermal, biomass and hydrogen. Relative to 2023, the share of carbon-free generation increases across all system plans. System plans under the Strong Climate Policy scenario achieve the highest share of carbon-free generation across all strategic approaches, nearing 90%, driven by the more stringent federal emissions target. The No New Fossil and Minimum Coal strategic approaches result in more carbon-free generation compared with Technology Neutral because these cases add more renewable energy and storage to meet the PRM requirement.

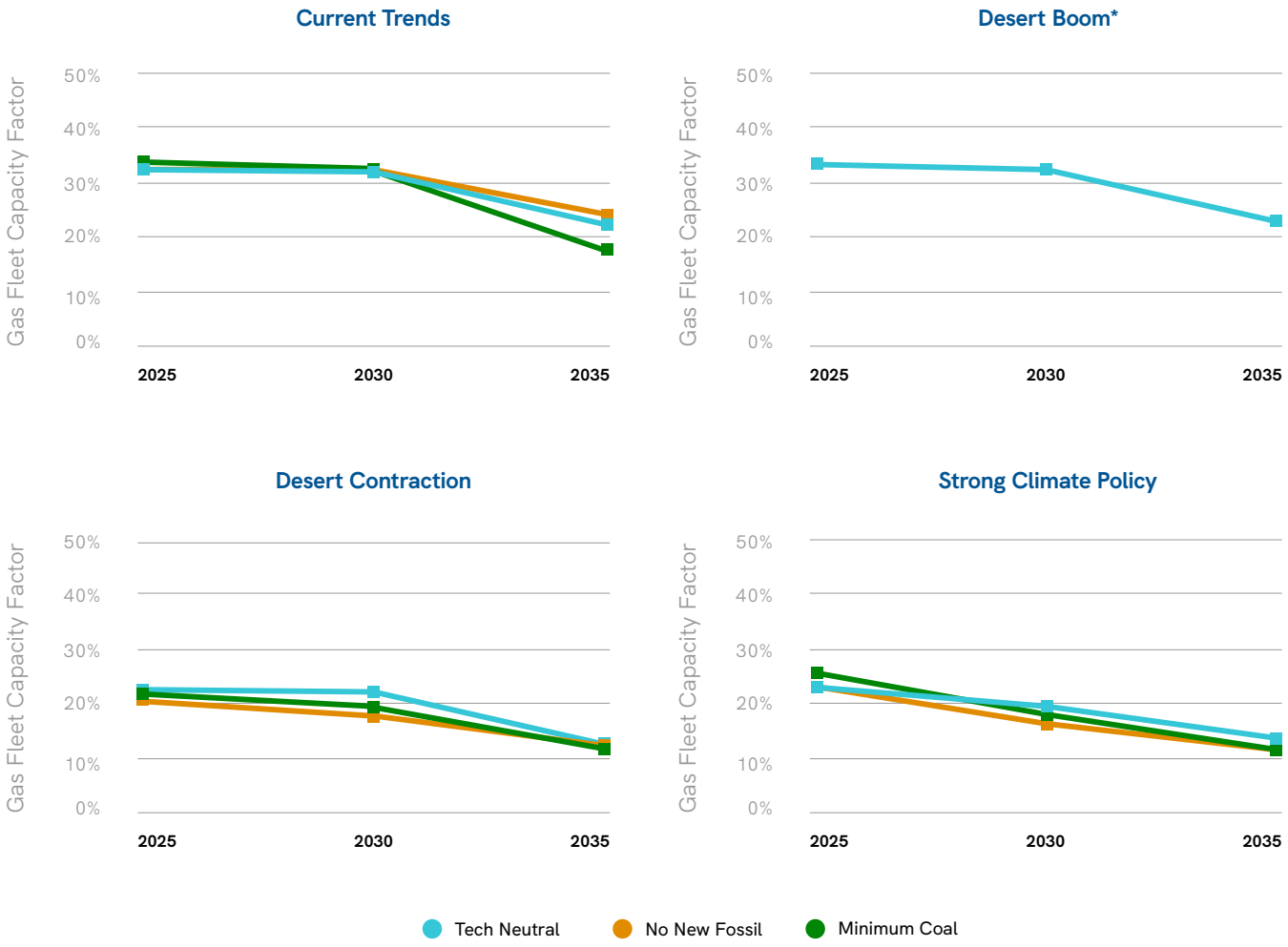
FIGURE 6.16: CARBON-FREE GENERATION BY 2035



*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

The extent to which the natural gas-fired power plant fleet is utilized relates inversely to the share of carbon-free generation. Figure 6.17 shows the average capacity factor[2] for SRP's gas fleet[3]. The utilization varies slightly between strategic approaches and scenarios, but in all cases, the average utilization of SRP's gas fleet is projected to decline through 2035 as the system relies increasingly on renewable energy. These resources are available to help ensure system reliability but generate less during the year, in line with integrating more carbon-free resources and decreasing emissions.

FIGURE 6.17: CAPACITY FACTOR FOR GAS FLEET

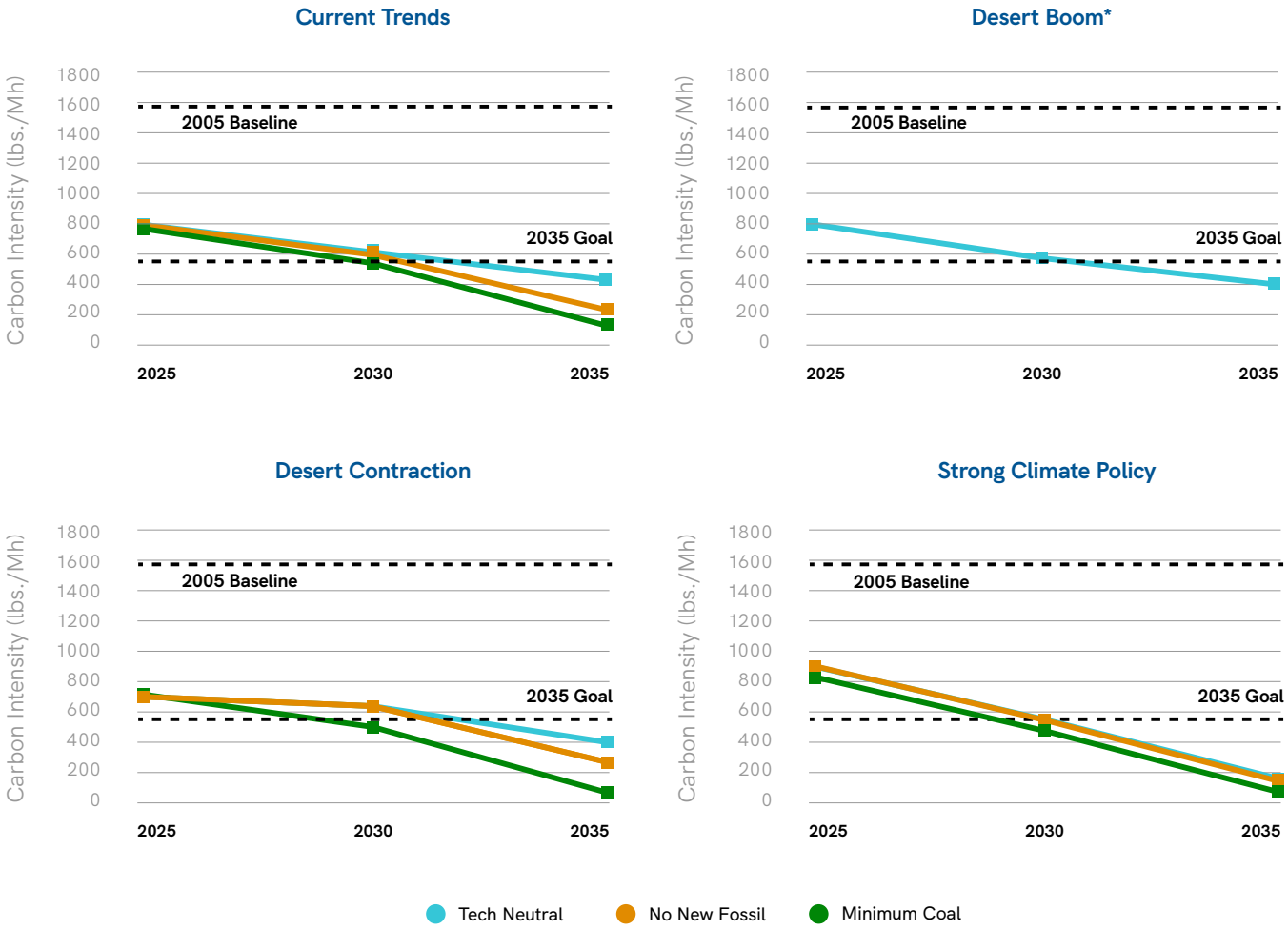


*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

[2] Capacity factor is a measure of resource utilization and is expressed as a ratio of the actual output over a given period of time compared to the theoretical continuous maximum output over that period.
[3] SRP's gas fleet includes combined cycle units, simple cycle combustion turbines (peakers) and boilers. Capacity factor for each type of gas unit will vary.

A growing share of carbon-free generation offsetting generation from gas and coal-fueled resources drives reductions in system CO_2 emissions. Figure 6.18 shows CO_2 emissions on an intensity basis.[4] All cases exceed SRP's 2035 goal of reducing carbon emissions intensity by 65% relative to 2005 levels. The No New Fossil and Minimum Coal strategic approaches result in greater CO_2 emission reductions, while the Strong Climate Policy scenario results in the most CO_2 emission reductions.

FIGURE 6.18: CO_2 EMISSIONS (INTENSITY BASIS IN LBS. PER MWH)

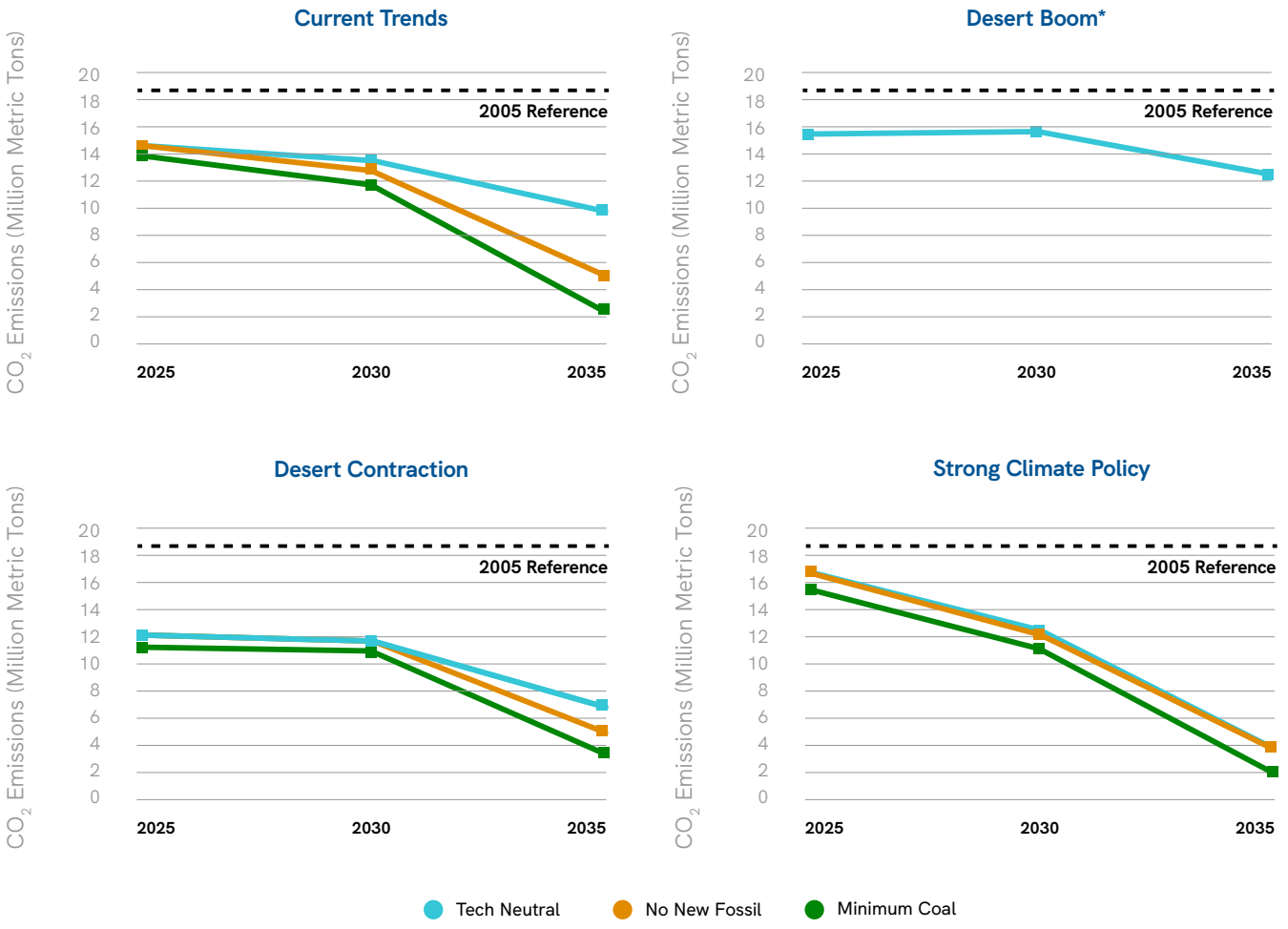


*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

[4] Carbon intensity is the amount of carbon dioxide emitted from generating electricity (in pounds), divided by the total generation required to serve SRP's customers (in megawatt-hours).

Figure 6.19 shows total annual CO_2 emissions on a mass basis. The trends within each scenario on a mass emissions basis align with the trends observed with CO_2 emissions intensity. However, the difference across scenarios is more pronounced for total CO_2 emissions because of differences in the load forecast: Higher load growth leads to an increase in total carbon emissions due to an increase in generation, some of which is carbon-emitting (when considering carbon intensity, higher emissions are offset when divided by a greater amount of energy generated). Total CO_2 emissions are higher in Desert Boom because load growth is higher, and emissions are lower in Desert Contraction because load growth is lower.

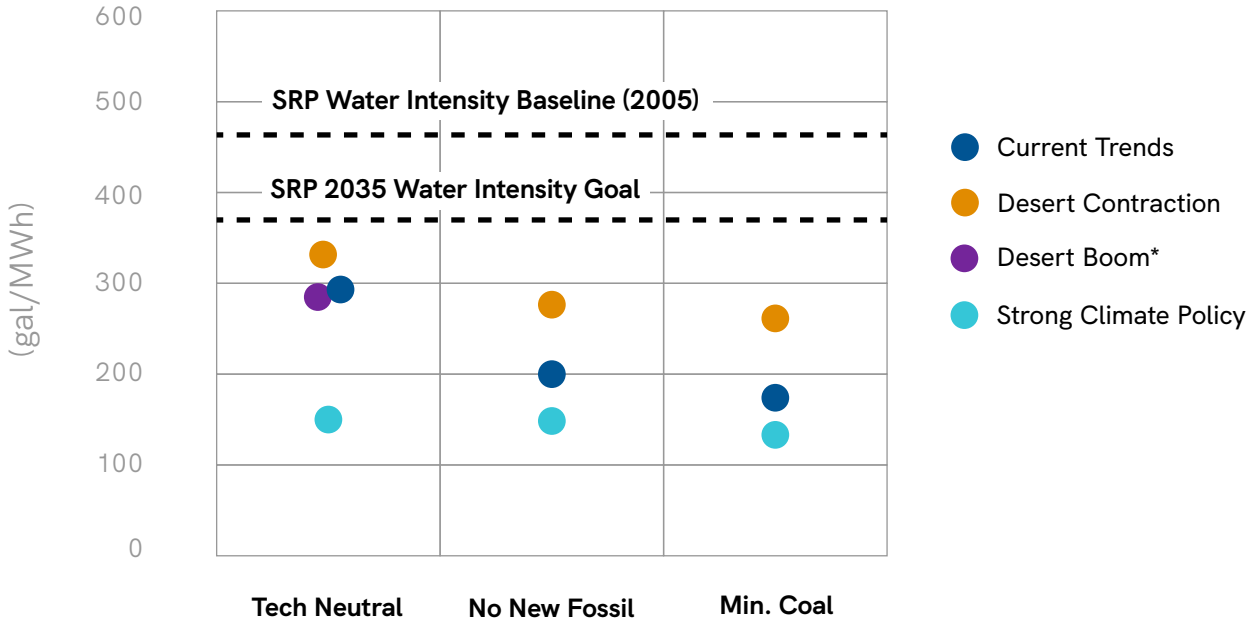
FIGURE 6.19: CO_2 EMISSIONS (MASS BASIS IN MILLION METRIC TONS)



*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

SRP also projected water consumption from power generation on an intensity basis[5] to evaluate performance with the 2035 goal of reducing water usage intensity by 20% relative to 2005 levels. As shown in Figure 6.20, all cases exceed the 2035 goal. The greatest reductions in water usage intensity occur under the No New Fossil and Minimum Coal strategic approaches, again due to a higher share of carbon-free resources that use little or no water.

FIGURE 6.20: WATER USAGE INTENSITY IN 2035



*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

[5] This is the amount of water consumed (in gallons) from generating electricity, divided by the total generation required to serve SRP's customers (in megawatt-hours).

Lastly, in addition to carbon emissions and water usage, SRP estimated direct air emissions from the generation fleet for several criteria air pollutants, and their precursor pollutants, including particulate matter (PM), nitrogen oxides (NO_X), sulfur dioxide (SO_2) and volatile organic compounds (VOC). Under all cases, emissions of all pollutants decline substantially by 2035 relative to 2025 levels. However, new biomass causes higher levels of NO_X and SO_2 emissions in the No New Fossil and Minimum Coal system plans.

FIGURE 6.21: DIRECT AIR EMISSIONS IN 2035



*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

System operations change significantly over time in all cases. Coal generation decreases, while customer programs and renewable generation increase across all cases, pushing down natural gas generation across the fleet and improving sustainability metrics. Reductions in carbon intensity ranged from 74% to 96% (compared to SRP's goal of 65%) while reductions in water usage intensity ranged from 31% to 71% (compared to SRP's goal of 20%), both relative to 2005 baseline levels. Cases with less renewable and storage additions resulted in smaller reductions in carbon and water usage intensity, while cases with higher renewable and storage additions resulted in larger reductions. *Note: SRP's 2035 Sustainability Goals are being refreshed in 2024 in collaboration with community stakeholders.*

KEY FINDING

The reduction in coal generation and expansion of carbon-free resources over time allow SRP to meet, and in many cases exceed, SRP's 2035 goals for carbon emission reductions and water resiliency.

Transmission Investments

Both load growth and changes in the resource mix influence investment needs for the transmission system. This section describes the transmission investment needs through 2035, including 230 kV lines, 500 kV lines and 500/230 kV transformers.

Figure 6.22 shows the transmission investment needs through 2035 for the three system plans analyzed (Technology Neutral Current Trends, Technology Neutral Desert Boom and Minimum Coal Current Trends) and the two resource location options analyzed (Pro-Rata and Hub). These cases are described in detail in Section 5.

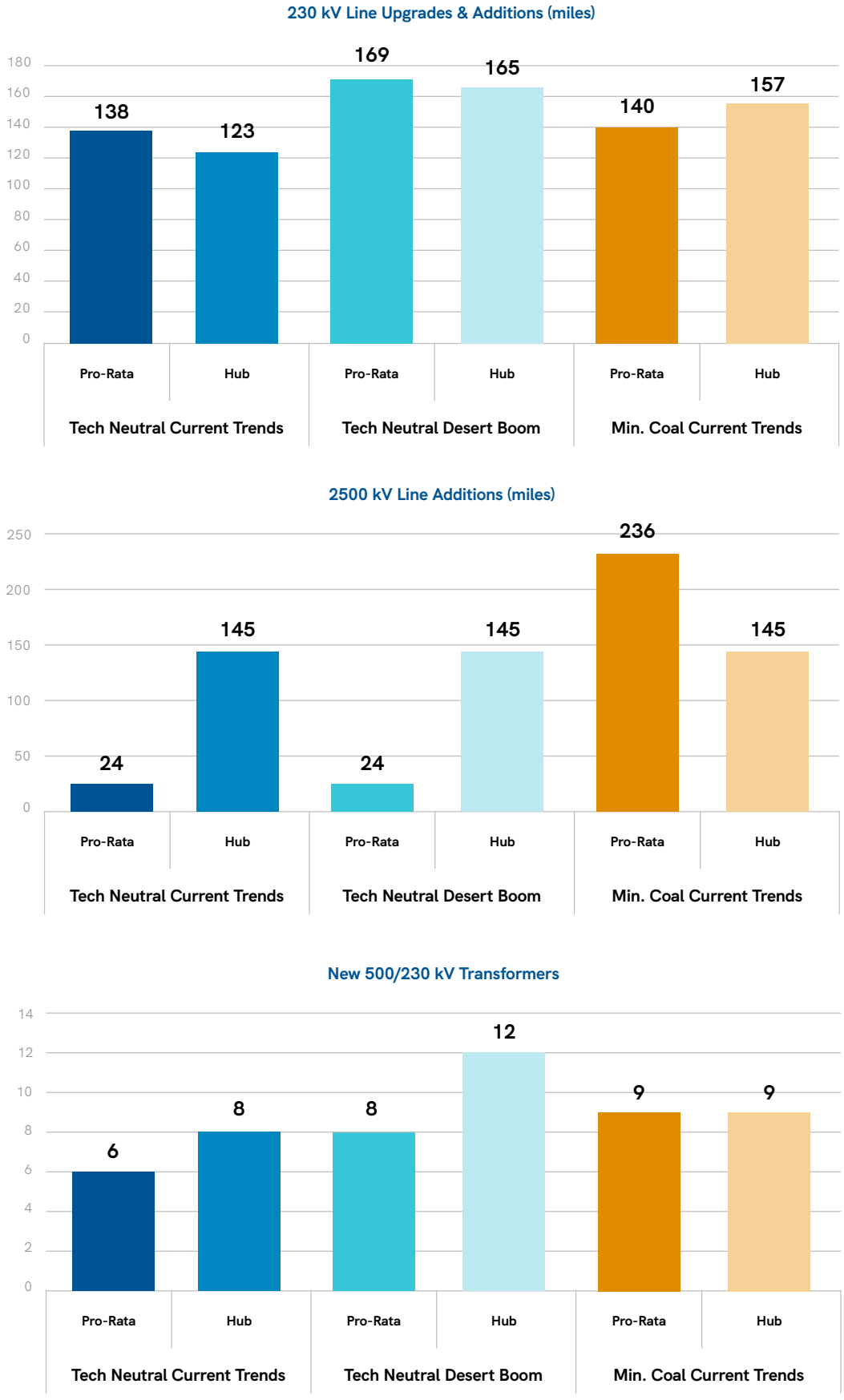
KEY FINDINGS

Location of generation matters and plays a significant role in the buildout of the 500 kV and 230 kV transmission system.

Significant investments in new transmission infrastructure are needed over the next decade to connect new resources and customers while also achieving reliability and sustainability goals. These investments will need to be strategically located and timed.

In all cases, a significant amount of transmission investment is needed by 2035. The investments in 230 kV lines are primarily driven by load growth in all cases; however, where 230 kV lines need to be added and which lines need to be upgraded depends on the resource location assumptions used. The investments in 500 kV lines, as well as the investments in 500/230 kV transformers, vary for each system plan based on the resource location assumptions. In the Technology Neutral Current Trends and Technology Neutral Desert Boom cases, the Hub resource location assumption requires far more 500 kV line-miles and more 500/230 kV transformers than the same cases using the Pro-Rata resource location assumption. In the Technology Neutral Current Trends and Technology Neutral Desert Boom cases, more investment is needed in the 500 kV system to connect resources at the hub to the rest of the system. By contrast, in the Minimum Coal Current Trends case, fewer 500 kV line-miles are needed under the Hub resource location assumption than under the Pro-Rata resource location assumption. This is driven by the higher levels of solar and battery resources in this case further exceeding existing transmission capabilities when located using the Pro-Rata location assumptions. The differences in results across the Pro-Rata and Hub resource location assumptions highlight how the location of resources has a significant impact on transmission investment needs.

FIGURE 6.22: TRANSMISSION SYSTEM INVESTMENTS BY 2035



KEY FINDING

Hundreds of miles of new or upgraded transmission lines and nearly double the number of 500/230 kV transformers could be needed relative to today.

The transmission analysis shows that up to 380 miles of new or upgraded transmission lines and 12 new 500/230 kV transformers could be needed over the next decade. The lead times for siting, permitting, building and energizing transmission infrastructure are 5–9-plus years for 500 kV lines, 3–7 years for 230 kV lines and 3–5 years for 500/230 kV transformers. To add the needed transmission infrastructure given these long lead times will require a proactive approach to transmission planning.

Total System Cost

Because maintaining affordability for customers is a fundamental component of SRP's mission, we developed affordability metrics for each system plan analyzed to assess and compare opportunities and risks. This section describes the total system cost and average system cost metrics, while the next section describes the residential bill impact metric.

The total system cost is the estimate of total costs in 2035 to serve customers, including costs related to customer programs, distribution, generation, transmission and normal utility operations. The average system cost is derived by dividing the total system cost by the total retail sales in 2035. Because energy demand growth varies across the scenarios, the average system cost provides a more direct comparison between cases for how costs are changing over time.

While these metrics allow comparison across system plans, they are developed using a simplified ISP analysis model and are not a comprehensive assessment of future financial indicators for SRP. Furthermore, the average system cost metric is not a customer rate metric and should not be interpreted as the rate that customers would pay under different cases. Lastly, differences in results across scenarios reflect scenario assumptions for external factors that are out of SRP's control (e.g., economic growth, fuel prices, resource costs and federal government policy).

Figure 6.23 shows the total system cost in 2035, broken out between generation, transmission, distribution, customer program and other costs. It also provides total system cost in 2025 for reference. Generation costs are the primary driver of differences in cost between cases. Transmission costs follow similar trends as generation costs, as both are influenced by load growth and new resource additions. Distribution costs vary across scenarios due to differences in load growth. Lastly, customer program costs grow through 2035 and continue to mitigate needs for new infrastructure across all cases.

Within the Current Trends and Desert Contraction scenarios, Technology Neutral is the lowest-cost strategic approach. While Technology Neutral allows new natural gas as a resource option, the other strategic approaches (No New Fossil and Minimum Coal) do not have a firm capacity option and thus lead to higher costs due to increased resource additions and transmission investments.

In general, the Desert Contraction cases have lower system costs than Current Trends, and the Desert Boom cases have higher costs, driven primarily by the differences in energy demand. In the Strong Climate Policy scenario, all three strategic approaches have similar costs due to a few factors. First, the aggressive federal emissions requirement in this scenario is a major driver, resulting in significant renewable and storage additions across all three strategic approaches. Second, in this scenario, a firm capacity resource is available in all three strategic approaches due to the accelerated availability of hydrogen. The unavailability of a firm capacity resource was the major driver of cost increases for these two strategic approaches under the other scenarios.

FIGURE 6.23: TOTAL SYSTEM COSTS FOR SRP'S POWER SYSTEM IN 2035 ($ BILLION)

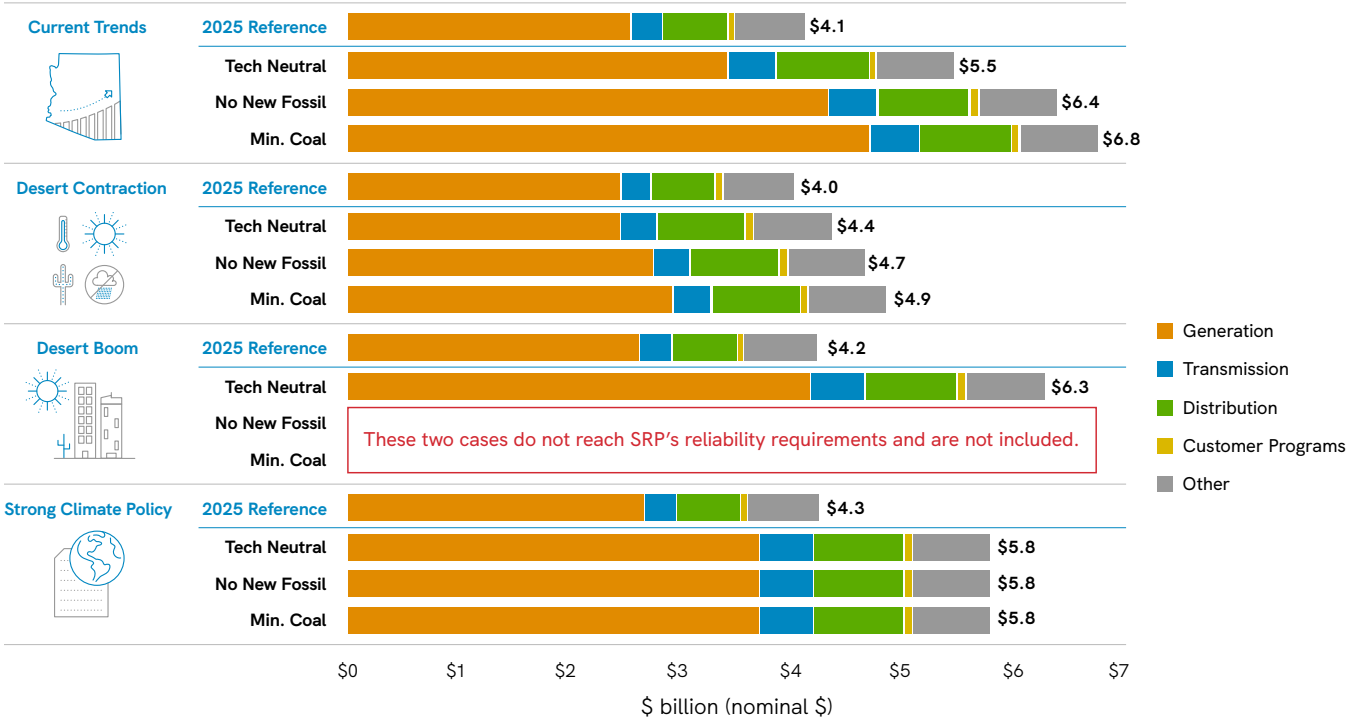
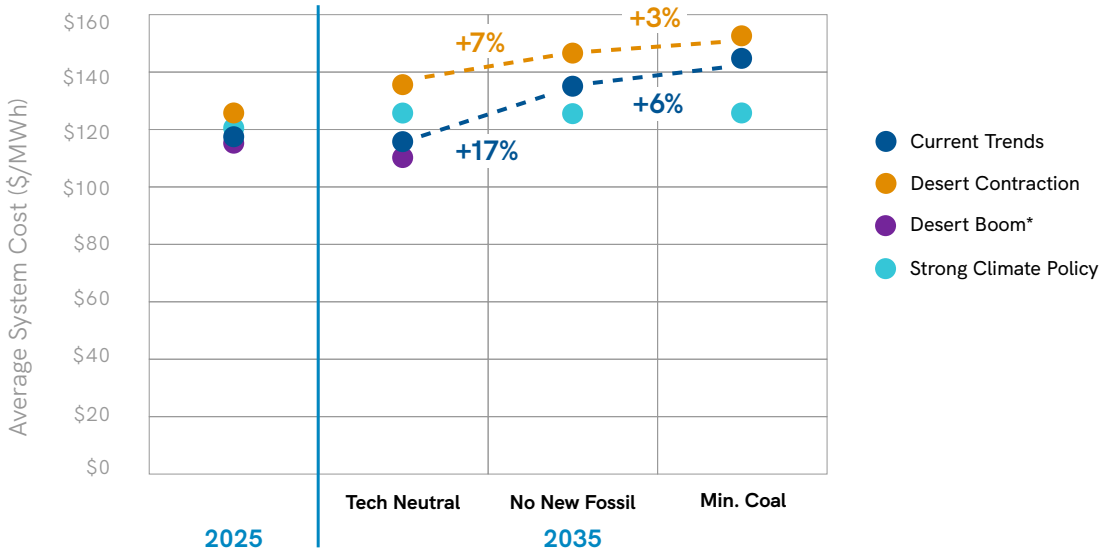


Figure 6.24 shows the average system cost in 2035, with 2025 provided for reference. The Technology Neutral strategic approach results in lower cost than the other strategic approaches with limited firm capacity options. In the Current Trends scenario, the No New Fossil and Minimum Coal approaches result in a 17% and 24% increase, respectively, in average system cost relative to Technology Neutral. In the Desert Contraction scenario, the No New Fossil and Minimum Coal approaches result in a 7% and 10% increase, respectively, in average system cost relative to Technology Neutral. The cost increase in Current Trends is greater than the cost increase in Desert Contraction because the higher load growth in Current Trends makes it more costly to reliably meet customer needs without new firm capacity resources.

FIGURE 6.24: AVERAGE SYSTEM COST ($/MWH)



*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

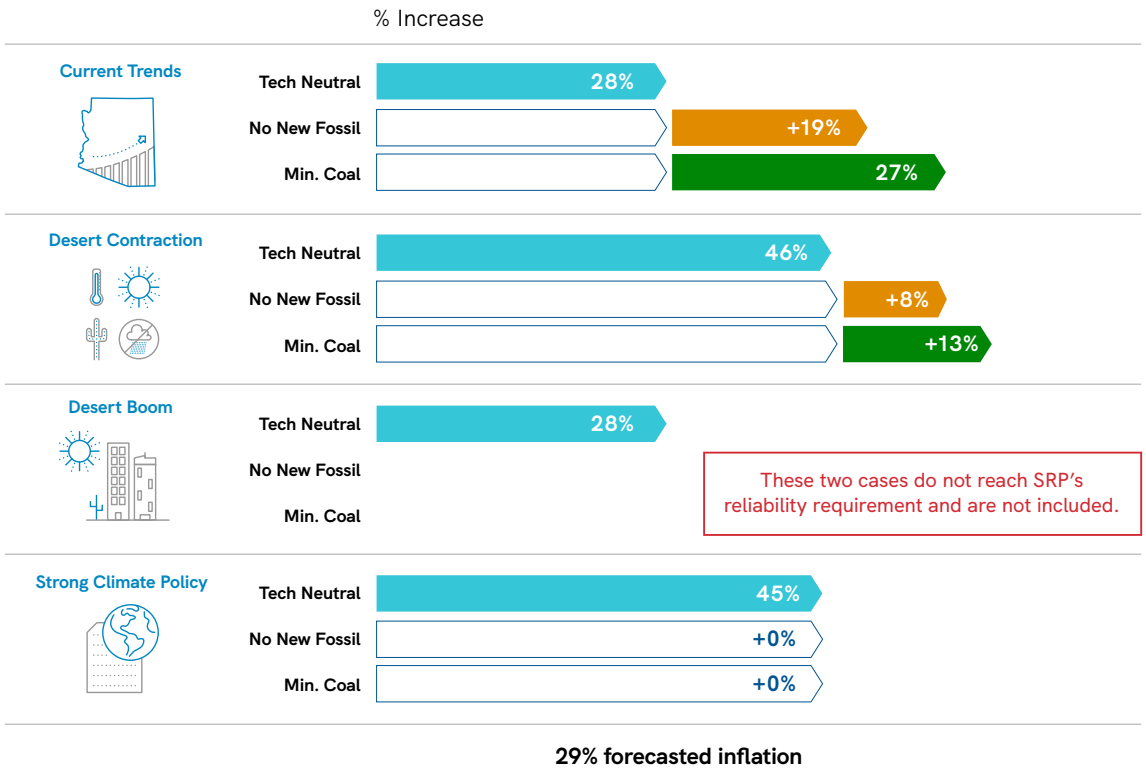
Residential Bill Impact

This section describes the residential bill impact metric across cases. This analysis does not necessarily reflect how future costs would be allocated and recovered from customers and therefore should not be considered a projection of customer rates. SRP will carry out pricing processes in the future that will determine future rates. Nevertheless, this metric is helpful for comparing across cases to understand relative differences.

Figure 6.25 shows the increase in average residential customer rates between 2023 and 2035 along with the forecasted inflation expected over this period for reference. The figure shows the increase in the Technology Neutral strategic approach and then shows the increase in the alternative strategic approaches relative to the Technology Neutral strategic approach. SRP projects the cumulative impact of inflation to be 29% between 2023 and 2035. The Technology Neutral Current Trends approach has an increase of 28% over this same period, meaning that rates increase by less than inflation in this case.

In all scenarios, the Technology Neutral strategic approach results in the lowest impact to average residential rates. The No New Fossil and Minimum Coal approaches are more costly, with the greatest increases relative to Technology Neutral under Current Trends. Under the Current Trends scenario, the No New Fossil strategic approach results in a 19% increase in customer rates relative to Technology Neutral, and the Minimum Coal strategic approach results in a 27% increase. Under the Desert Contraction scenario, increases are higher across the cases as the lower load growth leads to less revenue to offset costs. Comparing the cases in the Desert Contraction scenario, the No New Fossil strategic approach results in an 8% increase in customer rates relative to Technology Neutral, and the Minimum Coal strategic approach results in a 13% increase. Under the Strong Climate Policy scenario, the residential bill impact is similar across the three strategic approaches, for the same reasons discussed in the Total System Cost section.

FIGURE 6.25: INCREASE IN AVERAGE RESIDENTIAL CUSTOMER RATES BETWEEN 2023 AND 2035



Risk Assessments

The development and operational risk assessments identified risks and challenges that SRP could face for each of the system plans. It also identified potential mitigation options, which SRP is using to prepare its system and workforce for the future.

Development Risk

Because each of the ISP system plans requires significant development of new resources, we performed a qualitative risk assessment to better understand the risks and challenges in building out these future power systems, as well as mitigation options.

Development Risks and Mitigation Options

KEY FINDING

To meet the pace of infrastructure needs, supply chain and development solutions are essential to managing costs and to meet the pace of transformation needed.

Supply chain. SRP continues to observe inflation and supply chain disruptions that began during the COVID-19 pandemic. These disruptions led to rising costs and extended development timelines for new infrastructure projects, including solar projects, battery storage projects, transmission infrastructure, distribution infrastructure, etc. Future supply chain disruptions could also impact SRP's ability to develop new infrastructure, impacting ISP system plans with greater infrastructure additions the most. Mitigation steps that SRP is taking to address these risks include ordering key supplies as early as possible and seeking to develop a wider pool of potential suppliers to diversify supply chain risks.

Siting and permitting. Most infrastructure projects take several years for siting, permitting, construction and interconnection. Examples of projects with especially long and complex development processes include nuclear power plants, pumped hydro energy storage, gas pipelines and transmission. On the longer end of development timelines, some transmission projects can take well over a decade to site, permit, construct and energize. There are many variables that can impact the timing of developing projects, including stakeholder consultation, state and/or federal regulatory processes, development of enabling infrastructure (e.g., new transmission or gas pipelines), etc. If development timelines were to extend much longer than expected, this would limit the pace at which SRP can build out the system and put ISP system plans with greater infrastructure additions at more risk. To mitigate this risk, SRP strives to collaborate with government agencies, other utilities and key stakeholders as early as possible. We are also exploring multiple project options so that SRP is prepared to undertake any one of these options more readily should the need arise.

KEY FINDING

With the amount of future infrastructure and resources needed, internal and external partnerships are going to be essential to build the future system and maintain high customer value.

Multistate transmission. While any transmission can have long development timelines and face uncertainty in permitting, these challenges exist even more for transmission that spans multiple states. Such interstate transmission projects may span longer distances and require consultation with more landowners. They also require approvals from different state regulatory bodies and may require approval from multiple federal agencies. The complex nature of developing such projects results in risks to development timelines. These risks are greatest for ISP system plans that add geothermal or wind in states such as California and New Mexico. SRP is working to mitigate this risk by proactively pursuing regional transmission projects that facilitate integration of diverse renewable resources.

Technology maturity. Not all resource technologies have reached full maturity. Lithium-ion battery projects have proliferated in the last five years, but the total amount of capacity deployed is still limited relative to other technologies and they do not have a long track record of performance. Some battery projects, including a project contracted by SRP, have experienced fires that have rendered the resources unavailable. There are other technologies evaluated in the ISP that have not yet reached widespread commercialization, such as power plants powered by 100% hydrogen. There are still uncertainties in the cost, operations and enabling infrastructure for this technology. Given these risks and uncertainties, ISP system plans that rely more on less mature technologies have a greater amount of inherent risk. To mitigate these risks, SRP is actively gaining operational experience with newer technologies and monitoring advancements for emerging technologies. SRP is also balancing the development of newer technologies (e.g., battery storage) with the deployment of more mature technologies (e.g., pumped hydro storage).

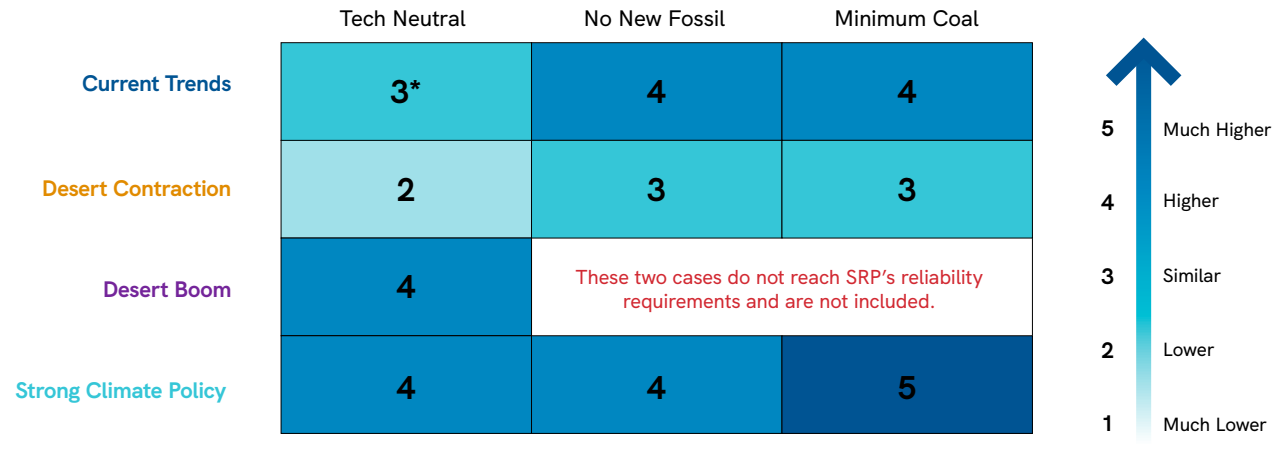
Diversification. The potential impact of any one of these development risks depends in part on the diversification of the system plan. If the system plan relies heavily on only a few technologies, then the entire system plan is at risk if one of those technologies encounters disruptions due to supply chain, permitting or other issues. To mitigate the risk associated with any one technology, SRP is pursuing a diverse system plan.

Development Risk Ratings

SRP identified a development risk rating for each of the core system plans in the ISP, as shown in Figure 6.26, using the considerations highlighted above. Technology Neutral Current Trends acted as a baseline, and SRP evaluated all other plans relative to the development risk associated with that plan.

Technology Neutral Desert Contraction has a lower risk level because the system plan adds far fewer generating resources, transmission and distribution than the other plans. For the Desert Contraction scenario, the two other strategic approaches (No New Fossil and Minimum Coal) have a similar amount of risk as the baseline due to the amount of resource additions. All other system plans have higher risk levels due to the very rapid pace of resource additions, with some cases reaching between 25,000 and 35,000 MW of installed capacity. The Minimum Coal Strong Climate Policy case has the highest risk level not only due to the rapid pace of resource additions, but also because of the reliance on almost 800 MW of hydrogen capacity, which would require significant development of hydrogen infrastructure that doesn't currently exist. As discussed above, SRP is employing a suite of strategies to help mitigate risks.

FIGURE 6.26: DEVELOPMENT RISK RATING



*Tech Neutral/Current Trends was the baseline case to which the development risk for all other cases were compared.

Operational Risk

Because each of the ISP system plans requires a meaningful shift in the future operations of the system, SRP also performed a qualitative risk assessment to better understand the risks and challenges in operating these future power systems, as well as mitigation options.

Operational Risks and Mitigation Options

KEY FINDING

A future system that relies more on variable renewable resources presents new challenges and will require new operating practices to ensure sufficient flexibility, reduce wear and tear on existing assets, and maximize benefits to customers.

Variability and uncertainty. The Inverter-Based Resources Integration Technical Working Session highlighted the profound changes that come with moving to a system that relies on more variable renewable generation to meet energy needs. Resources like solar and wind vary in output based on season and time of day. Also, this variability is not perfectly predictable, as the weather can impact solar generation due to cloud cover and wind generation due to changes in wind speed. Managing a system with higher penetrations of variable generation is more complex and comes with new risks in balancing energy demand, supply and market transactions. As a result, ISP system plans with higher penetrations of variable generation resources have greater operational risk. To mitigate these risks, SRP is taking several actions, including improving forecasts for variable renewable generation, increasing reserves to account for uncertainty and variability, pairing variable energy resources with flexible resources (e.g., energy storage) to reduce variability and increase dispatchability, managing resource curtailment to provide more flexibility to the system, and transacting with markets to provide more operational flexibility.

Ramping needs. With higher penetrations of variable generation, especially solar, the system experiences greater ramping needs for dispatchable generation. For example, on a system with a lot of solar generation, there is plentiful generation during the day. However, in the late afternoon and early evening, when electricity demand is high and solar generation rapidly declines, other resources need to ramp up output rapidly. This is a significant change in how the system must operate and creates new challenges. To mitigate these risks, SRP is working to add more flexible resources, such as battery storage, pumped storage hydro and natural gas, to maximize the flexibility from existing resources and from market transactions. SRP is exploring curtailing variable generation to help mitigate ramping needs and provide additional flexibility.

Natural gas plant operations. With increasing amounts of variable generation and increasing ramping needs, natural gas power plants operate differently than they have in the past. When variable renewable generation output is high and energy demand is low, natural gas plants ramp down output or even shut down. When variable renewable generation is low and/or energy demand is high, natural gas plants ramp up output. This may involve shutting down and starting up natural gas plants more frequently than in the past, potentially even daily, which puts increased wear and tear on the generating units. Some natural gas plants may shut down for extended periods of time before starting up again. Systems that cool completely can cause aging seals or fittings to shrink, which can increase risks for more frequent maintenance and repair.

Natural gas fuel transportation. SRP acquires transportation rights on regional natural gas pipelines to secure reliable delivery of natural gas fuel we purchase throughout the year. If natural gas fuel consumption were to increase significantly beyond today's level of consumption, such as in the Technology Neutral Desert Boom system plan, this could create risks in being able to deliver natural gas fuel during critical days for reliability.

Depending on the increase in fuel consumption and how the regional energy landscape evolves, this could require the need for new natural gas pipeline infrastructure. To mitigate this risk, SRP is deploying a diverse mix of additional generating resources such as solar and wind that help to offset natural gas fuel consumption. SRP may also explore fuel storage solutions that can allow natural gas plants to continue to have access to fuel without relying solely on pipelines during critical days.

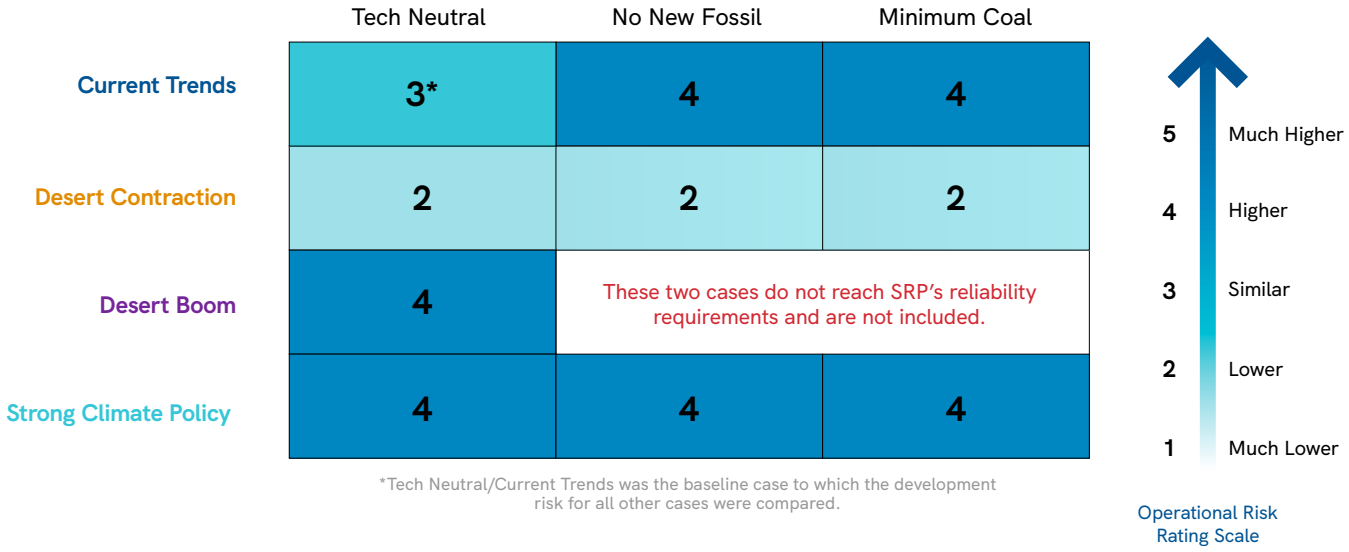
Curtailment. As variable renewable generation increases as a share of SRP's generation mix, there will increasingly be time periods when there is more renewable generation than can be delivered to customers, used to charge energy storage, or sold into markets. For example, during spring months, when energy demand is lower due to milder temperatures, solar generation is relatively high. The West already experiences higher levels of solar curtailment during these months, and this will become more pronounced as SRP and other utilities add more solar capacity. This will require changes in system operations to ensure the grid remains in balance. To accommodate these changes, SRP is making improvements to the dispatch of renewable resources to both curtail their energy production in a way that is most cost-effective and leverages their capabilities, when possible, and to provide ancillary services for controlling small mismatches between customer demand and generation. SRP is also exploring other uses for excess power generation, including storing in long-duration energy storage and generating hydrogen through electrolysis.

Operational Risk Ratings

SRP developed an operational risk rating for each of the core system plans in the ISP, as shown in Figure 6.27, using many of the considerations highlighted above. Technology Neutral Current Trends acted as a baseline, and SRP evaluated all other plans relative to the operational risk associated with that plan.

The three Desert Contraction system plans have a lower operational risk level because annual energy demand is lower, variable generation penetration is lower, and natural gas fuel demand is lower. These three factors mitigate many of the identified operational risks. The three Strong Climate Policy plans have a higher operational risk level because these plans would require a complete transformation of system operations, including a high generation share from variable resources, increased ramping needs, and increased stress for natural gas-fired generators that would need to start up, shut down and ramp up output more frequently. The No New Fossil Current Trends and Minimum Coal Current Trends system plans also have a higher operational risk level for similar reasons, although the operational risk is slightly lower due to a higher share of generation from dispatchable resources. The Technology Neutral Desert Boom system plan has a higher operational risk level because this plan would require increased natural gas fuel consumption to a point that may not be feasible without significant expansion to the regional natural gas delivery system. As discussed above, SRP is employing a suite of strategies to help mitigate risks.

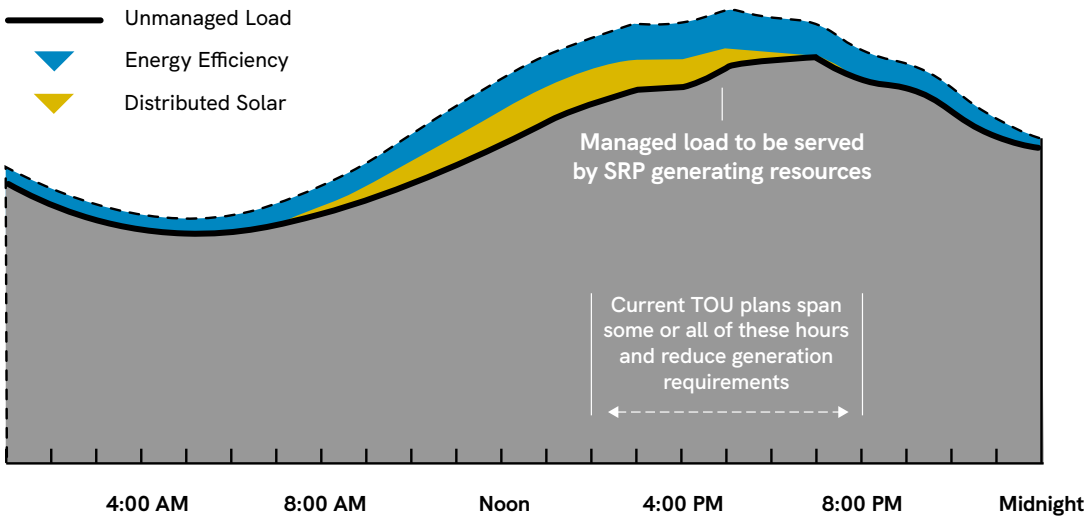
FIGURE 6.27: OPERATIONAL RISK RATING



Considerations for Future Customer Programs and Pricing Plans

Customer programs and pricing plans play an important role in managing SRP's load and peak energy demand. Figure 6.28 includes an illustrative projected peak day in 2035 and depicts how energy efficiency, distributed solar and time-of-use (TOU) programs can reduce SRP's load. Energy efficiency reduces total energy consumption throughout the day; distributed solar offsets generation from other resources during daytime hours; and TOU price plans can incentivize customers to reduce demand during peak hours. After accounting for these programs, the remaining load that SRP must serve is lower and shifted slightly later in the day.

FIGURE 6.28: ILLUSTRATIVE DEPICTION OF HOW CUSTOMER PROGRAMS AND PRICE PLANS HELP SRP MANAGE PEAK ENERGY DEMAND



SRP's existing customer programs work well for demand management in the current system. However, as increasing amounts of solar and wind are added to the system, the net load that is served by dispatchable resources begins to peak after the existing TOU window, as shown in Figure 6.29. This highlights the growing need for evening and overnight load reduction. However, the growth of mid-day renewable generation also presents the opportunity to shift load to these low-cost, low-emissions hours.

FIGURE 6.29: CUSTOMER PROGRAMS AND PRICING PLANS CAN HELP SRP MEET NEW SYSTEM NEEDS

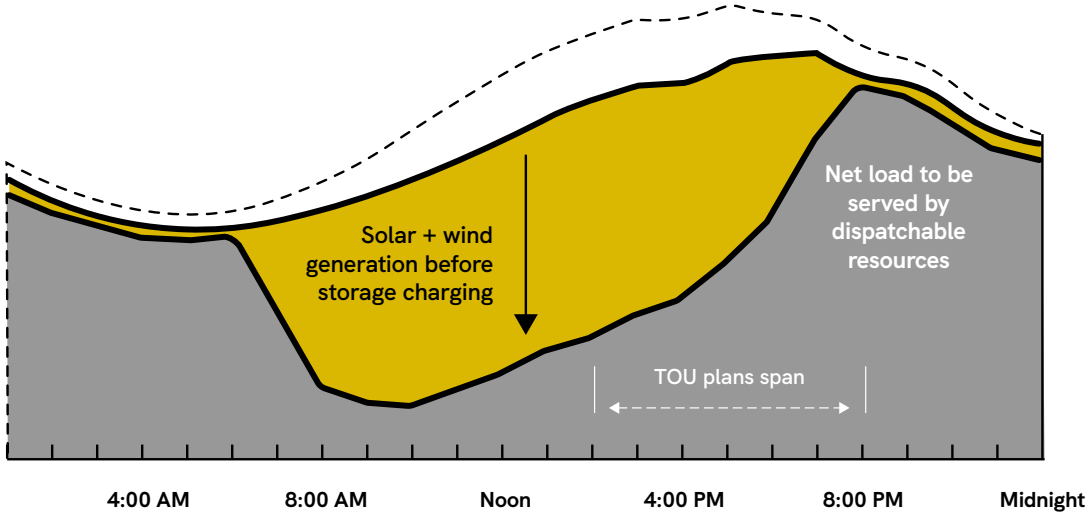


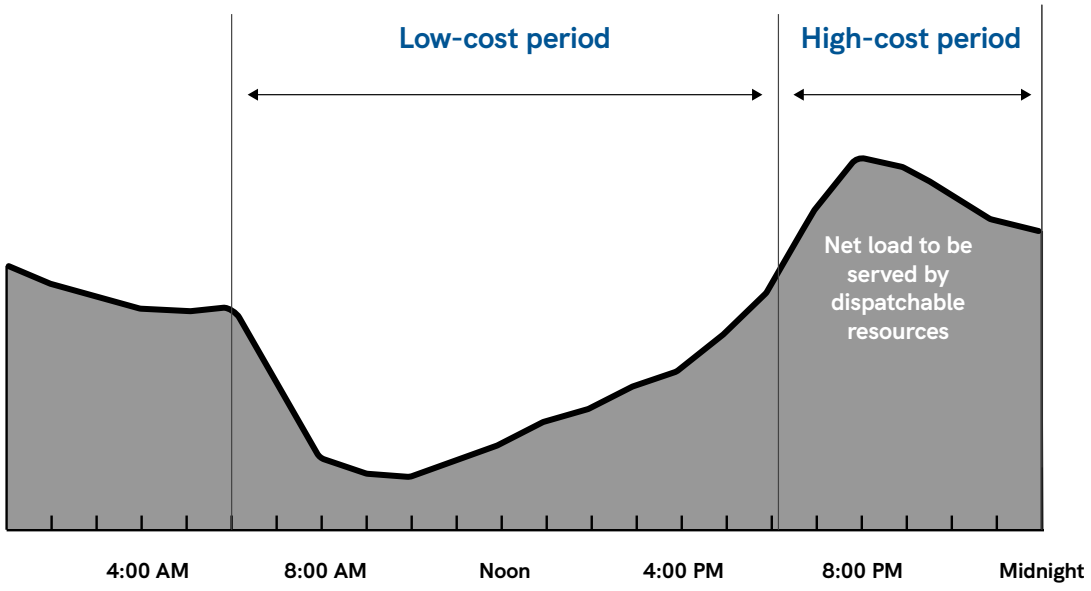
Figure 6.30 illustrates how system costs will change in the future system, with high-cost hours shifting to later in the evening, between 6 p.m. and midnight, and the low-cost period shifting to mid-day.

KEY FINDINGS

SRP will need to evolve programs and price plans to encourage shifts in consumer behavior, and further educate customers on when to consume and when to conserve energy.

Changes in how our customers use energy will require continued innovation and flexibility in planning.

FIGURE 6.30: AS THE SYSTEM TRANSFORMS, NET LOAD IS THE NEW TARGET FOR PRICING AND PROGRAMS.



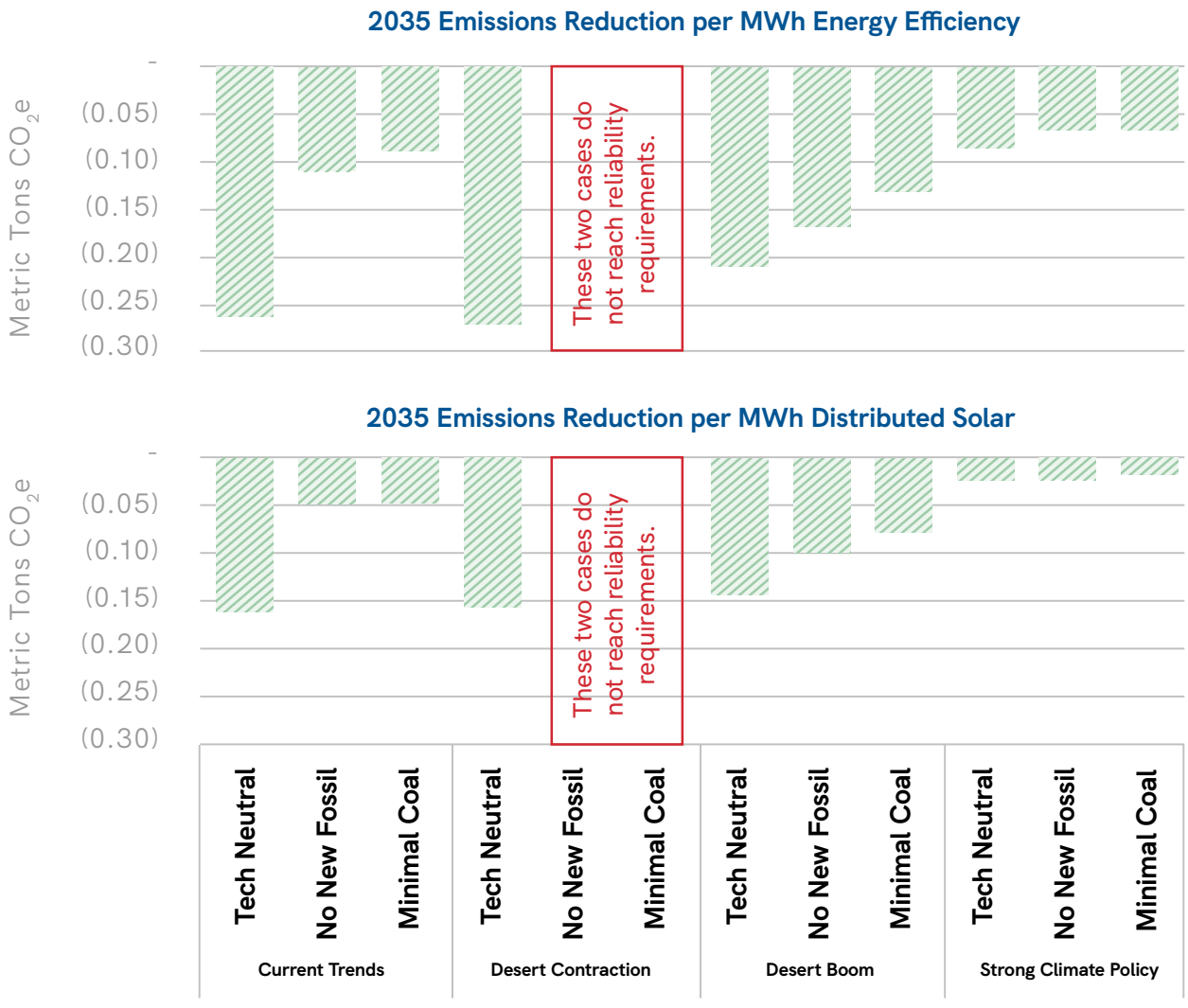
CO_2 Emissions Reductions from Energy Efficiency, Distributed Generation and Electrification

As customer programs reduce energy demand and peak load, they can also enable CO_2 emission reductions. Figure 6.31 first shows the avoided CO_2 per MWh of energy efficiency and distributed generation. Both programs result in avoided emissions without any increased grid emissions. The programs result in greater avoided CO_2 under Technology Neutral (except for under Strong Climate Policy) because the energy mix comprises a greater share of carbon-emitting sources in those cases. As the power sector decarbonizes, marginal carbon emission reductions from energy efficiency and distributed generation will diminish over time because the impacts of these programs tend to align with hours of lower marginal emissions. This finding is particularly prominent under Strong Climate Policy cases due to the more stringent carbon targets. However, continuing to offer programs that reduce load during high-demand hours will lead to greater emissions reductions.

KEY FINDING

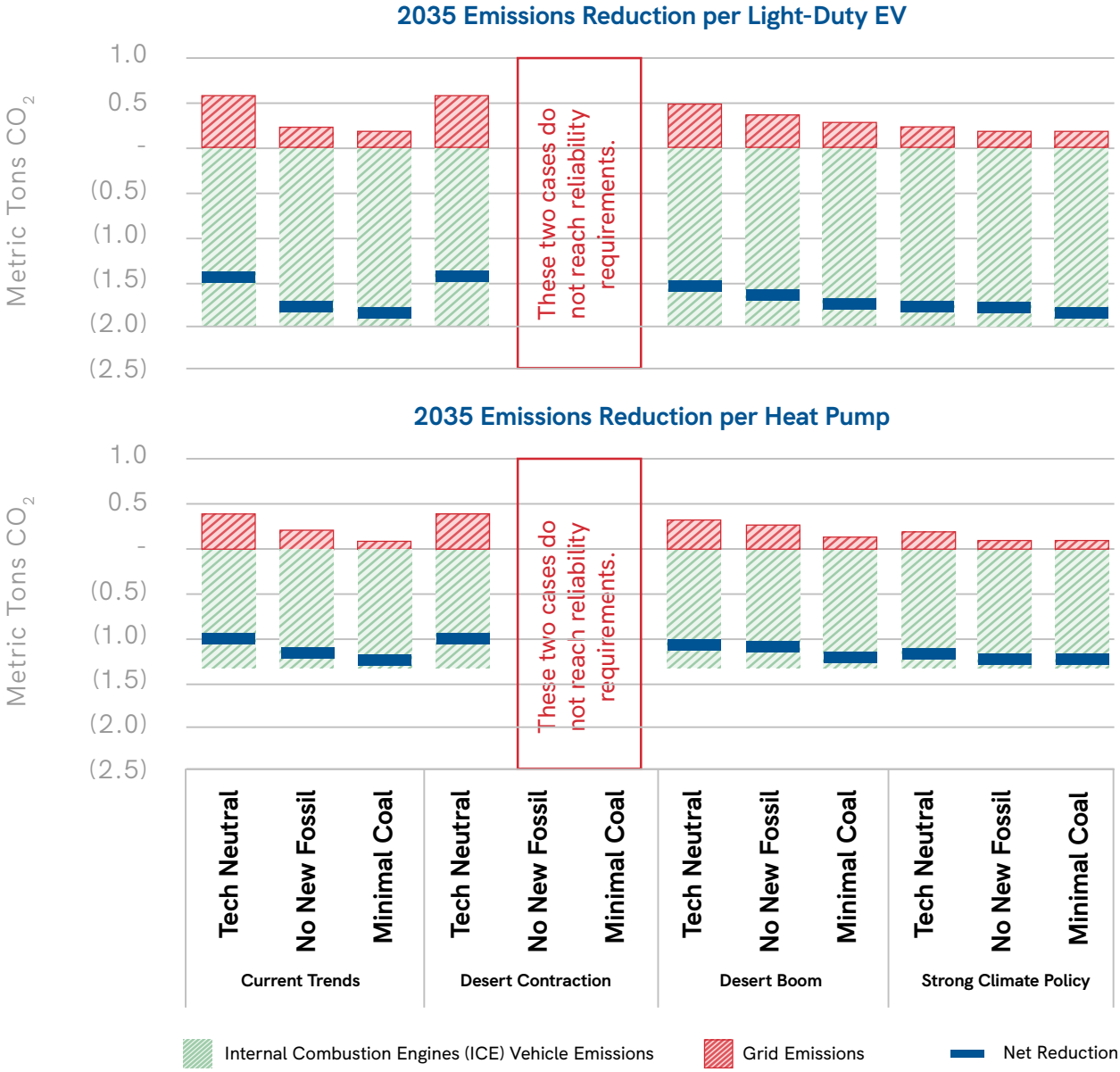
Electrification of end uses, including transportation and heating demand, creates new opportunities to shift energy usage to mid-day hours to help integrate more renewable energy and maximize carbon reduction impacts.

FIGURE 6.31: AVOIDED CO_2 FROM ENERGY EFFICIENCY AND DISTRIBUTED GENERATION



Transportation and building electrification can also result in economywide carbon reduction, such as through greater adoption of electric vehicles and heat pumps. However, as these measures shift energy consumption to the electricity system, potential increases in grid emissions need to be accounted for. Figure 6.32 shows the marginal emission reductions, grid emissions and net reductions from light-duty electric vehicles and heat pumps in each scenario in 2035. The reduction in carbon emissions by replacing internal combustion engine vehicles outweighs the incremental emissions from EV charging loads. Under the current rate structure, light-duty and heavy-duty vehicles primarily charge overnight, when grid emissions are higher. However, shifting EV charging to daytime periods, when emissions are lower, through managed charging programs and/or pricing plans, could lead to further emissions reductions. Similarly, although incremental load from heat pumps increases carbon emissions on the grid, carbon emission reductions from offsetting gas usage is much more significant. In this case, heat pump usage concentrates in the morning when grid emissions are relatively high.

FIGURE 6.32: AVOIDED CO_2 FROM ELECTRIC VEHICLES AND HEAT PUMPS



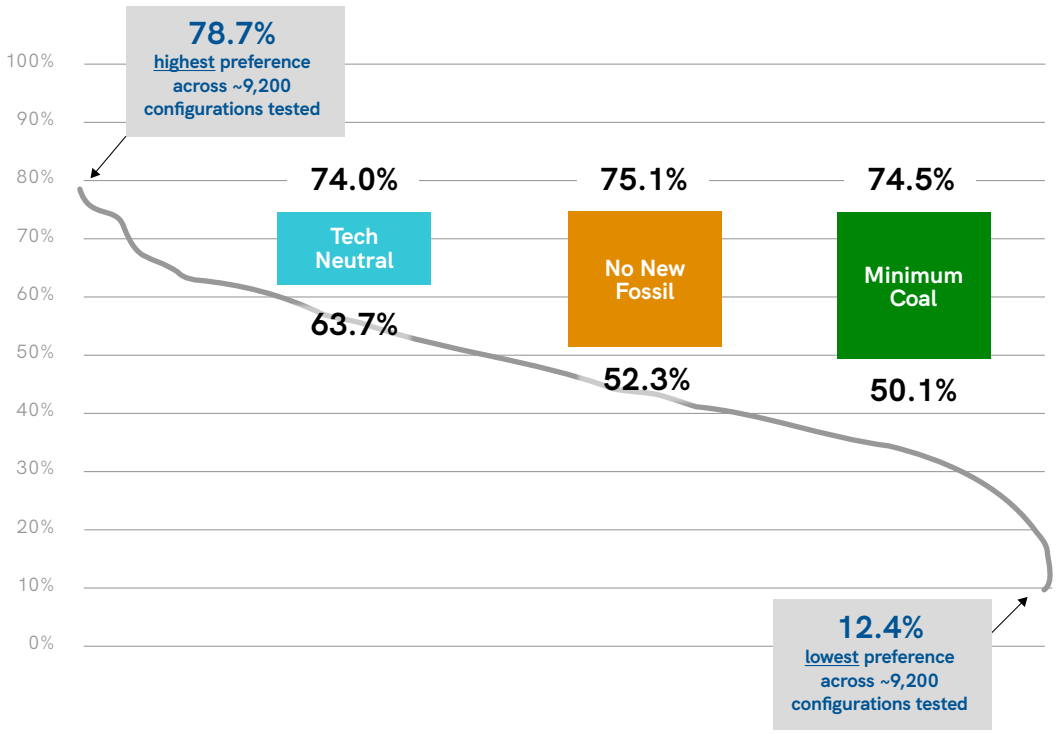
Residential Customer Research

Research consultant Bellomy assisted in the development of a Customer Preference Rating for each of the core system plans in the ISP, as shown in Figure 6.33. This metric was developed using over 1,000 residential customers' responses in a conjoint survey designed to understand how they value different aspects of the power system.

Residential Customer Preference Ratings represent the percentage by which customers expressed preferences of each strategic approach in various future scenarios relative to SRP's current system. Based on the results of the residential customer surveys, the preference ratings ranged between 12% and 79% versus the current system when all potential configurations were considered. System plans analyzed in this research that represented the ISP strategic approaches all achieved preferences over 50% versus SRP's energy system today.

Key findings from the research revealed that Technology Neutral was the most favorable strategic approach by SRP residential customers in futures with higher load growth such as Desert Boom and Current Trends. On the other hand, Minimum Coal and No New Fossil strategic approaches had a greater preference in futures where load growth was low, such as Desert Contraction, and additional federal incentives for carbon-free and hydrogen technologies were assumed, like in the Strong Climate Policy future scenario. Overall, there were more consistent preferences for Technology Neutral across the various futures when compared to the other strategic approaches.

FIGURE 6.33: CUSTOMER PREFERENCE RATINGS - SHARE OF PREFERENCE VERSUS CURRENT ENERGY SYSTEMS



Note: Within the Strong Climate Policy scenario, cases for Tech Neutral and No New Fossil are identical. Only one illustrative mix was shown to customers to represent both cases, thus data shown are identical for these two cases. No New Fossil and Minimum Coal cases were not tested in Desert Boom because they did not reach reliability targets.

Key findings from Residential Customer Research

Top factors – affordability and bill impacts: Affordability concerns were some of the most-selected future issues facing Arizona. In each phase of this research, affordability surpassed reliability slightly in importance when ranked by customers. Those with limited incomes, who make up approximately a third of SRP's residential customer base, put greater emphasis on affordability, while non-limited income customers reflected greater balance across factors. Additionally, when choosing a future energy system, customer selections revealed monthly bill impact as the top driver of preference.

Understanding and openness to change: Despite prioritizing affordability, customers recognized that the forthcoming challenges facing the region are interrelated and pose risks to sustainability, the economy and overall quality of life. Thus, they understood the need for a lower-carbon future energy system. Across scenarios, however, lower-cost strategic approaches were preferred by customers. While customers recognized the need for and expressed interest in SRP's investment in sustainable energy sources, they do not want to bear the cost of that investment.

Willingness to engage: Customers reported positive experiences with SRP's current programs and over half were interested in programs and rebates that will help them save money and energy. Additionally, about a third or more expressed interest in learning about SRP's energy efficiency programs, environmental efforts and infrastructure improvements.

Recommendations from residential customers for SRP's ISP

Findings revealed that from the residential customer's perspective, the ideal future energy system should:

- Manage cost, first and foremost.
- Keep monthly bill impacts below a 10% increase (from current electricity bills).
- Include a diverse energy mix to ensure reliability.
- Provide the cleanest, most sustainable energy without exceeding a 10% bill increase (from current electricity bills).

For additional details about the ISP customer research effort and key findings, please refer to the full reports for phases 1, 2 and 3 provided as appendices to this report.

Sensitivities

This section presents results for the 10 sensitivities that SRP analyzed for each strategic approach in the ISP.

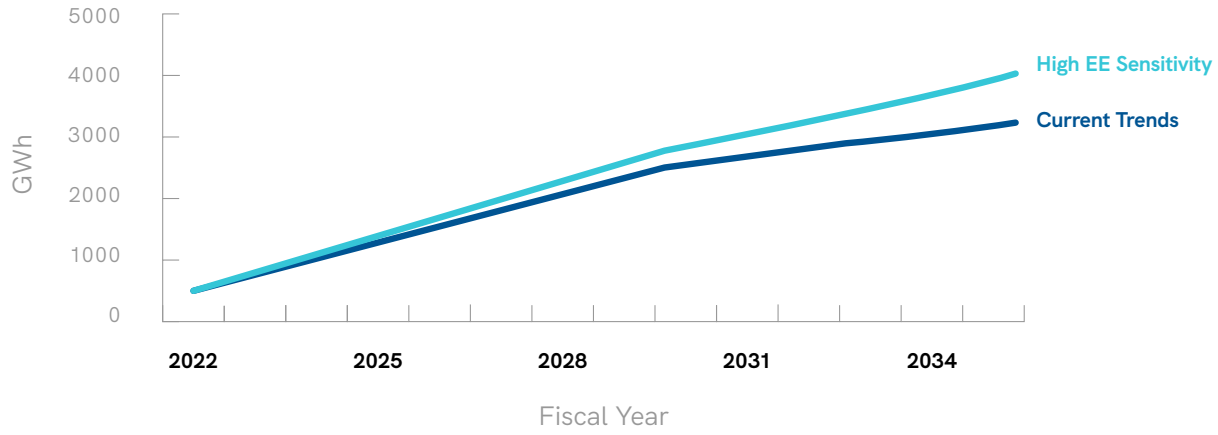
- High Energy Efficiency
- High Distributed Generation Adoption
- High Demand Response
- Increased Load Management
- High Gas Price
- Low Gas Price
- Volatile Gas Price
- High Technology Cost
- Low Technology Cost
- Regional Diversity

Each sensitivity is conducted relative to the Current Trends scenario as that scenario reflected the central planning assumptions. For presentation of the results, the three gas price sensitivities (High, Low and Volatile Gas Prices) are grouped together, as well as the two technology cost sensitivities (High and Low Technology Costs), yielding seven groups of sensitivities.

High Energy Efficiency

In the High Energy Efficiency (High EE) sensitivity, expansion of requirements pursuant to federal codes and standards lead to approximately 700 additional GWh of energy efficiency by 2035 relative to Current Trends. With this higher energy efficiency growth, total energy efficiency savings reach 4,471 GWh by 2035.

FIGURE 6.34: ANNUAL ENERGY EFFICIENCY ASSUMPTIONS



Figures 6.35 and 6.36 show peak load and energy demand forecasts for the High EE sensitivity, compared to Current Trends. In addition to reducing annual energy demand and overall load growth rates through 2035, these expanded energy efficiency customer programs reduce peak load by 395 MW in 2035 relative to Current Trends.

FIGURE 6.35: PEAK LOAD (MW) FORECASTS - HIGH ENERGY EFFICIENCY SENSITIVITY

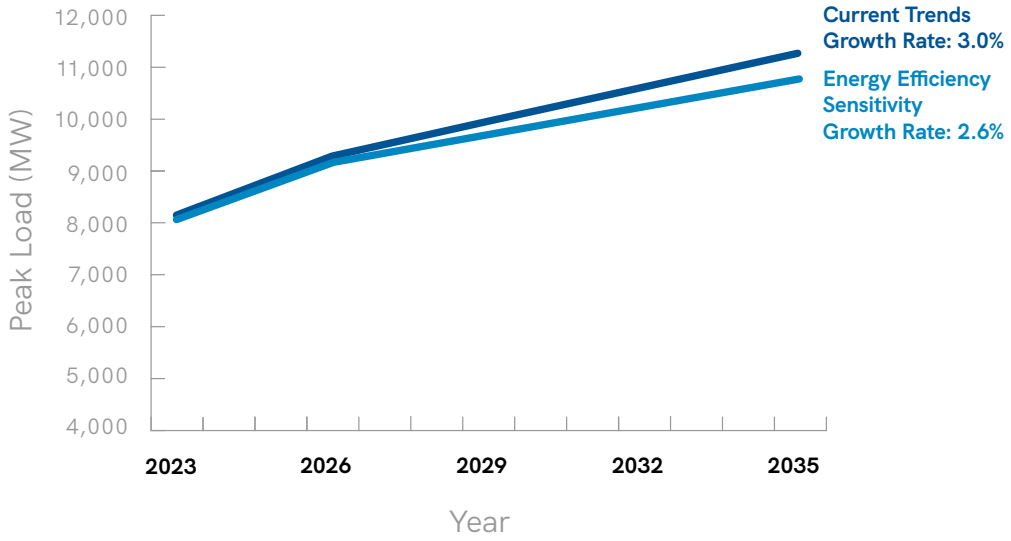


FIGURE 6.36: ENERGY DEMAND (GWH) FORECASTS - HIGH ENERGY EFFICIENCY SENSITIVITY

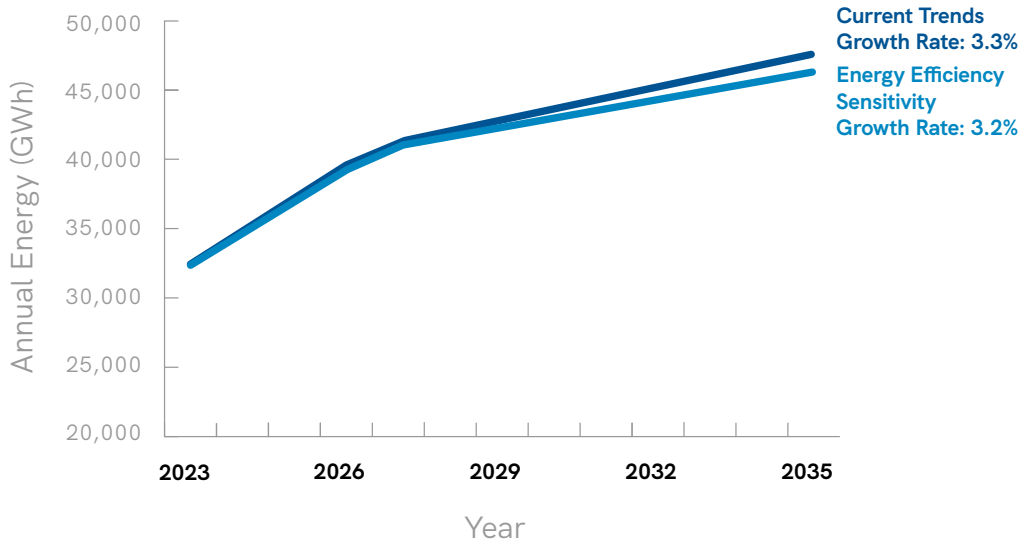
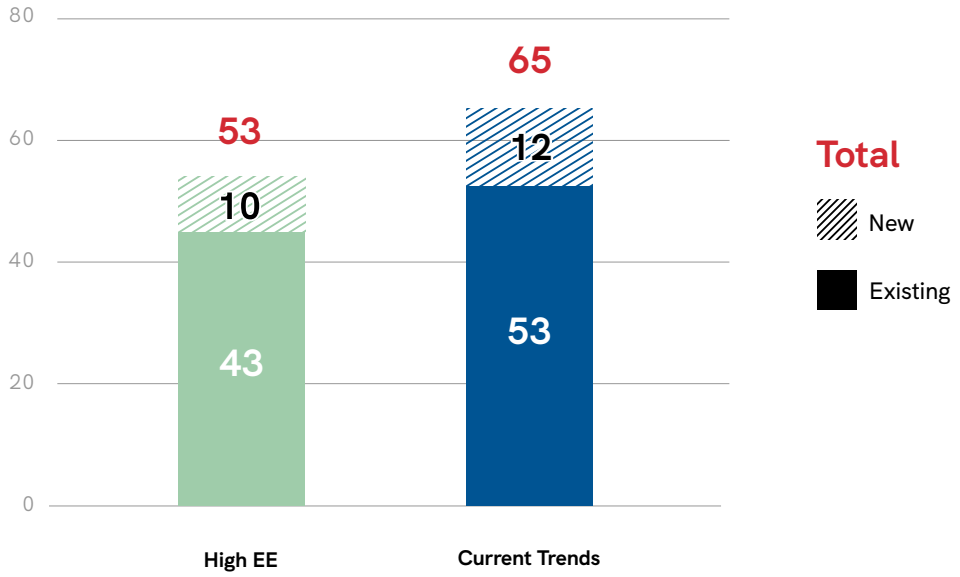


Figure 6.37 shows the distribution substation bay additions under the High EE sensitivity relative to the Current Trends scenario (see Figure 6.8 for the remaining scenarios). The High EE sensitivity results in slightly fewer substation bay additions than in Current Trends. The investment needs are similar to the Strong Climate Policy scenario, however, because the load forecasts are similar. The sensitivity results demonstrate a potential for energy efficiency to help defer distribution investment needs. However, this ability to help defer future investments will vary significantly across the system and must be assessed on a case-by-case basis when evaluating future distribution investments.

FIGURE 6.37: SUBSTATION BAY ADDITIONS AT EXISTING AND NEW SUBSTATIONS (FY23-35) - HIGH ENERGY EFFICIENCY SENSITIVITY



As shown in Figure 6.38, the additional energy efficiency in the High EE sensitivity case reduces the need for resources across all strategic approaches. In the Technology Neutral case, there are about 400 MW less new gas peaker builds in the High EE sensitivity than in Current Trends. In the No New Fossil and Minimum Coal cases, there are even fewer resource builds, particularly batteries (which had been the primary resource selected to meet capacity needs) and solar (which is less economic to add with fewer batteries to integrate the solar).

FIGURE 6.38: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO - HIGH ENERGY EFFICIENCY SENSITIVITY

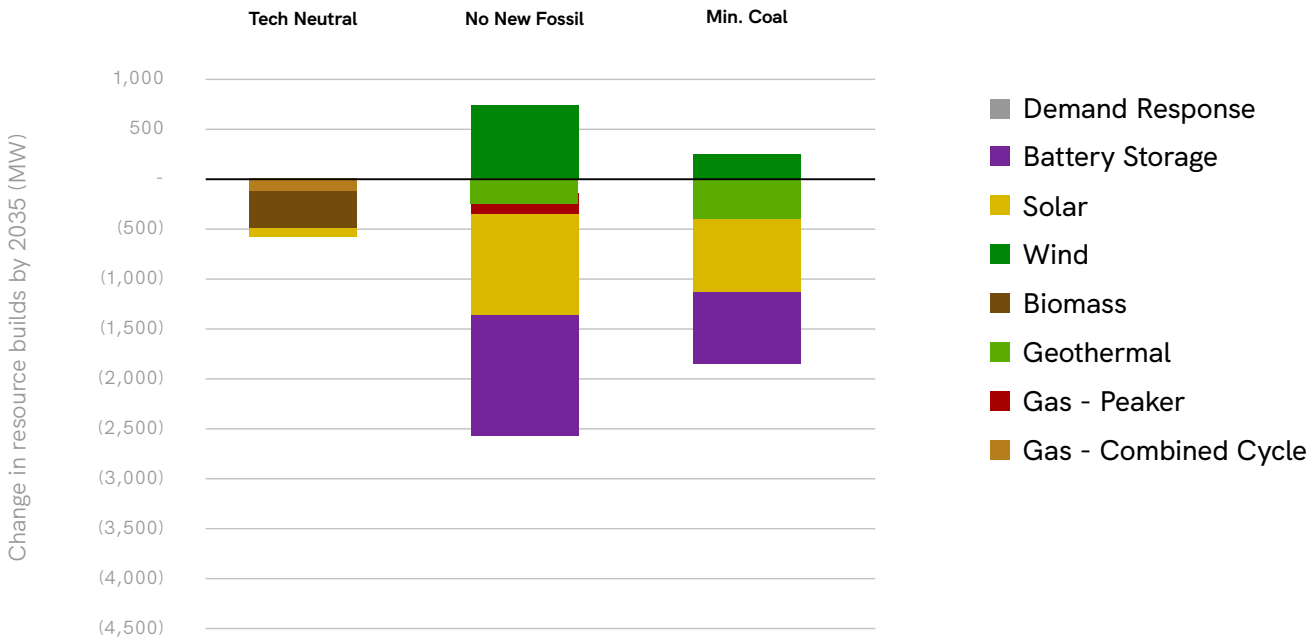
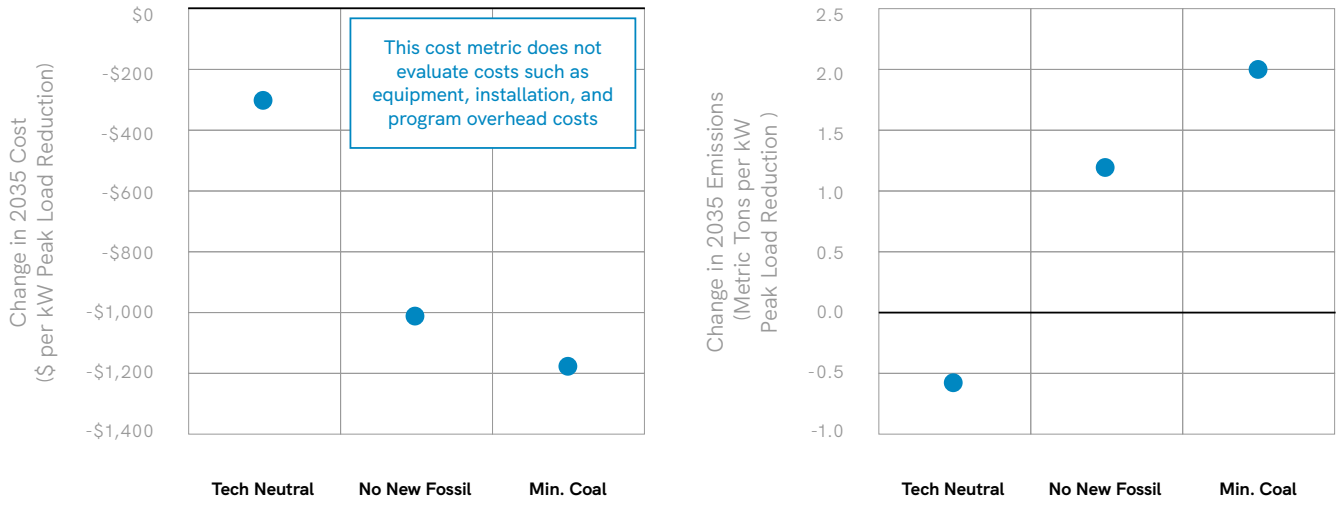




Figure 6.39 shows the resulting changes in total system cost and emissions under the High EE sensitivity, normalized by the kW reduction in PRM from the increased energy efficiency. It is important to note that the results do not include costs such as equipment, installation and program overhead, nor incentive payments or lost revenue that are relevant to ratepayer benefits and costs (such as those captured in the Ratepayer Impact Measure test). Because higher energy efficiency reduces the PRM requirement and the cost of meeting the PRM requirement under No New Fossil and Minimum Coal is higher without new firm resource options, additional energy efficiency results in greater cost savings in the Minimum Coal and No New Fossil cases. Conversely, additional energy efficiency results in relatively lower savings in the Technology Neutral case, where there are new firm capacity options. The Minimum Coal and No New Fossil cases also experienced emissions increases with more energy efficiency due to a net offset in renewable resource capacity and greater natural gas generation and market purchases, while the Technology Neutral case saw a decline in emissions due to a reduction in natural gas generation.

FIGURE 6.39: HIGH ENERGY EFFICIENCY: CHANGE IN 2035 TOTAL SYSTEM COST AND CO_2 EMISSIONS, NORMALIZED BY KW PEAK LOAD REDUCTION



Overall, the High EE sensitivity case demonstrates the ability for energy efficiency to not only offset overall energy demand but also demand during peak periods, which in turn can help mitigate the need for incremental investments in the distribution system and firm capacity resources. Cost savings are highest in cases with limited firm capacity resource options (No New Fossil and Minimum Coal) due to the higher cost of meeting the PRM in those cases (relative to Technology Neutral), although emissions increase in those cases due to greater reliance on emitting generation resources to meet energy demand.

High Distributed Generation Adoption

The High Distributed Generation sensitivity included approximately 960 additional MW of distributed solar and approximately 175 MW of distributed storage by 2035. The expanded distributed generation reduces annual peak load and energy demand growth relative to Current Trends, as shown in Figure 6.41.

FIGURE 6.40: HIGH DISTRIBUTED GENERATION SENSITIVITY CAPACITY (MW)

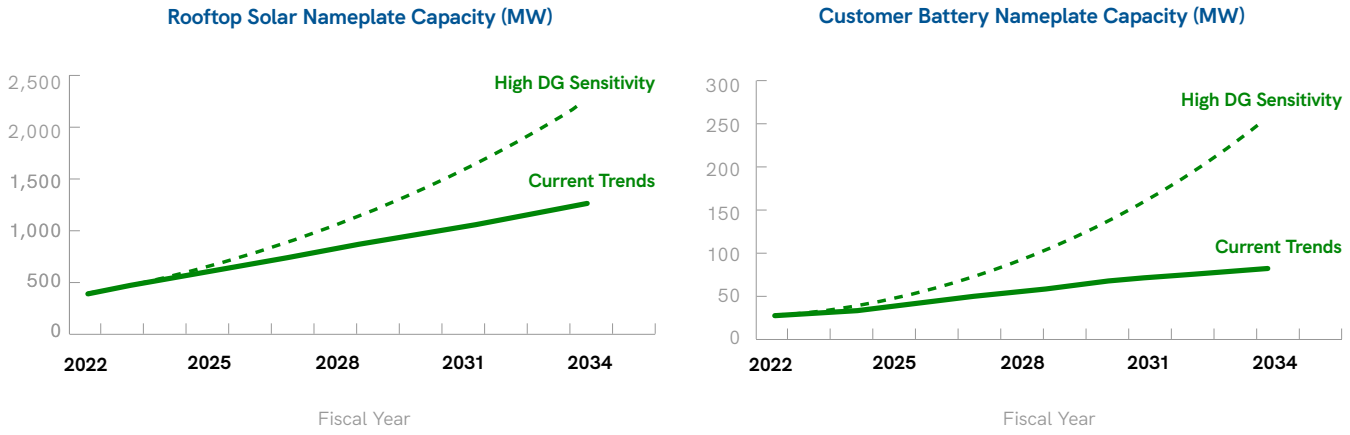


FIGURE 6.41: PEAK LOAD (MW) AND ENERGY DEMAND (GWH) FORECASTS - HIGH DISTRIBUTED GENERATION SENSITIVITY

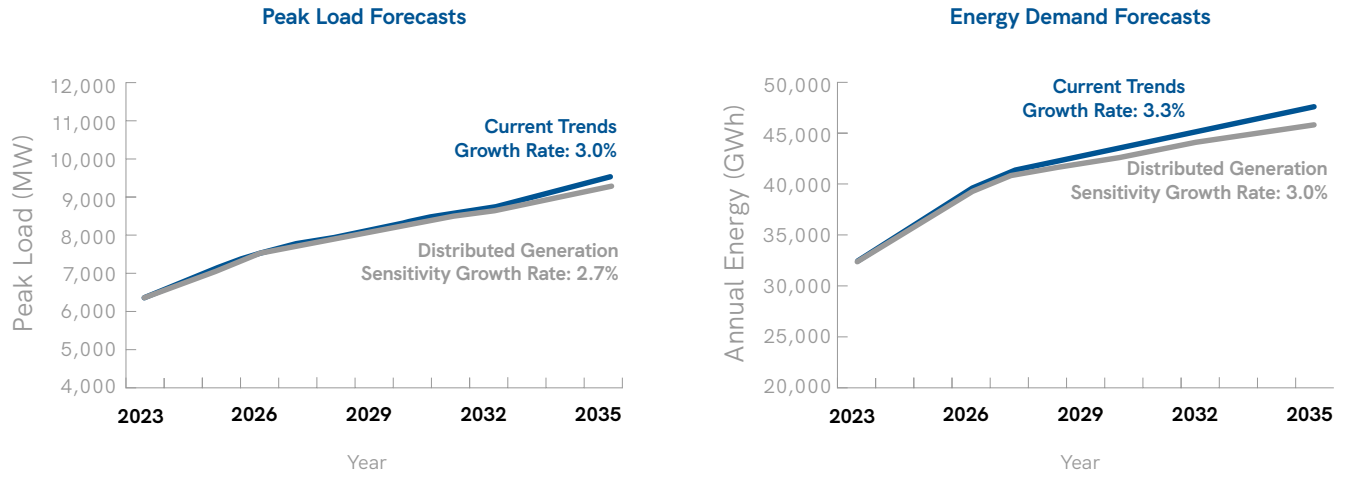
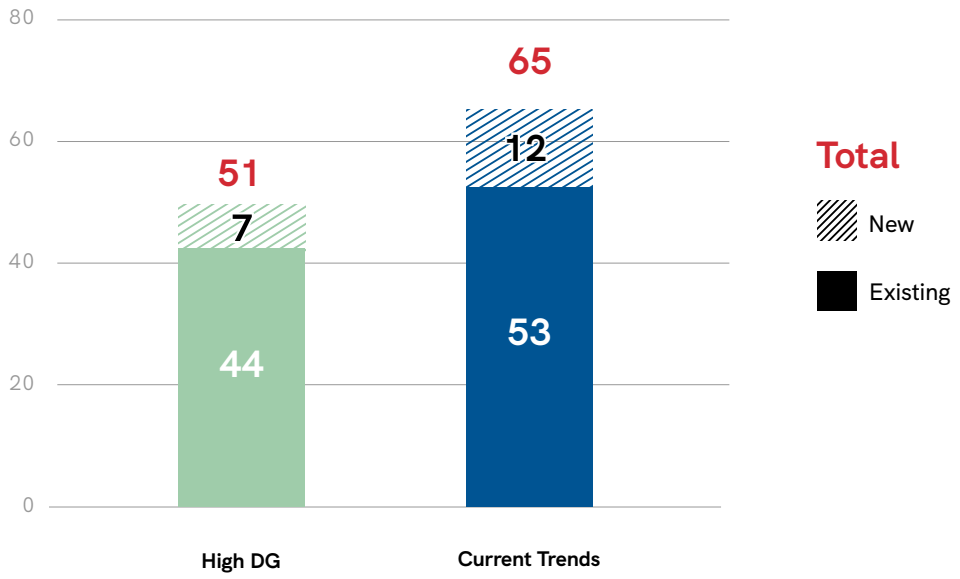


Figure 6.42 shows the distribution substation bay additions under the High Distributed Generation sensitivity relative to the Current Trends scenario (see Figure 6.8 for the remaining scenarios). The High Distributed Generation sensitivity results in slightly fewer substation bay additions than in the Current Trends scenario. The load forecast for this sensitivity is similar to that in the Strong Climate Policy scenario, which is why the investment needs are similar between these two cases. This result reflects the potential for distributed generation to help defer distribution investment needs generally. However, this ability to help defer future investments will vary significantly across the system and must be assessed on a case-by-case basis when evaluating future distribution investments.

FIGURE 6.42: SUBSTATION BAY ADDITIONS AT EXISTING AND NEW SUBSTATIONS (FY23-35) - HIGH DISTRIBUTED GENERATION SENSITIVITY



Additional distributed generation reduces the overall need for new resources, as shown in Figure 6.43. In the Technology Neutral case, increased distributed solar primarily displaces utility-scale solar, while distributed storage displaces some natural gas capacity. In the No New Fossil and Minimum Coal cases, increased distributed generation primarily displaces utility-scale solar and storage.

FIGURE 6.43: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO - HIGH DISTRIBUTED GENERATION SENSITIVITY

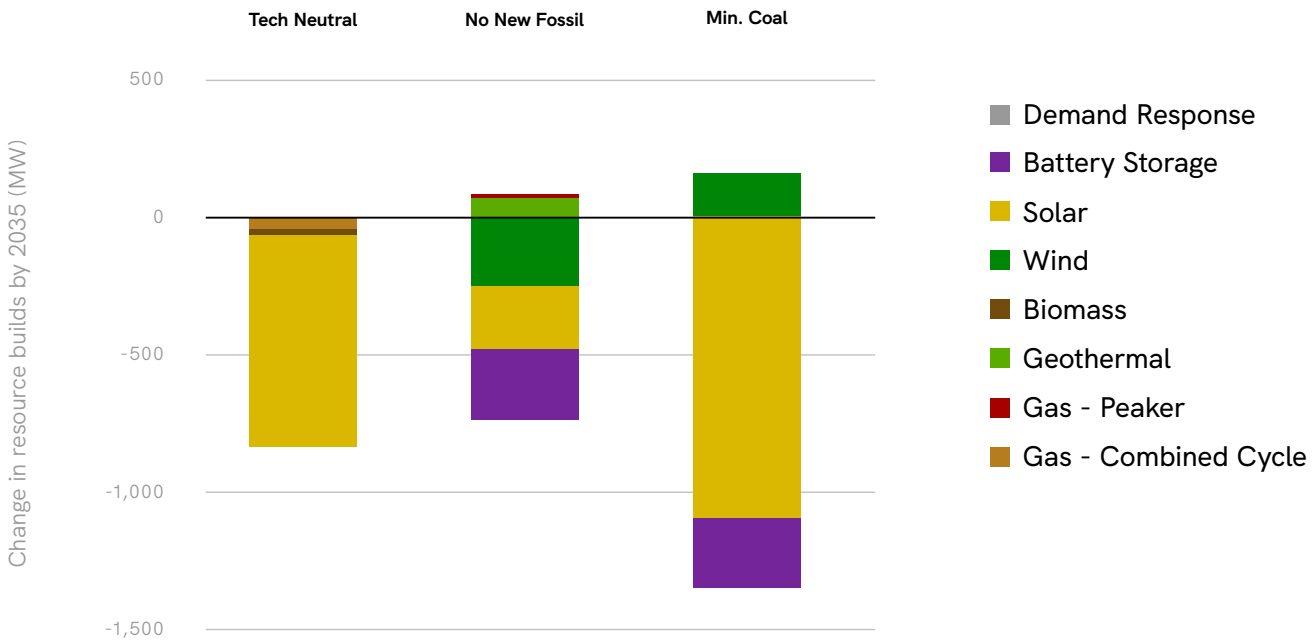
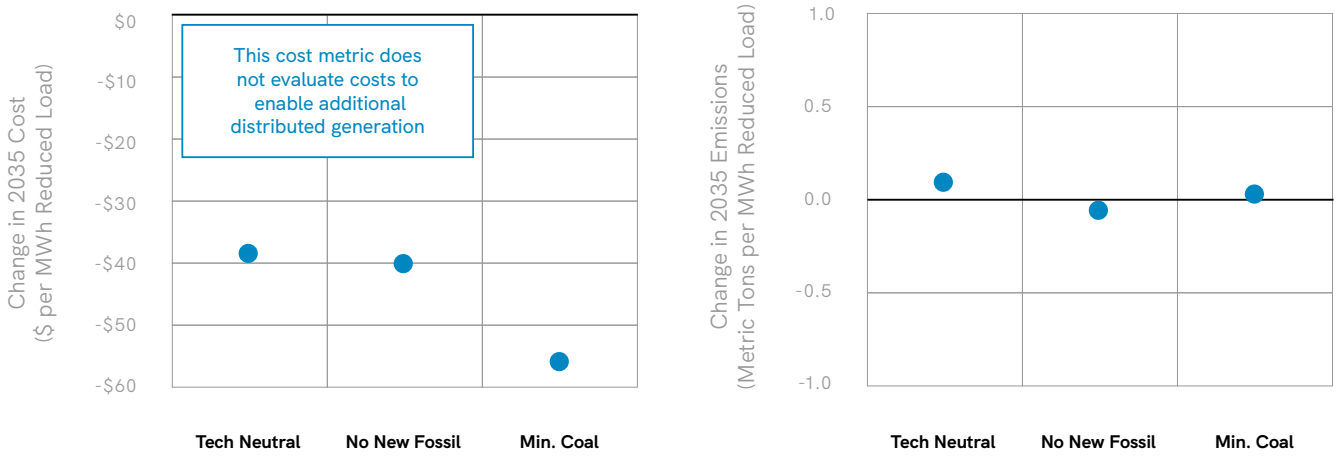


Figure 6.44 shows the resulting reductions in total system cost and changes in emissions under the sensitivity, normalized by the MWh of reduced load from additional distributed generation. It is important to note for these results that there is uncertainty as to how well distributed storage dispatch would align with grid needs and that these results do not include the costs to SRP or its customers of adding the distributed generation. Adding distributed generation generally leads to total system cost reductions, with the greatest reductions in the Minimum Coal case due to the greatest offset of capacity. However, there was very little impact of distributed generation on emissions across all cases, given it primarily substituted distributed solar generation for utility-scale solar generation.

FIGURE 6.44: HIGH DISTRIBUTED GENERATION: CHANGE IN 2035 TOTAL SYSTEM COST AND CO_2 EMISSIONS, NORMALIZED BY MWH REDUCED LOAD

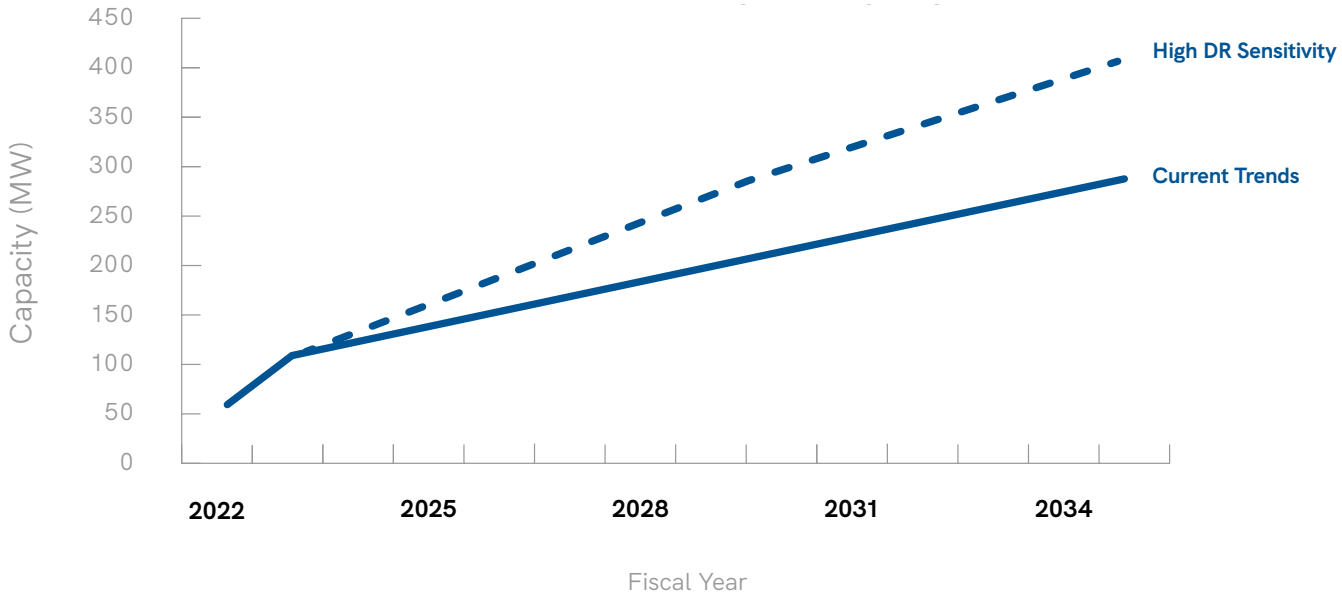


Overall, increased levels of distributed generation resources (solar PV and battery storage) reduce overall energy demand as well as energy demand during peak periods that need to be served by utility-scale resources. As a result, increased adoption of these resources helps mitigate the need for incremental distribution system investments and offsets the need for some utility-scale generation resources: Distributed solar primarily helps offset utility-scale solar, while increased distributed storage is able to offset a portion of capacity resources (gas and/or batteries). The analysis finds that increased adoption of distributed resources leads to the greatest reductions in total system costs in the Minimum Coal strategic approach due to the greatest offset of utility-scale resources and a relatively small impact on emissions across all cases.

High Demand Response

The High Demand Response sensitivity assumes an additional 100 MW of demand response by 2035, reaching a total of 400 MW (compared to 300 MW under the Current Trends scenario).

FIGURE 6.45: ANNUAL DEMAND RESPONSE CAPACITY ASSUMPTIONS



The additional demand response capacity results in a change in resource builds relative to the Current Trends scenario, as shown in Figure 6.46. Increased demand response displaces capacity resources in all strategic approaches. In the Technology Neutral case, adding an additional 100 MW of demand response reduces over 30 MW of natural gas peaker builds.
In the No New Fossil and Minimum Coal cases, the additional demand response substitutes for 50 MW of battery storage builds. The outcome that the reduction of battery capacity is equal to half of the demand response additions reflects the assumption that demand response provides less reliability capacity to the system than batteries; while demand response and battery resources provide similar services to the system, demand response is more limited in number and duration of dispatch events. Because some of the storage resources that are offset are battery storage paired with solar, there is a reduction in solar capacity and a corresponding increase in wind (and biomass in No New Fossil). Less capacity is offset in the Technology Neutral case because natural gas capacity has a greater contribution to reliability needs relative to demand response, battery storage and solar.

FIGURE 6.46: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO - HIGH DEMAND RESPONSE SENSITIVITY

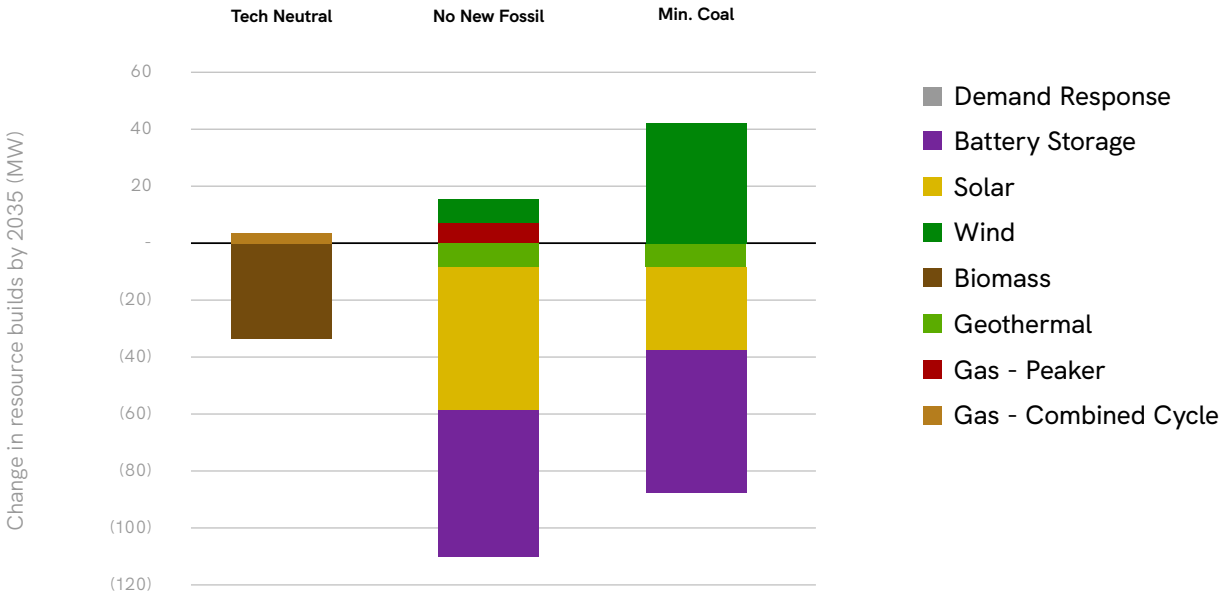
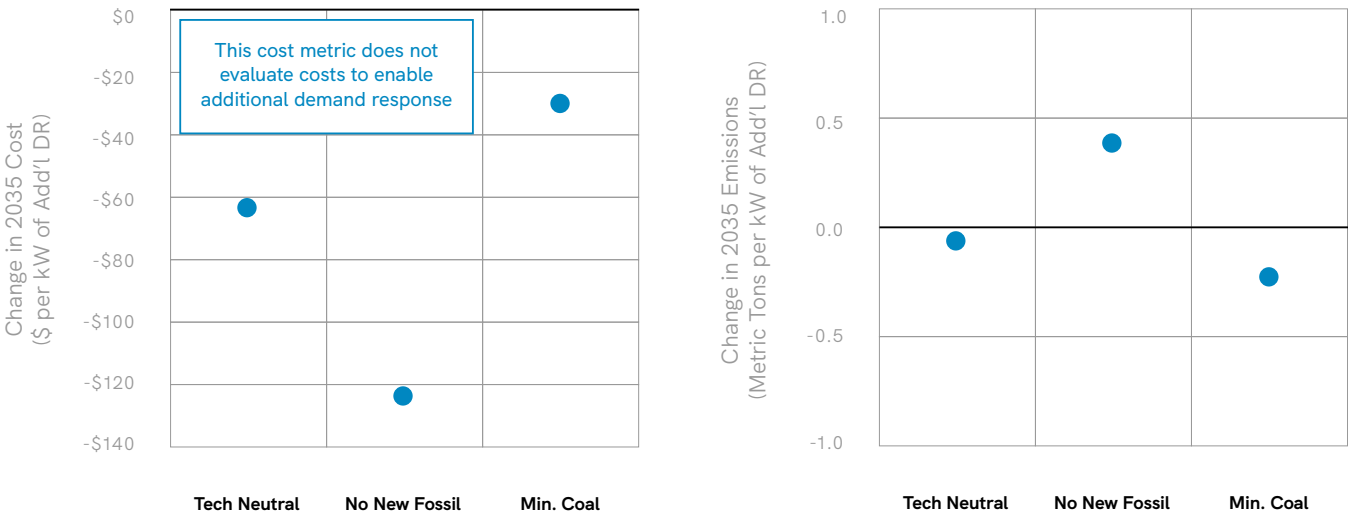


Figure 6.47 shows the resulting change in total system cost and emissions under the sensitivity, normalized by the additional demand response capacity. Note that the total system cost metric does not include the incremental costs needed to enable this additional demand response capacity, so the change in total system cost only reflects gross savings and not net savings. Additional demand response results in the greatest gross savings under the No New Fossil case due to larger offsets in capacity additions. The Technology Neutral case has a smaller reduction in costs because a relatively small amount of natural gas capacity is offset. Emissions increase in the No New Fossil case when demand response is added due to a slight increase in gas emissions to compensate for the net reduction in clean energy capacity. There are small emissions reductions in Technology Neutral due to the reduction in gas capacity and in the Minimum Coal case due to the greater additions of wind capacity offsetting the displaced capacity.

FIGURE 6.47: HIGH DEMAND RESPONSE: CHANGE IN 2035 TOTAL SYSTEM COST AND CO_2 EMISSIONS, NORMALIZED BY KW OF ADDITIONAL DEMAND RESPONSE



Overall, increased levels of demand response largely help mitigate the need for capacity resources (gas and/or batteries). Mitigating the need for these resources leads to total system cost savings, with the greatest savings in the No New Fossil case, although this case also sees an uptick in emissions.

Increased Load Management

The Increased Load Management sensitivity assumed that there is an additional 200 MW of aggregate flexibility through managed EV charging or other flexible loads, allowing SRP to shift up to 800 MWh of energy demand each day.

SRP found that increased load management displaces a portion of resources needed for reliability. In the Technology Neutral strategic approach, additional load management reduces gas builds and helps integrate more solar capacity by shifting energy demand from evening hours to daytime hours. In the No New Fossil and Minimum Coal cases, load management substitutes one for one for battery storage capacity, offsetting the paired battery storage and solar that is otherwise built and leading to a small increase in wind.

FIGURE 6.48: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO - INCREASED LOAD MANAGEMENT SENSITIVITY

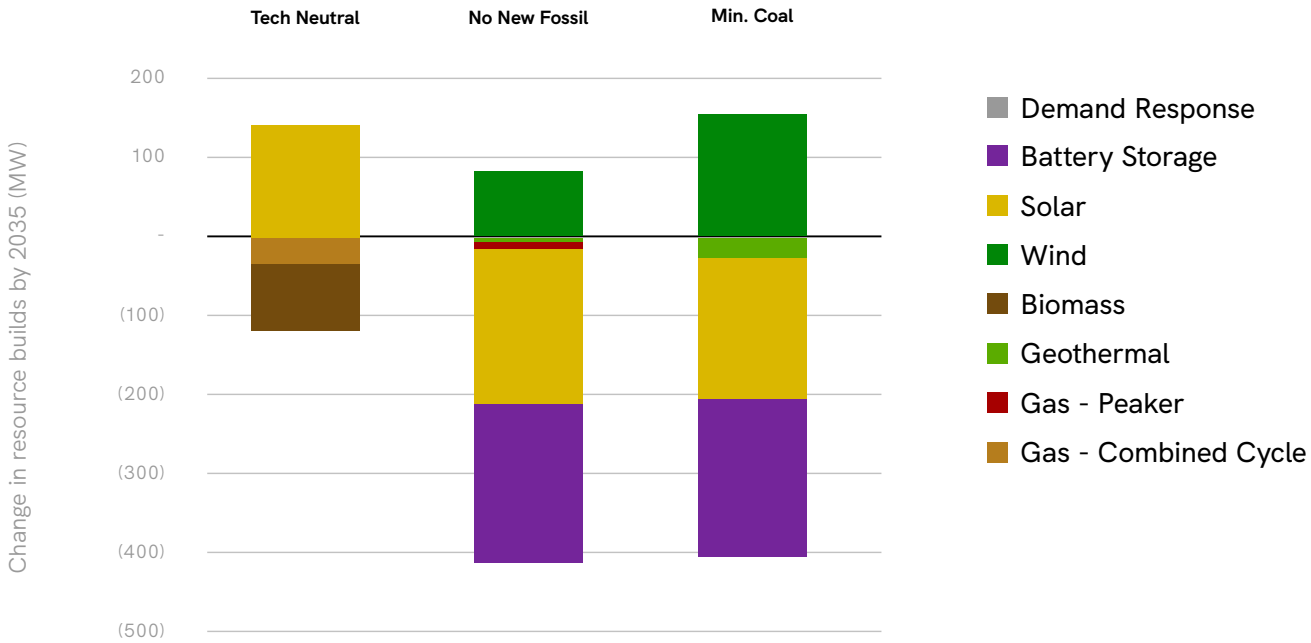
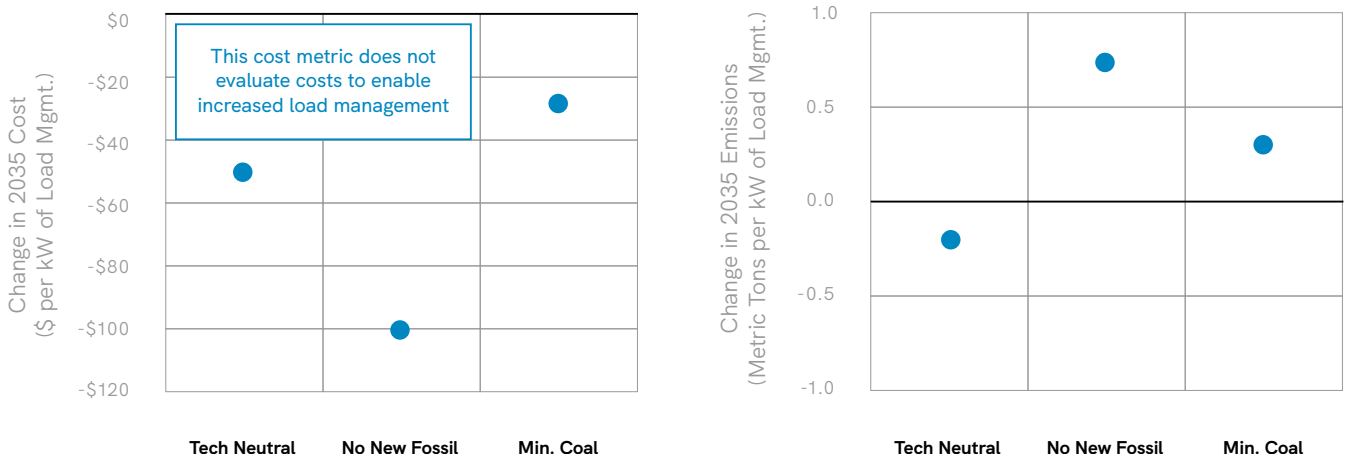


Figure 6.49 shows the resulting reductions in total system cost and changes in emissions under the sensitivity, normalized by kW of increased load management. This sensitivity assumes that SRP has sufficient control or can incentivize customers to get desired performance. Additionally, this sensitivity does not evaluate costs to enable increased load management. The dynamics of increased load management are similar to that of demand response, resulting in similar cost and emissions impacts. Relative to the Current Trends scenario, increased load management generally leads to reductions in total system costs, with the greatest impact on the No New Fossil case. The Minimum Coal case has the smallest reduction in costs because greater amounts of wind capacity are added to make up for the reduced solar and battery capacity. While emissions decrease in Technology Neutral due to the reduction in gas generation, emissions increase under No New Fossil and Minimum Coal due to the larger decline in clean energy capacity.

FIGURE 6.49: CHANGE IN 2035 TOTAL SYSTEM COST AND EMISSIONS, NORMALIZED BY KW OF INCREASED LOAD MANAGEMENT



Overall, increased levels of load management such as managed EV charging largely help mitigate the need for firm capacity resources (gas or batteries). Mitigating the need for these resources leads to total system cost savings, with the greatest savings in the No New Fossil case, although this case also sees the highest uptick in emissions.

High, Low and Volatile Gas Prices

The high and low gas price sensitivity cases were based on the 2022 EIA AEO Low and High Oil & Gas Supply Cases, respectively. SRP found that additions of natural gas and renewable/storage resources depend on gas prices, but in all cases, both new renewables and firm capacity are part of a least-cost portfolio. For example, higher natural gas prices (HGP) increase total capacity additions, driving increases for solar, wind and storage while offsetting some gas capacity. On the other hand, lower natural gas prices (LGP) reduce total capacity additions, driving higher additions of natural gas while offsetting solar and wind additions.

FIGURE 6.50: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO – HIGH AND LOW GAS PRICES SENSITIVITY

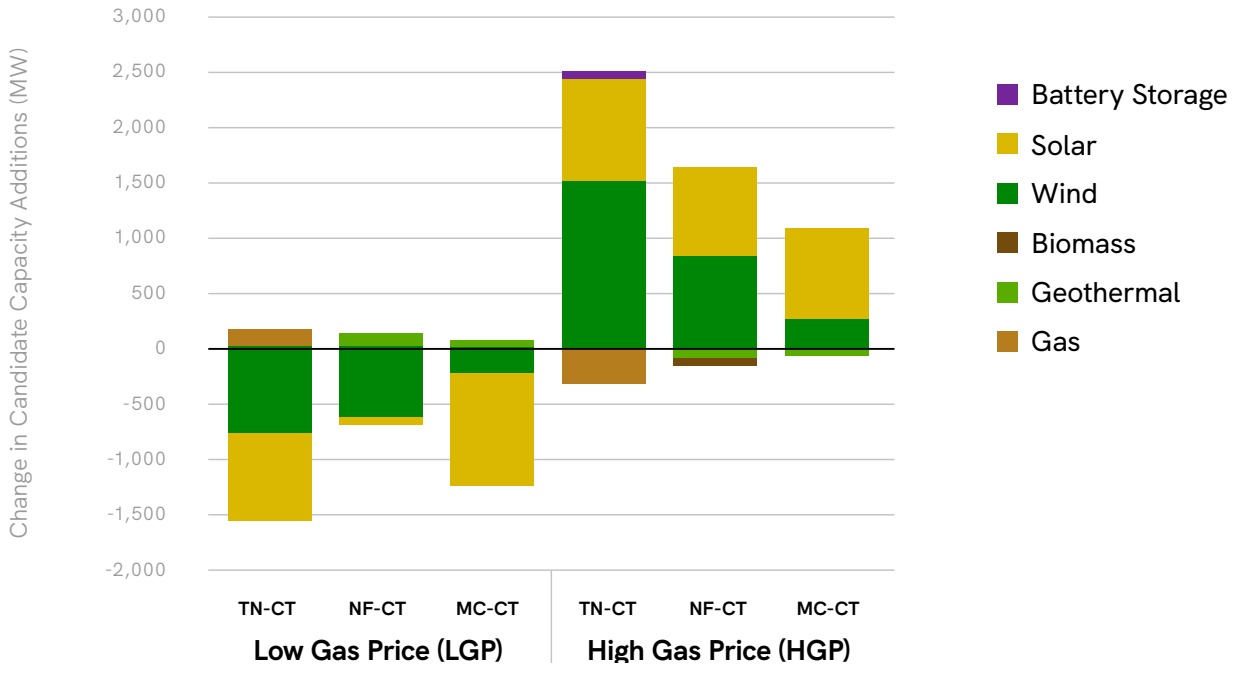


Figure 6.51 shows the change in 2035 total system cost and emissions, relative to the Current Trends scenario. High Gas Prices had the strongest impact on total system cost for the Technology Neutral approach, while the costs for the No New Fossil and Minimum Coal cases were relatively stable. For Technology Neutral, the High Gas Price sensitivity caused a larger change in cost than the Low Gas Price sensitivity because the high gas prices increased more than the low gas prices decreased. Cost impacts under No New Fossil and Minimum Coal were mild for both the High Gas and Low Gas price sensitivities. Emissions increased in the Low Gas Price sensitivity and decreased in the High Gas Price sensitivity for all strategic approaches, but to a lesser extent for No New Fossil.

KEY FINDING

New renewables and firm capacity are part of a least-cost portfolio, even under a wide range of gas prices.

FIGURE 6.51: CHANGE IN 2035 TOTAL SYSTEM COST AND CO_2 EMISSIONS, RELATIVE TO THE CURRENT TRENDS SCENARIO

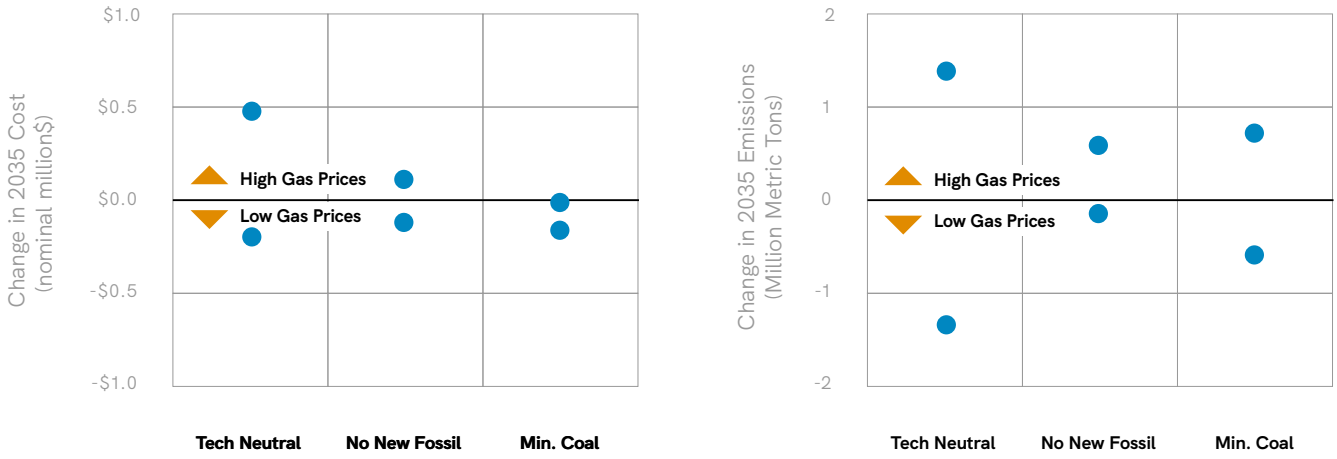
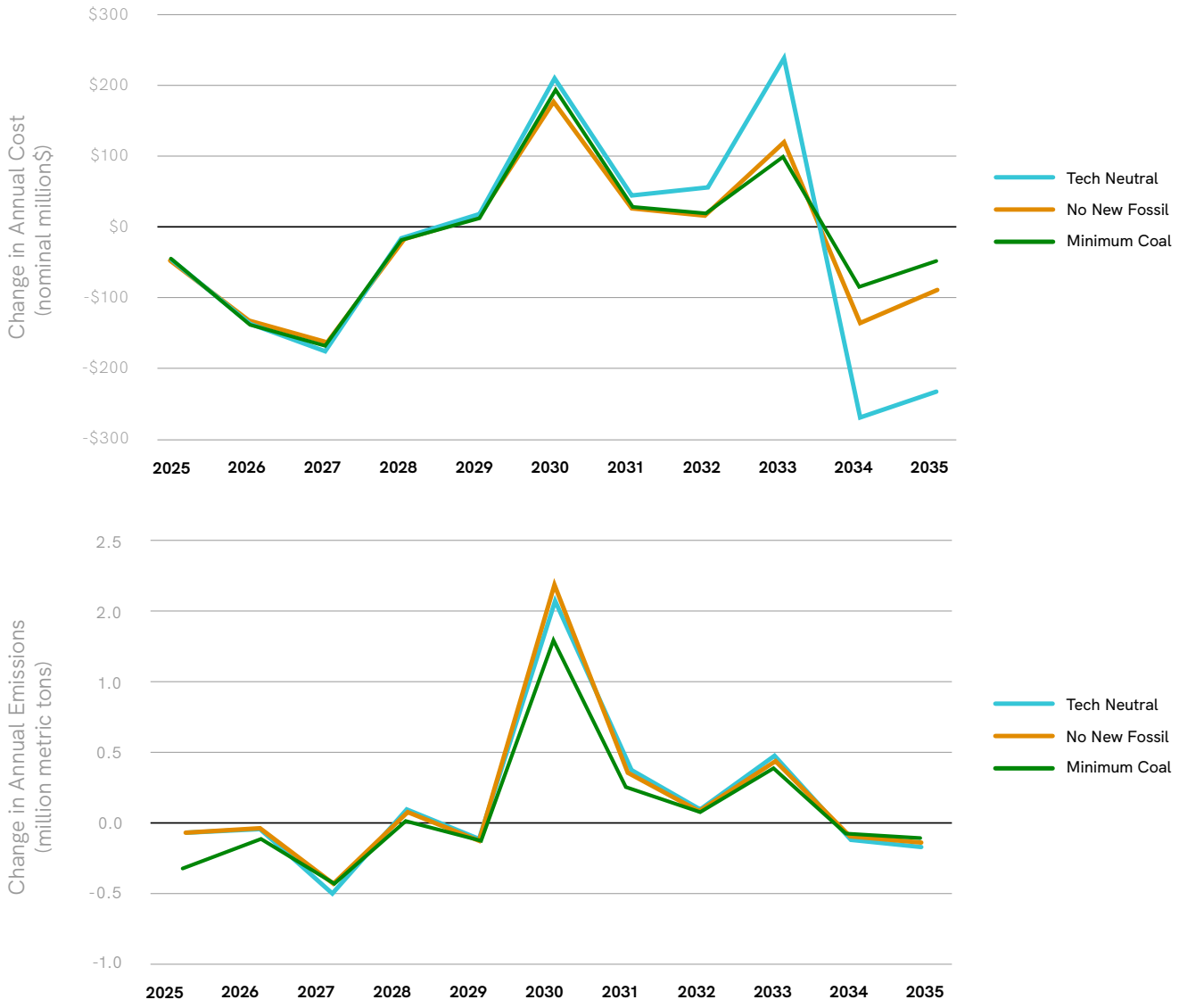


Figure 6.52 shows the impacts of the variable gas price sensitivity on total system cost and emissions between 2025 and 2035, relative to the Current Trends scenario. This sensitivity did not vary resource buildouts, so the changes over time are only a result of changes to gas prices (and associated impacts on market prices). The variability in natural gas prices leads to fluctuations in total system costs, particularly in the 2030s, with total system cost increasing or decreasing by over +/- $200 million in a given year and emissions increasing by over 2 million metric tons in a given year.



FIGURE 6.52: VARIABLE GAS PRICES: ANNUAL CHANGE IN TOTAL SYSTEM COST (TOP) AND EMISSIONS (BOTTOM), RELATIVE TO THE CURRENT TRENDS SCENARIO



Overall, the trajectory of future natural gas can have important implications for SRP's resource portfolio. Higher natural gas prices result in increased additions of renewables and storage (offsetting a smaller amount of natural gas builds in Technology Neutral), higher total system costs and lower emissions in 2035. Lower natural gas prices result in lower renewable additions (with a slight uptick in natural gas builds under Technology Neutral), lower total system costs and higher emissions. The potential for unexpected gas price volatility in the future could result in higher system costs or emissions.

High and Low Technology Costs

The High and Low Technology Cost sensitivities were based on the 2022 NREL ATB High and Low Cases, respectively. Lower Technology Costs (LTC) increase total capacity additions, driving increases in solar and battery storage while offsetting some natural gas capacity. On the other hand, Higher Technology Costs (HTC) reduce total capacity additions, primarily offsetting solar additions.

FIGURE 6.53: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO - HIGH & LOW TECHNOLOGY COSTS

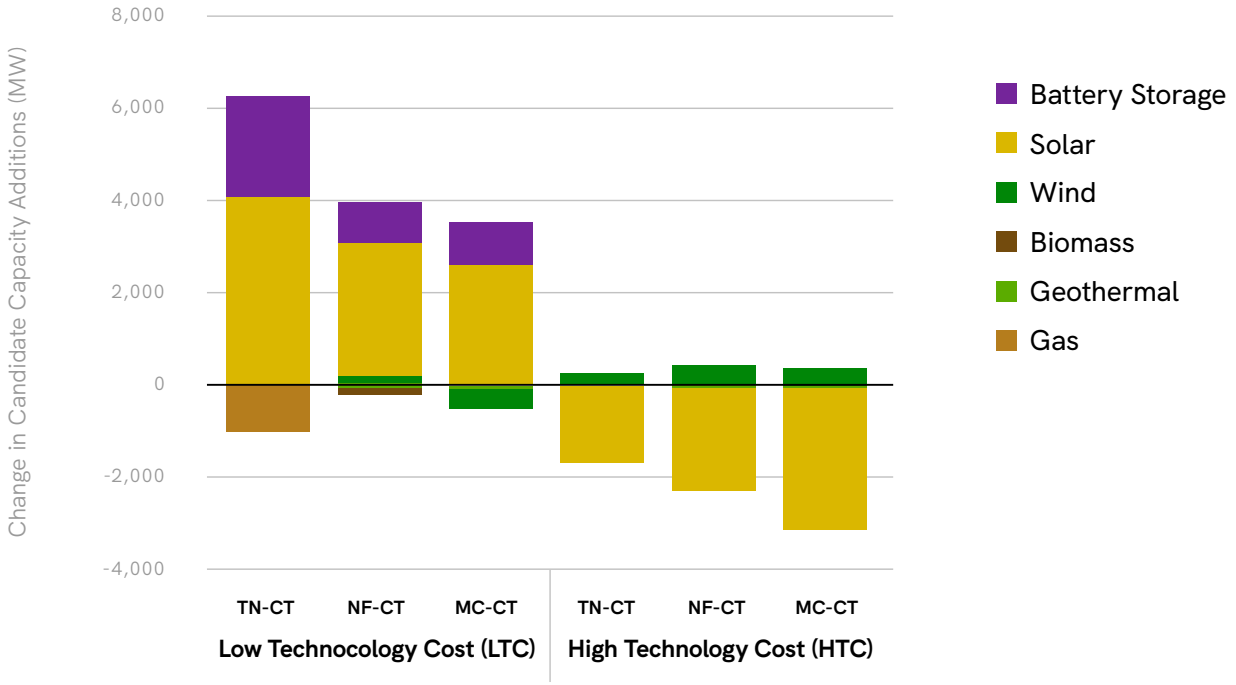
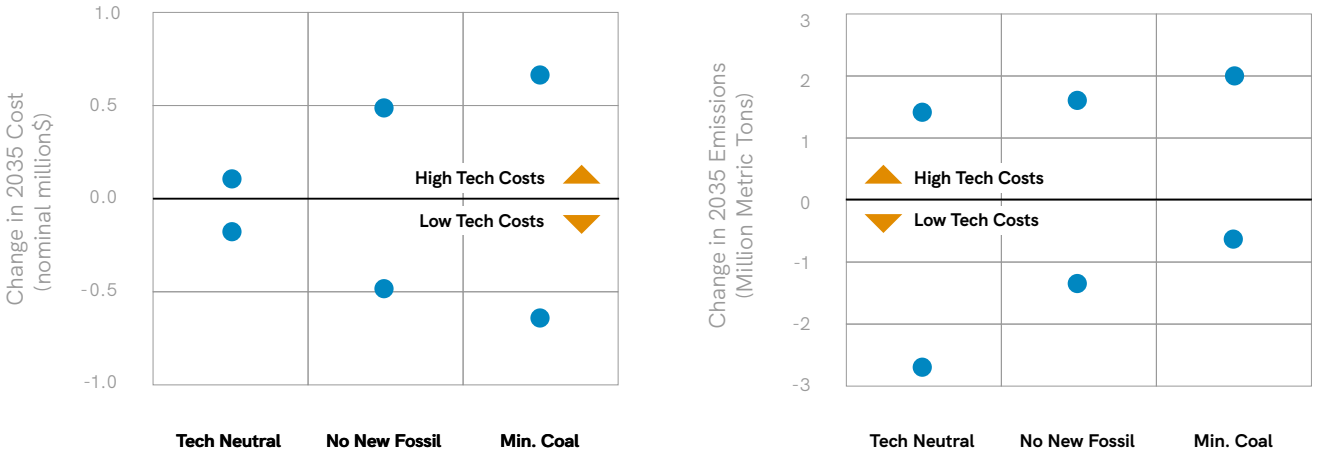


Figure 6.54 shows the change in 2035 total system cost and emissions, relative to the Current Trends scenario. The change in technology costs causes the greatest cost impact on the Minimum Coal case, while the Technology Neutral case experiences relatively low impacts to cost. Across all cases, higher technology costs lead to higher emissions and lower technology costs lead to lower emissions.

FIGURE 6.54: CHANGE IN 2035 TOTAL SYSTEM COST AND CO_2 EMISSIONS, RELATIVE TO THE CURRENT TRENDS SCENARIO



Overall, the trajectory of future technology costs can have important implications for SRP's resource portfolio. Lower renewables and storage technology costs result in increased additions of solar and storage (and higher total capacity additions), lower total system costs and lower emissions in 2035. Higher technology costs result in lower renewable additions, higher total system costs and higher emissions. In all cases, new firm capacity is still needed.

Regional Diversity

In the Regional Diversity sensitivity, SRP reduced the target planning reserve margin (PRM) from 16% to 13% (338 MW reduction by 2035) to serve as a proxy to represent the assumption that expanded transmission and regional coordination allow for increased resource and load diversity. The lower PRM reduces the need for resources on SRP's system. In the Technology Neutral strategic approach, there are fewer gas peaker builds. In the No New Fossil and Minimum Coal cases, larger amounts of resources are offset. The most impacted resources are batteries (due to the lower total PRM requirement) and solar (which is less economic to add with fewer batteries to integrate the solar). These resources are partially replaced by wind in both cases.

FIGURE 6.55: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO - REGIONAL DIVERSITY

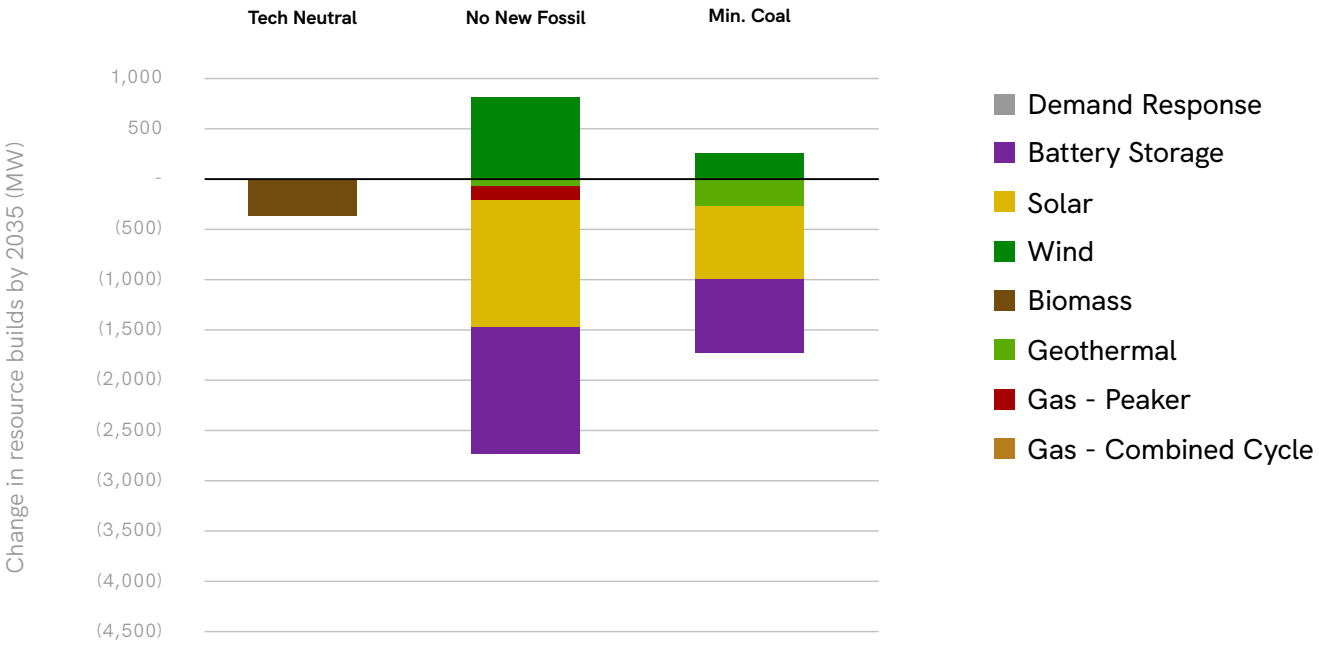


Figure 6.56 shows the resulting reductions in total system cost and changes in emissions under the sensitivity, normalized by the kW PRM reduction. For this sensitivity, the 3% PRM reduction is hypothetical, and the results do not consider any trade-offs or costs to realize greater regional diversity benefits for capacity planning. Because No New Fossil and Minimum Coal have higher costs of meeting the PRM due to the lack of new firm capacity resources, Regional Diversity results in the greatest cost reductions for these cases and the lowest cost reductions for Technology Neutral, in which there are new firm capacity resource options. While the Technology Neutral case experiences a very slight decrease in emissions, No New Fossil and Minimum Coal have increases in emissions due to natural gas generation and market purchases compensating for the reduction in renewable generation.

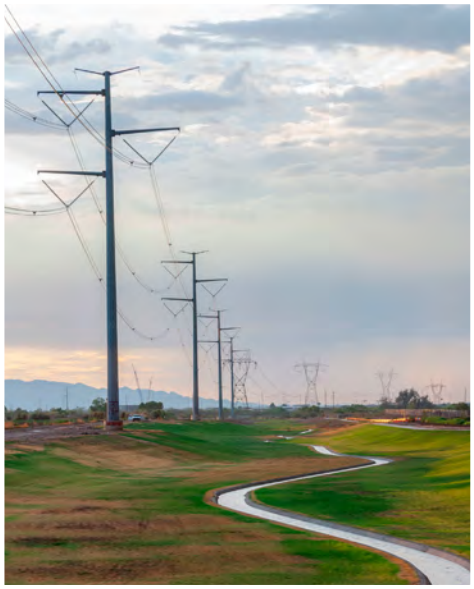
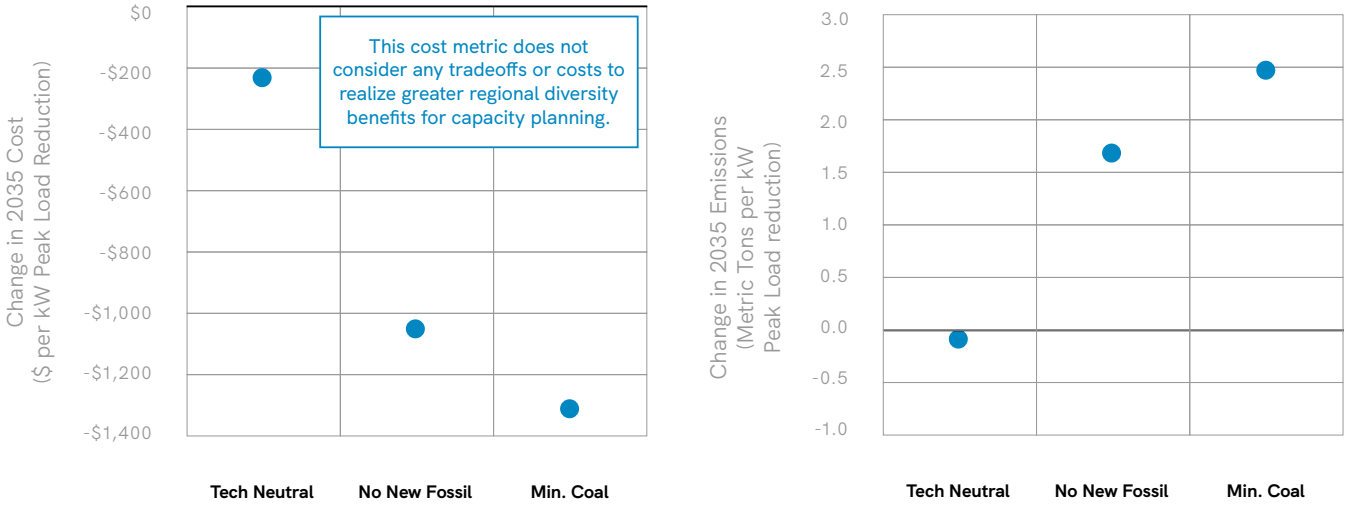


FIGURE 6.56: CHANGE IN 2035 TOTAL SYSTEM COST AND EMISSIONS, NORMALIZED BY KW PEAK LOAD REDUCTION



Overall, increased regional market participation largely helps mitigate the need for firm capacity resources (gas and/or batteries) due to increased resource and load diversity. Cost savings are highest in cases with limited firm capacity resource options (No New Fossil and Minimum Coal) due to the higher cost of meeting the PRM in those cases (relative to Technology Neutral), although emissions increase in those cases due to greater reliance on emitting generation resources to meet energy demand.

Summary of ISP Key Findings

The key findings from the analysis described above are summarized here for reference. These key findings served as the foundation to inform the ISP System Strategies described in Section 8.

Customer Programs and Pricing Plans

- SRP will need to evolve programs and price plans to encourage shifts in consumer behavior and further educate customers on when to consume and when to conserve energy.
- Electrification of end uses, including transportation and heating demand, creates new opportunities to shift energy usage to mid-day hours to help integrate more renewable energy and maximize carbon reduction impacts.
- Changes in how customers use energy will require continued innovation and flexibility in planning.

Infrastructure

- Customers' energy demand is expected to increase rapidly through 2035 in most scenarios, even with significant expansion of customer programs and customer-sited generation.
- Significant investments in new transmission infrastructure are needed over the next decade to connect new resources and customers while also achieving reliability and sustainability goals. These investments will need to be strategically located and timed.

- Load growth will drive new distribution infrastructure needs while changes in how our customers use energy will require innovation and flexibility.
- SRP will likely need to double or triple resource capacity in the next decade to serve customers while achieving reliability and sustainability goals. This will be at an unprecedented pace.
- New renewables and firm capacity are part of a least-cost portfolio, even under a wide range of gas price and technology cost sensitivities.
- When paired with firm capacity, solar and wind contribute to a least-cost portfolio while helping SRP reduce carbon emissions and water usage. If the U.S. government enacted a mandate for 85% CO_2 reductions by 2035 (Strong Climate Policy), further acceleration of renewable and storage deployment would be required.
- Hundreds of miles of new or upgraded transmission lines and nearly double the number of 500/230 kV transformers could be needed relative to today.
- Location of generation matters and plays a significant role in the buildout of the 500 kV and 230 kV transmission system.

Operations

- Without new firm generation capacity, the system cannot satisfy reliability requirements under a high load growth scenario. In other load growth scenarios, the system can satisfy reliability requirements without new firm generation capacity but requires significant additions of renewable and energy storage resources.
- The reduction in coal generation and expansion of carbon-free resources over time allow SRP to meet, and in many cases exceed, SRP's 2035 goals for carbon emission reductions and water resiliency.
- A future system that relies more on variable renewable resources presents new challenges and will require new operating practices to ensure sufficient flexibility, reduce wear and tear on existing assets, and maximize benefits to customers.

Partnerships to Meet the Pace of Transformation

- With the amount of future infrastructure and resources needed, internal and external partnerships are going to be essential to build the future system and maintain high customer value.
- To meet the pace of infrastructure needs, supply chain and development solutions are essential to managing costs and to meet the pace of transformation needed.

SECTION 7

System Strategies

System Strategies

SRP faces an uncertain future that will continue to change at a rapid pace. In this dynamic and evolving environment, we must establish diverse strategies that can stand up to these changes while allowing for flexibility and adaptation. Utilizing our analysis and key findings, we have established seven System Strategies that will allow us to deliver the best value to our customers under future uncertainty and a wide range of potential outcomes.

The **System Strategies** are the Board-approved long-term strategies for planning and operating the power system in an integrated manner. These are strategies for all power system areas, including customer programs, distribution planning, resource planning, transmission planning, pricing and system operations. The strategies will guide us today through 2035, and they consider system developments needed beyond 2035 to meet SRP's 2050 goals. As a whole, these strategies will help to:

- Guide how we plan the system for the future and serve as the focal point for prioritizing our investments.
- Provide direction while maintaining flexibility to allow us to respond to future conditions.
- Guide our decisions on day-to-day planning activities.
- Signal to stakeholders and customers how we plan to evolve the system and meet the changing needs of our customers.

The System Strategies are also the starting point for developing the ISP Balanced System Plan and the ISP Actions, which are covered in detail in sections 8 and 9.

SRP used key insights from the ISP analysis, as discussed in Section 6, to develop the System Strategies that will help us maintain reliability and affordability while driving increased sustainability across a wide range of potential future scenarios. We also gathered and incorporated feedback from the Advisory Group members on these strategies before bringing them to SRP's Board. On Oct. 2, 2023, the Board approved the System Strategies.



Below are the seven interdependent System Strategies. Each strategy is reliant on the other strategies also being in place to ensure success and achievability. These are the strategies we can begin to implement now. Some strategies may take longer to implement than others, but the execution of all strategies together will enable us to meet evolving customer needs, achieve our 2035 Sustainability Goals, manage costs for customers, achieve an adequate and reliable power system, and adapt to a more sustainable future regardless of what the future may be in 2035.

Below is a detailed description of the seven System Strategies and discussion of the key findings from the ISP analysis that support them.

Energy Investments



Invest in renewable resources and storage to manage fuel consumption and drive carbon and water reductions.

The ISP analysis demonstrated that new renewables combined with firm generation are part of a least-cost power generation portfolio. Across the different future scenarios, we saw the least-cost system plans add an average of 4,800 MW of renewables and storage.

Renewables do more than just contribute to a least-cost portfolio. They help reduce fossil fuel consumption and contribute to improved sustainability, helping SRP meet its 2035 carbon reduction and water use goals. Our customers also want more renewables. We found from the residential customer research that customers want us to provide the most sustainable energy portfolio possible without significantly increasing their costs or compromising reliability. This strategy focuses on investing in renewables and storage to deliver exceptional value to our customers and help drive carbon and water reductions.

Capacity Investments



Invest in firm generation, including natural gas, to support reliability and manage affordability while also supporting the advancement of emerging firm technologies.

The ISP analysis shows that firm generation, such as natural gas, is key to maintaining reliability. Firm generation includes resources that can dispatch on demand and generate over long periods of time (e.g., multiple days). Without new firm generation, reliability is compromised by 2028 under a high load growth scenario.

Firm generation resources, when added along with renewable and storage resources, are also key to maintaining affordability. On average, the least-cost system plan adds more than 2,000 MW of natural gas capacity by 2035, helping to offset losses in firm generation from coal plant retirements and the expiration of a natural gas tolling agreement. When new natural gas is not allowed to be added, total system costs are 17%–24% higher under the Current Trends scenario and 7%–11% higher under the Desert Contraction scenario. The addition of firm generation allows SRP to mitigate these cost impacts and maintain affordability.

While adding new firm generation is key to maintaining reliability and affordability, it does not mean that these resources will have high utilization. The Energy Investments system strategy envisions adding renewable and storage resources to reduce fuel consumption from fossil fuel-fired resources, which is reflected in the ISP analysis. As a result, new and existing natural gas generation resources are projected to operate less over time, with the anticipated systemwide capacity factor declining to roughly 25% by 2035.

This strategy recognizes the need for the advancement of other emerging firm technologies (such as hydrogen, new nuclear and long-duration storage) and the role that emerging technologies can play in helping meet a portion of firm resource needs in the future. We expect the new investments in natural gas generation to be hydrogen-ready to allow SRP to transition those resources to hydrogen if and when hydrogen becomes a commercially viable fuel option.

Proactive Transmission

Proactively plan to expand transmission infrastructure to enable generator interconnections and load growth.



The ISP analysis showed that a significant investment in transmission is needed over the next decade, driven by the large amount of generation required to meet our growing loads. By 2035, SRP could need hundreds of miles of new or upgraded transmission lines and nearly double the number of 500/230 kV transformers relative to today. The location of this new generation capacity matters and has a significant impact on the buildout of the 500 kV transmission system. We must strategically locate and build out new grid infrastructure to connect new resources and customers. It is in our best interest to strategically find the best location for new-generation resources and transmission. Siting and permitting transmission can be a decade-long process, necessitating a proactive approach in transmission planning.

Distribution Innovation

Ensure distribution grid readiness to maintain reliability and enable customer innovations to drive carbon reductions.



The distribution innovation strategy is focused on ensuring we are prepared for anticipated growth while maintaining reliability and enabling customer innovation. Load growth will drive additional infrastructure needs, while changes in how our customers use energy will require innovation and flexibility. This strategy allows us to understand and adapt to the complexities of balancing energy load growth with innovation that may reduce customer demand, such as managed EV charging, expanded deployment of distributed solar, and next-generation demand response programs.

This strategy helps enable us to provide a dependable supply of electricity to all SRP customers and provide a reliable grid that can prepare for and recover from unanticipated disruptions to ensure energy availability, while at the same time helping us meet evolving customer needs.

Partnerships & Suppliers

Explore partnerships and supply chain and development solutions that manage cost and availability to meet the pace of transformation.



SRP anticipates the need to double or triple resource capacity in the next decade to be able to best serve our customers while achieving our 2035 Sustainability Goals. This is an unprecedented pace of resource development, with potential additional needs for hundreds of miles of new transmission lines and numerous transformers on the transmission and distribution system. It will also require making decisions on specific investments, procurements, workforce development, information technology systems, etc. With the amount of future infrastructure and resources needed and long lead times for certain assets, external partnerships will be essential to build the future system and maintain high customer value.

Customers and community partnerships will also be critical to achieving the transformation of the power system. To enable construction of the large amount of infrastructure SRP is planning, we must proactively build relationships and partnerships with communities, cities, counties, towns, government agencies and tribes, and engage with advocacy organizations to understand their perspectives. We can then better identify, prepare and preserve options for feasible sites for future system infrastructure. Through these partnerships, SRP can respond to evolving customer needs by providing safe, reliable, affordable and sustainable power while recognizing the different needs, challenges and perspectives of our customers.

In addition to partnering with customers and communities, supply chain disruptions and delays that are still being felt following the pandemic necessitate the need to find supply chain and development solutions. Future supply chain disruptions could further impact our ability to develop new infrastructure. This strategy helps enable supply chain solutions essential to managing costs for our customers and to meeting the pace of transformation needed which could include ordering key supplies as early as possible and developing a wider pool of potential suppliers to diversify supply chain risks.

Evolution of Customer Programs & Pricing

Evolve pricing and customer programs to improve economywide carbon reductions and pace infrastructure development, while recognizing customers' diverse needs.



SRP will need to evolve programs and price plans to deliver the best value to our customers. We saw in our Time-of-Use Exploratory Study, existing customer programs and price plans are effective at managing peak energy demand today, but as our energy mix changes, so must our customer programs and price plans. Adding significant amounts of solar energy will mean abundant, low-cost energy is often available during daytime hours. The more expensive peak period will then shift later into the evening once the sun sets.

This also creates new opportunities to shift energy from increased electrification programs to mid-day hours to help integrate more renewable energy and maximize carbon reduction impacts.

During our transition to a more sustainable future, the timing and availability of low-cost resources will change with the increased adoption of renewable resources. We strive to strike the right balance of reliable, affordable and sustainable power for our customers. Currently, we have targets for Energy Efficiency and Demand Response adoption in our 2035 goals. We will continue studying options to accelerate and adapt to meet changing patterns in our customers' electricity use and help address significant load growth and capacity constraints over the next several years.

This strategy allows us to adapt to the needs of a changing grid and gives us an opportunity to recognize the different needs, challenges and perspectives of our customers and reflect that through new customer offerings that will help us maintain industry-leading customer satisfaction.

Strategic Investment & Reinforcement of Existing Assets



Reinforce and maximize value of existing infrastructure with strategic investments to manage affordability and ensure future performance, grid security and resilience.

SRP's existing assets and generation are the foundation for our future. Our existing and contracted generating assets will make up 50% of our capacity, 70% of our reliability needs and 45% of our carbon-free energy in 2035. Additionally, our existing transmission lines will make up an estimated 90% of the total number of 230-plus kV line miles in 2035, and our distribution substation bays will make up 85% of the substation bays we need in 2035. The existing system is important, and we must strategically reinvest in the system we have today by continuing to perform routine maintenance to extend the life of our assets. Existing resources are needed to meet future customer needs and maintain a reliable grid that can prepare for and recover from both anticipated and unanticipated disruptions to ensure energy availability. This will ensure continued grid security, safety and performance.

We must also explore repurposing existing or retired coal plants with other emerging technologies and making more strategic generation investments to connect and use existing transmission whenever possible.

This strategy allows us to deliver exceptional system and energy value by minimizing the need for additional grid resource investments, which helps keep costs lower for our customers.



The System Strategies discussed in this section will guide SRP's planning activities and investment decisions in a way that balances all important considerations in developing a reliable, affordable and sustainable power system. Through robust analysis in the ISP, SRP developed a detailed understanding of the inherent trade-offs between reliability, affordability and sustainability and sought to establish an Integrated System Plan that fully balances all considerations.

It is important to reiterate that none of the System Strategies above can stand on their own. These strategies are intertwined and need to be executed simultaneously to best serve our customers and ensure that we will continue to provide reliable, affordable and sustainable power regardless of what the future brings.

SECTION 8

Balanced System Plan

Balanced System Plan

The ISP Balanced System Plan is an illustration of what SRP's power system may look like in 2035 by implementing the seven System Strategies. We constructed the **Balanced System Plan** to help customers and stakeholders visualize the future power system based on what is known today. However, as discussed in previous sections, the entire utility industry faces a lot of change and uncertainty. As a result, we will inevitably need to adapt and evolve this plan as new information (e.g., updated economic development forecasts and technology cost projections) becomes available and as circumstances change, such as new laws or regulations being enacted.

Developing the Balanced System Plan

The ISP System Strategies detailed in Section 7 are the foundation for the Balanced System Plan. To identify how the system could evolve in a manner consistent with the System Strategies, SRP leveraged the results and key findings from the ISP analysis.

Of the strategic approaches analyzed, it was clear that no individual strategic approach performed best across all metrics. For example, the Technology Neutral strategic approach resulted in the lowest system cost and lowest residential customer bill impacts, whereas the Minimum Coal strategic approach performed best across multiple sustainability metrics. Separately, results from the ISP residential customer research found that customers want it all. They want SRP to advance sustainability performance while maintaining high levels of reliability and limiting cost increases.

In building out the Balanced System Plan, we considered the results of the various analyses, findings from the different strategic approaches and feedback from our customers to strike a balance between sustainability, affordability and various power system reliability risks.

Specific considerations used in developing the Balanced System Plan included the following goals:

- **Reliability:** Maintain firm generation capacity and expand grid needs while preparing for emerging grid technologies.
- **Affordability:** Utilize an all-of-the-above approach to diversify and moderate the pace of investments.
- **Sustainability:** Significantly expand investments in renewable energy and storage to drive carbon reductions and reduce water consumption.
- **Customer Focus:** Focus on managing costs and advancing sustainability and customer programs without sacrificing reliability.



FIGURE 8.1: GOALS OF THE BALANCED SYSTEM PLAN



Reliability

Maintain firm generation capacity and expand grid needs, while preparing for emerging grid technologies

Affordability

Utilize an all-of the-above approach to diversify and moderate pace of investments

Sustainability

Significantly expand renewable and storage development to drive emissions reductions and reduce water consumption from power generation

Customer Focus

Focus on managing costs, advancing sustainability and customer programs without sacrificing reliability

Resources and Customer Programs

The Balanced System Plan envisions significant resource additions between 2025 and 2035. By implementing the Energy Investment System Strategy, SRP could triple the total installed capacity of renewable and storage resources by 2035. Solar, being a low-cost renewable resource that helps displace fossil fuel generation, makes up the majority of the renewable energy additions in the Balanced System Plan, with 6,000 MW added. Other renewable additions include 800 MW of wind located in eastern Arizona to leverage existing transmission that becomes available when Coronado Generating Station retires in 2032, as well as 50 MW of geothermal and 50 MW of biomass to help provide resource diversity. The Balanced System Plan also includes 2,500 MW of additional energy storage, split between four-hour lithium-ion batteries and pumped hydro storage.

By implementing the Capacity Investment System Strategy, SRP would maintain similar levels of thermal generation as today to provide firm capacity. This includes investing in 2,000 MW of new natural gas generation to replace 1,300 MW of retiring coal generation and a 975 MW gas tolling agreement that expires in 2031. We did not include advanced nuclear or hydrogen in the Balanced System Plan due to development risks with those technologies becoming commercially available by 2035.

In addition to the utility-scale resource additions, the Balanced System Plan includes customer programs and customer-sited resources, which will help displace the need for utility-scale resources. Specifically, the Balanced System Plan envisions 700 MW of combined capacity from energy efficiency and demand response (labeled Customer Programs in figures 8.2 and 8.3) as well as 750 MW of customer-sited solar, demonstrating SRP's implementation of the Evolution of Customer Programs & Pricing System Strategy. While the Balanced System Plan does not reflect changes to customer pricing over time, SRP's evolution of price plans can help further mitigate resource additions by providing price signals to customers to moderate their demand during periods of lower supply.

FIGURE 8.2: BALANCED SYSTEM PLAN NAMEPLATE CAPACITY 2025-2035

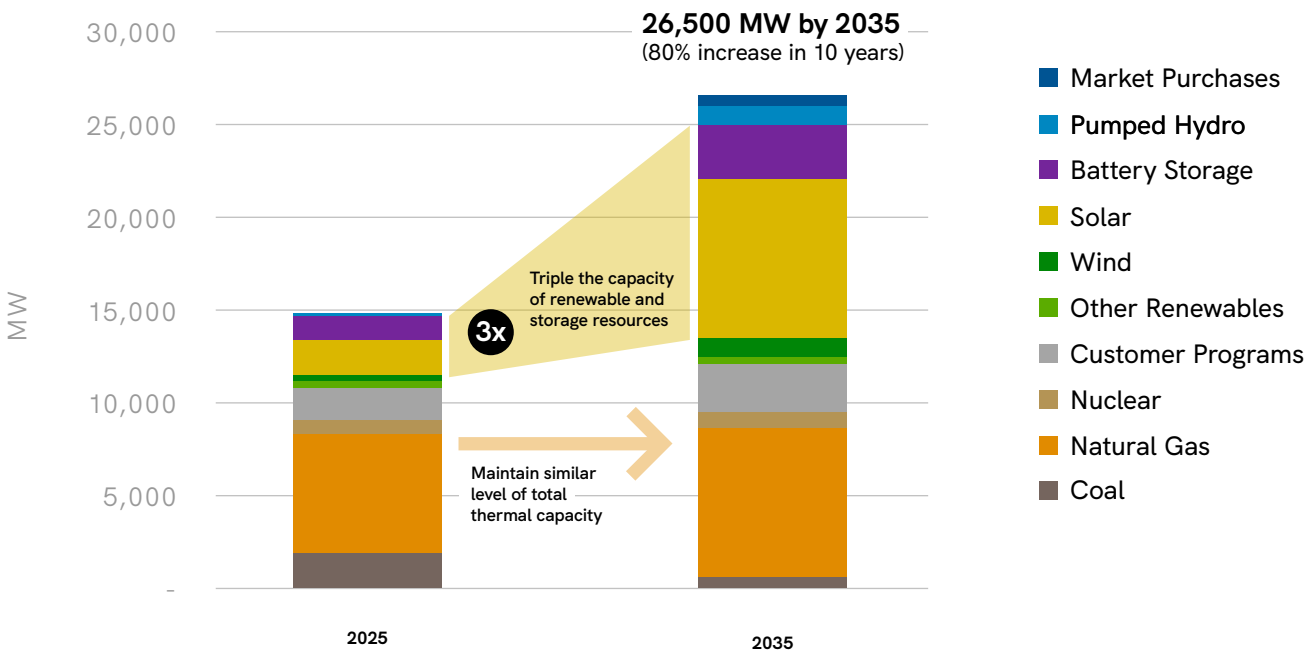


FIGURE 8.3: BALANCED SYSTEM PLAN NAMEPLATE CAPACITY ADDITIONS BY 2035 (MW)

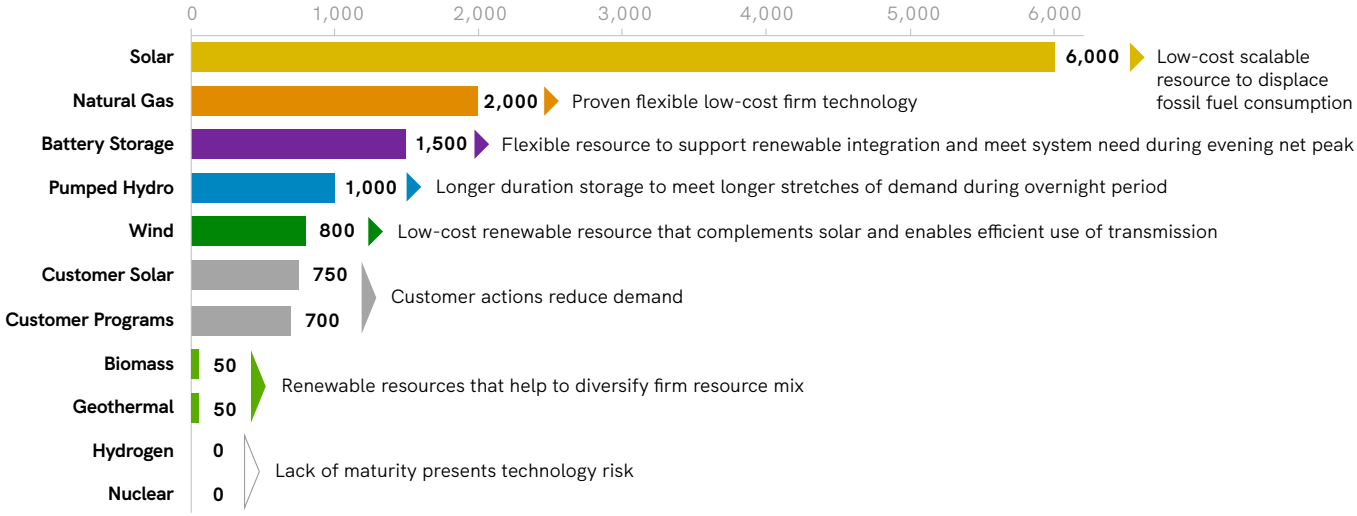
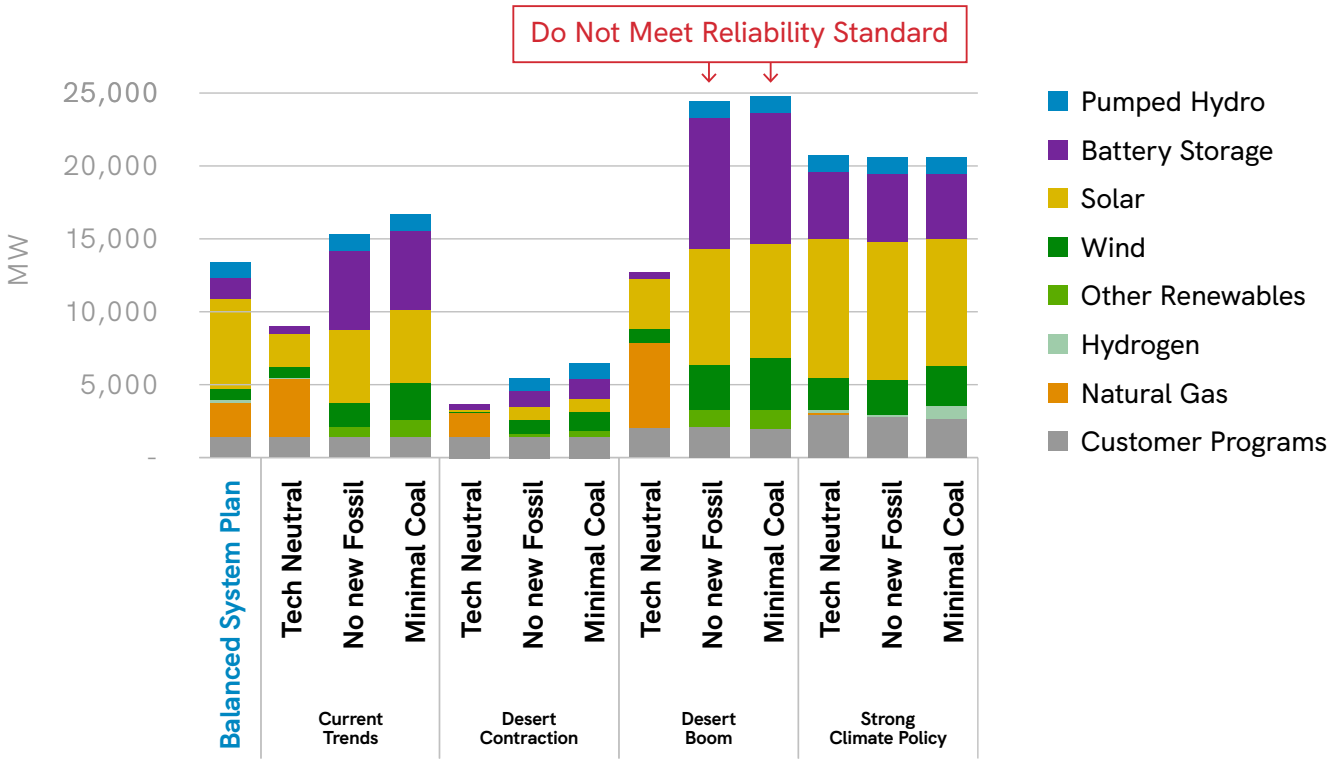


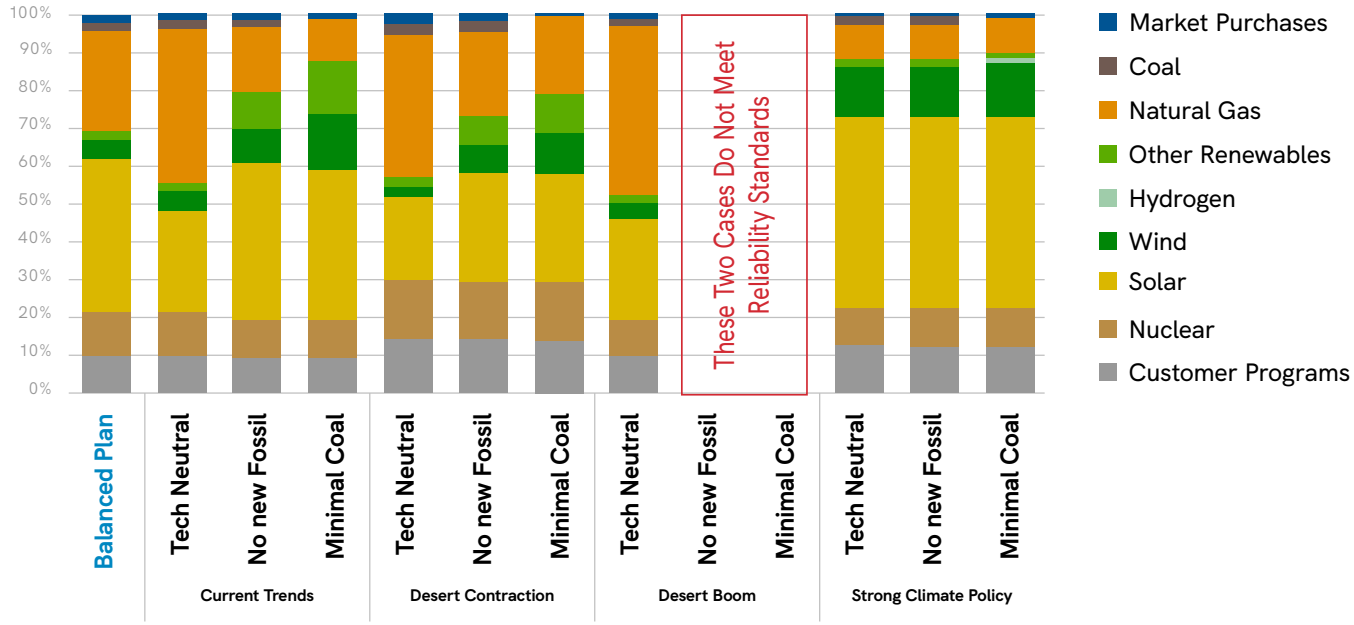
Figure 8.4 shows the nameplate capacity additions for the Balanced System Plan alongside those for the ISP cases for comparison. While we considered the full range of scenario analysis when constructing the Balanced System Plan, we used the Current Trends scenario assumptions to illustrate specific infrastructure requirements. In comparison to the other system plans under the Current Trends scenario, the Balanced System Plan includes approximately 6,000 MW of additional carbon-free resources and over 1,000 MW less gas than the Technology Neutral strategic approach (i.e., least-cost system). Natural gas is still included in the Balanced System Plan to help mitigate costs, unlike the No New Fossil and Minimum Coal strategic approaches, which were found to be considerably more expensive with natural gas not being included in the strategic approach assumptions. The Balanced System Plan thus results in less carbon-free resource additions compared to the No New Fossil and Minimum Coal cases in the Current Trends scenario.

FIGURE 8.4: NAMEPLATE CAPACITY ADDITIONS BY 2035



On an energy basis, for the Balanced System Plan, 70% of SRP's customer energy needs would come from carbon-free sources, which is in the middle of the range when compared to the other Current Trends scenario system plans, as shown in Figure 8.5.

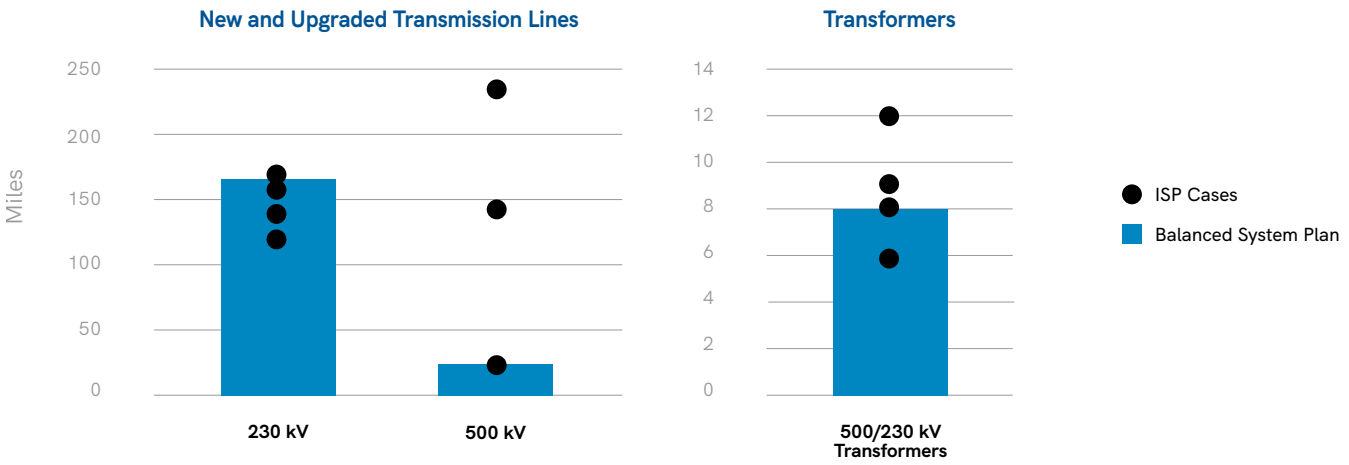
FIGURE 8.5: ENERGY MIX IN 2035



Transmission

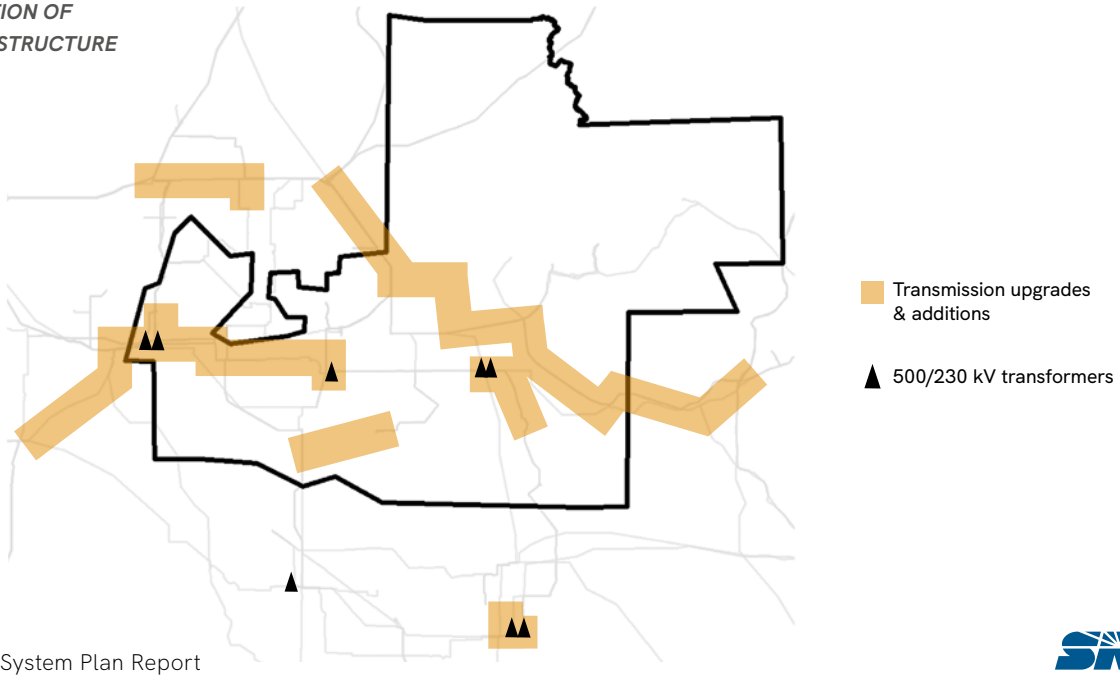
To connect the significant amount of new generation resources included in the Balanced System Plan to our customers, additional high-voltage transmission infrastructure would be needed at both the 500 kV and 230 kV levels. The additional transmission needs for the Balanced System Plan compared to the scenario-based system plans analyzed are shown in Figure 8.6. As detailed in Section 5, we evaluated two different location sensitivities for where the generation resources would be located (Pro-Rata and Hub). For the Balanced System Plan, we utilized a hybrid approach where resources were distributed across the transmission system, but certain areas that required significant upgrades were avoided. This resulted in 165 miles of new or upgraded 230 kV lines, 25 miles of new or upgraded 500 kV lines, and eight new 500/230 kV transformers by 2035. The long lead times for siting, permitting and procuring this transmission infrastructure emphasize the need to implement the Proactive Transmission System Strategy.

FIGURE 8.6: TRANSMISSION SYSTEM ADDITIONS BY 2035



An illustration of where this new transmission infrastructure could be located, overlaid with SRP's electric service area, is included in Figure 8.7.

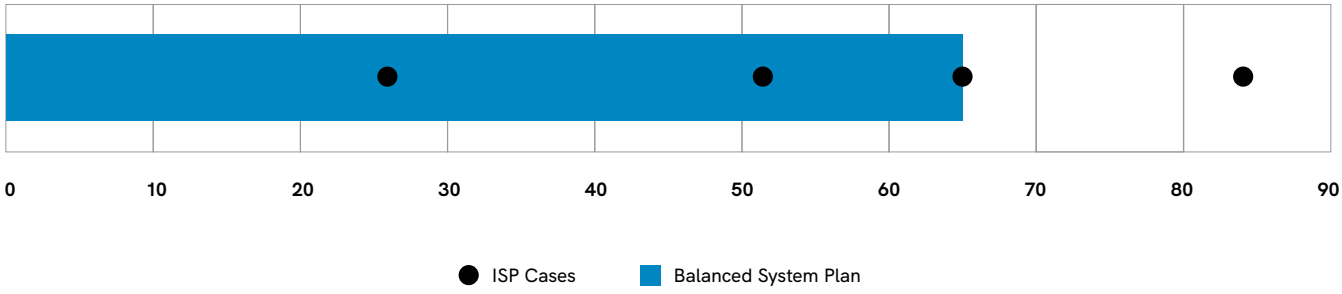
FIGURE 8.7: ILLUSTRATION OF TRANSMISSION INFRASTRUCTURE ADDITIONS



Distribution

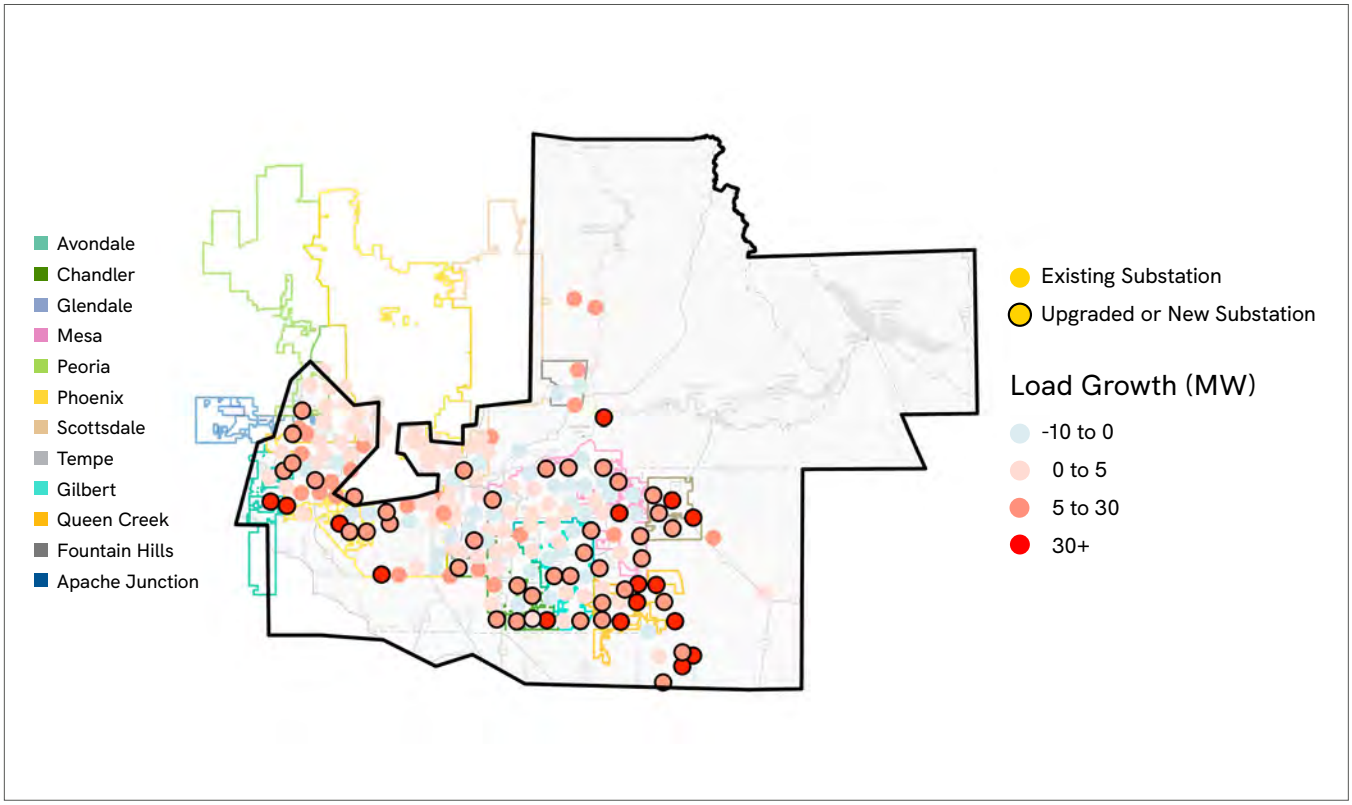
By implementing the Distribution Innovation System Strategy, SRP will need to add a number of additional distribution substation bays to ensure reliability. For the Balanced System Plan, this includes 65 additional substation bays to meet growing customer energy needs.

FIGURE 8.8: DISTRIBUTION SUBSTATION BAY ADDITIONS



We anticipated most of this substation bay addition will be located in the southeastern and western portion of the SRP electric service territory where there is the most potential for growth, as shown in Figure 8.9 below. However, additional substation bays will also be needed in central parts of SRP's electric service territory due to urbanization and growth in electric vehicles.

FIGURE 8.9: ILLUSTRATION OF DISTRIBUTION INFRASTRUCTURE ADDITIONS



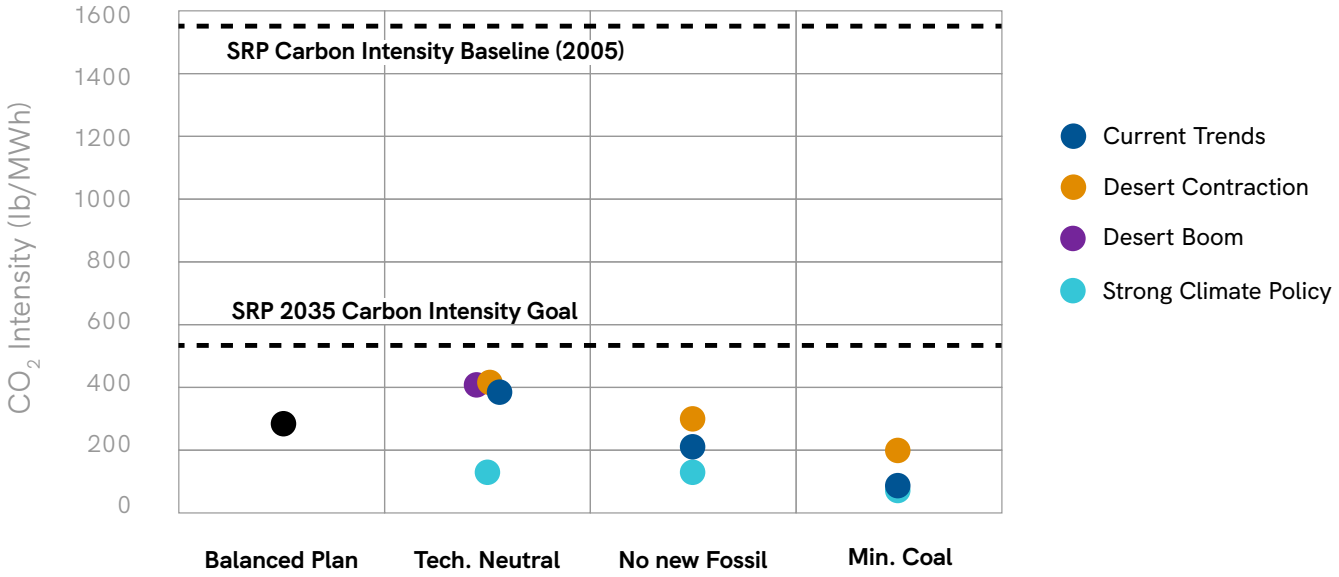
Balanced System Plan Performance

When developing the Balanced System Plan, we evaluated the plan's performance by quantifying the same metrics used to analyze each of the ISP cases. As noted earlier, we used findings from the ISP analysis and residential customer research to develop a system plan that advanced sustainability performance while avoiding significant cost increases to SRP and its customers. The following subsections discuss key metrics for the Balanced System Plan and show how it achieves this objective.

CO_2 Reductions

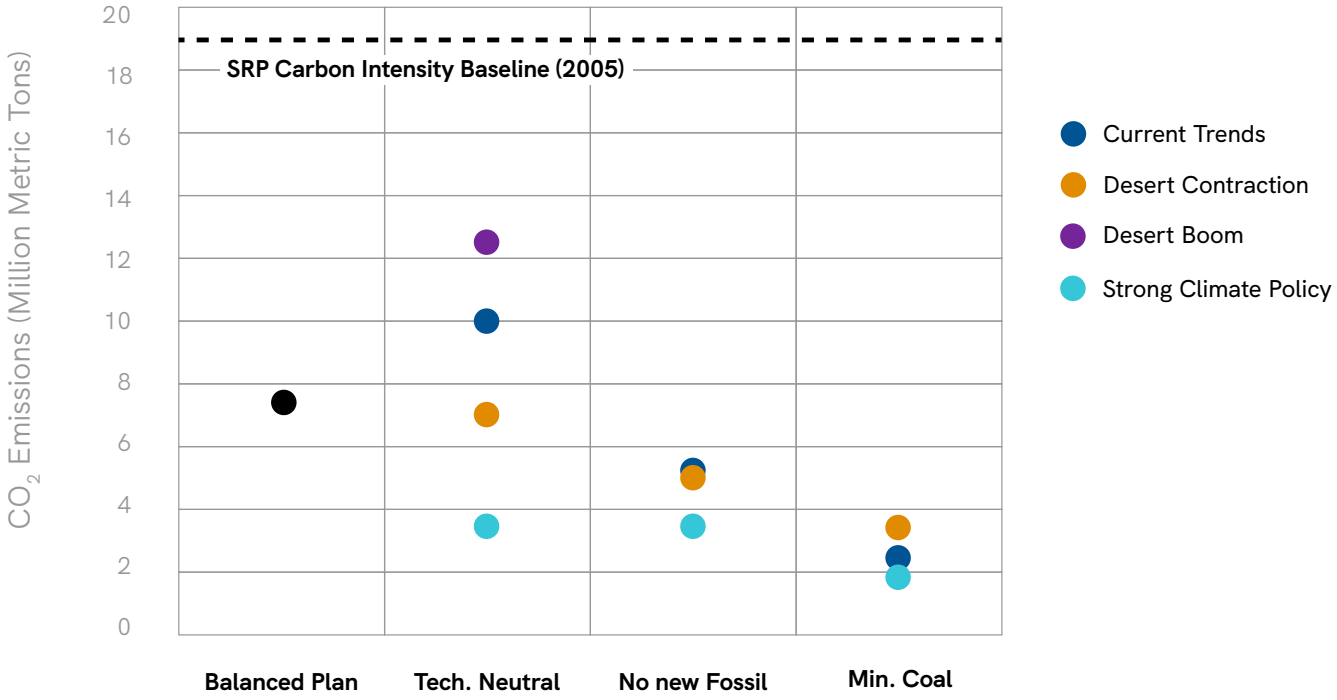
The CO_2 intensity and mass emissions for the Balanced System Plan in 2035 are included in figures 8.10 and 8.11, respectively, and are shown alongside the core system plans for comparison. The Balanced System Plan exceeds SRP's 2035 goal by achieving a CO_2 intensity rate of 284 lbs./MWh, an 82% reduction from SRP's 2005 baseline. Compared to the system plans developed for the Current Trends scenario (the scenario used for the Balanced System Plan), the Balanced System Plan carbon intensity is 28% lower than that of the Technology Neutral strategic approach at 396 lbs./MWh but is not as low as that of the No New Fossil and Minimum Coal strategic approaches at 202 lbs./MWh and 94 lbs./MWh, respectively.

FIGURE 8.10: BALANCED SYSTEM PLAN CO_2 INTENSITY IN 2035



Similarly, for CO_2 mass emissions, the Balanced System Plan performs in the middle of the range when compared to the core system plans, with a CO_2 emission rate of 7.39 million metric tons in 2035. This is a 61% reduction from SRP's 2005 baseline. Compared to the system plans developed for the Current Trends cases, the Balanced System Plan achieves 25% lower carbon emissions than the Technology Neutral strategic approach (9.83 million metric tons) but not as low as the No New Fossil and Minimum Coal strategic approaches (5.11 million metric tons and 2.40 million metric tons, respectively), as shown in Figure 8.11 on the next page.

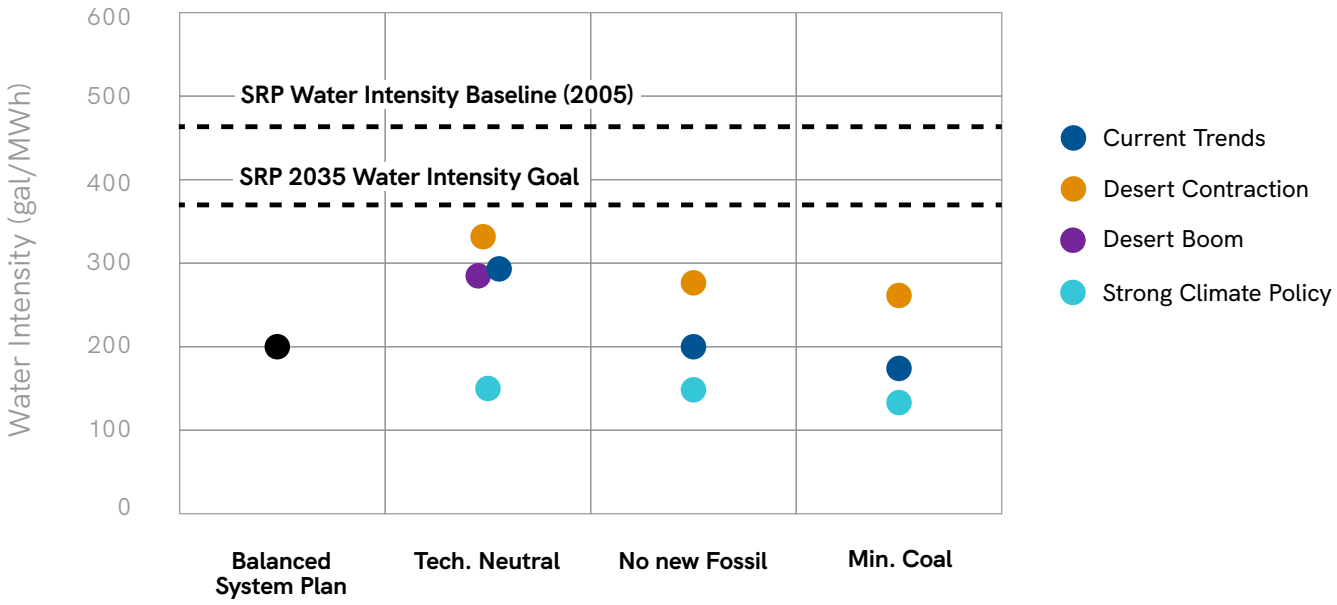
FIGURE 8.11: BALANCED SYSTEM PLAN CO_2 EMISSIONS IN 2035



Water Use

As shown in Figure 8.12, the Balanced System Plan also achieves a significant reduction in water consumption by 2035 with a water consumption rate of 204 gal/MWh (56% reduction from SRP's 2005 baseline levels), exceeding SRP's 2035 Sustainability Goal (20% reduction from 2005 baseline) and falling toward the lower end of the range of the core system plans analyzed in the ISP. Compared to the Current Trends cases, the Balanced System Plan achieves a 30% lower water consumption rate than the Technology Neutral strategic approach (293 gal/MWh), but not as low as the No New Fossil and Minimum Coal strategic approaches (199 gal/MWh and 171 gal/MWh, respectively).

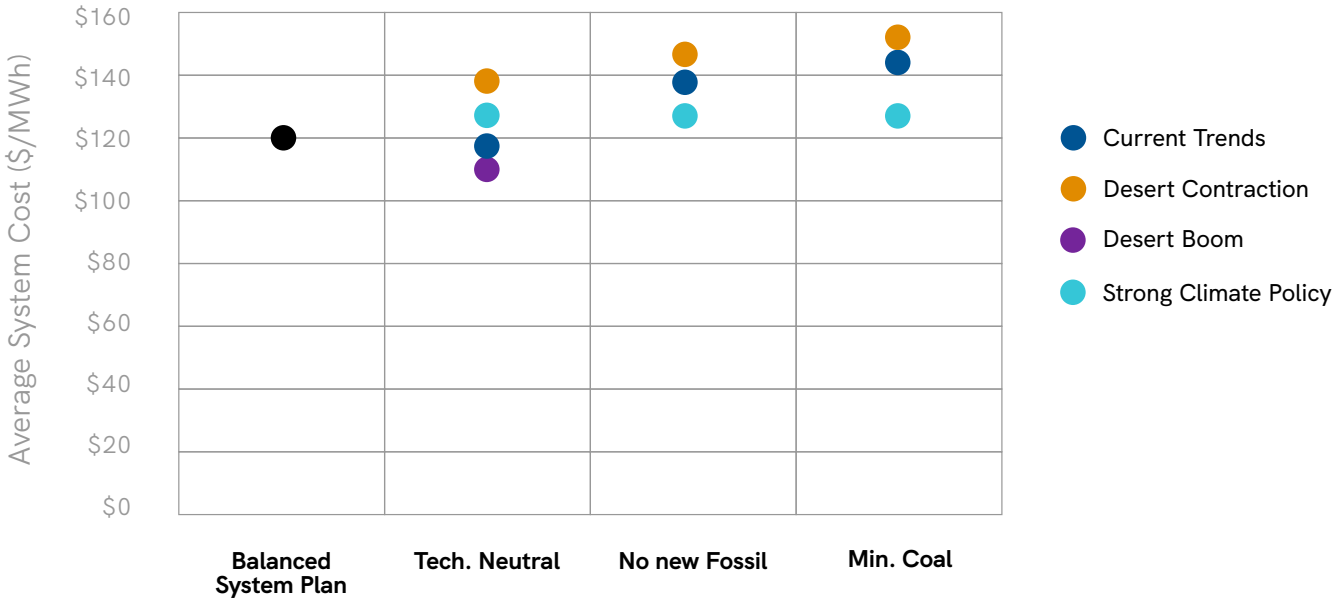
FIGURE 8.12: BALANCED SYSTEM PLAN WATER CONSUMPTION



Average System Cost

The average system cost for the Balanced System Plan, with comparisons to the core system plans from the ISP analysis, is shown in Figure 8.13. The Balanced System Plan results in an average system cost of $121/MWh, which is near the lower end of the range of costs observed from the ISP analysis. Compared to the Current Trends cases, the Balanced System Plan is only 4% higher than the Technology Neutral strategic approach ($116/MWh), despite adding more than double the amount of carbon-free resources and having a 28% lower carbon intensity. Meanwhile, the addition of 2,000 MW of firm natural gas in the Balanced System Plan allows the average system cost to be considerably lower than the No New Fossil and Minimum Coal strategic approaches ($136/MWh and $144/MWh, respectively).

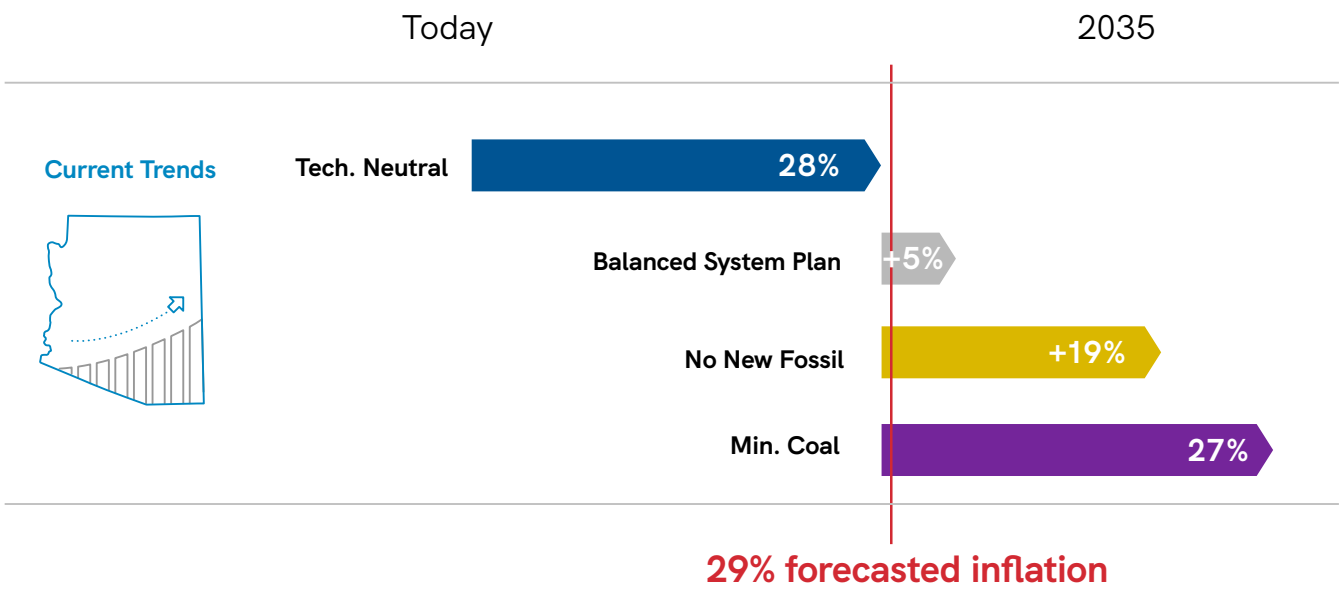
FIGURE 8.13: AVERAGE SYSTEM COSTS IN 2035 ($/MWH)



Residential Bill Impact

There are many factors that will impact costs in the future such as customer growth, inflation, the Inflation Reduction Act (IRA) funding and technology costs. Figure 8.14 shows the residential bill impacts for the Balanced System Plan compared to the other strategic approaches under the Current Trends scenario. This is a simplified look of what a base rate increase could look like in 2035, and we selected the Current Trends scenario because it reflects a central case for how the future might unfold. As shown in Section 6, the least-cost strategic approach, Technology Neutral, results in a price increase of 28% by 2035, just below inflation (estimated at 29% over the same time period). The Balanced System Plan results in a 5% increase in cost over the Technology Neutral strategic approach but is well below the residential price increases for the No New Fossil and Minimum Coal strategic approaches.

FIGURE 8.14: RESIDENTIAL PRICE INCREASE BY 2035



29% forecasted inflation

These are representative results based on ISP analysis modeling, not projections of SRP's future prices, and are not inclusive of factors beyond the scope of ISP analysis.

SECTION 9

ISP Actions

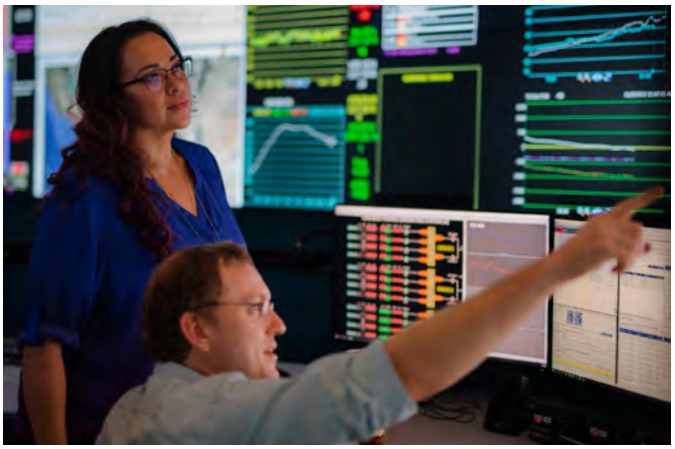
ISP Actions

SRP's planning processes do not stop with the ISP. In many ways, the conclusion of this ISP represents new beginnings as our planning groups begin to execute the System Strategies. To further progress toward implementing the System Strategies, we have defined 10 ISP Actions that we will take over the next few years.

We developed the ISP Actions based on the ISP key findings, the System Strategies and the Balanced System Plan. They include actions for all aspects of system planning, including pricing, customer programs, customer resources, utility-scale resources, distribution and transmission. Just as the seven System Strategies are integrated and interdependent, so are the ISP Actions. Each action furthers multiple System Strategies and requires collaboration across our planning groups. In this section, we will describe each of the 10 **ISP Actions** and show how each one furthers specific System Strategies.

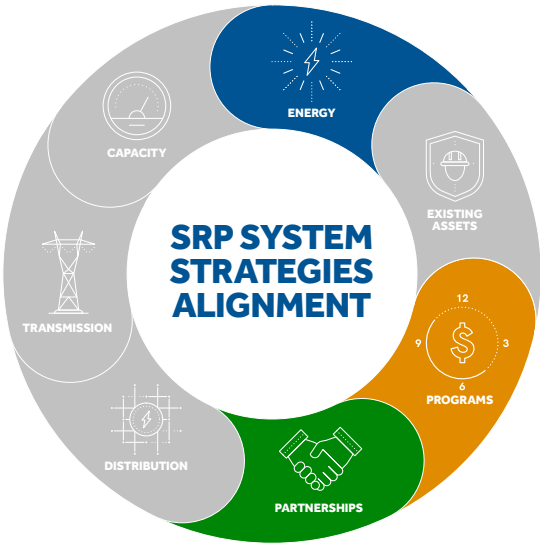
We are committed to pursuing diverse actions, establishing a roadmap for implementing the System Strategies and making progress toward our 2035 Sustainability Goals with the development of the ISP Actions.



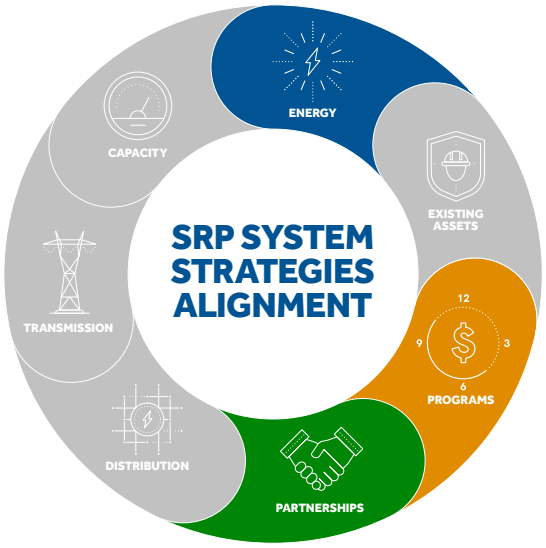


ISP Action #1: Residential Time-of-Use Pilot

We will execute a residential time-of-use price plan pilot and perform customer research to evaluate customers' responses to new time-of-use peak periods and a super off-peak period in the middle of the day, which will inform our load forecast for long-term system planning and our pricing process.



ISP Action #2: Time-of-Use Evolution



We will engage commercial, small business, large industrial, and residential customers and stakeholders to inform them of how the evolving grid will impact time-of-use periods and develop a roadmap for implementing new time-of-use periods.

To accomplish Action #2, we will:

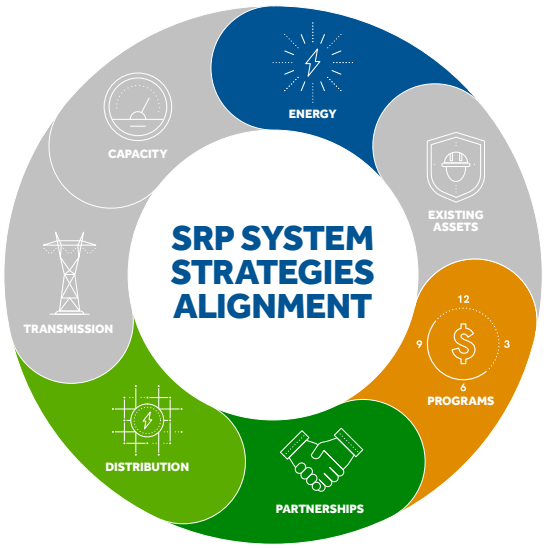
- Undertake a pricing process informed by the ISP to determine how time-of-use plans should evolve.
- Propose new time-of-use hours, including a super off-peak period when the cost to serve customers' needs is lowest and on-peak hours updated for the modern grid.
- Develop communication plans for all customer types and segments to educate about any new time-of-use price plans focusing on promoting affordability and potential sustainability benefits.

ISP Action #3: Customer Programs

We will continuously refresh program plans and take steps to drive participation in customer programs at levels consistent with those planned for in the ISP, representing a meaningful increase from our initial 2035 Sustainability Goal for Energy Efficiency.

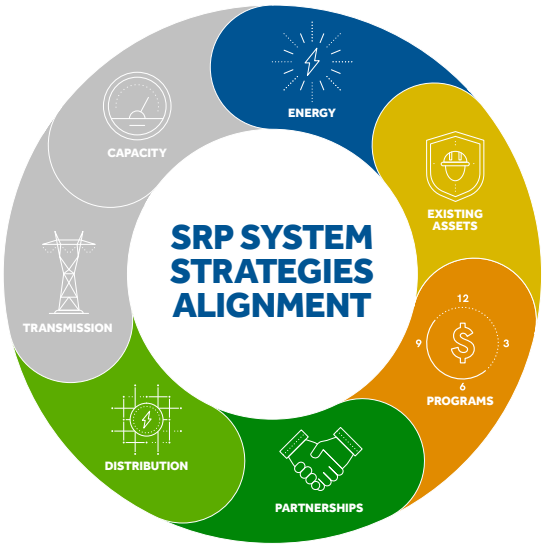
Steps will include:

- Evaluating the cost-effectiveness and emissions impacts of different customer program measures using the avoided costs and emissions impacts results from the ISP.
- Determining whether any changes to the customer programs portfolio are warranted based on this information, considering that these results must be weighed against other important factors such as customer access, equity, cost and satisfaction.



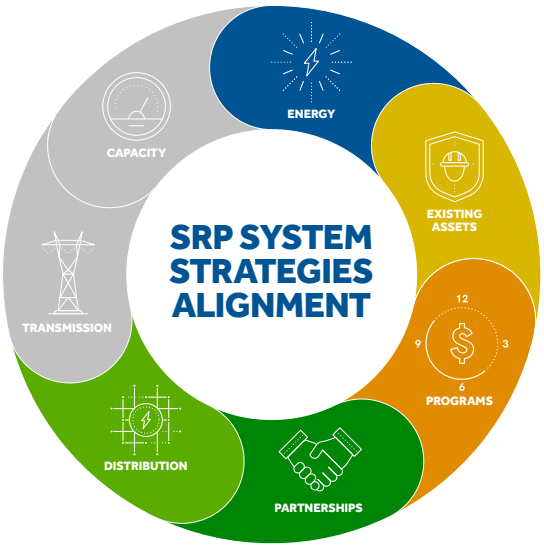
ISP Action #4: Electric Vehicle Management

We will develop an EV roadmap by evaluating customer needs and system impacts and assessing viable pathways for managing electric vehicle charging through price plans, customer programs and educational efforts to align with time periods that are lower-cost and minimize additional infrastructure needs.



ISP Action #5: Electrification

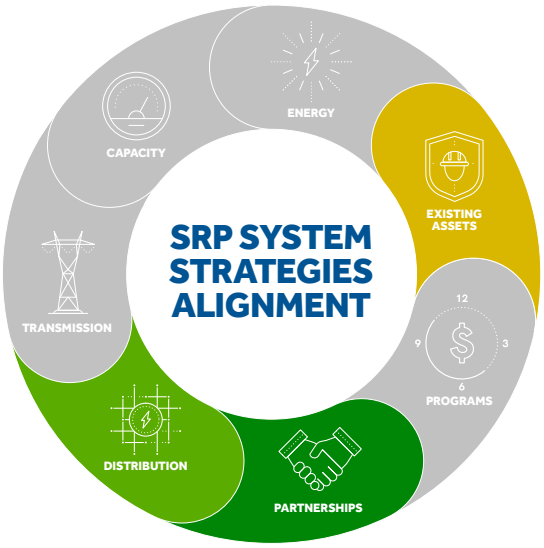
We will analyze the benefits and costs of non-EV electrification within SRP's service area, including effects on our operations and economywide emissions. Assess options for expanding E-Tech program offerings related to residential and commercial electrification.



ISP Action #6: Distribution Enablement Roadmap

We will continue implementing our Distribution Enablement (DE) Roadmap, which includes:

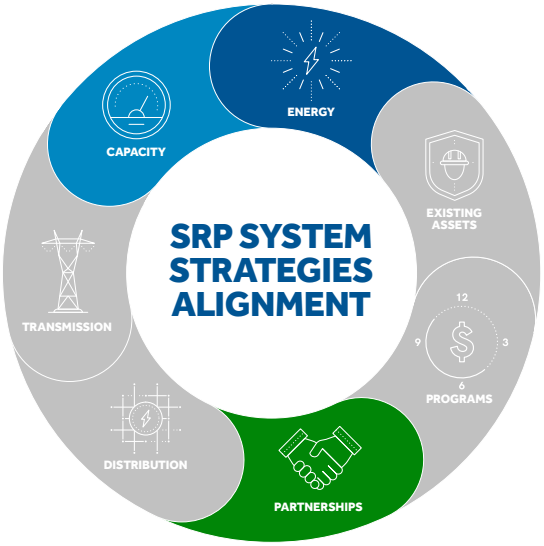
- Deploying the Advanced Distribution Management System (ADMS) and Distributed Energy Resources Management System (DERMS) in 2024. These systems are the foundational platforms needed to integrate distributed energy resources (DERs) with the existing distribution system. We will monitor signposts for the need to deploy more advanced capabilities to support the integration of customer-side resources.
- Implementing advanced planning tools, such as locational value maps and the ability to anticipate and plan solar, storage and electric vehicle adoption at specific customer locations.
- Advancing the interconnection process to enhance the customer experience and technical integration of customer-sited resource interconnections.



- Executing the DE Research and Development plan, which leverages R&D resources, including staff, lab facilities and standardized processes, to execute projects that will ensure readiness to onboard new distribution grid capabilities.
- Sharing the Distribution Enablement Roadmap with external stakeholders to build awareness and support for SRP's approach to transforming the distribution grid.

ISP Action #7: Resource Selection

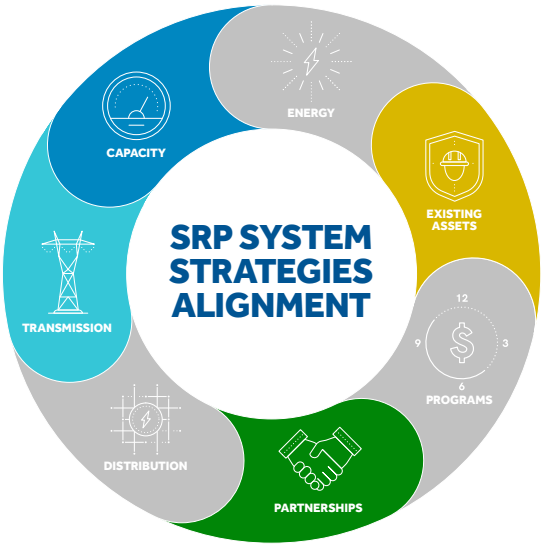
We will issue all-source requests for proposals (RFPs) or requests for information (RFIs) at least once every two years to compare with self-build options and ensure that we can agnostically select resource technologies that minimize total system costs while meeting our reliability and 2035 Sustainability Goals.



ISP Action #8: Coal Transition Action Plan

We will develop a coal repurposing action plan, which will include:

- Coordinating with co-owners to develop a path forward for the Springerville Generating Station, incorporating the need for replacement firm capacity to enable retirement and engagement with the community on a transition plan.
- Preparing plans for repurposing the Coronado Generating Station site, continuing development of system solutions that repurpose transmission following the retirement of coal plants.
- Developing solutions that preserve transmission access following the retirement of coal plants.
- Testing strategies for minimizing emissions from coal power plants, including dispatch strategies and seasonal operations, while leveraging their capacity to maintain reliability prior to retirement dates.

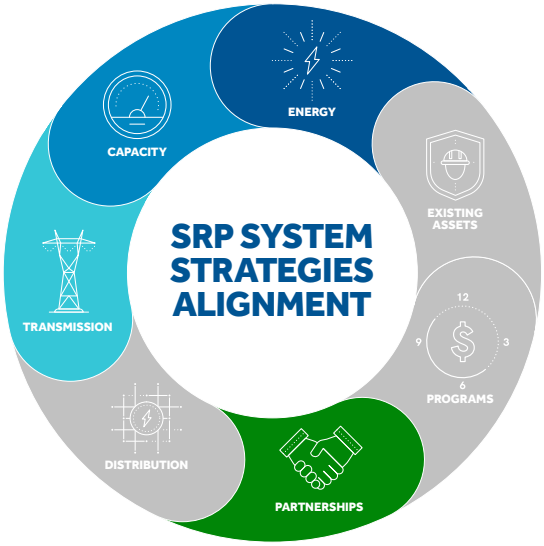


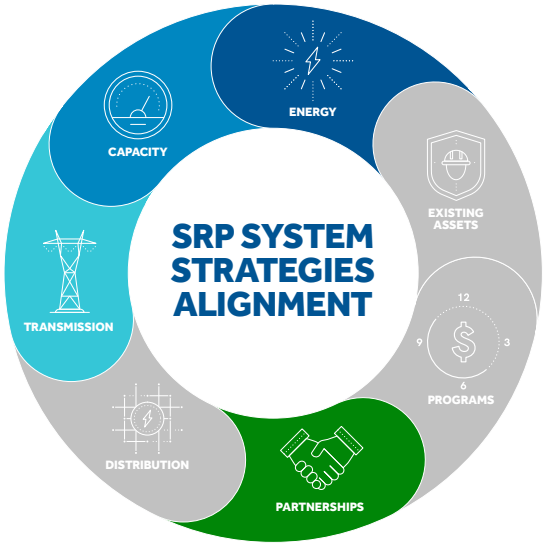
ISP Action #9: Proactive Siting

We will develop and initiate a collaborative community engagement, land, resources and transmission siting research process to proactively identify, prepare and preserve options for feasible sites for future system infrastructure.

ISP Action #10: Regional Transmission

We will pursue transmission projects to enable us to access diverse renewable resource options beyond solar, such as wind and geothermal, and engage with project developers as appropriate.





By implementing these 10 ISP Actions, we are confident that we can meet both the changing power needs of our growing customer base and evolving grid complexity. Many challenges lie ahead, but the actions related to customer programs, time-of-use price plans and EV management will help ensure our customers are provided with options to manage their energy costs while bolstering new clean energy technologies. Other ISP Actions related to phasing out coal resources, proactive siting and regional transmission flexibility will ensure SRP can provide sustained reliable power for the Valley while pursuing the best resource options for the future. These ISP Actions all work together to achieve a balance of reliability, affordability and sustainability for our future energy grid.

Future ISP Cycle and Next Steps

The first ISP was a significant advancement in our planning practices. For the first time, we performed integrated systemwide planning through 2035 and established a process for integrating planning activities across the organization. To continue to improve system planning practices and adapt plans to new information, we plan to complete an ISP on a regular cycle. We will continue to perform comprehensive systemwide modeling and engage SRP elected officials, customers and other stakeholders through a robust public process for future ISP cycles. While we have not yet established a schedule for the next ISP, we are targeting releasing an ISP every three to four years initially, recognizing that future ISP cycles may condense with technological and staff advancements.

SRP management and staff express appreciation for stakeholders and their participation in this first-ever Integrated System Plan process. Maintaining this open communication with customers and stakeholders will continue to produce a sound long-term strategic direction for future resources that balances system reliability, affordability and sustainability measures.

For more information and future updates on the progress of the ISP strategies and actions, refer to our website: srp.net/isp.

APPENDIX A

SRP's Integrated System Plan Assumptions Summary

SRP INTEGRATED SYSTEM PLAN STUDY PLAN APPENDIX – ASSUMPTIONS USED IN SCENARIOS, SENSITIVITIES AND STRATEGIC APPROACHES

This appendix details the assumptions underlying the key drivers outlined in the Integrated System Plan (ISP) Summary Study Plan document for the scenarios, sensitivities and strategic approaches that SRP will analyze. These assumptions were developed in collaboration with the ISP Advisory Group during the *Prepare* Phase of the ISP (November 2021–April 2022). SRP subsequently updated the assumptions in February 2023 to incorporate impacts from the Inflation Reduction Act of 2022. Additional details on these assumptions are included in the meeting materials from the *Advisory Modeling Subgroup Meeting 2: Inputs for the ISP Study Plan, Advisory Modeling Subgroup Meeting 3: Inputs for the ISP Study Plan – Part 2* and *Advisory Group Meeting 9: Continuing Forward*.[1]

Scenarios

Current Trends

Key Drivers	Assumptions
Economic Growth	Economic load grows 1,645 MW by 2035 and residential and commercial load grows by 1,776 MW by 2035, driven by an average population growth of 1.5% per year. The resulting total load growth is 2.9% per year.
Temperature Rise	"RCP[2] 4.5" climate scenario from the Intergovernmental Panel on Climate Change (IPCC)
Carbon Reduction Policy	No federal or state policy beyond SRP's 2035 Sustainability Goals (reduce the emissions intensity [CO2 per MWh] by 65% from 2005 levels by 2035)
Electrification	500,000 electric vehicles by 2035; 83% residential electric heating adoption by 2035
Distributed Generation	1,300 MW distributed solar by 2035
Energy Efficiency	3,800 GWh total energy efficiency by 2035
Renewable and Battery Storage Costs	Midpoint between low cost (Strong Climate Policy Scenario) and high costs (Desert Contraction Scenario) (see below)
Gas Resource Costs	Energy Information Administration 2022 Annual Energy Outlook (AEO)
Emerging Technology Availability	Carbon capture and sequestration (CCS) available in 2035. 100% hydrogen and nuclear (small modular reactors) are not available by 2035.
Emerging Technology Cost	Gas with CCS costs are midpoint between low costs (Strong Climate Policy Scenario) and high costs (Desert Contraction Scenario) (see below). 100% hydrogen and nuclear are not available by 2035.

[1] https://www.srpnet.com/grid-water-management/grid-management/integrated-system-plan
[2] Representative Concentration Pathway- RPC

Hydrogen Prices	Green hydrogen forecast developed by E3 using electricity production from solar (blend between Arizona and Utah using Renewable and Battery Storage Costs above), hydrogen production using alkaline electrolyzers (blend between optimistic and conservative cost declines from California Energy Commission publication CEC-500-2019-055), hydrogen storage (using costs from Department of Energy project ST-001), and hydrogen transport (blend between AZ and UT transport costs, using Argonne's Hydrogen Delivery Scenario Analysis Model (HDSAM) tool). $3/kg hydrogen production tax credit from Inflation Reduction Act applied at 85% monetization.
Gas Prices	Energy Information Administration (EIA) 2021 AEO "Reference" case regionalized based on SRP's gas supply
Hydro Availability	Hydro capacity and energy availability remain relatively constant at current drought conditions.
Market Support	Due to near-term capacity constraints, actions taken to contract maximum market capacity through 2032; afterwards 525 MW of market potential available.

Desert Boom

Key Drivers	Assumptions
Economic Growth	Economic development load grows by 2,900 MW by 2035 and population grows by an average rate of 1.8% per year.
Temperature Rise	"RCP 8.5" climate scenario from the IPCC
Carbon Reduction Policy	*Same as Current Trends*
Electrification	600,000 electric vehicles by 2035; 86% residential electric heating adoption by 2035
Distributed Generation	1,800 MW distributed solar by 2035
Energy Efficiency	*Same as Current Trends*
Renewable and Battery Storage Costs	*Same as Current Trends*
Gas Resource Costs	*Same as Current Trends*
Emerging Technology Availability	*Same as Current Trends*
Emerging Technology Cost	*Same as Current Trends*
Hydrogen Prices	*Same as Current Trends*
Gas Prices	*Same as Current Trends*
Hydro Availability	*Same as Current Trends*
Market Support	*Same as Current Trends*

Desert Contraction

Key Drivers	Assumptions
Economic Growth	Economic development load growth rate peaks in 2026 before declining, resulting in a total of 597 MW added by 2035 compared to 2022. Population growth rate follows a similar trend, peaking in 2027 before declining. This results in an average population growth rate of 0.4% per year between 2023 and 2035.
Temperature Rise	"RCP 8.5" climate scenario from the IPCC
Carbon Reduction Policy	*Same as Current Trends*
Electrification	*Same as Current Trends*
Distributed Generation	*Same as Current Trends*
Energy Efficiency	*Same as Current Trends*
Renewable and Battery Storage Costs	NREL 2022 ATB Market + Policy Conservative Scenario forecast. Inflation Reduction Act Investment Tax Credit (ITC) and Production Tax Credit (PTC) monetized at 80%.[3] Cost increases for solar (15%), wind (30%) and batteries (30%) added assuming existing supply chain challenges and trade friction worsen.[4]
Gas Resource Costs	*Same as Current Trends*
Emerging Technology Availability	*Same as Current Trends*
Emerging Technology Cost	Gas with CCS based on Energy Information Administration 2022 AEO +20%. 100% hydrogen and nuclear are not available by 2035.
Hydrogen Prices	Green hydrogen forecast developed by E3 using electricity production from UT solar (using Renewable and Battery Storage Costs above), hydrogen production using alkaline electrolyzers (conservative cost decline from California Energy Commission publication CEC-500-2019-055), hydrogen storage in UT (using costs from Department of Energy project ST-001) and hydrogen transport to AZ (using Argonne's Hydrogen Delivery Scenario Analysis Model (HDSAM) tool). $3/kg hydrogen production tax credit from Inflation Reduction Act applied at 80% monetization.
Gas Prices	*Same as Current Trends*
Hydro Availability	Glen Canyon Dam generation production is unavailable at the beginning of the study period (2025). Other hydrogeneration on the Colorado River and Salt River remain consistent with Current Trends assumptions.

[3] *Includes the base credit and 5x multiplier for satisfying prevailing wage and apprenticeship requirements. Includes the Energy Community bonus (+10%) for Arizona wind built after the retirement of Coronado (and Springerville in the Minimum Coal strategic approach). 80% reflects uncertainty in cost to monetize tax credits (e.g., profit margin for tax equity investor or transfer entity, transaction costs) and to satisfy applicable requirements (e.g., prevailing wage). Assumed phase-out post-2045.*

[4] *A smaller increase is made to solar as NREL's conservative scenario forecasts for solar already include adjustment to reflect trade frictions.*

Market Support	Loss of Glen Canyon Dam and other hydrogeneration facilities in the West results in 0 MW of market support available. Existing market purchases currently contracted by SRP are honored.

Strong Climate Policy

Key Drivers	Assumptions
Economic Growth	*Same as Current Trends*
Temperature Rise	*Same as Current Trends*
Carbon Reduction Policy	Federal policy that requires a CO2 mass emissions (tons) reduction by 85% from 2005 level by 2035.
Electrification	Electric vehicle adoption consistent with reaching economy-wide net-zero emissions by 2050 (975,000 by 2035); 86% residential electric heating adoption by 2035
Distributed Generation	2,300 MW of distributed solar by 2035
Energy Efficiency	Federal codes, standards and incentives lead to higher energy efficiency growth, reaching 4,500 GWh total energy efficiency by 2035.
Renewable and Battery Storage Costs	NREL 2022 ATB Market + Policy Moderate Scenario forecast. Inflation Reduction Act ITC and PTC monetized at 90%[5,6]. All near-term supply chain impacts are fully resolved by 2025.
Gas Resource Costs	Energy Information Administration 2022 AEO
Emerging Technology Availability	Gas with CCS available in 2030, 100% green hydrogen available in 2034, and nuclear (small modular reactors) available in 2034
Emerging Technology Cost	Energy Information Administration 2022 AEO. Inflation Reduction Act ITC applied to nuclear and 100% hydrogen, and CCS tax credit applied to gas with CCS all at 90% monetization.[4] 100% hydrogen unit based on frame combustion turbine.
Hydrogen Prices	Green hydrogen forecast developed by E3 using electricity production from AZ solar (using Renewable and Battery Storage Costs above), hydrogen production using alkaline electrolyzers (optimistic cost decline from California Energy Commission publication CEC-500-2019-055), hydrogen storage in AZ (using costs from Department of Energy project ST-001) and hydrogen transport (using Argonne's Hydrogen Delivery Scenario Analysis Model (HDSAM) tool). $3/kg hydrogen production tax credit from Inflation Reduction Act applied at 90% monetization.
Gas Prices	EIA 2021 AEO "Low Oil and Gas Supply" case regionalized based on SRP's gas supply
Hydro Availability	*Same as Current Trends*

[5] ITC and PTC include *the base credit and 5x multiplier for satisfying wage and apprenticeship requirements. 90% reflects uncertainty in cost to monetize tax credits (e.g., profit margin for tax equity investor or transfer entity, transaction costs) and to satisfy applicable requirements (e.g., prevailing wage). Assumed phase-out post-2045.*

[6] *Includes the Energy Community bonus (+10%) for Arizona wind built after the retirement of Coronado (and Springerville in the Minimum Coal strategic approach).*

Market Support	Favorable regional resource and load diversity allows for the potential for the wider region to carry slightly less total resource capacity while maintaining the same level of reliability. SRP assumes a regional coordination program and a regional diversity benefit and tests this assumption by reducing its Planning Reserve Margin requirement from 16% to 13%. Capacity (MW) market availability assumptions are consistent with Current Trends.

Sensitivities

Sensitivity	Assumptions
High Demand Response	Increased expansion in demand response over time, reaching 400 MW total Demand Response by 2035.
High Energy Efficiency	Federal codes, standards and incentives lead to higher energy efficiency growth, reaching 4,500 GWh total energy efficiency by 2035.
High Distributed Generation	Distributed solar and battery adoption reach 2,300 MW and 249 MW, respectively, by 2035.
Increased Load Management	Increased load flexibility through managed electric vehicle (EV) charging or other flexible loads. Modeled as a virtual battery addition with limitations on when it can charge or discharge.
Regional Diversity	Favorable regional resource and load diversity allows for the potential of a reduced loss of load probability on SRP's system. SRP tests this assumption by reducing the minimum Planning Reserve Margin requirement from 16% to 13%.
High Gas Price	EIA 2021 AEO "Low Oil and Gas Supply" case regionalized based on SRP's gas supply
Low Gas Price	EIA 2021 AEO "High Oil and Gas Supply" case regionalized based on SRP's gas supply
Volatile Gas Price	EIA 2021 AEO "Reference" gas regionalized based on SRP's gas supply, adjusted to reflect gas price volatility observed from 2000-2010
High Technology Cost	NREL 2022 ATB Market + Policy Conservative Scenario forecast. Inflation Reduction Act ITC and PTC monetized at 80%.[7] Cost increases for solar (15%), wind (30%), and batteries (30%) added assuming existing supply chain challenges and trade friction worsen.[8]
Low Technology Cost	NREL 2022 ATB Market + Policy Moderate Scenario forecast. Inflation Reduction Act ITC and PTC monetized at 90%[9]. All near-term supply chain impacts are fully resolved by 2025.

[7] *Includes the base credit and 5x multiplier for satisfying prevailing wage and apprenticeship requirements. Includes the Energy Community bonus (+10%) for Arizona wind built after the retirement of Coronado (and Springerville in the Minimum Coal strategic approach). 80% reflects uncertainty in cost to monetize tax credits (e.g., profit margin for tax equity investor or transfer entity, transaction costs) and to satisfy applicable requirements (e.g., prevailing wage). Assumed phase-out post-2045.*

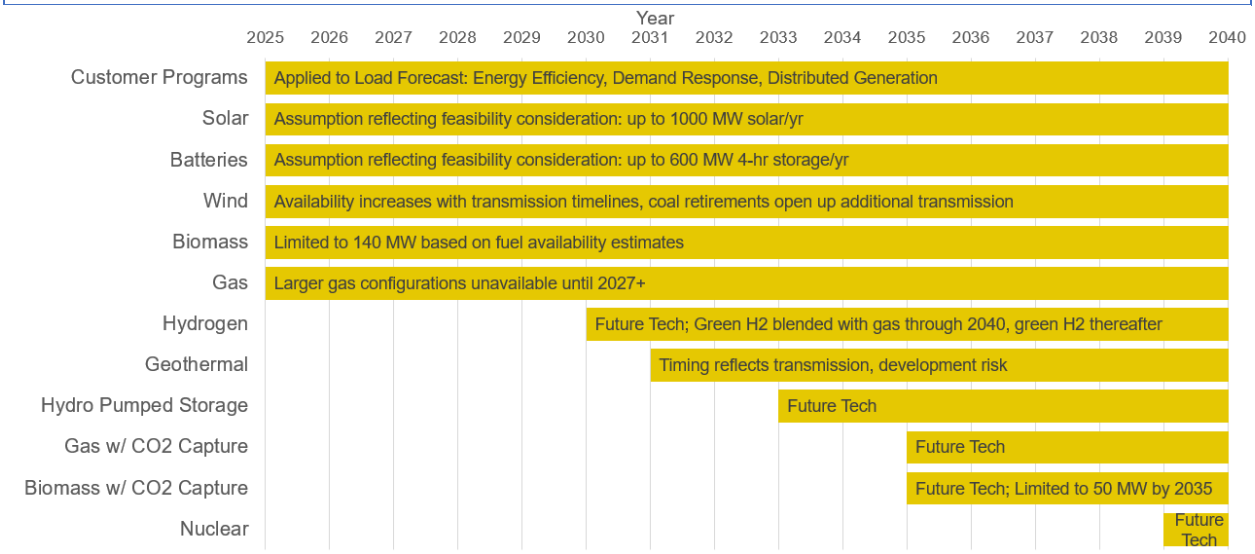
[8] *A smaller increase is made to solar as NREL's conservative scenario forecasts for solar already include adjustment to reflect trade frictions.*

[9] *Includes the base credit and 5x multiplier for satisfying wage and apprenticeship requirements for ITC and PTC. Includes the Energy Community bonus (+10%) for Arizona wind built after the retirement of Coronado (and Springerville in the Minimum Coal strategic approach). Monetization range reflects uncertainty in cost to monetize tax credits (e.g., profit margin for tax equity investor or transfer entity, transaction costs) and to satisfy applicable requirements (e.g., prevailing wage). Assumed phase-out post-2045.*

Strategic Approaches

Tech Neutral

Key Drivers	Assumptions
Technology Availability	All resource technologies available, limits based on technical feasibility availability of new resources (chart below). Strong Climate Policy Scenario includes accelerated availability dates for CO2 capture (2030), 100% green H2 (2034), and nuclear (2034).



No New Fossil

Key Drivers	Assumptions
Technology Availability	New gas and gas w/CO2 capture are removed as available resource technologies

Minimum Coal

Key Drivers	Assumptions
Technology Availability	New gas and gas w/CO2 capture are removed as available resource technologies
Coal Plant Operational Changes	Evaluates impacts from Coronado Generating Station Units 1 and 2 and Springerville Generating Station Unit 4 operating seasonally beginning in 2025 (off-line for three months of the year during non-peak periods) and SRP fully exiting coal by 4/30/2034.

Revision History

Revision	Date	Description
0	August 2022	Original
1	March 2023	Updated to incorporate impacts from the Inflation Reduction Act into technology costs.
2	April 2023	Corrected understated High DG sensitivity assumption and economic growth assumption in the Desert Boom scenario.

APPENDIX B

SRP Customer Research Future of Energy Phases 1 & 2 Report



Future of Energy

Phase I & II Report

June 30, 2022

bellomy

175 Sunnynoll Court
Winston-Salem, NC 27106

www.bellomy.com

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Background & Objectives

Background

Salt River Project (SRP) is preparing its first Integrated System Plan (ISP), which is focused on planning the power system through 2035. While multiple inputs are needed to prepare this plan, one crucial contribution is input from customers.

Looking into the future, SRP expects there to be many disruptions to the energy industry with a key aspect being the balance between reliability, sustainability, and affordability. Furthermore, the perspectives of different groups of customers, with different values and mindsets and each group's perspectives on this balance will need to be understood and considered.

Objectives

The goal of this research was to bring the voice of SRP's residential customers into the planning of the future power system.

More specifically, this research was designed to gain an understanding of how customers think about sustainability, affordability, and reliability related to power provision and gauge their reactions to a potential energy plan. SRP sought to understand areas of diverse viewpoints and agreement, as well as identify preferred methods of engagement with SRP on this topic.

The research aimed to address the following specific objectives:

1. Understand the concerns customers have about the future of Arizona, the economy and the U.S.
2. Understand diverse perspectives and opinions relating to SRP's sustainability plan and evolution.
3. Develop and test system-planning metrics that are understood and resonate with customers.
4. Generate a list of power system and future energy topics that interest customers.
5. Understand customer perspectives on power reliability and potential tradeoffs with sustainability and affordability.
6. Understand preferred methods of learning about and engaging with the power system planning process.

Methodology & Reporting

Approach

A three-phased research approach is being applied, starting with virtual focus groups (December 2021), followed by a quantitative confirmation (March 2022) and a choice exercise (planned for Fall 2022). This report addresses Phase I and Phase II.

All customers included in the research were SRP residential customers, energy decision makers, who did not work for a competing industry, and were over 18 years old.

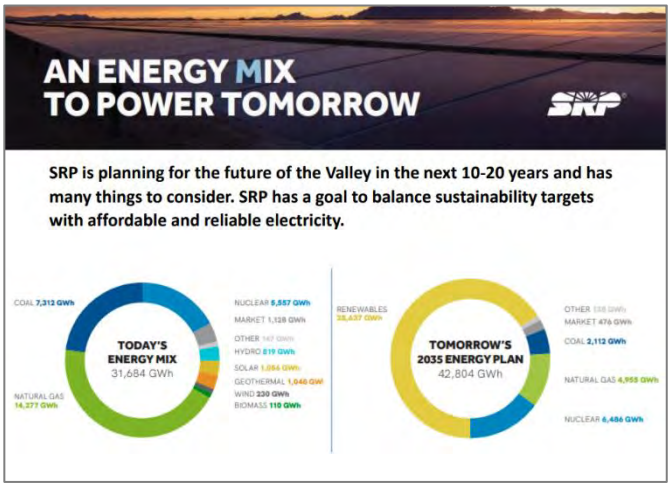
Phase I: Virtual Focus Groups

Four 90-minute virtual focus groups were held December 13 & 14, 2021. A total of 24 SRP customers participated virtually (via Zoom) and received a $125 bill credit for participating.

Customers were grouped to encourage engagement and maximize the ability to explore attitudes and extract observations.

Phase II: Online Survey

An online survey was fielded between March 7 – March 14, 2022. Respondents evaluated SRP's illustrative energy plan of how the system may develop in relation to attributes of customer interest identified in Phase I. Quotas were set for the survey to ensure the respondent pool best represented SRP's residential customer population.



Customers evaluated SRP's proposed energy mix, which describes the transition of the power system over the next 10-20 years. The visual depiction of the illustrative plan shown to respondents is displayed to the right. Customers were provided background on SRP's priorities.

Reporting

Quantitative results are reported in charts at the total level with qualitative results represented throughout. When evaluating survey data, sub-groups were compared to one another to investigate if there were statistically significant differences between two or more groups.

A 95% confidence level is used, which indicates we can conclude with 95% confidence that differences are not due to chance and that survey results should match results from the actual population (plus or minus the margin of error). Only significant differences relevant to the research objectives are reported.

The following subgroups are noted in this report:

- **Age** (18-44 years old/ 45-54 years old/ 55-64 years old/ 65+ years old)
- **Income** (Under $75k/year / $75k/year or more)
- **Gender** (Male/ Female)
- **Energy Mix Prioritization** (Affordability first/ Reliability first/ Sustainability first)
- **Hispanic** (Hispanic/ Non-Hispanic)
- **Credit Rating** (Preferred/ New Customer/ Satisfactory/Slow/Unsatisfactory)
- **Usage Category** (Low/ Moderate/ Medium/ High)
- **Overall Opinion of Energy Plan** (Positive/ Negative)
- **Overall Experience as SRP Customer** (Positive/ Neutral/ Negative)
- **Years at Address** (2 or less/ 3-5/ 6-20/ 21-39/ 40+)

Note: Rating scale questions are reported differently for 10-point and 5-point scales.
10-point scales are reported using Top-Box (TB – ratings of 10), Top-3-Box (T3B – ratings of 8,9, or 10), Middle-2-Box (M2B – ratings of 6 or 7), and Bottom-5-Box (B5B – ratings of 1-5).
5-point scales are reported using Top-Box (TB – ratings of 5), Top-2-Box (T2B – ratings of 4 or 5), Middle-Box (MB – ratings of 3), and Bottom-2-Box (B2B – ratings of 1 or 2).

Executive Summary



The illustrative plan was rated positively

Most customers reacted positively to the energy plan while a quarter felt it was excellent. Additionally, a majority expressed positive perceptions of SRP and cited outstanding customer service and reliability as reasons for this.

Affordability & reliability were top priorities for the future

Affordability was one of the most-selected future issues facing Arizona and customers felt that affordability should be prioritized.

Both affordability and reliability surpassed sustainability in importance. Customers noted that sustainable electricity was meaningless if not affordable and reliable, especially with rising inflation and increased usage during the Arizona summer heat.

- SRP might increase energy plan acceptance by anticipating and addressing questions on affordability and reliability.

A majority agreed SRP should prioritize the illustrative energy plan

Further, about half felt the plan fit with SRP's brand, was easy to understand, and seemed achievable. Customers reflected that the plan could be improved by providing more details on how it would be achieved and its impacts on affordability.

Respondents also hoped to ensure that SRP selected the best sources of electricity, though opinions on what sources were best varied. Customers were unclear on which sources of electricity SRP would use.

- Emphasizing transparency with customers as SRP solidifies energy sources, including cost impacts, may bolster trust.

Customers wanted to continue to hear about ways to save from SRP

Customers exhibited strong positive feedback on the benefits and effectiveness of SRP's cost saving offerings.

Customers most wanted to hear more about programs that can help them save money, including rebates and energy efficiency programs, which aligned with affordability priorities.

- Continuing to showcase and optimize offerings geared towards energy and cost savings may increase enrollment and contribute to positive overall perceptions of SRP.

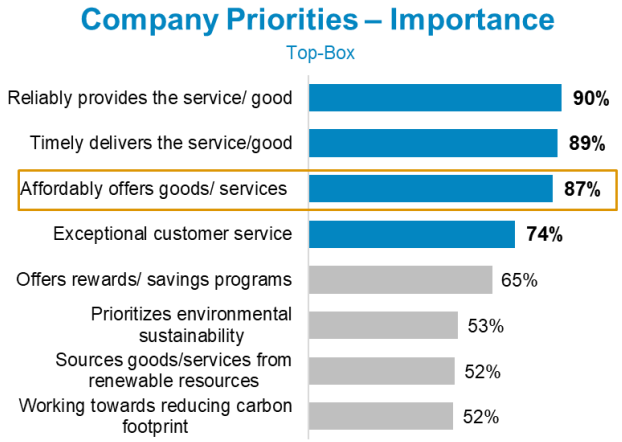
Detailed Findings

Future Issues and Priorities

Customers demonstrated affordability concerns

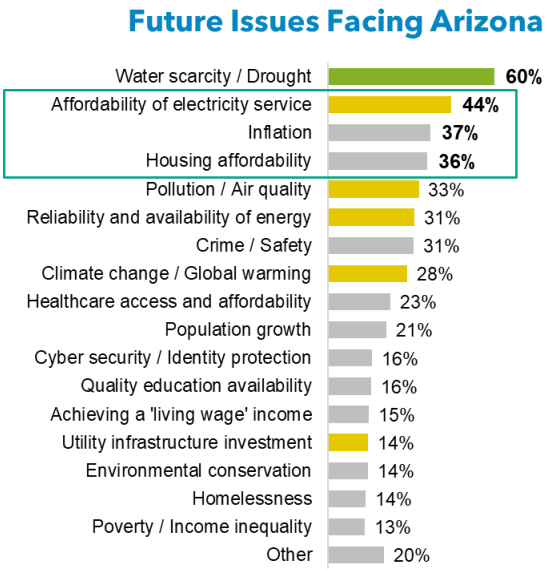
Affordability was rated as a top need for companies to prioritize in the future, with nearly 9 in 10 believing it was important for companies to prioritize the need.

This accompanied reliably providing goods and services, and providing them in a timely manner.



Respondents most selected that they were concerned about water scarcity. After water scarcity, affordability related to electricity, inflation, and housing were most concerning.

- The focus on affordability of electricity is of note, as it was the second-most selected future concern. These issues were followed by several items SRP is most able to impact related to pollution, energy reliability, and climate change (highlighted in yellow).
- Lower income customers (earning under $75k/year) reflected greater concern for affordability.



- *Year-round residents are more likely to prioritize housing affordability.*
- *Those with a household income of $75k or more were more likely to prioritize water scarcity but were less likely to prioritize housing affordability.*
- *Non-Hispanic customers were more likely to prioritize water scarcity.*

Further, 22% of customers were very concerned about other community members being able to pay their electricity bills.

*Groups **more likely** to be concerned about others' ability to pay their electric bill include:*

- *Customers with household incomes less than $75k*
- *Females*
- *Hispanic customers*

Similar concerns were seen across top issues

When asked to rank selected issues on importance, rankings mostly mirrored the most-selected future issues facing Arizona. Customers were most likely to rank the following first: Water scarcity (22%), Inflation (13%), Housing affordability (10%), Affordability of electricity (9%)

- *Younger customers (aged 18-44), those with a household income under $75k, females, and Hispanic customers were more likely to rank housing affordability first.*
- *Non-Hispanic customers were more likely to rank water scarcity first.*

Customers mentioned population growth/city sprawl and rising prices added to their concern about top-ranked Issues.

Ranked 1st: Water Scarcity/Drought

*"**Having enough water to sustain the millions of people within the state.** And the temperature increase due to global warming coupled with heat island effects from Phoenix and Tucson sprawl." – Survey Respondent*

Ranked 2nd: Inflation

*"Population growth and cost of living. Being senior citizen on set income inflation has hit hard, **gas prices and growing energy prices concern me**." – Survey Respondent*

Ranked 3rd: Housing Affordability/ Availability

*"**The housing prices are going up but the pay in work is not**, who makes 3x the rent anymore. Nobody and it's ridiculous." – Survey Respondent*

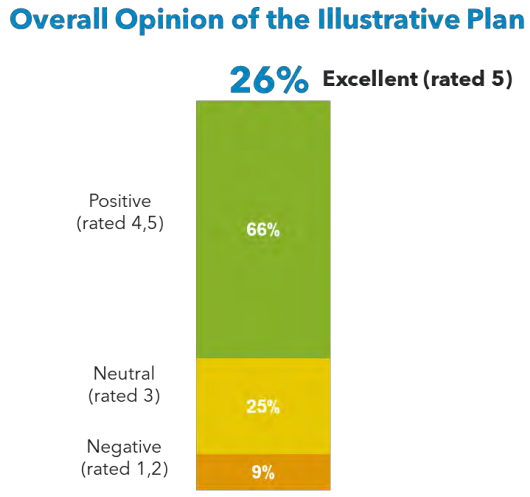
Ranked 4th: Affordability of Electricity Service

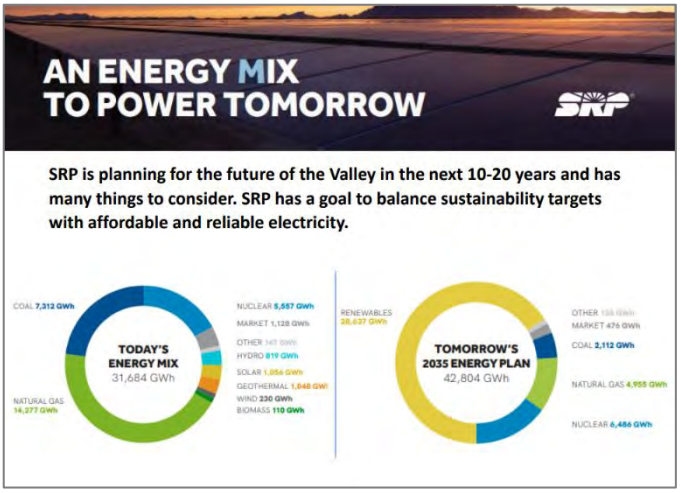
*"**Providing the uninterrupted service at an affordable price** for the growing population, taking inflation into consideration." – Survey Respondent*

SRP Energy Plan

Two thirds rated the energy plan positively

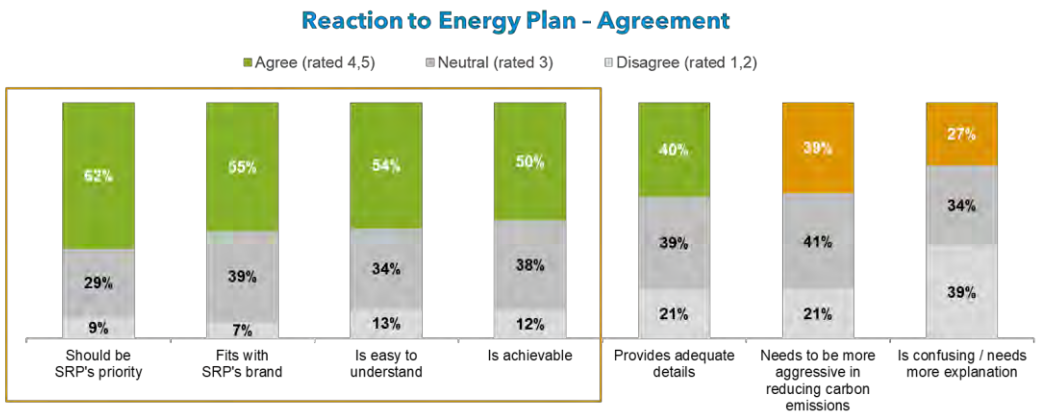
When evaluating SRP's energy plan, one-quarter (26%) rated it as excellent, but 66% rated it positively overall (rated 4 or 5 on a 5-point scale). This demonstrates opportunity for improvement.





- *Those ranking sustainability first had a more positive impression of the energy plan.*
- *Those with high electricity usage were less likely to rate the plan positively.*

Additionally, at least half agreed the plan should be SRP's priority (62%), fit with the brand (55%), is easy to understand (54%), and is achievable (50%).



- *Year-round residents were more likely to agree that the plan is achievable, fits with the SRP brand, is easy to understand, and provides adequate details.*
- *Customers with a household income under $75k and Hispanic customers were more likely to agree the plan fits with SRP's brand.*

Customers noted the plan could be improved with more specifics

Initial responses to viewing the plan revealed that customers were interested in more specifics. In addition to questions on plan affordability and achievability, respondents cited varying thoughts on which renewable sources SRP should prioritize.

- Twenty-seven percent (27%) of customers shared concerns around the type of energy sourced.
  *"**Renewable energy is fine, but solar and wind require lots of area to house enough energy to power cities.** Still have to maintain natural gas…and some coal. Nuclear power is the way to go, folks." – Survey Respondent*

- Nineteen percent (19%) shared affordability and cost concerns.
  *"I like the direction of the plan **but have my doubts that SRP will follow through on this plan in a way that is still affordable**." – Survey Respondent*

- Thirteen percent (13%) shared achievability concerns regarding the timing of the plan being too slow.
  *"How long will it take to achieve this? **Needs to be sooner rather than later**." – Survey Respondent*

  *"I don't view it as a plan. Rather strategic long-term objectives. **What is the road map to achieve, timing phases, costs, resources in the land?**" – Survey Respondent*

One-quarter (22%) felt that SRP should prioritize another goal (not already stated in the energy plan) and emphasized thoughts on specific energy sources.

*"**I did not see water conservation listed**, although I know it is on the SRP agenda." – Survey Respondent*

*"**Nuclear power is in my view, the only way forward**, renewable, wind, solar are efforts in futility. Sounds good to a few but a majority know better." – Survey Respondent*

*"**Making solar more affordable to the population**. This would increase the power grid, creating a partnership with the community. Making it more enticing for consumers to provide SRP with power." – Survey Respondent*

*"**Include hydrogen power** for vehicles in use." – Survey Respondent*

*"Since Arizona is a very hot state. **I believe solar panels would be excellent for SRP.** That should be the number one priority for SRP." – Survey Respondent*

Focus group participants were also generally positive about the plan's intent but suggested some opportunities for improvement. These opportunities included the amount of time needed to implement the plan, getting customer buy-in and being transparent, ensuring SRP's accountability for the changes, and clarifying how this would affect rates.

> *"Accelerate.* ***I want to see the short-term goals.*** *What, specifically, are we doing right now?" – Customer Focus Group Participant*

> *"****I feel like if we can reduce how much coal and other sources that we use at the moment****… So, if this is the company's goal and they want to focus on that, then I would be all for it." – Customer Focus Group Participant*

> *"****Why is it going to take us another 30 years*** *when I've gone to professional developments thrown by SRP about using renewable resources and whatnot?…I like that it's out there and that you have it projected. I also wish that you could be like the Lego corporation and be 100% renewable 20 years before your said date." – Customer Focus Group Participant*

> *"The thing that immediately stuck in my brain is the "Oh, solar isn't available 24 hours." And that's a really old talking point. And it's also not necessarily true anymore…So,* ***I feel like some of the messaging is based on talking points that are out of date and not necessarily forward-thinking****." – Customer Focus Group Participant*

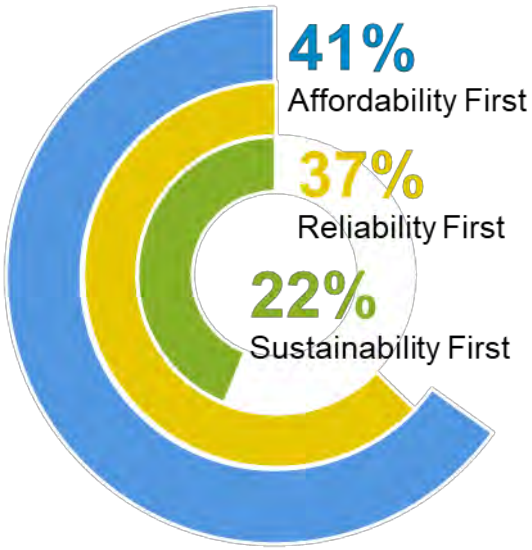
> *"****It's kind of curious why it would take so long to get more solar.*** *I mean, we're in the Valley of the Sun." – Customer Focus Group Participant*

> *"****I wonder how they could include in there something to do with conserving energy, wiser use****. I mean, I know there's been a lot of improvement like in the effectiveness of AC, with LEDs, and stuff like that. It would just be helpful…to consider the conserving side of it. And also, I wonder if the time has come to include in that chart an energy generated from the home, solar panels, whatever, like that. Because most of the people looking at the chart are homeowners like us." – Customer Focus Group Participant*

> *"What does all of this mean? And then, of course,* ***the financial piece of it, just like, okay, how would that even work, honestly, with thinking of all of it?*** *Like what could I do now to make a change? How is that going to develop over the years, just what that would all even look like?" – Customer Focus Group Participant*

Affordability and reliability were most ranked 1st

When asked how SRP should rank affordability, reliability and sustainability, two-fifths (41%) ranked affordability first, with 37% prioritizing reliability, and only 22% prioritizing sustainability.



In the focus groups, while a majority of customers ranked reliability first , they discussed a tough tradeoff between reliability and affordability

> *"If it's not on, it doesn't work, right? It doesn't matter what you spend. Again, we all have budgets, and we all try to stay within them." – Customer Focus Group Participant*

When asked reasons for ranking affordability, reliability, and sustainability as they did, customers responded as follows:

Affordability: Reasons Ranked First

23% Mentioned keeping energy costs down, the rising cost of living, and/or that if electricity isn't affordable, other priorities are meaningless.

*"I only have so much money, and already have seen enough scenarios where **people can't afford to run their air conditioning in summer due to costs**. I have been in valley 23 years and that's an issue every year." – Survey Respondent*

- *Both those with a satisfactory/low/unsatisfactory credit rating and those with a negative experience with SRP were significantly more likely to rank affordability first.*
- *Those with a household income less than $75k and Hispanic customers were more likely to rank affordability as first.*

Reliability: Reasons Ranked First

25% Mentioned that consistent energy is needed to maintain the status quo, and/or that if electricity isn't reliable, other priorities don't matter.

***"Residents and business are dependent upon a steady source of power.** Some uses are essential to life in the case of those who rely on devices to stay alive. Because of the summer heat, a break in power could be fatal to some." – Survey Respondent*

Sustainability: Reasons Ranked First

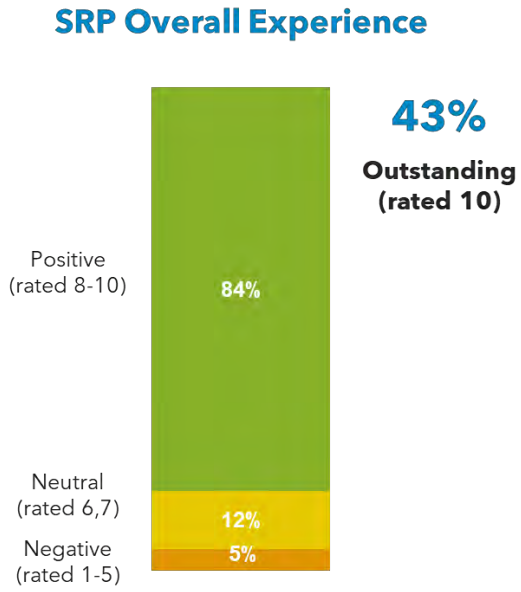
10% Mentioned the need to take care of the earth/ future energy needs.

***"Without sustainability there is no future."** – Survey Respondent*

Those who have lived at their address 2 years or less and those with a positive opinion of the energy plan were more likely to rank sustainability first.

Perceptions of SRP and Topics of Interest

Over four-fifths rated their experience with SRP positively



In qualitative findings, customers noted a highly positive perception of SRP, specifying that reliability of service and helpful customer service were key factors.

"Honestly, I'd give SRP a 10. I haven't had any major issues. Any time I've had anything that's come up, ***I'm able to get someone on the phone, speak with them****, … So, I've had a really good relationship with them." – Customer Focus Group Participant*

"I think the ***consistency of the service****. Being in Arizona, we do have the so hot weather all the time and having air conditioning is definitely a must…* ***And the consistency of them being able to provide that to us without any issues so far is something that I really appreciate****." – Customer Focus Group Participant*

- *Those with a household income under $75k were more likely to rate their experience as outstanding.*
- *Those who had a negative impression of the energy plan and those categorized with high usage were less likely to be satisfied with SRP.*

Over half had interest in ways to save

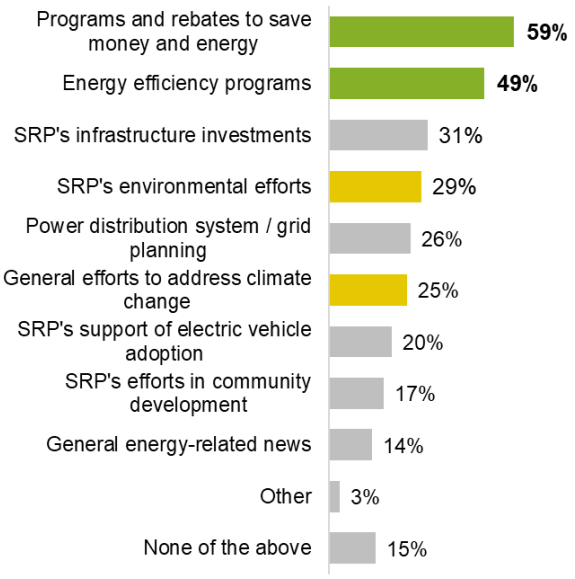
Customers would most like to continue to hear about ways to save via energy efficiency program and/or rebates. Meanwhile, over one-quarter were interested in topics related to SRP's environmental efforts and/or climate change.

Focus group participants agreed that SRP programs help customers manage and reduce their bills.

"I do have the M-Power so I do have prepaid electricity, so I am very acutely aware of my usage. ***I can see what I'm spending per day****." – Survey Respondent*

"I do like the idea that SRP does provide that time of use plan or ***keeps your bills consistent*** *throughout the month or throughout the year." – Survey Respondent*

Topics of Interest

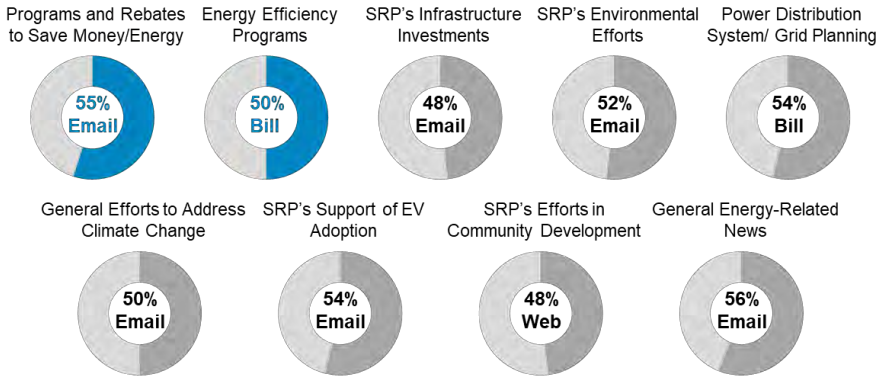


- *Those with a negative overall opinion of the energy plan were significantly more likely to want to hear about SRP's infrastructure investments and the power distribution system; they were less likely to want to hear about SRP's environmental efforts and general efforts to address climate change.*
- *Those with a household income less than $75k were more likely to want to hear about cost saving options.*

Across communication topics, customers most preferred to receive communication via bill insert and email.

Males were more likely to prefer email communications about programs and rebates to save money/energy.

Channel Preference



Appendix

Demographics

	Focus Group (n=24)	Online Survey (n=400)
GENDER		
Female	13	45%
Male	10	51%
Non-binary	1	0%
Prefer not to answer	-	4%
HOUSEHOLD INCOME		
Under $75k	15	41%
$75k or more	9	39%
Prefer not to answer	-	20%
CREDIT RATING		
Preferred	19	67%
Satisfactory/Slow/Unsatisfactory	3	12%
New Customer	2	21%
ETHNICITY (MULTIPLE SELECTIONS)		
White	20	69%
Black or African American	3	4%
Other	3	13%
Prefer not to answer	-	18%
HISPANIC ORIGIN		
Hispanic	2	15%
OWN/RENT HOME		
Own	18	73%
Rent	6	28%

	Focus Group (n=24)	Online Survey (n=400)
AGE		
18-44	13	30%
45-64	6	37%
65+	5	34%
EMPLOYMENT		
Ful-time/Part-time	-	51%
Self-employed	-	6%
Retired	-	33%
Unemployed/seeking employment/student	-	4%
Not working/not seeking	-	2%
N/A / Prefer not to answer	-	5%
YEARS AT ADDRESS		
2 or less	-	7%
3-5	-	10%
6-20	-	30%
21-39	-	30%
40+	-	15%
USAGE		
Low (6,000 kWh or less)	3	19%
Moderate (6,001-12,000 kWh)	8	33%
Medium (12,001-18,000 kWh)	8	29%
High (More than 18,000 kWh)	5	20%

Illustrative Plan Description and Background

In addition to the visual depiction of the illustrative plan, respondents were provided the following additional description and background:

> "SRP is working at all times to make sure your power stays on, including during Arizona's extreme summers. To ensure power quality continues to improve, SRP needs to plan long term for the future of the Valley. This means:
>
> - Balancing a transition to clean energy
> - Planning for population growth (and an increased demand for energy)
> - Considering the types of power to buy to make up their power mix (including solar, wind, geothermal, biomass, nuclear, natural gas, and coal)
> - Reducing SRP's carbon intensity (the amount of carbon released per unit of energy produced) by 90% by the year 2050"

APPENDIX C

SRP Customer Research Future of Energy Phase 3 Report



Future of Energy: ISP Residential Customer Research

Phase III Report

Revised: December 13, 2023

bellomy

175 Sunnynoll Court
Winston-Salem, NC 27106

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Appendix 18



Background & Objectives

Background

Salt River Project (SRP) is preparing its first Integrated System Plan (ISP), which is focused on a new way of planning the power system through 2035. While multiple inputs are needed to prepare this plan, one crucial contribution is input from residential customers.

Looking into the future, SRP expects there to be many changes and disruptions to the energy industry including evolving customer needs and expectations with a key aspect being the balance between reliability, sustainability, and affordability. Furthermore, the perspectives of different groups of customers, with different values and mindsets and each group's perception of this balance will need to be understood and considered.

Objectives

The goal of this research was to bring the voice of SRP's residential customers into the planning of the future power system.

More specifically, this research was designed to gain an understanding of how customers think about, and value sustainability, affordability, and reliability related to their electricity service from SRP and gauge their reactions to potential energy systems. SRP sought to understand areas of diverse viewpoints and agreement, as well as identify preferred methods of engagement on this topic.

The research aimed to address the following specific objectives:

1. Understand the concerns customers have about the future of Arizona, the economy and the U.S.
2. Understand diverse perspectives and opinions relating to SRP's sustainability plan and evolution.
3. Develop and test system-planning metrics that are understood and resonate with customers.
4. Generate a list of power system and future energy topics that interest customers.
5. Understand customer perspectives on power reliability and potential tradeoffs with sustainability and affordability.
6. Understand preferred methods of learning about and engaging with the power system planning process.

Methodology & Reporting

Approach

A three-phased research approach was applied, starting with virtual focus groups (December 2021), followed by a quantitative confirmation (March 2022) and culminating in a choice exercise (May 2023).

All customers included in the research were SRP residential customers, who were energy decision makers for their household (make decisions about their utility service and pay the bill), did not work for a related industry, and were over 18 years old.

Phase I: Virtual Focus Groups

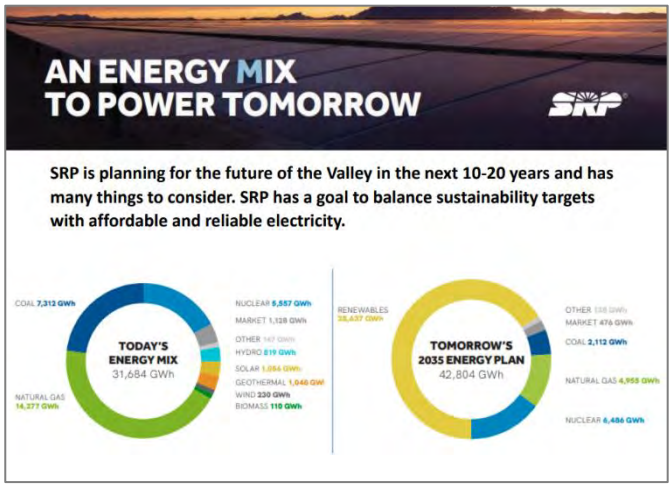
Four 90-minute virtual focus groups were held December 13 & 14, 2021. A total of 24 SRP customers participated virtually (via Zoom) and received a $125 bill credit for participating.

Customers were grouped to encourage engagement and maximize the ability to explore attitudes and have a meaningful conversation.

Phase II: Online Survey

An online survey was fielded between March 7 – March 14, 2022. Respondents evaluated SRP's illustrative energy plan of how the system may develop in relation to attributes of customer interest identified in Phase I. Quotas were set for the survey to ensure the respondent pool best represented SRP's residential customer population.

Customers evaluated a visual example of SRP's future potential energy mix, which describes the transition of the power system over the next 10-20 years. The visual depiction of the illustrative plan shown to respondents is displayed to the right. The illustrative energy plan shown in Phase II did not include details on bill impacts, water reduction, carbon emission reduction, or timing to meet the sustainability goals. Customers were provided background on SRP's priorities prior to evaluating energy mix; this wording is included in the Appendix on page 20.



Pre-Test Research: Optimizing Survey Materials

Prior to the Phase III survey, a multi-staged pre-test study was conducted to test education materials, survey instructions, and choice exercise design among non-SRP customers. The pre-test research included an initial pre-test survey, qualitative ride-along interviews, and a revised pre-test survey.

Throughout the three pre-test phases, respondents identified areas of the instructions and educational materials that were difficult to understand. Based on feedback from this pre-test, instructions for the choice exercise were crafted with clear tasks respondents could understand and accurately complete.

This confirmation helped secure the highest quality of actionable data. Changes made to the choice exercise included:

- Impactful phrase rewording which resulted in less confusion (~40% reduction in confusion)
- Redesign of the choice activity which created an easier survey experience.



This testing ensured SRP's diverse customer base would be able to understand and easily complete the choice exercise in Phase III.

Phase III: Choice Exercise Online Survey

In this 20-minute survey fielded between May 9 and May 29, 2023, offered in English and Spanish, respondents completed a choice exercise to assess their preferences for SRP's potential future energy system. Quotas were set to mirror the true population split for SRP's customer base. A choice-based methodology known as a conjoint exercise was utilized to understand customer preference for potential future energy systems being analyzed in the Integrated System Plan.

Conjoint methodology is used to optimize a product or service of interest by asking respondents to make a series of choices though an exercise simulating real-life situations, determining what tradeoffs they are willing to make.

The following best practices were used in development of the choice exercise for the Phase III survey:

- Exposing respondents to educational information regarding system inputs prior to asking them to make a choice (e.g., explaining energy mixes and defining carbon reduction)
- Ensuring complex inputs are positioned in customer-friendly terms (e.g., showing carbon reduction in terms of the number of gas-powered vehicles)
- Utilizing visuals where possible to "show" rather than "tell" (e.g., including a graphical representation of the energy mix)
- Creating precise levels for each system input (e.g., utilizing data outputs from other ISP research efforts to build levels)
- Ensuring system configurations are realistic to respondents to avoid asking them to make a non-sensical choice

- Including no more than seven inputs per system to ensure ease of comprehension
- Limiting the number of screens in the exercise to no more than twelve to minimize respondent fatigue

Customers were asked to evaluate 11 screens, each showing 2 energy plans and a “none of these” option representing the current energy system and choose the plan they would most prefer SRP to pursue. Through selections made, a customer preference rating was produced for each potential future energy system. An example of the choice exercise is shown on the following page.

The ISP's analytical framework and outputs from the system planning informed the following system inputs for the choice exercise:

- Illustrative energy mix (9 mixes tested)
- When SRP will meet its sustainability goals (2030 or 2035)
- Percent reduction in carbon emissions (4 levels for each energy mix)
- Percent reduction in water usage (4 levels for each energy mix)
- If SRP will build new gas power plants (yes or no)
- Monthly bill impact (4 levels calculated on customers' average bill)
- Number of 2-hour power outages (0, 1, 2, or 3)

Illustrative mixes and variations in options for the inputs shown were representative of the resource builds and implications for each strategic approach under the future scenarios from the ISP system plans. Various levels (or options) were shown for each component resulting in evaluation of over 9,200 possible system configurations. An example of the choice exercise screen respondents completed is located in the Appendix on page 21.

Reporting

Quantitative results are reported in charts at the total level with qualitative results represented throughout. When evaluating survey data, sub-groups were compared to one another to investigate if there were statistically significant differences between two or more groups.

A 95% confidence level is used, which indicates we can conclude with 95% confidence that differences are not due to chance and that survey results should match results from the actual population (plus or minus the margin of error). Only significant differences relevant to the research objectives are reported.

The following subgroups are noted in this report:

- **Age** (18-44 years old/ 45-54 years old/ 55-64 years old/ 65+ years old)
- **Income** (Under $75k/year / $75k/year or more) (Phase II Only)
- **Limited Income** (200% of HHS Poverty Guidelines/ Non-Limited at 200%)
- **Gender** (Male/ Female/Nonbinary)

- **Energy Mix Prioritization** (Affordability first/ Reliability first/ Sustainability first)
- **Hispanic** (Hispanic/ Non-Hispanic)
- **Credit Rating** (5 levels)
- **Usage Category** (Low/ Moderate/ Medium/ High)
- **Overall Opinion of Energy Plan** (Positive/ Negative)
- **Overall Experience as SRP Customer** (Positive/ Neutral/ Negative)
- **Years at Address** (2 or less/ 3-5/ 6-20/ 21-39/ 40+)

Analysis Note: Rating scale questions are reported differently for 10-point and 5-point scales.
10-point scales are reported using Top-Box (TB – ratings of 10), Top-3-Box (T3B – ratings of 8,9, or 10), Middle-2-Box (M2B – ratings of 6 or 7), and Bottom-5-Box (B5B – ratings of 1-5).
5-point scales are reported using Top-Box (TB – ratings of 5), Top-2-Box (T2B – ratings of 4 or 5), Middle-Box (MB – ratings of 3), and Bottom-2-Box (B2B – ratings of 1 or 2).

Executive Summary



In Phase I & II, most customers reacted positively to SRP's initial path forward, and a quarter felt it was excellent. A majority agreed the plan should be prioritized by SRP. Phase III revealed residential customers' preferences for the future energy system.

Top factors: affordability & bill impacts

Affordability concerns were some of the most-selected future issues facing Arizona. In each phase of this research, affordability surpassed reliability slightly in importance when ranked by customers. Those with limited incomes put greater emphasis on affordability, while non-limited income customers reflected greater balance across factors. Additionally, when choosing a future energy system, customer selections revealed monthly bill impact as the top driver of preference.

Understanding and openness to change

Despite prioritizing affordability, customers recognized that the forthcoming challenges facing the region are interrelated and pose risks to sustainability, the economy, and overall quality of life. Thus, they understood the need for a lower-carbon future energy system, however, across scenarios, lower cost strategic approaches were more preferred by customers. While customers recognized the need for and expressed interest in SRP's investment in sustainable energy sources, they do not want to bear the cost of that investment.

Willingness to engage

Customers reported positive experiences with SRP's programs and over half were interested in programs and rebates that will help them save money and energy. Additionally, about a third or more expressed interest in learning about SRP's energy efficiency programs, environmental efforts, and infrastructure improvements.

Recommendations

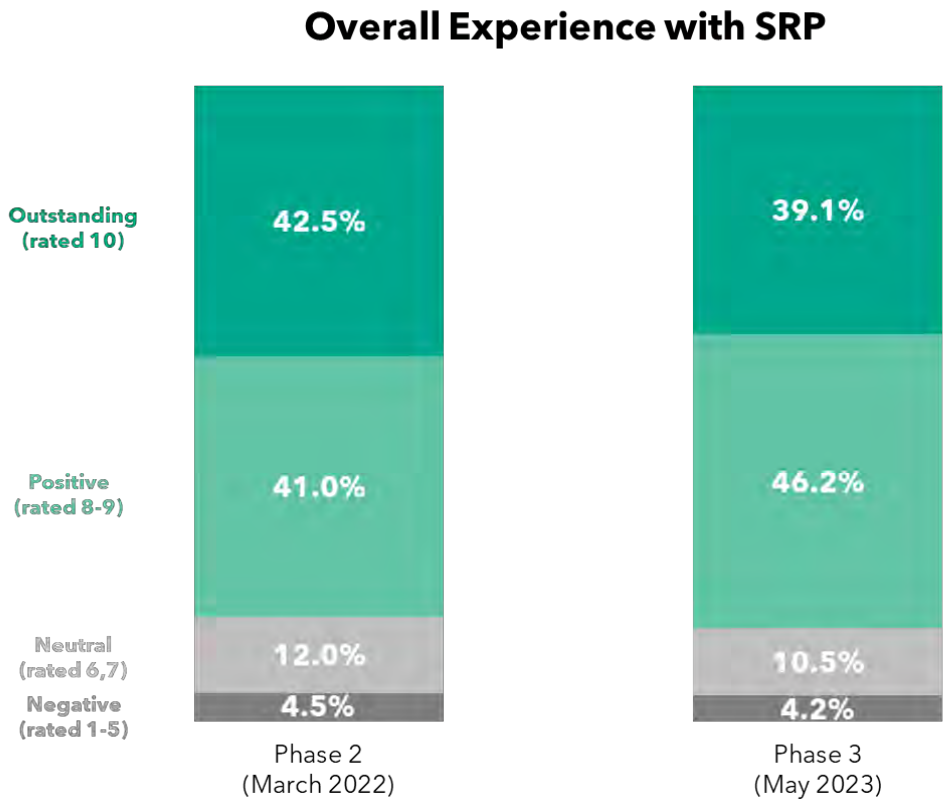
- **For SRP's ISP, focus investment on a least-cost portfolio:** With cost being the top driver of customer preference, it will be critical to ensure system costs are managed and explained to customers proactively and transparently.
- **For SRP's ISP, highlight and maintain grid readiness and resiliency:** Reliability was the second highest ranked priority.
- **In ISP implementation, utilize a targeted approach to customer programs:** Customers expressed a willingness to engage with SRP via customer programs. These programs should be designed to meet the varying needs of customers.

Detailed Findings

Experiences with SRP, Concerns, and Priorities

Most rated their experience with SRP positively

Similar to March 2022, in May 2023 surveying, over 4 in 5 customers rated their experience with SRP positively. While about 2 in 5 provided an "Outstanding" rating.



In qualitative focus groups, customers attributed their highly positive perception of SRP to the reliability of service and helpful customer service. Additionally, participants felt positively about SRP's customer programs, agreeing that programs help them manage
and reduce their electricity bills.

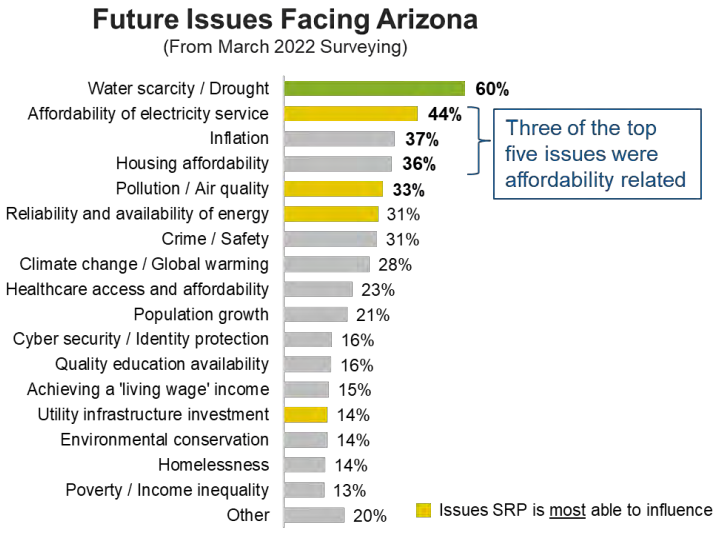
*Groups **more likely** to provide a positive rating of their experience with SRP included:*

- *Customers aged 55 or older*
- *Non-Hispanics*

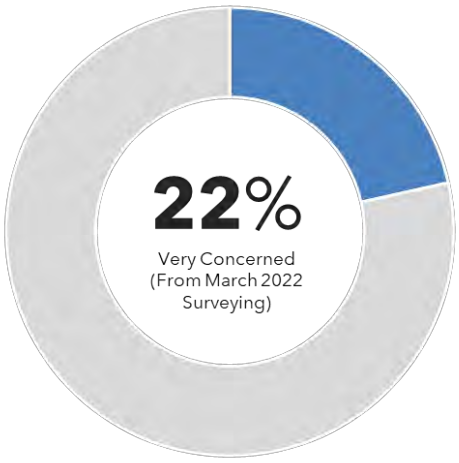
Customers demonstrated affordability concerns

Respondents most selected that they were concerned about water scarcity. After water scarcity, affordability related to electricity, inflation, and housing were most concerning.

The focus on affordability of electricity is of note, as it was the second-most selected future concern. These issues were followed by some items related to energy service, including pollution, energy reliability, and climate change.



- ***Lower income*** *customers (earning under $75k/year) reflected* ***greater concern for affordability****.*
- ***Year-round*** *residents are more likely to* ***prioritize housing affordability****.*
- *Those with a household* ***income of $75k or more*** *were more likely to* ***prioritize water scarcity*** *and were less likely to prioritize housing affordability.*
- ***Non-Hispanic*** *customers were more likely to* ***prioritize water scarcity****.*



Further, 22% of customers were very concerned about other community members being able to pay their electricity bills.

Groups ***more likely*** *to be concerned about others' ability to pay their electric bill include:*

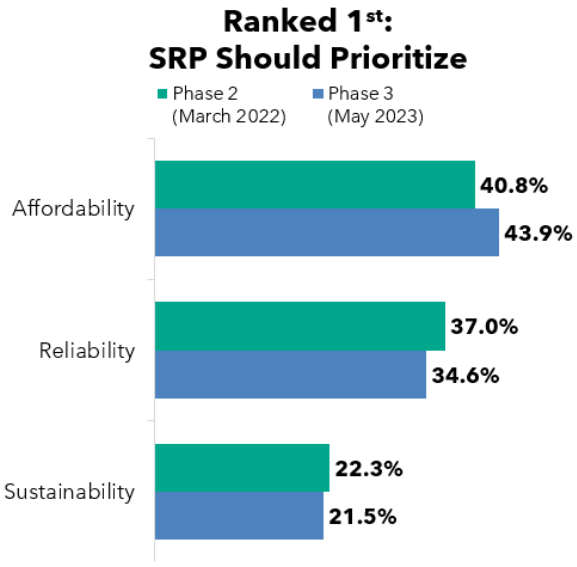
- *Customers with household incomes less than $75k*
- *Females*
- *Hispanic customers*

Affordability and Reliability were most often ranked 1st

When asked how SRP should rank affordability, reliability and sustainability, affordability was the top priority in both Phase II & III for over two-fifths of customers. Over one-third prioritized reliability, and less than one-quarter prioritized sustainability.

In the focus groups, while a majority of customers ranked reliability first, they discussed a tough tradeoff between reliability and affordability.

While the ranking of priorities was similar across Phases, reasons for these rankings in May 2023 highlighted greater emphasis on the rising cost of living and a need for consistent electricity.



Affordability: Reasons Ranked First

Almost half (46%) of those who ranked affordability first in Phase III mentioned keeping energy costs down and the rising cost of living. This was more than in Phase II where only one-third ranked affordability first for the same reason. The increase in concern over rising cost of living and keeping energy costs down may be due to the rise in inflation and increased conversation about rising prices across products and services in 2023.

*In Phase III surveying, groups **more likely** to rank **affordability first** included:*

- ***Limited income** customers (200% of HHS Poverty Guidelines)*
- *Females*
- *Hispanics*
- *Those enrolled in **M-Power for Pre-Pay***

Reliability: Reasons Ranked First

In Phase III, half (51%) of the customers who ranked reliability first noted a need for consistent electricity to maintain the status quo. This increased from about one-quarter (23%) ranking reliability first in Phase II for the same reason.

*In Phase III surveying, groups **more likely** to rank **reliability first** included**:***

- *Non-Limited income customers*
- *Males*
- *Those with Preferred Credit Ratings*

Sustainability: Reasons Ranked First

While the smallest proportion of customers ranked sustainability first, three-fifths (62%) of those who did in Phase III noted the importance of taking care of the Earth and future energy needs. This was higher than the almost half (45%) who ranked sustainability first for the same reason in Phase II.

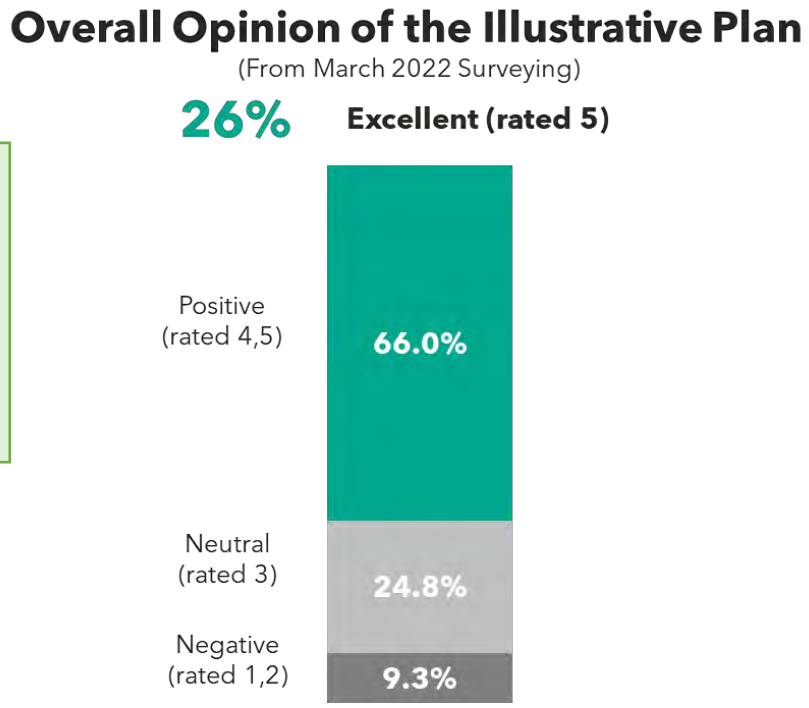
*Customers **aged 55 to 64 were less likely** than all other age groups to rank **sustainability first**. In Phase III surveying.*

SRP Energy Plan: Initial Reactions (Phase I & II)

Two thirds rated the initial energy plan positively

When evaluating an illustrative example of SRP's energy plan during initial phases of research (visual and background evaluated can be found in the Appendix on page 20), one-quarter (26%) rated it as excellent, but 66% rated it positively overall (rated 4 or 5 on a 5-point scale). This demonstrates opportunity for improvement.

- *Those ranking **sustainability first** had a **more positive** impression of the energy plan.*
- *Those with **high electricity usage** were **less likely** to rate the plan positively.*



Customers noted the plan could be improved with more specifics

Initial responses to viewing the plan revealed that customers were interested in more specifics. In addition to questions on plan affordability and achievability, respondents cited varying thoughts on which renewable sources SRP should prioritize.

- Twenty-seven percent (27%) of customers shared concerns around the type of energy sourced.
- Nineteen percent (19%) shared affordability and cost concerns.
- Thirteen percent (13%) shared achievability concerns regarding the timing of the plan being too slow.

Focus group participants were also generally positive about the plan's intent but suggested some opportunities for improvement. These opportunities included the amount of time needed to implement the plan, getting customer buy-in and being transparent, ensuring SRP's accountability for the changes, and clarifying how this would affect rates.

Phase III Customer Preference for Future Energy System

Monthly bill impact of most importance when selecting an energy system

After completing the exercise, over one-third of respondents (37%) reported the monthly bill impact was the most important input when choosing a preferred future energy system.

*Groups **more likely** to rank **monthly bill impact first** included:*

- *Year-round residents*
- *Those **employed part-time***

Among those ranking the **energy mix first (14%)**, top ranked priorities were evenly split:

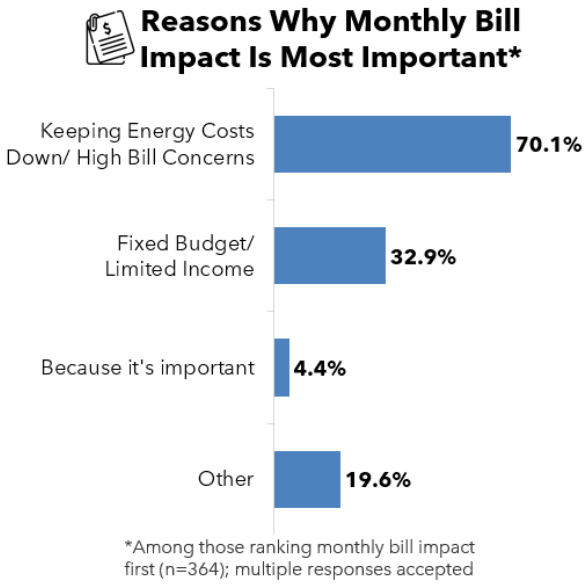
- Affordability – 31% ranked 1st
- Reliability – 36% ranked 1st
- Sustainability – 34% ranked 1st

This suggested the energy mix was seen as a component related to all three priorities.

Attribute	Ranked 1st Most Important
Monthly bill impact	36.8%
Reduction in carbon emissions	15.9%
Number of 2-hour power outages	14.5%
Energy mix	13.9%
Reduction in water usage	11.4%
If SRP will build new gas power plants	5.0%
When SRP will meet its sustainability goals	2.5%

Reasons for ranking inputs first varied

Customer open-ended comments highlighted concerns regarding financial constraints due to changing socio-economic conditions and future uncertainty stemming from inflation and escalating energy expenses. Looking to the future, customers attributed greater costs to the anticipated new infrastructure needed to meet growing demand for electricity and expressed concerns that cost increases could impact quality of life. Additionally, the viability and affordability of future green energy initiatives raised doubts for some given the present economic context.



*The following groups were **more likely** to mention **"fixed budget/ limited income"**:*

- *Customers **aged 55+***
- *Retirees*
- *Those with **limited incomes** (200% of HHS Poverty Guidelines)*

Among those ranking carbon reduction first, about a third mentioned reducing carbon via the use of cleaner energy sources (like solar or nuclear) while nearly half of those ranking energy mix first mentioned these topics as reasons for ranking energy mix as most important.

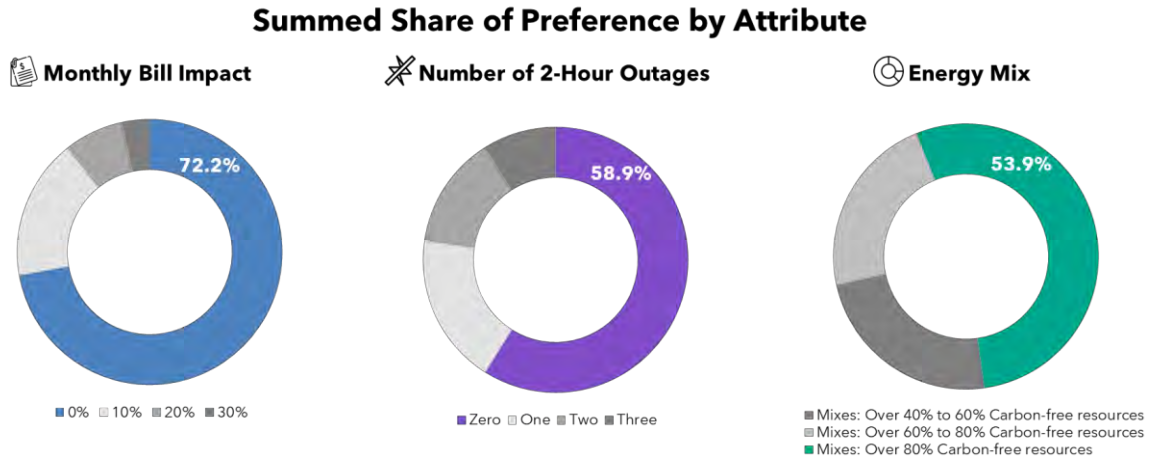
Reasons Why Most Important

Reduction in carbon emissions *(n=169)	Number of 2-hour power outages *(n=139)	Energy mix *(n=147)
37% Reducing carbon has direct impact on climate change	**58%** Dangers associated with outages (hot climate, health concerns, etc.)	**46%** Emphasis on reducing carbon and/or increasing solar or nuclear
32% Emphasis on reducing carbon and/or increasing solar or nuclear	**34%** General reliability concerns	**33%** Some energy sources are limited/ need a mix

Choices indicate a desire to "have it all"

The choice exercise also revealed the preference for each level of key factors in isolation.

- Bill Impact: a majority preferred 0% increase
- Outages: a majority preferred zero 2-hour outages
- Energy Mix: a majority preferred energy mixes with over 80% carbon-free sources



While monthly electricity bills have the largest impact on preference (72%), these preferences indicate that customers want the cleanest, greenest energy at the lowest cost with no implications to reliability.

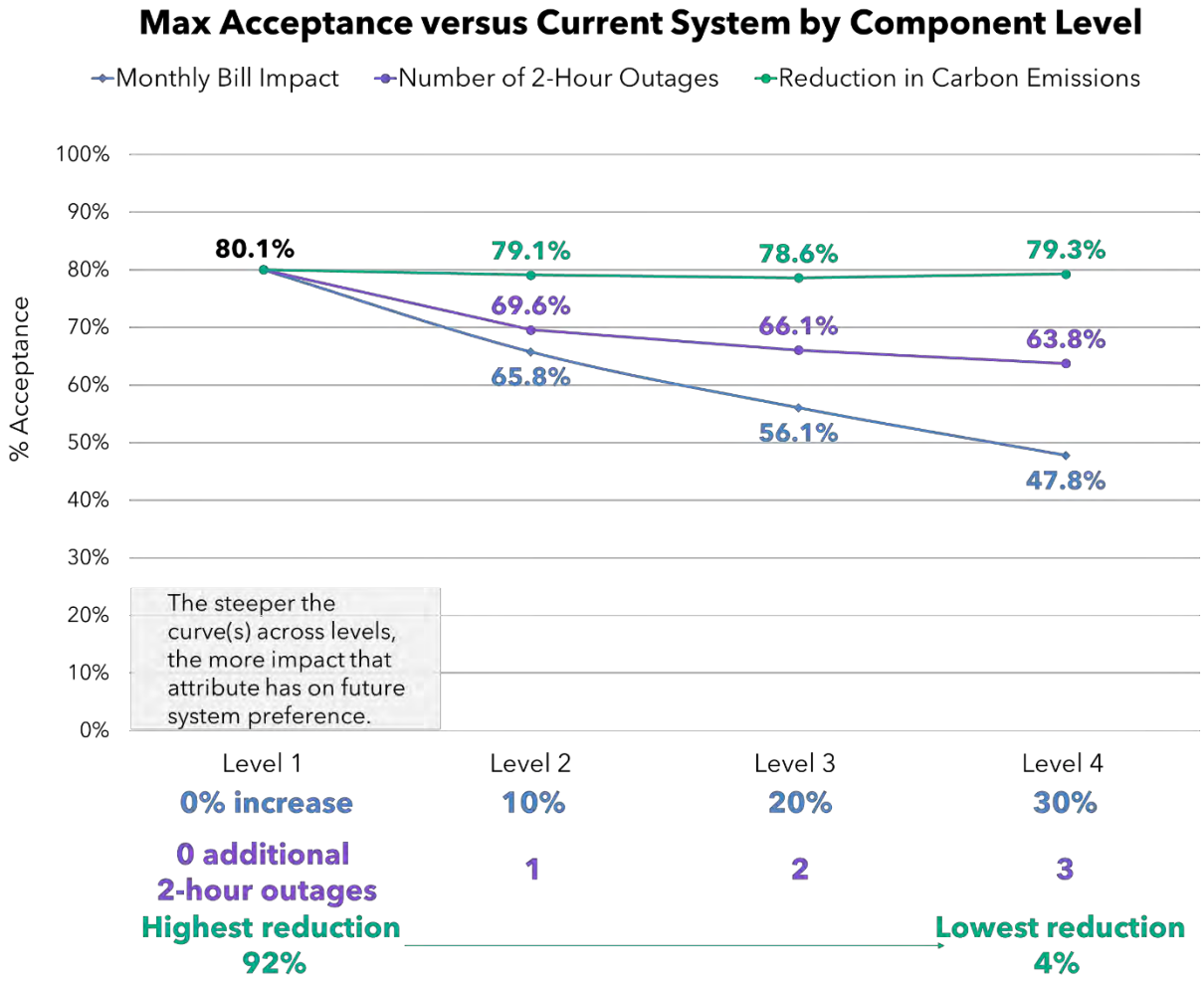
Real-world cost constraints force tradeoffs

While most customers agree that sustainability is important and should be considered by SRP and their customers, there are limitations on how much customers feel they can invest in the “greater good.” Customers expressed that fixed incomes and limited budgets often constrain the degree to which they can support and prioritize sustainability.

Acceptance of future energy systems declines above 0% bill impact

As bill impacts increase, the proportion of customers who accepted an energy system over the current system declined sharply. However, acceptance declines were less steep for the number of 2-hour outages suggesting that customers are less accepting of price increases and more tolerant of minimal additional 2-hour outages.

Furthermore, when tradeoffs are required, carbon reduction has minimal impact with acceptance of energy systems relatively unchanged as the level of reduction in carbon emissions increases.



Customer preferences for a balanced future energy system

While SRP does not know what the future will look like, it will be important to design the future energy system with customer preferences in mind. Findings revealed that from the residential customer's perspective the ideal future energy system should...

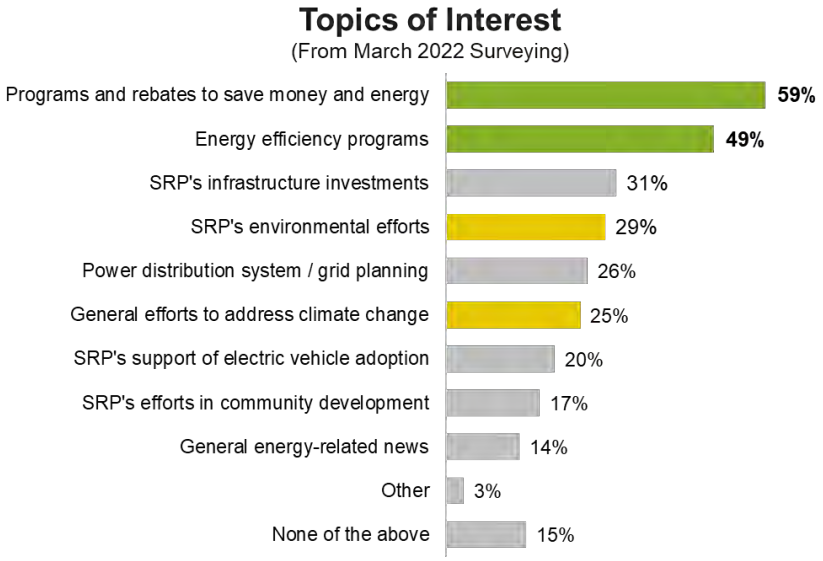
- Manage cost, first and foremost
- Strive to manage monthly bill impacts below a 10% increase
- Include a diverse energy mix to ensure reliability
- Provide the cleanest, most sustainable energy without exceeding a 10% bill increase

Topics of Interest

Over half had interest in ways to save

Customers would most like to continue to hear about ways to save via energy efficiency program and/or rebates. Meanwhile, over one-quarter were interested in topics related to SRP's environmental efforts and/or climate change.

Focus group participants agreed that SRP programs help customers manage and reduce their electricity bills.



*Those with a **household income less than $75k** were **more likely** to want to hear about the following:*

- *Programs and rebates to save money and energy*
- *SRP's support for community development*

*Groups more interested in hearing about **SRP's infrastructure investments** included:*

- *Customers **aged 65+***
- *Non-Hispanics*

***Part-time residents** were **more likely** than those living in Phoenix year-round to want to hear about the following**:** energy efficiency programs, SRP's environmental efforts, and general efforts to address climate change*

Appendix

Focus Group Participant Description*

Total	24
Gender	
Female	13
Male	10
Non-binary	1
Ethnicity	
Black	3
Hispanic	2
White	18
Other	1
Homeownership	
Own	18
Rent	6

Age	
25-34	6
35-44	7
45-54	2
55-64	4
65-74	2
75+	3
Income	
<25k	2
25-49k	5
50-74k	8
75-99k	3
100-149k	3
150+	3

** Focus Groups are exploratory in nature and cannot be projected to a larger population. Attendees are not representative of the full SRP customer base or stakeholders*

Survey Respondent Demographics

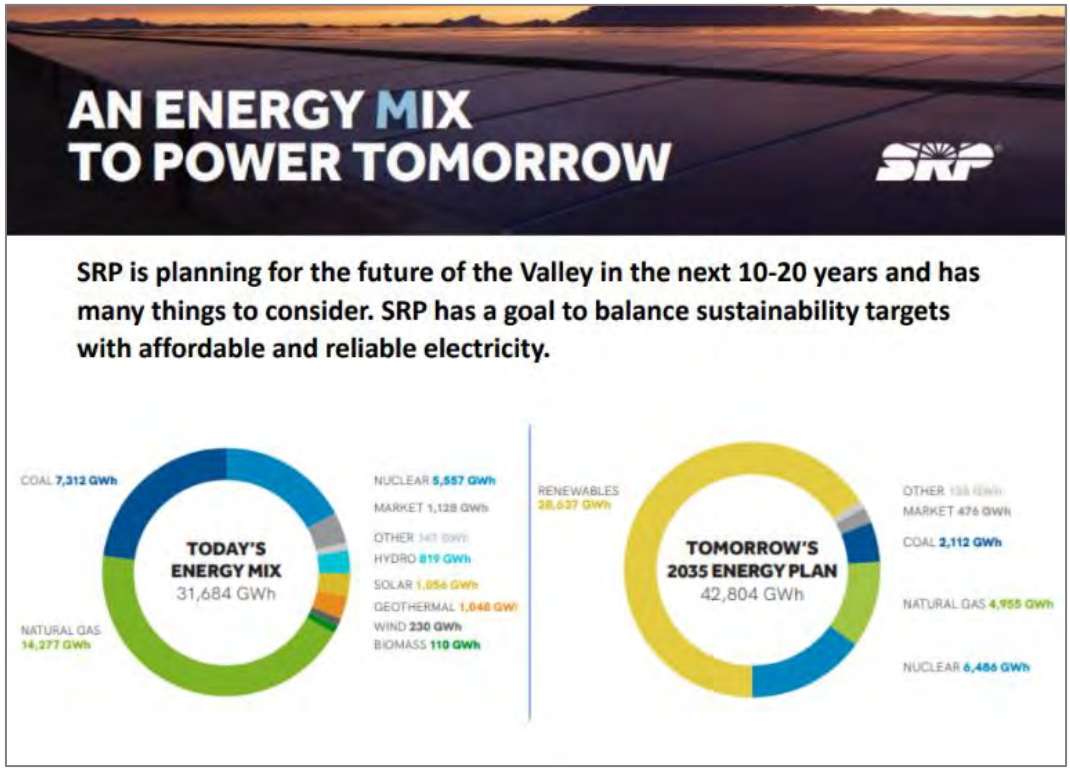
	Phase 2 Survey March 2022 (n=400)	Phase 3 Survey May 2023 (n=1,011)
GENDER		
Female	51%	49%
Male	45%	46%
Non-binary	0%	0%
Prefer not to answer	4%	5%
INCOME		
Limited Income 200%	31%	31%
Non-Limited Income 200%	69%	69%
CREDIT RATING		
Preferred	67%	64%
Satisfactory/Slow/ Unsatisfactory	12%	18%
New Customer	21%	18%
Cash Only	-	1%
ETHNICITY (MULTIPLE SELECTIONS)		
White	69%	69%
Black or African American	4%	5%
Other	13%	12%
Prefer not to answer	18%	17%
HISPANIC ORIGIN		
Hispanic	15%	12%
OWN/RENT HOME		
Own	73%	71%
Rent	28%	29%

	Phase 2 Survey March 2022 (n=400)	Phase 3 Survey May 2023 (n=1,011)
AGE		
18-44	30%	38%
45-64	37%	37%
65+	34%	25%
EMPLOYMENT		
Ful-time/Part-time	51%	53%
Self-employed	6%	8%
Retired	33%	27%
Unemployed/seeking employment/student	4%	3%
Not working/not seeking	2%	2%
N/A / Prefer not to answer	5%	7%
YEARS IN PHOENIX		
2 or less	7%	8%
3-5	10%	9%
6-20	30%	34%
21-39	30%	29%
40+	15%	20%
USAGE*		
Low (6,000 kWh or less)	19%	12%
Moderate (6,001-12,000 kWh)	33%	32%
Medium (12,001-18,000 kWh)	29%	31%
High (More than 18,000 kWh)	20%	23%

Illustrative Plan Description and Background (Phase I & II)

In addition to the visual depiction of the illustrative plan shown below, respondents were provided the following additional description and background during Phases I & II of this research:

> "SRP is working at all times to make sure your power stays on, including during Arizona's extreme summers. To ensure power quality continues to improve, SRP needs to plan long term for the future of the Valley. This means:
>
> - Balancing a transition to clean energy
> - Planning for population growth (and an increased demand for energy)
> - Considering the types of power to buy to make up their power mix (including solar, wind, geothermal, biomass, nuclear, natural gas, and coal)
> - Reducing SRP's carbon intensity (the amount of carbon released per unit of energy produced) by 90% by the year 2050"

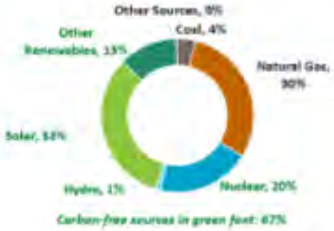


Choice Exercise Example Screen (Phase III)

Customers were asked to evaluate 11 screens, each showing 2 energy plans and a "none of these" option representing the current energy system. An example screen with question wording is shown below.

Which of these hypothetical future energy systems would you prefer SRP implement
Please read through each plan carefully and select the plan you most prefer.

Click here to view a glossary of terms. This will open in a new browser and you can come back to this page to complete the activity.

	2035	2030
Energy Mix:	 *Carbon-free sources in green font: 66%*	 *Carbon-free sources in green font: 67%*
SRP will meet its Sustainability Goals by:	**2035**	**2030**
% reduced carbon emissions (equal to number of gas-powered cars on the road each year):	**20% reduction** (about 675,000 gas-powered cars)	**61% reduction** (about 2.0 million gas-powered cars)
% reduced water usage (equal to the amount of water used by the number of 4-person households shown per year):	**16% reduction** (about 9,000 households)	**52% reduction** (about 30,000 households)
Will SRP build new gas power plants to source energy?	**Will** build	**Will not** build
Your monthly bill will:	Increase by **$30**	**Not increase**
Number of 2-hour power outages experienced in one year due to high energy demand (on a hot summer's day):	**Two** 2-hour outages	**Three** 2-hour outages
	Select	Select

None of these, I would stick with the current system at my current monthly bill amount.

Select



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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit I: Department, Order No. 202-25-7 (Aug. 20, 2025)

Order No. 202-25-7

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. §7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

Order No. 202-25-3

J.H. Campbell Generating Plant (Campbell Plant) is a 1,420 MW coal-fired plant primarily owned by Consumers Energy Company (Consumers) and located in West Olive, MI. In 2021, Consumers announced that it planned to implement a "speed closure" of the Campbell Plant fifteen years before the end of its scheduled design life.[1] Instead of retiring the Campbell Plant at the end of its design life, Consumers planned to accelerate the Campbell Plant's retirement and discontinue its operations on May 31, 2025.

Order No. 202-25-3, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until August 21, 2025. That order was based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO). Specifically, I determined that MISO likely faced tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. I determined that the continued operation of the Campbell Plant would provide additional generation capacity during these periods which would help prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety. I determined that the continued operation of the Campbell Plant was necessary to alleviate immediate and anticipated threats to reliability. My determination was based on a number of facts.

First, the North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[2] In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply

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[1] *See Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan's Clean Energy Transformation*, Consumers Energy (June 23, 2021), https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation. As a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline.

[2] *2025 Summer Reliability Assessment*, North American Electric Reliability Corporation, at 16 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf (NERC 2025 Summer Reliability Assessment).

shortfalls. NERC anticipated that the near-term period of greatest capacity shortfall for MISO would likely occur in August.[3]

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[4] Additionally, EIA stated, "[t]ypically, Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[5] The state's Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it was not projected to be available during the peak demand period this summer.[6]

Third, the Campbell Plant's retirement would have further decreased available dispatchable generation within MISO's service territory, adding to the loss of the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant into their supply forecasts and Consumers acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."[7]

Fourth, MISO's Planning Resource Auction Results for the 2025-2026 Planning Year, released in April 2025, noted that for the northern and central zones, which includes Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[8] While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and these results "reinforce the need to increase capacity."[9]

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order No. 202-25-3 continue, both in the near and long term. The summer season has not yet ended, and the production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO this summer. That need is evidenced by the fact that the Campbell Plant was called on by MISO to generate large amounts of electricity during the heat wave that hit MISO this past June. According

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[3] *Id.*
[4] *Michigan State Profile and Energy Estimates*, U.S. Energy Info. Admin. (Oct. 17, 2024), https://www.eia.gov/state/print.php?sid=MI.
[5] *Id.*
[6] The start-up of Palisades is scheduled for the fourth quarter of 2025.
[7] NERC 2025 Summer Reliability Assessment at 16.
[8] *Planning Resource Auction—Results for Planning Year 2025–2026,* Midcontinent Independent System Operator, Inc., 13 (May 29, 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf. (MISO Planning Resource Auction – Results for Planning Year 2025-26).
[9] *Id*. at 2,12.

to the U.S. Environmental Protection Agency's data, over the month of June, the Campbell Plant generated approximately 664,000 MWh, running at 61% capacity.[10] In fact, between June 11 and August 18, MISO issued dozens of alerts to manage grid reliability in its Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits. MISO issued alerts for the Central Region on at least 40 of the 69 days between June 11 and August 18. In June, MISO issued alerts affecting the Central Region on 18 days, including an Energy Emergency Alert (EEA) level 1 ("Max Gen Step 1b") on June 23 to enable MISO to take emergency action to ensure grid stability, including bringing additional resources online.[11] The Central Region had alerts on 21 days in July, including one Max Generation Warning on July 29 and two Max Generation Alerts on July 28 and 29.[12] Two Capacity Advisory Initiate alerts have been issued in August to date.[13] Moreover, the May 2025 NERC Summer Reliability Assessment referenced a Seasonal Outlook issued by the National Oceanic and Atmospheric Administration (NOAA), which estimates that much of the Midwest has a 33%-40% chance to experience above-normal temperatures this summer.[14] The Seasonal Outlook released by NOAA on July 17, 2025, increased this estimate for much of the region to a 40%-50% chance.[15]

MISO's resource adequacy problems are not limited to the summer. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[16] MISO justified this revision by explaining that "Reliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round

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[10] *See, Custom Data Download, EPA CAMPD (Clean Air Markets Program Data),* https://campd.epa.gov/data/custom-data-download *(search criteria to produce these results could include Emissions >> Monthly >> Unit (default) >>Apply >>"2025" and "June." The data can then be filtered to only include the Campbell Plant.)*

[11] An Energy Emergency Alert is an alert declared by the Transmission Provider in accordance with the NERC Operating Manual associated with the Transmission Provider's inability to provide for the Energy and Operating Reserve requirements of the MISO Balancing Authority Area. For more information, see MISO, FERC Electric Tariff, Module A, § 1.E (Definitions) (92.0.0). For more information on Energy Emergency Alert levels, see North American Electric Reliability Corporation. (n.d.). *EOP-011-1 Emergency Operations*. https://www.nerc.com/pa/stand/reliability%20standards/eop-011-1.pdf.

[12] A Max Gen Alert occurs when MISO is forecasting a potential capacity shortage. A Max Gen Warning is a warning to prepare for a possible Max Gen Event. *See* MISO Operating Procedures, https://efis.psc.mo.gov/Document/Display/9379 (20180920).

[13] A Capacity Advisory alert is an advisory issued based on the potential for limited operating capacity margins (<5%) in the following 2-3 days. *See* MISO Operating Procedures, https://efis.psc.mo.gov/Document/Display/9379 (20180920).

[14] NERC 2025 Summer Assessment at 9.

[15] *Seasonal Outlook*, NOAA Climate Prediction Ctr., (July 17, 2025), https://www.cpc.ncep.noaa.gov/products/predictions/long_range/seasonal.php?lead=1.

[16] M*idcontinent Independent System Operator, Inc.*, FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. Midcontinent Independent System Operator, Inc., 180 FERC ¶ 61,141 (2022).

concern."[17] MISO noted that over 60 percent of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[18]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[19] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projects that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[20]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative.*"[21] In a section of that report entitled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season.

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[22]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Michigan.[23]

On June 6, 2025, subsequent to the issuance of Order No. 202-25-3, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy

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[17] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).
[18] *Id.* at 3-4.
[19] *Attributes Roadmap*, MISO (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.
[20] *Id.* at 11.
[21] *MISO's Response to the Reliability Imperative*, MISO (Updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.
[22] *Id.* at 12.
[23] MISO Planning Resource Auction – Results for Planning Year 2025-26 at 13.

planning reserve margin requirements.[24] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[25] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[26] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[27]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large amounts of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[28] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[29]

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[30] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three year grace period to commence commercial operations.[31] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[32] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

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[24] *2025 OMS-MISO Survey Results*, OMS and MISO (Updated June 6, 2025) https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.
[25] *Id.* at 2.
[26] *Id.* at 7.
[27] *Id.* at 9.
[28] *Id.* at 7, 9.
[29] *Id.*
[30] M*idcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).
[31] 192 FERC ¶ 61,064 at P 84.
[32] *See generally, US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, S&P Global (May 2025), US gas-fired turbine wait times as much as seven years; costs up sharply | S&P Global. "With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."

Order 202-25-3 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[33] President Trump likewise recognized, in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[34] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[35]

The Department's July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy outlook. "Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[36] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.[37] In addition, as just one example, Consumers has announced an additional 1 GW of new power to a planned hyperscale data center and "continue[s] to see positive momentum with data centers within the 9 GW pipeline . . . ."[38]

Grid operators—including MISO itself—have likewise acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the

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[33] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/.

[34] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[35] *Id*.

[36] *See also Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, U.S. Department of Energy (July 2025), at 1, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[37] Ekku Jokinen, *Top 21 Artificial Intelligence Companies in Michigan*, (last accessed Aug. 13, 2025), https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan.

[38] *See Michigan utility Consumers Energy to provide 1GW of power to new hyperscale data center*, Data Center Dynamics (August 05, 2025), https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-to-provide-1gw-of-power-to-new-hyperscale-data-center/ (quoting Consumers Energy CEO Garrick Rochow).

changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[39] Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[40] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[41]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[42] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and accelerated retirements of generation facilities supporting the issuance of Order No. 202-25-3 will continue in the near term and are also likely to continue in subsequent years. This could lead to the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest under FPA section 202(c).

To ensure the Campbell Plant will be available if needed to address emergency conditions, the Campbell Plant shall remain in operation until November 19, 2025.[43]

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[39] Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce, Subcommittee on Energy, 119th Cong. (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), at 5, https://democrats-energycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/files/evo-media-document/witness-testimony_curran_eng_grid-operators_03.25.2025.pdf.

[40] *Id.* at 6.

[41] *Id.* at 7.

[42] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b) (2018).

[43] 16 U.S.C. § 824a(c)(4).

Based on my determination of an emergency set forth above, I hereby order:

A. From August 21, 2025, MISO and Consumer Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.

C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By September 4, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Campbell Plant shall not be considered a capacity resource.

H. This Order shall be effective from 00:00 Eastern Daylight Time (EDT) on August 21, 2025, and shall expire at 00:00 EDT on November 19, 2025, with the exception of applicable compliance obligations in paragraph D.

I. Issued in Norfolk, Virginia at 8:50pm Eastern Daylight Time on this 20th day of August 2025.

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

Michigan Public Service Commissioners
Chairman Dan Scripps
Commissioner Katherine Peretick
Commissioner Shaquila Myers

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit J: CoPUC, 120 Day ERP Implementation Report, Public, filed on April 11, 2025, in Proceeding No. 23A-0585E

Colorado PUC E-Filings System



Tri-State Generation and Transmission Association, Inc.

2023 Electric Resource Plan

Phase II Implementation Report

PUBLIC VERSION

(Colorado Public Utilities Commission Proceeding No. 23A-0585E)

NOTICE OF CONFIDENTIALITY

A portion of this document has been filed under seal.

Confidential Information has been redacted in the following documents.

- Report Pages 26, 27, 37, 38, 48, 49, 59, 69, 70, 80, 81
- Attachment B

Highly Confidential Information has been redacted in the following documents:

- Attachments B, B-4, B-7, B-8, C, C-1, D-1, D-2, D-3, D-4, D-5, D-6, F-1, F-2, F-3, G

April 11, 2025

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Executive Summary

Tri-State Generation and Transmission Association, Inc. (Tri-State) is a wholesale electric generation and transmission cooperative association with Utility Member Systems located across Colorado, Nebraska, New Mexico, and Wyoming.

This report is Tri-State's 2023 Electric Resource Plan (ERP) Phase II Implementation Report. The report complies with applicable Colorado Public Utilities Commission (CoPUC) Rules and Decisions as identified in Attachment A.

Tri-State's preferred portfolio is Portfolio 4 – New ERA Gas Flexibility Shafer Replacement (FLEXSR). The FLEXSR portfolio adds 700 MW of wind and solar, 650 MW of storage, and 307 MW of gas between 2026-2031, replaces the turbines at J.M. Shafer to improve its capacity contributions,[1] maintains the previously announced Craig 3 and SPV 3 retirement dates, and results in a generation portfolio that meets both Level 1 and Level 2 Reliability Metrics, the Colorado GHG emissions reduction targets,[2] the Colorado Renewable Energy Standard, and the New Mexico Renewable Portfolio Standard, all while avoiding costly transmission upgrades identified in other portfolios—making FLEXSR the least-cost portfolio.[3] This portfolio, which selects 1,657 MW of new resources from the 2024 Requests for Proposals (RFPs), reflects Tri-State Members' strategic directive to ensure reliable, affordable, and responsible service, and also addresses the CoPUC's recent concerns "…regarding the large, unexpected cost increases in transmission investments…" and a "need to improve [ ] transmission modelling and cost estimation processes in future ERP proceedings…"[4] The CoPUC Commissioners have also identified their concern in recent public meetings, recognizing that generation selected through ERPs has been "agnostic" in terms of evaluating associated transmission expenses and indicating a desire to "…analyze and optimize…options to ensure that our generation selection…to ensure that we're looking at optimizing costs across the system including the transmission system…"[5] Tri-State's approach to bid selections in the FLEXSR portfolio directly addresses these concerns, as described in detail in Attachment G.

Tri-State has selected the FLEXSR portfolio as a result of the portfolio's overall performance across the reliability, environmental, and financial categories analyzed and described in this report. Tri-State has taken steps to initiate a Resource Solicitation Cluster (RSC) for entering FLEXSR bids into Tri-State's Generator Interconnection through its Open Access Transmission Tariff (OATT) Large Generator

[1] The Shafer replacement is described in Attachment H.

[2] 2020 ERP Phase I Settlement Agreement, at Section 3.3.4 (Proceeding No. 20A-0528E): "Tri-State agrees that, going forward, it will operate its system in a manner that achieves, at a minimum, with respect to its APCD-verified 2005 Baseline, the following reductions in GHG emissions related to Tri-State's wholesale sales of electricity in Colorado (the "Interim-Year Emissions Reductions"): A twenty-six percent (26%) reduction in calendar-year 2025; a thirty-six percent (36%) reduction in calendar-year 2026; and a forty-six percent (46%) reduction in calendar-year 2027."

[3] Lowest PVRR, exclusive of SCoC and SCoM.

[4] These concerns arose in other recent Phase II proceedings. *See* Decision No. C24-0052, at ¶ 158 in Proceeding No. 21A-0141E (issued January 23, 2024).

[5] CWM March 5, 2025, Commissioner Gilman at 1:12:31 and 1:12:53. Publicly available at: https://www.youtube.com/watch?v=dol_38ci5dU.

Interconnection Process. Four of the ten bids already have a queue position and therefore do not need to be part of the RSC study. The benefits of FLEXSR over other portfolios are reflected in the analyses presented in this Phase II report.

Portfolio Analysis Summary

Tri-State modeled six portfolios for Phase II of the 2023 ERP and created three back-up bid pools, as identified in Attachment B-3. All of the Phase II modeling reflected input assumptions based on the best available information available at the start of modeling, reflective of any known Tri-State system constraints and compliance requirements, as described in Attachment B and Attachments B-1 through B-8.

Tri-State remains in a capacity-long position until 2030;[6] however, resource acquisitions are required through this Phase II for ensuring ongoing resource adequacy and reliability as two coal units are retired in 2028 and 2031 and to maintain progress toward emission reductions for Colorado statutory compliance as well as for New ERA funding eligibility. Waiting to procure resources needed for 2030 until the 2027 ERP would not be prudent given that the 2027 ERP Phase II process may not conclude until late 2028 or early 2029; however, Tri-State is cautious to not pursue new resources based on speculative loads. At the same time, retirement of dispatchable coal resources cannot be affordably or reliably replaced solely with semi-dispatchable resources. The new resources, including the dispatchable gas plant in Moffat County, will provide jobs and tax base that support community vitality across many areas of our system.

Tri-State considered the Social Cost of Carbon (SCoC) and Social Cost of Methane (SCoM) when determining which Phase II portfolio was preferred, including analysis of the environmental and financial comparisons shown in the Comparative Analysis section of this report. Tri-State has taken these comparisons into significant account in determining that our preferred portfolio in Phase II is the best course of action at this time. Tri-State's preferred portfolio achieves the lowest present value of revenue requirements (PVRR), meeting the affordability expectations of Tri-State Members in avoiding the risks associated with procuring bids selected in other portfolios at a higher cost that do not yield impactful environmental or reliability attributes.

All of the Phase II portfolios meet essential reliability targets, while achieving an 80 percent GHG emissions reduction in Colorado in 2030 (with respect to the 2005 baseline)[7] reflective of Colorado policy.[8] However, the other portfolios analyzed result in significant, unnecessary financial burdens by aggressively pursuing resources with high transmission interconnection upgrade costs that are not necessary to achieve the same operational, environmental, and reliability benefits resulting from procurement of FLEXSR bids. Tri-State is keenly aware of the economic challenges its Members face in rural America. Demographic data indicates 59 percent of our service area is considered economically disadvantaged or distressed.[9] Tri-State is not in a position to pursue generation procurements that

[6] *See* Table 2, Loads and Resources, submitted in the 2024 ERP Annual Progress Report filed December 2,2024 in Proceeding No. 23A-0585E.
[7] See Attachment D.
[8] §25-7-105(1)(e)(VIII)(I), C.R.S.
[9] U.S.D.A.: https://ruraldevelopment.maps.arcgis.com/apps/webappviewer/index.html.

would cause significant undue financial burdens for Members[10] or compromise its ability to meet the core reliability expectations of its Members.

Additional details on the comparative analysis Tri-State completed to support its preferred portfolio selection can be found in the Comparative Analysis section of this report.

Addressing Commission Rule 3605(h)(II)

The Commission must consider the following factors in issuing a Phase II decision:

> *In accordance with §§ 40-2-123 and 40-2-124, C.R.S., the Commission shall consider renewable energy resources, resources that produce minimal emissions or minimal environmental impact, energy-efficient technologies, and resources that affect employment and long-term economic viability of Colorado communities. The Commission shall further consider resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.*

Phase II of Tri-State's 2023 ERP included RFPs for a diverse mix of renewable, storage, and dispatchable resources located across the Tri-State system. Bidders were required to provide Best Value Employment Metrics (BVEM) information identifying Colorado employment benefits.[11] The Phase II portfolio analysis reflected GHG Targets (2025, 2026, 2027, and 2030),[12] Energy Efficiency Targets (2024, 2025, and 2030),[13] and Demand Response Targets (2025 and 2030)[14] as agreed upon in the Settlement Agreements in Phase I of the 2020 and 2023 ERPs.

Colorado's energy security, economic prosperity, and insulation from fuel price increases are best supported by a Tri-State portfolio that is diverse in the type, size, location, and operations of generation, including through bid procurements that avoid costly transmission network upgrades. Tri-State developed, in consultation with stakeholders, a set of robust reliability criteria in 2022, updated reflective of a third-party 2024 EWE Study, and tested portfolios' extreme weather event (EWE) sensitivities to ensure future resource additions can meet the necessary reliability and resource adequacy needs of its Members. The FLEXSR preferred portfolio meets these rigorous standards, both affordably and responsibly.

The preferred portfolio will continue to advance the environmental objectives of the State of Colorado because it is forecasted to achieve the Colorado GHG Targets. The GHG reductions were calculated using the Colorado Air Pollution Control District's (APCD) emissions workbook methodology.

[10] Tri-State is subject to Federal Energy Regulatory Commission rate jurisdiction, as of September 3, 2019.
[11] *See* HIGHLY CONFIDENTIAL Attachment F-1.
[12] 2020 ERP Settlement Agreement, at Section 3.3.4. (Proceeding No. 20A-0528E).
[13] 2020 ERP Settlement Agreement, at Section 3.11.9. (Proceeding No. 20A-0528E).
[14] 2020 ERP Settlement Agreement, at Section 3.11.8. (Proceeding No. 20A-0528E); 2023 ERP Settlement Agreement, at Section 4.9.1. (Proceeding No. 23A-0585E).

In accordance with § 40-2-129, C.R.S., the Commission shall determine: whether the utility has provided best value employment metrics; whether the utility has certified compliance with the objective standards for the review of such best value employment metrics as set forth in the RFP approved in the Phase I decision; and whether the utility has agreed to use a project labor agreement for the construction or expansion of a generating facility.

Tri-State has provided BVEM provided by bidders, for the bids advanced to modeling, in HIGHLY CONFIDENTIAL Attachment F-1.

Tri-State included evaluation of BVEM as a non-price factor in its bid evaluation, as described in the Bid Evaluation section of this report.

Tri-State intends to enter into power purchase agreements (PPAs) and Engineering, Procurement, and Construction contracts (EPCs) for the preferred portfolio generation and storage facilities; therefore, the developers and EPC contractors will be responsible for determining whether a project labor agreement will be used.

In accordance with § 40-2-134, C.R.S., the Commission shall determine whether the final cost-effective resource plan meets the energy policy goals of Colorado.

The FLEXSR preferred portfolio is the most cost-effective portfolio modeled, having the lowest PVRR. The preferred portfolio also complies with all applicable rules and regulations in the state of Colorado, including achieving at least an 80 percent reduction in GHG emissions by 2030 while continuing to ensure affordable and reliable service.

In accordance with § 40-3.2-106(3), C.R.S., the Commission shall consider the net present value of the cost of carbon dioxide emissions, the net present value of revenue requirements of the cost-effective resource plan, and other relevant factors as determined by the Commission in its Phase I decision.

The FLEXSR preferred portfolio has the lowest PVRR among the portfolios modeled, including analysis for optimization of interconnection cost as described in Attachment G. Tri-State considered the SCoC in its review of the portfolio modeling results as described in the Portfolio Analysis Summary section above and in the Comparative Analysis section below.

Stakeholder Engagement

Tri-State has engaged transparently and collaboratively in stakeholder engagement throughout the 2023 ERP. Numerous stakeholder groups representing a diverse set of interests participated in meetings in advance of Tri-State's filing of this Implementation Report. These discussions provided an opportunity to further educate stakeholders on the complexities of the Tri-State system, inform parties of key modeling inputs and assumptions, and facilitate dialogue on topics applicable to Phase II. These stakeholder meetings occurred between December 2023 and March 2025, covering the following topics:

1. November 29, 2023: Briefing on 2023 ERP Phase I Filing

2. January 24, 2024: EWE Focus Group[15] Meeting #1
3. March 1, 2024: EWE Focus Group Meeting #2
4. March 21, 2024: EWE Focus Group Meeting #3
5. April 23, 2024: 2024 DSM Roundtable Meeting (1 of 2)
6. June 11, 2024: FERC Filing Updates
7. September 24, 2024: Meeting on USDA Guidance and Phase II Portfolios[16]
8. October 30, 2024: Meeting on EWE[17]
9. December 10, 2024: 2024 DSM Roundtable Meeting (2 of 2)
10. December 23, 2024: Colorado PUC Staff Meeting on MIP[18]

Several e-mail communications and updates to stakeholders also occurred in advance of and during Phase II modeling with the aim of ensuring communications on key Phase II topics. Tri-State maintains ongoing collaboration with interested stakeholders across a variety of electric sector topics.

Bid Evaluation

Tri-State issued three Phase II RFPs on September 13, 2024. Tri-State's bid evaluation process was undertaken over a 45-day period following the close of the RFPs on October 28, 2024.[19] The bid evaluation process, completed prior to advancing projects to Phase II computer-based modeling, consisted of several steps – including a completeness screen, an economic screen, an interconnection/transmission screen, and a non-price factor screen.

The ***completeness review*** included an assessment of whether bids provided required information, such as fully completed bid forms or other narrative requirements. This screen also ensured submittal of the required bid fee(s). When bid information appeared incomplete or unclear, Tri-State contacted the bidders and provided them approximately two business days to supplement their bids with the necessary information to enable the bids to move forward in the bid evaluation process.

Following the completeness review, bids were sorted by technology type (wind, solar, etc.) and passed through an ***economic screen***. Either a levelized cost of energy (LCoE) or leveled cost of capacity (LCoC) was evaluated, depending on the technology type, as identified in the table below.

Table 1: Economic Screen by Technology Group Applied to Phase II Bids

LCoE	LCoC
Solar	Standalone Battery
Wind	Dispatchable Combustion Turbine
Solar + Battery	Dispatchable Natural Gas with CCS
Wind + Battery	
Geothermal	

[15] EWE Focus Group included Tri-State, Tri-State's Wyoming Members, Grid Lab, Sierra Club and their consultants, and Rocky Mountain Institute (RMI).
[16] 2023 ERP Settlement Agreement, at Section 4.4.3 (Proceeding No. 23A-0585E).
[17] 2023 ERP Settlement Agreement, at Section 4.8.3 (Proceeding No. 23A-0585E).
[18] 2023 ERP Settlement Agreement, at Section 4.4.8 (Proceeding No. 23A-0585E).
[19] The dispatchable RFP bid deadline was extended to November 27, 2024 due to the limited number of bids received.

Bids in each technology group, in various size ranges, were advanced to the transmission and interconnection screen if the costs were at or below the latest generic resource pricing and/or where other size, locational, or diversity considerations were applied.

The ***interconnection/transmission screen*** included a review of project/facility sizes (capacity), point of interconnection (POI), transmission provider, and queue status and transmission/interconnection provider verification. Bidders were expected to clearly identify projected interconnection and transmission costs in their proposals as well as reflect these costs in the prices associated with each bid. Tri-State's Transmission Planning team reviewed each bid's viability and the reasonableness of associated cost estimates. The viability screen focused on the ability of the transmission system to accommodate the new firm resource and the ability to construct the project, including network upgrades and interconnection facilities by the identified in-service date. Cost estimates were reviewed to ensure bids factored in a reasonable level of network upgrade and interconnection facility costs to integrate the project at the identified point of interconnection. Finally, Tri-State's Transmission Planning team verified whether the project was in an interconnection queue based on the information provided by the bidder. For projects achieving commercial operation in 2026 or 2027, bidders were required to be in an interconnection queue under a transmission provider's generator interconnection process. For those projects whose commercial operation dates (COD) were anticipated to be after 2027, bidders were encouraged to be in an interconnection queue, however, this will not be a requirement in the interconnection/transmission screen.

For projects under a PPA structure, interconnection with the Tri-State transmission system was viewed more favorably than those projects connecting to a third-party transmission system. For projects in which Tri-State was seeking ownership, interconnection with the Tri-State transmission system was required. The interconnection/transmission provider was noted as part of the interconnection/transmission screen.

Projects that did not receive favorable evaluation results during the interconnection/transmission screen were eliminated from further consideration in the bid evaluation process. In cases where the interconnection/transmission screen identified certain flawed aspects of an otherwise viable bid, related primarily to cost and/or in service date assumptions, Tri-State contacted bidders for clarification and cost updates.

Lastly, Tri-State conducted a ***non-price factor analysis*** of the bids that emerged from the interconnection and transmission screen. The non-price factor analysis considered project capabilities across four categories: community stewardship, counterparty profile, project feasibility, and project capability. The factors are identified in the table below.

Table 2: Non-Price Factors

Category	Factor
Community Stewardship	• Best Value Employment Metrics • Contribution to meeting GHG reductions in Colorado • Location in a Tri-State Member System • Location in Moffat County or West End of Montrose County • Community Benefits
Counterparty Profile	• Bidder's prior experience with project development

	• Bidder's record of litigation related to power supply agreements and failure to honor bids from prior solicitations, or failure to complete projects as proposed • Financial viability of the bidder • Markup of PPA or term sheet terms and conditions
Project Feasibility	• Certainty of financing and outside funding sources to include tax credits or government subsidies/incentives • Compliance with all applicable local, state and federal laws, rules and orders, and processes; permit(s) identification and status • Local opposition or community efforts to stop project development • Ability to source materials • Project retirement/decommissioning plan • Legal, engineering and other costs required to implement the proposed project
Project Capability	• Renewal and purchase options at end of PPA (if applicable) • Impact on scheduling project output to Tri-State load • Operational flexibility

Projects with overall favorable non-price factor analysis were advanced to modeling; however, poor evaluation results in certain non-price factor categories resulted in a project not being advanced to modeling.

Bids Received

Tri-State received 145 individual eligible bid proposals by the bid deadline, as identified in the 45-Day Report filed in Proceeding No. 23A-0585E on December 12, 2024. A total of 52 bids were advanced to modeling, as shown in HIGHLY CONFIDENTIAL Attachment C, following the bid evaluation described above. On December 5, 2024, Tri-State notified bidders whether their projects had advanced to modeling and offered a price refresh opportunity per Tri-State's Bid Policy,[20] due December 9, 2024. For bids not advanced to computer-based modeling, and for which bidders requested additional feedback on their bids, Tri-State identified at which stage of the bid evaluation process the bid failed to pass a screen and offered an opportunity for further discussion at or near the conclusion of Phase II. Tri-State also provided details in its 45-Day Report[21] identifying how many bids failed to pass each screen and factors that caused bids to fail at each screen.

Table 3: Summary of Bids Advanced to Modeling by Technology Type

Technology Type	Total (# of Bids)	MW	MW BESS
Solar	12	2,303	-
Wind	6	1,218	-
Solar+Battery	12	2,049	907
Wind+Battery	1	180	100
Short-Duration Storage	16	-	2,200

[20] Hearing Exhibit 102 Attachment SKH-7 (Proceeding No. 23A-0585E).

[21] https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1032592&p_session_id=

Long-Duration Storage	1	-	100
Gas Plant	2	495	-
Gas Tolling	1	314	-
Geothermal	1	20	-
TOTAL	**52**	**6,579**	**3,307**

Commission Rule 3605(h)(I)(A)(iii) requires that Tri-State "provide the Commission with the best value employment metrics information provided by bidders." The BVEM information provided by bidders whose bids were advanced to modeling is provided in Attachment F-1. As identified in Table 2 above, BVEM is a non-price factor analyzed by Tri-State as an element of bids' community stewardship.

Tri-State is also providing to the Commission and stakeholders a mapping of the bid project locations overlayed with a map of disproportionately impacted (DI) communities, in Highly Confidential Attachment C-1.[22] The file contains five maps: 1) all bids with DI overlay, 2) bids advanced to modeling with DI overlay, 3) bids selected in portfolio modeling with DI overlay, 4) bids selected in the preferred portfolio with DI overlay, and 5) bids selected in the preferred portfolio with Tri-State Member territories overlay.

Bids Selected in Portfolio Modeling

Table 4 identifies the bids selected in one or more of the portfolios modeled.

Table 4: Bids Selected in Portfolio Modeling

Bid	Technology Type	MW	Portfolios					
			1 – NEE	2 – NELG	3 – FLEX	4 – FLEXSR	5 – NNG	6 – NNGSR
PV-0004-4-nm	Solar	100	☒	☒	☒		☒	
PV-0004-5-wco	Solar	140	☒	☒			☒	
PV-0006-8-eco	Solar	200				☒		☒
WI-0013-2-wyo-wne	Wind	200	☒	☒	☒	☒	☒	☒
WI-0013-3-eco	Wind	200	☒	☒		☒	☒	☒
WI-0016-1-eco	Wind	297			☒			
PC-0009-2P-eco	Solar / Battery	150 / 75	☒	☒	☒		☒	
PC-0018-1P-nm	Solar / Battery	100 / 50	☒	☒	☒	☒	☒	☒
ST-0002-5-wco	4hr - Battery	50	☒	☒	☒	☒	☒	☒
ST-0002-6-wco	4hr - Battery	100		☒				
ST-0004-10-eco	4hr - Battery	100		☒		☒	☒	☒
ST-0004-6-eco	4hr - Battery	150				☒		☒
ST-0004-8-wco	4hr - Battery	200					☒	☒
ST-0004-9-eco	4hr - Battery	100					☒	☒
ST-0009-3-wco	4hr - Battery	200	☒	☒	☒	☒	☒	☒
ST-0009-4-nm	4hr - Battery	100	☒	☒	☒	☒	☒	☒
ST-0010-4-eco	4hr - Battery	150			☒		☒	☒
ST-0017-1-eco	4hr - Battery	100	☒	☒	☒		☒	☒
ST-0018-1-eco	4hr - Battery	50			☒		☒	
ST-0019-1-eco	Iron Air Battery	100	☒				☒	

[22] 2023 ERP Settlement Agreement, at Section 4.10.2. (Proceeding No. 23A-0585E).

GG-0006-1-wco	Combustion Turbine	307		☒				
GG-0006-2-wco	Combustion Turbine[23]	307	☒		☒	☒		

Independent Evaluator

Tri-State utilized the services of a third-party Independent Evaluator (IE) to support RFP administration, and to validate the bid evaluation process and results. The role of the IE was to ensure fairness, transparency, and consistency in Tri-State treatment of bids.

In order to provide the bidder a paperless (electronic only) experience and prior to the Phase II RFP release, the IE assisted Tri-State with web hosting, website development, and web-form development to provide a standardized bidder experience by hosting the following services: RFP website and bidder registration, notice of intent and non-disclosure agreements process support, and bidder document upload and storage management. Tri-State created an Outlook mailbox for each RFP that the IE could also access, enabling the IE to view communications with bidders, to monitor for consistency and transparency.

The IE reviewed the non-price factor evaluation criteria matrix prepared by Tri-State and confirmed its fairness and consistency and alignment to the Bid Policy. After Tri-State completed each bid evaluation screening phase, Tri-State prepared a summary of the results that included the purpose of the screen, the evaluation criteria, and the bid advancement results; then Tri-State and the IE discussed the results. The IE independently reviewed a subset of bids that passed and failed each screen to validate and ensure consistency across bid evaluation results. The IE communicated its completion of each screening review.

Due to only a very limited number of bids being received on October 28, 2024, in response to the Dispatchable RFP, Tri-State consulted with the IE for concurrence in issuing a 30-day extension for the Dispatchable RFP to November 27, 2024. Tri-State informed the 2023 ERP Settling Parties of the Dispatchable RFP extension via email. Beginning November 28, 2024, Tri-State and the IE completed an accelerated screening of dispatchable bids to remain on track with the 45-day bid evaluation period.

The IE uses and is familiar with EnCompass, the same modeling software used by Tri-State. Tri-State shared its model with the IE for review of Tri-State's modeling inputs and set-up, primarily for ensuring bid data was consistent with bidder-provided information. After Phase II portfolio modeling, the IE also reviewed modeling outputs for any anomalies.

The IE is expected to file a report providing its observations of Tri-State's Phase II process simultaneous to the filing of this report.

Phase II Portfolio Analysis

Tri-State modeled six portfolios:

1. New ERA Expanded (NEE)
2. New ERA Limited Gas (NELG)

[23] Eight 38.36 MW natural gas-fired turbines, hydrogen-capable with a demonstrated blend of 30%.

3. New ERA Gas Flexibility (FLEX)
4. FLEX Shafer Replacement (FLEXSR)
5. No New Gas (NNG)
6. NNG Shafer Replacement (NNGSR)

The modeling assumptions unique to each portfolio are identified in Attachment B-3.

Tri-State also conducted expansion plan modeling to identify three back-up bid pools:

7. Renewable Back-up Bid Pool (BkRE)
8. Standalone Storage Back-up Bid Pool (BkST)
9. Gas Plant Back-up Bid Pool (BkNG)

Tri-State will, to the extent necessary, utilize backup bid pools to replace preferred plan bids that fail. If a preferred plan bid cannot move forward, Tri-State aims to replace it with a similarly sized, similar technology type project, if possible, subject to limitations and economics. This designation of bids as back-ups is limited to creation of a potential pool of the next most economic bids, as Tri-State cannot anticipate which preferred plan bid or subset of bids could fail at a given point in time; therefore, modeling unknown and possible portfolio permutations would be inefficient. The bids identified in the back-up pools are not listed in an anticipated order of preference; this is because selection from the back-up pools depends upon which preferred plan bid would happen to fail and what location of the Tri-State system that bid was located and the transmission constraints projected at the bid locations at the time of CODs. Tri-State would, upon any bid failure(s), utilize bid(s)[24] from the relevant back-up bid pool along with the remaining preferred portfolio of bids still viable, and run a dispatch at that time to ensure continued adherence to the same affordability, reliability, and responsibility metrics and principles each Phase II portfolio was measured against. Tri-State will timely notify the Commission of any bid failures, identify steps taken to remediate the failed project, where feasible, and identify the back-up bid, or combination of backup bids, selected from the pools.

Additionally, a sensitivity analysis was performed to re-dispatch each portfolio under EWE conditions. The modeling assumptions and results of the sensitivity analyses are provided separately in Attachment E.[25]

Each section of this report that follows presents data and analytical results from base portfolio modeling, formatted in the following order:

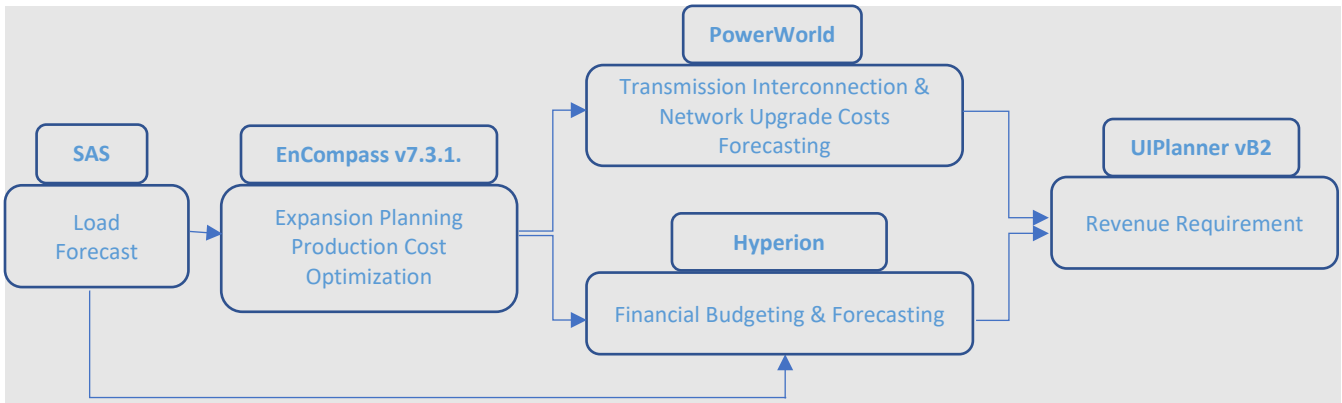
- Expansion Plan, Retirements, System Mix, and Capacity Factors
- Environmental Analysis
- Financial Analysis
- Transmission Analysis
- Reliability Analysis

An overview of Tri-State's approach to each element of the portfolio analyses is provided below.

[24] One bid, depending on the unit size, may need to be replaced by one or more bids.
[25] 2023 ERP Settlement Agreement at Section 4.8.1. (Proceeding No. 23A-0585E).

Figure 1 below identifies the software tools utilized by Tri-State for completing each component of the portfolio analyses and the succession of data flow through each modeling and analytical system. Use of the EnCompass modeling software for capacity expansion and portfolio optimization began in 2022.

Figure 1: Modeling Software Tools



Expansion Plan, Retirements, System Mix, and Capacity Factors

Tri-State used the EnCompass resource planning software to complete capacity expansion and portfolio optimization analyses for Phase II modeling, inputting the applicable modeling assumptions described in Attachment B and Attachments B-1 through B-8, as applicable. Resource bids advanced to modeling as a result of the RFPs issued by Tri-State on September 13, 2024 and selected in the portfolio expansion plans are identified by a bid identifier, resource type, and project megawatts (MW).

The RAP for Phase II is 2026-2031, with the full Resource Planning Period (RPP) modeled for 2024-2043.[26]

Environmental Analyses

Based on the expansion plan and dispatch produced for each portfolio, Tri-State has provided an analysis of forecasted system-wide emissions and water use, as well as the annual social costs of carbon and methane.

For each portfolio, Tri-State separately produced a verification workbook, using the Colorado Air Pollution Control Division's (APCD) latest template,[27] calculating forecasted carbon emissions reductions, provided in Attachment D files. Target-year emissions reductions percentages for each portfolio, calculated within the verification workbooks, are provided in this report.

Financial Analyses

Pursuant to Rule 3605(h)(I)(A)(ii), Tri-State provided a financial analysis of each portfolio and each Tri-State owned resource, including:

- Annual revenue requirements;

[26] Tri-State's Hyperion financial forecasting for 2024 consists of six months of actuals and six months of forecast. Tri-State's financial forecasting for 2025 reflects Tri-State's Budget rather than EnCompass 2023 ERP Phase II dispatch output due to timing of the modeling, however, neither year is part of the Resource Acquisition Period (RAP).

[27] *See* Attachment B.

- Present value revenue requirement, with and without the social costs of carbon and methane; and
- A net present value of each owned resource, over the planning period, with and without the social costs of carbon and methane.

Additionally, one of the benefits of utilizing the EnCompass software is that it offers increased visibility into generation unit curtailments. EnCompass allows for a prioritization of curtailment order.[28] For each portfolio, curtailment MWhs by intermittent resource type seasonally and year are provided.

Transmission Analyses

Bidder-provided transmission cost estimates for proposed generation projects submitted in response to Tri-State's RFP were analyzed as part of the bid evaluation process to identify bids that should be advanced to portfolio modeling. Each portfolio was analyzed for its impact on transmission expenditures – both forecasted interconnection costs and additional network upgrades anticipated to be required, beyond already planned upgrades.

In addition to the traditional transmission interconnection and upgrades estimates prepared for each portfolio, Tri-State evaluated preferred portfolio bid selection in a manner that optimized interconnection costs, given growing transmission system constraints in recent years. As Tri-State was completing 2023 ERP Phase II portfolio modeling, it became increasingly clear that the EnCompass model was effectively selecting least-cost bids based on their operational profiles and the Tri-State system needs and transmission constraints, but the expansion plan model did not have full insight into the downstream transmission interconnection and network upgrade costs that were resulting from the bid selections. Additionally, the model could not identify opportunities where use of surplus interconnection could maximize the value of existing interconnections.[29] Tri-State was able to complete interconnection optimization for two of the portfolios—the preferred portfolio (FLEXSR) and the NNGSR portfolio. Optimizing the preferred portfolio enabled the avoidance of approximately $370M in transmission capital expenditures inclusive of allowance for funds used during construction (AFUDC) during the RAP. Optimizing the NNGSR portfolio enabled the avoidance of approximately $317M in transmission capital expenditures including AFUDC during the RAP.

Transmission planning cannot at this time be fully integrated into the generation planning process due to regulatory jurisdiction and organized market considerations, unique transmission and generation planning compliance requirements, bid timeline constraints, and variations in key modeling input cycles. However, Tri-State was able to address interconnection optimization in this Phase II by separately evaluating transmission cost and locational aspects of the bids following expansion plan selection. Going forward, Tri-State will integrate this optimization step across all portfolios beginning in Phase II of

[28] In the event that resources must be curtailed, Tri-State's model will first reduce dispatch of thermal resources to economic minimum levels, including taking thermal resources offline if possible. The model then curtails solar resources, wind resources, thermal resources below economic minimum and must take contracts (*i.e.,* hydropower and Basin contracts)–in that order.

[29] A recent report from GridLab suggests "PUCs should require evaluation of surplus interconnection options in integrated resource planning (IRP)," See *Existing Power Plants Sharing Grid Access with Renewables Can Lower Costs and Double U.S. Generation Capacity*, at page 4, released in February 2025: https://surplusinterconnection.s3.us-east-1.amazonaws.com/2025-02-21_GridLab_Surplus_Interconnection_Technical_Paper.pdf.

the 2027 ERP, to continue to enable the avoidance of interconnection and upgrade expenses and optimize use of the existing transmission system. Tri-State will work with its EnCompass software provider, and the IE, to identify potential approaches to informing the model of bid interconnection costs and transmission upgrade costs within the expansion plan selections, and will describe any proposed modeling changes in its Phase I filing for the 2027 ERP.

Reliability Analyses

Level 1 reliability metric checks were performed on each portfolio for all years of the RPP,[30] including:

- *Planning Reserve Margin (PRM):* Measure of required surplus of forecast generation capacity above forecast peak load inclusive of firm sales obligations. Reserve Margin requirement is inclusive of operating contingency/planning reserves (%).[31]
    - Target (min) is 22% transitioning to 30.5% in 2028 after the retirement of the Craig facility
- *Loss of Load Hours (LoLH)*[32]: Measure of the likelihood of failing to meet system load (hours per 10 years).
    - Target (max) is 1 day in 10 years (99.973% reliability)[33]
        - 2024-2031 – annually cannot exceed 2.4 hours[34]
        - 2032-2043 – cannot exceed 24 hours over entire period
- *Expected Unserved Energy (EUE)*[35]: Measure of annual summation of hourly energy not available to meet load and firm sales obligations; representative of potential load that would otherwise need to be shed to maintain system reliability.
    - Targets (max):
        - ≤ 0.4 GWh annually[36]

Evaluation of Level 2 Reliability Metrics, identified in Attachment B-5, was performed on each portfolio's EWE dispatch for all years of the RPP,[37] with results reflected in Attachment E.

Comparative Analysis

Tri-State compared and analyzed results across portfolios, which can be found in the Comparative Analysis section of this report.

[30] 2023 ERP Settlement Agreement, at Section 4.8.2. (Proceeding No. 23A-0585E).
[31] *Reserve Margin and Effective Load Carrying Capability (ELCC) Study,* Astrape Consulting, publicly available here: https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1011579&p_session_id=
[32] LoLH is equivalent to Loss of Load Probability (LoLP) terminology used in Tri-State's 2023 ERP Phase I.
[33] Splitting the LOLH target over the planning period reflects Tri-State's desire to have added assurance that intra-year reliability in the near-term is met by resources coming online during the RAP as the generation fleet makes significant transitions through this period. This approach also allows Tri-State to cautiously assess the impact of having an increasing percentage of intermittent resources in its fleet and the uncertain potential for more severe EWEs before applying similarly stringent LOLH metrics to the outer years of the planning period. There is more flexibility allowed in the out years as forecasting and technology uncertainty is greater during this period.
[34] The annual LOLH target of 2.4 hours is an equivalent representation of the 1 day in 10 years reliability standard.
[35] EUE is equivalent to Energy Not Served (ENS) terminology used in Tri-State's 2020 ERP Phase I.
[36] This metric is aimed at limiting EUE to a reasonable level below the historical annual average, consistent with the 2023 ERP Phase I.
[37] 2023 ERP Settlement Agreement, at Section 4.8.2. (Proceeding No. 23A-0585E).

State Renewable Policy Compliance Analysis

Tri-State reviewed the results of each portfolio and affirms that all portfolios meet or exceed the minimum applicable state renewable energy standard (RES) or renewable portfolio standard (RPS) requirements. RES/RPS standards are shown in the following table.

Table 5: Colorado RES and New Mexico RPS Requirements during RPP

	Colorado RES[38, 39]		New Mexico RPS[40]
	Co-ops	**Tri-State**	**Co-ops**
2024	10%	20%	10%
2025-2029	10%	20%	40%
2030-2050	10%	20%	50%

[38] § 40-2-124(1)(c)(I)(D) and (c)(V)(D), C.R.S.
[39] § 40-2-124(8)(b), C.R.S.
[40] N.M. Stat. Ann. § 62-15-34.

1. New ERA Expanded (NEE)

Assumptions unique to the New ERA Expanded (NEE) portfolio are identified in Attachment B-3.

Portfolio 1 (NEE) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 6: Expansion Plan (Portfolio 1 – NEE)

Year	Bid Project	Technology	Planning Region	Unit Size (MW)	Number of Units[41]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	PV-0004-5-wco	Solar	West Colorado	140	1	140
2028	ST-0019-1-eco	Iron Air Battery	East Colorado	100	1	100
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
2029	WI-0013-3-eco	Wind	East Colorado	200	1	200
	GG-0006-2-wco	Combustion Turbine	West Colorado	38.36	8	307
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
2030	PC-0009-2P-eco	Solar / Battery	East Colorado	150	1	150
	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
	WI-0013-2-wyo-wne	Wind	Wyoming / W.Neb	200	1	200
2033	-	Wind / Battery	New Mexico	100	2	200
2035	-	Geothermal Storage	West Colorado	20	1	20
2036	-	Wind / Battery	New Mexico	100	1	100
	-	10hr - Battery	East Colorado	100	1	100
2037	-	Wind / Battery	Wyoming / W.Neb	100	1	100
2038	-	Wind / Battery	East Colorado	100	2	200
2041	-	Solar	New Mexico	100	1	100
2042	-	Solar	New Mexico	100	1	100
	-	Wind	East Colorado	100	3	300
2043	-	10hr - Battery	East Colorado	100	1	100
	-	Wind	East Colorado	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency was selected in the expansion plan of Portfolio 1 – NEE.
- 2030: Low Wyoming Energy Efficiency was selected in the expansion plan of Portfolio 1 – NEE.

[41] Each bid is modeled as a single project for purposes of expansion plan selection.

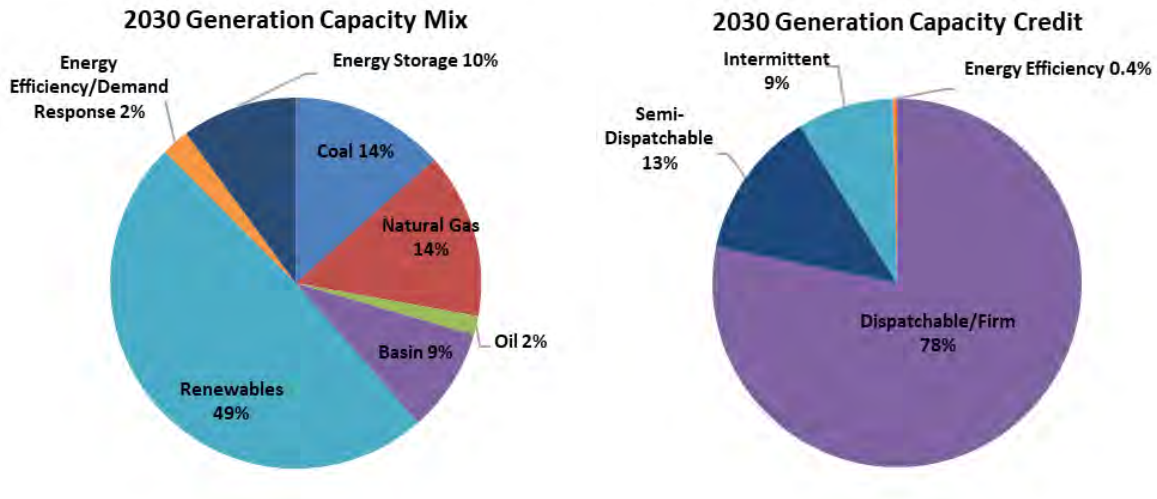
Unit retirements, scheduled or selected in the modeling, are shown in the following table.[42]

Table 7: Modeled Retirements (Portfolio 1 - NEE)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[43]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 2: Projected Tri-State System Capacity Mix 2030 (Portfolio 1 – NEE)[44, 45]



[42] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and its share of Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[43] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement by USDA to disperse all New ERA funds by September 30, 2031.

[44] "Renewables" category reflects wind and solar PPAs, Member Distributed Generation (DG), energy associated with renewable energy credits (RECs) received via the Basin contract, and hydropower purchases.

[45] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 3: Projected Tri-State System Energy Mix 2030 (Portfolio 1 – NEE)[46]

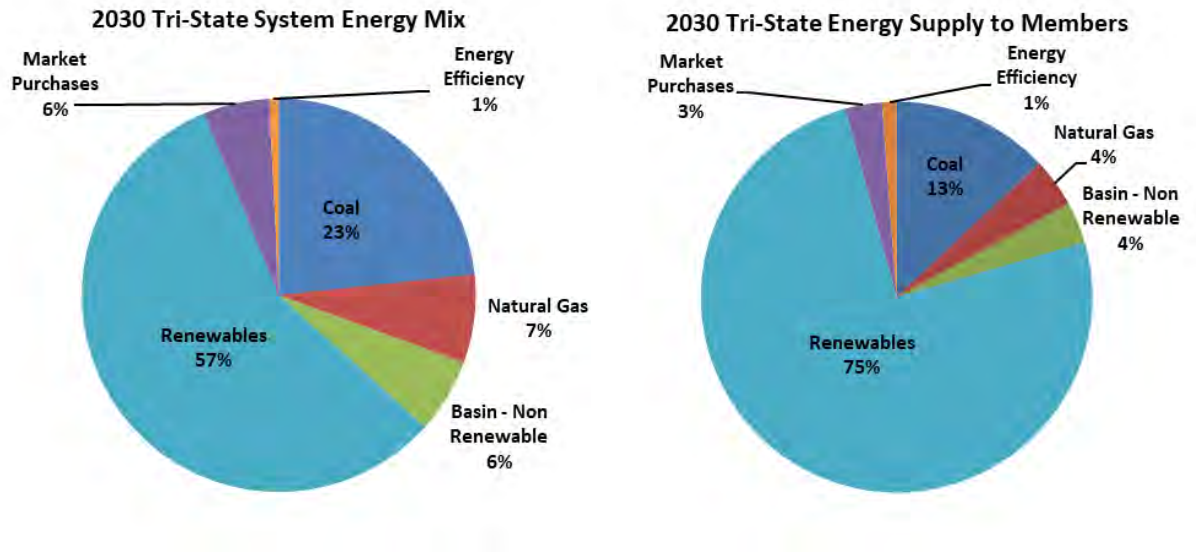


Table 8: Projected Annual Capacity Factors for Thermal Resources (Portfolio 1 – NEE)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	83%
LRS 3	68%	84%	65%	73%	83%	82%	80%
SPV 3	87%	87%	89%	77%	60%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	5%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	0%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	26%	19%	24%
GG-0006-2-wco	0%	0%	0%	0%	40%	40%	40%

Portfolio 1 (New ERA Expanded) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[46] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 9: Environmental Impact - System Wide (Portfolio 1 – NEE) [47]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,962,306	6,093	7,512	0.0335	975	4,183,354,305	24,235
2027	11,750,117	5,940	7,360	0.0327	961	4,161,589,886	23,953
2028	9,874,804	5,208	6,125	0.0290	841	3,480,893,766	20,201
2029	9,043,741	7,796	6,571	0.0268	729	3,080,720,212	17,940
2030	7,345,275	10,258	6,986	0.0238	607	2,691,211,959	16,047
2031	6,399,384	9,943	6,815	0.0207	370	2,139,654,056	13,265
2032	5,656,566	9,627	6,510	0.0177	259	1,784,885,467	11,492
2033	5,818,338	9,697	6,570	0.0187	278	1,863,239,379	11,783
2034	5,682,522	9,640	6,485	0.0181	274	1,803,058,523	11,491
2035	5,813,155	9,712	6,584	0.0187	273	1,845,867,435	11,847
2036	5,570,335	9,577	6,460	0.0173	252	1,750,921,710	11,305
2037	5,706,630	9,672	6,538	0.0181	266	1,785,001,792	11,627
2038	5,448,317	8,616	6,119	0.0176	252	1,666,538,080	11,330
2039	5,553,097	8,731	6,199	0.0181	254	1,712,426,151	11,584
2040	5,180,884	7,717	5,792	0.0167	221	1,547,476,901	10,991
2041	5,164,345	7,364	5,705	0.0167	222	1,513,398,513	11,008
2042	5,000,692	6,947	5,545	0.0159	210	1,426,738,301	10,699
2043	4,973,141	6,509	5,436	0.0159	202	1,395,662,722	10,776
Total	**134,188,571**	**154,604**	**122,581**	**0.406**	**8,306**	**43,732,557,038**	**273,981**
Pounds/Gallons per MWh[48]	**902**	**1.04**	**0.82**	**0.000003**	**0.06**	**147**	**2.030**

[47] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[48] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 10: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 1 – NEE)

Year	Annual Social Cost of Carbon
2025	$1,139,132,187
2026	$1,151,025,894
2027	$1,182,993,732
2028	$1,027,875,370
2029	$972,185,689
2030	$815,346,559
2031	$741,565,451
2032	$676,606,840
2033	$726,019,364
2034	$731,664,351
2035	$772,246,675
2036	$771,269,337
2037	$814,965,697
2038	$802,439,822
2039	$851,748,425
2040	$819,299,456
2041	$841,929,891
2042	$848,377,440
2043	$869,547,745

Table 11: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 1 – NEE)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,950,104
2027	$72,370,913
2028	$63,854,206
2029	$59,238,749
2030	$55,323,918
2031	$47,881,107
2032	$43,405,678
2033	$46,538,873
2034	$47,435,734
2035	$51,090,347
2036	$50,898,647
2037	$54,631,126
2038	$55,527,948
2039	$59,194,959
2040	$58,529,071
2041	$60,870,777
2042	$62,289,850
2043	$64,055,746

Table 12: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 1 – NEE)

Year	Target[49]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-1 for detailed GHG emissions calculations for the portfolio.

Portfolio 1 (New ERA Expanded) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 13: Total Financial (Portfolio 1 – NEE)

$, Millions	Portfolio PVRR (2024 WACC 5.9%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Portfolio PVRR inclusive of SCoC NPV	Portfolio PVRR inclusive of SCoC NPV & SCoM NPV
	$16,836	$12,911	$837	$29,746	$30,584
Difference to preferred plan (Nominal $)	$393	($18)	($1)	$375	$374

Table 14: Total Financial Generation and Transmission (Portfolio 1 – NEE)

$, Millions	Expansion Plan CapEx + AFUDC:	Difference to preferred plan
Generation (Nominal $)	$1,508	$971
Transmission (Nominal $)	$1,506	$389

Table 15: Annual Financial (Nominal $) (Portfolio 1 – NEE)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,050
2027	$1,206
2028	$1,539
2029	$1,401
2030	$1,424
2031	$1,501

[49] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2032	$1,518
2033	$1,552
2034	$1,531
2035	$1,529
2036	$1,597
2037	$1,634
2038	$1,679
2039	$1,717
2040	$1,711
2041	$1,785
2042	$1,835
2043	$1,921

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Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 490 MW of solar, and 675 MW of battery storage (including hybrid batteries) built during the RAP in Portfolio 1 – NEE. The amount of curtailment is reduced to zero in 2030 as more batteries are built.

Table 17: Curtailed Intermittent Energy, Annual MWh (Portfolio 1 – NEE)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	185	0	0	185
2026	0	896	0	0	896
2027	0	1,429	0	0	1,429
2028	0	1,811	0	0	1,811
2029	0	52	0	124	176
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**4,373**	**0**	**124**	**4,497**

Table 18: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 1 – NEE)

	Winter	Spring	Summer	Fall
2025	0	118	0	67
2026	13	713	39	131
2027	18	1,189	1	221
2028	61	954	69	727
2029	0	0	12	164
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**92**	**2,974**	**121**	**1,310**

The following table reflects PPA pricing, penalties, and taxes.

Table 19: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 1 – NEE)

	Wind ($)	Solar ($)
2025	$0	$23,999
2026	$0	$145,247
2027	$0	$224,019

2028	$0	$214,350
2029	$0	$18,138
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$625,753**

Portfolio 1 (New ERA Expanded) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

Table 20: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 1 – NEE)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2028	100	ST-0019-1-ECO	$1.50	$5.85	
2029	200	WI-0013-3-ECO		$14.62	$30.00
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2030	150	PC-0009-2P-ECO		$14.62	$130.00
2036	100	Battery	$1.50	$5.85	
2038	100	Wind + Battery		$5.85	
2038	100	Wind + Battery		$5.85	
2042	100	Wind		$14.62	$81.56
2042	100	Wind		$5.85	
2042	100	Wind		$5.85	
2043	100	Battery	$1.50	$5.85	
2043	100	Wind		$5.85	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2027	140	PV-0004-5-WCO		$3.25	$47.06
2029	307	GG-0006-2-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2035	20	Geothermal Storage	$1.30	$3.25	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	$119.24
2037	100	Wind + Battery		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2029	100	PV-0004-4-NM		$10.94	$165.62
2033	100	Wind + Battery		$5.85	$363.20

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2033	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2041	100	Solar		$5.85	$56.46
2042	100	Solar		$5.85	

Portfolio 1 (New ERA Expanded) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 1 New ERA Expanded.

Table 21: RAP Planning Reserve Margin, % Annual (Portfolio 1 – NEE)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	33%	52%	58%	35%

Table 22: Post-RAP Planning Reserve Margin, % Annual (Portfolio 1 – NEE)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
31%	31%	31%	33%	32%	31%	31%	33%	36%	34%	31%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 1 New ERA Expanded.

Table 23: RAP Loss of Load Probability, Hours (Portfolio 1 – NEE)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 24: Post-RAP Loss of Load Probability, Hours (Portfolio 1 – NEE)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 1 – NEE.

Table 25: RAP Expected Unserved Energy, Annual MWh (Portfolio 1 – NEE)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 26: Post-RAP Loss of Load Probability, Hours (Portfolio 1 – NEE)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

2. New ERA Limited Gas (NELG)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 2 (New ERA Limited Gas) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 27: Expansion Plan (Portfolio 2 – NELG)

Year	Bid Project	Technology	Planning Region	Unit Size (MW)	Number of Units[55]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	PV-0004-5-wco	Solar	West Colorado	140	1	140
	ST-0002-6-wco	4hr - Battery	West Colorado	100	1	100
2028	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	ST-0004-10-eco	4hr - Battery	East Colorado	100	1	100
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
	WI-0013-3-eco	Wind	East Colorado	200	1	200
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	GG-0006-1-wco	Combustion Turbine	West Colorado	38.36	8	307
2030	PC-0009-2P-eco	Solar / Battery	East Colorado	150	1	150
	WI-0013-2-wyo-wne	Wind	Wyoming / W.Neb	200	1	200
	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
2033	-	Geothermal Storage	West Colorado	20	1	20
	-	Wind / Battery	New Mexico	100	1	100
2036	-	10hr - Battery	East Colorado	100	1	100
	-	Wind / Battery	East Colorado	100	1	100
	-	Wind / Battery	New Mexico	100	1	100
2037	-	Wind / Battery	East Colorado	100	1	100
	-	Wind / Battery	New Mexico	100	1	100
2042	-	Wind	East Colorado	100	4	400
	-	Solar	New Mexico	100	2	200
2043	-	Wind	Wyoming / W.Neb	100	1	100

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 2 – NELG.

[55] Each bid is modeled as a single project for purposes of expansion plan selection.

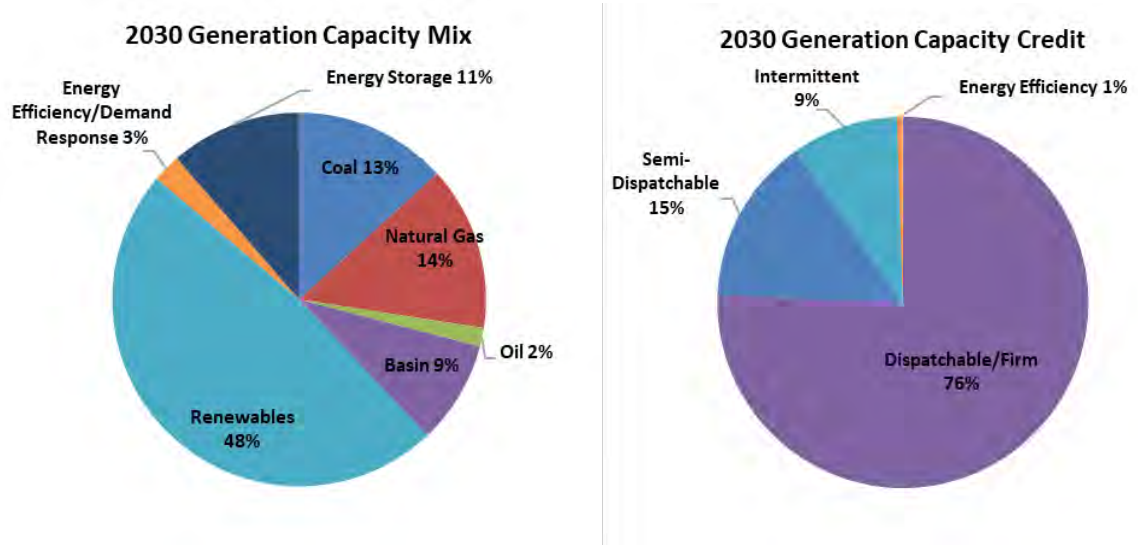
Unit retirements scheduled or selected in the modeling are shown in the following table.[56]

Table 28: Modeled Retirements (Portfolio 2 – NELG)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[57]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 4: Projected Tri-State System Capacity Mix 2030 (Portfolio 2 – NELG)[58, 59]



[56] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[57] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[58] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

[59] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 5: Projected Tri-State System Energy Mix 2030 (Portfolio 2 – NELG)[60]

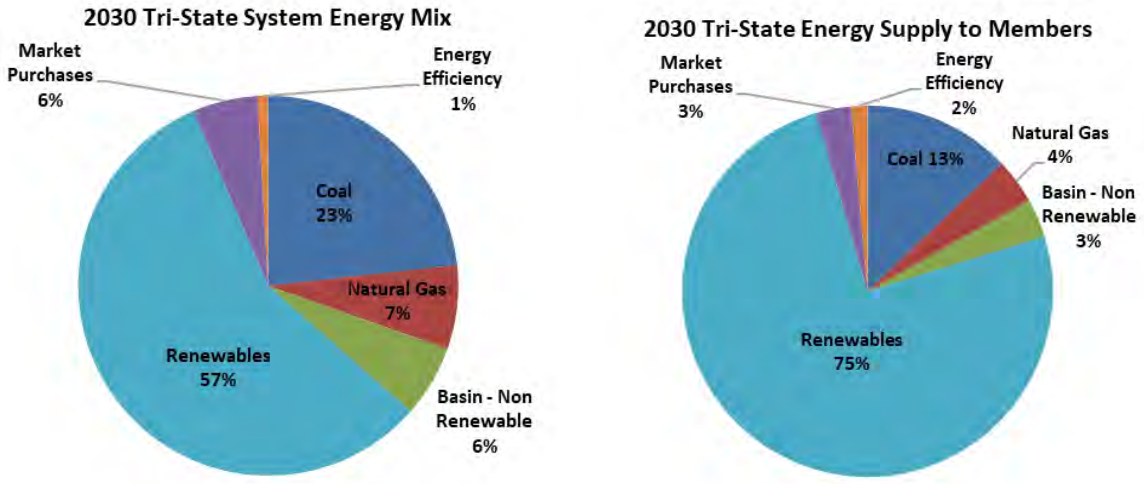


Table 29: Projected Annual Capacity Factors for Thermal Resources (Portfolio 2 – NELG)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	82%
LRS 3	67%	83%	64%	73%	83%	82%	80%
SPV 3	87%	87%	89%	77%	60%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	1%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	25%	18%	24%
GG-0006-1-wco	0%	0%	0%	0%	40%	40%	40%

Portfolio 2 (New ERA Limited Gas) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[60] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 30: Environmental Impact - System Wide (Portfolio 2 – NELG) [61]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,942,684	6,082	7,499	0.0335	974	4,177,652,419	24,195
2027	11,727,659	5,926	7,347	0.0325	958	4,150,755,120	23,895
2028	9,879,304	5,209	6,129	0.0290	839	3,477,044,578	20,198
2029	9,036,223	7,796	6,566	0.0268	726	3,057,173,748	17,831
2030	7,334,742	10,249	6,979	0.0238	606	2,670,517,035	15,863
2031	6,390,985	9,941	6,811	0.0207	369	2,119,971,139	13,074
2032	5,643,142	9,626	6,504	0.0177	258	1,756,894,095	11,314
2033	5,846,331	9,721	6,629	0.0185	276	1,840,356,862	11,660
2034	5,721,745	9,570	6,526	0.0180	272	1,784,592,739	11,401
2035	5,816,518	9,313	6,528	0.0185	267	1,808,182,520	11,756
2036	5,617,103	9,352	6,437	0.0175	253	1,746,259,917	11,294
2037	5,668,595	8,918	6,321	0.0183	262	1,762,046,825	11,511
2038	5,370,590	7,698	5,885	0.0174	240	1,607,675,000	11,165
2039	5,444,002	7,486	5,871	0.0179	237	1,637,977,953	11,421
2040	5,033,242	6,320	5,407	0.0162	202	1,458,912,630	10,787
2041	5,081,355	6,125	5,424	0.0162	205	1,437,999,469	10,924
2042	4,923,968	5,904	5,263	0.0158	200	1,383,150,176	10,618
2043	4,899,783	5,453	5,150	0.0159	192	1,362,250,327	10,712
Total	**133,622,891**	**146,245**	**120,547**	**0.404**	**8,194**	**43,139,330,433**	**272,022**
Pounds/Gallons per MWh[62]	**946**	**1.04**	**0.85**	**0.000003**	**0.06**	**153**	**2.123**

[61] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[62] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 31: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 2 – NELG)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,653,707
2027	$1,174,732,910
2028	$1,026,795,307
2029	$973,309,290
2030	$818,577,657
2031	$739,322,590
2032	$676,519,826
2033	$726,175,264
2034	$736,202,715
2035	$775,083,935
2036	$775,046,549
2037	$809,721,903
2038	$794,053,163
2039	$832,968,427
2040	$796,824,782
2041	$828,400,211
2042	$835,361,013
2043	$856,721,090

Table 32: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 2 – NELG)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,834,755
2027	$72,194,298
2028	$63,843,496
2029	$58,876,581
2030	$54,688,462
2031	$47,192,177
2032	$42,731,594
2033	$46,052,949
2034	$47,065,889
2035	$50,698,390
2036	$50,851,295
2037	$54,083,272
2038	$54,721,101
2039	$58,358,076
2040	$57,442,190
2041	$60,401,484
2042	$61,819,253
2043	$63,671,990

Table 33: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 2 – NELG)

Year	Target[63]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-2 for detailed GHG emissions calculations for the portfolio.

Portfolio 2 (New ERA Limited Gas) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and allowance for funds used during construction (AFUDC), annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 34: Total Financial (Portfolio 2 – NELG)

$, Millions	**Portfolio PVRR** (2024 WACC 5.9%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Portfolio PVRR inclusive of SCoC NPV**	**Portfolio PVRR inclusive of SCoC NPV & SCoM NPV**
	$16,841	$12,852	$831	$29,693	$30,524
Difference to preferred plan (Nominal $)	$399	($77)	($7)	$322	$314

Table 35: Total Financial Generation and Transmission (Portfolio 2 – NELG)

$, Millions	**Expansion Plan CapEx + AFUDC:**	**Difference to preferred plan**
Generation (Nominal $)	$370	($167)
Transmission (Nominal $)	$1,494	$378

Table 36: Annual Financial (Nominal $) (Portfolio 2 – NELG)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,046
2027	$1,231
2028	$1,312
2029	$1,326

[63] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2030	$1,432
2031	$1,510
2032	$1,571
2033	$1,572
2034	$1,556
2035	$1,552
2036	$1,623
2037	$1,670
2038	$1,709
2039	$1,746
2040	$1,781
2041	$1,821
2042	$1,907
2043	$1,962

[redacted]

64 [redacted]

65 [redacted]

66 [redacted]

67 [redacted]

68 [redacted]

[redacted]

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 490 MW of solar, and 775 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 38: Curtailed Intermittent Energy, Annual MWh (Portfolio 2 – NELG)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	73	0	0	73
2026	0	962	0	0	962
2027	0	853	0	0	853
2028	0	1,132	0	11	1,143
2029	0	242	0	337	579
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**3,262**	**0**	**348**	**3,610**

Table 39: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 2 – NELG)

	Winter	Spring	Summer	Fall
2025	0	50	0	23
2026	35	669	80	178
2027	33	703	32	85
2028	132	288	26	697
2029	0	0	288	291
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**200**	**1,710**	**426**	**1,274**

The following table reflects PPA pricing, penalties, and taxes.

Table 40: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 2 – NELG)

	Wind ($)	Solar ($)
2025	$0	$9,370
2026	$0	$156,979
2027	$0	$114,621
2028	$0	$143,388
2029	$0	$56,325
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$480,683**

Portfolio 2 (New ERA Limited Gas) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

Table 41: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 2 – NELG)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2028	100	ST-0004-10-ECO			
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2029	200	WI-0013-3-ECO		$14.62	$30.00
2030	150	PC-0009-2P-ECO		$14.62	$130.00
2036	100	Battery	$1.50	$5.85	
2036	100	Wind + Battery		$5.85	
2037	100	Wind + Battery		$5.85	
2042	100	Wind		$14.62	
2042	100	Wind		$5.85	$81.56
2042	100	Wind		$5.85	
2042	100	Wind		$5.85	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2027	140	PV-0004-5-WCO		$3.25	$47.06
2027	100	ST-0002-6-WCO	$1.30	$3.25	
2029	307	GG-0006-1-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2033	20	Geothermal Storage	$1.30	$3.25	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	$119.24

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2043	100	Wind		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2029	100	PV-0004-4-NM		$10.94	$165.62
2033	100	Wind + Battery		$5.85	$363.20
2036	100	Wind + Battery		$5.85	
2037	100	Wind + Battery		$5.85	
2042	100	Solar		$5.85	$56.46
2042	100	Solar		$5.85	

Portfolio 2 (New ERA Limited Gas) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 2 – NELG.

Table 42: RAP Planning Reserve Margin, % Annual (Portfolio 2 – NELG)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	36%	54%	59%	36%

Table 43: Post-RAP Planning Reserve Margin, % Annual (Portfolio 2 – NELG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
32%	31%	31%	32%	32%	33%	31%	34%	36%	34%	32%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 2 – NELG.

Table 44: RAP Loss of Load Probability, Hours (Portfolio 2 – NELG)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 45: Post-RAP Loss of Load Probability, Hours (Portfolio 2 - NELG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 2 – NELG.

Table 46: RAP Expected Unserved Energy, Annual MWh (Portfolio 2 - NELG)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 47: Post-RAP Loss of Load Probability, Hours (Portfolio 2 - NELG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

3. New ERA Gas Flexibility (FLEX)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 3 (New ERA Gas Flexibility) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 48: Expansion Plan (Portfolio 3 – FLEX)

Year	Bid Project	Technology	Planning Region	Unit Size (MW)	Number of Units[69]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2028	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	ST-0018-1-eco	4hr - Battery	East Colorado	50	1	50
	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
	ST-0010-4-eco	4hr - Battery	East Colorado	150	1	150
	WI-0016-1-eco	Wind	East Colorado	297	1	297
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	GG-0006-2-wco	Combustion Turbine	West Colorado	38.36	8	307
2030	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
	WI-0013-2-wyo-wne	Wind	Wyoming / W.Neb	200	1	200
	PC-0009-2P-eco	Solar / Battery	East Colorado	150	1	150
2033	-	Wind / Battery	New Mexico	100	1	100
	-	Geothermal Storage	West Colorado	20	1	20
2036	-	Wind / Battery	New Mexico	100	2	200
	-	10hr - Battery	West Colorado	100	1	100
	-	Solar	West Colorado	100	1	100
2038	-	Wind / Battery	East Colorado	100	2	200
2041	-	Solar	West Colorado	100	1	100
2042	-	Wind	East Colorado	100	3	300
	-	Solar	New Mexico	100	1	100
	-	Solar	West Colorado	100	2	200
2043	-	Wind	Wyoming / W.Neb	100	1	100

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 3 – FLEX.

[69] Each bid is modeled as a single project for purposes of expansion plan selection.

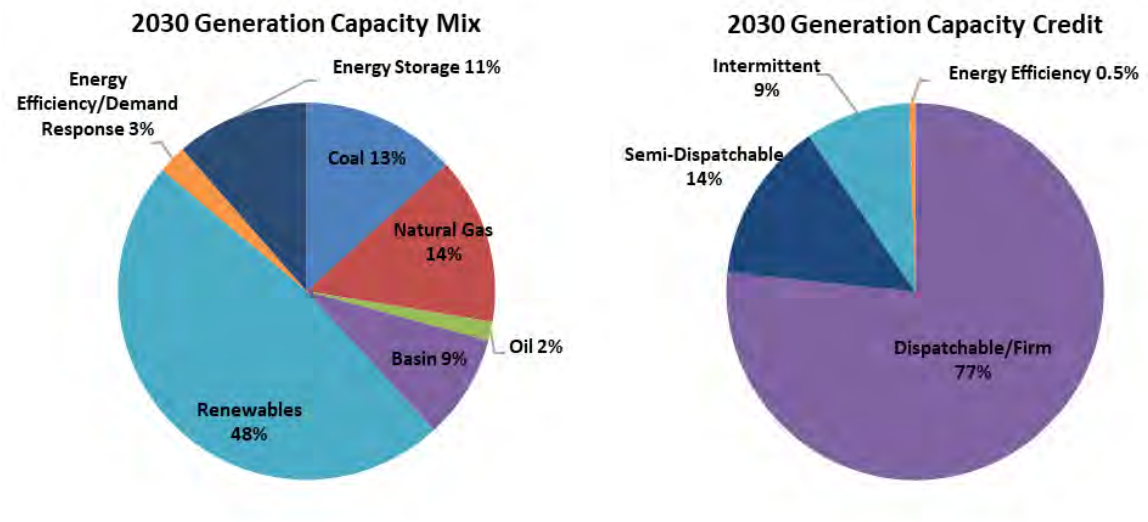
Unit retirements scheduled or selected in the modeling are shown in the following table.[70]

Table 49: Modeled Retirements (Portfolio 3 – FLEX)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[71]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 6: Projected Tri-State System Capacity Mix 2030 (Portfolio 3 – FLEX)[72, 73]



[70] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[71] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[72] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

[73] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 7: Projected Tri-State System Energy Mix 2030 (Portfolio 3 – FLEX)[74]

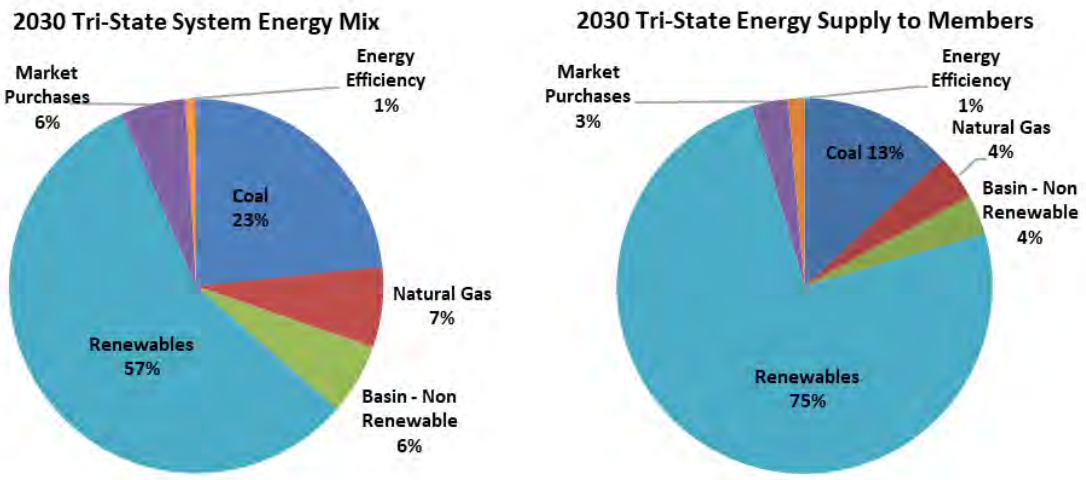


Table 50: Projected Annual Capacity Factors for Thermal Resources (Portfolio 3 – FLEX)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	82%
LRS 3	67%	83%	52%	70%	83%	82%	80%
SPV 3	87%	87%	89%	75%	60%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	3%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	22%	16%	21%
GG-0006-2-wco	0%	0%	0%	0%	40%	40%	40%

Portfolio 3 (New ERA Gas Flexibility) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[74] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 51: Environmental Impact - System Wide (Portfolio 3 – FLEX) [75]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,943,290	6,082	7,500	0.0335	974	4,177,494,353	24,196
2027	11,568,153	5,770	7,226	0.0311	936	4,045,072,240	23,327
2028	9,779,075	5,148	6,077	0.0284	818	3,407,958,468	19,883
2029	8,967,361	7,781	6,521	0.0267	724	3,038,458,535	17,867
2030	7,315,232	10,260	6,967	0.0237	605	2,657,827,563	16,039
2031	6,350,647	9,935	6,786	0.0206	367	2,096,814,877	13,210
2032	5,635,838	9,629	6,501	0.0176	257	1,753,123,139	11,482
2033	5,820,676	9,711	6,616	0.0184	274	1,827,280,223	11,797
2034	5,720,467	9,667	6,551	0.0179	272	1,784,031,850	11,563
2035	5,832,550	9,741	6,639	0.0185	270	1,814,000,679	11,908
2036	5,602,277	9,601	6,471	0.0175	255	1,753,655,478	11,394
2037	5,653,752	9,638	6,515	0.0177	261	1,752,980,829	11,500
2038	5,458,897	8,694	6,154	0.0176	252	1,654,130,594	11,329
2039	5,548,435	8,783	6,219	0.0180	252	1,690,762,833	11,575
2040	5,178,596	7,783	5,816	0.0165	220	1,530,568,107	10,959
2041	5,191,519	7,349	5,728	0.0167	223	1,503,734,603	11,078
2042	5,095,815	6,784	5,539	0.0165	218	1,460,467,941	10,943
2043	5,039,030	6,269	5,391	0.0164	208	1,427,643,128	10,961
Total	**133,946,532**	**154,182**	**122,485**	**0.404**	**8,246**	**43,275,923,319**	**273,416**
Pounds/Gallons per MWh[76]	**949**	**1.09**	**0.87**	**0.000003**	**0.06**	**153**	**2.134**

[75] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[76] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 52: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 3 – FLEX)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,712,185
2027	$1,158,755,608
2028	$1,016,378,097
2029	$965,892,008
2030	$816,400,243
2031	$734,656,192
2032	$675,644,270
2033	$722,988,638
2034	$736,038,329
2035	$777,220,279
2036	$773,000,815
2037	$807,601,751
2038	$807,109,612
2039	$848,947,387
2040	$819,836,199
2041	$846,359,980
2042	$864,515,211
2043	$881,068,315

Table 53: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 3 – FLEX)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,836,579
2027	$70,477,977
2028	$62,847,444
2029	$58,997,890
2030	$55,296,246
2031	$47,683,283
2032	$43,367,675
2033	$46,595,924
2034	$47,733,888
2035	$51,349,932
2036	$51,298,669
2037	$54,036,042
2038	$55,522,239
2039	$59,145,438
2040	$58,361,648
2041	$61,255,841
2042	$63,710,822
2043	$65,154,538

Table 54: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 3 – FLEX)

Year	Target[77]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-3 for detailed GHG emissions calculations for the portfolio.

Portfolio 3 (New ERA Gas Flexibility) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 55: Total Financial (Portfolio 3 – FLEX)

$, Millions	Portfolio PVRR (2024 WACC 5.9%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Portfolio PVRR inclusive of SCoC NPV	Portfolio PVRR inclusive of SCoC NPV & SCoM NPV
	$16,761	$12,891	$836	$29,652	$30,488
Difference to preferred plan (Nominal $)	$318	($38)	($2)	$281	$278

Table 56: Total Financial Generation and Transmission (Portfolio 3 – FLEX)

$, Millions	Expansion Plan CapEx + AFUDC:	Difference to preferred plan
Generation (Nominal $)	$1,129	$592
Transmission (Nominal $)	$1,457	$340

Table 57: Annual Financial (Nominal $) (Portfolio 3 – FLEX)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,050
2027	$1,220
2028	$1,371
2029	$1,399
2030	$1,427
2031	$1,503

[77] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2032	$1,525
2033	$1,557
2034	$1,537
2035	$ 1,531
2036	$1,607
2037	$1,639
2038	$1,697
2039	$1,726
2040	$1,751
2041	$1,785
2042	$1,833
2043	$1,906

[redacted]

78 [redacted]

79 [redacted]

80 [redacted]

81 [redacted]

82 [redacted]

[redacted]

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 497 MW of wind, 350 MW of solar, and 775 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 59: Curtailed Intermittent Energy, Annual MWh (Portfolio 3 – FLEX)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	101	0	0	101
2026	0	770	0	0	770
2027	0	1,019	0	0	1,019
2028	0	847	0	7	854
2029	0	9	0	207	216
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**2,746**	**0**	**214**	**2,960**

Table 60: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 3 – FLEX)

	Winter	Spring	Summer	Fall
2025	0	60	0	41
2026	13	601	79	77
2027	18	725	52	224
2028	49	412	1	392
2029	0	0	70	146
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**80**	**1,798**	**202**	**880**

The following table reflects PPA pricing, penalties, and taxes.

Table 61: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 3 – FLEX)

	Wind ($)	Solar ($)
2025	$0	$13,166
2026	$0	$125,261
2027	$0	$151,371
2028	$0	$107,958

2029	$0	$18,876
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$416,632**

Portfolio 3 (New ERA Gas Flexibility) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

Table 62: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 3 – FLEX)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2029	150	ST-0010-4-ECO	$1.50	$5.85	
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2029	50	ST-0018-1-ECO	$1.50	$5.85	
2029	297	WI-0016-1-ECO		$14.62	$30.00
2030	150	PC-0009-2P-ECO		$14.62	$130.00
2038	100	Wind + Battery		$5.85	$81.56
2038	100	Wind + Battery		$5.85	
2042	100	Wind		$14.62	
2042	100	Wind		$5.85	
2042	100	Wind		$5.85	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2029	307	GG-0006-2-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2033	20	Geothermal Storage	$1.30	$3.25	
2036	100	Solar		$5.85	
2036	100	Battery	$1.50	$5.85	
2041	100	Solar		$3.25	
2042	100	Solar		$6.56	
2042	100	Solar		$6.56	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	$119.24
2043	100	Wind		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2029	100	PV-0004-4-NM		$10.94	$165.62

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2033	100	Wind + Battery		$5.85	$363.20
2036	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2042	100	Solar		$5.85	$56.46

Portfolio 3 (New ERA Gas Flexibility) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 3 – FLEX.

Table 63: RAP Planning Reserve Margin, % Annual (Portfolio 3 – FLEX)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	33%	54%	58%	36%

Table 64: Post-RAP Planning Reserve Margin, % Annual (Portfolio 3 – FLEX)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
31%	31%	31%	32%	32%	31%	31%	33%	36%	34%	31%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 3 – FLEX.

Table 65: RAP Loss of Load Probability, Hours (Portfolio 3 – FLEX)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 66: Post-RAP Loss of Load Probability, Hours (Portfolio 3 – FLEX)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 3 – FLEX.

Table 67: RAP Expected Unserved Energy, Annual MWh (Portfolio 3 – FLEX)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 68: Post-RAP Loss of Load Probability, Hours (Portfolio 3 – FLEX)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

4. FLEX Shafer Replacement (FLEXSR)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 4 (FLEX Shafer Replacement) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 69: Expansion Plan (Portfolio 4 – FLEXSR)

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[83]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	ST-0004-6-eco	4hr - Battery	East Colorado	150	1	150
2028	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	ST-0004-10-eco	4hr - Battery	East Colorado	100	1	100
	PV-0006-8-eco	Solar	East Colorado	200	1	200
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	WI-0013-3-eco	Wind	East Colorado	200	1	200
	GG-0006-2-wco	Combustion Turbine	West Colorado	38.36	8	307
2030	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
	WI-0013-2-wyo-wne	Wind	Wyoming/ W. Neb.	200	1	200
2033	-	Wind / Battery	East Colorado	100	2	200
2036	-	Wind / Battery	New Mexico	100	2	200
	-	Wind / Battery	East Colorado	100	1	100
	-	Geothermal Storage	West Colorado	20	1	20
	-	Solar	New Mexico	100	1	100
2037	-	Wind / Battery	East Colorado	100	1	100
2038	-	Wind / Battery	East Colorado	100	1	100
	-	Wind / Battery	New Mexico	100	1	100
2042	-	Solar	New Mexico	100	2	200
	-	Wind	Wyoming/ W. Neb.	100	1	100
	-	Wind	East Colorado	100	2	200
2043	-	Wind / Battery	East Colorado	100	1	100

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 4 – FLEXSR.

[83] Each bid is modeled as a single project for purposes of expansion plan selection.

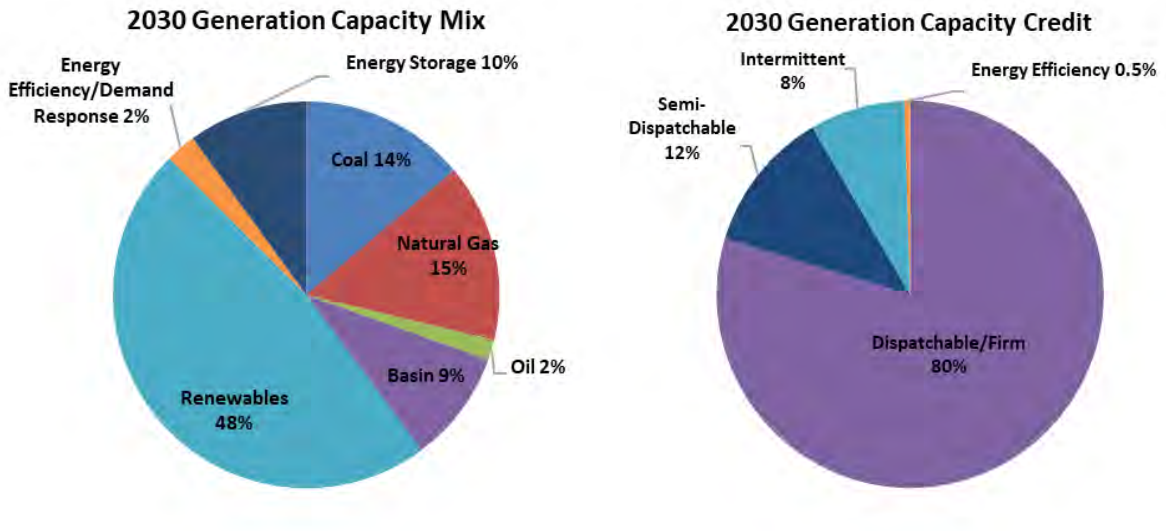
Unit retirements scheduled or selected in the modeling are shown in the following table.[84]

Table 70: Modeled Retirements (Portfolio 4 – FLEXSR)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[85]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 8: Projected Tri-State System Capacity Mix 2030 (Portfolio 4 – FLEXSR)[86, 87]



[84] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[85] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[86] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

[87] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 9: Projected Tri-State System Energy Mix 2030 (Portfolio 4 – FLEXSR)[88]

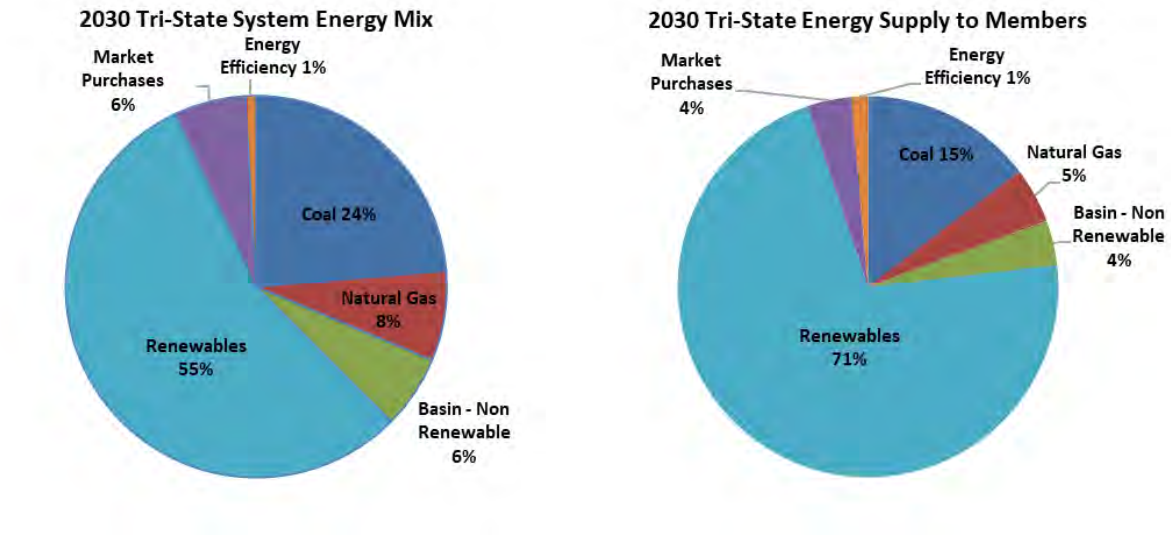


Table 71: Projected Annual Capacity Factors for Thermal Resources (Portfolio 4 – FLEXSR)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	83%
LRS 3	67%	83%	53%	70%	82%	82%	80%
SPV 3	87%	87%	89%	75%	65%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	3%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	25%	22%	23%
GG-0006-2-wco	0%	0%	0%	0%	40%	40%	40%

Portfolio 4 (FLEX Shafer Replacement) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[88] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 72: Environmental Impact - System Wide (Portfolio 4 – FLEXSR) [89]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,942,421	6,082	7,499	0.0335	974	4,177,610,423	24,195
2027	11,568,735	5,770	7,227	0.0311	937	4,046,667,348	23,331
2028	9,819,361	5,161	6,103	0.0283	814	3,399,083,138	19,893
2029	9,204,229	7,855	6,616	0.0273	767	3,162,829,891	18,345
2030	7,412,404	10,284	7,047	0.0238	610	2,702,448,101	16,151
2031	6,458,059	9,980	6,884	0.0207	371	2,133,619,472	13,382
2032	5,712,026	9,667	6,578	0.0177	259	1,771,382,260	11,617
2033	5,853,864	9,745	6,652	0.0185	275	1,823,859,347	11,905
2034	5,797,935	9,690	6,616	0.0180	276	1,814,833,359	11,665
2035	5,898,663	9,785	6,694	0.0187	274	1,828,879,124	12,058
2036	5,625,841	9,611	6,460	0.0178	260	1,775,162,952	11,446
2037	5,698,331	9,682	6,499	0.0184	270	1,777,568,735	11,664
2038	5,351,664	8,533	6,016	0.0175	249	1,631,722,206	11,143
2039	5,433,584	8,599	6,069	0.0180	250	1,664,645,441	11,377
2040	5,111,931	7,566	5,683	0.0167	220	1,515,089,860	10,911
2041	5,218,379	7,217	5,684	0.0171	227	1,526,405,089	11,155
2042	5,033,011	6,829	5,500	0.0163	216	1,447,560,576	10,793
2043	4,988,533	6,377	5,382	0.0162	206	1,414,798,721	10,834
Total	**134,373,893**	**153,989**	**122,479**	**0.406**	**8,315**	**43,514,083,924**	**274,271**
Pounds/Gallons per MWh[90]	**952**	**1.09**	**0.87**	**0.000003**	**0.06**	**154**	**2.141**

[89] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[90] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 73: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 4 – FLEXSR)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,628,339
2027	$1,158,813,840
2028	$1,020,565,222
2029	$991,405,565
2030	$827,244,896
2031	$747,081,881
2032	$684,777,928
2033	$727,110,962
2034	$746,005,989
2035	$786,030,277
2036	$776,252,143
2037	$813,969,586
2038	$791,254,956
2039	$831,374,435
2040	$809,282,328
2041	$850,738,875
2042	$853,860,285
2043	$872,238,852

Table 74: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 4 – FLEXSR)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,833,899
2027	$70,489,792
2028	$62,881,612
2029	$60,575,560
2030	$55,682,337
2031	$48,304,507
2032	$43,879,284
2033	$47,023,762
2034	$48,155,833
2035	$51,996,947
2036	$51,534,377
2037	$54,805,537
2038	$54,614,207
2039	$58,132,606
2040	$58,102,968
2041	$61,679,010
2042	$62,837,645
2043	$64,400,027

Table 75: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 4 – FLEXSR)

Year	Target[91]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-4 for detailed GHG emissions calculations for the portfolio.

Portfolio 4 (FLEX Shafer Replacement) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 76: Total Financial (Portfolio 4 – FLEXSR)

$, Millions	Portfolio PVRR (2024 WACC 5.9%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Portfolio PVRR inclusive of SCoC NPV	Portfolio PVRR inclusive of SCoC NPV & SCoM NPV
	$16,443	$12,928	$838	$29,371	$30,210

Table 77: Total Financial Generation and Transmission (Portfolio 4 – FLEXSR)

$, Millions	Expansion Plan CapEx + AFUDC:
Generation (Nominal $)	$537
Transmission (Nominal $)	$1,116

Table 78: Annual Financial (Nominal $) (Portfolio 4 – FLEXSR)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,050
2027	$1,227
2028	$1,306
2029	$1,362
2030	$1,383
2031	$1,435
2032	$1,489
2033	$1,509
2034	$1,511
2035	$1,509

[91] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2036	$1,599
2037	$1,606
2038	$1,669
2039	$1,695
2040	$1,702
2041	$1,745
2042	$1,779
2043	$1,855

[redacted]

92 [redacted]

93 [redacted]

94 [redacted]

95

96 [redacted]

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 300 MW of solar, and 650 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 80: Curtailed Intermittent Energy, Annual MWh (Portfolio 4 – FLEXSR)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	73	0	0	73
2026	0	945	0	0	945
2027	0	1,432	0	0	1,432
2028	0	707	0	10	717
2029	0	453	0	20	473
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**3,610**	**0**	**30**	**3,640**

Table 81: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 4 – FLEXSR)

	Winter	Spring	Summer	Fall
2025	0	50	0	23
2026	13	672	77	183
2027	19	1,127	58	228
2028	44	527	0	146
2029	0	0	1	472
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**76**	**2,376**	**136**	**1,052**

The following table reflects PPA pricing, penalties, and taxes.

Table 82: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 4 – FLEXSR)

	Wind ($)	Solar ($)
2025	$0	$9,370
2026	$0	$152,487
2027	$0	$193,537
2028	$0	$90,037
2029	$0	$51,807
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$497,237**

Portfolio 4 (FLEX Shafer Replacement) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

As described in the Executive Summary Portfolio Analysis section above and in Attachment G, Tri-State analyzed Portfolio 4 – FLEXSR bid selections for transmission interconnection and upgrade cost considerations and the potential to utilize surplus interconnection, and implemented transmission modeling optimizations. As a result of this analysis, the FLEXSR preferred portfolio avoids significant transmission upgrade costs during the RAP.

Table 83: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 4 – FLEXSR)

Year	**Size** *(MW)*	**Type**	**Interconnection Cost** *($M)*	**Network Upgrade at POI Cost** *($M)*	**Network Upgrade for Size** *($M)*
Eastern Colorado (ECO) Transmission Area					
2027	150	ST-0004-6-ECO	$0.00		
2028	200	PV-0006-8-ECO		$5.85	
2028	100	ST-0004-10-ECO			
2029	200	WI-0013-3-ECO		$14.62	$30.00
2033	100	Wind + Battery		$5.85	$81.56
2033	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2037	100	Wind + Battery		$5.85	
2038	100	Wind + Battery		$5.85	$148.74
2042	100	Wind		$5.85	
2042	100	Wind		$5.85	
2043	100	Wind + Battery		$5.85	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2029	307	GG-0006-2-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2036	20	Geothermal Storage	$1.30	$3.25	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	
2042	100	Wind		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2036	100	Solar		$5.85	$56.46
2036	100	Wind + Battery		$5.85	$363.20
2036	100	Wind + Battery		$5.85	
2038	100	Wind + Battery		$5.85	

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2042	100	Solar		$3.25	
2042	100	Solar		$3.25	

Portfolio 4 (FLEX Shafer Replacement) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 4 – FLEXSR.

Table 84: RAP Planning Reserve Margin, % Annual (Portfolio 4 – FLEXSR)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	38%	52%	54%	34%

Table 85: Post-RAP Planning Reserve Margin, % Annual (Portfolio 4 – FLEXSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
32%	32%	32%	33%	32%	32%	32%	35%	37%	35%	32%	32%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 4 – FLEXSR.

Table 86: RAP Loss of Load Probability, Hours (Portfolio 4 – FLEXSR)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 87: Post-RAP Loss of Load Probability, Hours (Portfolio 4 – FLEXSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 4 – FLEXSR.

Table 88: RAP Expected Unserved Energy, Annual MWh (Portfolio 4 – FLEXSR)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 89: Post-RAP Loss of Load Probability, Hours (Portfolio 4 – FLEXSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

5. No New Gas (NNG)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 5 (No New Gas) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 90: Expansion Plan (Portfolio 5 – NNG)

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[97]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	PV-0004-5-wco	Solar	West Colorado	140	1	140
2028	ST-0019-1-eco	Iron Air Battery	East Colorado	100	1	100
	ST-0004-9-eco	4hr - Battery	East Colorado	100	1	100
	ST-0004-8-wco	4hr - Battery	West Colorado	200	1	200
	ST-0004-10-eco	4hr - Battery	East Colorado	100	1	100
	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	WI-0013-3-eco	Wind	East Colorado	200	1	200
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	ST-0010-4-eco	4hr - Battery	East Colorado	150	1	150
	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
	ST-0018-1-eco	4hr - Battery	East Colorado	50	1	50
2030	PC-0009-2P-eco	Solar / Battery	East Colorado	150	1	150
	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
	WI-0013-2-wyo-wne	Wind	Wyoming / W.Neb	200	1	200
2033	-	Wind / Battery	New Mexico	100	2	200
2035	-	Geothermal Storage	West Colorado	20	1	20
2036	-	Wind / Battery	East Colorado	100	2	200
	-	Wind / Battery	New Mexico	100	1	100
2037	-	Wind / Battery	East Colorado	100	1	100
	-	Geothermal[98]	West Colorado	12	1	12
2038	-	Wind / Battery	East Colorado	100	2	200
2042	-	Wind / Battery	East Colorado	100	1	100
	-	Solar	New Mexico	100	1	100
	-	Solar	West Colorado	100	2	200
2043	-	Wind / Battery	East Colorado	100	2	200
	-	Wind / Battery	Wyoming / W.Neb	100	1	100

[97] Each bid is modeled as a single project for purposes of expansion plan selection.
[98] Enhanced Geothermal Baseload (*see* Attachment B-8). Unit size is 25 MW, dispatchable maximum of 12 MW.

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 5 – NNG.

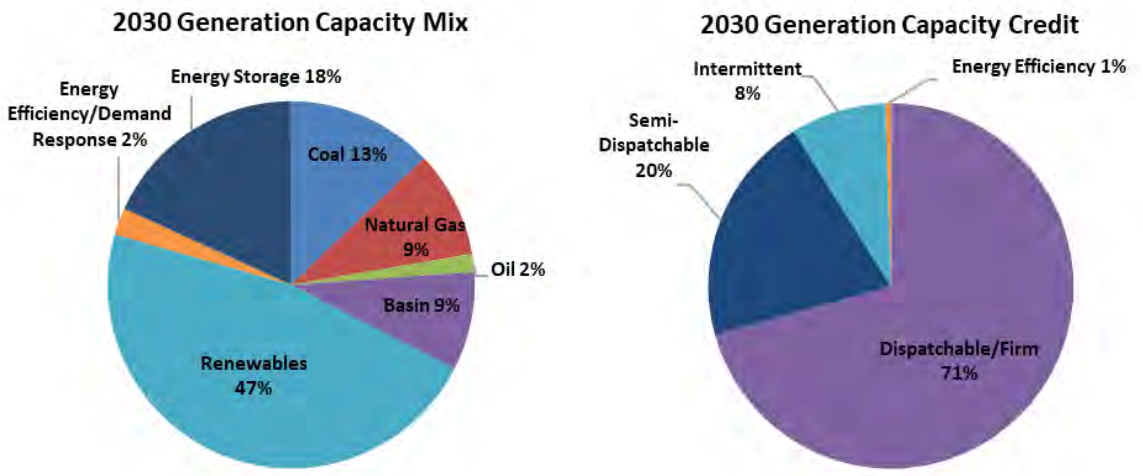
Unit retirements scheduled or selected in the modeling are shown in the following table.[99]

Table 91: Modeled Retirements (Portfolio 5 – NNG)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[100]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 10: Projected Tri-State System Capacity Mix 2030 (Portfolio 5 – NNG) [101]



[99] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[100] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[101] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

Figure 11: Projected Tri-State System Energy Mix 2030 (Portfolio 5 – NNG) [102]

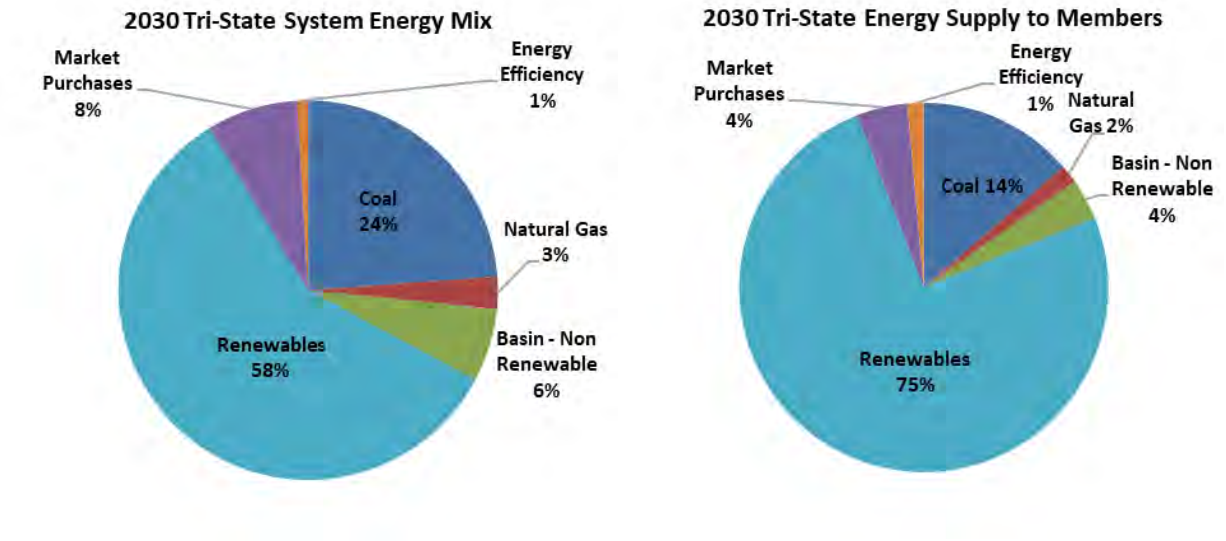


Table 92: Projected Annual Capacity Factors for Thermal Resources (Portfolio 5 – NNG)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	83%
LRS 3	67%	83%	64%	73%	82%	81%	79%
SPV 3	87%	87%	89%	77%	60%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	1%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	30%	27%	27%

Portfolio 5 (No New Gas) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[102] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 93: Environmental Impact - System Wide (Portfolio 5 – NNG)[103]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,942,265	6,082	7,499	0.0335	974	4,177,589,447	24,195
2027	11,726,163	5,927	7,347	0.0326	958	4,152,095,618	23,899
2028	9,883,456	5,211	6,132	0.0290	839	3,476,173,634	20,198
2029	8,959,962	4,974	5,831	0.0267	701	2,986,775,243	17,946
2030	7,013,425	4,657	5,500	0.0237	557	2,526,716,133	16,088
2031	5,999,591	4,341	5,298	0.0205	314	1,924,297,995	13,251
2032	5,264,320	4,036	5,000	0.0176	203	1,558,763,516	11,552
2033	5,390,667	4,091	5,043	0.0184	219	1,627,608,477	11,744
2034	5,289,574	4,044	4,975	0.0179	218	1,586,884,489	11,497
2035	5,408,588	4,109	5,066	0.0184	216	1,627,443,211	11,822
2036	5,196,722	3,983	4,903	0.0177	203	1,565,648,310	11,396
2037	5,297,401	4,068	4,958	0.0183	216	1,599,262,492	11,628
2038	5,013,729	3,964	4,754	0.0175	205	1,473,591,656	11,134
2039	5,111,419	4,012	4,817	0.0179	206	1,513,672,212	11,383
2040	4,871,635	3,892	4,696	0.0167	185	1,405,407,473	10,925
2041	4,990,642	3,996	4,805	0.0171	195	1,416,107,699	11,183
2042	4,890,992	3,945	4,778	0.0163	188	1,362,105,080	10,925
2043	4,853,274	3,938	4,726	0.0165	186	1,351,564,503	10,934
Total	**129,348,747**	**84,826**	**103,400**	**0.407**	**7,640**	**41,231,625,068**	**274,106**
Pounds/Gallons per MWh[104]	**916**	**0.60**	**0.73**	**0.000003**	**0.05**	**146**	**2.139**

[103] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[104] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 94: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 5 – NNG)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,613,302
2027	$1,174,583,082
2028	$1,027,226,838
2029	$965,095,102
2030	$782,717,739
2031	$694,045,278
2032	$631,105,309
2033	$669,577,102
2034	$680,596,397
2035	$720,724,943
2036	$717,042,375
2037	$756,699,323
2038	$741,290,549
2039	$782,081,140
2040	$771,240,407
2041	$813,611,550
2042	$829,766,536
2043	$848,588,980

Table 95: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 5 – NNG)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,833,909
2027	$72,206,255
2028	$63,846,020
2029	$59,255,701
2030	$55,464,509
2031	$47,830,289
2032	$43,632,908
2033	$46,386,308
2034	$47,461,289
2035	$50,983,048
2036	$51,311,539
2037	$54,636,281
2038	$54,569,169
2039	$58,162,802
2040	$58,177,007
2041	$61,837,927
2042	$63,603,366
2043	$64,997,048

Table 96: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 5 – NNG)

Year	Target[105]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-5 for detailed GHG emissions calculations for the portfolio.

Portfolio 5 (No New Gas) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 97: Total Financial (Portfolio 5 – NNG)

$, Millions	**Portfolio PVRR** (2024 WACC 5.9%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Portfolio PVRR inclusive of SCoC NPV**	**Portfolio PVRR inclusive of SCoC NPV & SCoM NPV**
	$17,067	$12,429	$838	$29,496	$30,334
Difference to preferred plan (Nominal $)	$624	($499)	($1)	$125	$124

Table 98: Total Financial Generation and Transmission (Portfolio 5 – NNG)

$, Millions	**Expansion Plan CapEx + AFUDC:**	**Difference to preferred plan**
Generation (Nominal $)	$652	$115
Transmission (Nominal $)	$3,008	$1,891

Table 99: Annual Financial (Nominal $) (Portfolio 5 – NNG)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,049
2027	$1,212
2028	$1,415
2029	$1,423
2030	$1,441

[105] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2031	$1,523
2032	$1,544
2033	$1,580
2034	$1,555
2035	$1,610
2036	$1,706
2037	$1,739
2038	$1,722
2039	$1,766
2040	$1,789
2041	$1,818
2042	$1,868
2043	$1,954



106 [redacted]

107 [redacted]

108 [redacted]

109 [redacted]

110 [redacted]

[redacted]

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 490 MW of solar, and 1,275 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 101: Curtailed Intermittent Energy, Annual MWh (Portfolio 5 – NNG)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	73	0	0	73
2026	0	860	0	0	860
2027	0	759	0	0	759
2028	0	1,707	0	0	1,707
2029	0	62	0	255	317
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**3,461**	**0**	**255**	**3,716**

Table 102: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 5 – NNG)

	Winter	Spring	Summer	Fall
2025	0	50	0	23
2026	47	579	57	177
2027	33	672	16	38
2028	117	709	0	881
2029	0	0	176	141
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**197**	**2,010**	**249**	**1,260**

The following table reflects PPA pricing, penalties, and taxes.

Table 103: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 5 – NNG)

	Wind ($)	Solar ($)
2025	$0	$9,370
2026	$0	$138,416
2027	$0	$105,188
2028	$0	$198,901

2029	$0	$31,189
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$483,064**

Portfolio 5 (No New Gas) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

Table 104: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 5 – NNG)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2028	100	ST-0004-9-ECO	$1.50	$5.85	$30.00
2028	100	ST-0004-10-ECO			
2028	100	ST-0019-1-ECO	$1.50	$5.85	
2029	150	ST-0010-4-ECO	$1.50	$5.85	
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2029	50	ST-0018-1-ECO	$1.50	$5.85	
2029	200	WI-0013-3-ECO		$14.62	$81.56
2030	150	PC-0009-2P-ECO		$14.62	$130.00
2036	100	Wind + Battery		$14.62	
2036	100	Wind + Battery		$5.85	
2037	100	Wind + Battery		$6.56	$1,098.06
2038	100	Wind + Battery		$6.56	
2038	100	Wind + Battery		$6.56	
2042	100	Wind + Battery		$6.56	
2043	100	Wind + Battery		$6.56	
2043	100	Wind + Battery		$6.56	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2027	140	PV-0004-5-WCO		$3.25	$47.06
2028	200	ST-0004-8-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2035	20	Geothermal Storage	$1.30	$3.25	
2037	12	Geothermal	$1.30	$3.25	
2042	100	Solar		$5.85	
2042	100	Solar		$5.85	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	$119.24

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2043	100	Wind + Battery		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2029	100	PV-0004-4-NM		$10.94	$165.62
2033	100	Wind + Battery		$5.85	$363.20
2033	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2042	100	Solar		$5.85	$56.46

Portfolio 5 (No New Gas) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 5 – NNG.

Table 105: RAP Planning Reserve Margin, % Annual (Portfolio 5 – NNG)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	39%	53%	58%	35%

Table 106: Post-RAP Planning Reserve Margin, % Annual (Portfolio 5 – NNG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
31%	31%	31%	33%	31%	31%	31%	33%	36%	33%	32%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 5 – NNG.

Table 107: RAP Loss of Load Probability, Hours (Portfolio 5 - NNG)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 108: Post-RAP Loss of Load Probability, Hours (Portfolio 5 - NNG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 5 – NNG.

Table 109: RAP Expected Unserved Energy, Annual MWh (Portfolio 5 – NNG)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 110: Post-RAP Loss of Load Probability, Hours (Portfolio 5 – NNG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

6. No New Gas Shafer Replacement (NNGSR)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 6 (No New Gas Shafer Replacement) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 111: Expansion Plan (Portfolio 6 – NNGSR)

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[111]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	ST-0004-6-eco	4hr - Battery	East Colorado	150	1	150
2028	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	ST-0004-8-wco	4hr - Battery	West Colorado	200	1	200
	ST-0004-10-eco	4hr - Battery	East Colorado	100	1	100
	ST-0004-9-eco	4hr - Battery	East Colorado	100	1	100
	PV-0006-8-eco	Solar	East Colorado	200	1	200
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
	ST-0010-4-eco	4hr - Battery	East Colorado	150	1	150
	WI-0013-3-eco	Wind	East Colorado	200	1	200
2030	WI-0013-2-wyo-wne	Wind	Wyoming/ W. Neb.	200	1	200
	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
2033	-	Wind / Battery	East Colorado	100	2	200
2036	-	Geothermal Storage	West Colorado	20	1	20
	-	Wind / Battery	New Mexico	100	3	300
2037	-	Wind / Battery	East Colorado	100	1	100
2038	-	Wind / Battery	East Colorado	100	2	200
2041	-	Solar	West Colorado	100	1	100
2042	-	Solar	West Colorado	100	1	100
	-	Wind	East Colorado	100	2	200
	-	Solar	New Mexico	100	2	200
2043	-	Solar	West Colorado	100	1	100
	-	Wind	Wyoming/ W. Neb.	100	1	100

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 6 – NNGSR.

[111] Each bid is modeled as a single project for purposes of expansion plan selection.

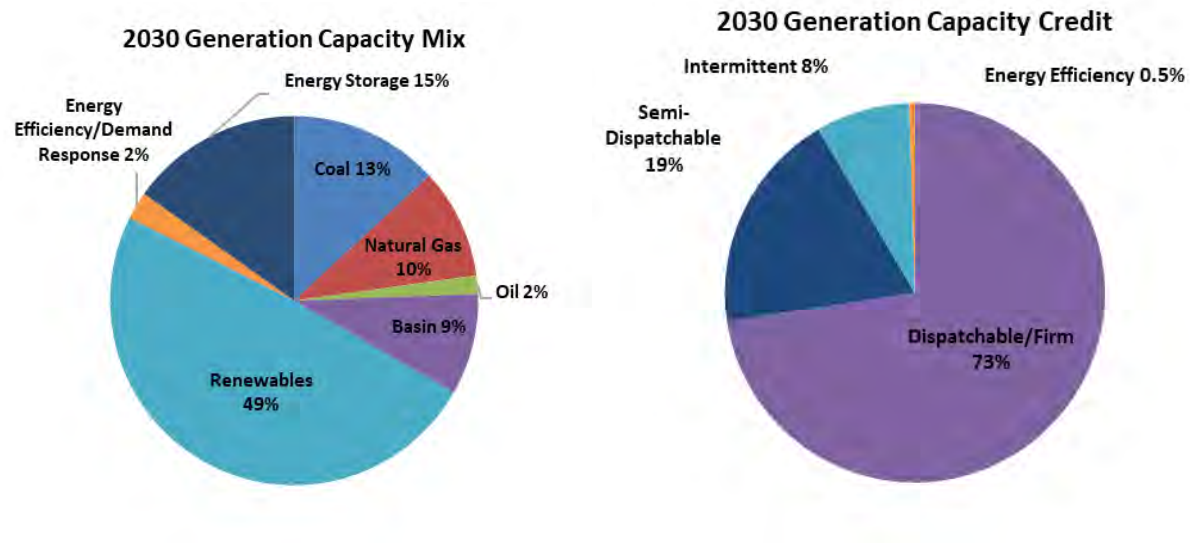
Unit retirements scheduled or selected in the modeling are shown in the following table.[112]

Table 112: Modeled Retirements (Portfolio 6 – NNGSR)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[113]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 12: Projected Tri-State System Capacity Mix 2030 (Portfolio 6 – NNGSR) [114, 115]



[112] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[113] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[114] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

[115] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 13: Projected Tri-State System Energy Mix 2030 (Portfolio 6 – NNGSR)[116]

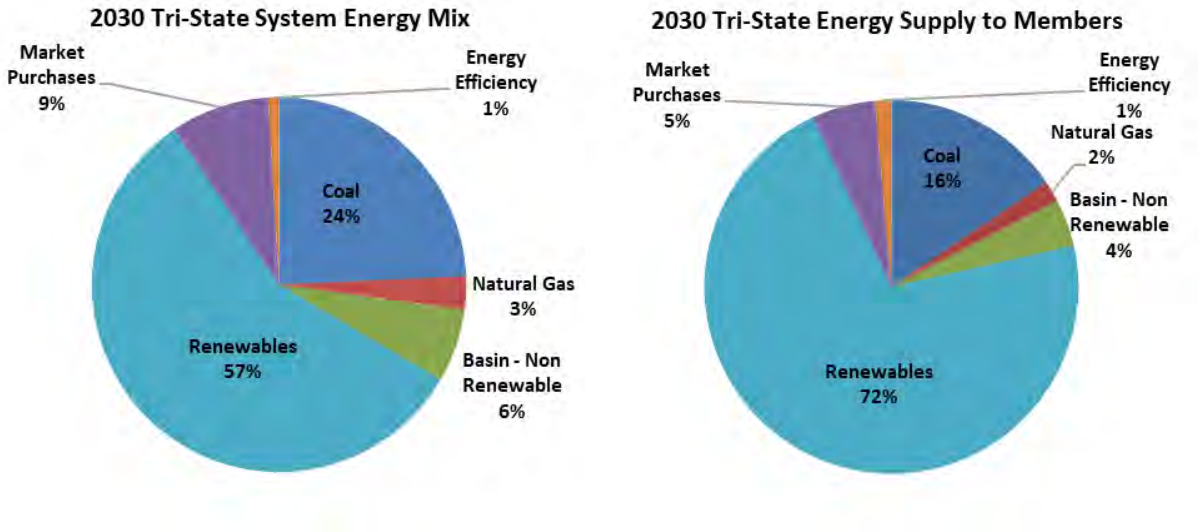


Table 113: Projected Annual Capacity Factors for Thermal Resources (Portfolio 6 – NNGSR)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	83%
LRS 3	67%	83%	53%	70%	81%	81%	78%
SPV 3	87%	87%	89%	75%	65%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	3%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	29%	27%	23%

Portfolio 6 (No New Gas Shafer Replacement) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[116] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 114: Environmental Impact - System Wide (Portfolio 6 – NNGSR)[117]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,946,206	6,083	7,503	0.0335	974	4,178,260,972	24,199
2027	11,570,025	5,771	7,228	0.0311	936	4,046,421,059	23,332
2028	9,814,861	5,160	6,100	0.0283	815	3,401,715,998	19,898
2029	9,111,475	5,027	5,871	0.0272	737	3,073,163,383	18,316
2030	7,050,577	4,679	5,541	0.0238	558	2,532,813,977	16,162
2031	6,019,427	4,364	5,342	0.0204	312	1,913,037,441	13,312
2032	5,363,900	4,052	5,095	0.0176	206	1,604,501,764	11,641
2033	5,520,168	4,151	5,180	0.0184	223	1,661,803,495	11,946
2034	5,414,719	4,107	5,110	0.0180	221	1,615,591,795	11,712
2035	5,560,472	4,185	5,220	0.0186	221	1,665,887,399	12,084
2036	5,239,029	3,999	4,961	0.0176	203	1,573,524,559	11,453
2037	5,344,620	4,099	5,025	0.0182	215	1,590,771,662	11,726
2038	5,084,182	4,014	4,837	0.0175	205	1,470,546,688	11,293
2039	5,164,519	4,055	4,885	0.0180	205	1,504,603,982	11,518
2040	4,894,020	3,929	4,744	0.0167	183	1,379,333,329	11,025
2041	5,034,909	4,021	4,859	0.0171	196	1,413,662,279	11,266
2042	4,876,519	3,942	4,765	0.0163	188	1,347,184,439	10,913
2043	4,887,594	3,957	4,771	0.0165	186	1,347,404,577	10,997
Total	**130,142,142**	**85,151**	**104,306**	**0.405**	**7,642**	**41,220,146,679**	**275,198**
Pounds/Gallons per MWh[118]	**922**	**0.60**	**0.74**	**0.000003**	**0.05**	**146**	**2.148**

[117] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.
[118] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 115: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 6 – NNGSR)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,993,624
2027	$1,158,943,111
2028	$1,020,097,553
2029	$981,414,787
2030	$786,863,978
2031	$696,339,955
2032	$643,043,287
2033	$685,662,450
2034	$696,698,482
2035	$740,964,313
2036	$722,879,934
2037	$763,444,178
2038	$751,707,224
2039	$790,205,684
2040	$774,784,316
2041	$820,828,229
2042	$827,311,151
2043	$854,589,790

Table 116: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 6 – NNGSR)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,847,236
2027	$70,492,985
2028	$62,895,824
2029	$60,478,517
2030	$55,718,807
2031	$48,051,268
2032	$43,969,826
2033	$47,182,943
2034	$48,348,612
2035	$52,112,380
2036	$51,565,121
2037	$55,096,401
2038	$55,345,788
2039	$58,855,626
2040	$58,711,741
2041	$62,293,992
2042	$63,533,142
2043	$65,368,924

Table 117: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 6 – NNGSR)

Year	Target[119]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-6 for detailed GHG emissions calculations for the portfolio.

Portfolio 6 (No New Gas Shafer Replacement) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 118: Total Financial (Portfolio 6 – NNGSR)

$, Millions	Portfolio PVRR (2024 WACC 5.9%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Portfolio PVRR inclusive of SCoC NPV	Portfolio PVRR inclusive of SCoC NPV & SCoM NPV
	$16,531	$12,509	$842	$29,039	$29,881
Difference to preferred plan (Nominal $)	$88	($420)	$3	($332)	($329)

Table 119: Total Financial Generation and Transmission (Portfolio 6 – NNGSR)

$, Millions	Expansion Plan CapEx + AFUDC:	Difference to preferred plan
Generation (Nominal $)	$265	($272)
Transmission (Nominal $)	$1,100	($16)

Table 120: Annual Financial (Nominal $) (Portfolio 6 – NNGSR)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,051
2027	$1,236
2028	$1,317
2029	$1,335
2030	$1,358

[119] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2031	$1,447
2032	$1,480
2033	$1,507
2034	$ 1,526
2035	$1,523
2036	$1,610
2037	$1,618
2038	$1,685
2039	$1,711
2040	$1,741
2041	$1,786
2042	$1,839
2043	$1,899



120 [redacted]

121 [redacted]

122 [redacted]

123 [redacted]

124 [redacted]



Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 300 MW of solar, and 1,200 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 122: Curtailed Intermittent Energy, Annual MWh (Portfolio 6 – NNGSR)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	101	0	0	101
2026	0	1,205	0	0	1,205
2027	0	1,233	0	0	1,233
2028	0	285	0	13	298
2029	0	5	0	0	5
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**2,829**	**0**	**13**	**2,842**

Table 123: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 6 – NNGSR)

	Winter	Spring	Summer	Fall
2025	0	60	0	41
2026	72	825	98	210
2027	36	938	54	205
2028	182	57	0	59
2029	0	0	0	5
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**290**	**1,880**	**152**	**520**

The following table reflects PPA pricing, penalties, and taxes.

Table 124: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 6 – NNGSR)

	Wind ($)	Solar ($)
2025	$0	$13,166
2026	$0	$166,014
2027	$0	$171,286
2028	$0	$42,920
2029	$0	$798
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$394,184**

Portfolio 6 (No New Gas Shafer Replacement) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

As described in the Executive Summary Portfolio Analysis section above and in Attachment G, Tri-State analyzed Portfolio 6 – NNGSR bid selections for transmission interconnection and upgrade cost considerations and the potential to utilize surplus interconnection, and implemented transmission modeling optimizations, to ensure that the benefits of this approach were evaluated under both a new gas and no new gas portfolio. As a result of this analysis, this portfolio avoids significant transmission upgrade costs during the RAP similar to the preferred portfolio, but has a higher PVRR.

Table 125: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 6 – NNGSR)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2026	150	ST-0004-6-ECO			
2028	200	PV-0006-8-ECO		$5.85	
2028	100	ST-0004-10-ECO			
2028	100	ST-0004-9-ECO			$30.00
2029	150	ST-0010-4-ECO	$1.50	$5.85	
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2029	200	WI-0013-3-ECO		$14.62	
2033	100	Wind		$5.85	$81.56
2033	100	Wind		$5.85	
2037	100	Wind + Battery		$5.85	
2038	100	Wind + Battery		$5.85	$148.74
2038	100	Wind + Battery		$5.85	
2042	100	Wind		$14.62	
2042	100	Wind		$5.85	

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2028	200	ST-0004-8-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2036	20	Geothermal Storage	$1.30	$3.25	
2041	100	Solar		$5.85	
2042	100	Solar		$6.56	
2043	100	Solar		$6.56	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	
2043	100	Wind		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2036	100	Wind + Battery		$5.85	$363.20
2036	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2042	100	Solar		$5.85	
2042	100	Solar		$5.85	

Portfolio 6 (No New Gas Shafer Replacement) – Reliability Analysis

PRM, LOLH, and EUE results are ("Level 1 Reliability Metrics") as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 6 – NNGSR.

Table 126: RAP Planning Reserve Margin, % Annual (Portfolio 6 – NNGSR)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	42%	51%	53%	33%

Table 127: Post-RAP Planning Reserve Margin, % Annual (Portfolio 6 – NNGSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
31%	31%	31%	32%	31%	31%	31%	33%	36%	34%	31%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 6 – NNGSR.

Table 128: RAP Loss of Load Probability, Hours (Portfolio 6 – NNGSR)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 129: Post-RAP Loss of Load Probability, Hours (Portfolio 6 – NNGSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 6 – NNGSR.

Table 130: RAP Expected Unserved Energy, Annual MWh (Portfolio 6 – NNGSR)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 131: Post-RAP Loss of Load Probability, Hours (Portfolio 6 – NNGSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

7. Renewable Back-up Bid Pool (BkRE)

The approach to modeling back-up bid pools is described in Attachment B-3 and in the Phase II Portfolio Analysis section in the Executive Summary. The expansion plan selected the following renewable bids as the most economic for the back-up pool.

Table 132: Renewable Back-up Bid Pool

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[125]	Total MW
2027	PC-0004-1P-nm	Solar / Battery	New Mexico	90	1	90
	PV-0004-5-wco	Solar	West Colorado	140	1	140
2029	WI-0016-1-eco	Wind	East Colorado	297	1	297
	PC-0021-1P-wco	Solar / Battery	West Colorado	125	1	125
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	WI-0005-3-eco	Wind	East Colorado	150	1	150

[125] Each bid is modeled as a single project for purposes of expansion plan selection.

8. Standalone Storage Back-up Bid Pool (BkST)

The approach to modeling back-up bid pools is described in Attachment B-3 and in the Phase II Portfolio Analysis section in the Executive Summary. The expansion plan selected the following standalone storage bids as the most economic for the back-up pool.

Table 133: Standalone Storage Back-up Bid Pool

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[126]	Total MW
2027	ST-0002-6-wco	4hr - Battery	West Colorado	100	1	100
2028	ST-0006-3-nm	4hr - Battery	New Mexico	100	1	100
2029	ST-0018-1-eco	4hr - Battery	East Colorado	50	1	50
	ST-0010-4-eco	4hr - Battery	East Colorado	150	1	150
	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100

[126] Each bid is modeled as a single project for purposes of expansion plan selection.

9. Gas Plant Back-up Bids (BkNG)

The approach to back-up bid pools is described in Attachment B-3 and in the Phase II Portfolio Analysis section in the Executive Summary. Only one alternative gas plant bid is available during the RAP, therefore Tri-State did not conduct further modeling to determine a gas plant back-up bid pool.

Table 134: Gas Plant Back-up Bid Pool

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[127]	Total MW
2030	GG-0005-1-wco	Combustion Turbine	West Colorado	45.325	4	181.3

[127] Each bid is modeled as a single project for purposes of expansion plan selection.

Comparative Analysis

A comparative analysis of environmental, financial, and reliability results across each of the Phase II portfolios is provided below.

Environmental Analysis

The following tables identify each portfolio's system-wide forecasted CO_2 and CH_4 emissions in 2026 and 2031.

Figure 14: Comparison of Forecasted System CO_2 Emissions in 2026 and 2031, by Portfolio

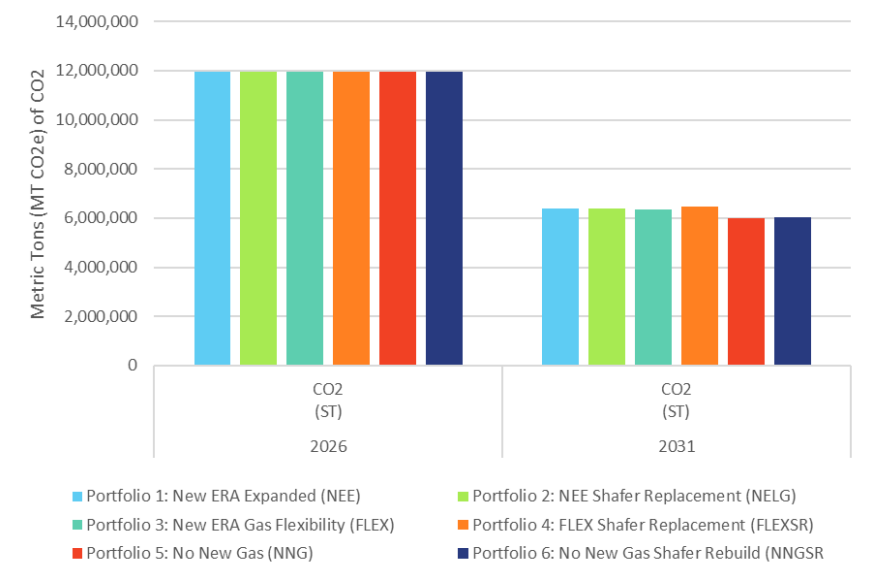
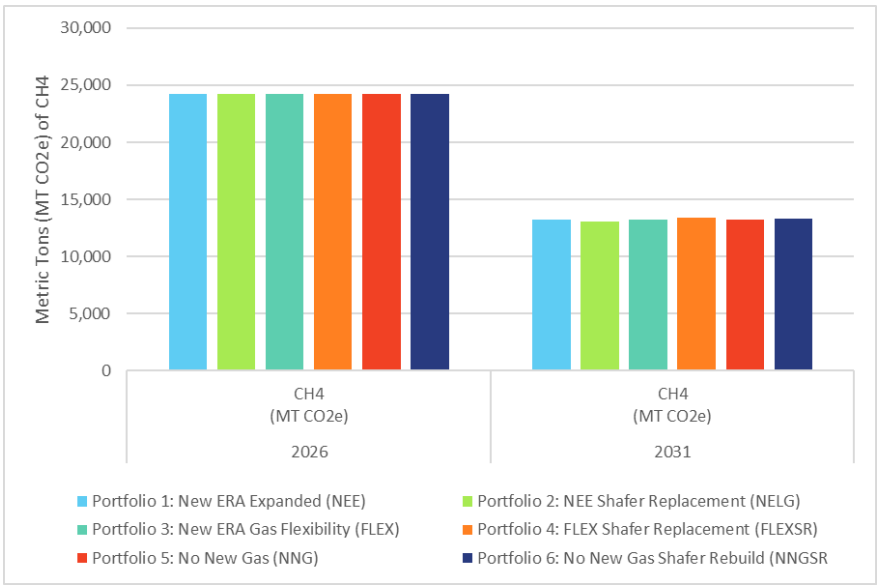


Figure 15: Comparison of Forecasted System CH_4 Emissions in 2026 and 2031, by Portfolio



The following table identifies each portfolio's forecasted achievements toward Colorado GHG reduction targets. Modeling indicates all Phase II portfolios are able to achieve the Colorado GHG reduction

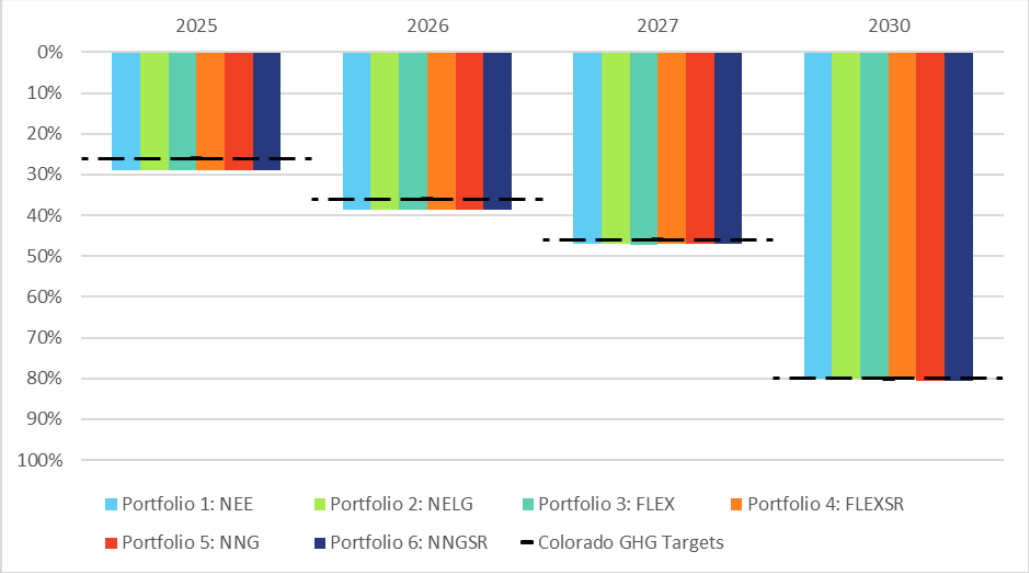
targets in 2025,[128] 2026, 2027, and 2030. Forecasted emissions reductions in 2030 in Phase II meet the minimum statutory requirement, and do not vary substantially across portfolios. This is driven in part by the model seeking a least-cost expansion plan, based on actual bid pricing (versus generic resources in Phase I), as well as new APCD guidance issued in December 2024 on the approach to forecasting market emission rates. In Phase II, emission rates for market purchases and sales are reflective of expectations that the residual mix of supply from the market is anticipated to be primarily thermal energy.

Additional discussion of Tri-State's consideration of the environmental results of the portfolio analyses can be found in the Portfolio Analysis section of the Executive Summary; and discussion of SCoC and SCoM in the Financial Analysis section below.

Table 135: Comparison of Forecasted Colorado GHG Reduction by Portfolio in GHG Target Years

	2025	2026	2027	2030
Portfolio 1: New ERA Expanded	29%	39%	47%	80%
Portfolio 2: New ERA Limited Gas	29%	39%	47%	80%
Portfolio 3: New ERA Gas Flexibility (FLEX)	29%	39%	47%	80%
Portfolio 4: FLEX Shafer Replacement	29%	39%	47%	80%
Portfolio 5: No New Gas (NNG)	29%	39%	47%	80%
Portfolio 6: NNG Shafer Replacement	29%	39%	47%	80%

Figure 16: Comparison of Portfolio Achievements Toward Colorado GHG Reduction Targets



[128] Trending at the end of Q1-2025 is positive toward achievement of Tri-State's first GHG reduction target.

Figure 17: Comparison of Colorado CO2e

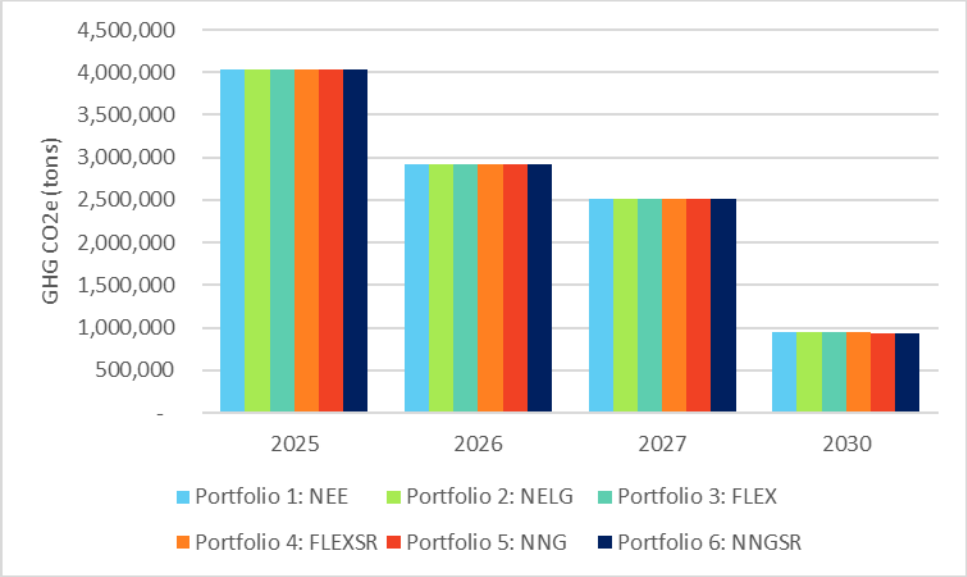


Figure 18: Comparison of SCoC During the RAP

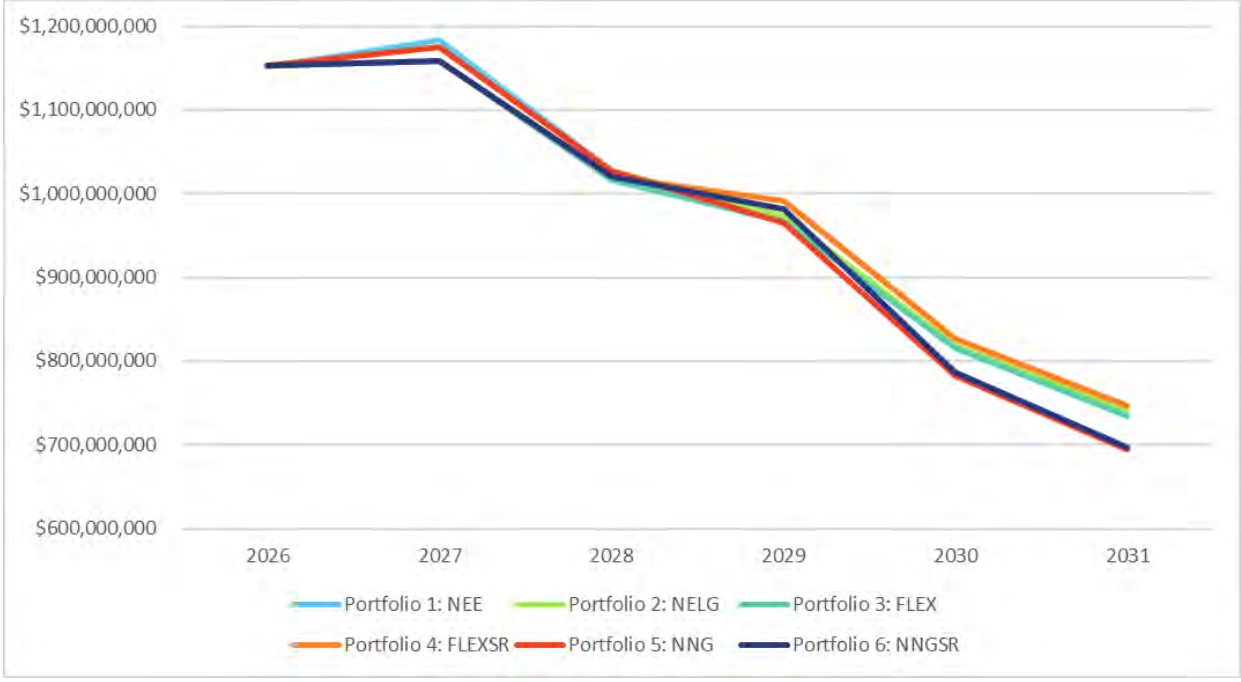
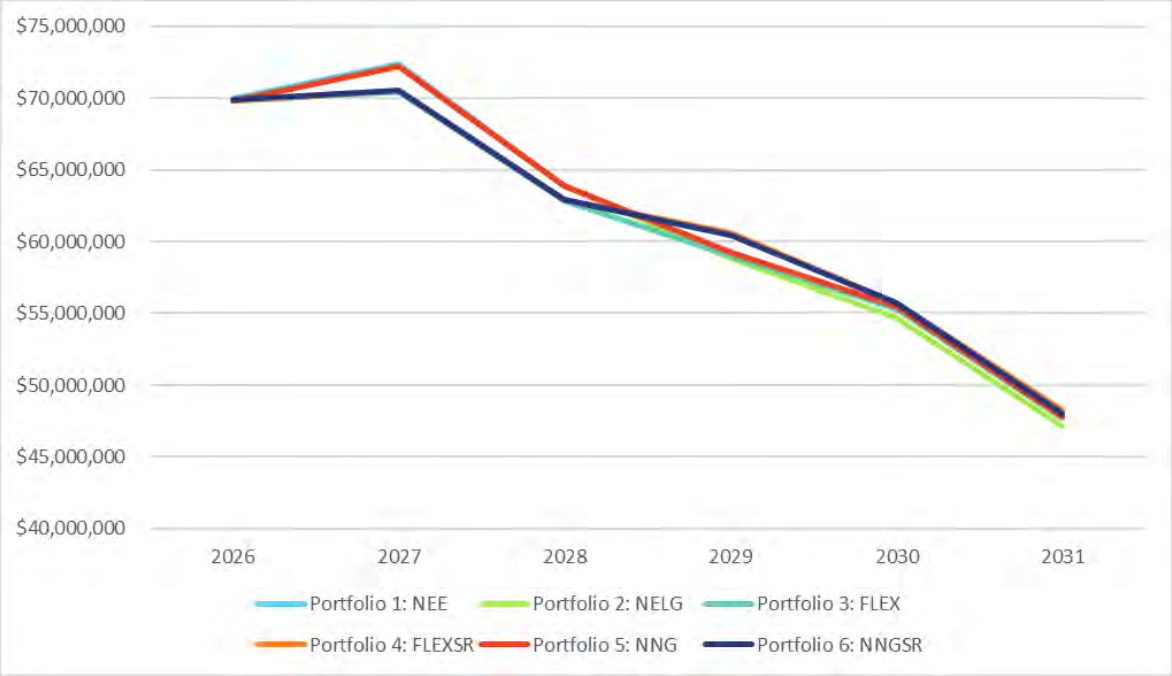


Figure 19: Comparison of SCoM During the RAP



Financial Analysis

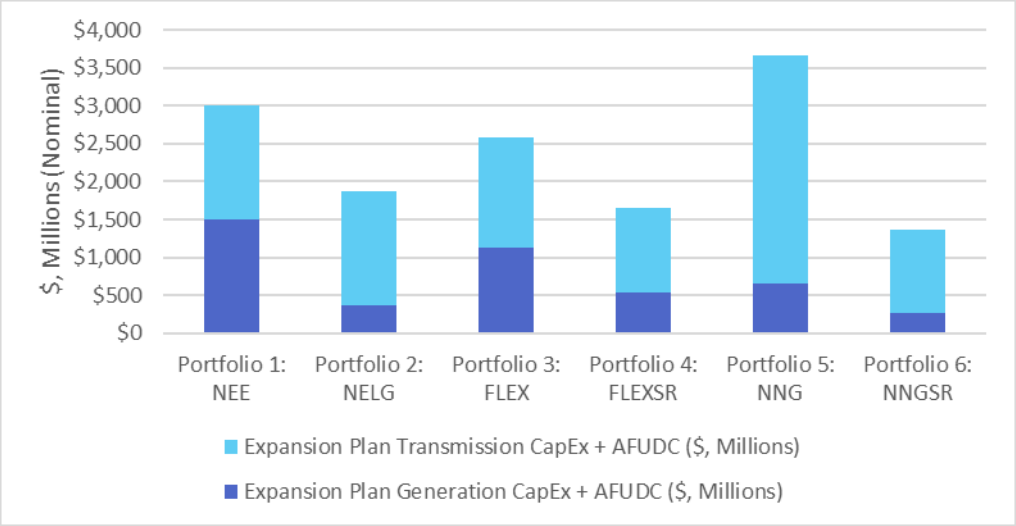
The following table compares total financial results for each portfolio, both with and without the SCoC and SCoM. Portfolio 4 – FLEXSR is the lowest cost plan on a PVRR basis, requiring fewer new resource acquisitions than other portfolios while achieving comparable emissions reductions and reliability results—an important value for Tri-State's Members. Further discussion of the financial benefits achieved with Portfolio 4 – FLEXSR bid selections is identified in Attachment G.

Table 136: Comparison of PVRR

	PVRR ($, Millions)	**PVRR w/SCoC and SCoM ($, Millions)**
Portfolio 1: New ERA Expanded	$16,836	$30,584
Portfolio 2: New ERA Limited Gas	$16,841	$30,524
Portfolio 3: New ERA Gas Flexibility	$16,761	$30,488
Portfolio 4: FLEX Shafer Replacement	$16,443	$30,210
Portfolio 5: No New Gas	$17,067	$30,334
Portfolio 6: No New Gas Shafer Replacement	$16,531	$29,881

The following figure compares capital expenditures and MW additions by portfolio.

Figure 20: Comparison of Generation and Transmission CapEx (Nominal $) During the RPP



As shown in below, the MW level and type of resource additions selected in Portfolios 2 and 3 are relatively similar. Renewable MWs were relatively consistent across all portfolios, except for Portfolio 3 which selected more wind and less solar. Portfolios 1-4 selected a gas plant bid and had a similar amount of storage MW selections, whereas Portfolios 5 and 6, which did not allow new gas, required a considerably larger amount of storage resource additions. Portfolio 4, the preferred portfolio, requires the least amount of resource additions with less transmission capital expenditures. Portfolio 5 requires more MW resource additions than other portfolios in order to maintain system reliability without the addition of a dispatchable gas resource, but at a higher PVRR than any other portfolio. Tri-State is concerned about the potential risk in overreliance on 4-hour batteries suggested by the resource additions in Portfolios 5 and 6; Tri-State has not yet deployed any batteries on its system and storage technologies, including longer duration storage options, are anticipated to make advancements in the coming years.

Table 137: Comparison of MW Additions by Portfolio, by Technology over the RAP

MW	Portfolio 1: NEE	Portfolio 2: NELG	Portfolio 3: FLEX	Portfolio 4: FLEXSR	Portfolio 5: NNG	Portfolio 6: NNGSR
Wind	400	400	497	400	400	400
Solar	240	240	100	200	240	200
Standalone Storage -Short Duration	450	650	650	600	1,050	1,150
Standalone Storage - Long Duration	100	0	0	0	100	0
Gas	307	307	307	307	0	0
Solar Hybrid	250	250	250	100	250	100
RAP Total	**1,747**	**1,847**	**1,804**	**1,607**	**2,040**	**1,850**
Solar Hybrid – Battery Storage Component	125	125	125	50	125	50
RAP Total w/Hybrid Storage	**1,872**	**1,972**	**1,929**	**1,657**	**2,165**	**1,900**

Table 138: Comparison of Number of Bids by Portfolio, by Technology over the RAP

	Portfolio 1: NEE	Portfolio 2: NELG	Portfolio 3: FLEX	Portfolio 4: FLEXSR	Portfolio 5: NNG	Portfolio 6: NNGSR
Wind	2	2	2	2	2	2
Solar	2	2	1	1	2	1
Standalone Storage -Short Duration	4	6	6	5	9	9
Standalone Storage - Long Duration	1	0	0	0	1	0
Gas	1	1	1	1	0	0
Solar Hybrid	2	2	2	1	2	1
RAP Total	**12**	**13**	**12**	**10**	**16**	**13**

Table 139 below identifies the percentage of Tri-State's system energy and energy supplied to Members that is forecasted to be renewable, for each portfolio in 2030. Table 140 identifies the percentage of generation capacity mix that is renewable for each portfolio in 2030. Table 141 identifies the percentage of generation capacity credit that is dispatchable/firm for each portfolio in 2030. While the preferred portfolio yields a slightly lower percentage of renewables on an energy supply basis, on a generation capacity supply basis the preferred portfolio has a similar percentage of renewables in its mix as the other portfolios. Importantly, all portfolios achieve Tri-State's aspirational target of having 70 percent clean supply to Members in 2030, but the preferred portfolio does so at the least cost.

Table 139: Comparison of Renewables' Contribution to System and Member Supply in 2030, by Portfolio

	2030 System Energy Mix	2030 Tri-State Energy Supply to Members
	% Renewables	
Portfolio 1: NEE	57%	75%
Portfolio 2: NELG	57%	75%
Portfolio 3: FLEX	57%	75%
Portfolio 4: FLEXSR	55%	71%
Portfolio 5: NNG	58%	75%
Portfolio 6: NNGSR	57%	72%

Table 140: Comparison of Renewables' Contribution to Generation Capacity in 2030, by Portfolio

	2030 Generation Capacity Mix
	% Renewables
Portfolio 1: NEE	49%
Portfolio 2: NELG	48%
Portfolio 3: FLEX	48%
Portfolio 4: FLEXSR	48%
Portfolio 5: NNG	47%
Portfolio 6: NNGSR	49%

Table 141: Comparison of Dispatchable/Firm Contribution to the System Mix in 2030, by Portfolio

	2030 Generation Capacity Credit
	% Dispatchable/Firm
Portfolio 1: NEE	78%
Portfolio 2: NELG	76%
Portfolio 3: FLEX	77%
Portfolio 4: FLEXSR	80%
Portfolio 5: NNG	71%
Portfolio 6: NNGSR	73%

Curtailments

The following table identifies the annual total curtailment costs (PPA pricing, penalties, and taxes) estimated to result from the modeled curtailments, by resource type. None of the portfolios result in wind PPA curtailment costs. Significant solar curtailment costs in all portfolios reflects the inherent challenges in integrating a large amount of intermittent resources into the system in a short timespan. More intermittent resources leads to more curtailment, but storage additions mitigate curtailments.

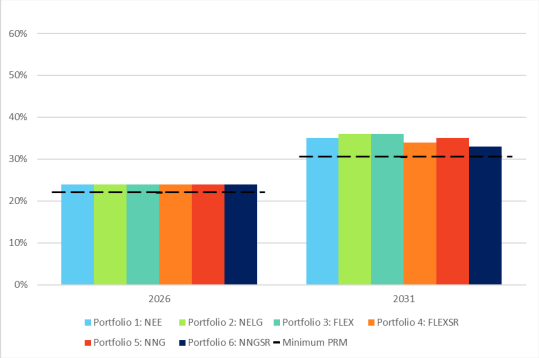
Table 142: Comparison of Solar Curtailment Costs by Portfolio, Real (2024) $

	Portfolio 1: NEE	Portfolio 2: NELG	Portfolio 3: FLEX	Portfolio 4: FLEXSR	Portfolio 5: NNG	Portfolio 6: NNGSR
2026	$145,247	$156,979	$125,261	$152,487	$138,416	$166,014
2027	$224,019	$114,621	$151,371	$193,537	$105,188	$171,286
2028	$214,350	$143,388	$107,958	$90,037	$198,901	$42,920
2029	$18,138	$56,325	$18,876	$51,807	$31,189	$798
2030	$0	$0	$0	$0	$0	$0
2031	$0	$0	$0	$0	$0	$0
RAP Total	**$601,754**	**$471,313**	**$403,466**	**$487,868**	**$473,694**	**$381,018**

Reliability Analysis

PRMs are relatively consistent across all portfolios. Increasing PRMs after 2026 occur as a result of the large amount of intermittent resource additions during the RAP.

Figure 21: Comparison of PRMs During the RAP



Each of the portfolios met Level 1 and 2 Reliability Metrics. The preferred portfolio (FLEXSR) achieves reliability in the most cost-effective manner.

NNG and NNGSR portfolios rely on an extensive amount of storage resources to maintain reliability, creating a heavy reliance on a semi-dispatchable technology during the energy transition—a technology that Tri-State has not yet deployed. Storage technology may evolve and improve in both cost and performance in the coming years, thus Tri-State and its Members seek to make investment during this RAP in a manner that result in a balanced and diversified technology mix, at the least cost.

Conclusion

This Implementation Report provides extensive detail on the multiple portfolios modeled. Tri-State believes this analysis builds a clear record that supports approval of Tri-State's preferred portfolio, FLEXSR, including as a result of the analyses provided in Attachments G and H. Tri-State requests the Commission approve Tri-State's preferred portfolio, Portfolio 4 – FLEXSR, as the final cost-effective resource plan for Phase II of the 2023 ERP, pursuant to Rule 3605(h)(II).

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit K: NERC, *2024 Long-Term Reliability Assessment* (Dec. 2024)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2024 Long-Term Reliability Assessment

December 2024

Corrected July 11, 2025



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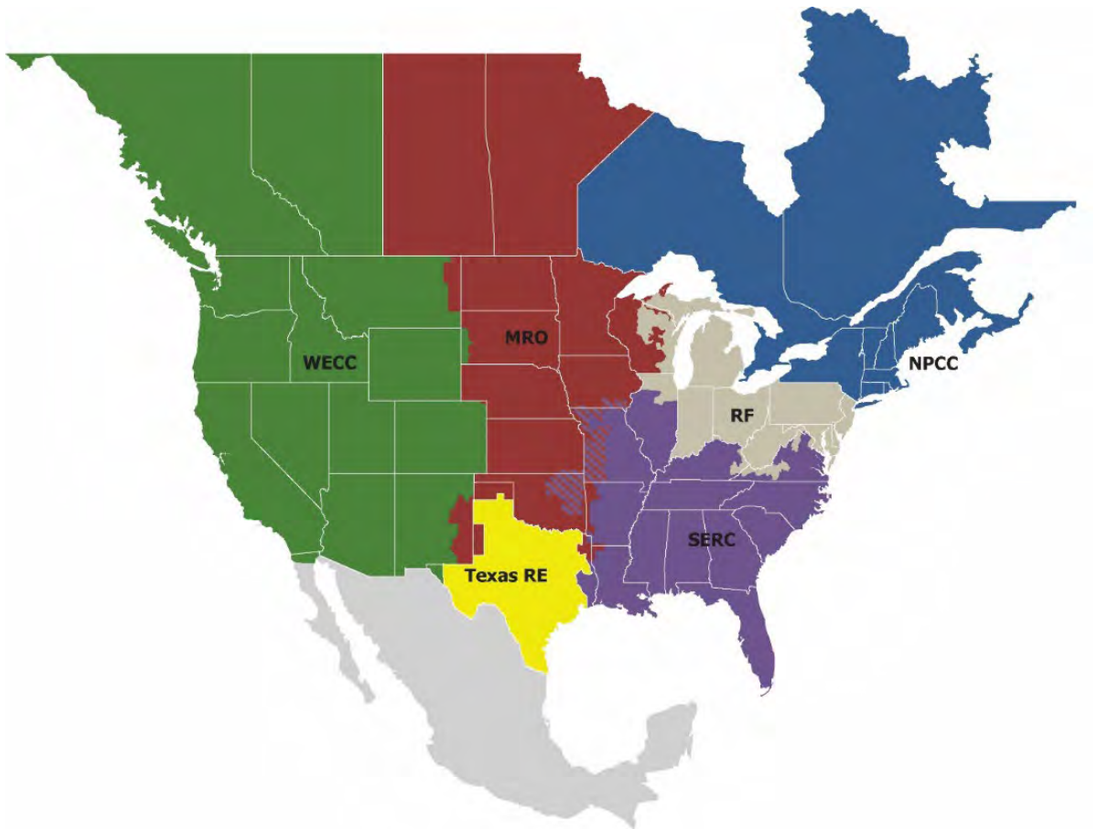
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About This Assessment

NERC is a not-for-profit international regulatory authority with the mission to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the North American BPS and serves more than 334 million people. Section 39.11(b) of FERC's regulations provides that "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

Development Process

This assessment was developed based on data and narrative information NERC collected from the six Regional Entities (see **Preface**) on an assessment area basis (see **Regional Assessments Dashboards**) to independently evaluate the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The Reliability Assessment Subcommittee (RAS), at the direction of NERC's Reliability and Security Technical Committee (RSTC), supported the development of this assessment through a comprehensive and transparent peer-review process that leverages the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts; this peer-review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees subsequently accepted this assessment and endorsed the key findings.

NERC develops the *Long-Term Reliability Assessment* (LTRA) annually in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations;[3] this is also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

Considerations

This assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2024 about known system changes with updates incorporated prior to publication. This *2024 LTRA* assessment period includes projections for 2025–2034; however, some figures and tables examine data and information for the 2024 year. NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in the **Demand Assumptions and Resource Categories** section of this report. Reliability impacts related to cyber and physical security risks are not specifically addressed in this assessment; it is primarily focused on resource adequacy and operating reliability. NERC leads a multi-faceted approach through NERC's Electricity Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electric industry.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data from each Regional Entity is also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and a portion of Baja California, Mexico. NERC's reliability assessments are developed to inform industry, policymakers, and regulators as well as to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

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[1] NERC Rules of Procedure - Section 803

[2] Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[3] Title 18, § 39.11 of the Code of Federal Regulations

[4] BPS reliability, as defined in the How NERC Defines BPS Reliability section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.

[5] ERO Reliability Assessment Process Document

Assumptions

In this *2024 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts submitted and validated in July 2024. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame have been included where appropriate.
- Peak demand is based on average peak weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Regional Entity's self-assessment.
- Generation and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned, planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

Reading this Report

This report is compiled into two major parts:

1. **A reliability assessment of the North American BPS with the following goals:**
   a. Evaluate industry preparations that are in place to meet projections and maintain reliability
   b. Identify trends in demand, supply, reserve margins, and probabilistic resource adequacy metrics
   c. Identify emerging reliability issues
   d. Focus the industry, policymakers, and the general public's attention on BPS reliability issues
   e. Make recommendations based on an independent NERC reliability assessment process
2. **A regional reliability assessment that contains the following:**
   a. A 10-year data dashboard
   b. Summary assessments for each assessment area
   c. A focus on specific issues identified through industry data and emerging issues
   d. A description of regional planning processes and methods used to ensure reliability

[6] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

Executive Summary

In the *2024 LTRA*, NERC finds that most of the North American BPS faces mounting resource adequacy challenges over the next 10 years as surging demand growth continues and thermal generators announce plans for retirement. New solar PV, battery, and hybrid resources continue to flood interconnection queues, but completion rates are lagging behind the need for new generation. Furthermore, the performance of these replacement resources is more variable and weather-dependent than the generators they are replacing. As a result, less overall capacity (dispatchable capacity in particular) is being added to the system than what was projected and needed to meet future demand. **The trends point to critical reliability challenges facing the industry: satisfying escalating energy growth, managing generator retirements, and accelerating resource and transmission development.**

This *2024 LTRA* is the ERO's independent assessment and comprehensive report on the adequacy of planned BPS resources to reliably meet the electricity demand across North America over the next 10 years; it also identifies reliability trends, emerging issues, and potential risks that could impact the long-term reliability, resilience, and security of the BPS. The findings presented here are vitally important to understanding the reliability risks to the North American BPS as it is currently planned and being influenced by government policies, regulations, consumer preferences, and economic factors. Summaries of the report sections are provided below.

Capacity and Energy Risk Assessment

The **Capacity and Energy Risk Assessment** section of this report identifies potential future electricity supply shortfalls under normal and extreme weather conditions. NERC's evaluation of resource adequacy in the LTRA considers both the capacity of the resources and the capability of resources to convert inputs (e.g., fuel, wind, and solar irradiance) into electrical energy. NERC used both a probabilistic assessment and a reserve margin analysis to assess the risk of future electricity supply shortfalls. Both are forward-looking snapshots of resource adequacy that are tied to industry forecasts of electricity supplies, demand, and transmission development.

Areas categorized as **High Risk** fall below established resource adequacy criteria in the next five years. High-risk areas are likely to experience a shortfall in electricity supplies at the peak of an average summer or winter season. Extreme weather, producing wide-area heat waves or deep-freeze events, poses an even greater threat to reliability. **Elevated-Risk** areas meet resource adequacy criteria, but analysis indicates that extreme weather conditions are likely to cause a shortfall in area reserves. **Normal-Risk** areas are expected to have sufficient resources under a broad range of assessed conditions. The results of the risk assessment are depicted in **Figure 1**.

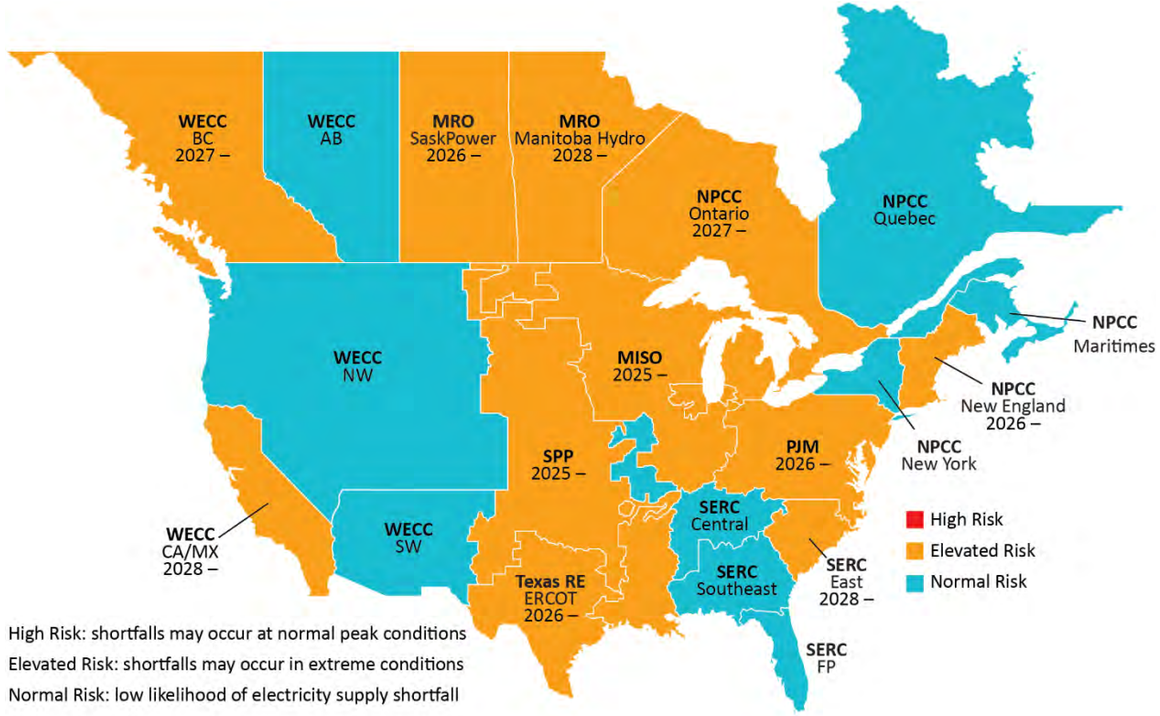


Figure 1: Risk Area Summary 2025–2029 (Corrected July 2025)

Regional Assessments Dashboards

The **Regional Assessments Dashboards** section contains dashboards and summaries for each of the 20 assessment areas, developed from data and narrative information collected by NERC from the six Regional Entities. Probabilistic Assessments (ProbA) are presented that identify energy risk periods and describe the contributing demand and resource factors.

Table 1: Capacity and Energy Risk Assessment Area Summary (Corrected June 2025)			
Area	**Risk Level**	**Years**	**Risk Summary**
MISO	Elevated	2025 -	Uncertainty around new resource additions and existing generator retirements results in resource adequacy risks. Above-normal generator outages during extreme weather can result in unserved energy or load loss.
Manitoba	Elevated	2028 -	Potential resource shortfalls in low-hydro conditions, driven by rising demand.
SaskPower	Elevated	2026 -	Risk of insufficient generation during fall and spring when more generators are off-line for maintenance.
Southwest Power Pool (SPP)	Elevated	2025 -	Potential energy shortfalls during peak summer and winter conditions arise from low wind conditions and natural gas fuel risk.
New England	Elevated	2026 -	Strong demand growth and persistent winter natural gas infrastructure limitations pose risks of supply shortfalls in extreme winter conditions.
Ontario	Elevated	2027 -	Reserve margins fall below RMLs as nuclear units undergo refurbishment and some current resource contracts expire. Demand growth is also adding to resource procurement needs.
PJM	Elevated	2026 -	Resource additions are not keeping up with generator retirements and demand growth. Winter seasons replace summer as the higher-risk periods due to generator performance and fuel supply issues.
SERC-East	Elevated	2028 -	Demand growth and planned generator retirements contribute to growing energy risks. Load is at risk in extreme winter conditions that cause demand to soar while supplies are threatened by generator performance, fuel issues, and inability to obtain emergency transfers.
ERCOT	Elevated	2026 -	Surging load growth is driving resource adequacy concerns as the share of dispatchable resources in the mix struggles to keep pace. Extreme winter weather has the potential to cause the most severe load-loss events.
California-Mexico	Elevated	2028 -	Demand growth and planned generator retirements can result in supply shortfalls during wide-area heat events that limit the supply of energy available for import.
British Columbia	Elevated	2027 -	Drought and extreme cold temperatures in winter can result in periods of insufficient operating reserves when neighboring areas are unable to provide excess energy.

Risk from Additional Generator Retirements

Plans for generator retirements continue at similar pace and scale to levels reported in the *2023 LTRA*. Confirmed generator retirements (52 GW by 2029 and 78 GW over the 10-year period) are accounted for in the Capacity and Energy Risk Assessment above. Economic, policy, and regulatory factors spur further fossil-fired generators to retire in the 10-year horizon. Announced retirements, which include many generators that have not begun formal deactivation processes with planning entities, total 115 GW over the 10-year period. The effect of all retirements on the assessment area Planning Reserve Margins (PRM) can be seen in **Figure 2**. On-peak reserve margins fall below RMLs; the levels required by jurisdictional resource adequacy requirements) in the next 10 years in almost every assessment area, signaling an accelerating need for more resources.

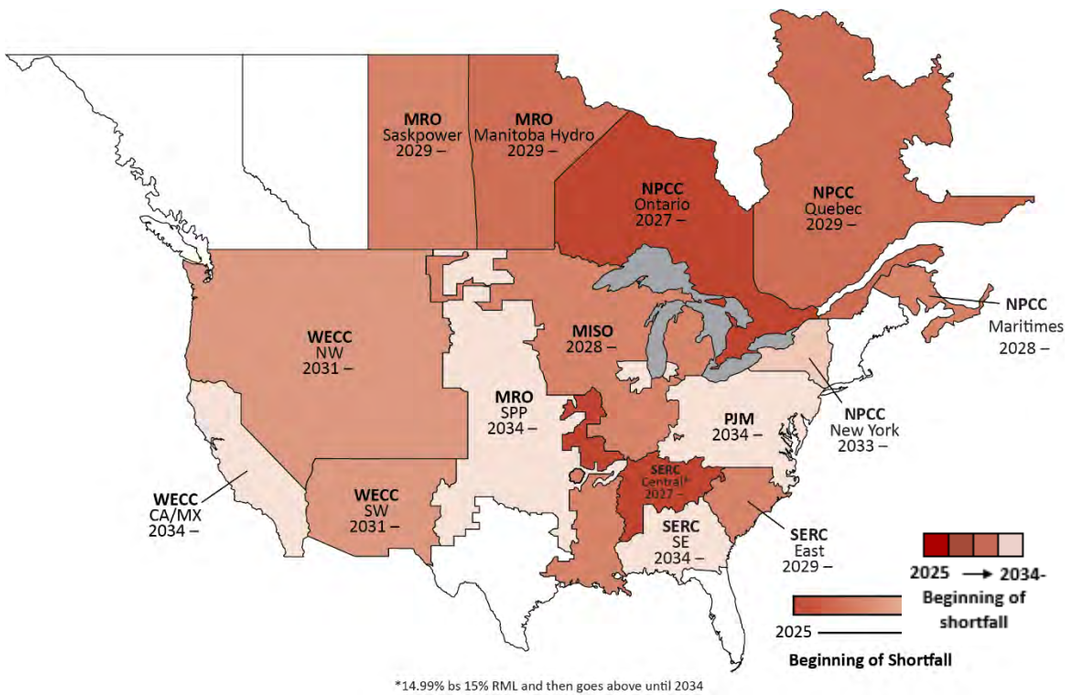


Figure 2: Projected Reserve Margin Shortfall Areas with Announced Generator Retirements (Corrected July 2025)

Changing Resource Mix and Reliability Implications

New resource additions continue at a rapid pace. Solar PV remains the overwhelmingly predominant generation type being added to the BPS followed by battery and hybrid resources, natural-gas-fired generators, and wind turbines. New resource additions fell short of industry's projections from the *2023 LTRA* with the notable exception of batteries, which added more nameplate capacity than was reported in development last year.

As older fossil-fired generators retire and are replaced by more solar PV and wind resources, the resource mix is becoming increasingly variable and weather-dependent. Solar PV, wind, and other variable energy resources (VER) contribute some fraction of their nameplate capacity output to serving demand based on the energy-producing inputs (e.g., solar irradiance, wind speed). The new resources also have different physical and operating characteristics from the generators that they are replacing, affecting the essential reliability services (ERS) that the resource mix provides. As generators are deactivated and replaced by new types of resources, ERS must still be maintained for the grid to operate reliably.

Natural-gas-fired generators are a vital BPS resource. They provide ERSs by ramping up and down to balance a more variable resource mix and are a dispatchable electricity supply for winter and times when wind and solar resources are less capable of serving demand. Natural gas pipeline capacity additions over the past seven years are trending downward, and some areas could experience insufficient pipeline capacity for electric generation during peak periods.

Trends and Reliability Implications

Demand and transmission trends affect long-term reliability and the sufficiency of electricity supplies. A summary for each is provided below and further discussed within the **Demand Trends and Implications** and **Transmission Development and Interregional Transfer Capability** sections.

Demand Trends

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb; demand growth is now higher than at any point in the past two decades. Increasing amounts of large commercial and industrial loads are connecting rapidly to the BPS. The size and speed with which data centers (including crypto and AI) can be constructed and connect to the grid presents unique challenges for demand forecasting and planning for system behavior. Additionally, the continued adoption of electric vehicles and heat pumps is a substantial driver for demand around North America. The aggregated BPS-wide projections for both winter and summer have increased massively over the 10-year period:

- The aggregated assessment area summer peak demand forecast is expected to rise by 15% for the 10-year period: 132 GW this LTRA up from over 80 GW in the *2023 LTRA*.
- The aggregated assessment area winter peak demand forecast is expected to rise over almost 18% for the 10-year period: 149 GW this LTRA up from almost 92 GW in the *2023 LTRA*.

Transmission Trends

For the first time in recent years, transmission projections reported for the LTRA reflect a significant increase in transmission development. This year's cumulative level of 28,275 miles of transmission (>100 kV) in various stages of development for the next 10 years is substantially higher than the *2023 LTRA* 10-year projections (18,675 miles) and is above the average of the past five years of NERC's LTRA reporting on average (18,900 miles of transmission planning projects in each 10-year period published in the last five LTRAs). Transmission in construction has yet to increase substantially; rather, the large increase in transmission projects is seen in planning stages of development.

New transmission projects are being driven to support new generation and enhance reliability. Transmission development continues to be affected by siting and permitting challenges. Of the 1,160 projects that are under construction or in planning for the next 10 years, 68 projects totaling 1,230 miles of new transmission are delayed by siting and permitting issues, according to data collected for the LTRA. Questions of cost allocation and recovery can also challenge transmission development when the benefits apply to more than one area, as often occurs with projects that enhance interregional transfer capability.

In NERC's separate Interregional Transfer Capability Study (ITCS), which was performed to meet requirements contained in the Fiscal Responsibility Act of 2023, NERC found that an additional 35 GW of transfer capability across the United States would strengthen energy adequacy under extreme conditions. Increasing transfer capability between neighboring transmission systems has the potential to alleviate energy shortfalls in some areas identified in this LTRA's **Capacity and Energy Risk Assessment**. Conversely, when resource plans are developed that address these same energy shortfalls, such as through resource additions, demand-side management initiatives, or changes to generator retirement plans, the need for increased transfer capability will also change. Planners have options for reducing energy adequacy risks from extreme weather. Selecting the best course of action will depend on weighing these options against various engineering, economic, policy, reliability, and resilience objectives.

The ITCS provides foundational insights that facilitate stakeholder analysis and actions; it is not a transmission plan. In the future, NERC will extend the study beyond the congressional mandate to include transfer capabilities from the United States to Canada and among Canadian provinces.

Emerging Issues

The **Emerging Issues** section discusses developments and trends that have the potential to substantially change future long-term demand and resource projections, resource availability, and reliable operations of the BPS. Topics include data centers and large industrial loads, battery energy storage systems, electric vehicles and load, and energy drought. NERC's RSTC has formed new task forces where needed to address emerging issues.

Recommendations

To address the energy and capacity risks identified in this LTRA, NERC recommends the following priority actions:

1. **Integrated Resource Planners, market operators, and regulators: Carefully manage generator deactivations.** Independent System Operator/Regional Transmission Organizations (ISO/RTOs) should evaluate mechanisms and process enhancements for obtaining information on expected generator retirements that would support early identification of reliability risks. State and provincial regulators and ISO/RTOs need to have mechanisms they can employ to extend the service of generators seeking to retire when they are needed for reliability, including the management of energy shortfall risks. Regulatory and policy-setting organizations must use their full suite of tools to manage the pace of retirements and ensure that replacement infrastructure can be developed and placed in service.

2. **NERC and Regional Entities: Improve the LTRA by incorporating new analysis and criteria to inform stakeholders of future reliability risks.** NERC increased the frequency of the ProbA from biennial to annual and included unserved energy and load-loss metrics as the basis for risk analysis in this year's LTRA. To be more effective in using energy criteria and outputs of probabilistic analysis, NERC must specify consistent methods and assumptions for assessment areas to follow in preparing the annual ProbA. NERC and the Regional Entities, in consultation with the RSTC, should also continue to enhance NERC's LTRA to assess ERSs in the future system and the potential impact of new and evolving electricity market practices, regulations, or legislation on resource adequacy. Finally, NERC should work with the Regional Entities to perform wide-area energy analysis with modeled interregional transfer capability. Wide-area energy analysis will support the evaluation of extreme weather and regional fuel supply issues on an interconnection level.

3. **Regulators and Policymakers: Streamline siting and permitting processes to remove barriers to resource and transmission development.** As ISO/RTOs continue looking for opportunities to speed transmission planning processes, delays from siting and permitting activities will need to be reduced. These are the most common causes for delayed transmission projects. Support from regulators and policymakers at the federal, state, and provincial levels is urgently needed.

4. **Regulators, electric industry, and gas industry member organizations: Implement a framework for addressing the operating and planning needs of the interconnected natural gas-electric energy system.** Various initiatives were launched in the past year to address the reliability needs that arise from the complexity of interconnecting natural gas and electric infrastructure. Voluntary actions taken by the natural gas industry in response to the North American Energy Standards Board (NAESB) Forum report are a positive step toward improving winter readiness. The National Association of Regulatory Utility Commissioners (NARUC) launched its Gas-Electric Alignment for Reliability (GEAR) task force this year and recently created the Natural Gas Readiness Forum. For its part, NERC continues to collaborate extensively with industry and policymakers. NERC has enhanced its Reliability Standards requiring generators to prepare for winter extremes, implement training, and establish communication protocols between generators and grid operators. Current standards projects encompass extreme weather planning and energy assurance requirements. NERC will continue to provide full support to initiatives aimed at achieving a reliable interconnected energy system and urges regulators and policymakers to support needed avenues of coordination between the two sectors.

5. **Regional transmission organizations, independent system operators, and FERC: Continue to ensure essential reliability services are maintained.** The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate ERSs.[7] Retiring conventional generation is being replaced with large amounts of wind and solar; planning considerations must adapt with more attention to ERSs. As replacement resources are interconnected, these new resources should be capable of supporting voltage, frequency, ramping, and dispatchability. Many technologies can contribute to ERSs, including variable energy resources; however, policies and market mechanisms need to reflect these requirements to ensure these services are provided and maintained. Regional transmission organizations, independent system operators, and FERC have taken steps in this direction, and these positive steps must continue.

In addition to these priorities, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. All recommendations are listed in the **Recommendations and ERO Actions Summary** section.

[7] Essential Reliability Services: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERS%20Abstract%20Report%20Final.pdf

Capacity and Energy Assessment

The resource mix transformation is making traditional capacity-based adequacy criteria obsolete. Resource Planners and state and provincial policymakers use resource adequacy criteria to ensure sufficient resources are available to meet demand. In their application, current capacity-based adequacy criteria were not designed to differentiate between the scenarios, size, frequency, duration, and timing of energy shortfalls. This has become increasingly important as the resource transformation evolves from capacity-based resources with assured and stored energy supplies to energy-constrained resources that are increasingly impacted by weather and environmental conditions. Therefore, supplemental criteria must be adapted to properly assess system adequacy and help determine appropriate solutions. This year's LTRA includes probabilistic indices to measure these additional dimensions of risk and provide a more robust approach to understanding risk of inadequacy in future plans.

Assessment Approach

NERC is using two approaches in this LTRA to assess future resource capacity and energy risk; both are forward-looking snapshots of resource adequacy that are tied to industry forecasts of electricity supplies, demand, and transmission development:

- Assessing load-loss metrics determined from probability-based simulation of projected demand and resource availability over all hours. This approach identifies high-risk periods and potential energy constraints resulting in load-loss events. The 2024 ProbA is performed for each assessment area and examines the system as planned for the years 2026 and 2028. Loss-of-load hours (LOLH) and expected unserved energy (EUE) from NERC's ProbA are used to identify risk levels.
- Comparing the margin between projected resources and peak net demand, or reserve margin, to a reserve margin target (known as RML) that represents the accepted level of risk based on a probability-based loss-of-load analysis.

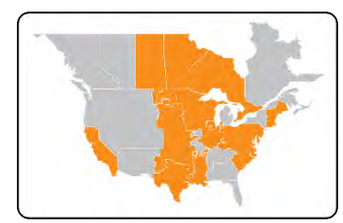
See the **Demand Assumptions and Resource Categories** for further details on these approaches. Assessment area dashboards (see **Regional Assessments Dashboards**) provide resource capacity and energy risk assessment results for all areas.

Risk Categories

An assessment area is **high risk** when established resource adequacy targets or requirements are not met during this assessment period. Regulatory authorities or market operators establish resource adequacy targets. Most targets in North America are currently based on a 1-day/event load loss in a 10-year planning requirement. See the **Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area**. Recently, regulators and policymakers in many states and market areas have begun considering or developing resource adequacy targets based on additional criteria that can better address energy risks and extreme weather-related supply disruption.[8] High-risk areas are likely to experience a shortfall in electricity supplies at the peak of an average summer or winter season. Unusual heat waves or deep-freeze events pose an even greater threat to reliability.

For the *2024 LTRA*, assessment areas are classified as high risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2025–2029):

- Annual LOLH exceeds 2.4 hours/year for one or more years in the ProbA.
- Annual normalized EUE exceeds 0.002% (20 ppm) for one or more years in the ProbA.
- Resource adequacy target(s) established by regulatory authority or market operator are not met.

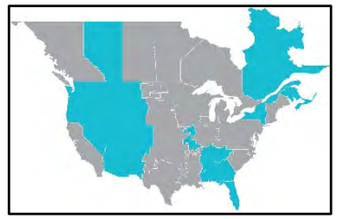


An assessment area is considered an **elevated risk** when it meets the established resource adequacy target or requirement, but probabilistic or deterministic analysis of conditions that are plausible but more extreme than normal seasonal peaks are likely to cause shortfall in area reserves. More extreme conditions can include temperatures that result in above-normal demand levels, low resource output or availability, and/or disruption of normal electricity transfers. In the analysis, elevated risk may be found by modeling above-normal demand and low resource availability. The risk can also be identified by examining output data from probabilistic analysis tools to determine the underlying conditions for load-loss events. Simply put, elevated-risk areas meet resource adequacy requirements but may face challenges meeting load under extreme conditions. For the *2024 LTRA*, assessment areas are classified as elevated risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2025–2029):

- Annual LOLH is between 0.1 and 2.4 hours/year for one or more years in the ProbA.

[8] See the NERC-National Academy of Engineering Workshop Report *Evolving Planning Criteria for a Sustainable Power Grid*.

- Annual normalized EUE is less than 0.002% (20 ppm) but non-zero for one or more years in the ProbA.
- Resource adequacy target(s) established by regulatory authority or market operator are met, but plausible scenarios of above-normal demand and/or low-resource conditions associated with a once-per-decade event indicate risk of load loss.



NERC assesses areas as **normal risk** when resource adequacy criteria are met and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance). Although areas categorized as normal risk are expected to have sufficient resources for plausible extreme[9] conditions, they are not immune to the effects of high-impact, low-frequency weather events that affect demand and generation simultaneously. For the *2024 LTRA*, assessment areas are classified as normal risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2025–2029):

- Annual LOLH is below 0.1 hours/year.
- Annual normalized EUE is negligible or zero.
- Resource adequacy target(s) established by regulatory authority or market operator are met and reserves are expected to be available in plausible scenarios of above normal demand and/or low resource conditions associated with a once-per-decade event indicate risk of load loss.

Application of the Risk Criteria: NERC uses industry-provided demand and resource information and the results from probabilistic assessments performed by NERC Regional Entities, ISO/RTOs, and regulated utilities to determine risk of energy and capacity shortfalls. The methods, assumptions, and approaches used by entities to perform probabilistic assessments affect the results and outputs. In this year's LTRA, NERC incorporated new probabilistic assessment criteria (LOLH and EUE) from the NERC-National Academy of Engineering Workshop Report *Evolving Planning Criteria for a Sustainable Power Grid* alongside established reserve margin criteria. In instances where an assessment area's probabilistic assessment results and reserve margins give mixed indications as to the risk category, adherence to resource adequacy targets (e.g., required RML and load-loss criteria) established by regulatory jurisdictions took precedence. Any other apparent contradictions with metrics and criteria were generally assessed according to results of all-hours probabilistic analysis.

Elevated-Risk Area Details

The below areas are projected to meet resource adequacy criteria and have energy and capacity for normal forecasted conditions but are at risk of supply shortfall in extreme conditions. Areas are listed in order of appearance in the **Regional Assessments Dashboards** section.

MISO

MISO has experienced slower resource additions due to market pressures and constraints faced by projects with signed interconnection agreements. MISO has highlighted uncertainties with a large number of new resources that have signed interconnection agreements (Tier 1 additions) and are expected to come on-line in the next several years.[10] Resource adequacy risks could grow over time absent the new capacity reflected in the Tier 1 additions and the deferral of announced retirements (see **Risk from Additional Generator Retirements**).

PRMs in MISO with resource additions are shown in **Figure 3** and **Figure 4**. MISO reports 56 GW of nameplate generating capacity, predominantly solar and batteries, with signed generation interconnection agreements (qualifying as Tier 1 and reflected in the ARM in **Figure 3** and **Figure 4**) as of July 2024 that can help meet resource adequacy needs if connection is completed. If resource additions remain at or near historically average levels (approximately 2.3 GW/year average over the last 3 years), PRMs in MISO will fall below the RML reserve margin requirements much faster. Summer PRMs with average resource additions are shown in **Figure 3** as **Reserve Margin-Avg Addition**.

[9] Plausible extreme conditions considered by NERC in this assessment are similar to those experienced during Winter Storm Elliott, Winter Storm Uri, and the 2020 Western Wide Area Heat Dome.
[10] See results from the 2024 Organization of MISO States (OMS)-MISO Survey.

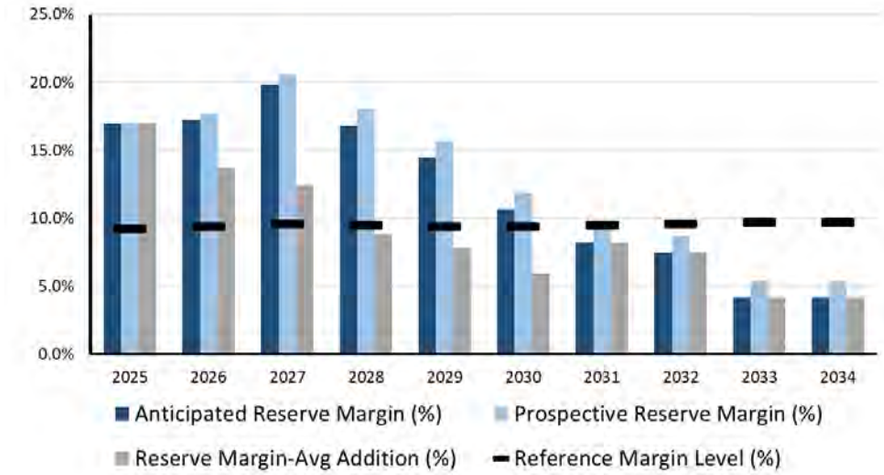


Figure 3: MISO Planning Reserve Margin–Summer

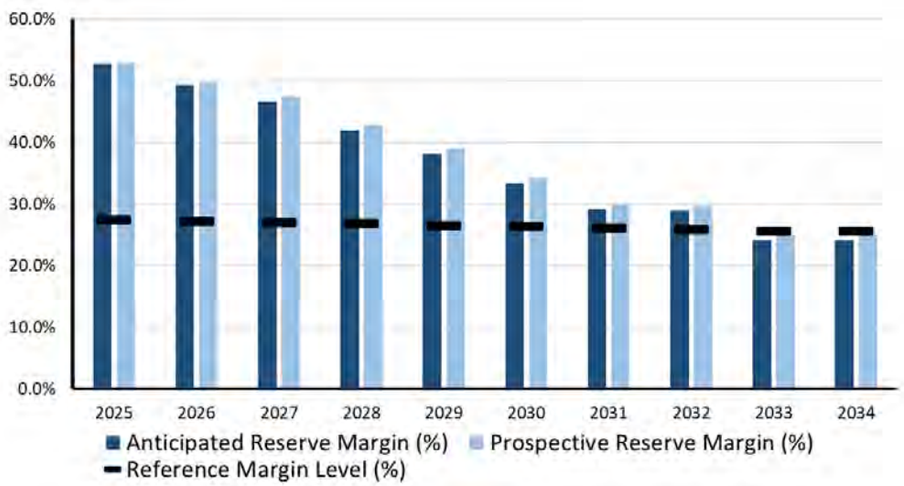


Figure 4: MISO Planning Reserve Margin–Winter

To establish the RMLs that define the minimum reserve margins for resource adequacy, MISO performs its annual probabilistic Loss-of-Load Expectation (LOLE) Study per MISO tariff. The study produces seasonal RMLs for the upcoming planning year that are used in MISO's planning resource auction. These RMLs are calculated such that they define the minimum PRM that will meet an LOLE of 1 day in 10 years. See the **MISO** assessment area pages.

MISO is an elevated risk in the *2024 LTRA* because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below RMLs within the next five years.

MRO-Manitoba Hydro

The electricity demand forecast in the province of Manitoba has increased since the *2023 LTRA*, driven by expected economic activity and adoption of electric vehicles. Resource projections have not changed significantly.

As in prior probabilistic assessments, Manitoba Hydro's 2024 ProbA indicates that there is some risk of load loss and unserved energy associated with very low hydro conditions (see **Table 2**). Electricity demand peaks in winter, making this the higher-risk season. However, electricity supplies could fall short during either peak summer or winter conditions should an extreme and prolonged drought affect hydro production.

Table 2: MRO-Manitoba Hydro ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	7.23	**4.71**	**68.87**
EUE (PPM)	0.29	**0.18**	**2.50**
LOLH (hours per year)	0.01	**0.06**	**0.91**
Operable On-Peak Margin	13.5%	**18.8%**	**15.6%**

** Year 2026 Results from the 2022 ProbA provided for trending*

MRO-SaskPower

Resource projections for Saskatchewan over the 10-year period have increased since the *2023 LTRA*, rising to just over 1 GW and include two new 377 MW gas-fired generation facilities, expansion of existing gas-fired generation facilities, and new geothermal resources. The peak demand forecast growth rate (1.35% annually) has changed little since the *2023 LTRA*.

The ProbA for SaskPower indicates there is some risk of load loss and unserved energy that diminishes with the new resource additions that are planned for 2027 (**Table 3**). Saskatchewan is a winter-peaking system; however, the unserved energy risks are more closely associated with the planned outages of large generators that typically occur in the fall and spring shoulder periods. The months of September and October are the highest risk periods because of the potential for high temperatures to unexpectedly extend beyond summer and into the maintenance period.

Table 3: MRO-SaskPower ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	117.0	**75.64**	**8.55**
EUE (PPM)	4.4	**2.81**	**0.30**
LOLH (hours per year)	0.9	**0.54**	**0.08**
Operable On-Peak Margin	24.6%	**24.8%**	**30.8%**

** Year 2026 Results from the 2022 ProbA provided for trending*

MRO-SPP

New resource capacity in the interconnection queue—primarily solar, battery, and wind—is currently projected to keep up with rising peak demand forecasts. DR programs are also increasing over the next 10 years. Resource adequacy issues can arise, however, if generators retire earlier than anticipated or new resource additions connect more slowly. Currently, there are over 8 GW of coal and gas-fired generators that have indicated that they may retire within the next 10 years, making the resource outlook unclear. SPP's summer reserve margins, based on installed generator capacity, remain above RMLs through 2029 (see **Figure 5**).

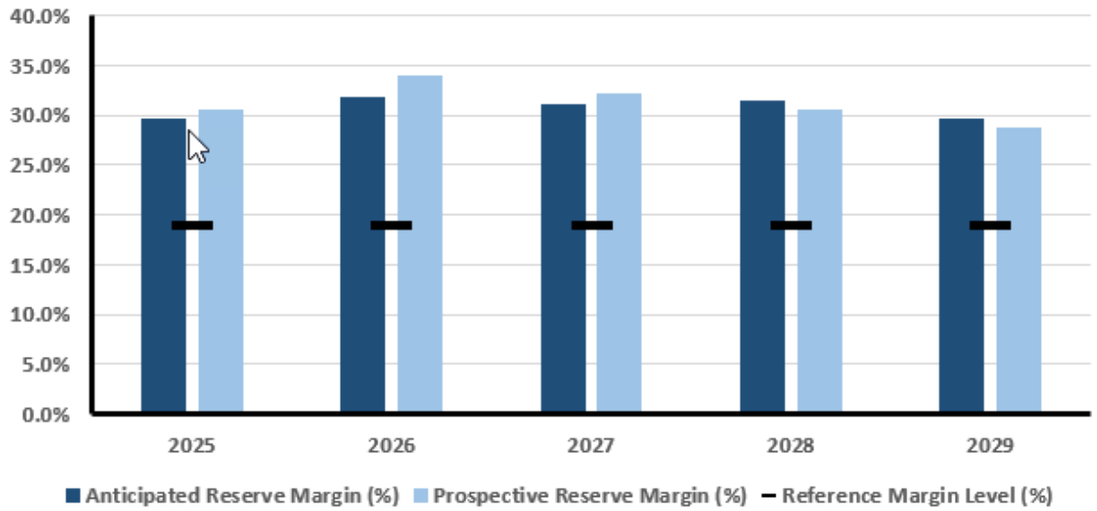


Figure 5: MRO-SPP Five-Year Planning Reserve Margin–Summer

All-hours probabilistic analysis performed by SPP shows that resource adequacy challenges are shifting from summer (when area demand is at its highest) to winter months (when the new resource mix is less capable of performing reliably). Annual results of the ProbA are in **Table 4** below. SPP's 2023 loss-of-load expectation (LOLE) study results indicate that a separate RML and seasonal resource capacity contributions are needed for the summer and winter seasons to effectively provide for resource adequacy.

Table 4: MRO-SPP ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	0.84	**0.00**	**6.61**
EUE (PPM)	0.00	**0.00**	**0.02**
LOLH (hours per year)	0.00	**0.00**	**0.01**
Operable On-Peak Margin	19.6%	**19.5%**	**16.0%**

** Year 2026 Results from the 2022 ProbA provided for trending*

NPCC-New England

New England is forecasting unprecedented demand growth driven by electrification of heating and transportation. Wind, solar, and batteries make up the projected resource additions, along with growth in distributed energy resources. Since the *2023 LTRA*, the peak demand forecast is relatively unchanged. New England has among the strongest winter demand forecast growth rates of any assessment area, rising over 7 GW in the 10-year period, or 35% from its current peak demand forecast.

The 2024 ProbA for NPCC-New England reveals increasing risk of load loss and unserved energy compared to the 2022 ProbA (see **Table 5**). Higher-demand forecast and replacement of dispatchable resources with more VERs contribute to this trend. In the ProbA modeling, supply shortfall risk is limited to the summer months and is associated with periods of above-normal demand and low resource output (e.g., low wind, solar, or high thermal outages).

Table 5: NPCC-New England ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	0.55	**10.69**	**67.40**
EUE (PPM)	0.00	**0.09**	**0.06**
LOLH (hours per year)	0.00	**0.07**	**0.03**
Operable On-Peak Margin	27.8%	**12.4%**	**13.7%**

** Year 2026 Results from the 2022 ProbA provided for trending*

While NPCC's ProbA results indicate that the risk of unserved energy in New England is concentrated in summer months, a persistent concern is whether there will be sufficient fuel available to satisfy electrical energy and operating reserve demands during an extended cold spell or a series of cold spells given the existing resource mix and regional fuel delivery infrastructure. Potential natural gas transportation constraints can affect supply to generators during extreme cold temperatures, when natural gas demand for space heating is also peaking. Most natural-gas-fired generators in the area do not have firm natural gas transportation service and can be subject to supply curtailment during peak conditions. Many natural-gas-fired generators in New England can also operate with stored oil, providing for assured electricity supply in extreme winter conditions while oil stores are procured and maintained. Scenarios of extended and extreme cold weather that affect the availability of natural gas and oil replenishments present a reliability risk but were not within the scope of the 2024 ProbA.

NPCC-Ontario

Near- and long-term resource adequacy challenges continue in the NPCC-Ontario assessment area as the Independent Electricity System Operator (IESO) manages lengthy refurbishment outages at nuclear generators and demand growth driven by agriculture and electrification. The beginning of projected shortfalls occurs in 2027 when some contracts for firm capacity are set to expire (see **Figure 6**). However, a number of resources with expiring contracts between 2026 and 2029 are anticipated to be re-committed for five-year terms through the IESO's second medium-term procurement, which is underway. As such, Ontario's Anticipated Reserve Margins (ARM) and Prospective Reserve Margins shown in **Figure 6** (which do not include this set of expiring resources) are conservative. Recommitment of these resources is expected to raise margins above the reference level in 2029 and help maintain reliability through the end of the decade. In May 2024, the IESO finalized long-term commitments for new-build battery storage facilities (1,784 MW) and new-build natural gas and biogas facilities (411 MW). Early operation incentives anticipated to bring a portion of these resources online as early as 2027 could help alleviate the reserve margin gap. The IESO also launched procurements for new capacity and energy-producing resources to be online as early as 2029. In addition, the IESO finalized an agreement with Hydro-Québec for capacity sharing in November 2024, providing 600 MW of firm imports to Ontario starting in Summer 2025 through Summer 2031. This capacity is also expected to help alleviate shortfalls indicated in 2027.

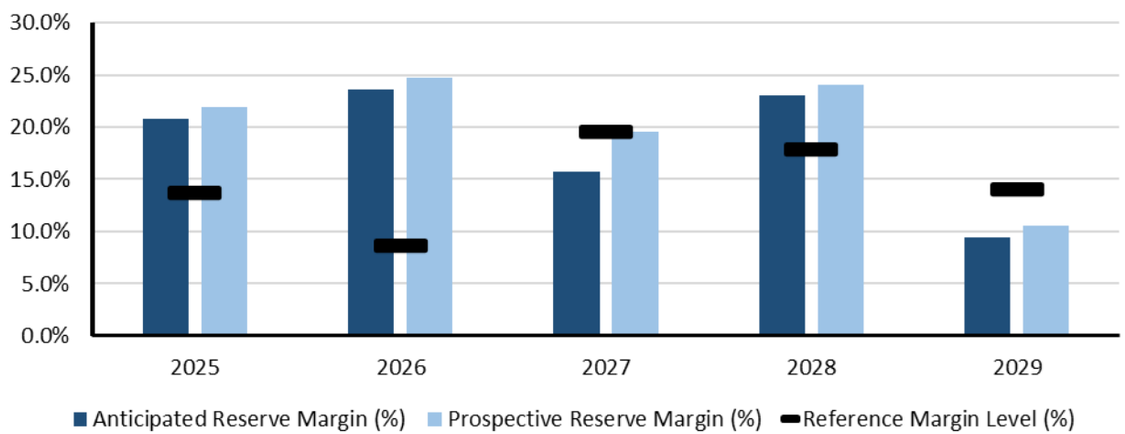


Figure 6: NPCC-Ontario Five-Year Planning Reserve Margin–Summer

The probabilistic assessment for Ontario performed by NPCC provides further insights into the potential for load loss and unserved energy. There is negligible risk of unserved energy and load loss in 2026 and earlier years; however, a small risk of load loss (< 0.01 hours) emerges after 2026 (Table 6). The 2024 ProbA study included only years 2026 and 2028, both of which have projected capacity surpluses above RMLs (see Figure 6). If 2027 and 2029 had been included in the ProbA, it can be expected that there would have been higher amounts of LOLH and unserved energy. ProbA results are also helped by the inclusion of electricity transfers from neighboring areas and modeling for some operating procedures used to manage supply shortfalls.

Table 6: NPCC-Ontario ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	72.16	**0.04**	**4.97**
EUE (PPM)	0.49	**0.00**	**0.03**
LOLH (hours per year)	0.44	**0.00**	**0.01**
Operable On-Peak Margin	-6.7%	**13.3%**	**9.5%**

** Year 2026 Results from the 2022 ProbA provided for trending*

PJM

PJM's projections for generator additions in 2025 and 2026 are scaled back dramatically from the *2023 LTRA* while demand forecasts continue to rise. As a result, ARMs for future years have fallen by as much as nine percentage points from last year. The trends in demand growth and resource additions create resource adequacy and system planning challenges for PJM as it carefully manages generator deactivation requests from the aging fossil and nuclear fleet.

PJM's ProbA results provide indication of the increasing resource adequacy risk to the system (see Table 7). EUE and LOLH are found in both ProbA assessment years (2026 and 2028) with risk concentrated in the winter months (especially January). The risk occurs on days where temperatures are very low across the entire PJM area, which results in high loads. While normal resource performance can meet these demand forecasts, resource performance from thermal resources on very cold days has historically been below normal due to freezing and fuel supply issues. Furthermore, solar resources are not likely to contribute during some of the coldest hours, resulting in very low total electricity supply and thus projections of load loss. ProbA analysis shows some summer load-loss and unserved energy risk but at much lower levels. Summer shortfall events are most likely to occur during wide-area heat events that coincide with low wind and low solar output, or very high outage and derates in the thermal generation.

Table 7: PJM ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	0.00	**537.52**	**1,043.44**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.12**	**0.22**
Operable On-Peak Margin	29%	**17.8%**	**17.7%**

** Year 2026 Results from the 2022 ProbA provided for trending*

SERC-East

The addition of solar resources is helping to raise summer on-peak reserve margins in the assessment area, despite rising demand forecasts and additional coal-fired generator retirements. Since the *2023 LTRA*, solar PV resources have grown from 1.5 GW to an expected 4.7 GW by the end of 2024. An additional 2 GW of solar PV resources are in the process of connecting. The summer peak demand forecast has also risen since the *2023 LTRA*, increasing by 2.8 GW (6.3%) over last year's projection. The area reserve margins have increased in the near term as a result of the solar resource additions then drop off after 2028 due to higher demand forecasts and planned generator retirements.

Despite these resource additions and higher summer reserve margins, the 2024 ProbA reveals growing resource adequacy risk in SERC-East (see Table 8). Measures of unserved energy and load-loss have increased since the 2022 ProbA as demand has risen and the resource mix has changed. SERC-East has changed from a summer-peaking area to one with peak electricity demand occurring in both the summer and winter seasons. This change is the result of added solar PV generation that shaves off summer peak demand and trends toward electrification in heating that drives up winter peak demand. The ProbA shows that the risk of unserved energy and load loss is concentrated in winter (January–February) months when wide-area extreme cold weather can affect electricity demand, generator performance, generator fuel supplies, and the availability of electricity imports. Based on current forecasts, resource adequacy risk will increase in SERC-East after 2028 due to the planned retirement of over 1,800 MW in coal-fired generation and continued load growth.

Table 8: SERC-East ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	92.49	**143.35**	**207.26**
EUE (PPM)	0.40	**0.60**	**0.81**
LOLH (hours per year)	0.08	**0.09**	**0.17**
Operable On-Peak Margin	16.1%	**14.2%**	**11.1%**

** Year 2026 Results from the 2022 ProbA provided for trending*

Texas RE-ERCOT

ERCOT is forecasting explosive demand growth, driven by data center projects, Bitcoin operations, development in oil- and natural-gas-producing areas, and industrial facilities. Over 20 GW of newly contracted large loads, in addition to other organic load growth, is projected to be added to ERCOT by 2028. Substantial amounts of solar PV and battery resources are being added to help meet rising demand, but there are significant reliability challenges to address during this period of rapid growth. Resource adequacy risks are mounting as fewer dispatchable resources comprise the resource mix. One of the strategies to address this risk is state implementation of a dispatchable resource generation loan program called the Texas Energy Fund. Furthermore, the forecasted growth in loads and resources poses significant challenges for transmission system planners.

Load growth and the characteristics of the resource mix are contributing to higher levels of unserved energy and load loss in probabilistic analysis (see **Table 9**). In the 2024 ProbA, EUE for the analyzed 2026 ERCOT system has risen to 19 ppm (0.0019 %) of the total annual supplied energy compared to the same analysis in the 2022 ProbA. The 2024 ProbA shows an improving trend in the analyzed 2028 ERCOT system, enabled by additional generation capacity from ERCOT scenarios developed to support rapid growth in large loads.[11]

A deeper analysis of the probabilistic assessment results reveals the unique characteristics of winter and summer risk. While peak winter loads can persist for 48 hours or longer, peak summer periods generally only last for a few hours. This is manifested in the duration and depth of the winter firm load-shed events that appear in the ProbA and has significant implications for the reliability contribution of energy-limited and non-dispatchable resources. The most extreme winter event modeled for 2026 was 16 hours in duration and up to 29 GW in load loss. In contrast, most summer unserved energy events were 1–2 hours in duration.

Table 9: Texas RE-ERCOT ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	1,235	**11,090**	**781**
EUE (PPM)	2.63	**18.95**	**1.12**
LOLH (hours per year)	0.30	**1.57**	**0.16**
Operable On-Peak Margin	35.9%	**28.8%**	**46.9%**

** Year 2026 Results from the 2022 ProbA provided for trending*

A key conclusion from the Texas RE-ERCOT 2024 ProbA is that matching the area's demand growth with a resource mix that is more variable and less fully dispatchable is increasing the risk of supply shortfalls that can result in load loss and unserved energy. When the seasonal characteristics of demand and resources are considered, Resource Planners can appropriately focus efforts to reduce the risk of potentially severe, long-duration winter shortfall events. The Public Utility Commission of Texas established a Reliability Standard and accompanying reliability assessment process in August 2024. The reliability standard is based on multiple probabilistic reliability measures that capture the different dimensions of loss-of-load events: average event frequency (LOLE), maximum event duration, and maximum event magnitude.

WECC-CA/MX

Resource additions continue to improve the overall resource adequacy outlook for the WECC California-Mexico assessment area. Since the 2022 ProbA, the planned extension of the Diablo Canyon nuclear plant (2.2 GW) and resource additions (over 5 GW nameplate in batteries, 3.3 GW nameplate in solar PV, and 0.2 GW in natural-gas-fired and geothermal generation) have alleviated supply shortfalls that were driving unserved energy and load-loss metrics in year 2026, as shown in the results of the 2024 ProbA performed by WECC (see **Table 10**).

Table 10: WECC-CA/MX ProbA Case Summary of Results

	2026*	2026	2028
EUE (MWh)	37,305	0	19,662
EUE (PPM)	136	0	70.07
LOLH (hours per year)	0.72	0	0.38
Operable On-Peak Margin	30.7%	43.2%	41.2%

** Year 2026 Results from the 2022 ProbA provided for trending*

Demand growth and planned generator retirements cause energy adequacy risks to re-emerge in future years. With a resource portfolio that includes a substantial amount of solar PV, the risk of supply shortfall is associated with summer evening periods when demand is high and solar output is diminished. WECC's analysis for the 2024 ProbA found only a small occurrence (<1 hour) of resources falling below margin levels for reliability in the 2028 study year. WECC further observed that load-loss and unserved energy risk was localized in the Mexico portion of the assessment area, reflecting localized resource and transmission system constraints.

[11] Due to the inclusion of an additional 20 GW of large loads based on newly signed interconnection agreements, study-year 2028 included additional generation capacity from the "High Large Load Adoption" scenario of the ERCOT 2024 Long-Term System Assessment (LTSA), which included 22 GW of combustions turbines (CT) and 4 GW of combined cycles (CC).

The CA/MX 2028 system analyzed by WECC for the 2024 ProbA reflects the continued rapid transformation of the power grid. The analysis assumes forecasted demand growth of 3.5 GW, substantial resource additions (4.6 GW of solar PV, 7.6 GW in batteries, and 0.8 GW of natural-gas-fired generation imported from repowered coal units in Utah), and the retirement of over 3 GW of gas-fired generation. As demand grows and the resource mix becomes increasingly variable, periods of supply shortfalls can emerge. Battery additions and transfers help make up for energy shortfalls that can arise during evening solar down ramps.

WECC-BC

BC has a predominantly hydroelectric generation system with vast amounts of energy storage provided by its reservoirs. Winter peak demand in the province is forecast to grow modestly over the next 10 years, from 11,966 MW this winter to 12,305 MW at the end of the 10-year period. Since the *2023 LTRA*, the winter peak demand compound annual growth rate (CAGR) has fallen from 1.0% to 0.3%. Growth rate and reserve margins are higher. While the overall resource adequacy outlook has improved, the 2024 ProbA indicates the area continues to be at an elevated risk of supply shortfall during extreme conditions. Drought and extreme cold temperatures in winter can result in periods of insufficient operating reserves when neighboring areas are unable to provide excess energy.

Western Interconnection-wide probabilistic analysis performed by WECC for the 2024 ProbA reveals that risk of reserve shortages emerges after 2026, potentially resulting in unserved energy and load-loss events during extreme weather. WECC's analysis identified over five hours in 2028 when high demand and low supply from WECC-BC's internal resources were not able to be remedied with imports from neighboring areas experiencing similar conditions (see **Table 11**). In contrast, 2026 had no unserved energy or load-loss periods. An examination of hourly results showed that imports from neighbors were more available in 2026 to cover periods of potential shortfalls in BC Hydro's internal resources.

Table 11: WECC-BC ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	24	**0**	**103,132**
EUE (PPM)	0.71	**0**	**1,456**
LOLH (hours per year)	0.00	**0**	**5.52**
Operable On-Peak Margin	12.7%	**16.9%**	**9.4%**

** Year 2026 Results from the 2022 ProbA provided for trending*

WECC's interconnection-wide analysis simulates the probabilistic performance of resource types using historic hourly output data to identify future risk periods. Operators of systems with large hydroelectric storage facilities make adjustments to generation based on the level of demand and shape the water use within the day, week, month, or between years. These actions help posture hydroelectric generation for expected conditions and can reduce energy shortfall risks.

BC's supply margins relative to demand are lowest during winter peak demand periods. Imports from neighbors in the U.S. Northwest are common during these periods, and often during the overnight hours of 23:00 to 4:00 local. WECC's analysis shows the need for imports growing year to year throughout most of the LTRA forecast horizon. A widespread, extreme cold weather event in the Northwest that limits transfer capability is thus a risk to BC. Even though WECC-BC is expecting only moderate demand growth and relatively few retirements, diminished surplus capacity in neighboring areas is negatively affecting the resource adequacy outlook.

Normal-Risk Area Details

All other assessment areas (see **Figure 1**) are assessed as normal risk. In these areas, resource adequacy criteria are met, and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance).

Resource and Demand Projections

The **Capacity and Energy Assessment** section in this LTRA is a forward-looking snapshot of resource adequacy that is tied to industry forecasts of electricity supplies, demand, and transmission development. Later sections in this report describe important trends in each of these forecast areas. The future electricity supply will come from a resource mix that is more variable, weather-dependent, and reliant on natural gas for fuel, requiring broad coordination and careful attention to manage reliability risks. Future electricity demand is being shaped by many factors that collectively influence peak demand forecast levels, peak seasons, and hourly profiles. Peak demand and energy forecasts are projected to continue rising dramatically over the *2024 LTRA* assessment period, exceeding their highest rates in recent years. Ongoing challenges with resource and transmission development and the continued pace of generator retirements raise concerns that, in the future, the risk assessment map will expand with more elevated and high-risk areas.

Risk from Additional Generator Retirements

Accelerated retirements of the existing coal, natural gas, and nuclear generators can have a profound and negative effect on the resource adequacy and reliability of the BPS in the next 10 years. In this preceding **Capacity and Energy Assessment** NERC accounted for nearly 79 GW of fossil-fired and nuclear generator retirements that are anticipated through 2034. Environmental regulations and energy policies have the potential to influence generators to seek deactivation during the 10-year assessment period.[12] An additional 43 GW of fossil-fired generators have announced plans to retire over the decade but have yet to enter deactivation processing with the planning authorities. These retirements, along with the confirmed retirements, contribute to declining reserve margins in the assessment areas over the next 10 years (see **Table 12**). As a result of demand growth and generator retirements, ARM is projected to fall below RML in 18 of the 20 assessment areas by 2034. While forecasts such as this factor into resource planning and market mechanisms to obtain resources needed for resource adequacy, it underscores the significant resource growth needed across North America. The lack of dispatchable resources and diverse generator fuel types in the interconnection processes makes the future resource mix look alarmingly unreliable. The potential for capacity and energy shortfalls and a higher-risk resource mix is heightened by economic and policy factors that place pressure on existing thermal generators.

The yearly projections of future retirements and an assessment area view are provided in the **Risk from** Additional Generator Retirements section.

[12] The Environmental Protection Agency (EPA) issued a final rule on May 9, 2024, establishing Greenhouse Gas Standards and Guidelines for Power Plants (the "GHG Rule"). This rule was released concurrently with three other EPA regulations that impact fossil-fueled power generation: Coal Combustion Residuals, Effluent Limitations Guidelines, and Mercury and Air Toxics Standards. Collectively, these four new regulations impose considerable financial and operational challenges on coal-fired generators.

Table 12: Anticipated Reserve Margins with Announced Retirements											
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MISO[13]	17.7%	10.3%	10.3%	13.2%	8.6%	7.1%	10.6%	8.2%	7.5%	4.2%	-2.5%
MRO-Manitoba	12.5%	21.3%	18.4%	18.0%	15.0%	9.8%	0.5%	-0.6%	-1.7%	-2.9%	-4.2%
MRO-SaskPower	28.9%	27.8%	26.6%	31.1%	29.4%	7.0%	28.8%	28.0%	26.7%	26.8%	1.2%
MRO-SPP	28.3%	26.7%	26.0%	25.0%	20.8%	19.1%	26.7%	24.9%	23.5%	22.4%	8.1%
NPCC-Maritimes	18.9%	20.6+%	25.5%	25.1%	18.6%	3.9%	23.4%	20.7%	19.1%	17.7%	-1.5%
NPCC-New England	20.4%	25.0%	25.0%	26.3%	24.9%	23.5%	22.0%	20.1%	19.7%	17.1%	14.6%
NPCC-New York	18.4%	17.1%	21.4%	22.5%	22.4%	21.6%	20.7%	18.3%	16.7%	14.9%	13.6%
NPCC-Ontario	22.5%	20.8%	23.6%	15.7%	23.0%	9.5%	5.1%	-0.2%	-1.4%	-3.9%	-5.5%
NPCC-Quebec	12.5%	12.2%	13.1%	14.2%	12.6%	11.3%	9.8%	6.2%	3.5%	0.5%	-2.2%
PJM	29.8%	34.9%	35.7%	28.1%	21.4%	18.2%	23.1%	21.6%	20.1%	18.5%	10.3%
SERC-C	28.2%	18.9%	18.9%	15.0%	16.0%	15.2%	17.3%	17.1%	18.4%	21.1%	11.8%
SERC-E	30.4%	27.3%	25.8%	24.6%	20.6%	14.4%	14.3%	10.2%	6.3%	4.6%	-2.2%
SERC-FP	27.0%	25.4%	26.0%	23.2%	22.1%	20.9%	18.4%	22.0%	20.4%	18.2%	16.0%
SERC-SE	44.9%	39.9%	35.9%	31.5%	24.5%	21.4%	27.7%	25.8%	24.7%	23.7%	13.0%
TRE-ERCOT	24.3%	30.2%	32.5%	29.7%	25.6%	25.4%	27.8%	28.0%	28.4%	28.9%	24.9%
WECC-AB	36.3%	35.8%	35.7%	38.5%	41.7%	41.9%	35.4%	41.2%	33.6%	27.8%	27.0%
WECC-BC	20.9%	25.2%	25.2%	15.8%	15.9%	22.3%	22.1%	21.6%	21.2%	13.4%	19.9%
WECC-CA/MX	38.6%	45.5%	45.2%	38.4%	43.1%	28.8%	29.6%	23.3%	25.0%	15.2%	11.1%
WECC-NW	34.5%	40.3%	38.9%	35.6%	30.7%	24.5%	18.3%	12.2%	10.2%	8.1%	5.9%
WECC-SW	28.6%	37.0%	35.6%	31.6%	24.2%	17.4%	11.3%	7.7%	0.2%	-4.7%	-9.6%

Reducing Resource Capacity and Energy Risk

The risk of electricity supply shortfalls in the assessment period can be lowered through the concerted efforts of resource and system planning stakeholders. The actions taken in electricity markets and regulatory jurisdictions with the improving trends noted previously provide examples of what can work: obtaining additional firm resources to meet resource adequacy targets, delaying generation retirements when reliability needs dictate, and using capacity targets and energy risk metrics based on better resource and demand models. Specific and actionable recommendations are contained in the Executive Summary.

[13] MISO reserve margins in this table reflect MISO Seasonal Accredited Capacity for summer. Adjustments and derates are applied to account for factors affecting expected resource output, resulting in unforced capacity (UCAP) reserve margins that are lower compared to installed capacity (ICAP) values. For more information see the **MISO assessment area** page.

Resource Mix Changes

Capacity Versus Energy: Changes in the Way to Plan for Resource Adequacy

Industry's methods of planning for resource adequacy need to change. The modern power system requires the enhancement of assumptions and supplementation of risk information for a better characterization of the risk. Historically, the resource adequacy criterion has been based on the LOLE metric, which should be no more than 1 event-day in 10 years when the generating resources are less than load (commonly known as "1-day-in-10"). This has been a design basis for the U.S. electric grid for at least 70 years (with its first formal mention in a 1951 American Institute of Electrical Engineers paper by C. W. Watchorn) and has historically served the industry well. Two important related but separate discussion topics include considerations for assumptions in the calculation of LOLE and other metrics and the establishment of the resource adequacy criteria (i.e., traditionally in terms of LOLE-1-day-in-10). The 1-day-in-10 LOLE criterion is commonly converted into a minimum capacity requirement resulting in a target or RML. In doing this, planners determine the minimum PRM required to maintain a 1-day-in-10 LOLE level. Historically, systems with an actual PRM above the minimum generally have sufficient resources and provide adequate energy and ERSs that operators need to reliably operate the BPS. Issues can arise in resource adequacy planning processes when planners solely rely on the RML comparison as the system transforms from an era of certain to more uncertain fuel sources and load behavior. In recent years, NERC has documented warnings of potential energy shortages in its reliability assessments, while in many cases the RML comparison indicates no shortfall. Substantial uncertainty has been introduced into planning the system with the addition of energy-constrained resources (variable energy resources such as wind and solar, and, at times, just-in-time fuels such as natural gas) that are highly dependent on weather and environmental conditions. Uncertainty in energy sufficiency is increasing as the types of resources change, leaving fewer resources that can be dispatched (dispatchable resources) in response to the variable resource availability and greater exposure to constraints in fuel supplies, reservoir levels, or battery discharge capabilities. Historical generator reliability assumptions based on the idea of well-maintained, well-invested units with an anticipated long life are no longer adequate. This increases uncertainty as a greater proportion of fossil-fueled resources continue to be retired, often with little notice to system planners. Nameplate values of variable energy resources are not as meaningful as projected energy availability, and environmental conditions can adversely impact the simultaneous availability of thousands of megawatts.

Probabilistic analysis enhances deterministic transmission planning from an energy adequacy standpoint given the following factors:

- Considers likelihood of events: It uses historical data to estimate how often different outages and weather conditions might occur.
- Provides more information: It calculates the average impact of these events, including how often and how long power outages might last.
- Helps compare options: It enables the selection of the upgrade(s) that provide the best balance between cost and reliability over time to be chosen.

Detailed recommendations are included in a recently published NERC report:
Evolving Planning Criteria for a Sustainable Power Grid: A Workshop Report, June 2024

Changes in Existing BPS Resource Capacity

Thermal generator retirements and new resource additions continue at a rapid pace. Since the *2023 LTRA*, over 8 GW of coal-fired generation has been retired, while substantial solar and battery resources have connected to the grid (see **Table 13**). From a strictly on-peak capacity perspective, there has been little change (8,348 MW is 0.8% of the total BPS summer on-peak resource capacity.)

Table 13: Existing BPS Resource On-Peak Capacity

	2023 Capacity (MW)	2024 Capacity (MW)	Difference (MW)
Coal	188,856	180,402	-8,454
Petroleum	32,107	30,987	-1,120
Natural Gas	483,391	484,148	757
Biomass	7,273	7,381	108
Solar[14]	52,998	66,293	13,295
Wind[15]	32,320	31,370	-950
Geothermal	4,319	3,881	-438
Conventional Hydro	103,368	105,792	2,424
Run of River Hydro	1,565	2,047	482
Pumped Storage	19,463	19,422	-41
Nuclear	106,173	105,385	-788
Hybrid & Battery	5,593	9,909	4,316
Other	2,217	774	-1,443
Total	1,039,643	1,047,791	8,348

This year-on-year change in on-peak capacity continues the general trend of declining baseload and dispatchable generation—which includes coal-fired, natural gas, and nuclear generators—and rising VERs. **Figure 7** shows the trend continuing through 2034, where 20% of the generating capacity will be provided by VERs. Focusing on the relatively small change in total on-peak capacity since 2023 can mask risks to reliability that result when important attributes of the retiring generation resources are not inherent in the replacement resource mix. Thermal generation resources, such as coal-fired generators, have the capability to be dispatched when needed and provide system inertia, dynamic reactive support, and frequency response for stable grid operation. Most types of replacement resources have limited or none of these attributes. Further, retirements in the thermal generator fleet are making the resource mix less effective in meeting winter energy needs.



Figure 7: North America Total Generation Capacity in 2024 and 2034

Capacity Additions

New generation is added to the BPS through the area interconnection planning processes. Solar PV is the overwhelmingly predominant generation type being added to the BPS, followed by battery and natural-gas-fired generators, wind turbines, and hybrid resources. Batteries are now the second most predominant resource in the North America BPS interconnection queues. A summary of generation resources in the interconnection planning queues is shown in **Figure 8**.

Capacity in planning has grown since the *2023 LTRA* by over 44 GW (12%). In general, **Tier 1** resources are in the final stages for connection, while **Tier 2** resources are further from completion (see text box). Some projects that are in the earlier stages of the interconnection queue process will be withdrawn before completion due to supply chain issues, planning and siting challenges, and business or economic factors. While interconnection queues continue to swell, considerable uncertainty

[14] The capacity values in this table represent the on-peak contribution of solar resources. The total installed (nameplate) capacity of BPS solar in 2024 is 111,102 MW. See Table 11.
[15] The capacity values in this table represent the on-peak contribution of wind resources. The total installed (nameplate) capacity of BPS wind in 2024 is 176,636 MW. See Table 11.

surrounds the timing and amount of resource additions. (See an analysis of projected and actual additions on the next page).

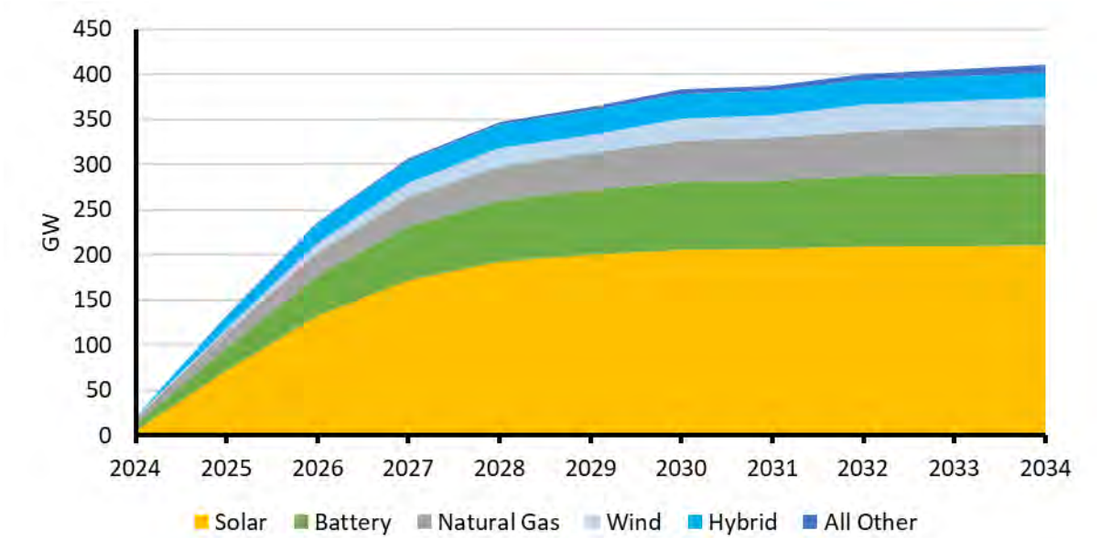


Figure 8: Tier 1 and 2 Planned Resources Projected Through 2034

Solar PV and wind nameplate capacity, both existing and planned, vary widely by area. Figure 9 and Figure 10 show current solar PV and wind installed capacities and the capacity in the planning process through 2034 for assessment areas with significant amounts. In addition, hybrid generation resources, which combine energy storage with a generating plant (i.e., a wind or solar farm), are connecting to the grid in parts of North America, and many more projects are in BPS planning processes.

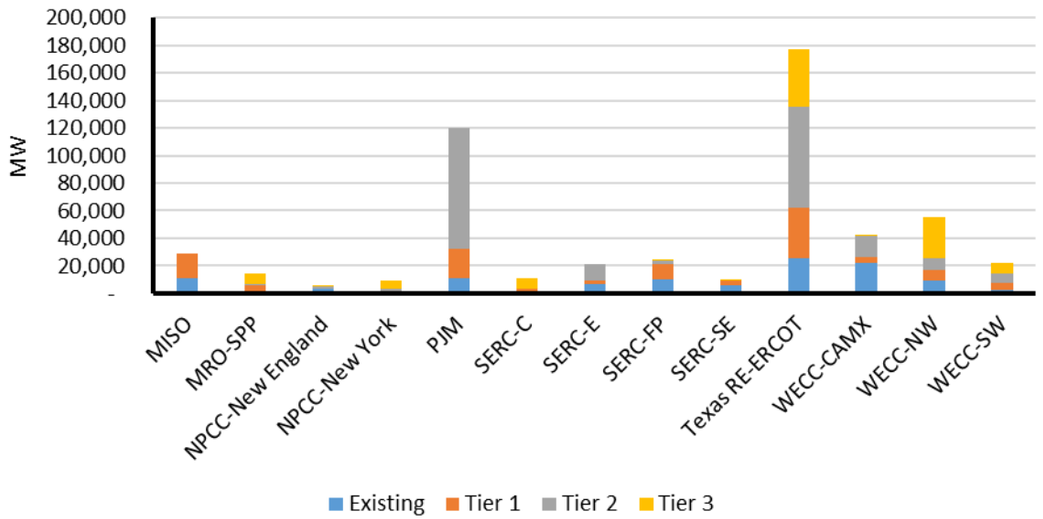


Figure 9: Solar Nameplate Capacity Existing and Planned through 2034

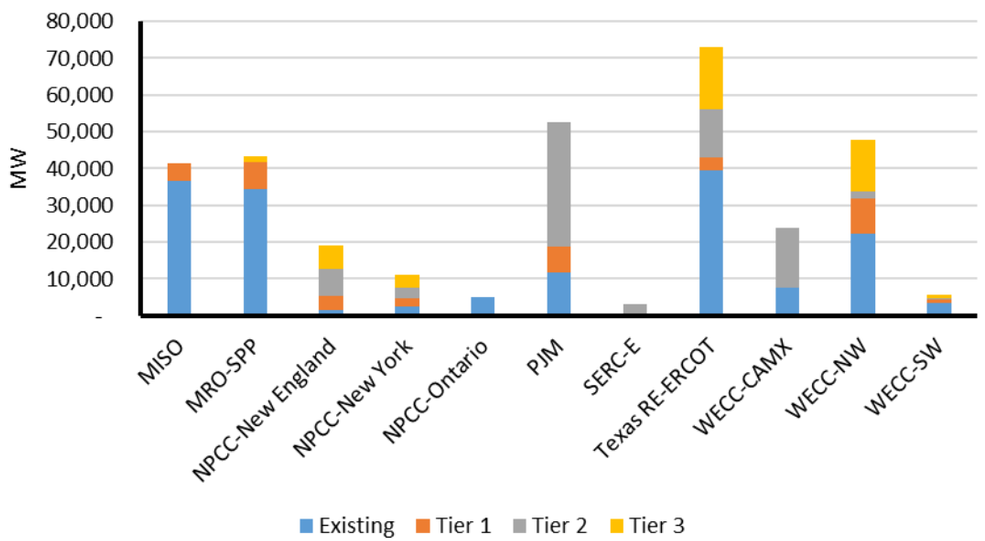
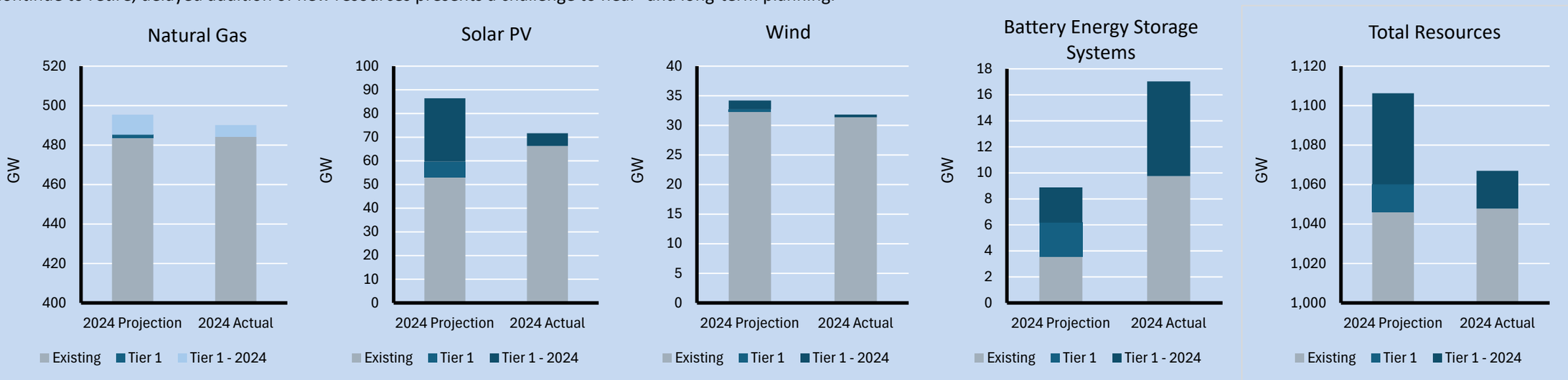


Figure 10: Wind Nameplate Capacity Existing and Planned through 2034

Resource Additions – How Much and When?

The added resource capacity on the BPS over the past year fell short of industry's projections, raising concerns that demand growth has the potential to outpace supply resources. The figures below compare the *2023 LTRA* projection of this year's installed capacity against the actual current installed capacity derived from data collected for this LTRA. Natural gas, solar PV, and wind resources were all over-projected last year. This gives evidence to industry reports of construction delays that prevented the expected interconnection of new resources. To a lesser extent, project withdrawals prior to commercial operation also contributed to lower-than-expected resource additions. One key exception—battery energy storage systems (BESS)—came in higher than last year's projections. As baseload and dispatchable generation continue to retire, delayed addition of new resources presents a challenge to near- and long-term planning.



Comparison of Projected Capacity from the 2023 LTRA to the Actual Capacity in the *2024 LTRA*

The sluggish rate at which new generation moves through the interconnection queue and begins service has been a cause for concern for long-term reliability planning. The Lawrence Berkeley National Laboratory published the results of an interconnection queue study in April 2024 assessing that less than one-fifth of generation capacity projects seeking interconnection between 2000 and 2018 actually came to fruition by the end of 2023.[16] Wait times have also been on the rise: According to the same study, the time from initiating a request for interconnection to the start of commercial operations has increased from less than two years, as was the case from 2000–2007, to more than four years from 2018–2023. The delay in bringing new generation capacity online in assessment areas that are anticipating steady or accelerated thermal capacity retirements, as well as increased demand, presents a significant reliability risk.

In recognition of the interconnection backlog risk, some regional transmission organizations have taken steps to address the lagging completion rates. MISO has assigned multiplication factors to generator requests based on the study phase and the likelihood of that resource coming on-line to more accurately gauge the likely incremental capacity in its footprint.[17] MISO also continues to advance the Joint Targeted Interconnection Queue (JTIQ) with SPP to resolve binding constraints that have delayed the interconnection process. PJM analyzed the completion rate of its interconnection queue and reported that less than 16% of resources submitted into the queue between 1999 and 2023 went into operation. The ISO has also applied a reduction to the nameplate capacity of value of Tier 1 resources to reflect the historical addition rate of new generation. PJM's interconnection process subcommittee is working on enhancements for new generation to interconnect as a capacity resource. These measures and others are examples of the broader effort to streamline generator additions and thus offset retiring capacity.

Offshore wind plants are increasingly entering interconnection queues, located around the Northeastern United States. **Figure 11** shows the current planned capacity in the planning process through 2034 by assessment area. Currently, the existing offshore wind nameplate capacities are small in comparison: a single 29 MW plant in NPCC-New England and a 12 MW plant in PJM.

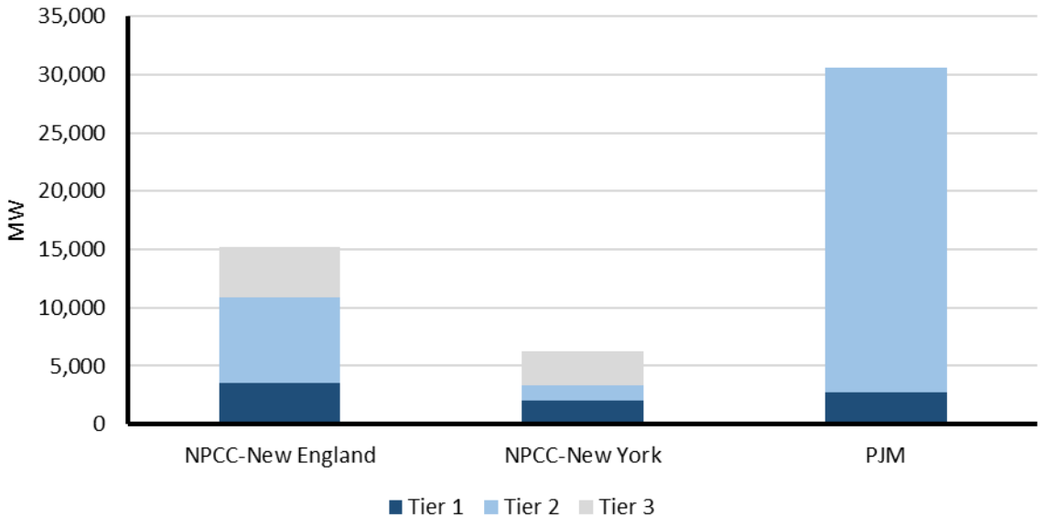


Figure 11: Offshore Wind Capacity Planned through 2034

Battery Resources

As the BPS increases the share of energy provided by VERs, the ability to provide energy by BESS or hybrid-solar PV and wind plants is increasingly important. While currently installed capacity totals just over 17 GW, an additional 306.5 GW of BESS are in planning. **Figure 12** shows the nameplate capacity of BESS resources currently in operation and in planning for connection to the BPS through 2034.

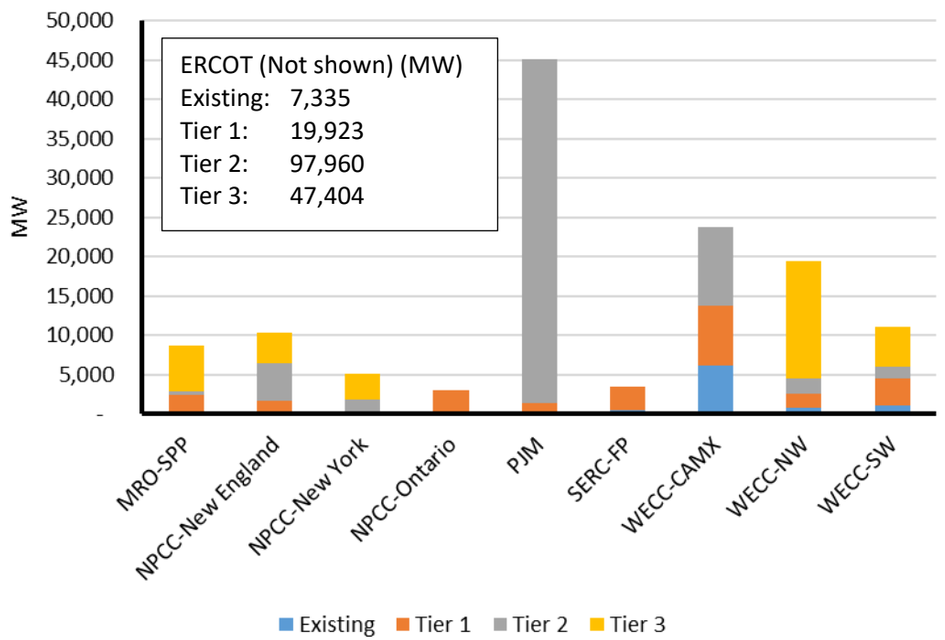


Figure 12: Battery Resource Capacity Existing and Planned through 2034

BESS are improving reliability by helping to offset the variability and uncertainty of inverter-based resources (IBR). BESS are, however, a relatively new type of grid resource with unique operating characteristics. The joint *NERC-WECC Staff Report: 2022 California Battery Energy Storage System Disturbances*[18] highlights an event when a BESS, like some other IBRs, failed to properly ride through a normal system fault. This indicates that BESS must be included in the currently underway strategies to address IBR performance issues.

Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. **Table 14** shows the nameplate value and the capacity contribution of existing wind, solar PV, hydro, and energy storage systems resources at the peak demand hour for each assessment area. During risk periods after peak demand (e.g., U.S. assessment areas in WECC), contributions of solar PV resources output is diminished during evening periods and additional resources are needed.

[18] NERC–WECC *2022 California Battery Energy Storage System Disturbances*

Table 14: BPS Wind, Solar, Hydro, and Battery Generation Resources by Assessment Area Year 2024												
Assessment Area	Wind			Solar			Hydro			Energy Storage Systems		
	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)
MISO	41,349	5,715	13.8%	30,502	5,305	17.4%	2,450	1,576	64.3%	401	84	21.0%
MRO-Manitoba Hydro		52	-	-	-	-	6,434	5,704	88.7%	-	-	-
MRO-SaskPower	815	164	20.1%	30	-	-	864	862	99.8%	-	-	-
MRO-SPP	34,475	5,134	14.9%	703	275	39.1%	5,633	4,079	72.4%	2	2	100%
NPCC-Maritimes	-	261	-	-	5.1	-	1,361	1,312	96.4%	-	-	-
NPCC-New England	2,548	127	5.0%	3,361	308	9.2%	1,917	1,469	76.6%	26	9	34.9%
NPCC-New York	2,706	461	17.1%	1,039	240	23.1%	4,915	3,736	76.0%	60	30	50.2%
NPCC-Ontario	4,943	1,364	28%	478	-	0.0%	8,748	6,215	71.0%	18	-	0.0%
NPCC-Québec	3,820	1,375	36.0%	10	-	0.0%	40,907	39,354	96.2%	-	-	-
PJM	11,701	1,760	15.0%	10,735	4,808	44.8%	3,071	2,367	77.1%	222	100	44.8%
SERC-C	982	172	17.5%	2,308	771	33.4%	4,995	3,364	67.4%	100	50	50.0%
SERC-E	-	-	-	6,777	4,753	70.1%	3,170	3,016	95.1%	15	6	38.4%
SERC-FP	-	-	-	10,121	5,618	55.5%	-	-	-	538	523	97.2%
SERC-SE	-	-	-	7,267	5,414	74.5%	3,293	3,260	99.0%	115	40	34.9%
Texas RE-ERCOT	39,532	11,062	28.0%	31,058	19,098	61.5%	583	458	78.6%	10,720	-	0.0%
WECC-AB	5,559	1,867	33.6%	3,042	-	0.0%	894	285	31.9%	270	264	97.8%
WECC-BC	776	279	36.0%	2	-	0.0%	16,902	12,623	74.7%	-	-	-
WECC-CA/MX	7,694	1,158	15.0%	24,905	14,641	58.8%	10,211	3,582	35.1%	11,883	11,155	93.9%
WECC-NW	23,518	3,489	14.8%	12,787	6,877	53.8%	41,257	21,168	51.3%	1,909	1,231	64.5%
WECC-SW	3,784	628	16.6%	5,944	2,527	42.5%	1,025	721	70.3%	2,997	2,592	86.5%

Solar PV Distributed Energy Resource Growth

Behind-the-meter (BTM) solar PV generators are solar PV resources connected on the distribution system, such as residential rooftop solar systems. The rapid growth of BTM solar PV continues with cumulative levels expected to reach over 123 GW by the end of this 10-year assessment period (up from 89 GW reported in the *2023 LTRA*, an increase of 38%). There are currently 58.7 GW of installed BTM solar PV across the North American BPS.

BTM solar PV generators, like grid-connected solar PV, are also VERs. In large penetrations, their predictable change in output from the time of day contributes to steep ramps in demand. As the sun sets and output diminishes, grid resources must make up for the decrease in solar generation and increase in demand that was being served. The opposite ramp occurs during morning hours; it may be less impactful to reliability but can be challenging for grid-connected generator scheduling and dispatch. **Figure 13** shows the current and projected BTM solar PV by area through 2034.

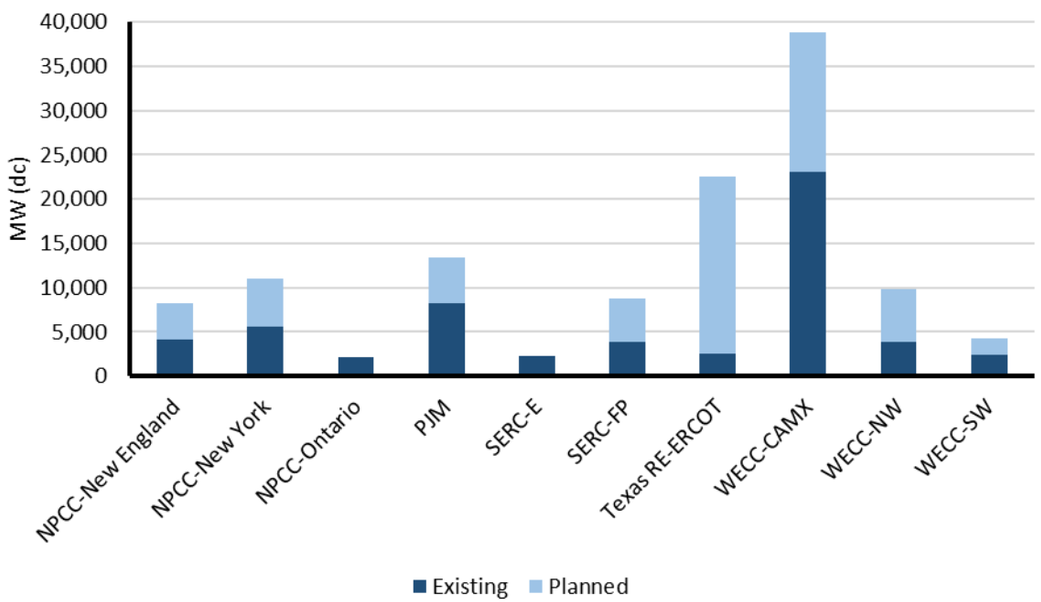


Figure 13: Solar PV DER Capacity Existing and Planned through 2034

Generation Retirements

The total capacity of traditional baseload generation fuel types will continue to decline as older generators retire. Generators become confirmed for retirement according to various processes in place in the Interconnections, such as regional planning tariffs in the wholesale electricity market areas or the integrated resource planning process in vertically integrated states. Properly designed mechanisms can prevent generators from retiring before planners can study and address reliability issues that could occur.

Currently, over 79 GW of fossil-fired and nuclear generating capacity is being retired over this assessment period (see **Figure 14**), a small decrease from the 83 GW in retirements reported in the *2023 LTRA*. This capacity includes generators that are confirmed for retirement through retirement planning processes or that have indicated plans to retire to an ISO/RTO or Planning Coordinator.

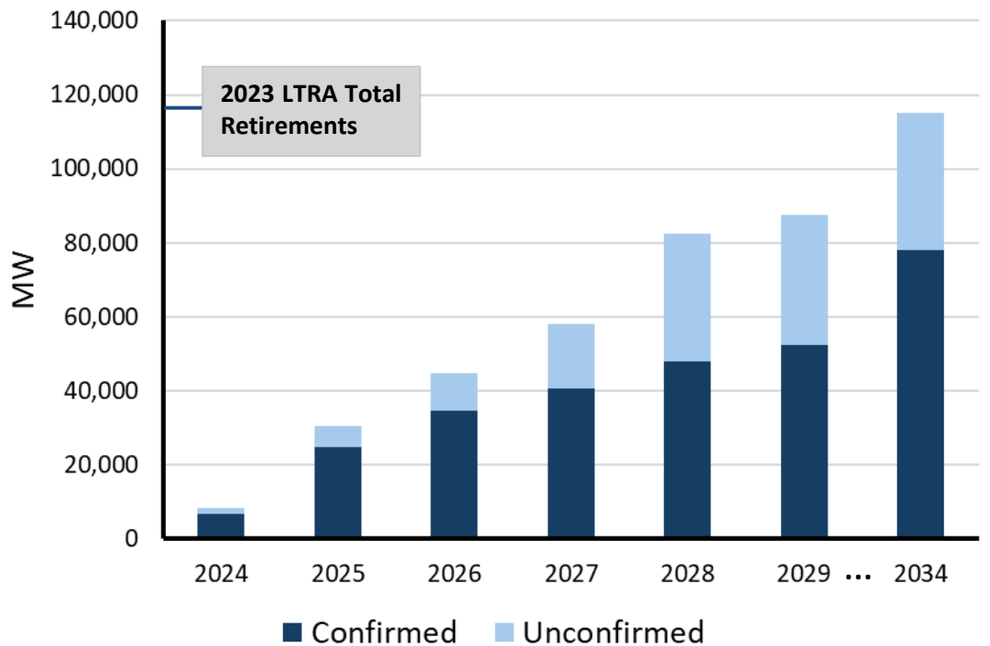


Figure 14: Projected Generation Retirement Capacity through 2034

Additional fossil-fired generator retirements are expected and would result in further loss of existing capacity. Generator Owners often announce plans to retire generator units before initiating the

interconnection planning process, and the announced plans or timing may be subject to change before the retirement is confirmed. Wholesale electricity market areas, where merchant electric generators make up a large part of the generating fleet, have more uncertainty around future generator retirements, making resource planning and adequacy assessment difficult. **Figure 15** shows the total capacity of reported retirements (i.e., reported to ISO/RTOs and planning entities) as well as owner-announced, unconfirmed retirements of fossil-fueled and nuclear generators across the BPS over the next 10 years in each assessment area.[19] This total of confirmed and announced-potential retirements over the next 10 years is over 115 GW (3 GW lower than 10-year projections in the *2023 LTRA*).

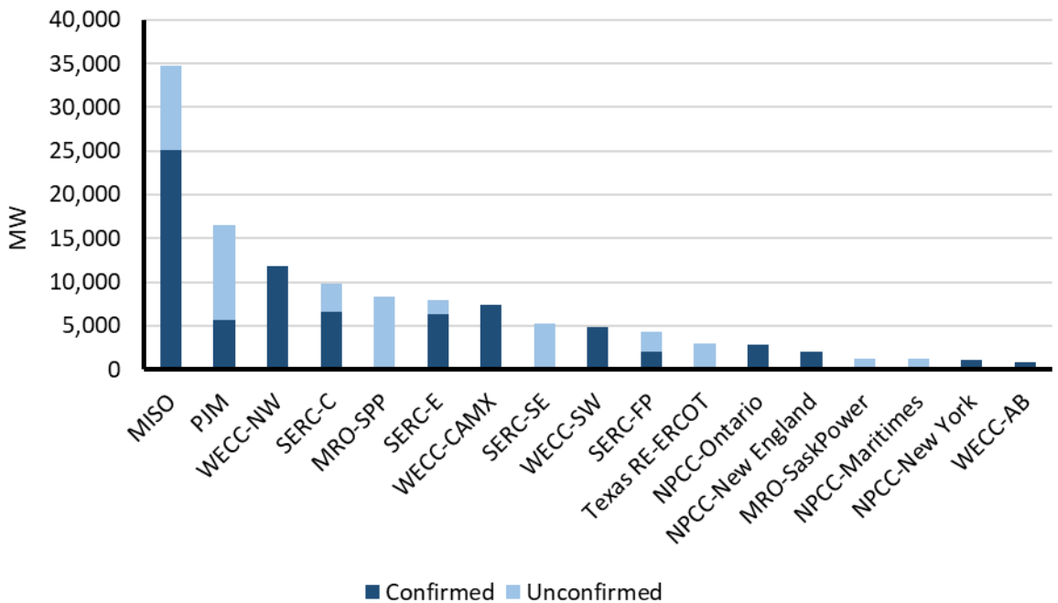


Figure 15: Projected Capacity Retirements of Nuclear and Fossil Generation 2024–2034

Natural Gas Fuel Reliance Trends

Natural-gas-fired generators are and will remain a critical resource for BPS reliability in many areas over the 10-year assessment period, especially during winter. These generators provide many necessary reliability attributes that are exiting the system as traditional generators retire and inverter-based renewable resources take their place in the resource mix. Natural-gas-fired generators are dispatchable and provide the ERSs of inertia, frequency response, and ramping flexibility. In winter, when peak demand in most areas occurs during early morning hours, natural-gas-fired generation is at its highest contribution to the resource mix in many areas. Severe winter weather events in 2021 and 2022 provided stark evidence of the critical nature of natural gas as a generator fuel and the importance of secure supplies during times of extreme electricity demand.

As the generation resource mix evolves and becomes more weather-dependent, fuel assurance becomes increasingly critical when conducting reliability assessments. Until recently, comparing seasonally available capacity to a predetermined PRM level has sufficed as a means to assess resource adequacy. However, resource adequacy is now only the first step of a meaningful reliability assessment. Energy adequacy must now be layered on top to assess the risk that available capacity may be rendered unavailable due to phenomena including low wind or solar output and/or natural gas supply and transportation issues.

This year, the Energy Information Administration (EIA) projected that more than 40% of delivered natural gas would be consumed by power generators, more than 0.6 Bcf/d higher than was consumed by power generators in 2023 and 7% higher than what the EIA had projected for 2024 in the fall of last year. Natural-gas-fired power plants generated 42% of the electrical energy consumed by end-use electricity customers in 2023 and are on track to maintain that share of generation this year. A significant percentage of natural-gas-fired power plants rely upon as-available, non-firm gas supply and transportation arrangements. Non-firm natural gas supply and transportation is generally sufficient for electric generators most of the year. However, during extreme cold weather, demand for natural gas by both generators and natural gas distribution companies (generally firm shippers) can at the same time dramatically increase. In these instances, generators that lack firm supply and transport arrangements are at risk of fuel unavailability, and when winter weather impacts gas production facilities, the resulting imbalance in pipeline injections and withdrawals can put at risk even firm pipeline customers as preparatory linepack is rapidly depleted.

[19] Confirmed generator retirements are reported to NERC by each assessment area in this *2024 LTRA* development process. NERC obtained data on announced, unconfirmed generator retirements from Energy Ventures Analysis, Inc. and from each assessment area. Some sources of information on announced generator retirements include EIA 860 data, trade press, and utility integrated resource plans.

The *2024 LTRA* projects that an additional 6,500 MW of new natural-gas-fired generation will be added in North America over the next five years. While some assessment areas project net decreases in natural-gas-fired capacity, other areas report increases ranging from 3% to over 50%.

In the United States, 8 out of 13 assessment areas are adding capacity to their fleet of natural-gas-fired power plants over the next 10 years, amounting to over 10 GW of new natural-gas-fired power capacity. Altogether, those additions translate to an increase in natural gas use for power generation of more than 84 Bcf (245 MMcf/d). Whether this increase in natural gas generation capacity is sufficient to meet the increase in net internal demand projected for these same assessment areas remains to be seen, but based on the capacity additions alone, some areas are set to see an insufficient increase in gas pipeline capacity, as per the EIA's database of nationwide U.S. gas pipeline projects. (see **Figure 16**).

PJM is one such area, projected to see a 3% increase in natural-gas-fired generation capacity (+2,500 MW). Net internal electricity demand in PJM is forecasted to rise by 25 GW over the planning horizon at the same time that non-variable resources are expected to shrink their share of the capacity mix from 96% to 88%. To the extent that variable resources are uncertain during times of peak stress on the grid, there is a risk of gas delivery capacity being insufficient for the amount of natural gas supply that could be required to meet the demand increase. SPP is another assessment area where natural-gas-fired power capacity is set to rise, by 5%, or roughly 1,500 MW. In both PJM and SPP, there is a risk of a shortfall in natural gas pipeline capacity that could facilitate delivery of the additional fuel that is necessary to meet their capacity expansion plans.

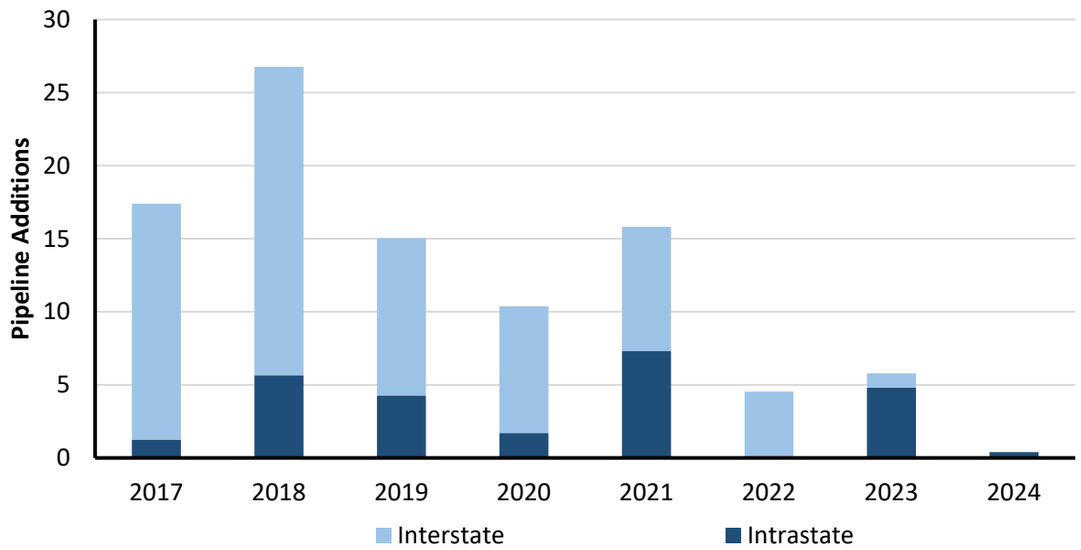


Figure 16: Annual U.S. Natural Gas Pipeline Capacity Additions by Type (2017–2024) Bcf/d (Source: U.S. Energy Information Administration)

Reliability Implications

The addition of variable resources, primarily wind and solar PV, and the retirement of conventional generation are fundamentally changing how the BPS is planned and operated. With electricity supplies coming increasingly from VERs and natural-gas-fired generators, there is a growing risk that supplies can fall short of demand during some periods. Geographically diverse wind and solar resources and loads can help reduce these risks, but they require robust transmission networks, comprehensive energy and transfer capability analysis, and effective operating procedures and market mechanisms.

Maintaining ERSs for Grid Support

For the grid to operate reliably, it needs resources that are not only sufficient for meeting demand and energy requirements but also capable of controlling voltages, maintaining stable frequency across the system, and flexibly ramping up or down to dispatch control at all times. Conventional generators, such as nuclear, coal, and natural gas-fired generators, provide much of the ERSs that support reliable operation today. New resources on the grid are almost all IBRs, which have different physical and operating characteristics that affect the level of ERSs that they can provide. Without the spinning mass or traditional excitation systems providing the voltage control of a hydroelectric or thermal generator,

most IBRs have limited capability for maintaining system voltages and stability. Batteries, with their fast response time, have some ERS capability that wind and solar do not. They are useful in regulating system frequency and are helping to balance variability from VERs in ERCOT and California where wind and solar make up a large portion of the resource mix.[20] As generators are deactivated and replaced by new types of resources, ERSs must still be maintained for the grid to operate reliably.

Accelerated generator retirements, especially unanticipated requests for deactivation, can cause ERS-related reliability issues in parts of the system due to the future loss of the generator's reliability attributes. This reduction in the level of ERSs can result in voltage violations or system instability. System planning and generator deactivation processes evaluate these changes to the system and ensure plans proceed only when reliability criteria, including ERS-related considerations, are met. For example, PJM's deactivation process identified reliability concerns to the system as a result of the requested deactivation of the Brandon Shores power plant (1,280 MW) in 2023. Until necessary system upgrades are completed to address identified system voltage and other reliability issues that would occur with the deactivation, PJM has requested that the Brandon Shores generators at the plant remain in service through the reliability-must-run process.[21]

To ensure the future system can operate reliably, market operators, system planners, regulators, and policymakers need to ensure effective mechanisms are in place to provide for the ERS needs of the future system. Long-term activities can provide incentives to generators with needed reliability attributes. Effective backstops will also be needed to prevent the loss of critical generators when analysis finds deactivation would violate reliability criteria.

Specific and actionable recommendations are contained in the **Recommendations and ERO Actions Summary** section of this report.

[20] See the *2023 Special Report on Battery Storage* from the California ISO.
[21] Information on this and other proposed deactivations in PJM are found on PJM's Generator Deactivations page.

Demand Trends and Implications

Demand and Energy Projections

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb higher than at any point in the past two decades. The aggregated assessment area summer peak demand forecast is expected to rise by over 132 GW, and aggregated winter peak demand forecasts are increasing by 149 GW. The growth rates of forecasted peak demand (see **Figure 17**) and energy (see **Figure 18**) continue to rise sharply since the 2022 LTRA, reversing an almost two-decade trend of falling or flat growth rates. See **Figure 17** for seasonal peak demand growth over the current and prior assessment periods and **Figure 18** for net energy growth. A map of the primary demand drivers for the North American BPS is illustrated for each assessment area in **Figure 19**.

Electrification and Demand Growth

Electrification of household appliances (e.g., heat pumps for household heating) and projections for electric vehicle growth over this assessment period are components of the demand and energy estimates provided by each assessment area. Since the *2023 LTRA*, peak season CAGR has risen in all assessment areas except two: NPCC-Maritimes' winter CAGR fell from 0.98% to 0.63% and WECC-BC's winter CAGR fell from 1.05% to 0.28%. Rising peak demand forecasts are contributing to the lower reserve margins projected for nearly all assessment areas.

Large Commercial and Industrial Loads

Increasing amounts of large commercial and industrial loads are connecting rapidly to the BPS. Emerging large loads, such as data centers (including crypto and AI) and hydrogen fuel plants, present unique challenges to forecasting and planning for increased demand. Earlier this year, NERC's RSTC established a Large Loads Task Force to better understand the reliability implications of growth in large loads and develop solutions.

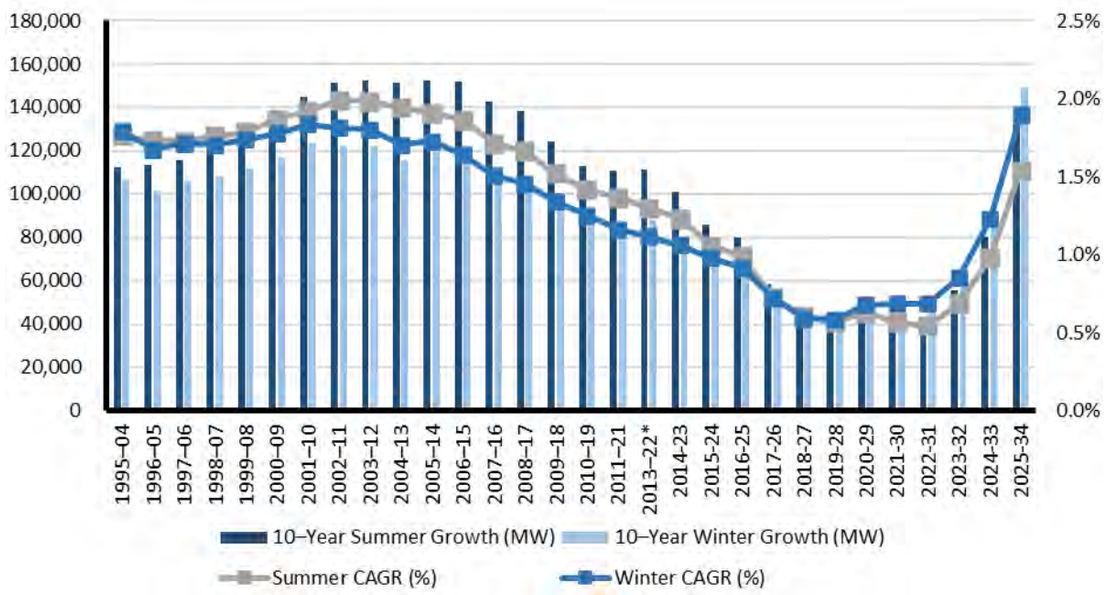


Figure 17: 10-Year Summer and Winter Peak Demand Growth and Rate Trends



Figure 18: Net Energy for Load Growth and Rate Projections

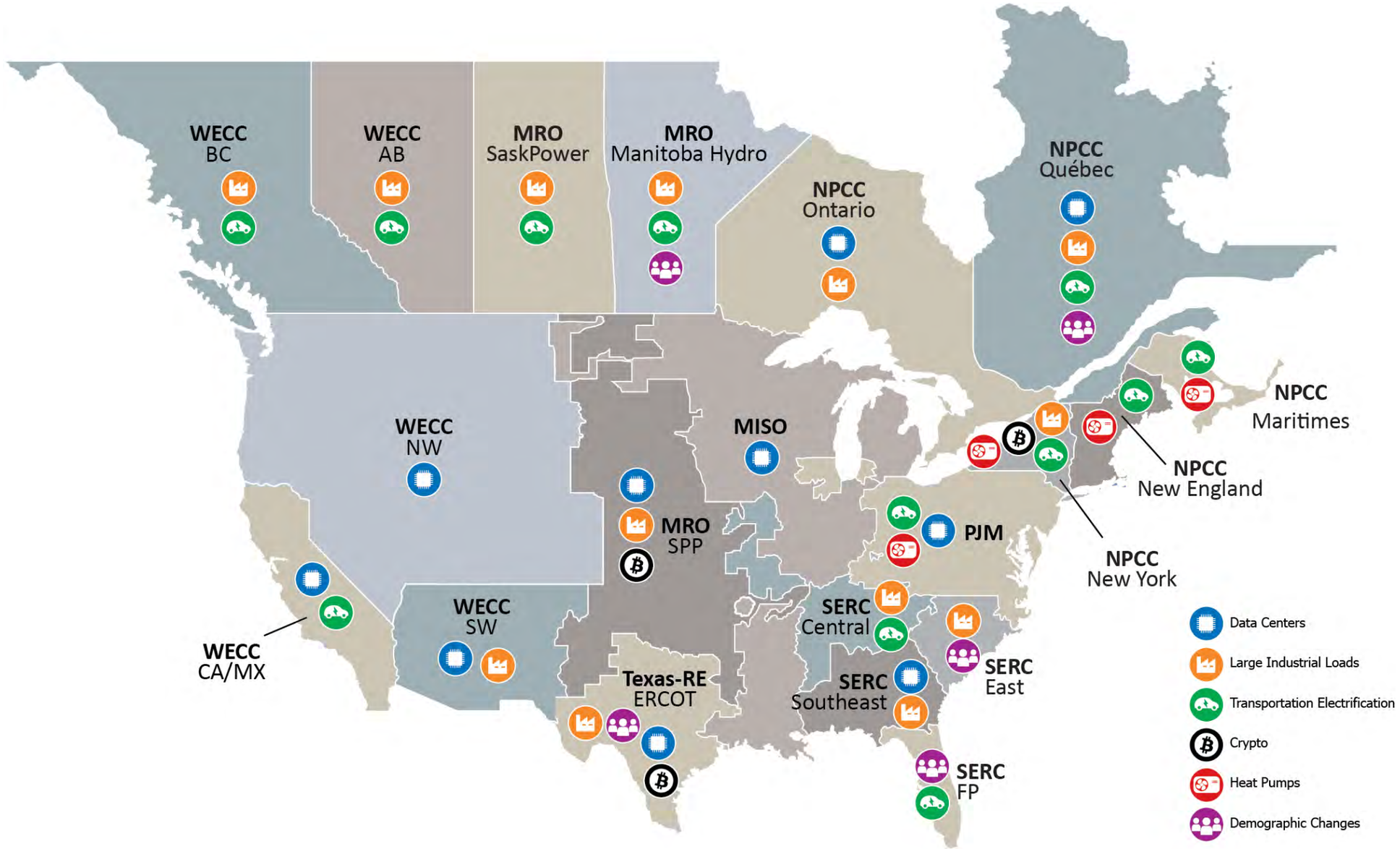


Figure 19: Primary Demand Drivers by Assessment Area

Peak Season Transition

Some of the sharpest peak demand forecast increases and growth rates can be seen in winter seasons as electrification in heating systems and transportation influence forecasts. Dual-peaking or changing from summer to winter peaking is anticipated in several areas, including the U.S. Southeast and Northeast. Electrification of heating systems and the anticipated growth of electric vehicles (which are expected to charge overnight and coincide with periods of electricity demand for heating) are driving factors. Such changes have wide-ranging implications for how the grid and resources are planned and operated. For example, resource output and fuel risks are significantly different in winter, requiring the focus of resource adequacy processes to change. The following are the areas that anticipate a change from a summer-peaking system to a winter-peaking (or dual-season peaking) system and the approximate year of the transition:

- NPCC-New England (mid-2030s)
- NPCC-New York (mid to late-2030s)
- NPCC-Ontario (2030)

In the U.S. Southeast, SERC-Central and SERC-East became dual-peaking systems in recent years. SERC-Southeast recently began experiencing slightly higher peak demand in winter compared to summer.

Reliability Implications

Demand and energy growth projections in this assessment period provide both challenges and opportunities for electric grid reliability. Planning for resource and transmission adequacy requires accurate long-term forecasting, but future demand and energy use will be influenced by many factors, including the economy, energy policies, technology development, weather, and consumer preferences. Changing patterns in electricity use, load behavior, and distributed energy resource performance affect the accuracy of operational load forecasts that are essential to grid operators. Large flexible loads and demand-side management programs hold promise for peak load management capabilities that can reduce the risk of firm load interruption.

Anticipating large commercial and industrial loads, electrification, electric vehicle adoption, and the impacts of energy transition programs on future demand and energy needs will require even more focus for planners and operators. Peak demand forecast changes in the past year had a noticeable effect on resource adequacy for many areas. A confluence of factors (economic, energy policies, technology development, and consumer preferences) has the potential to fuel continued growth.

Transmission Development and Interregional Transfer Capability

Transmission Projects

This year's cumulative level of 28,275 miles of transmission (>100 kV) in construction or stages of development for the next 10 years (see **Figure 20**) is substantially higher than the *2023 LTRA* 10-year projections (18,675 miles) and is above the average of the past five years of NERC's LTRA reporting on average (18,900 miles of transmission planning projects in each 10-year period published in the last five LTRAs). Transmission in construction has yet to increase substantially; rather, the large increase in transmission projects is seen in planning phases.

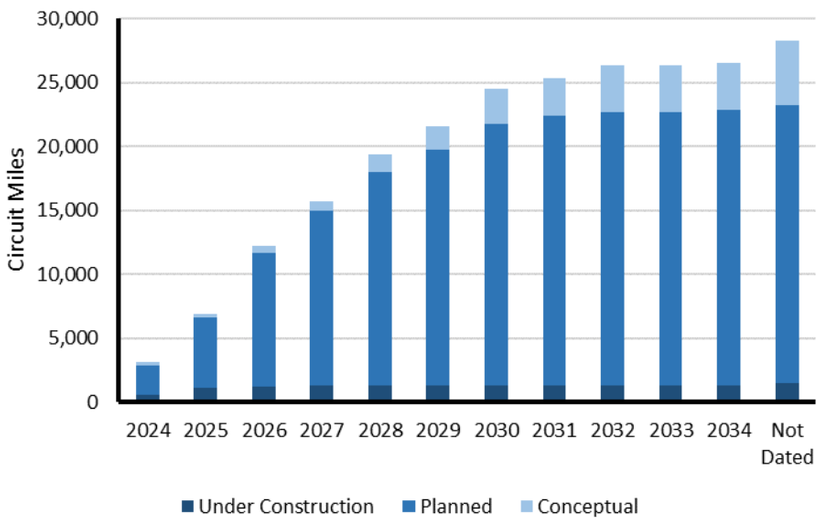


Figure 20: Future Transmission Circuit Miles >100 kV by Project Status

New transmission projects are being driven to support new generation and enhance reliability. **Figure 21** shows the percentage of future transmission circuit miles by primary driver. Most projects reported this year have been initiated for the purpose of grid reliability, which generally includes transmission projects that are needed to ensure that the BPS operates within established limits and design criteria. Some substantial new projects to integrate renewable generation are also in development or are entering planning processes. Nearly 70 of the 1,160 transmission projects in development are for tie-lines and tie-line upgrades, which support transfer capability between neighboring Balancing Authority areas. See the transmission summaries at the end of each assessment area's pages (in the **Regional Assessments Dashboards**) for current transmission development details.

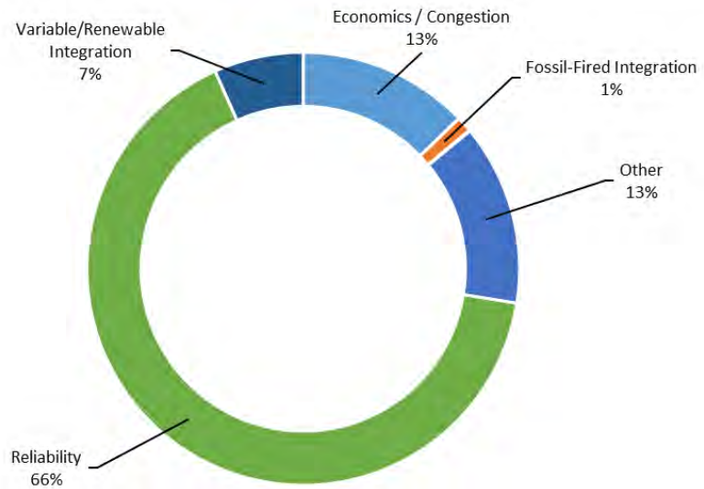


Figure 21: Future Transmission Circuit Miles by Primary Driver

Transmission development in some areas is hampered by siting and permitting challenges. Of the 1,160 projects that are under construction or in planning for the next 10 years, over 110 projects are currently delayed from their expected in-service dates. Siting and permitting issues are the most common cause for delays, affecting 68 projects (totaling 1,230 miles of new transmission). Other reasons for delays include economic impacts, planning and construction issues, or changing needs.

Interregional Transfer Capability Study (ITCS)

The Fiscal Responsibility Act of 2023[22] required NERC to conduct a comprehensive study of existing and future interregional transfer capability between each Transmission Planning Region[23] (TPR) to make recommendations for prudent additions to the amount of power that can be moved or transferred between neighboring TPRs and to make recommendations on how to meet and maintain transfer capability. In addressing this legislation, NERC identified additions to transfer capability that could support energy adequacy.[24] NERC filed the completed study report with FERC on November 19, 2024.[25]

Transfer Capability is the measure of the ability of the interconnected electric systems to reliably move or transfer electric power from one area to another area by way of all the transmission lines (or paths) between those areas under specific system conditions. The units of transfer capability are in terms of electric power, generally expressed in MW.

To provide further opportunities for stakeholder engagement and consultation, the project was divided into several stages, each with an accompanying report.

- **Overview of Study Need and Approach[26]:** Provided background and context regarding transfer capability calculations and the approach for recommending prudent additions, laying the foundation for the ITCS as a whole and its associated methods. (published in June 2024)
- **Transfer Capability Analysis (Part 1)[27]:** Addressed the first part of the congressional directive, which mandated a transfer capability analysis between each pair of neighboring TPRs, as well as the simultaneous import capability of each TPR. (published in August 2024)
- **Prudent Additions Recommendations (Part 2) and Meet/Maintain Recommendations (Part 3)**: Contained an energy margin analysis and resulting recommendations for prudent[28] additions to the transfer capability between neighboring TPRs to improve energy adequacy during, for example, extreme weather events. It also discussed how to meet and maintain transfer capability as enhanced by these prudent additions.
- **Canadian Analysis:** Due to the interconnected nature of the BPS, NERC will extend the study beyond the congressional mandate to identify and make recommendations to transfer capabilities from the United States to Canada and among Canadian provinces.[29]

Transfer Capability Analysis (Part 1)

Adequate transfer capability is fundamental to the reliable operation of the BPS. Balancing Authorities may rely on their neighbors to supply energy for various purposes, including economic or policy reasons. Transfer capability is also essential under stressed operating conditions, allowing Balancing Authorities to maintain reliability by importing needed energy from their neighbors. As the resource mix becomes increasingly dependent on just-in-time and weather-dependent fuel and energy for wind and solar, the ability to transfer electrical energy from areas of surplus to areas experiencing fuel or energy constraints has become essential to maintaining reliable delivery of electricity to end-use customers.

The ITCS is a congressionally mandated study to evaluate transfer capability and recommend additions to strengthen reliability.

A holistic view of the interconnected system and a thorough understanding of its behavior are essential when calculating or increasing transfer capability. When neighboring TPRs transfer energy over a highly interconnected system, the energy flows over many different lines based on the electrical characteristics, or impedance, of traveling each route, unless there is specific equipment used to control flows. As a result, energy typically flows not only across the tie lines that directly connect the exporting (source) TPR to the importing (sink) TPR but over many routes, some of which

[22] H.R.3746 - 118th Congress (2023–2024): Fiscal Responsibility Act of 2023 | Congress.gov | Library of Congress
[23] For the purposes of the ITCS, this term refers to the study regions as described in ITCS Overview of Study Need and Approach, Chapter 2.
[24] As evidenced during recent operational events including Western Interconnection Heatwave (2020), Winter Storm Uri (2021) and Winter Storm Elliott (2022), more needs to be done to support energy adequacy to be able to continuously meet customer demand. This is the reliability risk that the ITCS seeks to identify and mitigate through additions to transfer capability.
[25] NERC filing of the Interregional Transfer Capability Study, FERC Docket AD25-4-000.
[26] The ITCS Overview of Study Need and Approach can be found here.
[27] The ITCS Transfer Capability Analysis (Part 1) report can be found here.
[28] FERC defines prudence as the determination of whether a reasonable entity would have made the same decision in good faith under the same circumstances at the relevant point in time. See, e.g., New England Power Co., 31 FERC ¶61,047 at p. 61,084 (1985); and PotomacAppalachian Transmission Highline, LLC, 140 FERC ¶61,229 at P 82 2012 (Sept. 20, 2012).
[29] The ITCS Part 1 evaluated transfer capability from Canada into the United States.

may be running through third-party systems. The way electrical energy flows has broad implications for calculating and using transfer capability in an interconnected system, especially when traveling over long distances. For example, maintaining and increasing transfer capability may be highly dependent on the system conditions within the source and sink TPRs as well as surrounding areas. Likewise, transfer capability does not correlate one-to-one with the rating of new or upgraded transmission facilities.

Part 1 Key Findings

- Transfer capability varies seasonally and under different system conditions that limit transmission loading—it cannot be represented by a single number.
- Transfer capability varies widely across North America, with total import capability varying between 1% and 92% of peak load.
- Observed transfer capabilities are generally higher in the West Coast, Great Lakes, and Mid-Atlantic areas but relatively lower in the Mountain States, Great Plains, Southeast, and Northeast. There is limited transfer capability between interconnections

The transfer capability results in the Part 1 report reflect the conditions studied and are not an exhaustive evaluation of the potential for energy transfers. This study used a set of cases representative of stressed system conditions most relevant for the Part 2 analysis. As such, the study did not attempt to maximize transfer capability values for each interface through optimal generation re-dispatch, system topology changes, or other operational measures. Consequently, higher transfer capabilities may be available under different conditions. Changes to future resource additions, resource retirements, load forecast changes, and/or transmission expansion plans have the potential to significantly alter the study results.

Recommendations for Prudent Additions (Part 2) and to Achieve Transfer Capability (Part 3)

Part 2 of the ITCS evaluated the energy adequacy of the BPS should past weather conditions occur again in 2033. Specifically, the study applied 12 past weather years to the 2033 loads and resource mix using the current transfer capabilities as calculated in Part 1. The Part 2 study then evaluated the impact that additional transfer capability could have in mitigating the identified resource deficiencies[30] during extreme events, thereby improving energy adequacy. Using a six-step process, the ITCS developed a list of recommended additions to transfer capability. **Figure 22** shows the existing and potential new interfaces where additional transfer capability is recommended. While there are several factors that Transmission Planners consider, including reliability, economics, and policy objectives, given NERC's role as the ERO, the ITCS focused solely on reliability, specifically in terms of energy adequacy, for these recommendations.

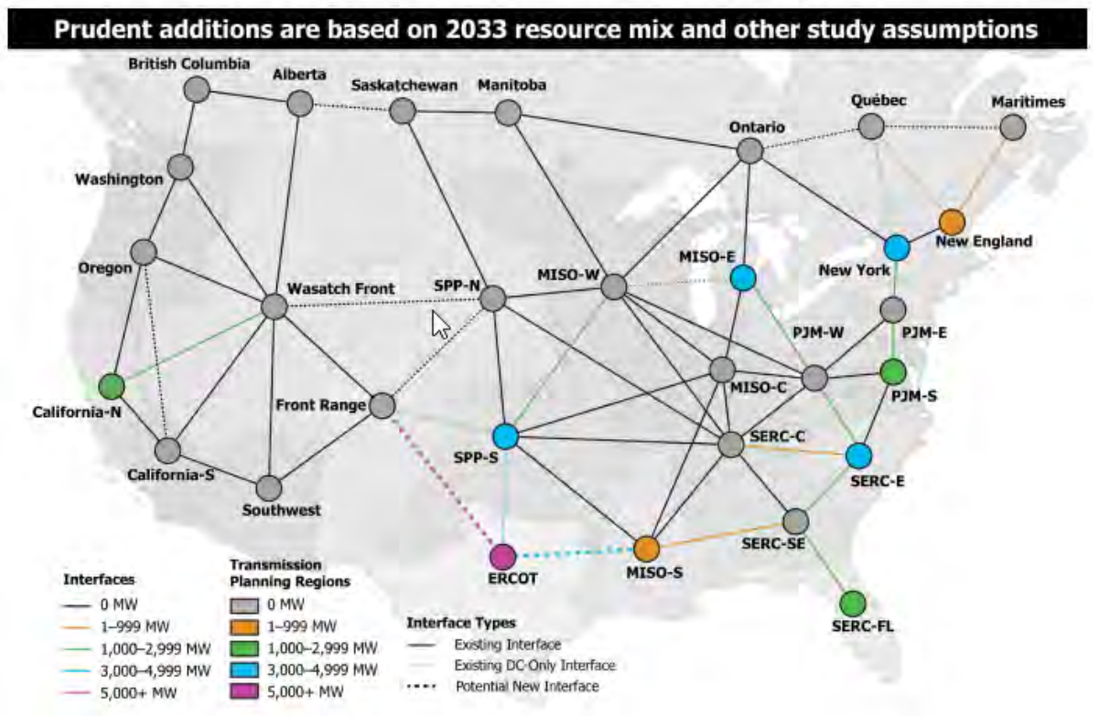


Figure 22: Prudent Additions to Transfer Capability

[30] For the purposes of this study, "resource deficiency" is used to describe instances where available resources, including energy transfers from neighbors, are insufficient to meet the projected demand plus minimum margin level.

The resulting recommendations for prudent additions to transfer capability (Part 2 study) were published in a report along with recommendations to meet and maintain transfer capability as enhanced by the prudent additions (Part 3).[31] Planners have multiple options for reducing the energy adequacy and extreme weather risks. In addition to the transmission enhancements that were in scope for the ITCS, due consideration should also be given to constructing local generation and storage, demand-side management approaches, and grid resilience projects. The ITCS recommended that planners consider all options and balance reliance on external resources vs. internal resources, noting that there may be better options than an over-reliance on one or the other.

Part 2 Key Findings

- Import capability required to reliably serve customers during extreme conditions varied significantly across the country, so a one-size-fits-all requirement would be inefficient and ineffective.
- Transmission limitations and the potential for energy inadequacy were identified in all 12 years studied.
- 35 GW of additional transfer capability is recommended across the United States to improve energy adequacy under extreme conditions.
- Some identified transmission needs could be alleviated by projects already in the planning, permitting, or construction phases. If completed, these projects could mitigate several risks highlighted by the ITCS, reinforcing their importance for grid resilience.
- The ITCS provides foundational insights for further discussion, and decisions. Transmission upgrades alone will not fully address all risks, and a broader set of solutions should be considered, emphasizing the need for local resources, energy efficiency, demand-side, and storage solutions.

See the *ITCS Final Report* for Detailed Key Findings

[31] The ITCS report *Recommendations for Prudent Additions to Transfer Capability (Part 2) and Recommendations to Meet and Maintain Transfer Capability (Part 3)* can be found here.

Emerging Issues

While developing this LTRA, NERC and the industry considered trends and developments that have the potential to impact the future reliability of the BPS over the next 10 years and beyond. Discussed below are emerging issues and trends not previously covered in this report that have the potential to impact future long-term projections or resource availability and operations.

Data Centers and Large Industrial Load

Growth in large load parcels like data centers and industrial facilities pose various challenges for system planners and operators, in addition to fueling rapid demand growth discussed elsewhere in this report. **Figure 23** shows one estimate of data center growth in the United States by 2027.[32] Other types of large industrial loads include smelters, manufacturing centers, hydrogen electrolyzers, and future electrified mass transit or shipping charging stations. Adding large parcels of load on the system can add new uncertainties to peak and hourly load forecasting. For example, data centers have longer operating hours and require more heating and cooling than other commercial buildings. In Texas, crypto mining facilities have connected in recent years that scale their operations (and thus electricity demand) depending on electricity prices. The behavior of large data centers during normal grid faults is also an emerging concern because customer-initiated automatic disconnecting of sizeable load can cause operating issues. Sudden and unexpected disconnecting load during a grid fault is analogous to well-known IBR performance issues and poses similar reliability risks. Planners and operators need to consider the characteristics of these loads as they begin to proliferate and support NERC RSTC's Large Loads Task Force to share best practices.

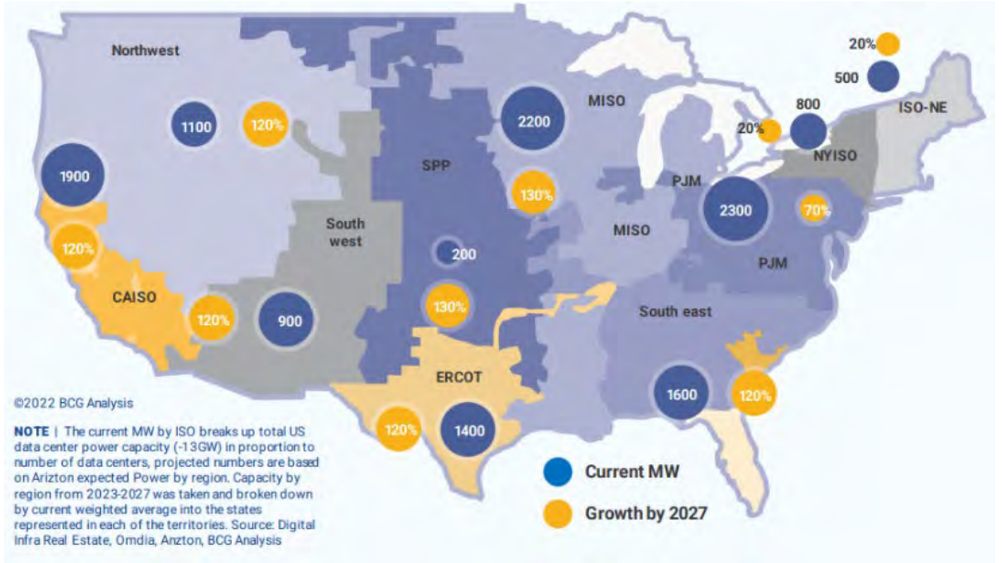


Figure 23: Projected Growth in Data Centers in the United States

Battery Energy Storage Systems

Planners and operators are focused on requirements to model, study, and operate the BPS with increased BESS and hybrid resources. BESS are increasingly being relied upon in areas with substantial amounts of solar PV resources to reduce ramping requirements on other resources by discharging in late afternoon as solar PV output rapidly declines. BESS are also often used for ancillary services, such as frequency response. Accurately accounting for BESS in operating and planning studies is a challenge because it requires assumptions and modeling capabilities for battery charging and discharging behavior. In real-time operations, system operators often do not have visibility into battery state-of-charge, a necessary condition for reliably integrating batteries into system operating plans. Without such information, operators may be surprised should battery resources fail to deliver when needed. In Texas, where battery resource growth is among the highest in North America, ERCOT uses a battery storage data collection program to obtain operational information and is pursuing market rules for state-of-charge accounting in unit commitment processes. System planners in many areas will be counting on new BESS facilities to manage variability and demand and resources. Obtaining the benefits of these resources requires careful integration into operating, planning, and market designs.

[32] *Grid Strategies: The Era of Flat Power Demand is Over*: https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf

Electric Vehicles and Electric Load

With increased adoption of electric vehicles (EV), which use batteries to store energy, there is a need to understand the impact of battery charging on system performance. EV forecasting is important for resource adequacy and system planning to account for changing load and load patterns. It is also important for system studies to include EV modeling and parameterization that account for the behavior of battery charging systems on system performance. In January 2024, NERC released the *EV Charging Study*, noting that the behavior of large amounts of EV chargers in operation can affect the BPS response to common outages. The RSTC established an EV Task Force to promote collaboration among the electric power industry and automotive representatives on areas of grid reliability.

Energy Drought

More reliance on wind, solar, and hydro resources in the resource mix has the potential to expose the electric system to supply shortages under abnormal weather patterns. When two or more resource types are simultaneously affected by conditions that cause below-normal resource output, operators can face challenges in meeting demand. Analysis of U.S. historical hourly generator data indicates that there are regional patterns to energy drought that can be expressed in terms of duration, magnitude, and seasonality (See **Figure 24**). There is also a higher likelihood for energy droughts to be more likely occur during high-load periods than at other times, underscoring the importance in considering such events in planning for resource and storage needs.[33]

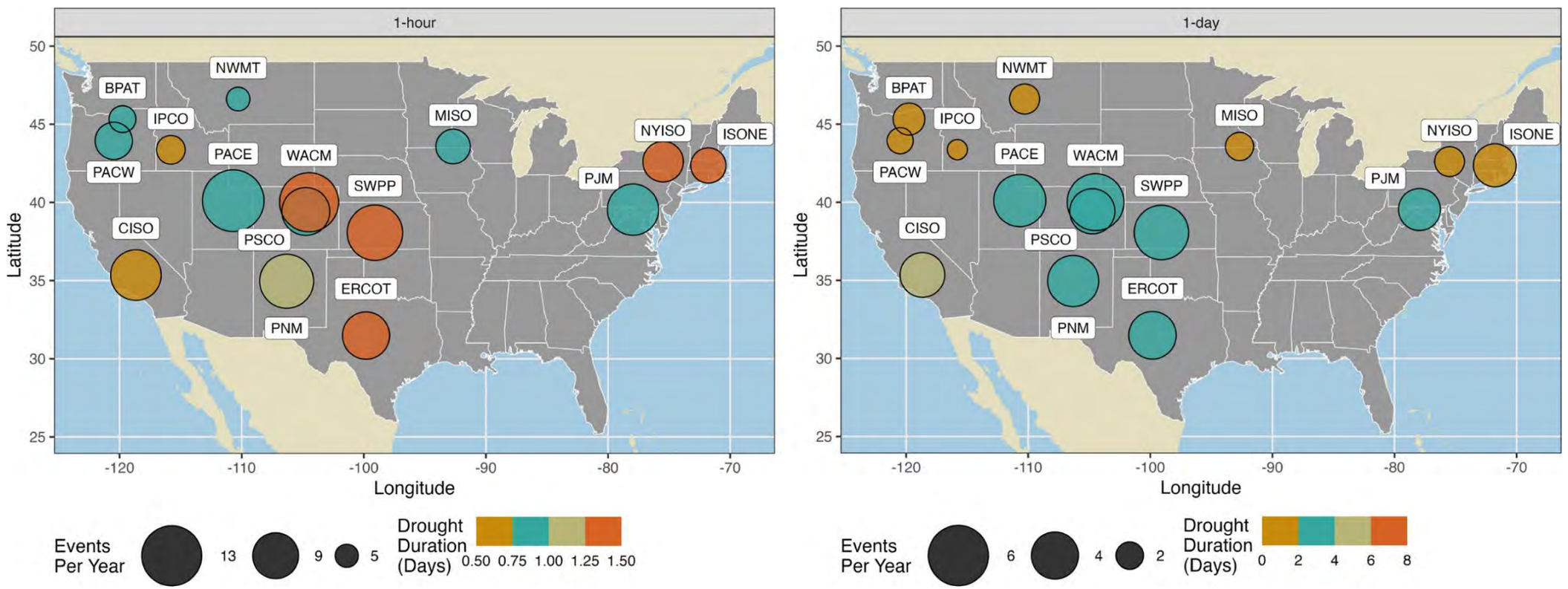
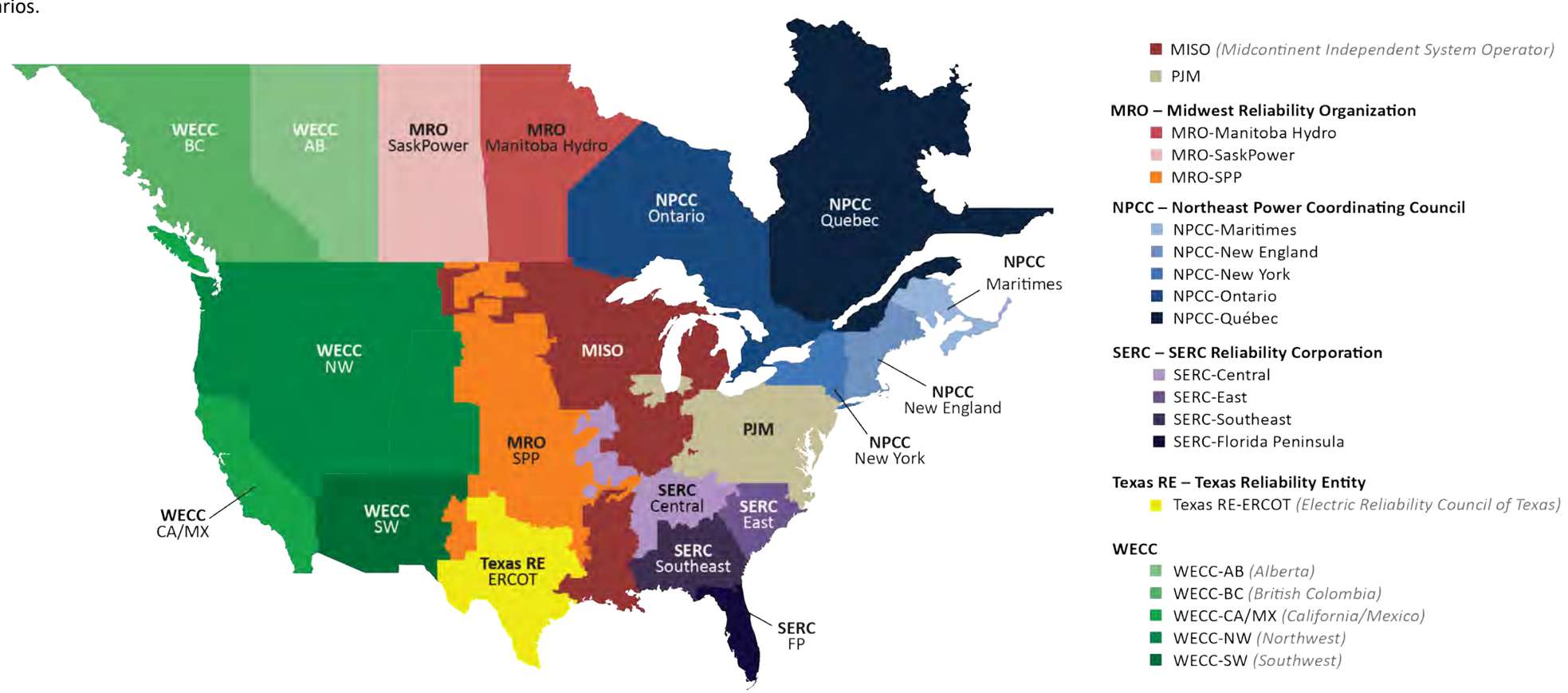


Figure 24: Frequency and Duration of Hourly (Left Panel) and Daily (Right Panel) Energy Droughts. Source: Pacific Northwest National Laboratory

[33] See Standardized benchmark of historical compound wind and solar energy droughts across the Continental United States

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Demand Assumptions and Resource Categories** table. On-Peak Reserve Margin bar charts show the ARM compared to the RML established for the area to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the Demand and Resource Tables), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the Demand and Resource Tables) and the extreme winter peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the WRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios.





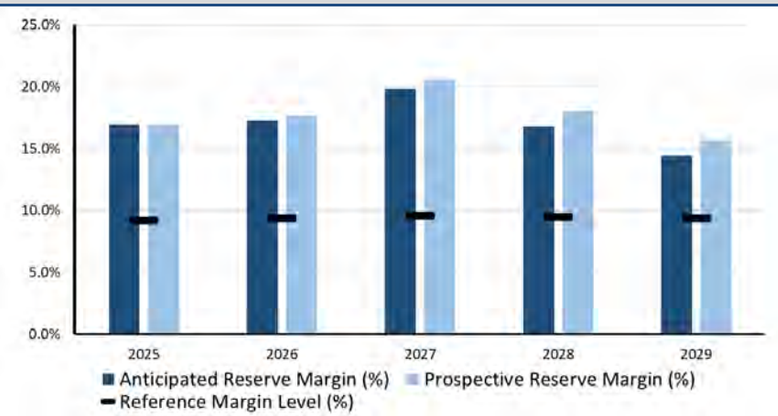
MISO

Midcontinent Independent System Operator, Inc. (MISO) is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authority and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

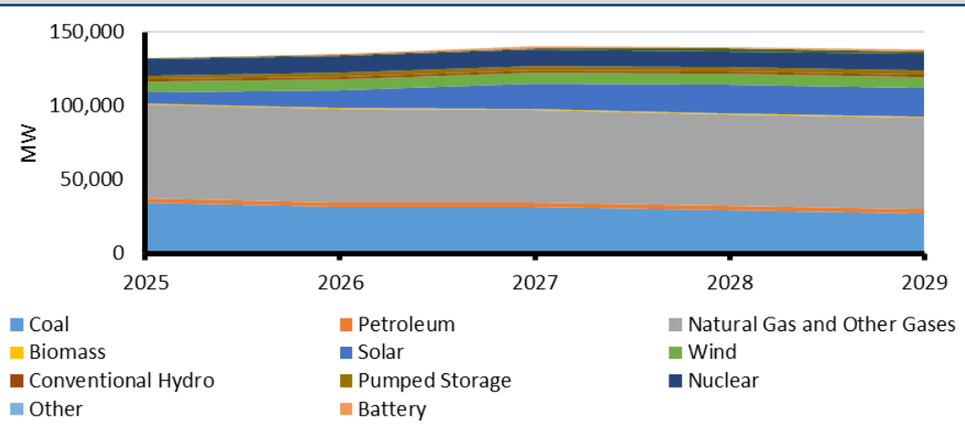
Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	122,328	124,343	126,073	128,700	129,401	130,120	130,493	131,327	131,952	131,952
Demand Response	8,205	8,221	8,058	8,065	8,074	8,077	8,079	8,075	8,075	8,075
Net Internal Demand	114,122	116,122	118,015	120,635	121,327	122,043	122,414	123,252	123,877	123,877
Additions: Tier 1	4,959	11,376	18,275	21,501	22,205	22,205	22,205	22,205	22,205	22,205
Additions: Tier 2	19	464	916	1,486	1,486	1,486	1,486	1,486	1,486	1,486
Additions: Tier 3	803	3,686	8,252	13,017	15,546	16,399	16,542	16,608	16,659	16,659
Net Firm Capacity Transfers	1,320	1,270	1,165	925	855	750	549	549	549	549
Existing-Certain and Net Firm Transfers	128,520	124,787	123,153	119,397	116,669	112,823	110,273	110,273	106,838	106,838
Anticipated Reserve Margin (%)	17.0%	17.3%	19.8%	16.8%	14.5%	10.6%	8.2%	7.5%	4.2%	4.2%
Prospective Reserve Margin (%)	17.0%	17.7%	20.6%	18.0%	15.7%	11.9%	9.4%	8.7%	5.4%	5.4%
Reference Margin Level (%) (Summer)	9.2%	9.4%	9.6%	9.5%	9.4%	9.4%	9.5%	9.6%	9.7%	9.7%

Note: See **Figure 3** for summer reserve margins with historically average resource additions in MISO based on results from the 2024 Organization of MISO States (OMS)-MISO Survey.



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- MISO's capacity resource turnover continues to occur with coal unit contributions being primarily replaced by solar, wind, and battery facilities. Furthermore, generation installation delays result in uncertainty throughout the assessment timeframe. As a result of these factors, MISO is facing capacity shortfalls in the next five years.
- MISO's reduction in capacity resources since the *2023 LTRA* has primarily been in the coal fleet with a reduction of 6,200 MW in the first year of the assessment.
- MISO has continued the seasonal capacity auction construct and has found growing evidence of risk in non-peak (e.g., spring and fall) seasons. Countering the risk during these off-peak seasons requires more resources to be available, and this can result in less opportunity for generators to pursue their maintenance needs. During peak seasons when high levels of generator availability are expected, short-notice unplanned outages and higher forced outages could occur as a result of deferred maintenance and challenge reliability.

MISO Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	34,637	31,706	31,618	29,067	26,841
Coal*	27,450	24,362	23,203	17,977	16,744
Petroleum	3,065	3,058	3,060	3,050	3,050
Petroleum*	2,992	2,990	2,992	2,992	2,992
Natural Gas	63,051	62,977	62,616	62,394	62,009
Natural Gas*	62,576	61,543	62,396	62,394	62,009
Biomass	577	571	553	481	481
Solar	8,091	12,538	17,318	19,174	19,763
Wind	6,954	7,236	7,536	7,632	7,660
Conventional Hydro	1,527	1,527	1,527	1,527	1,527
Pumped Storage	2,528	2,528	2,578	2,578	2,578
Nuclear	11,027	11,127	11,127	11,127	11,127
Other	72	72	72	72	72
Battery	208	582	1,011	1,358	1,377
Total MW	132,159	134,892	140,263	139,973	138,018
Total MW*	124,423	126,048	131,562	128,826	127,864
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to MISO are removed from the resource projection where marked.					

MISO Assessment

Planning Reserve Margins

The planning reserves across the MISO footprint in the summer are projected to fall below reserve margin requirements as new generation coming on-line could be insufficient to make up for generator retirements and load growth. It is important to note that there is 56 GW of generation with signed generation interconnection agreements that are yet to come on-line as of July 5, 2024, so there is an opportunity to accelerate installation speeds. However, if resource additions remain at or near historically average levels (approximately 2.3 GW/year average over the last 3 years), PRMs in MISO will fall below the RML reserve margin requirements much faster. Summer PRMs with average resource additions are shown in **Figure 3** as **Reserve Margin-Avg Addition**.

Increased coordination between MISO and its members will be critical to ensuring reliability throughout this resource transition of integrating new intermittent resources and continuing to retire conventional resources. Resource adequacy is a key function of MISO, and the MISO annual planning resource auction (PRA) provides a mechanism for capacity sellers to provide resources that meet the needs of load-serving entities for each of the four seasons in the upcoming year. MISO's resource adequacy construct complements the jurisdiction that regulatory authorities have in determining the necessary level of adequacy.

Note: Capacity values for existing resources in tables on p. 41–42 reported by MISO reflect the Seasonal Accredited Capacity (SAC) for Summer. Adjustments and derates are applied to account for factors affecting expected resource output. The RML in the Demand, Resources, and Reserve Margins table on p. 41 is the Unforced Capacity (UCAP) RML, consistent with the reported capacity values.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

The introduction of the seasonal PRA and inputs to the process provide more granularity and reliability planning for non-peak hour times during the year. In addition to that change, MISO conducts seasonal resource assessments evaluating generation availability, outage rates, and forecasted load variation across all four seasons. Refer to MISO's Resource Adequacy page.

Probabilistic Assessments

To establish RMLs that define the minimum reserve margins for resource adequacy, MISO performs its annual probabilistic Loss-of-Load Expectation (LOLE) Study per MISO tariff. In recent years, MISO improved its LOLE study modeling by including seasonal outage rates, correlated cold weather outage adder profiles, a probabilistic distribution of non-firm support, and 30 years of hourly wind and solar profiles. The LOLE study produces seasonal RMLs for the upcoming planning year that are used in MISO's planning resource auction. These RMLs are calculated such that they prescribe the minimum PRM that will meet an LOLE of 1 day in 10 years. For more information on the seasonal LOLE Study, visit: https://cdn.misoenergy.org/LOLE%20Study%20Report%20PY%202024-2025631112.pdf.

MISO also performed a probabilistic analysis for the 2024 ProbA. Because MISO used the same model for both the ProbA and the LOLE study, transmission limitations were not included explicitly in the simulations. It is appropriate for MISO to make this assumption for the LOLE study and for determining capacity needs in the MISO system because MISO accounts for transmission limitations elsewhere in the resource adequacy process. However, for an adequacy assessment like the ProbA, the assumption can overvalue resource performance by not accounting for transmission constraints on the deliverability of energy resources. The resulting 2024 ProbA metrics in the table below can understate the risk of unserved energy and load loss.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	68.8	**0.000**	**0.000**
EUE (PPM)	0.108	**0.000**	**0.000**
LOLH (hours per year)	0.393	**0.000**	**0.000**
Operable On-Peak Margin	13.9%	**11.3%**	**11.3%**

* Provides the 2022 ProbA Results for Comparison

MISO is an elevated risk in the *2024 LTRA* because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. All-hours probabilistic studies of the MISO system performed apart from the 2024 ProbA show that shortfall risks can also occur during spring and fall in months that are not peak demand seasons for MISO. The 2022 NERC ProbA Regional Risk Scenario Sensitivity Case included seasonal forced-outage rates and correlated cold weather outages instead of annual average outage rates. MISO found that not only did EUE increase in this sensitivity, but it was also spread throughout the year. Since this study, MISO implemented enhancements to its LOLE study and PRA to address seasonal resource needs.

Demand

The peak demand forecast has increased from the *2023 LTRA* by close to 3 GW (~2.5%), and, while the load forecasts still vary across year to year, the load at the end of the study horizon is ~5 GW higher (~4%). Load-serving entities do not include DR resources in the load forecast, and MISO does not have much insight into the amount of electrification built into the load forecasts. There are other studies at MISO investigating electrification and transportation industry impacts to load forecasts

through the MTEP report. MISO contracted with Applied Energy Group (AEG) to evaluate the MISO footprint's electrification potential. This is documented in the report and has been utilized to update the MISO Futures Report.

Demand-Side Management

DR programs continue to play a significant role in providing capacity to MISO. DR is steady around 8 GW in the summer and 6.5 GW in the winter and is projected to remain constant during the study horizon. MISO's transition to seasonal auctions highlights accreditation of DR and availability during non-summer seasons.

Distributed Energy Resources

Behind-the-meter generation (BTMG) resources contribute about 4.2 GW of capacity across the study horizon, of which ~1.2 GW are distributed PV. MISO's transition to seasonal auctions highlights the availability of DERs across the four seasons, and MISO is working with stakeholders to derive adequate methods of aggregating, reporting, and allowing DER participation in MISO markets.

Generation

The departure of MISO's coal fleet has continued with a reduction in capacity of around 6 GW in the past year, and a projected reduction of a further 12 GW over the next five years. Solar continues to rise in capacity contributions with a growth of 1,200 MW since the *2023 LTRA* and growth of 3,200 MW in the first year of the study.

There are ~56 GW installed capacity (ICAP) of generation (predominantly solar and battery) with signed generation interconnection agreements in MISO that are projected to come on-line over the next few years. There have been some supply chain and tariff issues that have delayed the commercial operation of these resources.

Due to the large size in the MISO interconnection queue, in the 2022 LTRA (similarly to the OMS-MISO Survey), prospective generation in the queue gets multiplied by a factor based on the study phase and likelihood of that resource coming on-line and gets added into the footprint over time. This reduction is utilized to minimize the impact of prospective generation projects that will not come to fruition through the queue cycle. MISO continues to pursue queue reform efforts to expedite the process by ensuring projects being studied are of adequate certainty.

Transmission

The MISO Transmission Expansion Plan (MTEP) 2021 included the Long-Range Transmission Plan (LRTP) tranche 1 projects totaling $10.3 billion in investment for reliability and economic benefits estimated at $23–52 billion across the MISO footprint while also facilitating the integration of ~53 GW of new resources. In MTEP22, $4.3 billion in transmission projects were approved with $550 million going toward integrating new resources, $550 million going toward baseline reliability projects, and the age and condition category for the rest. MTEP23 includes a further $9 billion investment into the MISO footprint to address the local needs of the region. MISO is also pursuing LRTP tranche 2 with an expected investment of $18-23 billion to implement a 765 kV backbone into the northern portion of the footprint. These projects are expected to be included as part of MISO's MTEP24 project portfolio. In MTEP24, $6.7 billion in transmission projects have been submitted for board approval. MISO is also pursuing LRTP tranche 2.1 with an expected investment of $21.8 billion to implement a 765 kV backbone into the midwestern portion of the footprint. Tranche 2.1 brings reliability and economic benefits estimated at $51.7–101 billion across the MISO Midwest footprint, facilitating integration of ~115.7 GW of new resources.

Energy Storage

MISO's energy storage resources are still primarily in the future with only 84 MW of on-line storage. The MISO interconnection queue does have a significant amount of energy storage upcoming, but these are primarily Tier 3 resources at present.

Capacity Transfers

MISO benefits from significant transfer capacity with neighboring assessment areas due to the geographic location. MISO and SPP continue to finalize the Joint Targeted Interconnection Queue (JTIQ) portfolio to resolve the binding constraints that have traditionally delayed the interconnection process. MISO's utilization of capacity transfers is identified in the LOLE report and memorialized through the MISO PRA.

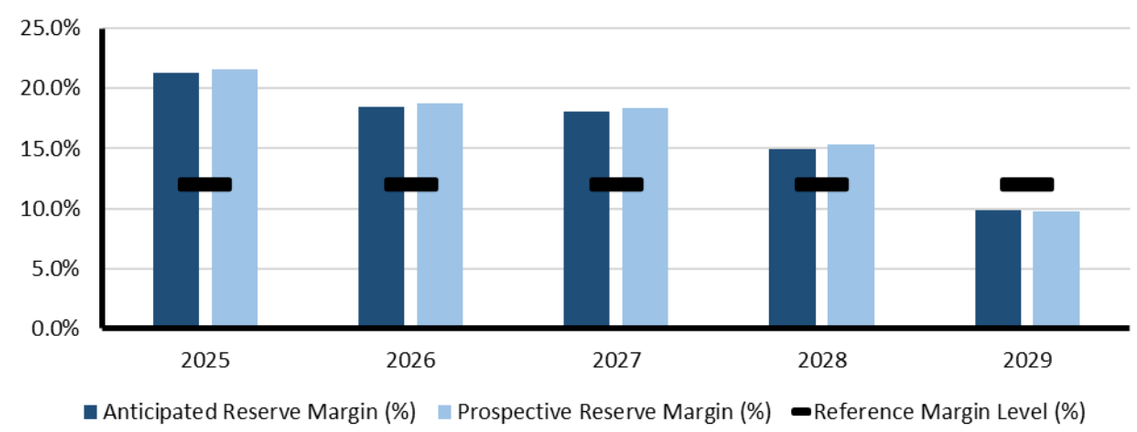


MRO-Manitoba Hydro

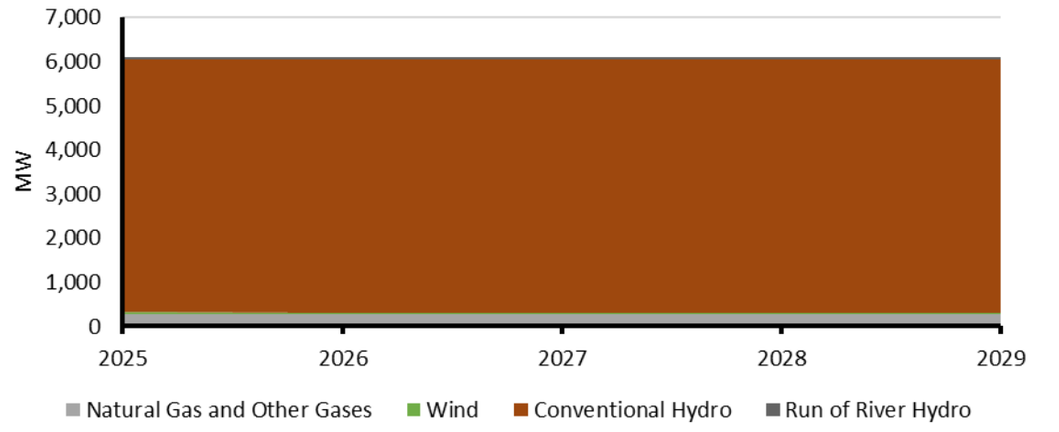
Manitoba Hydro is a provincial Crown Corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro provides electricity to approximately 616,000 electric customers in Manitoba and provides approximately 296,000 customers with natural gas in southern Manitoba. The service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter-peaking. Manitoba Hydro is its own Planning Coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	4,797	4,923	4,968	5,037	5,268	5,366	5,427	5,486	5,556	5,629
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	4,797	4,923	4,968	5,037	5,268	5,366	5,427	5,486	5,556	5,629
Additions: Tier 1	30	51	64	64	64	64	64	64	64	64
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-113	-113	-93	-167	-172	-565	-565	-565	-565	-565
Existing-Certain and Net Firm Transfers	5,786	5,780	5,800	5,726	5,721	5,328	5,328	5,328	5,328	5,328
Anticipated Reserve Margin (%)	21.3%	18.4%	18.0%	15.0%	9.8%	0.5%	-0.6%	-1.7%	-2.9%	-4.2%
Prospective Reserve Margin (%)	21.6%	18.8%	18.4%	15.3%	9.8%	0.5%	-0.6%	-1.7%	-3.0%	-4.2%
Reference Margin Level (%)	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The electricity demand forecast in the province of Manitoba has increased since the *2023 LTRA*, driven by expected economic activity and adoption of EVs. Resource projections have not changed significantly.
- The ARM falls below the RML of 12% beginning in Winter 2029–2030 due to load growth and the reduction of winter import capacity transfers. Manitoba Hydro is performing analysis to inform its integrated resource plan and support future decisions for resources.

MRO-Manitoba Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	**2026–2027**	**2027–2028**	**2028–2029**	**2029–2030**
Natural Gas	278	278	278	278	278
Wind	52	31	31	31	31
Conventional Hydro	5,705	5,726	5,739	5,739	5,739
Conventional Hydro*	5,705	5,726	5,739	5,739	5,721
Run of River Hydro	856	856	856	856	856
Total MW	6,094	6,094	6,107	6,107	6,107
Total MW*	6,094	6,094	6,107	6,107	6,089
*** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

MRO-Manitoba Hydro Assessment

Planning Reserve Margins

The winter ARM falls below the Reference Margin Level of 12% in 2029–2030. No resource adequacy issues are anticipated until Winter 2029–2030. A Tier 1 project to replace eight older and smaller hydro units is being planned for the Pointe du Bois Generating Station. The Pointe du Bois Renewable Energy Project (PREP), approximately 50 MW, replaces the original hydro units that were mothballed or retired based on economics/end of life after about 100 years of operation. No Tier 2 or Tier 3 resources have been assumed to come into service during the assessment period.

The ARM falls below the Reference Margin Level of 12% beginning in Winter 2029–2030 due to net load growth and the reduction of winter import capacity transfers. Manitoba Hydro's Integrated Resource Plan was published in Summer 2023. Further analysis is underway and will help inform Manitoba Hydro's future resource decisions for resources in the 2029 timeframe.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Under normal water conditions, over 95% of the generation in Manitoba Hydro's system is from renewable energy—primarily hydro generation and wind generation. As the operator of a predominantly hydro system, Manitoba Hydro frequently performs an all-hours energy adequacy analysis of the near-term through seasonal time periods to manage reservoir energy storage and meet system demand. Additionally, Manitoba Hydro conducts specific analyses to determine short-term storage and minimum flow requirements for maintaining Manitoba and extra-provincial resource adequacy obligations. As there are modest levels of wind and solar on the Manitoba Hydro system, the resource adequacy risk on the Manitoba Hydro system over the next five years and under normal water conditions is expected to coincide with peak demand hours**.**

There are a number of influencing factors associated with Manitoba Hydro's resource adequacy performance, such as the water resource conditions, energy and capacity exchanges with neighboring jurisdictions, forecast load level, uncertainties in load forecast and load variation profiles, demand responses, wind penetration, and generation fleet availability. Most of Manitoba Hydro's generating facilities are use-limited or energy-limited hydro units. The annual energy output of these facilities is mostly dependent on the availability of the water resource. In the 2024 ProbA, Manitoba Hydro examines the impact of the most significant factor over the long run—variations in water conditions.

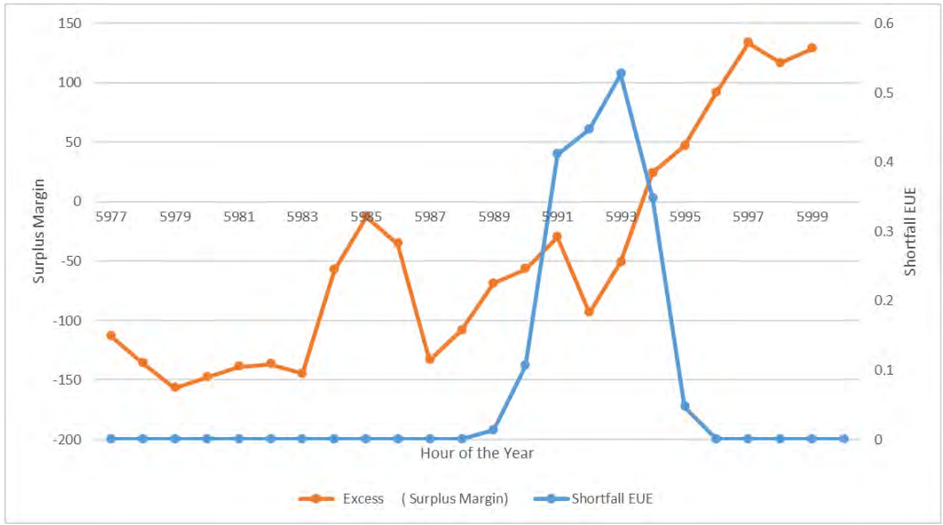
Nonzero LOLH and EUE are observed for both reporting years of 2026 and 2028 and shown in the table below. The LOLH and EUE indices are higher compared to the 2022 assessment mainly due to the increase in the forecast peak demand. Water flow conditions of 10th percentile or lower tend to increase the LOLH and EUE. As a small winter-peaking system on the northern edge of a large summer peaking system (MISO), there generally is assistance available, particularly in MISO's off-peak hours, to provide energy to supplement hydro generation in low-flow conditions in winter. Management of energy in reservoir storage in accordance with good utility practice provides risk mitigation under low water flow conditions.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	7.23	**4.711**	**68.870**
EUE (PPM)	0.29	**0.176**	**2.504**
LOLH (hours per year)	0.01	**0.059**	**0.914**
Operable On-Peak Margin	13.5%	**18.8%**	**15.6%**

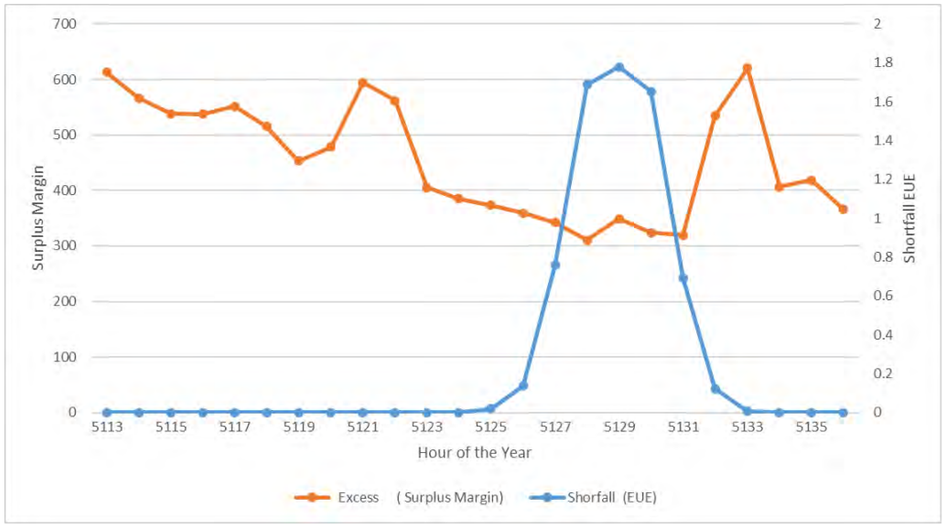
* Provides the 2022 ProbA Results for Comparison

The Monthly EUE and LOLH for 2026 and 2028 show that the highest LOLH and EUE contribution are from July and November, respectively, for 2026 and 2028.

The two graphs below show the hourly energy availability on the Manitoba Hydro system during the ProbA's highest risk days in 2026 and 2028. Surplus energy and shortfall EUE are plotted for the day when the highest loss of load event happens in the ProbA analysis. The Probability Weighted Average (PWA) surplus margin is negative, which indicates possible loss of loads for 2026. However, the PWA surplus energy is higher for 2028 during the day when the highest loss of load event is observed. This is because the surplus is an average for different water year data and the average surplus may not represent the event when loss of load occurs.

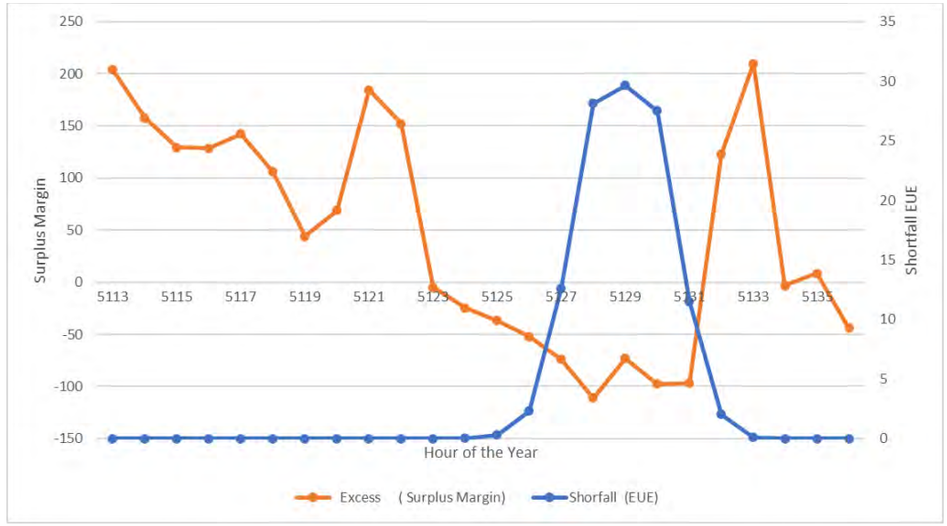


Hourly PWA Surplus Margin and Shortfall EUE for 2026 Representative Risk Day (Summer)



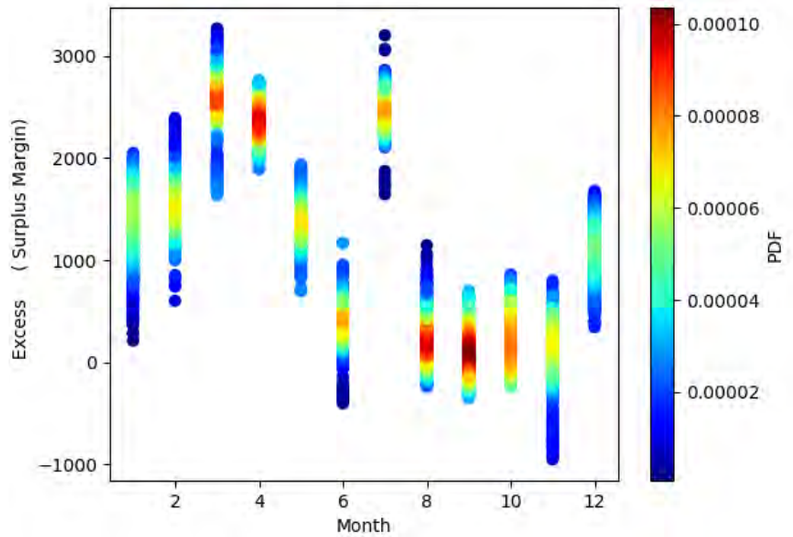
Hourly PWA Surplus Margin and Shortfall EUE for 2028 Representative Risk Day (Summer)

The figure below shows the surplus margin and shortfall EUE for 2028 under extreme drought conditions. It can be seen that the loss-of-load event occurs when the surplus margin becomes negative. This surplus energy shown in the figure is the average value for this hour for the entire simulation. It may not represent each individual loss-of-load event during simulation. By plotting the hourly surplus and unserved energy for the low-water years, it is possible to see what risk periods are likely to emerge during extreme drought.



Hourly PWA Surplus Margin and Shortfall EUE for 2028 Representative Risk Day (Summer) During Extreme Drought Condition

The scatter plots of surplus energy vs. month for 2026 and 2028 are shown in the figures below. In the months of June and August to November, the PWA surplus energy is relatively lower compared to the other months due to less import from MISO. The PWA surplus energy in July 2026 is high due to higher hydro energy availability for July. However, since PWA is the result of averaging, positive surplus energy does not mean that there will be no loss-of-load events.



PWA Surplus Energy Versus Month for 2026

Demand

Manitoba Hydro's load-growth forecast is up around 3.2% over the assessment period in comparison with the forecast used for the *2023 LTRA*. Factors considered in load-growth projections include economic activity, EV adoption, and demand-side management programs in Manitoba operated by Efficiency Manitoba. EV adoption in Manitoba is being driven in part by proposed federal regulations that are expected to require that at least 20 percent of new vehicles sold in Canada will be zero-emission by 2026, at least 60 percent by 2030, and 100 percent by 2035.

Manitoba Hydro is anticipating load growth of 1.3% over the last half of the assessment period. Limited surplus firm generation resources (resource adequacy) have the potential to slow the connection of very large new industrial loads. In order to limit load growth, Manitoba Hydro has been directed by the Province of Manitoba to suspend processing of cryptocurrency load connections until 2026.

Demand-Side Management

Manitoba Hydro currently does not have any form of directly controllable and dispatchable DR programs. Manitoba Hydro does have an indirectly controllable and dispatchable DR program called the Curtailable Rate Program.

The Curtailable Rate Program provides approximately 160 MW of load reduction through up to 16 load curtailments of 4¼ hours each on five minutes notice. The program is intended for peak load management. In addition, one product provides 50 MW of contingency reserves, also on five minutes' notice.

The terms and conditions of the Curtailable Rate Program were updated in August 2023 to require an annual curtailment test, increase the number of possible curtailments, extend the notice period for conversion to firm service, and make minor editorial changes.

Distributed Energy Resources

Manitoba is not currently experiencing large additions of wind and solar resources being seen in other regions; hence, emerging reliability issues arising from such large wind and solar resource additions are not anticipated in the next five years. Additions of energy storage resources in the next 10 years are not anticipated at this time. There is a potential for significant solar DER resources in the latter half of the assessment period, and plans are being developed to study the impacts on the Manitoba Hydro system. The potential for future solar DER may be dependent on solar PV subsidies and/or incentives.

Generation

Manitoba Hydro is monitoring federal and provincial policy/strategies/regulations related to electricity/energy. The Canadian federal government is considering significant carbon emission regulations. Through Environment and Climate Change Canada, it is taking multiple steps to develop clean electricity regulations that aim for Canadian electricity generation to achieve net-zero greenhouse gas emissions by 2035 by requiring generating units to meet a stringent emissions intensity standard (measured in tons CO2 equivalent per GWh) and pay a price for any remaining emissions. The proposed regulations are still in development and not proposed to be fully implemented until 2035, so it is too early to determine any potential impacts. The Province of Manitoba is developing a provincial energy strategy/policy which may be released in Fall 2024. As details are not yet available, it is too early to determine any potential impacts.

Energy Storage

Manitoba Hydro currently has no energy storage resources, and none have been committed to over the next 10-year period.

The hydro generation resources, while not storing electricity directly, do store water in a reservoir for conversion to electricity and have been in use for over 100 years. For most hours of the year, the only dispatchable resources online are hydro generation resources which therefore serve most operational, reliability, and economic functions.

Capacity Transfers

Manitoba Hydro has coordination and tie-line agreements with neighboring assessment areas, such as MISO, SaskPower, and the IESO. In accordance with these agreements, planning- and operating-related issues are discussed and coordinated through respective committees. In addition to this planning and operating committee work, Manitoba Hydro engages with the neighboring utilities of Minnesota Power, Xcel Energy, Otter Tail Power, Minnkota Power Cooperative, SaskPower, and Hydro One regularly to share information, discuss issues, and coordinate activities. Manitoba Hydro also coordinates planning studies (for example, transmission service request studies and requests for generation interconnections) with its neighboring assessment areas. In addition, capacity transfers are verified from a resource adequacy perspective with adjacent regions/entities. Significant capacity transfer limitations from MISO into Manitoba may have the potential to cause reliability impacts but only in extreme conditions occurring simultaneously.

Transmission

Manitoba Hydro has identified aging components of its HVdc system as a potential reliability issue that is unique to the assessment area. The concern is that the oldest HVdc system components could be approaching end of life. Studies have been initiated to study/evaluate modernization options and alternatives. The studies and procurement of replacement equipment could take up to 10 years to implement based on the current HVdc market capability. There is currently spare capacity on the HVdc system, and the end-of-life failure of a single pole would not create reliability issues. The further end-of-life failure of a second pole, while believed to be a very low probability, has the potential to create reliability concerns under peak winter loads if mitigation measures are not implemented. Mitigation measures to minimize the likelihood of experiencing this quantity of long-term outages are being actively pursued.

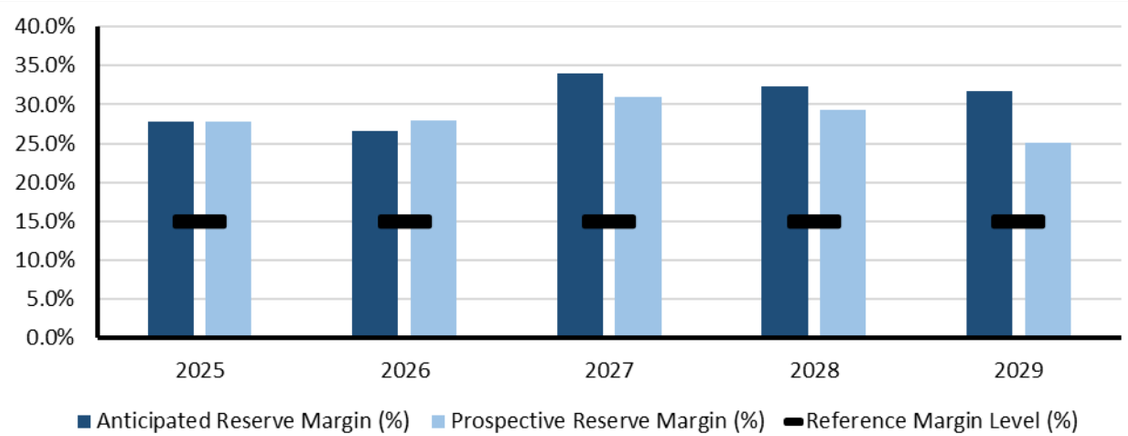


MRO-SaskPower

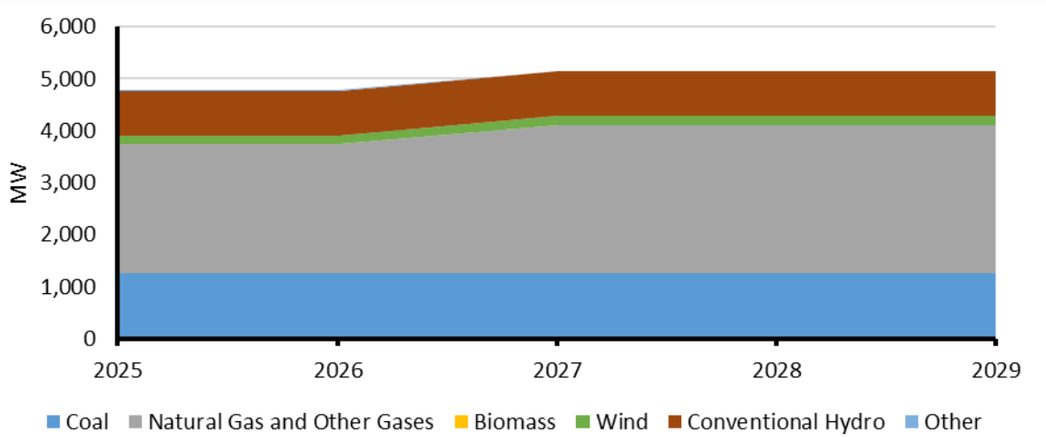
MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles), with a population of 1.2 million and approximately 550,000 customers. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown Corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System (BES) and its interconnections.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	3,917	4,025	4,149	4,189	4,210	4,242	4,271	4,315	4,359	4,408
Demand Response	72	72	72	72	72	72	72	72	72	72
Net Internal Demand	3,845	3,953	4,077	4,117	4,138	4,170	4,199	4,243	4,287	4,336
Additions: Tier 1	507	507	883	883	883	883	883	883	883	883
Additions: Tier 2	0	55	175	175	928	928	928	928	928	928
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	290	290	315	315	315	315	315	315	315	315
Existing-Certain and Net Firm Transfers	4,407	4,497	4,582	4,566	4,566	4,489	4,490	4,490	4,552	4,566
Anticipated Reserve Margin (%)	27.8%	26.6%	34.0%	32.4%	31.7%	28.8%	28.0%	26.6%	26.8%	25.7%
Prospective Reserve Margin (%)	27.8%	28%	31.0%	29.3%	25.1%	22.3%	20.8%	19.5%	19.8%	18.7%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- SaskPower's ARM is above the RML throughout the assessment period. No resource adequacy issues are anticipated.
- Saskatchewan is adding approximately 1,064 MW of generation under Tier 1 within the next five years. This includes a 200 MW wind generation facility, two new 377 MW gas generation facilities, and the expansion of two existing natural gas facilities totaling 90 MW. The remaining capacity addition comes from geothermal and flare gas.

MRO-SaskPower Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Coal	1,249	1,249	1,249	1,249	1,249
Coal*	1,249	1,249	1,088	1,088	188
Natural Gas	2,487	2,487	2,863	2,863	2,863
Biomass	3	3	3	3	3
Wind	164	164	162	162	162
Conventional Hydro	856	856	856	856	856
Other	22	17	17	1	1
Total MW	4,781	4,775	5,150	5,134	5,134
Total MW*	4,781	4,775	4,989	4,973	4,073
*** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

MRO-SaskPower Assessment

Planning Reserve Margins

Saskatchewan uses a criterion of 15% as the reference reserve margin and has assessed its PRM for the upcoming 10 years considering the summer and winter peak hour loads, available existing and anticipated generation resources, firm capacity transfers, and available demand response for each year. Saskatchewan's ARM ranges from approximately 19% to 34% and does not fall below the Reference Margin Level.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Saskatchewan performs energy assessments using probabilistic methods to inform the area's resource adequacy requirements. Saskatchewan evaluates non-peak hour risks and diminishing capacity credits associated with higher penetration levels of VERs as part of the long-term planning process.

Results of the 2024 ProbA are provided in the table below. Based on the deterministic calculations within this assessment, Saskatchewan's ARM is 27.8% and 34.0% for years 2026 and 2028, respectively. Since the 2022 ProbA, the reported forecast reserve margin for 2026 has remained consistent. The minor variation in the reserve margin is due to a slight change in the schedule of generator outages. EUE is also comparable to the 2022 ProbA, with some variation attributed to updated hydro energy dispatch, which is able to reduce the EUE in the months where it was highest in the prior ProbA.

Base Case Summary of Results			
	2026*	2026	2026
EUE (MWh)	117.0	**75.641**	**8.553**
EUE (PPM)	4.4	**2.807**	**0.300**
LOLH (hours per year)	0.9	**0.547**	**0.078**
Operable On-Peak Margin	24.6	**24.4%**	**30.5%**

* Provides the 2022 ProbA Results for Comparison

Saskatchewan does not anticipate resource adequacy issues during its off-peak hours. Currently, its resource mix consists of baseload and fast ramping generation resources, with little penetration of VERs. The main factor contributing to EUE is the amount of planned generator outages. When these short-term reliability issues are identified in advance, they can be mitigated by rescheduling the maintenance. The hourly EUE heat maps in the following figures show that risk of unserved energy is at its highest in the summer months. Risk can also be found in months before or after summer and be driven by unseasonable temperatures driving above-normal demand that coincides with generator maintenance periods. Winter risks of shortfall are associated with extreme cold weather and unexpected generator outages.

Hourly EUE Heat Map : 2026																								
EUE	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Feb-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mar-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apr-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
May-26	1.2	1.2	1.1	1.2	1.2	1.3	1.3	1.3	1.4	1.5	1.6	1.8	1.8	1.7	1.7	1.6	1.6	1.6	1.5	1.5	1.5	1.6	1.5	1.3
Jun-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Jul-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.1	0.0	0.0	0.0	0.0	0.0
Aug-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.0
Sep-26	0.5	0.6	0.6	0.6	0.6	0.5	0.6	0.7	0.7	0.8	0.9	1.2	1.2	1.3	1.4	1.5	1.5	1.6	1.4	1.5	1.7	1.3	1.0	0.7
Oct-26	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.4	0.3	0.3
Nov-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Dec-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.1	0.1

Hourly EUE Heat Map : 2028																								
EUE	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feb-28	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mar-28	0.0	0.0	0.0	-	-	-	-	0.0	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apr-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
May-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Jun-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0
Jul-28	0.0	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
Aug-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Sep-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oct-28	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1
Nov-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0
Dec-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0

Hourly EUE Heat Maps (in MWh)

Demand

Saskatchewan experiences its peak-season in the winter. Saskatchewan's system peak load forecast is based on econometric variables, weather normalization, and individual level forecasts for large industrial customers. The average annual summer and winter peak demand growth is expected to be approximately 1.35% throughout the assessment period.

Demand-Side Management
Saskatchewan's EE and energy conservation programs include incentive-based and education programs focusing on installed measures and products that provide verifiable, measurable, and permanent reductions in electrical energy, and demand reductions during peak hours.

Saskatchewan's DR consists of contracts with industrial customers for interruptible load based under conditions specified in demand response programs. The first of these programs provides a curtailable load, currently up to 72 MW, with a 12-minute event response time. Other programs are in place providing access to additional curtailable load requiring up to two hours notification time.

Distributed Energy Resources
The current BTM DER installed capacity in Saskatchewan is approximately 50 MW, which includes approximately 48 MW of solar PV and the remaining approximately 2 MW of distributed wind projects. An additional 25 MW of DER solar PV are expected to be added in the next five years. BTM DER installations are incorporated into the load forecast models, which are used in supply and transmission planning study models.

Small power producers contribute an additional 5 MW installed DER capacity (non-BTM) in Saskatchewan. There is currently an existing 8 MW and a potential for up to 20 MW of DERs being added in the next 2 years based on the currently approved Power Generation Partner program. These projects are included as generation additions, but currently their capacity is not considered in reliability planning.

Generation
Saskatchewan is adding approximately 1,064 MW into its resource mix of generation under the Tier 1 category within the next five years. The includes a 200 MW wind generation facility, expansion of two existing natural gas facilities totaling 90 MW, two new natural gas facilities totaling 754 MW, 15 MW of flare gas generation, and 5 MW of geothermal generation.

Under Tier 2, over 1,717 MW of new generation is projected in the assessment period. This includes 754 MW of natural gas, 600 MW of wind generation, 300 MW of utility-scale solar generation, and 63 MW of co-generation.

Generating resources being planned as Tier 2 and Tier 3 will replace generators planned for retirement prior to deactivation. Therefore, Saskatchewan is not expecting any long-term reliability impacts due to generation retirements.

Energy Storage
SaskPower currently has its first battery storage system, a 20 MW/20 MWh unit, under commissioning. There are plans to expand this site by an additional 60 MW/60MWh capacity. The prevalent use for the planned energy storage is to provide regulating reserve, peak capacity and energy reduction, net demand ramping control, reactive power/voltage control, primary frequency control, and blackstart.

Capacity Transfers
SaskPower has three interfaces with its neighboring areas. The interface with Manitoba is the largest of the three interfaces and is the only interface with long-term firm contracts. Capacity transfers from Manitoba would be limited in the event of a prior outage of tie lines between SaskPower and Manitoba Hydro, as well as nearby transmission facilities supporting the interface. This could only impact reliability if it is coincident with the extreme winter or summer peak demand and a prior outage of one or more larger generating units in Saskatchewan. Risk mitigation is in place through SaskPower's emergency operating procedure that will allow one or more measures such as short-term imports from other available interfaces (for example Alberta or SPP), initiating demand response and short-term load shedding.

Transmission
SaskPower's major transmission projects in the first five years of the assessment period are related to the interconnection expansion with SPP and the 650 MW of new transmission service. This includes two new international power lines between Saskatchewan and North Dakota. Within Saskatchewan, a total of approximately 180 kilometers of new 230 kV lines, a new 230 kV transmission station, expansion of several existing transmission stations, and installation of two phase-shifting transformer interfaces and two static var systems are being added.

The remaining other transmission projects (approximately 460 circuit kilometers) are under the planning and conceptual phase in the 5-to-10-year planning horizon. These projects are driven by load growth, new generation additions, and reliability needs.

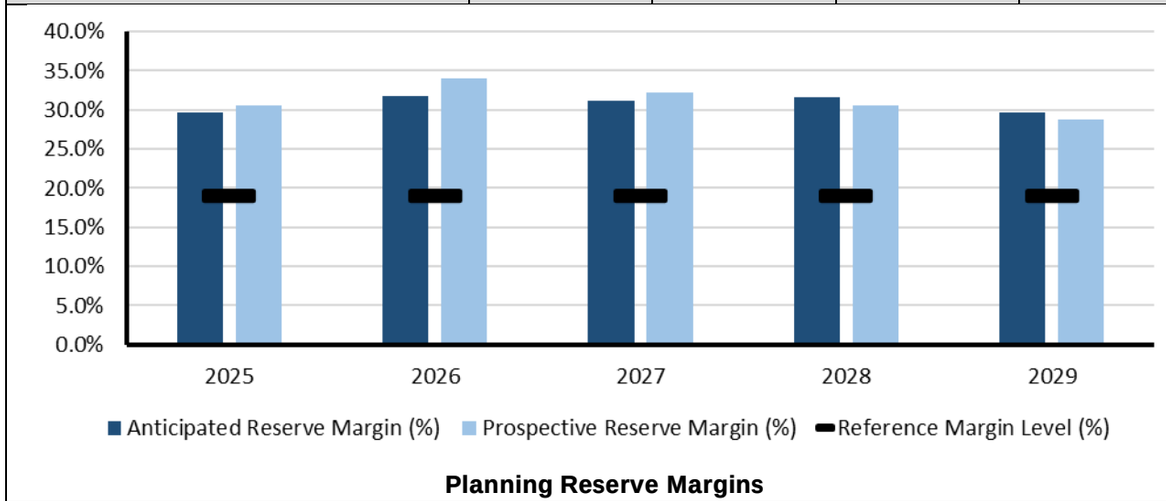


MRO-SPP

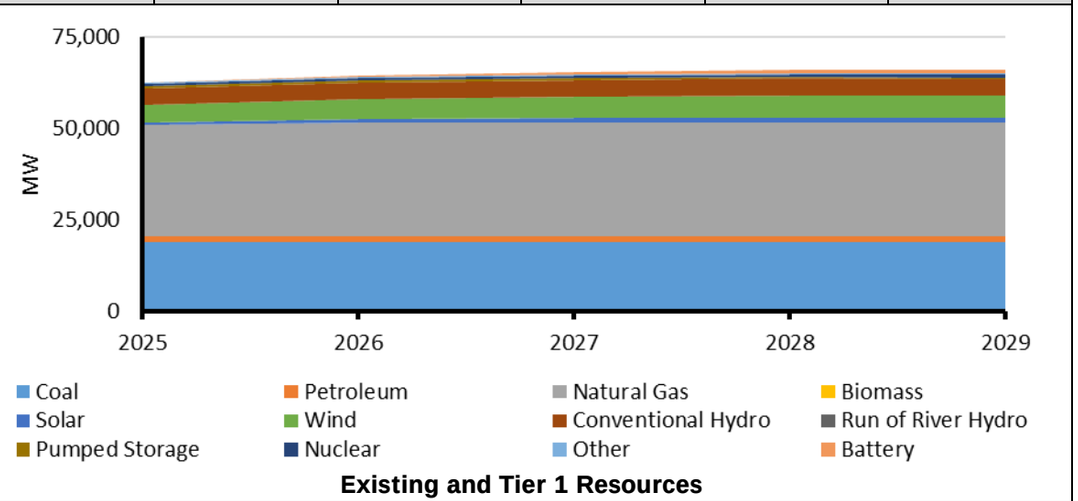
The Southwest Power Pool (SPP) Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	55,669	57,171	59,031	59,764	60,596	61,963	62,490	63,287	63,764	64,172
Demand Response	1,463	1,771	2,057	2,124	2,172	2,222	2,259	2,465	2,467	2,472
Net Internal Demand	54,206	55,400	56,975	57,640	58,424	59,741	60,231	60,822	61,297	61,700
Additions: Tier 1	2,123	4,966	6,750	7,843	7,957	7,957	7,957	7,957	7,957	7,957
Additions: Tier 2	1,239	2,454	2,756	2,756	2,756	2,756	2,756	2,756	2,756	2,756
Additions: Tier 3	6,823	16,770	22,655	28,948	28,948	28,948	28,948	28,948	28,948	28,948
Net Firm Capacity Transfers	-1,097	-1,077	-1,136	-1,131	-1,131	-1,131	-1,131	-1,133	-1,133	-1,133
Existing-Certain and Net Firm Transfers	68,157	68,039	67,981	67,984	67,799	67,749	67,253	67,175	67,055	67,094
Anticipated Reserve Margin (%)	29.7%	31.8%	31.2%	31.6%	29.7%	26.7%	24.9%	23.5%	22.4%	21.6%
Prospective Reserve Margin (%)	30.6%	34.1%	32.2%	30.6%	28.7%	25.2%	23.3%	22.0%	20.6%	19.6%
Reference Margin Level (%)	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- There are over 8 GW of coal and gas-fired generators that have indicated they plan to retire over the next 10 years in SPP. Without sufficient dispatchable generation, SPP can experience energy shortages when output from wind resources is low.

MRO-SPP Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	18,952	18,952	18,919	18,919	18,919
Coal*	17,934	16,647	16,614	14,062	14,062
Petroleum	1,629	1,629	1,631	1,631	1,631
Petroleum*	1,629	1,629	1,575	1,575	1,575
Natural Gas	30,471	31,098	31,098	31,098	31,098
Natural Gas*	29,896	30,220	29,924	29,812	29,812
Biomass	20	20	20	20	20
Solar	495	864	1,149	1,283	1,283
Wind	4,974	5,456	5,928	6,117	5,909
Conventional Hydro	4,526	4,541	4,573	4,605	4,628
Pumped Storage	472	472	472	472	472
Nuclear	769	769	769	769	769
Other	281	281	281	281	281
Battery	41	290	555	930	1,044
Total MW	62,630	64,370	65,392	66,124	66,053
Total MW*	61,037	61,188	61,858	59,925	59,855
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to SPP are removed from the resource projection where marked.					

Planning Reserve Margins

The Existing-Certain and Net Firm Transfers Reserve Margin for the SPP assessment area is projected to fall below the current coincident summer season RML of 19% in 2027. The current summer season reserve margin target for SPP is 15%, but that is based on the non-coincident peak demand of load-responsible entities (LRE) in the SPP assessment area. For purposes of NERC assessments, the 15% target is converted, along with forecasted demand values, to an SPP coincident peak representation based on the latest calculated diversity factor. This results in an RML of 19%. Based on resources submitted in the ARM calculation, including the impact of retirements, SPP is forecasted to be above the 19% RML for the 10-year horizon.

Like the generation unavailability scenario in NERC's *2024 Summer Reliability Assessment*, SPP shows the potential to utilize all the current projected capacity and there could be times of capacity shortfall based on performance impacts during high-load periods. While the potential to all available capacity has a lower probability, the assumptions and projections are based around historical unavailability during peak periods. Current LTRA projections are based on the latest resource adequacy data submittals, which are provided by the LREs and Generator Owners in SPP.

SPP performs a biennial LOLE study to establish a reserve margin target such that the LOLE for the applicable planning year (3- and 6-year study) does not exceed 1 day in 10 years, or 0.1 day per year. The target is determined using probabilistic methods by altering capacity through the application of generator forced outages and forecasted demand with load uncertainty to ensure that the LOLE does not exceed 0.1 day per year.

SPP's 2023 LOLE study results indicate that separate PRMs and capacity requirements are needed for the summer and winter seasons to recognize the seasonal balance of risk. Also, as colder temperature outages increase with the incorporation of additional wind and solar resources, the loss-of-load risk shifts to the winter season. Due to the shift in seasonal risk, it would be appropriate to consider a maximum LOLE threshold for the winter season or incorporation of an EUE reliability metric to complement the LOLE metric.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

As the resource mix continues to change from a standard base load conventional thermal and hydro resources to VERs and short-term energy storage resources (ESR), SPP is incorporating energy adequacy metrics (i.e., EUE) in the determination of PRMs, RMLs, additional reliability policies, and resource accreditation enhancements.

SPP will begin performing a yearly energy adequacy assessment and assessment of reliability attributes (inertia, primary frequency response, ramp, regulation, contingency reserves, voltage and reactive support capability, fuel assurance, flexibility, and blackstart capability). Results of the analysis will be presented annually to SPP stakeholders. The results will also be used to identify needs for new market products, changes to market functionality, or changes to resource adequacy policies and requirements.

The 2024 ProbA performed for the NERC LTRA used assumptions and methods that reflect SPP's Loss of LOLE studies. Results are shown in the following table.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.84	0.00	6.61
EUE (PPM)	0.00	0.00	0.02
LOLH (hours per year)	0.00	0.00	0.01
Operable On-Peak Margin	19.6%	19.5%	16.0%

*Provides the 2022 ProbA Results for Comparison

With the current SPP fleet, there was no loss of load for the 2026 study that included Tier 1 resource additions and 600 MW in generator retirements. The 2028 analysis included both Tier 1 and Tier 2 resource additions and 2,700 MW in generator retirements. The result was a small amount of EUE (6.61MWh) and LOLH (0.01hr/year). The loss of load/hour occurred mostly during the summer season (0.007hr/yr), while the winter season had 0.0004hr/yr. SPP is a summer-peaking region, and the results also supported that. The demand was highest in the afternoons between 13:00 and 19:00 during July and August.

Study improvements for 2024 from the previous NERC ProbAs include additional weather years, seasonal forced-outage modeling, and incremental cold weather outages.

SPP uses the Strategic Energy & Risk Valuation Model (SERVM) for the ProbA. It is a production-cost modeling tool that uses the Monte Carlo method to solve LOLE. Each weather year was simulated 300 times to simulate a multitude of random forced outage draws. Taking 300 draws for each weather year (43) and multiplying by 8,760 hours gets to a total of over 113 million simulated hours, from 1980 to 2022. Each iteration was performed on an 8,760-hour basis.

The study input model consisted of multiple modeling assumptions including multiple historical weather years (1980–2022); hourly load, solar, and wind profiles; load forecast uncertainty; random forced outages draws and variability; physical and economic resource parameters; resource retirements; future resource additions; zonal transmission limitations; and incremental conventional resource forced outages due to extreme cold temperature.

The generating resources modeled in the Probabilistic Assessment reflect the data supplied in the *2024 LTRA*. Existing and projected resources were included in the Probabilistic Assessment along with reported confirmed retirements. As mentioned previously, wind and solar resources, as well as historical weather years, were modeled at historical hourly values using 2012 to 2022 weather years. There were six study zones, and SPP modeled a projected 8,760 hourly demand profile for each area to provide load variability and volatility for chronological hours during simulation. Each local resource zone was modeled with an import and export limit based on a separate power flow transfer analysis. SPP used unit-specific outage rates within the analysis based on NERC Generation Availability Data System (GADS) data from 2015 to 2022. External assistance only included firm contracts from external entities with firm transmission service.

Demand

SPP peak load occurs during the summer season; the 2024 net internal demand forecast is projected to peak at 53,094 MW, which is projected to increase compared to the previous year's LTRA forecast for the 2022 summer season. The diversity factor used to convert the non-coincident peak demand forecast to an SPP coincident peak demand forecast was consistent with the ~3.5% applied in the *2023 LTRA*. SPP forecasts the coincident annual peak growth based on member submitted data over the 10-year assessment timeframe. One risk that SPP has noted is that the aggregated noncoincident demand forecast submitted by members in recent years, which is based on a 50/50 forecast and is weather normalized, is tracking at a lower demand level than what the BA has observed.

Demand-Side Management

SPP's energy efficiency (EE) and conservation programs are incorporated into the reporting entities' demand forecasts. There are no known impacts to the SPP assessment area's long-term reliability related to the forecasted increase in EE and DR across the assessment area. In addition, SPP is constructing a new policy to more appropriately categorize DR based on the flexibility of the program, which will ultimately be reflected in the accreditation process.

Distributed Energy Resources

The SPP Model Development, Economic Studies, and Supply Adequacy working groups are developing policies and procedures around DERs. SPP resource adequacy implemented policies for DERs that mandate certain testing, reporting, and document requirements for resources and programs not registered in the SPP Integrated Market. Accreditation methodology policies are being constructed and are planned to be approved in late 2024.

Generation

SPP currently has approximately 900 MW of installed solar generating facilities. In the ARM calculation, SPP is reporting nameplate capacity of approximately 11 GW of Tier 1, 2, and 3 wind resources, approximately 18 GW of Tier 1, 2, and 3 solar resources, approximately 9.8 GW of Tier 1, 2, and 3 battery resources and approximately 2.7 GW of Tier 1, 2, and 3 gas resources.

In 2024, SPP filed conventional based performance accreditation and effective load carrying capability (ELCC) methodology for wind and solar resources. The goal is for these policies to become effective in the 2026/2027 timeframe for both the summer and winter seasons.

There are concerns of drought conditions impacting the Missouri River and other water sources for generation resources that rely on once-through cooling processes. Low water can impact the generation's capacity output and reduce its ability to support congestion management and serve load. An additional concern could be the impact of river conditions on coal shipments, which could cause generators to run at a derated level to conserve supplies.

Energy Storage

Currently, SPP is studying approximately 17,000 MWs of energy storage and hybrid resource projects in the generator interconnection queue process. There are approximately 50 MWs of energy storage under contract by SPP members. These resources are being modeled as generation in the planning assumptions both near and long term.

Capacity Transfers

The SPP assessment area coordinates with neighboring areas to ensure that adequate transfer capabilities will be available for capacity transfers. On an annual basis during the model build season, SPP staff coordinate the modeling of transfers between Planning Coordinator footprints. The modeled transactions are fed into the models created for the SPP planning process.

SPP and ERCOT executed a Coordination Plan that superseded the prior coordination agreement. The Coordination Plan addresses operational issues for coordination of the dc ties between the Texas Interconnection and Eastern Interconnection, block load transfers (BLT), and switchable generation resources (SWGR). Under the terms of the Coordination Plan, SPP has priority to recall the capacity of any SWGRs that have been committed to satisfying the resource adequacy requirements contained in Attachment AA of the SPP Open Access Transmission Tariff. Annually, SPP and ERCOT update the

Coordination Plan based on the latest discussions and business decisions, and it was updated in June 2024.

Transmission

In the 2023 ITP Assessment, SPP approved 44 transmission projects, including 150 miles of new transmission. Additionally, the study calls for 93 miles of transmission to be rebuilt.

SPP is observing a number of transmission projects that are currently delayed. SPP is actively tracking these projects and discussing them throughout its stakeholder process. Many delays are driven by supply chain issues or increasing length of construction times. The delays of these transmission projects do not currently seem to be driving reliability issues.

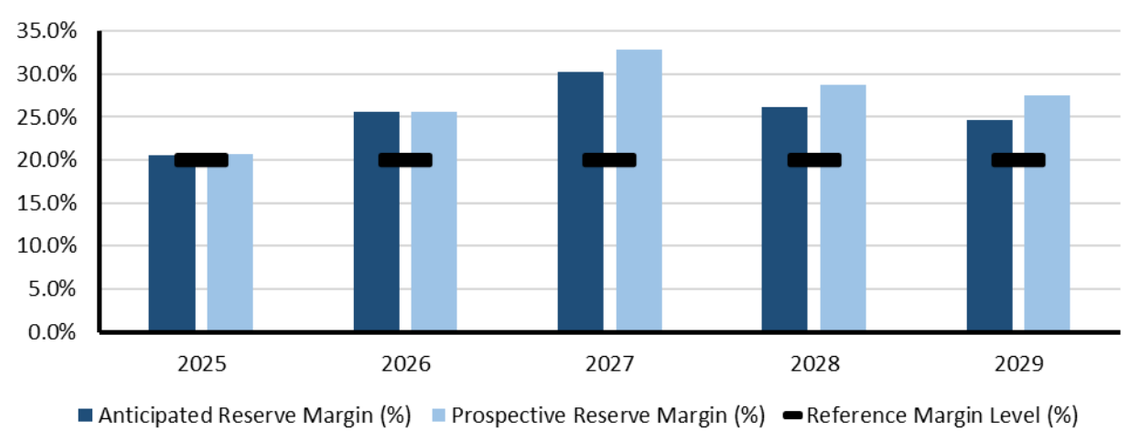


NPCC-Maritimes

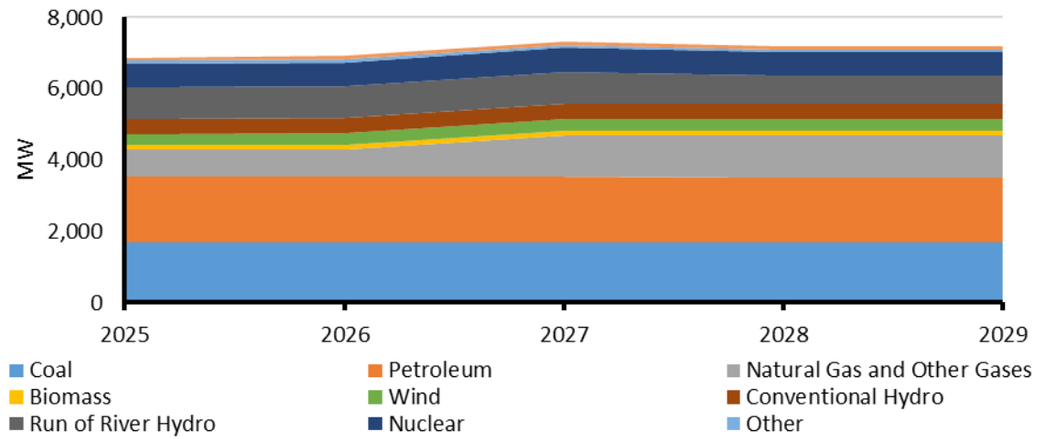
The Maritimes assessment area is a winter peaking NPCC sub-region with a single Reliability Coordinator and two Balancing Authority Areas (New Brunswick and Nova Scotia). It is comprised of the Canadian provinces of New Brunswick (NB), Nova Scotia (NS), and Prince Edward Island (PEI) and the northern portion of Maine (NM), which is radially connected to NB. The area covers 58,000 square miles with a total population of 2 million people.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	6,201	6,056	6,095	6,141	6,216	6,272	6,331	6,398	6,474	6,560
Demand Response	274	293	309	317	317	317	317	317	317	318
Net Internal Demand	5,927	5,763	5,786	5,825	5,899	5,954	6,014	6,081	6,157	6,242
Additions: Tier 1	108	171	579	579	579	579	579	579	579	579
Additions: Tier 2	6	4	447	600	1,398	1,398	1,398	1,398	1,398	1,398
Additions: Tier 3	0	13	80	127	197	255	267	279	291	291
Net Firm Capacity Transfers	289	322	215	145	145	145	145	145	145	145
Existing-Certain and Net Firm Transfers	7,038	7,063	6,959	6,771	6,771	6,771	6,679	6,665	6,665	6,752
Anticipated Reserve Margin (%)	20.6%	25.5%	30.3%	26.2%	24.6%	23.4%	20.7%	19.1%	17.7%	17.4%
Prospective Reserve Margin (%)	20.7%	25.6%	32.8%	28.8%	27.5%	26.3%	23.5%	21.9%	20.4%	20.1%
Reference Margin Level (%)	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Since the *2023 LTRA*, the overall resource outlook has improved with expected new natural-gas-fired generators coming into service in 2027. Winter peak demand forecasts for this assessment area have risen through 2030; however, ARMs are currently projected to remain above the RML of 20% until 2031 when the ARM dips to 19.7%.

NPCC-Maritimes Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	**2026–2027**	**2027–2028**	**2028–2029**	**2029–2030**
Coal	1,696	1,696	1,696	1,696	1,696
Coal*	1,696	1,696	1,396	1,248	467
Petroleum	1,831	1,831	1,825	1,819	1,819
Natural Gas	757	757	1,157	1,157	1,157
Biomass	148	148	148	148	148
Solar	5	5	5	5	5
Wind	293	321	329	329	329
Conventional Hydro	412	412	412	412	412
Run of River Hydro	902	902	902	791	791
Nuclear	663	663	671	671	671
Other	77	77	77	77	77
Battery	72	99	99	99	99
Total MW	6,856	6,911	7,321	7,204	7,204
Total MW*	6,856	6,911	7,021	6,756	5,975
*** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

NPCC-Maritimes Assessment

Planning Reserve Margins

The NPCC-Maritimes assessment area is comprised of NB, NS, PEI, and NM. The RML for the assessment area is 20%; however, this reserve margin is not mandated. The ARM over the study period for the Maritimes area ranges between 17% and 30% during the winter period and between 88% and 93% during the summer period.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

During off-peak hours, the Maritimes area has surplus generation and no constraints with converting the capacity to energy.

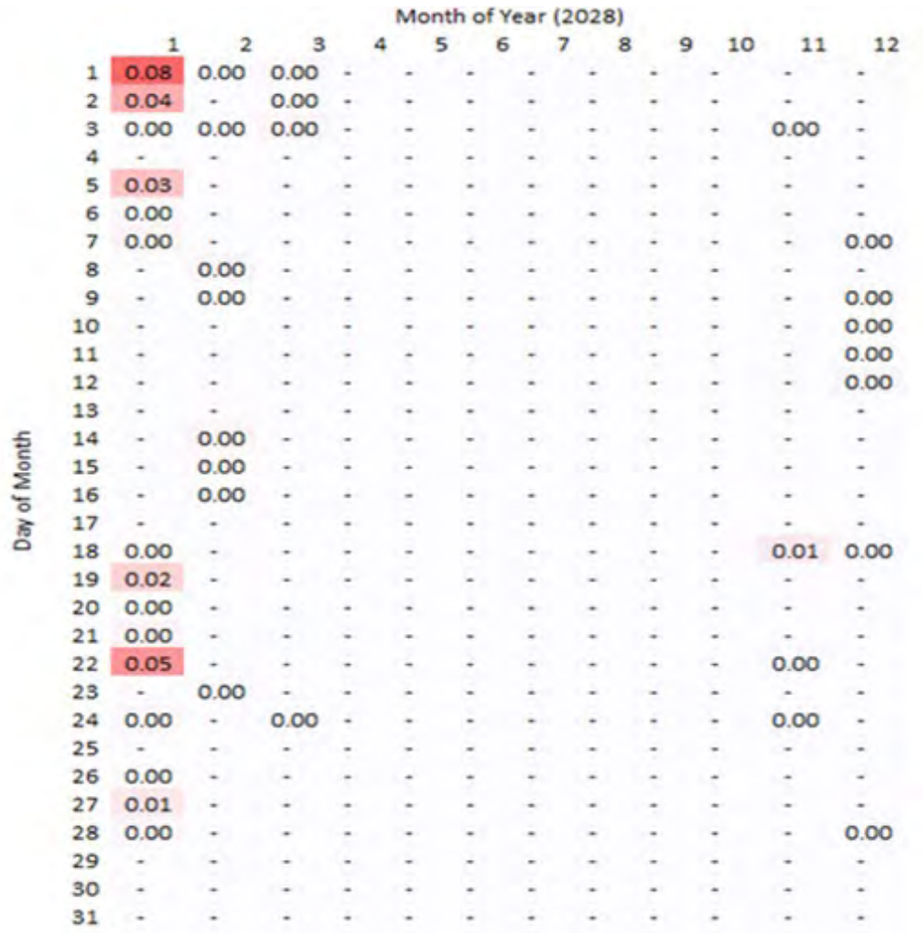
Probabilistic Assessments

Two Balancing Authorities within the Maritimes area are members of NPCC and jointly prepare annual probabilistic assessments that cover three- to five-year forward-looking periods and evaluate the adequacy of the Maritimes' transmission system and resources. In addition, the Maritimes area also supports NERC's annual seasonal ProbAs, which provides an evaluation of generation resource and transmission system adequacy that will be necessary to meet projected seasonal peak demands and operating reserves. Results of the 2024 ProbA are in the table below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	3.87	**5.02**	**0.28**
EUE (PPM)	0.14	**0.17**	**0.01**
LOLH (hours per year)	0.07	**0.09**	**0.02**
Operable On-Peak Margin	22.9%	**17.9%**	**29.0%**

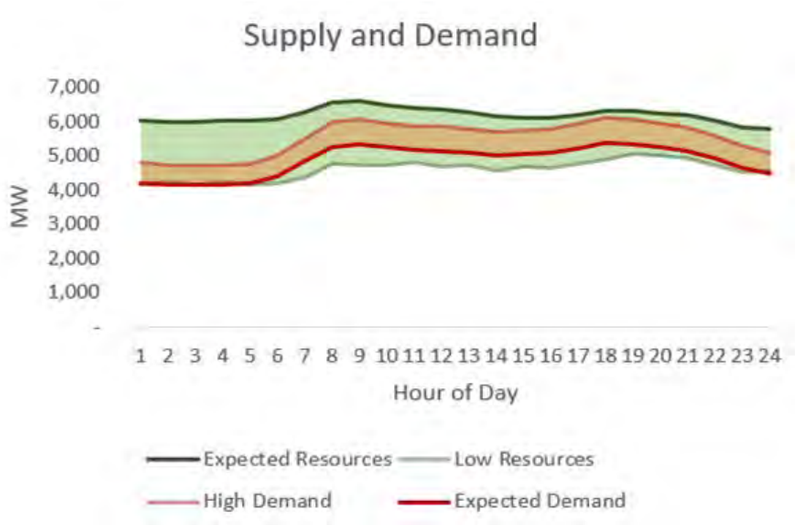
* Provides the 2022 ProbA Results for Comparison

The following table of LOLH for 2028 provides a depiction of risks across the calendar year and highlights the concentration of risk in winter. Most load-loss risk occurs in winter months of December–February, with some additional risk occurring in shoulder months. 2026 has a similar risk distribution.



Day of Month	1	2	3	4	5	6	7	8	9	10	11	12
1	0.08	0.00	0.00	-	-	-	-	-	-	-	-	-
2	0.04	-	0.00	-	-	-	-	-	-	-	-	-
3	0.00	0.00	0.00	-	-	-	-	-	-	-	0.00	-
4	-	-	-	-	-	-	-	-	-	-	-	-
5	0.03	-	-	-	-	-	-	-	-	-	-	-
6	0.00	-	-	-	-	-	-	-	-	-	-	-
7	0.00	-	-	-	-	-	-	-	-	-	-	0.00
8	-	0.00	-	-	-	-	-	-	-	-	-	-
9	-	0.00	-	-	-	-	-	-	-	-	-	0.00
10	-	-	-	-	-	-	-	-	-	-	-	0.00
11	-	-	-	-	-	-	-	-	-	-	-	0.00
12	-	-	-	-	-	-	-	-	-	-	-	0.00
13	-	-	-	-	-	-	-	-	-	-	-	-
14	-	0.00	-	-	-	-	-	-	-	-	-	-
15	-	0.00	-	-	-	-	-	-	-	-	-	-
16	-	0.00	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-	-	-
18	0.00	-	-	-	-	-	-	-	-	-	0.01	0.00
19	0.02	-	-	-	-	-	-	-	-	-	-	-
20	0.00	-	-	-	-	-	-	-	-	-	-	-
21	0.00	-	-	-	-	-	-	-	-	-	-	-
22	0.05	-	-	-	-	-	-	-	-	-	0.00	-
23	-	0.00	-	-	-	-	-	-	-	-	-	-
24	0.00	-	0.00	-	-	-	-	-	-	-	0.00	-
25	-	-	-	-	-	-	-	-	-	-	-	-
26	0.00	-	-	-	-	-	-	-	-	-	-	-
27	0.01	-	-	-	-	-	-	-	-	-	-	-
28	0.00	-	-	-	-	-	-	-	-	-	-	0.00
29	-	-	-	-	-	-	-	-	-	-	-	-
30	-	-	-	-	-	-	-	-	-	-	-	-
31	-	-	-	-	-	-	-	-	-	-	-	-

Hourly demand and resource projections for a typical risk-day in 2026 are shown in the figure below. Expected resource contributions are observed to cover expected demand on the risk day. However, the greatest risk for this assessment area is in the form of lower-than-expected resource contributions. If this were to occur, expected demand for all hours would not be met. This risk would be exaggerated by the addition of a higher-than-expected demand event. Reliance on external assistance may be necessary in these events. A risk day in 2028 has a similar profile.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

Demand

There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes area. The peak area demand occurs in winter and is highly reliant on the forecasts of the two largest sub-areas of NB and NS, which are historically highly coincidental. Demand for the Maritimes area is determined to be the non-coincident sum of the peak loads forecasted by the individual sub-areas. The aggregated growth of both demand and energy for the combined sub-areas see an upward trend over summer and winter seasonal periods of the LTRA assessment period. The area peak loads are expected to increase by 4.2% during summer and by 6.4% during winter seasons over the 10-year assessment period. This translates to compound average growth rates of 0.4% in summer and 0.6% in winter. The Maritimes Area annual energy forecasts are expected to increase by a total of 5.9% during the 10-year assessment period for an average growth of 0.6% per year.

Demand-Side Management

Plans to develop up to 100 MW by 2030/2031 of controllable direct load control programs using smart grid technology to selectively interrupt space and/or water heater systems in residential and commercial facilities are underway but no specific annual demand and energy saving targets currently exist. During the 10-year LTRA assessment period in the Maritimes area, annual amounts for summer peak demand reductions associated with EE and conservation programs rise from 20 MW to 169 MW while the annual amounts for winter peak demand reductions rise from 168 MW to 629 MW.[34]

Distributed Energy Resources

The DER installed capacity in NS is approximately 245 MW at present, including distribution-connected wind projects under purchase power agreements, small community wind projects under a feed-in tariff, and BTM solar.

LTRA wind capacity for NB, NS, and PEI is derated between 18% and 33% using probabilistic methods to calculate equivalent perfect capacities for each sub-area excluding NM, which uses seasonal capacity factors. BTM solar is assumed to have an ELCC of 0% during winter period. The Maritimes area has shown embedded BTM solar PV projections of 149 MW in 2024 rising to 881 MW by 2034. These projects include distributed small-scale solar (mainly rooftop) that fall under the net metering program and serve as a reduction in load mainly in the residential class. The forecasted increase in solar installations in the coming years is a result of initiatives including municipal and provincial incentive programs. There is no capacity contribution from solar generation due to the timing of the area's system peak, which occurs either before sunrise or after sunset in the winter period.

Generation

NB assumes extending 28 MW of diesel-fired generator starting in 2025 and recently upgraded 290 MW of natural-gas-fueled resource completed in 2023. There are 25.2 MW of wind power purchase agreements (PPA) also slated to start in 2025. An anticipated replacement PPA contract, a long-term firm energy contract from a neighboring jurisdiction, and opportunities to buy in day-ahead and real-time markets will be utilized to maintain the overall resource adequacy.

NB Tier 1 resources include 71 MW of wind and 400 MW of combustion turbines. Tier 2 resources include 200 MW of wind resources and Tier 3 includes 400 MW of wind.

In NS, Tier 1 resources include wind projects with a total nameplate capacity of 473 MW phased in from 2024–2027 with an ELCC of 10%, 150 MW battery storage, 4 MW tidal power, 2 MW biomass unit, and a small 0.14 MW solar farm. Tier 2 resources in NS include 250 MW of battery storage (2026–2032), 600 MW of combustion turbines (2027–2033), a 150 MW conversion of a coal-fired unit to natural gas (2028), 450 MW in conversion of coal-fire units to oil (2030), 220 MW of solar generation,

[34] Current and projected energy efficiency effects based on actual and forecasted customer adoption of various DSM programs with differing levels of impact are incorporated directly into the load forecast for each of the areas but are not separately itemized in the forecasts. Since controllable space and water heaters will be interrupted via smart meters, the savings attributed to these programs will be directly and immediately measurable.

and 416 MW of wind generation. Tier 3 resources in NS include natural gas additions (combustion turbines) of 50 MW in 2029 and new wind generation with a nameplate capacity of 850 MW phased in from 2026–2033. These Tier 3 resource additions are anticipated to facilitate the retirement of additional coal-fired generation by 2030. However, these retirements have not been included in the assessment due to their uncertainty.

Small amounts of new solar generation capacity (Tier 1) of up to 21 MW were being installed in PEI in 2024, along with 10 MW of new hybrid energy storage (Tier 1). PEI also has 30 MW of Tier 2 wind, 111 MW Tier 3 wind, and 140 MW of Tier 3 petroleum-based generation and 10 MW of Tier 3 batteries.

NB derates its wind capacity using a calculated year-round equivalent capacity of 22%. NS and PEI derate wind capacity to 18% and 17%, respectively, of nameplate based on year-round calculated equivalent load carrying capabilities for their respective individual sub areas. The peak capacity contribution of grid-based solar is estimated at zero since the Maritimes area peak occurs in the winter either before sunrise or after sunset.

Energy Storage

NS Power includes a 150 MW (4-hour duration) nameplate standalone battery resource as a Tier 1 resource and a 250 MW (4-hour duration) nameplate capacity standalone battery resource added as a Tier 2 resource phased in from 2026 through 2032. This grid-scale project will support the integration of new renewable generation, provide energy arbitrage and resiliency services, and provide firm capacity and fuel savings.

PEI includes a 10 MW nameplate capacity hybrid energy storage as a Tier 1 resource starting summer of 2024 and another 10 MW nameplate capacity energy storage system as a Tier 3 resource. This project will provide a storage option for the output from the 10 MW solar facility that is planned to come online during the same time frame. This project will provide fuel savings and may assist in providing additional reliability if a generation outage occurs.

NB Power has not included any energy storage resources in the *2024 LTRA* submission; however, the value of energy storage options is expected to increase as the technology improves and as NB's smart grid network develops. NB Power issued a request for expressions of interest for new renewable generation sources including 200 MW of wind, 15 MW of solar, 5 MW of tidal, and 50 MW of 4-hour duration battery storage in February 2023. Under this program, NB Power expects uptake in new energy storage projects in the coming years. Internal pilot projects and studies are underway to understand the economics, application, and performance of battery storage resources. Ongoing internal analyses are conducted by NB Power to determine the cost and benefit associated with battery storage options and dispatching these resources to reduce/shift peaks and/or balance intermittent resources, such as wind, to provide additional flexibility to the system.

Capacity Transfers

ProbA studies show that the Maritimes area is not reliant on inter-area capacity transfers to meet NPCC resource adequacy criteria.

Transmission

NS has multiple new transmission line projects compared to the *2023 LTRA*; most being shorter runs to enable the connection of renewable resources, with one major project of 165 miles designed to improve the reliability of the existing tie between NS and NB.

Reliability Issues

The Maritimes area has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind (derated), dual fuel oil/gas, tie benefits, and biomass with no single one type feeding more than about 27% of the total capacity in the area. The Maritimes area does not anticipate fuel disruptions that pose significant challenges for resources during this assessment period.



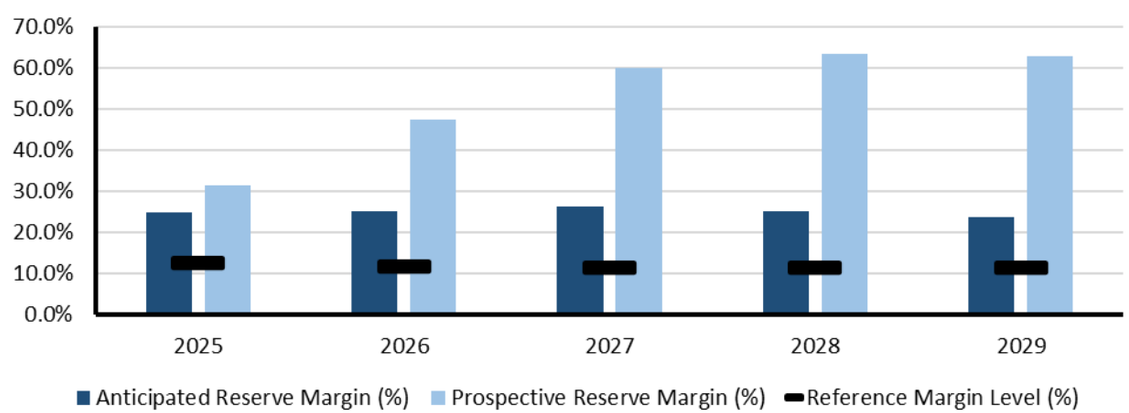
NPCC-New England

NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont served by ISO New England Inc. (ISO-NE). ISO-NE is a regional transmission organization responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS. Note: Northern Maine is not directly connected to the transmission system administered by ISO-NE.

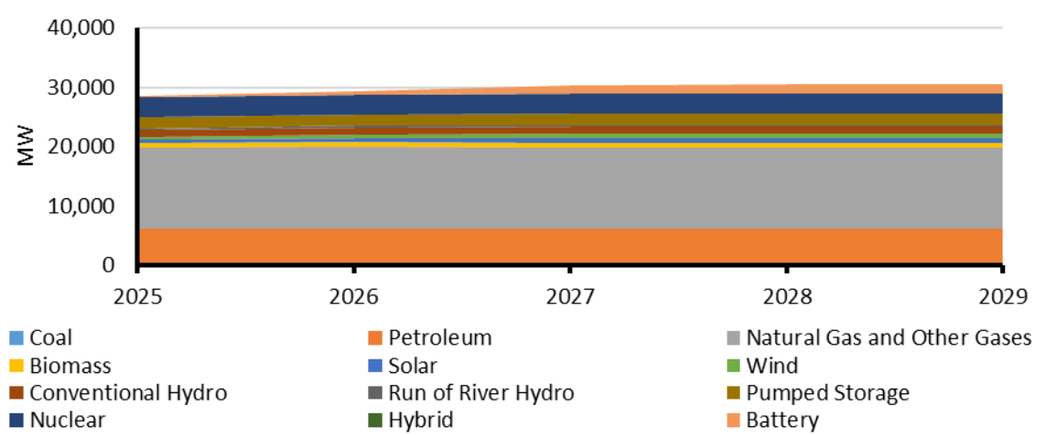
The New England BPS serves approximately 15.1 million customers over 68,000 square miles.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	24,579	24,702	24,845	25,076	25,364	25,706	26,100	26,547	27,052	27,567
Demand Response	566	588	544	544	544	544	544	544	544	544
Net Internal Demand	24,013	24,114	24,301	24,532	24,820	25,162	25,556	26,003	26,508	27,023
Additions: Tier 1	660	1,492	2,374	2,748	2,748	2,748	2,748	3,168	3,168	3,168
Additions: Tier 2	337	3,089	5,911	7,084	7,425	7,766	7,766	7,766	7,766	7,766
Additions: Tier 3	1,404	1,765	5,106	7,906	9,221	9,355	9,721	10,432	10,432	10,432
Net Firm Capacity Transfers	1,248	567	465	84	84	84	84	84	0	0
Existing-Certain and Net Firm Transfers	29,354	28,658	28,327	27,946	27,946	27,946	27,946	27,946	27,862	27,862
Anticipated Reserve Margin (%)	25.0%	25.0%	26.3%	25.1%	23.7%	22.0%	20.1%	19.7%	17.1%	14.8%
Prospective Reserve Margin (%)	31.4%	47.3%	60.1%	63.3%	62.8%	62.0%	59.5%	58.3%	55.0%	52.0%
Reference Margin Level (%)	12.7%	11.8%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- New England is forecast to have sufficient ARMs to meet consumer demand for electric energy for the first five years (2025–2029) of the assessment period and not require any Tier 2 resources.
- ISO-NE is addressing the issues brought on by grid transformation through several planning, operational, and market measures. A significant project is the redesign of the capacity market from a forward, annual auction to a prompt, seasonal auction with resource accreditation. The Capacity Auction Reforms (CAR) project began in Q2 2024 and is expected to be in place for the 19th Capacity Commitment Period (CCP 19) beginning on June 1, 2028. Additionally, New England has made tariff modifications to its Longer-Term Transmission Planning process to facilitate the New England states' achievement of their policy-based goals by enabling the development of transmission infrastructure. ISO-NE is also working with regional stakeholders to develop a regional energy shortfall threshold (REST) that defines the region's tolerance for energy shortfalls during low-probability extreme weather conditions.

NPCC-New England Projected Generating Capacity by Energy Source in Megawatts (MW)[35]					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	541	541	541	541	541
Coal*	445	445	445	7	7
Petroleum	5,703	5,703	5,687	5,687	5,687
Natural Gas	13,651	13,724	13,708	13,708	13,708
Biomass	780	780	780	780	780
Solar	533	663	663	663	663
Wind	391	594	819	819	819
Conventional Hydro	1,209	1,209	1,209	1,209	1,209
Run of River Hydro	289	289	289	289	289
Pumped Storage	1,860	1,860	1,860	1,860	1,860
Nuclear	3,331	3,331	3,331	3,331	3,331
Hybrid	34	35	35	35	35
Other	74	74	74	74	74
Battery	159	584	1,242	1,616	1,616
Total MW	28,553	29,385	30,237	30,611	30,611
Total MW*	28,458	29,290	30,141	30,077	30,077
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to ISO-NE are removed from the resource projection where marked.					

[35] MW totals reflect Existing and Tier 1 generation. Generator retirements in this timeframe would be captured if a resource submits a retirement request through the ISO-NE capacity market.

NPCC-New England Assessment

Planning Reserve Margins

ISO-NE's installed capacity requirement (ICR) is based on the capacity needed to meet the ISO-NE and NPCC resource adequacy reliability criterion of an LOLE of 0.1 day/year. The ICR varies from year to year depending on projected system conditions. The ICR is calculated on an annual basis, in advance of the capacity auctions for each Capacity Commitment Period. The latest ICR calculations result in an annual RML of 12.70% in 2025, 11.82% in 2026, and 11.33% in 2027, expressed in terms of the annual 50/50 peak demand forecast published in the *2024 Capacity, Energy, Loads, and Transmission (CELT) Report*. For the years 2028 through 2034, which are beyond the current forward capacity market timeframe, ISO-NE continued to use the last available RML value of 11.33%. The ISO-NE RML is relatively low compared to other regions due to the impact of reflecting external assistance from neighboring control areas and the continued increase in BTM solar facilities.

Non-Peak Hour Risk, Energy Assurance, and Probabilistic-Based Assessments

ISO-NE routinely prepares 21-day energy forecasts. These forecasts incorporate weather, transmission topology, resource capability and availability, fuel inventories and constraints, and projected imports/exports. If the forecasted regional supply/demand balance is negative, projected energy deficiencies can trigger energy alerts or energy emergencies that are then disseminated to market participants and federal and state regulators. This early notification of potential energy shortfalls is expected to inform market participants such that actions can be taken to increase the expected availability of generating resources as needed.

ISO-NE recently completed work with the Electric Power Research Institute (EPRI) to develop the Probabilistic Energy Adequacy Tool (PEAT) framework. This tool is a framework that has three major steps (weather modeling, risk screening/scenario generation, and 21-day energy assessment), which were subsequently applied to assess the summers and winters of 2027 and 2032.

Probabilistic Assessments

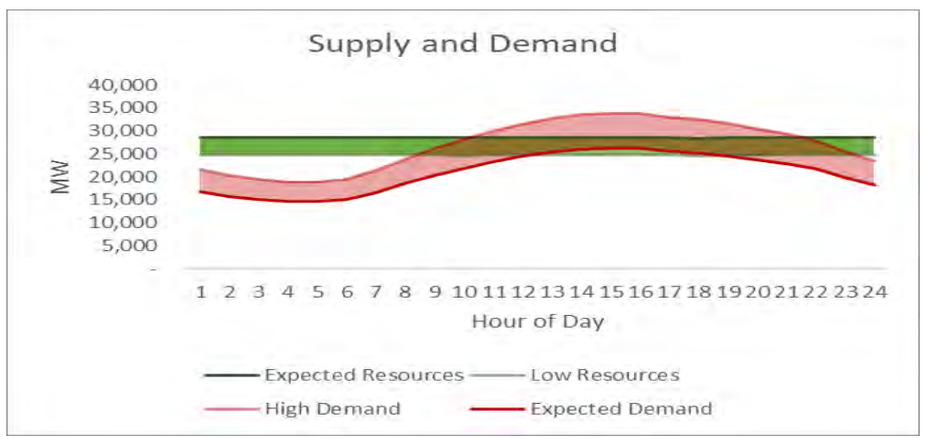
ISO-NE conducts probabilistic resource adequacy assessments annually in conjunction with NPCC to identify regional capacity resource needs and to comply with NPCC/NERC reliability requirements. In the transmission assessment domain, revisions to ISO-NE planning processes reflect the changing resource characteristics, probabilistic study assumptions, and changes to national and regional criteria. Coordinated planning activities with neighboring systems will continue and help support the New England states' policy objectives of providing access to a greater diversity of clean resources to meet environmental compliance obligations. Results from the 2024 ProbA, shown in the table below, reveal a slight increase in load-loss and unserved energy risk from the 2022 analysis, but values remain small. ISO-NE is considered to have sufficient resources for the planning horizon to meet NPCC resource adequacy criteria.

Base Case Summary 2024 ProbA of Results			
	2026*	2026	2028
EUE (MWh)	0.551	**10.69**	**7.40**
EUE (PPM)	0.004	**0.09**	**0.06**
LOLH (hours per year)	0.002	**0.07**	**0.03**
Operable On-Peak Margin	27.8%	**12.4%**	**13.7%**

* Provides the 2022 ProbA Results for Comparison

NPCC's ProbA results indicate that the risk of unserved energy in New England is concentrated in summer months (June–August).

Hourly demand and resource projections for a typical summer risk day in 2026 are shown in the figure below. Although expected resource contributions meet expected demand, there is risk that above-normal peak demand could exceed resources. Demand could be 25–30% higher than expected, which could cause strain on the system from the hours beginning 10:00 a.m. through 10:00 p.m. Also, below-normal resource performance from unexpected generator outages or low solar output could also cause supply shortfalls. If resource contributions are less than expected, strain on the system could be seen from the hour beginning 12:00 p.m. through 7:00 p.m. on a typical peak day. Reliance on external assistance may be necessary in these extreme conditions. A risk day in 2028 has a similar profile.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

Fuel availability during extreme winter conditions is a persistent reliability concern in New England that is not modeled in detail in the ProbA. Potential natural gas transportation constraints can affect supply to generators during extreme cold temperatures, when natural gas demand for space heating is also peaking. Most natural-gas-fired generators in the area do not have firm natural gas transportation service and can be subject to supply curtailment during peak conditions. Many natural-gas-fired generators in New England can also operate with stored oil, providing for assured electricity supply in extreme winter conditions while oil stores are procured and maintained. Scenarios of extended and extreme cold weather that affect the availability of natural gas and oil replenishments present a reliability risk and were not modeled in the 2024 ProbA.

Demand

Over the 10-year LTRA planning horizon, the forecast net internal summer peak demand increases by 2,988 MW from 24,579 MW in 2025 to 27,567 MW in 2034 (roughly 2% decrease from the 2023 forecast in the later years). The corresponding net internal winter peak demand increases by 7,342 MW from 20,639 MW in 2025–2026 to 27,981 MW in 2034–2035 (roughly a 2.5% decrease from the 2023 forecast). Net energy for load is forecast to grow by 24,701 GWh from 119,285 GWh in 2025 to 143,986 GWh in 2034 (roughly 10% decrease from the 2023 forecast). The changes from the 2023 forecast were in part due to continued enhancements of the heating and transportation electrification forecasts.

The higher winter peak growth rate due to anticipated electrification results in significant convergence with summer peak projections by the end of the 10-year period, such that New England's transition to a winter-peaking system is currently anticipated by the mid-2030s. It is also expected that the timing of the peaks will likely occur in the morning by this time, with heating electrification in particular inducing a greater tendency for morning peaks due to electrified residential and commercial heating.

Demand-Side Management

For the summer of 2025, ISO-NE forecasts 566 MW of controllable and dispatchable demand-side management (DSM) resources, and that amount is projected to decrease by 22 MW to 544 MW by 2034. For the summer of 2025, ISO-NE forecasts 1,873 MW of passive DSM resources (EE and conservation). Demand-side resources are projected to peak in 2030 at 2,117 MW and then begin to decrease to 1,978 MW by 2034. This decrease in the later years is due to expiring EE measures outpacing new passive DSM additions.

Distributed Energy Resources

For summer months, the BTM PV forecast is incorporated as estimated reductions to the ISO-NE gross demand forecast. In 2025, New England forecasts 1,141 MW of peak load reduction (4,533 MW nameplate) of BTM PV. BTM PV is forecast to grow to 1,299 MW of peak load reduction (8,217 MW nameplate) by 2034. The BTM PV peak load reduction values are calculated as a percentage of ac nameplate. The percentages include the effect of diminishing PV production at the time of the system peak as increasing PV penetrations shift the timing of peaks later in the day. The BTM peak load reduction decreases from 25.2% of nameplate in 2025 to 15.8% in 2034.

ISO-NE recently adopted a new planning procedure (PP12) to formalize and standardize data collection for DERs. Under this procedure, distribution providers would be responsible for providing installation-level data on DERs connected to their system. Additionally, transmission providers would be responsible for providing basic data to translate feeder IDs into substation names and other useful identifying information. Among the other benefits that this procedure will lead to is "*proper accounting for the location, size, and type of DER which will lead to more accurate study outcomes.*"

Generation

The largest change that will impact New England's generation fleet is ISO-NE's CARs.

Specifically, to better ensure power system reliability and cost efficiency as New England's resource mix evolves, ISO-NE is proposing a CAR that would transition the capacity market from a forward/annual market to a prompt/seasonal market with accreditation reforms. This initiative has three primary components that would be in place for the Capacity Commitment Period (CCP) scheduled to start on June 1, 2028.

- Prompt auction: Instead of taking place three years in advance, the capacity auction would take place shortly before the CCP, reflecting more accurate information about projected electricity supply and demand.
- Seasonal CCP: The CCP changes from annual to sub-annual (seasonal) commitment periods to better address the distinct reliability challenges of winter and summer, as well as variations in resource performance from season to season.
- Accreditation reforms: Work began in 2022 via the former "Resource Capacity Accreditation in the Forward Capacity Market" project to identify and implement methodologies that will more accurately reflect resource contributions to resource adequacy in the capacity market. It is critical to the reliable and efficient clean-energy transition that the accreditation methodologies are updated to reflect resources' capabilities and how those capabilities contribute to resource adequacy. This work continues through CAR in the context of the proposed market constructs.

Energy Storage

New England currently has a total of 1,899 MW of energy storage capacity. This number includes about 39 MW of battery storage (BESS) and hybrid solar/battery storage. The largest energy storage resource(s) in New England are three pumped-storage hydro-electric facilities that can supply a combined 1,860 MW of quick-start 10-minute operating reserve capability, and with full reservoirs, and can deliver over 11,800 MWh of energy to the BPS.

Over the next five years (2025–2029), the nameplate capacity of energy storage devices (BESS, integrated-hybrid, and co-located-hybrid) are projected to increase significantly (Tier #1 [1,607 MW], Tier #2 [5,047 MW], and Tier #3 [4,955 MW]). No new pumped-storage facilities are planned for the region. Over the next 10 years, those total Tier 1–3 capacities do not increase from the five-year projection. All the above capacity totals reflect summer seasonal claimed capability ratings.

Capacity Transfers

New England is interconnected with the three BAs of Québec, the Maritimes, and New York. ISO-NE considers the tie benefits associated with these BAs within its capacity market methodology to reduce the installed capacity requirement to meet the regional resource adequacy criterion. Assumed assistance from tie benefits ranges from 1,830 MW in 2025 to 2,115 MW in 2027. Aside from such assistance, ISO-NE's firm capacity imports are projected to range from a maximum of 1,248 MW in the summer of 2025 down to 465 MW in the summer of 2027. There is one long-term firm import contract of 84 MW that extends through the summers of 2028 through 2032. There are currently no firm imports projected for the summers of 2033 and 2034. In addition, there are no firm exports identified over the 10-year assessment.

Transmission

Transmission expansion in New England has improved the overall level of reliability and resiliency, reduced air emissions, and lowered wholesale market costs by nearly eliminating congestion. Generator retirements, off-peak system needs, the growth of DERs and VERs using IBRs, and changes to mandatory planning criteria promulgated by NERC, NPCC, and regional stakeholders have driven the need for longer-term transmission assessments.

The future reliable and economic performance of the BPS is expected to be maintained as a result of approximately $1.5 billion of planned transmission upgrades over the next 10 years. Generator retirements, the integration of many DERs and VERs, the use of IBR technologies, and issues rising from minimum load assessments and high-voltage conditions are changing the needs for reliability-based transmission upgrades. Interregional import capability will also increase with the completion of the 1,200 MW HVdc New England Clean Energy Connect (NECEC) tie line between Québec and Maine, scheduled to be in service by the beginning of 2026.

In addition, transmission improvements will also be needed to support state policies to access remotely located sources of clean energy and serve increased load as transportation and heating are electrified. Transmission assessments and resultant plans are being developed throughout the region to meet these future system needs.

Reliability Issues

New England's BPS is transitioning to a system with unprecedented demand growth, due to electrification of heating and transportation, and a growing number of renewables, clean energy resources, VERs, and DERs. ISO-NE is engaged in the implementation of revised interconnection standards for VERs and DERs that will ensure overall BPS reliability and facilitate the economic development of IBRs.

ISO-NE has observed some delays in projected in service dates for system upgrades due to supply chain issues. In these cases, ISO-NE develops operating plans to work around any issues caused by these delays. Additionally, the New England Transmission Owners have indicated that supply chain issues are causing a notable increase in project costs.

New England has already experienced constraints on electric energy production due to constraints on fuel infrastructure that have an impact on the power sector during winter. In response, ISO-NE has been a key player at the national level in promoting BPS reliability through sharing of lessons learned, best practices, and, more recently, through the performance of more detailed and in-depth BPS energy assessments. Additionally, to address winter energy security challenges, ISO-NE and regional stakeholders developed and put in place a two-year program to compensate certain resources that provide energy security during the winters of 2023–2024 and 2024–2025 (from December to February). ISO-NE's Inventoried Energy Program (IEP) is a voluntary program designed to provide incremental, winter-period compensation for participants that maintain inventoried energy for their assets during extreme cold periods when energy security is most stressed.

The just-in-time delivery of a generator's fuel supply, whether natural gas, wind, or solar, is creating the need for the electric sector to quickly develop ways to retain access to flexible, stored energy—either through long-term energy storage solutions that can capture and store renewable power or through the use of dispatchable resources.

ISO-NE is actively working on numerous major projects to prepare for the clean energy transition and ensure continued reliability. The following is a short list of major projects in which ISO-NE has engaged:

- **CAR Project**
- **Operational Impacts of Extreme Weather Events**
- **Regional Energy Shortfall Threshold**
- **Day-Ahead Ancillary Services Initiative**
- **Economic Planning for the Clean Energy Transition (EPCET)**
- **Extended-Term Transmission Planning Tariff Changes**
- **Longer-Term Transmission Studies**
- **Storage As Transmission Only Asset (SATOA)**
- **FERC Order No. 1920 Project**
- **FERC Order No. 2023 & 2023-A Project**
- **FERC Order No. 2222 Project**
- **FERC Order No. 881 Project**

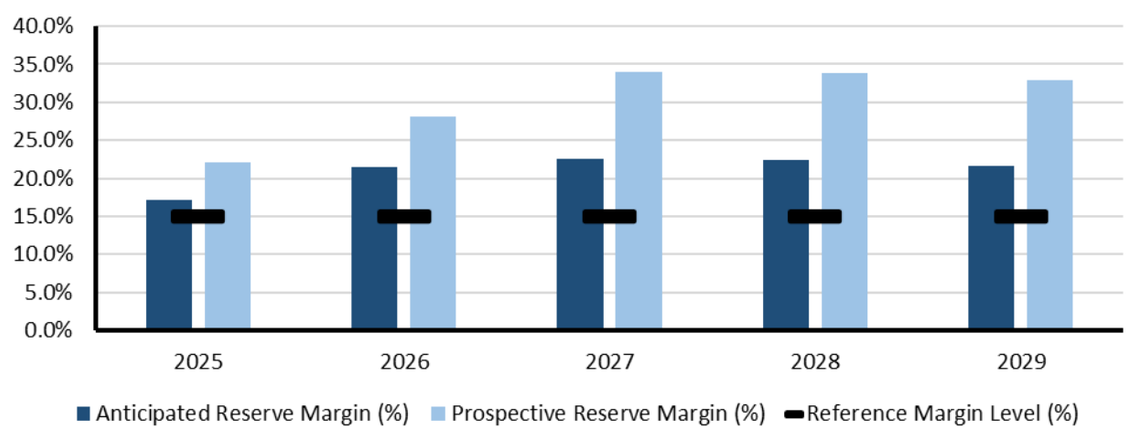


NPCC-New York

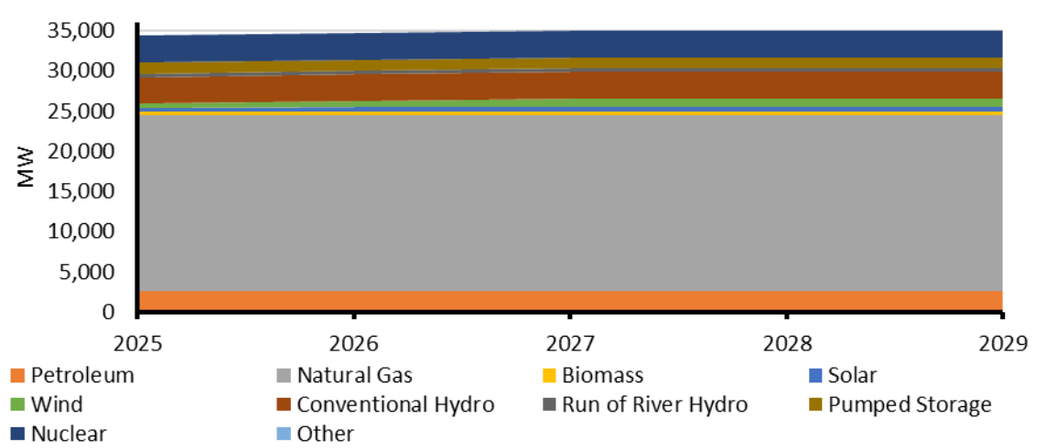
NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only Balancing Authority within the state of New York. The BPS encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this LTRA, the established RML is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). The NYSRC approved the 2025–2026 IRM at 24.4%.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	31,650	31,900	32,110	32,130	32,340	32,580	32,880	33,320	33,830	34,210
Demand Response	897	897	897	897	897	897	897	897	897	897
Net Internal Demand	30,754	31,004	31,214	31,234	31,444	31,684	31,984	32,424	32,934	33,314
Additions: Tier 1	495	858	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144
Additions: Tier 2	1,558	2,090	3,572	3,572	3,572	3,572	3,572	3,572	3,572	3,572
Additions: Tier 3	1,381	4,384	6,384	7,928	8,383	8,383	8,383	8,383	8,383	8,383
Net Firm Capacity Transfers	1,600	2,880	3,186	3,186	3,186	3,186	3,186	3,186	3,186	3,186
Existing-Certain and Net Firm Transfers	35,511	36,790	37,096	37,097	37,097	37,097	36,687	36,687	36,687	36,687
Anticipated Reserve Margin (%)	17.1%	21.4%	22.5%	22.4%	21.6%	20.7%	18.3%	16.7%	14.9%	13.6%
Prospective Reserve Margin (%)	22.1%	28.2%	34.0%	33.9%	33.0%	32.0%	29.5%	27.7%	25.7%	24.3%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Public policies, such as New York state's 2019 Climate Leadership and Community Protection Act (CLCPA), are driving rapid changes in New York's electric system, impacting how electricity is produced, transmitted, and consumed. The transition to a cleaner grid in New York is leading to an electric system that will be increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation.
- Recent assessments reveal that reliability margins are shrinking. Electrification programs are increasing the demand for electricity and placing New York on a trajectory to be a winter-peaking system in the future. Largely in response to public policies, fossil fuel generators are retiring at a faster pace than new renewable supply is entering service. The potential for delays in construction of new supply and transmission, higher than forecasted demand, and extreme weather could threaten reliability and resilience of the New York grid.
- NYISO's reliability studies identified actionable reliability needs starting 2025 in New York City. The reliability need is primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City affected by state legislation and regulations promulgated by the New York State Department of Environmental Conversation, commonly known as the Peaker Rule,[36] to limit emissions. Following a solicitation for proposed solutions to the reliability need, NYISO retained several plants in New York City that would have otherwise been deactivated to comply with the Peaker Rule. NYISO's 2024 Reliability Needs Assessment (RNA), targeting completion in the fourth quarter of 2024, identifies transmission security violations of reliability criteria primarily driven by a combination of forecasted increases in peak demand, limited additional supply, and the assumed retirement of generation in New York City in response to state law and regulations.
- Driven by public polices, new supply, large loads, and transmission projects are seeking to interconnect to the grid at record levels. NYISO's interconnection process balances developer needs with grid reliability. Efforts are underway to make this process more efficient while protecting grid reliability. New transmission is being built, but more investment is necessary to support the delivery of offshore wind energy and to connect new resources upstate to downstate load centers where demand is greatest. Planning for new transmission to support offshore wind is underway in NYISO's Public Policy Transmission Planning Process.
- To achieve the mandates of the CLCPA, new dispatchable emission-free resources (DEFR) with the necessary reliability services will be needed to replace the capabilities and attributes of today's generation. These types of resources, which can achieve the necessary attributes by a combination of solutions, must be significant in capacity and have attributes similar to traditional generation plants, such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, provide ERSs, and adapt to meet rapid, steep ramping needs. Such new emission-free supply is not yet available on a commercial scale.
- New wholesale electricity market rules are supporting the grid in transition. These markets are critical for a reliable transition. Wholesale electricity markets are open to significant investment in wind, solar, and battery storage as well as distributed energy resources. Demand management programs are also under development as a measure to facilitate achievement of CLCPA targets. By lowering the peak load and avoiding system buildout to serve the highest demand hour, fewer DEFRs will be needed and fewer fossil fuel-fired plants will be needed to meet lower peaks during the transition.

[36] Subpart 227-3 of Title 6 of the New York Codes, Rules an3,323d Regulations.

NPCC-New York Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Petroleum	2,631	2,631	2,631	2,631	2,631
Petroleum*	2,628	2,628	2,628	2,628	2,628
Natural Gas	21,907	21,907	21,907	21,907	21,907
Biomass	334	334	334	334	334
Solar	545	586	586	586	586
Wind	461	785	1,070	1,070	1,070
Conventional Hydro	3,323	3,323	3,323	3,323	3,323
Run of River Hydro	413	413	413	413	413
Pumped Storage	1,410	1,410	1,410	1,410	1,410
Nuclear	3,330	3,330	3,330	3,330	3,330
Battery	50	50	50	50	50
Total MW	34,405	34,769	35,054	35,054	35,054
Total MW*	34,401	34,765	35,051	35,051	35,051
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to NYISO are removed from the resource projection where marked.					

NPCC-New York Assessment

Planning Reserve Margins

The LTRA anticipated and prospective margins are above 15% with the exception of year 9 (2033) and year 10 (2034). However, the system margins are narrowing throughout the assessment period. Wind, grid-connected solar, and run-of-river totals were derated for the LTRA calculation. Under its reliability planning processes, NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of no greater than 0.1 event-days/year probability of unplanned load loss. NYISO's 2024 Reliability Needs Assessment, which is underway and targets completion in Q4 2024, will likely identify reliability criteria violations.

NYISO also provides support to the NYSRC in conducting an annual IRM study. This study determines the IRM for the upcoming capability year (May 1 through April 30). The IRM is used to quantify the capacity required to meet the NPCC and NYSRC resource adequacy criterion of "1 day in 10 years." The current IRM for the 2024–2025 capability year is 22% of the forecasted NYCA peak load. All values in the IRM calculation are based upon full installed capacity values of resources. The IRM has varied historically from 15% to 22%. Additionally, the NYISO performs an annual study to identify the locational minimum installed capacity requirements (LCR) for the upcoming capability year.

Energy Assessment, Including Non-Peak Hour Risk

New York State's CLCPA mandates to decarbonize span over all major industries and are a main driver for the electric system changes. NYISO staff in system operations, planning, and markets will continue to assess the system changes to prepare for the grid's transformation.

With high penetration of renewable intermittent resources, the system will need dispatchable emission-free resources (DEFR) and long-duration resources to balance intermittent supply with demand. These types of resources must be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. Additionally, although new transmission is being built, more investment is necessary to support the delivery of future offshore wind energy and to connect new resources upstate to downstate load centers where demand is greatest.

NYISO performs long-range assessments (10-year and beyond planning horizon), and certain energy aspects are accounted for in the hourly modeling and simulations performed under the resource adequacy studies through NYISO's reliability planning processes along with the production cost simulations performed under its System and Resource Outlook.

NYISO performs and supports energy assessments, including a fuel and energy security study, a study assessing potential impacts related to climate change, and weekly analysis of fuel and energy security based on load profiles and fuel inventories reported through NYISO's Generator and Fuel Emissions Reporting (GFER) data portal. These assessments are based on data and information provided by resources on an annual, weekly, and as-needed basis considering system operating conditions. These assessments have the capability to analyze the impact of changes in stored fuel inventory, resource outages, fuel supply disruptions, transmission constraints, and other relevant conditions that may adversely impact fuel and energy security. Additionally, the New York City and Long Island areas have a loss of gas supply dual-fuel requirement and certain combined cycle gas units participate in a "Minimum Oil Burn" program. While oil accounts for a relatively small percentage of the total energy production in New York, it is often called during critical periods, such as when severe cold weather limits access to natural gas.

Probabilistic Assessments (NERC ProbA and Other Studies)

NYISO performs probabilistic assessments using GE's Multi-Area Reliability Simulation (MARS) as part of its reliability planning processes as well as to determine annual IRM LCRs. NYISO also pursued capacity accreditation market rules to more accurately reflect capacity market suppliers' contributions to resource adequacy. These new market rules align compensation for capacity suppliers with an individual resource's expected reliability benefit to consumers and uses the probabilistic models from the LCR process to define capacity accreditation factors (CAF) for various capacity accreditation resource classes. The groundbreaking proposal was accepted by FERC in May 2022. The CAFs will reflect the marginal reliability contribution of the ICAP Suppliers within each Capacity Accreditation Resource Class toward meeting NYSRC resource adequacy requirements for the upcoming capability year, starting with the capability year that began in May 2024.

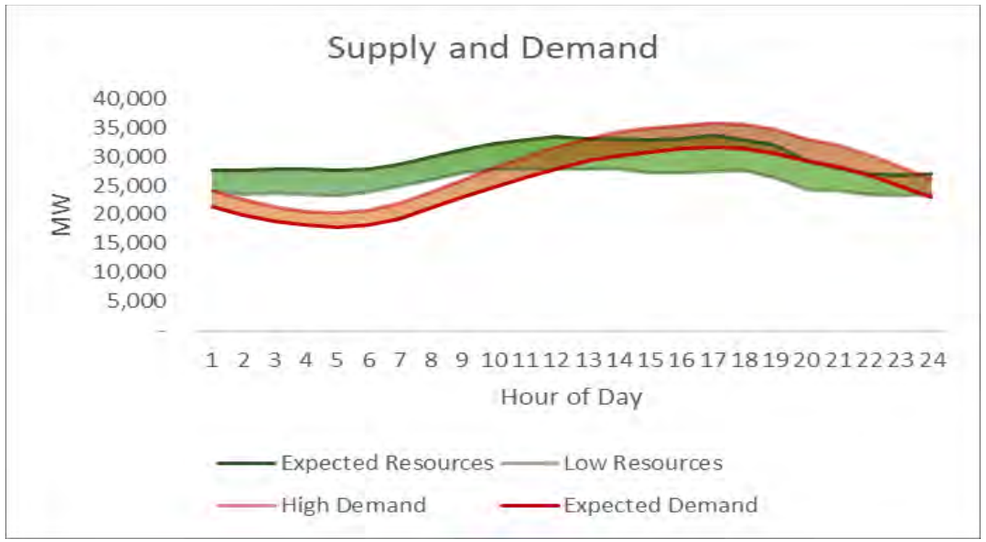
Additionally, NPCC provides results into NERC's ProbA process under the LTRA. The results from the ProbA performed in 2024 by NPCC are shown below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.06	1.91	1.30
EUE (PPM)	0.00	0.01	0.01
LOLH (hours per year)	0.00	0.01	0.01
Operable On-Peak Margin	16.7%	14.0%	15.0%

* Provides the 2022 ProbA Results for Comparison

Most load-loss and unserved energy risk is in the summer months of late June through August.

Hourly demand and resource projections for a typical summer risk day in 2026 are shown in the figure below. Although expected resource contribution is enough to meet expected demand, there is risk that above-normal peak demand could exceed resources. Demand could be 10–13% higher than expected, which could cause strain on the system from the hours beginning 2:00 p.m. through 11:00 p.m. Also, below-normal resource performance from unexpected generator outages or low-solar output could also cause supply shortfalls. If resource contributions are less than expected, strain on the system could be seen from hour beginning 12:00 p.m. through 12:00 a.m. on a typical peak day. Reliance on external assistance may be necessary in these events. A risk day in 2028 has a similar profile.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

NPCC's Directory 1 defines a compliance obligation for the NYISO, as a Resource Planner and Planning Coordinator, to perform a resource adequacy study evaluating a five-year planning horizon. NYISO delivers a report every year under this study process to verify the system against the 1-day-in-10-years LOLE criterion, which is usually based on NYISO's latest available reliability assessment results and assumptions. NYSRC Reliability Rules have recently included a requirement defining NYISO's obligation to deliver a Long-Term Resource Adequacy Assessment Report every year during which the NYISO publishes a Reliability Needs Assessment (RNA) and an annual update in the intervening year between RNAs.

Demand

NYISO employs a multi-stage process to develop load forecasts for each of the 11 zones within the New York Control Area (NYCA). The impacts of net electricity consumption of energy storage resources due to charging and discharging are added to the energy forecasts, while the peak-reducing impacts of BTM energy storage resources are deducted from the peak forecasts.

Currently, the NYCA summer peak typically occurs in late afternoon. The NYCA summer peak is projected to shift into the evening as additional BTM solar is added to the system and as EV charging impacts increase during the evening hours. Because the hour of the summer peak shifts into the evening over the course of the forecast horizon, BTM solar generation becomes less coincident with the NYCA peak hour, and BTM solar coincident peak reductions are forecasted to decrease in later years. The forecast of solar PV-related reductions to the winter peak is zero because the system typically peaks after sunset.

Trended weather conditions from the Climate Impact Study Phase I report are included in NYISO's end-use models and are reflected in the baseline, policy scenario, and percentile forecasts. NYISO develops 90th and 99th percentile forecasts to account for the impacts of extreme weather on seasonal peak demand and calculates 10th percentile forecasts to represent milder seasonal peak conditions.

The 10-year annual average energy (+1.7%) and summer peak demand (+0.8%) growth rates are higher than last year's forecast. Increases in growth rates relative to the prior forecast are primarily attributed to the significant impacts of interconnecting large load projects. Baseline energy and coincident peak demand increase significantly throughout the 30-year forecast period, driven largely by large load project growth in the early forecast years and electrification of space heating, non-weather sensitive appliances, and EV charging in the outer forecast years. New York is projected to become winter-peaking in future decades due to space heating electrification and EV penetration. To account for forecast uncertainty during winter due to electrification and large loads, NYISO implemented a winter dynamic load forecast uncertainty in the resource adequacy models for its 2024 RNA.

Demand-Side Management

NYISO is working on developing market concepts to encourage the participation of flexible load, which will become increasingly important as the levels of weather-dependent intermittent resources on New York's grid increase in response to the state's climate and clean energy policies. Many of New

York's utilities are piloting several load management programs (e.g., smart EV charging, home-thermostat use, and integration of BTM storage for local peak demand modulation). As part of NYISO's annual long-term forecasting process, the impacts of these programs are discussed and significant impacts on demand are included in the load forecast.

DR participation for the summer capability period has increased slightly from 1,234 MW to 1,281 MW since the *2023 LTRA*. There are currently 425 MW of DR participating in ancillary services programs and providing either 10-minute spinning reserves or 30-minute non-synchronous reserves.

Distributed Energy Resources

NYISO has implemented in 2024 a plan to integrate DERs, including DR resources, into the markets it administers. The DER Participation Model project aims to enhance participation of DERs in the competitive wholesale markets. These measures closely align the bidding and performance measurements for DERs with the rules for generators. The measures establish a state-of-the-art model that is largely consistent with the market design envisioned by FERC in its Order 2222. This project, which began in 2017, provides a single participation model for DER DR resources to provide energy, ancillary services, and installed capacity through an aggregation. The market rules for the DER and aggregation participation model were accepted by FERC in January 2020. NYISO filed additional proposed tariff revisions with FERC in June 2023 to clarify and enhance these market rules. NYISO deployed its DER participation model in 2024.

Generation

The pace of renewable project development and existing generation retirement is unprecedented and driving a need to increase the pace of transmission expansion, clean dispatchable generation, and demand management programs development. In general, resource and transmission expansion take many years from development to deployment. Coordination of project additions and retirements is essential to maintaining reliability and achieving policy. Significant new resource development will be required to achieve energy targets under the CLCPA. The total installed generation capacity to meet policy objectives within New York is projected to range between 111 GW and 124 GW by 2040. At least 95 GW of this capacity will consist of new generation projects and/or modifications to existing plants. Even with these additions, New York still may not be sufficient to maintain the reliable electricity supply. The sheer scale of resources needed to satisfy system reliability and policy requirements within the next 20 years is unparalleled.

Currently, NYISO's interconnection process contains a significant number of proposed projects in various stages of development with only a fraction in more advanced stages included in the reliability planning models. However, the grid will evolve to achieve the policy mandates, and those changes will affect the nature and amount of resources.

For the 2024 RNA, gas availability is derated during winter to further account for cold weather risks.

To achieve the CLCPA mandate of an emission-free grid by 2040, DEFRs must be developed and deployed throughout New York. DEFRs that provide sustained on-demand power and system stability will be essential to meeting policy objectives while maintaining a reliable electric grid. While essential to the grid of the future, such DEFR technologies are not commercially available today.

ERSs usually provided to the system by synchronous fossil generation will continue to be necessary. New technology is being developed to allow for a reliable transition to a clean grid. Grid-forming inverter capabilities, as well as DEFRs, will likely be part of this transformation. In May 2023, the New York State Public Service Commission (PSC) initiated a process to examine the need for resources to ensure the reliability of the CLCPA mandate for a zero-emissions electric grid by 2040. The PSC seeks to identify innovative technologies to ensure the reliability of a zero-emissions electric grid. Numerous other initiatives at both state and federal levels are in progress and may impact the grid of the future.

Energy Storage

Storage resources can help to fill in voids created by reduced output from renewable resources. However, sustained periods of reduced renewable generation can rapidly deplete storage capabilities. NYISO has implemented its Co-Located Storage Resources model to allow wind or solar resources that are interconnected with an energy storage resource the ability to participate in the markets while respecting a shared interconnection limitation. NYISO is developing a model for hybrid storage resources to allow multiple technologies at the same point of interconnection to participate in the market as a single resource. Additionally, the resource adequacy simulation tools (such as GE's MARS) used in system planning by NYISO and for setting the IRMs were enhanced to include energy-limited resources models that allow for charging and discharging and also include temporal constraints (e.g., hours/days or hours/month).

Capacity Transfers

The models used for NYISO's reliability planning studies include firm capacity transactions (purchases and sales) with the neighboring systems as a base-case assumption. Proposed projects that are in a more advanced stage are included. One such project is the 1,250 MW HVdc line from Québec to New York City, which is reflected in the LTRA summer total transfers starting in 2026. Additionally, the probabilistic model that NYISO uses to assess the adequacy of resources in the reliability planning processes employs several methods aimed at preventing overreliance on the external systems support. For example, NYISO employs limiting emergency assistance from neighbors by modeling a total limit of 3,500 MW, modeling five simultaneous peak days, modeling the long-term purchases and sales with neighboring control areas, and not modeling emergency operating procedure steps for the neighbors.

New York is fortunate to have strong interconnections with neighboring regions and has enjoyed reliability and economic benefits from such connections. As the energy policies in neighboring regions evolve, New York's imports and exports of energy could vary significantly due to the resulting changes in neighboring grids. The availability of energy for interchange is predicted to shift fundamentally as policy achievement progresses. As New York's and other regions' grids evolve, continuous monitoring and collaboration with our neighboring states will be required.

Transmission

Significant new transmission is being built across New York, but more investment is necessary to support, among other things, the delivery of offshore wind energy to connect new resources upstate to downstate load centers where demand is greatest.

Key transmission projects under development and accounted for in the reliability models include the following:

- The Northern New York Priority Transmission Project upgrading the transmission corridors from the renewable generation pocket in the north country to central New York
- The 1,250 MW Champlain-Hudson Power Express HVdc line from Hydro-Québec to New York City
- The AC Public Policy Transmission Projects that consist of upgrading transmission corridors in central New York and the lower Hudson Valley, which projects target completion of the majority of the components by December 2023
- The transmission project selected to address the Long Island Offshore Wind Expert Public Policy Transmission Need and that adds three new dc tie lines and a 345 kV backbone across western/central Long Island with an in-service date in 2030

Additionally, there are significant transmission projects either recently selected or under study that have not yet met the criteria to be in the reliability model. For instance, the PSC recently identified a new public policy transmission planning need for NYISO to solicit proposed solutions and that is intended to support the integration of 4.7 GW of wind resources in New York City.

Furthermore, in 2020, the PSC ordered the New York utilities to undertake planning assessments and make investment proposals to facilitate the cost-effective development of renewable and emissions-free resources while maintaining the reliability of New York's electric grid. The Coordinated Grid Planning Process (CGPP) was approved by the PSC in August 2023. The process is designed to assess the state's electric grid using a 20-year planning horizon. The CGPP is intended to identify electric grid expansions that can aid in unlocking renewable generation capacity and provide energy headroom for the purpose of meeting New York's clean energy goals while providing value to customers. Moreover, the CGPP is designed to identify opportunities for expansion of the bulk transmission system to advance the mandates of CLCPA. This provides another opportunity to inform the PSC's consideration of whether to establish a public policy transmission need for NYISO to solicit and evaluate proposed solutions.

Reliability Issues

The 2024 RNA, targeting completion in the fourth quarter of 2024, identifies transmission security violations of reliability criteria primarily driven by a combination of forecasted increases in peak demand, limited additional supply, and the assumed retirement of generation in New York City in response to state law and regulations. Accounting for these factors, the planned bulk power transmission system will not be able to securely and reliability serve the forecasted demand in New York City. When accounting for forecasted economic growth and policy-driven increases in demand, the New York City (Zone J) will be deficient starting in summer 2033 by as much as 17 MW for 1 hour and increasing to 97 MW for 3 hours in summer 2034 on the peak day during expected weather conditions. The Reliability Need occurs within the transmission district owned by Consolidated Edison Company of New York, Inc. ("Con Edison"). Con Edison is designated as the Responsible Transmission Owner in the NYISO's transmission planning process and required to submit a regulated backstop solution to address the need, which may be triggered if sufficient market-based solutions do not materialize.

Prior to the 2024 RNA, the NYISO completed the 2023 Q2 STAR on July 14, 2023. This assessment found a reliability need beginning in summer 2025 in New York City primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City affected by the New York Department of Environmental Conservation (DEC) Peaker Rule. The reliability need is a deficiency in the transmission security margin. Specifically, the New York City zone is deficient by as much as 446 MW for a duration of nine hours on the peak day during expected weather conditions (95 degrees Fahrenheit) when accounting for forecasted economic growth and policy-driven increases in demand. To ensure the continued reliability of electric service in New York City, NYISO designated the generators on the Gowanus 2 & 3 and Narrows 1 & 2 barges as necessary for reliability to temporarily remain in operation after the Peaker Rule compliance date until permanent solutions to the need are in place, for an initial period of up to two years (May 1, 2027).

The transition to a cleaner grid in New York is leading to an electric system that is increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation and may lead to increasing reliability issues on the New York system. Reliability margins are shrinking. Generators needed for ERSs are planning to retire. Delays in the construction of new supply and transmission, higher-than-expected demand, and extreme weather could threaten reliability and resilience in the future. The

system is projected to become winter-peaking in the next decade due to electrification and decarbonization policies. Large loads are being proposed to interconnect to the system. New York's current reliance on neighboring systems is expected to continue through the next 10 years. A successful transition of the electric system requires replacing the reliability attributes of existing fossil-fueled generation with clean resources with similar capabilities. Such resources must be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. New transmission is being built but more investment is necessary to support the delivery of offshore wind energy to connect new resources located in upstate to downstate load centers where demand is greatest.

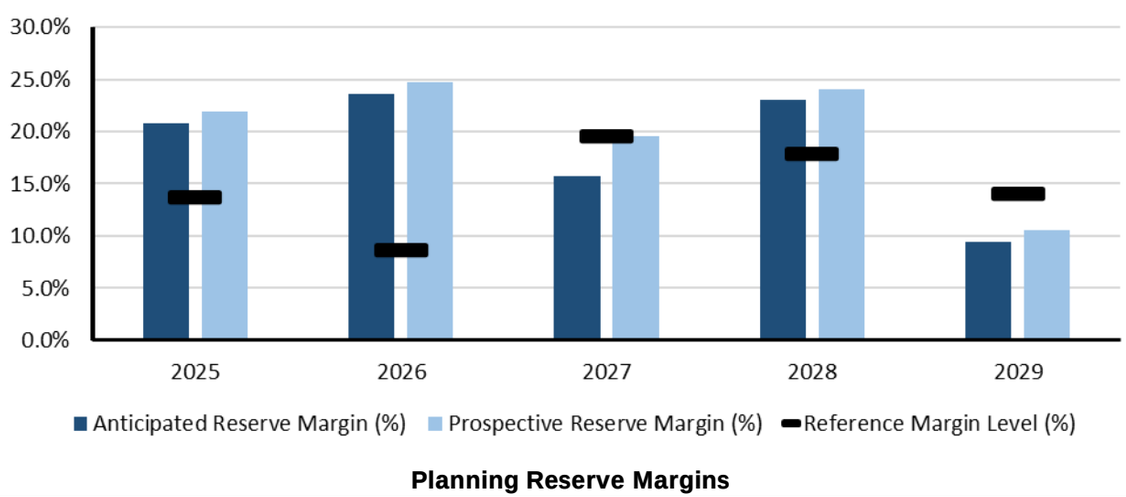


NPCC-Ontario

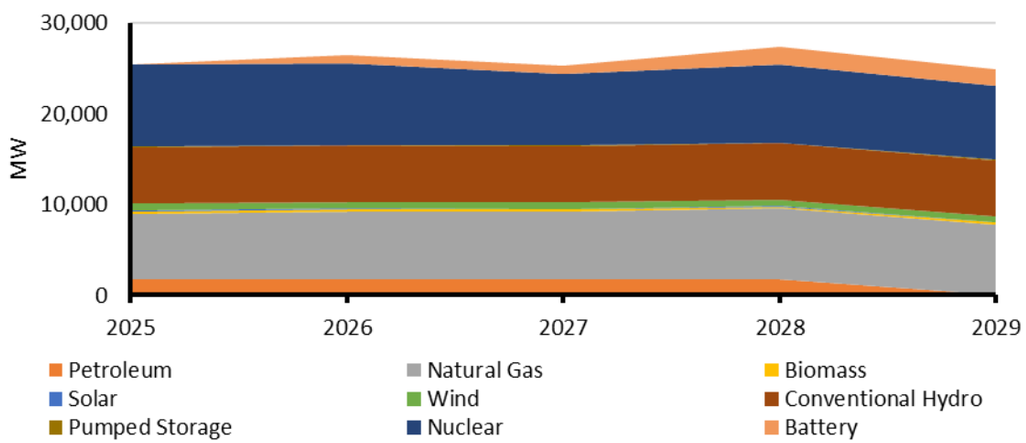
NPCC-Ontario is an assessment area in the Ontario province of Canada. The IESO is the Balancing Authority for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 16 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	23,385	23,860	24,264	24,627	25,248	26,038	26,473	27,373	27,974	28,789
Demand Response	1,791	1,914	1,914	1,914	1,914	1,914	1,914	1,914	1,914	1,914
Net Internal Demand	21,594	21,946	22,350	22,713	23,333	24,123	24,559	25,458	26,060	26,875
Additions: Tier 1	617	1,737	1,735	3,012	3,302	3,300	3,843	4,385	4,384	5,128
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	600	600	500	600	600	600	600	0	0	0
Existing-Certain and Net Firm Transfers	25,470	25,394	24,133	24,924	22,242	22,051	20,660	20,705	20,671	20,257
Anticipated Reserve Margin (%)	20.8%	23.6%	15.7%	23.0%	9.5%	5.1%	-0.2%	-1.4%	-3.9%	-5.5%
Prospective Reserve Margin (%)	22.0%	24.8%	19.5%	24.1%	10.5%	6.1%	0.8%	-0.5%	-2.9%	-4.6%
Reference Margin Level (%)	13.7%	8.6%	19.5%	17.8%	14.1%	9.4%	17.2%	8.1%	6.8%	8.5%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- While potential reserve margin shortfalls are forecast for 2027 and 2029, they are mainly driven by changes in the IESO's resource adequacy assessment methodology since the *2023 LTRA*. Last year, reserve margin calculations included the continuation of existing resources (following contract expiry) for the entire outlook period. For this LTRA, reserve margins reflect the contribution of existing resources only until the end of their contract or commitment period. This change to the methodology is more conservative and helps to better identify system needs in the IESO's planning assessments to establish resource acquisition targets and address anticipated needs.
- The IESO has two capacity sharing agreements with Hydro-Québec providing firm summer capacity, which will help to address future shortfalls this decade.
- The IESO has completed a broad set of actions to secure new capacity for this decade to ensure that Ontario's power system needs are met during a period of nuclear retirements and refurbishments and economy-wide demand growth. This includes securing long-term commitments amounting to 2,195 MW of new capacity to be on-line by 2028, with early operation incentives anticipated to bring a portion on-line as early as 2027 to help alleviate the reserve margin gap.
- The annual capacity auction, which helps to meet needs in the short term by securing capacity for up to one year at a time, has historically secured more capacity than targeted. Trends suggest that this should continue, as the November 2024 auction (which will help to ensure reliability through summer 2025 and winter 2025–2026) also secured more capacity than targeted.
- The IESO is taking steps that will address future shortfalls around the end of this decade and heading into the 2030s. The next round of medium- and long-term procurements was recently launched to ensure that capacity and energy needs continue to be met. The second medium-term procurement aims to re-commit existing resources with contracts expiring over the 2026–2029 period, while the second long-term procurement aims to secure capacity and energy from new resources (to be online as early as 2029), to meet needs emerging in the early 2030s.
- The IESO is also responsible for implementing new provincial policy as outlined in the Ontario government's July 2023 Powering Ontario's Growth report, which includes developing new nuclear projects, transmission expansions, and expanded conservation and demand management programs. The IESO will also incorporate changes stemming from the federal release of the final Clean Electricity Regulations, anticipated toward the end of 2024.

NPCC-Ontario Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Petroleum	1,695	1,695	1,695	1,695	5
Natural Gas	7,275	7,465	7,465	7,847	7,761
Biomass	297	294	257	209	209
Solar	100	100	100	100	100
Wind	743	722	711	711	602
Conventional Hydro	6,215	6,212	6,212	6,212	6,202
Pumped Storage	38	38	38	38	38
Nuclear	9,008	9,008	7,895	8,639	8,142
Battery	118	998	996	1,886	1,885
Total MW	25,487	26,531	25,368	27,336	24,944

Planning Reserve Margins

The ARM falls below the RML starting in 2027. While expected nuclear retirements, the ongoing nuclear refurbishment program, and demand growth are resulting in increased needs this decade, the reserve margin shortfalls indicated in 2027 and 2029 are primarily driven by the change in the IESO's resource adequacy assessment methodology described above.

Mid-decade capacity needs that were identified in the 2022 *Annual Acquisition Report* have been met through a series of competitive procurements. Since May 2023, the IESO has secured over 3,600 MW of new capacity from battery storage, natural gas, and biogas facilities, expected to come on-line between 2025 and 2028. In addition, the 2023 capacity auction secured 1,867 MW of summer capacity and 1,311 MW of winter capacity above targets of 1,400 and 850 MW, respectively. The IESO continues to actively procure existing and new resources to meet longer-term needs, using the mechanisms in the Resource Adequacy Framework.

Ongoing refurbishments at Bruce Nuclear Generating Station (NGS) and Darlington NGS will see between one and three reactors concurrently off-line through Summer 2033. Refurbishments remain on or ahead of schedule and outages continue to be managed to limit impacts to the grid. Following the return to service of refurbished units at Bruce, each unit is expected to be uprated, with the additional capacity anticipated to be available in the early 2030s.

The Ontario government has also announced a plan to deliver three additional small modular reactors in addition to the 300 MW unit already underway (anticipated on-line in 2029). The provincial government's July 2023 Powering Ontario's Growth plan directed the IESO to conduct an impact assessment on potentially adding 4,800 MW of large-scale nuclear capacity to Bruce NGS. Approval was granted from the federal nuclear regulator in October 2024 to extend operation of four units at Pickering NGS (previously scheduled for decommissioning in 2025) through September 2026. The government is also supporting the refurbishment of the four units at Pickering, with refurbishment of the first unit anticipated to be completed in 2031.

To address resource adequacy needs emerging mid-decade due to the combined effect of nuclear retirements and refurbishments, as well as expiring generation contracts, the IESO has employed competitive acquisition mechanisms from the Resource Adequacy Framework in part via the capacity auction referenced above. The IESO's first long-term procurement concluded in May 2024 and secured long-term commitments from 10 battery storage facilities for 1,784 MW of new capacity and three natural gas/biogas facilities for 411 MW of new capacity. Facilities are anticipated to be in service as early as May 2027.

The IESO calculates the reserve margin requirement on an annual basis and publishes this in the Annual Planning Outlook (APO). The requirement is calculated for each year for net demand at the time of the annual demand peak to provide an LOLE that is at or below 0.1 days per year. The reserve margin requirement in the *2024 LTRA* is derived from the capacity requirement in the 2024 APO, plus any material changes to demand and supply following APO publication.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Energy adequacy assessments are conducted annually for the APO by using a deterministic approach in the IESO's economic dispatch model. In addition, the IESO's capacity adequacy assessments consider the system's ability to serve load in all hours of the year (i.e., during peak hours as well as non-peak load hours).

As demand requirements increase, nuclear refurbishments continue, and some units at the Pickering NGS retire in 2024, Ontario's energy needs are expected to be met this decade by the resources secured through the IESO's recently completed procurements. The second medium-term procurement, which was recently launched, aims to secure capacity and energy from existing resources reaching contract end; this is expected to help alleviate energy risks in the latter half of this decade. The second long-term procurement that is underway aims to acquire new capacity and energy-producing resources and is anticipated to alleviate energy risks in the early 2030s.

Factors that could increase energy adequacy risks include aging resources and the potential for decreased performance, market exit of resources reaching contract end, extreme weather, and decarbonization policies and risks presented by new resources, including in-service delays or a high risk of forced outages during the initial period of operation. Deliverability challenges for new resources and long lead times required to build new transmission may also increase energy adequacy risks. Demand-side factors include materialization of data centers, increased industrial automobile production and EV supply chain loads, and climate change impacts on weather-sensitive load.

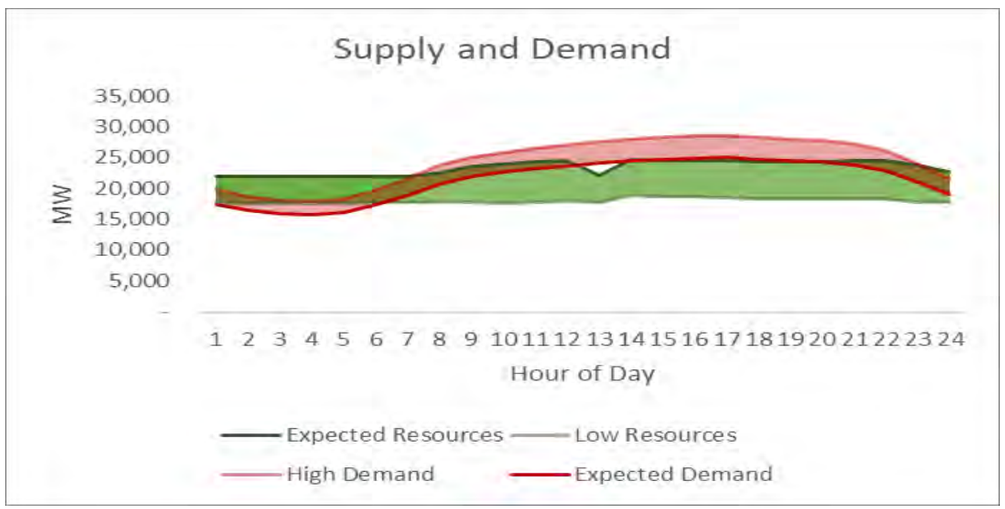
Looking forward, with the federal government's proposed Clean Electricity Regulations to decarbonize Canada's electric system by 2050, the IESO is assessing the role of natural gas generation as a flexible resource in the interim as new sources of non-emitting supply are added to the system.

The IESO conducts probabilistic resource adequacy assessments annually in conjunction with NPCC to identify regional capacity resource needs and to comply with NPCC and NERC reliability requirements. Results from the 2024 ProbA are shown in the table on the next page. The low risk of unserved energy is concentrated in the summer peak period, which typically occurs in late August.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	72.16	**0.04**	**4.97**
EUE (PPM)	0.49	**0.00**	**0.03**
LOLH (hours per year)	0.44	**0.00**	**0.01**
Operable On-Peak Margin	-6.7%	**13.3%**	**9.5%**

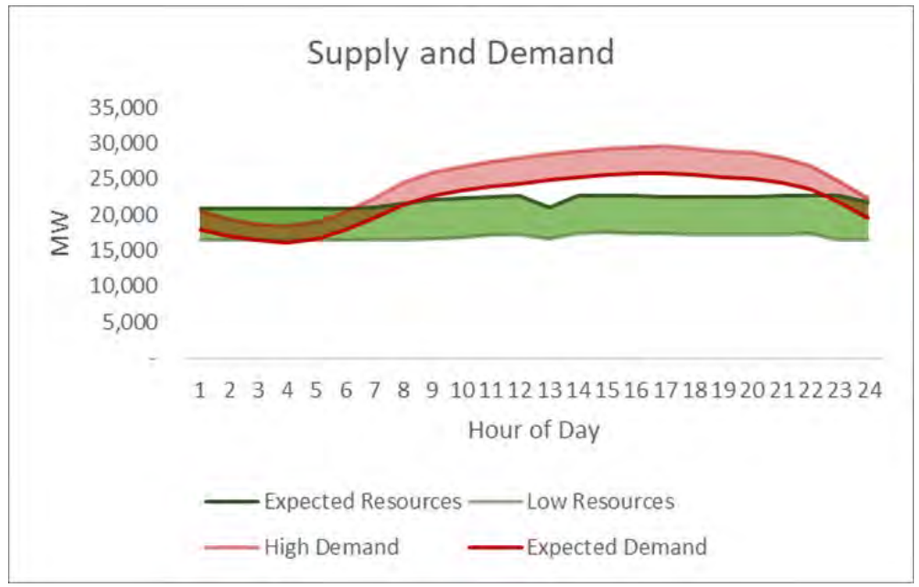
* Provides the 2022 ProbA Results for Comparison

Hourly demand and resource projections for a representative summer risk-day in 2026 are shown in the figure below. Expected resource contributions are not sufficient to meet expected demand on the risk day. The risk could be exacerbated by either a lower-than-expected resource contribution event or a higher-than-expected demand event, with greater risk being due to a larger variability in resource contribution. There is expected strain on the system from the hours beginning 12:00 p.m. through 8:00 p.m. If resource contributions are less than expected, strain on the system at expected demand conditions could be seen for almost all hours of the day beginning at 7:00 a.m. Reliance on external assistance may be necessary during peak conditions.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

In 2028, the EUE and LOLH are higher than 2026. Risk occurs during the same summer peak period but also during winter peak conditions in December. Demand growth that is forecasted to occur between 2026 and 2028 contributes to higher loss-of-load risk compared to the 2026 result. The risk day in 2028 has the same drivers as the 2026 result noted above.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2028

Demand

Forecasted demand for this *2024 LTRA* outlook period (relative to the *2023 LTRA* outlook period) indicates 10% higher annual energy demand, 8% higher summer peak demand, and 9% higher winter peak demand.

With an expanding agricultural and greenhouse sector, along with increasing electricity use for home heating and transportation, summer and winter peaks are anticipated to converge over the forecast period, leading Ontario to be dual-peaking by 2030. In the near term, the peak magnitude is expected to increase slightly as the province exits the remnants of the post-pandemic inflationary cycle, and new industrial projects supporting decarbonization begin commercial operation. Over this assessment period, the IESO projects total internal demand growth to increase at a compound annual growth rate of 2.34% for summer and 2.75% for winter. Offsetting the growth in demand are reductions from conservation, including savings from EE programs and codes and standards regulations, electricity price responsiveness and increased output by embedded generation.

Ontario's Industrial Conservation Initiative (ICI) acts as a critical peak pricing program leading to reductions in demand at peak and is expected to reduce around 1,500 MW if the hour of annual system peak demand occurs in the summer or around 1,000 MW if it occurs in the winter. It is expected to scale based on increased industrial growth in future years, with reductions in 2034 of 2,000 MW for a summer peak demand hour and over 1,400 MW for a winter peak demand hour.

Demand-Side Management

DR capacity, from both dispatchable loads and hourly DR resources (e.g., residential or commercial and industrial load), is procured through the IESO's annual capacity auction. Starting with the 2023 capacity auction, the IESO implemented a capacity qualification process for all resource types eligible to participate, which applies resource-specific calculation methodologies to determine the amount of unforced capacity (UCAP) each resource is eligible to offer into the auction.

In June 2023, the IESO launched Peak Perks, a residential DR program where participants help reduce demand by up to 150 MW through brief, time-limited thermostat adjustments during periods of peak electricity demand in the summer months.

In July 2023, the IESO launched an interruptible rate pilot to provide large-load customers with an interruptible rate in exchange for agreeing to temporarily reduce demand when directed by the IESO. The pilot spans a three-year period and up to 15 events of up to four-hour duration can be called, primarily in the day-ahead timeframe but also on shorter notice.

Forecast savings from the IESO's 2021–2024 Conservation and Demand Management Framework were included in the forecast and resulted in a decrease in demand. Savings from the 2021–2024 CDM framework are expected to persist beyond the end of 2024. In February 2024, Ontario's minister of energy asked the IESO to examine options and analysis for a post-2024 EE framework and programs.

Distributed Energy Resources

The IESO estimates that contracted DERs contributed more than 3,400 MW of capacity and 5.3 TWh of energy in 2023, more than half of which is solar PV, one-third wind, and modest contributions from hydroelectric and biomass resources. While the IESO has little insight into uncontracted DERs, it has observed energy contributions of approximately 2 TWh in 2023.

Generation

Recent generation procurements are provided in the PRM section.

The transmission-connected supply mix in Ontario has shifted over the past decade from having only synchronous generation facilities to one with more IBRs including wind, solar, and storage. Previous assessments performed by the IESO indicate that Ontario is expected to have sufficient inertia and frequency response to ensure stable operation up to 2025.

Going forward, the addition of over 2,900 MW of new battery storage resources in the next few years will increase the proportion of IBRs on the system. With the shift toward a higher proportion of IBRs, further areas that will be explored include the sufficiency of the resource mix to provide system inertia, primary frequency response, operating reserve, ramping capability, reactive support, and voltage control. If needs are identified, the IESO's procurements may be used as one avenue to acquire resources that can provide the required services.

The IESO has also been taking a proactive approach to dealing with challenges posed by IBRs. This includes working to optimize the location of IBR resources acquired through the IESO's procurements to minimize performance issues and initiating a review of the IESO's Market Rules to align with the latest IEEE 2800 standard, which aims to establish uniform technical minimum requirements for interconnection, capability, and lifetime performance of IBRs.

Energy Storage

By May 2028, over 2,900 MW of new battery storage resources are expected to come on-line, including the 250 MW/1,000 MWh Oneida battery storage facility (expected to be operational in June 2025), and 2,714 MW of battery storage resources secured through the IESO's first set of long-term procurements. Of this, 930 MW is expected to reach commercial operation by May 2026 and the remaining 1,784 MW by May 2028. These standalone battery storage resources (with a minimum four-hour duration) are expected to support the reliable operation of Ontario's electric system through the ability to be dispatched by the IESO and ramp up and down quickly. The resources are also located in areas of Ontario where transmission security or resource adequacy needs were identified.

Newly acquired energy storage facilities through the IESO's first set of long-term procurements will be required to be available during peak hours.

Capacity Transfers

Firm capacity imports and exports with neighboring jurisdictions are included in the IESO's planning studies. For non-firm imports, the IESO assumes a limited amount for the purposes of its reliability assessments. Non-firm imports are assumed to be 250 MW for summer and 240 MW for winter, an amount considered likely to flow throughout the year, including under tight supply conditions and prices.

In November 2024, the IESO and Hydro-Québec finalized a new capacity sharing agreement for a swap of a minimum of 600 MW of capacity per season. Under this agreement, the IESO will deliver capacity

to Québec during the winter period and Hydro-Québec will deliver capacity to Ontario during the summer period. The agreement commences in the Winter 2024–2025 season and runs to October 2031, with an option for an extension for an additional three years. Other terms of the agreement are expected to include the option for the IESO to increase the minimum amount provided to Québec each year and to bank any amount of the 600 MW from Québec for use in a future summer period over the term of the agreement.

The 2023 capacity auction secured 300 MW of system-backed imports from Québec for the Summer 2024 obligation period. As part of the 2016 capacity sharing agreement between Ontario and Québec, the IESO may call on a total of 500 MW of firm imports from Hydro-Québec, which may be requested all in one summer or in smaller amounts over multiple summers. The IESO's recent assessments indicate the intention to utilize the 500 MW of firm imports from June to September 2027 to help meet resource adequacy needs. However, depending on the outcomes of the ongoing procurements and changes to Ontario's resource adequacy outlook, the IESO may choose to utilize this capacity in another year.

Transmission

The existing transmission system in northeastern Ontario has insufficient capability to reliably supply forecasted load growth; as such, the IESO has recommended several new transmission reinforcements in the region to address this need. Several of the recommended reinforcements are in the early project development stage and one is undergoing a transmitter selection process.

The IESO recently recommended additional transmission reinforcements in southwest Ontario to support the area's medium-term needs, including a double circuit, 230 kV line from Lambton transmission station to Chatham substation, expected in-service by 2028, and a new 500 kV transmission line connecting Longwood and Lakeshore transmission stations, to be in-service by 2030. These projects will ensure that transfer capability continues to be sufficient as additional load continues to connect in the area.

Reliability Issues

Nuclear refurbishment over the next decade is a major resource risk that requires additional attention. The IESO has regular meetings with nuclear operators to assess probable delays and take appropriate mitigation actions.

For long-term planning purposes, the IESO carries an additional level of nuclear refurbishment reserve to account for the risk of refurbishment delays and increased forced outage rates pre- and post-refurbishment. In addition, advanced outage approvals are provided solely when Ontario is adequate under extreme weather.

Other factors that may pose reliability risks include supply chain issues, conditions in neighboring jurisdictions, extreme weather, decarbonization-driven changes to supply and demand, policy and regulatory uncertainty, asset health, and potential market exit of existing resources.

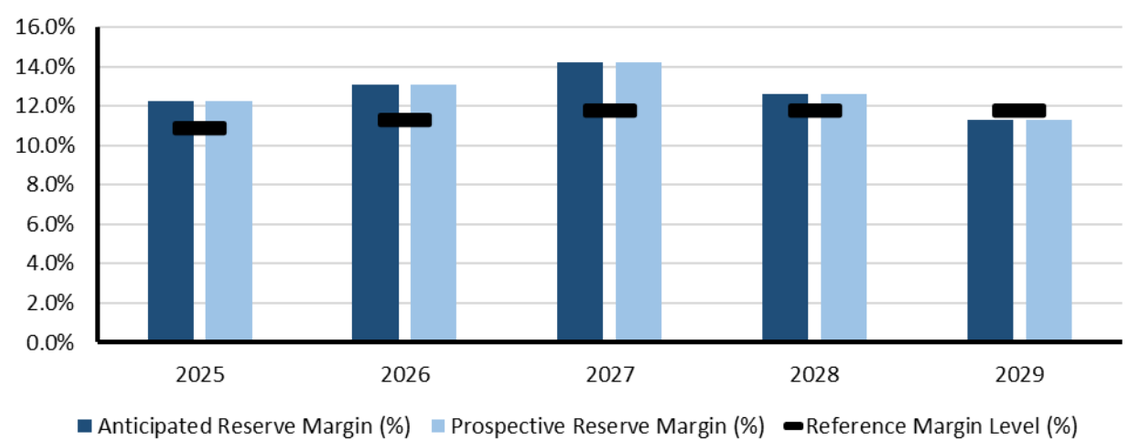


NPCC-Québec

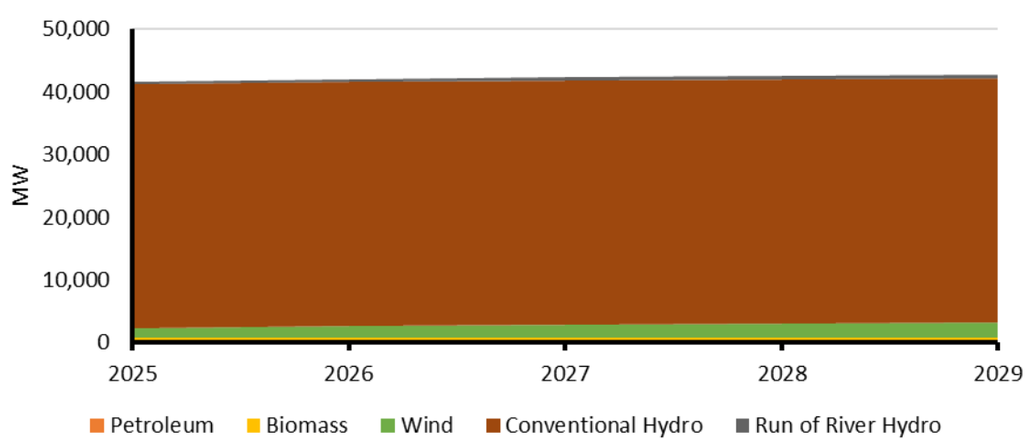
The Québec assessment area (Province of Québec) is a winter-peaking NPCC subregion that covers 595,391 square miles with a population of 8.5 million. Québec is one of the four NERC Interconnections in North America with ties to Ontario, New York, New England, and the Maritimes. These ties consist of either HVdc ties, radial generation, or load to and from neighboring systems.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	41,497	41,954	42,476	43,385	44,070	44,784	45,577	46,635	47,828	49,041
Demand Response	4,732	4,896	5,068	5,258	5,322	5,377	5,388	5,388	5,388	5,388
Net Internal Demand	36,765	37,058	37,408	38,127	38,748	39,408	40,189	41,247	42,440	43,652
Additions: Tier 1	73	469	665	835	1,016	1,016	1,016	1,016	1,016	1,016
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-390	-145	455	455	455	600	0	0	0	0
Existing-Certain and Net Firm Transfers	41,185	41,429	42,066	42,103	42,103	42,256	41,656	41,656	41,656	41,656
Anticipated Reserve Margin (%)	12.2%	13.1%	14.2%	12.6%	11.3%	9.8%	6.2%	3.5%	0.5%	-2.2%
Prospective Reserve Margin (%)	12.2%	13.1%	14.2%	12.6%	11.3%	9.8%	6.2%	3.5%	0.5%	-2.2%
Reference Margin Level (%)	10.9%	11.3%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM and PRM remain above the RML until 2029 (winter 2029–3030).
- A total of 4,048 MW wind generation capacity (1,016 MW capacity value at peak time) is expected to be in service by 2030.
- Two new transmission projects connecting Québec with New England and New York are expected to be in service by the end of 2025 and May 2026, respectively.

NPCC-Québec Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Petroleum	429	429	429	429	429
Biomass	400	400	400	400	400
Wind	1,449	1,807	2,002	2,173	2,354
Conventional Hydro	38,925	38,962	38,999	39,036	39,036
Run of River Hydro	446	446	446	446	446
Total MW	41,648	42,043	42,276	42,483	42,664

NPCC-Québec Assessment

Planning Reserve Margins

The ARM is based on existing and anticipated generating capacity and firm capacity transfers. The Québec area projects an ARM above the RML over the first five winters of the assessment period (2024–2025 to 2028–2029). The ARM is under the RML for the winters 2029–2030 to 2034–2035 mainly due to the demand growth.

The RML is derived from the NPCC 2023 Québec Balancing Authority Area Comprehensive Review of Resource Adequacy, which was approved by NPCC's Reliability Coordinating Committee on December 5, 2023. The demand uncertainty captured in the reserve ratio reflects both weather and economic uncertainty. The methods and assumptions can be found in the *Comprehensive Review* report available on the NPCC website.

The assumptions used for this assessment, including demand forecast and resources, are consistent with the Hydro-Québec 2023 Supply Plan update, which was filed with the Régie de l'énergie on November 1, 2023.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

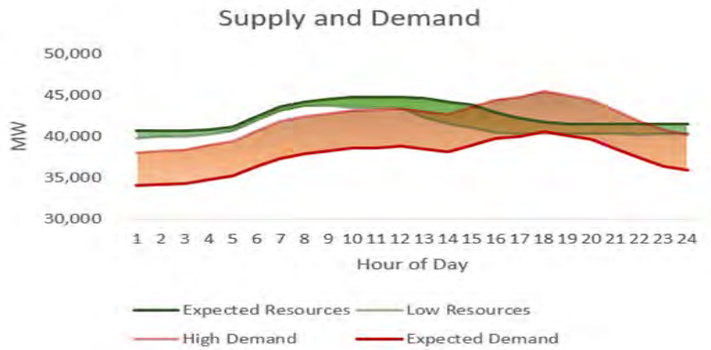
The main energy risk for the Québec area is associated with a series of dry years, hence the energy reliability criterion established by the Régie de l'énergie. This risk surpasses the energy risk associated with the other renewable resources over the horizon of this study. The potential impact of climate change on the water inflows could be an issue for energy reliability and is therefore the subject of various ongoing internal studies.

Hydro-Québec conducts probabilistic resource adequacy assessments annually in conjunction with NPCC to identify regional capacity resource needs and comply with NPCC and NERC reliability requirements. Results from the 2024 ProbA are shown in the table below. The low risk of unserved energy is concentrated in the winter peak period, which typically occurs in late January to early February.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**8.21**	**4.97**
EUE (PPM)	0.00	**0.04**	**0.03**
LOLH (hours per year)	0.00	**0.01**	**0.01**
Operable On-Peak Margin	-2.3%	**9.8%**	**11.9%**

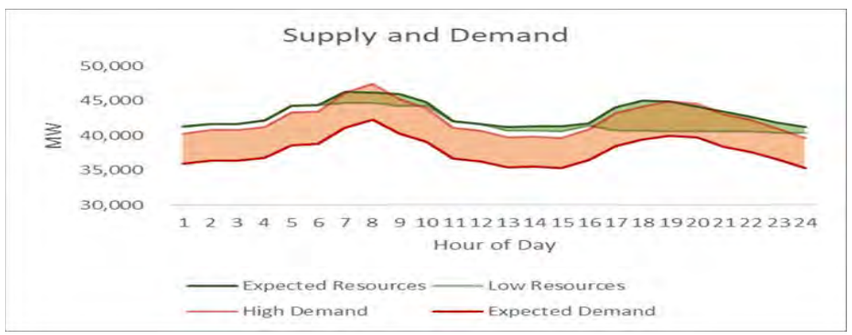
* Provides the 2022 ProbA Results for Comparison

Hourly demand and resource projections for a typical winter risk day in 2026 are shown in the figure below. Although expected resource contribution is expected to be enough to meet expected demand, there is risk that above-normal demand could exceed resources. Demand could be 10–15% higher than expected, which could strain the system from the hours beginning 3:00 p.m. through 10:00 p.m. Also, if resource contributions are less than expected, the peak hour beginning at 6:00 p.m. could lead to a loss-of-load situation. Reliance on external assistance may be necessary in these events.



Hourly Probabilistic Assessment Results | Representative Winter Risk Day 2026

Hourly demand and resource projections for a typical winter risk day in 2028 are shown in the figure below.



Hourly Probabilistic Assessment Results | Representative Winter Risk Day 2026

Demand

The requirements are obtained by adding transmission and distribution losses to the sales forecasts. The monthly peak demand is then calculated by applying load factors to each end-use and/or sector sale. The sum of these monthly end-use sector peak demands is the total monthly peak demand.

Demand-Side Management

The Québec area has various types of DR resources specifically designed for peak shaving during winter operating periods. The first type of DR resource is the interruptible load program that is mainly designed for large industrial customers; it has an impact of 2,784 MW on winter 2024–2025 peak demand. The area is also expanding its existing interruptible load program for commercial buildings, which will grow from 611 MW in 2024–2025 to 889 MW by the end of the period study. Another similar program for residential customers is in operation and should gradually rise from 166 MW for Winter 2024–2025 to 621 MW for Winter 2028–2029.

New dynamic rate options for residential and small commercial or institutional customers will also contribute to reducing peak load during winter periods by 371 MW for Winter 2024–2025 and 445 MW for Winter 2034–2035. Moreover, data centers specializing in blockchain applications are required to reduce their demand during peak hours at Hydro-Québec's request. Their contribution as a resource is expected to be around 269 MW over the study period. Finally, another DR resource consists in a voltage reduction scheme allowing for a 250 MW peak demand reduction. EE and conservation programs are integrated in the assessment area's demand forecasts.

Distributed Energy Resources

Total installed BTM capacity (solar PV) is expected to increase to 862 MW in 2035. Solar PV is accounted for in the load forecast. Nevertheless, since Québec is a winter-peaking area, DERs' on-peak contribution ranges from 2 MW for Winter 2024–2025 to 5 MW for the last winter period. No potential operational impacts of DERs are expected in the Québec area considering their low contribution.

Generation

Four wind projects with a total installed capacity of 4,000 MW are expected to be commissioned during the assessment period. The first project, Apuiat (204 MW), is expected to be commissioned in 2024–2025. The second project (1,144 MW divided into 6 wind farms) is expected to be commissioned in December 2026. The third project is Des Neiges (1,200 MW) and is divided into three phases (400 MW each). The first phase is expected to be operational in the winter of 2026–2027. The second and third phases are expected to be in service for the 2027–2028 and 2028–2029 winters, respectively. The fourth project is made of 1,500 MW divided into 8 wind farms, which are expected to be operational in the winters of 2027–2028, 2028–2029 and 2029–2030, depending on the location.

In addition to wind projects, unit replacement projects at existing hydroelectric facilities are being studied. Up to 2,000 MW of capacity could be added by replacing generating units with most recent models, as outlined in Hydro-Québec's Action Plan 2035.

Energy Storage

No energy storage facilities are planned to be commissioned during the assessment period.

Capacity Transfers

The governments of Québec and Ontario have signed an MOU of an agreement that allows a seasonal capacity exchange between the two areas for the next seven years except for the year 2027 (no exchange is allowed). The technical details of the agreement will be completed by Fall 2024 and will be in place from Winter 2024–2025 to winter 2030–2031. This agreement will be firm and allow Québec to import 600 MW from November to April. In summer, Québec will export 600 MW of firm capacity to Ontario from May to October.

Transmission

Appalaches-Maine Interconnection

This project, expected to increase transfer capability between Québec and Maine by 1,200 MW, has resumed construction. The project will connect to the New England Clean Energy Connect project (NECEC) in Maine. It involves the construction of a ±320 kV dc transmission line about 100 kilometers (62 miles) long from the Des Appalaches 735/230 kV substation to the Canada-United States. border. From the international border crossing, the dc transmission line will be extended 145 miles to a substation in Lewiston, ME, where the power will be converted from dc to ac. The project in Québec also includes the construction of an dc to dc converter at the Des Appalaches substation and triggers the need of thermally upgrade two 735 kV lines in the south of the system. The project is expected to be in service in December 2025.

Hertel-New York Interconnection (CHPE)

This project, expected to increase transfer capability between Québec and New York by 1,250 MW, is under construction. It involves the construction of a ±400 kV dc underground transmission line about 60 kilometers (37 miles) long from the Hertel 735/315 kV substation just south of Montréal to the Canada-United States border. The project will connect to the Champlain Hudson Power Express project (CHPE) in New York state. From the international border crossing, the dc transmission line will be extended 339 miles to a substation in Astoria, NY, where the power will be converted from dc to ac. The project in Québec also includes the construction of an ac to dc converter at the Hertel substation. The project is expected to be in service in May 2026.

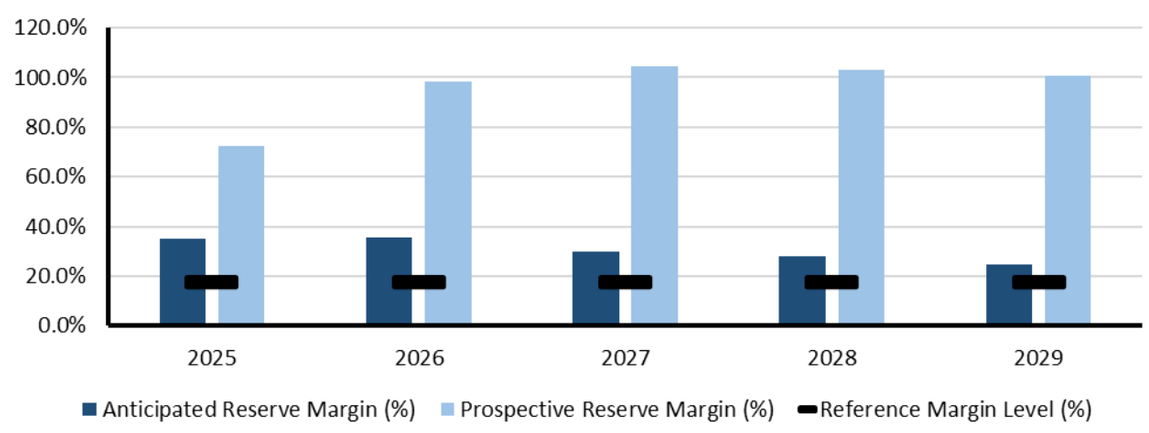


PJM

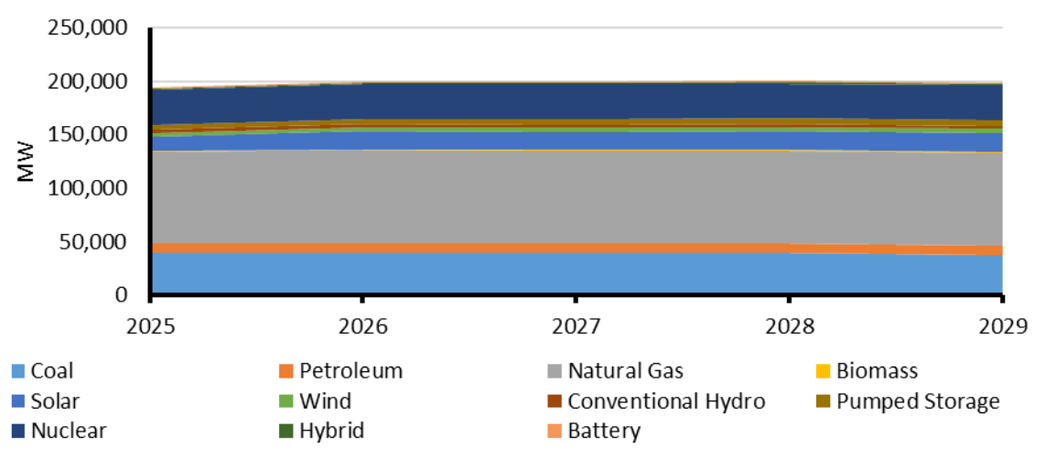
PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	153,493	156,803	159,859	162,972	165,681	167,873	170,008	172,109	174,366	176,822
Demand Response	7,554	7,693	7,808	7,913	8,000	8,083	8,162	8,230	8,312	8,400
Net Internal Demand	145,939	149,110	152,051	155,059	157,681	159,790	161,846	163,879	166,054	168,422
Additions: Tier 1	11,056	17,047	17,139	17,784	17,911	18,155	18,155	18,155	18,155	18,155
Additions: Tier 2	55,112	93,845	112,827	122,781	127,059	131,113	131,287	133,652	133,652	133,652
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	4,502	4,347	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	185,828	185,270	180,552	180,552	178,577	178,577	178,577	178,577	178,577	178,577
Anticipated Reserve Margin (%)	34.9%	35.7%	30.0%	27.9%	24.6%	23.1%	21.6%	20.0%	18.5%	16.8%
Prospective Reserve Margin (%)	72.4%	98.3%	104.7%	103.3%	100.5%	96.5%	94.1%	92.9%	82.1%	79.5%
Reference Margin Level (%)	17.7%	17.7%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the RML until 2034 when it falls below the 17.6% RML level.
- PJM implemented a number of changes to the 2023 load forecasting process to improve model accuracy, switching from an annual to monthly end-use model for PJM's sector models to better determine heating, cooling, and other non-weather-sensitive load and moving to an hourly model to better capture new technologies and peak shifting. Additionally, higher expectations for data center loads now incorporate 15-year forecasts from impacted electric distribution companies (EDC).
- PJM's review of recent policies (e.g., state laws and federal environmental initiatives) indicates over 32 GWs of potential deactivations through 2034. The pace of retirements is being driven in large part by these state laws and federal environmental initiatives that create a clear near-term, date-certain requirement for generation to comply or retire. Conversely, there are multiple mandates with renewable portfolio standards (RPS) that account for the majority of over 150 GWs submitted projects.

PJM Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	39,735	39,735	39,325	39,325	37,747
Coal*	39,394	39,394	33,313	28,240	25,124
Petroleum	8,810	8,514	8,514	8,514	8,117
Natural Gas	85,541	87,245	87,245	87,245	87,245
Natural Gas*	85,541	87,245	87,228	87,228	87,228
Biomass	928	928	928	928	928
Solar	13,349	16,770	16,908	17,621	17,754
Wind	3,017	3,512	3,507	3,507	3,507
Conventional Hydro	2,934	2,922	2,934	2,934	2,944
Pumped Storage	5,189	5,189	5,189	5,189	5,189
Nuclear	32,535	32,535	32,535	32,535	32,535
Hybrid	1,315	1,742	1,739	1,739	1,739
Battery	393	982	982	994	994
Total MW	193,747	200,074	199,807	200,532	198,699
Total MW*	193,406	199,733	193,779	189,430	186,060
*** Capacity with additional generator retirements.** Generators that are forecasted to retire by PJM are removed from the resource projection where marked.					

PJM Assessment

Planning Reserve Margins

The ARM does not fall below the RML in PJM until 2034. PJM's growing demand profile and a change in resource mix that favors VERs, however, present a new level of risk.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

PJM is forecasting around 30% installed reserves (including expected committed demand resources), which is well above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion. Due to the current low penetration of energy-limited and VERs in PJM relative to PJM's peak load, the hour with most loss of load risk remains the hour with highest forecasted demand. To address future reliability concerns due to growing VER penetration and limitations associated with the performance of those resources, PJM's Effective Load Carrying Capability methodology calculates the reliability and energy contribution of limited and variable resources.

Some of PJM's assumptions for determining the resource mix to use in the ProbA differ from those used in developing the LTRA. Only a portion of the Tier 1 resource additions are used in the ProbA to more accurately reflect historical rates of development. Additionally, more generator retirements are used in the ProbA based on PJM's generator forecasting. These assumptions are more consistent with the assumptions included in official studies performed by PJM to support its capacity market. In addition, the information in the ProbA for winter seasons refers to the Winter 2026–2027 and Winter 2028–2029 because PJM's studies are based on "delivery years," which start on June 1 of a year and end on May 31 of the subsequent year.

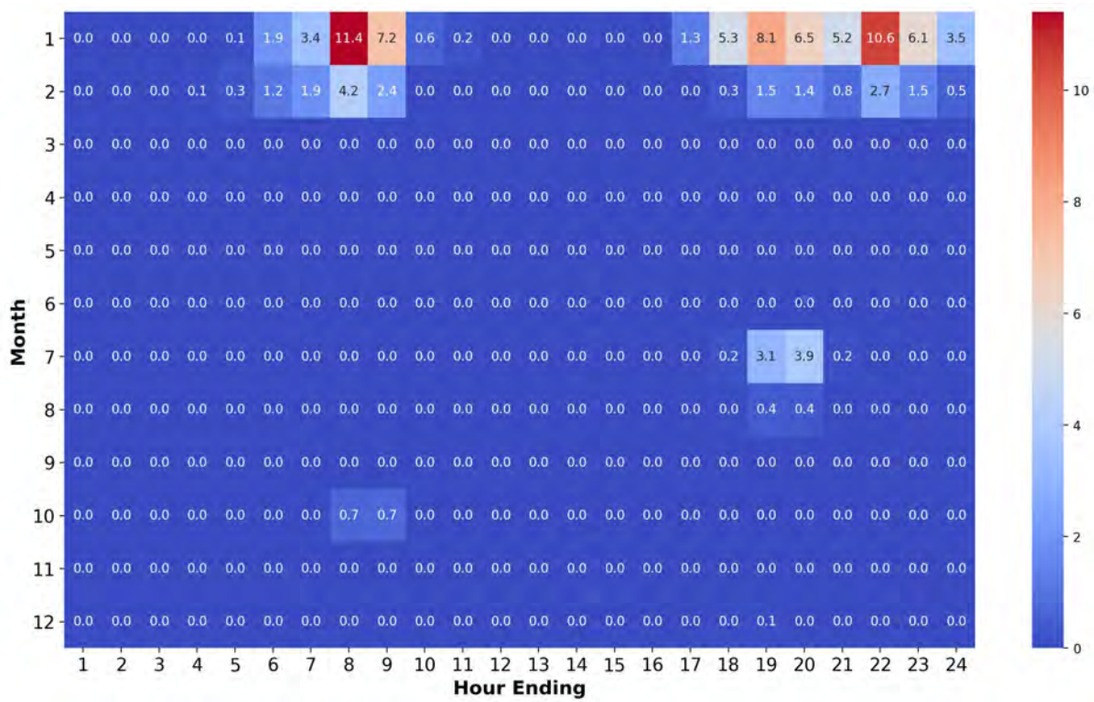
Results of the 2024 ProbA are provided in the table below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**537.52**	**1043.44**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.11**	**0.22**
Operable On-Peak Margin	29.0%	**17.8%**	**17.7%**

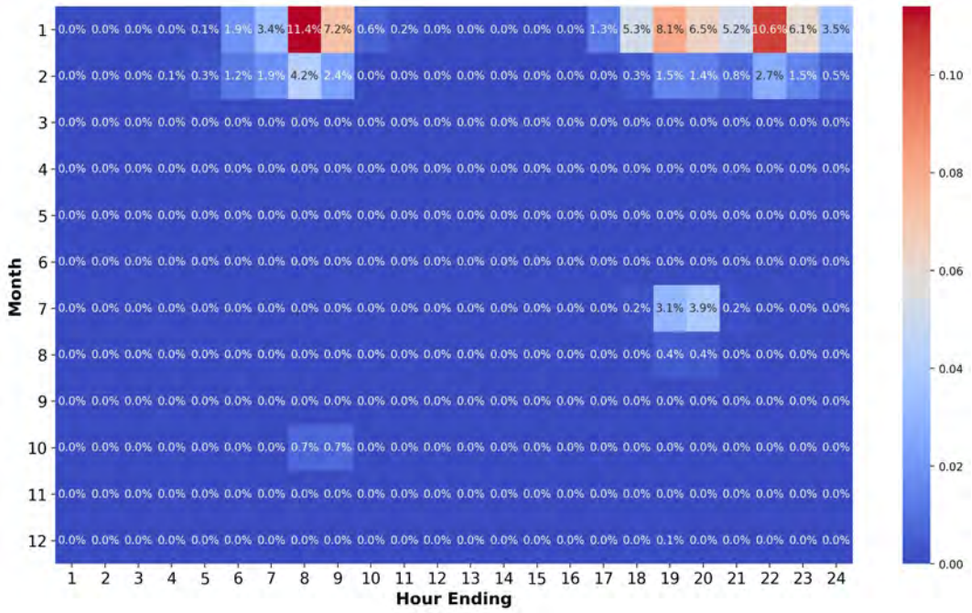
* Provides the 2022 ProbA Results for Comparison

In both 2026 and 2028, most EUE and LOLH are concentrated in the winter months (especially January), as shown in the following EUE heat maps. The risk occurs in days when temperatures are very low, which results in high loads across the assessment area. If resource performance were to occur at the levels expected during average winter days, the system should be able to serve these high loads. However, resource performance from thermal resources on very cold days, especially natural gas resources, is more likely to be poor. This, coupled with poor performance from solar resources, results in very low total electricity supply and causes loss-of-load events in the ProbA analysis. The winter load-loss events tend to occur during morning and evening demand peaks and coincide with poor thermal performance and poor solar performance.

The smaller shares of EUE and LOLH observed in the summer period for 2026 and 2028 are associated with high temperatures and high loads across the assessment area that drive load-loss events in the evening (hours ending 19 and 20) as grid-connected and BTM solar resource output declines. Low performance of wind resources and, to a lesser extent, slightly worse performance of thermal resources, also contribute to the load-loss events in the analysis.



2026 EUE Heat Map (Share of Annual EUE in %)



2028 EUE Heat Map (Share of Annual EUE in %)

PJM implemented capacity reforms (approved by FERC) at the start of 2024, which include using the loss-of-load model employed to perform the ProbA, as well as accreditation reforms based on the risk patterns identified by said model, for the capacity auctions starting with delivery year 2025–2026.

Demand

PJM is experiencing large growth in data centers that are in turn driving higher demand forecasts. Loudoun County, Virginia, in the PJM assessment area, is home to "Data Center Alley," the largest concentration of data centers in the world. Electrification in transportation, heating, and industrial sectors is also spurring demand growth.

The PJM Interconnection produces an independent peak load forecast of total internal demand using econometric regression models with daily load as the dependent variable and independent variables including calendar effects, weather, economics, and end-use characteristics. PJM annually reviews its load forecast methodology and implements changes when improvements are identified.
Summer peak load growth in PJM is projected to average 1.6% per year over the next 10-year period and 1.6% over the next 15 years. The PJM summer peak is forecasted to be 176,822 MW in 2034, a 10-year increase of 25,575 MW, and reaches 190,752 MW in 2039, a 15-year increase of 39,505 MW. Annualized 10-year growth rates for individual zones range from 0% to 5.5% with a median of 0.5%.

Winter peak load growth for PJM is projected to average 1.9% per year over the next 10-year period and 1.8% over the next 15 years. The PJM regional transmission organization winter peak load in 2033–2034 is forecasted to be 163,069 MW, a 10-year increase of 28,410 MW, and reaches 176,195 MW in 2038–2039, a 15-year increase of 41,536 MW. Annualized 10-year growth rates for individual zones range from 0% to 5.0% with a median of 0.7%.

Net energy for load growth for PJM is projected to average 2.3% per year over the next 10-year period and 2.2% over the next 15 years. Total PJM energy is forecasted to be 1,021,955 GWh in 2034, a 10-year increase of 208,627 GWh, and reaches 1,120,928 GWh in 2039, a 15-year increase of 307,600 GWh. Annualized 10-year growth rates for individual zones range from 0.1% to 7.3% with a median of 0.7%.

Demand-Side Management

DR resources can participate in all PJM markets—capacity, energy, and ancillary services. DR is forecast to grow during summer peak season from 7,550 MW in 2025 to 8,400 MW in 2034.

Distributed Energy Resources

PJM expects 4,470 MW of solar DERs at the time of the peak in 2029 and 5,103 MW in 2034. The effects of solar DERs are included in the load forecast for PJM. No effect of solar DERs is incorporated in the winter load forecast since winter expected peak occurs after sundown.

Generation

Overall, new generation is coming on-line slower than anticipated. Generator retirements are outpacing the new generation replacing them. As a result, PJM could face future resource adequacy challenges, impacting system reliability and PJM's ability to serve load. PJM could be at risk of facing resource adequacy challenges if these trends continue. PJM has applied an 11% reduction to the nameplate value of Tier 1 resources to reflect the historical rate of slower-than-anticipated addition of new generation.

PJM reviews the progression of generation interconnection to understand overall developer trends more fully and their impact on the interconnection process. Of new and expanded generation resources submitted in Queue A (1999) through December 31, 2023, 74,294 MW (or 15.8%) reached commercial operation, 33,166 MW (or 7%) were withdrawn from the interconnection process after Interconnection Service Agreement (ISA) execution, and 1,560 MW (or 0.3%) were withdrawn after wholesale market participant agreement (WMPA) execution but before construction. Overall, 20.4% of projects that requested uprates to existing capacity reached commercial operation.

Stakeholders at the June 6, 2023, Interconnection Process Subcommittee meeting approved an issue charge to examine how to enhance transfer of CIRs, which allow new generation to interconnect as a capacity resource, from deactivating resources to new generation. The goal is to develop a solution that both improves the efficiency of the process and clarifies that it applies to all energy-injecting capacity resource types. The existing provisions in the PJM Tariff, and related defined terms included in the Reliability Assurance Agreement (RAA), governing the CIR transfer process will be clarified to reduce confusion as to which capacity resource types the transfer process applies.

PJM's existing installed capacity reflects a fuel mix consisting of approximately 48% natural gas, 22% coal, and 18% nuclear. Hydro, wind, solar, oil, and waste fuels constitute the remaining 12%. A diverse generation portfolio reduces the system risk associated with fuel availability and reduces dispatch price volatility. Totaling nearly 125,000 MW of CIRs, renewable and hybrid fuels are changing the landscape of PJM's interconnection process. Solar energy makes up 40% of the new service requests in PJM's generation interconnection queue. State policies encouraging renewable generation are contributing to the rise in solar generation interconnection requests.

PJM's review of recent policies indicates over 32 GWs of potential deactivations through 2034. The pace of retirements is being driven in large part by state laws and federal environmental initiatives that create a clear near-term, date-certain requirement for generators to comply or retire. See *Energy Transition in PJM: Resource Retirements, Replacements, and Risks* (February 2023). Conversely, there are multiple mandates with RPS that account for the majority of over 150 GWs in submitted projects. Growing levels of intermittent and limited duration resources, such as wind, solar, and battery storage, do not replace conventional large-scale generation installations megawatt-for-megawatt but rather require multiple megawatts to replace one megawatt of dispatchable generation due to their limited availability in certain hours of the day and seasons of the year. Many megawatts from a range of generation technologies, available at different times, are required to replace a megawatt of thermal generating capacity. Looking out over the next 8 to 10 years of the energy resource transition, maintaining an adequate level of generation resources with operational and physical characteristics that support reliability will be crucial for PJM's ability to serve electrical demand reliably.

Energy Storage

Energy storage development continues in PJM. As solar generation increases in PJM, growth of storage is expected to follow since storage devices are frequently co-located with solar projects. Efficient grid operations in an era of rapid renewable energy resource growth will require greater system flexibility. Energy storage can offer grid operators another tool to maintain stable power supply under varying wind and solar power output driven by weather conditions or unit outages. Storage can also improve grid efficiency by increasing utilization of existing transmission lines. PJM continues to work with members, Department of Energy (DOE) national laboratories, and other industry entities to advance the use of energy storage and, in particular, enable its participation in PJM markets.

Today, there are approximately 177 GWs of solar, wind, battery, and hybrid in the PJM interconnection queue. Hybrid resources make up approximately 26 GWs and standalone storage makes up approximately 28 GWs.

Some developers are pairing storage with variable, renewable generation, such as solar or wind, to create opportunistic revenue streams. The pairing is either co-located (in which the storage facility and the generator facility are sited on the same parcel of land but each has its own connection to the grid) or hybrid (in which the storage facility and generator share a common connection to the grid).

Capacity Transfers

PJM does not rely on significant transfers to meet resource adequacy requirements. Maximum transfer (total transmission interchange capability) into PJM would amount to less than 2% of PJM's internal generation capability. At no time within this assessment period does the ARM get anywhere near 2%. PJM reliability would not be negatively affected if transfers were dropped to zero.

Transmission

PJM's Regional Transmission Expansion Plan (RTEP) continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. This shift is characterized by new wind and solar generating units driven by federal and state renewable incentives, generating plant deactivations, and market impacts introduced by DR and EE programs. As of December 31, 2023, renewable resources continue to represent a significant portion of PJM's new services requests.

The PJM board approved 48 new baseline projects during 2023 at an estimated $6.6 billion to ensure that fundamental system reliability criteria across the grid are met. The board also approved the inclusion of 93 new network transmission projects at an estimated $180 million into the RTEP.

Reliability Issues

PJM's 2023 *Load Forecast Report* addressed the impact of industry changes that are reshaping system hourly loads. As a result, the level and timing of coincident peak and non-coincident peak demands across PJM have begun to shift. Solar-power penetration, expected impacts of EVs, state electrification programs, home battery storage, and a significant increase in data center loads are markedly increasing the complexity of PJM's load forecasting process. Driven by discrete and localized load growth, like Data Center Alley in Loudoun County, Virginia, in 2022, PJM and stakeholders conducted a review of data center load growth and identified growth rates of over 300% in some instances. As a result, the 2023 PJM *Load Forecast Report* incorporates adjustments to specific zones for data center load growth.

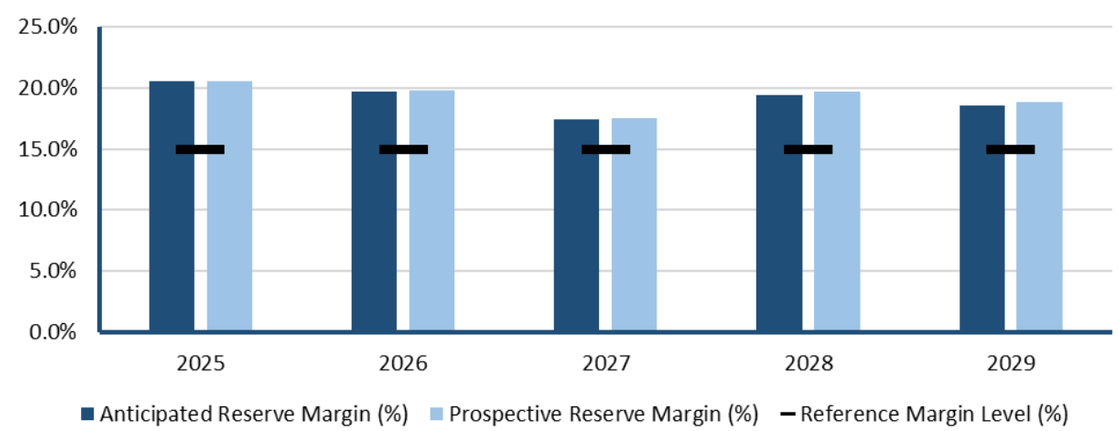


SERC-Central

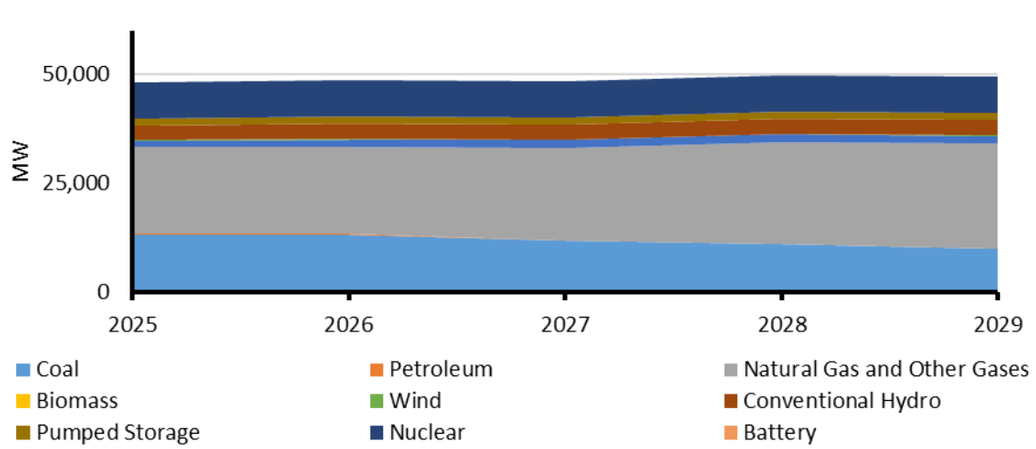
SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	42,983	43,202	43,399	43,384	43,440	43,636	43,725	43,913	44,077	44,316
Demand Response	1,859	1,856	1,852	1,849	1,847	1,844	1,842	1,840	1,839	1,837
Net Internal Demand	41,124	41,346	41,547	41,535	41,593	41,792	41,883	42,074	42,239	42,479
Additions: Tier 1	1,123	1,540	2,970	4,983	5,841	5,841	5,841	7,609	8,935	9,598
Additions: Tier 2	20	20	20	120	120	120	120	120	120	120
Additions: Tier 3	135	263	415	1,118	3,395	4,198	4,965	5,368	5,745	6,198
Net Firm Capacity Transfers	1,240	765	190	-288	-288	-288	-288	-287	-287	-287
Existing-Certain and Net Firm Transfers	48,437	47,962	45,813	44,608	43,478	43,191	43,191	42,224	42,224	41,153
Anticipated Reserve Margin (%)	20.5%	19.7%	17.4%	19.4%	18.6%	17.3%	17.1%	18.4%	21.1%	19.5%
Prospective Reserve Margin (%)	20.8%	20.0%	17.7%	19.7%	18.9%	17.6%	17.4%	18.8%	21.4%	19.8%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the 15% target RML for the assessment period.
- Projected coal generation retirements total 4,399 MW in the next 10 years. Resource additions include 6,838 MW of natural gas, 75 MW of BESS, and 760 MW of solar generation over the next 10 years.
- New transmission line additions total 209 miles through 2028. The entities also plan to upgrade 185 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows.

SERC-Central Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	13,348	13,348	11,774	11,047	9,917
Coal*	13,048	13,348	11,146	10,013	8,883
Petroleum	148	148	148	148	148
Natural Gas	19,857	19,857	21,287	23,300	24,158
Natural Gas*	19,476	19,476	20,906	22,919	23,777
Biomass	36	36	36	36	36
Solar	1,338	1,706	1,706	1,706	1,706
Wind	172	172	172	172	172
Conventional Hydro	3,393	3,393	3,393	3,393	3,393
Pumped Storage	1,673	1,673	1,673	1,673	1,673
Nuclear	8,280	8,280	8,280	8,280	8,280
Battery	75	125	125	125	125
Total MW	48,319	48,737	48,593	49,879	49,607
Total MW*	47,639	48,356	47,584	48,464	48,192
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Central Assessment

Planning Reserve Margins
The future reserve margins are above the RML for SERC-Central.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
The 2024 ProbA results shown in the table below indicate negligible unserved energy and load-loss. Analysis of detailed ProbA outputs shows that that this negligible risk occurring in 2026 is associated with hot summer conditions and upper levels of economic load forecast models.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**0.10**	**0.00**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.00**	**0.00**
Operable On-Peak Margin	18.4%	**13.2%**	**14.9%**

* Provides the 2022 ProbA Results for Comparison

Demand
Drivers of load growth are commercial expansion, electrification of heating and transportation, and growth in residential load. Entities expect to continue to have increased economic growth that will drive both population and employment to the SERC-Central assessment area, but these gains in employment are slightly offset by improvements in efficiency.

Distributed Energy Resources
SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Generation
Projected coal generation retirements total 4,399 MW in the next 10 years. Resource additions include 6,838 MW of natural gas, 75 MW of BESS, and 760 MW of solar generation over the next 10 years.

Generator retirements are carefully managed by entities in the SERC-Central assessment area. Entities perform studies to determine the impacts of confirmed or unconfirmed retirements. Entities incorporate these studies into resource plans that highlight the significance of future generation projects. Additionally, there are no significant retirement plans that will affect reliability.

Capacity Transfers
Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas within the Region for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission
The entities reported a total addition of 209 miles of new transmission lines until 2028. The entities are also planning to upgrade 185 miles of transmission lines in the next 10 years to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability. Entities do not anticipate any transmission limitations or constraints with significant impacts on reliability.

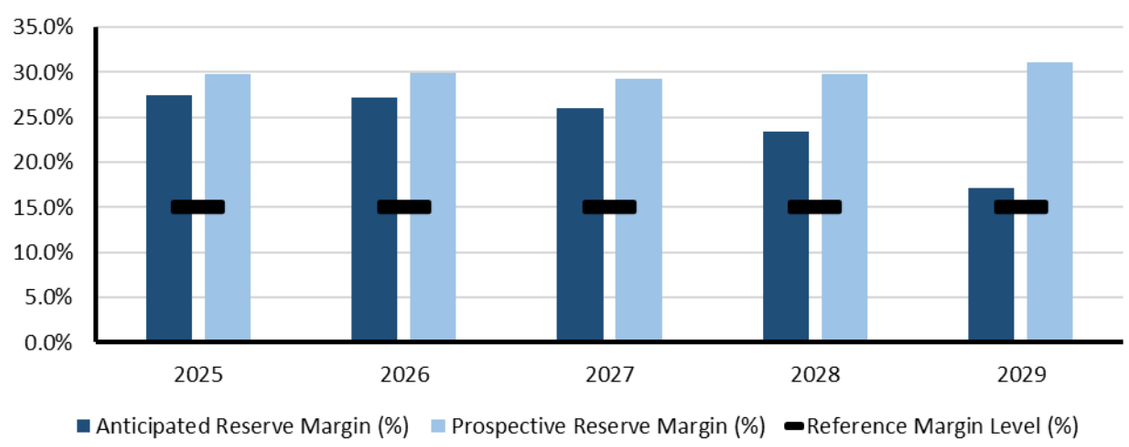


SERC-East

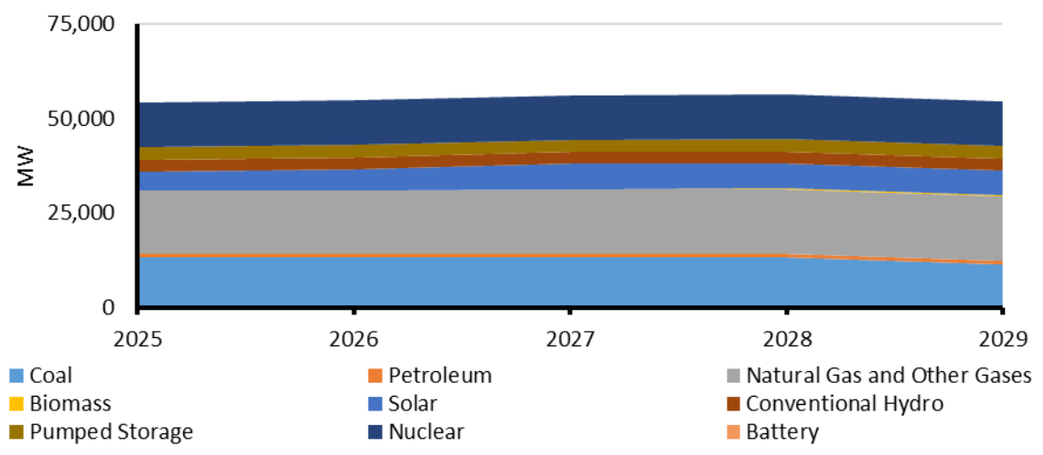
SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	44,099	44,789	46,308	47,378	48,286	49,533	50,349	50,896	51,741	52,155
Demand Response	1,092	1,186	1,214	1,225	1,228	1,229	1,230	1,231	1,232	1,233
Net Internal Demand	43,007	43,603	45,094	46,153	47,058	48,304	49,119	49,665	50,509	50,922
Additions: Tier 1	772	1,330	2,777	2,818	2,818	2,818	2,818	2,818	2,818	2,818
Additions: Tier 2	38	217	506	1,975	5,577	8,032	9,766	11,595	13,978	16,767
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	593	593	593	593	593	593	593	593	593	593
Existing-Certain and Net Firm Transfers	54,039	54,129	54,045	54,118	52,301	52,395	51,316	49,998	49,998	48,636
Anticipated Reserve Margin (%)	27.4%	27.2%	26.0%	23.4%	17.1%	14.3%	10.2%	6.3%	4.6%	1.0%
Prospective Reserve Margin (%)	29.8%	30.0%	29.3%	29.8%	31.1%	33.0%	32.1%	31.7%	34.2%	35.9%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the RML until 2030 when it falls below the 15.0% RML level.
- Since the *2023 LTRA*, solar PV resources have grown from 1.5 GW to an expected 4.7 GW by the end of 2024.

SERC-East Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	13,150	13,150	13,150	13,150	11,333
Coal*	13,108	12,564	12,564	11,910	10,093
Petroleum	1,044	1,044	992	992	992
Petroleum*	1,044	1,044	868	868	868
Natural Gas	16,627	16,717	17,061	17,121	17,121
Natural Gas*	16,601	16,691	17,061	17,121	17,121
Biomass	176	176	176	176	176
Solar	4,995	5,553	6,624	6,665	6,665
Conventional Hydro	3,102	3,102	3,102	3,102	3,102
Pumped Storage	3,324	3,324	3,324	3,324	3,324
Nuclear	11,795	11,795	11,795	11,808	11,808
Battery	6	6	6	6	6
Total MW	54,218	54,866	56,229	56,343	54,526
Total MW*	54,150	54,254	55,519	54,979	53,162
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-East Assessment

Planning Reserve Margins
The ARM falls below the RML starting in 2030 for SERC-East. Projected demand is expected to increase around 8.75% from 2024 to 2028 in the footprint.

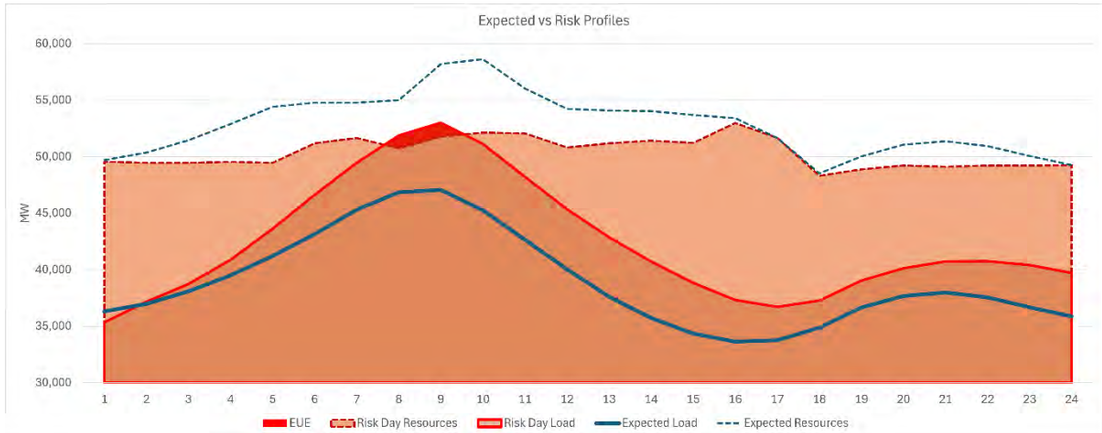
Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
SERC-East has an elevated risk of energy shortages based on results of the 2024 ProbA shown in the table below.

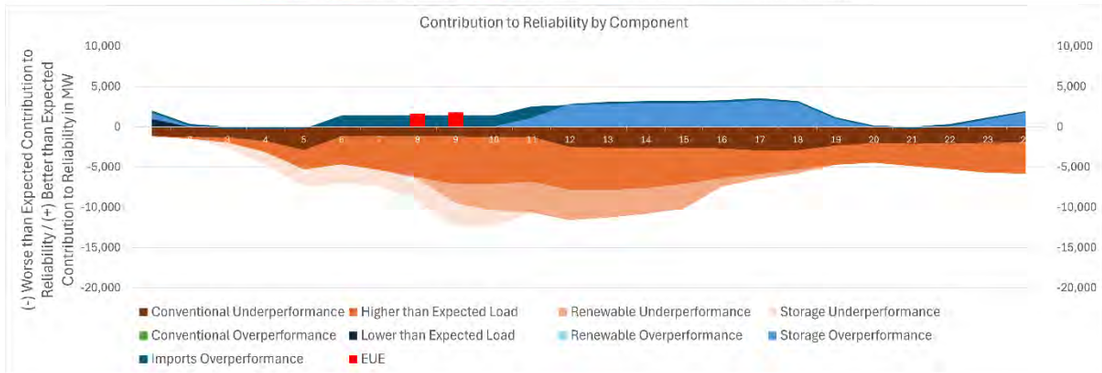
Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	92.49	**143.35**	**207.26**
EUE (PPM)	0.39	**0.60**	**0.81**
LOLH (hours per year)	0.08	**0.09**	**0.17**
Operable On-Peak Margin	16.1%	**14.2%**	**11.1%**

* Provides the 2022 ProbA Results for Comparison

SERC-East has changed from a summer-peaking assessment area to a dual-peaking assessment area, with both a summer and winter peak. The addition of solar PV generation shaves off summer peak demand, and a trend toward electrification of heating drives up winter peak demand. The ProbA results for 2026 indicate some risk for SERC-East in the winter months of January and February. The annual EUE is 143.35 MWh but for a very short, expected duration of 0.09 hours. The risk occurs during winter morning hours around 8:00 a.m. due to a combination of higher loads and solar resources not yet ramped up. For extreme cold weather events that might impact a wide geographical footprint, there is also a limit on imports from neighboring areas.

For 2028, SERC-East continues to show winter risk with 207.26 MWh of EUE and 0.17 hours of LOLH. The load is expected to grow by over 2%. The load-loss events in the analysis are for very few hours and short duration, occur around 8:00 a.m., and are tied to extreme weather, higher forecasted load levels, and lower resource performance. This can be seen in the following figures showing the risk profile and resource performance for a likely event-day.





Demand
Population growth is driving demand forecast increases in SERC-East. Entities expect faster-than-average growth in the urban areas and overall increasing energy and demand in the 10-year forecast. While the economic indicators used in the forecast have growth rates that vary during each year, the economic outlook will contribute to increased energy and demand over the 10-year forecast. Some entities project their EE adoption to impact roughly 1% of annual retail sales (after opt-outs) during the 10-year forecast.

There are also many large commercial/industrial loads accounted for in the forecast that have been announced or in discussions with the entities to locate in the service territory. If the large sites come to fruition, it will drive significant increases in energy and demand during the later part of the 10-year forecast.

The projected EV adoptions are driving energy and demand increases during the later part of the 10-year forecast window. EVs are currently the most significant contributor of all electrification sources (e.g., heating, industrial) in the 10-year forecast.

Distributed Energy Resources

SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Capacity Transfers

Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission

The entities reported a total addition of 286 miles of new transmission lines through 2028. The entities are also planning to upgrade 515 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability. Entities do not anticipate any transmission limitations or constraints with significant impacts on reliability.

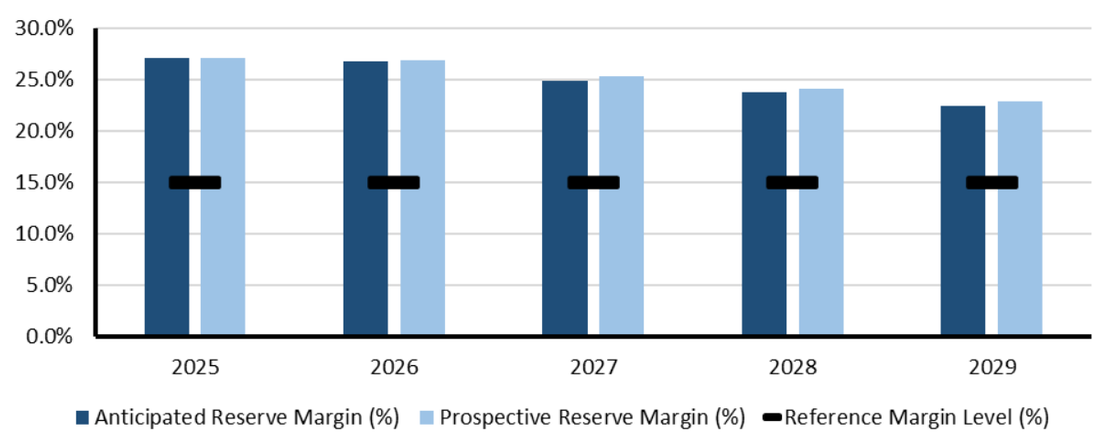


SERC-Florida Peninsula

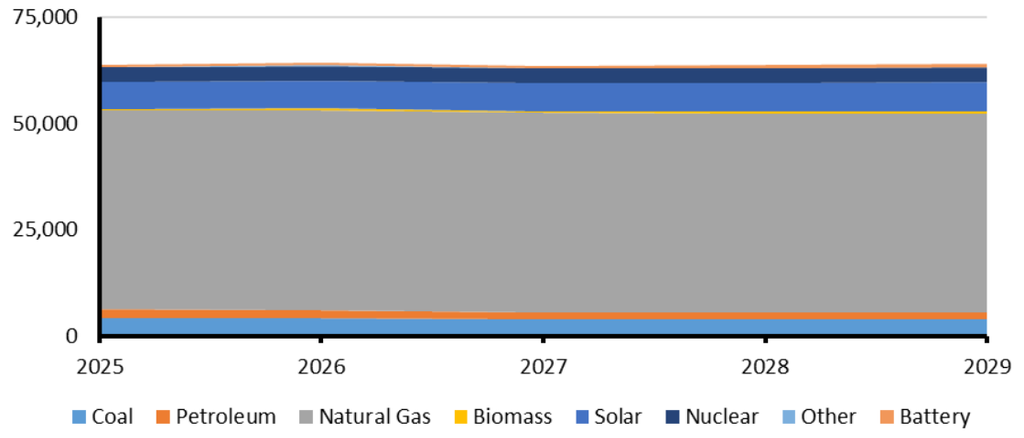
SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	53,509	53,795	54,015	54,551	55,250	55,879	56,593	57,612	58,631	59,679
Demand Response	2,840	2,834	2,837	2,820	2,806	2,795	2,783	2,771	2,761	2,748
Net Internal Demand	50,669	50,961	51,178	51,731	52,444	53,084	53,810	54,841	55,870	56,931
Additions: Tier 1	871	1,497	1,573	1,785	2,018	3,421	3,927	4,545	4,547	4,549
Additions: Tier 2	0	40	200	200	200	200	200	200	200	200
Additions: Tier 3	0	39	39	39	39	39	39	39	39	39
Net Firm Capacity Transfers	494	293	293	200	200	200	200	200	200	200
Existing-Certain and Net Firm Transfers	63,521	63,121	62,366	62,230	62,230	61,725	61,725	61,493	61,493	61,493
Anticipated Reserve Margin (%)	27.1%	26.8%	24.9%	23.7%	22.5%	22.7%	22.0%	20.4%	18.2%	16.0%
Prospective Reserve Margin (%)	27.1%	26.9%	25.3%	24.1%	22.9%	23.1%	22.4%	20.8%	18.6%	16.4%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the 15% target RML for the assessment period.
- Projected coal generation retirements total 459 MW in the next 10 years. Tier 1 additions include 484 MW of natural gas, 1,560 MW of BESS, and 1,792 MW of solar generation over the next 10 years.
- New transmission line additions total 668 miles through 2030. The entities also plan to upgrade 256 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows.

SERC-Florida Peninsula Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	4,367	4,367	3,908	3,908	3,908
Coal*	3,341	3,779	2,851	2,851	2,851
Petroleum	1,957	1,852	1,724	1,724	1,724
Petroleum*	1,892	1,786	1,477	1,477	1,477
Natural Gas	46,860	47,012	46,844	46,801	46,801
Biomass	310	310	310	310	310
Solar	6,255	6,635	6,711	6,853	6,997
Nuclear	3,502	3,502	3,502	3,502	3,502
Other	9	9	9	9	9
Battery	638	638	638	708	797
Total MW	63,898	64,324	63,646	63,815	64,048
Total MW*	62,807	63,671	62,343	62,512	62,745
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Florida Peninsula Assessment

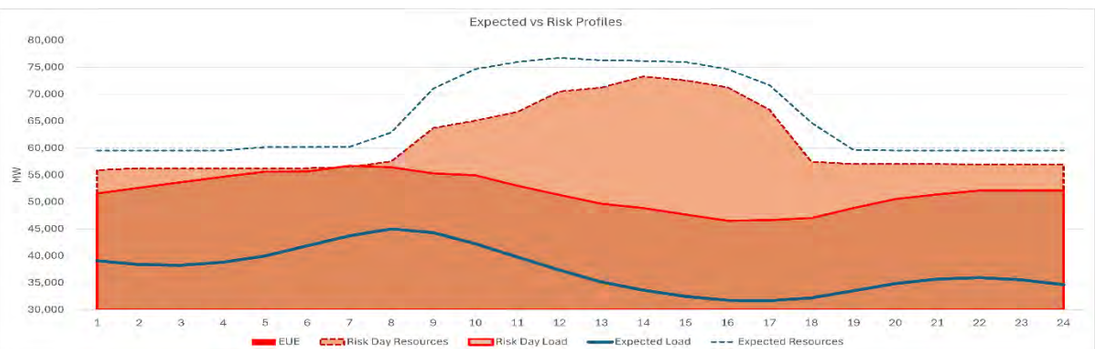
Planning Reserve Margins
The ARM is not expected to fall below the RML for any period of the assessment period.

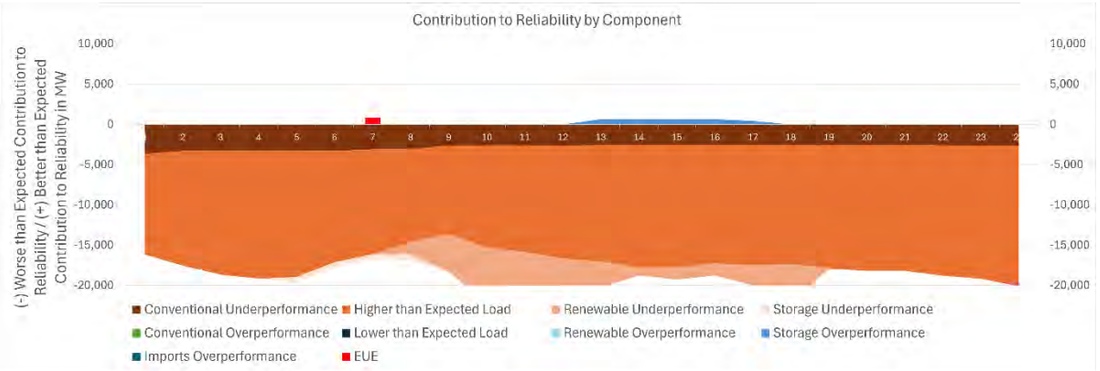
Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
The 2024 ProbA results shown in the table below indicate negligible unserved energy and load loss. Analysis of detailed ProbA outputs shows that that the negligible risk in year 2026 is associated with hot late-summer or early fall conditions, high generator forced outages, and upper levels of economic load forecast models. The risk occurs in evening hours around 7:00 p.m. when contribution from solar generation is limited.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	1.13	**2.18**	**16.28**
EUE (PPM)	0.00	**0.01**	**0.06**
LOLH (hours per year)	0.00	**0.01**	**0.02**
Operable On-Peak Margin	18.6%	**19.2%**	**16.3**

* Provides the 2022 ProbA Results for Comparison

For study year 2028, the ProbA results shows very low risk with 16.28 MWh of EUE and 0.02 LOLH hours. The driver of the risk is mainly extreme winter weather, similar to conditions from 1989, when Florida experienced one of the worst winter freezes on record. With higher load levels and lower resources in 2028, the low risk shifts to late December, occurring in morning hours when contribution from solar generation is limited, and is associated with winter freeze events that limit imports.





Demand
The individual entities within the FL-Peninsula Subregion develop their load forecasts and the Florida Reliability Coordinating Council (FRCC) then aggregates these forecasts to calculate a non-coincident seasonal peak for the subregion. Each entity adjusts their forecasts annually to account for their actual peak demands, updated economic outlooks, population growth, weather patterns, conservation and energy efficiency efforts, and electric appliances usage patterns. Based on the data reported in the 2023 FRCC Regional Load and Resource Plan, the net energy for load (NEL) and summer peak demands are forecasted to grow when compared to previous forecasts. The current average annual growth rate for the NEL is 0.97% per year. Firm summer and winter peak demand growth are expected to increase to 1.19% and 1.17%, respectively.

Demand-Side Management
Controllable DR from interruptible and dispatchable load management programs within the FL-Peninsula Subregion is treated as a load-modifier, and it is projected to be constant at approximately 6% of the summer and winter total peak demands for all years of the assessment period.

Distributed Energy Resources
SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Generation

Generator retirements are carefully managed by entities in the SERC-Florida Peninsula assessment area. Entities perform studies to determine the impacts of confirmed or unconfirmed retirements. Entities incorporate these studies into resource plans that highlight the significance of future generation projects. Additionally, there are no significant retirement plans that will affect reliability.

Energy Storage

Electricity storage (ES) is still a growing capacity contributor in the assessment area. Over the next 10 years, a total of approximately 2,900 MW of ES generation is projected to be in service by 2032 and is included in the utilities' 10-year site plans (approximately 775 MW by 2029).

Individual entities in the assessment area that have installed or are projecting the installation of ES are developing operating protocols on the use and dispatch of these facilities. ES units are studied as part of the normal generation interconnection process and included in other FRCC studies and processes with members providing individual dispatch profiles and study levels in order to identify potential operational impacts.

Capacity Transfers

Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission

The entities reported a total addition of 668 miles of new transmission lines through 2030. The entities are also planning to upgrade 256 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability.

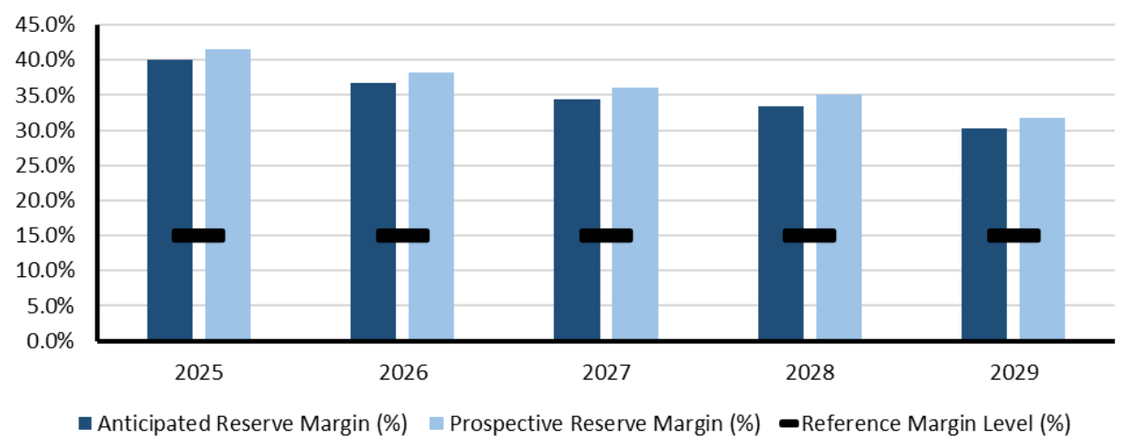


SERC-Southeast

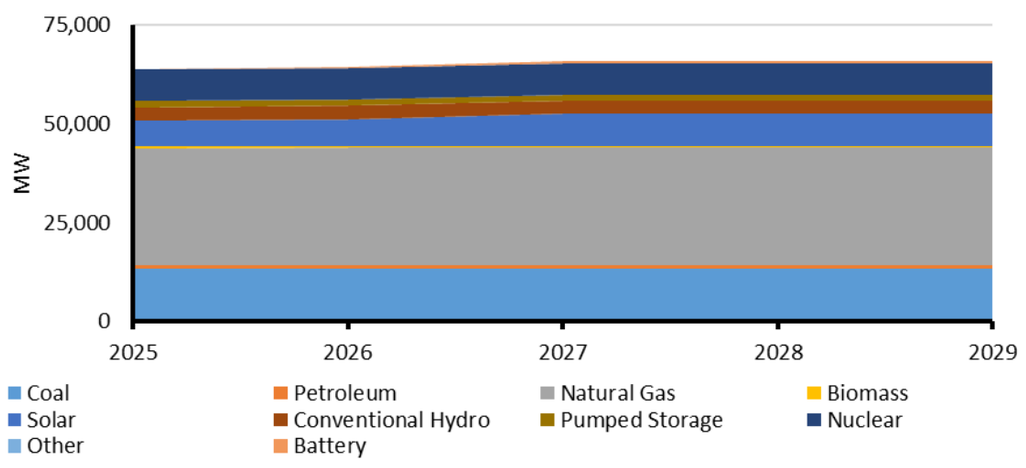
SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	46,984	48,384	50,467	50,852	51,974	53,031	53,794	54,233	54,677	55,078
Demand Response	1,633	1,666	1,723	1,755	1,875	1,876	1,875	1,875	1,876	1,876
Net Internal Demand	45,351	46,718	48,744	49,097	50,099	51,155	51,919	52,358	52,801	53,202
Additions: Tier 1	1,248	1,486	3,050	3,050	3,050	3,129	3,129	3,129	3,129	3,129
Additions: Tier 2	105	105	218	218	218	218	218	218	218	218
Additions: Tier 3	366	366	366	366	366	366	366	366	366	366
Net Firm Capacity Transfers	-392	-392	-392	-392	-684	-684	-684	-684	-684	-684
Existing-Certain and Net Firm Transfers	62,257	62,413	62,472	62,472	62,180	62,180	62,180	62,180	62,180	62,180
Anticipated Reserve Margin (%)	40.0%	36.8%	34.4%	33.5%	30.2%	27.7%	25.8%	24.7%	23.7%	22.8%
Prospective Reserve Margin (%)	41.5%	38.2%	36.0%	35.0%	31.7%	29.2%	27.3%	26.2%	25.1%	24.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the 15% target RML for the assessment period.

SERC-Southeast Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	13,275	13,275	13,275	13,275	13,275
Coal*	13,275	13,275	12,271	10,321	10,321
Petroleum	915	915	915	915	915
Petroleum*	915	915	915	899	899
Natural Gas	29,639	29,795	29,854	29,854	29,854
Natural Gas*	29,564	29,387	29,446	28,426	28,426
Biomass	424	424	424	424	424
Solar	6,597	6,835	8,021	8,021	8,021
Conventional Hydro	3,293	3,293	3,293	3,293	3,293
Pumped Storage	1,632	1,632	1,632	1,632	1,632
Nuclear	8,018	8,018	8,018	8,018	8,018
Battery	105	105	483	483	483
Total MW	63,897	64,291	65,914	65,914	65,914
Total MW*	63,822	63,883	64,502	61,516	61,516
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Southeast Assessment

Planning Reserve Margins

The future reserve margins are above the RMLs for SERC-Southeast.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

The 2024 ProbA results shown in the table below indicate negligible unserved energy and load loss.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**0.00**	**0.00**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.00**	**0.00**
Operable On-Peak Margin	30.8%	**29.6%**	**25.6%**

* Provides the 2022 ProbA Results for Comparison

Demand

Data centers, cryptocurrency facilities, and large commercial and industrial load are driving demand forecast growth in the assessment area. Metro areas are experiencing a higher growth rate compared to rural areas.

Demand-Side Management

Entities within the SERC-Southeast assessment area use a variety of controllable and dispatchable DR programs to reduce peak demand. One entity manages a voluntary DSM water heater program designed to allow system operators to control the appliances' usage during peak demand periods. Another entity monitors and dispatches DR programs commensurate with contract terms. Annual ELCC simulations are performed to determine the capacity value for each unique and active DR program. An adjustment to that capacity value is then made based on predicted customer response when the program is called or dispatched.

Distributed Energy Resources

SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Generation

Generator retirements are carefully managed by entities in the SERC-Southeast assessment area. Entities perform studies to determine the impacts of confirmed or unconfirmed retirements. Entities incorporate these studies into resource plans that highlight the significance of future generation projects. Additionally, there are no significant retirement plans that will affect reliability.

Capacity Transfers

Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas within the Region for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission

The entities reported a total addition of 1,078 miles of new transmission lines in the next 10 years. The entities are also planning to upgrade 694 miles of transmission lines during this time to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability.

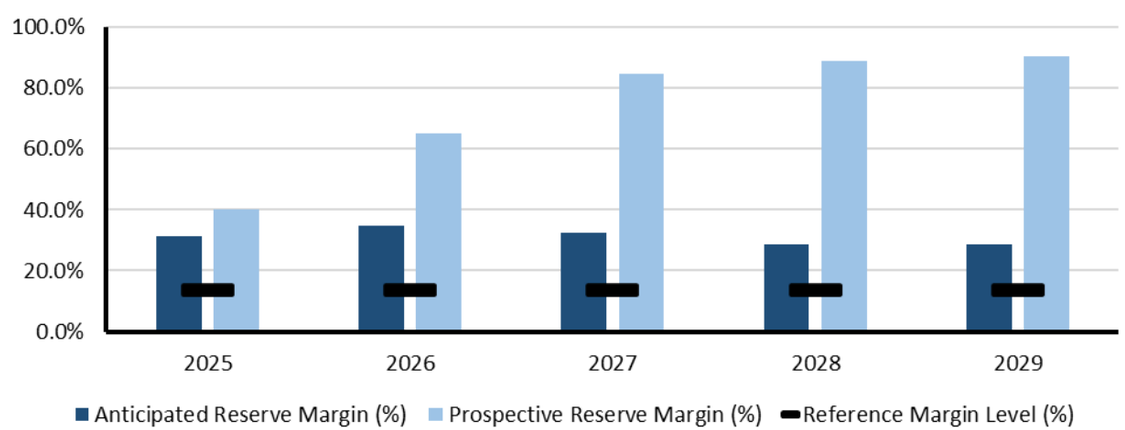


Texas RE-ERCOT

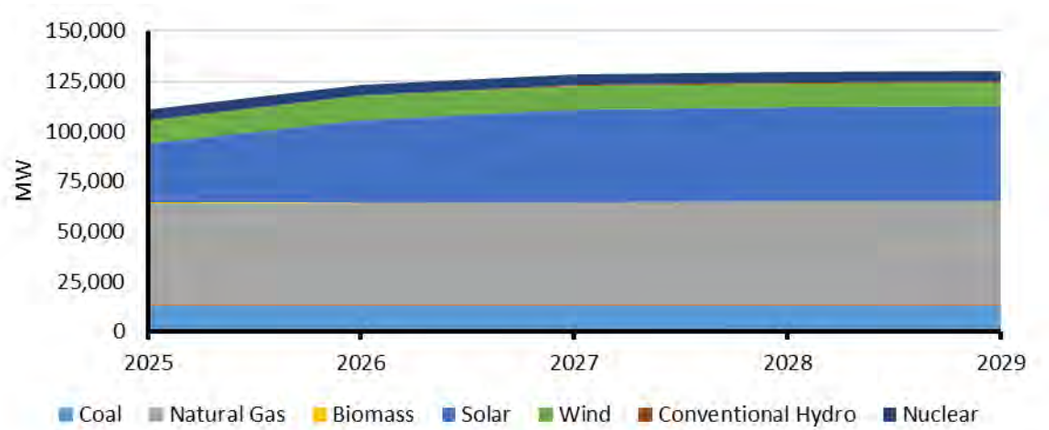
The Electric Reliability Council of Texas (ERCOT) is the ISO for the Texas Interconnection and is located entirely in the state of Texas; it operates as a single BAand performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking and covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,250 generation units, and serves more than 27 million people. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	88,873	95,721	101,405	105,417	106,365	106,951	106,772	106,463	106,062	106,961
Demand Response	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652
Net Internal Demand	86,220	93,069	98,753	102,765	103,713	104,298	104,119	103,811	103,410	104,309
Additions: Tier 1	11,187	23,684	28,725	29,226	29,903	29,903	29,903	29,903	29,903	29,903
Additions: Tier 2	7,281	27,876	51,414	62,225	65,786	65,939	65,939	65,939	65,939	65,939
Additions: Tier 3	7,252	17,627	29,082	41,174	45,318	47,062	47,062	47,062	47,062	47,062
Net Firm Capacity Transfers	20	20	20	20	20	20	20	20	20	20
Existing-Certain and Net Firm Transfers	101,906	101,645	102,003	103,088	103,338	103,338	103,338	103,338	103,338	103,338
Anticipated Reserve Margin (%)	31.2%	34.7%	32.4%	28.8%	28.5%	27.8%	28.0%	28.3%	28.8%	27.7%
Prospective Reserve Margin (%)	40.3%	65.2%	84.6%	88.8%	90.3%	88.8%	89.1%	89.7%	90.4%	88.8%
Reference Margin Level (%)	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Generation resources, primarily solar PV, continue to be added to the grid in Texas in large quantities, increasing ARMs but also elevating concerns of energy risks that result from the variability of these resources and the potential for delays in implementation. The summer ARM is above the RML (13.75%) for all 10 years of this assessment period (2025–2034). The ARM peaks at 34.7% by Summer 2026, reflecting the expected addition of about 23,680 MW of Tier 1 capacity, most of which is solar PV.

- The Public Utility Commission of Texas (PUCT) established a reliability standard and accompanying reliability assessment process in August 2024. The reliability standard is based on multiple probabilistic reliability measures that capture the different dimensions of loss-of-load events: average event frequency (LOLE), maximum event duration, and maximum event magnitude. ERCOT will begin performing reliability assessments required by the new standard in 2026.

- ERCOT's summer peak demand is forecast to increase by 4.6% per year from 2025 through 2029. In comparison, the five-year summer peak demand growth projection for the *2023 LTRA* was 1.1%. This high growth level is driven by a large amount of newly contracted loads planned for interconnection during this period. These contracted loads are mainly comprised of Permian Basin oil and gas production facilities, data centers, crypto-mining operations, and industrial facilities.

Texas RE-ERCOT Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	13,568	13,568	13,568	13,568	13,568
Coal*	13,568	13,568	12,913	12,353	12,353
Petroleum	10	10	10	10	10
Natural Gas	50,568	50,694	50,845	51,458	51,458
Natural Gas*	49,709	49,928	48,823	49,436	49,436
Biomass	163	163	163	163	163
Solar	29,557	41,201	45,984	46,485	47,163
Wind	11,332	11,908	12,166	12,166	12,166
Conventional Hydro	458	458	458	458	458
Nuclear	4,973	4,973	4,973	4,973	4,973
Total MW	110,628	122,975	128,167	129,281	129,958
Total MW*	109,769	122,208	125,490	126,044	126,721
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

Planning Reserve Margins

The summer ARM is above the RML (13.75%) for all 10 years of this assessment period (2025–2034). The ARM peaks at 34.7% by Summer 2026, reflecting the expected addition of about 23,680 MW of Tier 1 capacity, most of which is solar PV. However, the high reserve margin belies concerns over the continuing trend toward less fully dispatchable resources and more IBRs like solar PV and wind. While thermal resource availability and adequate gas supplies are still concerns during extreme winter weather events, the fleet performed well during Winter Storm Heather in January 2024, indicating that new weatherization standards, fully implemented in 2023, are effective.

Non-Peak Hour Risk and Energy Assurance

The PUCT established a reliability standard and accompanying reliability assessment process in August 2024. The reliability standard is based on multiple probabilistic reliability measures that capture the different dimensions of loss-of-load events: average event frequency (LOLE), maximum event duration, and maximum event magnitude. The latter two measures have an "exceedance tolerance," which is the maximum acceptable percentage frequency of loss-of load events that exceed the permissible thresholds based on a probabilistic simulation.

For non-winter months, ERCOT continues to experience the highest reserve scarcity risk during the early evening hours—peaking at hour ending (HE) 9:00 p.m.—based on probabilistic modeling of monthly peak load days. The elevated risk is due to the drop-off in solar generation and continued higher loads during those hours. The summer peak load hour continues to be 5:00 p.m. For winter, the peak load hour is HE 8:00 a.m. Risk modeling indicates elevated reserve scarcity risk for the morning hours (HE 7:00 a.m. to 9:00 a.m.) as well as the early evening hours.

ERCOT is experiencing transmission limitations as a result of load growth and resource development that affect energy delivery. On March 1, 2024, ERCOT introduced four new Interconnection reliability operating limits (IROL) in the South Texas region. This consists of two South Texas import constraints and two South Texas export constraints, which, if violated, could result in a thermal cascading condition. This is the first thermal IROL that could lead to a cascading condition in the Texas RE-ERCOT Region and has been attributed to the increase in generation capacity in South Texas and the rapid load growth in central Texas. To manage the South Texas export constraint, generation in South Texas must be curtailed to maintain transmission line flows below 100% of the impacted lines' thermal ratings. The risk of such curtailments, which is highest for the hours with the highest net peak loads (early evening), is included in the monthly probabilistic reserve risk assessments. ERCOT has approved two San Antonio Reliability projects that are expected to be completed in 2027 and should help alleviate some of risk drivers associated with these IROLs.

Probabilistic Assessment

Results of the 2024 ProbA are shown in the table below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	1,235	**11,090**	**781**
EUE (PPM)	2.63	**18.95**	**1.12**
LOLH (hours per year)	0.30	**1.57**	**0.16**
Operable On-Peak Margin	35.9%	**28.8%**	**46.9%**

* Provides the 2022 ProbA Results for Comparison

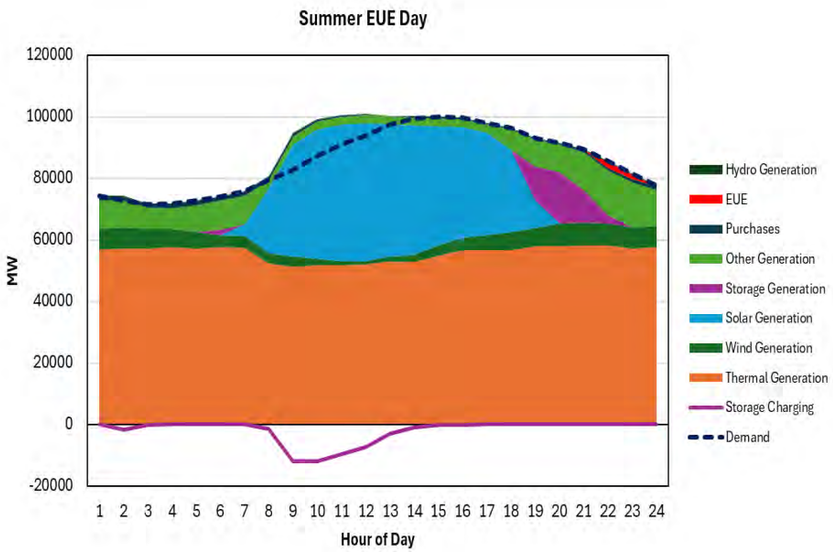
Increasing reliability risk in ERCOT is primarily driven by increasing large load demand anticipated from data centers, Bitcoin operations, continued load growth in oil and gas-producing areas (such as the Permian Basin), and growth in industrial facilities. Over 20 GW of newly contracted large loads, in addition to other organic load growth, is projected to be added to ERCOT by 2028. ERCOT also anticipates 1,860 MW of fossil-fueled plant capacity to be retired by Summer 2028. New planned units are primarily renewable and storage, which exhibit declining marginal reliability contributions. The reliability forecasts provided by this ProbA assessment for 2028 include resource capacity contributions from expansion planning analysis conducted for ERCOT's 2024 *Long-Term System Assessment*. While there is uncertainty around the deployment of these resources, the large load demand growth is also uncertain and large loads are subject to various requirements for being integrated into the grid.

All SERVM simulations for ERCOT and surrounding regions impose all relevant generator temporal constraints, including operating limitations on conventional units as well as state-of-charge on batteries, so this assessment accounts for energy adequacy. However, this assessment does assume fuel for conventional units will be available when needed.[37]

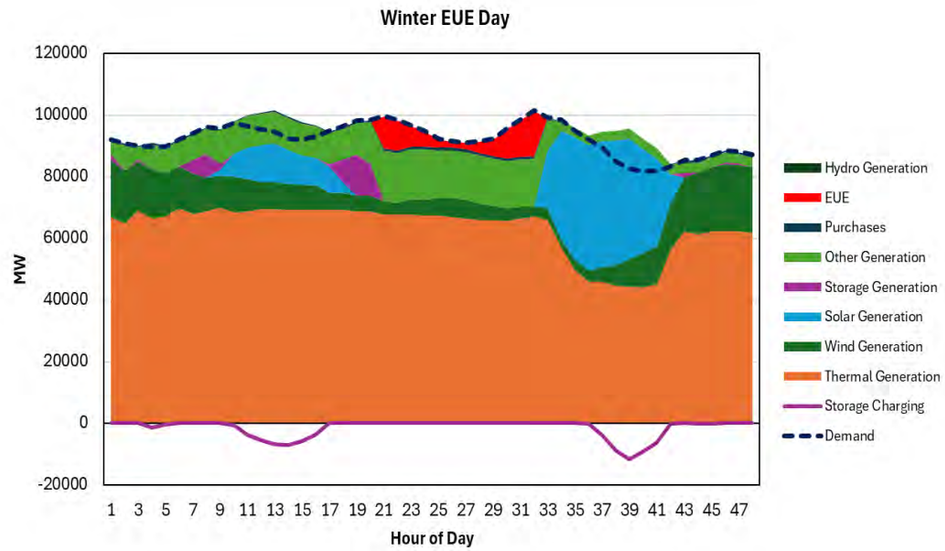
The unique characteristics of winter risk vs. summer risk can be seen in the following charts of a representative risk day. While peak winter loads can persist for 48 hours or longer, peak summer

[37] ERCOT and several other entities used SERVM software tool to perform the ProbA. Information about SERVM can be found at the company's website.

periods generally only last for a few hours. This has significant implications for the duration and depth of firm load-shed events in the winter as well as for the reliability contribution of energy limited and non-dispatchable resources. The most extreme winter event modeled for 2026 was 16 hours in duration and 29 GW in depth. The illustration below indicates a winter EUE event with duration >12 hours while most summer events were 1–2 hours in duration.



Metric	2026 Summer	2026 Winter	2028 Summer	2028 Winter
LOLE (days/year)	0.38	0.51	0.05	0.04
LOLH (hours/year)	1.41	1.57	0.18	0.16
EUE (MWh)	10,985	11,090	857	781
Max Hourly EUE (MWh)	29,124	29,266	17,762	16,851
Max EUE Duration (Hr)	15	16	12	11



From the hourly event data, ERCOT provided a multi-metric summary of the largest event showing the highest magnitude and longest-duration, as shown in the following figure.

Demand

ERCOT's long-term load forecast consists of the following individual components: (1) a base forecast that uses an econometric model with estimation data comprising 15 historical weather years, economic drivers, calendar information, and historical loads, (2) a roof-top PV forecast, (3) an EV forecast, a large flexible load forecast (crypto-mining facilities), and new "large loads" with a signed interconnection contract with their transmission or distribution service provider. Forecasts are provided for eight weather zones as well as system coincidental and non-coincidental demands. ERCOT's summer peak demand is forecast to increase by 4.6% per year from 2025 through 2029. In

comparison, the five-year summer peak demand growth projection for the *2023 LTRA* was 1.1%. This high growth level is driven by a large amount of newly contracted loads planned for interconnection during this period. These contracted loads are mainly comprised of Permian Basin oil and gas production facilities, data centers, crypto-mining operations, and industrial facilities. (A negligible amount of new contracted loads reported by transmission service providers occur past 2029). The base peak load, which excludes these new contracted loads as well as load reductions due to rooftop solar installations, grows at a more modest 1.4%.

A major load forecasting change from last year is a new Texas Legislature requirement to include non-contracted loads in transmission planning studies. Non-contracted loads lack a signed Interconnection or facility expansion agreement. ERCOT's previous practice had been to exclude these more speculative loads from the load forecast. The non-contracted loads total about 3.6 GW for summer 2025 and reach about 31.7 GW by 2029. The non-contracted loads are not included in the LTRA's peak load forecast. ERCOT is evaluating how these non-contracted forecasted loads will be handled for future resource adequacy and other planning activities.

Demand-Side Management

Most of the demand-side resources available to ERCOT are dispatchable in the form of noncontrollable load resources providing responsive reserve service and ERCOT's Emergency Response Service. The ERCOT Emergency Response Service consists of 10- and 30-minute ramping DRs and distributed generation that can first be deployed when physical responsive reserves drop to 3,000 MW and are not projected to be recovered above 3,000 MW within 30 minutes following the deployment of non-spin reserves. Responsive reserve is provided by industrial loads and is procured on an hourly basis in the day-ahead market. During 2023, load resources started to participate in two other ancillary services, the Non-Spinning Reserve Service and ERCOT Contingency Reserve Service (ECRS), which are used to help balance the system during periods when there may be net-load ramps that cannot be met with conventional supply-side resources.

The remaining dispatchable DR available to ERCOT is from the transmission and distribution service providers' (TDSP) load management programs. These programs provide price incentives for voluntary load reductions from commercial, industrial, and residential loads during energy emergency alert events.

Distributed Energy Resources

DERs that register with ERCOT to participate in wholesale energy and/or ancillary services markets are modeled and dispatched in ERCOT transmission planning studies similarly to transmission-connected resources participating in those markets. For DERs not participating in those markets, ERCOT relies on member TDSPs to provide information about individual DERs on their systems for shorter-term reliability and economic impact studies, typically a one-to-six-year timeframe.

A bill was approved in the 88th Texas Legislature (HB 3390) that outlines new DER reporting responsibilities. The bill authorizes ERCOT to require TDSPs to provide unregistered DER information that ERCOT deems necessary for grid reliability assessment. ERCOT is now developing annual data collection and maintenance processes.

A multi-phase aggregated DER (ADER) pilot program was implemented in 2022. As of May 2024, there were two ADERs with 13 MW of dispatchable capability actively participating in the pilot project with another nine ADERs in various stages of registration/qualification.

Generation

Natural-gas-fired generation makes up approximately 45% of the available generation inside the ERCOT footprint. Approximately 6% of the natural-gas-fired generation demonstrates firm fuel capabilities as part of ERCOT's Firm Fuel Supply Service required by the PUCT.

ERCOT has established formal working relationships with grid generators' fuel suppliers to gather operational and delivery information useful for its control room operators. ERCOT has focused the efforts on two fronts: (1) obtaining real-time (or near real-time) information on the health of the natural gas systems that serve the generators and (2) maintaining communication with pipelines to notify ERCOT of any planned or unplanned events that could impact deliveries to generators.

After the 2021 Odessa event, ERCOT intensified its efforts to find corrective measures to enhance the ride-through performance of IBRs and improve overall system resilience. The study, which recommended installing synchronous condensers at six locations in West Texas, has been completed, and the ERCOT board of directors endorsed the project in December 2023. The project is expected to be in service in 2027.

ERCOT has proposed new grid code requirements for IBRs to improve voltage ride-through (VRT) performance to align with IEEE Standard 2800. The proposed grid code requirements are continuing to go through ERCOT's stakeholder approval process. Until new rules go into effect, IBRs will be expected to maximize VRT capability and address existing performance failures (such as by reducing maximum output).

To provide an incentive to build new dispatchable resources, the PUCT adopted a new rule to establish a generation loan program, one of four incentive programs under the recently established Texas Energy Fund (TEF). The other three programs within the TEF include completion bonus grants for new dispatchable generation projects that consistently provide power generation over a 10-year period, grants for companies to establish or secure backup power resources, and grants to improve the resiliency and availability of electric utility service outside the ERCOT region. The TEF has $5 billion

available for all four programs. These loans and grants have thus far resulted in 72 applications seeking funding under the TEF loan program. The PUCT staff-recommended portfolio represents 9,781 MW in potential new generation if all recommended applicants were to execute a loan agreement at the requested loan amounts.

Energy Storage

The current installed BESS capacity is 9,149 MW. These systems participate in ERCOT's Energy and Ancillary Service markets. Most have durations in the one-to-two-hour range. ERCOT is seeing an increase in longer-duration systems (three to four hours) to take advantage of energy-shifting and capacity-firming opportunities arising from continued high renewable generation penetration. For the first half of 2024, energy storage provided 87% of ERCOT's regulation up and 91% of responsive reserve service from primary frequency response (RRS-PFR). In June 2023, ERCOT implemented a new ancillary service, the ERCOT Contingency Reserve Service (ECRS), which, in part, is designed to address the ramping needs of the system. This ancillary service product provides additional opportunities for BESS ancillary service participation. To support larger BESS penetration levels, ERCOT submitted new proposed rules for state-of-charge accounting in energy dispatch and reliability unit commitment that are planned for implementation this year.

Based on the latest developer information for projects that are in the interconnection queue, ERCOT expects about 10,500 MW of additional battery energy storage capacity to be operational by year-end 2025. This capacity constitutes projects for which developers have posted financial security to build the interconnection facilities. By year-end 2029, the additional cumulative Tier 1 planned capacity reaches about 20,000 MW.

ERCOT currently assigns a 0% on-peak contribution for battery energy storage. ERCOT has changed its rule to adopt an ELCC methodology for battery storage of various durations. Extending the proposed ELCC methodology for BESS to current and forecasted resources in ERCOT would improve the anticipated reserve margins in the future.

Capacity Transfers

ERCOT has coordination plans in place with neighboring grids. These plans cover dc tie emergency operations, procedures for generators that can switch between grids, and temporary block load transfers.

Transmission

In September, the PUCT approved ERCOT's Permian Basin Reliability Plan. The plan consists of new and upgraded local transmission projects as well as building new import paths to load centers in other areas of the Texas RE-ERCOT region, including options for extra high voltage (EHV) infrastructure operating at 345 kW or 765 kV. The plan supports Permian Basin load growth that is currently expected to reach 24 GW by 2030 and over 26 GW by 2038.

ERCOT's 2023 Regional Transmission Plan (RTP) identified 173 reliability projects, with the majority consisting of 138 kV and 345 kV system upgrades. The 2023 RTP also included an economic assessment of the ERCOT transmission system for years 2025 and 2028 using production cost savings and generator revenue reduction tests.

The substantial increase in new loads from a year ago is expected to present challenges for transmission planning. The forecasted pace of the load growth could exceed the pace at which transmission capacity can be built to support it. ERCOT is working on major changes to its transmission planning process to address these challenges. For example, ERCOT is investigating a "generation hub" concept to indicate optimal generation location to address regional load growth and optimize transmission investments.

A new biennial report on grid resiliency—the Grid Reliability and Resiliency Assessment—evaluates extreme weather scenarios considering different levels of thermal and renewable generation availability and the potential outages caused by extreme weather conditions. The assessment also includes proposed transmission projects that may mitigate regional resiliency risks. The first report will be released by December 31, 2024.

New minimum deliverability criteria were included in ERCOT's 2023 RTP to ensure the deliverability of 100% of generation resource capacity and energy storage resources with a duration greater than or equal to two hours. For storage systems with a duration less than two hours, a prorated deliverability was ensured. Corrective action plans (CAP) were proposed to address any reliability violations under the contingencies defined for the minimum deliverability criteria.

ERCOT has also started implementing the PUCT's amended rules relating to certification criteria and is in the process of integrating a new congestion cost savings test for economic projects evaluation.

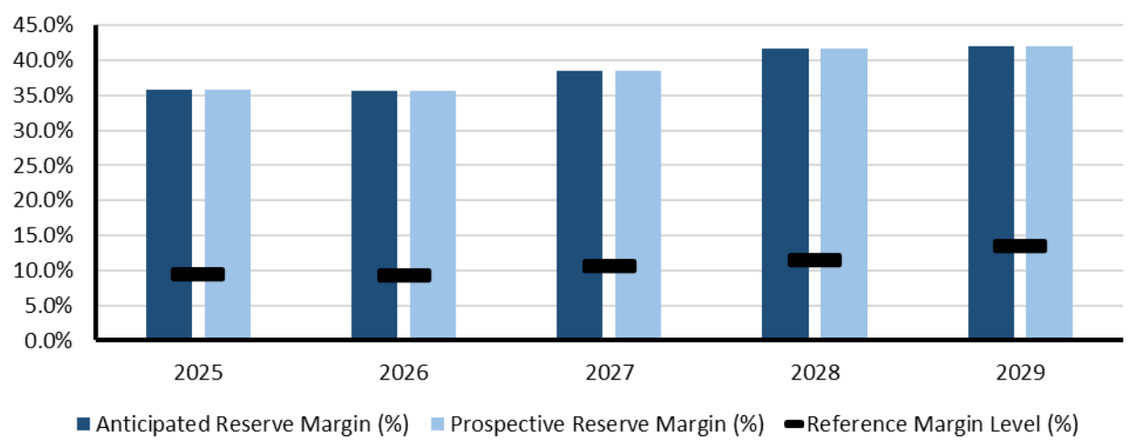


WECC-AB

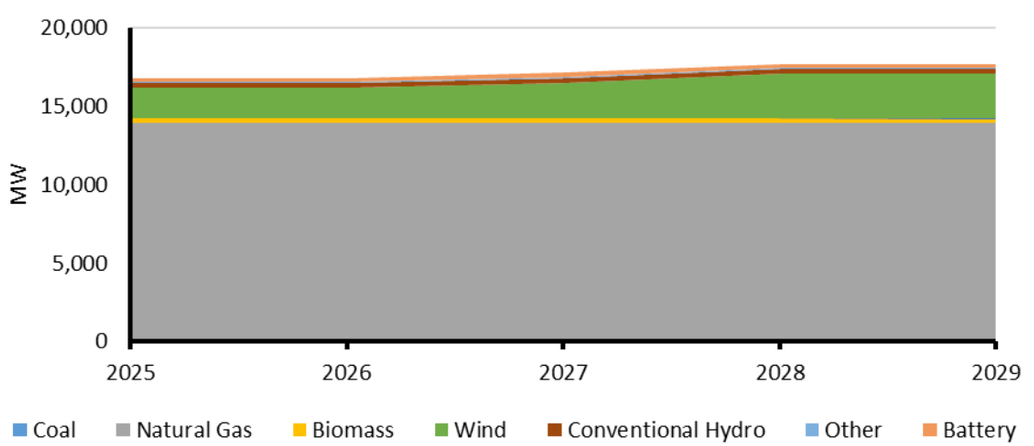
WECC-AB (Alberta) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and BC in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	12,411	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	12,411	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076
Additions: Tier 1	3,275	3,275	3,405	3,541	3,537	3,342	3,537	3,441	3,273	3,273
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	1,031	1,680	1,824	2,247	2,700	2,502	3,068	3,096	2,744	2,744
Net Firm Capacity Transfers	43	96	69	0	68	396	409	0	0	0
Existing-Certain and Net Firm Transfers	13,578	13,631	13,822	14,182	14,244	13,931	14,585	13,867	13,330	13,330
Anticipated Reserve Margin (%)	35.8%	35.6%	38.5%	41.7%	41.9%	35.4%	41.2%	33.6%	27.8%	27.0%
Prospective Reserve Margin (%)	35.8%	35.6%	38.5%	41.7%	41.9%	35.4%	41.2%	33.6%	27.8%	27.0%
Reference Margin Level (%)	9.4%	9.4%	10.6%	11.5%	13.6%	9.2%	13.2%	11.3%	9.0%	9.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML during the 2024–2034 timeframe.
- The peak hour of demand for Alberta occurs in the winter. The peak hour for total internal demand is expected to grow from about 12.3 GW in 2024 to 13.1 GW in 2034, a 6.5% load growth over the forecast horizon. The average year-to-year growth rate is 0.62%. There is a slight increase in the load forecast for this year's LTRA versus last year's.
- Despite low resource adequacy risk, operational risk is still present. Ensuring sufficient frequency response capability has been identified as the region's highest priority. Frequency response has been declining in the region due to the increasing share of IBR resources and declining baseload resources. This under frequency load shedding risk is exacerbated in islanded or near-islanded situations.
- Alberta's two remaining coal-fired generators completed their conversion to natural gas this year.

WECC-AB Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Natural Gas	13,932	13,932	13,941	13,930	13,920
Biomass	336	336	336	336	336
Wind	1,912	1,912	2,232	2,811	2,799
Conventional Hydro	285	285	303	302	312
Other	81	81	81	81	81
Battery	264	264	264	264	263
Total MW	16,810	16,810	17,157	17,723	17,713

WECC-AB Assessment

Planning Reserve Margins

The ARM does not fall below the RML during the 2024–2034 timeframe. From the 2032–2033 winter onward, Alberta shows a shortfall of existing-certain and net firm transfers. This indicates that imports may be necessary during this timeframe if new resources were to be significantly delayed.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the one-day-in-ten-year (ODITY) level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

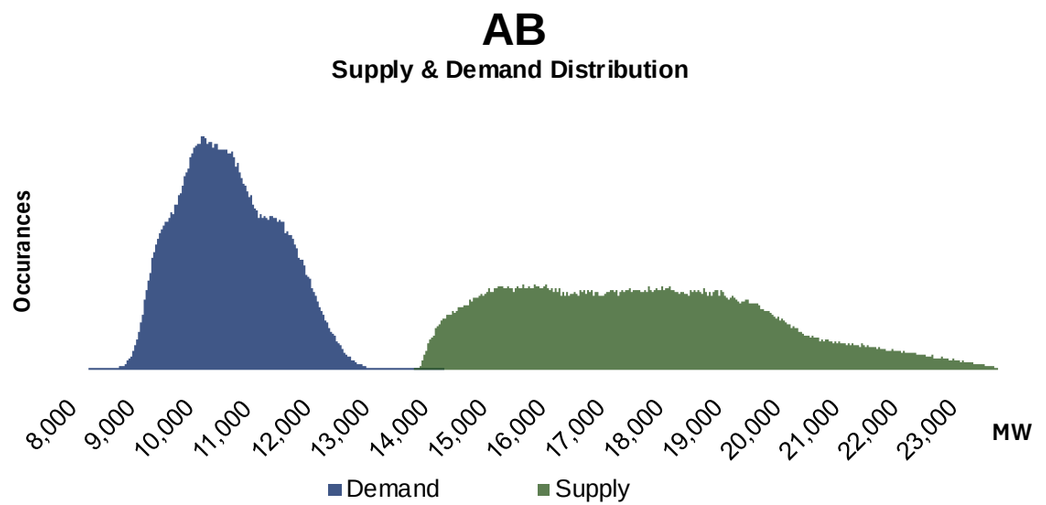
Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0	0	0
EUE (PPM)	0	0	0
LOLH (hours per year)	0	0	0
Operable On-Peak Margin	26.1%	41.6%	42.4%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the Multi-Area Variable Resource Integration Convolution (MAVRIC) model. The MAVRIC model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment. WECC also produces an annual reliability assessment called the *Western Assessment of Resource Adequacy* (WARA).[38]

The availability and demand distributions in the ProbA simulations do not overlap, indicating an extremely low probability of Alberta not being resource adequate over the next four years. For 2026 and 2028, the peak hour occurs in December at HE 18:00. Alberta does not show LOLH nor EUE in the LTRA forecast horizon. The gap between the demand distribution and the supply distribution shown in the figure below emphasizes that there is minimal resource adequacy risk in Alberta. The ARM appears to further validate this, as it is far above the RML for 2026 and 2028.



Demand

Peak demand for Alberta occurs in the winter. The peak hour for total internal demand is expected to grow from about 12.3 GW in 2024 to 13.1 GW in 2034, a 6.5% load growth over the forecast horizon. The average year-to-year growth rate is 0.62%. There is a slight increase in the load forecast for this year's LTRA versus last year's. Near-term load growth is driven by industrial loads, such as oil sands production, pulp and paper mills, and gas and oil processing. Long-term demand growth is driven by electrification of transportation and buildings as well as potential growth in emerging industries, such as hydrogen production.

[38] See WECC Reliability Assessments.

Distributed Energy Resources
BTM DERs are difficult to measure due to data gathering barriers. AESO released its updated 2022 Plan for DER Roadmap Integration Activities.

Generation
Over 6 GW of nameplate capacity are being added in Alberta through the end of 2028. There is significantly more solar, wind, and energy storage in this year's planned capacity additions than in the last LTRA. Additionally, several states and provinces in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions. Alberta's two remaining coal units have been converted to natural gas this year.

Energy Storage
Energy storage is being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage, but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers
In WECC's analysis, Alberta is not showing significant changes to capacity transfers. There is a slight increase in exports between 5:00 p.m. and 10:00 p.m. and in the later years of the assessment period.

Reliability Issues
WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

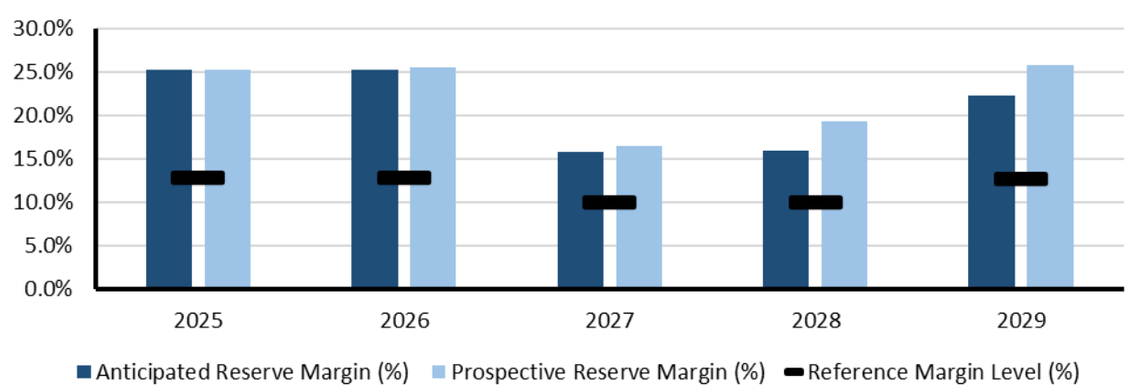


WECC-BC

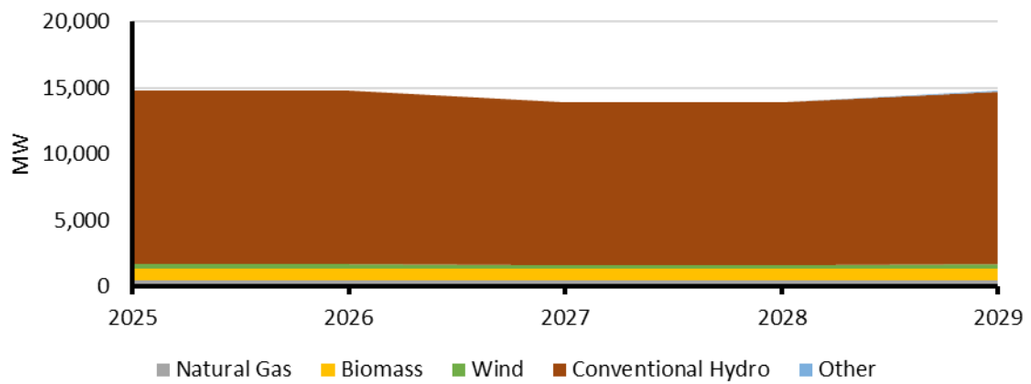
WECC-BC (British Columbia) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of BC, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and BC in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	11,986	11,959	12,015	11,983	12,075	12,082	12,130	12,174	12,237	12,305
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,986	11,959	12,015	11,983	12,075	12,082	12,130	12,174	12,237	12,305
Additions: Tier 1	956	956	893	893	956	956	956	956	893	956
Additions: Tier 2	0	41	79	398	419	748	1,077	1,077	1,012	1,405
Additions: Tier 3	0	5	5	5	6	6	59	59	56	59
Net Firm Capacity Transfers	184	188	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	14,054	14,022	13,019	12,998	13,812	13,795	13,795	13,795	12,982	13,795
Anticipated Reserve Margin (%)	25.2%	25.2%	15.8%	15.9%	22.3%	22.1%	21.6%	21.2%	13.4%	19.9%
Prospective Reserve Margin (%)	25.2%	25.6%	16.5%	19.2%	25.8%	28.3%	30.5%	30.0%	21.7%	31.3%
Reference Margin Level (%)	12.8%	12.8%	10.0%	10.0%	12.7%	12.7%	12.6%	12.6%	9.8%	12.5%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML during the 2024–2034 timeframe.
- BC shows a shortfall of existing-certain and net firm transfers for the 2027–2028 winter and the 2028–2029 winter. Shortfalls are also projected from the winter of 2033–2034 onward. This indicates that imports may be necessary during these periods if new resources were to be significantly delayed.
- The peak hour of demand for BC occurs in the winter. BC shows the lowest demand growth rate in the west. The peak demand is expected to grow from about 12.0 GW in 2024 to 12.3 GW in 2034, slightly less than in the previous LTRA forecast. This is an average annual growth rate of 0.28%, and a 2.8% load growth over the forecast horizon.
- BC is showing hours of demand at risk that are not fully mitigated by the addition of Tier 3 resources. Supply chain performance will play a significant role in BC's ability to reliably meet energy needs. Seasonal and daily fluctuations of hydro resource availability is also a risk. LOLH and EUE correlate with periods when river flows are at their lowest.

WECC-BC Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Natural Gas	459	459	456	456	459
Biomass	920	920	914	914	920
Wind	279	279	268	268	279
Conventional Hydro	13,145	13,110	12,253	12,232	13,087
Other	22	22	22	22	22
Total MW	14,825	14,790	13,912	13,891	14,768

WECC-BC Assessment

Planning Reserve Margins

The ARM does not fall below the RML during the 2024–2034 timeframe. BC shows a shortfall of existing-certain and net firm transfers for the 2027–2028 winter and the 2028–2029 winter. Shortfalls are also projected from winter of 2033–2034 onward. This indicates that imports may be necessary during these periods if new resources were to be significantly delayed.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the ODITY level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk in 2026. In 2028, however, WECC's analysis identified over five hours where resources, including imports from neighbors, fall below margins for system reliability.

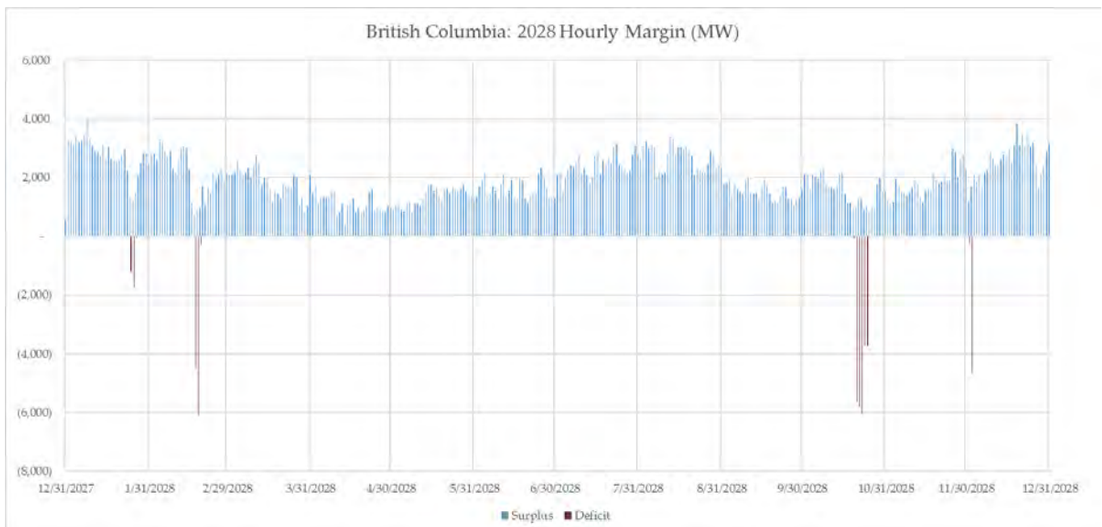
Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	24	0	103,132
EUE (PPM)	0.71	0	1,457
LOLH (hours per year)	0.002	0	5.52
Operable On-Peak Margin	12.7%	16.9%	9.4%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC model is a convolution based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment, as well as WECC's WARA.

For both 2026 and 2028, the peak hour occurs in December at HE 19:00. LOLH and EUE are not forecast in 2026 but do appear in 2028. No LOLH or EUE occurs at the peak hour. 88% of the EUE in 2028 occurs overnight between the hours of 23:00 and 4:00.

In 2026, the peak summer hour is HE 17:00 in September, and in 2028 the peak hour is HE 17:00 in August. There is no LOLH projected for 2026 or during peak hours. LOLH occurs in 2028 between the hours of 17:00 and 20:00.



Icicle Plot with Hourly Surplus and Deficits for British Columbia in 2028

WECC's interconnection-wide analysis simulates the probabilistic performance of resource types using historic hourly output data to identify future risk periods. Operators of systems with large hydroelectric storage facilities make adjustments to generation based on the level of demand and shape the water use within the day, week, month, or between years. These actions help posture hydroelectric generation for expected conditions and can reduce energy shortfall risks.

	1	2	3	4	5	6	7	8	9	10	11	12
0	(0)	(5)	-	-	-	-	-	-	-	(10)	-	-
1	(1)	(5)	-	-	-	-	-	-	-	(12)	-	-
2	(1)	(6)	-	-	-	-	-	-	-	(20)	-	-
3	(3)	(5)	-	-	-	-	-	-	-	(14)	(0)	-
4	(0)	(1)	-	-	-	-	-	-	-	(0)	(0)	-
5	-	(0)	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	(0)	-	-
8	-	(0)	-	-	-	-	-	-	-	(0)	-	(0)
9	(0)	(0)	-	-	-	-	-	-	-	-	-	(0)
10	-	(0)	-	-	-	-	-	-	-	-	-	(0)
11	-	-	-	-	-	-	-	-	-	-	-	(1)
12	-	-	-	-	-	-	-	-	-	-	-	(3)
13	-	(0)	-	-	-	-	-	-	-	-	-	(5)
14	-	-	-	-	-	-	-	-	-	-	-	(1)
15	-	(0)	-	-	-	-	-	-	-	-	-	(0)
16	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-	-	-	-	-
19	-	-	-	-	-	-	-	-	-	-	-	-
20	-	(0)	-	-	-	-	-	-	-	-	-	-
21	-	(0)	-	-	-	-	-	-	-	-	-	-
22	-	(0)	-	-	-	-	-	-	-	(0)	-	(0)
23	-	(2)	-	-	-	-	-	-	-	(5)	-	-

2028 Heat Map EUE (GW) - British Columbia

Demand

BC's average annual load growth in its forecast has fallen to a rate below Alberta's. The peak hour total internal demand for BC occurs in the winter. The peak demand is expected to grow from about 12.0 GW in 2024 to 12.3 GW in 2034, slightly less than in the last forecast. This is an average annual growth rate of 0.28% and a 2.8% load growth over the forecast horizon. BC's load growth is lower due to updated monthly profiles that reflect current trends and aggressive DSM which it includes as a demand reduction in the demand forecasts provided to WECC. Load growth in BC is primarily driven by EV and gas sector load growth and is partially offset by a decline in demand from the forestry sector.

Distributed Energy Resources

BTM DERs are difficult to measure due to data-gathering barriers. BC Hydro has net metering. Net metering for residential and commercial customer projects are up to 100 kW. The net metering program has no annual energy volume target.

Generation

Across WECC, several states and provinces as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

In BC, hydro and wind resources are being added to the system. The BC Hydro Authority (BCHA) is taking steps to mitigate risks associated with climate change by improving coastal watershed inflow forecasting to an hourly level and increasing investment in capital projects to increase the resiliency of its hydro-dominant portfolio. Drought conditions in BC have led to water conservation measures, such as encouraging generation at facilities located in less drought-impacted areas, revising discharge plans at storage capable sites, and importing power when available to reduce water consumption.

Capacity Transfers

WECC's probabilistic analysis indicates that BC's need for imports is increasing during the assessment period.

Transmission

Three transmission projects with voltage design of 500 kV and higher are planned in the BC region.

Reliability Issues

WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

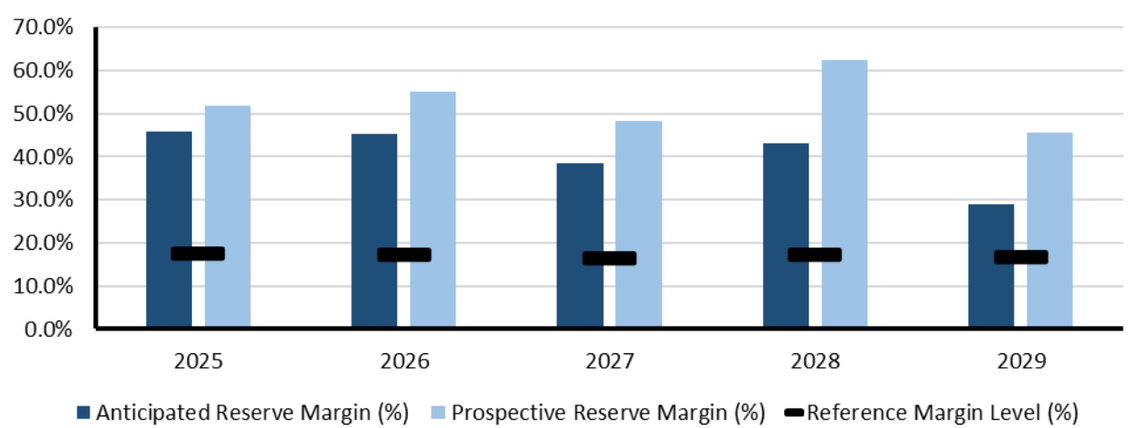


WECC-CA / MX

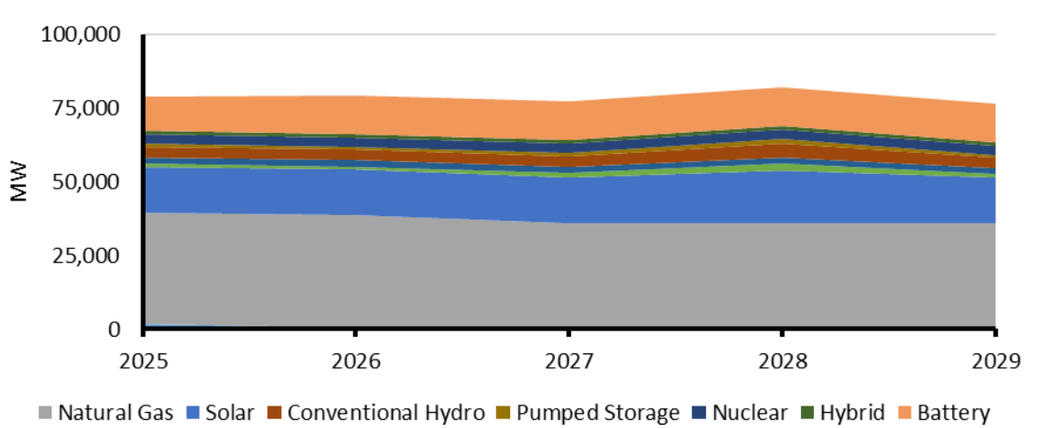
WECC-CA/MX (California/Mexico) is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	56,619	57,274	59,291	60,131	61,289	61,067	62,336	65,876	67,251	69,064
Demand Response	795	797	793	793	793	794	794	794	794	794
Net Internal Demand	55,824	56,477	58,499	59,338	60,496	60,273	61,542	65,082	66,457	68,269
Additions: Tier 1	9,700	11,074	11,128	11,546	11,074	11,990	11,990	12,437	12,047	11,990
Additions: Tier 2	3,349	5,628	5,727	11,483	10,121	17,017	17,017	22,135	23,212	24,650
Additions: Tier 3	9	19	19	22	19	321	321	326	322	321
Net Firm Capacity Transfers	1,509	1,828	2,760	1,953	448	357	342	898	317	314
Existing-Certain and Net Firm Transfers	71,707	70,921	69,827	73,373	66,866	66,142	63,916	68,939	64,533	63,888
Anticipated Reserve Margin (%)	45.8%	45.2%	38.4%	43.1%	28.8%	29.6%	23.3%	25.0%	15.2%	11.1%
Prospective Reserve Margin (%)	51.8%	55.1%	48.2%	62.5%	45.6%	57.9%	51.0%	59.0%	50.2%	47.3%
Reference Margin Level (%)	17.4%	17.4%	16.4%	17.4%	16.6%	16.4%	16.1%	16.3%	14.9%	15.3%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM falls below the RML in Summer 2034, but the RML is covered by the PRM, which includes Tier 2 resource additions.
- Starting in Summer 2029 onward, CA/MX shows a shortfall of existing-certain and net firm transfers. However, with planned generation resource additions the shortfalls are eliminated. Imports may be necessary if the new resources were to be significantly delayed. LOLH and EUE are mitigated over the assessment horizon with the addition of Tier 2 resources and primarily correspond with the evening down ramp of solar and lingering demand after peak.
- The peak hour of demand for CA/MX occurs in the summer. Total internal demand at peak hour is expected to grow from about 56.4 GW in 2024 to 69.1 GW in 2034, a 22.5% load growth over the forecast horizon. The average annual growth rate is 2.07%.
- Diablo Canyon, a 2.2 GW nuclear site, will no longer be retired by 2025 and is now slated to be retired in 2030.

WECC-CA/MX Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	1,572	466	466	465	466
Coal*	1,122	16	16	15	16
Petroleum	185	185	185	184	185
Natural Gas	38,180	38,180	35,565	35,504	35,506
Biomass	726	726	727	726	726
Solar	15,464	15,464	15,501	17,990	15,464
Wind	1,158	1,158	1,428	2,144	1,158
Geothermal	2,004	2,059	2,061	2,056	2,059
Conventional Hydro	3,582	3,582	3,838	4,727	3,582
Pumped Storage	889	889	951	1,710	889
Nuclear	3,282	3,282	3,287	3,283	3,282
Hybrid	32	32	34	39	32
Other	32	32	32	32	32
Battery	12,792	14,111	14,119	14,106	14,111
Total MW	79,898	80,166	78,194	82,967	77,492
Total MW*	79,448	79,716	77,744	82,517	77,042
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

Planning Reserve Margins

The ARM falls below the RML in the summer of 2034. With the addition of Tier 2 resources, reserve margins remain above RML. Starting in Summer 2029 onward, CA/MX shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed.

The California Independent System Operator (CAISO) is responsible for much of the BPS that is in CA/MX. CAISO manages the transmission system, oversees transmission planning, and operates the wholesale electricity market for its territory. Other entities in CA/MX include the Balancing Authority of Northern California (BANC), the Imperial Irrigation District (IID), and Mexico's National Center for Energy Control (CENACE), which operates the connected Baja California system.

CAISO Only: The ARM falling below the RML in Summer 2034 and the shortfall of existing-certain and net firm transfers in Summer 2029 is consistent when looking at CA/MX or solely at CAISO. The RML of CAISO averages 0.7% higher than the CA/MX region RML over the LTRA horizon. This is due to the exclusion of natural gas and coal resource energy contributions from CA/MX entities outside of CAISO. Decreasing baseload generators results in increased variability, which in turn requires a greater RML to maintain the ODITY threshold. However, the gap between the anticipated, prospective, and existing reserve margins and the RML for CAISO are greater than the broader CA/MX region. The proportion of energy availability to anticipated net internal demand is larger for CAISO, accounting for this increase.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment, as well as WECC's WARA.

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the ODITY level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk in 2026. After 2026, however, WECC's analysis identified periods of unserved energy and load loss in CA/MX during June through October. Of note, this risk is limited to the Mexico portion of CA/MX (i.e., ProbA results for the CAISO do not indicate LOLH or EUE) until 2029, when the risk extends across the entire assessment area.

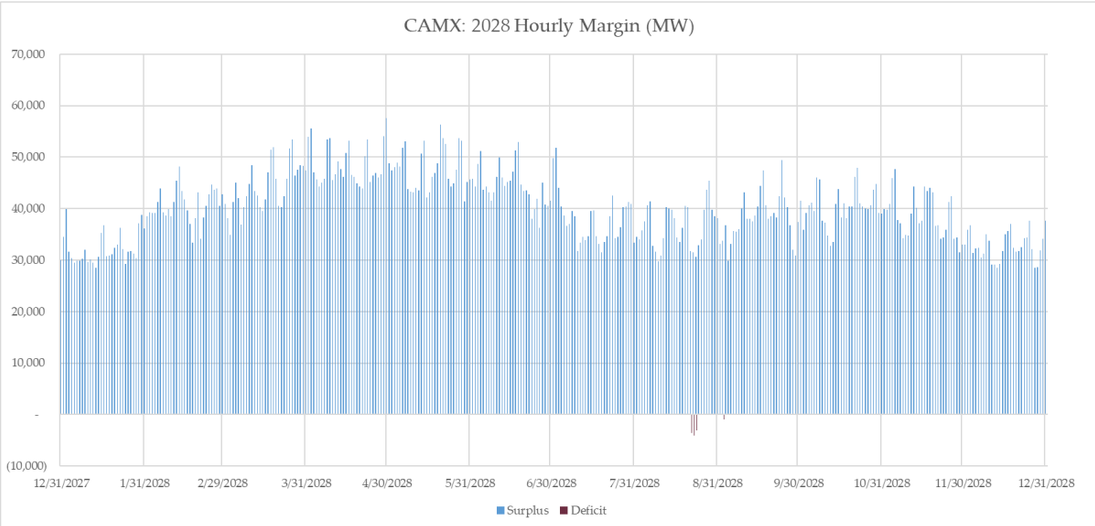
Base Case Summary of Results

	2026*	2026	2028
EUE (MWh)	37,305	0	19,662
EUE (PPM)	136	0	70.07
LOLH (hours per year)	0.721	0	0.38
Operable On-Peak Margin	30.7%	43.2%	41.2%

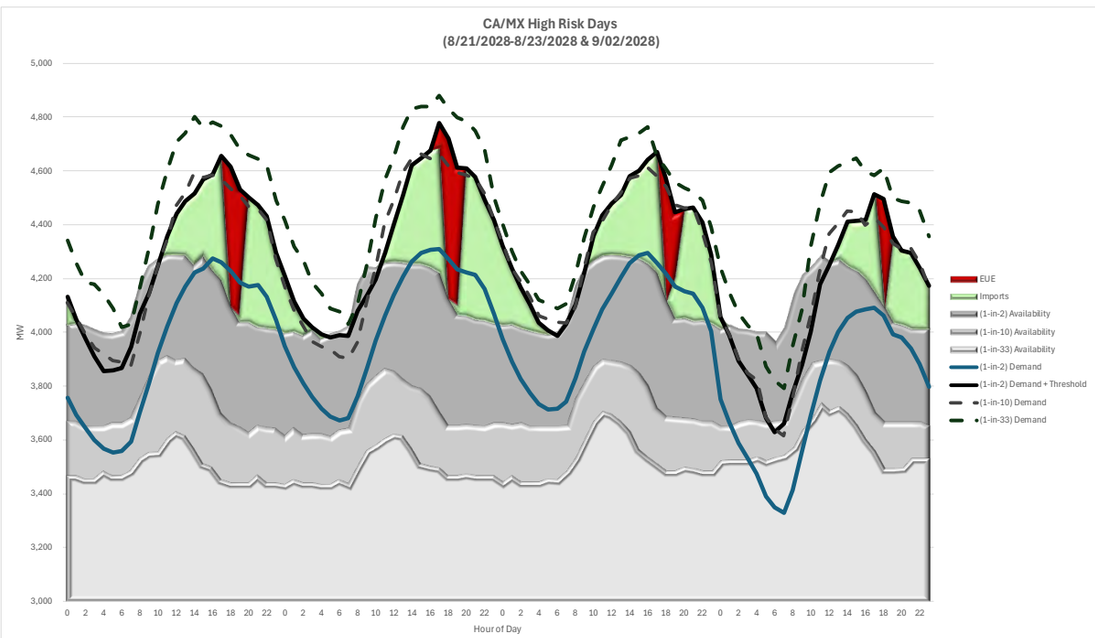
* Provides the 2022 ProbA Results for Comparison

Though the hour and month of peak demand are the same for both CAISO and the broader CA/MX region, CAISO shows the greatest amount of EUE and LOLH in September, whereas CA/MX shows the greatest amount of EUE and LOLH in August. This coincides with the seasonal reduction of solar irradiance in the fall and CAISO having a proportionally larger share of solar resources than the CA/MX region. Excluding regions external to CAISO results in a 96% reduction in LOLH events and EUE over the LTRA horizon.

The hour of peak demand in summer occurs at 5:00 p.m. The hours of highest risk, however, occur during periods after the peak demand hour as solar PV resource output diminishes. There is no LOLH projected for 2026; however in 2028, the ProbA reveals some LOLH between the hours of 5:00 and 8:00 p.m.



Icicle Plot with Hourly Surplus and Deficits for CA/MX in 2028



Demand

The peak demand for CA/MX occurs in the summer. The peak hour for total internal demand is expected to grow from about 56.4 GW in 2024 to 69.1 GW in 2034, a 22.5% load growth over the forecast horizon. The average annual growth rate is 2.07%. Transportation and building electrification are the primary drivers of demand growth.

CAISO Only: The demand forecast for CAISO grows at a slightly higher rate than the broader CA/MX region, with a load growth of 25.2% over the LTRA forecast horizon, and an average annual rate of 2.1%.

Demand-Side Management

A portion of the near-term decline in controllable and dispatchable DR for Summer 2024 is partly driven by regulatory changes in the CA/MX region. This includes making resource adequacy DR crediting adjustments based on historical performance and increasing DR availability requirements. The California Public Utilities Commission (CPUC) determined resource adequacy values of utility DR were overestimated during high load days. In response, the CPUC removed transmission gross-ups and some credits from utility DR resource adequacy values starting in 2024. The CPUC also directed that DR resource adequacy capacity must be available during all days the ISO calls a flex alert or issues a grid warning or on which the governor's office has issued an emergency notice, representing a significant increase in required availability. In addition, the CPUC now requires all DR capacity to be available a minimum of three days per week for at least four hours per day.

For CAISO, energy efficiency and conservation drops significantly when excluding non-CAISO entities from the CA/MX region. The entities outside of CAISO account for an average of 70% of the energy efficiency and conservation DSM for the CA/MX region for the LTRA timeframe.

Distributed Energy Resources

BTM DERs are difficult to measure due to data-gathering barriers. CAISO allows seven DER aggregators as market participants for energy and ancillary services. Additionally, PG&E's Partnership Pilot includes new or existing solar, storage, energy efficiency and demand response used via third party DER providers, vendors, or aggregators.

Generation

There is significantly more solar, wind, and energy storage in planned capacity additions than in the last LTRA. Additionally, several states in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

Energy Storage
Energy storage is being relied on to help mitigate ramping risk from afternoon net demand caused by increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers
CA/MX is showing increasing amounts of exports to the northwest, especially during winter months.

Transmission
Seventeen transmission projects with 500 kV and higher are planned.

Reliability Issues
WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

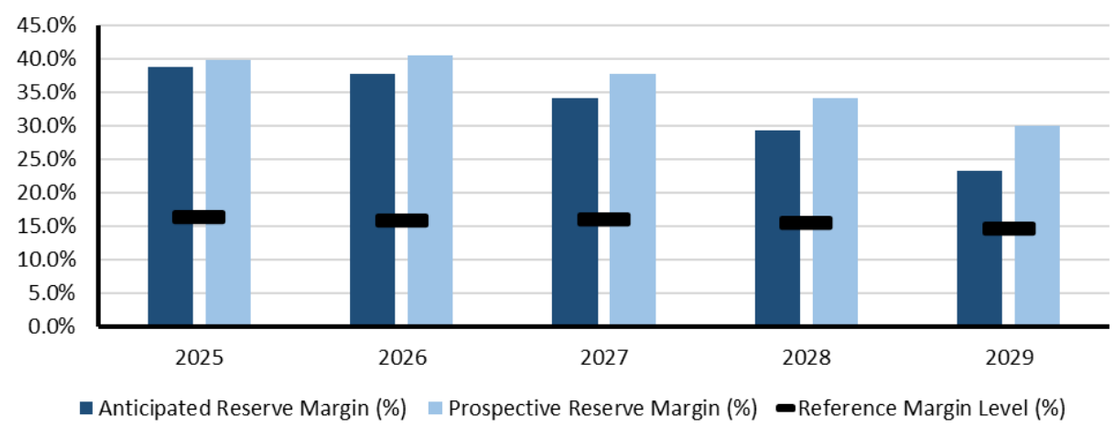


WECC-NW

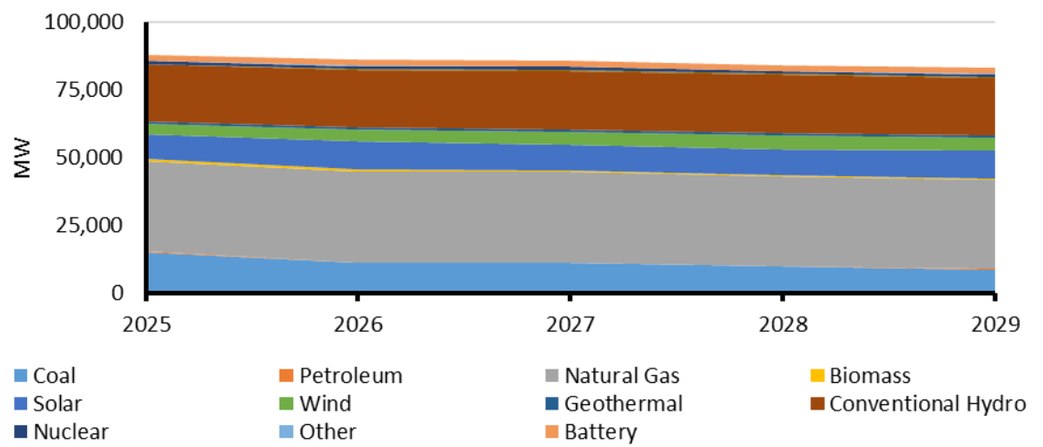
WECC-NW (Northwest) is a summer-peaking assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming and parts of California, Nebraska, Nevada, and South Dakota. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	68,274	69,745	71,580	73,626	75,079	75,917	76,736	77,462	78,316	78,835
Demand Response	806	808	811	814	806	809	812	814	817	820
Net Internal Demand	67,469	68,936	70,768	72,811	74,273	75,108	75,925	76,647	77,499	78,016
Additions: Tier 1	7,000	9,386	9,295	9,489	9,752	9,752	10,141	10,141	9,915	10,141
Additions: Tier 2	788	1,955	2,628	3,595	5,046	6,593	7,258	7,273	6,935	7,253
Additions: Tier 3	2,945	8,874	14,008	21,247	28,296	33,802	40,239	42,260	41,876	43,809
Net Firm Capacity Transfers	5,627	8,796	9,087	9,863	8,462	6,037	2,783	2,423	2,370	2,140
Existing-Certain and Net Firm Transfers	86,609	85,564	85,605	84,618	81,788	78,094	74,003	73,297	72,810	71,446
Anticipated Reserve Margin (%)	38.7%	37.7%	34.1%	29.3%	23.3%	17.0%	10.8%	8.9%	6.7%	4.6%
Prospective Reserve Margin (%)	39.9%	40.6%	37.8%	34.2%	30.0%	25.7%	20.4%	18.4%	15.7%	13.9%
Reference Margin Level (%)	16.3%	15.8%	15.9%	15.4%	14.7%	14.5%	14.3%	14.2%	14.4%	13.8%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM falls below the RML starting in Summer 2031. With the addition of Tier 2 capacity, the PRM stays above the RML for all years in the LTRA time horizon.
- Starting in Summer 2029 onward, the Northwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed. Five GW of baseload resource retirements are anticipated between 2024 and 2028. The energy needs are to be replaced by solar and wind, supported by BESS. Supply chain issues preventing the construction of BESS resources are a concern as they assist in meeting demand during shoulder periods where solar availability is dropping but loads remain high. LOLH and EUE are mitigated over the assessment horizon with the addition of Tier 3 resources.
- The Northwest is dual peaking, so the peak hour can occur in either the summer or the winter. Probabilistic modeling efforts show a peak in the summer for this LTRA. The summer peak for the total internal demand is expected to grow from about 66.4 GW in 2024 to 78.8 GW in 2034, which is lower than in the previous LTRA. This represents a nearly 18.7% load growth over the forecast horizon, with an average growth rate of 1.73%.

WECC-NW Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	14,965	11,031	11,021	9,667	8,761
Coal*	14,661	10,223	10,607	9,349	8,060
Petroleum	321	321	319	319	316
Natural Gas	33,452	33,636	33,304	32,954	32,749
Biomass	729	723	683	683	604
Solar	9,086	10,191	9,350	9,431	10,379
Wind	3,924	4,566	4,939	4,939	4,561
Geothermal	884	934	933	1,007	997
Conventional Hydro	21,003	21,000	21,542	21,522	20,958
Pumped Storage	373	373	375	375	373
Nuclear	1,096	1,096	1,096	1,096	1,096
Other	64	64	64	64	64
Battery	2,084	2,219	2,188	2,188	2,219
Total MW	87,981	86,154	85,814	84,245	83,077
Total MW*	87,679	85,346	85,398	83,926	82,377
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

WECC-NW Assessment

Planning Reserve Margins

The ARM falls below the RML starting in Summer 2031. With the addition of Tier 2 capacity, the PRM stays above the Reference Margin for all years in the LTRA time horizon. Starting in Summer 2029 onward, the Northwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the ODITY level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	1,722	0	1
EUE (PPM)	4	0	0
LOLH (hours per year)	0.04	0	0
Operable On-Peak Margin	37.6%	36.1%	27.8%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC model is a convolution based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment, as well as WECC's WARA.

Imports to the Northwest from the CA/MX region grow throughout the LTRA forecast horizon. A calm, cloudy, extreme heat event occurring in the Northwest and CA/MX regions simultaneously poses a risk to the Northwest by limiting surplus energy in CA/MX to send northward.

Energy variability is greater in the Northwest than other WECC regions due to the large share of wind and hydro in the portfolio. More variability in energy output requires a greater reserve margin to maintain resource adequacy.

For 2026 and 2028, the peak hour occurs in August at HE 17:00. LOLH and EUE are not forecast in 2026 and only occur for a single hour in 2028. The LOLH occurred in August at HE 19:00, slightly after peak. The LOLH corresponds with the declining solar availability in the evening while demand remains high.

Demand

The Northwest is dual peaking, so the peak hour can occur in either the summer or the winter. Probabilistic modeling efforts show a peak in the summer for this LTRA. The summer peak for the total internal demand is expected to grow from about 66.4 GW in 2024 to 78.8 GW in 2034, which is lower than in the previous plan. This represents a nearly 18.7% load growth over the forecast horizon, with an average growth rate of 1.73%. There are significant differences between balancing areas, with some showing large load growth impacts while others showing a slight decrease in demand. Entities reporting large load growth cite new data centers as a primary driver.

Demand-Side Management

In the Northwest, Idaho Power implements a substantial dispatchable DR program focused on the agricultural sector with its Irrigation Peak Rewards Programs. This allows Idaho Power to remotely turn off specific irrigation pumps a minimum of four times during the summer. Participation varies year to year based on factors such as the availability of water and program parameters. In 2022, the utility lengthened the season and included additional evening hours, which drove some reduction in participation that carried over to the Summer 2024 availability.

PacifiCorp states in its most recent Integrated Resource Plan (IRP) that it hopes to reach 1,123 MW of demand response by 2042 in its preferred portfolio plan, which is a 21% increase by 2042 from its previous plan. PacifiCorp's dispatchable DR programs include residential, small commercial air-conditioner load control, irrigation load management, and 203 MW of interruptible contracts.

The Public Service Company of Colorado (PSCo) also offers a wide array of DR programs, such as Saver's Switch, which is a program where the air-conditioning unit of a customer may be controlled

remotely and cycled during extreme heat events. Peak Day Partners allows for the direct load control and reduction of customers 0.5 MW or greater in size when system peaking conditions are met. The Interruptible Service Credit Option (ISOC) is a program where customers agree to reduce consumption in return for a rate discount with non-compliance being met with a fee.

Distributed Energy Resources
BTM DERs are difficult to measure due to data-gathering barriers. One example is Idaho Power's filing of annual DER Resources Status Reports by customer class and resource type, such as in 2023.

Generation
Five GW of baseload resource retirements are anticipated between 2024 and 2028. The energy needs are to be replaced by solar, wind, and BESS, further increasing variability in the portfolio. Given the retiring of baseload resources, supply chain issues preventing the construction of BESS resources are a concern as they assist in meeting demand during shoulder periods where solar availability is dropping but loads remain high.

There is significantly more solar, wind, and energy storage in planned capacity additions than in the last LTRA. Additionally, several states in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

Energy Storage
Energy storage is being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage, but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers
The Northwest is showing greatly increasing import needs over the 10-year time horizon, especially in the winter months. Most of the imports in the model simulations come from CA/MX, with a smaller portion coming from BC**.**

Transmission
Twelve transmission projects with 500 kV and higher are planned.

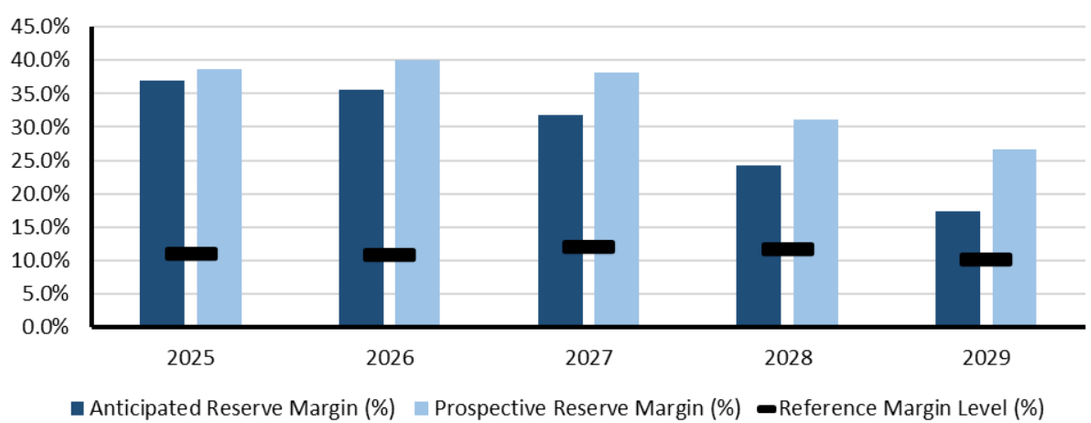


WECC-SW

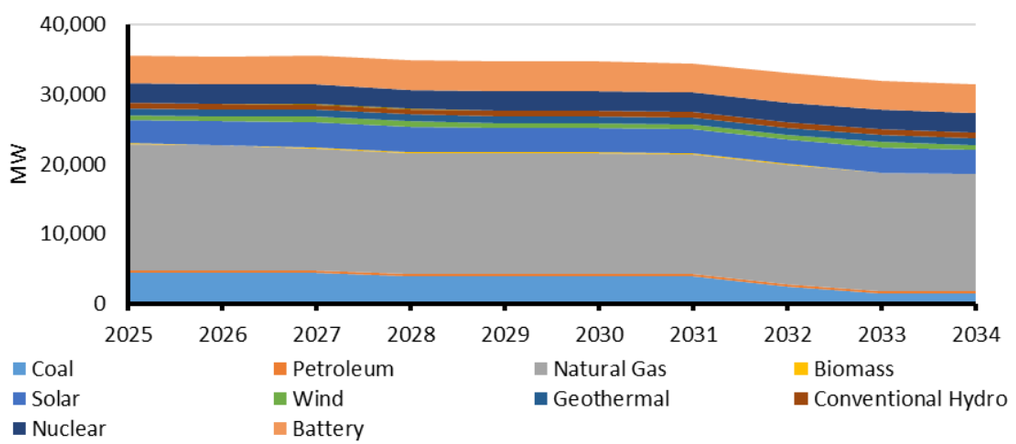
WECC-SW (Southwest) is a summer-peaking assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and part of California and Texas. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada as well as the northern portion of Baja California in Mexico and all or portions of the 14 Western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	28,347	29,184	30,098	30,905	31,684	32,401	33,082	33,676	34,301	34,886
Demand Response	417	392	396	424	373	389	392	396	424	373
Net Internal Demand	27,930	28,792	29,702	30,481	31,311	32,012	32,690	33,279	33,876	34,512
Additions: Tier 1	5,140	5,251	5,656	5,656	5,557	5,557	5,557	5,557	5,656	5,557
Additions: Tier 2	475	1,305	1,899	2,079	2,932	2,932	2,966	2,984	3,221	2,984
Additions: Tier 3	40	677	1,148	2,589	3,113	4,438	5,734	7,479	8,960	10,027
Net Firm Capacity Transfers	2,651	3,556	3,554	2,966	2,045	928	716	320	322	0
Existing-Certain and Net Firm Transfers	33,110	33,784	33,491	32,212	31,187	30,070	29,644	27,787	26,645	25,956
Anticipated Reserve Margin (%)	36.9%	35.6%	31.8%	24.2%	17.4%	11.3%	7.7%	0.2%	-4.7%	-8.7%
Prospective Reserve Margin (%)	38.6%	40.1%	38.2%	31.1%	26.7%	20.4%	16.8%	9.2%	4.9%	0.0%
Reference Margin Level (%)	11.0%	10.8%	12.0%	11.7%	10.2%	10.1%	9.9%	9.7%	10.8%	9.4%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML until Summer 2031, and the PRM falls below the RML in Summer 2032.
- Starting in Summer 2028 onward, the Southwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed. LOLH and EUE are mitigated over the assessment horizon with the addition of Tier 3 resources. Both supply chain and zoning issues have been cited as inhibiting project completion.
- The Southwest's peak demand in summer is forecast to grow at an average of 2.49%. Over the LTRA horizon, the forecast grows by a total of 27.8%, which is the highest forecasted growth in the WECC region. The Southwest's total internal demand forecast is nearly the same as last year's over the near and medium term, with a slight drop from last year's in the longer term, growing from a summer peak of 27.3 GW in 2024 to 34.9 GW by 2034.
- Natural gas derates during extreme heat events are a risk for the Southwest as these resources make up a large share of the resource portfolio in the area.

WECC-SW Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	4,436	4,436	4,432	3,939	3,941
Coal*	4,432	4,432	4,148	3,655	3,657
Petroleum	323	323	322	322	323
Natural Gas	18,165	17,933	17,520	17,323	17,343
Biomass	82	82	82	82	82
Solar	3,354	3,354	3,628	3,628	3,479
Wind	628	695	799	799	695
Geothermal	1,047	1,047	1,047	1,047	1,047
Conventional Hydro	721	721	721	721	721
Pumped Storage	104	104	104	104	104
Nuclear	2,724	2,724	2,711	2,711	2,724
Battery	4,016	4,061	4,226	4,226	4,240
Total MW	35,599	35,479	35,593	34,902	34,698
Total MW*	35,595	35,475	35,309	34,618	34,414
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

Planning Reserve Margins

The ARM does not fall below the RML until Summer 2031, and the PRM falls below the RML in Summer 2032. This indicates that imports may be necessary if new resources were to be significantly delayed, as Tier 3 resources will be required for reserve margins to meet the RML. Starting in Summer 2028 onward, the Southwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the ODITY level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	84	0	19
EUE (PPM)	1	0	0.13
LOLH (hours per year)	0.003	0	0.00
Operable On-Peak Margin	18.3%	33.8%	22.5%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC model is a convolution based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment. Another report produced is a WECC report called the WARA.

For 2026 and 2028, the peak hour occurs in July at HE 17:00. LOLH and EUE are not anticipated in 2026 and are minimal in 2028. LOLH was only observed in August at HE 19:00. The LOLH corresponds with the evening down ramp of solar and lingering demand after peak.

Due to the significant share of natural gas resources in the Southwest portfolio, a concern for the Southwest is natural gas derates during extreme heat events. A strategy to assist with resource planning is to construct derate curves for natural gas resources as a function of temperature. Resource procurement practices have also changed to focus on adding resources that have no dependence on temperature.

Demand

The Southwest has the highest rate of load growth in the Western Interconnection for the LTRA horizon. Large industrial and commercial load additions, such as data centers, have been cited as the reason for this growth.

The Southwest's peak demand in summer is forecast to grow at an average of 2.49%. Over the LTRA horizon, the forecast grows by a total of 27.8%. The Southwest's total internal demand forecast is nearly the same as last year's over the near and medium term, with a slight drop from last year's in the longer term, growing from a summer peak of 27.3 GW in 2024 to 34.9 GW by 2034.

Demand-Side Management

Arizona Public Service (AZPS) has numerous DSM pilots and programs, such as the Residential Energy Storage Pilot and Commercial Advanced Rooftop Controls. In the Residential Energy Storage Pilot, residents may install a small BESS at their residence and enable it to be dispatched by AZPS in response to grid needs 100 times a year, but not below 20% of its capacity. AZPS is projecting an almost 50 MW increase in available DR from 2024 to 2025.

In 2023, the Salt River Project (SRP) subscribed 87 MW of DR capability through the installation of 76,143 smart thermostats and enrolled over 500 businesses as interruptible customers providing 41 MW of controllable DR capacity. The SRP aims to achieve 300 MW of dispatchable DR capability by 2035.

The Public Service Company of New Mexico (PNM) operates the Peak Saver and Power Saver programs. Peak Saver reduces demand from commercial customers greater than 50 kW in size during peak demand periods, and the Power Saver program cycles the compressor of air conditioners to reduce peak demand in the summer. One hundred hours of curtailment are available for both

programs with a four-hour limit per curtailment, and it was found that both programs combined reduce peak demand by an average of 45 MW per curtailment event.

El Paso Electric (EPE) operates a smart thermostat program to cycle air conditioners with the potential to achieve 50 MW of relief by 2040.

Additionally, AZPS, SRP, PNM, and EPE all offer time of use (TOU) rate structures for their customers.

Distributed Energy Resources
BTM DERs are difficult to measure due to data gathering barriers. In the Southwest, NV Energy has added DER plans to its triennial IRPs.

Generation
Southwest entities have slightly under 10 GW of nameplate capacity Tier 1 solar resources planned between 2024 and 2028. Supply chain issues resulting in project delays or failure of completion are a concern for the Southwest. Zoning issues prohibiting the construction of new solar assets are also an issue.

There is significantly more solar, wind, and energy storage in planned capacity additions than in the last LTRA. Additionally, several states in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

Energy Storage
Energy storage is being relied on to help mitigate ramping risk from afternoon net demand caused by increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage, but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers
The Southwest is not showing a significant increase in reliance on imports in the model, with peak exports occurring between 5:00 p.m. and 10:00 p.m.

Transmission
Twelve transmission projects with 500 kV and higher are planned.

Reliability Issues
WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

Demand Assumptions and Resource Categories

Demand (Load Forecast)	
Total Internal Demand	This is the peak hourly load[39] for the summer and winter of each year.[40] Projected total internal demand is based on normal weather (50/50 distribution)[41] and includes the impacts of distributed resources, EE, and conservation programs.
Net Internal Demand	This is the total internal demand reduced by the amount of controllable and dispatchable DR projected to be available during the peak hour. Net internal demand is used in all reserve margin calculations.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident[42]**	**Load Forecasting Entity**
MISO	Summer	Coincident	MISO LSEs
MRO-Manitoba Hydro	Winter	Coincident	Manitoba Hydro
MRO-SaskPower	Winter	Coincident	SaskPower
MRO-SPP	Summer	Noncoincident	SPP LSEs
NPCC-Maritimes	Winter	Noncoincident	Maritimes sub-areas
NPCC-New England	Summer	Coincident	ISO-NE
NPCC-New York	Summer	Coincident	NYISO
NPCC-Ontario	Summer	Coincident	IESO
NPCC-Québec	Winter	Coincident	Hydro-Québec
PJM	Summer	Coincident	PJM
SERC-East	Summer	Noncoincident	SERC LSEs
SERC-Florida Peninsula	Summer	Noncoincident	
SERC-Central	Summer	Noncoincident	
SERC-Southeast	Summer	Noncoincident	
Texas RE-ERCOT	Summer	Coincident	ERCOT
WECC-AB	Winter	Noncoincident	WECC BAs, aggregated by WECC
WECC-BC	Winter	Noncoincident	
WECC-CA/MX	Summer	Noncoincident	
WECC-NW	Summer	Noncoincident	

[39] Glossary of Terms Used in NERC Reliability Standards.

[40] The summer season represents June–September and the winter season represents December–February. In this assessment, the year of a winter period is referred to by the year of the month of December (e.g., Winter 2025 is December 2025 – February 2026).

[41] Essentially, this means that there is a 50% probability that actual peak demand will be higher and a 50% probability that actual peak demand will be lower than the value provided for a given season/year.

[42] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval. This is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident[42]**	**Load Forecasting Entity**
WECC-SW	Summer	Noncoincident	

Resource Categories

NERC collects projections for the amount of existing and planned capacity and net capacity transfers (between assessment areas) that will be available during the forecast hour of peak demand for the summer and winter seasons of each year. Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy.

Anticipated Resources[43]

- Existing-certain generating capacity: includes capacity to serve load during period of peak demand from commercially operable generating units with firm transmission or other qualifying provisions specified in the market construct.
- Tier 1 capacity additions: includes capacity that is either under construction or has received approved planning requirements
- Firm capacity transfers (Imports minus Exports): transfers with firm contracts
- Less confirmed retirements[44]

Prospective Resources: Includes all "anticipated resources" plus the following:

- Existing-other capacity: includes capacity to serve load during period of peak demand from commercially operable generating units without firm transmission or other qualifying provision specified in the market construct. Existing-other capacity could be unavailable during the peak for a number of reasons.
- Tier 2 capacity additions: includes capacity that has been requested but not received approval for planning requirements
- Expected (non-firm) capacity transfers (imports minus exports): transfers without firm contracts but a high probability of future implementation.
- Less unconfirmed retirements.[45]

[43] Projected capacities are inputs to reserve margin calculations and probabilistic assessments. Projections are dependent on official retirement notices to system operators. If no notice is given, capacity projections assume no retirements, even if established trends for resource retirements show declines over past years

[44] Generators that have formally announced retirement plans. These units must have an approved generator deactivation request where applicable.

[45] Capacity that is expected to retire based on the result of an assessment area generator survey or analysis. This capacity is aggregated by fuel type.

Resource Categories

Generating Unit Status: Status at time of reporting:

- Existing: It is in commercial operation.
- Retired: It is permanently removed from commercial operation.
- Mothballed: It is currently inactive or on standby but capable for return to commercial operation. Units that meet this status must have a definite plan to return to service before changing the status to "Existing" with capacity contributions entered in "Expected-Other." Once a "mothballed" unit is confirmed to be capable for commercial operation, capacity contributions should be entered in "Expected-Certain."
- Cancelled: planned unit (previously reported as Tier 1, 2, or 3) that has been cancelled/removed from an interconnection queue.
- Tier 1: A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):[46]
  - Construction complete (not in commercial operation)
  - Under construction
  - Signed/approved Interconnection Service Agreement (ISA)
  - Signed/approved Power Purchase Agreement (PPA) has been approved
  - Signed/approved Interconnection Construction Service Agreement (CSA)
  - Signed/approved Wholesale Market Participant Agreement (WMPA)
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to Vertically Integrated Entities)
- Tier 2: A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):[47]
  - Signed/approved Completion of a feasibility study
  - Signed/approved Completion of a system impact study
  - Signed/approved Completion of a facilities study
  - Requested Interconnection Service Agreement
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)
- Tier 3: A units in an interconnection queue that do not meet the Tier 2 requirement.

[46] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)
[47] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)

Reserve Margin Descriptions
Planning Reserve Margins: The primary metric used to measure resource adequacy defined as the difference in resources (anticipated or prospective) and net internal demand divided by net internal demand, shown as a percentile
Anticipated Reserve Margin (ARM): The amount of anticipated resources less net internal demand calculated as a percentage of net internal demand
Prospective Reserve Margin (PRM): The amount of prospective resources less net internal demand calculated as a percentage of net internal demand
Reference Margin Level (RML): The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, system planners use this metric is to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increased demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the RML is a requirement. RMLs can fluctuate over the duration of this assessment period or may be different for the summer and winter seasons. If an RML is not provided by a given assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Methods and Assumptions

How NERC Defines BPS Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:

- **Adequacy:** The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components
- **Operating Reliability:** The ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components

When extreme or otherwise unanticipated conditions result in a resource shortfall, system operators take controlling actions or implement procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area); these actions include the following:

- Public appeals
- Interruptible demand that the end-use customer makes available to its LSEs via contract or agreement for curtailment[48]
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as 5%)
- Rotating blackouts (The term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, rotating the outages among individual feeders.)

System disturbances affect operating reliability when they cause the unplanned and/or uncontrolled interruption of customer demand. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When interruptions spread over a wide area of the grid, they are referred to as "cascading blackouts," the uncontrolled successive loss of system elements triggered by an incident at any location.

The BES is a defined subset of the BPS that includes all facilities necessary for the reliable operation and planning of the BPS.[49] NERC Reliability Standards are intended to establish requirements for BPS owners and operators so that the BES delivers an adequate level of reliability (ALR),[50] which is defined by the following characteristics.

- **Adequate Level of Reliability:** It is the state that the design, planning, and operation of the BES will achieve when the following reliability performance objectives are met:
  - The BES does not experience instability, uncontrolled separation, cascading,[51] and/or voltage collapse under normal operating conditions or when subject to predefined disturbances.[52]
  - BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
  - BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
  - Adverse reliability impacts on the BES following low-probability disturbances (e.g., multiple BES contingences, unplanned/uncontrolled equipment outages, cyber security events, malicious acts) are managed.

[48] Interruptible demand (or interruptible load) is a term used in NERC Reliability Standards. See Glossary of Terms used in Reliability Standards: NERC Glossary of Terms
[49] BES Definition
[50] NERC Informational Filing (to FERC) on the Definition of Adequate Level of Reliability, Docket Number RR06-1, May 10, 2013.
[51] NERC's Glossary of Terms defines Cascading: "Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."
[52] NERC's Glossary of Terms defines Disturbance: "1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load."

- Restoration of the BES after major system disturbances that result in blackouts and widespread outages of BES elements is performed in a coordinated and controlled manner.

How NERC Evaluates Reserve Margins in Assessing Resource Adequacy

PRMs are calculated by finding the difference between the amount of projected on-peak capacity and the forecasted peak demand and then dividing this difference by the forecasted peak demand. Each assessment area has a peak season, summer or winter, for which its peak demand is higher. PRMs used throughout this LTRA are for each assessment area's peak season listed in the load forecasting table of the **Demand Assumptions and Resource Categories**.

NERC assesses resource adequacy by evaluating each assessment area's PRMs relative to its RML—a "target" or requirement based on traditional capacity planning criteria. The projected resource capacity used in the evaluations is reduced by known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations) and compared to the RML, which represents the desired level of risk based on a probability-based loss-of-load analysis. On-peak resource capacity reflects expected output at the hour of peak demand. Because the electrical output of VERs (e.g., wind and solar) depend on weather conditions, on-peak capacity contributions are less than nameplate capacity. Based on the five-year projected reserves compared to the established RMLs, NERC determines the risk associated with the projected level of reserve and concludes in terms of the following:

Adequate: The ARM is greater than RML.

Marginal: The ARM is lower than the RML and the PRM is higher than RML.

Inadequate: The ARM and PRMs are less than the RML and Tier 3 resources are unlikely to advance.

Metrics for Probabilistic Evaluation Used in this Assessment

Probabilistic Assessment: Biennially, NERC conducts a probabilistic evaluation as part of its resource adequacy assessment and publishes results in the LTRA.

Loss-of-Load Hours: LOLH is generally defined as the expected number of hours per time period (often one year) when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated by using each hourly load in the given period (or the load duration curve).

LOLH is evaluated using all hours rather than just peak periods. It can be evaluated over seasonal, monthly, or weekly study periods. LOLH does not inform of the magnitude or the frequency of loss-of-load events, but it is used as a measure of their combined duration. LOLH is applicable to both small and large systems and is relevant for assessments covering all hours (compared to only the peak demand hour of each season). LOLH provides insight to the impact of energy limited resources on a system's reliability, particularly in systems with growing penetration of such resources. Examples of such energy limited resources include the following:

- DR programs that can be modeled as resources with specific contract limits, including hours per year, days per week, and hours per day constraints
- EE programs that can be modeled as reductions to load with an hourly load shape impact
- Distributed resources (e.g., BTM solar PV) that can be modeled as reductions to load with an hourly load shape impact
- VERs can be modeled probabilistically with multiple hourly profiles

Expected Unserved Energy: EUE is the summation of the expected number of megawatt hours of demand that will not be served in a given time period as a result of demand exceeding the available capacity across all hours. EUE is an energy-centric metric that considers the magnitude and duration for all hours of the time period and is calculated in MWhs. This measure can be normalized based on various components of an assessment area (e.g., total of peak demand, net energy for load). Normalizing the EUE provides a measure relative to the size of a given assessment area (generally in terms of parts per million or ppm).

EUE is the only metric that considers magnitude of loss-of-load events. With the changing generation mix, to make EUE a more effective metric, hourly EUE for each month provides insights on potential adequacy risk during shoulder and nonpeak hours. EUE is useful for estimating the size of loss-of-load events so the planners can estimate the cost and impact. EUE can be used as a basis for reference reserve margin to determine capacity credits for VERs. In addition, EUE can be used to quantify the impacts of extreme weather, common mode failure, etc.

NERC is not aware of any planning criteria in North America based on EUE; however, in Australia, the Australian Energy Market Operator is responsible for planning using 0.002% (20 ppm) EUE as their energy adequacy requirement.[53] This requirement incorporates economic factors based on the risk of load shedding and the value of load loss along with the load-loss reliability component.

On the basis of the two years of the ProbA results, NERC determines the risk in terms of the following:

Normal Risk: Negligible amounts of LOLH and EUE.

Periods of Risk: LOLH < 2 Hours and EUE < 0.002% of total annual net energy.

Significant Risk: LOLH > 2 Hours and EUE > 0.002% of total annual net energy.

Understanding Demand Forecasts

Future electricity requirements cannot be predicted precisely. Peak demand and annual energy use are reflections of the ways in which customers use electricity in their domestic, commercial, and industrial activities. Therefore, the electric industry continues to monitor electricity use and generally revise its forecasts on an annual basis or as its resource planning requires. In recent years, the difference between forecast and actual peak demands have decreased, reflecting a trend toward improving forecasting accuracy.

The peak demand and annual net energy for load projections are aggregates of the forecasts of the individual planning entities and LSEs. These resulting forecasts reported in this LTRA are typically “equal probability” forecasts. That is, there is a 50% chance that the forecast will be exceeded and a 50% chance that the forecast will not be reached.

Forecast peak demands, or total internal demand, are electricity demands that have already been reduced to reflect the effects of DSM programs, such as conservation, EE, and time-of-use rates; it is equal to the sum of metered (net) power outputs of all generators within a system and the metered line flows into the system less the metered line flows out of the system. Thus, total internal demand is the maximum (hourly integrated) demand of all customer demands plus losses. The effects of DR resources that are dispatchable and controllable by the system operator, such as utility-controlled water heaters and contractually interruptible customers, are not included in total internal demand. Rather, the effects of dispatchable and controllable DR are included in net internal demand.

Future Transmission Project Categories

- **Under Construction:** Construction of the line has begun.
- **Planned** (any of the following):
  - Permits have been approved to proceed
  - Design is complete
  - Needed in order to meet a regulatory requirement

- **Conceptual** (any of the following):
  - A line projected in the transmission plan
  - A line that is required to meet a NERC TPL standard or power-flow model and cannot be categorized as “Under Construction” or “Planned”

Other projected lines that do not meet requirements of “Under Construction” or “Planned”

[53] https://wa.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf

Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area

Reference Margin Levels for Each Assessment Area (2025–2029)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
MISO	2024-2025 Summer: 9.0% Fall: 14.2% Winter: 27.4% Spring (2025): 26.7%	Planning Reserve Margin	Yes: Established Annually[54]	0.1 day/Year Loss of Load Expectation (LOLE)	MISO
MRO-Manitoba Hydro	12.0%	Reference Margin Level	No	0.1 day/Year LOLE	Reviewed by the Manitoba Public Utilities Board
MRO-SaskPower	15.0%	Reference Margin Level	No	EUE and Deterministic Criteria	SaskPower
MRO-SPP	19.0%	Resource Adequacy Requirement	Yes: studied on Biennial Basis	0.1 day/Year LOLE	SPP Staff, Stakeholders, SPP Regional State Committee.
NPCC-Maritimes	20.0%[55]	Reference Margin Level	No	0.1 day/Year LOLE	Maritimes Sub-areas; NPCC
NPCC-New England	11.3–12.7%	Installed Capacity Requirement	Yes: three year requirement established annually	0.1 day/Year LOLE	ISO-NE, NPCC Criteria
NPCC-New York	15.0%[56]	Installed Reserve Margin	Yes: one year requirement, established annually by NYSRC based on full installed capacity values of resources	0.1 day/Year LOLE	NYSRC, NPCC Criteria
NPCC-Ontario	8.6–19.5%	Reserve Margin Requirement	Yes: established annually for all years	0.1 day/Year LOLE	IESO, NPCC Criteria
NPCC-Québec	10.9–11.8%	Reference Margin Level	No: established Annually	0.1 day/Year LOLE	Hydro-Québec, NPCC Reliability Coordinating Committee
PJM	17.6–17.7%	Installed Reserve Margin	Yes: established Annually for each of three future years	0.1 day/Year LOLE	PJM Board of Managers, ReliabilityFirst BAL-502-RFC-02 Standard
SERC-Central	15.0%[57]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities

[54] In MISO, the states can override the MISO PRM.

[55] The 20% RML is used by the individual jurisdictions in the Maritimes area with the exception of Prince Edward Island, which uses a margin of 15%. Accordingly, 20% is applied for the entire area.

[56] The NERC LTRA RML for NY is 15%; however, there is no PRM criteria in New York. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. Additionally, the NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year. However, New York requires LSEs to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2025/2026 IRM at 24.4%. All values in the IRM calculation are based upon full installed capacity (ICAP) MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year.

[57] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.

Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area

Reference Margin Levels for Each Assessment Area (2025–2029)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
SERC-East	15.0%[58]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SERC-Florida Peninsula	15.0%[59]	Reliability Criterion	No: Guideline	0.1 day/Year LOLP	Florida Public Service Commission
SERC-Southeast	15.0%[60]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
Texas RE-ERCOT	13.75%	Target Reserve Margin	No	0.1 day/Year LOLE plus adjustment for non-modeled market considerations	ERCOT Board of Directors
WECC-AB	9.0–13.6%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[61]
WECC-BC	9.8–12.8%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-CA/MX[62]	14.9–17.4%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-NW	13.8–16.3%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-SW	9.4–12.0%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]

[58] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[59] SERC-FP uses a 15% reference reserve margin as approved by the Florida Public Service Commission for non-IOUs and recognized as a voluntary 20% reserve margin criteria for IOUs; individual utilities may also use additional reliability criteria.
[60] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[61] WECC's RML in this table is for the hour of peak demand. Some hours in the year require a higher reserve margin to meet the 0.02% reliability criteria due to the variability in resource availability and resource performance characteristics.
[62] California is the only state in the Western Interconnection that has a wide-area RML, currently 17.5%: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage,

Recommendations and ERO Actions Summary

In addition to the recommendations in the Executive Summary, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. The ERO, industry, vendors/manufacturers, and stakeholders should continue acting on the following recommendations to inform system and operations planning, develop the transmission network, and address resource performance issues attributed to IBR characteristics, cold weather, and fuel supply limitations. The ERO has a range of activities underway to monitor, assess, and reduce long-term BPS reliability risks. The selected ERO activities summarized below will result in new or enhanced Reliability Standards requirements, reliability guidelines, resources, or significant findings and actionable steps for stakeholders to address reliability risks.

LTRA Recommendations and Ongoing ERO Actions

Add new resources with needed reliability attributes and make existing resources more dependable.

1. **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource Planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Multi-metric criteria applied to results from probabilistic studies that include load loss, unserved energy, event magnitude, and event duration will support achieving the levels of reliability that are required for modern society.
2. **Address performance deficiencies with existing and future inverter-based resources:** Reliably integrating IBRs onto the grid is paramount, and evidence indicates that the risk of grid vulnerabilities from interconnection practices and IBR performance issues are growing. IBRs include most solar and wind generation as well as new BESS or hybrid generation and account for 85% of the new generation in development for connecting to the BPS. IBRs respond to disturbances and dynamic conditions based on programmed logic and inverter controls. The tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused sudden loss of generation resources (over wide areas in some cases). Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California, and similar events have occurred in new geographic areas as recently as the summer of 2023.[63] A common thread with these events is the lack of IBR ride-through capability that causes a minor system disturbance to become a major disturbance. Based on the findings of a recent NERC alert, more ride-through and ERS capabilities can be enabled within existing solar PV resources to improve performance and support the reliable operation of the BPS.[64] Industry adoption of the recommended practices set forth in NERC reliability guidelines and the NERC alert will reduce risks from IBR performance issues to the grid as NERC also develops mandatory Reliability Standards based on those reliability guidelines. It is also critically important for interconnection processes to include accurate modeling and studies requirements.[65] Guided by NERC's comprehensive Inverter-Based Resources Strategy and in response to FERC Order No. 901, the ERO, industry, and manufacturers should take additional steps to ensure that IBRs operate reliably and that the system is planned with due consideration for their characteristics.[66,67]
3. **Improve the performance of the generating fleet in extreme cold temperatures:** The ERO and industry need to complete enhanced requirements for generator cold-weather performance to address reliability related findings from the FERC, NERC, and Regional Entity joint staff inquiry into the February 2021 cold weather grid outages.[68] Revisions to Reliability Standard EOP-012-2 will improve the effectiveness of the standard and speed the implementation of corrective actions necessary to address unacceptable freezing issues. Findings of the inquiry into Winter Storm Elliott (December 2022) reinforce the urgency of this effort.[69]

[63] See the ERO's extensive IBR event reporting here: NERC Major Event Reports
[64] The NERC Level 2 alert to gather data from solar PV resource owners and issue recommendations can be found here: *Industry Recommendation: Inverter-Based Resource Performance Issues*.
[65] NERC's comprehensive initiatives to reduce IBR risks are detailed here: IBR Quick Reference Guide
[66] NERC IBR Activities
[67] Order No. 901 Work Plan
[68] *The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report*
[69] *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott*

LTRA Recommendations and Ongoing ERO Actions

4. **Mitigate fuel-related risks to electricity generation (fuel assurance):** In addition to serving as base and intermediate-load plants, natural-gas-fired generation has become a necessary balancing resource that enables reliable integration of VERs into the dispatch. As a result, the BES has never been more dependent upon the round-the-clock continuity of just-in-time natural gas delivery. The past two winters have seen interruptions of natural gas delivery to generators that resulted in energy deficiencies. Collaborative assessments involving NERC, the Regional Entities, the National Labs, and natural gas and electric power industry participants are needed to identify natural gas fuel supply needs for reliable operation of the BPS. NERC strongly endorses actions to establish reliability rules for the natural gas infrastructure necessary to support the grid as recommended in the Winter Storm Elliott report. Additionally, as part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electricity reliability. The NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System,* provides planning guidance.[70]

Initiative	Description	Product/Reliability Solution
Cold Weather Reliability Standards and Activities	New cold weather Reliability Standards adopted by the NERC Board of Trustees in June 2021 went into effect in the United States in 2023. Generator Owners and Generator Operators are required to implement plans for cold weather preparedness and provide cold weather operating parameters to their Reliability Coordinators, Transmission Operators, and Balancing Authorities for use in operating plans. Additional Reliability Standard requirements have been developed by NERC and industry to address further recommendations of the *FERC-NERC-Regional Entity staff report—The February 2021 Cold Weather Outages in Texas and Southcentral United States.* The NERC Board adopted these requirements in October 2023 and directed NERC to file them with regulatory authorities for approval and industry implementation. NERC and the industry are currently developing the remaining Reliability Standard enhancements to address the staff report. Refer to *Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination* on NERC's standards development page.[71]	Reliability Standards NERC Alerts Event Analysis Reports Lessons Learned
Inverter-Based Resources Strategy	NERC's IBR strategy includes four key focus areas: Risk Analysis, Interconnection Process Improvements, Sharing Best Practices and Industry Education, and Regulatory Enhancements. The statuses of NERC's extensive activities in each area are described in detail in the *IBR Activities Reference Guide*.[72] NERC has investigated and analyzed IBR performance issues during grid disturbances dating back to 2016. Since that time, NERC and its technical groups have published a range of reliability guidelines for studying, modeling, controlling, and interconnecting IBRs. In partnership with many experts from across the industry, NERC maintains an active campaign of education, awareness, and outreach to support its strategy and reduce IBR performance risks. NERC and the RSTC recognized that Reliability Standard requirements would be needed as part of a comprehensive approach to reliability and undertook a full review of existing standards to identify gaps. Several reliability standards projects were initiated following this review. In October 2023, FERC issued Order No. 991, which provided clear direction for the industry to develop requirements that address reliability gaps related to IBR in data sharing, model validation, planning and operational studies, and performance requirements.	Reliability Standards NERC Alerts Reliability Guidelines Event Analysis Reports Lessons Learned Educational Webinars

[70] Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised Guideline also identifies as fuel risks requiring evaluation many of the scenarios industry has encountered during recent periods of extreme cold weather and high demand for natural gas. The revised guideline is under review with the Reliability and Security Technical Committee. The approved and revised draft guideline can be found on the RSTC website: NERC Reliability and Security Guidelines

[71] Project 2021-07

[72] IBR Activities

LTRA Recommendations and Ongoing ERO Actions		
	FERC issued an order in 2022 directing NERC to identify and register owners and operators of currently unregistered bulk power system-connected IBRs.[73] Working closely with industry and stakeholders, NERC is executing a FERC-approved work plan to achieve the identification and registration directive by 2026. Resources are also posted on the Registration page of the NERC website.	
Natural Gas-Electric Interdependence Initiatives	Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised guideline also identifies the fuel risks encountered by industry during recent periods of extreme cold weather and high demand for natural gas. These natural gas supply risks can inform industry's development of planning scenarios. The revised guideline is under review with the RSTC. Refer to the RSTC-Approved Documents page.[74]	Reliability Guideline
Expand the transmission network to deliver supplies from new resources and locations to serve changing loads. 5. **Develop the transmission network:** ISOs and RTOs should continue looking for opportunities to streamline transmission planning processes and reduce the time required for transmission development. However, addressing the siting and permitting challenges that are the most common cause for delayed transmission projects will require regulators and policymakers at the federal, state, and provincial levels to focus attention and provide support.		
Initiative	**Description**	**Product/Reliability Solution**
Interregional Transfer Capability Study (ITCS)	NERC completed the ITCS required by the Fiscal Responsibility Act of 2023 and filed the final report with FERC on November 19, 2024. The ITCS is the first-of-its-kind assessment of transmission transfer capability under a common set of assumptions. However, the ITCS is not a transmission plan or blueprint. Transmission expansion analysis, resource plans, and other inputs must be considered in effective system planning. The ITCS is designed to provide foundational insights that facilitate stakeholder analysis and actions. Due to the interconnected nature of the BPS, NERC will extend the study beyond the congressional mandate to identify and make recommendations for transfer capabilities from the United States to Canada and among Canadian provinces. The Canadian analysis will be published in 2025. See **Interregional Transfer Capability Study (**ITCS).	ERO Study and Recommendations

[73] FERC Order Issued November 17, 2022
[74] RSTC Approved Documents

LTRA Recommendations and Ongoing ERO Actions

Adapt BPS planning, operations, and resource procurement markets and processes to the realities of a more complex power system.

6. **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource Planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Multi-metric approaches to resource adequacy using load loss, unserved energy, and event magnitude and duration criteria and results from probabilistic studies will support achieving the levels of reliability that are required for modern society.

7. **Resource contributions must be accurately represented in resource planning, wholesale electricity markets, and operating models:** Resource Planners and wholesale market designers must use appropriate methods for determining the contribution of resources to meeting demand. Weather-dependent resources, fuel supplies, and demand profiles result in seasonal risks. This can be seen in the increasing winter resource adequacy risks observed in the 2024 ProbA for many traditionally summer-peaking areas. ISO/RTOs can help reduce seasonal risks by implementing seasonal resource adequacy procurement (e.g., spring, summer, fall, winter) based on reserve requirements and resource performance that are tailored to each season. The explosive growth of BESS and hybrid resources seen in most areas requires additional details to be incorporated into operating and planning models, such as state of charge, BESS duration, and BESS operating mode.

8. **Maintain sufficient amounts of flexible resources and essential reliability services:** To maintain load-and-supply balance in real-time with higher penetrations of variable supply and less-predictable demand, dispatchable generators must be available and capable of following changing electricity demand. Retirements of fossil-fired generators are reducing the amounts of dispatchable generation in many areas. As more solar PV and wind generation is added, additional flexible resources are needed to offset these resources' variability, such as supporting solar down ramps when the sun goes down and complementing wind pattern changes. Natural-gas-fired generators and hydro generators have traditionally provided this ERS. Battery resources can provide flexibility during short durations, while new wind and solar PV have minimal assured flexibility. Maintaining ERSs is critically important. Resource Planners and wholesale electricity market operators should ensure resources are procured and made available in the long-range resource portfolio as part of the planning process; markets and other mechanisms need to be in place to deliver weather-ready resources with sufficient energy and ERS capabilities to the operators. [75]

9. **Include energy risks and extreme weather scenarios in resource and system planning:** Industry and regulators need to conduct all-hours analyses for evaluating and establishing resource adequacy and include extreme conditions in integrated resource planning and wholesale market designs. While more sophisticated capabilities for assessing extreme event risk are being developed, scenario planning can be more readily incorporated in resource and system planning. Scenarios should consider the potential effects of wide-area, long-duration extreme weather events, including the impact they can have on natural gas fuel supplies and on the interconnected energy system. NERC and the industry should continue to prioritize completion of new reliability standards supporting energy assurance in operating and planning time horizons, and for the assessment of extreme heat and cold weather events in transmission system planning.

10. **Accommodate the growth of DERs:** Preparing the grid to operate with increasing levels of distributed resources is a priority for most areas. Data sharing, models, and information protocols are needed to support BPS planners and operators. Industry must continue to evaluate potential reliability concerns associated with increasing DER penetration and DER performance and, when necessary, develop reliability standards requirements to address identified gaps. DER aggregators will also play an increasingly important role for BPS reliability in the coming years. ISO/RTOs must consider how the implementation of DER aggregators in the wholesale market will affect BPS planning and operations.[76]

[75] NERC ERS Measure 6 Forward Tech Brief

[76] A comprehensive guide to ERO activities on DERs can be found here: DER Activities

LTRA Recommendations and Ongoing ERO Actions		
Initiative	**Description**	**Product/Reliability Solution**
Energy Assessments Initiatives	NERC conducts seasonal long-term and probabilistic reliability assessments and issues reports like this *2024 LTRA* to advise industry and stakeholders of findings on BPS adequacy, including energy adequacy. In recent years, NERC has enhanced the energy risk analysis in seasonal assessments by incorporating deterministic energy risk scenarios and introducing probability-based assessments. NERC's ProbA uses hourly simulations to examine the ability of resources to meet demand over the entire study year, helping to identify energy risks that could otherwise go unaddressed by peak hour reserve margin resource adequacy analysis. NERC reliability assessments continue to evolve as more sophisticated energy assessment tools, models, and capabilities are developed. The RSTC created the Energy Reliability Assessment Working Group (ERAWG) to support wide adoption of technically sound approaches to energy assessments by BPS planners and operators. Working group projects and activities are described on the ERAWG page.[77] The working group is developing a technical reference document to inform registered entities on approaches and considerations for assessing and reducing the risk of energy shortfalls. New and revised Reliability Standards requirements for BPS planners and operators to address energy risks are in development in Project 2022-03 *Energy Assurance with Energy Constrained Resources.*[78] In other Reliability Standard development work, Project 2023-07 *Transmission System Planning Performance Requirements for Extreme Weather* requirements are being developed that will ensure entities consider extreme heat and cold weather scenarios in BPS planning, including the expected availability of the future resource mix.[79]	Reliability Assessments Reliability Standards
Distributed Energy Resources Strategy	NERC has proactively worked with industry stakeholders to identify BPS reliability risks associated with the increasing DER levels and has initiated actions to support broad awareness and education as well as to provide guidance for industry and enhance Reliability Standards where gaps exist. The status of NERC's extensive activities in each area are described in detail in the *DER Activities Reference Guide*.[80]	Reliability Standards Reliability Guidelines Educational Webinars
4: Strengthen relationships among reliability stakeholders.		
Initiative	**Description**	**Product/Reliability Solution**
Ongoing Strategic Engagements	NERC and the Regional Entities engage in frequent dialogue and conduct outreach with regulators and policymakers at the state/provincial, regional, and federal/national levels.	Constructive Partnerships

[77] ERAWG
[78] Project 2022-03
[79] Project 2023-07
[80] DER Activities

Errata

In June 2025, NERC, MRO, and MISO determined that incorrect RMLs were used in the 2024 LTRA for MISO.[81] After applying the correct RMLs, the following changes have been made:

- Figure 1 Risk Area Summary 2025–2029 (p. 6) | MISO changed from High Risk to Elevated Risk
- Table 1: Capacity and Energy Risk Assessment Summary (p. 7)| MISO changed from High Risk to Elevated Risk and Risk Summary updated
- Figure 2: Projected Reserve Margin Shortfall Areas with Announced Generator Retirements (p. 8) | MISO year of shortfall changed from 2025 to 2028 and caption updated
- High Risk Area Details and Elevated Risk Area Details (p. 12) | Removed the description of High Risk, moved relevant discussion of MISO risks to Elevated Risk Area Details, and updated text.
- Figures 3 and 4: MISO Planning Reserve Margins for Summer and Winter (p.13)| Updated with correct RMLs
- Table 12: Anticipated Reserve Margins with Announced Retirements (p. 40) | Footnote added to identify use of UCAP reserve margins for MISO
- MISO Demand, Resources and Reserve Margins (p. 41) | Updated the Reference Margin Level (%) row in the table and updated the Planning Reserve Margins bar graph with correct RMLs; added a note and reference to OMS-MISO Survey
- MISO Highlights (p. 42) | Changed MISO projected capacity shortfall from *2025* to *within the next five years* in the first bullet
- MISO Assessment (p. 43) | Removed the shortfall capacity value in the Planning Reserve Margins section and added a note on the capacity values for existing resources in the MISO tables; removed the statement of ARM falling below RML in the Probabilistic Assessments section

[81] See the *Statement on NERC's 2024 Long-Term Reliability Assessment* issued on June 17, 2025.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit L: NERC, *2025-2026 Winter Reliability Assessment* (Nov. 2025)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2025–2026 Winter Reliability Assessment

November 2025



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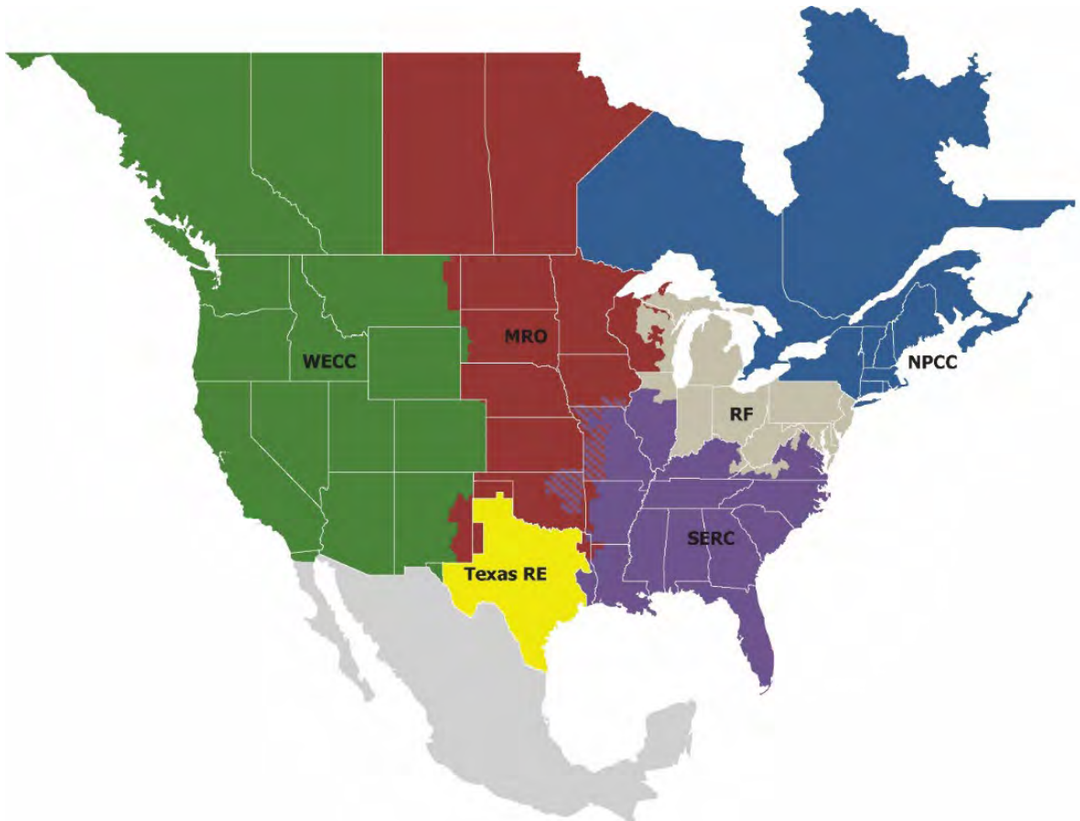
Preface

Electricity is a key component of the fabric of modern society, and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

About this Assessment

NERC's *2025–2026 Winter Reliability Assessment* (WRA) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming winter season. In addition, the WRA presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS.

The reliability assessment process is a coordinated evaluation between the Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas.

This report reflects an independent assessment by the ERO Enterprise (i.e., NERC and the six Regional Entities) and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming winter period.

Key Findings

This WRA covers the upcoming three-month (December–February) winter period, providing an evaluation of the generation resource and transmission system adequacy necessary to meet projected winter peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional risks. The following findings are the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as the potential operational concerns that may need to be addressed for the upcoming winter.

Two trends affecting resource adequacy across the BPS for the upcoming winter are rising electricity demand forecasts and a continued shift in the resource mix characterized by the retirement of thermal generators and growth in battery resources. After years of flat or low (~1%) peak demand growth, the aggregate peak demand for all NERC assessment areas has risen by 20 GW (2.5%) since the previous winter. Nearly all assessment areas are reporting year-on-year demand growth; some are forecasting increases near 10%. Total BPS resources have also increased since last winter, but by a smaller amount of 9.4 GW. This number includes the net change in generating capacity as well as additional demand response. These demand and resource changes are described in **Escalating Winter Demand** and **Resource Trends** sections.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operating concerns that should receive attention for Winter 2025–2026:

1. **All areas are assessed as having adequate resources for normal winter peak-load conditions (i.e., the area's 50-50 peak forecast). However, more extreme winter conditions extending over a wide area could result in electricity supply shortfalls.** Prolonged, wide-area cold snaps can drive sharp increases in electricity demand and threaten reliable BPS generation and the availability of fuel supplies for natural-gas-fired generation. Four severe arctic storms have descended to cover much of North America since 2021, causing regional demand for electricity and heating fuel to soar and exposing generation and fuel infrastructure in temperate areas to freezing conditions.[1] The following areas face risks of electricity supply shortfalls during periods of more extreme conditions this winter (see **Figure 1**):

    - **NPCC-Maritimes**: The peak demand forecast has fallen slightly (-1.6%) in the NPCC-Maritimes assessment area, contributing to higher reserves compared to the 2024–2025 winter. Maritimes is projected to have an Anticipated Reserve Margin (ARM) of 16.9%, which is 270 MW below the area's Reference Margin Level of 20% . New Brunswick has long-term energy contracts that can be used to mitigate resource adequacy challenges through the purchase of energy on a day-ahead basis. NPCC's all-hours probabilistic assessment for the NPCC Region included the simulation of both a base case (i.e., normal 50/50 demand) and highest peak load scenario (having an approximate 7% chance of occurring), for both an expected and a low-likelihood, reduced-resource condition. The preliminary results of this assessment indicate that operators in Maritimes are likely to require emergency operating mitigations and/or energy emergency alerts (EEA) during above-normal demand or low-resource output conditions.
    - **NPCC-New England**: A lower peak demand forecast and additional resources from demand response and firm imports offset recent generator retirements, resulting in little change to the NPCC-New England ARM for this winter. New England continues to closely monitor regional energy adequacy, particularly during extended cold snaps where constrained natural gas pipelines contribute to rapid depletion of stored fuel supplies. ISO-NE's deterministic winter scenario analysis shows limited exposure to energy shortfalls this winter. In New England, winter energy concerns are highest in scenarios when stored fuels are rapidly depleted; during these periods, timely replenishment is critical to minimizing the potential for energy shortfalls.
    - **SERC-East**: The winter peak demand forecast has increased by 700 MW (1.6%) since last winter, while winter firm capacity has declined, resulting in lower reserves. SERC-East has changed from a summer-peaking area to potentially peaking during both summer and winter. This is due to the continued addition of solar photovoltaic (PV) generation that shaves off summer peak demand and a trend toward electrification of heating that drives up winter peak demand. All-hours probabilistic analysis from SERC found some load-loss hours (<0.1 hrs) and small amounts of expected unserved energy, with the highest risk occurring during above-normal peak demand and early morning hours when solar output is absent.
    - **SERC-Central:** Additional demand response and flat load growth since last winter is offsetting declining resource capacity (down 1,120 MW), resulting in little change to the ARM at 30.5%. There are adequate resources for normal winter peak demand; however, higher levels of demand that can occur during extreme cold temperatures can result in insufficient reserves that operators would need to manage with non-firm imports and potential energy emergencies.
    - **Texas RE-ERCOT:** Strong load growth from new data centers and other large industrial end users is driving higher winter electricity demand forecasts and contributing to continued risk of supply shortfalls. For the upcoming winter season, Texas RE-ERCOT is expected to continue facing reserve shortage risks during the peak load hour and high-

[1] See detailed reports on the January 2024 and January 2025 Arctic Storms, Winter Storm Elliott, and Winter Storm Uri.

net-load hours, particularly under extreme load conditions that accompany freezing temperatures. Elevated forced outage of thermal resources and reduced output from intermittent resources during these conditions exacerbates the risk of supply shortfalls. In winter, peak demands typically occur before sunrise and after sunset coinciding with the unavailability of solar generation making the system dependent on wind generation and dispatchable resources. Data centers are altering the daily load shape due to their round-the-clock operating pattern, lengthening peak demand periods. Additional battery storage and demand-response resources since last winter help mitigate shortfall risks. However, with the continued flattening of the load curve, maintaining sufficient battery state of charge will become increasingly challenging for extended periods of high loads, such as a severe multi-day storm like Winter Storm Uri.

- **WECC-Basin**: There is sufficient capacity in the area for expected peak conditions; however, Balancing Authorities (BA) are likely to require external assistance during extreme winter weather that causes thermal plant outages, adverse wind turbine conditions, and natural gas fuel supply issues for area internal resources. External assistance may not be available during region-wide extreme winter conditions. With an expected winter peak demand of 11.1 GW, under an extreme combination of generator derates and outages, the region could be short 1.6 GW before imports. Forecasted net internal demand has increased 1% since last year, with little change in winter capacity. Note that the WECC-Basin assessment area includes Utah, southern Idaho, and a portion of western Wyoming. In prior WRA reports, this part of the BPS was included as part of the WECC-NW assessment area. The *2025–2026 WRA* includes a new assessment area map for the Western Interconnection. The new assessment area boundaries provide reliability risk information in more geographic detail for the United States and Mexico.
- **WECC-NW**: Like WECC-Basin, there is sufficient capacity in the area for expected peak conditions; however, BAs are likely to require external assistance during extreme winter weather that causes thermal plant outages and adverse wind turbine conditions for area internal resources. External assistance may not be available during region-wide extreme winter conditions. Winter peak demand for the area is forecast to be 2.9 GW higher (9.3%) compared to last year. Over 3 GW of new resources have been in development for the assessment area this year, primarily battery storage, solar PV, and wind resources. Delays that threaten timely completion of these resource additions will make the area more reliant on imports to meet peak demand.

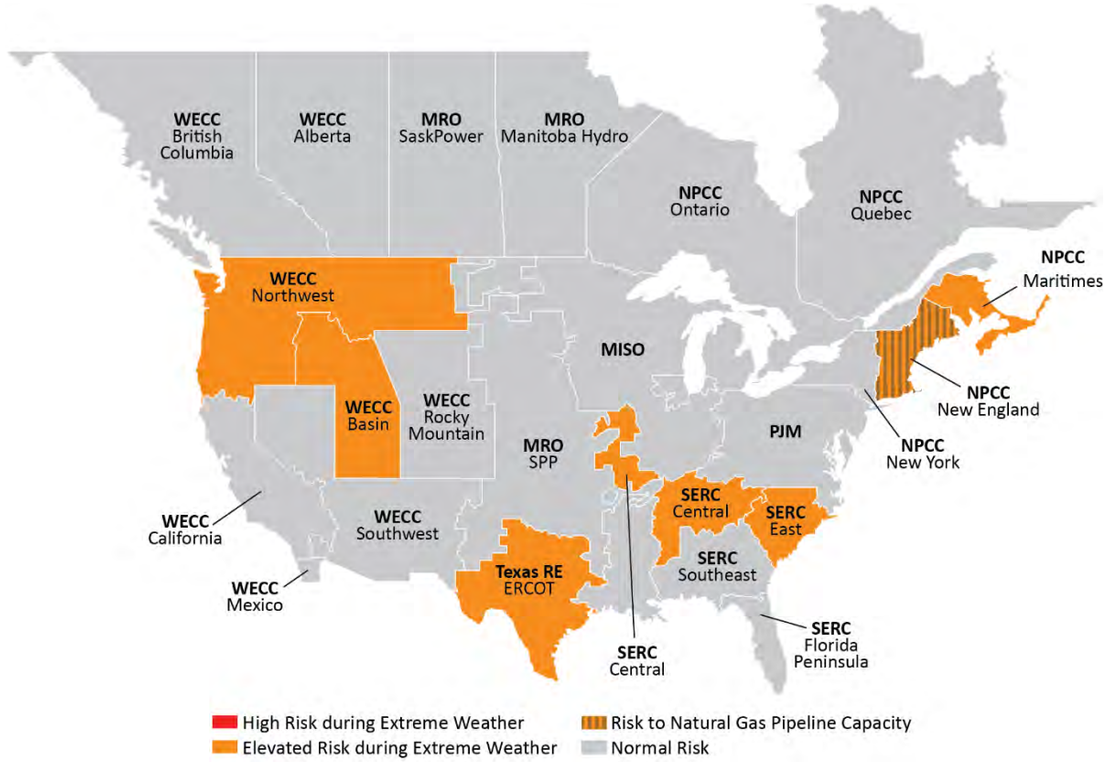


Figure 1: Winter Reliability Risk Area Summary

2. **The performance of natural gas production and supply infrastructure during peak winter conditions will again have a significant effect on BPS reliability.** Natural gas is an essential fuel for electricity generation in winter. Winter fuel supplies for thermal generators must be readily available during the periods of high electricity and natural gas demand that accompany extreme cold weather. Yet these periods are the most challenging for natural-gas-fired Generator Operators to obtain sufficient fuel and delivery. Natural gas production often falls off in extreme winter temperatures as supply infrastructure is affected by freezing issues, and Generator Operators that fail to secure firm fuel delivery are frequently unable to access fully subscribed pipelines. Evidence from the past two winters indicates notable improvement in the delivery of natural gas to BPS generators since winter storms Elliott and Uri with overall less natural gas production decline during cold weather and fewer natural gas infrastructure

force majeures.[2] Still, natural gas infrastructure freeze protection mitigations are voluntary for the natural gas industry in most of North America, resulting in uneven application of protections and continued supply risks during extreme conditions. Furthermore, timing misalignments between the natural gas and electric markets continue to challenge generator fuel procurement in advance of severe winter conditions that occur over winter holiday weekends. As winter approaches, NERC encourages all entities across the gas-electric value chain—from production to the burner tip—to take all necessary preparations for extreme cold and keep natural gas flowing and the lights on.

3. **Cold weather Reliability Standards first introduced in 2023 have been improved prior to the upcoming winter and address recommendations from winter storms Elliott and Uri.** In September 2025, the Federal Energy Regulatory Commission (FERC) approved EOP-012-3 with an effective date of October 1, 2025, concluding the development of Reliability Standards for generator cold weather preparedness.[3] The EOP-012 Reliability Standard contains requirements for generator freeze protection measures, cold weather preparedness plans, and operator training. Among the improvements in the new version are enhanced and expanded requirements to ensure that Generator Owners (GO) are implementing corrective actions to address known issues affecting their ability to operate in cold weather in a timely manner. NERC collects data on the winterization of generating units, which, in conjunction with NERC's monitoring of BPS performance and analysis of cold weather events, helps determine the effectiveness of Reliability Standards. NERC submitted to FERC its first annual *Cold Weather Data and Analysis* informational filing in October 2025.[4] Based on the data reported this year, 96% of the total net winter capacity reported extreme cold weather temperatures (ECWT) at or below 32 degrees Fahrenheit, triggering winter preparedness measures under the Cold Weather Preparedness Standard, and 99% of total net winter capacity in the continental US reporting the ability to operate at the calculated ECWT. As the first such report, this *Cold Weather Data and Analysis* filing provides a benchmark for future analysis.

Recommendations

To reduce the risks of energy shortfalls on the BPS this winter, NERC recommends the following:

- Reliability Coordinators (RC), BAs, and Transmission Operators (TOP) in the elevated risk areas identified in the key findings should review seasonal operating plans and the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially high generator outages and extreme demand levels. Operators should review NERC's Resources on Cold Weather Preparations.
- GOs should complete winter readiness plans and checklists prior to December, deploy weatherization packages well in advance of approaching winter storms, and frequently check and maintain cold weather mitigations while conditions persist.
- BAs should be cognizant of the potential for short-term load forecasts to underestimate load in extreme cold weather events and be prepared to take early action to implement protocols and procedures for managing potential reserve deficiencies. Proactive issuance of winter advisories and other steps directed at generator availability contributed to improved reliability during cold weather events of the past two winters.
- RCs and BAs should implement generator fuel surveys to monitor the adequacy of fuel supplies. They should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, load curtailment, and sustained operations in extreme conditions.
- Generator Owners/Operators of natural-gas-fired units should maintain awareness of potential extreme cold weather developing over holiday weekends and the implications for fuel planning and procurement that may result given the natural gas purchase close dates that precede long holiday weekends.
- State and provincial regulators can assist grid owners and operators in advance of and during extreme cold weather by maintaining awareness of BA, natural gas pipeline, and gas local distribution company (LDC) operational public announcements and notices, amplifying public appeals for electricity and natural gas conservation, and supporting requested environmental and transportation waivers.

[2] See *January 2025 Arctic Events | A System Performance Review*, April 2025
[3] See NERC's Statement on FERC September Open Meeting for summary and link to FERC's order.
[4] See 2025 Cold Weather Data Collection and Analysis Informational Filing

Risk Highlights

Escalating Winter Demand

Winter electricity demand is rising at the fastest rate in recent years, particularly in areas where data center development is occurring. After several years of low (~1%) growth, total internal demand for the BPS is forecast to increase by 20.2 GW (2.5%) over last winter's forecast. The changes in forecasted net internal demand for each assessment area are shown in **Figure 2** below.[5] Assessment areas develop these forecasts based on historical load and weather information as well as future projections. Most assessment areas are projecting an increase in peak demand. SaskPower, PJM, the U.S. Southeast, and parts of the U.S. West have the largest increase in peak demand forecasts.

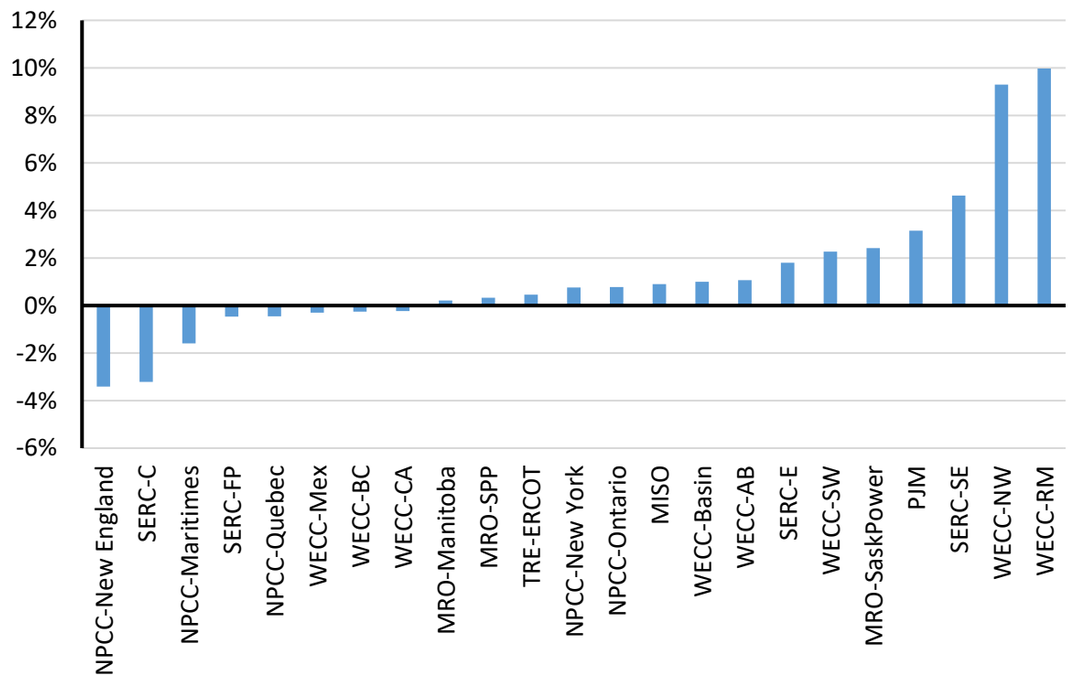


Figure 2: Change in Net Internal Demand—Winter 2025–2026 Forecast Compared to Winter 2024–2025 Forecast

[5] See **Data Concepts and Assumptions** section for demand definitions.

Resource Trends

BPS resources are growing, but at a slower rate than demand is rising. Battery and solar facilities were the leading resource types added to the BPS since last winter. Solar resources, however, often do not supply output during hours of peak winter demand. Growth in demand response is also contributing to BPS resources for the upcoming winter. **Table 1** shows the total change in BPS resources since last winter. For battery, solar, and wind resources, the table includes change in both nameplate (installed) capacity as well as the change in on-peak demand capacity, which is the capacity that resources are expected to provide in their area during the time of peak demand. For assessment-area specific information see **Variable Energy Resource Contributions** section.

Table 1: BPS Resource Change from Winter 2024–2025 to Winter 2025–2026

Resource	Net Change Nameplate Capacity (MW)	Net Change Peak Demand Capacity (MW)
Total Generator Capacity		1,335
Battery	19,659	11,121
Solar	11,097	1,176
Wind	-562	-14,238
Thermal and Hydro		3,276
Demand Response		8,112
Total Resources		9,447

Total BPS resources for serving winter peak demand, including generating capacity and demand response, have increased since last winter by 9,447 MW. Sizeable additions in battery resources and some new natural gas-fired generators contribute to the increase in resource capacity. However, the increase is offset by lower on-peak capacity values for wind resources, which are the result of revised valuations of wind resource capability at peak demand hours in some areas.[6] As a result, BPS generator capacity for winter peak demand makes up only a small portion of the total BPS increase. Generation accounts for 1,335 MW of the total 9,445 MW increase, while the larger share comes from demand response programs. Area specific information on demand response is provided in the **Demand and Resource Tables**.

The recent trend in resource additions is contributing to higher risk of electricity supply shortfalls in winter. BA operators are likely to face higher winter demand without a comparable increase in supply resources. Furthermore, the types of resources that are growing the most-- battery resources and

[6] Since last winter, ERCOT and MISO have implemented new methods for determining capacity contributions that result in lower wind and solar resources contributions at peak demand. See ERCOT's Resource Adequacy page and MISO's *Planning Year 2025-2026 Wind and Solar Capacity Credit Report*.

demand response—have unique characteristics that operators will need to account for and could limit the use of these resources in extreme winter conditions. Battery energy is reliable when it can be dispatched and has sufficient charge for the period it is needed, yet little time to recharge can be expected during extreme winter weather. System operators will need good visibility on battery state of charge and should anticipate that some extreme winter events will cause these resources to become depleted when needed. Demand response is limited by contract terms, which typically specify how often and for how long the resource may be used. Other resource types are also challenged in winter (see **Thermal Generator Fuel Adequacy and Security**). As BAs grapple with higher demand in most parts of the BPS, they will do so with resources that are becoming increasingly complex to dispatch especially in winter.

Thermal Generator Fuel Adequacy and Security

The performance of the thermal generator fleet remains critical to winter BPS operations. Winter fuel supplies for thermal generators must be readily available during periods of high demand and extreme cold weather. Generally, fuel adequacy for the thermal generating fleet is bolstered through strategic infrastructure investments and fuel stockpiling that increases the certainty of having fuel on hand that can be converted to electricity when needed. Because of this, winter performance of thermal generators is inextricably linked to extraction, processing, storage, and delivery infrastructure for a variety of fuels. Fuel supply risks have been noted in recent years' WRAs related to coal and natural gas availability and illustrate the interconnected nature of these critical energy infrastructure systems.

BPS stakeholders across North America note multiple fuel-related issues that are being monitored entering the winter season. For example, while coal represents a waning share of the overall resource mix, it continues to play an important role in meeting demand during extreme winter weather events, and oil inventories at dual-fuel gas-oil generators lessen risks related to natural gas deliverability in infrastructure-constrained regions, especially during the winter. Notably, it is infeasible or prohibitively costly to stockpile natural gas locally at power plants, and this exposes the BPS to the risk profile of the constituent systems that comprise the supply and delivery of this just-in-time fuel.

Natural Gas Generator Fuel Supplies

Natural gas generators remain a crucial part of on-peak resources meant to meet winter electricity demand across much of North America. While many Generator Owners and Operators secure backup fuel supplies at critical gas-fired generators, particularly in the northeastern United States and Florida, large contributions to the on-peak winter resource mix by single-fuel natural-gas-fired generators remain across North America (see **Figure 3**).

Natural gas generator performance can be threatened when natural gas supplies are insufficient or when natural gas infrastructure is unable to maintain the flow of fuel to critical generators. Grid operators continue to acknowledge and enhance their winter planning processes to firm up their fuel supplies and guard against natural gas disruptions, but winter storms Uri and Elliott demonstrated that combinations of natural gas flow restrictions and supply insufficiency can occur regardless of whether cold temperatures are common or uncommon in the region and can affect more than one BA area concurrently.

Many BPS areas that regularly experience cold weather events, like New England, have adopted mitigating technologies to lessen the impact of natural gas shortages through generator dual-fuel capability and stored backup fuel. In those areas, prolonged cold weather events present a risk of rapid depletion of stored backup fuel. Robust regional and distributed storage investments and winter planning for timely fuel replenishment are critical to minimizing potential energy shortfalls in the operational time frame in these areas.

Natural gas and electricity infrastructures have the added complexity of interdependence. Electricity is used to power some facilities, such as compressor stations and processing plants that make up natural gas infrastructure. These interdependencies mean that reliability events that originate on one system have the potential to affect the other and worsen the overall event magnitude or duration.

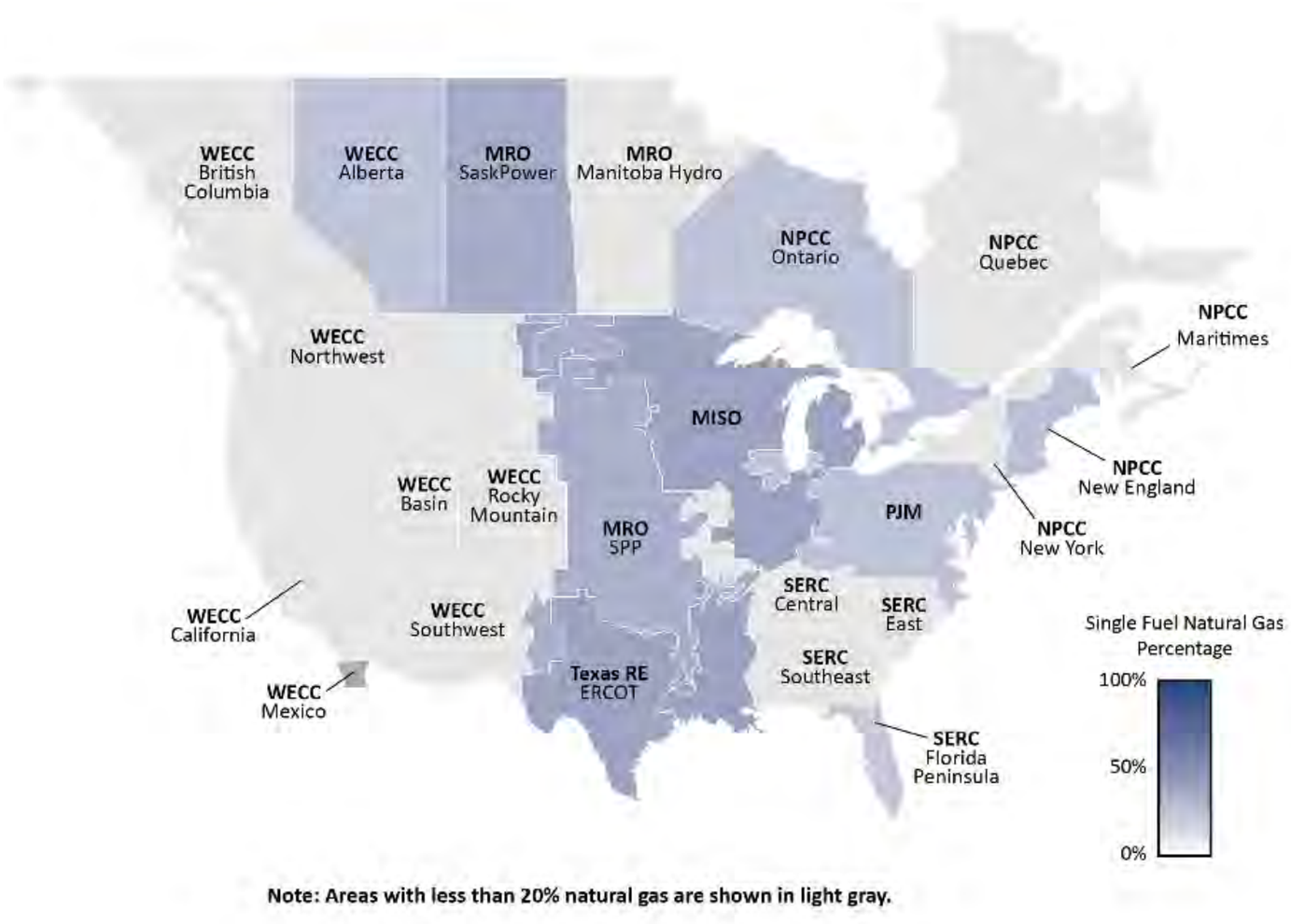
Natural gas infrastructure freeze protection mitigations are voluntary for the natural gas industry in most of North America. Texas is an exception, where the Railroad Commission of Texas adopted rules to require critical natural gas facilities to implement weather-related emergency preparation measures.[7] Lack of consistent standards for natural gas infrastructure protections will result in uneven application of freeze protections and continued supply risks during extreme conditions in many areas.

These considerations have driven higher levels of coordination to ensure sustained reliable operation of the natural gas and electricity systems. While a FERC and ERO staff review of system performance during the January 2025 arctic events[8] details improvements in electric and natural gas coordination since winter storms Uri and Elliott, the review also identifies continuing gaps between the electricity and natural gas industries that remain entering the 2025–2026 Winter season. These include natural gas scheduling challenges during winter holiday weekends, market time frame and process incompatibility, and electric power entities' lack of visibility into operational impact data from natural gas producers and suppliers.

[7] See Railroad Commission of Texas weatherization rule.

[8] FERC, NERC Issue Report on System Performance During the January 2025 Arctic Weather | Federal Energy Regulatory Commission

The U.S. Energy Information Administration (EIA)[9] anticipates a slightly milder winter than last year across much of the United States, especially in the Northeast, leading to a projection that households will consume approximately 2% less natural gas than last winter. Working natural gas storage inventories are about 5% above the previous five-year average in the United States heading into the winter season. The EIA attributes this relative surplus in part to robust production this summer and lower-than-expected natural gas consumption by power generators.



Single-Fuel Natural-Gas-Fired Generation

	Winter Capacity (GW)	Contribution to Total Winter Resource Mix
MISO	63.9	38%
TRE-ERCOT	53.0	38%
WECC-MX	2.2	34%
MRO-SaskPower	2.5	34%
SPP	33.4	32%
NPCC-New England	12.1	24%
PJM	60.9	23%
WECC-AB	13.9	23%
NPCC-Ontario	8.0	23%
SERC-FP	45.6	21%
WECC-CA	35.9	18%
WECC-SW	21.5	17%
WECC-Basin	4.9	16%
WECC-RM	6.2	14%
SERC-C	17.0	13%
SERC-SE	21.5	13%
WECC-NW	8.7	12%
SERC-E	11.3	9%
NPCC-New York	5.0	8%
NPCC-Maritimes	0.5	7%
MRO-Manitoba	0.3	4%
WECC-BC	0.1	1%
NPCC-Quebec	0.0	0%

Figure 3: Single-Fuel Natural-Gas-Fired Generation Capacity Contribution to the 2025–2026 Winter Generation Mix

[9] See the U.S. Energy Information Administration's Winter Fuels Outlook 2025–26

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in Table 2.

Table 2: Seasonal Risk Assessment Summary

Category	Criteria[1]
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels (RML); or • Probabilistic indices exceed benchmarks, e.g., loss of load hours (LOLH) of 2.4 hours over the season; or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand and outage scenarios**[2]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season); or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **extreme peak-day demand with normal resource scenarios** (i.e., typical or expected outage and derate scenarios for conditions);[2] or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand with reduced resources** (i.e., extreme outage and derate scenarios)[3]
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

Table Notes:
[1]The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2]**Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand.
[3]**Reduced resource scenarios** include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted.
[4]Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins (ARM), which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins with typical forced outage levels and for the most extreme seasonal risk scenarios are provided in Table 3.

Table 3: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Reserve Margin with Typical Outages	Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	49.5%	22.3%	3.7%
MRO-Manitoba	13.7%	11.4%	6.1%
MRO-SaskPower	35.1%	29.0%	16.1%
MRO-SPP	56.5%	29.4%	16.9%
NPCC-Maritimes	16.9%	12.5%	-4.7%
NPCC-New England	58.9%	45.4%	8.7%
NPCC-New York	78.2%	52.4%	16.2%
NPCC-Ontario	28.6%	21.8%	13.2%
NPCC-Québec	15.2%	15.1%	5.0%
PJM	35.6%	24.8%	15.6%
SERC-C	30.5%	22.4%	-0.9%
SERC-E	21.9%	17.5%	3.0%
SERC-FP	41.7%	28.3%	25.6%
SERC-SE	39.7%	24.7%	17.7%
TRE-ERCOT	36.0%	25.2%	-20.0%
WECC-AB	35.2%	32.4%	10.0%
WECC-Basin	29.6%	19.7%	-21.1%
WECC-BC	25.9%	25.8%	15.4%
WECC-CA	82.3%	73.7%	57.9%
WECC-Mex	83.1%	79.4%	52.9%
WECC-NW	30.9%	29.5%	-8.5%
WECC-RM	61.7%	53.2%	10.0%
WECC-SW	104.4%	90.1%	50.1%

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario charts in each dashboard provide potential winter peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; more information about these dashboard charts is provided in the **Data Concepts and Assumptions** section.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 3**, each assessment area's ARMs are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Areas highlighted in orange in **Figure 1** above have been identified as having resource adequacy or energy risks for the winter and are included in the **Key Findings** section's discussion that follows. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced-outage margin is the same as the ARM, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the winter season. Results are summarized in **Table 5**. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include loss of load expectation (LOLE), loss of load hours (LOLH), expected unserved energy (EUE), and the probabilities of energy emergency alert (EEA) declarations (see **Table 4** for a description of EEA levels).

Table 4: Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required operating reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum operating reserve requirements.
EEA 3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum operating reserve requirements.

Energy Emergency Alerts

The combination of above-normal generation outages, low resource output, and peak loads as occurred during the extreme cold weather events of Winter Storm Uri in 2021 and Winter Storm Elliott in 2022 are ongoing winter reliability risks. When supply resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ EEAs to maintain balance between available capacity and energy and real-time demand. A description of each EEA level is provided above.

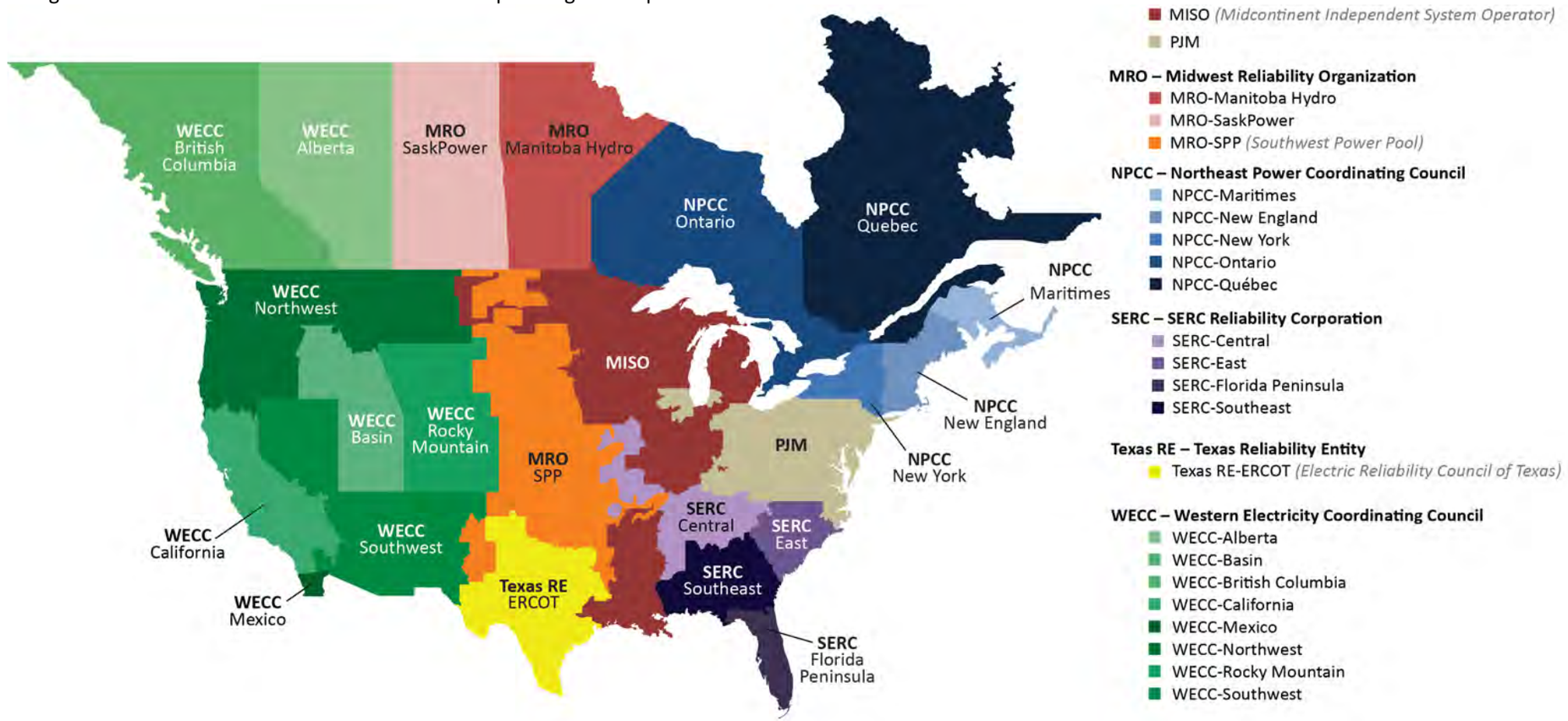
Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	Deterministic	MISO does not provide a probabilistic assessment for the WRA. MISO applies a deterministic look at expected system conditions, looking at generation availability under typical and extreme outages and looking at a typical 50/50 load forecast and an extreme 90/10 load forecast. For the upcoming winter season, under an extreme outage and extreme 90/10 load forecast, this is the riskiest scenario for the MISO footprint. This scenario produces the shortest actual reserve margin for January.
MRO-Manitoba	Probabilistic study for the NERC Probabilistic Assessment (ProbA)	Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 *Long-Term Reliability Assessment* (LTRA) found no load-loss or unserved energy hours for 2026.
MRO-SaskPower	Probability-based capacity adequacy assessment	SaskPower's probabilistic assessment for the 2025–2026 Winter indicates that risk of shortfalls is lower than the previous winter. LOLH for an elevated risk scenario for the 2025–2026 Winter season is 0.08 hours. The month with the highest LOLH is December (0.05 hours).
MRO-SPP	NERC 2024 ProbA	Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
NPCC	NPCC conducted an all-hour probabilistic reliability assessment that included detailed neighbor modeling and consisted of a base case and severe case examining low resources, reduced imports, and higher loads. The assessment evaluates the probabilistic indices of LOLE, LOLH, and EUE. The highest peak load scenario has an approximately 7% probability of occurring.	
NPCC-Maritimes	The Maritimes Area low-likelihood resource case assumed: wind derated by 50% for every hour in December through February and a 50% natural gas capacity curtailment for December through February (dual-fuel units assumed reverting to oil) and reduced transfer capabilities.	The preliminary assessment indicates that established operating procedures are not sufficient to maintain a balance between electricity supply and demand. Under highest peak load levels, the Maritimes Area shows a notable likelihood of utilizing its operating procedures such as reducing 30-minute reserves, initiating interruptible loads, and reducing 10-minute reserves to maintain system reliability during the upcoming winter period.
NPCC-New England	The New England Area low-likelihood resource case assumed: 500 MW of additional maintenance outages, ~4,513 MW of gas-fired generation unavailable due to fuel supply constraints, and 50% reduced import capabilities of external ties.	The preliminary results of this assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand
NPCC-New York	The New York Area low-likelihood resource case assumed: ~500 MW of extended maintenance in southeastern New York, 600 MW of cable transmission reduction across HVdc facilities, and ~5,000 MW of generation unavailable due to fuel delivery issues.	The preliminary results of this assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the December–February winter period, for all the scenarios modeled.
NPCC-Ontario	An energy assessment for the Ontario Assessment Area was conducted for two scenarios: firm resources and firm demand with expected weather, and planned resources with planned demand with expected weather.	No cumulative LOLH or EUE risks were identified over the entire November-to-April winter season for both scenarios modeled.

Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Québec	The Québec Area low-likelihood resource case assumed 1,000 MW of generation reductions.	The preliminary results of this assessment indicate that established operating procedures are sufficient to maintain a balance between electricity supply and demand if needed. No cumulative LOLE, LOLH or EUE risks were indicated over the December–February winter period for all the scenarios modeled
PJM	Probabilistic study for the NERC Probabilistic Assessment (ProbA)	Probabilistic study for 2025–2026 Winter is not provided for the WRA. PJM performed probabilistic analysis for 2026-2027 winter as part of the 2024 ProbA summarized in NERC's 2024 LTRA. The results of this study indicate risk of load loss (<0.1 hours) and unserved energy during winter months. For the upcoming winter, load-loss hours are expected to be less than this value because forecasted load is lower and anticipated resource capacity is higher than the case studied for the 2024 ProbA.
SERC	Based on the 2024 NERC Probabilistic Assessment (ProbA) base-case result. SERC's assessment used 38 years of historical load shapes to assess the resource adequacy of years 2026 and 2028, primarily based on data from the 2024 Long Term Reliability Assessment (LTRA).	
SERC-Central		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
SERC-East		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found a small number of load-loss hours (<0.1) and EUE (61 MWh / 1 ppm) for 2026.
SERC-Florida Peninsula		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found negligible load-loss hours and EUE.
SERC-Southeast		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
Texas RE-ERCOT	ERCOT Probabilistic Reserve Risk Model	ERCOT's probabilistic risk assessment indicates a 2% probability of having to declare EEAs during the January forecasted winter peak day (which coincides with the highest reserve shortage risk) and a controlled load shed probability of 1.8%. ERCOT defines low-risk hours as when the probability of an EEA is less than 10%.
WECC	The resource adequacy work performed at WECC used the Multi-Area Variable Resource Integration Convolution (MAVRIC) model for the 2025 LTRA. The MAVRIC model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and ProbA.	
WECC-AB		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Basin		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-BC		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.

Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-CA		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Mexico		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Rocky Mountain		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-NW		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026. Results for a case where new resource additions are not completed for the upcoming winter found some EUE and LOLH.
WECC-SW		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-Peak Reserve Margin bar charts show the ARM compared to a reference margin level (RML) that is established for each area to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the **Demand and Resource Tables**), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme winter peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the WRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods vary by assessment area and provide further insights into the risk conditions forecasted for this upcoming winter period.



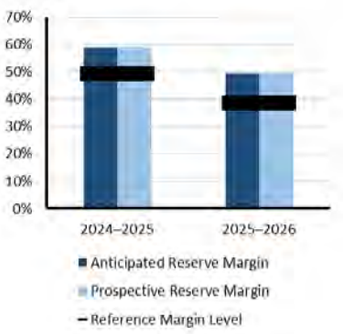


MISO

The Midcontinent Independent System Operator, Inc. (MISO) is an independent, not-for-profit organization responsible for operating the bulk electric power system and administering wholesale electricity markets across 15 U.S. states and the Canadian province of Manitoba. MISO ensures the reliable delivery of electricity to approximately 45 million people by managing regional transmission operations as well as energy and ancillary services markets and advising on long-term resource planning. The MISO footprint includes 39 Local BAs and more than 550 market participants. MISO operates one of the world's largest organized electricity markets, with its members operating a system that consists of over 77,000 miles of transmission lines and approximately 1,888 generating units. The peak electricity demand on the MISO system currently occurs during the summer season. MISO's footprint lies across three regional entities (MRO, RF, and SERC), but MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

- MISO expects limited risk in the 2025–26 Winter season as MISO was able to procure 6.1% more resources through the annual planning reserve auction than required by its minimum resource adequacy target. A further 3.3 GW of resources were available but not chosen to be committed for the winter season.
- Some risk has been identified for this upcoming winter season. In a high generation outage and high winter load scenario reliability is expected to be maintained by reliance upon operational mitigations that include non-firm energy transfers into the system, energy-only resources not subject to a must-offer requirement that may still offer into the energy markets, load-modifying resources, and internal transfers that exceed the Sub-Regional Import/Export Constraint (SRIC/SREC) between the MISO North/Central and South areas.
- MISO continues to coordinate with neighboring RCs and BAs to improve situational awareness and vet any needs for energy transfers to address extreme system conditions.
- MISO continues to survey and coordinate with its members on winter preparedness and fuel sufficiency.
- MISO has implemented a seasonal resource adequacy construct and seasonal unit accreditation to better affirm adequate supply in all seasons.

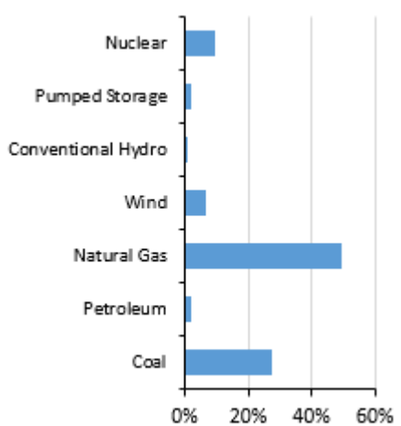
On-Peak Reserve Margin[10]



Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed demand scenarios. Above-normal winter peak load combined with generator outages from freezing or fuel supply issues and low wind output result in the need to employ operating mitigations (i.e., demand response and transfers).

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: 50/50 net internal demand and additional demand during extreme weather conditions (e.g., Winter Storm Enzo) using member submitted data and historical load data

Typical Maintenance Outages: Rolling three-year winter average of peak-day maintenance and planned outages

Typical Forced Outages: Three-year average of all peak-day outages that were not planned

Resource Derates for Extreme Conditions: Represents derates aligning with the most extreme hour of each of the past 3 years,

Operational Mitigations: Non-firm energy transfers into the system, energy-only resources that do not have a must-offer requirement, or internal transfers that exceed the SRIC/SREC between the MISO North/Central and South regions

[10] The MISO Risk Scenario Assessment for the 2025-26 Winter Season is not directly comparable to that for the 2024-25 Winter Season as methodology improvements have been implemented.



MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas. Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and natural gas to approximately 293,000 customers in southern Manitoba. Its service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter-peaking. Manitoba Hydro is its own Planning Coordinator (PC) and Balancing Authority (BA). Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

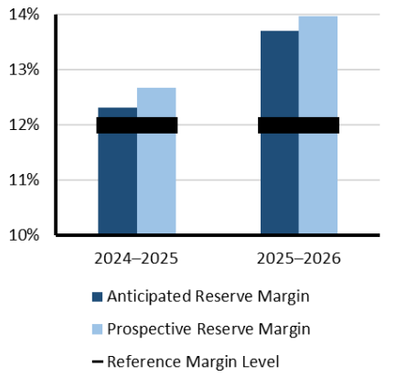
Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Winter 2025–2026.
- Manitoba Hydro expects to reliably supply its internal demand and export obligations even under continued drought conditions.
- Manitoba Hydro is experiencing well below-average water supply conditions; however, the Manitoba Hydro system is designed and operated such that reliable operations can be maintained under extreme drought.
- The ARM for Winter 2025–26 exceeds the 12% RML.

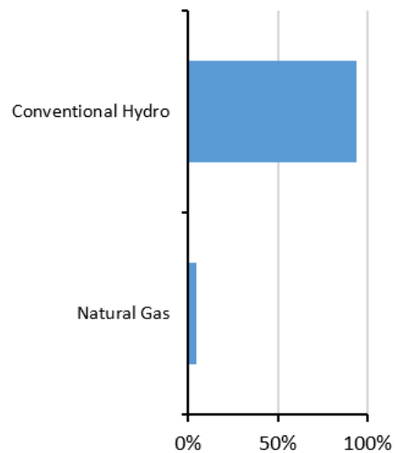
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

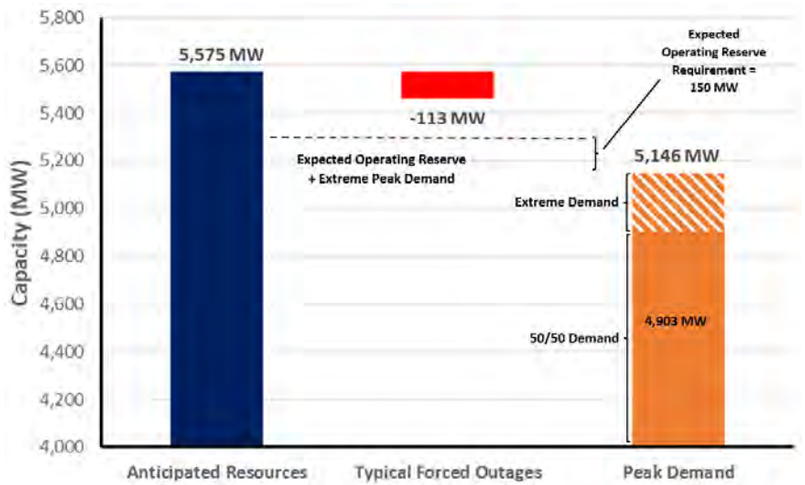
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of weather data

Typical Forced Outages: Accounts for average forced outages



MRO-SaskPower

MRO-SaskPower is an assessment area that covers the Canadian province of Saskatchewan. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of just over 1.1 million people. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System (BES) and its interconnections. Overall, SaskPower operates nearly 14,816 circuit-km of transmission lines, 65 high-voltage switching stations, and 191 distribution substations. Peak electricity demand on the SaskPower system currently occurs during the winter season.

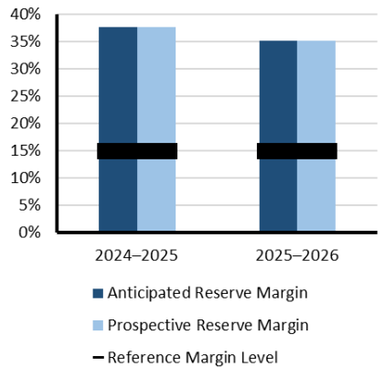
Highlights

- Saskatchewan experiences its peak load during the winter months due to extreme cold weather.
- Based on the planned maintenance, typical forced outages from historical data, and expected renewable generation under the normal and extreme demand conditions, SaskPower does not anticipate any reliability issues during the 2025–2026 Winter.
- During extreme winter conditions, SaskPower would utilize available demand-response programs, short-term power transfers from neighboring utilities, maintenance rescheduling, and/or short-term load interruptions to manage the situation.

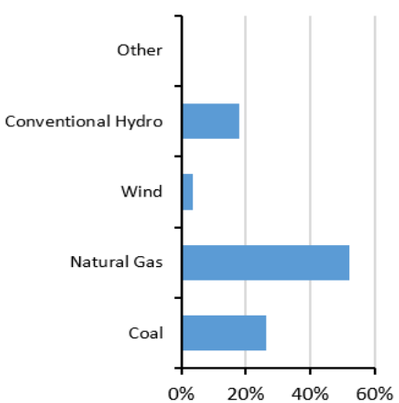
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

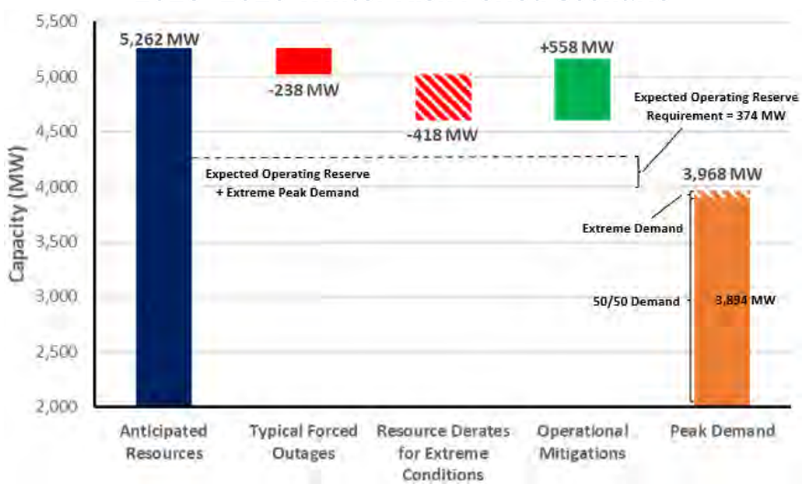
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Based on the historical load variability, SaskPower calculates a probability density function for load to simulate various scenarios that include extreme conditions.

Typical Forced Outages: Estimated using SaskPower forced outage model

Resource Derates for Extreme Conditions: Wind capacity is derated by 96% due to the cut-out of most wind farms below -30°C. Solar generation is expected to be fully unavailable under extreme conditions.

Operational Mitigations: Includes the non-firm import capability (360 MW) and generators in layup status (167 MW) that can be brought online with one to five days' notice; additional demand-side resources are estimated based on other demand response programs and non-firm loads that require 15 minutes to 2 hours of notification



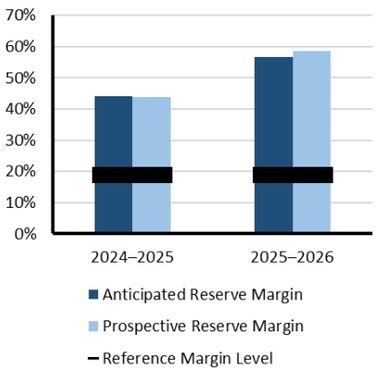
MRO-SPP

SPP's footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the MRO Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

Highlights

- SPP anticipates that planning reserves are adequate for the upcoming winter season even as SPP continues to set new winter season load records.
- SPP does not anticipate any emerging reliability issues impacting the area for the 2025–2026 Winter season but realizes that interruptions to fuel supply combined with higher penetration of variable energy resources could create unique operation challenges.
- SPP continues to work at enhancing communications and operator preparedness with neighboring regions to address potential electric deliverability issues associated with extreme weather events.
- To minimize conservative operations, EEAs, and mid-range forecast error uncertainty response in wind forecasts, SPP implemented several new operational mitigation processes and procedures to deal with high-impact real-time areas of reliability concern.
- SPP has proposed numerous resource adequacy initiatives, including addressing EUE standards, fuel assurance, winter planning reserve margins, outage policies, demand response, and accreditation; all were recently approved by FERC.

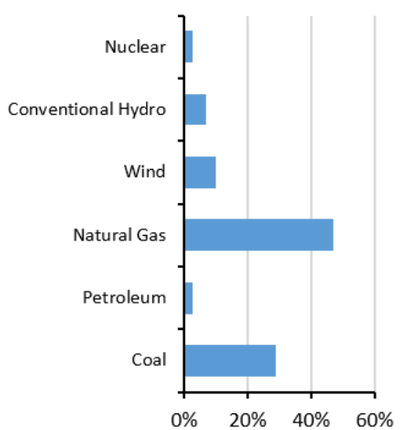
On-Peak Reserve Margin



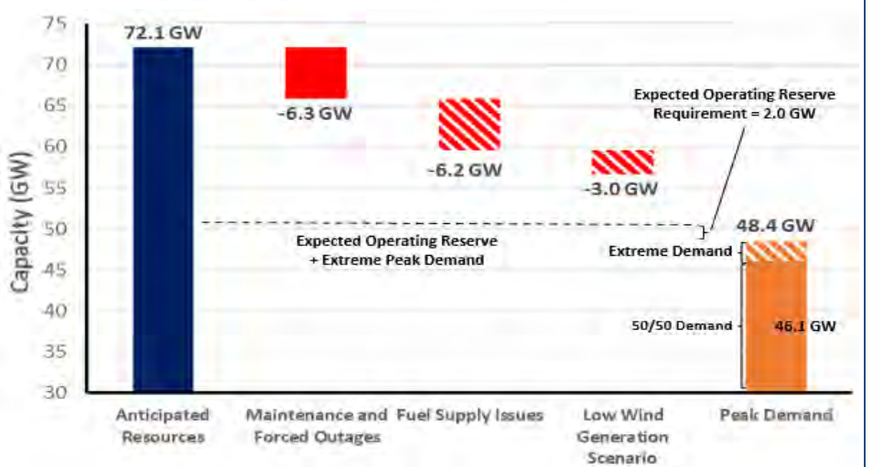
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast using historical data

Maintenance and Forced Outages: A capacity derate of 6.3 GW for maintenance outages, forced outages, and performance in extreme weather based on historical data

Fuel Supply Issues: BA derate of 6.2 GW based on MW capacity of gas-fired generators experiencing fuel supply issues in winter storm Elliott.

Low Wind Generation Scenario: 3 GW of wind potentially off-line when temperatures fall below their cold weather performance packages



NPCC-Maritimes

NPCC-Maritimes is an assessment area that covers the Canadian Maritime provinces—New Brunswick, Nova Scotia, and Prince Edward Island—and the northernmost portion of the U.S. state of Maine. The area covers approximately 150,000 square kilometers (58,000 square miles) and has a total population of nearly 1.9 million people. The New Brunswick Power Corporation (NB Power) is the balancing authority for New Brunswick, Prince Edward Island, and the northern portion of Maine. Nova Scotia Power Inc. (NSPI) is the balancing authority for Nova Scotia. NB Power's system is electrically interconnected with NPCC-Québec and NPCC-New England, and the electric systems in the provinces of Nova Scotia and Prince Edward Island have ties with New Brunswick but no direct ties with other assessment areas. Peak electricity demand in NPCC-Maritimes occurs during the winter season.

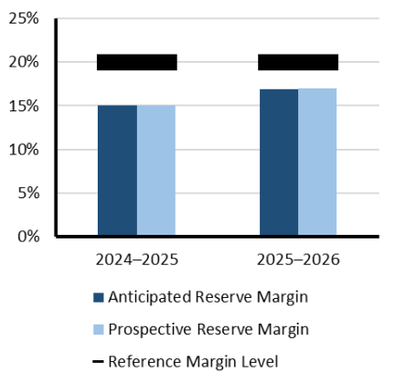
Highlights

- The Maritimes has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind, dual-fuel oil/gas, tie benefits, and biomass with no one type making up more than about 27% of the total capacity in the area.
- The Maritimes has long-term energy contracts in place for its winter supply and can purchase additional energy in the day-ahead and in real time as required.
- As part of the winter planning and preparation process, dual-fueled units will have sufficient supplies of heavy fuel oil stored on site to enable sustained operation in the event of natural gas supply interruptions.

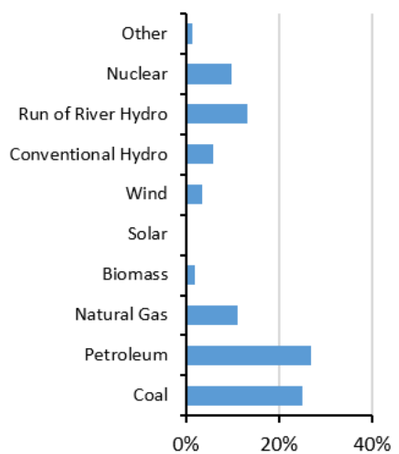
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response, transfers, appeals) and EEAs. NPCC probabilistic analysis indicates some risk of unserved energy and LOLH under high demand or low resource scenarios.

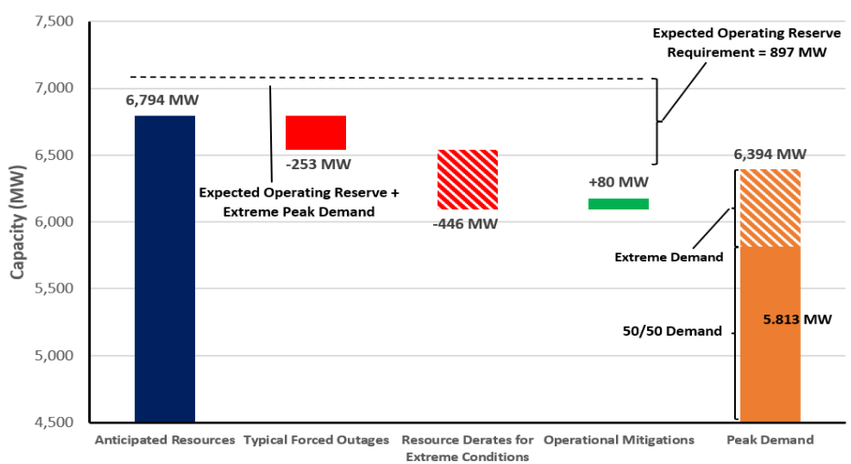
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Scenario peak load with adjustment calculated by adding a 10% margin of error to the peak internal demand forecast taken from the *Long-Term Reliability Assessment* (LTRA) for the 2025–2026 Winter period (aligns with the all-time winter peak, which occurred on February 4, 2024)

Typical Forced Outages: Based on historical operating experience

Resource Derates for Extreme Conditions: Based on ambient temperature thermal derates, wind derated to zero, as well as natural gas capacity derated by 50% due to supply issues

Operational Mitigations: Based on emergency operations and planning procedures in place including fuel switching



NPCC-New England

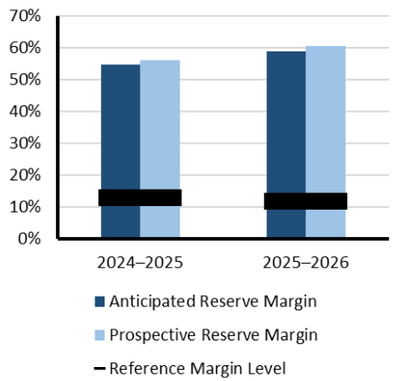
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- ISO-NE expects to meet its regional resource adequacy requirements this 2025–2026 Winter operating period without calling upon operating procedures to maintain a balance between electricity supply and demand.
- A standing concern is whether there will be sufficient energy available to satisfy electricity demand during an extended cold spell given the existing resource mix, fuel delivery infrastructure, and expected fuel arrangements without considerable effort to replenish stored fuels (i.e., fuel oil and liquefied natural gas (LNG)).
- ISO-NE expects to have sufficient capacity resources to meet the 2025–2026 50/50 and 90/10 winter peak demand forecast of 19,616 MW and 21,125 MW, respectively, for the weeks beginning January 10, January 17, and January 24.
- ISO-NE has recently developed the Regional Energy Shortfall Threshold (REST) as an effort to quantify the tolerable risk of energy shortfall during extreme events. Within the 0.25% highest-risk scenarios, the REST thresholds are 3.0% normalized EUE over 72-hour periods and 18.0 hours over 21-day periods.
    - ISO-NE does not anticipate exceeding the REST criteria for Winter 2025–2026.

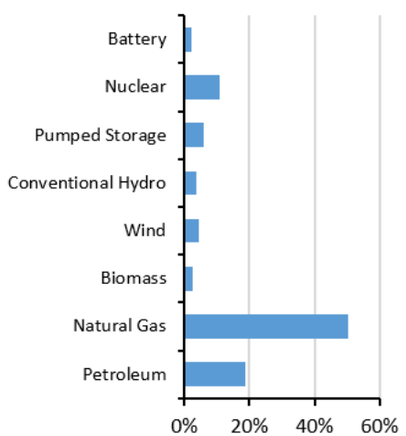
On-Peak Reserve Margin



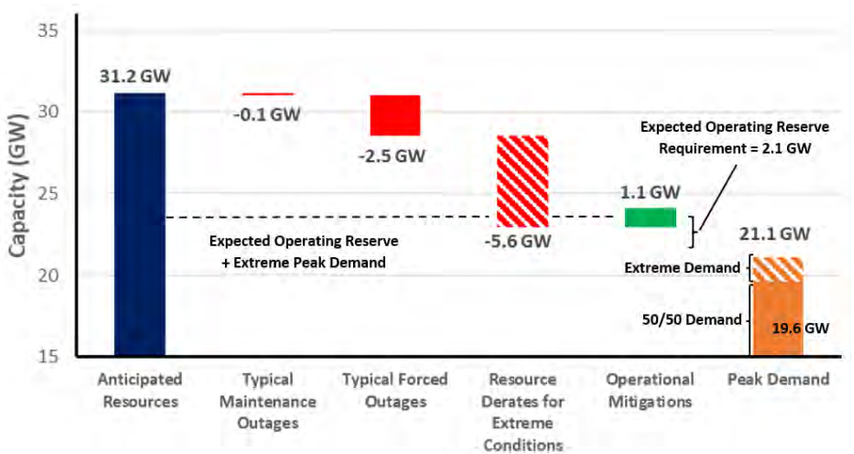
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed demand scenarios. Above-normal winter peak load combined with high generator outages could result in the need for operating mitigations (i.e., demand response and transfers). Prolonged extreme cold weather events that result in depletion of stored fuels can lead to resource shortfalls.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast capturing the region's coldest day in the last 30 years using current and future load models

Typical Maintenance Outages: Based on historical weekly averages

Typical Forced Outages: Based on seasonal capacity of each resource as determined by ISO-NE

Resource Derates for Extreme Conditions: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages and additional reductions for generation at risk due to natural gas supply and cold weather-related outages

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures



NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this WRA, the established RML is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. The council approved the 2025–2026 IRM at 24.4%.

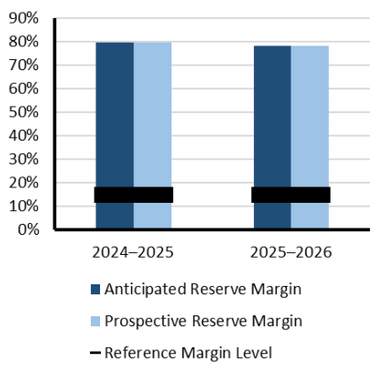
Highlights

- New York is presently a summer-peaking area, and no emerging reliability issues are anticipated during the 2025–26 Winter assessment period.
- Expected resources meet operating reserve requirements under the assessed demand and resource scenarios. A scenario involving an extended cold snap that causes above-normal demand and diminished natural gas supplies would result in low but sufficient reserves.
- The preliminary results of the NPPCC winter probabilistic assessment indicate that operating procedures are not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOL,H or EUE risks were indicated over the December–February winter period for all the scenarios modeled.

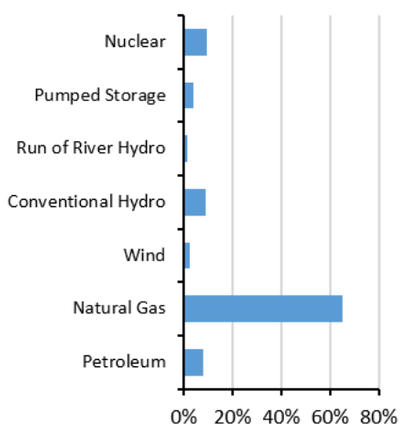
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed demand and resource scenarios.

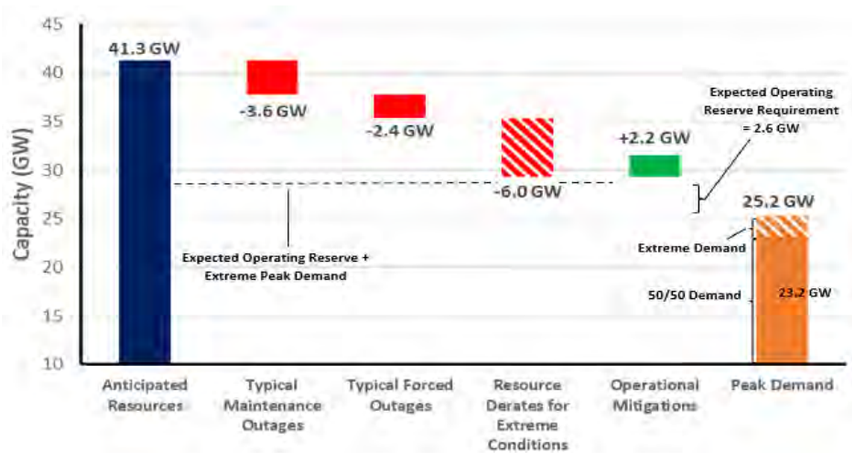
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Maintenance Outages: Based on planned scheduled maintenance

Typical Forced Outages: Based on 5–year averages from GADS data.

Resource Derates for Extreme Conditions: Potential natural gas generation at risk if non-firm supply is unavailable in a period of extended cold weather. Based on a 2025 analysis, approximately 6,307 MW of gas generation with non-firm fuel supplies could be unavailable.

Operational Mitigations: Based on NYISO operating procedures



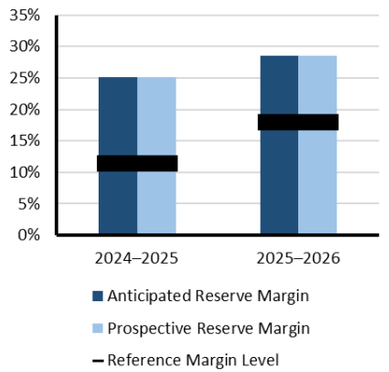
NPCC-Ontario

NPCC-Ontario is an assessment area that covers the Canadian province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of almost 16 million people. The Independent Electricity System Operator (IESO) is the balancing authority for the province of Ontario. NPCC-Ontario is electrically interconnected with NPCC-Québec, MRO-Manitoba, MISO, and NPCC-New York. Peak electricity demand in NPCC-Ontario occurs during the summer season.

Highlights

- As Ontario is a summer-peaking province, there is typically a lower risk of reliability issues during the winter than the summer. However, Ontario regularly experiences extreme cold weather in the winter.
- NPCC-Ontario is well prepared for Winter 2025–2026, and IESO expects that the electric system will remain reliable with reserve margins well above required levels.
- Operators and forecasters in Ontario work closely with neighboring jurisdictions to manage extreme weather events.
- Natural-gas-fired generators in Ontario are supplied by pipelines with access to the Enbridge Gas Dawn Hub and its associated storage facilities, which significantly reduces natural gas deliverability and reliability concerns by connecting those systems to several major gas transportation corridors, enabling access to multiple supply basins.

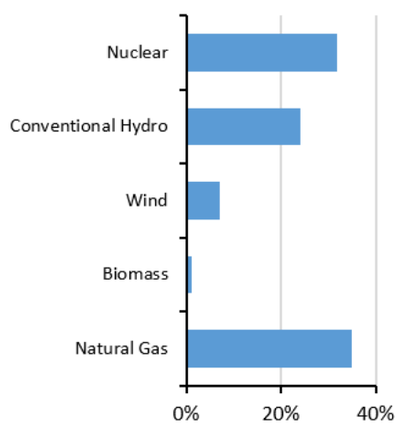
On-Peak Reserve Margin



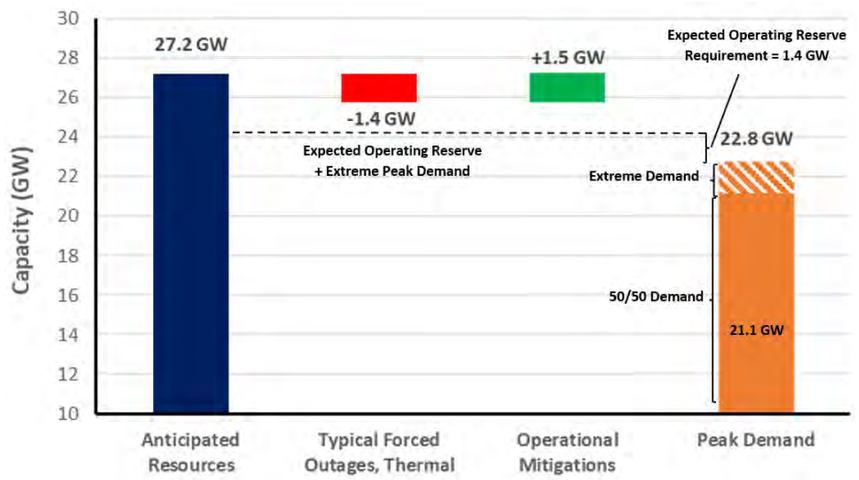
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand from 31 years of winter demand history

Typical Forced Outages, Thermal: Based on analysis of a rolling five-year history of actual forced outage data.

Operational Mitigations: Imports anticipated from **neighbors** during emergencies



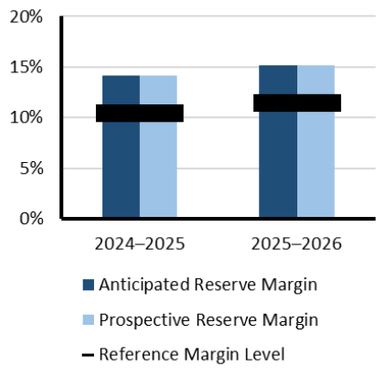
NPCC-Québec

NPCC-Québec is an assessment area that covers the Canadian province of Québec. The province of Québec covers over 1.5 million square kilometers (nearly 600,000 square miles) and has a population of 9 million people. Hydro-Québec is the BA for the province of Québec. The Québec BPS is one of the four electric Interconnections in North America. It is a predominately hydroelectric-generation-based system that is electrically interconnected with NPCC-Ontario, NPCC-New York, NPCC-New England, and NPCC-Maritimes. Peak electricity demand in NPCC-Québec occurs during the winter season.

Highlights

- NPCC-Québec projects adequate capacity margins above its reference reserve requirements and that system resource adequacy will be maintained for the province for the 2025–26 Winter assessment period.
- No hydropower performance issues are expected during extreme cold because of design criteria for cold weather.
- No fuel supply or transportation issues are anticipated for the upcoming winter season.
- While a slight decrease in net firm transfers has occurred since last winter (-89 MW), significant increases in demand-side management programs (+450 MW year-over-year) have been realized over the same period and are expected to compensate for this winter's modest expected load growth.

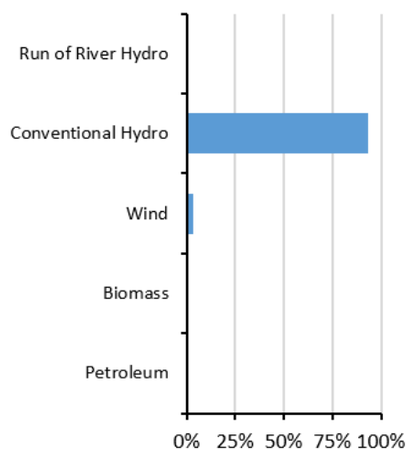
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 8:00 a.m.

Demand Scenarios: Demand forecasts include demand-side resources. The demand side resources are the same for the 50/50 and extreme demand scenarios. The extreme load forecast is determined at two standard deviations higher than the mean, which has a 6.06% probability of occurrence.

Extreme Derates: Maintenance outages and other deratings are already included in existing-certain capacity calculation. Wind capacity is 64% derated

Typical Forced Outages: Unplanned outages are 1,500 MW.

Operational Mitigations: Operational mitigations include imports from neighboring areas and reduction of reserves



PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM's footprint covers approximately 369,054 square miles and with an approximate population of 67 million people. PJM is the area's BA, Transmission and Resource Planner, interchange authority, TOP, transmission service provider, and RC. PJM is electrically interconnected with MISO, NPCC-New York, SERC-Central, and SERC-East. Peak electricity demand in PJM occurs during the summer season.

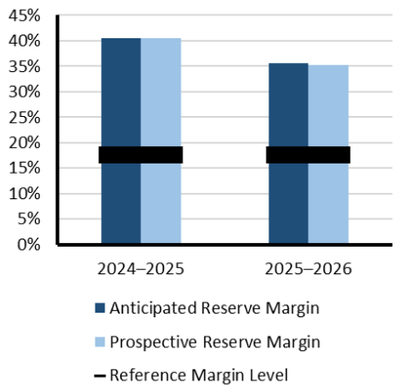
Highlights

- Due to the low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with highest loss-of-load risk remains the hour with highest forecasted demand.
- PJM is expecting little capacity adequacy risk during Winter 2025–2026 and expects around 35% installed reserves, which is above the target IRM of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion.
- Last winter, PJM hit a new all-time winter peak, but generator preparations anticipating congestion and tight capacity projections led to sufficient reserves throughout the demand event and PJM's transmission system performed well.
- The decrease in reserves from Winter 2024–2025 is due to load increases and retirement of generation without like (non-solar dispatchable) replacement generation.

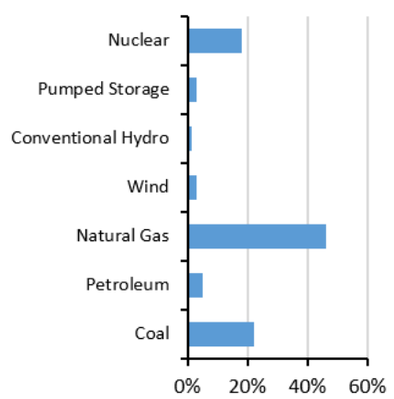
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

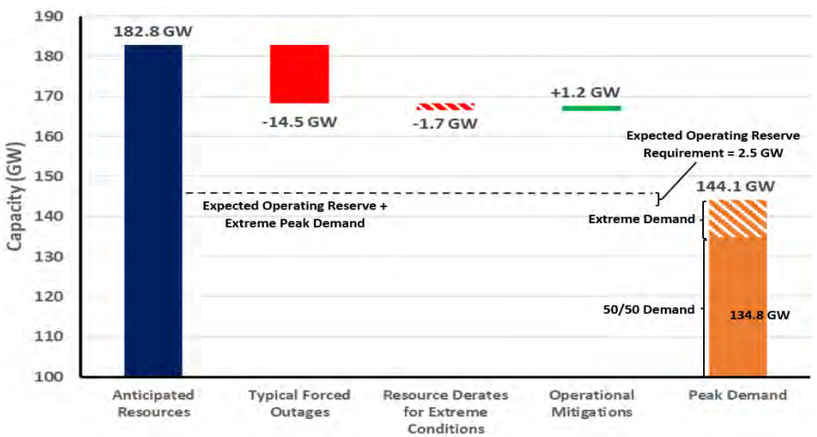
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Forced Outages: Based on historical data and trending

Resource Derates for Extreme Conditions: Reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: accounts for an estimated value based on operational / emergency procedures



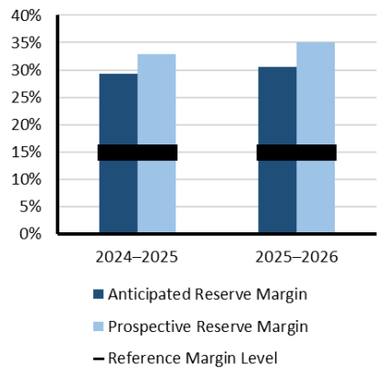
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC-Central is transitioning from a summer-peaking area to a dual-peaking system.
- For the 2025–2026 Winter, SERC-Central projects a sufficient level of resources to serve the expected load under median weather and typical system operating conditions, based on the 2024 NERC ProbA base-case results.
- Most entities across SERC-Central report that fuel security is strong since it is supported by firm natural gas contracts, storage resources, and reliable pipeline capacity. Coal inventories are projected to remain within operational ranges necessary to meet winter demand.
- Following lessons from Winter Storm Elliott, one SERC-Central entity raised its winter Planning Reserve Margin target to 26% and updated preparedness programs with improved heat trace capabilities.

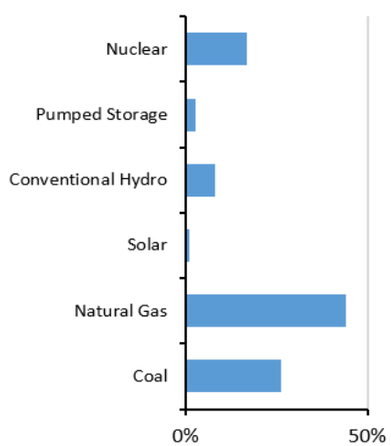
On-Peak Reserve Margin



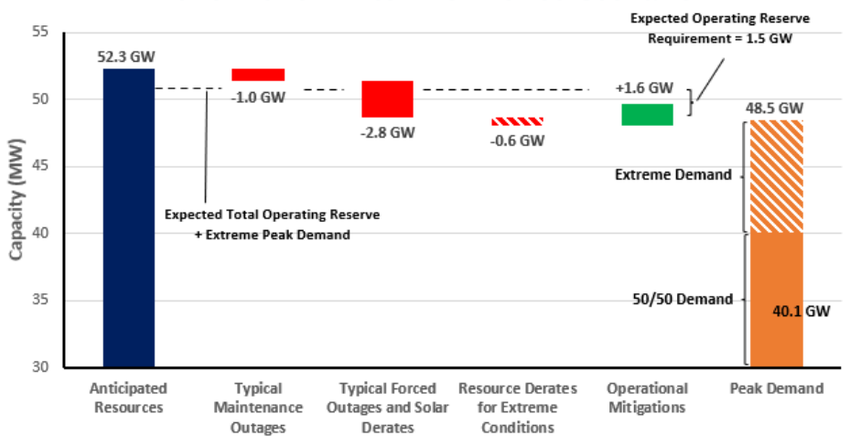
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand. A severe cold weather event that extends to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Typical Maintenance Outages: Data collected through a survey of members for expected outages during December through February

Typical Forced Outages and Solar Derate: Includes any weighted average forced-outage rates on-peak that are not factored into the anticipated resources calculation . Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Entity-provided values for low likelihood extreme conditions

Operational Mitigations: A total of over 1.6 GW based on operational/emergency procedures



SERC-East

SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six Regional Entities across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

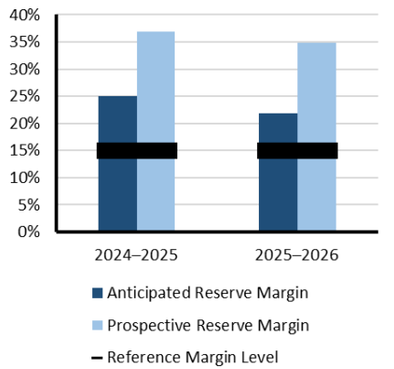
Highlights

- SERC-East is transitioning from a summer-peaking area to potentially peaking during both summer and winter. This shift is attributed to the continued addition of solar PV generation, which reduces summer peak demand, and a trend toward electrification of heating, which drives up winter peak demand.
- For the 2025–2026 Winter, the SERC-East region projects a sufficient level of resources to serve the expected load under median weather and typical system operating conditions, based on the 2024 NERC ProbA base-case results.
- Fuel supplies and transportation remain stable, and entities anticipate maintaining adequate coal and oil inventories with no reported changes to fuel procurement or operator plans for the upcoming winter.
- Probabilistic Base Case Results (Median Weather): EUE is 61.95 MWh and LOLH is 0.06 hours/year. EUE values are likely due to higher winter peaks and/or lower supply of capacity that can meet early winter morning demand.
- Mitigation measures for extreme conditions include voltage reduction (25–50 MW) and load-shedding programs that cover up to 30% of system load.

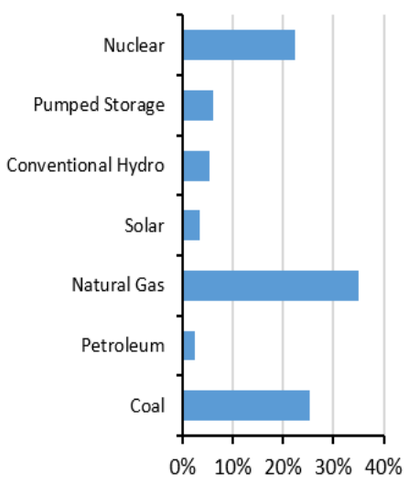
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal demand scenarios. A severe cold weather event extending to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

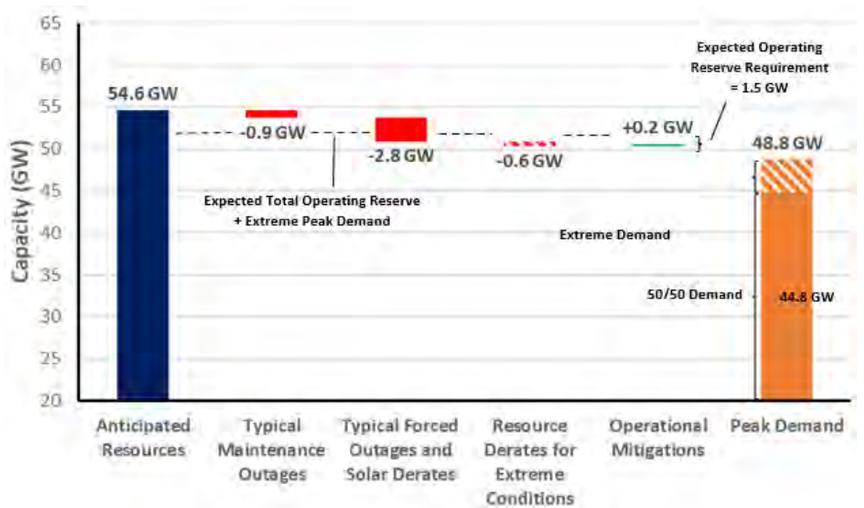
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Maximum historical generation outages (excluding 2022–2025)

Operational Mitigations: A total of 0.2 GW based on operational/emergency procedures



SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six Regional Entities across North America that is responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity area covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

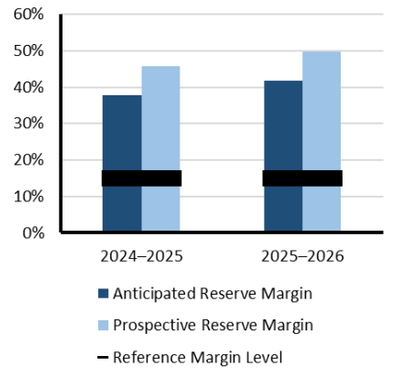
Highlights

- SERC-Florida Peninsula is a summer-peaking assessment area.
- Florida Peninsula entities have not identified any emerging reliability issues for the upcoming 2025–26 Winter season with an ARM projected at 39%, well above the RML, while the 2024 NERC ProbA base-case results project a sufficient level of resources to serve the expected load under median weather and typical system operating conditions (EUE is 1.09 MWh and LOLH is 0.00 hours/year).
- Many entities report strong fuel security, supported by firm natural gas contracts, storage resources, reliable pipeline capacity, and actively managed coal and oil inventories, which are projected to remain within operational ranges to meet winter demand.
- Florida Peninsula entities do not assume non-firm external assistance from neighboring areas during extreme conditions.

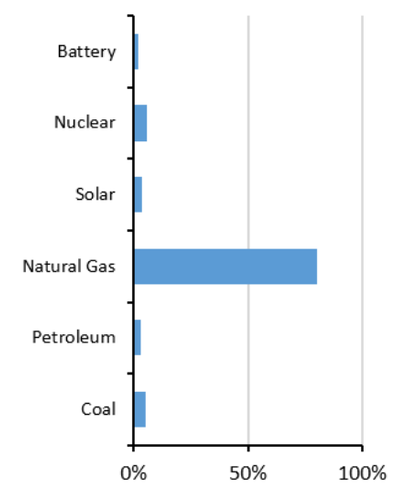
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

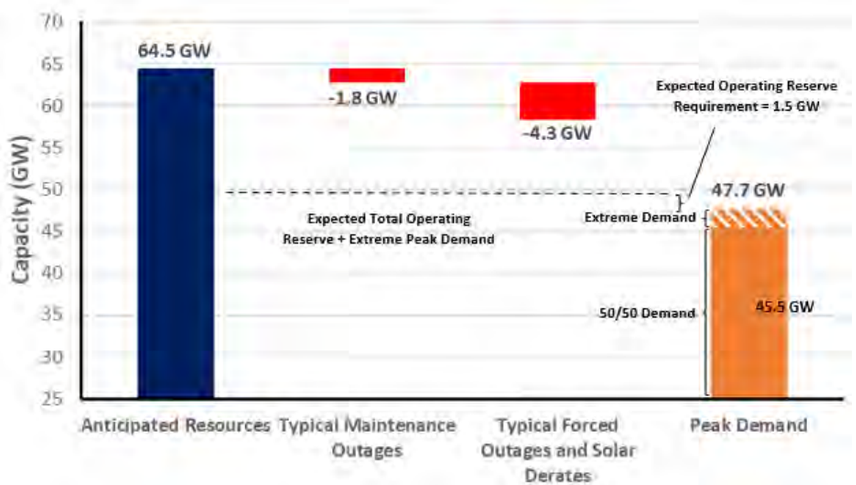
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Entity-provided values for low likelihood extreme conditions



SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six Regional Entities across North America that is responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

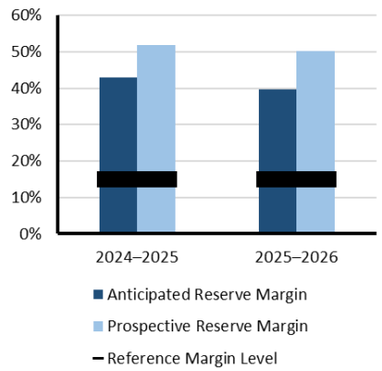
Highlights

- SERC-Southeast is trending towards becoming slightly winter-peaking.
- For the 2025–2026 Winter, SERC-Southeast entities report no emerging reliability concerns and expect to have adequate resources, supported by firm natural gas transportation contracts, diverse fuel portfolios, and sufficient on-site coal inventories to serve the expected load under typical system operating conditions. The 2024 NERC ProbA base-case results in EUE and LOLH are both 0.00.
- While most SERC-Southeast BAs expect to have adequate resources, supported by firm natural gas transportation contracts, diverse fuel portfolios, and sufficient on-site coal inventories, one BA highlights potential risks related to natural gas transportation capacity, citing high pipeline utilization, competition for delivered gas, and ratable flow requirements. Mitigation strategies include securing third-party gas supply, adding dual-fuel capability, and implementing coal inventory management.
- Entities have made refinements such as replacing specific 230 kV circuit breakers and increasing monitoring frequencies for critical plant systems after January 2025 winter events.

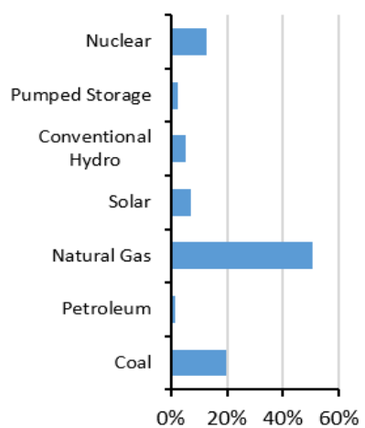
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

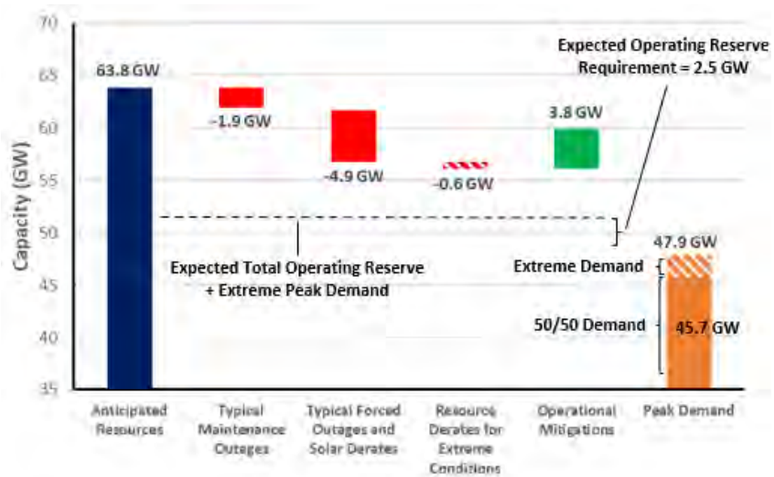
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Maximum historical generation outages

Operational Mitigations: A total of 3.8 GW based on operational/emergency procedures



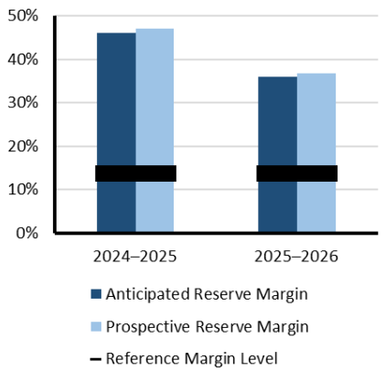
Texas RE-ERCOT

ERCOT is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking and covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,250 generation units, and serves more than 27 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas power grid.

Highlights

- Given expected system conditions, an ARM of 36% and RML of 13.75%, ERCOT expects to have sufficient operating reserves for the peak hour ending 8:00 a.m.
- ERCOT does not expect any significant fuel supply issues for the winter.
- ERCOT has conducted 2,028 generation resource and transmission service provider (TSP) winter weatherization inspections since Winter 2021–2022.
- Winter peak demands typically occur before sunrise and after sunset when solar generation is not available. Significant battery storage mitigates these risks.
- ERCOT's probabilistic risk assessment indicates a 2% probability of having to declare EEAs during the January forecasted winter peak day (which coincides with the highest reserve shortage risk) and a controlled load shed probability of 1.8%. ERCOT defines low-risk hours as when the probability of an EEA is less than 10%.
- Increased load growth in west Texas combined with "no solar" and low wind conditions can cause transmission lines into this area to become heavily loaded. ERCOT has introduced improved dynamic line ratings that allow for greater transfers at colder temperatures and periods of low irradiance.

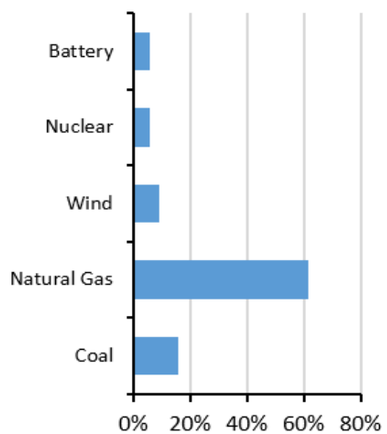
On-Peak Reserve Margin



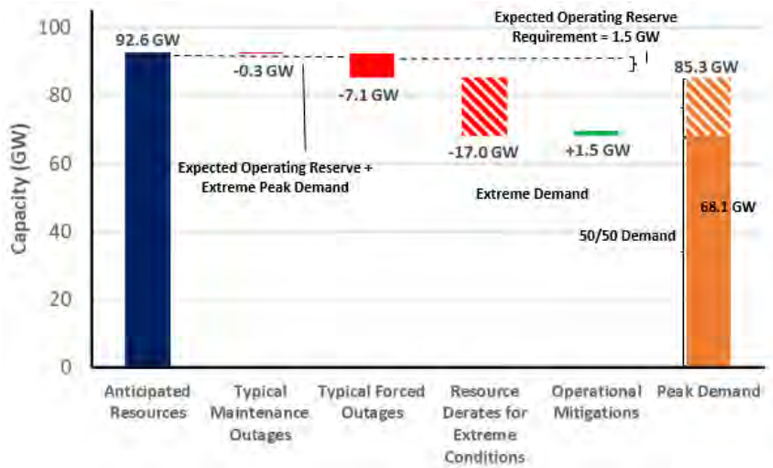
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Presumes weather conditions comparable to Winter Storm Uri. The adjustment is calculated as the difference between the 100th percentile and 50th percentile values from ERCOT's Probabilistic Reserve Risk Model (PRRM) simulated load outcome distribution for hour ending 8:00 a.m.

Typical Maintenance Outages: Based on historical winter data and consideration of ERCOT's allowed maximum system daily planned outage capacity

Typical Forced Outages: Based on a probability distribution created using historical ERCOT Outage Scheduler data for the last three Januarys.

Resource Derates for Extreme Conditions: Weather-related thermal and wind outages based on Winter Storm Uri levels, adjusted for reductions due to weatherization standards. Also includes high non-weather-related outages.

Operational Mitigations: Additional potential capacity from switchable generation and imports



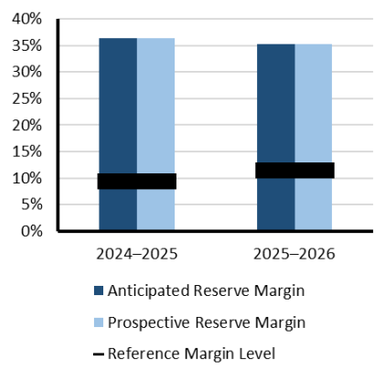
WECC-Alberta

WECC-Alberta is an assessment area that covers the Canadian province of Alberta. The province has a geographic area of 661,848 square kilometers (255,541 square miles) and a population of almost 5 million people. The Alberta Electric System Operator (AESO) is the province's Planning Entity and RC responsible for safe, reliable, and economic operation of the Alberta Interconnected Electric System. AESO is a non-profit corporation that operates a system that includes approximately 26,000 kilometers of transmission lines and connects approximately 426 qualified generating units and nearly 250 market participants through a wholesale market. Alberta's transmission system has three interties with neighboring areas: Saskatchewan (see MRO-SaskPower), British Columbia (see WECC-British Columbia), and Montana (see WECC-Northwest). Peak electricity demand on the AESO system currently occurs during the winter season.

Highlights

- At an extreme winter peak of 12,982 MW, with extreme forced outages at 530 MW and derates for extreme conditions bringing wind energy availability down by 1,800 MW and hydroelectricity by 88 MW, the required reserves are 759 MW and are sufficiently met, even with low availability.
- Demand is expected to increase 1.1% from last winter with the existing-certain installed capacity having increased 23%.
- Solar availability is down because 1,000 MW of PV moved from originally expecting to come on-line in 2024 as Tier 1 resources to Tier 2s mostly anticipated to come on-line in 2025, but with less certainty.

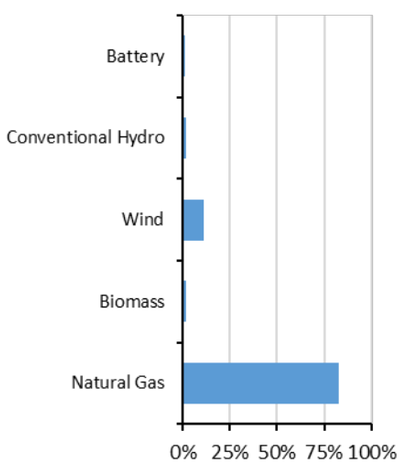
On-Peak Reserve Margin



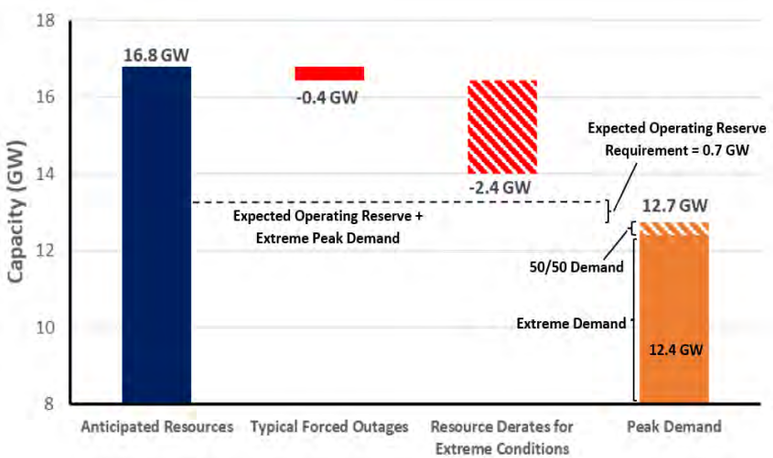
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS data

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



WECC-Basin

WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern BA area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025-26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA*.

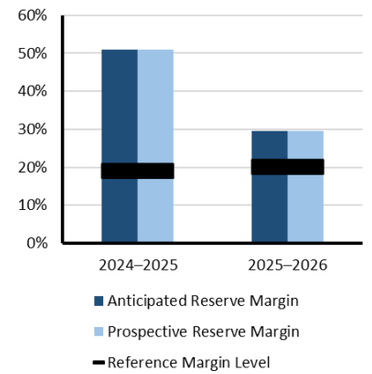
Highlights

- At an extreme winter peak of 11.1 GW under an extreme combination of derates and outages, the region could be short 1.0 GW before imports and is expected to need to rely on transfers.
- Net internal demand is expected to increase 1% since last year, with total internal demand up 1.8% being offset by a doubling of controllable and dispatchable demand response.
- Tier 1 resources have declined and do not appear to be offset by increases in existing-certain generation resource capacity. Nameplate wind has increased by almost 18% and solar by almost 30%. Hydro is also up over 7% in total installed capacity.
- Reliance on imports is expected to be required to maintain resource adequacy during extreme peak demand and extreme derate conditions.

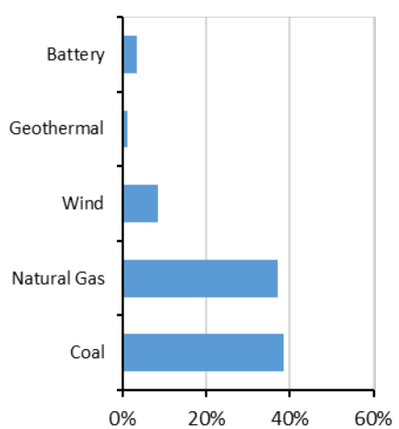
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal peak demand combined with high generator outages in extreme conditions results in the need for external assistance to maintain reserves.

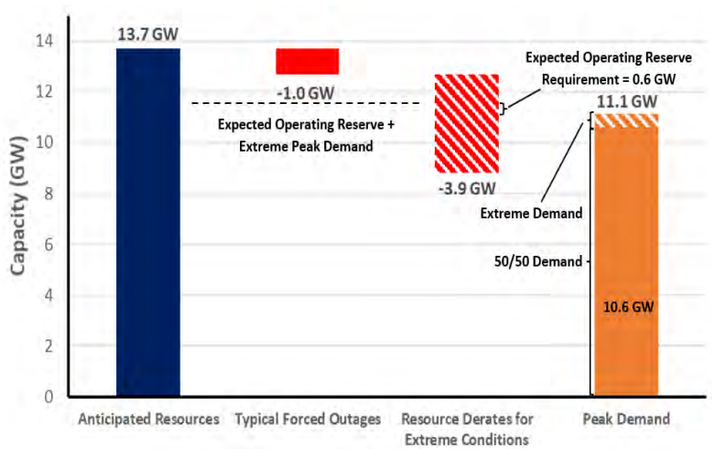
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Extreme Derates: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



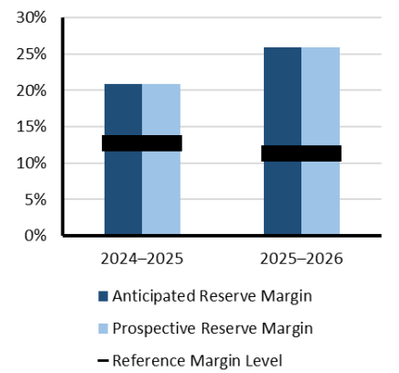
WECC-British Columbia

WECC-British Columbia is an assessment area that covers the Canadian province of British Columbia. The province has a geographic area of 944,735 square kilometers (364,764 square miles) and a population of just over 5 million people. BC Hydro is the Planning Entity and RC for the province of British Columbia and is the principal supplier of electricity for the province. BC Hydro is a provincial Crown corporation and, under provincial legislation, is responsible for the oversight of the British Columbia BES and its interconnections. BC Hydro operates an integrated system supported by 30 hydroelectric plants, approximately 80,000 kilometers of transmission and distribution lines, and 125 contracts with independent power producers. BC Hydro's transmission system has two interties with neighboring areas: the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta). Peak electricity demand on the BC Hydro system currently occurs during winter.

Highlights

- Peak demand is expected to remain about the same as last winter.
- There are about 200 MW more (47%) planned Tier 1 resources for this winter than last.
- Solar nameplate capacity has increased from 2 MW to 17 MW since last winter and hydroelectric nameplate capacity is up more than 5%, or 1,366 MW.

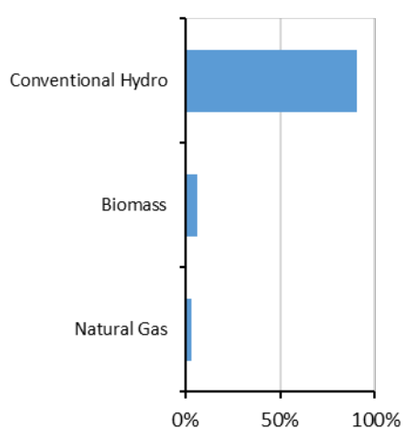
On-Peak Reserve Margin



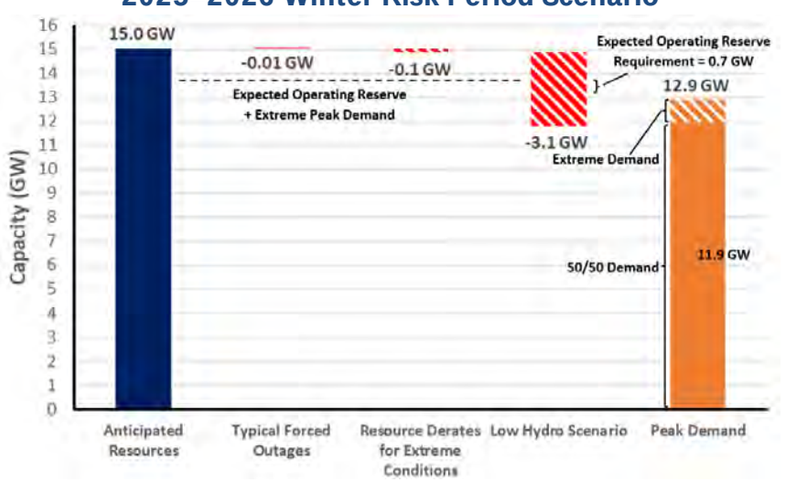
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal and extreme demand scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

Low Hydro Scenario: Estimated derate for lower hydro output



WECC-California

WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, the Los Angeles Department of Water and Power, the Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

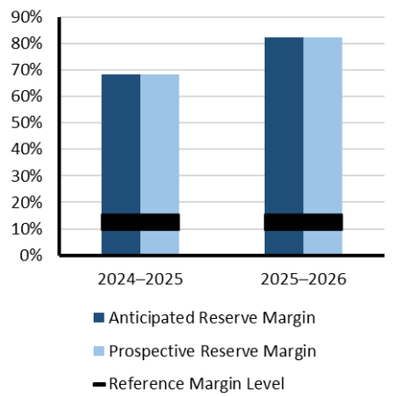
Highlights

- Operating reserve margins are met before imports in all winter resource availability scenarios.
- On-peak demand is expected to remain about the same as last winter. Demand-side management is down about 10%.
- Existing-certain capacity is up almost 5%, while planned Tier 1 resources are up more than 2 GW. The total wind nameplate capacity is up almost 27% and solar almost 13%. Hydro is down 4%.
- No reliance on imports is expected to be required to maintain resource adequacy for Winter 2025–2026.

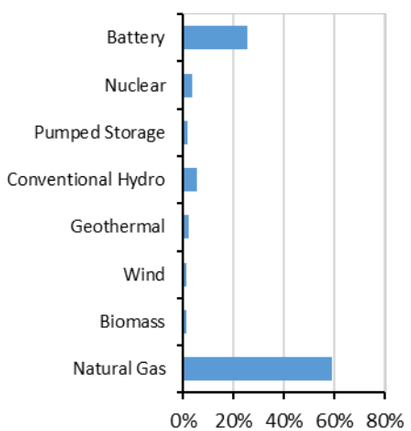
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

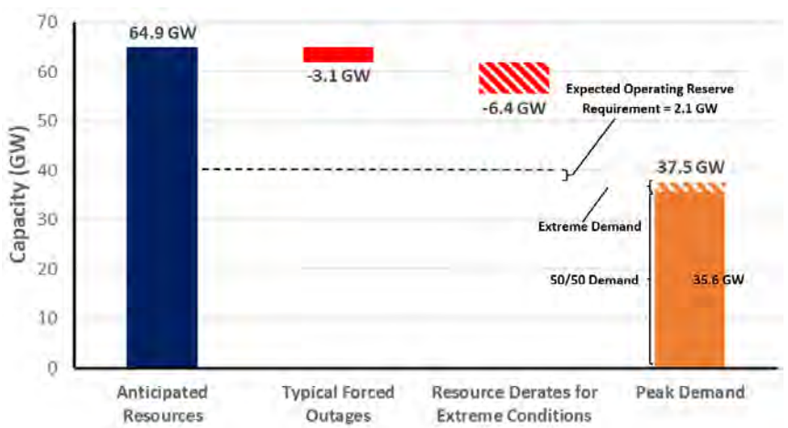
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



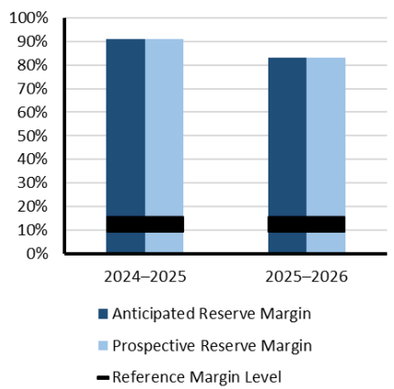
WECC-Mexico

WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

Highlights

- As a summer-peaking region, operating reserve margins are met before imports in all scenarios.
- Planned Tier 1 resources are down 100% to zero as expected resources have either been brought on-line to move into existing or, in the case of some natural gas, have been delayed until 2026 and moved into Tier 2.
- The existing-certain on peak reserve margin is down by 5.2%, and the anticipated and prospective reserve margins are down by 7.8%; however, since Mexico is heavily summer-peaking, the 83% reserve margin still exceeds the RML of 12.5%, which remains unchanged.

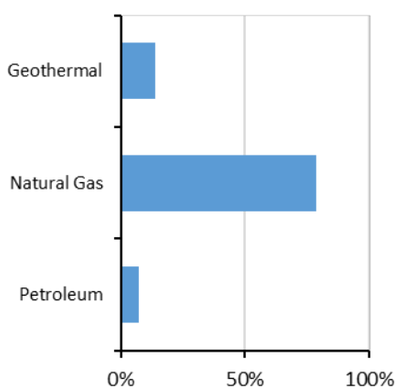
On-Peak Reserve Margin



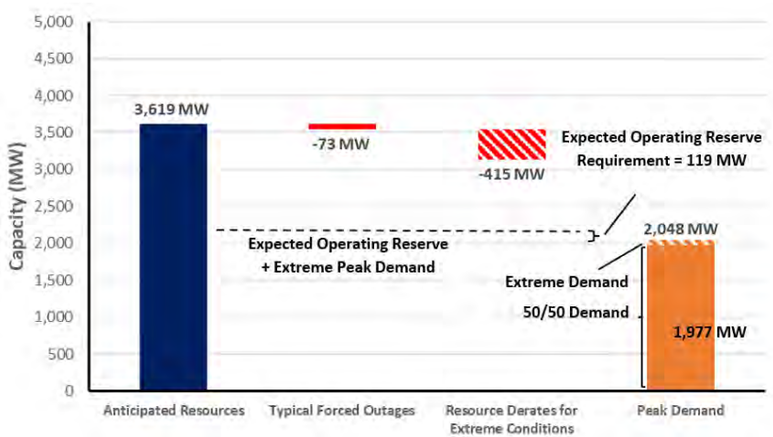
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



WECC-Northwest

WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

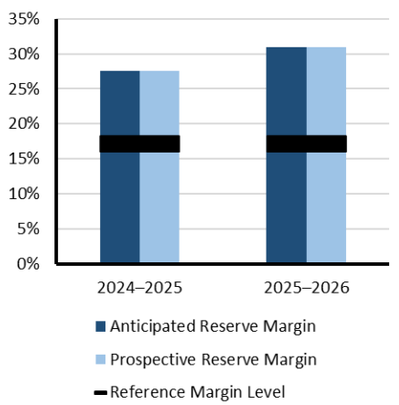
Highlights

- The Northwest has historically been a mixed season-peaking region.
- Operating reserve margins are expected to be met after imports in all winter scenarios.
- Total and net internal demand are up 9.3% with the primary drivers being data centers, residential electrification, transportation electrification, and semiconductor manufacturing.
- Large coal unit retirements and conventional hydro unit retirements are attributable to the reduction in existing certain capacity of 10.5%; however, planned Tier 1 resources have soared over 580%, from 463 MW to over 3 GW.
- Nameplate wind capacity is up over 3 GW (26%) and solar nameplate capacity is up nearly 2,690 MW (134%), which has also increased the solar availability on the peak hour.
- An increase in firm imports is seen in the model, 6.1 GW, absorbing the reduction in existing certain capacity of 4 GW.

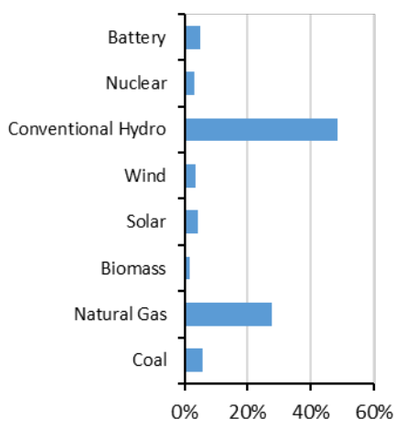
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal peak demand combined with high generator outages in extreme conditions results in the need for external assistance to maintain reserves.

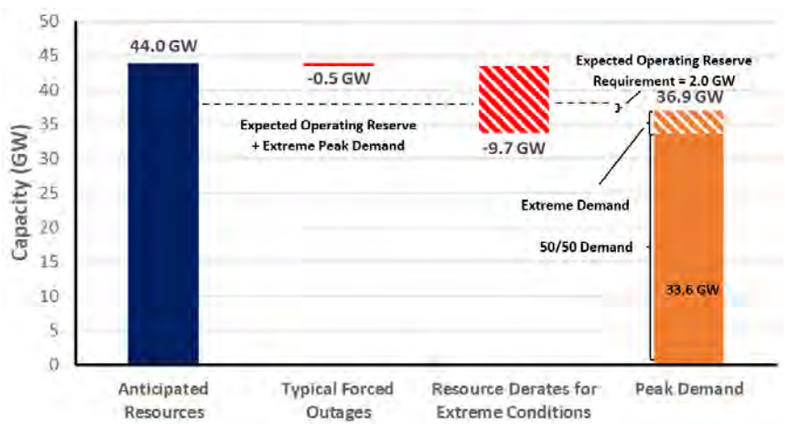
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period. This value includes 6.8 GW of hydro derates.



WECC-Rocky Mountain

WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration's Rocky Mountain Region. It has 18,797 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

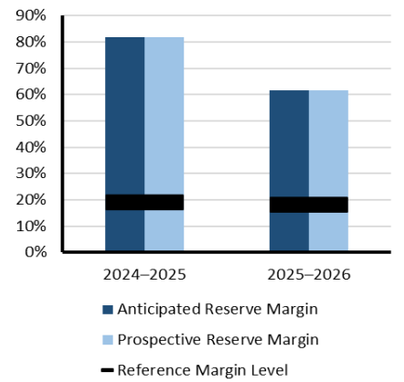
Highlights

- In Rocky Mountain, operating reserve margins are expected to be met before imports in all winter scenarios.
- Total and net internal demand are up almost 1%. The primary drivers are data centers and commercial and industrial customer growth.
- Planned Tier 1 resources are up over 84%, from almost 200 MW to over 365 MW. Solar nameplate capacity is up 27%; however, on-peak solar energy availability is down 100% due to the shift to after sunset. Expected hydro on peak energy availability is also down by around a quarter on the peak hour. Existing-Certain, Anticipated, and Prospective Reserve Margins are all down by over 20% on the peak hour; however, the region still maintains resource adequacy with margins hovering around 60% compared to the RML of 18%.
- No reliance on imports is expected to be required to maintain resource adequacy under combined extreme peak and extreme derated conditions.

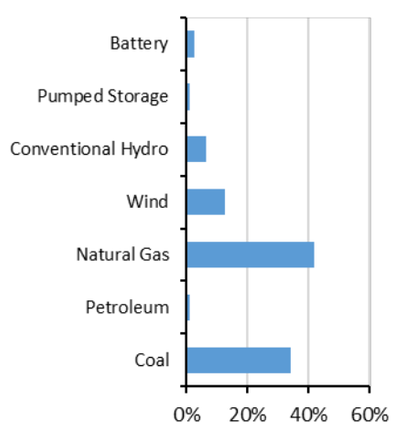
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

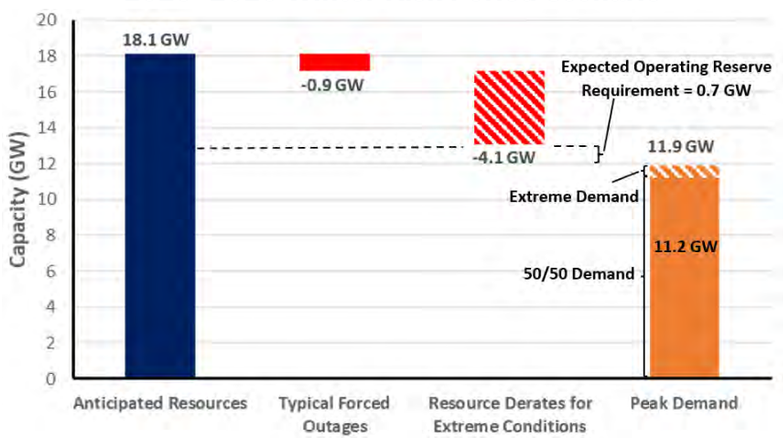
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



WECC-Southwest

WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

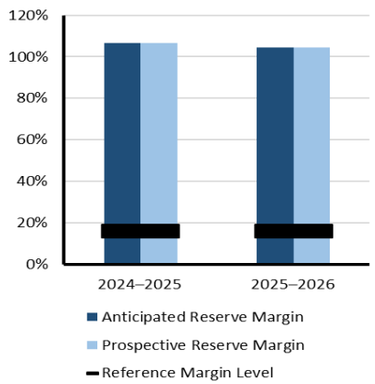
Highlights

- The Southwest is anticipated to be resource adequate under all winter expected and extreme energy availability and demand scenarios before imports.
- Total internal demand is expected to be up 1.5% and net internal demand up 2.3% since last winter. The primary drivers for load growth are data centers and industrial and residential electrification. Controllable and dispatchable demand response is down nearly half, by 163 MW.
- Planned Tier 1 resources are down over 19% as some have moved into existing certain, which is up almost 3%, over 1 GW, and other projects have experienced delays.
- Wind nameplate is up 12%, 470 MW, correlating to on-peak energy availability from wind increasing almost 11%, by 114 MW, while solar nameplate is up 27% or over 2.5 GW.

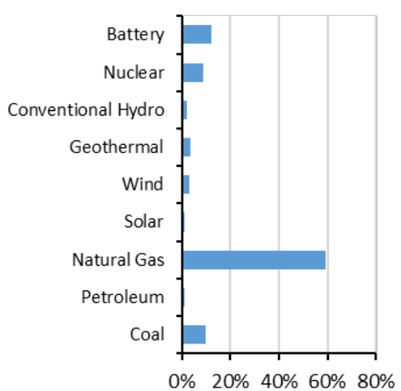
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

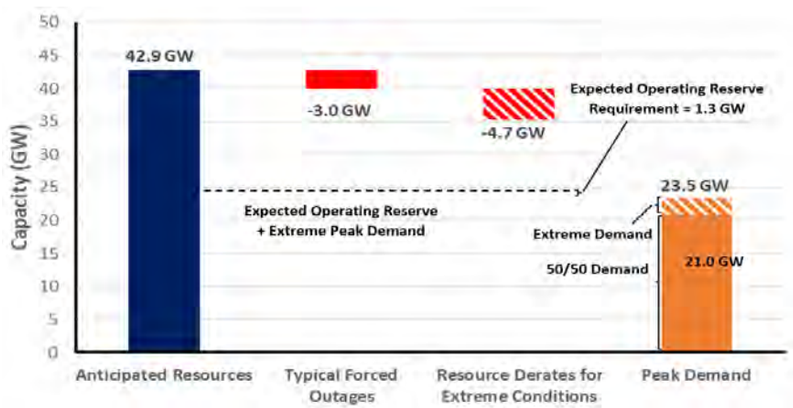
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[11] or total internal demand for the summer and winter of each year.[12]
• Total internal demand projections are based on normal weather (50/50 distribution)[13] and are provided on a coincident[14] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (VER) (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.
Anticipated Resources: • **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. • **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements. • **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.
Prospective Resources: Includes all anticipated resources plus the following: **Existing-Other Capacity**: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

[11] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf used in NERC Reliability Standards

[12] The summer season represents June–September and the winter season represents December–February.

[13] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[14] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC calculates total internal demand on a noncoincidental basis.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the RML is a requirement. RMLs may be different for the summer and winter seasons. If an RML is not provided by an assessment area, NERC applies 15% for predominantly thermal systems and 10% for predominantly hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left blue column shows anticipated resources, and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme summer peak demand.

Resource Adequacy

The ARM, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[15] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. NPCC-Maritimes marginally does not meet its RML for the upcoming winter. Other than NPCC-Maritimes, all assessment areas have sufficient ARMs to meet or exceed their RML for the 2025 winter as shown in **Figure 4**.

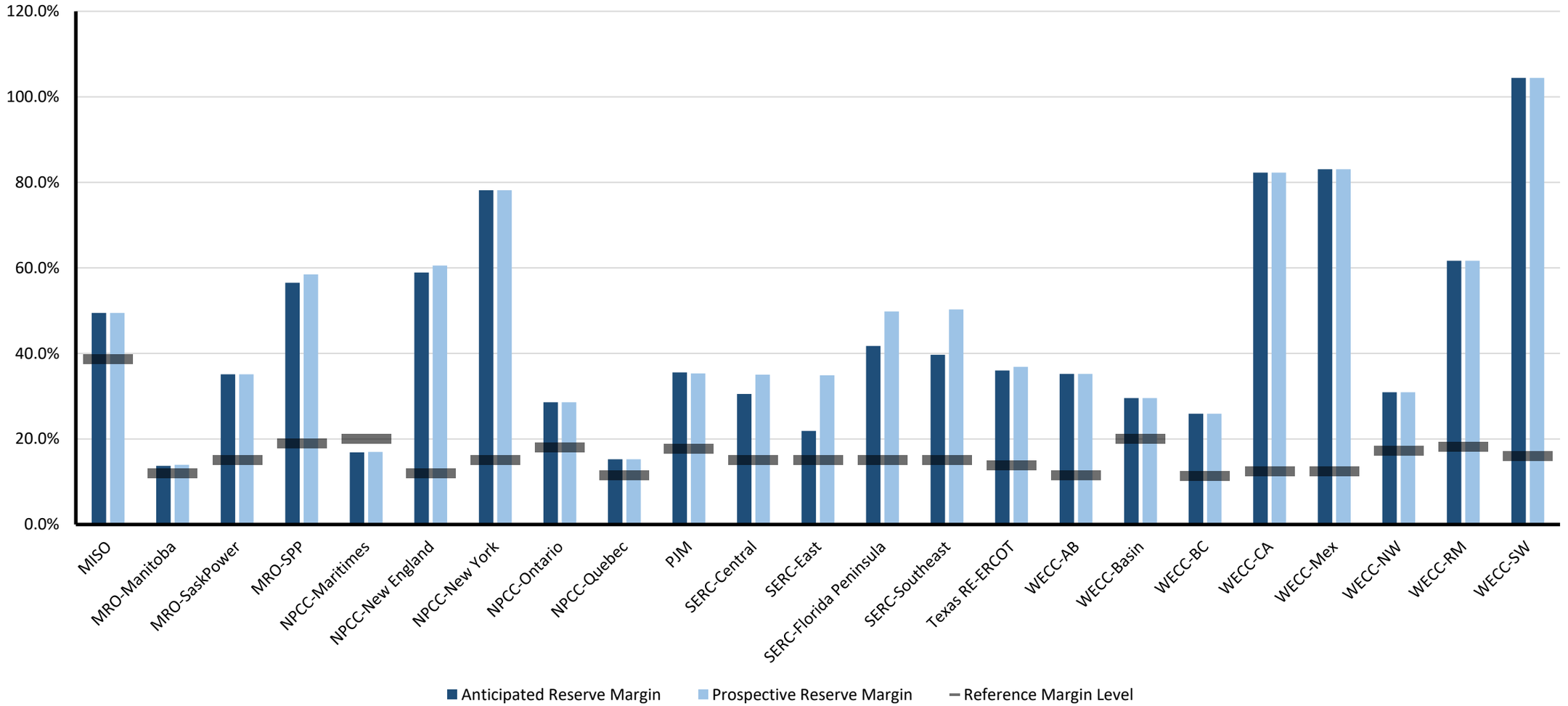


Figure 4: Winter 2025–2026 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[15] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and RMLs.

Changes from Year-to-Year

Figure 5 provides the relative change in the forecast ARMs from the 2024–2025 Winter to the 2025–2026 Winter. All areas except NPCC-Maritimes remain above their RMLs for 2025–2026 Winter. The Canadian winter-peaking systems, which include MRO-Manitoba, MRO-SaskPower, NPCC-Maritimes, NPCC-Québec, WECC-Alberta, and WECC-British Columbia, may have reserve margins that are near RMLs but are unlikely to experience high outage rates from their winterized generators. Additional details are provided in the Data Concepts and Assumptions section.

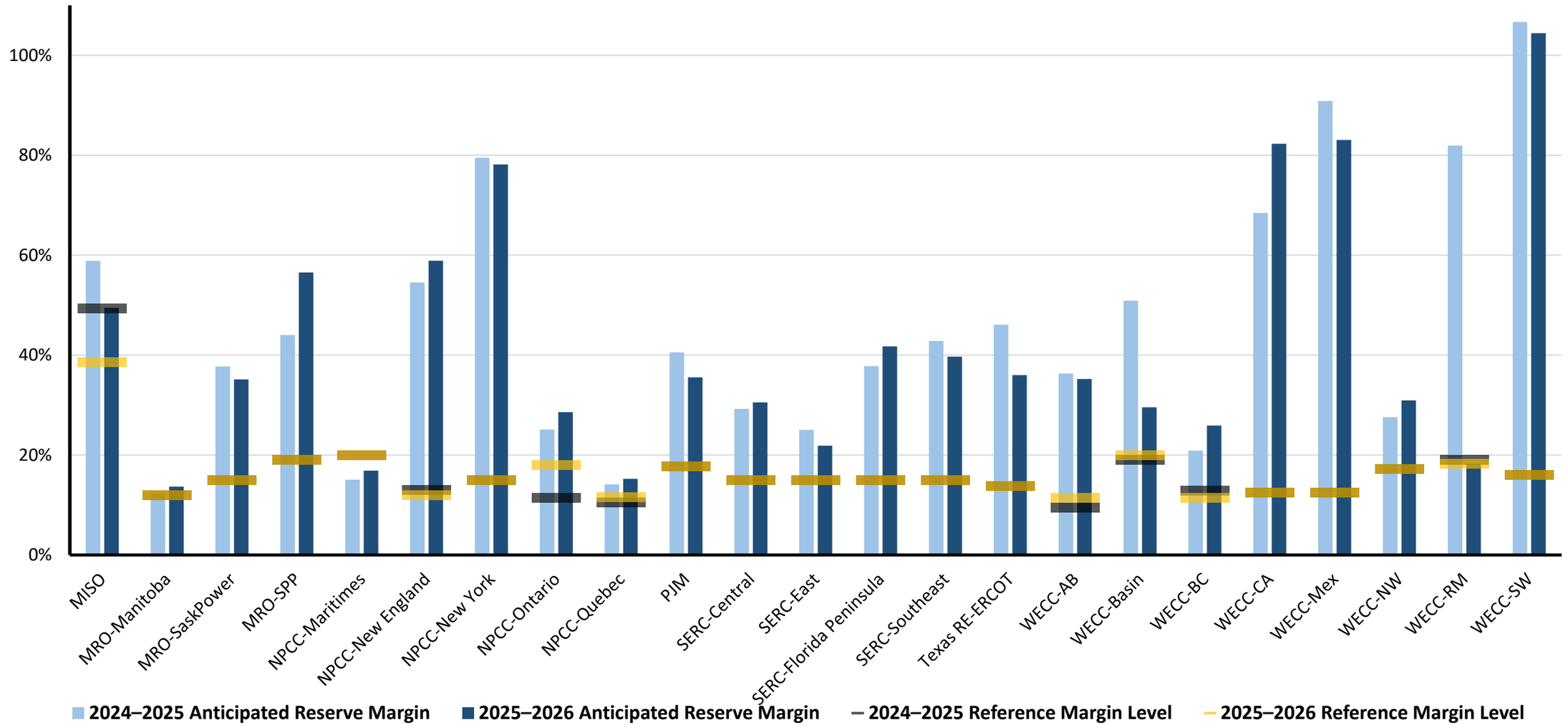


Figure 5: Winter 2024–2025 and Winter 2025–2026 Anticipated Reserve Margins Year-to-Year Change

Demand and Resource Tables

Peak demand and supply capacity data (i.e., resource adequacy data) for each assessment area are as follows in each table.

MISO			
Demand, Resource, and Reserve Margins	**2024–2025 WRA[16]**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	102,353	105,249	2.8%
Demand Response: Available	6,219	8,250	32.7%
Net Internal Demand	96,134	96,999	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	150,407	142,880	-5.0%
Tier 1 Planned Capacity	122	0	0.0%
Net Firm Capacity Transfers	2,310	2,113	-8.5%
Anticipated Resources	152,717	144,993	-5.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	152,839	144,993	-5.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	58.9%	49.5%	-9.4
Prospective Reserve Margin	59.0%	49.5%	-9.5
Reference Margin Level	49.4%	38.6%	-10.8

MRO-SPP			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,788	47,168	3.0%
Demand Response: Available	1,128	1,091	-3.3%
Net Internal Demand	45,926	46,077	0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	67,252	71,074	5.7%
Tier 1 Planned Capacity	0	1087	0.0%
Net Firm Capacity Transfers	-1,116	-32	-97.1%
Anticipated Resources	66,136	72,129	9.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	66,090	73,029	10.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.0%	56.5%	12.5
Prospective Reserve Margin	43.9%	58.5%	14.6
Reference Margin Level	19.0%	19.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,852	3,944	2.4%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,802	3,894	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,946	4,972	0.5%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	5,236	5,262	0.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	5,236	5,262	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.7%	35.1%	-2.6
Prospective Reserve Margin	37.7%	35.1%	-2.6
Reference Margin Level	15.0%	15.0%	0.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	4,814	4,903	1.8%
Demand Response: Available	0	0	0.0%
Net Internal Demand	4,814	4,903	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,924	5,688	-4.0%
Tier 1 Planned Capacity	10	0	-100.0%
Net Firm Capacity Transfers	-527	-113	-78.5%
Anticipated Resources	5,407	5,575	3.1%
Existing-Other Capacity	18	13	-26.8%
Prospective Resources	5,425	5,588	3.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	12.3%	13.7%	1.4
Prospective Reserve Margin	12.7%	14.0%	1.3
Reference Margin Level	12.0%	12.0%	0.0

[16] MISO-provided updated data post 2024-25 WRA publication.

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	6,167	6,061	-1.7%
Demand Response: Available	259	248	-4.4%
Net Internal Demand	5,907	5,813	-1.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	6,647	6,704	0.9%
Tier 1 Planned Capacity	6	88	0.0%
Net Firm Capacity Transfers	145	1	-99.0%
Anticipated Resources	6,798	6,794	-0.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	6,798	6,800	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.1%	16.9%	1.8
Prospective Reserve Margin	15.1%	17.0%	1.9
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,651	20,056	-2.9%
Demand Response: Available	343	440	28.2%
Net Internal Demand	20,308	19,616	-3.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	30,030	29,935	-0.3%
Tier 1 Planned Capacity	194	0	-100.0%
Net Firm Capacity Transfers	1,161	1,235	6.4%
Anticipated Resources	31,385	31,170	-0.7%
Existing-Other Capacity	306	322	5.2%
Prospective Resources	31,691	31,492	-0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	54.5%	58.9%	4.4
Prospective Reserve Margin	56.1%	60.5%	4.5
Reference Margin Level	13.0%	12.0%	-1.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	23,800	24,200	1.7%
Demand Response: Available	802	1,027	28.1%
Net Internal Demand	22,998	23,173	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	40,522	40,080	-1.1%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	759	1,203	58.5%
Anticipated Resources	41,281	41,283	0.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	41,281	41,283	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	79.5%	78.2%	-1.3
Prospective Reserve Margin	79.5%	78.2%	-1.3
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,898	22,013	0.7%
Demand Response: Available	915	868	-5.2%
Net Internal Demand	20,982	21,146	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,652	27,319	2.5%
Tier 1 Planned Capacity	0	294	#DIV/0!
Net Firm Capacity Transfers	-450	-420	-6.7%
Anticipated Resources	26,202	27,193	3.8%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	26,202	27,193	3.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.1%	28.6%	3.5
Prospective Reserve Margin	25.1%	28.6%	3.5
Reference Margin Level	11.5%	18.0%	6.5

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	40,512	40,799	0.8%
Demand Response: Available	4,451	4,902	10.9%
Net Internal Demand	36,061	35,897	-0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	41,560	41,698	0.3%
Tier 1 Planned Capacity	73	61	0.0%
Net Firm Capacity Transfers	-479	-390	-18.6%
Anticipated Resources	41,154	41,368	0.5%
Existing-Other Capacity	-479	0	0.0%
Prospective Resources	41,154	41,368	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.1%	15.2%	1.1
Prospective Reserve Margin	14.1%	15.2%	1.1
Reference Margin Level	10.5%	11.5%	1.0

PJM			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	136,328	140,827	3.3%
Demand Response: Available	5,616	5,998	6.8%
Net Internal Demand	130,712	134,829	3.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	179,216	178,335	-0.5%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	4,502	4,448	-1.2%
Anticipated Resources	183,718	182,783	-0.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	183,718	182,452	-0.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	40.6%	35.6%	-5.0
Prospective Reserve Margin	40.6%	35.3%	-5.2
Reference Margin Level	17.7%	17.7%	-12.3

SERC-Central			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,895	42,875	0.0%
Demand Response: Available	1,497	2,809	87.6%
Net Internal Demand	41,397	40,067	-3.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,578	50,454	-2.2%
Tier 1 Planned Capacity	0	0	0%
Net Firm Capacity Transfers	1,922	1,847	-3.9%
Anticipated Resources	53,500	52,301	-2.2%
Existing-Other Capacity	1,498	1,810	20.8%
Prospective Resources	54,998	54,111	-1.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.2%	30.5%	1.3
Prospective Reserve Margin	32.9%	35.1%	2.2
Reference Margin Level	15.0%	15.0%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,005	45,703	1.6%
Demand Response: Available	982	888	-9.6%
Net Internal Demand	44,023	44,815	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	54,379	54,460	0.1%
Tier 1 Planned Capacity	72	11	-84.3%
Net Firm Capacity Transfers	593	150	-74.7%
Anticipated Resources	55,045	54,622	-0.8%
Existing-Other Capacity	5,209	5,832	12.0%
Prospective Resources	60,254	60,453	0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.0%	21.9%	-3.2
Prospective Reserve Margin	36.9%	34.9%	-2.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	48,494	48,628	0.3%
Demand Response: Available	2,780	3,127	12.5%
Net Internal Demand	45,714	45,501	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	62,579	63,502	1.5%
Tier 1 Planned Capacity	15	692	4510.0%
Net Firm Capacity Transfers	400	300	-25.0%
Anticipated Resources	62,994	64,494	2.4%
Existing-Other Capacity	3,673	3,671	0.0%
Prospective Resources	66,667	68,165	2.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.8%	41.7%	3.9
Prospective Reserve Margin	45.8%	49.8%	4.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,308	47,056	3.9%
Demand Response: Available	1,638	1,365	-16.7%
Net Internal Demand	43,670	45,691	4.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	62,805	63,339	0.9%
Tier 1 Planned Capacity	765	0	-100.0%
Net Firm Capacity Transfers	-1,192	489	-141.0%
Anticipated Resources	62,378	63,828	2.3%
Existing-Other Capacity	3,920	4,847	23.7%
Prospective Resources	66,298	68,675	3.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	42.8%	39.7%	-3.1
Prospective Reserve Margin	51.8%	50.3%	-1.5
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	73,193	77,387	5.7%
Demand Response: Available	5,447	9,330	71.3%
Net Internal Demand	67,746	68,057	0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	98,712	89,977	-8.8%
Tier 1 Planned Capacity	239	1351	464.9%
Net Firm Capacity Transfers	20	1,235	6075.0%
Anticipated Resources	98,971	92,562	-6.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	99,691	93,137	-6.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	46.1%	36.0%	-10.1
Prospective Reserve Margin	47.2%	36.9%	-10.3
Reference Margin Level	13.75%	13.8%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,280	12,411	1.1%
Demand Response: Available	0	0	0.0%
Net Internal Demand	12,280	12,411	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,535	16,658	23.1%
Tier 1 Planned Capacity	3206	124	-96.1%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	16,740	16,782	0.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	16,740	16,782	0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.3%	35.2%	-1.1
Prospective Reserve Margin	36.3%	35.2%	-1.1
Reference Margin Level	9.5%	11.5%	2.0

WECC-Basin			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	10,568	10,758	1.8%
Demand Response: Available	85	170	100.0%
Net Internal Demand	10,483	10,588	1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,213	13,183	-0.2%
Tier 1 Planned Capacity	2,605	533	-79.5%
Net Firm Capacity Transfers	0	0	0%
Anticipated Resources	15,817	13,717	-13.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	15,817	13,717	-13.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	50.9%	29.6%	-21.3
Prospective Reserve Margin	50.9%	29.6%	-21.3
Reference Margin Level	19.0%	20.0%	1.0

WECC-CA			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	36,441	36,281	-0.4%
Demand Response: Available	743	666	-10.4%
Net Internal Demand	35,698	35,615	-0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	55,380	57,923	4.6%
Tier 1 Planned Capacity	4,757	6,997	47.1%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	60,138	64,920	8.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	60,138	65,920	8.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	68.5%	82.3%	13.8
Prospective Reserve Margin	68.5%	82.3%	13.8
Reference Margin Level	12.5%	12.5%	0.0

WECC-BC			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,966	11,936	-0.3%
Demand Response: Available	0	0	0.0%
Net Internal Demand	11,966	11,936	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,870	14,389	3.7%
Tier 1 Planned Capacity	433	637	47.0%
Net Firm Capacity Transfers	164	0	-100.0%
Anticipated Resources	14,467	15,026	3.9%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	14,467	15,026	3.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.9%	25.9%	5.0
Prospective Reserve Margin	20.9%	25.9%	5.0
Reference Margin Level	12.8%	11.4%	-1.5

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	1,983	1,977	-0.3%
Demand Response: Available	0	0	0%
Net Internal Demand	1,983	1,977	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,733	3,619	-3.0%
Tier 1 Planned Capacity	52	0	-100.0%
Net Firm Capacity Transfers	0	0	0%!
Anticipated Resources	3,784	3,619	-4.4%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	3,784	3,619	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	90.8%	83.1%	-7.8
Prospective Reserve Margin	90.8%	83.1%	-7.8
Reference Margin Level	12.5%	12.5%	0

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–25 vs. 2025–26**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	30,748	33,604	9.3%
Demand Response: Available	30	30	0.0%
Net Internal Demand	30,718	33,574	9.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	38,729	34,671	-10.5%
Tier 1 Planned Capacity	463	3,152	581.5%
Net Firm Capacity Transfers	0	6,136	100%!
Anticipated Resources	39,192	43,959	12.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	39,192	43,959	12.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.6%	30.9%	3.3
Prospective Reserve Margin	27.6%	30.9%	3.3
Reference Margin Level	17.2%	17.2%	0.0

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–25 vs. 2025–26**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	10,481	11,501	9.7%
Demand Response: Available	282	285	1.1%
Net Internal Demand	10,199	11,216	10.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	18,356	17,768	-3.2%
Tier 1 Planned Capacity	199	366	84.3%
Net Firm Capacity Transfers	0	0	0%
Anticipated Resources	18,555	18,134	-2.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	18,555	18,134	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	81.9%	61.7%	-20.3
Prospective Reserve Margin	81.9%	61.7%	-20.3
Reference Margin Level	19.0%	18.2%	-0.8

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–25 vs. 2025–26**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,844	21,147	1.5%
Demand Response: Available	340	177	-47.9%
Net Internal Demand	20,504	20,970	2.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	38,991	40,135	2.9%
Tier 1 Planned Capacity	3,381	2,733	-19.2%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	42,372	42,868	1.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	42,372	42,868	1.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	106.6%	104.4%	-2.2
Prospective Reserve Margin	106.6%	104.4%	-2.2
Reference Margin Level	16.0%	16.0%	0.0

Variable Energy Resource Contributions

Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity and may vary widely year to year based on the identified risk hour. In many areas, winter demand peaks in the early morning hours or early evening resulting in little or no electrical resource output from solar PV resources and wide variability in wind availability. The following table shows the capacity contribution of existing wind and solar PV resources at the identified risk hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS.

BPS Variable Energy Resources On-Peak Capacity Contributions by Assessment Area

	Wind			Solar			Run of River Hydro		
Assessment Area/Interconnection (* - includes all hydro)	Nameplate Wind (MW)	Expected Wind (MW)	Expected Share of Nameplate (%)	Nameplate Solar PV (MW)	Expected Solar (MW)	Expected Share of Nameplate (%)	Nameplate Hydro (MW)	Expected Hydro (MW)	Expected Share of Nameplate (%)
MISO	30,247	8,772	29%	13,726	686	5%	2,351	1,404	60%
MRO-Manitoba Hydro	259	52	20%	0	0	0%	202	0	0%
MRO-SaskPower	816	433	53%	30	0	13%	884	703	80%
MRO-SPP	35,714	7,198	20%	1,197	457	38%	114	72	63%
NPCC-Maritimes	1,635	241	15%	155	10	6%	1,357	1,283	95%
NPCC-New England	2,675	455	17%	3,620	0	0%	3,742	1,453	39%
NPCC-New York	2,586	737	29%	627	0	0%	974	596	61%
NPCC-Ontario	4,943	1,971	40%	478	0	0%	0	0	0%
NPCC-Québec	4,024	1,426	35%	10	0	0%	445	445	100%
PJM*	13,318	5,463	41%	15,732	1	0%	8,134	7,900	97%
SERC-Central	1,324	370	28%	1,576	455	29%	4,991	4,027	81%
SERC-East	0	0	0%	7,068	1,792	25%	3,010	2,951	98%
SERC-Florida Peninsula	0	0	0%	12,058	2,151	18%	0	0	0%
SERC-Southeast	0	0	0%	8,670	4,461	51%	3,258	3,258	100%
Texas RE-ERCOT	40,629	7,833	19%	35,609	660	2%	579	566	98%
WECC-AB*	5,712	1,919	34%	2,206	0	0%	894	285	32%
WECC-Basin*	5,932	1,148	19%	3,853	62	2%	2,667	1,473	55%
WECC-BC*	747	85	11%	17	0	0%	17,752	13,560	76%
WECC-CA*	9,382	682	7%	28,328	0	0%	15,740	4,572	29%
WECC-Mex	40	4	11%	350	0	0%	0	0	0%
WECC-NW*	14,744	1,319	9%	4,695	1,556	33%	32,915	18,502	56%
WECC-RM*	5,681	2,265	40%	3,521	0	0%	3,251	1,327	41%
WECC-SW*	4,303	1,182	27%	12,139	391	3%	3,117	948	30%
EASTERN INTERCONNECTION	93,517	25,692	27%	64,937	10,013	15%	29,017	23,647	81%
QUÉBEC INTERCONNECTION	4,024	1,426	35%	10	0	0%	445	445	100%
TEXAS INTERCONNECTION	40,629	7,833	19%	35,609	660	2%	579	566	98%
WECC INTERCONNECTION	46,541	8,605	19%	55,108	2,008	4%	76336	40667	53%
INTERCONNECTION TOTAL:	184,711	43,556	23%	155,664	12,685	8%	106,377	65,325	61%

Review of Winter 2024–2025 Capacity and Energy Performance

The meteorological winter across the contiguous United States had an average temperature of 34.1 degrees F—1.9 degrees above average—ranking in the warmest third of NOAA's historical record. Total winter precipitation in the US was 5.87 inches, 0.92 of an inch below average, ranking in the driest third of the December–February climate record.[17] Most of Canada experienced temperatures at least 2°C above the baseline average with the Maritime provinces, southern Ontario, and the Canadian west coast recording temperature departures nearer the baseline average while a small region in southern Saskatchewan recorded temperatures just slightly below the baseline average.[18]

In February 2025, FERC and NERC and its Regional Entities launched a joint review of the BPS' performance during the January 2025 arctic events, which comprised Winter Storms Blair, Cora, Demi, and Enzo.[19] The week of January 19–25, 2025 was the third coldest winter week (spanning Sunday through Saturday) across the United States since 2000. Between January 21 and 22, 2025, natural gas demand peaked at 150 Bcf/day, electric demand peaked at 683 GW, and unplanned outages peaked at 71,022 MW. Nevertheless, during the January 2025 arctic events, manual load shed was not required. The January 2025 arctic events had lower observed hourly wind chill temperatures in pockets of the Northeast, the Louisiana Gulf, California, and the Southwest compared to Winter Storms Uri, Elliott, Gerri, and Heather. During the January 2025 arctic events, the most extreme storm relative to typical weather was Winter Storm Enzo—a Gulf and Southern storm. On January 20, 2025, a burst of snow, sleet, and freezing rain developed across Texas and Louisiana late in the day. A mixture of sleet and freezing rain fell from Austin to San Antonio and to the southernmost point of Texas. By the early morning hours of January 21, 2025, for the first time in history, a blizzard warning was issued for southwest Louisiana and the southeastern-most point of Texas. Snow fell in Gulf cities in Texas, southern Mississippi, southern Alabama, and western Florida. On January 21, 2025, Baton Rouge recorded 7.6 inches of snowfall, making it the city's snowiest day since recordkeeping began in 1892, while New Orleans saw its snowiest day on record, with a total of 8.0 inches. Temperatures plunged to single digits in Louisiana. Temperatures in some parts of the state fell to levels not seen in more than 125 years.

The review team engaged with 10 electric entities across the Eastern and Texas Interconnections to gather the information necessary to provide a high-level overview of the BPS' performance during the cold weather events. Based on the data and interviews that the team reviewed, electric generators appear to have performed better during the January 2025 arctic events because of additional generator commitments, improved preparedness, increased situational awareness, and the implementation of lessons learned from previous extreme cold weather events and prior report recommendations. The natural gas system also performed better overall, serving record levels of natural gas demand and experiencing only minor production declines and short-duration force majeure events.

On October 1, 2025, NERC submitted to the Federal Energy Regulatory Commission its first *Cold Weather Data Annual Report*. This report includes a review of forced outage data from GADS for the winter 2024–2025 period indicating performance consistent with historical performance as reported in NERC's annual *State of Reliability* report. This is within the normal range of capacity that occurs across the fleet. During the Winter 2024–2025 period, the highest amount of capacity in a forced outage state for all reasons occurred on January 20, 2025, with 68,519 MW across all regions. The outages occurring over January 20, 2025, were analyzed as part of the joint FERC, NERC, and Regional Entity *2025 System Performance Review*. The joint FERC, NERC, and Regional Entity *2025 System Performance Review* found a reduction in peak coincident unplanned generator outages for the four 2025 winter storms reviewed compared to past winter storms; however, this review also noted that it was not an exact comparison due to prior winter storms having different characteristics.

Eastern Interconnection–Canada and Québec Interconnection

No EEAs were needed during the previous winter season. One entity plans to make a slight increase to the demand-response program based on last winter's operations.

[17] Despite Arctic air outbreaks, U.S. had warm, dry winter on average | National Oceanic and Atmospheric Administration
[18] Climate Trends and Variations Bulletin – Winter 2024/2025 - Canada.ca
[19] https://www.ferc.gov/media/report-january-2025-arctic-events-system-performance-review-ferc-nerc-and-its-regional

Eastern Interconnection–United States

Several entities indicated that generators performed better during the January 2025 arctic events than in previous winter storms. For example, TVA stated that generator performance within its footprint was stable, with minimal natural gas delivery issues. Southeastern RC detailed that no major fuel-related outages occurred. FRCC noted that generator performance was strong during this period. The significant characteristics of Winter Storm Enzo in the Southern and Gulf states were freezing precipitation and snow accumulation, especially in regions where those conditions rarely occur. In FRCC, only the northern portion of Florida experienced severe arctic weather including freezing precipitation and snowfall (record-setting, in some cities) that were abnormal for the region even though certain northern cities have faced cold temperatures in the past. In Florida, entities experienced energy emergencies caused by extended generation outages from hurricanes Milton and Helene, compounded by unusually high loads from cold weather. Entities were able to serve native load and firm delivery obligations, though non-firm sales were curtailed during certain events. ISO-NE, NYISO, and PJM all generally described the January 2025 arctic events as having cold temperatures but overall weather conditions that were similar to a winter without a major storm.

MISO emerged from Winter 2024–2025 without turning to emergency procedures despite the wide-ranging winter storms from January 6 to 9 and again from January 20 to 22. Generators continue to prioritize scheduling planned or maintenance outages to the shoulder seasons of fall and spring to maximize unit availability for the winter season. Also, extreme cold weather outage adders were added to the LOLE model to make sure that winter storm risks are included in planning. In PJM, demand reached a new all-time winter peak on January 22, 2025, of 143,714 MW with sufficient reserves. PJM did call an EEA1 on January 22, 2025, however reserves remained adequate. PJM had less than 3% load forecast error over the peak days of the January cold weather events. Reliability cases were conducted, and units with extended start times were evaluated and started early to ensure units were on-line before extreme cold weather settled in. PJM had a 9.24% forced outage rate on the peak day, a relatively low forced outage rate for the weather experienced. There were also very few gas production problems; however, market issues prevented proper scheduling because of the four-day holiday weekend.

In SERC-Central, entities reported only limited impacts from Winter 2024–2025 coldest weather and made minor adjustments. One entity declared conservative operations ahead of peak conditions but experienced no emergencies. One entity raised its winter Planning Reserve Margin target to 26% following lessons learned from Winter Storm Elliott. Corrective actions were implemented due to isolated equipment issues, including improved heat trace capabilities and adding heat trace equipment to the cold weather critical component list. During the previous winter season, some SERC-Florida Peninsula entities experienced energy emergencies caused by extended generation outages from hurricanes Milton and Helene, compounded by unusually high loads from cold weather. Despite these challenges, entities were able to serve native load and firm delivery obligations, though non-firm sales were curtailed during certain events.

Texas Interconnection–ERCOT

There were no energy emergencies for the Texas RE-ERCOT region last winter and no conditions that prompted changes in operating procedures. Winter Storm Kingston, which occurred in February 2025, was the only storm where ERCOT utilized firm fuel supply service resources (FFSS), a firm-fuel product that provides additional grid reliability and resiliency during extreme cold weather and compensates generation resources that meet a higher resiliency standard. A maximum FFSS deployment of 470 MW occurred on February 19 between the hours 13:10 and 17:02. Two other storms, Enzo and Cora, impacted ERCOT in January 2025, but these storms did not cause any system reliability issues.

Western Interconnection

Between January 11 and 17, 2024, a prolonged Arctic outbreak impacted British Columbia, Alberta, and the U.S. Pacific Northwest, driving record electricity demand and widespread reliability challenges. Four U.S. Northwest BAs and one Canadian BA declared energy emergencies, underscoring two core vulnerabilities: Inadequate capacity during evening peak hours (4 to 8 p.m.) and Insufficient fuel supply (limited hydro availability) across multiple days.

Although temperatures were comparable to the December 2022 cold snap, WECC-Northwest peak demand rose two percentage points to 6% over then, with BC Hydro and AESO both setting new all-time records. The U.S. Northwest relied heavily on imports—averaging 4,745 MW during peaks and 5,241 MW across all hours, mostly from the Southwest and Rockies. California remained a net importer, providing little relief. Market prices in the Northwest reached or neared caps across most hours, indicating persistent scarcity rather than short-term peaks. Overall, the January 2024 event illustrated capacity alone does not ensure resilience. Sustained energy availability with interregional flexibility (both physical and market-based) will be key to maintaining reliability through the 2025–2026 and future winter seasons.

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	**Peak Demand Date**	**Peak Demand Hour**	**Demand[1] (MW)**	**WRA Peak Demand Scenarios[2] (MW)**	**Generation[1] (MWh)**	**Transfers[1] (MW)**	**Wind – Actual[1] (MWh)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MWh)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
MISO	Jan. 21	18:00	108,888*	96,134 100,395	101,655	-977	18,468	16,761	0	519	17,010
MRO-Manitoba Hydro	Jan. 20	08:00	5,132	4,814 5,060	5,292	-277	142	52	N/A	0	146
MRO-SaskPower	Dec. 18	18:00	3,785	3,802 3,897	3,641	-231	664	368	0	3	0
MRO-SPP	Feb. 20	08:00	47,981	45,926 47,054	40,898	-1,424	4,886	4,783	255	36	9,272
NPCC-Maritimes	Jan. 22	07:00	5,810	5,907 6,498	4,266	-1,174	368	261	3	5	*
NPCC-New England	Jan. 21	18:00	19,607	20,308 21,814	17,686	-1,896	285	329	4	23	624
NPCC-New York	Jan. 22	19:00	23,521	22,998 24,023	18,932	-4,589	654	728	0	0	4,835

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	**Peak Demand Date**	**Peak Demand Hour**	**Demand[1] (MW)**	**WRA Peak Demand Scenarios[2] (MW)**	**Generation[1] (MWh)**	**Transfers[1] (MW)**	**Wind – Actual[1] (MWh)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MWh)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
NPCC-Ontario	Jan. 22	18:00	21,940	20,951 22,179	24,250	2,990	3,693	1,914	0	0	*
NPCC-Québec	Jan. 22	08:00	37,178	36,061 39,545	39,514	-766	1,463	1,449	0	0	*
PJM	Jan. 22	09:00	144,420	130,712 144,939	152,142	7,731	3,704	3,620	3,076	1	8,663
SERC-C	Jan. 22	08:00	47,815	41,397 47,062	40,898	-6,921	563	176	214	455	1,538
SERC-E	Jan. 23	08:00	47,130	44,023 47,662	41,810	-5,323	0	0	145	2,526	1,830
SERC-FP	Jan. 25	08:00	43,974	45,714 54,239	41,702	-557	0	0	362	1,684	2,824
SERC-SE	Jan. 22	08:00	46,490	43,670 45,116	48,227	1,741	0	0	592	3,861	2,210

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	**Peak Demand Date**	**Peak Demand Hour**	**Demand[1] (MW)**	**WRA Peak Demand Scenarios[2] (MW)**	**Generation[1] (MWh)**	**Transfers[1] (MW)**	**Wind – Actual[1] (MWh)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MWh)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
TRE-ERCOT	Feb. 20	08:00	80,560	73,193[5] 90,405[5]	79,960	-191	9,397	15,697	1,586	15	5,742
WECC-AB	Dec. 18	17:00	12,241	12,280 12,635	12,711	-470	3,175	1,867	4	0	*
WECC-BC	Feb 3	18:00	11,359	11,996 12,749	11,415	44	70	279	0	0	839
WECC-CA/MX	Dec. 12	15:00	35,555	35,359 36,823	31,925	-4,669	4,021	569	11,547	0	1,627
WECC-NW	Feb. 12	08:00	54,278	58,001 62,230	48,437	-920	2,607	7,876	1,494	2,198	3,281
WECC-SW	Feb. 13	16:00	22,969	16,177 17,777	25,087	2,117	2,741	1,065	1,599	182	1,496
Highlighting Notes:			Actual peak demand in the highlighted areas met or exceeded extreme scenario levels				Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	**Peak Demand Date**	**Peak Demand Hour**	**Demand[1] (MW)**	**WRA Peak Demand Scenarios[2] (MW)**	**Generation[1] (MWh)**	**Transfers[1] (MW)**	**Wind – Actual[1] (MWh)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MWh)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
Table Notes: [1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from EIA From 930 data. For areas in Canada, this data was provided to NERC by system operators and utilities. [2] See NERC *2024–2025* WRA demand scenarios for each assessment area. Values are the normal winter peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand. [3] Expected values of wind and solar resources from the *2024–2025 WRA*. [4] Values from NERC Generator Availability Data System for the 2024–2025 winter hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024–2025 winter risk period scenarios in the *2024–2025 WRA*. [5] Texas RE-ERCOT peak demand scenarios are obtained by adding expected demand response (5.4 GW for winter 2024-2025) to the demand scenarios found on p. 29 of the 2024-2025 WRA. *Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.										

Errata

December 2025

- Corrections made to the VER Table (page 50): Hydro values for WECC NW, Western Interconnection Total, and Total

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	)	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit M: Department, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (July 2025)

U.S. DEPARTMENT of ENERGY



Resource Adequacy Report

Evaluating the Reliability and Security of the United States Electric Grid

July 2025

Acknowledgments

This report and associated analysis were prepared for DOE purposes to evaluate both the current state of resource adequacy as well as future pressures resulting from the combination of announced retirements and large load growth.

It was developed in collaboration with and with assistance from the Pacific Northwest National Laboratory (PNNL) and National Renewable Energy Laboratory (NREL). We thank the North American Electric Reliability Corporation (NERC) for providing data used in this study, the Telos Corporation for their assistance in interpreting this data, and the U.S Energy Information Administration (EIA) for their dissemination of historical datasets. In addition, thank you to NREL for providing synthetic weather data created by Evolved Energy Research for the Regional Energy Deployment System (ReEDS) model.

DOE acknowledges that the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level. The DOE study team built the methodology and analysis upon the best data that was available. However, entities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience.

Historically, the nation's power system planners would have shared electric reliability information with DOE through mechanisms such as EIA-411, which has been discontinued. Thus, one of the key takeaways from this study process is the underscored "call to action" for strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our collective economic and national security.

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List of Acronyms

AI	Artificial Intelligence
CAISO	California Independent System Operator
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EO	Executive Order
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
GADS	Generating Availability Data System
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ITCS	Interregional Transfer Capability Study
LBNL	Lawrence Berkeley National Laboratory
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LTRA	Long-Term Reliability Assessment
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
PJM	PJM Interconnection, LLC
PNNL	Pacific Northwest National Laboratory
ReEDS	Regional Energy Deployment System
RTO	Regional Transmission Organization
SERC	SERC Reliability Corporation
TPR	Transmission Planning Region
USE	Unserved Energy

Background to this Report

On April 8, 2025, President Trump issued Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid." EO 14262 builds on EO 14156, "Declaring a National Emergency (Jan. 20, 2025)," which declared that the previous administration had driven the Nation into a national energy emergency where a precariously inadequate and intermittent energy supply and increasingly unreliable grid require swift action. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy and the integrity of our Nation's electrical grid.

EO 14262 mandates the development of a uniform methodology for analyzing current and anticipated reserve margins across regions of the bulk power system regulated by the Federal Energy Regulatory Commission (FERC). Among other things, EO 14262 requires that such methodology accredit generation resources based on the historical performance of each generation resource type. This report serves as DOE's response to Section 3(b) of EO 14262 by delivering the required uniform methodology to identify at-risk region(s) and guide reliability interventions. The methodology described herein and any analysis it produces will be assessed on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States.

Executive Summary

Our Nation possesses abundant energy resources and capabilities such as oil and gas, coal, and nuclear. The current administration has made great strides—such as deregulation, permitting reform, and other measures—to enable addition of more energy infrastructure crucial to the utilization of these resources. However, even with these foundational strengths, the accelerated retirement of existing generation capacity and the insufficient pace of firm, dispatchable generation additions (partly due to a recent focus on intermittent rather than dispatchable sources of energy) undermine this energy outlook.

Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation. A failure to power the data centers needed to win the AI arms race or to build the grid infrastructure that ensures our energy independence could result in adversary nations shaping digital norms and controlling digital infrastructure, thereby jeopardizing U.S. economic and national security.

Despite current advancements in the U.S. energy mix, this analysis underscores the urgent necessity of robust and rapid reforms. Such reforms are crucial to powering enough data centers while safeguarding grid reliability and a low cost of living for all Americans.

Key Takeaways

- **Status Quo is Unsustainable**. The status quo of more generation retirements and less dependable replacement generation is neither consistent with winning the AI race and ensuring affordable energy for all Americans, nor with continued grid reliability (ensuring "resource adequacy"). Absent intervention, it is impossible for the nation's bulk power system to meet the AI growth requirements while maintaining a reliable power grid and keeping energy costs low for our citizens.
- **Grid Growth Must Match Pace of AI Innovation**. The magnitude and speed of projected load growth cannot be met with existing approaches to load addition and grid management. The situation necessitates a radical change to unleash the transformative potential of innovation.
- **Retirements Plus Load Growth Increase Risk of Power Outages by 100x in 2030**. The retirement of firm power capacity is exacerbating the resource adequacy problem. 104 GW of firm capacity are set for retirement by 2030. This capacity is not being replaced on a one-to-one basis and losing this generation could lead to significant outages when weather conditions do not accommodate wind and solar generation. In the "plant closures" scenario of this analysis, annual loss of load hours (LOLH) increased by a factor of a hundred.
- **Planned Supply Falls Short, Reliability is at Risk**. The 104 GW of retirements are projected to be replaced by 209 GW of new generation by 2030; however, only 22 GW would come from firm baseload generation sources. Even assuming no retirements, the model found increased risk of outages in 2030 by a factor of 34.

- **Old Tools Won't Solve New Problems.** Antiquated approaches to evaluating resource adequacy do not sufficiently account for the realities of planning and operating modern power grids. At a minimum, modern methods of evaluating resource adequacy need to incorporate frequency, magnitude, and duration of power outages; move beyond exclusively analyzing peak load time periods; and develop integrated models to enable proper analysis of increasing reliance on neighboring grids.

This report clearly demonstrates the need for rapid and robust reform to address resource adequacy issues across the Nation. Inadequate resource adequacy will hinder the development of new manufacturing in America, slow the re-industrialization of the U.S. economy, drive up the cost of living for all Americans, and eliminate the potential to sustain enough data centers to win the AI arms race.

Developing a Uniform Methodology

DOE's resource adequacy methodology assesses the U.S. electric grid's ability to meet future demand through 2030. It provides a forward-looking snapshot of resource adequacy that is tied to electricity supply and new load growth, systematically exploring a range of dimensions that can be compared across regions. As detailed in the methodology section of this report, the model is derived from the North American Electric Reliability Corporation (NERC) Interregional Transfer Capability Study (ITCS) which leverages time-correlated generation and outages based on actual historic data.[1] A deterministic approach[2] simulates system stress in all hours of the year and incorporates varied grid conditions and operating scenarios based on historical events:

- **Demand for Electricity – Assumed Load Growth:** The methodology accounts for the significant impact of data centers, particularly those supporting AI workloads, on electricity demand. Various organizations' projections for incremental data center electricity use by 2030 range widely (35 GW to 108 GW). DOE adopted a national midpoint assumption of 50 GW by 2030, aligning with central projections from Electric Power Research Institute (EPRI)[3] and Lawrence Berkeley National Laboratory (LBNL).[4] This 50 GW was allocated regionally using state-level growth ratios from S&P's forecast,[5] reflecting infrastructure characteristics, siting trends, and market activity; and, mapped to NERC Transmission Planning Regions (TPRs).

1. This model differs from traditional peak hour reliability assessments in that it explicitly simulates grid performance hour-by-hour across multiple weather years with finer geographic detail and optimized inter-regional transfers, and explores various retirement and build-out scenarios. Furthermore, the DOE approach integrates weather-synchronized outage data.
2. Deterministic approaches evaluate resource adequacy using relatively stable or fixed assumptions about the representation of the power system. Probabilistic approaches incorporate data and advanced modeling techniques to represent uncertainty that require more computing power. Deterministic was chosen for this analysis for transparency and to model detailed historic system conditions.
3. EPRI, "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption," March 2024, https://www.epri.com/research/products/3002028905.
4. Shehabi, A., et al., "2024 United States Data Center Energy Usage Report," https://escholarship.org/uc/item/32d6m0d1.
5. S&P Global – Market Intelligence, "US Datacenters and Energy Report," 2024.

An additional 51 GW of non-data center load was modeled using NERC data, historical loads (2019-2023), and simulated weather years (2007-2013), adjusted by the Energy Information Administration's (EIA) 2022 energy forecast, with interpolation between 2024 and 2033 to estimate 2030 demand.

- **Supply of Electricity – Assumed Generation Retirements and Additions:** Between the current system and the projected 2030 system, the model considers three scenarios for generator retirements and additions. These scenarios were selected to describe the metrics of interest and how they change during certain assumptions of generation growth and retirements.

The resource adequacy standard (or criterion) is the measure that defines the desired level of adequacy needed for a given system. Conceptually, a resource adequacy criterion has two components—metrics and target levels—that determine whether a system is considered adequate. Comprehensive resource adequacy metrics[6] are incorporated in this analysis to capture the magnitude and duration of system stress events:

- **Magnitude of Outages – Normalized Unserved Energy (NUSE):** Measures the amount of unmet electrical energy demand because of insufficient generation or transmission, typically measured in megawatt hours (MWh).

  While USE describes the absolute amount of energy not delivered, it is less useful when comparing systems of different size or across different periods. Normalizing, by dividing by total load over a whole period (for example, a year) allows comparison of these metrics across different system sizes, demand levels, and periods of analysis. For example, 100 MWh of USE in a small, isolated microgrid can be more impactful than 100 MWh of USE in a larger regional grid that serves millions of people. USE is normalized by dividing by total load:

$$\frac{100\ MWh\ (of\ unserved\ energy)}{10{,}000{,}000\ MWh\ (of\ total\ energy\ delivered\ in\ a\ year)} x100 = 0.001\ percent$$

Although the use of NUSE is not standardized in the U.S. today,[7] several system operators domestically and across the world have begun using NUSE as a useful metric.

- **Duration of Outages – Loss of Load Hours (LOLH):** Measures the expected duration of power outages when a system's load exceeds its available generation capacity. At the core, LOLH helps assess how frequently and for how long the power system is likely to experience insufficient supply, providing a picture of reliability in terms of time. LOLH is calculated as both a total and average value per year, in addition to the maximum percentage of load lost in any given hour per year.

6. In the interest of technical accuracy, and separate from their contextualization in the main text, NUSE is more precisely a measure of volume that is expressed as a percentage. Similarly, 2.4 hours of LOLH represents the cumulative sum of distinct periods of load loss, not a singular, continuous duration.
7. There is no common planning criterion for this metric in North America. NERC's Long-Term Reliability Assessment employs a normalized expected unserved energy (NEUE) metric to define target risk levels for each region. Grid operators, such as ISO-NE, have also considered NUSE in energy adequacy studies. For example, see ISO-NE, "Regional Energy Shortfall Threshold (REST): ISO's Current Thinking Regarding Tail Selection," April 2025, https://www.iso-ne.com/static-assets/documents/100022/a09_rest_april_2025.pdf.

Reliability Standard

DOE's methodology recognizes that the traditional 1-in-10 loss of load expectation (LOLE) criterion is insufficient for a complete assessment of resource adequacy and risk profile. This antiquated criterion is not calculated uniformly and fails to adequately account for crucial factors such as the duration and magnitude of potential outages.[8] To provide a comprehensive understanding of system reliability and, specifically, to complement current resource adequacy standards while informing the creation of new criteria, the methodology uses the following reliability standard:

- **Duration of Outages:** No more than 2.4 hours of lost load in an individual year.[9] This translates into one day of lost load in ten years to meet the 1-in-10 criteria.

- **Magnitude of Outages:** No more than an NUSE of 0.002%.[10] This means that the total amount of energy that cannot be supplied to customers is 0.002% of the total energy demanded in a given year.

Achieving Reliability Standard

- **Perfect Capacity Surplus/Deficit:** Defined as the amount of generation capacity (in MW) a region would need to achieve specified threshold conditions. Based on these thresholds, this standard helps answer the hypothetical question of how much more (or less) power plant capacity is needed for a power system to be considered "perfectly reliable" according to pre-defined standards. This methodology employs this perfect capacity metric to identify the amount of capacity needed to remedy potential shortfalls (or excesses) in generation.

Key Results Summary

This analysis developed three separate cases for 2030. The "**Plant Closures"** case assumes all announced retirements occur plus mature generation additions based on NERC's Tier 1 resources category,[11] which encompasses completed and under-construction power generation projects, as well as those with firm-signed and approved interconnection service or power purchase agreements. The "**No Plant Closures"** case assumes no retirements plus mature additions. A "**Required Build**" case further compares the impacts of retirements on perfect capacity additions needed to return 2030 to the current system level of reliability.

8. While 1-in-10 analyses have evolved, industry experts have raised concerns about its effectiveness to address future system risks. Concerns include energy constraints that arise from intermittent resources, increasing battery storage, limited fuel supplies, and the shifting away of peak load periods from times of supply shortfalls.
9. The "1-in-10 year" reliability standard for electricity grids means that, on average, there should be no more than one day (24 hours) of lost load over a ten-year period. This translates to a maximum of 2.4 hours of lost load per year.
10. This analysis targets NUSE below 0.002% for each region because this is the target NERC uses to represent high risk in resource adequacy analyses. Estimates used in industry and analyzed recently range from 0.0001% to 0.003%.
10. Mature generation additions are based on NERC's 2024 LTRA Tier 1 resources, which assume that only projects considered very mature in the development pipeline will be built. For example, Tier 1 additions are those with signed interconnection agreements or power purchase agreements, or included in an integrated resource plan, indicating a high degree of certainty in their addition to the grid. Full details of the retirement and addition assumptions can be found in the methodology section of this report.

DOE ran simulations using 12 different years of historical weather. Every hour was based on actual data for wind, solar, load, and thermal availability to stress test the grid under a range of realistic weather conditions. The benefit of this approach is that it allows for transparent review of how actual conditions manifest themselves in capacity shortfalls. For all scenarios, LOLH and NUSE are calculated and used to compare how they change based on generation growth, retirements, and potential weather conditions.

- **Current System:** Supply of power (generation) and demand for power (load) consistent with 2024 NERC Long-Term Reliability Assessment (LTRA), including 2023 actual generation plus Tier 1 additions for 2024.

- **Plant Closures:** This case assumes 104 GW of announced retirements based on NERC estimates including approximately 71 GW of coal and 25 GW of natural gas, which closely align with retirement numbers in EIA's 2025 Annual Energy Outlook. In addition, this case assumes 100% of 2024 NERC LTRA Tier 1 additions totaling 209 GW are constructed by 2030. This includes 20 GW of new natural gas, 31 GW of additional 4-hour batteries, 124 GW of new solar and 32 GW of incremental wind. Details of the breakdown can be found in Appendix A.

- **No Plant Closures:** This case adds all the Tier 1 NERC additions but assumes no retirements.

- **Required Build:** To understand how much capacity may need to be added to reach reliability targets, the analysis adds hypothetical perfect capacity (which is idealized capacity that has no outages or profile) until a NUSE target of 0.002% is realized in each region. This scenario includes the same assumptions about retirements as our Plant Closures scenario described above.

As shown in the figures and tables below, the model shows a significant decline in all reliability metrics between the current system scenario and the 2030 Plant Closures scenario. Most notably, there is a hundredfold increase in annual LOLH from 8.1 hours per year in the current case to 817 hours per year in the 2030 Plant Closures. In the worst weather year assessed, the total lost load hours increase from 50 hours to 1,316 hours.

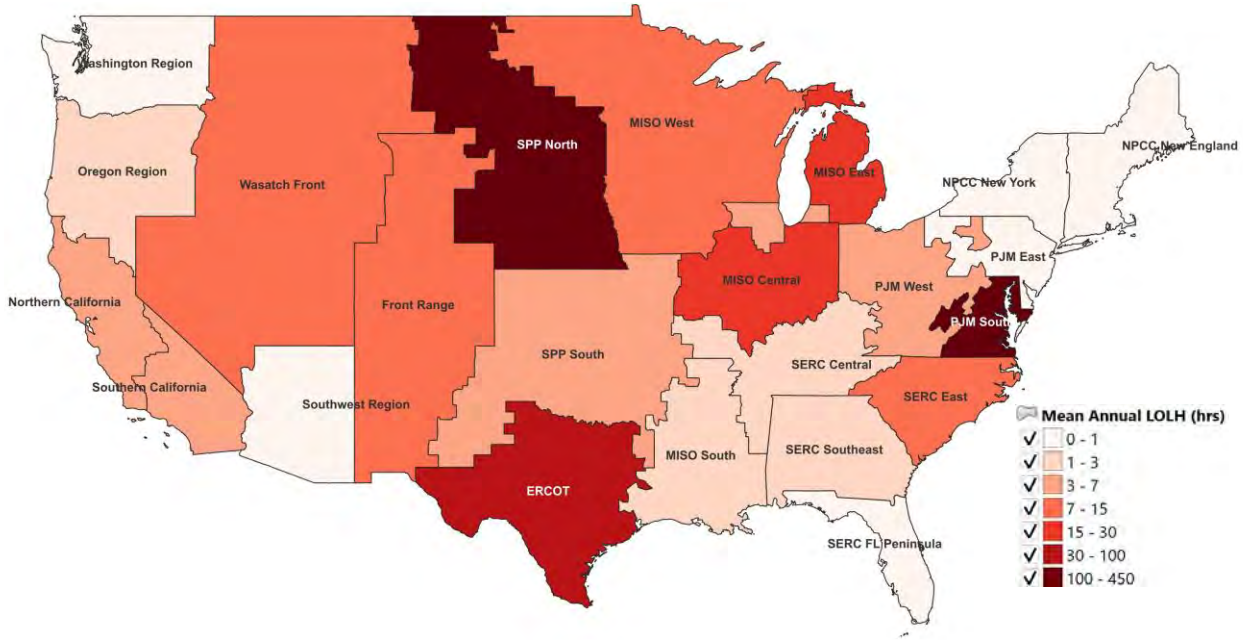


Figure 1. Mean Annual LOLH by Region (2030) – Plant Closures

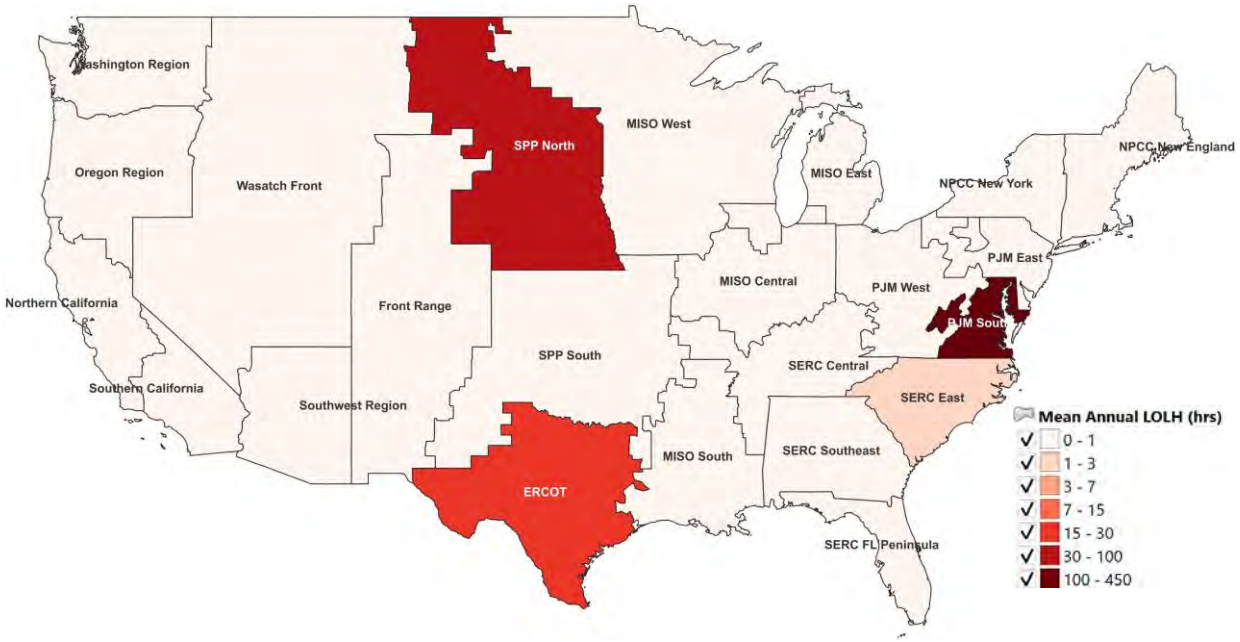


Figure 2. Mean Annual LOLH by Region (2030) – No Plant Closures

Table 1. Summary Metrics Across Cases

Reliability Metric		2030 Projection		
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	8.1	817.7	269.9	13.3
Normalized Unserved Energy (%)	0.0005	0.0465	0.0164	0.00048
WORST WEATHER YEAR				
Annual Loss of Load Hours	50	1316	658	53
Normalized Unserved Load (%)	0.0033	0.1119	0.0552	0.002

Current System Analysis

Analysis of the current system shows all regions except ERCOT have less than 2.4 hours of average loss of load per year and less than 0.002% NUSE. This indicates relative reliability for most regions based on the average indicators of risk used in this study. In the current system case, ERCOT would be expected to experience on average 3.8 LOLH annually going forward and a NUSE of 0.0032%. When looking at metrics in the worst weather years, regions meet or exceed additional criteria. All regions experienced less than 20% of lost load in any hour.

However, PJM, ERCOT,[12] and SPP experienced significant loss of load events during 2021 and 2022 winter storms Uri and Elliot which translated into more than 20 hours of lost load. This results in a concentration of lost load within certain years such that some regions exceeded 3-hours-per-year of lost load. It is worth noting that in the case of PJM and SPP, the current system model shortfalls occurred within subregions rather than for the entire ISO footprint.

12. ERCOT has since winterized its generation fleet and did not suffer any outages during Winter Storm Elliot.

2030 Model Results

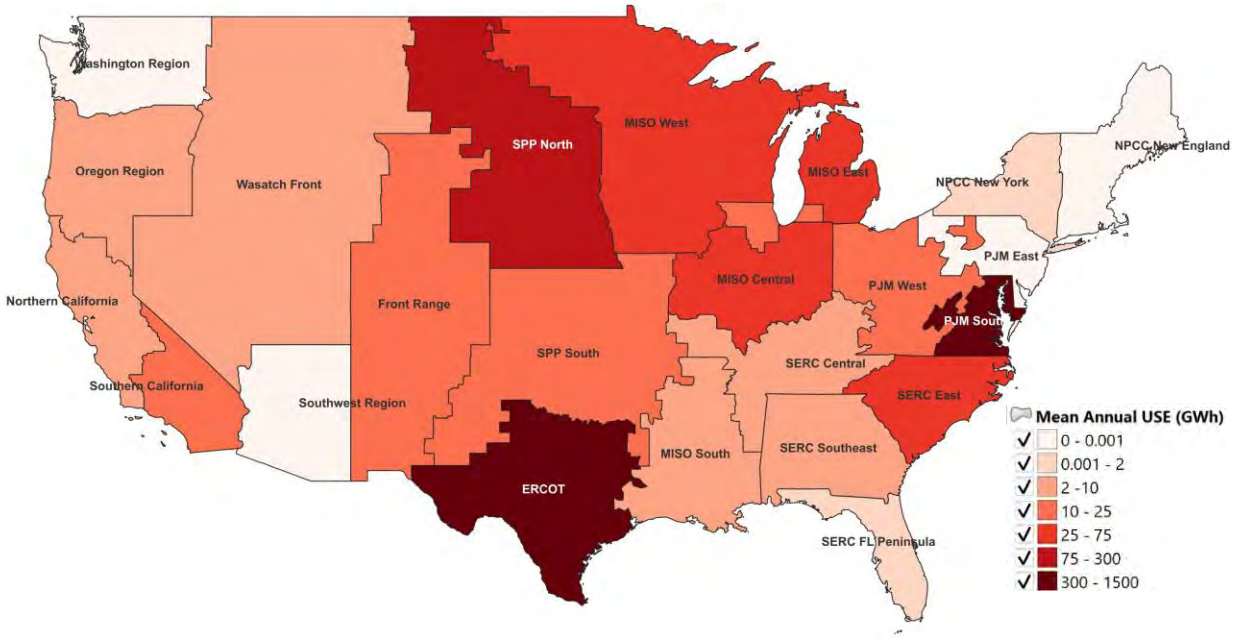


Figure 3. Mean Annual NUSE by Region (2030) -Plant Closures

Key Findings – Plant Closures Case:

- **Systemwide Failures**: All regions except ISO-NE and NYISO failed reliability thresholds. These two regions did not have additional AI/data center (AI/DC) load growth modeled.
- **Loss of Load Hours (LOLH)**: Ranged from 7 hours/year in CAISO to 430 hours/year in PJM.
- **Load Shortfall Severity**: Max shortfall reached as high as 43% of hourly load in PJM; 31% in CAISO.
- **Normalized Unserved Energy**: Normalized values ranged from 0.0032% (non-CAISO West) to 0.1473% (PJM), far exceeding thresholds of 0.002%.
- **Extreme Events**: Most regions experienced ≥3 hours of unserved load in at least one year. PJM had 1,052 hours in its worst year.
- **Spatial Takeaways**: Subregions in PJM, MISO, and SERC met thresholds—indicating possible benefits from transmission—but SPP and CAISO failed in all subregions.

Key Findings – No Plant Closures Case:

- **Improved System Performance**: Most regions avoided loss of load events. PJM, SPP, and SERC still experienced shortfalls.
- **Regional Failures**:

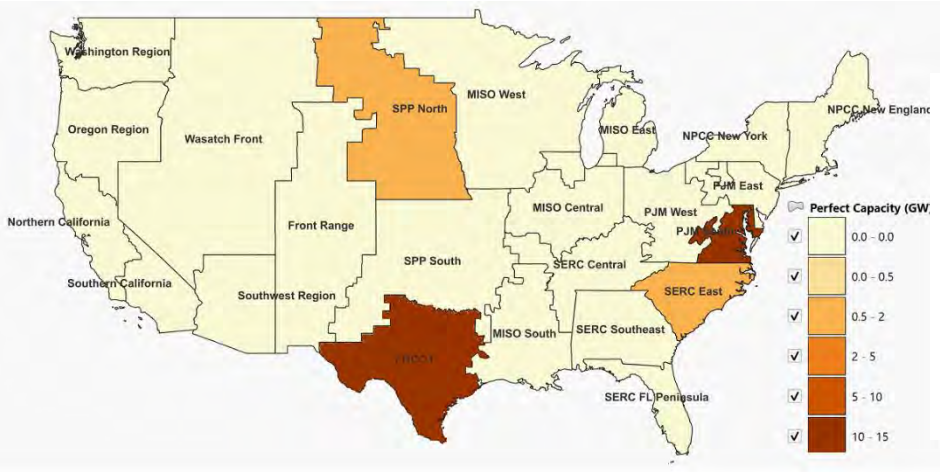
- **PJM**: 214 hours/year average, 0.066% normalized unserved energy, 644 hours in worst year, max 36% of load lost.
- **SPP**: 48 hours/year average, 0.008% normalized unserved energy, max 19% load lost.
- **ERCOT**: 20 average hours, 0.028% normalized unserved energy, 101 max hours/year, peak shortfall of 27%.
- **SERC-East**: Generally adequate (avg. 1 hour/year, 0.0003% NUSE), but Elliot storm in 2022 caused 42 hours of shortfall.

The overall takeaway is that avoiding announced retirements improves grid reliability, but shortfalls persist in PJM, SPP, ERCOT, and SERC, particularly in winter.

Required Build

This required build analysis quantifies "hypothetical capacity," defined as power that is 100% reliable and available that is needed to resolve the shortfalls. Known in industry as “perfect capacity,” this metric is utilized to avoid the complex decision of selecting specific generation technologies, as that is ultimately an optimization of reliability against cost considerations. Nevertheless, it serves as a valuable indicator, illustrating either the magnitude of a resource gap or the scale of large load that will be unable to interconnect. For the Required Build case, this hypothetical capacity was calculated by adding new generating resources to each region until a target of 0.002% of NUSE is reached.

The table below shows the tuned perfect capacity results. For the current system, this analysis identifies an additional 2.4 MW of capacity to meet the NUSE target for PJM, which experiences shortfalls due to the winter storm Elliot historical weather year. By 2030, without considering any generation retirements, an additional 12.5 GW of generating capacity is needed across PJM, SPP, and SERC to reduce shortfalls.



	2024-Current System (MW)	2030-No Plant Closures (MW)
PJM	2400	10,500
SERC-E		500
SPP-N		1,500
ERCOT	1600	10500
Total	4000	23000

Perfect Capacity/Additions

Figure 4. Tuned Perfect Capacity (MW) By Region

1 Modeling Methodology

The methodology uses a zonal PLEXOS[13] model with hourly time-synchronous datasets for load, generation, and interregional transfer for the 23 U.S. subregions (referred to as TPRs in this study)[14] including ERCOT (see Figure 5 below). While ERCOT operates outside of FERC's general jurisdiction,[15] it provides a valuable case for understanding broader reliability and resource adequacy challenges in the U.S. electric grid, and FPA Section 202(c) allows DOE to issue emergency orders to ERCOT.

We base this analysis on actual weather and power plant outage data from 2007 to 2023 using NERC's ITCS[16] base dataset. DOE specifically decided to start this analysis with the ITCS dataset since it is a complete representation of the interconnected electrical system for the lower 48 and it has been thoroughly reviewed by industry experts in a public and transparent process. DOE has in turn made modifications to the dataset to fit the needs of this study. The contents of this section focus on those modifications which DOE implemented for purposes of this study.

PLEXOS is an industry-trusted simulation tool used for energy optimization, resource adequacy, and production cost modeling. This study leverages PLEXOS' ability to exercise an hourly production cost model to determine the balance between loads, generation, and imports for each region. Modeling was carried out using a deterministic approach that evaluates whether a power system has sufficient resources to meet projected demand under a pre-defined set of conditions which correspond to the past few years of real-world events. The model ultimately determines the amount of unmet load if generation resources and imports are not sufficient for meeting the load in each discrete time period.

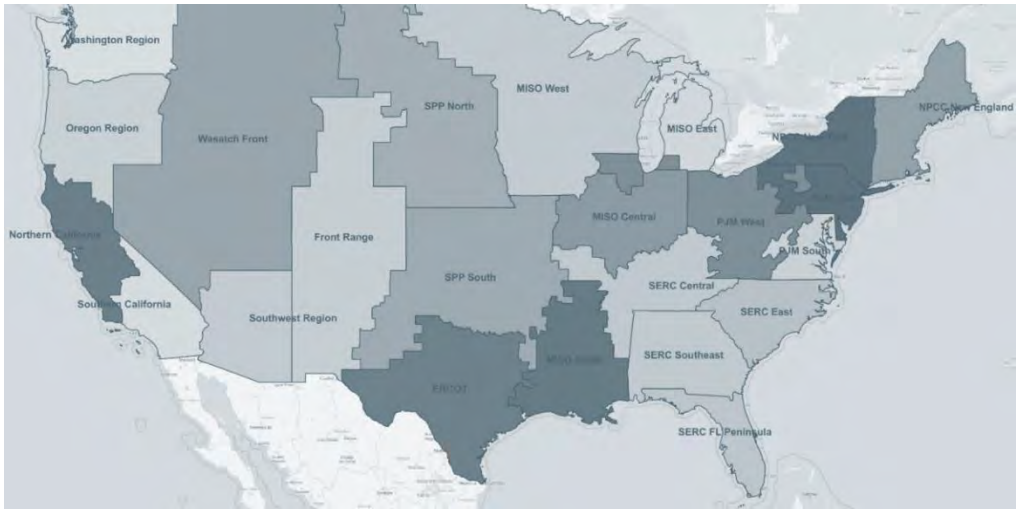


Figure 5. TPRs used in NERC ITCS

13. Energy Exemplar, "PLEXOS," https://www.energyexemplar.com/plexos.
14. The TPRs match the regional subdivisions in the NERC ITCS study, itself based on FERC's transmission planning regions.
15. Transmission within ERCOT is intrastate commerce. 16 U.S.C. § 824(b)(1) (provisions applying to "the transmission of electric energy in interstate commerce").
16. NERC "Integrated Transmission and Capacity System (ITCS)," accessed June 25, 2025, https://www.nerc.com/pa/RAPA/Pages/ITCS.aspx.

This methodology developed a current model and series of scenarios to explore how different assumptions impact resource adequacy. This sensitivity analysis includes assumptions regarding load growth, generation build-outs and retirements, and transfer capabilities. By comparing the results of the current model with the scenario results, we can assess how generation retirements and load growth affect future generation needs.

The assessment uses data from 2007–2013 (synthetic weather data) and 2019–2023 (historical data). A brief summary of the methodological assumptions is provided here, with additional details available in the relevant appendixes.

- **Solar and Wind Availability** – Created from historical output from EIA 930 data, with bias correction of any nonhistorical data to match regional capacity factors, as calibrated to EIA 930 data.[17] Synthetic years used 2018 technology characteristics from NREL based on the Variable Energy Potential (reV) model, then mapped to synthetic weather year data. See Appendix A for more details.

- **Thermal Availability** – Calculated according to NERC LTRA capacity data, adjusted for historical outages and derates, primarily with GADS data. GADS data does not capture historical outages caused by fuel supply interruptions.[18]

- **Hydroelectric Availability** – Historical outputs are processed by NERC to establish monthly power rating limits and energy budgets, but energy budgets are not enforced in alignment with how they were treated in the ITCS. The team evaluated performance under different energy budget restrictions, but did not find significant differences during peak hours, justifying NERC ITCS assumptions that hydroelectric resources could generally be dispatched to peak load conditions. Later work may benefit from exploring drought scenarios or combinations of weather and hydrological years, where energy budgets may be significantly decreased.

- **Outages and Derates** – Data for the actual data period (2019–2023) are based on historical forced outage rates and deratings. Outage and deratings data for the synthetic period (2007–2013) are based on the historical relationships observed between temperature and outages (see Appendix G of the NERC ITCS Final Report for more information).

- **Load Projections and AI Growth** – Load growth through 2030 is assumed to match NERC 2024 ITCS projections, scaling the 12 weather years to meet 2030 projections. Additional AI and data center load is then added according to reports from EPRI and S&P regarding potential futures.

- **Transfer Capabilities and Imports/Exports -** Each subregion is treated as a “copper plate,” with the transfer capacity between each subregion defined by the availability of transmission pathways. It is an approximation that assumes all resources are connected to a single point, simplifying the transmission system within the model. Subregions are generally assumed to exhaust their own capacity before utilizing capacity available from their neighbors. Once the net remaining capacity is at or below 10 percent of load, the subregion begins to use capacity from a neighbor.

17. See ITCS Final Report, Appendix F, for the method that was implemented to scale synthetic weather years 2007–2013.
18. See ITCS Final Report, Appendix G, for outage and derate methods.

  - Imports are assumed to be available up to the minimum total transfer capacity and spare generation in the neighboring subregion.

  - To the extent the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario, the model projects an energy shortfall. See "Outputs" in the appendix for more details.

  - To ensure that transfers are dispatched only after local resources are exhausted, a wheeling charge of $1,000 is applied for every megawatt-hour of energy transferred between regions through transmission pathways.

- **Storage** – In alignment with the NERC ITCS methodology, storage was split into pumped hydro and battery storage. Pumped hydro was assumed to have 12 hours duration at rated capacity with 30% round-trip losses, while battery storage was assumed to have four hours and 13% round-trip losses. Storage is dispatched as an optimization to minimize USE and demand response usage under various constraints and is recharged during periods of surplus energy.
- **Demand Response –** Demand Response (DR) is treated as a supply-side resource and dynamically scheduled after all other regional resources and imports are exhausted. It is modeled with both capacity (MW) and energy (MWh) limitations and assumed to have three hours of availability at capacity but could be spread across more than three hours up to the energy limit. DR capacity was based on LTRA Form A data submissions for "Controllable and Dispatchable Demand Response – Available", or firm, controllable DR capacity.
- **Retirements** – Retirements as per the NERC LTRA 2024 model. To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant level data are used to tabulate generation retirement or addition capacity for each ITCS region and NERC assessment area. Disaggregation fractions are then calculated by technology based on planned retirements through 2030. See Appendix B for further information. Retirements are categorized into two categories:

  1. *Announced Retirements*: Includes both confirmed retirements and announced retirements. Confirmed retirements are generators formally recognized by system operators as having started the official retirement process and are assumed to retire on their expected date. To go from LTRA regions to ITCS regions, weighting factors are derived in the same way as in the generation set, based on EIA retirement data. In addition to confirmed retirements, announced retirements are generators that have publicly stated retirement plans that have not formally notified system operators and initiated the retirement process. This disaggregation method for announced retirements mirrors used for confirmed retirements.[19]
  2. *None*: Removes all retirements (after 2024) for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirement contributes to some of the adequacy challenges in some regions.

- **Additions** – Assumes only projects that are very mature in the pipeline (such as those with a signed interconnection agreement) will be built. This data is based on projects

19. If announced retirements were less than or equal to confirmed retirements, the model adjusted the announced retirement to equal confirmed.

designated as Tier 1 in the NERC 2024 LTRA and are mapped to ITCS regions with EIA 860-derived weighting factors similar to those described for the retirements above. See Appendix A for further information.

- **Perfect Capacity Required** - Estimates perfect capacity (which is idealized capacity that has no outages or profile and is described in Section 2) until we reach a pre-defined reliability target. We used a metric of NUSE given the deterministic nature of the model, to be consistent with evolving metrics, and to be consistent with NERC's recent LTRAs. We targeted NUSE of below 0.002% for each region.

1.1 Modeling Resource Adequacy

This model calculates several reliability metrics to assess resource adequacy. These metrics were calculated using PLEXOS simulation outputs, which report the USE (in MWh) for all 8,760 hourly periods in each of the 12 weather years:

- **USE** refers to the amount of electricity demand that could not be met due to insufficient generation and/or transmission capacity. Several USE-derived indicators were considered:
    - *Normalized USE (percentage %):* The total amount of unserved load over 12 years of weather data, normalized by dividing by total load, and reported as a percentage.[20]
    - *Mean Annual USE (GWh)*: The 12-year average of each region's total USE in each weather year. This mean value represents the average annual USE across weather variability.
    - *Mean Max Unserved Power (GW)*: The 12-year average of each region's maximum USE value in each weather year. This mean value characterizes the typical non-coincident peak stress on system reliability.
    - *% Max Unserved Power*: The Mean Max Unserved Power expressed as a percentage of the average native load during those peak unserved hours for each region. This percentage value provides a normalized measure of the severity of peak unserved events relative to demand.
    - *Total number of customers without power*. The Mean Max Unserved Power expressed as the equivalent number of typical U.S. persons assuming a ratio of 17,625 persons/MW lost. This estimation contextualizes the effects of the outage on average Americans.
- **Loss of Load Hours (LOLH)** refers to the number of hours during which the system experiences USE (i.e., any hour with non-zero USE). Two LOLH-based indicators were considered:

20. NUSE can be reported as parts per million or as a percentage (or parts per hundred); though for power system reliability, this would include several zeros after the decimal point.

- *Mean Annual LOLH*: for each weather year and *TPR*, we count the total number of hours with USE across all 8,760 hours, and we then take the average of those 12 totals. *Annual LOLH Distribution* is represented in box and whisker plots for 12 samples, each sample corresponding to a unique weather year.

- *Max Consecutive LOLH (hours)*[21]: The longest continuous period with reported USE in each weather year.

It should be noted that USE is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system. Rather, it represents the unrealizable AI and data center load growth under the given assumptions for generator build outs by 2030, generator retirements by 2030, reserve requirements, and potential load growth. These numbers are used as indicators to determine where it may be beneficial to encourage increased generation and transmission capacity to meet an expected need.

This study does not employ common probabilistic industry metrics such as EUE or LOLE due to their reliance on probabilistic modeling. Instead, deterministic equivalents are used.

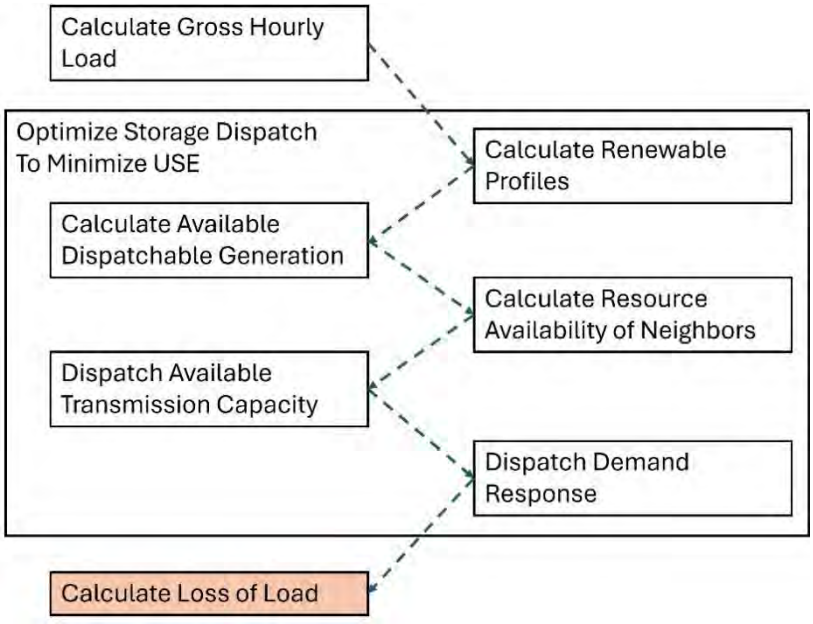


Figure 6. Simplified Overview of Model

21. One caveat on the maximum consecutive LOLH and max USE values is in how storage is dispatched in the model. Storage is dispatched to minimize the overall USE and is indifferent to the peak depth or the duration of the event. This may construe some of the max USE and max consecutive LOLH values to be higher than if storage was dispatched to minimize these values.

1.2 Planning Years and Weather Years

For the planning year (2030), historical weather year data are applied based on conditions between 2007 and 2024 to calculate load, wind and solar generation, and hydro generation. Dispatchable capacity (including dispatchable hydro capacity) is calculated through adjustment of the 2024 LTRA capacity data for historical outages from GADS data. Storage assets are scheduled to arbitrage hourly energy margins or else charge during periods of high energy margins (surplus resources) and discharge during periods of lower energy margins.

1.3 Load Modeling

Data Center Growth

Several utilities and financial and industry analysts identify data centers, particularly those supporting AI workloads, as a key driver of electricity demand growth. Multiple organizations have developed a wide range of projections for U.S. data center electricity use through 2030 and beyond, each using distinct methodologies tailored to their institutional expertise.

These datasets were used to explore reasonable boundaries for what different parts of the economy envision for the future state of AI and data center (AI/DC) load growth. For the purposes of this study, rather than focusing on any specific analysis, a more generic sweep was performed across AI/DC load growth and the various sensitivities that fit within those assumptions, as summarized below:

- McKinsey & Company projects ~10% annual growth in U.S. data center electricity demand, reaching 2,445 TWh by 2050. Their model blends internal scenarios with public signals, including announced projects, capital investment, server shipments, and chip-level power trends, supported by third-party market data.

- Lawrence Berkeley National Laboratory (LBNL) uses a bottom-up approach based on historical and projected IT equipment shipments, paired with assumptions on power draw, utilization, and infrastructure efficiency (PUE, WUE). Their projections through 2028 account for AI hardware adoption, operational shifts, and evolving cooling technologies.

- EPRI combines public data, expert input, and historical trends to define four national growth scenarios, low to higher, for 2023–2030, reflecting data processing demand, efficiency improvements, and AI-driven load impacts.

- S&P Global merges technology and power-sector models, evaluating grid readiness and facility growth under varying demand scenarios. Their forecasts consider AI adoption, efficiency trends, grid and permitting constraints, on-site generation, and offshoring risk, resulting in a wide range of outcomes.

These projections show wide variation, with 2030 electricity demand ranging from approximately 35 GW to 68 GW of average load. Given this uncertainty, including differences in hardware intensity, thermal management, siting assumptions, and behind-the-meter generation, the modeling team adopted a national midpoint assumption of approximately 50 GW by 2030.

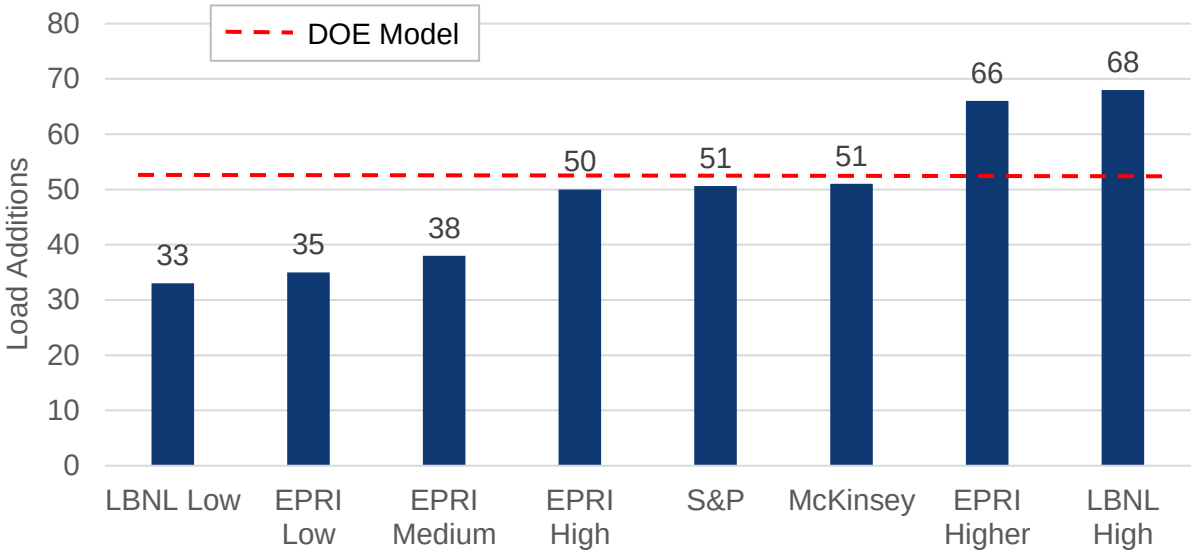


Figure 7. 2024 to 2030 Projected Data Center Load Additions

Figure 7 above displays a benchmark reflecting roughly the median across major studies and aligns with central projections from EPRI and LBNL. Using a single planning midpoint avoids double counting and enables consistent load allocation across national transmission and resource adequacy models. [Note: this figure was updated on October 27, 2025 to address a correction to the S&P projection.]

Data Center Allocation Method

To allocate the 50 GW midpoint regionally, the team used state-level growth ratios from S&P's forecast. These ratios reflect factors such as infrastructure, siting trends, and projected market activity. The modeling team mapped the state-level projections to NERC TPRs, ensuring transparent and repeatable regional allocation. While other methods exist, this approach ensured consistency with the broader modeling framework.

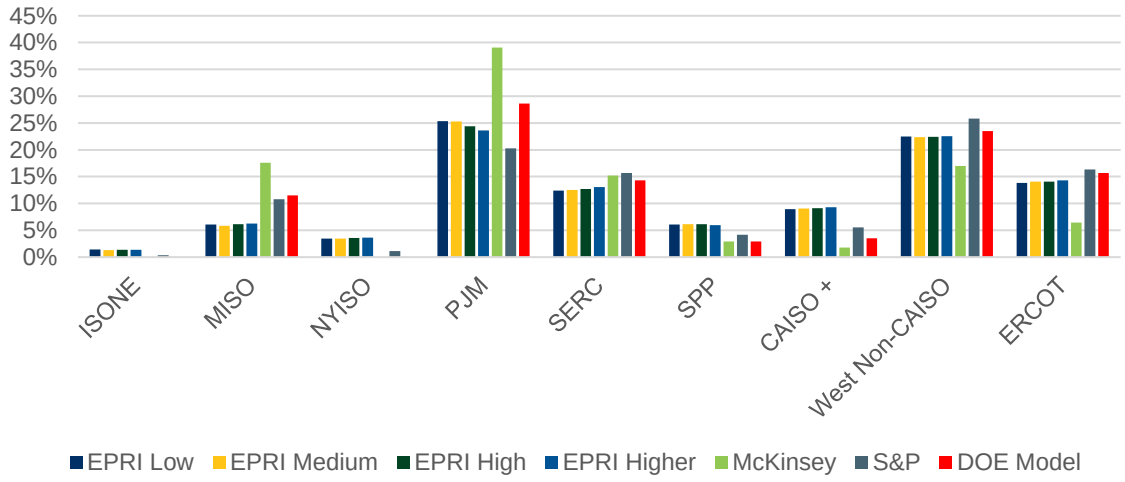


Figure 8. New Data Center Build (% Split by ISO/RTO) (2030 Estimated)

Non-Data Center Load Modeling

The current electricity demand projections were built from NERC data, using historical load (2019–2023) and simulated weather years (2007–2013). These were adjusted based on the EIA's 2022 energy forecast. To estimate 2030 demand, the team interpolated between 2024 and 2033, scaling loads to reflect energy use and seasonal peaks. NERC provided datasets to address anomalies and include behind-the-meter and USE.

Given the rapid emergence of AI/DC loads, additional steps were taken to account for this category of demand. It is difficult to determine how much AI/DC load is already embedded in NERC LTRA forecast, for example, the 2024 LTRA saw more than 50GW increase from 2023, signaling a major shift in utility expectations. To benchmark existing AI/DC contribution, DOE assumed base 2023 AI/DC load equaled the EPRI low-growth case of 166 TWh.

Overall Impact on Projected Peak Load

As a result of the methods applied above, the average year co-incident peak load is projected to grow from a current average peak of 774 GW to 889 GW in 2030. This represents a 15% increase or 2.3% growth rate per year. Excluding the impact of data centers, this would amount to a 51GW increase from 774 GW to 826 GW which represents a 1.1% annual growth rate.

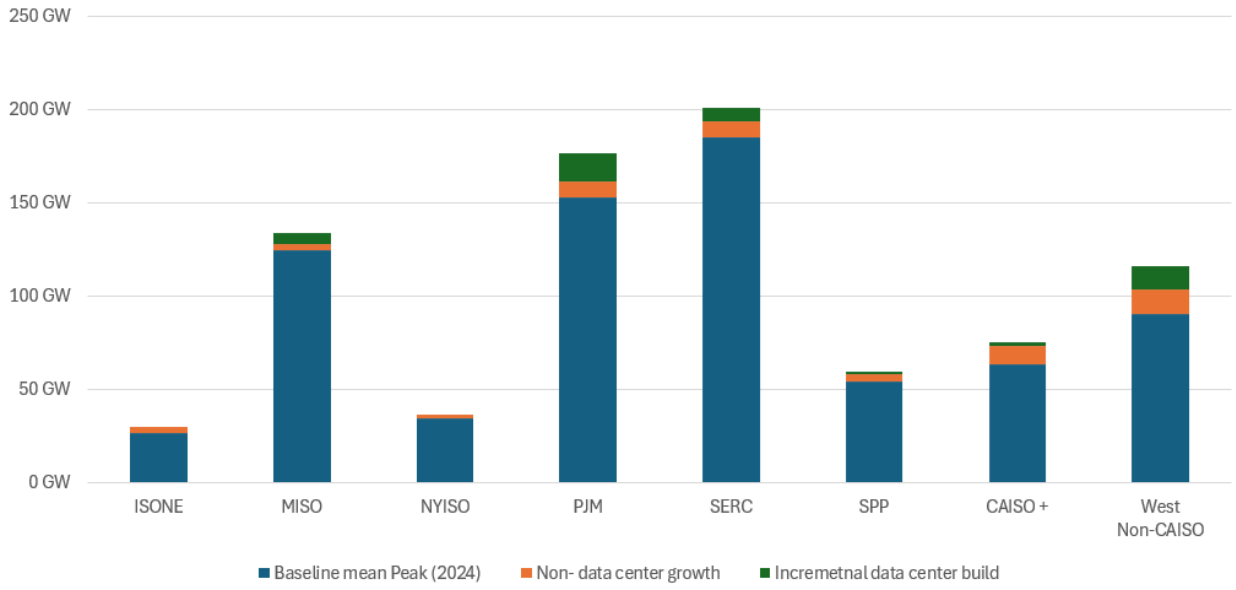


Figure 9. Mean Peak Load by RTO (Current Case vs 2030 Case)

1.4 Transfer Capabilities and Import Export Modeling

The methodology assumes electricity moves between subregions, when conditions start to tighten. Each region has a certain amount of capacity available, and the methodology determines if there is enough to meet the demand. When regions reach a “Tight Margin Level” of 10% of capacity, i.e., if a region’s available capacity is less than 110% of load, it will start transferring from other regions if capacity is available. A scarcity factor is used to determine which regions to transfer from and at what fraction – those with a greater amount of reserve capacity will transfer more. A region is only allowed to export above when it is above the Tight Margin Level.

Total Transfer Capability (TTC) was used and is the sum of the Base Transfer Level and the First Contingency Incremental Transfer Capability. These were derived from scheduled interchange tables or approximated from actual line flows. It should be noted that the TTC does not represent a single line, but rather multiple connections between regions. It is similar to path limits used by many entities but may have different values.

Due to data and privacy limitations, the Canadian power system was not modeled directly as a combination of generation capacity and demand. Instead, actual hourly imports were used from nearly 20 years of historical data, along with recent trends (generally less transfers available during peak hours), to develop daily limits on transfer capabilities. See Appendix B for more details on Canadian transfer limits.

1.5 Perfect Capacity Additions

To understand how much capacity may need to be added to reach approximate reliability targets, we tuned two scenarios by adding hypothetical perfect capacity to reach the reliability threshold based on NUSE.[22] Today, NERC uses a threshold of 0.002% to indicate regions are at high risk of resource adequacy shortfalls. In addition, several system operators, including the Australia Energy Market Operator and Alberta Electric System Operator, are using NUSE thresholds in the range of 0.001% to 0.003%. Several U.S. entities are considering lower thresholds for U.S. power systems in the range of 0.0001% to 0.0002%. [23]

For this analysis, we target NUSE below 0.002% for each region to align with NERC definitions. We iteratively ran the model, hand-tuning the "perfect capacity" to be as small as possible while reaching NUSE values below 0.002% in all regions.[24] As the work was done by hand with a limited number of iterations (15), this should not be considered the minimum possible capacity to accomplish these targets. Further, because the perfect capacity can be located in various places, there would be multiple potential solutions to the problem. These scenarios represent the approximate quantity of perfect capacity each region would require (beyond announced retirements and mature generation additions only) that would lead to Medium or Low risk based on the NERC metrics for USE.

Due to some regions with zero USE, the tuned cases do not reach the same level of adequacy, where the national average is 0.00045% vs. 0.00013%. Due to transmission and siting selection of perfect capacity, there could be many solutions.

22. We are not using the standard term "expected unserved energy" because we are not running a probabilistic model, so we do not have the full understanding of long-term expectations

23. MISO, "Resource Adequacy Metrics and Criteria Roadmap," December 2024. https://cdn.misoenergy.org/Resource%20Adequacy%20Metrics%20and%20Criteria%20Roadmap667168.pdf.

24. NERC, "Evolving Criteria for a Sustainable Power Grid," July 2024. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Evolving_Planning_Criteria_for_a_Sustainable_Power_Grid.pdf.

2 Regional Analysis

This section presents more regional details on resource adequacy according to this analysis. For each of the nine Regional Transmission Organizations (RTOs) and sub-regions, comprehensive summaries are provided of reliability metrics, load assumptions, and composition of generation stacks.

2.1 MISO[25]

In the current system model and the No Plant Closures cases, MISO did not experience shortfall events. MISO's minimum spare capacity in the tightest year was negative, showing that adequacy was achieved by importing power from neighbors. In the Plant Closures case, MISO experienced significant shortfalls, with key reliability metrics exceeding each of the threshold criteria defined for the study.

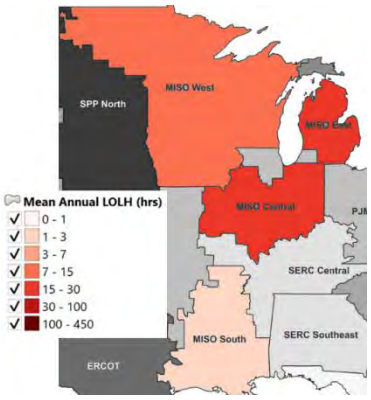


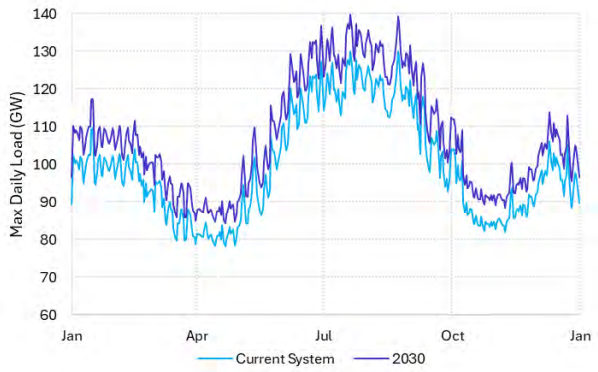
Table 2. Summary of MISO Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	37.8	-	-
Normalized Unserved Energy (%)	-	0.0211	-	-
Unserved Load (MWh)	-	157,599	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	124	-	-
Normalized Unserved Load (%)	-	0.0702	-	-
Unserved Load (MWh)	-	524,180	-	-

Load Assumptions

MISO's peak load was roughly 130 GW in the current model and projected to increase to roughly 140 GW by 2030. Approximately 6 GW of this relates to new data centers being installed (12% of U.S. total).

25. Following the initial data collection for this report, MISO issued its 2025 Summer Reliability Assessment. Based on that report, NERC revised evaluations from its 2024 LTRA and reclassified the MISO footprint from being an 'elevated risk' to 'high risk' in the 2028–2031 timeframe, depending on new resource additions/retirements. While DOE's analysis is based on the previously reported figures, DOE is committed to assessing the implications of updated data on overall resource adequacy and providing technical updates on findings, as appropriate.



Subregion	2024	2030
MISO-W	37,913	40,981
MISO-C	35,387	39,243
MISO-S	36,476	38,596
MISO-E	23,167	23,758
Total	**130,136**	**139,846**

Figure 10. MISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 207 GW.[26] In 2030, 21 GW of new capacity was added leading to 228 GW of capacity in the No Plant Closures case. In the Plant Closures case, 32 GW of capacity was retired such that net retirements in the Plant Closures case were -11 GW, or 196 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
MISO-W	71,612	67,453	77,605
MISO-C	51,982	47,735	58,823
MISO-S	54,511	52,756	59,710
MISO-E	29,213	28,105	32,255
Total	**207,319**	**196,049**	**228,393**

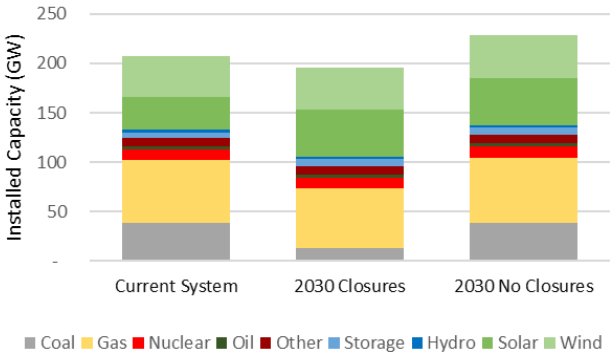


Figure 11. MISO Generation Capacity by Technology and Scenario

MISO's generation mix was comprised primarily of natural gas, coal, wind, and solar. In 2024, natural gas comprised 31% of nameplate, wind comprised 20%, coal 18%, and solar 14%. In 2030, most retirements come from coal and natural gas while additions occur for solar, batteries, and wind. In addition, the model assumed 3 GW of rooftop solar and 8 GW of demand response.

26. The total installed capacity numbers reported in this regional analysis section do not reflect the generating capability of all resources during stress conditions.

Table 3. Nameplate Capacity by MISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**37,914**	**64,194**	**11,127**	**2,867**	**8,717**	**5,427**	**2,533**	**32,826**	**41,715**	**207,319**
MISO-W	12,651	13,608	2,753	1,491	2,613	200	777	8,109	29,411	**71,612**
MISO-C	15,050	10,307	2,169	494	2,211	1,272	769	12,361	7,350	**51,982**
MISO-S	5,493	31,052	5,100	589	2,469	54	845	8,315	596	**54,511**
MISO-E	4,720	9,227	1,105	292	1,424	3,901	143	4,042	4,359	**29,213**
Additions	**0**	**2,535**	**0**	**330**	**0**	**1,929**	**0**	**14,354**	**1,926**	**21,074**
MISO-W	0	537	0	172	0	374	0	3,552	1,358	**5,993**
MISO-C	0	407	0	57	0	934	0	5,103	339	**6,841**
MISO-S	0	1,226	0	68	0	9	0	3,868	27	**5,199**
MISO-E	0	364	0	34	0	611	0	1,831	201	**3,042**
Closures	**(24,913)**	**(6,597)**	**0**	**(324)**	**(140)**	**(16)**	**(83)**	**0**	**(272)**	**(32,345)**
MISO-W	(8,313)	(1,398)	0	(168)	(56)	0	(25)	0	(192)	**(10,152)**
MISO-C	(9,889)	(1,059)	0	(56)	(7)	(3)	(25)	0	(48)	**(11,088)**
MISO-S	(3,609)	(3,191)	0	(67)	(55)	(0)	(28)	0	(4)	**(6,954)**
MISO-E	(3,102)	(948)	0	(33)	(21)	(13)	(5)	0	(28)	**(4,150)**

2.2 ISO-NE

In the current system model and the No Plant Closures case, ISO-NE did not experience shortfall events. The region maintained adequacy throughout the study period through reliance on imports. In the Plant Closures case, ISO-NE still did not exceed any key reliability thresholds, despite moderate retirements. This finding is partly due to the absence of additional AI or data center load growth modeled in the region. Accordingly, no additional perfect capacity was deemed necessary by 2030 to meet the study's reliability standards.

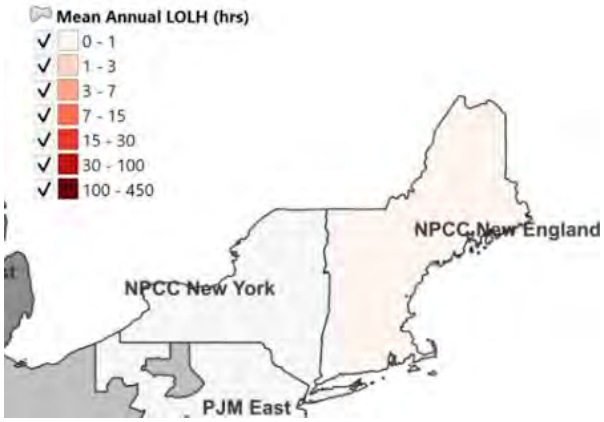
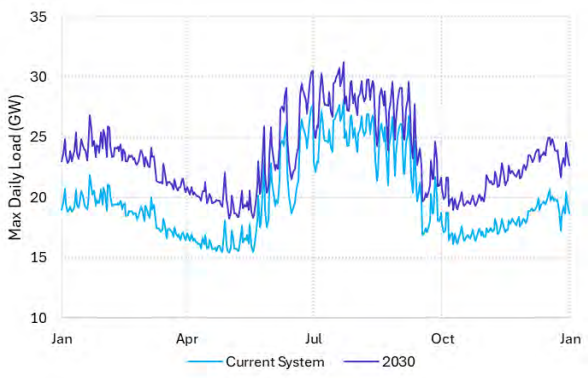


Table 4. Summary of ISO-NE Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	-	-	-
Normalized Unserved Energy (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	-	-	-
Normalized Unserved Load (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
Max Unserved Load (MW)	-	-	-	-

Load Assumptions

ISO-NE's peak load was roughly 28 GW in the current model and projected to increase to roughly 31 GW by 2030. No additional AI/DCs were projected to be installed.



Subregion	2024	2030
ISO-NE	28,128	31,261
Total	**28,128**	**31,261**

Figure 12. ISO-NE Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 40 GW. In 2030, 5.5 GW of new capacity was added leading to 45.5 GW of capacity in the No Plant Closures case. In the Plant Closures case, 2.7 GW of capacity was retired such that net generation change in the Plant Closures case was +11 GW, or 42.8 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ISO-NE	39,979	42,845	45,534
Total	**39,979**	**42,845**	**45,534**

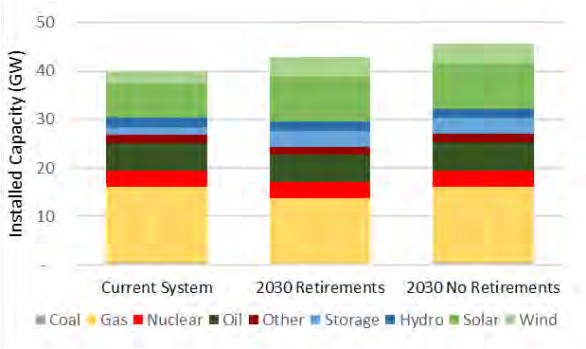


Figure 13. ISO-NE Generation Capacity by Technology and Scenario

ISO-NE's generation mix was comprised primarily of natural gas, solar, oil, and nuclear. In 2024, natural gas comprised 39% of nameplate, solar comprised 17%, oil 14%, and nuclear 8%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed nearly 2 GW of rooftop solar and 1.6 GW of energy storage.

Table 5. Nameplate Capacity by ISO-NE Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**541**	**15,494**	**3,331**	**5,710**	**1,712**	**1,628**	**1,911**	**7,099**	**2,553**	**39,979**
ISONE	541	15,494	3,331	5,710	1,712	1,628	1,911	7,099	2,553	**39,979**
Additions	**0**	**90**	**0**	**181**	**0**	**1,607**	**0**	**2,183**	**1,495**	**5,555**
ISONE	0	90	0	181	0	1,607	0	2,183	1,495	**5,555**
Closures	**(534)**	**(1,875)**	**0**	**(203)**	**(77)**	**0**	**0**	**0**	**0**	**(2,690)**
ISONE	(534)	(1,875)	0	(203)	(77)	0	0	0	0	**(2,690)**

2.3 NYISO

In both the current system model and the No Plant Closures case, NYISO maintained reliability and did not exceed any shortfall thresholds. Adequacy was preserved through reliance on imports. In the Plant Closures case, NYISO experienced shortfalls but average annual LOLH remaining well below the 2.4-hour threshold and NUSE under the 0.002% standard. The worst weather year produced only 6 hours of lost load and a peak unserved load of 914 MW. Given the modest impact of retirements and no additional AI/data center load modeled, the study concluded that NYISO would not require additional perfect capacity to remain reliable through 2030.

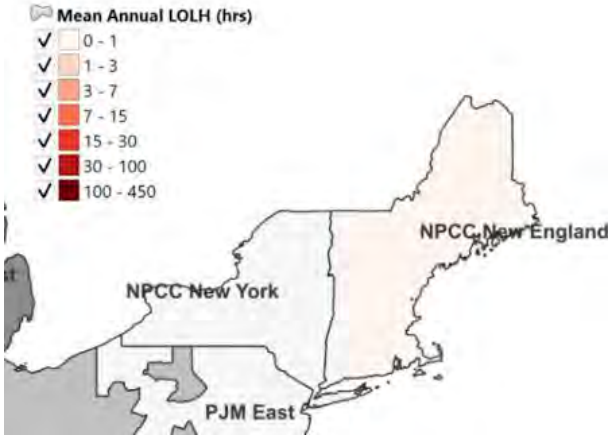
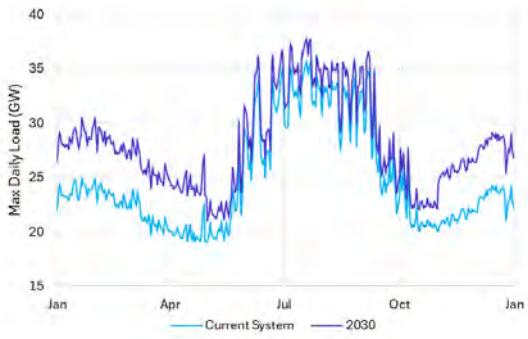


Table 6. Summary of NYISO Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.2	0.5	-	-
Normalized Unserved Energy (%)	0.00001	0.0001	-	-
Unserved Load (MWh)	18	209	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	2	6	-	-
Normalized Unserved Load (%)	0.0001	0.0013	-	-
Unserved Load (MWh)	216	2,505	-	-
Max Unserved Load (MW)	194	914	-	-

Load Assumptions

NYISO's peak load was roughly 36 GW in the current system model and projected to increase to roughly 38 GW by 2030. No additional AI/DCs were projected to be installed.



Subregion	2024	2030
NYISO	35,669	37,844
Total	**35,669**	**37,844**

Figure 14. NYISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 46 GW. In 2030, 5.5 GW of new capacity was added leading to 51 GW of capacity in the No Plant Closures case. In the Plant Closures case, 1 GW of capacity was retired such that net generation in the Plant Closures case was +4 GW, or 50 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
NYISO	45,924	50,396	51,444
Total	**45,924**	**50,396**	**51,444**

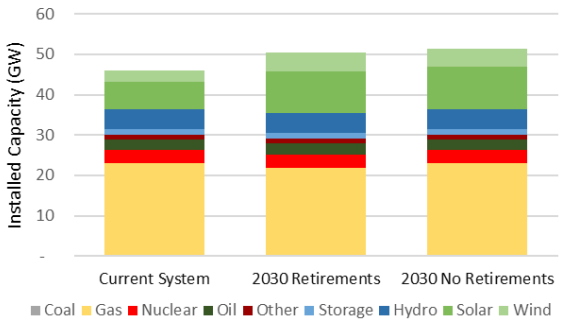


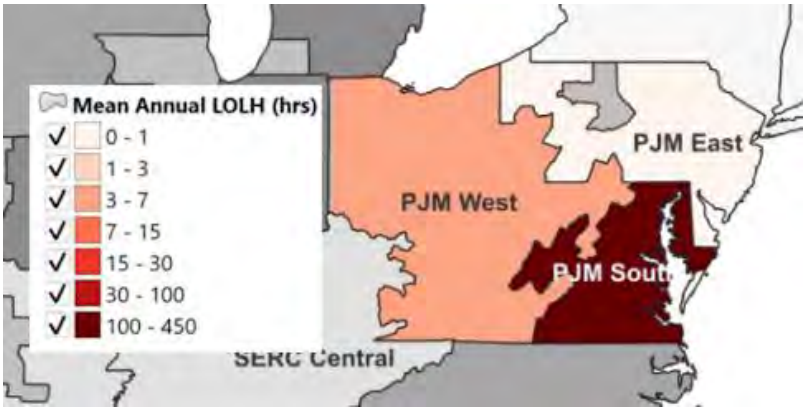
Figure 15. NYISO Generation Capacity by Technology and Scenario

NYISO's generation mix was comprised primarily of natural gas, solar, and hydro. In 2024, natural gas comprised 50% of total nameplate generation, solar comprised 14%, and hydro 11%. In 2030, most retirements come from natural gas while additions occur for solar and wind. The model assumed 6 GW of rooftop solar and nearly 1 GW of demand response.

Table 7. Nameplate Capacity by NYISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**0**	**22,937**	**3,330**	**2,631**	**1,194**	**1,460**	**4,915**	**6,749**	**2,706**	**45,924**
NYISO	0	22,937	3,330	2,631	1,194	1,460	4,915	6,749	2,706	**45,924**
Additions	**0**	**0**	**0**	**15**	**0**	**0**	**0**	**3,604**	**1,902**	**5,521**
NYISO	0	0	0	15	0	0	0	3,604	1,902	**5,521**
Closures	**0**	**(1,030)**	**0**	**(19)**	**0**	**0**	**0**	**0**	**0**	**(1,049)**
NYISO	0	(1,030)	0	(19)	0	0	0	0	0	**(1,049)**

2.4 PJM



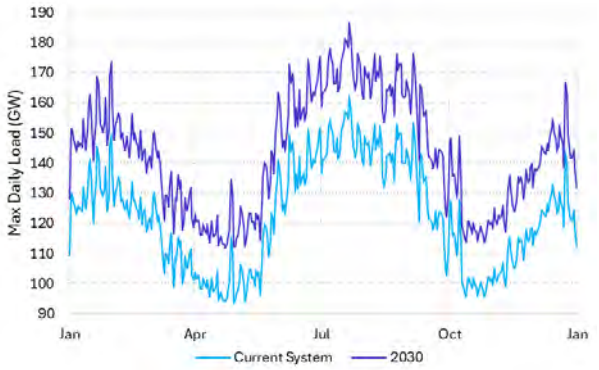
In the current system model, PJM experienced shortfalls, but they were below the required threshold. In the No Plant Closures case, shortfalls increased dramatically, with 214 average annual LOLH and peak unserved load reaching 17,620 MW, indicating growing strain even without retirements. In the Plant Closures case, reliability metrics worsened significantly, with annual LOLH surging to over 430 hours per year and NUSE reaching 0.1473%—over 70 times the accepted threshold. During the worst weather year, 1,052 hours of load were shed. To restore reliability, the study found that PJM would require 10,500 MW of additional perfect capacity by 2030.

Table 8. Summary of PJM Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	2.4	430.3	213.7	1.4
Normalized Unserved Energy (%)	0.0008	0.1473	0.0657	0.0003
Unserved Load (MWh)	6,891	1,453,513	647,893	2,536
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	29	1,052	644	17
Normalized Unserved Load (%)	0.0100	0.4580	0.2703	0.0031
Unserved Load (MWh)	82,687	1,453,513	647,893	2,536
Max Unserved Load (MW)	4,975	21,335	17,620	4,162

Load Assumptions

PJM's peak load was roughly 162 GW in the current system model and projected to increase to roughly 187 GW by 2030. Approximately 15 GW of this relates to new AI/DC being installed (29% of U.S. total), primarily in PJM-S.



Subregion	2024	2030
PJM-W	81,541	92,378
PJM-S	39,904	51,151
PJM-E	41,003	43,118
Total	**162,269**	**186,627**

Figure 16. PJM Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 215 GW. In 2030, 39 GW of new capacity was added leading to 254 GW of capacity in the No Plant Closures case. In the Plant Closures case, 17 GW of capacity was retired such that net generation in the Plant Closures case was +22 GW, or 237 GW of overall nameplate capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
PJM-W	114,467	123,100	135,810
PJM-S	39,951	48,850	50,667
PJM-E	60,221	64,848	67,027
Total	**214,638**	**236,798**	**253,504**

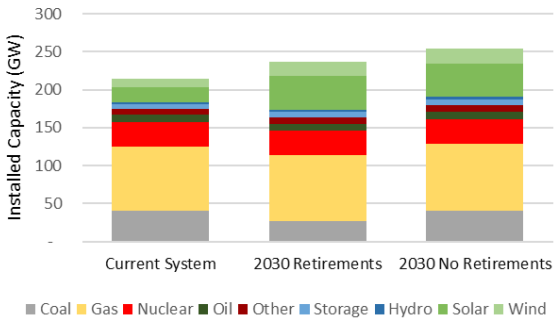


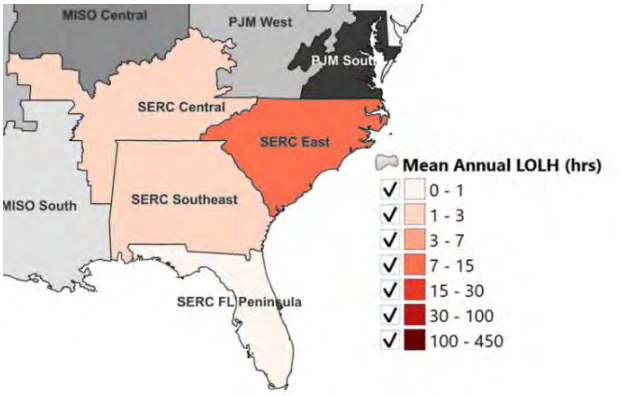
Figure 17. PJM Generation Capacity by Technology and Scenario

PJM's generation mix was comprised primarily of natural gas, coal, and nuclear. In 2024, natural gas comprised 39% of nameplate, coal comprised 19%, and nuclear 15%. In 2030, most retirements come from coal and some natural gas and oil while significant additions occur for solar plus lesser additions of wind, storage, and natural gas. The model assumed 9 GW of rooftop solar and 7 GW of demand response.

Table 9. Nameplate Capacity by PJM Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**39,915**	**84,381**	**32,535**	**9,875**	**8,248**	**5,400**	**3,071**	**19,495**	**11,718**	**214,638**
PJM-W	34,917	39,056	16,557	1,933	3,926	383	1,252	6,379	10,065	**114,467**
PJM-S	2,391	15,038	5,288	3,985	2,303	3,085	1,070	6,430	360	**39,951**
PJM-E	2,608	30,287	10,690	3,956	2,019	1,932	749	6,686	1,294	**60,221**
Additions	**0**	**4,499**	**0**	**32**	**317**	**1,938**	**0**	**24,991**	**7,089**	**38,866**
PJM-W	0	2,082	0	6	135	855	0	12,176	6,089	**21,343**
PJM-S	0	802	0	13	102	726	0	8,856	218	**10,717**
PJM-E	0	1,615	0	13	81	357	0	3,958	783	**6,806**
Closures	**(13,253)**	**(1,652)**	**0**	**(1,790)**	**(11)**	**0**	**0**	**0**	**0**	**(16,706)**
PJM-W	(11,593)	(765)	0	(350)	(1)	0	0	0	0	**(12,710)**
PJM-S	(794)	(294)	0	(722)	(6)	0	0	0	0	**(1,817)**
PJM-E	(866)	(593)	0	(717)	(3)	0	0	0	0	**(2,179)**

2.5 SERC



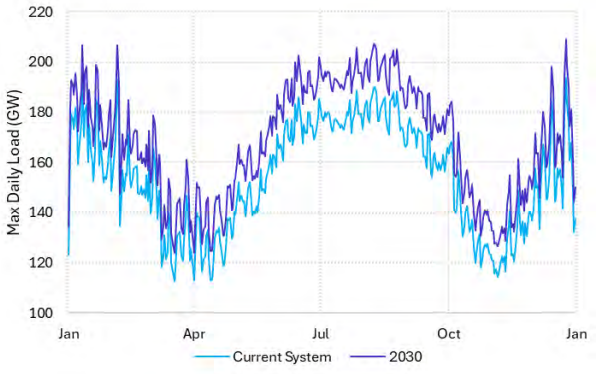
In the current system model and the No Plant Closures case, SERC maintained overall adequacy, though some subregions—particularly SERC-East—faced emerging winter reliability risks. In the Plant Closures case, shortfalls became more severe, with SERC-East experiencing increased unserved energy and loss of load hours during extreme cold events, including 42 hours of outages in a single winter storm. The analysis identified that planned retirements, combined with rising winter load from electrification, would stress the system. To restore reliability in SERC-East, the study found that 500 MW of additional perfect capacity would be needed by 2030. Other SERC subregions performed adequately, but continued monitoring is warranted due to shifting seasonal peaks and fuel supply vulnerabilities.

Table 10. Summary of SERC Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.3	8.1	1.2	0.8
Normalized Unserved Energy (%)	0.0001	0.0041	0.0004	0.0002
Unserved Load (MWh)	489	44,514	3,748	2,373
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	4	42	14	10
Normalized Unserved Load (%)	0.0006	0.0428	0.0042	0.0026
Unserved Load (MWh)	5,683	465,392	44,977	2,373
Max Unserved Load (MW)	2,373	19,381	6,359	5,859

Load Assumptions

SERC's peak load was roughly 193 GW in the current system model and projected to increase to roughly 209 GW by 2030. Approximately 7.5 GW of this relates to new AI/DCs being installed (14% of U.S. total).



Subregion	2024	2030
SERC-C	50,787	52,153
SERC-SE	48,235	54,174
SERC-FL	58,882	62,572
SERC-E	51,693	56,313
Total	**193,654**	**209,269**

Figure 18. SERC Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 254 GW. In 2030, 26 GW of new capacity was added leading to 279 GW of capacity in the No Plant Closures case. In the Plant Closures case, 19 GW of capacity was retired such that net generation change in the Plant Closures case was +7 GW, or 260 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SERC-C	53,978	54,014	59,660
SERC-SE	67,073	64,768	69,478
SERC-FL	72,714	83,127	86,173
SERC-E	59,914	58,513	63,973
Total	**253,680**	**260,423**	**279,285**

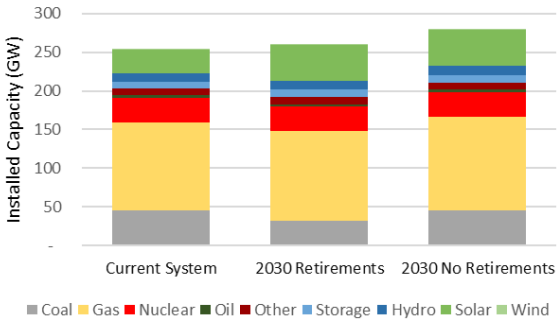


Figure 19. SERC Generation Capacity by Technology and Scenario

SERC's generation mix was comprised primarily of natural gas, coal, nuclear, and solar. In 2024, natural gas comprised 45% of nameplate, coal comprised 18%, nuclear 12%, and solar 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar and some storage. The model assumed 3 GW of rooftop solar and 8 GW of demand response.

Table 11. Nameplate Capacity by SERC Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**45,747**	**113,334**	**31,702**	**4,063**	**8,779**	**7,469**	**11,425**	**30,180**	**982**	**253,680**
SERC-C	13,348	20,127	8,280	148	1,887	1,884	4,995	2,328	982	**53,978**
SERC-SE	13,275	29,866	8,018	915	2,493	1,662	3,260	7,584	0	**67,073**
SERC-FL	4,346	47,002	3,502	1,957	3,198	538	0	12,172	0	**72,714**
SERC-E	14,777	16,340	11,902	1,044	1,202	3,384	3,170	8,096	0	**59,914**
Additions	**0**	**6,898**	**0**	**0**	**381**	**2,254**	**0**	**16,073**	**0**	**25,606**
SERC-C	0	4,831	0	0	0	80	0	771	0	**5,682**
SERC-SE	0	906	0	0	19	0	0	3,135	0	**4,059**
SERC-FL	0	1,161	0	0	218	1,670	0	10,410	0	**13,459**
SERC-E	0	0	0	0	144	504	0	1,757	0	**2,405**
Closures	**(14,075)**	**(4,115)**	**0**	**(672)**	**0**	**0**	**0**	**0**	**0**	**(18,862)**
SERC-C	(4,465)	(1,181)	0	0	0	0	0	0	0	**(5,646)**
SERC-SE	(5,160)	(124)	0	(176)	0	0	0	0	0	**(5,460)**
SERC-FL	(1,495)	(1,071)	0	(480)	0	0	0	0	0	**(3,046)**
SERC-E	(2,955)	(1,739)	0	(16)	0	0	0	0	0	**(4,710)**

2.6 SPP

In the current system model, SPP experienced shortfalls, but they were below the required threshold. Adequacy was preserved through reliance on imports. In the No Plant Closures case, SPP experienced persistent reliability challenges, with average annual LOLH reaching approximately 48 hours per year and peak hourly shortfalls affecting up to 19% of demand. In the Plant Closures case, system conditions deteriorated further, with unserved energy and outage hours increasing substantially. These shortfalls were concentrated in the northern subregion, which lacks the firm generation and import capacity needed to meet peak winter demand. The analysis determined that 1,500 MW of additional perfect capacity would be needed in SPP by 2030 to restore reliability.

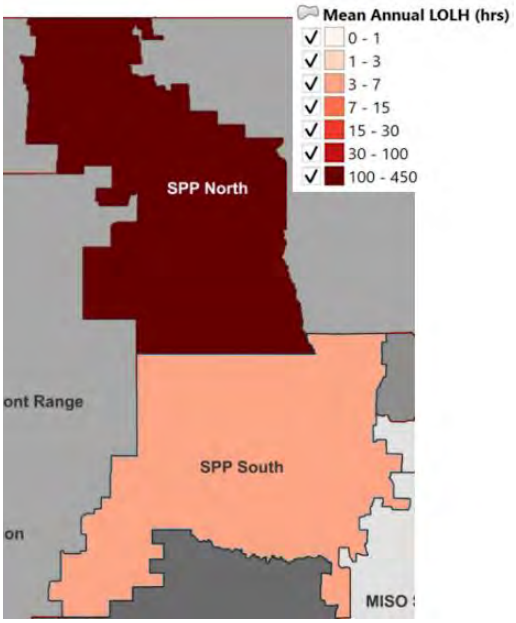
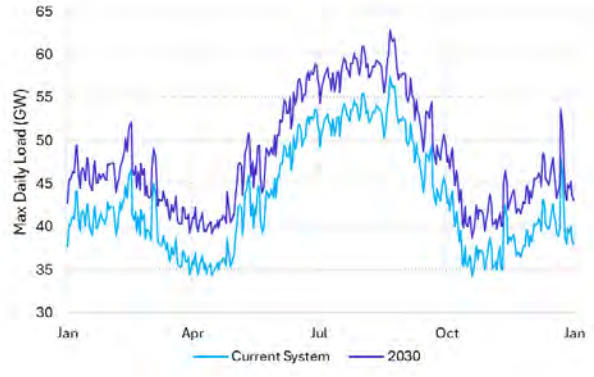


Table 12. Summary of SPP Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	1.7	379.6	47.8	2.4
Normalized Unserved Energy (%)	0.0002	0.0911	0.0081	0.0002
Unserved Load (MWh)	541	313,797	27,697	803
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	20	556	186	26
Normalized Unserved Load (%)	0.0022	0.2629	0.0475	0.0027
Unserved Load (MWh)	6,492	907,518	163,775	9,433
Max Unserved Load (MW)	606	13,263	2,432	762

Load Assumptions

SPP's peak load was roughly 57 GW in the current system model and projected to increase to roughly 63 GW by 2030. Approximately 1.5 GW of this relates to new AI/DCs being installed (3% of U.S. total).



Subregion	2024	2030
SPP-N	12,668	14,676
SPP-S	44,898	48,337
Total	**57,449**	**62,891**

Figure 20. SPP Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 95 GW. In 2030, 15 GW of new capacity was added leading to 110 GW of capacity in the No Plant Closures case. In the Plant Closures case, 7 GW of capacity was retired such that net generation change in the 2030 Plant Closures case was +8 GW, or 103 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SPP-N	20,065	20,679	22,385
SPP-S	75,078	82,451	88,064
Total	**95,142**	**103,130**	**110,449**

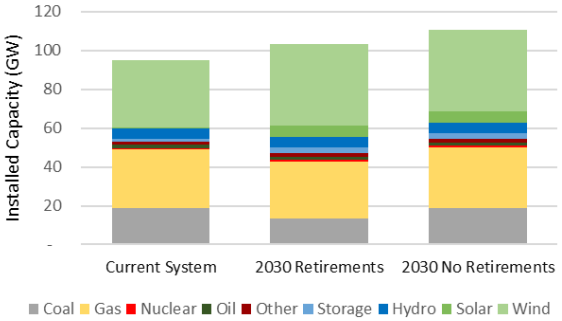


Figure 21. SPP Generation Capacity by Technology and Scenario

SPP's generation mix was comprised primarily of wind, natural gas, and coal. In 2024, wind comprised 36% of nameplate, natural gas comprised 32%, and coal 20%. In the 2030 case, most retirements come from coal and natural gas while additions occur for wind, solar, storage, and natural gas. The model assumed almost no rooftop solar and 1.3 GW of demand response.

Table 13. Nameplate Capacity by SPP Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**18,919**	**30,003**	**769**	**1,626**	**1,718**	**1,522**	**5,123**	**774**	**34,689**	**95,142**
SPP-N	5,089	3,467	304	504	519	8	3,041	91	7,041	**20,065**
SPP-S	13,829	26,536	465	1,121	1,199	1,514	2,082	683	27,649	**75,078**
Additions	**0**	**1,094**	**0**	**7**	**462**	**1,390**	**0**	**5,288**	**7,066**	**15,306**
SPP-N	0	126	0	2	114	11	0	633	1,434	**2,320**
SPP-S	0	968	0	5	348	1,379	0	4,655	5,632	**12,987**
Closures	**(5,530)**	**(1,732)**	**0**	**(56)**	**0**	**0**	**0**	**0**	**0**	**(7,318)**
SPP-N	(1,488)	(200)	0	(17)	0	0	0	0	0	**(1,705)**
SPP-S	(4,042)	(1,532)	0	(39)	0	0	0	0	0	**(5,613)**

2.7 CAISO+

In the current system and No Plant Closures cases, CAISO+ did not experience major reliability issues, though adequacy was often maintained through significant imports during tight conditions. In the Plant Closures case, however, the region faced substantial shortfalls, particularly during summer evening hours when solar output declines. Average LOLH reached 7 hours per year, and the worst-case year showed load shed events affecting up to 31% of demand. The NUSE exceeded reliability thresholds, signaling the system's vulnerability to high load and low renewable output periods.

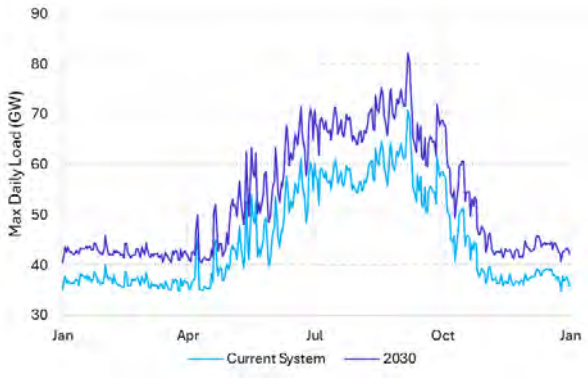


Table 14. Summary of CAISO+ Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	6.8	-	-
Normalized Unserved Energy (%)	-	0.0062	-	-
Unserved Load (MWh)	-	23,488	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	21	-	-
Normalized Unserved Load (%)	-	0.0195	-	-
Unserved Load (MWh)	-	73,462	-	-
Max Unserved Load (MW)	-	12,391	-	-

Load Assumptions

CAISO+'s peak load was roughly 79 GW in the current system model and projected to increase to roughly 82 GW by 2030. Approximately 2 GW of this relates to new AI/DCs being installed (4% of U.S. total).



Subregion	2024	2030
CALI-N	29,366	34,066
CALI-S	41,986	48,666
Total	**70,815**	**82,146**

Figure 22. CAISO+ Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 117 GW. In 2030, 14 GW of new capacity was added leading to 131 GW of capacity in the No Plant Closures case. In the Plant Closures case, 8 GW of capacity was retired such that net closures in the Plant Closures case were +6 GW, or 123 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
CALI-N	47,059	48,897	52,501
CALI-S	69,866	74,041	78,308
Total	**116,925**	**122,938**	**130,809**

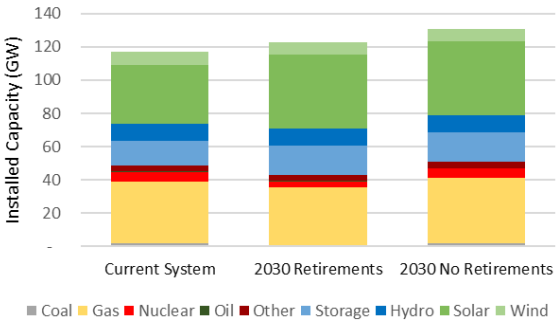


Figure 23. CAISO+ Generation Capacity by Technology and Scenario

CAISO+'s generation mix was comprised primarily of natural gas, solar, storage, and hydro. In 2024, natural gas comprised 32% of nameplate, solar comprised 31%, storage 13%, and hydro 9%. In 2030, most retirements come from coal, natural gas, and nuclear while additions occur for solar and storage. The model assumed 10 GW of rooftop solar and less than 1 GW of demand response.

Table 15. Nameplate Capacity by CAISO+ Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**1,816**	**37,434**	**5,582**	**185**	**3,594**	**14,670**	**10,211**	**35,661**	**7,773**	**116,925**
CALI-N	0	12,942	5,582	165	1,872	4,639	8,727	11,759	1,373	**47,059**
CALI-S	1,816	24,492	0	20	1,722	10,031	1,483	23,902	6,400	**69,866**
Additions	**0**	**2,126**	**0**	**0**	**92**	**3,161**	**0**	**8,507**	**0**	**13,885**
CALI-N	0	735	0	0	44	757	0	3,906	0	**5,442**
CALI-S	0	1,391	0	0	48	2,404	0	4,600	0	**8,442**
Closures	**(1,800)**	**(3,771)**	**(2,300)**	**0**	**0**	**0**	**0**	**0**	**0**	**(7,871)**
CALI-N	0	(1,304)	(2,300)	0	0	0	0	0	0	**(3,604)**
CALI-S	(1,800)	(2,467)	0	0	0	0	0	0	0	**(4,267)**

2.8 West Non-CAISO

In both the current system and No Plant Closures cases, the West Non-CAISO region maintained adequacy on average. In the Plant Closures case, the region's reliability declined, with annual LOLH increasing and peak shortfalls in the worst year affecting up to 20% of hourly load in some subregions. While overall NUSE normalized unserved energy remained just above the 0.002% threshold, specific areas, especially those with limited local resources and constrained transmission, exceeded acceptable risk levels. These reliability gaps were primarily driven by increasing reliance on variable energy resources without sufficient firm generation.

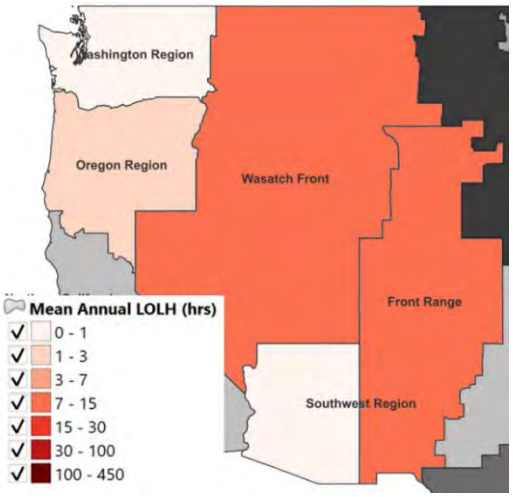
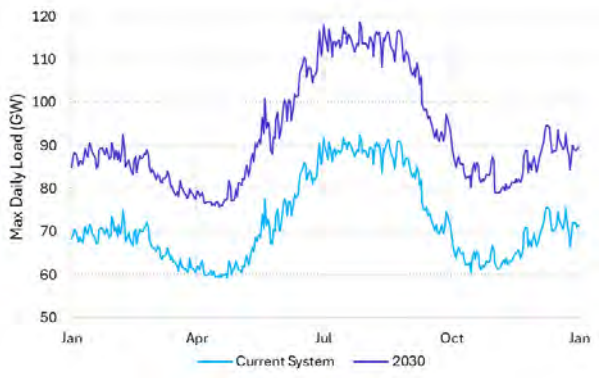


Table 16. Summary of West Non-CAISO Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	17.8	-	-
Normalized Unserved Energy (%)	-	0.0032	-	-
Unserved Load (MWh)	-	21,785	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	47	-	-
Normalized Unserved Load (%)	-	0.0098	-	-
Unserved Load (MWh)	-	66,248	-	-
Max Unserved Load (MW)	-	5,071	-	-

Load Assumptions

West Non-CAISO's peak load was roughly 92 GW in the current system model and projected to increase to roughly 119 GW by 2030. Approximately 12 GW of this relates to new AI/DCs being installed (24% of U.S. total).



Subregion	2024	2030
WASHINGTON	20,756	23,187
OREGON	11,337	16,080
SOUTHWEST	23,388	30,169
WASATCH	27,161	35,440
FRONT R	20,119	24,996
Total	**92,448**	**118,657**

Figure 24. West Non-CAISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 178 GW. In 2030, 29 GW of new capacity was added leading to 207 GW of capacity in the No Plant Closures case. In the Plant Closures case, 13 GW of capacity was retired such that net generation change in the Plant Closures case was 16 GW, or 193 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
WASHINGTON	35,207	36,588	37,573
OREGON	19,068	21,689	22,081
SOUTHWEST	42,335	47,022	49,158
WASATCH	42,746	45,175	50,251
FRONT R	38,572	43,011	47,844
Total	**177,929**	**193,485**	**206,908**

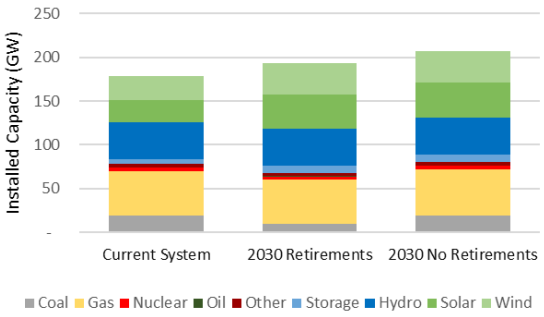


Figure 25. West Non-CAISO Generation Capacity by Technology and Scenario

West Non-CAISO's generation mix was comprised primarily of natural gas, hydro, wind, solar, and coal. In 2024, natural gas comprised 28% of nameplate, hydro comprised 24%, wind 15%, solar 13%, and coal 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar, wind, storage, and natural gas. The model assumed 6 GW of rooftop solar and over 1 GW of demand response.

Table 17. Nameplate Capacity by West Non-CAISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**19,850**	**49,969**	**3,820**	**644**	**4,114**	**5,104**	**42,476**	**24,652**	**27,298**	**177,929**
WASHINGTON	560	3,919	1,096	17	595	489	24,402	1,438	2,690	**35,207**
OREGON	0	3,915	0	6	456	482	8,253	2,517	3,440	**19,068**
SOUTHWEST	4,842	17,985	2,724	323	1,316	2,349	1,019	8,093	3,685	**42,335**
WASATCH	7,033	14,061	0	87	1,433	1,194	7,587	7,299	4,052	**42,746**
FRONT R	7,415	10,089	0	211	314	590	1,215	5,306	13,432	**38,572**
Additions	**0**	**2,320**	**0**	**1**	**8**	**2,932**	**0**	**14,759**	**8,959**	**28,979**
WASHINGTON	0	246	0	0	0	109	0	1,059	952	**2,366**
OREGON	0	246	0	0	0	150	0	1,399	1,218	**3,013**
SOUTHWEST	0	309	0	0	0	2,338	0	3,578	599	**6,823**
WASATCH	0	884	0	0	7	233	0	4,946	1,435	**7,505**
FRONT R	0	634	0	0	0	102	0	3,779	4,756	**9,271**
Closures	**(9,673)**	**(2,540)**	**0**	**(6)**	**(311)**	**(170)**	**(627)**	**0**	**(95)**	**(13,422)**
WASHINGTON	(317)	(195)	0	(0)	(66)	(28)	(369)	0	(11)	**(986)**
OREGON	0	(195)	0	(0)	(58)	0	(125)	0	(14)	**(392)**
SOUTHWEST	(1,185)	(951)	0	0	0	0	0	0	0	**(2,136)**
WASATCH	(3,978)	(699)	0	(2)	(178)	(89)	(115)	0	(16)	**(5,077)**
FRONT R	(4,194)	(501)	0	(4)	(8)	(53)	(18)	0	(54)	**(4,832)**

2.9 ERCOT

In the current system model, ERCOT exceeded reliability thresholds, with 3.8 annual Loss of Load Hours and a NUSE of 0.0032%, indicating stress even before future retirements and load growth. In the No Plant Closures case, conditions worsened as average LOLH rose to 20 hours per year and the worst-case year reached 101 hours, driven by data center growth and limited dispatchable additions. The Plant Closures case intensified these risks, with average annual LOLH rising to 45 hours per year and unserved load reaching 0.066%. Peak shortfalls reached 27% of demand, with outages concentrated in winter when generation is most vulnerable. To meet reliability targets, ERCOT would require 10,500 MW of additional perfect capacity by 2030.

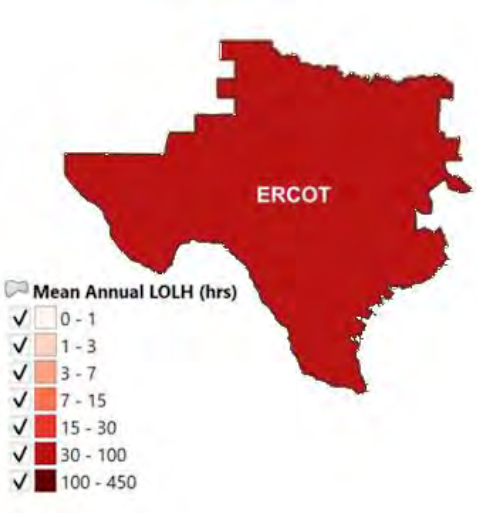
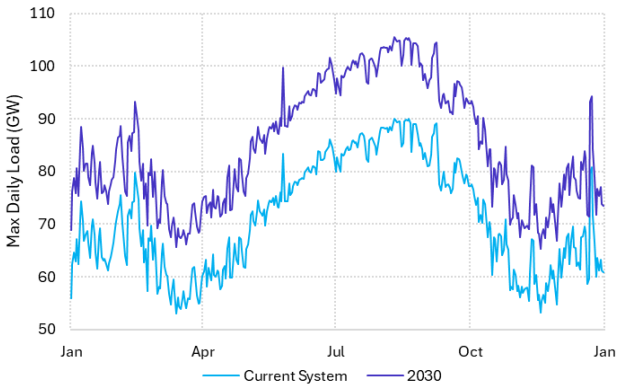


Table 18. Summary of ERCOT Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	3.8	45.0	20.3	1.0
Normalized Unserved Energy (%)	0.0032	0.0658	0.0284	0.0008
Unserved Load (MWh)	15,378	397,352	171,493	4,899
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	30	149	101	12
Normalized Unserved Load (%)	0.0286	0.02895	0.01820	0.0098
Unserved Load (MWh)	136,309	1,741,003	1,093,560	58,787
Max Unserved Load (MW)	10,115	27,156	23,105	8,202

Load Assumptions

ERCOT's peak load was roughly 90 GW in the current system model and projected to increase to roughly 105 GW by 2030. Approximately 8 GW of this relates to new data centers being installed (62% of U.S. total).



Subregion	2024	2030
ERCOT	90,075	105,485
Total	**90,075**	**105,485**

Figure 26. ERCOT Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 157 GW. In 2030, 55 GW of new capacity was added leading to 213 GW of capacity in the No Plant Closures case. In the Plant Closures case, 4 GW of capacity was retired such that net generation change in the Plant Closures case was +51 GW, or 208 GW of overall nameplate capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ERCOT	157,490	208,894	212,916
Total	**157,490**	**208,894**	**212,916**

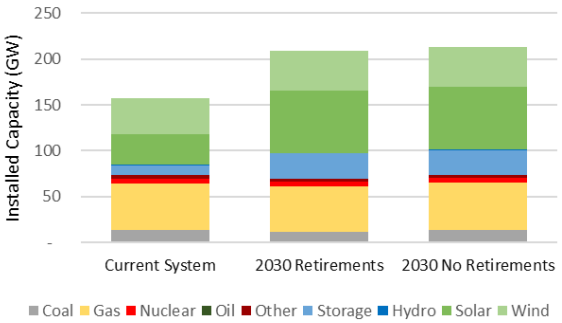


Figure 27. ERCOT Generation Capacity by Technology and Scenario

ERCOT's generation mix was comprised primarily of natural gas, wind, and solar. In 2024, natural gas comprised 32% of nameplate, wind comprised 25%, and solar 22%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed 2.5 GW of rooftop solar and 3.5 GW of demand response.

Table 19. Nameplate Capacity for ERCOT and by Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**13,568**	**50,889**	**4,973**	**10**	**3,627**	**10,720**	**583**	**33,589**	**39,532**	**157,490**
ERCOT	13,568	50,889	4,973	10	3,627	10,720	583	33,589	39,532	**157,490**
Additions	**0**	**569**	**0**	**0**	**0**	**16,538**	**0**	**34,681**	**3,638**	**55,426**
ERCOT	0	569	0	0	0	16,538	0	34,681	3,638	**55,426**
Closures	**(2,000)**	**(2,022)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(4,022)**
ERCOT	(2,000)	(2,022)	0	0	0	0	0	0	0	**(4,022)**

Appendix A - Generation Calibration and Forecast

The study team started with the grid model from the NERC ITCS, which was published in 2024 with reference to NERC 2023 LTRA capacity.[27] This zonal ITCS model serves as the starting point for the network topology (covering 23 U.S regions), transmission capacity between zones, and general modeling assumptions. The resource mix and retirements in the ITCS model were updated for this study to reflect the various 2030 scenarios discussed previously. Prior to developing the 2030 scenarios, the study team also updated the 2024 ITCS model to ensure consistency in the current model assumptions.

2024 Resource Mix

Because there were noted changes in assumed capacity additions between the 2023 and 2024 LTRAs[28], the ITCS model was updated with the 2024 LTRA data, provided directly by NERC to the study team. The 2024 LTRA dataset, reported at the NERC assessment area level—which is more aggregated in some areas than the ITCS regional structure (covering 13 U.S. regions; see Figure A.1)—includes both existing resource capacities[29] and Tier 1, 2, and 3 planned additions for each year from 2024 to 2033. As explained below, to incorporate this data into the ITCS model, a mapping process was developed to disaggregate generation capacities from the NERC assessment areas to the more granular ITCS regions by technology type. To preserve the daily or monthly adjustments to generator availability for certain categories (wind, solar, hybrid, hydropower, batteries, and other) by using the ITCS methods, the nameplate LTRA capacity was used. For all other categories (mostly thermal generators), summer and winter on-peak capacity contributions were used.

27. NERC, “Interregional Transfer Capability Study (ITCS).” https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf.

28. NERC, “2024 Long-Term Reliability Assessment,” December, 2024, 24. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

29. Capacities are reported for both winter and summer seasonal ratings, along with nameplate values.

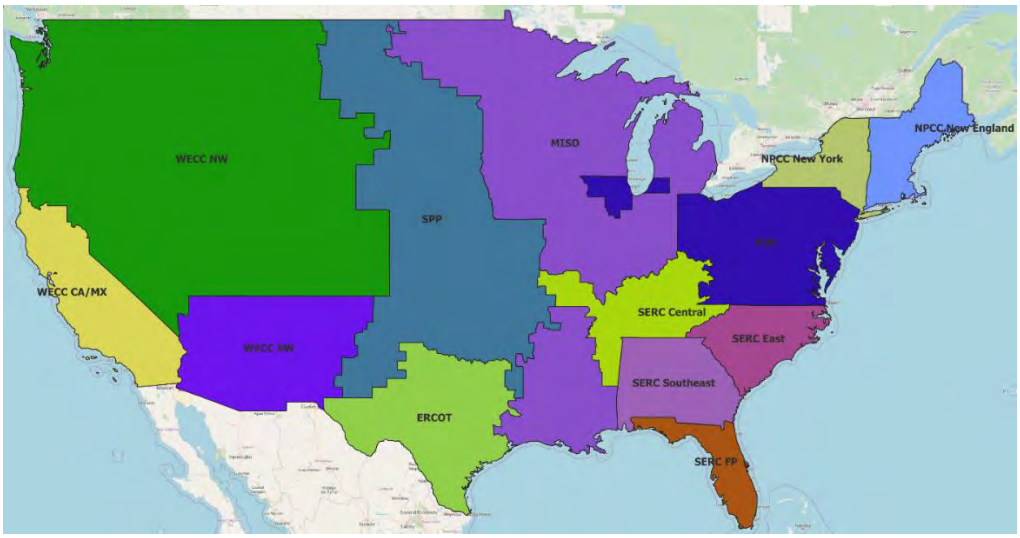


Figure A.1. NERC assessment areas.

To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant-level data were used to tabulate the generation capacity for each ITCS region and NERC assessment area. The geographical boundaries for the NERC assessment areas and the ITCS regions were constructed based on ReEDS zones.[30] Disaggregation fractions were then calculated by technology type using the combined existing capacity and planned additions through 2030 from EIA 860 data as of December 2024. Specifically, to compute each fraction, an ITCS region's total (existing plus planned) capacity was divided by the corresponding total capacity across all ITCS regions within the same mapped NERC assessment area and fuel type group:

$$Fraction_{rf} = \frac{Capacity_{rf}}{\sum_{r' \in ITCS(R)} Capacity_{r'f}} \qquad \textit{(Equation.1)}$$

Where $Capacity_{rf}$ is the capacity of fuel type f in ITCS region r and $ITCS(R)$ is the set of all ITCS regions mapped to the same NERC assessment area R. The denominator is the total capacity of that fuel type across all ITCS regions mapped to R.

Note that in cases where NERC assessment areas align one-to-one with ITCS regions, no mapping was required. Table A.1 summarizes which areas exhibited a direct one-to-one matching and which required disaggregation (1-to-many) or aggregation (many-to-one) to align with the ITCS regional structure.

An exception to this general approach is the case of the Front Range ITCS region, which geographically spans across two NERC assessment areas—WECC-NW and WECC-SW—resulting in two-to-one mapping. For this case, a separate allocation method was used: Plant-level data from EIA 860 were analyzed to determine the proportion of Front Range capacity located in each NERC area. These proportions were then used to derive custom weighting factors for allocating capacities from both WECC-NW and WECC-SW into the Front Range region.

30. NREL, "Regional Energy Development System," https://www.nrel.gov/analysis/reeds/.

Table A.1. Mapping of NERC assessment areas to ITCS regions.

NERC Area	ITCS Region	Match
ERCOT	ERCOT	1 to 1
NPCC-New England	NPCC-New England	1 to 1
NPCC-New York	NPCC-New York	1 to 1
SERC-C	SERC-C	1 to 1
SERC-E	SERC-E	1 to 1
SERC-FP	SERC-FP	1 to 1
SERC-SE	SERC-SE	1 to 1
WECC-SW	Southwest Region	1 to 1
MISO	MISO Central	1 to 4
MISO	MISO East	
MISO	MISO South	
MISO	MISO West	
SPP	SPP North	1 to 2
SPP	SPP South	
WECC-CAMX	Southern California	1 to 2
WECC-CAMX	Northern California	
WECC-NW	Oregon Region	1 to 3
WECC-NW	Washington Region	
WECC-NW	Wasatch Front	
WECC-NW	Front Range	2 to 1
WECC-SW	Front Range	

Table A.2 and Figure A.2 show the same combined capacities by ITCS region and NERC planning region, respectively.

Table A.2. Existing and Tier 1 capacities by NERC assessment area (in MW) in 2024.

2024 Exsting + Tier 1			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**143,035**	**330,342**	**82,793**	**26,771**	**3,624**	**-**	**991**	**19,607**	**3,298**	**28,980**	**72,757**	**94,364**	**25,753**	**24,367**	**856,682**
	ISONE	**Total**	541	15,494	3,331	5,710	818	-	233	1,571	57	1,911	3,386	2,553	661	3,713	39,979
	MISO	**Total**	**37,914**	**64,194**	**11,127**	**2,867**	**613**	**-**	**329**	**4,396**	**1,031**	**2,533**	**29,777**	**41,715**	**7,775**	**3,049**	**207,319**
		MISO-W	12,651	13,608	2,753	1,491	244	-	2	-	200	777	7,368	29,411	2,367	741	71,612
		MISO-C	15,050	10,307	2,169	494	32	-	152	773	499	769	10,587	7,350	2,026	1,774	51,982
		MISO-S	5,493	31,052	5,100	589	243	-	117	49	5	845	8,024	596	2,109	291	54,511
		MISO-E	4,720	9,227	1,105	292	94	-	57	3,574	327	143	3,799	4,359	1,273	243	29,213
	NYISO	**Total**	-	22,937	3,330	2,631	334	-	-	1,400	60	4,915	1,039	2,706	860	5,710	45,924
	PJM	**Total**	**39,915**	**84,381**	**32,535**	**9,875**	**851**	**-**	**-**	**5,062**	**338**	**3,071**	**10,892**	**11,718**	**7,397**	**8,603**	**214,638**
		PJM-W	34,917	39,056	16,557	1,933	112	-	-	234	149	1,252	5,780	10,065	3,814	599	114,467
		PJM-S	2,391	15,038	5,288	3,985	479	-	-	2,958	127	1,070	3,932	360	1,824	2,498	39,951
		PJM-E	2,608	30,287	10,690	3,956	260	-	-	1,870	62	749	1,180	1,294	1,759	5,506	60,221
	SERC	**Total**	**45,747**	**113,334**	**31,702**	**4,063**	**989**	**-**	**83**	**6,701**	**768**	**11,425**	**26,959**	**982**	**7,707**	**3,221**	**253,680**
		SERC-C	13,348	20,127	8,280	148	36	-	-	1,784	100	4,995	2,308	982	1,851	20	53,978
		SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	115	3,260	7,267	-	2,069	317	67,073
		SERC-FL	4,346	47,002	3,502	1,957	310	-	83	-	538	-	10,121	-	2,804	2,051	72,714
		SERC-E	14,777	16,340	11,902	1,044	219	-	-	3,369	15	3,170	7,263	-	983	833	59,914
	SPP	**Total**	**18,919**	**30,003**	**769**	**1,626**	**20**	**-**	**345**	**477**	**1,044**	**5,123**	**703**	**34,689**	**1,353**	**71**	**95,142**
		SPP-N	5,089	3,467	304	504	1	-	185	-	8	3,041	84	7,041	333	7	20,065
		SPP-S	13,829	26,536	465	1,121	19	-	160	477	1,037	2,082	619	27,649	1,020	64	75,078
ERCOT	**Total**		**13,568**	**50,889**	**4,973**	**10**	**163**	**-**	**-**	**-**	**10,720**	**583**	**31,058**	**39,532**	**3,464**	**2,531**	**157,490**
	ERCOT	**Total**	13,568	50,889	4,973	10	163	-	-	-	10,720	583	31,058	39,532	3,464	2,531	157,490
WEST	**Total**		**21,666**	**87,403**	**9,403**	**829**	**1,565**	**4,093**	**106**	**4,536**	**15,238**	**52,687**	**44,042**	**35,071**	**1,944**	**16,271**	**294,854**
	CAISO+	**Total**	**1,816**	**37,434**	**5,582**	**185**	**726**	**2,004**	**35**	**3,514**	**11,156**	**10,211**	**25,614**	**7,773**	**829**	**10,047**	**116,925**
		CALI-N	-	12,942	5,582	165	465	1,049	9	1,967	2,672	8,727	6,723	1,373	349	5,036	47,059
		CALI-S	1,816	24,492	-	20	261	955	26	1,547	8,484	1,483	18,891	6,400	480	5,011	69,866
	Non-CA WECC	**Total**	**19,850**	**49,969**	**3,820**	**644**	**839**	**2,089**	**71**	**1,022**	**4,082**	**42,476**	**18,428**	**27,298**	**1,115**	**6,224**	**177,929**
		WA	560	3,919	1,096	17	352	-	-	140	350	24,402	1,052	2,690	243	386	35,207
		OR	-	3,915	-	6	293	21	-	-	482	8,253	2,145	3,440	141	372	19,068
		SOUTHWEST	4,842	17,985	2,724	323	102	1,047	-	176	2,173	1,019	5,641	3,685	168	2,452	42,335
		WASATCH	7,033	14,061	-	87	56	1,011	61	444	750	7,587	5,625	4,052	305	1,674	42,746
		FRONT R	7,415	10,089	-	211	36	10	10	262	328	1,215	3,966	13,432	258	1,340	38,572
		Total	**178,268**	**468,635**	**97,169**	**27,610**	**5,353**	**4,093**	**1,096**	**24,144**	**29,256**	**82,249**	**147,856**	**168,966**	**31,161**	**43,169**	**1,309,026**

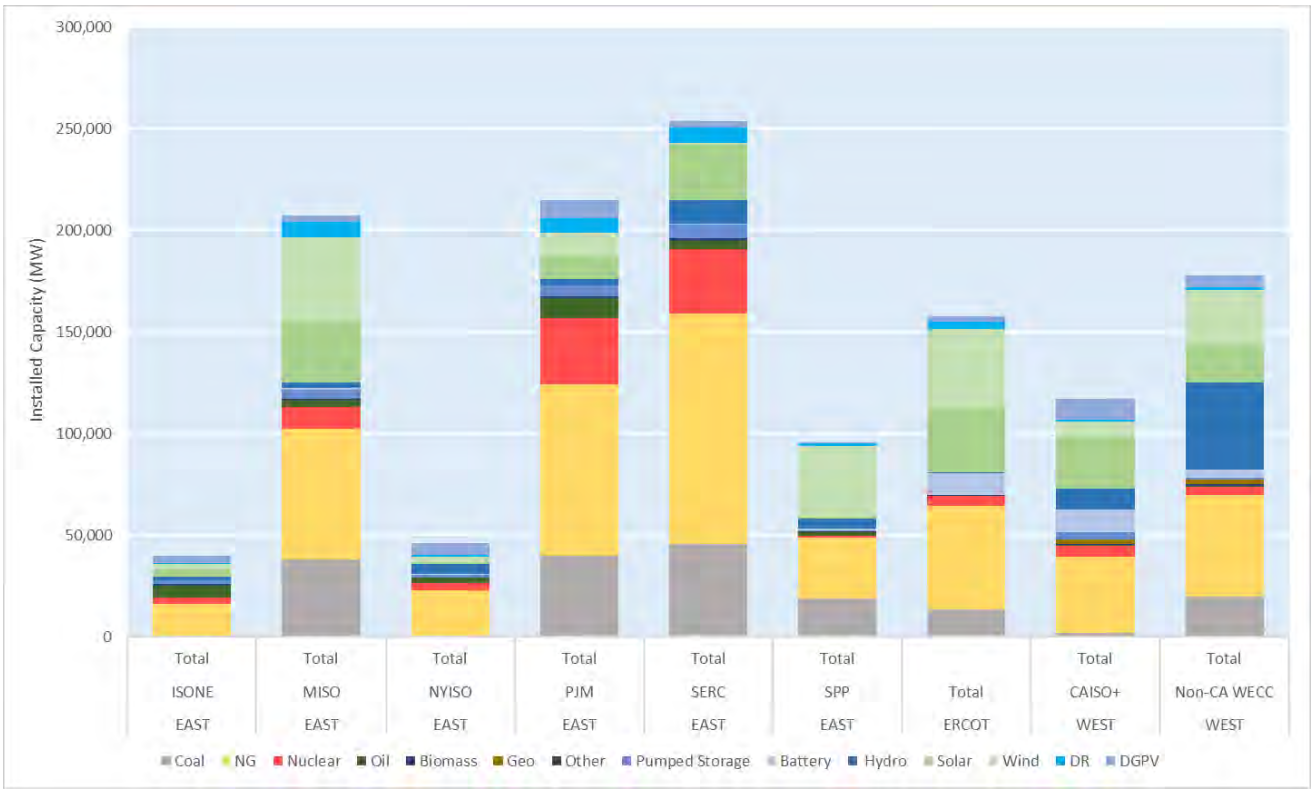


Figure A.2. Existing and Tier 1 capacities by NERC assessment area in 2024.

Forecasting 2030 Resource Mixes

To develop the 2030 ITCS generation portfolio, the study team added new capacity builds and removed planned retirements.

(i) *Tier 1*: Assumes that only projects considered very mature in the development pipeline—such as those with signed interconnection agreements—will be built. This results in minimal capacity additions beyond 2026. The data are based on projects designated as Tier 1 in the 2024 LTRA data for the year 2030.

Retirements

To project which units will retire by 2030, the study team primarily used the LTRA 2024 data and cross-checked it with EIA data. The assessment areas were disaggregated to ITCS zones based on the ratios of projected retirements in EIA 860 data. The three scenarios modeled are as follows:

(i) *Announced*: Assumes that in addition to confirmed retirements, generators that have publicly announced retirement plans but have not formally notified system operators have also begun the retirement process. This is based on data from the 2024 LTRA, which were collected by the NERC team from sources like news announcements, public disclosures, etc.

(ii) *None*: Assumes that there are no retirements between 2024 and 2030 for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirements contribute to resource adequacy challenges in regions where rapid AI and data center growth is expected.

Generation Stack for Each Scenario

Finally, when summing all potential future changes, the team arrived at a generation stack for each of the various scenarios to be studied. The first figure provides a visual comparison of all the cases, which vary from 1,309 GW to 1,519 GW total generation capacity for the entire continental United States, to enable the exploration of a range of potential generation futures. The tables below provide breakdowns by ITCS region and by resource type.

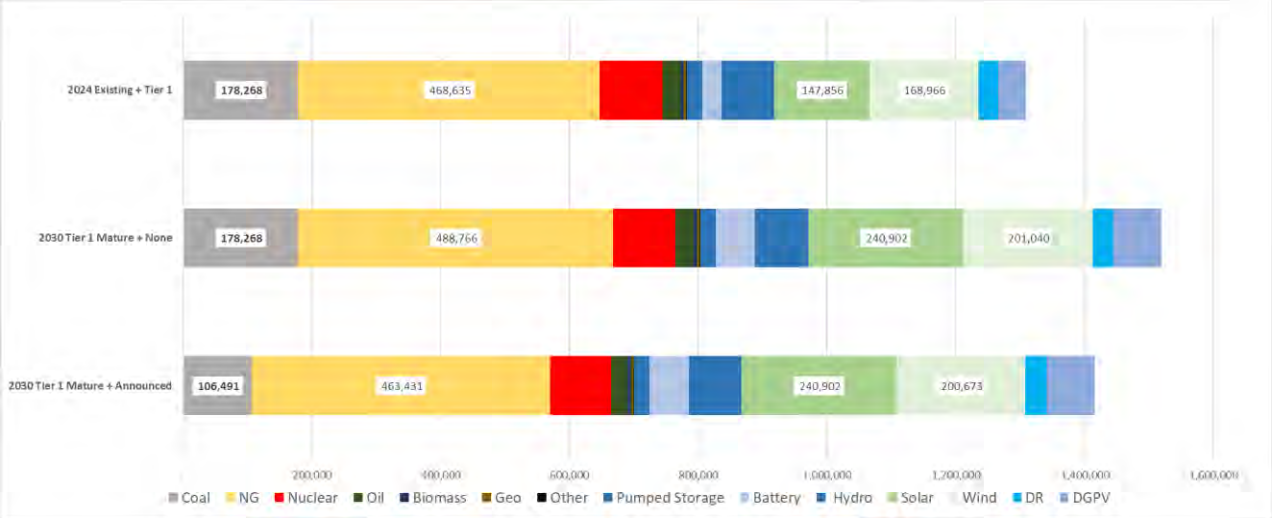


Figure A.9. Comparison of 2030 generation stacks for the various scenarios.

Table A.4. 2030 generation stack for Tier 1 mature + announced retirements.

2030 Tier 1 Mature + Announced			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**84,730**	**328,457**	**82,793**	**24,272**	**3,473**	**-**	**991**	**19,591**	**12,415**	**28,897**	**126,849**	**113,568**	**26,837**	**36,768**	**889,641**
	ISONE	**Total**	7	13,708	3,331	5,687	741	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	42,845
	MISO	**Total**	**13,001**	**60,132**	**11,127**	**2,873**	**473**	**-**	**329**	**4,380**	**2,960**	**2,450**	**44,132**	**43,369**	**7,775**	**3,049**	**196,049**
		MISO-W	4,338	12,747	2,753	1,494	188	-	2	-	574	751	10,920	30,577	2,367	741	67,453
		MISO-C	5,161	9,655	2,169	495	25	-	152	770	1,433	743	15,690	7,642	2,026	1,774	47,735
		MISO-S	1,883	29,087	5,100	591	187	-	117	49	14	817	11,892	619	2,109	291	52,756
		MISO-E	1,619	8,643	1,105	293	72	-	57	3,561	938	138	5,630	4,531	1,273	243	28,105
	NYISO	**Total**	-	21,907	3,330	2,628	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	50,396
	PJM	**Total**	**26,662**	**87,228**	**32,535**	**8,117**	**917**	**-**	**-**	**5,062**	**2,276**	**3,071**	**33,530**	**18,807**	**7,638**	**10,955**	**236,798**
		PJM-W	23,323	40,373	16,557	1,589	120	-	-	234	1,004	1,252	17,793	16,153	3,939	762	123,100
		PJM-S	1,597	15,546	5,288	3,276	516	-	-	2,958	853	1,070	12,105	577	1,883	3,181	48,850
		PJM-E	1,742	31,309	10,690	3,252	280	-	-	1,870	419	749	3,632	2,076	1,816	7,012	64,848
	SERC	**Total**	**31,672**	**116,117**	**31,702**	**3,391**	**989**	**-**	**83**	**6,701**	**3,021**	**11,425**	**38,360**	**982**	**8,088**	**7,893**	**260,423**
		SERC-C	8,883	23,777	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	54,014
		SERC-SE	10,321	28,127	8,018	899	424	-	-	1,548	618	3,260	9,024	-	2,213	317	64,768
		SERC-FL	2,851	47,092	3,502	1,477	310	-	83	-	2,208	-	16,717	-	3,022	5,865	83,127
		SERC-E	9,617	17,122	11,902	868	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	58,513
	SPP	**Total**	**13,389**	**29,365**	**769**	**1,576**	**20**	**-**	**345**	**477**	**2,434**	**5,123**	**5,991**	**41,755**	**1,815**	**71**	**103,130**
		SPP-N	3,602	3,394	304	489	1	-	185	-	18	3,041	717	8,475	447	7	20,679
		SPP-S	9,787	25,971	465	1,087	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	82,451
ERCOT	**Total**		**11,568**	**49,436**	**4,973**	**10**	**163**	**-**	**-**	**-**	**27,258**	**583**	**62,406**	**43,169**	**3,464**	**5,864**	**208,894**
	ERCOT	**Total**	11,568	49,436	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	208,894
WEST	**Total**		**10,193**	**85,538**	**7,103**	**823**	**1,427**	**3,983**	**106**	**4,366**	**21,330**	**52,060**	**51,648**	**43,935**	**1,981**	**31,931**	**316,424**
	CAISO+	**Total**	**16**	**35,789**	**3,282**	**185**	**726**	**2,059**	**35**	**3,514**	**14,316**	**10,211**	**27,112**	**7,773**	**866**	**17,055**	**122,938**
		CALI-N	-	12,373	3,282	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	48,897
		CALI-S	16	23,416	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	74,041
	Non-CA WECC	**Total**	**10,177**	**49,749**	**3,820**	**639**	**701**	**1,924**	**71**	**852**	**7,014**	**41,849**	**24,536**	**36,162**	**1,115**	**14,876**	**193,485**
		WA	243	3,971	1,096	16	286	-	-	111	459	24,033	1,404	3,631	243	1,092	36,588
		OR	-	3,967	-	6	238	18	-	-	632	8,128	2,865	4,644	141	1,051	21,689
		SOUTHWEST	3,657	17,343	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	47,022
		WASATCH	3,055	14,247	-	86	45	850	61	355	983	7,472	7,512	5,470	305	4,733	45,175
		FRONT R	3,221	10,222	-	208	30	8	10	209	430	1,197	5,296	18,133	258	3,789	43,011
		Total	**106,491**	**463,431**	**94,869**	**25,106**	**5,063**	**3,983**	**1,096**	**23,958**	**61,003**	**81,539**	**240,902**	**200,673**	**32,282**	**74,563**	**1,414,959**

Table A.5. 2030 generation stack for Tier 1 mature + no retirements.

2030 Tier 1 Mature + No Retirements			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**143,035**	**345,459**	**82,793**	**27,336**	**3,701**	**-**	**991**	**19,607**	**12,415**	**28,980**	**126,849**	**113,840**	**26,837**	**36,768**	**968,610**
	ISONE	**Total**	541	15,584	3,331	5,891	818	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	45,534
	MISO	**Total**	**37,914**	**66,729**	**11,127**	**3,197**	**613**	**-**	**329**	**4,396**	**2,960**	**2,533**	**44,132**	**43,641**	**7,775**	**3,049**	**228,393**
		MISO-W	12,651	14,145	2,753	1,662	244	-	2	-	574	777	10,920	30,768	2,367	741	77,605
		MISO-C	15,050	10,714	2,169	551	32	-	152	773	1,433	769	15,690	7,690	2,026	1,774	58,823
		MISO-S	5,493	32,278	5,100	657	243	-	117	49	14	845	11,892	623	2,109	291	59,710
		MISO-E	4,720	9,592	1,105	326	94	-	57	3,574	938	143	5,630	4,560	1,273	243	32,255
	NYISO	**Total**	-	22,937	3,330	2,646	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	51,444
	PJM	**Total**	**39,915**	**88,880**	**32,535**	**9,907**	**928**	**-**	**-**	**5,062**	**2,276**	**3,071**	**33,530**	**18,807**	**7,638**	**10,955**	**253,504**
		PJM-W	34,917	41,138	16,557	1,939	122	-	-	234	1,004	1,252	17,793	16,153	3,939	762	135,810
		PJM-S	2,391	15,840	5,288	3,998	522	-	-	2,958	853	1,070	12,105	577	1,883	3,181	50,667
		PJM-E	2,608	31,902	10,690	3,969	284	-	-	1,870	419	749	3,632	2,076	1,816	7,012	67,027
	SERC	**Total**	**45,747**	**120,232**	**31,702**	**4,063**	**989**	**-**	**83**	**6,701**	**3,021**	**11,425**	**38,360**	**982**	**8,088**	**7,893**	**279,285**
		SERC-C	13,348	24,958	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	59,660
		SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	618	3,260	9,024	-	2,213	317	69,478
		SERC-FL	4,346	48,163	3,502	1,957	310	-	83	-	2,208	-	16,717	-	3,022	5,865	86,173
		SERC-E	14,777	17,246	11,902	1,044	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	63,973
	SPP	**Total**	**18,919**	**31,098**	**769**	**1,632**	**20**	**-**	**345**	**477**	**2,434**	**5,123**	**5,991**	**41,755**	**1,815**	**71**	**110,449**
		SPP-N	5,089	3,594	304	506	1	-	185	-	18	3,041	717	8,475	447	7	22,385
		SPP-S	13,829	27,504	465	1,126	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	88,064
ERCOT	**Total**		**13,568**	**51,458**	**4,973**	**10**	**163**	**-**	**-**	**-**	**27,258**	**583**	**62,406**	**43,169**	**3,464**	**5,864**	**212,916**
	ERCOT	**Total**	13,568	51,458	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	212,916
WEST	**Total**		**21,666**	**91,849**	**9,403**	**829**	**1,565**	**4,156**	**106**	**4,536**	**21,330**	**52,687**	**51,648**	**44,030**	**1,981**	**31,931**	**337,717**
	CAISO+	**Total**	**1,816**	**39,560**	**5,582**	**185**	**726**	**2,059**	**35**	**3,514**	**14,316**	**10,211**	**27,112**	**7,773**	**866**	**17,055**	**130,809**
		CALI-N	-	13,677	5,582	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	52,501
		CALI-S	1,816	25,883	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	78,308
	Non-CA WECC	**Total**	**19,850**	**52,289**	**3,820**	**645**	**839**	**2,097**	**71**	**1,022**	**7,014**	**42,476**	**24,536**	**36,257**	**1,115**	**14,876**	**206,908**
		WA	560	4,166	1,096	17	352	-	-	140	459	24,402	1,404	3,642	243	1,092	37,573
		OR	-	4,161	-	6	293	22	-	-	632	8,253	2,865	4,658	141	1,051	22,081
		SOUTHWEST	4,842	18,294	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	49,158
		WASATCH	7,033	14,945	-	88	56	1,018	61	444	983	7,587	7,512	5,486	305	4,733	50,251
		FRONT R	7,415	10,723	-	212	36	10	10	262	430	1,215	5,296	18,187	258	3,789	47,844
		Total	**178,268**	**488,766**	**97,169**	**28,175**	**5,429**	**4,156**	**1,096**	**24,144**	**61,003**	**82,249**	**240,902**	**201,040**	**32,282**	**74,563**	**1,519,243**

Appendix B - Representing Canadian Transfer Limits

Introduction

The reliability and stability of cross-border electricity interconnections between the United States and Canada are critical to ensuring continuous power delivery amid evolving demands and variable supply conditions. In recent years, increased integration of wind and solar generation, coupled with extreme weather events, has introduced significant uncertainties in regional power flows.

This report describes the development and implementation of a machine learning (ML)-based model designed to project the maximum daily energy transfer (MaxFlow) across major United States–Canada interfaces, such as BPA–BC Hydro and NYISO–Ontario. Leveraging 15 years of high-resolution load and generation data, summarizing it into key daily statistics, and training a robust eXtreme Gradient Boosting (XGBoost) regressor can allow data-driven predictions to be captured with quantified uncertainty.

The project team provided percentile-based forecasts—25, 50, and 75 percent—to support both conservative and strategic planning. The conservative methodology (25 percent) was used for this report to ensure availability when needed.

The subsequent sections detail the methodology used for data processing and feature engineering, the architecture and training of the predictive model, and the validation metrics and feature importance analyses used. Future enhancements could include incorporating weather patterns, neighboring-region dynamics, and fuel-specific generation profiles to further strengthen predictive performance and support grid resilience.

Methodology

This section describes the ML approach used to build the MaxFlow prediction model.

Dataset Collection and Preparation

Data were collected for hourly and derived daily load and generation over a 15-year period (2010–2024), comprising 8,760 hourly observations annually. Hourly interconnection flow rates were collected for the same years across all major United States–Canada interfaces.[1–17]

Underlying Hypothesis

The team hypothesized that the MaxFlow between interconnected regions is critically influenced by regional load and generation extrema (maximum and minimum) and their variability. These statistics reflect grid stress conditions, influencing interregional energy flow. Additionally, nonlinear interactions due to imbalances in adjacent regions further affect energy transfer dynamics.

Regression Model

The XGBoost regression model was chosen because of its ability to capture complex, nonlinear relationships, regularization capability to prevent overfitting, high speed and performance, fast convergence, built-in handling of missing data, and ease of confidence interval approximation.

XGBoost builds many small decision trees, one after another. Each new tree learns to correct the mistakes of the previous ensemble by focusing on which predictions had the greatest error. Instead of creating one large, complex tree, it combines many simpler trees—each making a modest adjustment—so that, together, they capture nonlinear patterns and interactions. Regularization (penalties for tree size and leaf adjustments) prevents overfitting, and a "learning rate" scales each tree's contribution so that improvements are made gradually. The final prediction is simply the sum of all those small corrections.

Model Training, Validation, and Assessment

Figure B.1 shows the data analysis and prediction process, which ties together seven stages—from raw CSV loading through outlier filtering, feature engineering, projecting to 2030, rebuilding 2030 features, training an XGBoost model, and finally making and evaluating the 2030 flow forecasts with quantiles. Each stage feeds into the next, ensuring that the features used for training mirror exactly those that will be available for future (2030) predictions.

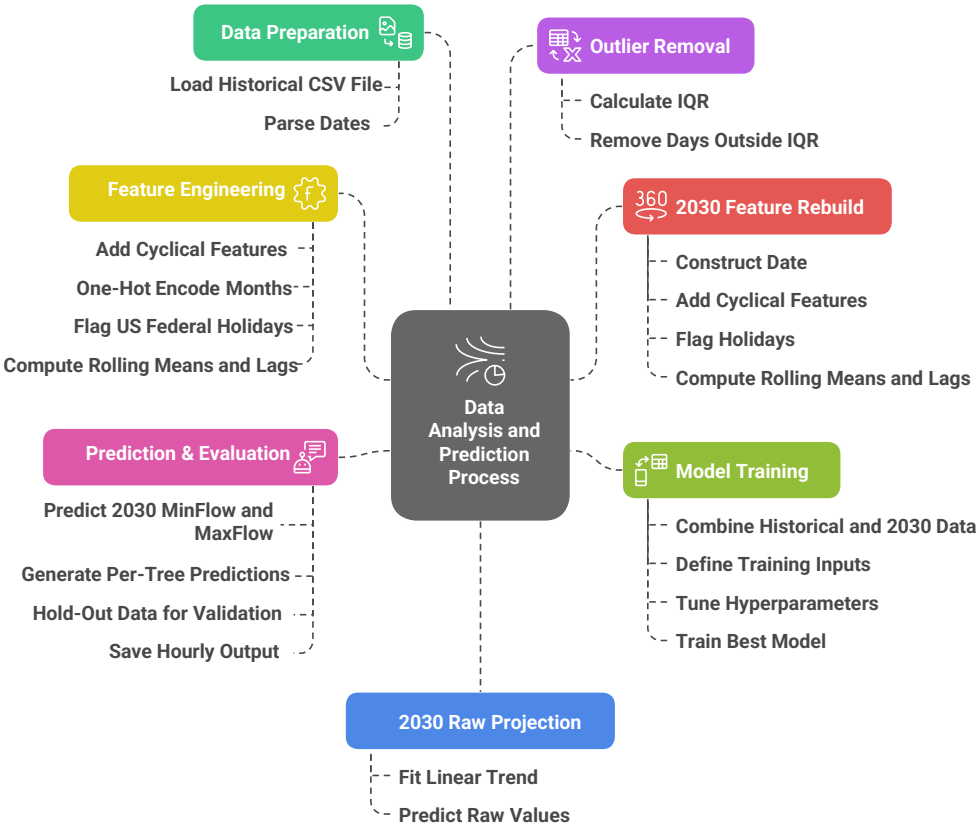


Figure B.1. Data analysis and prediction process.

Example Feature Importance for Predicting MaxFlow from Ontario to NYISO

The trained ML/XGBoost model can be used for predicting the desired year's MaxFlow. In addition, feature importance analysis can be added to assess the contribution of each variable.

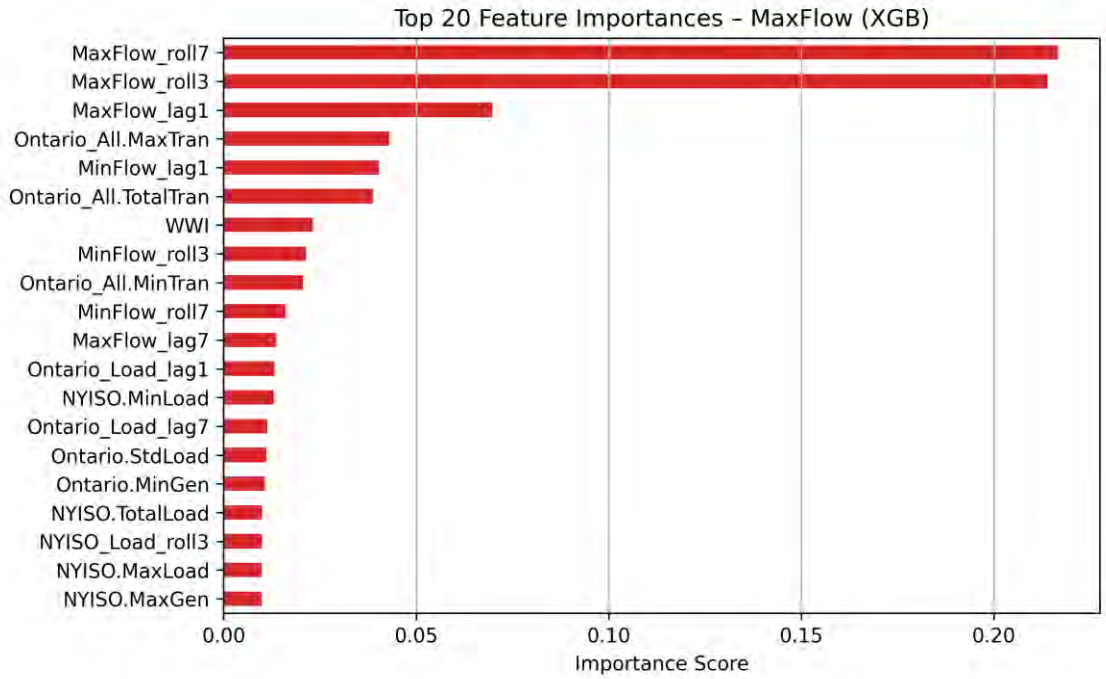


Figure B.2. Feature importance for predicting the hourly maximum energy transfer (MaxFlow) between NYISO and Ontario. XGB = eXtreme Gradient Boosting.

The feature importance plot shows that MaxFlow rolling/lagging features and Ontario_All.MaxTran are the dominant predictors of MaxFlow, meaning temporal patterns and Ontario's peak transfer capacity strongly influence interregional flow limits. Weather-related variables (WWI, e.g., temperature, humidity, etc.) and Ontario_All.TotalTran also rank highly. The 2030 MaxFlow prediction plot shows seasonal fluctuations, with higher values early and late in the year. The red shaded area represents a 95 percent confidence interval for the predictions.

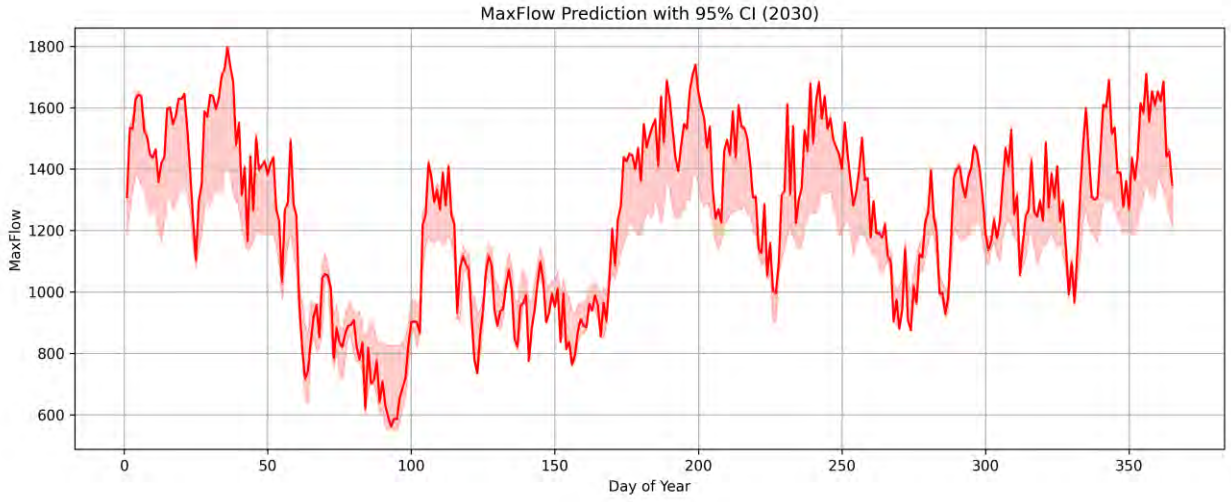


Figure B.3. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI).

Model Performance

Validating model performance on unseen data is essential to ensure the model's reliability and generalizability. The following evaluation examines how well the XGBoost model predicts minimum energy transfer (MinFlow) and MaxFlow on the validation split, highlighting strengths and areas for improvement.

Rigorous performance evaluation is a fundamental step in any ML workflow. From quantifying error metrics (root mean square error and mean absolute error) and goodness-of-fit (R^2) on both training and validation splits, it is possible to identify overfitting, assess generalization, and guide model refinement. Table B.1 shows XGBoost model performance for the Ontario–NYISO transfer limit.

Table B.1. eXtreme Gradient Boosting model performance for the Ontario–NYISO transfer limit.

Metric	Value	Explanation
MinFlow RMSE (Train)	69.2528	Root mean square error (RMSE) on training data for minimum energy transfer (MinFlow)
MinFlow R^2 (Train)	0.9651	R^2 on training data for MinFlow (higher → better fit)
MinFlow RMSE (Validation)	163.6642	RMSE on held-out data for MinFlow
MinFlow R^2 (Validation)	0.8073	R^2 on held-out data for MinFlow (higher → better generalization)
MaxFlow RMSE (Train)	114.4234	RMSE on training data for maximum energy transfer (MaxFlow)
MaxFlow R^2 (Train)	0.8838	R^2 on training data for MaxFlow (higher → better fit)
MaxFlow RMSE (Validation)	144.9614	RMSE on held-out data for MaxFlow
MaxFlow R^2 (Validation)	0.8178	R^2 on held-out data for MaxFlow (higher → better generalization)

Overall, the XGBoost model delivers excellent in-sample as well as out-of-sample accuracy. Similar outputs are available for each transfer limit.

Maximum flow predictions: Ontario to New York

Ontario and NYISO are connected through multiple high-voltage interconnections, which collectively provide a total transfer capability of up to 2,500 MW, subject to individual tie-line limits. Table B.2 outlines the data sources, preparation process, and assumptions used in creating datasets for the prediction models.

Table B.2. Ontario to New York transmission flow data and assumptions overview.

	Description
Data source	https://www.ieso.ca/power-data/data-directory
Data preparation	IESO public hourly inter-tie schedule flow data can be accessed for the years spanning from 2002 to 2023.
Assumptions	Positive flow indicates that Ontario is exporting to NY, and negative flow indicates that Ontario is importing from NY.

Figure B.4 illustrates the historical monthly MaxFlow for Ontario from 2007 through 2024, alongside 2030 projected quartile scenarios (Q1, Q2, and Q3). Analyzing these trends helps assess future reliability and facilitates capacity planning under varying conditions.

Historical monthly peaks (2007–2023) reveal a clear seasonal cycle for ONT–NYISO transfers: flows typically increase in late winter/early spring (February–April) and again in late fall/early winter (November–December). Over 16 years, the average spring peaks hovered around 1,700–1,900 MW, with occasional spikes above 2,200 MW. The 2030 forecast for Q1, Q2, and Q3 aligns with this pattern, predicting a springtime peak near 1,800 MW, a summer trough around 1,400 MW, and a modest late-summer uptick near 1,500 MW.

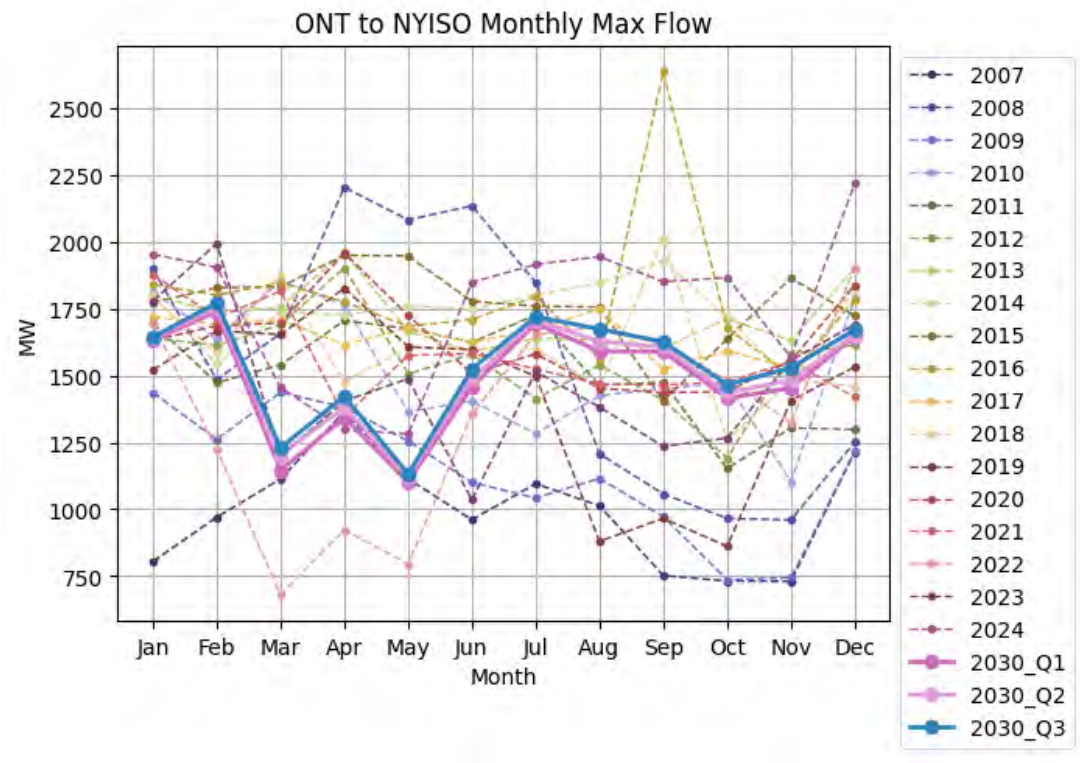


Figure B.4. Monthly maximum energy transfer between Ontario (ONT) and New York (NYISO).

The team used robust validation metrics to justify these results. When trained on daily data from the 2010–2024 period—incorporating projected 2030 loads, seasonal flags, and holiday effects—the XGBoost model achieved $R^2 > 0.80$ and a root mean square error below 150 MW on an unseen 20 percent hold-out dataset. Moreover, the 95 percent confidence intervals for monthly maxima were narrow (approximately ±150 MW), demonstrating low predictive uncertainty. A comparison of predicted maxima with historical extremes revealed that 2030 forecasts consistently fell within (or slightly above) the previous window of variability, implying realistic demand-driven behavior. In summary, the close alignment with historical peaks, strong cross-validated performance, and tight confidence bands collectively validate the results.

Discussion

The reason that the team used ML/XGBoost to approximate the 2030 transfer profiles was to ensure that there would be no violations or inconsistencies between transfer limits, load, and generation. The 15 years of data used were sufficient for having the models learn historical relationships and project them forward to 2030 to capture the underlying trends in load,

generation, and their interactions. The use of such an extensive dataset justifies using ML to establish consistent transfer profiles.

However, in some regions, like Ontario to NYISO, the available data encompassed a shorter time period, and the relationships were only partially captured because of a lack of neighboring-region data. In such cases, it was necessary to incorporate additional predictors, such as rolling and lag features from the transfer limits. Although the direct use of transfer limit data to project future transfer limits would typically be avoided, these engineered features help improve predictions when data coverage is sparse and the model's goodness-of-fit is low.

In all cases, the ML models ensured that these historical relationships were not violated, maintaining internal consistency among load, generation, and transfer limits. Overall, the team relied on ML when long-term data were available for training and projecting load and generation profiles. Rolling and lag features were used to reinforce the model when data availability was limited, but always with the goal of upholding consistent physical relationships in the 2030 projections.

Supplementary Plots for Additional Transfers

This section presents figures and tables showing results and source data information for each transfer listed below:

(iii) Pacific Northwest to British Columbia

(iv) Alberta to Montana

(v) Manitoba to MISO West

(vi) Ontario to MISO West

(vii) Ontario to MISO East

(viii) Ontario to New York

(ix) Hydro-Quebec to New York

(x) Hydro-Quebec to New England

(xi) New Brunswick to New England

The figures show the daily MaxFlow for each transfer that was considered in this analysis.

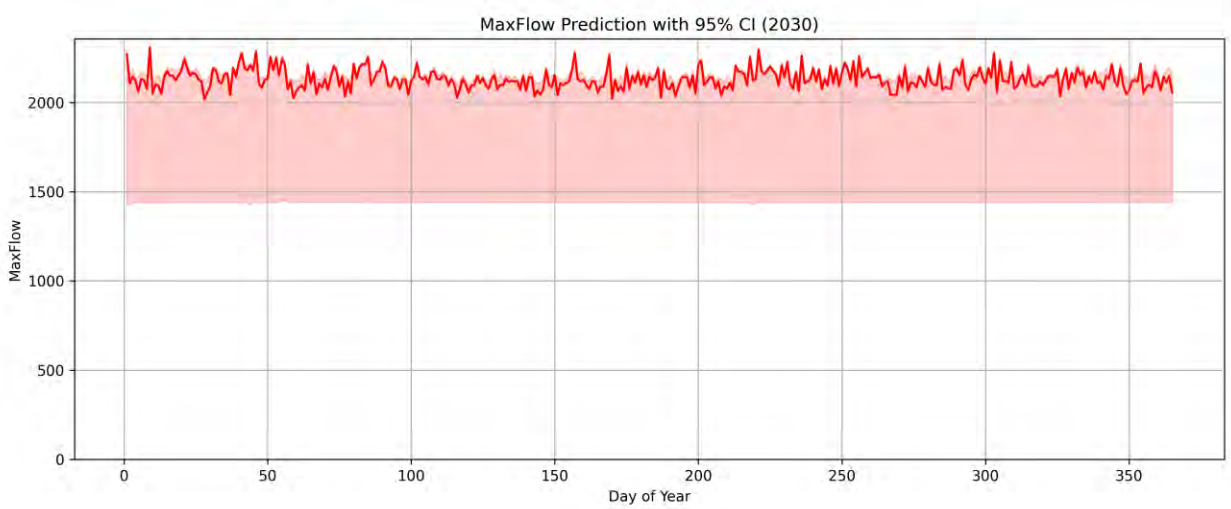


Figure B.5. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between British Columbia and the Pacific Northwest.

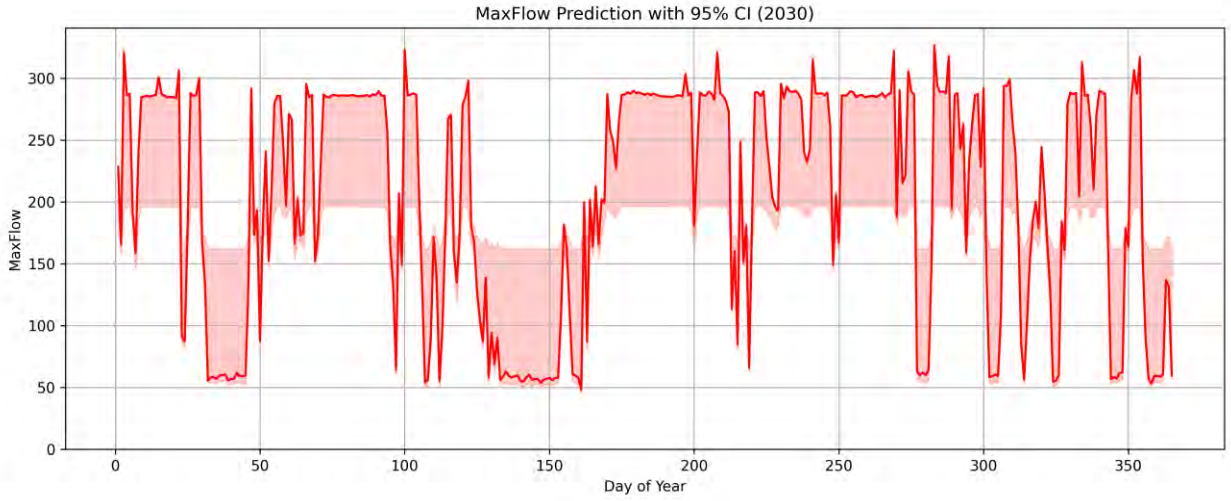


Figure B.6. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between AESO and Montana.

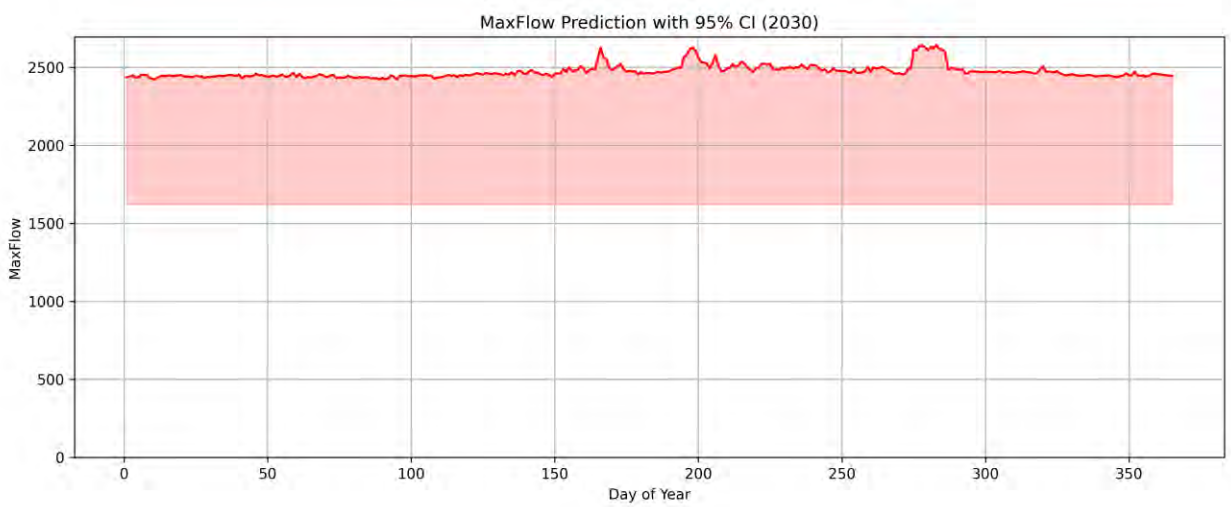


Figure B.7. Projected 2030 maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Manitoba and MISO.

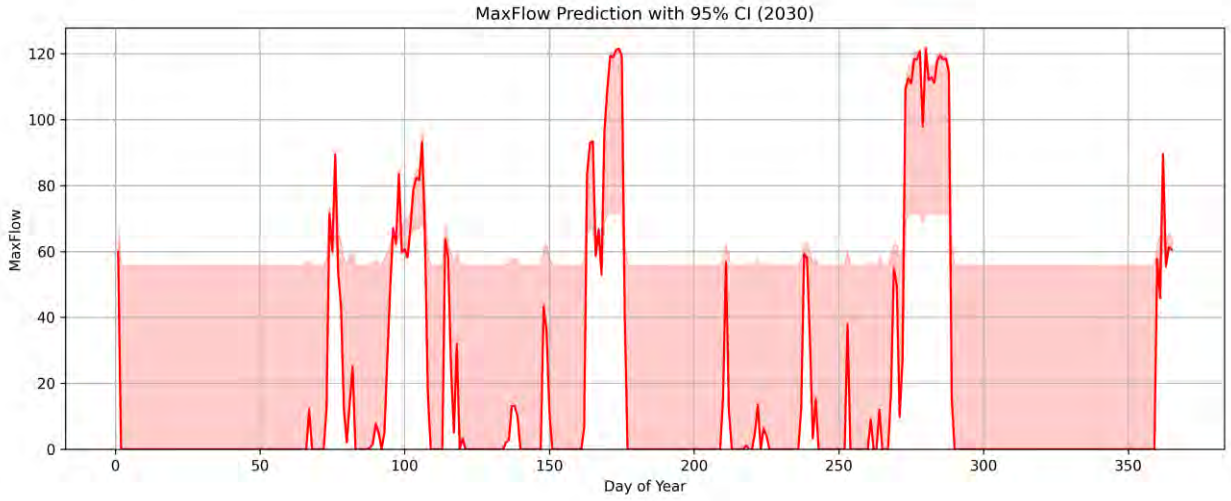


Figure B.8. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO West.

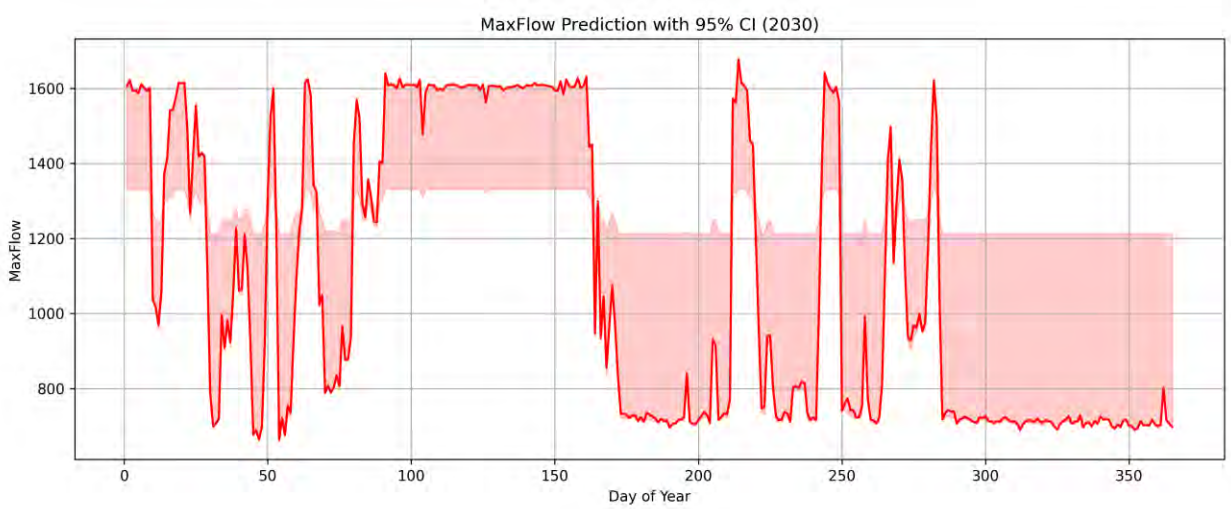


Figure B.9. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO East.

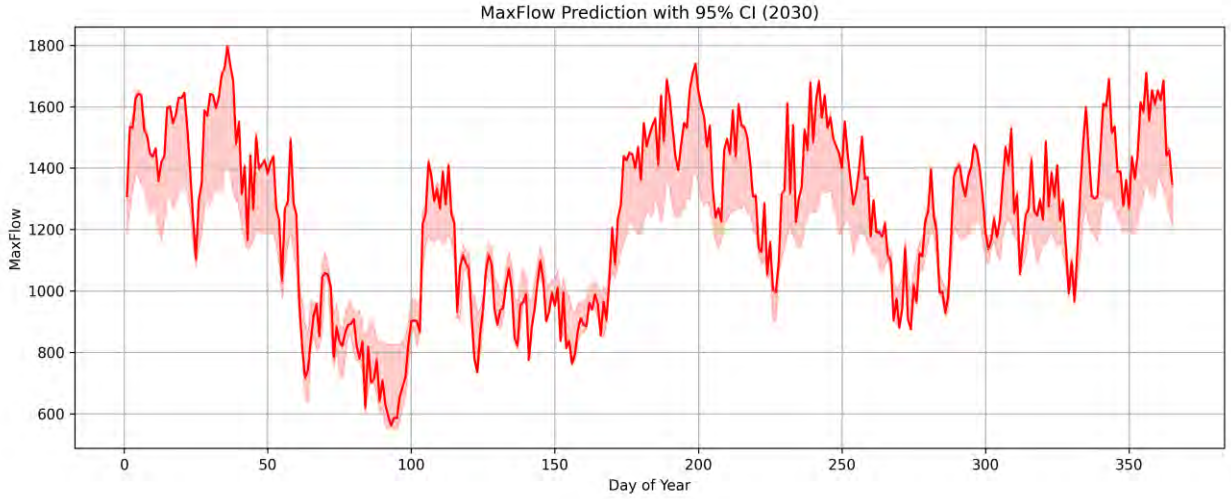


Figure B.10. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and New York.

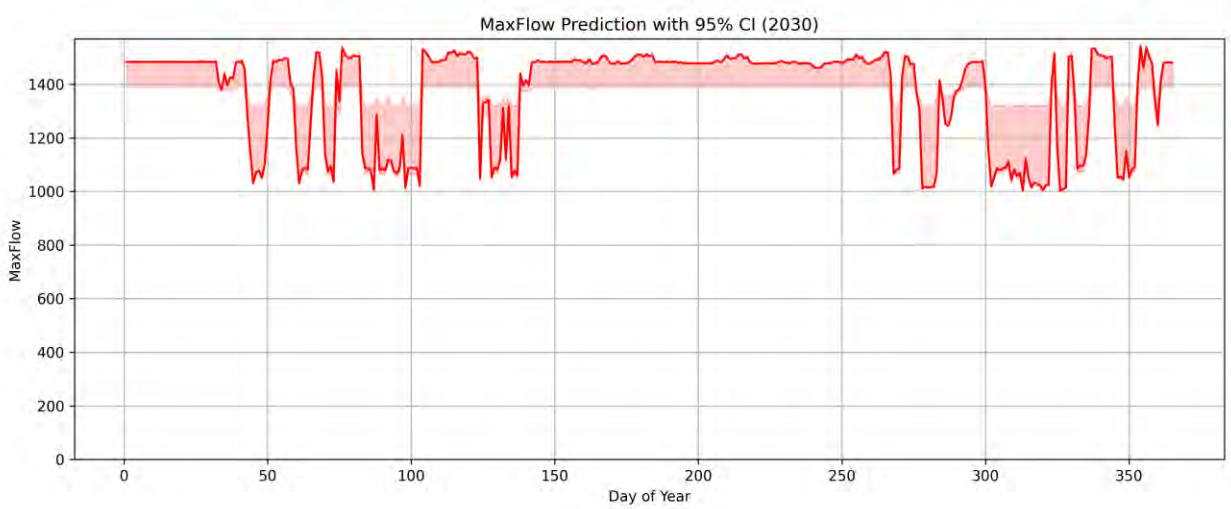


Figure B.11. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New York.

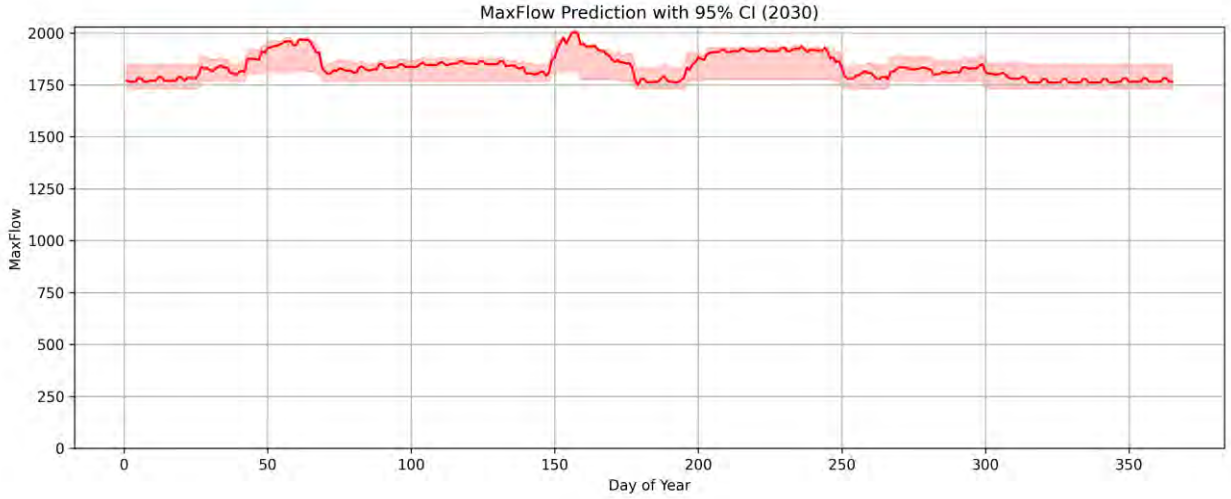


Figure B.12. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New England.

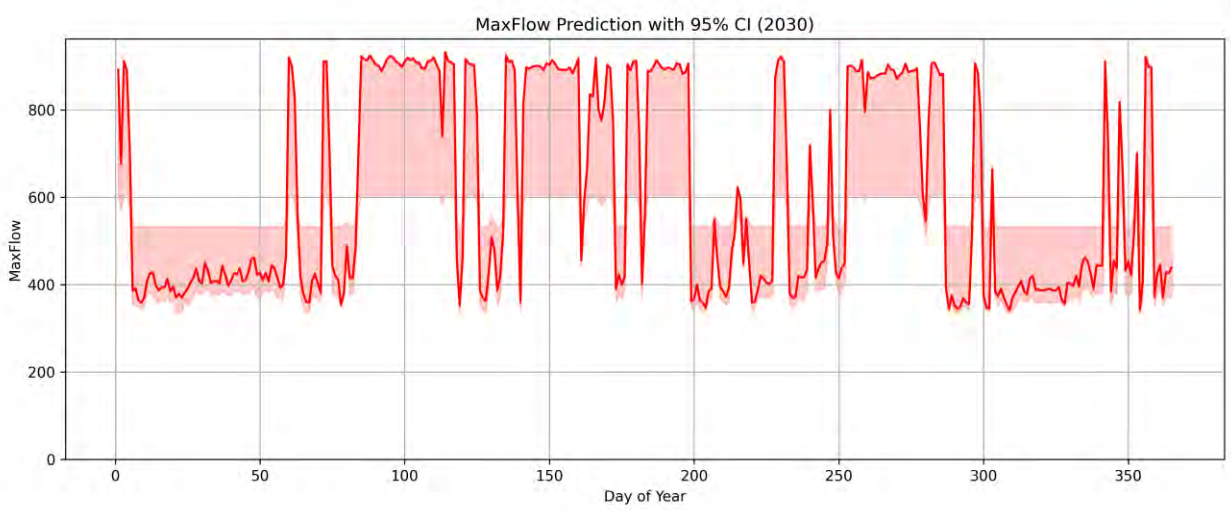


Figure B.13. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between New Brunswick and New England.

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EO 14262

Federal Register / Vol. 90, No. 70 / Monday, April 14, 2025 / Presidential Documents 15521

Presidential Documents

Executive Order 14262 of April 8, 2025

Strengthening the Reliability and Security of the United States Electric Grid

By the authority vested in me as President by the Constitution and the laws of the United States of America, it is hereby ordered:

Section 1. *Purpose*. The United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and an increase in domestic manufacturing. This increase in demand, coupled with existing capacity challenges, places a significant strain on our Nation's electric grid. Lack of reliability in the electric grid puts the national and economic security of the American people at risk. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy from all available electric generation sources and the integrity of our Nation's electric grid.

Sec. 2. *Policy*. It is the policy of the United States to ensure the reliability, resilience, and security of the electric power grid. It is further the policy of the United States that in order to ensure adequate and reliable electric generation in America, to meet growing electricity demand, and to address the national emergency declared pursuant to Executive Order 14156 of January 20, 2025 (Declaring a National Energy Emergency), our electric grid must utilize all available power generation resources, particularly those secure, redundant fuel supplies that are capable of extended operations.

Sec. 3. *Addressing Energy Reliability and Security with Emergency Authority*. (a) To safeguard the reliability and security of the United States' electric grid during periods when the relevant grid operator forecasts a temporary interruption of electricity supply is necessary to prevent a complete grid failure, the Secretary of Energy, in consultation with such executive department and agency heads as the Secretary of Energy deems appropriate, shall, to the maximum extent permitted by law, streamline, systemize, and expedite the Department of Energy's processes for issuing orders under section 202(c) of the Federal Power Act during the periods of grid operations described above, including the review and approval of applications by electric generation resources seeking to operate at maximum capacity.

(b) Within 30 days of the date of this order, the Secretary of Energy shall develop a uniform methodology for analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy. This methodology shall:

(i) analyze sufficiently varied grid conditions and operating scenarios based on historic events to adequately inform the methodology;

(ii) accredit generation resources in such conditions and scenarios based on historical performance of each specific generation resource type in the real time conditions and operating scenarios of each grid scenario; and

(iii) be published, along with any analysis it produces, on the Department of Energy's website within 90 days of the date of this order.

(c) The Secretary of Energy shall establish a process by which the methodology described in subsection (b) of this section, and any analysis and results it produces, are assessed on a regular basis, and a protocol to identify which generation resources within a region are critical to system reliability. This protocol shall additionally:

(i) include all mechanisms available under applicable law, including section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource within the at-risk region; and

(ii) prevent, as the Secretary of Energy deems appropriate and consistent with applicable law, including section 202 of the Federal Power Act, an identified generation resource in excess of 50 megawatts of nameplate capacity from leaving the bulk-power system or converting the source of fuel of such generation resource if such conversion would result in a net reduction in accredited generating capacity, as determined by the reserve margin methodology developed under subsection (b) of this section.

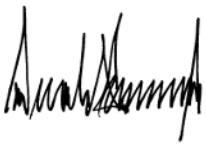
Sec. 4. *General Provisions.* (a) Nothing in this order shall be construed to impair or otherwise affect:

(i) the authority granted by law to an executive department or agency, or the head thereof; or

(ii) the functions of the Director of the Office of Management and Budget relating to budgetary, administrative, or legislative proposals.

(b) This order shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.



THE WHITE HOUSE,
April 8, 2025.

[FR Doc. 2025–06381
Filed 4–11–25; 8:45 am]
Billing code 3395–F4–P

Available at (accessed on 5/27/2025):
https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid



U.S. DEPARTMENT of ENERGY

For more information, visit:
energy.gov/topics/reliability

DOE/Publication Number • July, 7 2025

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit N: Motion to Intervene and Protective Request for Rehearing by the Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York, filed on August 6, 2025 with the Department

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BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

In re: Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, July 2025	Submitted via e-mail to: AskCR@hq.doe.gov August 6, 2025

Motion to Intervene and Protective Request for Rehearing by the Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York

The Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York ("the States") make this filing to raise our concerns with the Department of Energy's ("Department" or "DOE") report titled *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, published July 7, 2025 ("Report"),[1] and request rehearing of the same.

Given that DOE has not yet applied the report to issue future emergency orders, the States do not concede that the Federal Power Act requires the States to request rehearing at this time.[2] Still, the States acknowledge that President Trump instructed DOE to use the methodology in this report as part of a "protocol" to issue orders pursuant to Section 202(c) of the Federal Power Act preventing the retirement of power plants identified as critical to reliability in DOE's report.[3] DOE has indicated that it intends to comply with that mandate and use this Report to "guide reliability interventions" and issue Section 202(c) emergency orders.[4] The States reserve all rights to present these objections, or any other objection or legal challenge to the Report or DOE's reliance on this report going forward. However, out of an abundance of caution and to preserve their arguments, the States also formally request rehearing of the methodology,

[1] Available at https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29_0.pdf [https://perma.cc/J2XU-2RRJ].
[2] *See* 16 U.S.C. § 825*l*.
[3] *See* Exec. Order No. 14,262, 90 Fed. Reg. 15,521 (Apr. 14, 2025).
[4] *See* U.S. DEP'T OF ENERGY, *Fact Sheet: The Department of Energy's Resource Adequacy Report Affirms The Energy Emergency Facing The U.S. Power Grid* (2025), https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf [https://perma.cc/YLX7-8G7T] (explaining that DOE's methodology will be used, pursuant to the executive order, "prevent [] generation resources from leaving the bulk-power system"); Press Release, U.S. Dep't of Energy, Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security (July 7, 2025), https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security [https://perma.cc/8TEJ-AGH6]. (stating that its "methodology also informs the potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act"); Report at *vi* (explaining that DOE's standard will be used to "guide reliability interventions"), 1 (emphasizing the need for DOE's "decisive intervention" in energy markets), 10 (analyzing ERCOT because "FPA Section 202(c) allows DOE to issue emergency orders to ERCOT").

standards, and protocol identified in this Report under Section 313*l* of the Federal Power Act, 16 U.S.C. § 825*l*.

This filing details the ways in which the Report is arbitrary and why it would be unlawful to rely on it to justify future Section 202(c) orders. The States also request DOE review the Report independently before it is used in any capacity in order to address the serious errors in the analysis highlighted here.

I. Motion to Intervene

The Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York move to intervene in this proceeding pursuant to Section 313*l* of the Federal Power Act, 16 U.S.C. § 825*l*, and request that the Department of Energy grant rehearing of its July 7, 2025 report titled *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*.

Executive Order 14262 and DOE's own statements alongside the Report's publication indicate that it will be used to "guide reliability interventions" and justify issuance of emergency orders under Section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c). The Report is deeply flawed and, if DOE is taken at its word, it will inflict significant harm on our states.

Many of the retiring resources targeted by this report are located in our states. In Washington, for example, the Transalta Centralia coal-fired power plant is scheduled to retire in December 2025. In Colorado, the Craig and Comanche coal-fired power plants are scheduled to retire by the end of the year as well and the state's remaining coal fired power plants are scheduled to retire by 2031. These retirements have been thoroughly vetted by state and regional authorities and approved only following an extensive examination of cost considerations and reliability impacts.

And even when a source is not located directly in one of our states, the ratepayer impacts of overriding a planned retirement based on the DOE Report will often be felt by our residents. That is because many of these resources operate within regional transmission systems that spread costs across all, or a portion of, their footprint. In MISO, for example, ratepayers across the ISO's north and central regions are being asked to foot the bill for the continued operation of the J.H. Campbell coal-fired power plant in Michigan pursuant to a Section 202(c) order issued by DOE in May. In just five weeks, complying with that Order has cost the plant's owner $29 million.[5] The order is expected to cost consumers close to $100 million if it expires on August 21 and is not renewed.[6]

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[5] *See* CMS Energy Corp., Quarterly Report (Form 10-Q) (Jul. 31, 2025), https://www.sec.gov/ix?doc=/Archives/edgar/data/0000201533/000081115625000071/cms-20250630.htm.

[6] Brian Dabbs, *Coal Plant Ordered to Stay Open Cost $29M to Run in 5 Weeks*, POLITICO ENERGYWIRE (Aug. 1, 2025), https://subscriber.politicopro.com/article/eenews/2025/08/01/coal-plant-ordered-to-stay-open-cost-29m-to-run-in-5-weeks-00487542.

Our states are also harmed when Section 202(c) is used to keep polluting facilities from retiring in upwind locations. Fossil-fuel power plants are large sources of ozone-forming pollution and toxic emissions that contribute to nonattainment of air quality standards in downwind states like Connecticut, New York, and Maryland. Planned retirements have the benefit of reducing this pollution and overriding those state and regional determinations based on the DOE Report will further the harm that downwind states face from upwind sources.

Moreover, the report unlawfully intrudes on the states' authority to regulate generation resources within their borders. Section 201 of the Federal Power Act clearly reserves to the states their traditional authority "over facilities used for the generation of electric energy."[7] That authority "is a matter that has traditionally rested with the states, and it should continue to rest there."[8]

Both EO 14262 and subsequent statements by DOE make clear that the report will be used to justify Section 202(c) orders going forward.[9] The States are aggrieved by the report which paints an unrealistic picture of resource adequacy to justify use of DOE emergency authority. Exercising that authority in non-emergency situations will harm ratepayers and the environment and unlawfully infringe on an area of state sovereign authority. Moreover, our states are also purchasers of retail electricity and are directly harmed by the rate impacts from these decisions.

II. Background

a. Resource adequacy is highly regulated at the state and regional levels.

Existing regulatory mechanisms govern both federal requirements for reserve margins and state resource adequacy determinations. Resource adequacy is an integral part of prudent, least-cost, utility planning in every state and region of the country.[10] DOE plays no role in the complex proceedings to determine either reserve margins or specific resource adequacy conclusions. The Report fails to grapple with the complicated task of resource adequacy planning undertaken by state utility offices and regional grid planners across the country, yet these existing procedures are a key part of the alleged resource adequacy conundrum which the DOE Report claims to address.

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[7] 16 U.S.C. § 824(b)(1).
[8] *Devon Power LLC et al.,* 109 FERC ¶ 61,154, para. 47 (Nov. 8, 2004).
[9] *See* U.S. Dep't of Energy, Order No. 202-25-4 (May 30, 2025) [https://perma.cc/PS3M-6CJA] [*hereinafter* "Eddystone Order"] (The methodology "will be used to establish a protocol to identify which generation resources within a region are critical to system reliability and prevent identified generation resources from leaving the bulk power system. . . . DOE plans to use [the July 7] methodology to further evaluate Eddystone Units 3 and 4.").
[10] *See* SYNAPSE ENERGY ECONOMICS & LAWRENCE BERKELEY NATIONAL LABORATORY, BEST PRACTICES IN INTEGRATED RESOURCE PLANNING 1-2 (Nov. 2024), https://www.synapse-energy.com/sites/default/files/IRP_Best_Practices_2024_Synapse_LBNL_24-061_1.pdf [https://perma.cc/D68F-WHWQ].

i. States directly regulate resources to ensure an adequate supply of electricity.

Most states rely on resource planning processes to ensure that adequate generation is available to meet projected demand. While some states have largely delegated this authority to the regional grid operators and rely on market-based mechanisms to ensure future demand is met, it is ultimately the state that retains regulatory authority over generation resources.[11] These state processes are transparent and iterative, relying on technical and expert analysis to ensure that adequate resources are procured in a prudent manner. The States describe just a few of the mechanisms at play in our jurisdictions as relevant examples below.

1. Arizona

Arizona, like other states, regulates the power generation, transmission, and distribution needs of the electric grid to ensure resource adequacy and reliability. This regulatory authority is established in the State's constitution. The Arizona Constitution grants the Arizona Corporation Commission ("ACC") broad authority to regulate public service corporations, including electric utilities.[12] The Arizona Constitution also empowers the ACC to set just and reasonable classifications, rates, and charges, as well as to make and enforce rules, regulations, and orders for the governance of utilities. This constitutional authority underpins the ACC's ability to establish requirements for resource planning and grid reliability.[13]

The ACC has reliability requirements in its Resource Planning and Procurement ("RPP") rules.[14] The ACC's RPP rules require load-serving entities to file and seek acknowledgement of their prospective, 15-year resource plans every three years, which include projected data for generating units and power supply systems, capital costs, environmental impacts, and cost analyses.

The most recent version of Integrated Resource Plans was authorized by the ACC on October 21, 2024,[15] which approved the power generation, transmission, and distribution acquisition plans that were submitted by Arizona Public Service,[16] Tucson Electric Power,[17] and UNS Electric.[18] The ACC requires similar data from its electric cooperatives in order to improve

[11] 16 U.S.C. § 824(b)(1).
[12] ARIZ. CONST. art. 15, § 3.
[13] *Id.*
[14] A.A.C. R14-2-701.
[15] ACC Decision No. 79589, https://docket.images.azcc.gov/0000212120.pdf?i=1754080707112.
[16] ARIZONA PUBLIC SERVICE, *2023 Integrated Resource Plan* (Nov. 1, 2023), https://docket.images.azcc.gov/E000031965.pdf?i=1754080707112.
[17] TUCSON ELECTRIC POWER, *Tucson Electric Power 2024 Integrated Resource Plan* (Nov. 1, 2023), https://docket.images.azcc.gov/E000031960.pdf?i=1754080707112.
[18] UNS ELECTRIC, *UNS Electric 2023 Integrated Resource Plan* (Nov. 1, 2023), https://docket.images.azcc.gov/E000031961.pdf?i=1754080707112.

grid performance and reliability in rural areas of the state.[19] The decision requires technology-neutral portfolio methodologies, annual load forecast accuracy reports, and analysis of coal-fired power plant retirement timelines to enhance reliability, building on existing triannual utility analyses. It also requires sharing modeling data with stakeholders.

While one major utility in Arizona, the Salt River Project, is not subject to the ACC's jurisdiction, it has adopted its own planning and goal-setting requirements, referred to as the Integrated System Plan.[20]

2. New York

The New York Independent System Operator ("NYISO") plays a significant role in safeguarding electric grid reliability while supporting the clean energy transition.[21] As part of its biennial reliability planning process, NYISO first conducts a Reliability Needs Assessment, which examines whether New York's power grid will have enough generation, storage, and transmission capacity to meet demand over the next ten years.[22] Specifically, the Assessment uses probabilistic simulations to evaluate whether New York meets the Loss of Load Expectation (LOLE) criterion of not more than 0.1 event-days/year (equivalent to one day in ten years), which is the standard reliability criterion used by the New York State Reliability Council and the Northeast Power Coordinating Council.[23] The Assessment also evaluates how New York's environmental and energy laws—such as the Climate Leadership and Community Protection Act, which requires 100% zero-emission electricity by 2040—will affect grid reliability, especially as fossil fuel-fired power plants retire, and electricity demand increases due to building electrification and the continued growth of the electric vehicle market.[24]

Following the Reliability Needs Assessment, NYISO completes the biennial planning process by issuing a Comprehensive Reliability Plan that documents the plans for a reliable electric grid over the same ten years.[25] The Comprehensive Reliability Plan provides solutions to any shortfalls identified in the Reliability Needs Assessment, such as accelerating battery deployment, deferring certain retirements, upgrading transmission lines, or increasing demand-side participation.[26] While the 2022 Reliability Needs Assessment did not identify any actionable

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[19] ARIZONA ELECTRIC POWER COOPERATIVE, *Demand-and Supply-Side Data Filing* (Apr. 1, 2025), https://docket.images.azcc.gov/E000042810.pdf?i=1753996193952.
[20] SALT RIVER PROJECT, *Integrated System Plan* (Apr. 1, 2025), https://www.srpnet.com/grid-water-management/future-planning/integrated-system-plan.
[21] *See About Us*, NYISO, https://www.nyiso.com/about-us.
[22] *See* NYISO, 2024 RELIABILITY NEEDS ASSESSMENT (Nov. 19, 2024), https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf.
[23] *Id.* at 41.
[24] *Id.* at 23-24 fig. 13.
[25] *See* NYISO, 2023–2032 COMPREHENSIVE RELIABILITY PLAN (Nov. 28, 2023), https://www.nyiso.com/documents/20142/2248481/2023-2032-Comprehensive-Reliability-Plan.pdf (following the 2022 RNA and incorporating finding and solutions from the quarterly short term reliability process).
[26] *See id.*

reliability shortfalls, the 2023–2032 Comprehensive Reliability Plan nonetheless provided a forward-looking analysis that evaluated key risk factors related to reliability, including delays in major transmission projects, winter peaking and gas shortage risks, and extreme weather.[27]

In parallel with the biennial reliability planning process, as of 2019, NYISO also conducts a quarterly short-term reliability ("STAR") process to identify reliability needs that may arise over the next five years due to various changes in the grid, such as generator deactivations, revised transmission plans, or updated electricity demand.[28] For example, NYISO's Quarter 2 2023 STAR report, published on July 14, 2023, identified the potential for electricity supply shortfalls in New York City beginning in the summer 2025 as a result of the New York State Department of Environmental Conservation's "Peaker Rule," which seeks to reduce nitrogen oxide (NO_x) emissions from simple-cycle combustion turbines that supply backup generation during peak demand.[29] Following this STAR report, NYISO sought proposed solutions from market participants and ultimately exercised its authority under the Peaker Rule to require specific peaker units to remain operational until long-term solutions—such as the Champlain Hudson Power Express line, scheduled to enter service in spring 2026, bringing 1,250 MW of hydropower to New York City—could come online.[30] NYISO incorporates any needs or shortfalls identified in the STAR process into its biennial reliability planning process.[31]

3. Connecticut

Connecticut General Statutes § 16a-3a requires that the Department of Energy and Environmental Protection ("DEEP") prepare an Integrated Resource Plan ("IRP"). An IRP is composed of an assessment of the future electric needs and a plan to meet those future needs. It is "integrated" in that it looks at both demand side (conservation, energy efficiency, etc.) resources as well as the more traditional supply side (generation/power plants, transmission lines, etc.) resources in making its recommendations on how best to meet future electric energy needs in the state. Connecticut's current IRP was completed in 2020 and updated in 2022. DEEP is currently developing the 2025 IRP, which involves planning for the next ten years.

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[27] *Id.* at 48-67.

[28] *See Short-Term Reliability Process*, NYISO, https://www.nyiso.com/short-term-reliability-process (last visited July 28, 2025); *Reliability Planning Process and Declaring a Reliability Need: Next Steps*, NYISO (July 14, 2023), https://www.nyiso.com/-/reliability-planning-process-and-declaring-a-reliability-need-next-steps.

[29] NYISO, Short-Term Assessment of Reliability: 2023 Quarter 2 (July 14, 2023), https://www.nyiso.com/documents/20142/16004172/2023-Q2-STAR-Report-Final.pdf/5671e9f7-e996-653a-6a0e-9e12d2e41740.

[30] Press Release, NYISO, *NYISO Identifies Solution to Solve New York City Reliability Need* (Nov. 20, 2023), https://www.nyiso.com/-/press-release-%7C-nyiso-identifies-solution-to-solve-new-york-city-reliability-need.

[31] *See* NYISO, 2023–2032 COMPREHENSIVE RELIABILITY PLAN, *supra* note 25, at 30–32.

4. Colorado

Colorado regulations require every investor-owned retail electric utility and wholesale electric generation and transmission cooperative operating in the state to file an energy resource plan ("ERP") with the Public Utilities Commission ("PUC") every four years.[32] ERPs must contain electric demand and energy forecasts, evaluation of existing resources, an assessment of planning reserve margins and contingency plans for the acquisition of additional resources.[33] If an ERP includes retirement of an existing coal-fired generating facility, detailed workforce transition and community assistance plans must be filed.[34]

The planning process includes a reserve margin to meet a 0.1 days per year loss of load expectation standard.[35] Utilities use this reserve margin to propose additional generation for the planning period, where necessary. Those proposals are vetted through extensive stakeholder input and consideration by the Colorado PUC and the additional generation must satisfy availability and dispatchability criteria.[36] And where generation needs arise outside of the four-year ERP process, interim ERPs and applications for certificates of public convenience and necessity can be filed to meet those needs.[37] These proceedings are transparent and iterative and conducted with technical and expert analysis of grid conditions and ratepayer impacts.

5. Illinois

Illinois ratepayers are served by two Regional Transmission Organizations ("RTO"), Midcontinent Independent System Operator, Inc. ("MISO") and PJM Interconnection, L.L.C. ("PJM"). Central and Southern Illinois are encompassed by MISO Local Resource Zone 4 and a small portion of Northwest Illinois is included in MISO Local Resource Zone 1.[38] The service area of Commonwealth Edison Company, the load serving entity for Illinois electricity customers in Northern Illinois, is encompassed by PJM's ComEd Zone.[39] The Illinois Attorney General's office represents Illinois ratepayers who have a significant interest in resource adequacy and maintaining reliable service at least possible cost that is materially affected by the outcome of this proceeding.

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[32] 4 COLO. CODE REGS. § 723-3-3603(a).
[33] 4 COLO. CODE REGS. § 723-3-3604(b-f).
[34] COLO. REV. STAT. § 40-2-125.5(4)(a)(VII).
[35] *See* Colo. Pub. Utils. Comm'n Proceeding No. 24A-0422E, HE 109 and HE 109 ZM-1; Colo. Pub. Utils. Comm'n Proceeding No. 21A-0141E, Hrg. Exh. 115, pp. 8-10.
[36] COLO. REV. STAT. § 40-2-125.5 (4)(d)(II).
[37] *Id*.
[38] *See* MISO Tariff, Attachment VV, Map of Local Resource Zone Boundaries, https://docs.misoenergy.org/miso12-legalcontent/Attachment_VV_-_MAP_of_Local_Resource_Zone_Boundaries.pdf.
[39] *See* MISO Tariff, Attachment VV, Map of Local Resource Zone Boundaries, https://docs.misoenergy.org/miso12-legalcontent/Attachment_VV_-_MAP_of_Local_Resource_Zone_Boundaries.pdf.

6. Washington

Washington electric utilities file clean energy implementation plans to the Washington Utilities and Transportation Commission once every four years with a biennial update filing at the midway point of every plan.[40] They also file long term integrated resource plans every four years.[41] For investor-owned utilities, if an integrated resource plan identifies a resource need within the next four years, the utility must file a request for proposal with the Commission for approval.[42]

7. Michigan

In Michigan, ratepayers are served primarily by MISO, with a smaller portion included within PJM. In MISO, the regulation of resource adequacy planning has both a state and federal aspect. MISO member states have a capacity obligation under the MISO tariff. MISO's resource adequacy requirements, however, are designed to be complementary to the primary role of the states in ensuring resource adequacy.[43] In Michigan, the investment decisions of utilities are regulated by the Michigan Public Service Commission ("MI PSC"). Through Michigan's state Integrated Resource Planning process, the MI PSC exercises regulatory authority over utilities in order to ensure that the utilities obtain the amounts of capacity they need to meet their obligations under the MISO tariff, and that they do so at the best value to ratepayers, and with a composition of resources that otherwise complies with state law, including environmental requirements.

Michigan's IRP statute requires electric utilities whose rates are regulated by the MI PSC to periodically file an integrated resource plan. The IRP is a projection of the utility's load obligations and a plan to meet those obligations.[44] The IRP statute directs the MI PSC to approve

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[40] *See* WASH. REV. CODE § 19.405.060; WASH. ADMIN. CODE § 480-100-640, -645; *see also* WASH. UTILS. AND TRANSP. COMM'N, *Clean Energy Implementation Plans*, https://www.utc.wa.gov/regulated-industries/utilities/energy/conservation-and-renewable-energy-overview/clean-energy-transformation-act/clean-energy-implementation-plans-ceips.

[41] *See* WASH. REV. CODE § 19.280.040 to 050; WASH. ADMIN. CODE § 480-100-620, -625; *see also* WASH. UTILS. AND TRANSP. COMM'N, *Integrated Resource Plans*, https://www.utc.wa.gov/integrated-resource-plans-irps.

[42] *See* WASH. ADMIN. CODE § 480-107-009(2), -017.

[43] *Midcontinent Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,215, 62,606 at P 13 (2020) ("approximately 90% of the load in MISO is served by vertically integrated LSEs, the vast majority of which are subject to state integrated resource planning processes. To accommodate the make-up of the MISO's footprint, MISO's proposed Tariff provisions accepted in the February 2018 Order provide that its resource adequacy requirements "are complementary to the reliability mechanisms of the states and the Regional Entities ... within the [MISO] region."); *see also id*. ("MISO's proposed Tariff language explains that the resource adequacy requirements 'are not intended to and shall not in any way affect state actions over entities under the states' jurisdiction.' In other words, unlike the centralized capacity constructs used in the Eastern RTOs/ISOs, MISO's Auction is not—*and has never been*—the primary mechanism for its [Load Serving Entities] to procure capacity."); *Midwest Indep. Transmission Sys. Operator, Inc*., 119 FERC ¶ 61,311, 62,722 at P 75 (2007) ("From the beginning . . . the Commission has recognized the role that state resource planning plays in managing the resource adequacy of [MISO]").

[44] MICH. COMP. LAWS § 460.6t(3).

a plan if the MI PSC determines that it "represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs."[45] To make that decision, the statute instructs the MI PSC to consider whether the IRP appropriately balances seven statutory factors: (i) resource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement; (ii) compliance with applicable state and federal environmental regulations; (iii) competitive pricing; (iv) reliability; (v) commodity price risks; (vi) diversity of generation supply; and (vii) whether proposed levels of peak load reduction and energy waste reduction are reasonable and cost effective.[46]

The IRP statute also directs the MI PSC to establish – among other things – computer modeling scenarios that must be used to analyze the costs of possible plans in an IRP, including costs associated with plant retirement dates.[47] In Consumers Energy's 2021 IRP, for example, the company conducted modeling that compared other possible retirement dates of its J.H. Campbell coal-fired power plant to a 2025 retirement and concluded that the most cost-effective retirement date was 2025.

8. Minnesota

Since 1991, Minnesota law has required each public utility to propose a set of resource options that the utility could use to meet the electricity service needs of its customers over a forecast period of 15 years.[48] The resource options include using, refurbishing and constructing utility plant and equipment, buying power generated by other entities, controlling customer loads, and implementing customer energy conservation. The Minnesota Public Utilities Commission ("Minnesota Commission") evaluates the plan's ability to ensure reliability of utility service, keep customer's bills and utility rates as low as practicable, minimize adverse socioeconomic effects and adverse effects on the environment, and limit risk.[49] The Commission uses an extensive notice and comment process in which the utilities and stakeholders evaluate detailed modeling of demand and various resource costs. The Minnesota Commission may approve, reject or modify utility resource plans.[50] In the most recent resource plan for Minnesota's largest utility, the Minnesota Commission approved including in the resource plan a new natural-gas fired 420 MW combustion turbine plant to address peak load.[51]

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[45] MICH. COMP. LAWS § 460.6t(8)(a).
[46] *Id*.
[47] MICH. COMP. LAWS § 460.6t(1).
[48] MINN. STAT. § 216B.2422; MINN. R. ch. 7843; *see also Electric Integrated Resource Planning (IRP)*, MINN. PUB. UTILS. COMM'N, https://mn.gov/puc/activities/economic-analysis/planning/irp/ (last accessed Aug. 6, 2025).
[49] MINN. R. 7843.0600, subp. 3.
[50] MINN. STAT. § 216B.2422.
[51] MINN. PUB. UTILS. COMM'N, Dkt. No. E-002/RP-24-67; E-002/CN-23-212, Order Approving Settlement Agreement With Modifications (Apr. 21, 2025), https://www.edockets.state.mn.us/documents/%7B30F45996-0000-CF1F-80E3-5E41B2F16918%7D/download?contentSequence=0&rowIndex=3.

ii. Regional operators establish mechanisms to ensure resource adequacy and grid stability.

State primacy over resource adequacy is further complemented by the regional transmission operators. For example, MISO and PJM both have extensive processes for obtaining resource adequacy and reliability. MISO works collaboratively with its member states to ensure resource adequacy throughout its service area.[52] MISO ensures there is sufficient generation capacity through forecasting demand growth, assessing existing generation assets, and planning for new generation resources.[53] MISO accounts for state Integrated Resource Planning and also operates a capacity auction where utilities and other load-serving entities can procure the necessary generation capacity to meet projected demand. MISO's capacity market is intended to incentivize the development and maintenance of adequate generation resources.[54] MISO's annual Planning Resource Auction ("PRA") procures sufficient resources and allows market participants to buy and sell capacity via the auction.[55]

Resource adequacy within the PJM footprint is subject to an established, extensive, layered, framework of oversight and regulation. The resource adequacy contribution of each PJM electric generating plant operating is subject to ongoing, technical reviews by PJM, pursuant to its tariff, and in conformity with rules promulgated and periodic grid reliability reviews conducted by Reliability First Corporation and NERC, respectively.[56] PJM also conducts an auction, its base residual auction ("BRA"), for the procurement of capacity from generating resources.

b. Historic use of 202(c) is limited.

Section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c), grants the Secretary of Energy the authority to issue orders that require the "temporary connection[]" of power plants and the "generation, delivery, interchange, or transmission of electric energy" in order to address certain emergencies "and serve the public interest."[57] The law also effectively waives compliance with "any Federal, State, or local environmental law or regulation" that would conflict with any

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[52] *System Planning*, MISO, https://www.misoenergy.org/meet-miso/about-miso/industry-foundations/grid_planning_basics/ (last visited July 30, 2025).
[53] *Id.*
[54] *Id.*
[55] *Resource Adequacy*, MISO, https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc (last visited July 30, 2025).
[56] *See, e.g., North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom*. *Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009); Order No. 748, Final Rule, 134 FERC ¶ 61,213 (2011). FERC approved regional reliability standards applicable to PJM, developed by RFC and submitted to FERC by NERC. *Notice of Proposed Rulemaking on Plan. Res. Adequacy Assessment Reliability Standard*,133 FERC ¶ 61,066 (2010) (proposed rule for RFC); *Plan. Res. Adequacy Assessment Reliability Standard*, Order No. 747, 134 FERC ¶ 61,212 (2011) (final approval of RFC's Resource Adequacy Reliability Standard).
[57] 16 U.S.C. § 824a(c)(1).

party's obligations under such an order, but limits the length of any order that conflicts with a pollution control requirement to 90-days, with extension possible.[58]

That authority originated principally as a wartime power of what was then the Federal Power Commission. Section 202(c) was enacted in 1935, in the leadup to World War II, with the same "emergency" language that exists in the statute today, specifically to guard against energy related shortages that were viewed as hampering national security during World War I.[59] It was initially used largely to issue "interconnection" orders specifically between utilities at a time when America's electric grid was more fragmented, monopolized, and less diversified than it is today.[60] Interconnection was seen as a powerful means to increase grid reliability, but the federal government largely lacked regulatory power over the electric sector at the time.[61] The then-Federal Power Commission did not invoke its emergency authority until the United States entered World War II.[62] Section 202(c) orders were issued repeatedly during the war, primarily to order interconnection between utilities, but the provision was rarely invoked once the war ended. A number of organizational changes ensued in the decades following the War and the provision's authority eventually came to rest with the Secretary of Energy.[63]

From 2000, when the authority of Section 202(c) was "rediscovered" in response to the California Energy Crisis, through 2024, the provision was sparingly invoked to respond to true emergencies to avoid imminent widespread blackouts.[64] Most 202(c) orders issued during this period involved natural disasters or other acute power outages.[65] These emergencies included one high-profile incident near the nation's capital that led to the statute's 2015 amendment, adding the provisions explicitly waiving environmental liability due to compliance with a Section 202(c) order, leading the statute to read as it does today.[66] Orders issued during this period were typically of limited duration, lasting for a period of days to weeks.[67]

The typical process for issuing a Section 202(c) order is outlined by DOE implementing regulations at 10 C.F.R. §§ 205.370-379. In the normal course, requests for Section 202(c) orders originate with a grid operator or utility facing an acute and unforeseen emergency that normal processes and demand response mechanisms are incapable of addressing, though they may be issued by the Department unprompted as well.[68] Applications for Section 202(c) orders made by

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[58] *Id.* at § 824a(c)(3)-(4).
[59] For a deeper discussion of the history of Section 202(c), see Benjamin Rolsma, *The New Reliability Override*, 57 CONN. L. REV. 789 (2025). *See also id.* at 798-802.
[60] *Id.* at 802-804.
[61] *Id.* at 801-802.
[62] *See id.* at 803 n.82 *and accompanying text*.
[63] *Id.* at 803-04; 42 U.S.C. § 7151(b).
[64] *Id*. at 805-509.
[65] Rolsma, *supra* note 59, at 805-09, 839-42 tbl.1.
[66] *Id.* at 806-08 (citing DEP'T OF ENERGY, ORDER NO. 202-05-3 (Dec. 20, 2005)); 16 U.S.C. § 824a(c)(3)-(5).
[67] *See* Rolsma, *supra* note [x], at 839-42 tbl.1 (chronicling all Section 202(c) orders issued "after dissolution of the Federal Power Commission").
[68] *See* 10 C.F.R. § 205.370.

outside entities are to include specific details to "be considered by the DOE in determining that an emergency exists" and the appropriate intervention.[69] This information is supposed to include "[d]aily peak load and energy requirements for each of the past 30 days and projections for each day of the expected duration of the emergency," "[a] description of the situation and a discussion of why this is an emergency, … includ[ing] any contingency plan of the applicant and the current level of implementation," and "[a] description of efforts made to obtain additional power through voluntary means and the results of such efforts."[70] Section 202(c) orders bypass environmental review under NEPA and can waive pollution control requirements that would otherwise apply to the facilities.[71]

c. President Trump Declares a National Energy Emergency on his first day in office and subsequently issues EO 14262.

On January 20, 2025, his first day in office, President Trump issued Executive Order 14156 titled "Declaring a National Energy Emergency".[72] That unilateral declaration did not provide any factual support for its assertion that emergency conditions had overtaken the electricity grid.[73]

On April 8, 2025, President Trump issued Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid."[74] Section 3(b) of the executive order directs the Secretary of Energy (Secretary) to:

> develop a uniform methodology for analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy.[75]

It further requires that the methodology in the Report (Methodology) "be published, along with any analysis it produces, on the Department of Energy's website within 90 days of the date of this order," or July 7, 2025.[76]

The Executive Order describes the featured role that the Report will play in future DOE actions. EO 14262 § 3 is titled "Addressing Energy Reliability and Security with Emergency Authority" and § 3(c) directs the Secretary to "establish a process by which the [Methodology],

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[69] 10 C.F.R. § 205.373.
[70] 10 C.F.R. §§ 205.373(a)-(o).
[71] *See, e.g.*, *Environmental Integrity Project v. DOE*, 471 F. Supp. 3d 132 (D.D.C. 2023).
[72] 90 Fed. Reg. 8433.
[73] *See Id*. (providing no factual support for claimed emergency). Many of the States have since joined litigation challenging that declaration. *See* Complaint, *Washington v. Trump*, NO. 2:25-cv-00869 (W.D. Wa. May 9, 2025).
[74] The EO was signed alongside Exec. Order No. 14261, Reinvigorating America's Beautiful Clean Coal Industry and Amending Executive Order 14241, 90 Fed. Reg. 15517 (Apr. 8, 2025), at a White House event with members of the coal industry.
[75] Exec. Order No. 14262, 90 Fed. Reg. 15521, 15521 (Apr. 8, 2025).
[76] Exec. Order No. 14262, 90 Fed. Reg. 15521, 15521 (Apr. 8, 2025) (referring to § 3(b)(iii)).

and any analysis and results it produces, are assessed on a regular basis, and a protocol to identify which generation resources within a region are critical to system reliability."[77] It indicates the protocol shall "include all mechanisms available under applicable law, including Section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource within the at-risk region."[78] In short, Executive Order 14262 instructs DOE to publish a methodology by July 7, 2025 that will form the basis for future exercises of its Section 202(c) authority.

d. DOE's 2025 Emergency Orders Preventing the Retirement of Fossil Fuel Power Plants.

Since January 20, 2025, the U.S. Department of Energy (DOE) has issued five emergency orders under Section 202(c) of the Federal Power Act (FPA), a sharp uptick from the less than one order per year issued on average from 2017-2024.[79] Three of these orders were largely in line with DOE's historic Section 202(c) practice – allowing units to modify their operations in response to acute risks to the grid.[80] However, in late May 2025 DOE issued a pair of Section 202(c) orders requiring facilities that were slated to retire the very next business day to remain on-line. These orders represent a marked shift in how Section 202(c) has historically been used.[81]

For example, the orders for the J.H. Campbell Generating Station in Michigan and the Eddystone Plant in Pennsylvania, both previously slated for retirement, cited general concerns about resource adequacy and not any acute emergency. In Michigan, regulators warned that the Campbell order would place upward pressure on ratepayers, particularly in Consumers Energy's service territory, where decommissioning costs were already being recovered through base rates. One Michigan regulator estimated that the costs of complying with DOE's order for 90 days would approach $100 million.[82] Consumers Energy has since disclosed that continued operation

[77] Exec. Order No. 14262, 90 Fed. Reg. 15521, 15522 (Apr. 8, 2025) (referring to § 3).
[78] Exec. Order No. 14262, 90 Fed. Reg. 15521, 15522 (Apr. 8, 2025) (referring to § 3) (emphasis added).
[79] U.S. DEP'T OF ENERGY, *DOE Issues 202(c) Orders to PREPA for Grid Stability*, https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority.
[80] *See* Duke Energy Carolinas (Order No. 202-25-5) (allowing increased operations to support grid stability); H.A. Wagner (Order No. 202-25-6) (allowing exceedance of operational limit – but maintained compliance with pollution control requirements – to allow units to respond to demand); PREPA (Order No. 202-25-1) (requiring measures to mitigate outage risks during high load conditions)
[81] U.S. Dep't of Energy, Order No. 202-25-3 (May 23, 2025), https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf [https://perma.cc/Q7P7-TDTX] [*hereinafter* "Campbell Order"]; Eddystone Order, *supra* note 9.
[82] *See, e.g.*, Ella Nilsen, *The Trump Admin Ordered a Coal Power Plant to Stay On Past Retirement. Customers in 15 States Will Foot the Bill*, CNN (June 6, 2025), https://www.cnn.com/2025/06/06/climate/michigan-coal-plant-energy-cost-wright.

of the plant in the first five weeks since the Order was issued has resulted in a net financial impact of $29 million.[83]

e. DOE Publishes its Methodology and Reliability Standard to Guide Future Section 202(c) "Reliability Interventions."

On July 7, 2025, DOE published a "Report on Evaluating U.S. Grid Reliability and Security," which set forth the methodology and reliability standard that the Executive Order had mandated. *See* Report at *vi* (hereinafter, "the Report"). DOE stated the methodology "will be assessed on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States." *Id*. Despite this statement, DOE has not explained how or when it will re-assess the methodology and, to date, has not involved the public in the creation of the methodology or offered an opportunity for public comment on the methodology.

i. DOE did not provide public notice or an opportunity for comment on the Report.

Before publishing the Report, DOE provided no public notice or request for comment on methods or reliability standards that DOE was considering. DOE did not consult with the undersigned States or, to the States' knowledge and belief, consult with any grid operator or other State on appropriate mechanisms to ensure grid reliability and grid reliability issues around the country.[84] Other than the statements in the Report, DOE has not made the underlying data or models available to allow the public to reproduce or test DOE's analysis. DOE has not requested public comment on the Report, opened any administrative proceeding to otherwise involve the public in DOE's methodology, or published the Report in the Federal Register.

DOE has confirmed, consistent with the Executive Order's mandate, that it will rely on the Report to justify future Section 202(c) orders.[85] DOE explained in the June 2025 Eddystone Order that it would use the forthcoming Report "to establish a protocol to identify which generation resources within a region are critical to system reliability and prevent identified generation resources from leaving the bulk power system[,]" including potential Section 202(c) orders extending DOE's Eddystone Order.[86] DOE also issued the Report with a "Fact Sheet,"

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[83] *See supra* notes 5-6 *and accompanying text*; NRDC, *Trump Administration's DOE Is Forcing Coal Plants to Stay Open. Michigan Is the First Target* (June 16, 2025), https://www.nrdc.org/bio/derrell-e-slaughter/trump-administrations-doe-forcing-coal-plants-stay-open-michigan-first.
[84] *See* Report at i (acknowledging lack of data from regional and utility levels).
[85] See Report at vi (explaining that DOE's standard will be used to "guide reliability interventions"), 1 (emphasizing the need for DOE's "decisive intervention" in energy markets), 10 (analyzing ERCOT because "FPA Section 202(c) allows DOE to issue emergency orders to ERCOT").
[86] Eddystone Order, *supra* note 9.

wherein DOE explained that the methodology will be used to "prevent [] generation resources from leaving the bulk-power system."[87]

ii. DOE's analysis rests on key assumptions about load growth, retirements, and capacity additions.

The Report's analysis rests on assumptions about future electricity demand (referred to as "load growth"), anticipated retirements of existing facilities ("retirements"), and future electricity generation sources (referred to as "capacity additions"). DOE made additional assumptions, some explicit and others implicit, which the States have not yet been able to fully analyze or comment on here.[88]

Regarding load growth, DOE assumes 101 Gigawatts ("GW") of new load will be added to the grid by 2030.[89] DOE projects that data centers, especially for developing Artificial Intelligence ("AI"), will add 50 GW of that new load, and other demand growth will add 51 GW. DOE appears to assume that data-center load will be "firm," meaning electricity to meet that demand must be guaranteed at all times.[90] That is in contrast to "interruptible" load for which supply can be reduced during peak periods.[91] DOE also appears to assume that all the new data centers will connect to the grid, rather than rely on "behind-the-meter" generation and that regulators and grid operators will allow every MW of new load to connect to the grid on a firm basis, even if doing so threatens the grid's reliability.[92] Based on these assumptions, DOE projects a 15% increase in load by 2030.[93]

The Report assumes 51 GW of non-data-center load, purportedly based on the NERC's 2024 ITCS projections.[94] DOE does not explain why using projections from a NERC report on inter-regional transmission is reasonable or why those projections are reliable for DOE's purposes. Additionally, NERC's 2024 projections likely already include some data center load expectations, as well as policies to encourage the electrification of transportation, heating and cooling, and other energy uses that the Trump Administration has rescinded or is planning to

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[87] U.S. DEP'T OF ENERGY, *Fact Sheet: The Department of Energy's Resource Adequacy Report Affirms The Energy Emergency Facing The U.S. Power Grid* (2025), https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf [https://perma.cc/YLX7-8G7T]; *see also* Press Release, U.S. Dep't of Energy, Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security (July 7, 2025), https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security [https://perma.cc/8TEJ-AGH6] (stating that its "methodology also informs the potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act").
[88] *See generally* Report at 10-19.
[89] Report at 2-3.
[90] Report at 18.
[91] *Id.*
[92] *See id.* at 2-3, 15-18.
[93] *See* Ric O'Connell, *GridLab Analysis: Department of Energy Resource Adequacy Report* (July 11, 2025), https://gridlab.org/gridlab-analysis-department-of-energy-resource-adequacy-report/ [https://perma.cc/GN56-VLNA].
[94] *See* Report at 11.

rescind.[95] DOE apparently did not account for shifting electrification policies in its load projections.

Regarding retirements, DOE assumed 104 GW of "firm capacity" retirements by 2030, roughly three-quarters from coal-fired power plants and one-quarter gas plants.[96] *Id*. at 5; see also Report at 3, 12-13, A1-A8. DOE included approximately 50 GW of "confirmed retirements," retirements that have been formally recognized by system operators as having started the official retirement process and are assumed to retire on their expected date.[97] DOE also included approximately 50 GW of "announced retirements," which are generators that have publicly stated retirement plans but not formally notified system operators or initiated the retirement process.[98]

Regarding capacity additions, DOE took a more conservative approach. Rather than including all announced projects, DOE assumed "that only projects considered very mature in the development pipeline—such as those with signed interconnection agreements—will be built." Report at A-5. These projects, known as Tier 1 resources, are by their very nature likely to be built in the short term. As a result, DOE assumed "minimal capacity additions beyond 2026." *Id*. In addition, DOE does not appear to have modeled new transmission projects, despite their grid reliability benefits.

The Report's assumptions about load growth and electricity supply differ significantly from other forecasts.[99] As one grid reliability expert commented, DOE's report "used aggressive assumptions regarding load growth and retirements, but conservative assumptions about how much new generation capacity will be added, even assuming no new resources after 2026."[100] For example, DOE assumed 15% load growth by 2030, but the U.S. Energy Information Agency recently assumed just 6% in their "high" growth" case.[101] Other differences with the Energy

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[95] *See* NERC, 2024 Long Term Reliability Assessment Report 8 (July 15, 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf [https://perma.cc/NMP4-KRN5] (discussing how "the continued adoption of electric vehicles and heat pumps is a substantial driver for demand around North America").
[96] Report at 5.
[97] *Id.* at 12; *see also* O'Connell, *supra* note 93.
[98] Report at 12.
[99] Report at 2 (noting that demand forecasts vary widely).
[100] O'Connell, *supra* note 93.
[101] U.S. Energy Information Administration, Form EIA-860 (June 11, 2025) https://www.eia.gov/electricity/data/eia860/.

Information Agency forecasts are described in the chart below:[102]

DOE Report Assumptions vs. U.S. Energy Information Administration Data:

	DOE Report	EIA 860
Load growth:	101 GW	N/A
Capacity Additions	209 GW	200 GW
Gas Capacity Additions	22 GW	35 GW
Battery Capacity Additions	31 GW	53 GW
Retirements	104 GW	52 GW

The Report also does not address actions already being taken by states, utilities, and regional grid operators to meet increased load growth or how markets are already responding to increasing demand. As GridLab explained in its analysis:

> Markets and utilities have already responded with plans to add new capacity and fast track new resources. These include PJM's Reliability Resource Initiative, which plans on adding 11 GW of new firm resources by 2030. SPP and MISO both have proposals at FERC (called ERAS) that could add another 30 GW of firm resources. Those three regional efforts alone would add roughly twice what the DOE assumed for the entire nation.[103]

iii. Based on these assumptions and DOE's resource adequacy standard, DOE concluded intervention in electricity markets is needed to prevent outages.

DOE then adopted a novel "resource adequacy standard," using a combination of non-traditional and non-standardized metrics ("Loss of Load Hours" and "Normalized Unserved Energy").[104] DOE selected the target to be achieved with each metric.[105]

DOE did not define what energy sources it considered "firm" capacity or why only those sources provide the necessary attributes for grid reliability. DOE's usage of the term in the report suggests that only coal or gas power plants count as "firm" capacity and excluded other sources that could provide similar, greater, or different levels of reliability (like batteries or transmission) from its analysis.[106]

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[102] O'Connell, *supra* note 93.
[103] *Id*.
[104] Report at 3-4.
[105] *Id.*
[106] *See, e.g.*, *id.* at 1, 32, 37.

DOE portrayed three scenarios in an attempt to assess the impact of planned retirements on resource adequacy in 2030.[107] The first scenario is "Plant Closures," which assumes that announced retirements and capacity additions "in the final stages for connection" that are "either under construction or ha[ve] received approved planning requirements" will occur.[108] The second scenario is "No Plant Closures," which has the same assumption about additions as the "Plant Closures" scenario but assumes no retirements.[109] The third scenario is "Required Build" which uses the "Plant Closures" scenario's assumptions about retirements and then artificially adds enough hypothetical perfect capacity to the system to meet DOE's new reliability standard.[110] Perfect capacity is hypothetical capacity that experiences no outages and is used in the modeling "to avoid the complex decision of selecting specific generation technologies, as that is ultimately an optimization of reliability against cost considerations."[111]

DOE then concluded, based on the above assumptions, the risk of power outages in 2030 would be 100 times higher in 2030 than it is today.[112] DOE concluded that "decisive intervention" and "robust and rapid reforms" are necessary to avoid this result and to accommodate "projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation.[113] Numerous grid experts have commented on the shortcomings of this approach.[114]

III. Statement of Issues and Specification of Errors.

1. The Report is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the Administrative Procedure Act and Federal Power Act because it suffers from numerous analytical, mathematical, and empirical flaws, including but not limited to the following:
    a. DOE relies on key assumptions about load growth, retirements, and capacity additions that are unreasonable and unsupported by evidence or logic.

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[107] *Id.* at 3, 5.
[108] *Id.* at 4-5.
[109] *Id.*
[110] *Id.*
[111] *Id.* at 5.
[112] *Id.* at 1.
[113] *Id.*
[114] *See, e.g.*, Jeff St. John, *Critics Fear Trump Will Use Flawed DOE Report to Push Pro-Coal Agenda*, CANARY MEDIA (July 14, 2025), https://www.canarymedia.com/articles/fossil-fuels/trump-doe-report-open-coal-plants [https://perma.cc/2T7L-3FWX]; Matthias Fripp & Brendan Pierpont, *Energy Department's Flawed Grid Study Props Up Expensive, Zombie Power Plants*, UTILITYDIVE (July 24, 2025), https://www.utilitydive.com/news/doe-grid-reliability-study-zombie-power-plants/753596/ [https://perma.cc/QH3V-KM5R]; INST. FOR POL'Y INTEGRITY, ENOUGH ENERGY: A REVIEW OF DOE'S RESOURCE ADEQUACY METHODOLOGY (July 2025), https://policyintegrity.org/files/publications/IPI_EnoughEnergy_FinalReport.pdf [https://perma.cc/WN39-K9LE].

b. DOE assumes the transmission grid will remain static over the next five years and fails to consider how new transmission projects in development will impact reliability.
c. DOE fails to define "firm power capacity" or reasonably explain why DOE apparently considers only coal and gas to be "firm power capacity" when other generation sources, energy storage, or transmission could provide similar or greater reliability attributes.
d. DOE's assumptions unreasonably presume that the market, grid operators, and state regulators will take no action in the next five years to address load growth or reliability issues, and that no alternative other than preserving aging coal and gas power plants will ensure grid reliability.
e. DOE's analysis suffers from mathematical errors, analytical flaws, and lacks sufficient data or regional input. Those flaws are amply described in the attached analysis by the Institute for Policy Integrity and are incorporated and adopted here. *See* IPI Report (attached as Ex. XX).
f. Although DOE acknowledged that data and input from states and regional entities could improve the analysis, DOE chose not to consult with those entities or seek to obtain that data.
g. DOE selected non-traditional and non-standardized resource adequacy metrics and targets to be achieved without providing a reasoned explanation for its choices, including why it selected Normalized Unserved Energy ("NUSE") and Loss of Load Hours ("LOLH") instead of other possible metrics that would provide different data, an explanation of the costs and benefits of its choices and the target to be achieved, and why a nationwide target is appropriate despite regional differences in the costs and benefits with regard to resource adequacy.
h. DOE offers no reasonable explanation how the Report could be used to identify "at-risk region[s] and guide reliability interventions" when it arbitrarily relies on geographic groupings that do no match boundaries used by utilities, balancing authority areas, transmission planning regions, regional wholesale markets, NERC regional entities, or NERC reliability coordinators to reliably operate the nation's electric grid.

These assumptions and omissions work together to arbitrarily tip the scales in favor of finding a resource adequacy risk. *See Motor Vehicles Mfrs. Ass'n v. State Farm*, 463 U.S. 29, 43 (1983); *WildEarth Guardians v. U.S. Bureau of Land Mgmt*., 870 F.3d 1222, 1237 (10th Cir. 2017); *Nat. Res. Def. Council, Inc. v. Herrington*, 768 F.2d 1355, 1391 (D.C. Cir. 1985); *see also infra* Section 4.a.

2. The Report is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the Administrative Procedure and Federal Power Acts because it pursues an extra-statutory motive of preserving aging and uneconomic fossil fuel

power plants at consumer expense, which contradicts the Federal Power Act's express goal of preserving just and reasonable rates and preventing undue discrimination or preference. The Administration's energy actions, when viewed collectively, also demonstrate that DOE has prejudged the outcome of this proceeding and intended its analysis to reach only one result: preventing the retirement of fossil-fueled power plants. *See Dep't of Com. v. New York*, 588 U.S. 752, 785 (2019); *Gresham v. Azar*, 950 F.3d 93, 104 (D.C. Cir. 2020), *vacated as moot*, *Becerra v. Gresham*, 142 S. Ct. 1665 (2022). *See also infra* Section 4.a.iii-iv.

3. The Report is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the Administrative Procedure and Federal Power Acts because it purports to guide emergency action under Section 202(c) of the Federal Power Act but does not describe an "emergency" within the meaning of the Federal Power Act or DOE's implementing regulations. *See* 16 U.S.C. § 824a(c)(1); 10 C.F.R. § 205.371; *Otter Tail Power Co. v. Federal Power Com.*, 429 F.2d 232, 234 (8th Cir. 1970). *See also infra* Section 4.b.

4. The Report is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the Administrative Procedure and Federal Power Acts because it "fails to consider an important aspect of the problem" and fails to consider reasonable alternatives. Specifically, the Report ignores alternatives, or in some cases actively prevents viable alternatives with no explanation, such as expanding interregional transmission, batteries, renewable energy, incorporating data centers flexibly into load, and the existing resource adequacy mechanisms that are used by states and regional grid operators to assess reliability and respond to resource adequacy needs. *See State Farm*, 463 U.S. at 43. *See also infra* Section 4.a. (arbitrary and capricious) and section 4.c. (existing resource adequacy mechanisms)].

5. The Report is *ultra vires* and contrary to law in violation of the Administrative Procedure and Federal Power Acts because it intrudes upon matters reserved for the States and the Federal Energy Regulatory Commission. DOE does not possess authority to set nationwide resource adequacy standards or regulate sources of electricity generation. *See* 16 U.S.C. § 824b(1); *Whitman v. Am. Trucking Ass'ns, Inc.*, 531 U.S. 457, 468 (2001). *See also infra* Section 4.d.

6. The Report violates the Administrative Procedure Act, 5 U.S.C. 553, because it establishes a legislative rule without first providing public notice and comment. *See Shalala v. Guernsey Mem'l Hosp.*, 514 U.S. 87, 99–100 (1995); *Nat'l Min. Ass'n v. McCarthy*, 758 F.3d 243 (D.C. Cir. 2014); *Children's Health Care v. Centers for Medicare & Medicaid Servs.*, 900 F.3d 1022 (8th Cir. 2018). *See infra* Section 4.e.

7. The Report is arbitrary, capricious, and contrary to law in violation of the Administrative Procedure Act because it allegedly supports issuing Section 202(c) emergency orders based on factors and procedures that conflict and are inconsistent with DOE's existing regulations. *See Emergency Interconnection of Electric Facilities*, 46 Fed. Reg. 39,984 – 39,989 (Aug. 6, 1981); 10 C.F.R. §§ 205.371 *et seq*. *See infra* Section 4.e.ii.

8. The Report is arbitrary and capricious in violation of the Administrative Procedure Act because DOE failed to acknowledge that its methodology and protocol for issuing Section 202(c) orders is inconsistent with the factors for determining when an emergency exists that DOE's regulations already set out. *See Emergency Interconnection of Electric Facilities*, 46 Fed. Reg. at 39,985; 10 C.F.R. §§ 205.371, 205.373. It is also inconsistent with DOE's previous position that emergency orders are inappropriate for long-term reliability issues and a "utility must solve long-term problems itself." 46 Fed. Reg. at 39,985; *see also* 10 C.F.R. § 205.371. Agencies act arbitrarily when they fail to display awareness that they are changing position and offer good reasons for the change in policy. *See Food & Drug Administration v. Wages & White Lion Invs*., 604 U.S. ---, 145 S. Ct. 898, 918 (2025); *see also infra* Section 4.e.

IV. Request for Rehearing

a. DOE's Report is Based on Flawed and Arbitrary Assumptions and is Unsupported by Substantial Evidence.

The Report's conclusions rest on critical assumptions about load growth, retirements, and capacity additions, but DOE did not reasonably explain how it arrived at those assumptions or support its choices with substantial evidence. At times, DOE's assumptions are internally inconsistent and arbitrarily tip the scales in favor of finding a need to prevent scheduled retirements. The Report also seems to adopt a definition of "firm capacity" that includes only fossil-fuel power plants, but does not explain why other generation sources or batteries are not also "firm capacity." DOE has also failed to make the data it relied on publicly available – rendering it impossible to fully test DOE's analysis.[115]

[115] Due to the lack of public notice or any consultation or opportunity for involvement in the DOE's development of this report, the States have not had an opportunity to fully analyze DOE's methodology. DOE also has not made the data or models it used publicly available, which would allow the States to critically assess or replicate DOE's analysis and uncover additional flaws in DOE's approach. As such, the States reserve the right to raise additional flaws with DOE's analysis and conclusions at a later date, as they continue to analyze the Report.

Agencies act arbitrarily when they base decisions on key assumptions that are irrational or unsupported.[116] Moreover, when agencies use complex models, they must publicly reveal the assumptions and data incorporated into their models and "provide a full analytical defense" of their model.[117]

i. DOE fails to reasonably explain or support its load growth assumptions

DOE assumes 15% load growth by 2030, half of which DOE assumes will serve new data centers.[118] In doing so, DOE presumes – without evidence or a rational explanation – that data center load is firm (i.e., it cannot be interrupted at peak times). That assumption is arbitrary and directly undermined by recent advances in both policy and technology.

Some policymakers are already requiring data centers to be flexible, interruptible load.[119] In Texas, for example, a new law grants ERCOT more flexibility to curtail certain data center loads in the event of a grid emergency.[120] DOE did not grapple with the impact of this law on its underlying assumptions despite the fact that curtailing such load during peak hours "could go a long way towards avoiding the DOE-identified resource adequacy problem" in ERCOT.[121]

DOE also ignores the possibility of industry reducing its demand for electricity either as a matter of policy or innovation in this rapidly developing field. NVIDIA, the foremost supplier of hardware for AI data centers, recently announced a new power supply unit that can reduce peak grid demand by up to 30%.[122] In another recent example, Google agreed to a demand response framework with two utilities that would reduce how much electricity is used by its data centers during peak hours.[123]

DOE's reliance on an inflexible assumption for data center load reflects a failure to consider how this rapidly developing industry may adapt to address its significant energy

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[116] *WildEarth Guardians v. U.S. Bureau of Land Mgmt*., 870 F.3d 1222, 1237 (10th Cir. 2017); *Hisp. Affs. Project v. Acosta*, 901 F.3d 378, 389 (D.C. Cir. 2018) (noting agencies' affirmative duty to examine key assumptions underlying their policies).
[117] *Nat. Res. Def. Council, Inc. v. Herrington,* 768 F.2d 1355, 1385 (D.C. Cir. 1985); *see also Columbia Falls Aluminum Co. v. EPA*, 139 F.3d 914, 923 (D.C. Cir. 1998).
[118] Report at 18.
[119] *See* Ex. D, Nicholas Institute Report at 25; *see also* Ex. C, IPI Report at 24
[120] S.B. No. 6 § 4, 89th Legislature (Tex. 2025) (to be enacted at Tex. Util. Code § 39.170); *See also* Ex. C, IPI Report at 26.
[121] Ex. C., IPI Report at 26.
[122] Meris Lutz, *NVIDIA addresses AI peak power demand, spikes in new rack-scale systems*, UtilityDive (July 30, 2025), https://www.utilitydive.com/news/nvidia-rack-scale-system-smooth-ai-power/756279/.
[123] Laila Kearney, *Google agrees to curb power use for AI data centers to ease strain on US grid when demand surges*, Reuters (Aug. 4, 2025), https://www.reuters.com/sustainability/boards-policy-regulation/google-agrees-curb-power-use-ai-data-centers-ease-strain-us-grid-when-demand-2025-08-04/.

demand. This renders DOE's blunt conclusions regarding resource adequacy arbitrary and capricious.[124]

The Report also adopts an unreasonably high estimate of future data center load, arbitrarily claiming it is simply adopting a "midpoint assumption." Report at 15. DOE admits that there are "wide variations" in estimates of future data center load growth, yet the agency does not appear to have conducted any actual evaluation of those estimates to determine their respective accuracy. DOE must explain why its adoption of an estimated 50 GW load growth is more reliable or likely than other projections. It cannot just pick what it calls a "midpoint" from available studies and move forward. A rational approach would involve projecting future growth under a number of scenarios. Indeed, DOE did not account for a number of factors that temper against aggressive assumptions for future data center load growth. Those factors include the fact that data center developers often make duplicative requests for service; that data center deployment is limited by the availability of chips and processing systems; that data center efficiency may increase in the future as technology develops; and that utilities are incentivized to adopt aggressive load forecasts.[125]

The Report also assumes an additional 51 GW of non-data center load growth. DOE states that it adopted this assumption from NERC's 2024 ITCS Report. But NERC's 2024 ITCS Final Report does not contain its own load growth projections.[126] DOE has not cited which NERC projections it is relying on, what data underlie those projections, or why DOE considers it reliable for purposes of setting a uniform resource adequacy standard and guiding reliability interventions. Moreover, NERC's forecasts already contain data center load expectations meaning the Report may be double counting projected future demand from data centers.[127] NERC's forecasts may also contain other assumptions that are no longer appropriate, such as demand forecasts based on federal incentives to electrify transportation that no longer exist. Additionally, as the Institute for Policy Integrity explains in its report, DOE's method for distributing load growth across the country is questionable and does not necessarily reflect actual market decisions.[128]

ii. DOE arbitrarily assumes 104 GW of retiring capacity by 2030 but only 22 GW of additions in the same time period.

The Report also assumes the retirement of 104 GW of generating capacity by 2030, an extremely aggressive estimate that cannot withstand any level of scrutiny. [129] That assumption is inconsistent with the U.S. Energy Information Administration's data from June 2025 showing

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[124] *See* Report at 17, 40; *see also* Ex. C, IPI Report at 26 ("DOE should have considered the possibility that some of the projected data center load would be flexible, especially in ERCOT").
[125] *See generally* Ex. E, London Economics International Report.
[126] Ex. A, NERC ITCS Report.
[127] Report at 17.
[128] See Ex. C, IPI report at 24; *see also* Ex. E, LEI Report at 10-14 (noting that data centers have many choices where to locate).
[129] *See* Report at 5, A-5.

only half of that capacity is actually set for retirement. [130] This projection is also flawed because it arbitrarily includes announced retirements even though those generators have not formally provided notice of their retirement or initiated the retirement process. [131] Many of these resources have, however, pushed back their actual retirement dates due to changing market conditions and the policies of the current administration.[132]

At the same time that the Report overestimates the amount of load growth and retirements by 2030, it underestimates capacity additions that can be reasonably expected to come online in that same timeframe. DOE assumes only Tier 1 projects will be built by 2030. Because Tier 1 additions are projects that are either under construction or received approved planning requirements, nearly all will be in service by 2026.[133] DOE acknowledged that the Tier 1 assumption "results in minimal capacity additions beyond 2026," Report at A-5, yet DOE did not explain why that assumption was nonetheless reasonable when forecasting conditions to 2030.

By focusing solely on Tier 1 projects, DOE excludes announced capacity additions or even capacity additions that are seeking approval to interconnect to the grid (NERC "Tier 2" projects).[134] Excluding capacity that has been requested but has not yet received approval for planning requirements does not make sense for predictions stretching out five years from now. Both common sense and history suggest that at least some of these additions will receive approval in that time.[135] DOE has thus adopted a view of generator additions that is completely at odds with its projection of generator retirements and together the approach arbitrarily tips the scales in favor of finding a resource adequacy risk.

These assumptions seem to ignore a fundamental property of market dynamics: that supply will respond to rising demand. DOE assumes that generators who have not initiated the retirement process will retire even if remaining in the market would still be economic for them. And DOE assumes that developers will refrain from building any new energy projects from 2027-2030 despite market signals that additional capacity is needed. Those assumptions are unreasonable and render the Report arbitrary and capricious.[136]

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[130] U.S. Energy Information Administration, Form EIA-860 (June 11, 2025) https://www.eia.gov/electricity/data/eia860/.
[131] *See* Report at 5, A-5.
[132] Kevin Clark, *Where coal plant retirements are happening – And what could delay them*, Power Engineering (July 14, 2025), https://www.power-eng.com/coal/plant-decommissioning/where-coal-plants-are-closing-and-what-could-delay-them/. *See also,* Joe Schulz, *We Energies will delay Oak Creek coal plant retirement by one year to 2026*, Wisconsin Public Radio (June 26, 2025), https://www.wpr.org/news/we-energies-delay-oak-creek-coal-plant-retirement-2026. See also Ex. C, IPI Report at 23-24 (explaining why DOE's retirement figure likely overstates retirements).
[133] NERC, *2024 Long-Term Reliability Assessment* at 22, 136-37 (2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.
[134] *Id*.
[135] *See also* Ex. C, IPI Report at 21-22 (applying historical statistics and data to demonstrate why DOE's exclusion of Tier 2 additions is unreasonable).
[136] *See* Report at 1 (concluding that, based on its model, intervention is needed to ensure a reliable power grid and meet the AI growth requirements).

DOE also arbitrarily excludes new transmission projects from its analysis altogether. Interregional transmission improvements are known to be one of the most cost-effective ways of improving grid reliability.[137] DOE apparently assumes that the nation's transmission will remain static over the next five years, despite ongoing planning processes and reforms to increase transmission projects and the well-documented reliability benefits that more transmission can provide.[138] DOE also appears to undercount the reliability benefit of existing transmission systems in its analysis.[139] It is nonsensical to ignore the benefits of new transmission when DOE is purportedly seeking to improve the reliability of the electric grid and keep costs affordable for consumers.

iii. DOE's analysis lacks sufficient regional granularity and suffers from other analytical flaws.

DOE's analysis also suffers from mathematical errors, analytical flaws, and lacks sufficient data or regional input further highlighting the importance of leaving resource adequacy to the states. DOE itself recognized that the Report's lack of regional data was a shortcoming that undercut its conclusions. As DOE acknowledges, "[e]ntities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience."[140] Despite this admission, DOE made no attempt to consult with States or grid operators on reliability issues or to obtain this data. An agency "may not tolerate needless uncertainties in its central assumptions when the evidence fairly allows investigation and solution of those uncertainties."[141]

This lack of state and regional granularity contributes to the report's unreasonable assumptions and overstated conclusions. Rather than focus on a region-specific analysis, DOE engaged in broad approximations to allocate nationwide projections to the various regions. For example, DOE started with a nationwide estimate of 50 GW of incremental data center load, allocated it across regions using state-level growth ratios from S&P's forecast, then mapped these state-level projections to the regions used for its analysis, the NERC Transmission Planning Regions (TPRs).[54] It is also unclear how DOE accomplished this mapping, given that the referenced NERC TPRs do not perfectly map to states.[56]

Further, the Report's conclusions regarding resource adequacy are contradictory at times, even within a single region, rendering DOE's characterization of certain regions' resource adequacy arbitrary and capricious. To guide its assessments, DOE set reliability standards of "[n]o more than 2.4 hours of lost load in an individual year" and "[n]o more than an NUSE [Normalized Unserved Energy] of 0.002%."[142] In its analysis of the PJM region, the Report highlights PJM's average loss of load figure of 2.4 hours under the current system analysis, apparently to indicate resource inadequacy despite clearly not *exceeding* the threshold DOE set,

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[137] *See generally* Ex. A, NERC ITCS Report; *see also* Ex. F, GridStrategies Report at 1.
[138] *See generally* Ex. A, NERC ITCS 2024 Report (identifying areas where new transmission can significantly improve reliability); Ex. F, GridStrategies, Resource Adequacy Value of Interregional Transmission (June 2025)
[139] *See* Ex. C, IPI Report at 25.
[140] Report at i.
[141] *Nat. Res. Def. Council, Inc. v. Herrington*, 768 F.2d 1355, 1391 (D.C. Cir. 1985).
[142] Report at 4.

while also describing the region's current system as "experienc[ing] shortfalls, but … below the required threshold."[143] At the same time, the Report notes that "[f]or the current system, this analysis identifies an additional 2.4 MW of capacity to meet the NUSE target for PJM," despite the Report's summary of the PJM's modeled NUSE metric in the current system clocking in at 0.0008%, again clearly meeting the reliability threshold that DOE itself selected.[144]

The Report also fails to explain how it could be used to identify "at-risk region(s) and guide reliability interventions"[145] while relying on many geographic groupings that do not match the boundaries used by utilities, balancing authority areas, transmission planning regions, regional wholesale markets, NERC regional entities, or NERC reliability coordinators to reliably operate the nation's electric grid.

For example, the "Front Range" region in the Report includes Colorado and portions of New Mexico and Wyoming but those boundaries are geographically different from regions analyzed in NERC's reliability assessments. NERC's 2025 Summer Reliability Assessment includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota in the "WECC-Rocky Mountain" region, and includes Arizona and New Mexico, most of Nevada, and small parts of California and Texas in the "WECC-Southwest" region.[146] The regional grouping used in the Report is arbitrary and inconsistent with these existing groupings.

The Report states its model is derived from NERC's Interregional Transfer Capability Study ("ITCS")[147] and asserts the subregions used in the Report, called Transmission Planning Regions ("TPRs"), "match the regional subdivisions in the NERC ITCS study, itself based on FERC's transmission planning regions."[148] However, the ITCS makes clear that FERC's transmission planning regions were altered to create the TPRs for the ITCS,[149] which was focused on transfer capability between neighboring regions and not resource adequacy. [150] The ITCS Final Report does not explain how specific footprints were determined in any detail.[151] In January 2025 comments filed with FERC in response to the ITCS report, DOE commented "[t]he subregion boundaries used in the ITCS are useful for evaluating interregional transfer capability given the chosen methodology, *but not for evaluating resource adequacy of those subregions*."[152] DOE explained the ITCS subregions do not reflect actual monitored transmission constraints, nor

[143] Report at 27 & Tbl. 8.
[144] Report at 9, 27 Tbl. 8. *See also* Ex. C, IPI Report at 20.
[145] Report at vi.
[146] NERC, *2025 Summer Reliability Assessment* at 36, 38 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf.
[147] Report at 2.
[148] Report at 10 n.14.
[149] Ex. A, NERC ITCS Report at 7.
[150] Fiscal Responsibility Act of 2023, H.R. 3746, 118th Congress (2023–2024) (directing NERC to study the total transfer capability between transmission planning regions).
[151] *See* Ex. A, NERC ITCS Report at 7.
[152] Comments of the U.S. Dep't of Energy, FERC Docket No. AD25-4-000, at 6 (Jan. 17, 2025) (emphasis added).

do they accurately capture the service territories or balancing authority areas that are the footprints on which resource adequacy decisions are made.[153]

Despite DOE's earlier comments, the DOE Report fails to explain why the TPR subregions, many of which have no similarities to the regions actually used by NERC to assess reliability nor the planning regions used by entities with resource adequacy obligations, are now appropriate geographic boundaries for running resource adequacy scenarios and guiding reliability interventions. Returning to the example of the Front Range region, neither the ITCS Final Report nor the DOE Report explain why resource adequacy analysis should be done collectively for Colorado and portions of New Mexico and Wyoming, in which the load serving entities and balancing authorities plan their systems, acquire generating resources, and decide to interconnect to neighboring systems under completely separate processes. Because many of the Report's subregions are divorced from how the grid is actually planned and operated, they risk inaccurate groupings of load and available generating resources and incomplete understandings of how transmission capacity may be used in times of peak demand.

The Report suffers from other analytical shortcomings, which are amply described in the Institute for Policy Integrity's report and are expressly incorporated and adopted here.[154] As the Institute for Policy Integrity explained, DOE fails to offer a reasonable explanation for its choice of resource adequacy metrics and targets, outage thresholds, or the use of a deterministic model instead of a more accurate probabilistic model. By relying solely on weather data from recent years in a deterministic model, rather than a more statistically accurate probabilistic model, the Report "does not sufficiently account for uncertainty," weakening the strength of its modeled findings for 2030.[155]

Given the abundant shortcomings in DOE's methodology, it is unreasonable to rely on the data and analysis contained in the Report to draw any firm conclusions about the resource adequacy of any region of the United States electrical grid now or in 2030, and DOE's various findings of resource inadequacy despite these flaws is arbitrary and capricious.

iv. DOE's flawed analysis establishes an arbitrary and unlawful preference for fossil fuel plants over other methods to preserve grid reliability, contrary to the Federal Power Act.

The flawed assumptions discussed above lead to an obvious conclusion: that DOE designed the Report to satisfy the White House's goal of bailing out uneconomic and environmentally harmful power plants. DOE's report is not addressing an emergency, but seeking to prop up a coal industry that is unable to compete with cheaper and cleaner modern energy sources like wind, solar, and batteries.

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[153] *See id.* at 6-7.
[154] See Ex. C, IPI Report at 18-26
[155] *Id*. at 21.

Executive Order 14262 was signed alongside EO 14261 *Reinvigorating America's Beautiful Clean Coal Industry and Amending Executive Order 14241*. EO 14261 claims to "encourage and support our Nation's coal industry to increase our energy supply, lower electricity costs, stabilize our grid, create high-paying jobs, support burgeoning industries, and assist our allies." And President Trump's statements at the signing ceremony make clear that the two orders are intended to serve a complementary purpose. As the President said, with coal workers lining the stage behind him for a photo-op, "we're bringing back an industry that was abandoned" and "all those plants that have been closed are going to be opened."[156]

The President's Grid Reliability Order references his earlier Declaration of an Energy Emergency, *see* EO 14156 "Declaring a National Energy Emergency," which created an energy emergency based on an alleged shortage of affordable and domestic energy sources. In all orders, the President narrowly focuses on fossil fuels and specifically excludes wind, solar, or batteries from the definition of "energy." And the Administration has simultaneously taken steps to derail the wind and solar industries, revoking previously issued permits for offshore wind projects, pausing the issuance of approvals, permits, and loans for wind projects nationwide, and adding bureaucratic hurdles to the permitting process for wind and solar.[157]

To the extent that the Report advances the Administration's policy of discriminating against renewable energy, batteries, and transmission to advance the extra-statutory motive of preserving aging fossil fuel power plants at consumer expense, it is contrary to express goals of the Federal Power Act.[158] Sections 205 and 206 of the Federal Power Act require rates to be just and reasonable and not unduly discriminatory or preferential.[159] Purporting to justify Section 202(c) orders for fossil fuel plants that are not needed and ignoring other viable methods to preserve grid reliability at a lower cost for consumers is likely to result in unjust and unreasonable rates. While 202(c) permits deferral of this issue to FERC in a rate proceeding, DOE must – at minimum – consider how a streamlined and uniform methodology may impact rates and cost recovery.

Significantly, when DOE proposed in 2017 that FERC adjust its rates to compensate generation that could store 90 days of fuel on-site (i.e., coal and nuclear generation), FERC unanimously rejected that proposal.[160] FERC concluded that DOE failed to demonstrate that allowing all eligible resources to receive a special rate regardless of the specific reliability needs of that region would be a just and reasonable outcome.[161] DOE also failed to show that such a remedy "would not be unduly discriminatory or preferential" since only "certain resources [could] be eligible for the rate, thereby excluding other resources that may have resilience

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[156] Adam Burke, *Trump orders coal revival, but market favors natural gas*, NPR (April 17, 2025) https://www.npr.org/2025/04/16/nx-s1-5359013/trump-orders-coal-revival-market-favors-natural-gas.
[157] *See generally*, Complaint, New York, et al. v. Trump, et al., No. 25-cv-11221 (D. Mass., filed May 5, 2025) (describing Administration's assault on wind energy). *See also e.g.,* Department of the Interior, Secretarial Order 3437, https://www.doi.gov/document-library/secretary-order/so-3437-ending-preferential-treatment-unreliable-foreign; Department of the Interior, Secretarial Order 3438, https://www.doi.gov/document-library/secretary-order/so-3438-managing-federal-energy-resources-and-protecting.
[158] *See* FPA Sections 205 and 206; 16 U.S.C. §§ 824d, 824e.
[159] *Id*.
[160] *See* Order Terminating Rulemaking, 162 FERC ¶ 61,012, ¶ 16 (Jan. 8, 2018).
[161] *Id*.

attributes."[162] DOE's second attempt to manipulate the energy markets in favor of its preferred energy sources suffers from the same fatal flaws and its motives are contrary to the goals of the Federal Power Act.

b. The Report does not describe an "emergency" and cannot be used to justify future grid reliability interventions by DOE.

i. Common usage and regulation define "emergency" narrowly.

Section 202(c) is limited, by its own terms, to either "the continuance of any war in which the United States is engaged," or "whenever the Commission determines that an emergency exists *by reason of*" certain enumerated causes.[163] Those causes include: (1) "a *sudden* increase in the demand for electric energy," (2) "a shortage of electric energy or of facilities for the generation or transmission of electric energy," (3) a shortage of "fuel or water for generating facilities," and (4) "other causes."[164]

The relevant focus is therefore on the definition of "emergency." In 1930, just a few years before the Act's passage, Webster's New International Dictionary of the English Language defined "emergency" as a "sudden or unexpected appearance or occurrence… an unforeseen occurrence or combination of circumstances which calls for immediate action or remedy; pressing necessity; exigency." The year before the statute was last amended, Merriam-Webster's Dictionary and Thesaurus (2014) defined "emergency" as "an *unforeseen* event or condition requiring prompt action." Thus, at all relevant times "emergency" was defined as being unexpected or unforeseen and requiring some form of exigent response.

That limited reading of Section 202(c) is bolstered by the emergency provision's immediate statutory context. Section 202(c) is preceded by Section 202(b), which grants what is now the Federal Energy Regulatory Commission the authority to issue similar interconnection orders "*after* opportunity for hearing," indicating that Congress intended to place a temporal constraint upon the emergency authority in Section 202(c), limiting it to situations not amenable to public notice and hearing.[165]

DOE's regulations implementing Section 202(c) also suggest the provision's narrow applicability to only true emergencies. [166] DOE has provided that "actions under this authority are envisioned as meeting a specific inadequate power supply situation."[167] The regulations

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[162] *Id*.
[163] 16 U.S.C. § 824a(c)(1) (emphasis added).
[164] *Id.* (emphasis added). The catchall "other causes" must still be the "reason" that an emergency exists. *Id*. *See also* Rolsma, *The New Reliability Override,* 57 U. Conn. L. Rev. at 810-13.
[165] 16 U.S.C. § 824a(b); 42 U.S.C. § 7172(a)(1)(B).
[166] *See also* 46 Fed. Reg. 39987 (Aug. 6, 1981).
[167] 10 C.F.R. § 205.371.

further define applicable emergencies to include "an *unexpected* inadequate supply of electric energy," "*unforeseen* occurrences," or "a *sudden* increase in customer demand," echoing the.[168]

In guidelines for defining "inadequate utility system fuel inventory or energy supply," the regulations further specify that the threshold for such an emergency may be met "when, combined with other conditions, the projected energy deficiency upon the applicant's system *without emergency action by the DOE*, will equal or exceed 10 percent of the applicant's then normal daily net energy for load, or will cause the applicant to be unable to meet its normal peak load requirements *based upon use of all of its otherwise available resources* so that it is unable to supply adequate electric service to its ultimate customers."[169] This definition again narrows the circumstances in which DOE may exercise its 202(c) authority to those not redressable by other means, implicating only acute or imminent power shortages where no other recourse is available.[170]

ii. The report does not point to any sudden or unforeseen circumstances.

. DOE's report does not identify any region, except ERCOT, that currently fails to meet DOE's reliability targets.[171] DOE's flawed analysis points to a failure to meet reliability targets only in 2030. An expected increase in demand that can be projected over the next five years is not an energy emergency. Those shortfalls are not "unexpected" or "imminent" so as to justify a departure from normal planning procedures. The Report is squarely focused on 2030 and does not assess resource adequacy in any of the intervening years. According to the standard set out in *Otter Tail Power Co. v. Federal Power Com.*, 429 F.2d 232, 234 (8th Cir. 1970), the shortfalls predicted by the Report are at best policy crises "which [are] likely to develop in the foreseeable future but which [do] not necessitate immediate action." In other words, the concerns may be addressable using FPA § 202(b), but certainly not FPA § 202(c).

Significantly, DOE has never before issued a 202(c) order based on such a broad and speculative increase in load demand. On the contrary, prior to 2025, DOE had only used 202(c) to delay the retirement of generation facilities on three narrow occasions, as requested by the system operator or government body, and only for as long as necessary to address the imminent emergency.[172]

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[168] *Id.* (emphasis added).
[169] 10 C.F.R. § 205.375 (emphasis added).
[170] While the regulations also state that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency … ," the definition crucially does not allow for *projections* of such circumstances to qualify or include any qualifying terms indicating similar intent. On the face of the regulation, and consistent with reasonable interpretations of the statute, such an eligible power shortage must be sufficiently imminent to avoid reducing the inherent limitation of the word "emergency" to an absurdity. 10 C.F.R.§ 205.371.
[171] Report at 7.
[172] *See* Benjamin Rolsma, *The New Reliability Override*, 57 U. Conn. L. Rev. 789, 843-46 (2025).

iii. Reliance on the Report to justify a Section 202(c) order would be contrary to law.

Based on EO 14262 and DOE's own statements, it is evident that the Department intends to rely upon the analysis and methodology in the Report to justify future Section 202(c) orders.[173] But the Report cannot lawfully be relied upon to justify the exercise of DOE's limited emergency authority. Doing so would be contrary to law.[174]

As discussed above, the Secretary of Energy's authority under Section 202(c) of the Federal Power Act is statutorily limited to wartime or certain "emergency" situations; otherwise, similar proceedings fall under the jurisdiction of the Federal Energy Regulatory Commission through a process of notice and hearing.[175] Even taking the Report at face value, its own conclusions fail to describe anything resembling an emergency in any part of the country besides ERCOT.[176] Any conclusion that an emergency exists is undermined by the arbitrary nature of the Report's analysis.[177]

Moreover, the Report's conclusions, on their face, fail to describe an "emergency". Conclusions about resource adequacy five years in the future, in 2030, fall outside of the temporal limits of an "emergency" and are exactly the type of concern that should be dealt with through usual planning processes.[178] Any attempt by DOE to bootstrap future Section 202(c) orders to the Report would be in direct contradiction to its statutory authority to issue such orders and its own regulations implementing that authority.[179]

c. DOE failed to consider an important aspect of the problem: existing reliability mechanisms.

Agency action is arbitrary and capricious under the APA if it "fails to consider an important aspect of the problem." *Motor Vehicle Mfrs. Assn. of United States, Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983). Here, DOE has acted as if the Report exists on a blank slate of resource adequacy and reliability planning yet that could not be farther from the

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[173] *See* Report at vi; EO 14262 Sec. 3(c). In at least one Section 202(c) order issued after the publication of EO 14262 but before the release of the Report, the Department stated that it "plans to use this methodology to further evaluate" the generation units subject to that order. Order No. 202-25-4 ("Eddystone 202(c) Order") at 2 (May 30, 2025).

[174] *See* 16 U.S.C. § 824a(c); 10 C.F.R. §§ 205.370-371, 375.

[175] 16 U.S.C. §§ 824a(b)-(c); 42 U.S.C. §§ 7151(b), 7172(a)(1)(B).

[176] Report at 7 ("Analysis of the current system shows all regions except ERCOT have less than 2.4 hours of average load loss per year and less than 0.002% NUSE. This indicates relative reliability for most regions based on the average indicators of risk used in this study."); *see also* Ex. C, IPI Report at 29-31 ("Despite DOE's press statement asserting that the study's methodology can help guide [sic] 'guide Federal reliability interventions,' presumably to address the EO's [EO 14262] mandate that DOE find a way to routinize further 202(c) emergency orders, the study reports a fundamental limitation for doing so: It does not find any near-term reliability risk from current levels of resource adequacy." (footnotes omitted)).

[177] *See supra* Section 4.a.

[178] *See* Report at 8-9.

[179] 16 U.S.C. § 824a(c); 10 C.F.R. §§ 205.370-371, 375.

truth. As described above, a multilayered system of resource planning involving states and regional grid operators ensures adequate supplies and grid stability.[180]

The Report's conclusion that "absent intervention, it is impossible for the nation's bulk power system to meet the AI growth requirements while maintaining a reliable power grid and keeping energy costs low for our citizens," is undermined by this failure.[181] States across the nation are grappling with how to meet increased demand from AI data centers while maintaining grid reliability and distributing the costs of those changes in an equitable manner. Without an analysis of the existing framework for making such determinations, and ongoing efforts to adjust those systems to meet new challenges, there is no basis for DOE's conclusion that "intervention" – likely through 202(c) orders – is the only way to possibly reach those goals.[182]

d. As described in the EO, the report intrudes upon state authority.

EO 14262 directs the Secretary of Energy to rely upon the methodology disclosed in the Report to "identify current and anticipated regions with reserve margins below acceptable thresholds" and "identify which generation resources within a region are critical to system reliability."[183] The Executive Order also directs DOE to further develop a "protocol" for applying this analysis to "include all mechanisms available under applicable law, including section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource."[184] The Report is therefore foundational to the "protocol" that EO 14262 intends will direct emergency orders to override planned retirements. The Report thus directly intrudes on the States' lawful resource adequacy planning processes.

With respect to regulatory oversight for resource adequacy, section 201 of FPA, 16 U.S.C § 824(b)(1), reserves authority over generation facilities to the states. It states in pertinent part: "The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, *but shall not have jurisdiction*, except as specifically provided in this subchapter and subchapter III of this chapter, *over facilities used for the generation of electric energy* or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter."[185]

The Federal Power Act is likewise clear that federal regulatory jurisdiction over the power sector "extend[s] only to those matters which are not subject to regulation by the States."[186] With the few and specific exceptions outlined elsewhere in the statute, this jurisdiction

[180] *See Supra,* Section 2.a.
[181] Report at 1.
[182] *Id*.
[183] Executive Order 14262, §§ 3(b)-(c).
[184] *Id.* at § 3(c).
[185] *Id*. (emphasis added).
[186] 16 U.S.C. § 824(a).

does *not* extend to "facilities used for the generation of electric energy … ."[187] This statutory language places the regulation of generation resource adequacy squarely in the ambit of the states, not the federal government.[188]

States have typically exercised this authority through a combination of individual state legislative and regulatory functions as well as engaging in multistate RTOs and ISOs. Some states have retained this authority over resource adequacy in its entirety,[189] while others have directed their utilities to join RTOS/ISOs that, through their tariffs, impose resource adequacy requirements. Those RTO/ISOs also generally establish markets that allow market participants to buy and sell capacity and thereby to facilitate market entry and exit decisions based on price signals. Resource adequacy requirements in RTO/ISO tariffs have been held to be practices affecting wholesale rates subject to the jurisdiction of FERC under sections 205 and 206 of the Federal Power Act, 16 U.S.C. §§ 824d & 824e.[190]

Through these channels, states conduct the careful, calculated, long-term capacity planning that goes ignored in DOE's Report.[191] The Report utterly fails to recognize or properly account for the states' traditional and statutory role in resource adequacy planning, and as forecasted by EO 14262, the Report constitutes a central component of the federal government's proposed protocol to usurp the states' authority over this issue.

The use of emergency orders to illegally override state resource adequacy planning has been challenged on the same grounds by the Organization of MISO States, Inc. (OMS), in its Petition for Rehearing of DOE Order No. 202-25-3 (ordering continued operation of the J.H. Campbell coal-fired power plant). In its Petition, OMS noted among other points that "[t]his is the first time the DOE has invoked Section 202(c) outside a severe weather event or emergency, and for the first time, uses the power to suspend a retirement and interfere with established and vetted state and regional planning processes."[192] OMS' petition continues, "[t]his expansive use of emergency powers sets a troubling precedent, enabling interventions in routine, state-approved planning decisions without an actual crisis and risks establishing its use to circumvent normal utility, RTO, and states processes, and likely exposes ratepayers to costs that should not be borne."[193] In DOE's issuance of the Report pursuant to EO 14262, the federal government is

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[187] *Id.* § 824(b)(1).
[188] *See, e.g.*, Ashley J. Lawson, CONG. RESEARCH SERV., R47521, *Electricity: Overview and Issues for Congress*, at 7 (Feb. 14, 2025).
[189] *See Devon Power LLC et al.,* 109 FERC ¶ 61,154, P 47 (2004) ("Resource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsible for procuring adequate capacity to serve loads within their respective jurisdictions.").
[190] *See Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 483 (D.C. Cir. 2009).
[191] *E.g.*, Report at 2-3, 5, 12-13 (relying solely on federal, EIA, and NERC estimates and failing to mention nuanced state, RTO, or ISO figures and actions).
[192] *See* Petition to Intervene and Request for Rehearing of the Organization of MISO States, Inc., Order No. 202-25-3 (filed June 23, 2025), https://www.energy.gov/sites/default/files/2025-07/Petition%20to%20Intervene%20and%20Request%20for%20Rehearing%20of%20the%20Organization%20of%20MISO%20States.pdf.
[193] *See id*. at 5; *see also id.* at 4 (challenging "Violation of the Federal Power Act and State Jurisdiction.").

attempting to establish its own rule for resource adequacy planning from which it can routinely issue illegal orders under the same flawed premise that OMS challenges in its Petition.

Lastly, Section 202(c) does not serve as a widespread grant of DOE jurisdiction over resource adequacy and capacity planning. "Congress … does not … hide elephants in mouseholes."[194] First, as described above in Part [3b], Congress assigned non-emergent questions of interconnection and transmission necessity amenable to public notice and hearing to FERC, not DOE.[195] Moreover, even this authority should not be seen as a substitute for the overarching reservation of regulatory jurisdiction over resource adequacy planning to the states.[196] No reasonable reading of the relevant statutory authorities could construe DOE's authority in 16 U.S.C. § 824a(c) as intruding on the explicit and traditional role of the states in regulating electricity generation and resource adequacy. However, all available indicators in the Report and EO 14262 evince a flawed understanding contrary to DOE's appropriate and limited role in this space, thus the Department should reconsider its findings and position on this authority.

e. DOE's Failure to Provide Public Notice and Comment on its New Standard and Methodology Violated the Administrative Procedure Act, 5 U.S.C. § 553.

Before adopting a final rule, the Administrative Procedure Act requires agencies to publish in the Federal Register a notice of proposed rulemaking and accept public comment.[197] An agency action that imposes legally binding obligations or prohibitions on regulated parties, substantially removes the agency's discretion, or would be the basis for an enforcement action for violations of those requirements, is a legislative rule that requires notice and comment.[198] Notice and comment is also required when agencies establish new standards that are not derived from an existing statute or regulation or when an agency relies on its statutorily delegated authority to establish policy.[199] Additionally, agency documents that adopt a "new position inconsistent with any of the [agency's] existing regulations" are subject to notice and comment.[200]

DOE's report creates a brand-new national standard and methodology for evaluating resource adequacy. This standard has concrete legal effects because DOE plans to enforce it via Section 202(c) emergency orders. It also is inconsistent with DOE's existing regulations, which direct DOE to issue emergency orders in very different circumstances based on different criteria than what DOE now proposes. Significantly, DOE acknowledges that its conclusions lack sufficient input from the entities responsible for operating the grid, but DOE nonetheless refused to submit the Report to notice and comment where the public could have tested DOE's assumptions and conclusions. Assuming DOE continues to comply with the Executive Order's

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[194] *Whitman v. Am. Trucking Ass'ns, Inc.*, 531 U.S. 457, 468 (2001).
[195] 16 U.S.C. § 824a(b); 42 U.S.C. § 7172(a)(1)(B).
[196] 16 U.S.C. §§ 824(a)-(b).
[197] 5 U.S.C. § 553(b)-(c).
[198] *See Nat'l Min. Ass'n v. McCarthy*, 758 F.3d 243, 251–52 (D.C. Cir. 2014).
[199] *See Children's Hosp. of the King's Daughters, Inc. v. Azar*, 896 F.3d 615, 622 (4th Cir. 2018).
[200] *Shalala v. Guernsey Mem'l Hosp.*, 514 U.S. 87, 99–100 (1995).

unlawful command to use this Report to support future Section 202(c) orders, the Report and any action relying on it must be set aside for failure to provide notice and comment.

i. DOE's standard is an exercise of assumed legislative authority, and it has concrete legal effects.

Pursuant to the Executive Order, DOE established a "uniform methodology" for assessing resource adequacy across the country.[201] That methodology adopts a new "resource adequacy standard" to measure the desired level of adequacy needed for the bulk power system.[202] DOE acknowledges that it is not using the "traditional . . . criterion" for measuring resource adequacy and is relying on metrics that are "not standardized in the U.S. today."[203] Instead, DOE unilaterally adopts new metrics to evaluate resource adequacy and establishes the reliability targets that should be obtained.[204] DOE's choice of metrics and the targets to be achieved are value judgments and should be informed by economic tradeoffs and other policy considerations about what level of system reliability should be achieved and at what cost to consumers, areas where public input is essential to sound decision making.[205]

DOE also fills its methodology with value-laden policy choices around the data inputs and assumptions that determine when DOE's reliability standard is achieved. As just one example, DOE includes projected future demand from potential new AI data centers as part of its calculation of future load.[206] Those data centers have not yet been built and some may never be.[207] And, as DOE recognized, grid operators are not likely to allow those large loads to connect if doing so threatens reliability.[208] Including those potential loads in DOE's determinations of system reliability thus inherently represents a policy choice: Should present-day consumers pay to keep retiring power plants online to ensure that potential data centers can be reliably served in the future?[209]

Even assuming *arguendo* that DOE has the statutory authority to set a uniform reliability standard, place risks of future large load growth on current consumers, or engage in long-term resource adequacy planning for the entire nation, it still must involve stakeholders through notice and comment in those legislative choices. "When an agency relies on expressly delegated authority to establish policy . . . courts generally treat the agency action as legislative [] rulemaking" and require notice and comment.[210] In other words, "when Congress leaves [] a policy choice to the agency, [courts] should lean toward finding that the agency's making of that

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[201] *See* Report at *vi* (explaining that the report is "delivering the required uniform methodology to identify at-risk region(s)"); Executive Order 14262 § 3(b).
[202] Report at 3.
[203] *Id*. 3-4.
[204] *See id*.
[205] *See* Ex. C, IPI Report at ii (criticizing DOE's choice of targets as not "appropriately justified based on a cost-benefit framework, and the use of a one-size-fits-all target for the entire country ignores regional differences").
[206] *See* Report at 1-3.
[207] *See, e.g*., Ex. E, London Economics International Report; Laila Kearney and Liz Hampton, *U.S. Power Stocks Plummet as DeepSeek Raises Data Center Demand Doubts*, Reuters (Jan. 27, 2025) https://www.reuters.com/business/energy/us-power-stocks-plummet-deepseek-raises-data-center-demand-doubts-2025-01-27/.
[208] *See* Report at 14.
[209] *See also supra* Section 4.a. (discussing other arbitrary assumptions in DOE's analysis).
[210] *Children's Hosp. of the King's Daughters, Inc.*, 896 F.3d at 622.

choice requires notice and comment.[211] "Otherwise, it would be difficult to imagine what regulations *would* require notice and comment procedures."[212]

DOE's standard also has concrete legal effects because, consistent with the Executive Order, DOE will use Section 202(c) emergency orders (or the threat of Section 202(c) orders) to ensure regions meet the new standard. The Executive Order directs DOE to use this standard to "establish . . . a protocol" to identify generation resources that are critical to system reliability.[213] DOE's "protocol shall additionally" use Section 202(c) of the Federal Power Act to "ensure" those resources are retained and prevent their retirement.[214] "Protocol" means "a set of rules to be followed . . ."[215] As DOE has made clear, DOE "plans to use" this new standard to evaluate retiring coal plants and potentially issue Section 202(c) emergency orders preventing their retirement.[216]

DOE's new standard, and protocol for enforcing it, removes DOE's discretion and is intended to provide the basis for enforcement actions via Section 202(c) orders.[217] The new standard is not derived from the Federal Power Act or, as explained further below, from DOE's existing regulations, but is an entirely new method of determining resource adequacy across the country. DOE must accordingly submit its new standard and methodology to public notice and comment.[218]

ii. DOE must provide notice and comment because its standard allegedly supports issuing emergency orders based on factors that conflict with existing regulations.

DOE's Report provides new bases for issuing emergency orders that conflict with DOE's existing regulations, but DOE cannot amend those standards without first providing notice and comment.[219] DOE promulgated regulations detailing how and when it issues Section 202(c) emergency orders following public notice and comment in 1981.[220] Under DOE's current regulations, emergency orders "are envisioned as meeting a *specific* inadequate power supply situation," occasioned by "acts of God[] or unforeseen occurrences not reasonably within the

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[211] *Id*.
[212] *Id*. (quoting *N.H. Hosp. Ass'n v. Azar*, 887 F.3d 62, 70–71 (1st Cir. 2018)).
[213] Executive Order 14262 at § 3(c).
[214] *Id*.
[215] PROTOCOL, Black's Law Dictionary (12th ed. 2024).
[216] Order No. 202-25-4 at 2 (Eddystone Order). *See also* U.S. DEP'T OF ENERGY, *Fact Sheet: The Department of Energy's Resource Adequacy Report Affirms The Energy Emergency Facing The U.S. Power Grid* (2025), https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf [https://perma.cc/YLX7-8G7T] (explaining that DOE's methodology will be used, pursuant to the executive order, "prevent [] generation resources from leaving the bulk-power system"); Press Release, U.S. Dep't of Energy, Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security (July 7, 2025), https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security [https://perma.cc/8TEJ-AGH6]. (stating that its "methodology also informs the potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act"); Report at *vi* (explaining that DOE's standard will be used to "guide reliability interventions"), 1 (emphasizing the need for DOE's "decisive intervention" in energy markets), 10 (analyzing ERCOT because "FPA Section 202(c) allows DOE to issue emergency orders to ERCOT").
[217] *See Nat'l Min. Ass'n v. McCarthy*, 758 F.3d 243, 251–52 (D.C. Cir. 2014).
[218] *See id*.; *Children's Hosp. of the King's Daughters, Inc. v. Azar*, 896 F.3d 615, 622 (4th Cir. 2018).
[219] *See Shalala*, 514 U.S. at 99–100.
[220] *See Emergency Interconnection of Electric Facilities*, 46 Fed. Reg. 39,984 - 39,989 (Aug. 6, 1981).

power of the affected 'entity' to prevent."[221] DOE did not intend its emergency authority to replace long-term planning by utilities: "while a utility may rely upon these regulations for assistance during a period of unexpected inadequate supply of electricity, it must solve long-term problems itself."[222]

As DOE stated then, "[t]he factors that DOE will consider in determining whether an emergency exists are specified in § 205.373."[223] Section 205.373 requires applicants to submit detailed information on "daily peak load and energy requirements for each of the past 30 days and projections for each day of the expected duration of the emergency" and make a "showing that adequate electric service cannot be maintained without additional power transfers." Applicants must also describe what "conservation or load reduction actions have been implemented" before seeking emergency relief.[224] In sum, DOE's current regulations direct a case-by-case analysis of specific, temporary shortages in particular situations, based on detailed information from an applicant.

DOE's new standard and methodology is an unprecedent expansion of the bases upon which DOE will justify Section 202(c) emergency orders, but DOE has not offered public comment on that expansion. Rather than focusing on specific showings of an imminent threat to grid stability, the report rests on DOE's analysis of "the U.S. electric grid's ability to meet future demand through 2030."[225] Rather than consider the "daily peak load and energy requirements of the past 30 days and projections for each day of the [] emergency," 10 C.F.R. § 205.373, DOE now plans to base Section 202(c) decisions on speculation over the development of artificial intelligence, re-industrialization of the U.S. economy, and other uncertain developments over the next five years.[226] Rather than consider the "scheduled . . . deliveries" during the emergency period and needs of existing firm customers, § 205.373(d),(f), DOE now proposes to find an emergency based on potential load growth for customers who do not currently, and may never, exist.[227]

Rather than allowing utilities and grid operators to solve long-term planning issues themselves, DOE now seeks to intervene in those state- and FERC-regulated processes based on its own assumptions about future load growth and electricity supply. But unlike DOE's Report, the long-term resource adequacy plans developed by utilities and grid operators are transparent and publicly-accountable processes that involve relevant stakeholders and the public.[228] DOE, on the other hand, published its analysis without critical data or insights from the entities who actually operate and maintain the electric grid.[229]

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[221] 10 C.F.R. § 205.371 (emphasis added).
[222] 46 Fed. Reg. at 39,985; *see also* 10 C.F.R. § 205.371
[223] 46 Fed. Reg. at 39,985.
[224] *Id*.; *see also* 10 C.F.R. § 205.375 (defining an inadequate energy supply as when an applicant is "unable to meet its normal peak load requirements based upon use of all its otherwise available resources.").
[225] Report at 2.
[226] Report at 2; *see also supra* Section 4.a.
[227] *See, e.g*., Ex. E London Economics International Report; Laila Kearney and Liz Hampton, *U.S. Power Stocks Plummet as DeepSeek Raises Data Center Demand Doubts*, Reuters (Jan. 27, 2025) https://www.reuters.com/business/energy/us-power-stocks-plummet-deepseek-raises-data-center-demand-doubts-2025-01-27/.
[228] *See supra* Section 2.a.
[229] Report at *i.*

Rather than considering what other "conservation or load reduction actions have been implemented" before turning to emergency relief, 10 C.F.R. § 205.373, DOE's standard ignores those possibilities altogether. Instead, DOE adopts aggressive and likely overstated assumptions of load growth and ignores whether any of that future demand could be flexibly integrated into the grid, what measures state and local regulators are taking to mitigate the impact of new data center demand on grid reliability, or other factors influencing grid reliability over the long-term.[230] DOE appears to admit that its overstated potential load growth will not *actually* lead to any grid reliability emergency, as there is no "indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system."[231]

DOE appropriately involved the public when it initially set out the process and factors to consider for Section 202(c) orders in its 1981 rulemaking. Yet now, DOE seeks to expand the bases for Section 202(c) orders in ways that intrude on state-regulated processes and the free market, without any input from stakeholders or the public who will ultimately pay for DOE's actions. Because the methodology and protocol effectively "expand[s] the footprint [of DOE's emergency authority] by imposing new requirements, rather than simply interpreting the legal norms Congress or the agency itself has previously created" and is inconsistent with DOE's existing regulations, it is a "rule" under the APA and notice and comment is required.[232]

iii. DOE acknowledges the importance of involving the States and other actors yet fails to provide public notice and comment to test DOE's assumptions and conclusions.

DOE's failure to provide public notice and comment is prejudicial error. DOE admittedly lacks the "range of data and insights" to make robust reliability decisions that entities responsible for the maintenance and operation of the grid have access to.[233] Had the States been given adequate notice and an opportunity to comment, they could have provided more information to DOE on how existing mechanisms address grid reliability, issues with DOE's assumptions, chosen metrics, and choice of data, identified gaps in DOE's analysis and data, and other issues. Numerous grid experts have commented on shortfalls with DOE's report.[234] Given adequate notice and an opportunity to comment, the States could have obtained their own expert analysis and potentially raised even more issues with DOE's proposed standard and methodology than what time permitted the States to raise here.

DOE has previously acknowledged the importance of involving States and the public in these questions. When DOE initially established regulations governing how and when it would

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[230] *See, e.g.*, Ex. D, Nicholas Institute Report; Jason Plautz, *State lawmakers grapple with energy demand for data centers*, E&E News (Mar. 3, 2025) https://www.eenews.net/articles/state-lawmakers-grapple-with-energy-demand-for-data-centers/; Washington Office of the Governor, *Gov. Bob Ferguson Signs Executive Order Establishing a Data Center Workgroup* (Feb. 4, 2025) https://governor.wa.gov/news/2025/governor-bob-ferguson-signs-executive-order-establishing-data-center-workgroup.

[231] Report at 14.

[232] *Children's Health Care v. Centers for Medicare & Medicaid Servs.*, 900 F.3d 1022, 1025 (8th Cir. 2018); *see also Shalala*, 514 U.S. at 99–100.

[233] Report at *i*

[234] *See, e.g.*, Jeff St. John, *Critics fear Trump will use flawed DOE report to push pro-coal agenda*, Canary Media (July 14, 2025), https://www.canarymedia.com/articles/fossil-fuels/trump-doe-report-open-coal-plants; Matthias Fripp and Brendan Pierpont, Opinion, *Energy Department's flawed grid study props up expensive, zombie power plants*, UtilityDive, https://www.utilitydive.com/news/doe-grid-reliability-study-zombie-power-plants/753596/.

issue emergency orders, DOE consulted with the Federal Energy Regulatory Commission and state officials.[235] DOE also explained that "[t]he DOE intends to utilize any available State and local expertise in resolving an emergency."[236] Indeed, DOE's organizational statute *requires* it to consult with States "[w]henever any proposed action by the Department conflicts with the energy plan of any State."[237] And States are already taking actions to address reliability issues and load growth in their jurisdictions.[238] DOE's refusal to collaborate with States or meaningfully involve other stakeholders here is inexplicable, conflicts with DOE's organizational statute, and the APA.

V. Conclusion

The State's request for rehearing should be granted and DOE should withdraw or otherwise amend the subject Report following public vetting through notice and comment proceedings. In the meantime, DOE cannot rely on the challenged report to support the exercise of its 202(c) authority. Doing so would be arbitrary and capricious and otherwise contrary to law and impose significant harm on our States.

Filed: August 6, 2025

[235] 46 Fed. Reg. at 39,985.
[236] *Id*.
[237] 42 U.S.C. § 7113; *see also* 16 U.S. Code § 824h (encouraging federal-state collaboration).
[238] Jason Plautz, *State lawmakers grapple with energy demand for data centers*, E&E News (Mar. 3, 2025) https://www.eenews.net/articles/state-lawmakers-grapple-with-energy-demand-for-data-centers/; Washington Office of the Governor, *Gov. Bob Ferguson Signs Executive Order Establishing a Data Center Workgroup* (Feb. 4, 2025) https://governor.wa.gov/news/2025/governor-bob-ferguson-signs-executive-order-establishing-data-center-workgroup.

Respectfully Submitted,

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit O: Department, Order No. 202-25-3 (May 23, 2025)

Order No. 202-25-3

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

The Midcontinent Independent System Operator (MISO) faces potential tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. The North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[1] In particular, the retirement of thermal generation capacity creates the potential for electricity supply shortfalls. NERC anticipates that the near-term period of highest capacity shortfall for MISO will occur in August.[2]

Multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[3] Additionally EIA stated, "[t]ypically Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[4] The state's Big Rock Point nuclear power plant shut down in 1997 and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it will not be available during the peak demand period this summer.

The 1,560 MW J.H. Campbell coal-fired power plant in West Olive, MI, is scheduled to cease operations on May 31, 2025. Its retirement would further decrease available dispatchable generation within MISO's service territory, removing additional such generation along with the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. In 2021, Consumers announced that it planned to "speed closure" of Campbell in 2025, several years before the end of its scheduled design life.[5] Although MISO and Consumers have

[1] 2025 summer reliability assessment. (May 14, 2025). https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf
[2] *Id*.
[3] U.S. Energy Information Administration, Michigan State Energy Profile, Oct. 17, 2024, *available at*: https://www.eia.gov/state/print.php?sid=mi.
[4] *Id.*
[5] https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation

incorporated the planned retirement into their supply forecasts and acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."

MISO's Planning Resource Auction Results for Planning Year 2025-26, released in April 2025, note that for the northern and central zones, which includes Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources." While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and the results "reinforce the need to increase capacity."[6]

ORDER

Given the determination that an emergency exists as discussed above, the responsibility of MISO to ensure reliability of its system, and the ability of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on the insufficiency of dispatchable capacity and anticipated demand during the summer months, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety.

This Order is limited in duration to align with the emergency circumstances. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on May 23, 2025, MISO and Consumers Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

[6] https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250428694160.pdf

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units through the expiration of the Order. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.

C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By June 15, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability and economic dispatch of the Campbell Plant consistent with the public interest. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

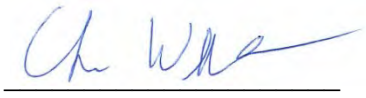
E. The extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so.

F. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

G. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. This Order shall be effective upon its issuance, and shall expire at 00:00 EDT on August 21, 2025, with the exception of the reporting requirements in paragraph D and applicable compliance obligations in paragraph E.

I. Issued in Washington, D.C. at 3:15:pm Eastern Daylight Time on this 23rd day of May 2025.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Mark Christie
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

Michigan Public Service Commissioners
Chairman Dan Cripps
Commissioner Katherine Peretick
Commissioner Alessandra Carreon

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit P: Department, Order 202-25-4 (May 30, 2025)

Order No. 202-25-4

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in portions of the electricity grid operated by PJM Interconnection (PJM) due to a shortage of facilities for the generation of electric energy, resource adequacy concerns, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

PJM has recently stated its system faces "growing resource adequacy concern" due to load growth, the retirement of dispatchable resources, and other factors.[1] Upcoming retirements, including the planned retirement of Unit 3 and Unit 4 of the Eddystone Generating Station in Eddystone, Pennsylvania, will exacerbate these resource adequacy issues.

PJM indicates that resource constraints could exist within the service territory under peak load conditions, stating that "available generation capacity may fall short of required reserves in an extreme planning scenario."[2] In its February 2023 assessment "*Energy Transition in PJM: Resource Retirements, Replacements & Risks*," PJM highlights the increasing risk of reliability risk in the coming years due to the "potential timing mismatch between resource retirements, load growth and the pace of new generation entry" under "low new entry" scenarios for renewable generation.[3]

In December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found "the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry."[4] In March 2025 congressional testimony, PJM found "a growing resource adequacy concern" due to a combination of load growth, the retirement of dispatchable resources, and other factors.[5] Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics of resources in PJM's interconnection queue.[6]

[1] https://www.pjm.com/-/media/DotCom/library/reports-notices/testimony/2025/20250325-asthana-testimony-us-house-subcommittee-on-energy.pdf
[2] https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/
[3] https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx
[4] https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250211-3120
[5] https://www.pjm.com/-/media/DotCom/library/reports-notices/testimony/2025/20250325-asthana-testimony-us-house-subcommittee-on-energy.pdf
[6] Ibid.

Constellation Energy owns the Eddystone Generating Station, which includes Unit 3 and Unit 4, each of which has a nameplate capacity of 380 MW. Units 3 and 4 have a planned retirement date of May 31, 2025. The retirement of these units would further decrease available dispatchable generation within PJM's service territory.

Pursuant to Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid* (EO 14262), DOE is developing a methodology to identify current and anticipated reserve margins for all regions of the bulk-power system regulated by the Federal Energy Regulatory Commission. EO 14262 requires this methodology to be published by July 7, 2025, and be used to establish a protocol to identify which generation resources within a region are critical to system reliability and prevent identified generation resources from leaving the bulk-power system. DOE plans to use this methodology to further evaluate Eddystone Units 3 and 4.

ORDER

Given the emergency nature of resource adequacy concerns, the declared state of national energy emergency, the responsibility of PJM to ensure maximum reliability on its system, and the ability of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, operational availability and economic dispatch of the aforementioned Eddystone Units 3 and 4 (Eddystone Units) is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the potential load stress due to aforementioned resource adequacy concerns, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The potential shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the region support the need for the Eddystone Units to contribute to system reliability.
- PJM's responsibility to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Eddystone Units, necessary to meet the load demands.

This Order is limited in duration to align with the anticipated emergency circumstances. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse

environmental impacts. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on May 30, 2025, PJM and Constellation Energy shall take all measures necessary to ensure that Eddystone Units are available to operate. For the duration of this order, PJM is directed to take every step to employ economic dispatch of the units to minimize cost to ratepayers. Following conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units through the expiration of the Order. PJM shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Eddystone Units have operated in compliance with the allowances contained in this Order.

C. All operation of the Eddystone Units must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

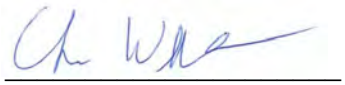
D. By June 15, 2025, PJM is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with the public interest. PJM shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. In addition, PJM and Constellation Energy are directed to file with the Federal Energy Regulatory Commission any tariff revisions or waivers necessary to effectuate this order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Eddystone Units to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. This Order shall be effective upon its issuance, and shall expire at 5:03 PM EDT on August 28, 2025, with the exception of the reporting requirements in paragraph D.

H. Issued in Simi Valley, California, at 5:03 PM Eastern Daylight Time on this 30th day of May 2025.



Chris Wright
Secretary of Energy

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit Q: Department, Order No. 202-25-11 (Dec. 16, 2025)

Department of Energy
Washington, DC 20585

Order No. 202-25-11

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists within the Western Electricity Coordinating Council (WECC) Northwest assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

EMERGENCY SITUATION

In its 2025–2026 Winter Reliability Assessment, NERC finds that the WECC Northwest region, which includes Montana, Oregon, Washington, and parts of northern California and northern Idaho, is at elevated risk during periods of extreme weather.[3] The assessment notes that "there is sufficient capacity in the area for expected peak conditions; however, [balancing authorities] are likely to require external assistance during extreme winter weather that causes thermal plant outages and adverse wind turbine conditions for area internal resources. External assistance may not be available during region-wide extreme winter conditions. Winter peak demand for the area is forecast to be 2.9 GW higher (9.3%) compared to last year."[4]

In a September 2025 report evaluating Resource Adequacy in the Pacific Northwest, Energy + Environmental Economics (E3) determined that "[a]ccelerated load growth and continued retirements create a resource gap beginning in 2026 and growing to 9 GW by 2030"[5] and that "[l]oad growth and retirements mean the region faces a power supply shortfall in 2026."[6] E3 reported that nearly 9000 MW of new capacity will be needed in the region by 2030, but currently only 3000 MW of projects for new capacity are in active development.[7] Overall, E3 found that "[p]referred resources such as wind, solar and batteries make only small contributions to meeting resource adequacy needs" and "[t]imely development of all resources is extremely challenging due to permitting and interconnection delays, federal policy headwinds, and cost pressures."[8]

TransAlta Centralia Generation ("Centralia") is an electric generating facility in Centralia,

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] *NERC 2025-2026 Winter Reliability Assessment*, at 6 (November 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.
[4] *Id.*
[5] E3, *Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results*, at 2 (Sept. 22, 2025), https://www.utc.wa.gov/sites/default/files/2025-10/Revised%20V3%20E3%20Presentation%20RA%20Study%20September%2022%20WA%20RA%20Meeting.pdf. *See also id.* for the list of E3's study sponsors, which include certain "regional utilities and generation owners."
[6] *Id.* at 10.
[7] *Id.*
[8] *Id.* at 2.

Washington. Centralia is owned and operated by the TransAlta Centralia Generation LLC ("TransAlta"). Centralia consists of one remaining coal-fired generation unit, Unit 2, with a nameplate capacity of 729.9 MW.[9] Unit 2 began operations in 1973 and is slated to cease operations in December 2025. Unit 1 was retired in 2020. Unit 2 is slated to cease operation in December 2025, based on a 2011 Washington law[10] and a subsequent agreement between TransAlta and the State of Washington.[11] TransAlta has announced plans to convert the unit to natural gas by 2028.[12]

More broadly, Executive Orders issued by President Donald J. Trump on January 20, 2025, and April 8, 2025, underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, "Declaring a National Energy Emergency," in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[13] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[14] In a subsequent Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[15]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order

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[9] U.S. Energy Information Administration, Form EIA-860, Schedule 3: Generator Data (2024) (2024 Form EIA-860), https://www.eia.gov/electricity/data/eia860/.

[10] Act of Apr. 29, 2011, Ch. 180, 2011 Wash. Laws, https://lawfilesext.leg.wa.gov/biennium/2011-12/Pdf/Bills/Session%20Laws/Senate/5769-S2.SL.pdf#page=1.

[11] *See* MOA (Dec. 23, 2011), https://ecology.wa.gov/getattachment/858591f6-dd25-47be-ba1d-0f58264ca147/20111223TransAltaMOA.pdf ("D. In exchange for the benefits of entering into an MOA with the State pursuant to RCW 80.80.100, the Company will . . . (5) permanently cease power generation operations of one Boiler in 2020 and the other Boiler in 2025, which dates are prior to the 2035 end of their expected useful lives . . . ."); *see also* First Amendment to MOA (July 13, 2017), https://fortress.wa.gov/ecy/ezshare/AQ/PDFs/TransAltaMOAAmend1-20170713.pdf. As a coal-fired facility, it would be difficult for the Centralia Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if TransAlta were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

[12] *TransAlta Signs Long-Term Agreement for 700 MW at Centralia Facility Enabling Coal to Natural Gas Conversion* (Dec. 9, 2025), https://transalta.com/newsroom/transalta-signs-long-term-agreement-for-700-mw-at-centralia-facility-enabling-coal-to-natural-gas-conversion/.

[13] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (Declaring a National Energy Emergency), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

[14] *Id.*

[15] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (Strengthening the Reliability and Security of the United States Electric Grid), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[16]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[17] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Centralia Unit 2 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the potential loss of power to homes, businesses, and facilities critical to the national defense in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety.

I have also made the determination that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Centralia Unit 2 shall be made available for operation until March 16, 2026.

Based on my determination of an emergency set forth above, I hereby order:

A. From December 16, 2025, TransAlta shall take all measures necessary to ensure that Centralia Unit 2 is available to operate at the direction of either Bonneville Power Administration (BPA) (in its role as Balancing Authority) or the California Independent System Operator Corporation Reliability Coordinator West[18] (in its role as the Reliability Coordinator). Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices.

B. To minimize adverse environmental impacts, this Order limits operation of Centralia Unit

[16] U.S. Department of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[17] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

[18] *See* NERC list of acronyms for Reliability Coordinators at https://www.nerc.com/programs/bulk-power-system-awareness/reliability-coordinators. On the official NERC Compliance Registry, CAISO is listed as the Reliability Coordinator. *See* NERC Compliance Registry at https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.nerc.com%2Fglobalassets%2Fprograms%2Fregistration%2Fcompliance-registry-files%2Fnerc_compliance_registry_matrix_excel.xlsx&wdOrigin=BROWSELINK.

2 to the times and within the parameters established in paragraph A. TransAlta shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Centralia Unit 2 has operated in compliance with this Order.

C. All operations of Centralia Unit 2 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By December 30, 2025, TransAlta is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Centralia Unit 2 consistent with this Order. TransAlta shall also provide such additional information regarding the environmental and operational impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. TransAlta is directed to file with the Federal Energy Regulatory Commission tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. BPA is directed to facilitate transmission service, as needed, to effectuate this Order.

G. This Order shall not preclude the need for Centralia Unit 2 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Centralia Unit 2 shall not be considered a capacity resource.

I. This Order shall be effective from 11:59 PM Eastern Standard Time (EST) on December 16, 2025, and shall expire at 11:59 PM Eastern Daylight Time (EDT) on March 16, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. at 5:20PM EST on this 16th day of December 2025.

Chris Wright

Chris Wright
Secretary of Energy

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit R: Department, Order No. 202-25-13 (Dec. 23, 2025)

Department of Energy
Washington, DC 20585

Order No. 202-25-13

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The F.B. Culley Generating Station (Culley) is an electric generating facility in Warrick County, Indiana. Culley is owned and operated by CenterPoint Energy and consists of two coal-fired generation units, Unit 2 (103.7 MW) and Unit 3 (265.2 MW), with a combined name plate capacity of 368.9 MW. Unit 2 and Unit 3 began operations in 1966 and 1973, respectively. Unit 2 is slated to cease operations in December 2025.[3]

EMERGENCY SITUATION

Midcontinent Independent System Operator, Inc.'s (MISO) year-round resource adequacy concerns are well documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[4] MISO justified this revision by explaining that "Reliability risks associated with Resource Adequacy have shifted from 'Summer only' to a year-round concern."[5] MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[6]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] As a coal-fired facility, it would be difficult for Culley Unit 2 to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Culley were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.
[4] *Midcontinent Independent System Operator, Inc.*, FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. *See Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).
[5] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).
[6] *Id.* at 3-4.

transforming energy landscape."[7] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projected that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[8]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative.*"[9] In a section of that report entitled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season:

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[10]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season. The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO.

In its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area is at an elevated risk "because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below [Reference Margin Levels] within the next five years."[11]

When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Indiana.[12]

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to

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[7] MISO, *Attributes Roadmap*, at 3 (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.
[8] *Id.* at 11.
[9] MISO, *MISO's Response to the Reliability Imperative* (Updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.
[10] *Id.* at 12.
[11] *NERC 2024 Long-Term Reliability Assessment*, at 13 (December 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.
[12] MISO, *Planning Resource Auction: Results for Planning Year 2025-26*, at 13 (April 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

which expected capacity resources satisfy planning reserve margin requirements.[13] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[14] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[15] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[16]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large quantities of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[17] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[18]

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[19] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three-year grace period to commence commercial operations.[20] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[21] Consequently, it is not at all clear that the new ERAS process will result in the addition of new capacity in the next few years.

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[13] OMS and MISO, *OMS-MISO Survey Results* (Updated June 6, 2025), https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.

[14] *Id.* at 2.

[15] *Id.* at 7.

[16] *Id.* at 9.

[17] *Id.* at 7, 9.

[18] *Id.*

[19] *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

[20] *Id.* P 84.

[21] *See generally*, S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, (May 2025), ("With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."), https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply.

More broadly, executive orders issued by President Donald J. Trump on January 20, 2025, and April 8, 2025, underscore the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump likewise declared a national energy emergency in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[22] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[23] In a subsequent Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[24]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[25]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[26] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Culley Unit 2 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

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[22] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

[23] *Id*.

[24] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

[25] U.S. Department of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[26] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of Energy. *See* 42 U.S.C. § 7151(b).

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of Culley Unit 2 is necessary to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c).

To ensure Culley Unit 2 will be available if needed to address emergency conditions, Culley Unit 2 shall remain in operation until March 23, 2026.

Based on my determination of an emergency set forth above, I hereby order:

A. From December 23, 2025, MISO and CenterPoint Energy shall take all measures necessary to ensure that Culley Unit 2 is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Culley Unit 2 to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. CenterPoint Energy is directed to comply with all orders from MISO related to the availability and dispatch of Culley Unit 2.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO, pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Culley Unit 2 has operated in compliance with the allowances contained in this Order.

C. All operations of Culley Unit 2 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By January 13, 2026, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Culley Unit 2 consistent with this Order. MISO and CenterPoint Energy shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. CenterPoint Energy is directed to file with the Federal Energy Regulatory Commission tariff revisions or waivers to effectuate this Order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for Culley Unit 2 to comply with applicable state, local, or Federal laws or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Culley Unit 2 shall not be considered a capacity resource.

H. This Order shall be effective from 11:59 PM Eastern Standard Time (EST) on December 23, 2025, and shall expire at 11:59 PM Eastern Daylight Time (EDT) on March 23, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Denver, Colorado at 6:39 PM EST on this 23rd day of December 2025.

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Indiana Utility Regulatory Commission
Chairman Jim Huston
Commissioner David Veleta
Commissioner David Ziegner

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit S: Department, Order No. 202-25-12 (Dec. 23, 2025)

Department of Energy
Washington, DC 20585

Order No. 202-25-12

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The R.M. Schahfer Generating Station (Schahfer) is an electric generating facility in Wheatfield, Indiana. Schahfer is owned and operated by Northern Indiana Public Service Company (NIPSCO), a division of NiSource Inc. Schahfer consists of two 129 MW natural-gas fired units and two coal-fired units, Unit 17 (423.5 MW) and Unit 18 (423.5 MW).[3] Unit 17 and Unit 18 began operations in 1983 and 1986 respectively. Unit 17 and Unit 18 are both slated to cease operations in December 2025.[4]

EMERGENCY SITUATION

Midcontinent Independent System Operator, Inc.'s (MISO) year-round resource adequacy concerns are well documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[5] MISO justified this revision by explaining that "Reliability risks associated with Resource Adequacy have shifted from 'Summer only' to a year-round concern."[6] MISO noted that over 60% of all

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] U.S. Energy Information Administration, Form EIA-860, Schedule 3: Generator Data (2024), https://www.eia.gov/electricity/data/eia860/.
[4] As coal-fired facilities, it would be difficult for the Schahfer Units 17 and 18 to resume operations once they have been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Schahfer were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.
[5] *Midcontinent Independent System Operator, Inc.*, FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. *See Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).
[6] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).

"MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[7]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[8] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projected that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[9]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative.*"[10] In a section of that report entitled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season:

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[11]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season. The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO.

In its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area is at an elevated risk "because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below [Reference Margin Levels] within the next five years."[12]

When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Indiana.[13]

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[7] *Id.* at 3-4.
[8] MISO, *Attributes Roadmap*, at 3 (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.
[9] *Id.* at 11.
[10] MISO, *MISO's Response to the Reliability Imperative* (Updated February 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.
[11] *Id.* at 12.
[12] *NERC 2024 Long-Term Reliability Assessment*, at 13 (December 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.
[13] MISO, *Planning Resource Auction: Results for Planning Year 2025-26*, at 13 (April 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.[14] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[15] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[16] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[17]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large quantities of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[18] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[19]

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[20] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three-year grace period to commence commercial operations.[21] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[22] Consequently, it is not at all clear that the new ERAS process will result in the addition of new capacity in the next few years.

More broadly, executive orders issued by President Donald J. Trump on January 20, 2025 and April 8, 2025, underscored the dire energy challenges facing the Nation due to growing

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[14] OMS and MISO, *OMS-MISO Survey Results* (Updated June 6, 2025), https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.

[15] *Id.* at 2.

[16] *Id.* at 7.

[17] *Id.* at 9.

[18] *Id.* at 7, 9.

[19] *Id*.

[20] *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

[21] *Id.* P 84.

[22] *See generally*, S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply* (May 2025), ("With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."), https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply.

resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, "Declaring a National Energy Emergency," in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[23] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[24] In a subsequent Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[25]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[26]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[27] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Schahfer Units 17 and 18 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety. Given the responsibility of MISO to

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[23] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.
[24] *Id*.
[25] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.
[26] U.S. Department of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025.07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.
[27] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of Energy. *See* 42 U.S.C. § 7151(b).

identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of Schahfer Units 17 and 18 is necessary to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c).

To ensure Schahfer Units 17 and 18 will be available if needed to address emergency conditions, Schahfer Units 17 and 18 shall remain in operation until March 23, 2026.

Based on my determination of an emergency set forth above, I hereby order:

A. From December 23, 2025, MISO and NIPSCO, shall take all measures necessary to ensure that Schahfer Units 17 and 18 are available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Schahfer Units 17 and 18 to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. NIPSCO is directed to comply with all orders from MISO related to the availability and dispatch of the Schahfer Units 17 and 18.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO, pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Schahfer Units 17 and 18 has operated in compliance with the allowances contained in this Order.

C. All operation of Schahfer Units 17 and 18 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By January 13, 2026, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Schahfer Units 17 and 18 consistent with this Order. MISO and NIPSCO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. NIPSCO is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for Schahfer Units 17 and 18 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Schahfer Units 17 and 18 shall not be considered capacity resources.

H. This Order shall be effective from 11:59 PM Eastern Standard Time (EST) on December 23, 2025, and shall expire at 11:59 PM Eastern Daylight Time (EDT) on March 23, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Denver, Colorado at 6:39 PM EST on this 23rd day of December 2025.

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Indiana Utility Regulatory Commission
Chairman Jim Huston
Commissioner David Veleta
Commissioner David Ziegner

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	)	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit T: Congressional Research Service, *Federal Power Act: The Department of Energy's Emergency Authority* (June 12, 2025)

Congressional Research Service
Informing the legislative debate since 1914

Federal Power Act: The Department of Energy's Emergency Authority

June 12, 2025

Congressional Research Service
https://crsreports.congress.gov
R48568

CRS REPORT
Prepared for Members and
Committees of Congress

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Section 202(c) of the Federal Power Act (16 U.S.C. §824a(c)) grants the Secretary of Energy certain authorities over the temporary operation of the electricity system during emergencies. Actions by the Trump Administration have highlighted this authority and raised questions about its future implementation. This report provides a brief history of the emergency authorities and discusses current issues.

History of Section 202(c)

The Federal Power Act was enacted in 1935 and included emergency authority language. At the time, federal oversight of the electricity system was conducted by the Federal Power Commission (FPC). Now, the Federal Energy Regulatory Commission (FERC) has most responsibilities for electricity system oversight—but not for emergencies. The emergency authority was transferred to the Secretary of Energy when the Department of Energy (DOE) was established by the Department of Energy Organization Act (P.L. 95-91) in 1977. Hereinafter, the emergency authority is described as residing with DOE.

Section 202(c) provides DOE broad discretion to require almost any change to the operation of the U.S. electricity system on a temporary basis. Specifically, DOE may "require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."

DOE may execute this authority during war or at any other time it "determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes." This report focuses on the authority as used during emergencies, not war, and it focuses on DOE's authority—it does not discuss other energy emergency authorities.[1]

In 2015, Congress amended Section 202(c) to specify how the emergency authority should interact with environmental requirements for power plants. In practice, the amendments prioritize electric reliability over environmental outcomes, essentially by providing a waiver of federal, state, or local environmental laws and regulations during times of emergencies.

This waiver has limitations. First, DOE emergency orders that may result in conflicts with environmental requirements may be issued only for 90-day periods. They may be renewed for additional 90-day periods as long as DOE deems these renewals necessary to meet the emergency.

Second, if an emergency order would result in a violation of a federal, state, or local environmental law or regulation, DOE must ensure the order is in effect "only during hours necessary to meet the emergency and serve the public interest." Lastly, DOE must "to the maximum extent practicable" ensure the order is consistent with environmental laws or regulations and "minimizes any adverse environmental impacts."

DOE Implementation

DOE's regulations for implementing its emergency authority were finalized in 1981.[2] The regulations define terms, including "emergency," and specify requirements for requesting an emergency order.

[1] For example, in the 1970s, Congress passed several laws granting the President certain authorities to respond to energy shortages at the time. A discussion of those laws is beyond the scope of this report.

[2] 10 C.F.R. §§205.370-205.379.

The Section 202(c) emergency authority is focused primarily on short-term situations—though, as shown below, DOE has exercised this authority in situations of varying duration. DOE's regulations emphasize the short-term nature of "emergencies" in this context. In the 1981 rulemaking, DOE explained,

> The DOE does not intend these regulations to replace prudent utility planning and system expansion. This intent has been reinforced in the final rule by expanding the 'Definition of Emergency' to indicate that, while a utility may rely upon these regulations for assistance during a period of unexpected inadequate supply of electricity, it must solve long-term problems itself.[3]

DOE and FPC have used the emergency authority several dozen times since 1935 in response to different kinds of emergencies.

DOE's website contains information on use of the emergency authority from 2000.[4] From 2000 through May 2025, DOE used its emergency authority in response to 19 events. Eleven events were weather-related and included hurricanes, heat waves, and winter storms. Some events prompted multiple emergency orders, either because more than one utility experienced emergency conditions (e.g., Winter Storm Elliot in 2022) or because the initial emergency order was extended (e.g., the California energy crisis of 2000-2001).

Details on the use of the Section 202(c) emergency authority prior to 2000 are not available in a single DOE repository; they are therefore more difficult to comprehensively compile. According to one compilation, the emergency authority was used 29 times prior to 2000; 22 of these occasions were in association with World War II.[5]

The duration of emergency orders under Section 202(c) has varied; some have lasted just a few hours, while others have been extended to cover events lasting more than a year. Among the orders listed on DOE's website, the shortest order CRS identified occurred in response to a heat wave in Texas in September 2023. DOE granted an emergency order in this case for four hours on each of two days to respond to the highest levels of expected electricity demand.[6] The order allowed one coal-fired unit and 16 natural gas-fired units to operate in violation of limits on sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and wastewater during those hours, if required to maintain reliability.

In the longest event CRS identified, DOE granted multiple renewals to a request to allow two coal-fired units in Virginia to continue operating, as needed for reliability, in violation of mercury emissions limitations while a transmission facility was constructed. Emergency orders in response to that event were in effect from June 16, 2017, to March 8, 2019.[7]

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[3] Department of Energy (DOE), Economic Regulatory Administration, "Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power" (final rule), 46 *Federal Register* 39985, August 6, 1981, https://archives.federalregister.gov/issue_slice/1981/8/6/39984-39991.pdf#page=2.

[4] See DOE, "DOE's Use of Federal Power Act Emergency Authority," https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority; and DOE, "DOE's Use of Federal Power Act Emergency Authority – Archived," https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority-archived.

[5] Benjamin Rolsma, "The New Reliability Override," *Connecticut Law Review*, vol. 57, no. 3 (May 2025).

[6] Additional information is available at DOE, "Federal Power Act Section 202(c): ERCOT September 2023," https://www.energy.gov/ceser/federal-power-act-section-202c-ercot-september-2023.

[7] Additional information is available at DOE, "Federal Power Act Section 202(c) – PJM Interconnection & Dominion Energy Virginia, 2017," June 19, 2017, https://www.energy.gov/oe/articles/federal-power-act-section-202c-pjm-interconnection-dominion-energy-virginia-2017.

Trump Administration Actions

On April 8, 2025, President Trump issued Executive Order (E.O.) 14262, "Strengthening the Reliability and Security of the United States Electric Grid."[8] E.O. 14262 directs DOE to "streamline, systemize, and expedite" its processes for issuing emergency orders when "the relevant grid operator forecasts a temporary interruption of electricity supply is necessary to prevent a complete grid failure." A blackout is an example of a temporary interruption of electricity supply.

The E.O. additionally directs DOE to develop a protocol to identify generation resources that are critical to system reliability. The protocol must "include all mechanisms available under applicable law, including Section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained." Further, the protocol must prevent, "as the Secretary of Energy deems appropriate and consistent with applicable law," identified resources from "leaving the bulk-power system" or converting fuels in such a way that reduces their accredited capacity. An example of fuel conversion that could reduce accredited capacity is replacing a coal-fired power plant with a solar farm.

The language of the E.O. is nonspecific regarding the duration of any DOE action to retain resources or prevent them from leaving the bulk-power system. The E.O. language could be interpreted to mean DOE should take long-term action (i.e., lasting multiple years) or indefinite action. Emergency orders issued in response to multiyear events would be unusual, though not unprecedented, applications of DOE's Section 202(c) authority. It is unclear the extent to which limits to the authority might exist through judicial review or other avenues if DOE chose to issue long-term or indefinite emergency orders.

DOE issued emergency orders for three separate events in May 2025, all involving seemingly new interpretations of the emergency authority. One event is anticipated electricity supply shortages in Puerto Rico in summer 2025.[9] One of the DOE emergency orders pertaining to Puerto Rico directs the local utility to conduct vegetation management (e.g., shrub clearing) around specified transmission lines on the island.[10] No other emergency order issued from 2000 to the present has addressed vegetation management.

The other events involve elevated risk of supply shortages in parts of the Midwest and Eastern United States this summer. DOE ordered a delay in retirement plans for a coal-fired power plant in Michigan and a natural gas/oil dual-fired power plant in Pennsylvania.[11] Unlike in the cases of other emergency orders issued since 2000, the grid operators in these cases had not requested the delayed retirements. Moreover, neither had identified reliability risks specifically associated with

[8] Executive Order 14262 of April 8, 2025, "Strengthening the Reliability and Security of the United States Electric Grid," 90 *Federal Register* 15521-15522, April 14, 2025, https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

[9] For background on Puerto Rico's electricity system, see CRS In Focus IF12913, *Electric Reliability and Resiliency in Puerto Rico*, by Corrie E. Clark.

[10] Secretary of Energy Chris Wright, *Order No. 202-25-2*, May 16, 2025, https://www.energy.gov/sites/default/files/2025-05/PREPA%20202%28c%29%20Emergency%20Measures%20Transmission.pdf.

[11] Secretary of Energy Chris Wright, *Order No. 202-25-3*, May 23, 2025, https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf; and Secretary of Energy Chris Wright, *Order No. 202-25-4*, May 30, 2025, https://www.energy.gov/sites/default/files/2025-05/Federal%20Power%20Act%20Section%20202%28c%29%20PJM%20Interconnection.pdf.

the retirement of the power plants in question at the time they approved those retirements. One of the affected grid operators, PJM, issued a supportive statement following the emergency order.[12]

Issues for Congress

E.O. 14262 does not specify how DOE should streamline its processes for issuing emergency orders. Congress could evaluate whether DOE's existing regulations require streamlining and, if Congress determines they do, could provide policy direction and set a timeline for updating the regulations. Congress could also leave it to DOE's discretion as to when and how to update its regulations.

Congress could weigh DOE action in this space against other priorities for the department, given that updating processes for issuing emergency orders could divert DOE resources from other activities. On the one hand, brownouts or blackouts due to insufficient electricity supplies are relatively rare in the United States. Grid operators have their own processes in place for managing the grid during times of supply shortages and, historically, DOE emergency orders have rarely been requested. On the other hand, many observers anticipate electricity demand to increase in the coming years faster than new supply can be brought online. If these trends continue, brownouts or blackouts could become more common, potentially increasing DOE's use of its emergency authority or Congress's interest in addressing emergency situations for electricity supply.

Regarding the statutory authority itself, Congress could consider whether amendments to Section 202(c) of the Federal Power Act are appropriate. The language has remained unchanged since 1935, potentially reflecting Congress's continued view over this time period that the original authorization is appropriate. Nonetheless, the U.S. electricity system has changed in many ways since 1935, and Congress might choose to consider reevaluating the authority.

One potential aspect for congressional consideration is the duration of DOE emergency orders, especially in relation to critical resources identified pursuant to E.O. 14262. Under current law, and assuming such orders might result in a conflict with environmental requirements, DOE could potentially reissue its emergency orders every 90 days for an indeterminate amount of time. Repeated emergency orders may raise feasibility questions, such as whether successive emergency orders would be upheld by the courts or whether power plant owners would make long-term investments to maintain power plants that are operating primarily under emergency orders.

Congress could consider evaluating and clarifying via legislation whether the Section 202(c) authority is better reserved for short-term situations or whether application to long-term situations is appropriate. Some backers of power plants at risk of retirement (e.g., coal-fired power plants) might support extended emergency orders based on long-term economic considerations. At the same time, some backers of power plants with low greenhouse gas emissions (e.g., solar generators) might support extended emergency orders based on long-term environmental considerations. Others might prefer to limit DOE's emergency authorities to short-term situations. A more limited role for DOE in electricity system operations allows for greater use of market forces and reliance on local- and state-level processes to prepare for and respond to emergencies.

Another potential aspect for congressional consideration is the definition of "emergency" in the context of Section 202(c). Current law gives DOE broad discretion in determining what

[12] PJM, "PJM Statement on the U.S. Department of Energy 202(c) Order of May 30," press release, May 31, 2025, https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/2025-releases/20250531-doe-202c-statement-to-defer-retirements-of-certain-generators.pdf.

constitutes an emergency. Congress could consider whether this level of discretion is appropriate, or whether additional (or alternative) statutory direction would better serve current system needs.

As noted above, some supporters of specific kinds of power plants might view sustained economic conditions or environmental impacts as emergencies that warrant DOE action. Those situations would appear to be novel exercises of DOE authority under Section 202(c), if DOE were to interpret them in such a way. Amendments to the Federal Power Act could clarify congressional intent regarding use of DOE's emergency authority in response to those situations or any other long-term situation.

Other stakeholders might wish to limit DOE's discretion in when to issue emergency orders—for example, by modifying the currently broad statutory language or by requiring additional review by FERC or another entity.

A third potential aspect for congressional consideration is the scope of interventions allowed under the emergency authority. Current law allows DOE to order almost any change in operation of the electricity system.

Emergency orders between 2000 and 2024 directed either the operation of certain generators as needed for reliability or the temporary interconnection of the main Texas grid with neighboring regions' grids. One of DOE's May 2025 emergency orders requires Puerto Rico's local utility to conduct vegetation management activities.

One operational consideration that has not been tested under DOE's emergency authority (at least not in the orders available on DOE's website) is the curtailment of certain generators. Curtailment occurs when a grid operator directs a generator to reduce its output or cease operating altogether for a certain amount of time. Curtailment is sometimes necessary when generation levels in a given location exceed the transmission system's capacity to transmit energy out of that location.

Congress could evaluate the appropriateness of DOE's currently broad discretion to order interventions in the operation of the electricity system. Amendments to the Federal Power Act could clarify what kinds of interventions DOE may require.

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	)	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit U: Department, Order 202-25-9 (Nov. 18, 2025)

Department of Energy
Washington, DC 20585

Order No. 202-25-9

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

Order Nos. 202-25-3 and 202-25-7

J.H. Campbell Generating Plant (Campbell Plant) is a 1,420 MW coal-fired plant primarily owned by Consumers Energy Company (Consumers) and located in West Olive, MI. In 2021, Consumers announced that it planned to implement a "speed closure" of the Campbell Plant fifteen years before the end of its scheduled design life.[3] Instead of retiring the Campbell Plant at the end of its design life, Consumers planned to accelerate the Campbell Plant's retirement and discontinue its operations on May 31, 2025.

Order No. 202-25-3, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until August 21, 2025. Subsequently, Order No. 202-25-7, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until November 19, 2025. Those orders were based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO). Specifically, I determined that MISO likely faced tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. I determined that the continued operation of the Campbell Plant would provide additional generation capacity during these periods which would help prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety. I determined that the continued operation of the Campbell Plant was necessary to alleviate immediate and anticipated threats to reliability. My determination was based on a number of facts.

First, the North American Electric Reliability Corporation (NERC) released its 2025

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. §7151(b).
[3] *See Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan's Clean Energy Transformation*, Consumers Energy (June 23, 2021), https://www.consumersenergy.com/news-releases/newsrelease-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-cleanenergy-transformation.

Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[4] In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply shortfalls. NERC anticipated that the near-term period of greatest capacity shortfall for MISO would likely occur in August.[5]

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[6] Additionally, EIA stated, "[t]ypically, Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[7] The state's Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. The Palisades plant remains unavailable, although according to a recent news report, "Holtec International expects the Palisades plant in Michigan to resume service early next year…."[8]

Third, the Campbell Plant's retirement would have further decreased available dispatchable generation within MISO's service territory, adding to the loss of the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant into their supply forecasts and Consumers acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."[9]

Fourth, MISO's Planning Resource Auction Results for the 2025-2026 Planning Year, released in April 2025, noted that for the northern and central zones, which include Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[10] While the results "demonstrated sufficient

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[4] *2025 Summer Reliability Assessment*, North American Electric Reliability Corporation, at 16 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf (NERC 2025 Summer Reliability Assessment).

[5] *Id.*

[6] *Michigan State Profile and Energy Estimates*, U.S. Energy Info. Admin. (Oct. 17, 2024), https://www.eia.gov/state/print.php?sid=MI.

[7] *Id.*

[8] *Nuclear plants face decadelong timeline to meet AI energy needs*, Los Angeles Times. (Nov. 13, 2025), https://www.latimes.com/business/story/2025-11-13/despite-80-billion-commitment-nuclear-plants-face-decade-long-timeline-to-meet-ai-energy-needs.

[9] NERC 2025 Summer Reliability Assessment at 16.

[10] *Planning Resource Auction—Results for Planning Year 2025–2026*, Midcontinent Independent System Operator, Inc., 13 (May 29, 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf. (MISO Planning Resource Auction – Results for Planning Year 2025-26).

capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and these results "reinforce the need to increase capacity."[11]

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order Nos. 202-25-3 and 202-25-7 continue, both in the near and long term.[12] The production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO. According to the U.S. Environmental Protection Agency's data, the plant has generated an average of approximately 509,000 MWh per month, from June 2025 through September 2025,[13] providing vital generation capacity to the region. Additionally, between June 11 and November 5, MISO issued dozens of alerts to manage grid reliability in its Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits.

MISO's year-round resource adequacy concerns are well documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[14] MISO justified this revision by explaining that "Reliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round concern."[15] MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[16]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[17] Among other things, this report described changes in the time of year during

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[11] *Id*. at 2,12. For further information regarding the determination that emergency conditions existed, *see* Order No. 202-25-7.

[12] Further, as noted in Order No. 202-25-7, as a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Consumers were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

[13] *See, Custom Data Download, EPA CAMPD (Clean Air Markets Program Data), https://campd.epa.gov/data/custom-data-download (search criteria to produce these results could include Emissions >> Monthly >> Unit (default) >>Apply >>"2025" and "June, July, August, September." The data can then be filtered to only include the JH Campbell Plant.)*

[14] M*idcontinent Independent System Operator, Inc.*, FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. Midcontinent Independent System Operator, Inc., 180 FERC ¶ 61,141 (2022).

[15] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).

[16] Id. at 3-4.

[17] *Attributes Roadmap*, MISO (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf

which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projects that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[18]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, *"MISO's Response to the Reliability Imperative."*[19] In a section of that report entitled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season.

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[20]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

While the 2025 – 2026 NERC Winter Reliability Assessment has not yet been released as of the date of this Order, two recent winter studies (2024 – 2025 NERC Winter Reliability Assessment[21] and the 2023 – 2024 NERC Winter Reliability Assessment[22]) have assessed the MISO assessment area as an elevated risk, with the "potential for insufficient operating reserves in above-normal conditions." Specifically, the 2024 – 2025 Winter Reliability Assessment noted that "[ge]nerating capacity is 10 GW lower (-6.8%) compared to the prior winter as generators have retired, withdrawn from MISO's capacity market, or received lower winter accredited capacity."[23]

The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased

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[18] *Id.* at 11.

[19] *MISO's Response to the Reliability Imperative*, MISO (Updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf

[20] *Id.* at 12.

[21] 2024 – 2025 NERC Winter Reliability Assessment at 5, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf

[22] 2023 – 2024 NERC Winter Reliability Assessment at 5, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf

[23] 2024 – 2025 NERC Winter Reliability Assessment at 15, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf

accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Michigan.[24]

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.[25] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[26] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[27] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[28]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large amounts of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[29] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[30]

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[31] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three-year grace period to commence commercial operations.[32] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are

[24] MISO Planning Resource Auction – Results for Planning Year 2025-26 at 13.
[25] *OMS-MISO Survey Results*, OMS and MISO (Updated June 6, 2025) https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf
[26] *Id.* at 2.
[27] *Id.* at 7.
[28] *Id.* at 9
[29] *Id.* at 7, 9.
[30] *Id.*
[31] M*idcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).
[32] 192 FERC ¶ 61,064 at P 84.

likely to further hinder rapid construction and exacerbate reliability concerns.[33] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order Nos. 202-25-3 and 202-25-7 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[34] President Trump likewise recognized, in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[35] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[36]

The Department's July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy outlook. "Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[37] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.[38] In addition, as just one example,

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[33] *See generally*, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, S&P Global (May 2025), US gas-fired turbine wait times as much as seven years; costs up sharply | S&P Global. "With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."

[34] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliabilityand-security-of-the-united-states-electric-grid/.

[35] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[36] *Id*.

[37] *See also Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, U.S. Department of Energy (July 2025), at 1, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[38] Ekku Jokinen, *Top 21 Artificial Intelligence Companies in Michigan*, (last accessed Aug. 13, 2025), https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan.

Consumers has announced an additional 1 GW of new power to a planned hyperscale data center and "continue[s] to see positive momentum with data centers within the 9 GW pipeline . . . ."[39]

Grid operators — including MISO itself — have also acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[40] Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[41] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[42]

Pursuant to section 202(c)(4)(B) of the FPA, the Department has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[43] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant when the Secretary has

[39] *See Michigan utility Consumers Energy to provide 1GW of power to new hyperscale data center*, Data Center Dynamics (August 05, 2025), https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-toprovide-1gw-of-power-to-new-hyperscale-data-center/ (quoting Consumers Energy CEO Garrick Rochow).
[40] Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce, Subcommittee on Energy, 119th Cong. (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), at 5, https://democratsenergycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/files/evo-mediadocument/witness-testimony_curran_eng_grid-operators_03.25.2025.pdf
[41] *Id.* at 6.
[42] *Id.* at 7.
[43] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-3 and 202-25-7 will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Campbell Plant is necessary to best meet the increased demand and determined shortage and serve the public interest under FPA section 202(c).

To ensure the Campbell Plant will be available if needed to address emergency conditions, the Campbell Plant shall remain in operation until February 17, 2026.[44]

Based on my determination of an emergency set forth above, I hereby order:

A. From November 19, 2025, MISO and Consumer Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.

C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

[44] 16 U.S.C. § 824a(c)(4).

D. By December 3, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Campbell Plant shall not be considered a capacity resource.

H. This Order shall be effective from 00:00 Eastern Standard Time (EST) on November 19, 2025, and shall expire at 00:00 EST on February 17, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. at 5:58PM EST on this 18th day of November 2025.

Chris Wright

Chris Wright
Secretary of Energy

cc:

FERC Commissioners
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Michigan Public Service Commissioners

Chairman Dan Scripps

Commissioner Katherine Peretick

Commissioner Shaquila Myers

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit V: Department, Order No. 202-25-8 (Aug. 28, 2025)

Department of Energy
Washington, DC 20585

Order No. 202-25-8

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in the PJM Interconnection, L.L.C. (PJM) region due to a shortage of facilities for the generation of electric energy, resource adequacy concerns, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

Order No. 202-25-4

The Eddystone Generating Station is a power plant owned by Constellation Energy Corporation (Constellation Energy) and located in Eddystone, PA. Units 3 and 4 (Eddystone Units), each with 380 MW of generation capacity, are subcritical steam boiler-turbine generator units that can run on either natural gas or oil, depending on market conditions. The Eddystone Units were initially scheduled for retirement on May 31, 2025.

Order No. 202-25-4, issued pursuant to FPA section 202(c), required that the Eddystone Units remain in operation for 90 days, until August 28, 2025. That order was based on my determination that emergency conditions existed in the PJM region. I explained that there was a potential shortage of electric energy and shortage of facilities for generation of electric energy. I stated that the potential loss of power to homes and local businesses presents a risk to public health and safety. I determined that the operational availability and economic dispatch of the Eddystone Units is necessary to best meet the emergency and serve the public interest. My determination was based on a number of different facts.

First, in congressional testimony, PJM's president and CEO recently stated that its system faces a "growing resource adequacy concern" due to load growth, the retirement of dispatchable resources, and other factors.[1] He stated that, through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics of resources in PJM's interconnection queue.[2] Upcoming retirements, including the planned retirement of the Eddystone Units, would exacerbate these resource adequacy issues.

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[1] *Keeping the Lights On: Examining the State of Regional Reliability*, Before the *H. Comm. on Energy and Com., S. Comm. on* Energy, 119th Cong. (Mar. 25, 2025) (testimony of Mr. Manu Asthana, President and CEO of PJM Interconnection) (Asthana Test.) at 4-5, available at https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf.
[2] *Id.*

Second, PJM indicated that resource constraints could exist within its service territory under peak load conditions, stating that "available generation capacity may fall short of required reserves in an extreme planning scenario."[3] In its February 2023 assessment "*Energy Transition in PJM: Resource Retirements, Replacements & Risks* (Four Rs Report)," PJM highlighted increasing reliability risks in the coming years due to the "potential timing mismatch between resource retirements, load growth and the pace of new generation entry" under "low new entry" scenarios for renewable generation.[4]

Third, in December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found "the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry."[5]

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order No. 202-25-4 continue, both in the near and long term. The summer season has not yet ended, and the production of electricity from the Eddystone Units will continue to be critical to maintaining reliability in PJM this summer. This need is evidenced by the fact that the Eddystone Units were called on by PJM to generate electricity during heat waves that hit the region in June and July.

According to U.S. Environmental Protection Agency data, the Eddystone Units generated over 17,000 MWhs during the month of June.[6] Further, over a period of hot weather from June 23 to June 26, Unit 3 ran for a total of 65 hours and Unit 4 ran for a total of 59 hours.[7] During a hot weather period from July 28 to July 30, Unit 3 ran for 39 hours and Unit 4 ran 8 hours.[8]

Over the course of the summer, PJM has issued Hot Weather Alerts and/or Maximum Generation Alerts (EEA 1) covering a total of 20 days, including days in June, July, and August.[9] The hot weather may continue in the near term, as the Seasonal Outlook released by the National Oceanic and Atmospheric Administration (NOAA) on August 21, 2025, projects between a 40%

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[3] *PJM Summer Outlook 2025: Adequate Resources Available for Summer Amid Growing* Risk, PJM Interconnection, L.L.C. (May 9, 2025), https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/.

[4] *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, PJM (Four Rs Report) at 1, (Feb. 24, 2023), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx.

[5] *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084 (2025).

[6] *See Custom Data Download, EPA CAMPD* (Clean Air Markets Program Data), https://campd.epa.gov/data/custom-data-download (search criteria Emissions >> Monthly >> Unit (default) >>Apply >>"2025" and "June" (search date Aug. 22, 2025).

[7] *See PJM daily reports to DOE under Order No. 202-25-4, June 24-27, 2025.*

[8] *See PJM daily reports to DOE under Order No. 202-25-4, July 29-31, 2025.*

[9] *See* PJM Emergency Procedures Postings for the period between June 1 and August 31, *Emergency Procedures*, https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf (search range set to: effective from 06/01/2025 until 08/31/2025).

and 60% probability of above-normal temperatures in the Mid-Atlantic region, which includes the PJM region, over the next three calendar months.[10]

The evidence also indicates that there is a potential longer term resource adequacy emergency in the PJM region.

In its news release expressing support for Order No. 202-25-4, PJM explained that it has "repeatedly documented and voiced its concerns over the growing risk of a supply and demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers."[11]

PJM has indeed voiced these concerns for years. In its February 2023 Four Rs Report, PJM cautioned that 40 GW of thermal generation are at risk of retirement by 2030.[12] PJM also noted that, while there were then 290 GW of renewable generation capacity in the PJM interconnection queue, historically, the rate of completion for renewable projects is approximately five percent.[13] PJM determined that the pace of new capacity additions "would be insufficient to keep up with expected retirements and demand growth by 2030."[14] PJM estimated that, depending on the pace of new capacity additions, reserve margin erosion would occur between 2026 and 2028.

More recently, in its December 2024 RRI filing with FERC, PJM stated that "[c]oncerns about resource adequacy . . . have only increased since the Four Rs Report . . . ."[15] PJM warned that its "resource adequacy concerns are increasing at an extraordinary pace."[16] PJM went on to explain, its "resource adequacy concerns are driven in large part by significant load growth caused by, among other things, large data centers" and that its preliminary analysis shows "substantial increases [in load additions] since the 2024 forecast" for both the summer and winter seasons.[17] According to PJM, "load growth and generator retirements are significantly outpacing the entry of new generation in the PJM Region with this trend expected to continue unabated based on all available evidence."[18] Although the RRI process will help expedite the construction of needed

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[10] *Seasonal Outlook*, NOAA Climate Prediction Ctr., (Aug. 21, 2025), https://www.cpc.ncep.noaa.gov/products/predictions/long_range/seasonal.php?lead=1.
[11] *PJM Statement on the U.S. Department of Energy 202(c) Order of May 30*, PJM (May 31, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/2025-releases/20250531-doe-202c-statement-to-defer-retirements-of-certain-generators.pdf.
[12] Four Rs Report, *supra* n. 4, at 2.
[13] *Id.*
[14] *Id.* at 16, Table 1.
[15] *PJM Interconnection, L.L.C.*, FERC Docket No. ER25-712, Tariff Revisions for Reliability Resource Initiative at 10 (Dec. 13, 2024).
[16] *Id.*
[17] *Id.* at 10-11. *See also id.* at 13 ("the exponential load growth resulting from development of new data centers and the intense energy needs of Artificial Intelligence technology overshadows any relaxation in the pace of fossil fuel generation retirements…").
[18] *Id.* at 14.

new capacity, it is unlikely to result in the addition of any new generation capacity in the next few years.[19]

In support of the RRI filing, PJM submitted an affidavit from Donald Bielak, PJM's Director, Interconnection Planning. Mr. Bielak characterized the increase in forecasted load growth throughout PJM as "extraordinary" and "unprecedented," stating that it "could not have been foreseen as recently as a year ago."[20] Mr. Bielak expressed the opinion that the "rapid" retirement of thermal generation resources, "extreme" forecasted load growth, and "delays in new generation resources achieving commercial operation," would adversely affect resource adequacy throughout PJM's electricity grid.[21]

The North American Electric Reliability Corporation (NERC) has raised similar concerns. According to NERC's 2024 Long Term Reliability Assessment, "PJM could face future resource adequacy challenges, impacting system reliability and PJM's ability to serve load."[22] NERC assessed the PJM region at an elevated risk starting in 2026,[23] explaining that "[r]esource additions are not keeping up with generator retirements and demand growth."[24] NERC stated that the loss-of-load hour (LOLH) and expected unserved energy (EUE) risks are concentrated in the winter months (especially January), in both 2026 and 2028.[25]

Order 202-25-4 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[26] President Trump likewise recognized, in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[27] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure,

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[19] *See id.*, Attachment C (Affidavit of Mr. Donald Bielak) ¶ 18-19 (explaining that projects studied in Transition Cycle #2, which includes RRI projects, "could be constructed and in commercial operation by the 2029/30 Delivery Year or sooner.").
[20] *Id*. at 12.
[21] *Id*. at 7.
[22] *2024 Long-Term Reliability Assessment*, North American Electric Reliability Corporation at 92 (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf at 92.
[23] *Id.* at 4.
[24] *Id.* at 7.
[25] *Id.* at 91-92.
[26] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (Strengthening the Reliability and Security of the United States Electric Grid), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliabilityand-security-of-the-united-states-electric-grid/.
[27] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (Declaring a National Energy Emergency), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[28]

The Department of Energy's (Department) July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy outlook. It concludes, "Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[29] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. For example, PPL Electric Utilities has 11.7 GW of advanced data center requests in Pennsylvania through to 2030.[30] As of December 2024, Dominion Energy has 40.2 GW of contracted data center capacity, which is an 18.2 GW increase over the amount from July 2024, an approximately 88% increase.[31] Regarding the PJM region, the Department's analysis performed this year in collaboration with the national labs modeled the effects of approximately 25 GW of load growth in PJM, of which 15 GW came from data centers, as well as approximately 17 GW of announced coal, gas, and oil generation retirements.[32] Under these assumptions, the model estimated approximately 430.3 loss of load hours in an average weather year. Under worst weather year assumptions, the model estimated 1,052 loss of load hours and a max unserved load hours of approximately 21.335 GW.[33]

Grid operators, including PJM, have likewise acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the United States House of Representatives Committee on Energy and Commerce, Manu Asthana, President and CEO, PJM, testified that there was a "growing resource adequacy concern . . . impacting a significant part of our country."[34] Mr. Asthana explained that the "rate of electricity demand is anticipated to increase significantly in the future due to development of large data centers in the PJM service Area . . . [and] increases in demand coming from the transportation and heating sectors and from industrial growth."[35] Mr. Asthana noted that, "though various reforms instituted by PJM had succeeded in bringing new generation online and preventing the retirement of existing units, supply conditions within PJM are still tightening." Therefore, Mr. Asthana stated that PJM

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[28] *Id.*

[29] *See also* Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, U.S. Department of Energy (July 2025), at 1, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[30] *See PPL Corporation Q2 2025 Investor Update*, PPLC Corporation (July 31, 2025) at 7, https://filecache.investorroom.com/mr5ir_pplweb2/1245/PPL_2025_Q2_Investor_Update_vFINAL.pdf

[31] *See* Dominion Energy Virginia, Q4 2024 Earnings Call (Feb. 12, 2025), at 18, https://s2.q4cdn.com/510812146/files/doc_financials/2024/q4/2025-02-12-DE-IR-4Q-2024-earnings-call-slides-vTCII.pdf.

[32] *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, U.S. Department of Energy (July 2025), at 28, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[33] *Id.* at 27.

[34] Asthana Test. at 4.

[35] *Id*.

"encourage[s] all generation owners who have signaled an intent to retire their units to reconsider their decision to support resource adequacy and grid reliability."[36]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[37] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Eddystone Units when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and accelerated retirements of generation facilities supporting the issuance of Order No. 202-25-4 will continue in the near term and are also likely to continue in subsequent years. This could lead to the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Eddystone Units is necessary to best meet the emergency and serve the public interest under FPA section 202(c).

To ensure the Eddystone Units will be available if needed to address emergency conditions, the Eddystone Units shall remain in operation until November 26, 2025.[38]

Based on my determination of an emergency set forth above, I hereby order:

A. From 5:03PM EDT on August 28, 2025, PJM and Constellation Energy shall take all measures necessary to ensure that the Eddystone Units are available to operate. For the duration of this Order, PJM is directed to take every step to employ economic dispatch of the Eddystone Units to minimize cost to ratepayers. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by PJM pursuant to paragraph A. PJM shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Eddystone Units has operated in

[36] *Id.* at 10.
[37] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b) (2018).
[38] 16 U.S.C. § 824a(c)(4).

compliance with the allowances contained in this Order.

C. All operation of the Eddystone Units must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By September 12, 2025, PJM is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with this Order. PJM shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. Constellation Energy is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Eddystone Units to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Eddystone Units shall not be considered capacity resources.

H. This Order shall be effective from 5:03 PM Eastern Daylight Time (EDT) on August 28, 2025, and shall expire at 00:00 EST on November 26, 2025, with the exception of applicable compliance obligations in paragraph D.

I. Issued in Washington, D.C., at 7:11 PM Eastern Daylight Time on this 27th day of August 2025.

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

Pennsylvania Public Utility Commissioners
Chairman Stephen M. DeFrank
Vice Chair Kimberly M. Barrow
Commissioner Kathryn L. Zerfuss
Commissioner John F. Coleman, Jr.
Commissioner Ralph V. Yanora

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit W: CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

PROCEEDING NO. 23A-____E

IN THE MATTER OF THE APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2023 ELECTRIC RESOURCE PLAN

DIRECT TESTIMONY AND ATTACHMENTS OF LISA K. TIFFIN ON BEHALF OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

NOTICE OF CONFIDENTIALITY
A portion of this document has been filed under seal.

This document contains Highly Confidential Attachments.

- LKT-7 ~~LKT-1-Attachment B~~
  - Pages: 5-9, 16, 17
- LKT-10 ~~LKT-1-Attachment B-3~~
  - Pages: 1, 2
- LKT-15 ~~LKT-1-Attachment C-1~~
  - Pages: 3, 4
- LKT-16 ~~LKT-1-Attachment C-2~~
  - Pages: 9, 10, 11 12, 15, 16, 19
- LKT-17 ~~LKT-1-Attachment C-3~~
  - Pages: 5, 6, 7
- LKT-19 ~~LKT-1-Attachment D-1~~
  - Pages: 6-10, 16~~,~~
- LKT-20 ~~LKT-1-Attachment D-2~~
  - Pages: 9-13, 21-22
- LKT-21 ~~LKT-1-Attachment D-3~~
  - Pages: 10, 11, 13, 16, 18, 19, 26, 27
- LKT-22 ~~LKT-1-Attachment D-4a~~
  - Pages: 8, 10, 12, 14, 16, 17, 18, 25, 26
- LKT-23 ~~LKT-1-Attachment D-4b~~
  - Pages: 10, 13, 16, 19, 20, 21, 28, 29
- LKT-24 ~~LKT-1-Attachment D-5~~
  - Pages: 10, 12, 14, 16, 18, 20, 22, 23, 24, 32, 33
- LKT-26 ~~LKT-1-Attachment F~~
  - Pages: 15
- LKT-27 ~~LKT-1-Attachment F-1~~
  - Pages: 5-1,686
- LKT-30 ~~LKT-1-Attachment G-2~~
  - Pages: all
- LKT-32 ~~LKT-1-Attachment G-4~~
  - Pages: all

This document contains Confidential Attachments.

- LKT-7 ~~LKT-1-Attachment B~~
  - Pages: 4, 5, 7, 13
- LKT-16 ~~LKT-1-Attachment C-2~~
  - Pages: 7
- LKT-17 ~~LKT-1-Attachment C-3~~
  - Pages: 5, 6, 7
- LKT-26 ~~LKT-1-Attachment F~~
  - Pages: 8, 9
- LKT-29 ~~LKT-1-Attachment G-1~~
  - Pages: 44

December 1, 2023

Colorado PUC E-Filings System

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[1] ~~LKT-1 includes several attachments,~~ each of which are listed on page 5 the report.

I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY AND RECOMMENDATIONS

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Lisa K. Tiffin. My business address is 1100 West 116th Avenue, Westminster, CO 80234.

Q: BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A: I am employed by Tri-State Generation and Transmission Association, Inc. ("Tri-State") as Vice President, Planning & Analytics.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A: I am testifying on behalf of Tri-State.

Q: HAVE YOU PREPARED A STATEMENT OF YOUR EXPERIENCE AND QUALIFICATIONS?

A: Yes. My Statement of Qualifications is attached to my testimony as **Attachment LKT-4**.

Q: PLEASE SUMMARIZE YOUR BACKGROUND AND EXPERIENCE IN THE ELECTRICITY UTILITY INDUSTRY.

A: I have 30 years of experience in the electric utility industry. Prior to my current position, I managed Tri-State's short-term marketing and operations, applications support services, and resource planning. Prior to joining Tri-State, I worked in consulting, bulk electric system marketing and operations, and energy transportation and sales for the Structure Group, Illinois Municipal Electric Agency, Freeman Energy, and ABB Power T&D. I have a Bachelor of Science degree in Political Science from MacMurray College in Illinois and hold a North American

Electric Reliability Corporation ("NERC") Balancing Interchange and Transmission Operator certification.

I have worked for Tri-State for 16 years, non-consecutively, and have served in a variety of management leadership roles within the organization focused on energy planning, management, and delivery. These roles included overseeing teams of staff supporting day-ahead trading and scheduling, budgeting and forecasting, resource planning, and analytics. In my current role, I oversee Tri-State's long-term generation resource plan, load forecasting, merchant transmission function, and related state regulatory affairs.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A: My testimony provides a summary of Tri-State's 2023 Electric Resource Plan ("ERP"), as well as the underlying and influential factors reflected in the ERP, such as Member needs, regulatory and environmental compliance, market and policy dynamics, and financial and reliability considerations.

Q: PLEASE IDENTIFY THE OTHER WITNESSES WHO WILL BE TESTIFYING ON BEHALF OF TRI-STATE.

A: Tri-State's witnesses that have also filed Direct Testimony in this proceeding are as follows:

- Ms. Susan Hunter, Vice President, Energy Resources. Ms. Hunter's testimony addresses Tri-State's proposed approach to Phase II of the 2023 ERP for competitive bidding and procurement procedures. She also addresses the Resource Acquisition Period ("RAP") Action Plan.

- Mr. Brian Thompson, Resource Planning Manager. Mr. Thompson's testimony addresses the technical aspects of Tri-State's Phase I filing, including the analytical methodologies employed, the significant technical and operational assumptions used in scenario and sensitivity modeling, as well as studies commissioned for or prepared by Tri-State to support analytical inputs to the modeling.
- Ms. Lisa Lynn, Manager Analytics and Forecasting. Ms. Lynn describes Tri-State's process for developing the load forecasts used in the scenario and sensitivity modeling.
- Mr. Barry Ingold, Chief Operating Officer. Mr. Ingold describes Tri-State's owned thermal resources and processes for procurement and construction of a new gas facility.
- Mr. Andy Berger, Vice President, Environmental Compliance and Policy. Mr. Berger provides an overview of the environmental laws and policies influencing Tri-State's resource planning and will explain how compliance with state and federal environmental laws affects Tri-State's ERP.
- Mr. Ryan Hubbard, Senior Manager, Transmission Business Strategy. Mr. Hubbard discusses transmission system capabilities, including injection capabilities, of Tri-State's transmission system, Tri-State's transmission planning process, and relevant transmission needs and planned projects. He also provides information as required by Rule 3605(d) or identifies where such information can be found in the ERP.

- Mr. Chad Orvis, Senior Manager, People and Culture. Mr. Orvis describes Tri-State's workforce transition planning efforts and community engagement related to anticipated plant closures.

Q: WHAT RECOMMENDATIONS ARE YOU MAKING IN YOUR DIRECT TESTIMONY?

A: I recommend that the Colorado Public Utilities Commission ("Commission") approve Tri-State's Phase I 2023 ERP, including the Inflation Reduction Act Scenario ("IRA Scenario") as Tri-State's preferred plan and the following items Tri-State has proposed for Phase II of the 2023 ERP:

- Phase II timeline;
- Phase II RFPs;
- Bid evaluation criteria and bid policy;
- Independent Evaluator ("IE") Statement of Work;
- Model power purchase agreements ("PPAs") and Term Sheets;
- Phase II Implementation Report components;
- 45-Day Report content; and
- RAP Action Plan.

II. TRI-STATE OVERVIEW

Q: WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A: The purpose of this section of my Direct Testimony is to provide an overview of Tri-State and its system.

Q: WHO IS TRI-STATE?

A: Tri-State is a not-for-profit cooperative wholesale power supplier whose mission is

to provide its Member systems a reliable, affordable, and responsible supply of electricity in accordance with cooperative principles. Tri-State is a cooperative of 45 members, including 42 electric distribution cooperatives and public power districts in four states (Colorado, New Mexico, Wyoming and Nebraska) that provide power to more than one million customers across nearly 200,000 square miles of the western United States.

Q: PLEASE PROVIDE AN OVERVIEW OF THE TRI-STATE SYSTEM.

A: Tri-State's load and/or its resources are located in six Balancing Authorities ("BAs") – Southwest Power Pool ("SPP"), PacifiCorp ("PAC"), Public Service Company of New Mexico ("PNM"), Public Service Company of Colorado ("PSCo"), Tucson Electric Power ("TEP") and Western Area Colorado Missouri ("WACM"). Tri-State had 2454 MW of owned generation capacity, 786 MW of renewable PPA capacity, 580MW of federal hydropower capacity and 616 MW of firm contracted capacity in 2022 serving 3071 MW of peaking load and 100 MW of long-term unit contingent power supply.

Tri-State's Merchant is a network transmission customer of eight Transmission Providers ("TPs") – PAC, PNM, PSCo, TEP, Black Hills Colorado, Platte River Power Authority, Loveland Area Power Authority, and Tri-State Transmission, which purchases point-to-point transmission service from multiple TPs. The Direct Testimony of Mr. Hubbard further describes the Tri-State Transmission network.

The Direct Testimony of Mr. Thompson identifies the Tri-State system topology inclusive of multiple BAs and TPs, which maps the load pockets, resource

locations, and Tri-State Merchant's transmission service rights within the system into the resource planning model for each planning region.

Q: HOW DOES THE COMPLEXITY OF TRI-STATE'S SYSTEM IMPACT ITS ERP PROCESS?

A: As described above, Tri-State operates a complex multi-state system to reliably provide service to its Members, maintain compliance with all applicable federal, state, and local rules, minimize costs as a not-for-profit supplier, and meet environmental responsibility commitments and Member expectations. Tri-State's operations allow it to be a supplier that can maximize the benefits of a diverse and geographically dispersed system for the shared benefit of its Members. To enable these benefits, Tri-State's generation and transmission resources are operated as a system. With this system-wide operational approach, Tri-State reviews and develops its resource plans on a system-wide basis; the same is true for this plan, which is focused on demonstrating compliance with Colorado's ERP requirements.

III. 2023 ERP POLICY FRAMEWORK

Q: WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A: The purpose of this section of my Direct Testimony is to provide an overview of the ERP process, the objectives of Tri-State's 2023 ERP, as well as how the 2023 ERP compared to Tri-State's inaugural 2020 ERP. The electric resource planning process is the standard for determining generation procurement needs, or identifying modifications to existing generation resources, in Colorado under a regulated model. In this case, Tri-State has put to work this now established process to advance both Colorado's and Tri-State's emissions reduction objectives

and energy policy goals.

Q: PLEASE DESCRIBE THE PHASE I PROCESS.

A: Phase I identifies generation quantities (MW), resource types (technologies), and timing of resource needs for meeting load requirements through the modeling of an expansion plan which must meet certain performance criteria and policy objectives. As described in the Direct Testimony of Mr. Hubbard, Tri-State's transmission planning processes are separate from the ERP. While the ERP does include indicative transmission expansion needs associated with generation planning, as well as forecasted costs for upgrades, it is not a comprehensive transmission planning analysis. The focus of Phase I of the ERP is to assess generation needs and determine resource plans.

Q: PLEASE DESCRIBE THE PHASE II PROCESS.

A: As part of a Phase II process, Tri-State will be implementing a competitive solicitation process for new resources, as well as evaluating and developing portfolios of bids that meet Tri-State system needs and Commission directives through the ERP. Tri-State has proposed the use of an IE to oversee this Phase II process, as described in the Direct Testimony of Ms. Hunter. Subsequently, Tri-State may pursue the acquisition of additional resources identified in its RAP Action Plan through any necessary Certificate of Public Convenience and Necessity ("CPCN") proceedings and/or via PPAs.

a. <u>2020 ERP</u>

Q: THIS IS TRI-STATE'S SECOND ERP. PLEASE PROVIDE A SUMMARY OF TRI-STATE'S 2020 ERP IN PROCEEDING NO. 20A-0528E.

A: As part of Tri-State's inaugural ERP in Proceeding No. 20A-0528E, the Commission approved the Unopposed and Comprehensive Settlement Agreement ("2020 ERP Settlement Agreement") which, among other components, approved: Tri-State's Phase I Revised Preferred Plan; a commitment to reduce greenhouse gas ("GHG") emissions related to its wholesale electricity sales in Colorado by 80 percent in 2030; a Phase II competitive solicitation for new resources with in-service dates through 2026; as well as a continued robust stakeholder engagement process.

Q: WERE THERE ANY COMMITMENTS MADE WITHIN THE 2020 ERP THAT IMPACT TRI-STATE'S 2023 ERP?

A: Yes. As part of the 2020 ERP Settlement Agreement, Tri-State agreed, as part of its 2023 ERP, to update certain resource plan modeling assumptions; continue to apply targets related to GHG emissions, energy efficiency, and demand response; hold meetings with interested stakeholders on certain topics; and model certain stakeholder-requested scenarios. These requirements are outlined in Section 3.11 of the 2020 ERP Settlement Agreement.

Q: DOES THE 2023 ERP COMPLY WITH THE 2020 ERP SETTLEMENT AGREEMENT COMMITMENTS MADE IN PROCEEDING NO. 20A-0528E?

A: Yes. Fulfillment of each of these obligations is identified and described in the compliance matrix provided as ~~**Attachment A** to the ERP (**Attachment LKT-1**)~~ Attachment LKT-5.

b. <u>Key Objectives and Considerations</u>

Q: WHAT ARE TRI-STATE'S KEY OBJECTIVES WITHIN THE 2023 ERP?

A: The ERP process is a vehicle to vet and advance the changes that Tri-State

Members and interested stakeholders should anticipate in the coming years. With this 2023 ERP, Tri-State will ensure reliability and resource adequacy, maintain affordability for Members, and meet compliance obligations, including those related to environmental responsibility. Tri-State also feels it is important to reflect key Responsible Energy Plan ("REP") objectives, which are the basis of Tri-State's overarching strategy, within its resource plan. The backdrop for these objectives is a generation fleet that is changing significantly during the turn-of-the-decade—a timeframe that is encapsulated within the 2023 ERP's RAP. Our system also faces unique challenges and opportunities in its operations—being in the desert West, facing emerging extreme weather conditions, and having a multi-state system with complex load, resource, and market dynamics.

Q: PLEASE IDENTIFY ANY OTHER POLICY OBJECTIVES RELEVANT FOR THIS ERP.

A: GHG emission reduction targets as established in the 2020 ERP Settlement Agreement are met and exceeded in our 2023 ERP. Tri-State aims to leverage benefits under the Inflation Reduction Act of 2022 ("IRA") to further accelerate REP goals related to environmental responsibility and Member flexibility, while maintaining an affordable and reliable system. Reliability metrics along with extreme weather event impacts are utilized to evaluate and demonstrate reliability and resource adequacy objectives.

Q: HOW HAS TRI-STATE'S RESOURCE MIX CHANGED IN RECENT YEARS?

A: In 2016, Tri-State's system capacity consisted of 43 percent coal resources, 21 percent gas and oil resources, 12 percent firm contract non-renewable resources

and 24 percent renewable resources. In 2022, Tri-State system capacity consisted of 34 percent coal resources, 19 percent gas and oil resources, 14 percent firm contract non-renewable resources and 33 percent renewable resources. By 2025, Tri-State anticipates 50 percent of the electricity its Members use will come from clean resources, in alignment with the REP. Tri-State has made progress and is continuing on its path to achieving an 80 percent reduction in GHG emissions regarding wholesale electricity sales in Colorado from a 2005 baseline by 2030 and 70 percent clean energy serving Member systems by 2030. The IRA Scenario forecasts an 89 percent reduction in GHG emissions regarding wholesale electricity sales in Colorado from a 2005 baseline in 2030 and approximately 70 percent clean energy serving Member systems by 2030.[2]

Q: AS TRI-STATE MAKES A SIGNIFICANT FLEET TRANSITION OVER THE REMAINDER OF THIS DECADE, WHAT OTHER SIGNIFICANT FACTORS MUST BE CONSIDERED?

A: Several key factors influence the transition of Tri-State's fleet over the remainder of the decade, those most significant include load reduction as a result of Member exits and Partial Requirements, transition of a portion of Tri-State's load and resources into a regional transmission organization ("RTO"), potential to access IRA funding and the continued need to meet reliability while retiring thermal resources and acquiring resources that are still emerging technologies.

Q: WHAT CHANGES TO TRI-STATE'S SYSTEM LOAD ARE TAKING PLACE

[2] Figure 5 of the ERP Report (**LKT-1**) identifies the IRA Scenario system energy mix for sales to Members and non-Members.

SINCE TRI-STATE'S 2020 ERP?

A: The most significant change between our 2020 ERP and the 2023 ERP is the reduction in load modeled throughout most of the Resource Planning Period ("RPP") resulting from the planned exit of three Tri-State Members in 2024 and 2025.[3] These Members, combined, represented 21 percent of Tri-State's load, primarily in Colorado. The Direct Testimony of Ms. Lynn provides further detail on the process for developing the load forecasts used for the 2023 ERP modeling. Despite the reduced load, new resource acquisitions planned during the RAP are still robust due to the drive to reduce GHG emissions while bringing on resources to reliably integrate renewables, with the assistance of potential Empowering Rural America ("New ERA") funding from the U.S. Department of Agriculture ("USDA").

Q: ARE THERE PLANNED MEMBER EXITS THAT IMPACT SYSTEM LOAD FOR THE DURATION OF THE 2023 ERP PLANNING PERIOD?

A: Yes. United Power has provided an unconditional notice to exit on May 1, 2024 and Mountain Parks has provided an unconditional notice to exit on February 1, 2025. The load associated with these Member Systems is removed from the 2023 ERP load forecast, on their respective dates, reducing system capacity and energy requirements in the RPP.

c. Federal and State Legislation Impacting the 2023 ERP

Q: WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A: In this section of my Direct Testimony, I describe the various federal and state laws

[3] ERP modeling reflects United Power and Northwest Rural Public Power District exiting May 1, 2024 and Mountain Parks exiting February 1, 2025. See also **Attachment ~~B of the ERP Report (LKT-1)~~**. LKT-7

that impact Tri-State's 2023 ERP.

Q: HOW DOES THE INFLATION REDUCTION ACT OF 2022 IMPACT TRI-STATE'S RESOURCE PLANNING PROCESS?

A: The IRA, passed in 2022, included provisions for $9.7 billion in direct funding for electric cooperatives transitioning to clean energy ("New ERA Funding"). This unprecedented funding opportunity resulted in two impacts to Tri-State's 2023 ERP:

- Updates to generic resource pricing to reflect the IRA's extension and expansion of tax credits for renewable and storage resources (discussed further in the Direct Testimony of Mr. Thompson), as well as eligibility for Tri-State to receive the tax credits through "direct pay"; and
- Modeling of an IRA Scenario that reflects Tri-State's pursuit of New ERA Funding as a result of the IRA, which I discuss further below.

Q: PLEASE SUMMARIZE HOW GHG REDUCTION REQUIREMENTS IN COLORADO APPLY TO TRI-STATE'S ERP.

A: Significantly, in the 2020 ERP Settlement Agreement, Tri-State committed to GHG reduction targets for the years 2025, 2026, 2027, and 2030 for its wholesale sales of electricity in Colorado, relative to a 2005 baseline. These targets include GHG

reductions of:

- A twenty-six percent (26%) in 2025;
- a thirty-six percent (36%) in 2026;
- a forty-six percent (46%) in 2027; and
- an eighty percent (80%) in 2030.

Tri-State's 2030 target is aligned with § 25-7-105(1)(e)(VIII)(I), C.R.S. which requires wholesale generation and transmission ("G&T") cooperatives to file an ERP that achieves at least an 80 percent reduction in GHG emissions associated with Colorado sales by 2030, relative to a 2005 baseline.

Q: IS TRI-STATE REQUIRED TO FILE A CLEAN ENERGY PLAN?

A: No, Tri-State is not statutorily required to submit a Clean Energy Plan ("CEP") and has not done so here since Tri-State is not a qualifying retail utility.

d. <u>Stakeholder Engagement</u>

Q: WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A: In this section of my Direct Testimony, I describe Tri-State's ongoing efforts at creating a continued, robust stakeholder collaboration process.

Q: HAS TRI-STATE BEEN ENGAGING WITH STAKEHOLDERS SINCE THE 2020 ERP IN PROCEEDING NO. 20A-0528E?

A: Yes. Throughout Proceeding No. 20A-0528E, Tri-State held approximately two dozen stakeholder meetings in order to solicit input regarding Phase I supplemental modeling and Phase II modeling assumptions and portfolio analysis, among many other topics. Even prior to the conclusion of the 2020 ERP, in January 2023, Tri-State began convening stakeholder meetings to discuss Phase

I scenario development, modeling assumptions, sensitivity analyses, and other topics of interest. We have involved interested stakeholders in the technical details of our data and modeling approaches and have considered and adopted many of their ideas along the way. We appreciate the participation of the state agencies, environmental organizations, developers, and our Members in our resource planning process. We convened more than a dozen of the stakeholder meetings prior to beginning modeling, and several meetings after beginning. Some of these meetings served to fulfill commitments Tri-State made through the 2020 ERP Settlement Agreement, but most were set outside those parameters and pursued in the spirit of collaboration and consensus-building. The full list of stakeholder meetings convened is provided in the ERP Report (**LKT-1**).

Q: HAS THIS APPROACH BEEN SUCCESSFUL?

A: Yes. Tri-State has continuously employed a philosophy of transparency, education, and collaboration in the development of its ERP and Tri-State is proud to have fostered beneficial partnerships with the stakeholders engaged in its ERP processes.

IV. 2023 ERP: PLANNING PERIOD, ASSESSMENT OF EXISTING RESOURCES

Q: WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A: In this section of my Direct Testimony, I discuss the RAP and planning period that Tri-State proposes to use for the 2023 ERP.

Q: PLEASE EXPLAIN THE SIGNIFICANCE OF THE RAP.

A: The RAP is a period of time over which Tri-State acquires generation resources to meet its resource needs, which is typically between six and 10 years, pursuant to

Commission rules.

Q: PLEASE EXPLAIN THE SIGNIFICANCE OF THE RPP.

A: The RPP provides for the period of time over which Tri-State models its resource plan, as well as the period of time in which the costs and benefits of new resources and resource retirements are evaluated by Tri-State.

Q: WHAT RPP DID TRI-STATE MODEL FOR THE 2023 ERP?

A: Tri-State has modeled a planning period of 2024 through 2043, consistent with Rule 3602(k), which specifies "…the planning period is twenty to forty years and begins from the date the utility files its plan with the Commission." In his Direct Testimony, Mr. Thompson discusses the technical and analytical approach to resource plan modeling.

Q: WHAT RAP IS TRI-STATE PROPOSING IN THE 2023 ERP?

A: The RAP proposed by Tri-State is six years, from 2026 through 2031, consistent with Rule 3602(n). Tri-State's acquisition process for addressing the resource needs selected in the RAP, and the resulting RAP Action Plan are described in the Direct Testimony of Ms. Hunter.

Q: WHY DID TRI-STATE SELECT A SIX-YEAR RAP?

A: As Tri-State approaches the end of the decade, a time when a significant amount of baseload power is anticipated to retire and renewable and semi-dispatchable resources are anticipated to come online to meet Colorado's emission reduction goals, there must be a plan in place for ensuring sufficient dispatchable replacement capacity to continue to meet Tri-State's Member load needs reliably. Tri-State's next ERP will not occur until 2027, and at that time, a Phase II would

not be concluded with sufficient time to enable the permitting, procurement, and construction steps necessary to bring such resources online prior to the end of the decade. Planning for resources to be in place now for this unprecedented resource shift is essential to meeting reliability requirements.

Q: DID TRI-STATE CONSIDER A LONGER RAP?

A: While Tri-State must plan for the significant resource shift in the coming years, Tri-State must also carefully pursue capital expenditures at a pace that is reasonable in terms of the resulting financial impact to Tri-State Members. Therefore, a six-year RAP strikes the right balance in addressing near-term planning needs.

Q: ARE THERE SIGNIFICANT DIFFERENCES IN THE APPROACH TO THE RAP FOR THE 2023 ERP COMPARED TO THE 2020 ERP?

A: Yes, there are two key changes in Tri-State's approach to the RAP. Tri-State's RAP in the 2020 ERP was limited to renewable and storage resources, and while the 2023 ERP will continue to seek procurement of those resources, it will also include opportunity for new innovative technologies[4] and address the need for a dispatchable natural gas resource. Also, Tri-State intends to leverage IRA funding to enable Tri-State to take significant steps forward in achieving its REP objectives during the RAP.

a. <u>Generation Capacity Needs</u>

Q: HOW DID TRI-STATE ASSESS WHETHER ADDITIONAL GENERATION CAPACITY IS NEEDED FOR SYSTEM RELIABILITY?

A: Tri-State forecasts whether sufficient planning reserve margin ("PRM") is

LKT-16

[4] *See* **Attachment ~~C-2 of the ERP Report (LKT-1)~~** for description of the innovative technology options being modeled in the 2023 ERP.

maintained throughout each summer peak season during the RAP, as well as assessing system performance under modeled extreme weather event ("EWE") conditions, in order to sufficiently make this determination. In addition to system resources achieving the minimum PRM, they must also meet several additional minimum reliability metrics. Tri-State has worked with its stakeholders to identify appropriate Level I and II reliability metrics, discussed further below.[5]

Q: PLEASE EXPLAIN THE PLANNING RESERVE MARGIN.

A: Planning reserve margin is the amount of generation capacity in excess of peak firm obligation load that a utility must carry on its system in order to meet Member demand and firm sales, including under system uncertainties. Tri-State's PRM is 22 percent initially transitioning to 30.5 percent upon the retirement of Craig station, as determined by the Effective Load Carrying Capability and Reserve Margin Study ("ELCC/PRM Study") completed by Astrape August 2023 (**Attachment G-1** of the ERP Report). The ELCC/PRM Study is described further in the Direct Testimony of Brian Thompson.

Q: HAS TRI-STATE PROVIDED AN ASSESSMENT OF ITS EXISTING RESOURCES PER RULE 3605(c)?

A: Yes. Tri-State has provided its assessment of existing resources within **Attachment LKT**LKT-17 ~~**-1 (LKT-1 Attachment C-3).**~~ This assessment identifies the key operational and environmental features, and facility characteristics of all owned and purchased generation resources. In addition, Black & Veatch completed an assessment of the performance and financial characteristics of Tri-State

[5] *See* ERP Report (**LKT-1**) for a description of Level I and II reliability metrics for the 2023 ERP.

generation. Tri-State owns or co-owns coal and natural gas units located throughout its four-state system and has a growing supply of renewable resources through purchased power agreements. Several of Tri-State's natural gas combustion turbines are dual-fuel capable, with the ability to operate on fuel oil in cases of natural gas supply or market volatility, providing additional resource flexibility—which has been useful in historical EWE conditions. Tri-State has also recently taken steps in the fall of 2023 toward regulatory approval of construction of its first solar projects,[6] and plans to expand its ownership of resources to include storage through procurements in Phase II of the 2023 ERP, as described further below and in the Direct Testimony of Susan Hunter.

Tri-State has remained capacity-long in recent years and, with its diverse supply and system geography, has not experienced and does not anticipate resource adequacy concerns. Additional detail on Tri-State's existing resources can be found in **Attachments** ~~**C-3** and **G-2** of the ERP Report (**LKT-1**)~~ LKT-17 and LKT-30 as well as in the Direct Testimony of Mr. Thompson.

As described above, Tri-State is planning for an unprecedented resource shift at the end of this decade, as are many utilities, to meet our environmental responsibility commitments. Following our REP commitment, our in-state coal fleet will be fully retired in 2028. This shift places additional pressure on the performance of our aging gas fleet along with intermittent performance of renewable resources to maintain reliability. With these significant portfolio changes, this ERP highlights the emerging importance of maintaining sufficient

[6] *See* Proceeding No. 23A-0548E.

dispatchable capacity, the role of advanced energy storage systems, and expanded access to energy markets to continue to meet the reliability standards expected by all of our Members.

Q: IS TRI-STATE TAKING STEPS TO MAXIMIZE THE VALUE OF ITS EXISTING RESOURCES' INTERCONNECTION FOR PURPOSES OF THE 2023 ERP?

A: Yes. As stated in Tri-State's RFPs, provided as **Attachments SKH-3, SKH-4**, and **SKH-5,** Tri-State is encouraging bidders in its 2023 ERP Phase II process to offer renewable resources at existing Tri-State owned peaking resource locations with the intent of utilizing surplus interconnection service at those locations if the bids are selected in Phase II modeling. This allows the use of existing interconnections to integrate additional renewable resources while maintaining the ability to dispatch thermal resources for reliability or economic needs when intermittent resources are not available. The Direct Testimony of Ms. Hunter and Mr. Hubbard provide additional detail on surplus interconnection and its anticipated use in the 2023 ERP Phase II process.

b. <u>Forecasted Resource Need</u>

Q: HAVE THERE BEEN ANY CHANGES TO TRI-STATE'S FORECASTED RESOURCE ADDITIONS AND ITS ASSESSMENT OF NEED SINCE COMPLETING THE 2020 ERP PHASE II?

A: Yes. The selected 200 MW wind resource in Tri-State's 2020 ERP Phase II procurement, along with the identified backup bid resource, were not available at the accepted bid prices. The wind resource was therefore not reflected in the 2023 ERP Phase I modeling. Tri-State has terminated the Coyote Gulch PPA due to

the delayed status of the project. However, due to timing of the decision, Coyote Gulch was included in Phase I modeling. A replacement solar resource will be identified for procurement through Phase II of the 2023 ERP. Due to the inclusion of known Member exits and anticipated Partial Requirements load, along with changing resource economics, modeling shows an earlier date for the retirement of Craig 3 of January 1, 2028. These and other factors, such as updated base modeling input assumptions, are driving a significantly different resource need as compared to the 2020 ERP.

Q: WHAT IS TRI-STATE'S FORECASTED RESOURCE NEED FOR THE 2023 ERP?

A: Tri-State's preferred plan, the IRA Scenario described below, identifies a need for 290 MW of dispatchable capacity, 940 MW of renewable resources, and 310 MW of battery storage during the RAP.

V. 2023 ERP SCENARIO MODELING AND RESULTS

a. Modeling

Q: DID TRI-STATE CONVENE STAKEHOLDER MEETINGS TO DISCUSS SCENARIO MODELING FOR THE 2023 ERP?

A: Yes, Tri-State initiated a transparent and cooperative stakeholder engagement process in advance of 2023 ERP modeling to identify scenarios and sensitivities to be modeled. Tri-State committed to hold at least two meetings with interested stakeholders in advance of beginning Phase I modeling for the next ERP, with the intention of collaboratively identifying scenarios to be modeled.[7] Tri-State held

[7] Settlement Agreement, Section 3.11.12.

more than the minimum number of meetings and also provided flexibility in determination of stakeholder-requested scenarios to be modeled by providing stakeholders with a preview of certain Business As Usual Scenario modeling outputs to assist in their assessment of useful modeling parameters for other scenarios.

Additionally, as described above, Tri-State undertook a comprehensive effort to transparently share modeling input assumptions and educate stakeholders on the continued and evolving complexities of the Tri-State system. Details on the numerous stakeholder meetings convened can be found in the ERP Report (**LKT-1**).

Q: PLEASE DESCRIBE THE SCENARIOS AND SENSITIVITIES MODELED FOR THE 2023 ERP.

A: Tri-State modeled five scenarios for Phase I of the 2023 ERP, including:

1. Business As Usual (“BAU”);
2. Inflation Reduction Act (“IRA”);
3. Early Springerville 3 Retirement (“ESPV3”);
4. System-Wide Emissions Reduction (“SWER”); and
5. Aggressive Colorado Emissions Reduction ("ACER”).

Base modeling assumptions for each scenario are identified in **Attachment ~~B of the ERP Report (LKT-1)~~** LKT-7, with the assumptions unique to each scenario identified in **Attachment ~~B-3 of the ERP Report (LKT-1)~~** LKT-10. Tri-State also conducted two sensitivity analyses on each scenario, including:

1. Extreme Weather Event ("EWE") Analysis; and

2. High Gas ("HG") Analysis.

The Direct Testimony of Mr. Thompson describes the approach to modeling the scenarios and sensitivities using the EnCompass software, as well as the modifications to the approach to EWE modeling made since the 2020 ERP.

Q: DID TRI-STATE MODEL STAKEHOLDER-REQUESTED REDUCTIONS OR ELIMINATIONS OF COAL UNITS IN AT LEAST ONE SCENARIO?

A: Yes, pursuant to Section 3.11.14 of the 2020 ERP Settlement Agreement, Tri-State convened stakeholder meetings to discuss 2023 ERP Phase I scenarios and modeling assumptions, including retirement date windows to be modeled for certain coal units. These meetings also served to address the Commission's request in Decision No. C23-0437[8] to "…work with interested parties to refine modeling assumptions and practices in an attempt to forge as great a degree of consensus as possible, by using its model to analyze the benefits and costs associated with various retirement dates for Craig Unit 3, including identifying economically optimal retirement dates as part of the direct case in its 2023 ERP."

Q: WHICH OF THE SCENARIOS AND SENSITIVITIES DID TRI-STATE FIND TO BE MOST INFORMATIVE FOR ITS RESOURCE PLANNING?

A: The IRA Scenario as compared to the ESPV3 Scenario showed more robust emissions reductions during the RAP while allowing for a diversified resource mix during the same period, to both meet reliability and allow for a potential replacement energy sale to the third-party off taker of Springerville 3 after its

[8] Decision No. C23-0437, at ¶77 (Proceeding No. 20A-0528E).

retirement. Without these resources ESPV3 relies on an estimated penalty[9] related to the third-party sale which impacts the affordability of the scenario and drives the Springerville 3 retirement date selected in the ESPV3 scenario to the latest date the model was given.[10] Despite having more aggressive Colorado or system emissions reductions, ACER and SWER Scenarios have less Colorado GHG reductions by 2030 than the IRA Scenario.

The IRA Scenario positions Tri-State to meet current environmental targets with the ability to respond to additional environmental legislation or regulation. The EWE sensitivity performed on each scenario provides reasonable certainty of reliability of service to Tri-State Utility Member Systems during likely future weather events. All scenarios successfully passed required reliability metrics during the RAP in their respective EWEs, even with minimal resource additions due to Tri-State's current and evolving capacity length spurred by Member exits and other load reductions. The IRA Scenario secures significantly larger quantities of resources during the RAP, adding diversity in resource location and technology types which can bolster system performance during EWEs.

Q: ARE THERE CONSISTENT RESULTS ACROSS ALL SCENARIOS THAT INFORM THE RESOURCE PLAN?

A: Yes. In every scenario modeled, the retirement date for Craig 3 is January 1, 2028. This is a change from the 2020 ERP. Decision No. C23-0437[11] directed Tri-State

[9] The estimated penalty is a proxy for what might possibly be required by the third-party to exit the contract without replacement energy. Tri-State cannot exit the third-party sale without reaching agreement with the impacted party.

[10] Unique scenario modeling assumptions are identified in **Attachment** ~~**B-3** of the ERP Report (**LKT-1**~~). LKT-10

[11] ¶ 77, Proceeding No. 20A-0528E.

to "evaluate alternate retirement dates for Craig Unit 3 in its 2023 ERP filing…including identifying economically optimal retirement dates as part of the direct case it will file in its 2023 ERP." Tri-State's 2023 ERP modeling clearly indicates that January 1, 2028 is the optimal retirement date for Craig 3. Additionally, all scenarios modeled recognize the need for a dispatchable gas resource in the Western Colorado planning region during the RAP. These are significant outcomes that support Tri-State's preferred plan.

b. Preferred Plan: IRA Scenario

Q: WHICH SCENARIO DOES TRI-STATE SUPPORT AS ITS RESOURCE PLAN? PLEASE EXPLAIN.

A: Tri-State requests Commission approval of the IRA Scenario as its 2023 ERP Phase I preferred plan. The IRA Scenario, as discussed in the following sections, meets core reliability, financial and environmental metrics that are essential to Tri-State Members. In particular, the financial benefits of pursuing this scenario that cannot otherwise be captured without capitalizing on this one-time window for federal funding, far exceed the benefits of any other scenario modeled.

Q: WHAT ARE THE CORE ELEMENTS OF THE IRA SCENARIO?

A: The IRA Scenario retires 1,207 MW (nameplate – 1,067 net MW) of coal-fired generation during the RAP. Under the IRA Scenario, if USDA funding is received as requested and if contractual commitments are adequately addressed, Tri-State intends to announce a retirement date of 2031 for the coal-fired Springerville Station Unit 3 (458 MW nameplate capacity). This is a dramatic acceleration from its expected operating life of 2066. Additionally, the IRA Scenario further

accelerates the retirement date for coal-fired Craig 3 (535 MW nameplate capacity) by two years, to 2028. The IRA Scenario also adds 1,250 MW of renewables and storage between 2024 and 2031, 1,040 MW of those projects are anticipated through PPAs, with 210 MW being build-transfer arrangements. Lastly, the IRA Scenario continues to select a 290 MW dispatchable, natural gas combined-cycle plant for 2028, with conversion to carbon capture and storage capability in 2031. This set of ambitious, near-term resource plan actions is predicated on Tri-State receiving New ERA Funding as requested.

Q: WHAT FACTORS INFLUENCE TRI-STATE'S ABILITY TO IMPLEMENT THE IRA SCENARIO?

A: There are several critical path factors that must have favorable outcomes in order for Tri-State to implement the IRA Scenario, these include:

- New ERA Funding award as requested from USDA;
- Negotiation of contractual agreements impacted by the resource plan;
- Affirmation of Tri-State eligibility for U.S. Internal Revenue Service ("IRS") "direct pay" of tax credits;[12] and
- Phase II bid prices, locations, and commercial operation dates ("CODs") that enable fulfillment of New ERA Funding award obligations and approved resource plan needs.

If financially viable through direct pay tax credits, Tri-State may still elect to pursue the approximately 10 MW iron air battery storage project for 2026 without New ERA Funding. This relatively small project is being pursued outside of the

[12] 26 U.S. Code § Section 6417 Elective Payment of Applicable Credits.

Phase II procurement process, as discussed in the Direct Testimony of Susan Hunter.

Q: WHAT ACTIONS MIGHT BE TAKEN BY TRI-STATE IF THESE EXTERNAL FACTORS IMPACT THE VIABILITY OF THE IRA SCENARIO?

A: Due to uncertainties related to federal funding and contractual agreements at the time of this filing, Tri-State acknowledges there may be impacts to the resource plan that occur subsequent to the initial filing. If federal funding awarded varies significantly from Tri-State's request to USDA, Tri-State anticipates the need to conduct additional scenario modeling. Such modeling may result in a necessary delay in the procedural schedule for Phase I. Tri-State would collaborate with stakeholders and act expeditiously to complete supplemental modeling to support a timely Phase II that facilities the target CODs for new projects.

Q: ARE THERE ELEMENTS OF THE IRA SCENARIO THAT ARE NOT IMPACTED BY NEW ERA FUNDING OUTCOMES?

A: Yes, the retirement date for Craig Unit 3 is not contingent upon Tri-State receiving New ERA Funding from USDA. This is because the economics of Craig Unit 3's operations during the remaining years of its operations are not influenced by any federal funding.

VI. 2023 ERP PERFORMANCE METRICS

a. Reliability

Q: WHAT RELIABILITY METRICS DOES TRI-STATE UTILIZE TO ASSESS SCENARIO / SENSITIVITY PERFORMANCE UNDER THE ERP?

A: Tri-State applies two levels of reliability metrics to all scenarios:

- Level I:
  - Planning Reserve Requirement ("PRM") of 22 percent, transitioning to 30.5 percent upon the retirement of Craig Station, based upon the third-party ELCC and PRM Study (**Attachment** ~~**G-1** of the ERP Report (**LKT-1**)~~ LKT-15);
  - Loss of load hours ("LOLH") of no more than 1 day in 10 years;
    - 2.4 hours per year 2024 to 2033;
    - 24 hours total 2034 to 2043; and
  - No more than 0.4 GWh annually of expected unserved energy ("EUE").
- Level II:
  - No more than 12 hours of EUE in 12 EWE from 2026 to 2031;
  - No more than 3 hours of expected unserved energy in any year during EWE event periods 2026 to 2031; and
  - EUE in any EWE hour cannot exceed 20 percent of load in that hour.

Level I metrics set a baseline that ensures Tri-State resources will meet industry-standard service reliability requirements and Level II metrics provide an added level of assurance of resource adequacy under potential EWE conditions, which are becoming more frequent and extreme. The Commission acknowledged in Decision No. C23-0437 that "…history may not be fully predictive of future weather extremes given climate change…"[13]

Q: HOW WERE THE RELIABILITY METRICS DEVELOPED?

A: Tri-State has long utilized the industry-recognized standards for PRM and LOLH

[13] Decision No. C23-0437, at ¶ 57 (Proceeding No. 20A-0528E).

to establish minimum reliability requirements for its system. Beginning in 2022, Tri-State expanded its ERP modeling process to include EWE analyses, to assess the reliability of its system under potential extreme weather conditions which have been experienced more frequently in recent years. Tri-State developed EUE criteria referred to as "Level II" to further evaluate the reliability and resource adequacy of potential future resource plans. The EWE stress conditions and reliability metrics were shared with stakeholders and discussed over the course of several meetings that were convened prior to and at the start of 2023 ERP modeling, as described in the ERP Report (**LKT-1**). The direct testimony of Brian Thompson further discusses the approach to sensitivity modeling.

Q: WHY IS IT IMPORTANT THAT THE RELIABILITY ASSESSMENT ENSURE TRI-STATE HAS RESOURCES SUFFICIENT TO MEET CAPACITY NEEDS WITHOUT MARKET RESOURCES?

A: First and foremost, Tri-State is a Load Responsible Entity ("LRE") meaning it must maintain capacity to meet its load and planning reserve needs. Even as a future Market Participant in SPP RTO in the western interconnection, Tri-State will continue to be responsible for its performance obligation as an LRE. Each LRE is required to maintain the total of planning capacity necessary to serve Net Peak Demand (load) and PRM. This is consistent with the 2020 ERP Settlement Agreement at section 3.11.14. which describes certain elements of "Tri-State's Next ERP Filing," which commits that "reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access." Additionally, Tri-State must also maintain compliance with applicable North

American Electric Reliability Corporation ("NERC") reliability standards.

Q: DOES THE IRA SCENARIO MEET ALL LEVEL I AND II RELIABILITY METRICS EXPECTATIONS?

A: Yes. Tri-State and its Members would not support any resource plan that did not meet all minimum reliability metric requirements. Not only does the IRA Scenario meet the minimum Level I and II reliability thresholds set, but it also has the highest planning reserve margin during the RAP which gives room to accommodate potential delays with load reductions or in resource acquisition, construction, and commercial operation. The IRA Scenario as modeled, delivers the highest confidence for Tri-State and its Members that the future generation fleet action plan will result in the most reliable system going forward.

b. <u>Financial Results</u>

Q: WHAT KEY CIRCUMSTANCES MUST TRI-STATE CONSIDER WHEN ASSESSING THE FINANCIAL PERFORMANCE OF THE 2023 ERP SCENARIOS?

A: Pursuant to Decision No. C23-0437, Tri-State's load forecast reflects anticipated member departures at the time of filing. Additionally, as uncertainty remains regarding Tri-State's Partial Requirements ("PR") contracts, the load forecast also reflects a one-year delay in anticipated member PR resources coming online (now 2026).[14] Beyond forecasted load needs, Tri-State's resource plan targets achievement of its Member-driven REP objectives, which include prudently managing costs associated with the energy transition. Tri-State has aggressively

[14] Decision No. C23-0437, at ¶ 63 (Proceeding No. 20A-0528E).

pursued federal funding opportunities in recent years to reduce the cost of generation investments for its Members and provided a summary of these pursuits in a March 2, 2023 letter to the Commission in Proceeding No. 23M-0053ALL.[15]

Q: HAS TRI-STATE BEEN AWARDED FEDERAL FUNDING SINCE ITS MARCH 2023 LETTER TO THE COMMISSION?

A: Yes. On October 18, 2023, the U.S. Department of Energy ("DOE") awarded Tri-State $26.8 million in funding, subject to final negotiations, under DOE's Grid Resilience and Innovation Partnerships ("GRIP") Program. The DOE funding, with an equal match from Tri-State, will support Tri-State's Cooperative Energy Ecosystem project,[16] which supports deployment of energy efficiency, demand response ("DR"), beneficial electrification, and integration of distributed energy resources; and will accelerate deployment of our new Distributed Energy Resource Management System ("DERMS"). The DERMS platform is anticipated to launch in 2024, as an important component of our plans to achieve the 2025 DR Target identified in our 2020 ERP Settlement Agreement.[17]

Q: WHAT OTHER FEDERAL FUNDING HAS TRI-STATE PURSUED SINCE ITS MARCH 2023 LETTER TO THE COMMISSION?

A: To support necessary generation investments in the coming years and to assist in alleviating the impact of stranded assets due to coal unit retirements, Tri-State submitted a Letter of Interest to the USDA on September 13, 2023 seeking to leverage the maximum program budget authority of $970 million in grant and loan

[15] Decision No. C23-0437, at ¶ 86 (Proceeding No. 20A-0528E).
[16] https://www.energy.gov/sites/default/files/2023-10/DOE-GRIP-Tri-State-Generation-and-Transmission-Association_0.pdf.
[17] Section 3.11.8.

funding under the USDA's New ERA program, authorized by the IRA.

Q: HOW IS THE FEDERAL FUNDING THAT IS BEING PURSUED BY TRI-STATE REFLECTED IN THE ERP?

A: As described above, Tri-State incorporated its requested level of New ERA Funding into the financial modeling completed for the IRA Scenario.

Q: WHICH SCENARIO RESULTS IN THE LOWEST PRESENT VALUE REVENUE REQUIREMENT ("PVRR") FORECASTED OVER THE RPP?

A: Given the financial benefit of New ERA Funding assumed for the IRA Scenario, it has the lowest resulting PVRR, $16,352M.

Q: WHICH SCENARIO HAS THE LOWEST ANNUAL REVENUE REQUIREMENTS DURING THE RAP?

A: Given the financial benefit of New ERA Funding assumed for the IRA Scenario, it has the lowest annual revenue requirements.

Q: WHAT DO MODELING RESULTS INDICATE WITH REGARD TO CURTAILMENTS?

A: Solar curtailments are highest in the RAP in years 2026 and 2027 for the BAU, ESPV3, SWER, and ACER Scenarios given the growing amount of renewable resource additions on the Tri-State system during that period. The IRA Scenario has the least amount of curtailments on an annual basis during the RAP, with the exception of year 2031 due to resources coming online ahead of SPV3 retirement. Participation in regional organized markets and pursuit of renewable generation ownership will help to mitigate the financial impact of curtailments for Tri-State Members.

c. Environmental Compliance

Q: PLEASE EXPLAIN TRI-STATE'S GHG TRACKING AND REPORTING COMMITMENTS UNDER THE 2020 ERP SETTLEMENT AGREEMENT.

A: Under the 2020 ERP Settlement Agreement, Tri-State committed that, going forward, it will operate its system in a manner that achieves, at a minimum, with respect to its Colorado Air Pollution Control Division ("APCD") verified 2005 Baseline, the following reductions in GHG emissions related to Tri-State's wholesale sales of electricity in Colorado (the "Interim-Year Emissions Reductions"): a twenty-six percent (26 percent) reduction in calendar-year 2025; a thirty-six percent (36 percent) reduction in calendar-year 2026; and a forty-six percent (46 percent) reduction in calendar-year 2027.[18] Tri-State also agreed that, going forward, it will operate its system in a manner that achieves, at a minimum, with respect to its APCD verified 2005 Baseline, an eighty percent (80 percent) reduction in GHG emissions related to Tri-State's wholesale sales of electricity in Colorado in calendar-year 2030 ("the 2030 Emissions Reduction").[19]

The Interim-Year Emissions Reductions and 2030 Emissions Reduction will be calculated and reported consistent with the methodology adopted by APCD for the Verification Workbook.[20] In each year following a year in which Tri-State has committed to emissions reductions, Tri-State will report the results of emissions reductions in its ERP Annual Progress Report (the "Annual Progress Report") submitted to the Commission under Rule 3618.[21]

[18] Settlement Agreement, Section 3.3.4.
[19] Settlement Agreement, Section 3.3.5.
[20] Settlement Agreement, Section 3.3.6.
[21] Settlement Agreement, Section 3.3.11.

Q: PLEASE EXPLAIN THE VERIFICATION WORKBOOK.

A: Presently, emissions tracking in Colorado is accomplished primarily through use of the APCD CEP Guidance and Verification Workbook (the "Workbook"). The Workbook includes methodologies for tracking and assigning emission rates to market purchases and sales and for netting market purchase and sales activity at the emission rate of the respective market. Tri-State utilized the Workbook to calculate projected emissions in 2030 and other target years for emissions reduction commitments. This practice will continue for forecasting and reporting emissions and Tri-State anticipates using the APCD Workbook to report actual emissions for target years as part of its 2023 ERP Annual Progress Report beginning with reporting for target year 2025.

The CEP Guidance provides a standardized format for utilities to submit data and information so that the APCD may verify the emissions reductions, as required under SB-236 and HB-1261. The CEP Guidance includes a qualitative narrative of the purpose and details of the guidance, which includes three appendices: (1) Appendix A: which establishes the APCD's role and responsibilities in the ERP process; (2) Appendix B, a Verification Workbook, which collects data related to both the Phase I and Phase II of the ERP process; and (3) Appendix C: Adjusted Baseline and Comprehensive Safe Harbor Proposal.

The Workbook provides the basis for the APCD to perform emission reductions verification, as well as a high level of transparency while also providing clarity and certainty an ERP evaluation. Further, the Workbook establishes carbon accounting protocols, including transparent accounting for any baseline

adjustment requirements.

Q: HAS TRI-STATE COMPLETED AN APCD WORKBOOK FOR EACH SCENARIO MODELED?

A: Yes, pursuant to Sections 3.11.1. and 3.11.3. of the 2020 ERP Settlement Agreement, Tri-State has completed an APCD Workbook for each Scenario modeled, provided in **Attachment** ~~**D** of the ERP Report (**LKT-1**)~~ LKT-18. Additionally, Tri-State has utilized the APCD Workbook methodology to calculate emissions reductions forecasted on a system-wide basis for the System-Wide Emissions Reduction Scenario; however, Tri-State is not seeking verification from APCD for that workbook given that it is outside the scope of Colorado rules and regulations.

Q: DO ALL OF THE SCENARIOS MODELED ACHIEVE TRI-STATE'S COLORADO GHG REDUCTION TARGETS?

A: Yes, section 3.3.7. of the 2020 ERP Settlement Agreement identifies that Tri-State's Colorado GHG Targets will be incorporated into Tri-State's future ERP filings as a binding requirement. As shown in the **Attachment D** files, all of the scenarios meet or exceed Tri-State's Colorado GHG Targets. Notably, the IRA Scenario meets the targets and exceeds the 2030 target at the lowest cost.

Q: DID TRI-STATE MAKE ANY SIGNIFICANT UPDATES IN ITS APPROACH TO EMISSION RATES OR DATA INPUTS FOR THE APCD WORKBOOKS?

A: Yes, Tri-State made necessary adjustments to the 2005 baseline and updated certain emissions rates used in the Workbook. First, the 2005 baseline was updated to address load reductions from Member exits and timing changes of

Partial Requirements in Colorado. The reduced load forecast[22] for the planning period starting in 2025 (Member exits) and 2026 (Partial Requirements) results in a need to correspondingly adjust the 2005 Baseline in the Workbooks. Upon those Colorado Member exits and implementation of Partial Requirements elected by Colorado Members, Tri-State will no longer be responsible for emissions and emissions reductions associated with those loads. The 2005 Baseline used for determination of emissions reductions for 2025 adjusts for the Member exits only, as the Partial Requirements contracts are not anticipated to begin until 2026. Partial Requirements Members can select MAX (Firm capacity) or MARS (intermittent resource) options, where only the MAX selections reduce the system capacity that Tri-State is responsible – currently forecasted as 163 MW, 86 MW of which is related to Members in Colorado. The Workbook accounts for the impacts of 117 MW of the MARS option as a renewable resource.

This timing of load changes required the development of a second 2005 Baseline calculation for use in determining emission reductions for years after 2025; therefore, each Workbook includes two 2005 Baseline tabs—one used for 2025 emission reduction calculations, and one used for all other years' emissions reduction calculations. Additionally, market and contract emissions rates were updated to reflect the latest eGrid rates.

Q: DID STAKEHOLDERS REQUEST THE MODELING OF GHG REDUCTIONS BEYOND THE REQUIREMENTS OF THE 2020 ERP SETTLEMENT AGREEMENT OR COLORADO LAW?

[22] Decision No. C23-0437 at Paragraph 63 directs that Tri-State "submit a load forecast that is indicative of anticipated member departures at the time of filing."

A: Yes. Some stakeholders requested that Tri-State model two scenarios (Scenarios 4 SWER and 5 ACER) in Phase I of the 2023 ERP that achieve GHG reductions beyond legislative or regulatory commitments. These scenarios include a scenario with minimum Tri-State system-wide GHG reduction targets over the RAP and a scenario with more aggressive Colorado GHG reductions.

Q: WHAT CONCERNS DOES TRI-STATE HAVE WITH REGARD TO SCENARIOS 4 (SWER) AND 5 (ACER)?

A: Tri-State is concerned with the potential lack of fairness and consistency that could result for its Members if they were to be involuntarily held to 2030 emissions reduction targets more aggressive than those applicable to all Colorado utilities under current law. Complications may also arise from Colorado regulatory actions that would seek to extend emissions policies beyond the borders of Colorado. Furthermore, it is also possible that adoption of more aggressive emissions reduction targets, beyond those agreed to in the 2020 ERP Settlement Agreement, could conflict with Section 3.3.8. of the agreement which specified that "the Settling Parties agree that Tri-State retains sole discretion over the resource dispatch decisions used to achieve the Interim-Year Emissions Reductions." Lastly, it would appear imprudent to hastily adopt more aggressive emissions reduction targets at a point in time when not even the first year of the targets has come to pass, for commitments made less than two years ago.

VII. RESOURCE ACQUISITION PLAN

Q: WHAT SIGNIFICANT ELEMENTS OF TRI-STATE'S ACQUISITION APPROACH ARE NEW FOR THE 2023 ERP?

A: In the 2020 ERP Phase II, Tri-State utilized a single RFP for renewable and storage PPA resources only for the 2025-26 period, indicating Tri-State did not intend to pursue self-build or ownership options for resources at that time[23] and agreeing to a limited procurement window[24] given load uncertainties and its capacity-long position. The 2020 ERP Phase II procurement and modeling process resulted in identification of the need to procure only one 200 MW wind resource within that two-year period.

However, since that time, load requirements are being modified going forward, dispatchable resources are being retired during the RAP, a myriad of updated modeling assumptions such as new effective load carrying capabilities ("ELCCs") are being created, as well as the financial implications resulting from the IRA. As such, Tri-State's 2023 ERP procurement strategy has substantially changed since Tri-State's last ERP.

Additionally, it is now imperative, in order to maintain system reliability while procuring renewable and semi-dispatchable innovative technologies to replace retiring generation, to procure a new dispatchable resource. Given these conditions, Tri-State intends to issue three RFPs in Phase II of the 2023 ERP – one for storage resources to be owned by Tri-State as a result of build-transfer ("BT") agreements or by working with an EPC contractor, one for a dispatchable gas resource, with ability to convert to accommodate carbon capture and sequestration ("CCS"), to be owned and constructed by Tri-State working with an

[23] *See* Hearing Exhibit 106, Direct Testimony and Attachments of Susan K. Hunter, Proceeding No. 20A-0528E at 7: 8-9.
[24] Settlement Agreement, Sections 3.4.3. and 3.4.4.

EPC contractor, and one for renewable resources to be procured through PPAs. Bid evaluation criteria and screening processes will be similar to the 2020 ERP, but with some updates to reflect lessons learned.

Q: DOES TRI-STATE INTEND ON UTILIZING AN IE FOR THE 2023 ERP?

A: Yes, Tri-State will utilize an IE for the 2023 ERP to add further assurance of consistency and fairness in its bid evaluation process for both BT and PPA agreements. Additional information on Tri-State's Phase II procurement plans, including use of an IE, is provided in the Direct Testimony of Ms. Hunter. Further detail on Tri-State's anticipated approach to acquisition of a new dispatchable gas resource is provided in the Direct Testimony of Mr. Ingold.

Q: WHAT CONSIDERATIONS AND MODELING RESULTS ARE DRIVING THE NEED FOR A 290 MW COMBINED CYCLE GAS RESOURCE INTERCONNECTING TO TRI-STATE'S SYSTEM IN WESTERN COLORADO?

A: The modeling software assesses resource retirements and acquisitions over the entire resource planning period determining the most economic resource mix given transmission and environmental constraints. Given the retirement of Craig Station by the fall of 2028 including the early retirement of Craig 3 on January 1, 2028, greenhouse gas reduction targets in Colorado, and system GHG reductions targets in the IRA scenario, the model selected the 290 MW combined cycle gas resource in 2028 with conversion to CCS in 2031 to meet capacity and energy needs over the RPP. The IRA Scenario has 1,067 MW of coal retirements over the RAP and the 290 MW NGCC with CCS is the only fully dispatchable resource added to the system. This resource, along with semi-dispatchable batteries, allows

for the successful integration of 940 MW of renewables from 2026 to 2031 under the IRA Scenario.

Q: DO OTHER MODELING RESULTS BEYOND THE IRA SCENARIO SUPPORT THE NEED FOR A DISPATCHABLE GAS RESOURCE?

A: Yes. While there is slight variation in the date that the model selects a gas resource in each scenario, all five of the scenarios select a gas resource addition during the RAP. In every 2023 ERP Phase I scenario the modeling selected the need for a gas resource in Western Colorado planning region. This is also generally consistent with Tri-State's approved preferred plan and portfolio resulting from the 2020 ERP modeling, which also called for a dispatchable gas resource.[25]

Q: DOES THE FEDERAL PRODUCTION TAX CREDIT INFLUENCE THE SELECTION OF A COMBINED CYCLE RESOURCE WITH CCS?

A: Yes. Section 45Q under Title 26 of the U.S. Code provides for an $85/tonne production tax credit ("PTC") for sequestered carbon for twelve years once placed in service, with a requirement that construction of CCS must begin by January 2033 for PTC eligibility. This tax credit exceeds the forecasted cost of fuel and variable O&M for a combined cycle resource. The result is a baseload dispatchable resource with a minimal carbon footprint at a significantly more affordable operational price point.

Q: WHAT ACQUISITION PROCESS IS TRI-STATE PROPOSING FOR THIS RESOURCE AND OTHERS IN THE RAP?

[25] The Phase I Revised Preferred Plan (80pc CR v5) Scenario selected a 290 MW combined cycle gas unit in Western Colorado in 2030. The Phase II Revised Preferred Plan Portfolio selected a 193 MW combustion turbine gas unit in Western Colorado in 2030.

A: Tri-State will simultaneously issue three RFPs for Phase II of the 2023 ERP, within 30 days of the Commission's final decision on Phase I. One for storage resources, one for dispatchable gas resources with ability to convert to CCS, and one for renewable resource bids. An IE will assist Tri-State in monitoring the application of the bid evaluation criteria and reviewing the analysis of bids through the portfolio modeling. Detailed information on Tri-State's Phase II procurement plans is provided in the Direct Testimony of Ms. Hunter, including draft RFPs, a proposed Phase II timeline, and a Statement of Work for the IE.

Q: HOW DOES THIS PROCESS ENSURE TRI-STATE IS OBTAINING A COST-EFFECTIVE RESOURCE FOR ITS MEMBERS?

A: Tri-State is not a publicly-traded entity with stock or shareholders, and therefore does not produce stock earnings as a result of its investments. Tri-State is a not-for-profit entity providing wholesale power under the cooperative principles for the benefit of its Members, which requires Tri-State to provide service at the lowest cost possible while maintaining system reliability standards and achieving environmental responsibility commitments. Not only will the 2023 ERP procurement process be overseen by an IE, but it will be conducted pursuant to Commission rules and with the review and collaboration of numerous interested stakeholders with diverse interests. These realities set the stage for Tri-State to pursue the most cost-effective resource mix that meets our Members' needs, whether through PPAs, build or build-transfer arrangements, or a combination thereof.

Q: WHAT ARE THE KEY FACTORS IN TRI-STATE CONSIDERING ACQUISITION

APPROACHES?

A: Given the significant opportunities presented by the IRA, it would not be financially prudent for Tri-State to consider a PPA-only procurement strategy. Additionally, with the expansion of new resource types emerging in the 2023 ERP, as well as the planned retirement of Tri-State-owned resources, our procurement strategy seeks to maintain an appropriate balance of owned and contracted resources for serving our Members. The Direct Testimony of Ms. Hunter further expands on the drivers and value in the acquisition approach.

Q: WHAT ARE THE CONSTRUCTION AND SITING CONSIDERATIONS THAT TRI-STATE MUST NOW BEGIN TO TAKE ACTION ON?

A: Tri-State engaged a third-party consultant to conduct a siting study related to the construction of a 290 MW NGCC in 2028 with anticipated addition of CCS in the early 2030s. This study will analyze potential locations for the new resource taking into consideration gas pipeline accessibility, CCS capabilities and transmission interconnection. The resource will be located in electrical west Colorado which is defined as a resource interconnecting to the transmission system west of TOT 5, north of TOT 2, and east of TOT 1. Given those parameters the resource could be located in western Colorado or southern Wyoming. In addition to this initial study and contingent upon Commission approval in Tri-State's 2023 ERP process, Tri-State will need to initiate applicable state regulatory and environmental permitting processes. Anticipated next steps in construction and siting considerations are discussed in the Direct Testimony of Ms. Hunter and Mr. Ingold.

VIII. Organized Market Participation

Q: WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A: The purpose of this section of my Direct Testimony is to provide Tri-State's current market participation status, as well as its future plans to join an RTO and how that will affect future Tri-State resource planning efforts.

Q: PLEASE DESCRIBE TRI-STATE'S CURRENT AND PLANNED MARKET PARTICIPATION.

A: Tri-State's load in PacifiCorp has been in CAISO's Western Energy Imbalance Market ("WEIM") since 2014. Tri-State's load and resources in PNM moved into the WEIM in April 2021. In February 2021, Tri-State's load and resources in WACM began participation in SPP's Western Energy Imbalance Services market ("WEIS"). In April 2023, the remainder of Tri-State's load and resource moved into WEIS with the entry of the PSCO BA into the market. In 2020,[26] Tri-State announced its intention along with other western entities to explore transitioning its load and resources in the WACM BA into the SPP RTO. In June 2022, Tri-State's Board signed a commitment, along with other western entities, to transition load and resources in WACM into the SPP RTO by April 1, 2026. More information on this transition is available in Proceeding No. 23M-0195E. We also continue to monitor developments in the Markets+ arena given the potential for Tri-State load and resources in other BAs to join that market.

Q: DOES TRI-STATE ACCOUNT FOR ITS PLANNED RTO PARTICIPATION IN ITS

[26] https://www.tristate.coop/spp-and-stakeholders-will-consider-rto-expansion-west-study-anticipates-49m-annual-savings-current.

MODELING?

A: While Tri-State has not yet implemented a nodal model that would be required to fully represent markets in its resource plan modeling, Tri-State has analyzed and expanded market depths (sales and purchase) levels in its model to represent the WACM BA transition to SPP RTO in 2026, expected transition of PSCO and PNM to an RTO in 2030. Market depth assumptions are identified in **Attachment** ~~**B** of the ERP Report (**LKT-1**)~~ LKT-7. The testimony of Mr. Thompson further describes Tri-State's approach and assumptions regarding market depths and RTO market products used in the 2023 ERP modeling.

Q: FROM A POLICY PERSPECTIVE, HOW DOES ORGANIZED MARKET PARTICIPATION IMPACT TRI-STATE'S RESOURCE PLANNING?

A: Participation in an organized market allows for the more efficient, cost-effective use of resources including the ability to better integrate a large quantity of intermittent renewable resources. Access to a larger footprint and collective use of transmission within the footprint allows for a decrease in the curtailment of renewable resources. Additionally, market optimization over a larger footprint allows for diversity of region and resources to shore up reliability while utilizing transmission in a manner to produce the most economic dispatch, increasing affordability.

IX. LOAD AND RESOURCE BALANCE

Q: WHAT DOES TRI-STATE'S LOAD AND RESOURCE BALANCE INDICATE?

A: As shown in the ERP Report (**LKT-1**), Tri-State's load and resource ("L&R") balance forecasts, without any new resource additions, Tri-State would continue

to be resource-long until 2029. With the resource additions planned under the IRA Scenario, our resource-long position will extend through the planning period.

Q: WHAT ARE SOME OF THE KEY CHANGES FROM THE 2022 L&R?

A: First, Member load has declined due to Member exits and Partial Requirements. Second, the capacity contribution from renewable resources has declined due to the ELCC and PRM Study results (**Attachment** ~~**G-1** of the ERP Report (**LKT-1**)~~ LKT-15). Additionally, coal resource retirements occur during the RAP that result in firm capacity reductions.

Q: DOES THIS PHASE I ERP FILING SUPPLANT THE NEED FOR A 2023 ERP ANNUAL PROGRESS REPORT?

A: Yes. Tri-State has not filed ERP Annual Progress Reports ("APRs") in the years when a Phase I ERP is filed, given the comprehensive nature of a resource plan filing.

X. CONCLUSION

Q: WHAT PHASE I APPROVAL IS TRI-STATE REQUESTING IN THIS PROCEEDING?

A: Tri-State requests approval of the 2023 ERP and the accompanying assumptions and studies, as reflected in the IRA Scenario, which is Tri-State's preferred plan. For the reasons established in the ERP Report (**LKT-1**) and attachments, as well as in Tri-State's Direct Testimony, the IRA Scenario is the most reliable, affordable, and responsible path for Tri-State to reach both the goals of the State of Colorado and those of our Members, system-wide.

Q: WHAT PHASE II APPROVAL IS TRI-STATE REQUESTING IN THIS

PROCEEDING?

A: Tri-State requests Commission approval of the proposed Phase II timeline, Phase II RFPs, Bid Policy, IE SoW, Model PPAs and Term Sheets, Implementation Report outline, 45-Day Report approach, and RAP Action Plan. Tri-State also requests that the Commission approve its proposal to model no more than eight Phase II portfolios[27] to be modeled, two of which will be identified through informal discussions with stakeholders prior to the start of Phase II.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

[27] As identified in the ERP Report (**LKT-1**).

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

PROCEEDING NO. 23A-____E

APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2023 ELECTRIC RESOURCE PLAN

VERIFICATION

STATE OF ___COLORADO____)
) ss:
COUNTY OF __ADAMS_____)

I, Lisa K. Tiffin, being duly sworn, do hereby depose and state that I have read the foregoing Direct Testimony, and the facts set forth therein are true and correct to the best of my knowledge, information, and belief.

Subscribed and sworn to before me this 16th day of November 2023, at Westminster, Colorado.

TRI-STATE GENERATION AND
TRANSMISSION ASSOCIATION, INC.

By: Lisa K. Tiffin
Senior Manager, Analytics & Forecasting

Witness my hand and official seal.

Notary Public

My Commission expires: 12/28/25.

Kimberly M. Strasburger
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20134072316
MY COMMISSION EXPIRES December 28, 2025

ATTACHMENTS

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Attachment LKT-2	Phase II Timeline
Attachment LKT-3	Phase II ERP Implementation Report Outline
Attachment LKT-4	Statement of Qualifications of Lisa K. Tiffin
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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit X: CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1 (Tri-State, 2023 ERP Phase I, Rev. 2 (Apr. 22, 2024)

Colorado PUC E-Filings System



Tri-State Generation and Transmission Association, Inc.

2023 Electric Resource Plan

Phase I

(Colorado Public Utilities Commission Proceeding No. 23A~~-----~~-0585E)

~~December 1, 2023~~April 22, 2024

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	~~F-1: Load Forecasts by State & Member~~	Attachment LKT-27	Load Forecasts by State & Member
~~Attachment G~~	~~Studies Cover Sheet~~	Attachment LKT-28	Third Party Studies Cover Sheet
	~~G-1: ELCC and PRM Study (Astrape)~~	Attachment LKT-29	ELCC and PRM Study (Astrape)
	~~G-2: Benchmarking Analysis (B&V)~~	Attachment LKT-30	Benchmarking Analysis (B&V)
	~~G-3: Addendum to 2020 DSM Potential (Mesa Point Energy)~~	~~Attachment LKT-31~~	Addendum to 2020 DSM Potential Study and BE Potential Study (Mesa Point Energy)
	~~G-4: Reliability Evaluation~~	Attachment LKT-32	Reliability Evaluation

Executive Summary

Tri-State Generation and Transmission Association, Inc. (Tri-State) is a wholesale electric generation and transmission cooperative association with 42 Utility Member Systems located across Colorado, Nebraska, New Mexico, and Wyoming.

Tri-State's Responsible Energy Plan (REP) issued in January of 2020 called for eliminating 100 percent of the carbon dioxide ("CO_2") emissions from Tri-State-owned coal generation in Colorado by 2030 and for 70 percent of the electricity used by its Members to come from clean sources by 2030. Tri-State has pursued an Electric Resource Plan (ERP) that aligns with its REP commitments.[1]

This is Tri-State's Phase I ERP. The plan complies with Colorado Public Utilities Commission (Commission) Rule 3605 and relevant paragraphs of Decision No. R22-0191 in Proceeding No. 20A-0528E issued March 28, 2022, approving the Unopposed Comprehensive Settlement Agreement (2020 ERP Settlement Agreement) filed with the Commission on January 18, 2022, concluding Phase I of Tri-State's 2020 ERP. Attachment ~~A~~ LKT-5 to this report identifies the components of this report and 2023 ERP Phase I filing that comply with Commission directives.

The 20-year[2] resource planning period (RPP) for the 2023 ERP is 2024-2043 and the resource acquisition period (RAP) is the six-year[3] period from 2026-2031. Although Tri-State evaluated "highly competitive"[4] bids for 2026 in Phase II of the 2020 ERP, given that no projects were ultimately procured, Tri-State included 2026 in the 2023 ERP RAP to assess whether additional near-term resources might be selected under updated modeling input assumptions. Tri-State selected an acquisition period of six years through 2031 to ensure that, as fossil resource retirements in Colorado occur through the end of the decade, sufficient resources would be in place to continue to meet resource adequacy and reliability requirements. The RAP also recognizes the extended lead-time for certain resource types.

Tri-State's preferred plan for its ERP is the IRA Scenario. The preferred plan is reliable, affordable, and responsible. The plan brings online 1,540 MW of new resources during the RAP, including:

- 700 MW of wind (200 MW of wind hybrids);
- 310 MW of storage (110 MW of standalone 100-hour iron air batteries; 100 MW of standalone 4-hour batteries; and 100 MW of 4-hr batteries with wind hybrids);
- 290 MW of combined-cycle natural gas in 2028 (with carbon capture and sequestration in 2031); and
- 240 MW of solar.

These resource additions are forecasted to result in one of ~~–~~the lowest present value revenue requirements (PVRR), among the scenarios modeled, over the planning period if Tri-State is awarded

[1] The REP also identifies that Tri-State is striving for 100 percent clean energy in Colorado by 2040. While Phase I of the 2023 ERP does not yet forecast achievement of that stretch goal, Tri-State will continue to strive to make progress toward this aim in Phase II of the 2023 ERP and in the 2027 ERP. Notably, 2040 remains well outside of the Resource Acquisition Period (RAP) for the 2023 ERP.
[2] Commission Rule 3602(k).
[3] Commission Rules 3602(n) and 3605(a)(IV)(A).
[4] 2020 ERP Settlement Agreement, Section 3.4.4.2.

federal funding to support generation additions and provide stranded asset relief under the U.S. Department of Agriculture's Empowering Rural America (New ERA) funding opportunity initiated by the Inflation Reduction Act of 2022 (IRA). The plan enables Tri-State to take full advantage of new direct pay of federal tax benefits for renewable and storage resources by increasing owned resources—while adding and maintaining PPA resources, which also helps to minimize renewable curtailment costs. The preferred plan also retires two coal-fired generation resources during the RAP, including:

- Craig Unit 3 (448 MW) on January 1, 2028; and
- Springerville Unit 3 (419 MW) on September 15, 2031.[5]

These significant shifts in Tri-State's generation portfolio over the coming years would result in an 89 percent greenhouse gas (GHG) emissions reduction related to Tri-State's wholesale sales of electricity in Colorado in 2030, over a 2005 baseline—more than any other scenario modeled in the 2023 ERP. The IRA Scenario results in the highest percentage of renewable generation capacity in 2030 (39 percent) while meeting all Level I and Level II reliability criteria, by maintaining sufficient dispatchable generation and bringing online new battery storage resources to ensure system performance during extreme weather events (EWEs).

Tri-State is keenly aware of the economic challenges its Members face in rural America. Demographic data shows fourteen percent of the end-use customers served by Tri-State Members live below the federal poverty line, and up to half of the residential end-use customers suffer from some form of energy burden. The IRA has the potential to fundamentally alter the landscape for cooperative utilities. The IRA has "…tilt[ed] the balance in favor of cooperatives to develop their own renewables instead of utilizing purchase power agreements (PPAs). Thanks to the "direct-pay" provision in the law, cooperatives may now have a cost advantage depending on significant new grants from the U.S. Department of Agriculture (USDA) and the new ability to monetize tax credits that previously were available only to traditional developers with taxable income. These changes will have a big impact, as we saw when we compared renewables built by a representative cooperative versus an equivalent PPA…"[6]

Without new resource additions and assuming no change to previously announced generation retirement dates, with the exception of moving the Craig 3 retirement date to January 1, 2028, Tri-State would remain in a capacity-long position only through 2028, as identified in the 10-year loads and resources (L&R) shown in Table 1 below.[7] Under the IRA Scenario, Tri-State would remain capacity-long throughout the planning period[8], as shown in Figure 2 below.

[5] Predicated on Tri-State receiving New ERA funding as requested and negotiation of contractual agreements impacted by the resource plan.
[6] https://www.mcr-group.com/wp-content/uploads/2023/06/Coops-IRA-White-Paper_v3.pdf
[7] In years where Tri-State files a Phase I ERP, the filing serves to comply with Commission Rule 3618(a) regarding ERP annual progress reports.
[8] The IRA scenario graph is reflective of all generic resources selected throughout the RPP but Tri-State will only be acquiring resources in the RAP (2026 to 2031).

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Table 1: Load & Resources (L&R)[9]

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Resources (MW)	3225	3298	3212	3215	2818	2734	2746	2747	2753	2747
Total Obligations (MW)[10]	~~2826~~2815	~~2736~~2725	~~2516~~2505	~~2560~~2549	~~2733~~2722	~~2801~~2790	~~2827~~2816	~~2846~~2835	~~2897~~2797	~~2927~~2827
Excess (MW)	~~398~~409	~~561~~572	~~697~~708	~~656~~667	~~84~~95	~~-68~~-57	~~-82~~-71	~~-99~~-88	~~-143~~-43	~~-180~~-80

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Figure 1: Load & Resources (L&R)[11]

[9] No new resource additions from 2023 ERP modeling are included, reflects the current Tri-State system with known, contracted resource additions from previous procurements.
[10] Includes Member load (less energy efficiency and Partial Requirements, with Beneficial Electrification), losses, planning and operating reserves, and contract sales.
[11] No new resource additions from 2023 ERP modeling are included, reflects the current Tri-State system with known, contracted resource additions from previous procurements.

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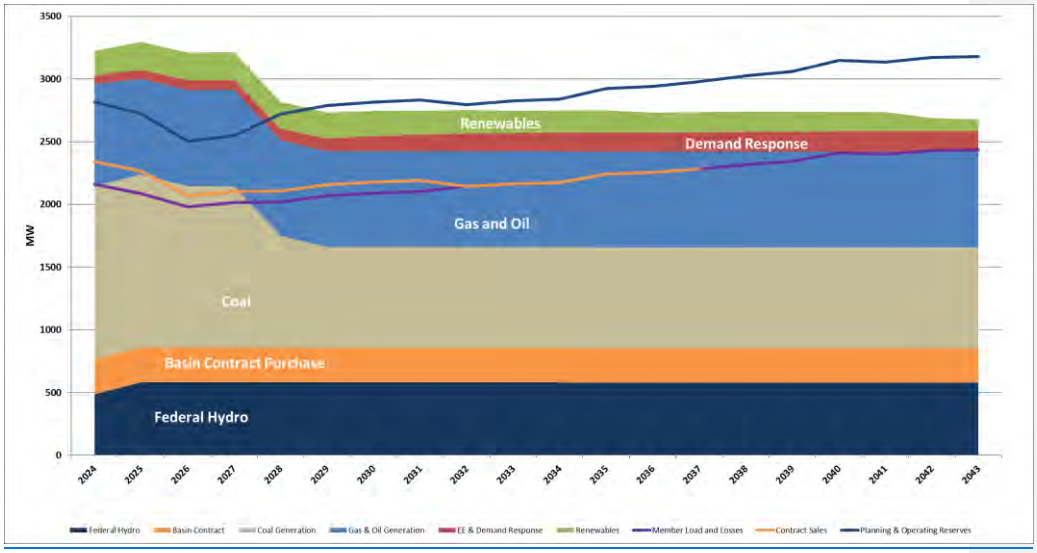

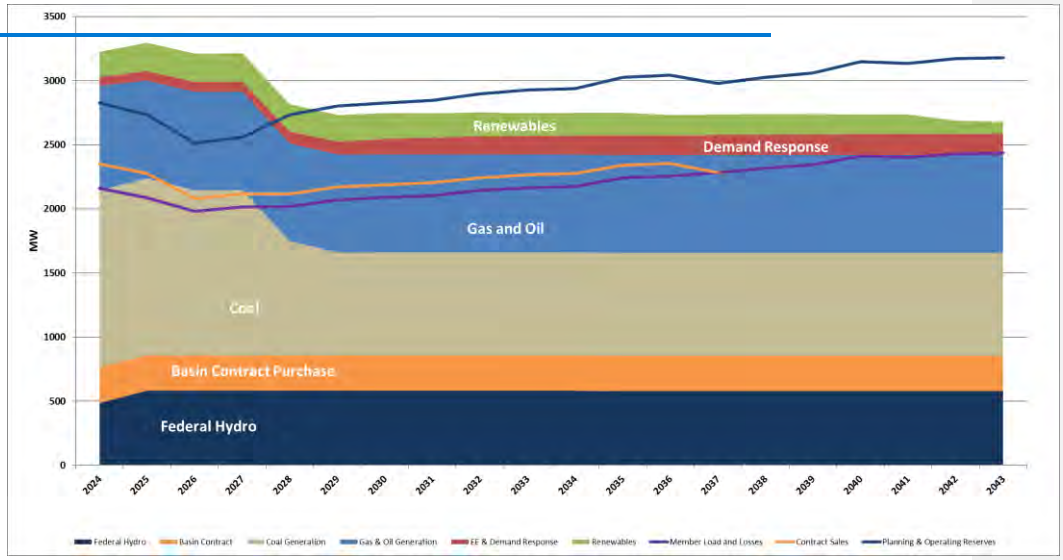

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Table 2: Load & Resources (L&R), IRA Scenario

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Resources (MW)	3225	3303	328632 76	329132 81	321032 01	319331 84	3332	345834 48	313431 24	313431 24
Total Obligations (MW)[12]	282628 15	297029 59	275027 39	279427 83	273327 22	280127 90	282728 16	284628 35	2997	3027
Excess (MW)	398409	333344	536509 37	498509 499	477487 8	392403 393	504515 06	612621 3	137127	10797

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[12] Includes Member load (less energy efficiency and Partial Requirements, with Beneficial Electrification), losses, planning and operating reserves, and contract sales.

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Figure 2: Load & Resources (L&R), IRA Scenario

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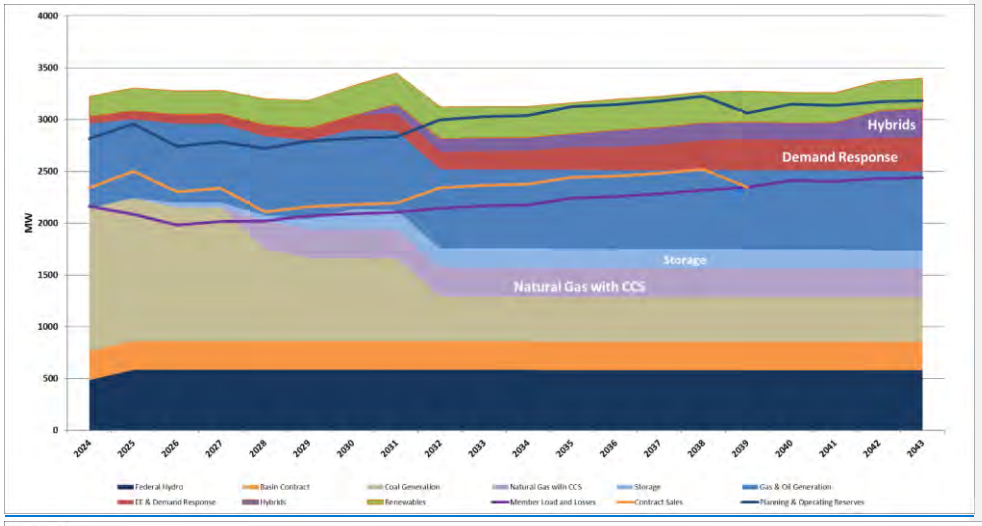

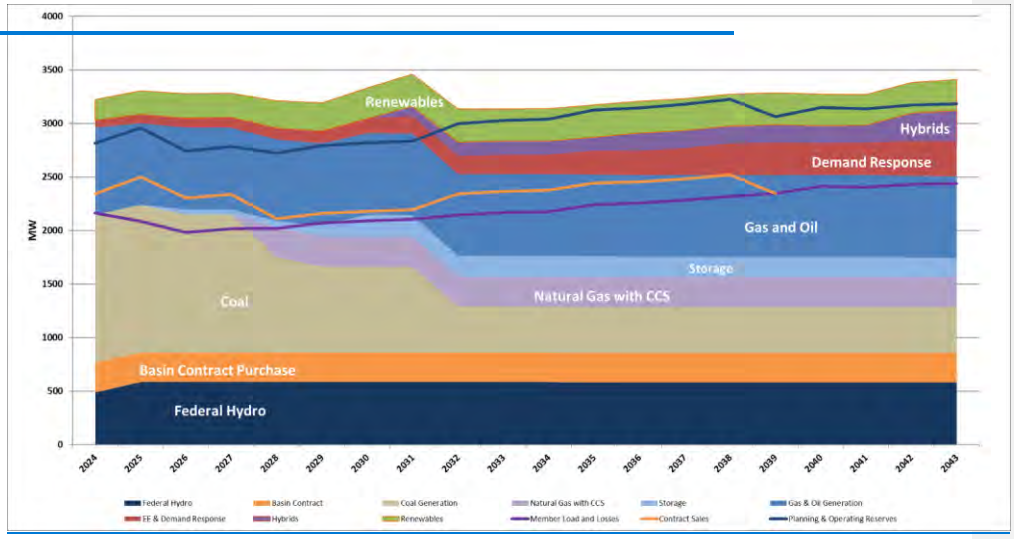

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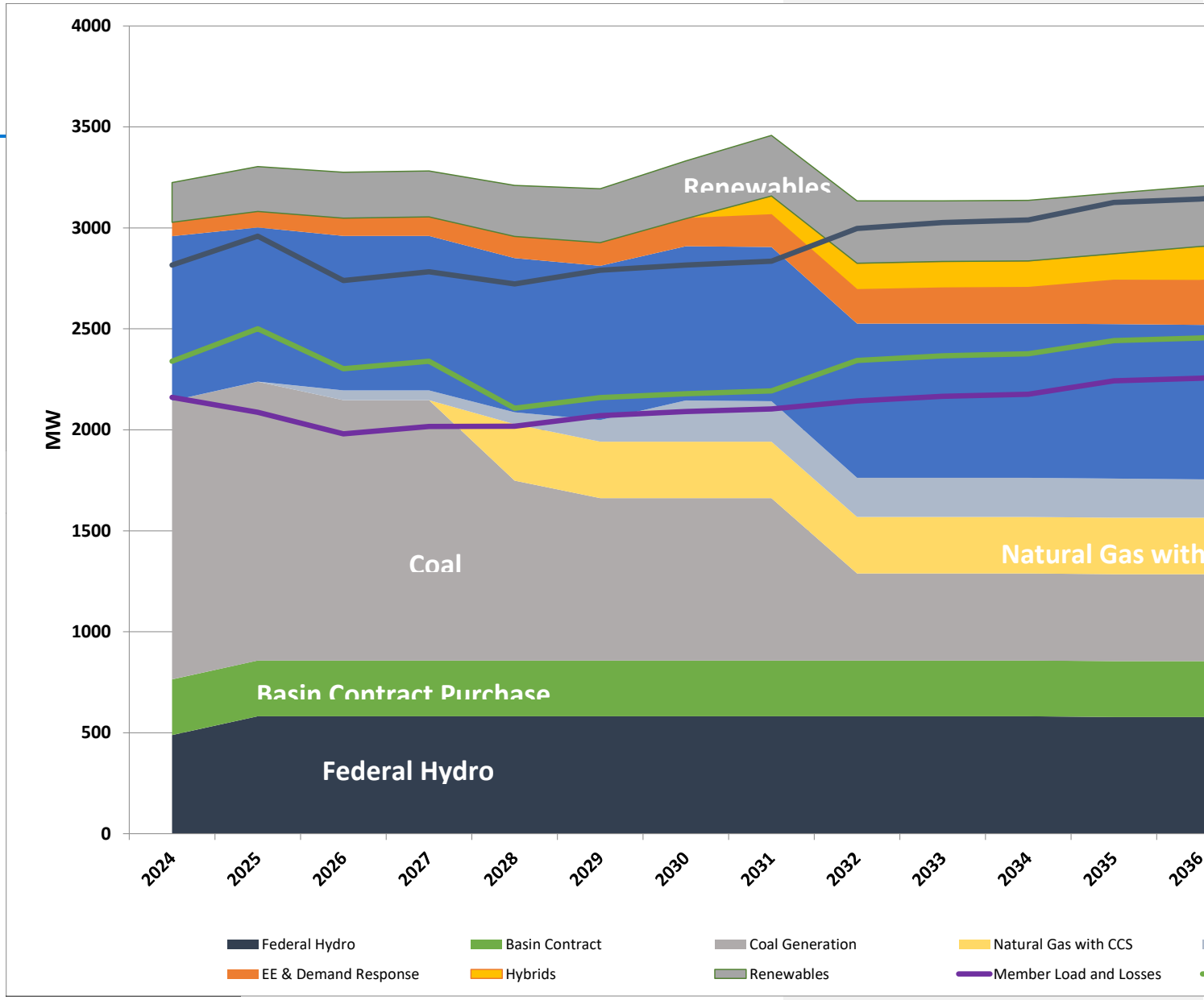

[13] Commission Rule 3605(a)(IV)(O).

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Beneficial Electrification Potential Study	Mesa Point Energy	Evaluates the achievable potential to convert non-electrical load to electrical load within Tri-State's Utility Member System territories while reducing carbon emissions.	~~G-3~~ LKT-31
Demand Side Management/Energy Efficiency Potential Study	Mesa Point Energy	Evaluates Demand Side Management achievable potential in relation to energy efficiency and demand response across Tri-State's Utility Member Systems' territories.	~~G-3~~ LKT-31
Evaluation of Tri-State G&T Preferred Plan (IRA Scenario) Reliability	Astrape	Evaluates reliability of preferred plan (IRA Scenario) in 2032	~~G-4~~ LKT-32

Tri-State also received input from ACES to analyze Tri-State's forward power curve forecasting and potential benefits of offering new products in an organized market, as well as related model set-up.

Assessment of Existing Resources

Tri-State's assessment of existing resources is provided in Attachment ~~C-3.~~ LKT-17 Resources capable of self-supplying certain ancillary services are identified in Attachment ~~B-4.~~ LKT-11 Information on Tri-State's PPA and contract resources is provided in Attachment ~~C-1~~. LKT-15 An analysis of the performance of Tri-State's existing resources was performed by the third-party consultant, provided as a Benchmarking Study (Attachment ~~G-2~~ LKT-30).

Electric Energy and Demand Forecast

Attachments ~~F and F-1~~ LKT-26 and LKT-27 contain Tri-State's load forecast summary and graphical presentation of load forecast data, pursuant to Commission Electric Rule 3605(a)(IV)(B) and 3605(b).

Scenario Modeling and Analysis Summary

Tri-State modeled five scenarios for Phase I of the 2023 ERP: 1) the Business-as-Usual (BAU), 2) IRA, 3) Early Springerville 3 Retirement (ESPV3), 4) System Wide Emissions Reductions (SWER), and 5) Aggressive Colorado Emissions Reductions (ACER). Both the BAU and IRA Scenarios include modeling input assumptions that Tri-State believes to be the most accurate and reflective of its system operations and Members' needs. Scenarios 3, 4, and 5 were modeled at the request of stakeholders.

Additionally, two[14] sensitivity analyses were performed on each scenario's expansion plan to re-dispatch the plans under extreme weather event (EWE) and high gas (HG) price conditions. The EWE sensitivity modeling assumptions are provided in Attachment ~~B-5~~ LKT-12 and results of the EWE sensitivity analyses are

[14] Tri-State contemplated performing a drought sensitivity analysis for one year of the BAU Scenario, however, at the time 2023 ERP modeling began the U.S. Bureau of Reclamation's latest five-year projection for the Colorado River system indicated 0 percent probability of minimum power pool through 2027, so Tri-State deferred drought analysis to a future ERP.

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provided in this report. The assumptions and results for the HG sensitivity analysis are provided in Attachment ~~E.~~ LKT-25

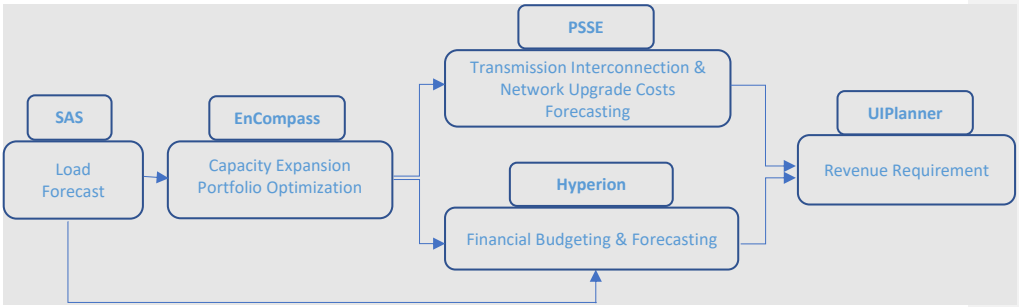
The Tri-State system is modeled as four planning regions. The planning regions are not state boundary restricted, rather they reflect significant power flow constraints within the Tri-State system:

- Wyoming / Electrically West Nebraska (WYO/WNE*)* – includes Tri-State owned or contracted resources capable of interconnecting north of TOT 3 in Wyoming and Nebraska located in the western interconnection and Western Area Colorado Missouri (WACM) Balancing Authority (BA);[15] and Tri-State load identified as WACM BA Wyoming loads.
- Eastern Colorado (ECO) – includes Tri-State owned or contracted resources capable of connecting to transmission in Colorado south of TOT 3, east of TOT 5, and in the western interconnection and WACM BA; and Tri-State load identified as WACM BA east loads and Tri-State loads in Public Service Company of Colorado (PSCO) BA.
- Western Colorado (WCO) – includes Tri-State owned or contracted resources capable of connecting to transmission in Colorado north of TOT 2, west of TOT 5, and east of TOT 1 in WACM BA; and Tri-State load identified as WACM BA west load.
- New Mexico (NM) – includes Tri-State load and owned or contracted resources physically located in or pseudo-tied into Public Service of New Mexico (PNM) BA. PNM BA is located in New Mexico and a portion of southeast Colorado.

Additional detail on the Tri-State system reflected in the EnCompass model is available in Attachment ~~B-~~ LKT-13 ~~6:~~ Tri-State System Topology.

Figure 3 below identifies the software tools (SAS, EnCompass, PSSE, Hyperion, and UIPlanner) utilized by Tri-State for completing each component of the scenario analyses and the succession of data through each system.

Figure 3: Modeling Software Tools



[15] TOTs represent a collection of transmission lines identified as a transfer path between regions.

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Each scenario was evaluated in terms of its performance under reliability, financial, and environmental criteria, and state renewable policy compliance, as described below.

Expansion Plan, Retirements, System Mix, and Capacity Factors

Tri-State used the EnCompass resource planning software to complete capacity expansion and portfolio optimization analyses for Phase I modeling, inputting the applicable modeling assumptions described in Attachment ~~B~~[16] and reflecting the Tri-State system topology, provided as Attachment ~~B-6~~.

LKT-7

LKT-13

Environmental Analyses

Based on the expansion plan and dispatch produced for each scenario, Tri-State has provided an analysis of forecasted system-wide emissions and water use, as well as the annual social costs of carbon (SCoC) and social cost of methane (SCoM). SCoC values reflect the February 2021 Interagency Working Group (IWG) on Social Cost of Greenhouse Gases, Technical Support Document.[17]

For each scenario, Tri-State separately produced an Air Pollution Control Division (APCD) verification workbook (APCD Workbook) calculating forecasted carbon emissions reductions, provided in Attachment ~~D.~~[18] Target-year emissions reductions percentages for each scenario, calculated from the APCD Workbooks, are provided in this report.

LKT-18

Tri-State used the most recent available EPA eGRID rates, year 2021, for forecasted market purchases and sales, the Basin Eastern Interconnection contract, and the Basin Electrically Western Interconnection contract. The carbon emission rate assumption for market purchases and sales is 1,159 pounds per MWh through 2029 per 2021 RMPA eGRID rate and 450 pounds per MWh (WECC), per APCD Workbook requirement, starting in 2030. The carbon emission rate assumption for Basin Western Interconnection contract is 2,596 pounds per MWh 2024 through 2025 per 2021 LRS eGRID rate, 1,159 pounds per MWh 2026 through 2029 per 2021 RMPA eGRID rate, and 450 pounds per MWh (WECC), per APCD Workbook requirement, starting in 2030. The carbon emission rate assumption for Basin Eastern Interconnection contract is 996 pounds per MWh through 2029, which is the 2021 MROW[19] eGRID rate and 525 pounds per MWh (SPP), per APCD Workbook requirement starting in 2030.

Financial Analyses

Tri-State and 39 of our 42 Members serve 170 census tracts that are identified as Disadvantaged Communities, and 161 census tracts are identified as Low Income.[20] Pursuant to Rule 3605(g)(III)(C)(iii), Tri-State provided a financial analysis of each scenario, including:

- Annual revenue requirements;

LKT-7, LKT-8, LKT-9, LKT-10

[16] *See* Attachments ~~B, B-1, B-2, and B-3.~~

[17] https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

[18] 2020 ERP Settlement Agreement, Section 3.11.1.

[19] Midwest Reliability Organization West

[20] Council on Environmental Quality Climate and Economic Justice Screening Tool (Explore the map - Climate & Economic Justice Screening Tool (geoplatform.gov), and USDA look-up map (Locations of Distressed and Disadvantaged Communities (arcgis.com).

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- Present value revenue requirement, with and without the social costs of carbon and methane; and
- Curtailment MWhs by intermittent resource type seasonally and year.[21]

Transmission Analyses

Each scenario was analyzed for its impact on transmission expenditures – both forecasted interconnection costs and additional network upgrades anticipated to be required, beyond already planned upgrades.

Reliability Analyses

Tri-State utilizes industry standard reliability metrics for its resource planning, referred to in the ERP as "Level I Reliability Metrics," and has also developed an additional set of reliability metrics for assessing the plan's performance under simulated EWE conditions, and refers to those standards as "Level II Reliability Metrics." All metrics are given equal weight as minimum requirement thresholds for any scenario to be supported as a reliable, preferred plan for Tri-State.

These metrics are critical for mitigating risks associated with:

- Not meeting resource adequacy obligations as a load-serving entity (LSE);
- Reliability impacts during a single EWE as well as the impact of EWEs on reliability over the course of the RAP;
- Uncertainty of performance of emerging technologies and contribution of increased intermittent resources at higher levels;
- Lost productivity and cost of deploying emergency response measures during an EWE; and
- Member reliability expectations for high reliability across the system and limited load shedding or reduced system reliability during an EWE, and over time.

Level 1 reliability metric checks were performed on each scenario, including:

- *Planning Reserve Margin (PRM):* Measure of required surplus of forecast generation capacity above forecast peak load inclusive of firm sales obligations. Reserve Margin requirement is inclusive of operating contingency/planning reserves (%). The third-party study of PRM (Attachment ~~G-1~~ LKT-29) was developed using a Strategic Energy Risk Valuation Model (SERVM)—a system-reliability planning and production cost model designed to analyze the capabilities of an electric system during a variety of conditions under thousands of different scenarios and is thus able to identify potential risks to system reliability across the entire year, not just at system peak. The model, therefore, provides insight into risks and costs during these periods as well as the expectation of being able to meet peak load under many, varying conditions. The results of the model help determine the amount of reserves an electric system requires to adequately maintain system reliability.

[21] One of the benefits of utilizing the EnCompass software is that it offers increased visibility into generation unit curtailments. EnCompass allows for a prioritization of curtailment order. In the event that resources must be curtailed, Tri-State's model will first reduce dispatch of thermal resources to economic minimum levels, including taking thermal resources offline if possible. The model then curtails solar resources, wind resources, thermal resources below economic min and must take contracts (i.e., hydropower and Basin contracts)–in that order.

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    - Target (min) is 22% transitioning to 30.5% in 2028 after the retirement of the Craig facility.
- *Loss of Load Hours (LoLH)*[22]: Measure of the likelihood of failing to meet system load (hours per 10 years).
    - Target (max) is 1 day in 10 years (99.973% reliability).[23]
        - 2024-2033 – annually cannot exceed 2.4 hours.[24]
        - 2034-2043 – cannot exceed 24 hours over entire period.
- *Expected Unserved Energy (EUE)*[25]: Measure of annual summation of hourly energy not available to meet load and firm sales obligations; representative of potential load that would otherwise need to be shed to maintain system reliability.
    - Targets (max):
        - ≤ 0.4 GWh annually.[26]

Level 2 reliability target checks were performed on each scenario's EWE sensitivity result, including:

- ≤ 12 loss of load hours during all EWEs in 2026-2031
- ≤ 3 loss of load hours per each year, 2026-2031
- EUE must be ≤ 20% of load in any hour[27]
- Evaluation of market purchases vs remaining hourly available dispatchable capacity to ensure that EUE was not avoided through the use of market purchases as capacity.[28]

A detailed analysis of how additions of new intermittent capacity can serve load and maintain reliability is provided for each scenario.[29]

State Renewable Policy Compliance Analysis

Tri-State reviewed the results of each scenario and affirms that all scenarios meet or exceed the minimum applicable state renewable energy standard (RES) or renewable portfolio standard (RPS) requirements. RES/RPS standards are shown in the following table.

[22] LoLH is equivalent to Loss of Load Probability (LoLP) terminology used in Tri-State's 2020 ERP Phase I.
[23] Splitting the LOLH target over the planning period reflects Tri-State's desire to have added assurance that intra-year reliability in the near-term is met by resources coming online during the RAP as the generation fleet makes significant transitions through this period. This approach also allows Tri-State to cautiously assess the impact of having an increasing percentage of intermittent resources in its fleet and the uncertain potential for more severe EWEs before applying similarly stringent LOLH metrics to the outer years of the planning period. There is more flexibility allowed in the out years as forecasting and technology uncertainty is greater during this period.
[24] The annual LOLH target of 2.4 hours is an equivalent representation of the 1 day in 10 years reliability standard.
[25] EUE is equivalent to Energy Not Served (ENS) terminology used in Tri-State's 2020 ERP Phase I.
[26] This metric is reflective of lower load forecasted based on both member exits and Partial Requirements and is aimed at limiting EUE to a reasonable level below the historical annual average, consistent with the 2020 ERP Phase II.
[27] This metric is an equivalent to the Level I annual EUE target, reflected as an hourly target to assess reliability during EWE stress periods. According to NREL, ~26 percent of estimated load in ERCOT was curtailed during Winter Storm Uri in 2021.
[28] In evaluating historical events, Tri-State confirmed that there was no reliance on third party capacity during extreme weather events. If market purchases occurred an equal or greater amount of Tri-State capacity was unused.
[29] 2020 ERP Settlement Agreement, Section 3.11.14.

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Table 4: Colorado RES and New Mexico RPS Requirements during RPP

	Colorado RES[30, 31]		New Mexico RPS[32]
	Co-ops	Tri-State	Co-ops
2024	10%	20%	10%
2025-2029	10%	20%	40%
2030-2050	10%	20%	50%

Comparative Analysis

The analysis Tri-State completed to compare and assess results across scenarios can be found in the Comparative Analysis section of this report.

Commission Electric Rule 3605(g)(III)(C) and (D)

The Commission must consider the following factors in issuing a Phase I decision:

The Phase I decision will set forth the information the utility shall provide in the ERP Implementation Report regarding potential resources, proposed utility-owned resources, and the modeling of portfolio combinations of resources to support the development of cost-effective resource plans.

Tri-State proposes an outline for the ERP Implementation Report to be filed in Phase II of the 2023 ERP, provided as Attachment LKT-3.

Tri-State proposes to procure utility-owned resources and PPAs, in alignment with the resource mix modeled in the IRA Scenario, shown in the table below. This approach would result in approximately 500 MW of owned resources and 1040 MW of PPA resources.

Table 5: Proposed MW of Utility-Owned and PPA Resources, by Technology, in IRA Scenario RAP

Technologies	Own	PPA
Solar		240
Wind		500
Wind Hybrid		200
4-hr Storage[33]	100	100
Iron Air Storage	110	
Natural Gas Combined Cycle (NGCC) with Carbon Capture and Sequestration (CCS) Conversion	290	
Total	**500**	**1040**

[30] § 40-2-124(1)(c)(I)(D) and (c)(V)(D), C.R.S.
[31] § 40-2-124(8)(b), C.R.S.
[32] N.M. Stat. Ann. § 62-15-34.
[33] Owned storage is standalone and PPA storage is tied to 200 MW of wind (wind hybrid).

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The Commission shall determine the cost of carbon dioxide emissions to assess the cost, benefit, and net present value of revenue requirements to be presented in the ERP Implementation Report.

Tri-State has utilized the most recent IWG on Social Cost of Greenhouse Gases, Technical Support Document for the SCoC at the time modeling began and suggests continuation of that practice is sufficient for reporting portfolio analysis results in Phase II of the 2023 ERP.

In consideration of the base case portfolio of resources and alternative portfolios proposed by the utility, the Commission shall define the base case portfolio and alternative portfolios for modeling in Phase II.

If New ERA funding is received as requested, Tri-State requests that the IRA Scenario be the base case portfolio in Phase II. Tri-State proposes to model one portfolio that reflects the IRA Scenario resource selections and five portfolios that identifies back-up bid selections for each technology cohort. Tri-State requests limiting stakeholder-requested portfolios to two, given the number of back-up bid portfolios that will be necessary.

The Commission may require the utility to provide information regarding alternative portfolios in addition to the base case portfolio and information regarding the cost, benefit, and net present value of revenue requirements of the alternative portfolios using different levels of costs for carbon dioxide.

Tri-State has provided cost, benefit, and PVRRs for five scenarios in Phase I, including a base case (Business as Usual Scenario), and would provide similar information for Phase II portfolios.

In accordance with § 40-3.2-106(3), C.R.S., the Commission shall establish the relevant factors other than the cost of carbon dioxide emissions for consideration of the approval of the utility's electric resource plan.

Factors that Tri-State has considered in evaluation of its preferred plan, the IRA Scenario, are identified in the Executive Summary and Comparative Analysis sections of this report. Factors include reliability, financial, and environmental considerations.

The Phase I decision will establish the deadline for the utility to submit its ERP Implementation Report.

Tri-State has proposed a Phase II timeline (Attachment LKT-2), which plans for the ERP Implementation Report to be filed 120 days after Bid Evaluation Complete (estimated to be January 2025). The proposed timeline for the ERP Implementation Report aims to ensure sufficient time for modeling preparation and completion, while recognizing RAP includes 2026.

Stakeholder Engagement

Tri-State has engaged transparently and collaboratively in ongoing stakeholder engagement in advance of and during the Phase I resource planning process. Numerous stakeholder groups representing a diverse set of interests participated in more than a dozen meetings in 2023 in advance of Tri-State beginning Phase I modeling and several additional meetings during development of the Phase I filing. These discussions provided an opportunity to further educate stakeholders on the complexities of the Tri-State system, inform participants of key modeling inputs and assumptions, and facilitate dialogue on topics

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applicable to Phase I. These stakeholder meetings occurred between January and October 2023, covering the following topics:

1. January 17, 2023: Phase I Scope, Timeline, Generic Resources, Storage Valuation, ELCCs, Scenarios/Sensitivities, and Phase II RFP[34]
2. February 16, 2023: Beneficial Electrification (BE) Meeting #1[35]
3. February 23, 2023: Phase I Storage Valuation, ELCCs, DSM/DR/BE,[36] and Scenarios/Sensitivities[37]
4. March 10, 2023: Phase I Scenario and Sensitivity Planning #1[38]
5. March 14, 2023: Phase I Reliability and Extreme Weather Event (EWE) Sensitivities
6. March 22, 2023: BE Meeting #2[39]
7. March 24, 2023: Phase I Reliability and Extreme Weather Sensitivities
8. March 27, 2023: Phase I Scenario and Sensitivity Planning #2[40]
9. April 24, 2023: Phase I Battery Modeling and ELCC Study[41]
10. April 26, 2023: DSM Roundtable Meeting #1
11. May 4, 2023: Phase I Scenario and Sensitivity Planning #3 (GHG Reduction Modeling)[42]
12. May 17, 2023: Phase I Pre-Modeling Assumptions Feedback[43]
13. July 19, 2023: Phase I PRM, ELCC, and EWE Modeling[44]
14. August 14, 2023: Phase I Scenario and Sensitivity Planning #4[45]
15. September 27, 2023: Phase II Planning[46]
16. October 18, 2023: DSM Roundtable Meeting #2

Several other meetings, e-mail communications and updates to stakeholders also occurred in advance of and during Phase I modeling with the aim of ensuring communications on key ERP topics.[47] All 2023 ERP stakeholder meetings were identified on Tri-State's website[48] in advance of the meetings and were open for public participation.[49]

[34] 2020 ERP Settlement Agreement, Sections 3.11.12., 3.11.13 and 3.11.15.
[35] 2020 ERP Settlement Agreement, Section 3.11.10.
[36] Per 2020 ERP Settlement Agreement, Sections 3.11.5, Tri-State held three meetings on DSM prior to December 31, 2022 which were identified in the 2020 ERP Phase II Implementation Report (April 27, June 14, and August 1, 2022). DSM modeling was also discussed during the February 23, 2023 stakeholder meeting.
[37] 2020 ERP Settlement Agreement, Sections 3.11.12, 3.11.13, and 3.11.14.
[38] 2020 ERP Settlement Agreement, Section 3.11.12 and 3.11.14.
[39] 2020 ERP Settlement Agreement, Section 3.11.10.
[40] 2020 ERP Settlement Agreement, Section 3.11.12 and 3.11.14.
[41] 2020 ERP Settlement Agreement, Section 3.11.13.
[42] 2020 ERP Settlement Agreement, Section 3.11.12.
[43] 2020 ERP Settlement Agreement, Section 3.11.12.
[44] 2020 ERP Settlement Agreement, Section 3.11.13.
[45] 2020 ERP Settlement Agreement, Section 3.11.12 and 3.11.14.
[46] Decision No. C23-0437, at¶ 67.
[47] Of note, discussion of emissions rates occurred August 16, 2022, per 2020 ERP Settlement Agreement, Section 3.11.4, as identified in the 2020 ERP Phase II Implementation Report.
[48] https://tristate.coop/resource-planning
[49] 10 C.F.R. § 905.11(b)(4)

Tri-State maintains ongoing collaboration with interested stakeholders related to its ERP, federal funding pursuits, and organized market-related matters.

Scenario Results: Highlights

Key facets of the scenario modeling results, such as generic resource selection during the RAP, and unit retirements modeled and PVRRs over the RPP are summarized below. Detailed scenario results and comparisons across scenarios are in the sections that follow.

Generic Resource Selection in Scenario Modeling

Table 6 identifies the generic resource types selected across the scenarios modeled.

Table 6: Generic Resources Selected in Scenario Modeling During the RAP, by MW and Technology

Scenario	Gas	Storage[50]	Solar[51]	Wind	Wind Hybrid	Total
Scenario 1: BAU	290	250	140	0	300	**980**
Scenario 2: IRA	290	310	240	500	200	**1,540**
Scenario 3: ESPV3	290	350	140	0	300	**1,080**
Scenario 4: SWER	290	50	140	0	100	**580**
Scenario 5: ACER	290	100	140	0	200	**730**

Unit Retirement Selection in Scenario Modeling

Table 7 identifies the retirements dates modeled for resources during the RPP.

Table 7: Retirements Modeled by Scenario

Scenario	Craig 3	SPV 3	LRS 2
Scenario 1: BAU	1/1/2028	1/1/2037	1/1/2043
Scenario 2: IRA	1/1/2028	9/15/2031	N/A
Scenario 3: ESPV3	1/1/2028	1/1/2031	N/A
Scenario 4: SWER	1/1/2028	1/1/2037	N/A
Scenario 5: ACER	1/1/2028	1/1/2037	1/1/2042

Scenario PVRRs

Error! Reference source not found.~~Table 8~~ identifies the PVRRs resulting from each scenario modeled, over the RPP.

Table 8: PVRR by Scenario

Scenario	PVRR ($, Millions)
Scenario 1: BAU	$17,507.40
Scenario 2: IRA	$176,221~~352~~.40~~0~~
Scenario 3: ESPV3	$17,304.20
Scenario 4: SWER	$17,343.90

[50] Storage inclusive of standalone and hybrid batteries.

[51] Solar values are representative of selected generic resources during the RAP. Due to the cancellation of the Coyote Gulch after the start of modeling, 140 MW of solar replacement in 2026 will be pursued in Phase II and is reflected in this data.

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Scenario 5: ACER	$17,208.20

Phase I Scenario Results and Analysis

Each section that follows presents data and analytical results from each scenario modeled, addressed in the following order:

- Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales/Purchases
- Environmental Analysis
- Financial Analysis
- Transmission Analysis
- Reliability Analysis

1. Business As Usual (BAU) Scenario

The BAU Scenario and assumptions served as the base case scenario for Phase I.[52] Assumptions unique to each scenario are identified in Attachment ~~B-3~~. LKT-10

Scenario 1 (BAU) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, DSM selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

Table 9: Expansion Plan (Scenario 1 – BAU)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	Solar[53]	West Colorado	140	1	140
2028	NGCC with CCS[54]	West Colorado	290	1	290
2030	Wind/Battery Hybrid	East Colorado	100	2	200
	100 hr – Iron Air Battery	East Colorado	100	1	100
2031	Wind/Battery Hybrid	New Mexico	100	1	100
2032	Wind/Battery Hybrid	East Colorado	100	1	100
2033	Wind	East Colorado	100	1	100
2036	Wind/Battery Hybrid	East Colorado	100	1	100
2037	Wind/Battery Hybrid	New Mexico	100	1	100
2040	Wind/Battery Hybrid	Wyoming / W. Neb.	100	1	100
2041	Wind/Battery Hybrid	Wyoming / W. Neb.	100	1	100
2042	Wind/Battery Hybrid	East Colorado	100	2	200
	Wind/Battery Hybrid	Wyoming / W. Neb.	100	2	200

[52] Commission Rule 3605(a)(IV)(M).
[53] This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.
[54] NGCC installed in 2028 and CCS conversion startup anticipated in 2031.

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Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2043	Solar	New Mexico	100	1	100
	Wind/Battery Hybrid	Wyoming / W. Neb.	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:[55]

- All plans include applicable Colorado energy efficiency targets in base assumptions.[56]
- Low New Mexico Energy Efficiency was selected in the expansion plan of Scenario 1 – BAU in 2040.
- Low Wyoming Energy Efficiency was selected in the expansion plan of Scenario 1 – BAU in 2040.

The expansion plan also included the following Demand Response (DR) levels by region:[57]

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.[58]
- 84 MW of New Mexico Demand Response was selected in the expansion plan of Scenario 1 – BAU starting in 2040.
- 52 MW of Wyoming Demand Response was selected in the expansion plan of Scenario 1 – BAU starting in 2038.

Unit retirements selected in the modeling are shown in the following table.[59]

Table 10: Modeled Retirements (Scenario 1 – BAU)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	1/1/2037
LRS 2 (TS portion)	241	Coal	1/1/2043[60]

Resulting system capacity and energy mix, based on the modeling are shown below.

[55] Commission Rule 3605(c)(I)(I).
[56] 2020 ERP Settlement Agreement at Section 3.11.6.
[57] Commission Rule 3605(c)(I)(I).
[58] 2020 ERP Settlement Agreement at Section 3.11.8.
[59] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners").
[60] This a modeling result based on input assumptions for Tri-State's portion of Laramie River Station (LRS) Unit 2; at the time of this report, Tri-State does not have the right to unilaterally retire any Missouri Basin Power Project (MBPP) resource (LRS 2 or LRS 3). Tri-State along with MBPP participants will continue to evaluate changing industry regulations, system and market conditions to inform operational decisions related to its joint owned coal units.

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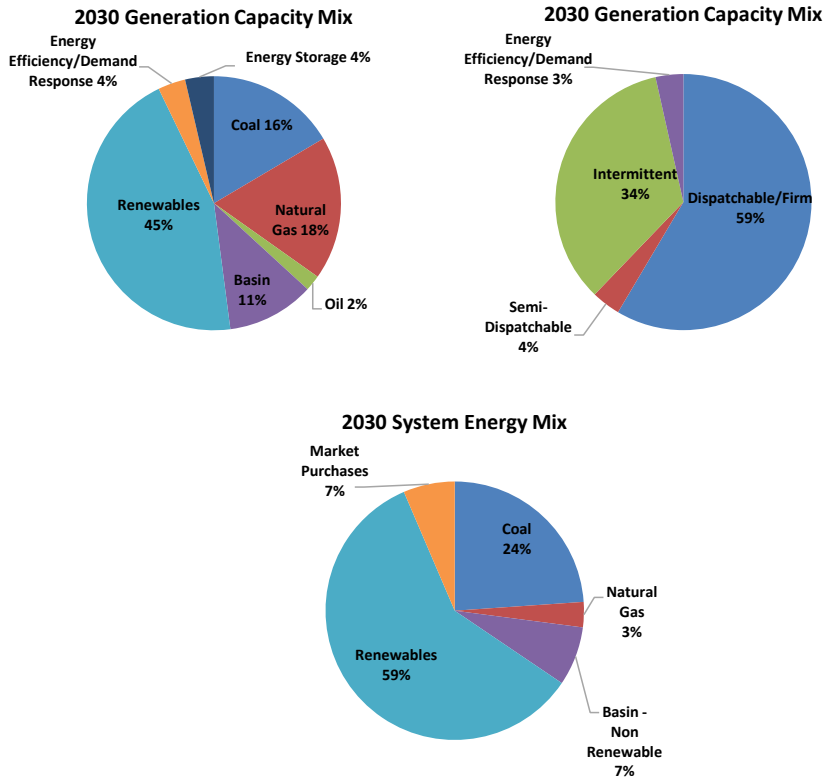
Figure 4: Projected Tri-State System Resource Mix 2030 (Scenario 1 – BAU)[61, 62, 63]



[61] "Renewables" category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[62] Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.
[63] System Energy Mix reflects sales to Members and non-Members.

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Table 11: Projected Annual Capacity Factors for Thermal Resources (Scenario 1 – BAU)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	18%	0%	0%	0%	0%	0%	0%
Craig 2	98%	15%	27%	12%	15%	0%	0%	0%
Craig 3	79%	13%	22%	18%	0%	0%	0%	0%
LRS 2	93%	89%	86%	78%	76%	74%	71%	70%
LRS 3	75%	63%	62%	55%	57%	48%	45%	51%
SPV 3	72%	67%	43%	42%	43%	36%	44%	42%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	1%	0%	0%	0%	0%	0%	0%
Shafer	26%	11%	0%	1%	0%	0%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	28%	28%	19%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 12: Forecasted Energy Sales and Purchases (Scenario 1 – BAU)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,534	1,506	3,095	2,877	3,344	2,774	3,286	3,911
Purchases (GWh)	344	946	523	884	610	717	926	742

Scenario 1 (BAU) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 13: Environmental Impact - System Wide (Scenario 1 – BAU)[64]

Year	CO_2 [65] (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2024	15,834,465	7,750	10,740	0.0383	704	6,777,851,478	32,082
2025	10,918,985	5,416	6,423	0.0243	515	4,098,496,075	20,000
2026[66]	8,555,344	5,071	5,977	0.0230	413	3,640,953,702	18,040

[64] Commission Rule 3605(c)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[65] In all scenarios the 2021 eGRID emission rate for LRS is used for calculating emissions of the Basin Western Interconnection Contract in 2024 and 2025. This is a change from reporting in the 2020 ERP which used regional eGRID rates in those years. From 2026 to 2029 the 2021 RMPA eGRID is used for this contract which then transitions to the APCD assigned rate for WECC in 2030.

[66] Load reduced due to partial requirements contracts in 2026 forward.

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Year	CO_2 [65] (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2027	8,004,261	4,747	5,558	0.0204	378	3,239,042,574	16,444
2028	7,398,021	4,273	4,742	0.0182	384	3,109,973,662	14,569
2029	6,751,561	3,964	4,414	0.0161	336	2,752,993,696	12,908
2030	5,884,898	4,044	4,477	0.0161	350	2,732,958,152	13,397
2031	5,745,992	4,070	4,513	0.0166	370	3,287,323,551	13,629
2032	5,310,741	3,880	4,343	0.0153	333	3,053,750,612	12,597
2033	5,652,647	4,035	4,490	0.0162	361	3,227,998,157	13,431
2034	5,698,340	4,065	4,532	0.0163	362	3,244,468,138	13,533
2035	5,458,062	3,970	4,464	0.0157	339	3,116,848,744	12,923
2036	5,083,006	3,833	4,367	0.0149	302	2,923,162,545	12,018
2037	4,083,249	3,443	4,075	0.0130	206	2,443,989,009	9,470
2038	4,101,311	3,456	4,095	0.0130	206	2,447,420,964	9,511
2039	4,167,871	3,501	4,158	0.0132	208	2,466,937,312	9,661
2040	4,173,730	3,512	4,178	0.0131	207	2,460,238,397	9,674
2041	4,163,504	3,509	4,183	0.0130	205	2,442,136,997	9,651
2042	4,205,424	3,542	4,241	0.0130	205	2,439,323,762	9,744
2043	2,858,155	2,789	3,381	0.0071	127	1,651,568,018	6,808
Total	**124,049,570**	**82,870**	**97,350**	**0.337**	**6,512**	**61,557,435,546**	**270,090**
Pounds/Gallons per MWh[67]	857	0.57	0.67	0.000002	0.04	213	2.056

[67] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

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Table 14: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 1 – BAU)

Year	Annual Social Cost of Carbon
2024	$1,390,597,459
2025	$995,687,914
2026	$810,659,426
2027	$787,912,259
2028	$755,247,562
2029	$714,655,955
2030	$645,736,709
2031	$653,860,869
2032	$626,587,101
2033	$691,336,216
2034	$722,286,260
2035	$716,850,786
2036	$691,597,305
2037	$575,435,014
2038	$598,539,612
2039	$629,766,814
2040	$652,840,646
2041	$670,965,445
2042	$705,605,295
2043	$494,486,160

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Table 15: Social Cost of Methane Nominal Dollars – System Wide (Scenario 1 – BAU)

Year	Annual Social Cost of Methane
2024	$82,734,317
2025	$54,056,308
2026	$51,119,484
2027	$48,825,849
2028	$45,233,558
2029	$41,884,087
2030	$45,409,865
2031	$48,392,878
2032	$46,826,362
2033	$52,235,896
2034	$55,037,923
2035	$54,924,746
2036	$53,357,940
2037	$43,900,675
2038	$46,012,180
2039	$48,752,421
2040	$50,897,483
2041	$52,750,303
2042	$56,102,875
2043	$40,040,866

Table 16: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 1 – BAU)

Year	Target[68]	Forecast
2025	26%	47%
2026	36%	60%
2027	46%	68%
2030	80%	86%

See Appendix D for detailed GHG emissions calculations for the scenario.

Scenario 1 (BAU) – Financial Analysis

The present value revenue requirement (PVRR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

[68] 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.

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Table 17: Total Financial (Scenario 1 – BAU)

$, Millions	Scenario PVRR (2023 WACC 4.12%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Scenario PVRR inclusive of SCoC NPV	Scenario PVRR inclusive of SCoC NPV & SCoM NPV
	$17,507.4	$11,608.8	$800.2	$29,116.2	$29,916.4
Expansion Plan CapEx + IDC: Generation (Nominal $)	$1,806.8				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$598.2				

Table 18: Annual Financial (Nominal $) (Scenario 1 – BAU)

Year	Total Annual Revenue Requirement ($, Millions)
2024	$1,016
2025	$987
2026	$898
2027	$966
2028	$1,053
2029	$1,218
2030	$1,262
2031	$1,283
2032	$1,305
2033	$1,399
2034	$1,503
2035	$1,519
2036	$1,562
2037	$1,461
2038	$1,490
2039	$1,514
2040	$1,534
2041	$1,544
2042	$1,566
2043	$1,734

Financial analysis of the of the scenario under the extreme-weather event stress is provided below.

*Table 19~~-XX~~: Total Financial Under **EWE** Sensitivity (Scenario 1 – BAU)*

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Scenario PVRR ($, Millions) (2023 WACC 4.12%)
$17,472.1

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 1 – BAU dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin. Thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the investment tax credit (ITC) they do not have a production tax credit (PTC) penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 1 – BAU are $518,551.

Table 20: Curtailed Intermittent Energy, Annual MWh (Scenario 1 – BAU)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Total
2024	0	0	0	0	**0**
2025	0	0	0	0	**0**
2026	0	5,653	0	0	**5,653**
2027	0	3,345	0	0	**3,345**
2028	0	2,732	0	0	**2,732**
2029	0	2,193	0	0	**2,193**
2030	0	0	0	0	**0**
2031	0	0	0	0	**0**
RAP Total	**0**	**13,923**	**0**	**0**	**13,923**

Table 21: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 1 – BAU)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	125	4,447	20	1,061
2027	0	3,025	44	276
2028	25	2,275	16	416
2029	0	2,123	6	64
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**150**	**11,870**	**86**	**1,817**

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The following table reflects PPA pricing, penalties, and taxes.

Table 22: Estimated PPA Curtailment Costs and Penalties, Real (2023) $ (Scenario 1 – BAU)

	Wind ($)	Solar ($)
2024	0	0
2025	0	0
2026	0	$208,078
2027	0	$125,060
2028	0	$102,674
2029	0	$82,738
2030	0	0
2031	0	0
RAP Total	**$0**	**$518,550**

Scenario 1 (BAU) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the point of interconnection (POI), resulting from the scenario are shown in the table below.

Table 23: Transmission Interconnection & Network Upgrade Expenses Real (2023) $ (Scenario 1 – BAU)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2030	100	Wind + Battery		$2.88	
2030	100	Wind + Battery		$2.88	
2030	100	Battery	$1.40	$2.88	
2032	100	Wind + Battery		$2.88	
2033	100	Wind		$2.88	
2036	100	Wind + Battery		$10.20	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
Western Colorado (WCO) Transmission Area					
2028	290	Gas	$1.50	$4.20	
Wyoming (WYO) Transmission Area					
2040	100	Wind + Battery		$12.00	$109.00
2041	100	Wind		$4.20	
2042	100	Wind + Battery		$4.20	
2042	100	Wind + Battery		$4.20	$34.00
2043	100	Wind + Battery		$4.20	
New Mexico (NM) Transmission Area)					
2031	100	Wind + Battery		$2.88	$238.50
2037	100	Wind + Battery		$2.88	

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2043	100	Solar		$1.68	

Scenario 1 (BAU) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources' ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 24: Planning Reserve Margin, % Annual (Scenario 1 – BAU)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	46%	43%	49%	42%	52%	54%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 25: Loss of Load Probability, Hours (Scenario 1 – BAU)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

Table 26: Expected Unserved Energy, Annual MWh (Scenario 1 – BAU)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 1 – BAU)

Section 3.11.14. of the 2020 ERP Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment ~~G-1)~~ LKT-29 and ELCCs continue to decline with the addition of intermittent resources. In Scenario 1 – BAU, 150 MW of 4-hour hybrid storage, 100 MW of long-duration storage, and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable resources to replace the dispatchable resources retiring during the RAP, and support integration of intermittent resources.

Scenario 1 (BAU) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

Table 27~~Table 26~~ represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all twelve EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the Scenario 1 – BAU extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours in Scenario 1 – BAU.

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Table 27: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 1 – BAU)

Event (Season/Year)	Date	Hour
All EWE Periods	N/A	N/A

Table 28~~Table 27~~ represents any EUE identified by hour in the twelve EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

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Table 28: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 1 – BAU)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All EWE Periods	N/A	N/A	N/A	N/A	N/A	N/A

Tri-State also analyzed EWE performance for Scenario 1 – BAU in the post-RAP period and all Level II metrics were met.

Analysis of Market Purchases and Available Capacity (Scenario 1 – BAU)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the "analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access."

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
  - NM Market HE 2 to HE 6 and HE 11 to 15
  - 1 day in event no market depth
- Summer:
  - ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
  - 1 day in event no market depth

In the EWE analysis for Scenario 1 – BAU, market was used for 6.4 GWh in 118 hours during the January EWE events between 2026-2031. The market was used for 11.9 GWh in 80 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics. Market purchases during these limited hours were confirmed to not lean on the market for capacity.

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2. Inflation Reduction Act of 2022 (IRA) Scenario

Assumptions unique to each scenario are identified in Attachment ~~B-3.~~ LKT-10

Scenario 2 (IRA) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

Table 29: Expansion Plan (Scenario 2 – IRA)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	4hr – Battery	New Mexico	50	1	50
	100hr – Iron Air Battery	East Colorado	10	1	10
	Solar[69]	West Colorado	140	1	140
2028	Wind	Wyoming / W. Neb.	100	2	200
	NGCC with CCS[70]	West Colorado	290	1	290
2029	Solar	New Mexico	100	1	100
	4hr – Battery	East Colorado	50	1	50
	Wind	East Colorado	100	1	100
2030	Wind	East Colorado	100	1	100
	Wind	Wyoming / W. Neb.	100	1	100
	100hr – Iron Air Battery	East Colorado	100	1	100
2031	Wind/Battery	New Mexico	100	2	200
2032	Wind/Battery	New Mexico	100	1	100
2036	Wind/Battery	East Colorado	100	1	100
2042	Wind/Battery	East Colorado	100	3	300
	Wind	Wyoming / W. Neb.	100	1	100
2043	Wind/Battery	Wyoming / W. Neb.	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:[71]

- All plans include applicable Colorado energy efficiency targets in base assumptions.[72]
- Low New Mexico Energy Efficiency was selected in the expansion plan of Scenario 2 – IRA in 2025.

[69] This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.
[70] NGCC installed in 2028 and CCS conversion startup anticipated 2031.
[71] Commission Rule 3605(c)(I)(I).
[72] 2020 ERP Settlement Agreement at Section 3.11.6.

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- Low Wyoming Energy Efficiency was selected in the expansion plan of Scenario 2 – IRA in 2025.

The expansion plan also included the following Demand Response (DR) levels by region:[73]

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.[74]
- 52 MW of Wyoming Demand Response was selected in the expansion plan of Scenario 2 – IRA starting in 2035.
- 84 MW of New Mexico Demand Response was selected in the expansion plan of Scenario 2 – IRA starting in 2038.

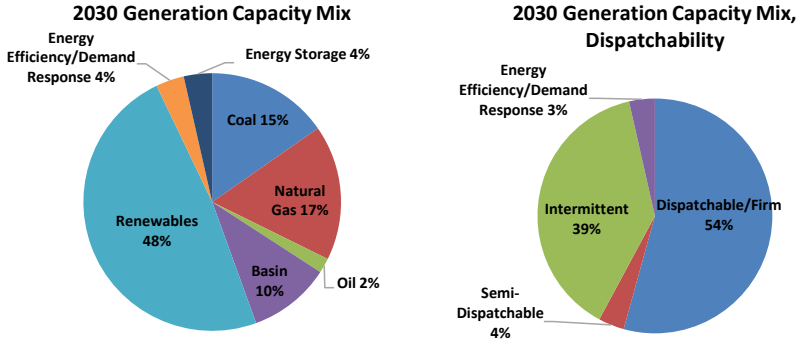
Unit retirements modeled are shown in the following table.[75]

Table 30: Modeled Retirements (Scenario 2 – IRA)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	9/15/2031

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 5: Projected Tri-State System Resource Mix 2030 (Scenario 2 – IRA)[76, 77, 78]



[73] Commission Rule 3605(c)(I)(I).
[74] 2020 ERP Settlement Agreement at Section 3.11.8.
[75] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners").
[76] "Renewables" category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[77] Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.
[78] System Energy Mix reflects sales to Members and non-Members.

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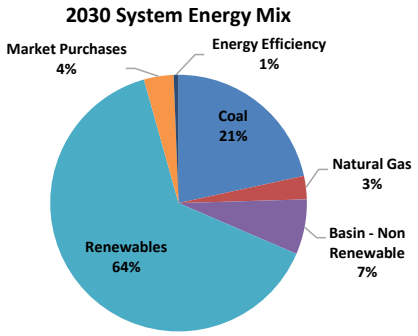

Table 31: Projected Annual Capacity Factors for Thermal Resources (Scenario 2 – IRA)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	18%	0%	0%	0%	0%	0%	0%
Craig 2	97%	16%	35%	25%	34%	0%	0%	0%
Craig 3	78%	12%	22%	17%	0%	0%	0%	0%
LRS 2	93%	89%	71%	71%	71%	68%	63%	64%
LRS 3	75%	64%	72%	60%	57%	55%	49%	50%
SPV 3	64%	66%	42%	42%	42%	36%	42%	37%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	0%	0%	0%	0%	0%	0%	0%
Shafer	26%	11%	1%	1%	0%	0%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	27%	25%	19%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 32: Forecasted Energy Sales and Purchases (Scenario 2 – IRA)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,304	1,499	3,067	2,873	3,957	3,883	4,259	5,014
Purchases (GWh)	283	952	515	813	422	422	542	512

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Scenario 2 (IRA) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 33: Environmental Impact - System Wide (Scenario 2 – IRA)[79]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2024	15,451,106	7,595	10,593	0.0376	674	6,622,378,196	31,305
2025	10,888,923	5,401	6,381	0.0243	515	4,078,147,420	19,913
2026[80]	8,468,490	4,994	5,893	0.0225	408	3,590,666,662	17,862
2027	7,993,868	4,710	5,504	0.0204	380	3,249,891,892	16,483
2028	7,253,155	4,178	4,625	0.0178	381	3,076,352,800	14,438
2029	6,563,974	3,928	4,348	0.0163	333	2,735,998,999	12,813
2030	5,608,261	3,884	4,262	0.0155	337	2,634,907,653	12,808
2031	4,831,239	3,643	4,079	0.0145	299	2,871,821,954	11,464
2032	3,824,819	3,280	3,865	0.0122	194	2,334,603,678	8,895
2033	3,933,841	3,345	3,952	0.0125	199	2,379,546,703	9,139
2034	3,964,238	3,367	3,982	0.0126	200	2,385,882,853	9,211
2035	3,927,079	3,349	3,971	0.0123	197	2,356,788,752	9,117
2036	3,985,696	3,392	4,021	0.0125	199	2,381,021,036	9,258
2037	4,022,648	3,417	4,064	0.0125	200	2,384,355,478	9,343
2038	4,021,708	3,421	4,072	0.0125	199	2,375,788,747	9,338
2039	3,974,658	3,373	3,968	0.0128	203	2,414,033,911	9,235
2040	3,998,873	3,400	4,018	0.0127	201	2,401,751,376	9,291
2041	3,983,443	3,399	4,036	0.0124	198	2,364,432,696	9,251
2042	4,027,793	3,434	4,095	0.0124	198	2,363,931,030	9,354
2043	4,013,781	3,433	4,106	0.0122	195	2,338,232,936	9,322
Total	**114,737,592**	**78,943**	**93,836**	**0.318**	**5,707**	**57,340,534,771**	**247,837**
Pounds/Gallons per MWh[81]	792	0.55	0.65	0.000002	0.04	198	1.886

[79] Commission Rule 3605(c)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.
[80] Load reduced due to partial requirements contracts in 2026 forward.
[81] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

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Table 34: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 2– IRA)

Year	Annual Social Cost of Carbon
2024	$1,356,930,446
2025	$992,946,534
2026	$802,429,547
2027	$786,889,198
2028	$740,458,538
2029	$694,799,728
2030	$615,381,995
2031	$549,767,216
2032	$451,270,783
2033	$481,120,934
2034	$502,482,209
2035	$515,774,643
2036	$542,296,523
2037	$566,894,764
2038	$586,922,384
2039	$600,572,264
2040	$625,490,158
2041	$641,947,763
2042	$675,801,518
2043	$694,419,551

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Table 35: Social Cost of Methane Nominal Dollars – System Wide (Scenario 2 – IRA)

Year	Annual Social Cost of Methane
2024	$80,730,077
2025	$53,818,969
2026	$50,613,362
2027	$48,939,435
2028	$44,826,979
2029	$41,577,985
2030	$43,413,041
2031	$40,707,122
2032	$33,064,168
2033	$35,541,561
2034	$37,457,706
2035	$38,749,984
2036	$41,103,874
2037	$43,309,094
2038	$45,174,789
2039	$46,600,954
2040	$48,883,426
2041	$50,563,745
2042	$53,858,083
2043	$54,827,634

Table 36: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 2 – IRA)

Year	Target[82]	Forecast
2025	26%	47%
2026	36%	60%
2027	46%	67%
2030	80%	89%

See Appendix D for detailed GHG emissions calculations for the scenario.

Scenario 2 (IRA) – Financial Analysis

The present value revenue requirement (PVRR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

[82] 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.

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Table 37~~3736~~: Total Financial (Scenario 2 – IRA)

$, Millions	Scenario PVRR (2023 WACC 4.12%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Scenario PVRR inclusive of SCoC NPV	Scenario PVRR inclusive of SCoC NPV & SCoM NPV
	$17,221.4~~16,352.0~~	$10,726.7	$733.1	$27,948.1~~27,078.7~~	$28,681.2~~27,811.8~~
Expansion Plan CapEx + IDC: Generation (Nominal $)	$2,093.9				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$555.5				

Table 38: Annual Financial (Nominal $) (Scenario 2 – IRA)

Year	Total Annual Revenue Requirement ($, Millions)
2024	$1,017~~1,011~~
2025	$969~~968~~
2026	$904~~870~~
2027	$962~~928~~
2028	$1,104~~1,001~~
2029	$1,231~~1,073~~
2030	$1,258~~1,144~~
2031	$1,301~~1,204~~
2032	$1,285~~1,267~~
2033	$1,317~~1,287~~
2034	$1,349~~1,313~~
2035	$1,379~~1,333~~
2036	$1,416~~1,357~~
2037	$1,440~~1,379~~
2038	$1,464~~1,404~~
2039	$1,506~~1,433~~
2040	$1,566~~1,459~~
2041	$1,593~~1,494~~
2042	$1,601~~1,519~~
2043	$1,700~~1,546~~

Financial analysis of the of the scenario under the extreme-weather event stress is provided below.

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*Table 39: Total Financial Under **EWE** Sensitivity (Scenario 2 – IRA)*

Scenario PVRR ($, Millions) (2023 WACC 4.12%)
$17,166.8~~16,300.1~~

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 2 – IRA dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the ITC they do not have a PTC penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 2 – IRA are $503,718.

Table 40: Curtailed Intermittent Energy, Annual MWh (Scenario 2– IRA)

	Existing Wind	**Existing Solar**	**Generic Wind**	**Generic Solar**	**Total**
2024	0	0	0	0	**0**
2025	0	0	0	0	**0**
2026	0	75	0	0	**75**
2027	0	0	0	0	**0**
2028	0	287	0	0	**287**
2029	0	583	0	1,197	**1,780**
2030	0	376	0	203	**579**
2031	0	632	154	3,633	**4,419**
RAP Total	**0**	**1,953**	**154**	**5,033**	**7,140**

Table 41: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 2 – IRA)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	0	75	0	0
2027	0	0	0	0
2028	7	280	0	0
2029	1	1,572	0	207
2030	0	579	0	0
2031	0	3,902	13	504
RAP Total	**8**	**6,408**	**13**	**711**

The following table reflects PPA pricing, penalties, and taxes.

Table 42: Estimated PPA Curtailment Costs and Penalties, Real (2023) $ (Scenario 2 – IRA)

	Wind ($)	Solar ($)
2024	0	0
2025	0	0
2026	0	$2,816
2027	0	$0
2028	0	$9,596
2029	0	$122,947
2030	0	$29,692
2031	$8,765	$329,902
RAP Total	**$8,765**	**$494,953**

Scenario 2 (IRA) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the POI, resulting from the scenario are shown in the table below.

Table 43: Transmission Interconnection & Network Upgrade Expenses Real (2023) $ (Scenario 2 – IRA)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2026	10	Battery	$1.40	$2.88	
2029	50	Battery	$1.40	$2.88	
2029	100	Wind		$2.88	
2030	100	Wind		$2.88	
2030	100	Battery	$1.40	$2.88	
2036	100	Wind + Battery		$2.88	
2042	100	Wind		$10.20	
2042	100	Wind		$2.88	

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Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2042	100	Wind		$2.88	
Western Colorado (WCO) Transmission Area					
2028	290	Gas	$1.50	$4.20	
Wyoming (WYO) Transmission Area					
2028	100	Wind		$12.00	$109.00
2028	100	Wind		$4.20	
2030	100	Wind		$4.20	
2042	100	Wind		$4.20	$26.00
2043	100	Wind + Battery		$4.50	
New Mexico (NM) Transmission Area)					
2026	50	Battery		$2.88	
2029	100	Solar		$1.68	
2031	100	Wind + Battery		$2.88	$238.50
2031	100	Wind + Battery		$2.88	
2032	100	Wind + Battery		$2.88	

Scenario 2 (IRA) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources' ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 44: Planning Reserve Margin, % Annual (Scenario2 – IRA)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	49%	47%	54%	50%	55%	60%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 45: Loss of Load Probability, Hours (Scenario 2 – IRA)

2024	2025	2026	2027	2028	2029	2030	2031
0	1	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

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Table 46: Expected Unserved Energy, Annual MWh (Scenario 2 – IRA)

2024	2025	2026	2027	2028	2029	2030	2031
0	1	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 2 – IRA)

Section 3.11.14. of the 2020 ERP Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment ~~G-1~~ LKT-29) and ELCCs continue to decline with the addition of intermittent resources. In Scenario 2 – IRA, 200 MW of short duration storage, 110 MW of long duration storage and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable resources to replace the dispatchable resources retiring during the RAP and support integration of intermittent resources.

Scenario 2 (IRA) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

*Table 47: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 2– IRA)*Table 47~~Table 46~~ represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all twelve EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours.

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Table 47: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 2– IRA)

Event (Season/Year)	Date	Hour
All Event Periods	N/A	N/A

Table 48~~Table 47~~ represents any EUE identified by hour in the twelve EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

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Table 48: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 2 – IRA)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All Event Periods	N/A	N/A	N/A	N/A	N/A	N/A

Tri-State also analyzed the post-RAP period EWE and all Level II metrics were met.

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Analysis of Market Purchases and Available Capacity (Scenario 2 –IRA)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the "analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access."

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
  - NM Market HE 2 to HE 6 and HE 11 to 15
  - 1 day in event no market depth
- Summer:
  - ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
  - 1 day in event no market depth

In the EWE analysis for Scenario 2 – IRA, the market was used for 5.5 GWh in 97 hours during the January EWE events between 2026-2031. The market was used for 11.5 GWh in 79 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics.

Market purchases during these limited hours were confirmed to not lean on the market for capacity.

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3. Early Springerville 3 Retirement Scenario (ESPV3)

Assumptions unique to each scenario are identified in Attachment ~~B-3~~ LKT-10.

Scenario 3 (ESPV3) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

Table 49: Expansion Plan (Scenario 3 – ESPV3)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	Solar[83]	West Colorado	140	1	140
2028	4hr – Battery	West Colorado	50	1	50
	NGCC with CCS[84]	West Colorado	290	1	290
2030	Wind/Battery	East Colorado	100	1	100
2031	4hr – Battery	West Colorado	50	1	50
	Wind/Battery	New Mexico	100	2	200
	100hr – Iron Air Battery	East Colorado	100	1	100
2036	Wind	East Colorado	100	1	100
2037	Wind	East Colorado	100	2	200
2039	Wind/Battery	Wyoming / W. Neb.	100	1	100
2040	Wind/Battery	Wyoming / W. Neb.	100	1	100
2041	Wind	Wyoming / W. Neb.	100	2	200
2042	Wind/Battery	East Colorado	100	3	300
2043	Solar	New Mexico	100	1	100
	Wind/Battery	Wyoming / W. Neb	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:[85]

- All plans include applicable Colorado energy efficiency targets in base assumptions.[86]
- Low New Mexico Energy Efficiency was selected in the expansion plan of Scenario 3 – ESPV3 in 2040.
- Low Wyoming Energy Efficiency was selected in the expansion plan of Scenario 3 – ESPV3 in 2040.

[83] This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.
[84] NGCC installed in 2028 and CCS conversion startup anticipated in 2031.
[85] Commission Rule 3605(c)(I)(I).
[86] 2020 ERP Settlement Agreement at Section 3.11.6.

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The expansion plan also included the following Demand Response (DR) levels by region:[87]

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.[88]
- 84 MW of New Mexico Demand Response was selected in the expansion plan of Scenario 3 – ESPV3 starting in 2031.
- 52 MW of Wyoming Demand Response was selected in the expansion plan of Scenario 3 – ESPV3 starting in 2031

Unit retirements selected in the modeling are shown in the following table.[89]

Table 50: Modeled Retirements (Scenario 3 –ESPV3)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	1/1/2031

Resulting system capacity and energy mix, based on the modeling are shown below.

[87] Commission Rule 3605(c)(I)(I).
[88] 2020 ERP Settlement Agreement at Section 3.11.8.
[89] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners").

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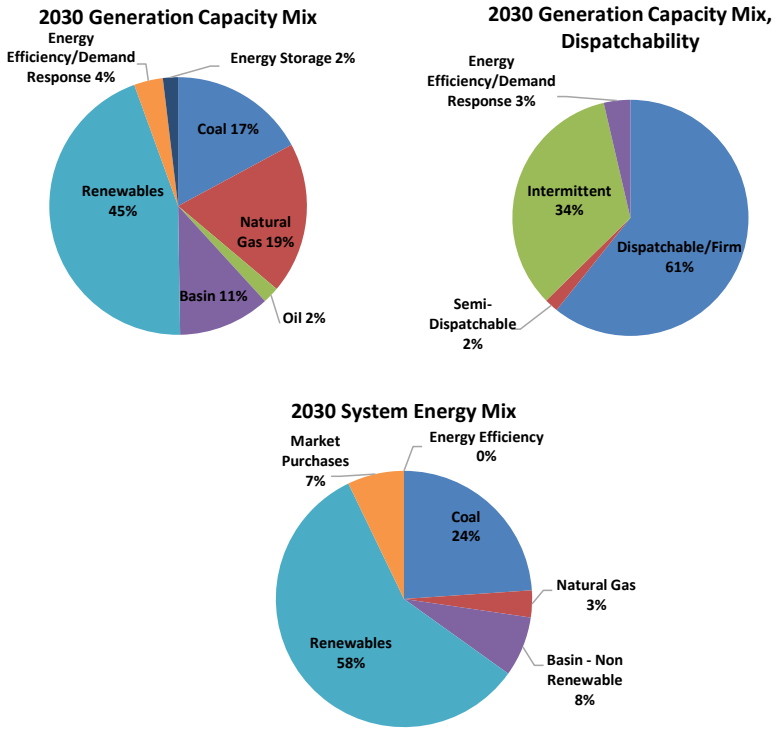
Figure 6: Projected Tri-State System Resource Mix 2030 (Scenario 3 – ESPV3)[90, 91, 92]



[90] "Renewables" category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[91] Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.
[92] System Energy Mix reflects sales to Members and non-Members.

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Table 51: Projected Annual Capacity Factors for Thermal Resources (Scenario 3 – ESPV3)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	16%	0%	0%	0%	0%	0%	0%
Craig 2	98%	9%	34%	23%	20%	0%	0%	0%
Craig 3	79%	14%	22%	16%	0%	0%	0%	0%
LRS 2	93%	89%	71%	71%	71%	69%	63%	64%
LRS 3	75%	64%	70%	60%	58%	51%	48%	54%
SPV 3	72%	67%	43%	42%	43%	37%	44%	0%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	1%	0%	0%	0%	0%	0%	0%
Shafer	24%	11%	1%	0%	0%	0%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	29%	28%	20%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 52: Forecasted Energy Sales and Purchases (Scenario 3 – ESPV3)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,505	1,506	3,044	2,850	3,312	2,712	3,018	3,098
Purchases (GWh)	355	946	545	852	623	722	1,004	1,167

Scenario 3 (ESPV3) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 53: Environmental Impact - System Wide (Scenario 3 – ESPV3)[93]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2024	15,839,102	7,764	10,741	0.0383	704	6,772,194,117	32,129
2025	10,919,154	5,447	6,450	0.0245	513	4,099,792,207	19,995
2026[94]	8,469,494	4,985	5,874	0.0224	409	3,579,117,374	17,834
2027	7,999,822	4,707	5,493	0.0203	381	3,238,736,958	16,456
2028	7,332,465	4,209	4,671	0.0177	380	3,069,522,031	14,392
2029	6,711,585	3,942	4,388	0.0160	333	2,727,887,902	12,834
2030	5,808,252	3,998	4,428	0.0157	345	2,680,280,773	13,221

[93] Commission Rule 3605(c)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[94] Load reduced due to partial requirements contracts in 2026 forward.

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2031	3,936,370	3,337	3,931	0.0126	201	2,399,903,106	9,134
2032	3,835,588	3,290	3,891	0.0121	193	2,324,000,130	8,911
2033	3,950,512	3,360	3,986	0.0124	198	2,369,472,111	9,166
2034	3,982,627	3,382	4,019	0.0125	199	2,377,578,327	9,240
2035	3,951,406	3,370	4,016	0.0122	196	2,345,304,444	9,165
2036	4,026,737	3,423	4,077	0.0125	199	2,380,608,886	9,347
2037	4,060,785	3,435	4,078	0.0128	203	2,416,104,215	9,428
2038	4,051,989	3,435	4,086	0.0126	201	2,399,586,707	9,406
2039	4,098,100	3,460	4,108	0.0129	204	2,432,494,784	9,515
2040	4,094,950	3,467	4,124	0.0128	203	2,419,226,942	9,510
2041	4,088,441	3,459	4,110	0.0128	203	2,420,432,239	9,492
2042	4,131,169	3,499	4,190	0.0127	201	2,399,136,160	9,588
2043	4,099,795	3,483	4,170	0.0125	199	2,380,264,589	9,520
Total	**115,388,344**	**79,453**	**94,833**	**0.318**	**5,667**	**57,231,644,003**	**248,282**
Pounds/Gallons per MWh[95]	797	0.55	0.65	0.000002	0.04	198	1.890

Table 54: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 3 – ESVP3)

Year	Annual Social Cost of Carbon
2024	$1,391,004,648
2025	$995,703,293
2026	$802,524,764
2027	$787,475,263
2028	$748,555,145
2029	$710,424,496
2030	$637,326,494
2031	$447,936,321
2032	$452,541,393
2033	$483,159,901
2034	$504,813,123
2035	$518,969,660
2036	$547,880,617
2037	$572,269,158
2038	$591,341,514
2039	$619,224,271
2040	$640,518,145
2041	$658,868,730
2042	$693,146,438
2043	$709,300,764

[95] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

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Table 55: Social Cost of Methane Nominal Dollars – System Wide (Scenario 3 – ESPV3)

Year	Annual Social Cost of Methane
2024	$82,855,374
2025	$54,041,930
2026	$50,535,594
2027	$48,861,264
2028	$44,684,056
2029	$41,645,072
2030	$44,814,668
2031	$32,432,806
2032	$33,124,403
2033	$35,647,372
2034	$37,577,397
2035	$38,954,135
2036	$41,497,117
2037	$43,705,831
2038	$45,503,307
2039	$48,013,151
2040	$50,034,448
2041	$51,880,457
2042	$55,205,912
2043	$55,991,156

Table 56: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 3 – ESPV3)

Year	Target[96]	Forecast
2025	26%	47%
2026	36%	60%
2027	46%	67%
2030	80%	85%

See Appendix D for detailed GHG emissions calculations for the scenario.

Scenario 3 (ESPV3) – Financial Analysis

The present value revenue requirement (PVRR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

[96] 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.

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Table 57: Total Financial (Scenario 3 – ESPV3)

$, Millions	Scenario PVRR (2023 WACC 4.12%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Scenario PVRR inclusive of SCoC NPV	Scenario PVRR inclusive of SCoC NPV & SCoM NPV
	$17,304.2	$10,789.6	$734.8	$28,093.8	$28,828.6
Expansion Plan CapEx + IDC: Generation (Nominal $)	$1,983.6				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$590.6				

Table 58: Annual Financial (Nominal $) (Scenario 3 – ESPV3)

Year	Total Annual Revenue Requirement ($, Millions)
2024	$1,016
2025	$988
2026	$904
2027	$962
2028	$1,060
2029	$1,178
2030	$1,441
2031	$1,335
2032	$1,345
2033	$1,361
2034	$1,382
2035	$1,404
2036	$1,428
2037	$1,450
2038	$1,474
2039	$1,495
2040	$1,514
2041	$1,529
2042	$1,546
2043	$1,562

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Financial analysis of the of the scenario under the extreme-weather event stress is provided below.

*Table 59~~XX~~: Total Financial Under **EWE** Sensitivity (Scenario ~~13 – BAU~~ESPV3)*

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Scenario PVRR ($, Millions) (2023 WACC 4.12%)

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$17,~~472.1~~275.6

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 3 – ESPV3 dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin. Thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the ITC they do not have a PTC penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 3 – ESPV3 are $520,955.

Table 60: Curtailed Intermittent Energy, Annual MWh (Scenario 3 – ESPV3)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Total
2024	0	0	0	0	**0**
2025	0	0	0	0	**0**
2026	0	5,640	0	0	**5,640**
2027	0	3,345	0	0	**3,345**
2028	0	2,732	0	0	**2,732**
2029	0	2,193	0	0	**2,193**
2030	0	0	0	0	**0**
2031	0	0	44	0	**44**
RAP Total	**0**	**13,910**	**44**	**0**	**13,954**

Table 61: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 3 – ESPV3)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	112	4,447	20	1,061
2027	0	3,025	44	276
2028	25	2,275	16	416
2029	0	2,123	6	64
2030	0	0	0	0
2031	0	44	0	0
RAP Total	**137**	**11,914**	**86**	**1,817**

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The following table reflects PPA pricing, penalties, and taxes.

Table 62: Estimated PPA Curtailment Costs and Penalties, Real (2023) $ (Scenario 3 – ESPV3)

	Wind ($)	Solar ($)
2024	$0	$0
2025	$0	$0
2026	$0	$208,309
2027	$0	$124,914
2028	$0	$102,651
2029	$0	$82,570
2030	$0	$0
2031	$2,511	$0
RAP Total	**$2,511**	**$518,444**

Scenario 3 (ESPV3) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the POI, resulting from the scenario are shown in the table below.

Table 63: Transmission Interconnection & Network Upgrade Expenses Real (2023) $ (Scenario 3 – ESPV3)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2030	100	Wind + Battery		$2.88	
2031	100	Battery	$1.40	$2.88	
2036	100	Wind		$10.20	
2037	100	Wind		$2.88	
2037	100	Wind		$2.88	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
Western Colorado (WCO) Transmission Area					
2028	290	Gas	$1.50	$4.20	
2028	50	Battery	$1.40	$2.88	
2031	50	Battery	$1.40	$2.88	
Wyoming (WYO) Transmission Area					
2039	100	Wind + Battery		$12.00	$109.00
2040	100	Wind + Battery		$4.20	
2041	100	Wind		$4.20	
2041	100	Wind		$4.20	$26.00
2043	100	Wind + Battery		$4.20	
New Mexico (NM) Transmission Area)					

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2031	100	Wind + Battery		$2.88	$238.50
2031	100	Wind + Battery		$2.88	
2043	100	Solar		$1.68	

Scenario 3 (ESPV3) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources' ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 64: Planning Reserve Margin, % Annual (Scenario 3 –ESPV3)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	46%	43%	52%	44%	47%	48%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 65: Loss of Load Probability, Hours (Scenario 3 – ESPV3)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

Table 66: Expected Unserved Energy, Annual MWh (Scenario 3 – ESPV3)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 3 – ESPV3)

Section 3.11.14. of the 2020 ERP Phase I Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment ~~G-1~~ LKT-29) and ELCCs continue to decline with the addition of intermittent resources. In Scenario 3 – ESPV3, 250 MW of 4-hr storage, 100 MW of long-duration storage, and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable

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resources to replace the dispatchable resources retiring during the RAP and support integration of intermittent resources.

Scenario 3 (ESPV3) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

Table 67~~Table 65~~ represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all 12 EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours.

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Table 67: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 3 – ESPV3)

Event (Season/Year)	Date	Hour
All EWE Periods	N/A	N/A

Table 68~~Table 66~~ represents any EUE identified by hour in the 12 EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

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Table 68: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 3 – ESPV3)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All EWE Periods	N/A	N/A	N/A	N/A	N/A	N/A

Tri-State also analyzed the post-RAP period EWE and all Level II metrics were met.

Analysis of Market Purchases and Available Capacity (Scenario 3 – ESPV3)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the "analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access."

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
  - NM Market HE 2 to HE 6 and HE 11 to 15
  - 1 day in event no market depth
- Summer:
  - ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
  - 1 day in event no market depth

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In the EWE analysis for Scenario 3—ESPV3, the market was used for 7.4 GWh in 131 hours during the January EWE events between 2026-2031. The market was used for 14.3 GWh in 85 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics. Market purchases during these limited hours were confirmed to not lean on the market for capacity.

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4. System-wide Emissions Reduction Scenario (SWER) LKT-10

Assumptions unique to each scenario are identified in Attachment ~~B-3~~.

Scenario 4 (SWER) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

Table 69: Expansion Plan (Scenario 4 – SWER)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	Solar[97]	West Colorado	140	1	140
2029	NGCC with CCS[98]	West Colorado	290	1	290
2030	Wind/Battery	East Colorado	100	1	100
2033	Wind	New Mexico	100	1	100
	Wind/Battery	New Mexico	100	1	100
2034	Wind/Battery	East Colorado	100	1	100
2036	Wind/Battery	East Colorado	100	1	100
2037	Wind/Battery	New Mexico	100	1	100
2038	Wind/Battery	East Colorado	100	1	100
2040	Wind/Battery	Wyoming / W. Neb.	100	1	100
2041	Wind	Wyoming / W. Neb.	100	2	200
2042	Wind	East Colorado	100	1	100
	Wind/Battery	East Colorado	100	2	200
2043	Solar – Build Transfer	West Colorado	100	3	300
	Solar	New Mexico	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:[99]

- All plans include applicable Colorado energy efficiency targets in base assumptions.[100]

[97] This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.
[98] NGCC installed in 2029 and CCS conversion startup anticipated in 2031.
[99] Commission Rule 3605(c)(I)(I).
[100] 2020 ERP Settlement Agreement at Section 3.11.6.

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The expansion plan also included the following Demand Response (DR) levels by region:[101]

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.[102]
- 39 MW of Wyoming low level Demand Response was selected in the expansion plan of Scenario 4 – SWER starting in 2030.
- 117 MW New Mexico moderate level Demand Response was selected in the expansion plan of Scenario 4 – SWER starting in 2039.

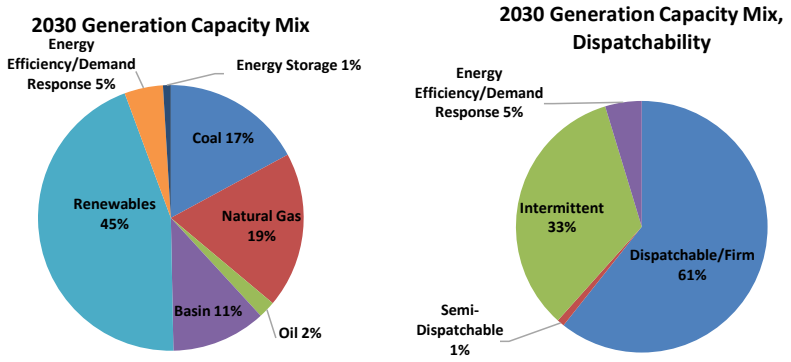
Unit retirements selected in the modeling are shown in the following table.[103]

Table 70: Modeled Retirements (Scenario 4 – SWER)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	1/1/2037

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 7: Projected Tri-State System Resource Mix 2030 (Scenario 4- SWER)[104, 105, 106]



[101] Commission Rule 3605(c)(I)(I).
[102] 2020 ERP Settlement Agreement at Section 3.11.8.
[103] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners").
[104] "Renewables" category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[105] Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.
[106] System Energy Mix reflects sales to Members and non-Members.

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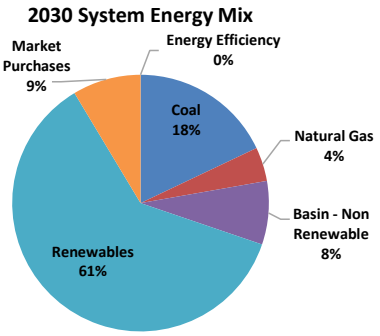

Table 71: Projected Annual Capacity Factors for Thermal Resources (Scenario 4 - SWER)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	17%	0%	0%	0%	0%	0%	0%
Craig 2	98%	16%	26%	13%	36%	0%	0%	0%
Craig 3	79%	13%	25%	19%	0%	0%	0%	0%
LRS 2	93%	89%	71%	72%	71%	67%	41%	16%
LRS 3	75%	64%	69%	57%	58%	50%	30%	13%
SPV 3	72%	67%	43%	42%	45%	36%	37%	36%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	1%	0%	0%	0%	0%	0%	0%
Shafer	27%	11%	0%	1%	1%	0%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	0%	29%	24%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 72: Forecasted Energy Sales and Purchases (Scenario 4 – SWER)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,561	1,496	3,063	2,872	2,902	2,615	2,245	1,687
Purchases (GWh)	346	941	550	912	748	658	1,154	1,265

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Scenario 4 (SWER) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 73: Environmental Impact - System Wide (Scenario 4 - SWER)[107]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2024	15,863,704	7,761	10,763	0.0383	705	6,793,247,708	32,133
2025	10,919,812	5,420	6,407	0.0244	516	4,098,699,996	19,995
2026[108]	8,477,517	5,026	5,962	0.0225	404	3,583,422,154	17,903
2027	7,972,529	4,721	5,542	0.0202	374	3,210,051,302	16,365
2028	7,358,120	4,302	4,787	0.0182	377	2,927,811,446	14,845
2029	6,573,723	3,872	4,303	0.0156	327	2,680,149,760	12,556
2030	4,514,050	3,295	3,646	0.0108	262	1,990,503,327	10,296
2031	3,157,659	2,666	2,918	0.0062	212	1,818,549,023	7,869
2032	3,203,866	2,736	3,048	0.0067	205	1,845,960,399	7,905
2033	3,208,225	2,703	2,972	0.0063	213	1,829,638,245	7,985
2034	3,226,798	2,710	2,973	0.0064	215	1,851,008,307	8,024
2035	3,254,631	2,763	3,078	0.0069	208	1,876,225,341	8,012
2036	3,315,308	2,850	3,219	0.0077	200	1,929,252,664	8,076
2037	3,614,749	3,177	3,763	0.0110	179	2,178,755,684	8,428
2038	3,622,455	3,180	3,760	0.0111	181	2,189,879,374	8,448
2039	3,611,385	3,180	3,770	0.0110	178	2,169,009,462	8,423
2040	3,596,535	3,182	3,782	0.0108	176	2,145,151,059	8,397
2041	3,613,093	3,188	3,781	0.0109	178	2,160,677,499	8,433
2042	3,585,634	3,191	3,825	0.0104	171	2,091,352,778	8,369
2043	3,610,874	3,196	3,807	0.0107	175	2,135,484,251	8,432
Total	**106,300,669**	**73,119**	**86,106**	**0.266**	**5,456**	**51,504,829,781**	**230,898**
Pounds/Gallons per MWh[109]	734	0.50	0.59	0.000002	0.04	178	1.757

[107] Commission Rule 3605(c)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.
[108] Load reduced due to partial requirements contracts in 2026 forward.
[109] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

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Table 74: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 4 – SWER)

Year	Annual Social Cost of Carbon
2024	$1,393,165,248
2025	$995,763,266
2026	$803,284,931
2027	$784,788,638
2028	$751,174,190
2029	$695,831,712
2030	$495,316,652
2031	$359,323,495
2032	$378,007,746
2033	$392,375,842
2034	$409,008,952
2035	$427,456,666
2036	$451,083,112
2037	$509,411,285
2038	$528,656,041
2039	$545,681,555
2040	$562,557,798
2041	$582,264,404
2042	$601,614,118
2043	$624,713,086

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Table 75: Social Cost of Methane Nominal Dollars – System Wide (Scenario 4 - SWER)

Year	Annual Social Cost of Methane
2024	$82,867,370
2025	$54,042,415
2026	$50,729,638
2027	$48,591,361
2028	$46,092,106
2029	$40,743,674
2030	$34,900,045
2031	$27,942,182
2032	$29,384,966
2033	$31,054,907
2034	$32,634,103
2035	$34,054,127
2036	$35,858,109
2037	$39,068,247
2038	$40,865,813
2039	$42,504,595
2040	$44,182,882
2041	$46,091,559
2042	$48,190,439
2043	$49,596,337

Table 76: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 4 - SWER)

Year	Target[110]	Forecast
2025	26%	47%
2026	36%	60%
2027	46%	68%
2030	80%	82%

Table 77: System-wide GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 4 - SWER)

Year	Target[111]	Forecast
2027	20.9%	44%
2028	33.2%	44%
2029	45.4%	51%
2030	57.7%	61%
2031	70%	73%

See Appendix D for detailed GHG emissions calculations for the scenario.

[110] 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.
[111] 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.

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Scenario 4 (SWER) – Financial Analysis

The present value revenue requirement (PVRR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

Table 78: Total Financial (Scenario 4 - SWER)

$, Millions	Scenario PVRR (2023 WACC 4.12%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Scenario PVRR inclusive of SCoC NPV	Scenario PVRR inclusive of SCoC NPV & SCoM NPV
	$17,343.9	$9,899.2	$679.1	$27,243.1	$27,922.2
Expansion Plan CapEx + IDC: Generation (Nominal $)	$1,694.1				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$546.3				

Table 79: Annual Financial (Nominal $) (Scenario 4 - SWER)

Year	Total Annual Revenue Requirement ($, Millions)
2024	$1,016
2025	$978
2026	$894
2027	$957
2028	$1,003
2029	$1,092
2030	$1,232
2031	$1,270
2032	$1,434
2033	$1,459
2034	$1,497
2035	$1,512
2036	$1,534
2037	$1,421
2038	$1,445
2039	$1,497
2040	$1,518
2041	$1,536
2042	$1,557
2043	$1,730

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Financial analysis of the of the scenario under the extreme-weather event stress is provided below.

*Table 80~~XX~~: Total Financial Under **EWE** Sensitivity (Scenario 4 – SWER)*

Scenario PVRR ($, Millions) (2023 WACC 4.12%)
$17,~~275.6~~315.4

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Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 4 – SWER dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin. Thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the ITC they do not have a PTC penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 4 – SWER are $531,366.

Table 81: Curtailed Intermittent Energy, Annual MWh (Scenario 4 - SWER)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Total
2024	0	0	0	0	**0**
2025	0	0	0	0	**0**
2026	0	5,854	0	0	**5,854**
2027	0	3,378	0	0	**3,378**
2028	0	2,821	0	0	**2,821**
2029	0	2,193	0	0	**2,193**
2030	0	0	0	0	**0**
2031	0	0	0	0	**0**
RAP Total	**0**	**14,246**	**0**	**0**	**14,246**

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Table 82: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 4 - SWER)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	258	4,515	20	1,061
2027	0	3,057	45	276
2028	114	2,275	16	416
2029	0	2,123	6	64
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**372**	**11,970**	**87**	**1,817**

The following table reflects PPA pricing, penalties, and taxes.

Table 83: Estimated PPA Curtailment Costs and Penalties, Real (2023) $ (Scenario 4 - SWER)

	Wind ($)	Solar ($)
2024	$0	$0
2025	$0	$0
2026	$0	$216,270
2027	$0	$126,321
2028	$0	$106,117
2029	$0	$82,658
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$531,366**

Scenario 4 (SWER) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the POI, resulting from the scenario are shown in the table below.

Table 84: Transmission Interconnection & Network Upgrade Expenses Real (2023) $ (Scenario 4 - SWER)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2030	100	Wind + Battery		$2.88	
2034	100	Wind + Battery		$2.88	
2036	100	Wind + Battery		$2.88	
2038	100	Wind + Battery		$2.88	
2042	100	Wind		$2.88	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	

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Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Western Colorado (WCO) Transmission Area					
2029	290	Gas	$1.50	$4.20	
2043	100	Solar		$2.88	
2043	100	Solar		$2.88	
2043	100	Solar		$1.68	
Wyoming (WYO) Transmission Area					
2040	100	Wind + Battery		$12.00	$109.00
2041	100	Wind		$4.20	
2041	100	Wind		$4.20	
New Mexico (NM) Transmission Area)					
2033	100	Wind		$2.88	$238.50
2033	100	Wind + Battery		$2.88	
2037	100	Wind + Battery		$2.88	
2043	100	Solar		$1.68	

Scenario 4 (SWER) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources' ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 85: Planning Reserve Margin, % Annual (Scenario 4 - SWER)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	46%	43%	35%	42%	46%	45%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 86: Loss of Load Probability, Hours (Scenario 4 - SWER)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

Table 87: Expected Unserved Energy, Annual MWh (Scenario 4 - SWER)

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2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 4 - SWER)

Section 3.11.14. of the 2020 ERP Phase I Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment ~~G-1)~~ LKT-29 and ELCCs continue to decline with the addition of intermittent resources. In Scenario 4 – SWER, 50 MW of short duration storage and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable resources to replace the dispatchable resources retiring during the RAP and support integration of intermittent resources.

Scenario 4 (SWER) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

Table 88~~Table 85~~ represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all 12 EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours.

Table 88: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 4 – SWER)

Event (Season/Year)	Date	Hour
All EWE Periods	N/A	N/A

Table 89~~Table 86~~ represents any EUE identified by hour in the 12 EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

Table 89: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 4 – SWER)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All EWE Periods	N/A	N/A	N/A	N/A	N/A	N/A

Tri-State also analyzed the post-RAP period EWE and all Level II metrics were met.

Analysis of Market Purchases and Available Capacity (Scenario 4 – SWER)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the "analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access."

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
  - NM Market HE 2 to HE 6 and HE 11 to 15

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    - 1 day in event no market depth
- Summer:
    - ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
    - 1 day in event no market depth

In the EWE analysis for Scenario 4 – SWER, the market was used for 7.3 GWh in 133 hours during the January EWE events between 2026-2031. The market was used for 17 GWh in 99 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics. Market purchases during these limited hours were confirmed to not lean on the market for capacity.

5. Aggressive Colorado Emissions Reductions Scenario (ACER)

Assumptions unique to each scenario are identified in Attachment ~~B-3.~~ LKT-10

Scenario 5 (ACER) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

Table 90: Expansion Plan (Scenario 5 - ACER)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	Solar[112]	West Colorado	140	1	140
2029	Wind/Battery	East Colorado	100	1	100
2030	NGCC with CCS[113]	West Colorado	290	1	290
2031	Wind/Battery	Wyoming / W. Neb.	100	1	100
2033	Wind	East Colorado	100	2	200
2035	Wind/Battery	East Colorado	100	1	100
2037	Wind/Battery	East Colorado	100	1	100
	Wind/Battery	New Mexico	100	2	200
2040	Wind/Battery	Wyoming / W. Neb.	100	2	200
	Solar – Build Transfer	West Colorado	100	2	200
2042	Wind/Battery	East Colorado	100	4	400
	Wind/Battery	Wyoming / W. Neb.	100	3	300
2043	Wind/Battery	Wyoming / W. Neb.	100	1	100
	Solar	New Mexico	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:[114]

- All plans include applicable Colorado energy efficiency targets in base assumptions.[115]
- Low New Mexico Energy Efficiency was selected in the expansion plan of Scenario 5 – ACER in 2040.
- Low Wyoming Energy Efficiency was selected in the expansion plan of Scenario 5 – ACER in 2040.

[112] This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.
[113] NGCC installed in 2030 and CCS conversion startup anticipated in 2031.
[114] Commission Rule 3605(c)(I)(I).
[115] 2020 ERP Settlement Agreement at Section 3.11.6.

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The expansion plan also included the following Demand Response (DR) levels by region:[116]

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.[117]
- 52 MW of Wyoming Demand Response was selected in the expansion plan of Scenario 5 - ACER in 2038
- 84 MW of New Mexico Demand Response was selected in the expansion plan of Scenario 5 – ACER starting in 2042.

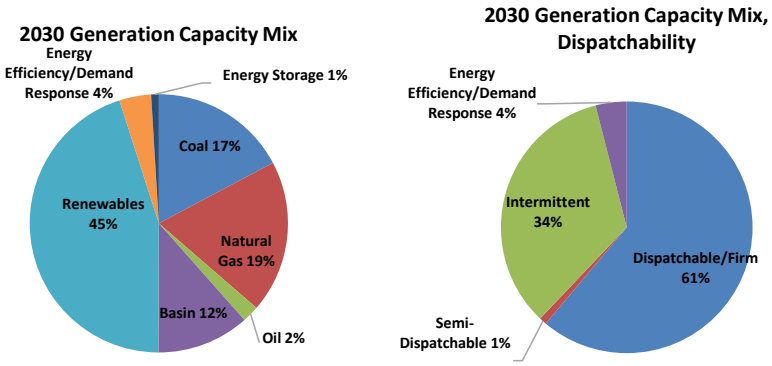
Unit retirements selected in the modeling are shown in the following table.[118]

Table 91: Modeled Retirements (Scenario 5 - ACER)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	1/1/2037
LRS 2 (TS portion)	241	Coal	1/1/2042

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 8: Projected Tri-State System Resource Mix 2030 (Scenario 5 - ACER)[119, 120, 121]



[116] Commission Rule 3605(c)(I)(I).
[117] 2020 ERP Settlement Agreement at Section 3.11.8.
[118] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners").
[119] "Renewables" category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[120] Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.
[121] System Energy Mix reflects sales to Members and non-Members.

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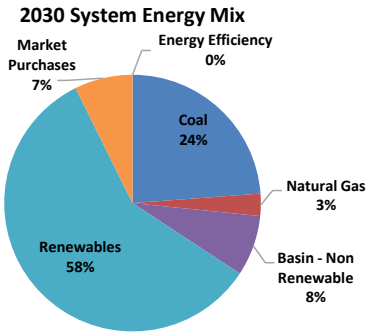

Table 92: Projected Annual Capacity Factors for Thermal Resources (Scenario 5 - ACER)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	16%	0%	0%	0%	0%	0%	0%
Craig 2	98%	9%	17%	4%	9%	0%	0%	0%
Craig 3	79%	14%	15%	11%	0%	0%	0%	0%
LRS 2	93%	89%	86%	78%	75%	71%	69%	69%
LRS 3	75%	64%	55%	48%	43%	40%	40%	45%
SPV 3	72%	67%	43%	42%	42%	36%	44%	43%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	1%	0%	0%	0%	0%	0%	0%
Shafer	24%	11%	1%	1%	1%	1%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	0%	0%	16%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 93: Forecasted Energy Sales and Purchases (Scenario 5 – ACER)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,508	1,506	2,719	2,521	2,453	2,347	2,911	3,587
Purchases (GWh)	352	946	641	985	803	854	1,020	776

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Scenario 5 (ACER) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 94: Environmental Impact - System Wide (Scenario 5 - ACER)[122]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2024	15,841,198	7,764	10,744	0.0383	704	6,774,266,318	32,133
2025	10,919,154	5,447	6,450	0.0245	513	4,099,792,207	19,995
2026[123]	8,046,894	4,781	5,543	0.0211	393	3,336,852,935	16,657
2027	7,524,321	4,471	5,149	0.0187	359	2,957,263,352	15,143
2028	6,758,931	4,045	4,479	0.0164	340	2,603,401,641	13,418
2029	6,279,584	3,827	4,253	0.0150	303	2,351,374,862	12,230
2030	5,720,642	3,969	4,393	0.0154	340	2,617,482,127	13,065
2031	5,621,064	3,993	4,418	0.0159	364	3,205,678,404	13,331
2032	5,229,420	3,827	4,281	0.0147	330	2,990,089,809	12,392
2033	5,542,856	3,963	4,395	0.0157	357	3,162,785,437	13,164
2034	5,600,099	3,999	4,444	0.0158	359	3,185,362,689	13,291
2035	5,341,998	3,895	4,362	0.0153	335	3,057,746,388	12,644
2036	4,976,911	3,771	4,291	0.0144	297	2,858,196,567	11,765
2037	3,872,884	3,313	3,900	0.0123	197	2,353,044,102	8,984
2038	3,889,235	3,328	3,924	0.0123	197	2,350,104,263	9,021
2039	3,958,518	3,372	3,983	0.0125	199	2,378,852,575	9,176
2040	3,928,034	3,352	3,944	0.0125	200	2,381,909,167	9,114
2041	3,954,875	3,371	3,977	0.0125	199	2,380,272,599	9,172
2042	2,550,838	2,573	3,064	0.0065	119	1,575,749,975	6,087
2043	2,537,465	2,577	3,059	0.0065	118	1,562,045,832	6,084
Total	**118,094,923**	**79,640**	**93,054**	**0.316**	**6,224**	**58,182,271,249**	**256,864**
Pounds/Gallons per MWh[124]	816	0.55	0.64	0.000002	0.04	201	1.955

[122] Commission Rule 3605(c)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.
[123] Load reduced due to partial requirements contracts in 2026 forward.
[124] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

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Table 95: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 5 - ACER)

Year	Annual Social Cost of Carbon
2024	$1,391,188,757
2025	$995,703,293
2026	$762,481,386
2027	$740,668,558
2028	$690,004,358
2029	$664,696,921
2030	$627,713,272
2031	$639,644,830
2032	$616,992,472
2033	$677,908,422
2034	$709,833,808
2035	$701,607,194
2036	$677,161,912
2037	$545,789,145
2038	$567,589,551
2039	$598,133,480
2040	$614,409,701
2041	$637,343,954
2042	$427,991,342
2043	$439,003,933

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Table 96: Social Cost of Methane Nominal Dollars – System Wide (Scenario 5 - ACER)

Year	Annual Social Cost of Methane
2024	$82,865,100
2025	$54,041,930
2026	$47,200,356
2027	$44,961,643
2028	$41,658,773
2029	$39,685,014
2030	$44,283,639
2031	$47,333,383
2032	$46,063,578
2033	$51,195,405
2034	$54,050,793
2035	$53,741,866
2036	$52,234,099
2037	$41,644,283
2038	$43,640,015
2039	$46,305,451
2040	$47,955,236
2041	$50,131,697
2042	$35,047,588
2043	$35,786,521

Table 97: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 5 - ACER)

Year	Target[125]	Forecast
2025	47%	47%
2026	60%	66%
2027	67.8%	73%
2028	74.2%	76%
2029	80.6%	82%
2030	87.1%	88%
2031	90%	91%

See Appendix D for detailed GHG emissions calculations for the scenario.

Scenario 5 (ACER) – Financial Analysis

The present value revenue requirement (PVRR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

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[125] Modified targets per stakeholder-requested scenario assumptions identified in Attachment ~~B-3,~~ but still meets GHG reduction targets in 2020 ERP Settlement Agreement Sections 3.3.4. and 3.3.5.

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Table 98: Total Financial (Scenario 5 - ACER)

$, Millions	Scenario PVRR (2023 WACC 4.12%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Scenario PVRR inclusive of SCoC NPV	Scenario PVRR inclusive of SCoC NPV & SCoM NPV
	$17,208.2	$11,026.8	$758.1	$28,235.0	$28,993.1
Expansion Plan CapEx + IDC: Generation (Nominal $)	$1,635.9				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$623.0				

Table 99: Annual Financial (Nominal $) (Scenario 5 - ACER)

Year	Total Annual Revenue Requirement ($, Millions)
2024	$1,016
2025	$978
2026	$898
2027	$960
2028	$1,007
2029	$1,075
2030	$1,212
2031	$1,232
2032	$1,400
2033	$1,415
2034	$1,452
2035	$1,474
2036	$1,506
2037	$1,447
2038	$1,470
2039	$1,501
2040	$1,523
2041	$1,537
2042	$1,554
2043	$1,730

Financial analysis of the of the scenario under the extreme-weather event stress is provided below.

*Table 100: Total Financial Under **EWE** Sensitivity (Scenario 5 – ACER)*

Scenario PVRR ($, Millions) (2023 WACC 4.12%)
$17,180.6

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Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 5 - ACER dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin. Thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the ITC they do not have a PTC penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 5 – ACER are $544,004.

Table 101: Curtailed Intermittent Energy, Annual MWh (Scenario 5 - ACER)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Total
2024	0	0	0	0	**0**
2025	0	0	0	0	**0**
2026	0	5,613	0	0	**5,613**
2027	0	3,345	0	0	**3,345**
2028	0	2,732	0	0	**2,732**
2029	0	2,955	0	0	**2,955**
2030	0	0	0	0	**0**
2031	0	0	0	0	**0**
RAP Total	**0**	**14,645**	**0**	**0**	**14,645**

Table 102: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 5 - ACER)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	85	4,447	20	1,061
2027	0	3,025	44	276
2028	25	2,275	16	416
2029	0	2,767	18	170
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**110**	**12,514**	**98**	**1,923**

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The following table reflects PPA pricing, penalties, and taxes.

Table 103: Estimated PPA Curtailment Costs and Penalties, Real (2023) $ (Scenario 5 - ACER)

	Wind ($)	Solar ($)
2024	$0	$0
2025	$0	$0
2026	$0	$207,282
2027	$0	$125,001
2028	$0	$102,660
2029	$0	$109,061
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$544,004**

Scenario 5 (ACER) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the POI, resulting from the scenario are shown in the table below.

Table 104: Transmission Interconnection & Network Upgrade Expenses Real (2023) $ (Scenario 5 - ACER)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2029	100	Wind + Battery		$2.88	
2033	100	Wind		$2.88	
2033	100	Wind		$2.88	
2035	100	Wind + Battery		$2.88	
2037	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
Western Colorado (WCO) Transmission Area					
2030	290	Gas	$1.50	$4.20	
2040	100	Solar		$2.88	
2040	100	Solar		$2.88	
Wyoming (WYO) Transmission Area					
2031	100	Wind + Battery		$12.00	$109.00
2040	100	Wind + Battery		$4.20	
2040	100	Wind + Battery		$4.20	
2042	100	Wind + Battery		$4.20	$34.00
2042	100	Wind + Battery		$4.20	

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Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2042	100	Wind + Battery		$4.20	
2043	100	Wind + Battery		$4.20	
New Mexico (NM) Transmission Area)					
2037	100	Wind + Battery		$2.88	$238.50
2037	100	Wind + Battery		$2.88	
2043	100	Solar		$1.68	

Scenario 5 (ACER) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources' ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 105: Planning Reserve Margin, % Annual (Scenario 5 - ACER)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	46%	43%	35%	31%	44%	47%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 106: Loss of Load Probability, Hours (Scenario 5 - ACER)

2024	2025	2026	2027	2028	2029	2030	2031
1	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

Table 107: Expected Unserved Energy, Annual MWh (Scenario 5 - ACER)

2024	2025	2026	2027	2028	2029	2030	2031
2	0	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 5 - ACER)

Section 3.11.14. of the 2020 ERP Phase I Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment ~~G-1~~ LKT-29) and ELCCs continue to decline with the addition of intermittent resources. In Scenario

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5 – ACER, 100 MW of 4-hr storage and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable resources to replace the dispatchable resources retiring during the RAP and support integration of intermittent resources.

Scenario 5 (ACER) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

Table 108~~Table 104~~ represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all 12 EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours.

Table 108: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 5 - ACER)

Event (Season/Year)	Date	Hour
All EWE Periods	N/A	N/A

Table 109~~Table 105~~ represents any EUE identified by hour in the 12 EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

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Table 109: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 5 - ACER)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All EWE Periods	N/A	N/A	N/A	N/A	N/A	N/A

Tri-State also analyzed the post-RAP period EWE and, Level II metrics were not met in the latter part of the RAP for Scenario 5 – ACER. Scenario 5 – ACER did not meet Level 2 reliability metric thresholds:

- Six hours of LOLH in 2037 (which is beyond the three hours per year threshold); and
- Two hours of capacity lean on the market (which is beyond the zero-tolerance threshold), in the following hours and capacity amounts:
  - July 12, 2042 HE2, 40 MW; and
  - July 13, 2043 HE2, 29 MW.

Analysis of Market Purchases and Available Capacity (Scenario 5 – ACER)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the "analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access."

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
  - NM Market HE 2 to HE 6 and HE 11 to 15
  - 1 day in event no market depth

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- Summer:
  - ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
  - 1 day in event no market depth

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In the EWE analysis for Scenario 5 – ACER, the market was used for 6.4 GWh in 115 hours during the January EWE events between 2026-2031. The market was used for 12.5 GWh in 78 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics. Market purchases during these limited hours were confirmed to not lean on the market for capacity.

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Comparative Analysis

A comparative analysis of environmental, financial, and reliability results across each of the Phase I scenarios is provided below.

Environmental Analysis

The following tables identify each scenario's system-wide forecasted CO_2 and CH_4 emissions in 2025 and 2030.

Figure 9: Comparison of Forecasted CO_2 Emissions in 2025 and 2030, by Scenario

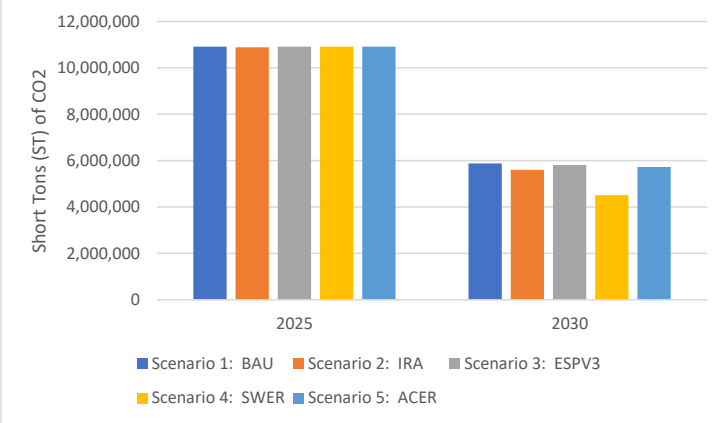
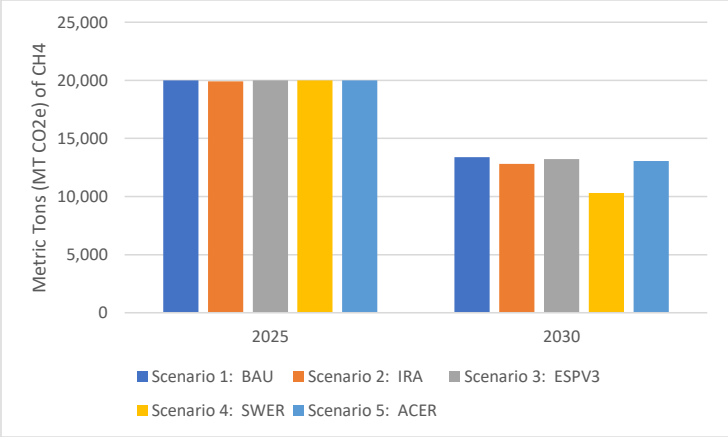


Figure 10: Comparison of Forecasted CH_4 Emissions in 2025 and 2030, by Scenario



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The following table identifies each scenario's forecasted achievements toward Colorado GHG reduction targets. As shown in Figure 9 and Table 110~~Table 106~~, all scenarios achieve a consistent level of CO_2 and GHG reductions in 2025. The trend of similar GHG reductions across all scenarios holds for 2026 and 2027 as well, with the exception of Scenario 5 (ACER) achieving slightly higher reductions earlier—a result of the underlying modeling input constraint requiring minimum emissions achievements for each year of the RAP (see Attachment LKT-10 ~~B-3~~ of the ERP Report (LKT-1). Those underlying constraints on emissions for Scenario 5 (ACER) result in significant reductions in the capacity factors for Craig 2 and LRS 3 starting in 2026 and result in the new gas plant not being utilized until 2030. Market sales are also reduced during the RAP under Scenario 5 (ACER). Notably, Scenario 2 (IRA), achieves the highest GHG reduction by 2030, 89%, as compared to the other scenarios as show in Table 110~~Table 106~~ and Figure 11.

Additional discussion of Tri-State's consideration of the environmental results of the scenario analyses can be found in the Executive Summary; and in the Financial Analysis section below, which scenario identifies PVRRs with SCoC and SCoM.

Table 110: Comparison of Scenario Achievements Toward Colorado GHG Reduction Targets

	2025	2026	2027	2030
Scenario 1: BAU	47%	60%	68%	86%
Scenario 2: IRA	47%	60%	67%	89%
Scenario 3: ESPV3	47%	60%	67%	85%
Scenario 4: SWER	47%	60%	68%	82%
Scenario 5: ACER	47%	66%	73%	88%

Figure 11: Comparison of Scenario Achievements Toward Colorado GHG Reduction Targets

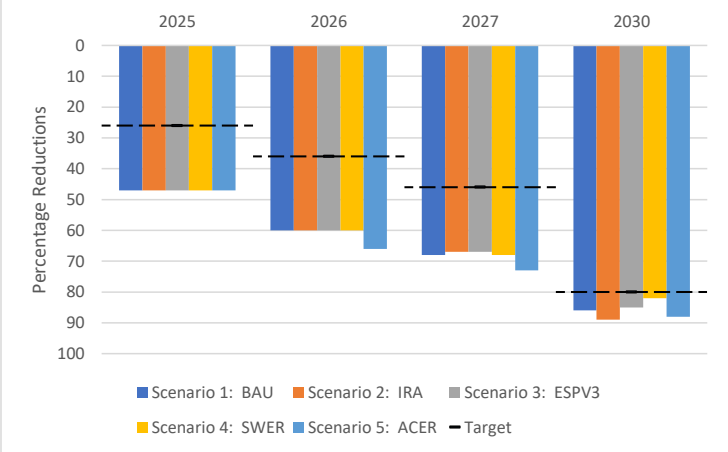

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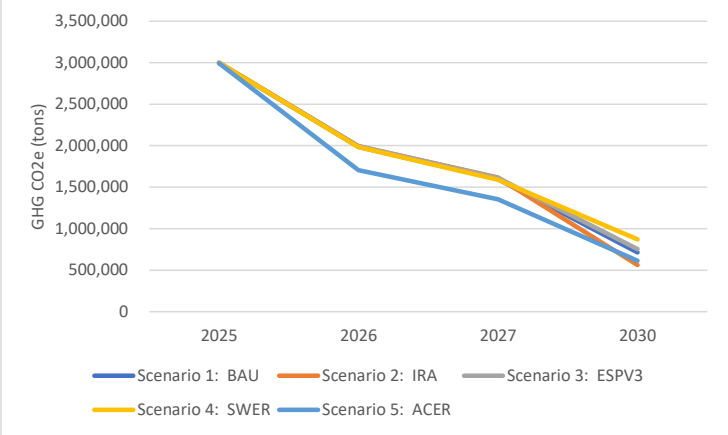
Figure 12: Comparison of Colorado CO2e



As shown in Figure 13 below, there is little deviation in the annual SCoC across the scenarios modeled, until after 2030. Scenario 1 (BAU) and Scenario 5 (ACER) have fairly similar SCoC levels in the early 2030s as Colorado greenhouse gas reduction levels are similar (roughly a 2 percent difference) in 2030; and from 2024 to 2033 the primary differences between the two scenarios being the timing of new resource additions. Neither Scenario 1 (BAU) or Scenario 5 (ACER) retires SPV 3 in the first ten years of the RPP. Scenario 2 (IRA) achieves a lower SCoC due to more renewable resources being added during the RAP, as well as the early retirement of SPV3. Scenario 3 (ESPV3) also results in lower levels of SCoC due to retirement of SPV 3 during the RAP. Scenario 4 (SWER) sets minimum system-wide emission reductions as underlying modeling input constraints, which result in the lowest SCoC levels across the scenarios. Similar trends across the scenarios are seen in Figure 14 below, for SCoM.

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Figure 13: Comparison of SCoC

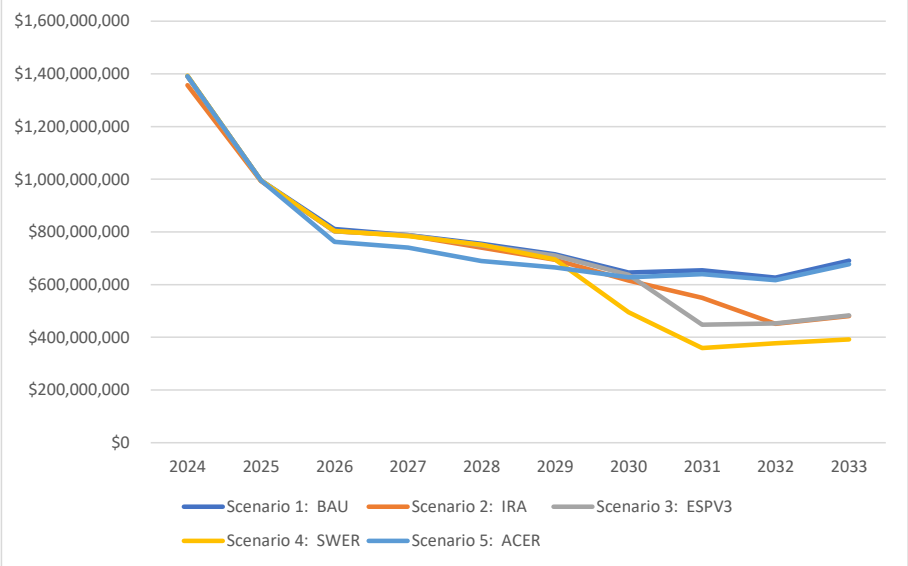
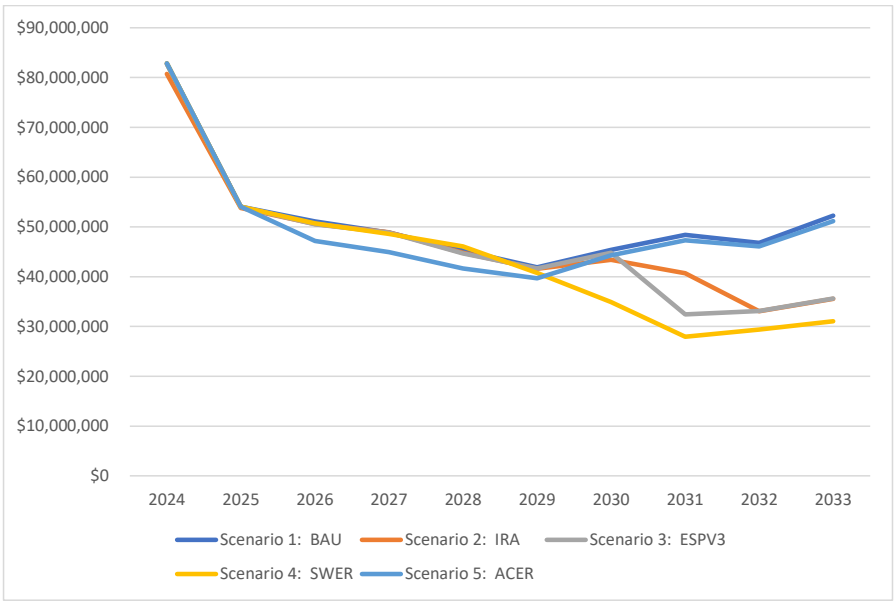


Figure 14: Comparison of SCoM



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Financial Analysis

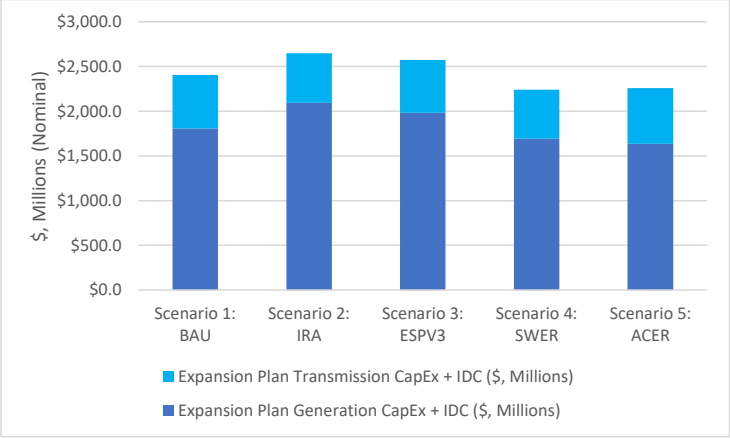
The following table compares total financial results for each scenario, both with and without the SCoC and SCoM. Scenario 2 (IRA) is one of the lowest cost plans on a PVRR basis, and has the lowest renewable curtailment costs during the RAP. ~~Scenario 2 (IRA) also has the lowest PVRR when SCoC and SCoM are included.~~ Scenario 2 (IRA) exceeds Colorado GHG reduction target for 2030, while maintaining reliability and affordability—which best serves Tri-State Members.

Table 111~~111107~~: Comparison of PVRR

	PVRR ($, Millions)	PVRR w/SCoC and SCoM ($, Millions)
Scenario 1: BAU	$17,507.4	$29,916.4
Scenario 2: IRA	$176,221~~352~~.40	$287,6881~~1~~.28
Scenario 3: ESPV3	$17,304.2	$28,828.6
Scenario 4: SWER	$17,343.9	$27,922.2
Scenario 5: ACER	$17,208.2	$28,993.1

Figure 15 below compares capital expenditures for resource additions and transmission interconnection and upgrades by scenario over the RPP. While the Scenario 2 (IRA) results in comparatively higher CapEx, the overall financial impact of the scenario is the lowest due to New ERA funding being pursued by Tri-State for the benefit of its Members.

Figure 15: Comparison of Generation and Transmission CapEx (Nominal $)



As shown in Table 112~~Table 108~~ below, all scenarios selected a 290 MW gas plant during the RAP (in 2028, 2029, or 2030), with conversion to CCS in 2031, and selected some amount of wind hybrids. All scenarios include 140 MW of solar to replace the Coyote Gulch PPA that was terminated in 2023. Scenario 1 (BAU)

and Scenario 3 (ESPV3) have similar levels of MWs and resource additions during the RAP. Scenario 4 (SWER) and Scenario 5 (ACER) have similar levels of MWs and resource additions. Scenario 2 (IRA) selects 1,400 MW of resources during the RAP, in addition to the 140 MW of replacement solar, more than double the total resource additions in Scenario 4 (SWER) and Scenario 5 (ACER) and significantly higher than the total resource additions in Scenario 1 (BAU) and Scenario 3 (ESPV3). The increase in resource selection during the RAP in Scenario 2 (IRA) is due to potential federal funding being available only through the RAP period. The funding would allow Scenario 2 (IRA) to bring on more resources during the RAP while improving affordability, maintaining reliability, and making strides toward evolving environmental requirements.

Table 112: Comparison of MW Additions by Scenario, by Technology over the RAP

	Scenario 1 – BAU	Scenario 2 – IRA	Scenario 3 – ESPV3	Scenario 4 – SWER	Scenario 5 – ACER
Wind	0	500	0	0	0
Solar	140	240	140	140	140
Standalone Storage	100	210	200	0	0
Gas	290	290	290	290	290
Wind Hybrid	300	200	300	100	200
Wind Hybrid – Battery Storage Component	150	100	150	50	100
RAP Total	**980**	**1,540**	**1,080**	**580**	**730**

Note: Wind Hybrid components share interconnect.

Table 113~~Table 109~~ below identifies the percentage of generation capacity that is intermittent or dispatchable/firm, and the percent of system energy that is renewable for each scenario in 2030. Scenario 2 (IRA) yields the highest percentage of renewables in terms of system energy mix in 2030, while maintaining a reasonable mix of intermittent and dispatchable/firm capacity at 39 percent and 54 percent, respectively.

Table 113: Comparison of Renewables, Intermittent and Dispatchable Resources in the 2030 Mix, by Scenario

	2030 Generation Capacity Mix, % Intermittent	2030 Generation Capacity Mix, % Dispatchable/Firm	2030 System Energy Mix, % Renewables
Scenario 1: BAU	34%	59%	59%
Scenario 2: IRA	39%	54%	64%
Scenario 3: ESPV3	34%	61%	58%
Scenario 4: SWER	33%	61%	61%
Scenario 5: ACER	34%	61%	58%

Note: Capacity from energy efficiency / demand response and semi-dispatchable resources are not reflected in either the intermittent or dispatchable/firm, therefore the sum of the capacity mix percentages does not total 100%.

Curtailments

The following tables identify the annual PPA curtailment costs (pricing, penalties, and taxes) estimated to result from the modeled curtailments, by resource type.

Table 114: Comparison of Wind PPA Curtailment Costs by Scenario, Real (2023) $

	Scenario 1: BAU	Scenario 2: IRA	Scenario 3: ESPV3	Scenario 4: SWER	Scenario 5: ACER
2024	$0	$0	$0	$0	$0
2025	$0	$0	$0	$0	$0
2026	$0	$0	$0	$0	$0
2027	$0	$0	$0	$0	$0
2028	$0	$0	$0	$0	$0
2029	$0	$0	$0	$0	$0
2030	$0	$0	$0	$0	$0
2031	$0	$8,765	$2,511	$0	$0
RAP Total	**$0**	**$8,765**	**$2,511**	**$0**	**$0**

Table 115: Comparison of Solar PPA Curtailment Costs by Scenario, Real (2023) $

	Scenario 1: BAU	Scenario 2: IRA	Scenario 3: ESPV3	Scenario 4: SWER	Scenario 5: ACER
2024	$0	$0	$0	$0	$0
2025	$0	$0	$0	$0	$0
2026	$208,078	$2,816	$208,309	$216,270	$207,282
2027	$125,060	$0	$124,914	$126,321	$125,001
2028	$102,674	$9,596	$102,651	$106,117	$102,660
2029	$82,738	$122,947	$82,570	$82,658	$109,061
2030	$0	$29,692	$0	$0	$0
2031	$0	$329,902	$0	$0	$0
RAP Total	**$518,550**	**$494,953**	**$518,444**	**$531,366**	**$544,004**

Scenario 4 (SWER) and Scenario 5 (ACER) have the highest curtailment costs compared to the other scenarios. Scenario 2 (IRA) has the lowest curtailment costs while still achieving the highest GHG reduction in Colorado by 2030.

Table 116: Comparison of Total Wind + Solar Curtailment Costs during the RAP, by Scenario, Real (2023) $

	Scenario 1: BAU	Scenario 2: IRA	Scenario 3: ESPV3	Scenario 4: SWER	Scenario 5: ACER
RAP Total	$518,550	$503,718	$520,955	$531,366	$544,004

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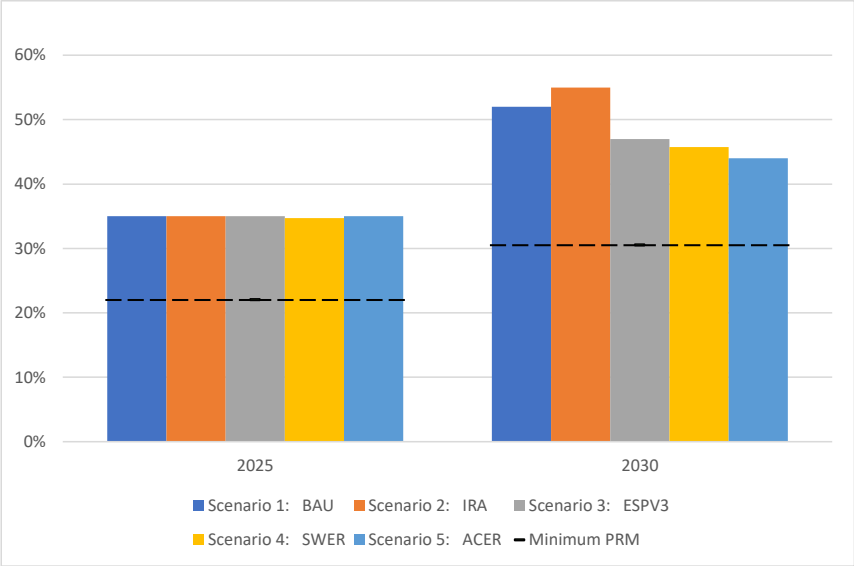
Reliability Analysis

PRMs were relatively consistent across all scenarios through 2027. PRMs in 2030 range from 44 percent to 55 percent. The level of resource additions enabled by potential New ERA funding in Scenario 2 (IRA) resulted in higher PRMs during the RAP as compared to other scenarios.

Figure 16: Comparison of PRMs During the RAP



Each of the scenarios were able to meet Level I and II reliability metrics during the RAP. Scenario 2 (IRA) is the scenario that results in the greatest certainty in achieving reliability in the most cost-effective manner because it allows for the acquisition of more resources earlier in Tri-State's planning period. Tri-State's PRMs stay well above requirements, allowing for potential procurement or operational delays to more likely be addressed without reliability issues.

Conclusion

Given the comprehensive and thorough data obtained on the multiple scenarios modeled, the ERP Report supports approval of the IRA Scenario as Tri-State's preferred plan. As such, Tri-State requests the Commission: (1) find that the IRA Scenario within Tri-State's ERP Application meets the applicable rule requirements, (2) approve the IRA Scenario as Tri-State's Phase I preferred plan, and (3) approve Tri-State's Phase II procurement plans in this proceeding.

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit Y: CoPUC, *Verified Petition of Trial Staff of the Commission, CEO, UCA, and Public Service for a Variance from Decision No. C18-0761 and Any Other Requirements, Request for Shortened Notice and Intervention Period, and Request for Approval of Associated Procedures,* filed on November 10, 2025, in Proceeding No. 25V-0480E

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

*** * * * ***

IN THE MATTER OF THE VERIFIED PETITION OF TRIAL STAFF OF THE COMMISSION, THE COLORADO ENERGY OFFICE, THE COLORADO OFFICE OF THE UTILITY CONSUMER ADVOCATE, AND PUBLIC SERVICE COMPANY OF COLORADO FOR A VARIANCE FROM ORDERING PARAGRAPHS 1 AND 2 OF DECISION NO. C18-0761 AND ANY OTHER REQUIREMENTS	)))))))))))	**PROCEEDING NO. 25V-____E**

VERIFIED PETITION OF TRIAL STAFF OF THE COMMISSION, THE COLORADO ENERGY OFFICE, THE COLORADO OFFICE OF THE UTILITY CONSUMER ADVOCATE, AND PUBLIC SERVICE COMPANY OF COLORADO FOR A VARIANCE FROM DECISION NO. C18-0761 AND ANY OTHER REQUIREMENTS, REQUEST FOR A SHORTENED NOTICE AND INTERVENTION PERIOD, AND REQUEST FOR APPROVAL OF ASSOCIATED PROCEDURES

Pursuant to Rules 1003 and 1304(e) of the Colorado Public Utilities Commission's ("Commission") Rules of Practice and Procedure, Trial Staff of the Colorado Public Utilities Commission ("Staff"), the Colorado Energy Office ("CEO"), the Colorado Office of the Utility Consumer Advocate ("UCA"), and Public Service Company of Colorado ("Public Service" or the "Company") (collectively, the "Joint Petitioners") seek a variance from Ordering Paragraphs 1 and 2 of Decision No. C18-0761, and any other decisions the Colorado Public Utilities Commission ("Commission") deems necessary, to modify the plan to retire Comanche Unit 2 from December 31, 2025, to December 31, 2026. Good cause exists to grant the variance, and the limited modification of the planned Comanche Unit 2 retirement date is in the public interest.

Colorado PUC E-Filings System

Electric resource planning ("ERP") proceedings have assumed the retirement of Comanche Unit 2 at year-end 2025 for several years dating back to 2018 when the Commission issued Decision No. C18-0761. The ensuing years have brought numerous changes in state policy, federal policy, resource planning, and power procurement. And, over that same timeframe, we have seen increasing peak load growth, requiring incremental resources to serve this demand. Most recently, supply chain challenges, tariff uncertainties, and changes to federal law have led to delayed in-servicing of resources that could have helped address this challenge, ultimately affecting Public Service's loads and resources projections. In addition, the Company has updated its resource accreditation and planning reserve margin development approaches based on industry best practices and resulting greater than anticipated resource needs.

A variance to the requirement to file an application to amend the Certificate of Public Convenience and Necessity ("CPCN") for Comanche Unit 2 and a one year extension of the plan to retire Comanche Unit 2 to December 31, 2026 is appropriate at this time and keeps the unit available to Public Service system operators in 2026. The Joint Petitioners believe that the continued operation of Comanche Unit 2 in 2026 is the most cost-effective approach to providing needed electricity for the system (as shown in the Company's loads and resources projections for summer 2026 in resource planning filings). Importantly, this Petition does not seek an order allowing for the operation of Comanche Unit 2 in perpetuity—it seeks a modest extension in the plan to retire the unit while setting up a process that will assess both resource options and mechanisms to continue orderly progress towards the State of Colorado's 2030 emissions reduction objectives.

To facilitate the timely resolution of the variance sought through this Petition, the Joint Petitioners request a shortened notice and intervention period of ten (10) days pursuant to Rule

1003(b), along with associated procedures set forth in this Petition. At this time, the Joint Petitioners are not requesting any further modification of existing resource plans beyond the variance requested here to address recent events and associated issues discussed in this Petition.

I. OVERVIEW

The orderly transition of coal-fired generation resources has been a centerpiece of Colorado resource planning for over a decade. In Public Service's 2016 ERP, Proceeding No. 16A-0396E, parties reached a settlement requiring the Company to propose portfolios in which Comanche Units 1 and 2 would retire early. The Commission approved that settlement, and Public Service then presented portfolios showing that retiring Comanche Units 1 and 2 in 2022 and 2025, respectively, would result in no additional cost to customers relative to portfolios in which the units retired in later years. The Commission-approved portfolio in Proceeding No. 16A-0396E resulted in a portfolio of resources to replace portions of the energy and capacity from Comanche Units 1 and 2. The Commission subsequently approved an accelerated depreciation and cost recovery schedule for Comanche Units 1 and 2 in Proceeding No. 17A-0797E.

In the Company's next resource plan, the 2021 ERP and Clean Energy Plan ("2021 ERP & CEP"), Proceeding No. 21A-0141E, modeling assumed that Comanche Unit 2 would retire on December 31, 2025. Numerous parties to the proceeding reached an Updated Non-Unanimous Partial Settlement Agreement ("USA") with Comanche Unit 3 retiring by January 1, 2031. The parties to the USA included a diverse set of parties, including the Joint Petitioners. The Commission approved the USA, and subsequently approved a portfolio of resources in Proceeding No. 21A-0141E based on modeling and analyses assuming that Comanche Unit 2 would retire on December 31, 2025.

These plans were reasonable and appropriate based on the information available at the time they were created and approved by the Commission. Recent events have resulted in challenges to those plans that generally fall into four areas: (1) the impact of the extended outage of Comanche Unit 3 on the Public Service system; (2) increasing peak load growth in the Public Service territory; (3) supply chain and geopolitical/macroeconomic impacts; and (4) reassessment of resource accreditation and planning reserve margin methodologies. While the Commission has multiple planning and other regulatory processes that are available to manage and address these issues, each of these issues layers atop one another, contributing to the need for the variance presented here.

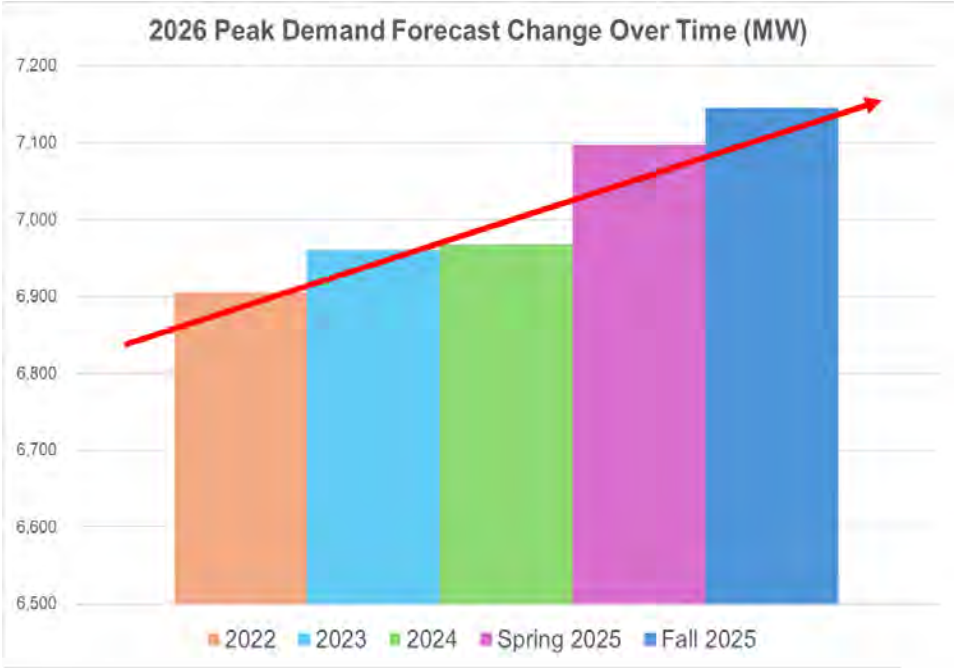
A. Comanche Unit 3 Outage and the Need for Comanche Unit 2 in 2026

Comanche Unit 3, which provides Public Service's system with 415 MW of accredited capacity, experienced an unplanned outage and is offline through at least June 2026. This outage, combined with the other layered issues described below, i.e., supply chain and geopolitical issues, and increasing peak demand, leads to this proposal to operate Comanche Unit 2 (which has a nameplate capacity of 335 MW and an accredited capacity of 296 MW) as a cost effective, near-term solution and supports the need for the requested variance. The Joint Petitioners propose a process below for a future report and application; the extension of Comanche Unit 2 facilitates time for that reporting and review to occur.

B. Increasing Peak Demand in Public Service Territory

Figure 1 below shows the peak demand forecast for summer of 2026 over time in megawatts ("MWs") year-over-year from forecasts developed in 2022 through the fall of this year. Each updated forecast illustrates the growing peak demand on the Company's system, reflective of the load growth forecasted by Public Service and focused on the year 2026.

Figure 1: Peak Demand Forecast Over Time (2022-2025) for Year 2026



C. Supply Chain and Geopolitical Issues

Supply chain and geopolitical issues also contribute to the challenge, impacting the viability of projects in various ways. The Company addressed this in the CEP Delivery Plan in September 2024 (also in Proceeding No. 21A-0141E). The Commission issued a final decision approving the CEP Delivery Plan parameters on January 14, 2025. In approving the CEP Delivery Plan with modifications, the Commission stated:

> Our Decision allows the generation and storage projects included within the CEP to continue advancing despite changing market dynamics and geopolitical uncertainties, including importantly potential future changes in federal law. Advancing these generation and storage projects as part of the overall determinations made through the course of this Proceeding moves Colorado forward towards achieving aggressive state emission reduction targets.[1]

The CEP Delivery Plan and associated evidentiary record illustrates the supply chain and geopolitical challenges that utilities and developers are navigating, along with the State of

[1] Decision No. C25-0024, at ¶ 2 (Jan. 14, 2025).

Colorado's response to them. While the CEP Delivery Plan assists with navigating these issues, it does not cure them.

D. Resource Accreditation and Planning Reserve Margin Changes

In accordance with the USA, the Company worked with an industry-leading consultant in the ongoing Just Transition Solicitation ("JTS") in Proceeding No. 24A-0442E to update its method for determining accredited capacity in a way that was more accurate and aligned with industry best practices.[2] That analysis revealed additional energy and capacity needs compared to prior modeling approaches. As such, the Company's need for resources—including in 2026 and 2027—identified through electric resource planning processes has increased over the coming years. The Commission continues to address overall energy and capacity needs through on-going planning proceedings, including the Near-Term Procurement ("NTP"), an innovative multi-stage electric resource plan solicitation, and other planning proceedings. However, just like the supply chain and geopolitical impacts on resource development and in-servicing, the updated accreditation and planning reserve margin approach affects the Company's loads and resources balance.

E. Next Steps

The Comanche Unit 3 development brought the Joint Petitioners together in requesting a variance to extend the planned retirement date of Comanche Unit 2. But simply obtaining a variance here is not the end of the work. Indeed, the variance sought through this Petition creates

[2] *See, e.g.*, Hrg. Ex. 102, Direct Testimony of Jon T. Landrum, at 30:12-20 (explaining that consultant Energy and Environmental Economics, Inc. ("E3") utilized their Renewable Energy Capacity Planning Model (RECAP), which is a loss of load probability model used to evaluate the resource adequacy of electric power systems. E3 originally developed RECAP in 2011 for the California Independent System Operator ("CAISO") and has since adapted the model for other Independent System Operators, including MISO, PJM, NYISO, and ISO-NE; utilities, including Duke Energy, the Sacramento Municipal Utilities District, Portland General Electric, Puget Sound Energy, Dominion Energy, Salt River Project, Public Service of New Mexico, and New Brunswick Power; and public utilities commissions, including the Oregon and Texas PUCs.").

an appropriate period of time to assess more permanent, long-term options, including resources that are projected to come on-line through on-going resource planning and other processes and consideration of updated retirement dates for Comanche Unit 2 and Comanche Unit 3. These efforts will include assessments of resource "portfolio" options for near-term, mid-term, and more permanent resource adequacy solutions, paired with emissions assessments of different approaches.

The Joint Petitioners propose two updates to the Commission on work in the extended review period in two different steps, as follows:

Step 1: March 1, 2026 Report. The Company will provide a report to the Commission on or before March 1, 2026. This report will include an update on the repair and return to service status of Comanche Unit 3, including forecasted cost of repairs, any resource options identified in collaborative work with the Joint Petitioners for potential near-term resource adequacy benefits, and other analysis relevant to the four areas outlined above. It will also include an initial plan to address on-going needs considering all available options, including not only plant extensions, but also expedited resource additions and demand-side options, with further refinement in Step 2. In addition, the Joint Petitioners intend to discuss the operations of Comanche Unit 2 over the course of the first quarter to determine appropriate operational parameters or approaches that may work for the unit while it operates in 2026, with a specific focus on operations after Comanche Unit 3 returns to service. The Step 1 report would include the results or status of these operations-focused discussions among the Joint Petitioners to keep the Commission apprised of potential options under consideration or options that the Company is comfortable pursuing.

Step 2: June 1, 2026 Application. For the second step, the Company commits to file an application for any additional variances or resource approvals, building on the Step 1 report and

depending on options identified through the collaborative work with the Joint Petitioners in the review period, by June 1, 2026. As part of that filing, the Company will include updated loads and resources tables and loss of load calculations that include analysis of new resources projected to come on-line from the NTP, JTS Phase II resource solicitation (in Proceeding No. 24A-0442E and to the extent known), or other relevant proceedings. The Company would likely seek consideration of any such requests on an expedited basis, e.g., a 120-day schedule. Options proposed for approval will focus on intermediate and long-term contracts, generation resource acquisitions, generation resource development, new distributed energy resource opportunities, potential demand response or programming changes beyond currently-approved program limits, or any other options that can benefit the Company's near- or mid-term resource adequacy position on either a temporary (e.g., a few years) or more permanent basis.[3]

These two steps make use of the extended review period with appropriate check-ins with the Commission. Moreover, and equally important, they set out an orderly process of next steps as the Company, in collaboration with the other Joint Petitioners, assesses the future operation of Comanche Unit 2, Comanche Unit 3, and other resource options.

II. REQUEST FOR VARIANCE

Rule 1003(c) sets forth the requirements for a variance petition:

(I) citation to the specific paragraph of the rule or decision from which the waiver or variance is sought;

(II) a statement of the waiver or variance requested;

(III) a statement of facts and circumstances relied upon to demonstrate why the Commission should grant the request.

[3] The other Joint Petitioners may or may not join this application and reserve their rights with respect to this future application.

(IV) a statement regarding the duration of the requested waiver or variance, explaining the specific date or event that will terminate it;

(V) a statement whether the waiver or variance, if granted, would be full or partial; and

(VI) any other information required by rule.

Decision No. C18-0761, at Ordering Paragraphs 1-2, states as follows:

> 1. The proposed early retirement of units 1 and 2 at the Comanche generation station, owned and operated by Public Service Company of Colorado (Public Service), is approved as part of its 2016 Electric Resource Plan (ERP), consistent with the discussion above.
>
> 2. Public Service shall file an application to amend the Certificates of Public Convenience and Necessity (CPCNs) for Comanche units 1 and 2, pursuant to 4 Code of Colorado Regulations (CCR) 723-3-3103 of the Commission's Rules Regulating Electric Utilities, as modified by this Decision, consistent with the discussion above."

Among other things, Ordering Paragraph 1 approves the Company's plan to retire Comanche Unit 2. Ordering Paragraph 2 requires a limited scope CPCN amendment filing associated with such retirement. The Joint Petitioners seek relief in the form of a variance from the Commission's directive to file a CPCN amendment to effectuate a retirement of the unit by the end of this year, as well as any other requirements the Commission deems necessary. The discussion that follows addresses each rule requirement in more detail.

A. Rule 1003(c)(I): citation to the specific paragraph of the rule or decision from which the waiver or variance is sought.

Joint Petitioners seek a variance from Ordering Paragraphs 1 and 2 of Decision No. C18-0761; specifically the requirement to file for a CPCN amendment to retire Comanche Unit 2

consistent with the Company's 2016 ERP in Decision No. C18-0761 and any other requirements the Commission deems necessary.

B. Rule 1003(c)(II): a statement of the waiver or variance requested.

The Joint Petitioners seek a variance of 365 days, i.e., until December 31, 2026, for the planned retirement of Comanche Unit 2, with the CPCN filing requirement held in abeyance until that time. In Step 2 defined above, the Joint Petitioners or the Company may bring a longer variance request to the extent necessary. Any longer extension, however, is not at issue here in this proceeding. In addition, neither the Company nor the Joint Petitioners seek any ratemaking relief as part of this Petition. Any such requests can be brought forward and addressed by the Commission in other appropriate proceedings.

C. Rule 1003(c)(III): a statement of facts and circumstances relied upon to demonstrate why the Commission should grant the request.

Section II above outlines the facts, circumstances, and need for the variance requested by the Joint Petitioners. The variance and 365-day extension allows time for the two-step process outlined above to assess future plant operations and resource options. In addition, it provides a level of certainty to system operators and the workers at the unit by having a date certain for the plan to retire the unit. Moreover, it is worth noting that, viewed from a greenhouse gas ("GHG") emissions perspective, a Comanche Unit 2 extension will result in GHG emissions in 2026 from the unit that would not otherwise have occurred; however, that should be viewed in the context of a Comanche Unit 3 outage, where the emissions from the larger Comanche Unit 3 will *not occur*, leading to lower GHG emissions in the first half of 2026 (along with lower GHG emissions in the latter part of 2025). The Company also intends to evaluate the emissions impact, including other

pollutants beyond GHG emissions, and to work with the Colorado Department of Public Health and Environment on that effort.

D. Rule 1003(c)(IV): a statement regarding the duration of the requested waiver or variance, explaining the specific date or event that will terminate it.

The duration of the requested variance is through December 31, 2026. The variance will terminate on that date absent an additional variance request and the subsequent grant of the request by the Commission.

E. Rule 1003(c)(V): a statement whether the waiver or variance, if granted, would be full or partial.

The variance is partial as it is time-limited through December 31, 2026, absent a further variance.

F. Rule 1003(c)(VI): any other information required by rule.

The Joint Petitioners are not aware of any additional information required by rule.

IV. REQUEST FOR SHORTENED NOTICE AND INTERVENTION PERIOD AND RELATED PROCEDURES

The Joint Petitioners request a shortened notice and intervention period pursuant to Rule 1003(b), along with related procedures. Rule 1003(b) states: "If a petition requests a waiver or variance to be effective less than 40 days after the date of filing, the petition must include a request to waive or shorten the Commission notice and intervention period found in paragraph (d) of rule 1206."

The Joint Petitioners request approval of the procedures and schedule set forth below, which feature: (1) a shortened notice and intervention period of ten calendar days; (2) the filing of responses to the petition *with* any motions to intervene; and (3) a two-calendar day reply timeline

for the Joint Petitioners to address any responses.[4] The procedures are set forth with specific dates, including a proposed date for Commission deliberation and action.

Process Step	***Timing***
Joint Petition	+0 (November 10, 2025)
Commission accepts Petition	(November 12, 2025)
Intervention Deadline (petition responses included with interventions)	+10 calendar days after filing (November 20, 2025)
Joint Petitioner Reply	+6 calendar days after response (November 26, 2025)
Commission Deliberation	December 3, 2025
Commission Action	December 10, 2025

V. CONCLUSION AND REQUEST FOR RELIEF

The Joint Petitioners ask for swift Commission action on this Petition, and time is of the essence given the upcoming retirement date for Comanche Unit 2. The Joint Petitioners appreciate the Commission's prompt consideration of this request and the related procedural requests.[5]

The Joint Petitioners request approval of:

- A variance from Ordering Paragraphs 1 and 2 of Decision No. C18-0761 and any other requirements deemed necessary by the Commission.
- A shortened notice and intervention period of ten days.
- The procedures for consideration and decision on this Petition set forth above.

The Joint Petitioners further request that the Commission grant this Petition without a hearing.

[4] The Joint Petitioners are providing electronic courtesy service of this Petition to all parties to Proceeding No. 16A-0396E, Proceeding No. 21A-0141E, and Proceeding No. 24A-0442E given the request for a shortened notice and intervention period and associated procedures here.

[5] The Joint Petitioners ask the Commission to ensure that the relief sought in this petition will not interfere with the Company's planned or in-progress acquisition or interconnection of new generating resources. Nothing in this proposal shall be construed as the Joint Petitioners' request to alter the Company's proposal to acquire new resources through the NTP and the JTS. The Joint Petitioners strongly encourage the Commission to ensure that the NTP remains on the procedural schedule that the Commission approved, and to move as quickly as possible to conclude the Phase I JTS and proceed to Phase II of the JTS.

Dated this 10th day of November 2025.

Respectfully submitted,

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ATTORNEYS FOR PUBLIC SERVICE COMPANY OF COLORADO

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

*** * * ***

IN THE MATTER OF THE VERIFIED PETITION OF TRIAL STAFF OF THE COMMISSION, THE COLORADO ENERGY OFFICE, THE COLORADO OFFICE OF THE UTILITY CONSUMER ADVOCATE, AND PUBLIC SERVICE COMPANY OF COLORADO FOR A VARIANCE FROM ORDERING PARAGRAPHS 1 AND 2 OF DECISION NO. C18-0761 AND ANY OTHER REQUIREMENTS	)	**PROCEEDING NO. 25V-____E**

VERIFICATION OF JACK W. IHLE

STATE OF COLORADO)
CITY AND COUNTY OF DENVER) SS:

I, Jack W. Ihle, being duly sworn, do hereby depose and state that I am the Regional Vice President, Regulatory Policy, at Xcel Energy Services Inc., and am an authorized agent for Public Service Company of Colorado. I have read the foregoing Verified Petition of Trial Staff of the Commission, the Colorado Energy Office, the Colorado Office of the Utility Consumer Advocate, and Public Service Company of Colorado for a Variance from Decision No. C18-0761 and Any Other Requirements, Request for Shortened Notice and Intervention Period, and Request for Approval of Associated Procedures. The facts set forth therein are true, accurate, and correct to the best of my knowledge, information, and belief.

Dated at Denver, Colorado, this 10th day of November, 2025.

_____
Jack W. Ihle
Regional Vice President, Regulatory Policy
3500 Blake Street
Denver, Colorado 80205

Subscribed and sworn to before me this 10th day of November, 2025.

KRISTEN DIAZ
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20244015138
MY COMMISSION EXPIRES 04/18/2028

_____
Notary Public

My Commission expires 4/18/2028

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit Z: CoPUC, Tri-State, *2025 Annual Progress Report*, filed on December 1, 2025, in Proceeding No. 23A-0585E

Colorado PUC E-Filings System



Tri-State Generation and Transmission Association, Inc.

2025 Annual Progress Report

2023 Electric Resource Plan

Colorado Public Utilities Commission
Proceeding No. 23A-0585E

December 1, 2025

Forward-Looking Statement

Forward-looking statements include statements concerning our plans, objectives, goals, strategies, future events, future revenue or performance, forecasts, including load, energy, resources, and commodities, future capital expenditures, capacity needs, plans or intentions relating to development, acquisition, operation, or closure of facilities, in-service dates of facilities, emission reductions, demand response targets, energy efficiency targets, Member withdrawals, business trends or business strategy and other information that is not historical information. When used in this Annual Progress Report, the terms "estimates," "expects," "anticipates," "projects," "plans," "intends," "believes" and "forecasts" or future or conditional verbs, such as "will," "should," "could" or "may," and variations of such words or similar expressions, are intended to identify forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties, and assumptions, including those described in our filings with the Securities and Exchange Commission. All forward-looking statements, including, without limitation, management's examination of historical operating trends and data, are based upon our current expectations and various assumptions. These expectations and beliefs are expressed in good faith grounded in a reasonable basis. However, we cannot guarantee that management's expectations and beliefs will be achieved. There are a number of risks, uncertainties, and other important factors that could cause actual results to differ materially from the forward-looking statements contained in this Annual Progress Report.

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3. Updated Evaluation of Planning Reserve Margins and Contingency Plans 8
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Introduction

Tri-State Generation and Transmission Association, Inc. ("Tri-State") filed Phase I of its 2023 Electric Resource Plan ("ERP" or "Resource Plan") with the Colorado Public Utilities Commission ("Commission") on December 1, 2023 in Proceeding No. 23A-0585E. At the time of this report, Phase II resource acquisitions remain ongoing, pursuant to Decision No. C25-0612. In compliance with Commission Rule 3618(a), Tri-State submits the following Annual Progress Report ("APR") on its efforts under its electric resource plan.

As discussed below, Tri-State is forecasting a need for 19 MW of additional generation capacity by summer 2035.[1] This forecast incorporates existing resources, 2023 ERP Phase II preferred portfolio resources, and planned unit retirements.

This 2025 APR contains the following sections, in compliance with Commission Rule 3618(a):

A. An updated annual electric demand and energy forecast;
B. An updated evaluation of existing resources;
C. An updated evaluation of planning reserve margins and contingency plans;
D. An updated assessment of need for additional resources;
E. An updated report of the utility's action plan and resource acquisitions; and
F. An explanation of Tri-State's efforts to give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions.
G. An update on Tri-State's progress toward its GHG emissions reduction targets.

The intent of the APR is to discuss material changes in assumptions, fleet characteristics, load forecasts and other factors that have occurred since the 2024 APR and 2023 ERP Phase II were filed. To the extent issues addressed in Tri-State's 2024 APR or 2023 ERP Phase I and Phase II filing have not materially changed, they are not addressed herein.

[1] 2024 APR: 11 MW need projected stating in 2030
2023 ERP: 68 MW need projected starting in 2029
2022 APR: 126 MW need projected starting in 2030
2021 APR: 248 MW need projected starting in 2030
2020 ERP: 95 MW need projected starting in 2029
2019 APR: 70 MW need projected starting in 2027
2018 APR: 115 MW need projected starting in 2026
2017 APR: 148 MW need projected starting in 2026
2015 ERP: 9 MW need projected starting in 2023

Tri-State has made several changes to its resource portfolio in recent years reflecting increasing amounts of renewable resources and lower emissions trajectory, notably:

- Craig Unit 1[2] is planned to cease operations by December 31, 2025, Craig Unit 3 will retire January 1, 2028, and Craig Unit 2[3] will retire by September 30, 2028.
- Springerville Unit 3 ("SPV 3") is planned to cease operations by March 1, 2031.[4]
- Two solar projects came online in 2024 in Colorado, Spanish Peaks Solar (100 MW) and Spanish Peaks II Solar (40 MW) in Las Animas County.
- Two solar projects came online at the end of October 2025 in Colorado, Axial Basin Solar (145 MW) in Moffat County and Dolores Canyon Solar (110 MW) in Dolores County.

1. Updated Annual Electric Demand and Energy Forecast

Commission Rule 3618(a)(I)

Tri-State's most current demand and energy forecast was modeled in 2023 ERP Phase II and no subsequent revisions have been made. The forecast reflected in Table 1 represents Tri-State's System Wide annual energy and seasonal peaks as modeled in 2023 ERP Phase II. Subsequent to the commencement of modeling in Phase II, Tri-State received notice from the Northwest Rural Public Power District in Nebraska ("NRPPD") that it intends to depart Tri-State Utility Membership on January 1, 2027. NRPPD is served solely in the Eastern Interconnection through an all requirements contract, and NRPPD's departure does not impact Tri-State's electric demand and energy forecast for purposes of Tri-State's Colorado ERP. [5]

[2] Tri-State's ownership share is 102 MW (24%) of this unit, which has a total nameplate capacity of 427 MW.
[3] Tri-State's ownership share is 98 MW (24%) of this unit, which has a total nameplate capacity of 410 MW.
[4] Decision No. R24-0602 found that a retirement date of September 15, 2031 for SPV 3 was reasonable contingent upon Tri-State receiving a New ERA funding award and successful negotiation of contractual agreements impacted by the unit's retirement. The New ERA award is contingent upon a March 1, 2031 retirement date for SPV 3, consistent with the requirement for USDA to disperse all New ERA funds by September 30, 2031.
[5] *See* Attachment B to Tri-State's Phase II Implementation Report, filed April 11, 2025 in Proceeding No. 23A-0585E.

TABLE 1 – 10-YEAR DEMAND AND ENERGY FORECAST

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Annual Energy Sales (GWh)	13,051	13,110	13,455	13,642	13,830	14,049	14,289	14,521	14,773	15,036
Winter Peak Demand (MW)	1,865	1,739	1,778	1,825	1,847	1,888	1,886	1,955	1,998	2,038
Summer Peak Demand (MW)	2,344	2,423	2,454	2,431	2,472	2,535	2,583	2,635	2,646	2,629

2. Updated Evaluation of Existing Resources

Commission Rule 3618(a)(II)

Figure 1 below depicts the sources of generation serving Tri-State's 2024 total energy sales. Figure 2 below depicts Tri-State's 2024 capacity by generation source. Tri-State's assessment of its existing resources remains the same as what was presented in Tri-State's 2023 ERP Phase I.

FIGURE 1 – 2024 ENERGY MIX, GROSS SALES

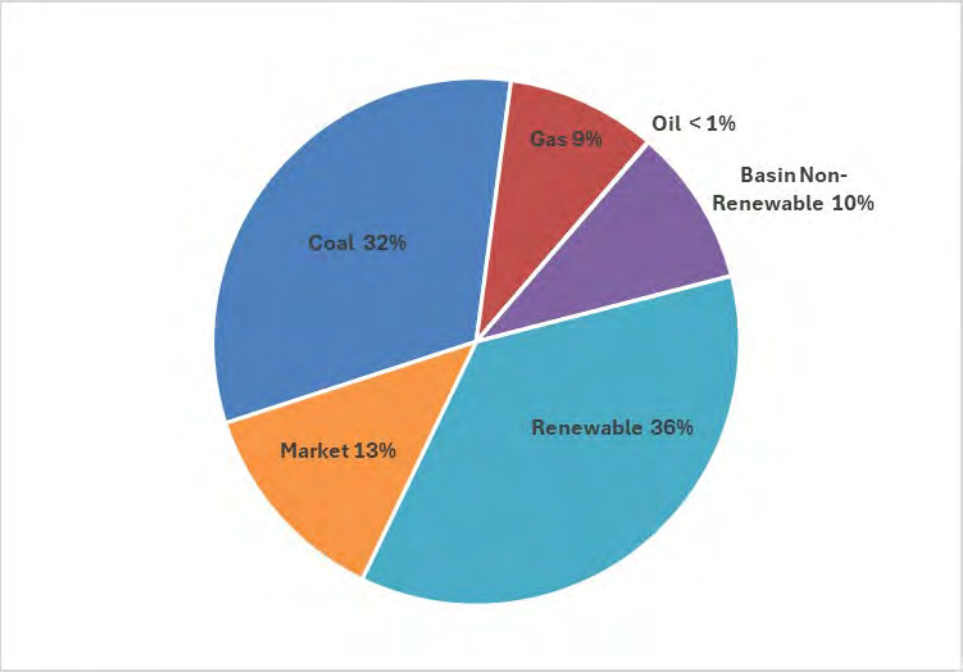
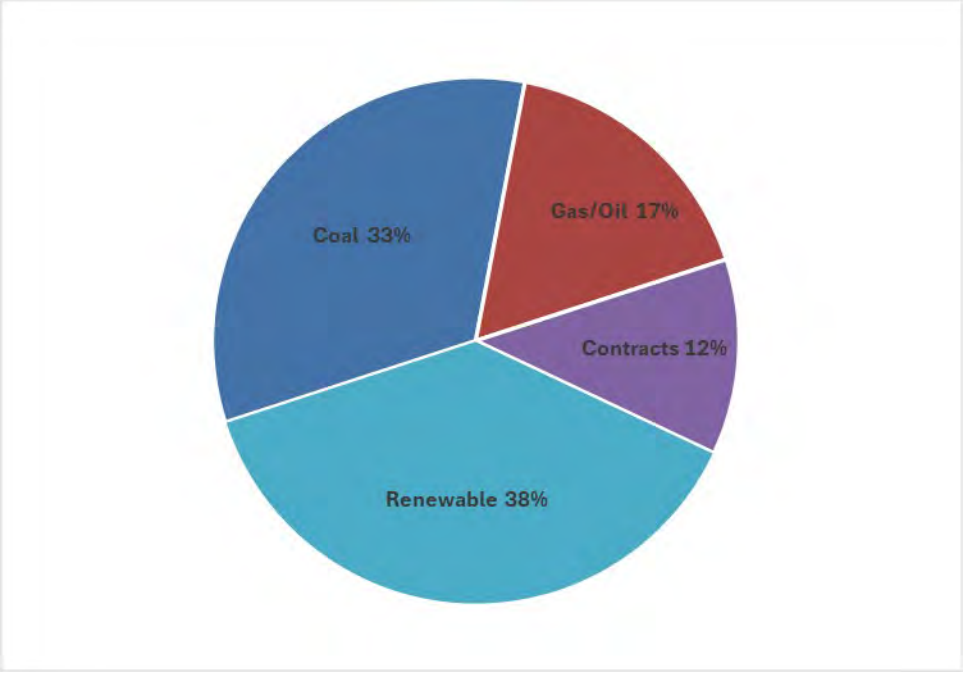


FIGURE 2 – 2024 CAPACITY PORTFOLIO



3. Updated Evaluation of Planning Reserve Margins and Contingency Plans

Commission Rule 3618(a)(III)

There are no updates or changes to the planning reserve margin ("PRM") or contingency plans from those contained in Tri-State's 2023 ERP Phase I or Phase II filing.[6] Tri-State continues to base its resource plans on a 22% PRM until the retirement of Craig Unit 3, after which the PRM increases to 30.5% beginning in 2028. Tri-State's participation in reserve sharing agreements and bilateral hazard-sharing arrangements provide additional support for reliable operations.

Tri-State continues to plan for its WACM load and resources to enter the Southwest Power Pool ("SPP") RTO in April 2026. Once in the RTO, Tri-State's assets in the WACM BA authority will be subject to SPP's PRM requirements. Tri-State is evaluating the SPP PRM requirements and will compare them to Tri-State's most recent PRM requirement. Tri-State intends to follow the more stringent of the two PRM requirements for its system planning.[7]

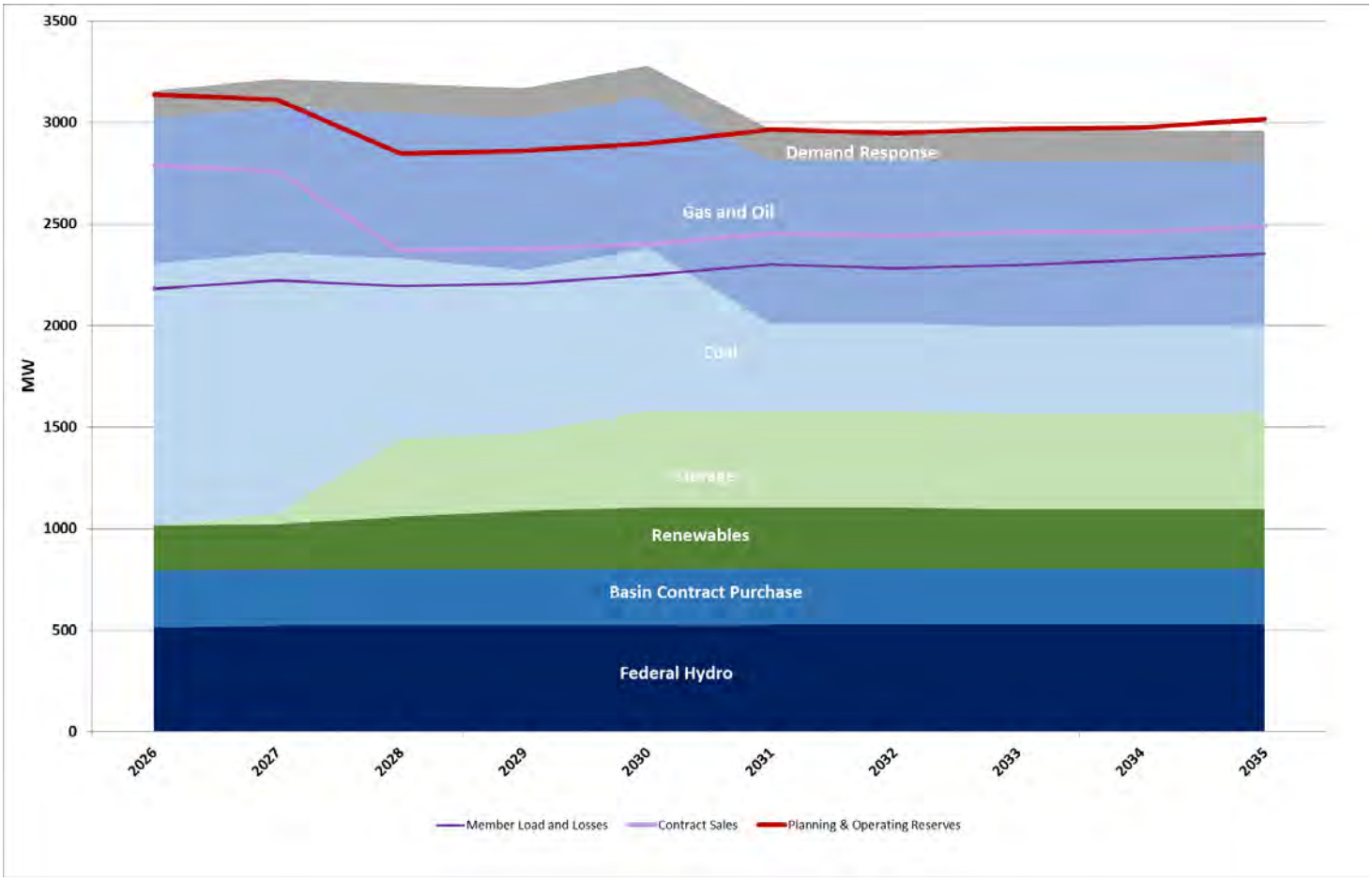
4. Updated Assessment of Need for Additional Resources

Commission Rule 3618(a)(IV)

Tri-State stated within Phase I of the 2023 ERP that it did not forecast a capacity shortfall until 2029. With the updated load forecast, shown above, utilized in Phase II and Phase II preferred portfolio resources, a capacity shortfall is not forecasted to occur until 2035, as shown in Figure 3 and Table 2 below. Tri-State's electrically east load is supplied by a full requirements contract with Basin Electric Power Cooperative and is not included in the load or resource portion of Figure 3 and Table 2.

[6] LKT-1 - Attachment G-1 - Confidential - ELCC and PRM Study (Astrape) filed December 1, 2023 in Proceeding No. 23A-0585E.
[7] Response Comments of Tri-State Generation and Transmission Association, Inc., Proceeding No. 25A-0266E.

FIGURE 3 –LOAD AND RESOURCES



The data for Figure 3 is shown in Table 2.

TABLE 2 – LOAD AND RESOURCES

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Federal Hydro	516	524	523	524	525	527	527	527	527	527
Contract Purchases	278	278	278	278	278	278	278	278	278	278
Renewables[8]	224	221	259	285	303	299	299	290	291	291
Demand Response	134	141	144	147	149	151	152	153	154	155
Coal Generation[9]	1287	1286	888	800	431	431	432	431	432	431
Gas & Oil Generation[10]	717	717	717	751	751	806	806	806	806	806
Storage[11]	0	49	383	383	474	474	474	474	474	474
Total Resources	3155	3215	3193	3169	3280	2965	2967	2959	2961	2961
Member Load and Losses[12]	2180	2223	2195	2206	2249	2302	2282	2297	2323	2355
Planning & Operating Reserves	350	351	478	482	495	511	505	509	517	527
Contract Sales	608	536	173	173	151	151	162	162	135	135
Total Obligations	3138	3110	2846	2861	2895	2964	2949	2968	2976	3017
Excess Resources	8	89	372	335	412	30	46	19	22	-19

5. Updated Report of the Utility's Action Plan and Resource Acquisitions

Commission Rule 3618(a)(V)

Tri-State's 2023 ERP Phase II procurement process is underway. Bids were received on October 28, 2024, in response to three Phase II requests for proposals.[13] A summary of bids was filed in Proceeding No. 23A-0585E on December 12, 2024;[14] and bids selected in the Phase II preferred portfolio were identified in Tri-State's ERP Implementation Report filed April 11, 2025. Tri-State has 500 MW of preferred portfolio storage resources under contract, 200 MW of preferred portfolio wind resources under contract, and is continuing contracting efforts for other preferred

[8] Capacity is based on applying the effective load carrying capability by renewable technology to the nameplate of renewable resources.
[9] Capacity is based on summer season capacity multiplied by 1 minus the demand equivalent forced outage rate.
[10] Capacity is based on summer season capacity multiplied by 1 minus the demand equivalent forced outage rate.
[11] Capacity is based on applying the effective load carrying capability for storage to the nameplate of storage resources.
[12] Western Interconnection Load.
[13] Bids for the Dispatchable RFP were received November 27, 2024.
[14] *See* Tri-State's 45-Day Report filed in Proceeding No. 23A-0585E.

portfolio resources, including evaluation of back-up bids as needed. The preferred portfolio bids under contract include:

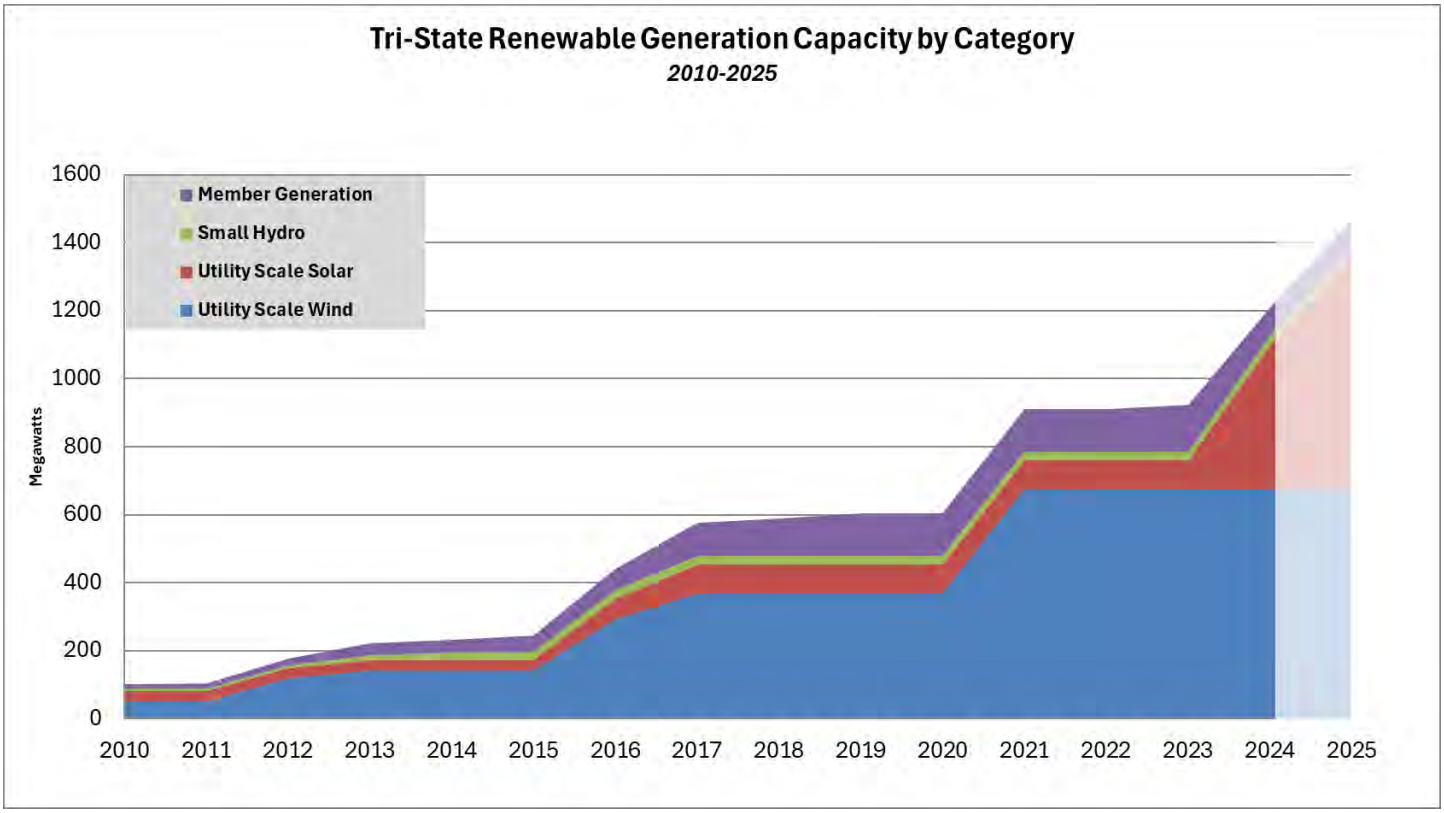
- High Country Energy Station 2 (Montrose County, CO), 50 MW, Q2-2027 COD;
- Oso Negro Energy Storage (Bernalillo County, NM), 100 MW, Q2-2028 COD;
- Morel Energy Storage (Moffat County, CO), 200 MW, Q1-2030 COD;
- Carousel Energy Storage (Kit Carson County, CO), 150 MW, Q4 2027 COD; and
- Arriba Wind (Lincoln County, CO), 200 MW, Q1 2029 COD.

Expansion of Renewable Energy Portfolio

Tri-State's first owned renewable energy resources, Axial Basin Solar (145 MW) and Dolores Canyon Solar (110 MW) came online in October 2025. With those additions, along with existing renewable PPA resources, the renewable resources on Tri-State's system total approximately 2 GW.[15] Tri-State's renewable generation capacity, actuals through 2024 and forecasted for 2025, is shown in Figure 4 below.

[15] 1,466 MW wind, solar, small hydro, and renewable Member generation; and 580 MW large hydro.

FIGURE 4 – TRI-STATE RENEWABLE GENERATION CAPACITY[16]



6. Update on Consideration of Acquisition of Cost-Effective New Clean Energy and Energy-Efficient Technologies

Commission Rule 3618(a)(VI)

Emerging Technologies

Tri-State expanded its generic resource data set for Phase I of the 2023 ERP to include additional clean energy and energy efficient technologies, as technologies continue to evolve and become more competitive.[17] Tri-State utilizes the Electric Power Research Institute ("EPRI") for advanced generation and storage research, input from internal Tri-State Generation Engineering staff, industry benchmarking, and relationships with vendors, stakeholders, and consultants to stay aware of the progress of emerging technologies at a utility scale that can assist in a clean

[16] Figure 4 does not include Western Area Power Administration Colorado River Storage Project or Loveland Area Projects hydro allocations.

[17] *See* Hearing Exhibit 101, Attachment LKT-16, Rev. 2, filed on May 15, 2024, in Proceeding No. 23A-0585E.

energy transition to maintain affordability and reliability for Tri-State's Utility Member Systems. Tri-State will continue to evaluate emerging technologies to consider for its 2027 ERP generic resource data set, to the extent the resources are utility-scale proven and cost-competitive.

Tri-State's entry of its resources into the SPP RTO in April 2026 is key for integrating intermittent resources on a large scale and further supporting affordable and reliable operations, while meeting carbon reduction targets.

Renewables

Tri-State's renewable resource portfolio includes utility scale projects and distribution level projects. Tri-State's wholesale power contract with each of its Utility Members and Board policies allow for, and facilitate, the development of local distributed resources in its Utility Members' service territories. The Federal Energy Regulatory Commission ("FERC") accepted, subject to refund and settlement procedures, Tri-State's amended Board Policy 115 effective August 6, 2025, enabling Utility Members to now self-supply up to 20% of their energy needs through distributed or renewable generation, a substantial increase from the previous 5% allocation. These renewable and distributed projects are helping to fulfill both Colorado and New Mexico Renewable Energy Standards ("RES")/Renewable Portfolio Standards ("RPS") requirements, as well as satisfy Utility Members'/consumers' interests in purchasing renewable power from locally-sited projects.

Figure 5 below shows the decline in capacity of these distributed projects through the end of 2024, reflecting the departures of United Power and Mountain Parks Electric, accounting for a decrease in distributed generation capacity of 49.6 MW. The number and capacity of these projects is expected to continue to grow, with a small net increase in 2025, as many of Tri-State's Utility Members remain interested in supporting local renewable projects.

FIGURE 5 – MEMBER RENEWABLE AND DISTRIBUTED GENERATION PROJECTS, NAMEPLATE CAPACITY UNDER CONTRACT, 2007-2024 AND FORECASTED for 2025

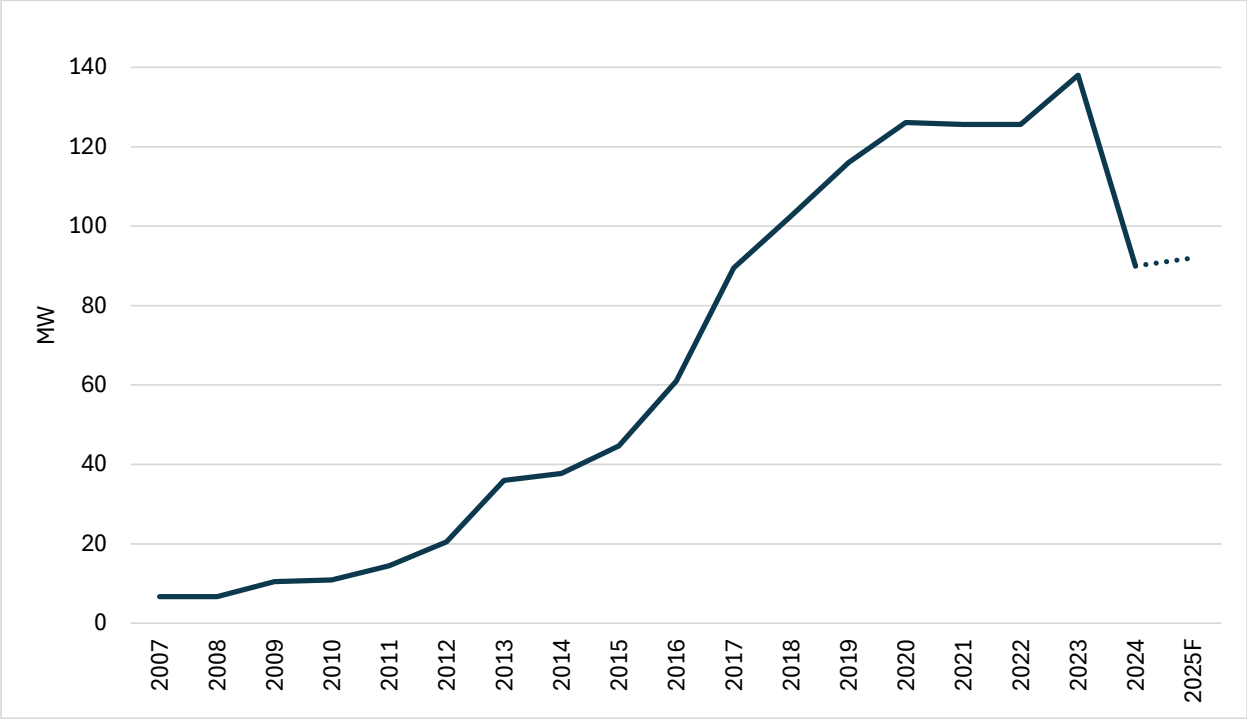
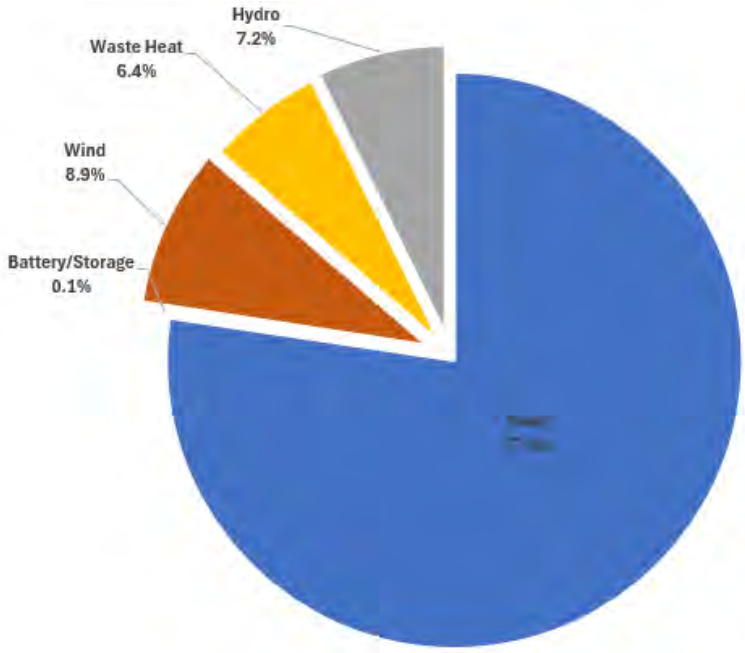


Figure 6 shows the breakdown of these projects by technology category. As of December 31, 2024, fifty-eight renewable or distribution generation projects totaling 90 MW were in operation across 20 Member Systems, with solar technology comprising over 77% of Member generation distributed resources.

FIGURE 6 – MEMBER BP 115 RENEWABLE AND DISTRIBUTED GENERATION PROJECTS BY TECHNOLOGY, NAMEPLATE CAPACITY OPERATING AS OF 12/31/2024



Bring Your Own Resource (BYOR)

Tri-State's BYOR program was accepted by FERC on August 2, 2025. Within this program Utility Members can bring forth resources equivalent up to 40% of their peak capacity needs through their owned or controlled projects, with Tri-State supporting all Utility Members by integrating BYOR projects into its multi-state system. BYOR allows Utility Members to have additional flexibility to develop resources under their Wholesale Electric Service Contracts with Tri-State, while not increasing wholesale rates or shifting costs between Utility Members. All load served under the BYOR resources remains Class A load.

Energy Efficiency

In 2024, Tri-State's long-standing energy efficiency program spent a total of $5.8 million on incentives in support of energy efficiency and certain electrification programs (not including administrative costs associated with this program). The programs delivered 56,133 MWh of first-year savings in Colorado, and an estimated 322,612 MWh of lifetime energy savings resulting from 2024 efficiency installations. Annual and cumulative savings from the program through 2024, including the removal of all items that have reached their established end of useful life, are shown in Figure 7 below.

FIGURE 7 – TRI-STATE 2024 ENERGY EFFICIENCY MEASURES AND SAVINGS, CUMULATIVE AND ANNUAL

Cummulative

Category	Typical Measures	kW Savings	kWh Savings
Agricultural	Irrigation Motors Variable Speed Drive Retrofits	13,065	22,226,468
C&I HVAC	Air Source and Ground Source Heat Pumps	3,471	2,716,881
C&I Lighting	LED Lighting Street & Parking Lot Lighting Refrigerated Case Doors	47,229	175,876,342
C&I Motors	Variable Speed Drive Retrofits and Process Measures	9,403	48,493,751
Residential HVAC	Air Conditioners Air Source and Ground Source Heat Pumps	50,255	42,700,554
Residential - Other	LED Lamps, Energy Star Appliances Electric Water Heaters Low Income Weatherization	54,728	30,597,885
Total		**178,151**	**322,611,881**

Annual Savings

Category	Typical Measures	kW Savings	kWh Savings
Agricultural	Irrigation Motors Variable Speed Drive Retrofits	738	1,175,175
C&I HVAC	Air Source and Ground Source Heat Pumps	139	447,190
C&I Lighting	LED Lighting Street & Parking Lot Lighting Refrigerated Case Doors	1,294	4,938,378
Industrial	Process Measures	3,076	36,674,828
Residential HVAC	Air Conditioners Air Source and Ground Source Heat Pumps	5,086	11,187,795
Residential - Other	LED Lamps, Energy Star Appliances Electric Water Heaters Low Income Weatherization	1,127	1,710,328
Total		**11,459**	**56,133,693**

On September 1, 2022, Tri-State submitted its 2023/24 Colorado Demand-Side Management ("DSM") Plan, informationally, in Proceeding No. 20A-0528E. The DSM Plan describes Tri-State energy efficiency programs and its plans to scale programs to meet energy savings targets agreed upon in the 2020 ERP Settlement Agreement ("Colorado EE Targets"), which began in 2023.

By the end of 2024, Tri-State met its second Colorado EE Target.

2024 Colorado EE Target		2024 Colorado EE Achievement	
0.50%	45.6 GWh	0.61%	56.6 GWh

The programs that contributed most significantly to the 2024 EE Target included: Air-Source Heat Pumps for Space Conditioning, Commercial Lighting, Oil and Gas, and Commercial and Industrial ("C&I") savings.

Tri-State anticipates meeting its 2025 Colorado EE Target due to growth in oil and gas ("O&G") sector energy efficiency projects. As of October 2025, Tri-State's EE program savings is 36.1 GWh or 60.1% of the 2025 Tri-State's goal of 60.04 GWh (0.75% of Colorado Member load). Tri-State held informational DSM Roundtable Meetings with interested stakeholders on June 17, 2025 and November 12, 2025.

Demand Response

Tri-State is committed to the development of in-house demand response ("DR") programs designed to meet the target of 4% of Colorado peak load under control in 2025 ("2025 Colorado DR Target").[18]

2025 Colorado DR Target	
4%	59.5 MW

Tri-State's Demand Response Rider was accepted by the Federal Energy Regulatory Commission ("FERC") effective May 2025.[19] Following FERC acceptance, Tri-State's DR programs became available to the entirety of the Tri-State Utility Membership in late May 2025, subject to Tri-State and relevant vendor implementation resources. These programs include:

- Irrigation Load Control
- Commercial & Industrial Load Control

[18] 2020 ERP Phase I Settlement Agreement, section 3.11.8. states: "Tri-State will either conduct an RFP for demand response prior to submitting its next ERP or develop in-house demand response offerings in Colorado by 2025 that are designed to control at least 4% of Tri-State's Colorado peak load."

[19] Docket No. ER25-1733.

- Smart Thermostats
- Member Battery Energy Storage

Between 2026 and 2029, Tri-State will continue to evaluate additional program concepts to support reaching the 2030 Colorado DR Target,[20] including but not limited to water heater controls, electric vehicle charging, and distribution-scale virtual power plants.

In 2025, Tri-State worked with its contracted partner, OATI, to implement a new Distributed Energy Resource Management System ("DERMS") which is a platform that enables event scheduling, DR and Distributed Energy Resource ("DER") integration and dispatch, DR/DER meter data analysis, and reporting. Most facets of the OATI DERMS are now operational for Tri-State users, with development resources now focused on Member system integrations. Tenants of the OATI DERMS platform will be made available to participating Utility Members, subject to terms and conditions of the Demand Response programs. Additionally, Tri-State has partnered with an outside consultant to assist with program design recommendations, in collaboration with Utility Members.

As of November 2025, the total DR capacity enrolled is 40 MW; in addition, approximately 45 battery assets are slated for enrollment once associated funding is released and will join the DR program at that time. Through the remainder of the year, Tri-State is working with Utility Members to continue to implement DERMS tenants and enroll additional C&I, residential and irrigation load, as well as battery storage resources. Tri-State informed stakeholders of its delay in implementing the DR program, and provided an update on the new DR Rider, during the June 17, 2025 DSM Roundtable Meeting.

7. Update on Emissions Reductions

In January 2022, Tri-State filed a Settlement Agreement with numerous parties to its 2020 Phase I ERP. Emissions reductions were among the many topics addressed through the Settlement Agreement. Tri-State agreed to emissions reduction targets for Tri-State's wholesale sales of electricity in Colorado, with respect to Tri-State's APCD-verified 2005 Baseline, as follows:

[20] 2023 ERP Phase I Settlement Agreement, section 4.9.1 states: "Tri-State will aim to control at least 5.5% of Tri State's Colorado peak load through demand response programs by 2030."

TABLE 3 – GHG EMISSIONS REDUCTION TARGETS[21]

Year	Percentage GHG Emissions Reduction
2025	26%
2026	36%
2027	46%
2030	80%

Tri-State also committed to including the following information in its APRs in each year following a year shown in Table 3:[22]

- The amount of GHG emissions, in tons, related to Tri-State's wholesale sales of electricity in Colorado for the prior calendar year, as reported by Tri-State to the Colorado Air Quality Control Commission under Regulation 22; and
- The percentage reduction in GHG emissions related to Tri-State's wholesale sales of electricity in Colorado for the prior calendar year, computed using the CEP Guidance and the 2005 Baseline. The percentage reduction will be consistent with the tonnages that Tri-State reports under Regulation 22.
- Information on how the emission rate for unspecified energy purchases specified by the CEP Guidance differed from the actual annual reported emissions rate for those purchases. Tri-State also will provide information as to whether any adjustments in operations or resource acquisitions are needed in order to ensure Tri-State meets the targets.

Tri-State will begin reporting this information in its December 2026 APR, for the 2025 GHG emissions reduction target.

As of October 31, 2025, Tri-State is forecasting a ~31% reduction in greenhouse gas (GHG) emissions from energy serving its Colorado load, from a 2005 baseline; the 2025 target is a 26% reduction,[23] making Tri-State on-target toward achieving its first Colorado emissions reduction milestone.

[21] Section 3.3.4. of the Settlement Agreement filed in Proceeding No. 20A-0528E.
[22] Section 3.3.11. of the Settlement Agreement filed in Proceeding No. 20A-0528E.
[23] Section 3.3.4. of the Settlement Agreement filed in Proceeding No. 20A-0528E.