BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-40:
PIOs' RFR of July Resource Adequacy Report

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

In re	)
Resource Adequacy Report	)
Evaluating the Reliability and Security	)
Of the United States Electric Grid	)
	)

Motion to Intervene and Request for Rehearing of
Natural Resources Defense Council, the Ecology Center, Environmental Defense Fund, Environmental Law and Policy Center, Public Citizen, Sierra Club, and Vote Solar

I. INTRODUCTION

Pursuant to section 313 of the Federal Power Act ("the Act"), 16 U.S.C. § 825*l*, Natural Resources Defense Council, the Ecology Center, Environmental Defense Fund, Environmental Law and Policy Center, Public Citizen, Sierra Club, and Vote Solar ("Public Interest Organizations") hereby move, to the extent necessary, to intervene and request rehearing of the Department of Energy's ("Department" or "DOE") "Resource Adequacy Report: Evaluating the Reliability and Security of the United States" ("RAR").[1] The Department issued the RAR in response to Executive Order 14,262 *Strengthening the Reliability and Security of the United States Electric Grid,* April 8, 2025 ("Grid EO"),[2] and claims that the RAR is a "uniform methodology to identify at-risk region(s) and guide reliability interventions" as directed by the Grid EO.[3] But the Department simultaneously disclaims the utility of the RAR to guide interventions uniformly, acknowledging on the very first page that the various "entities responsible for the maintenance and operation of the grid" have information "that could further enhance the robustness of reliability decisions" in their parts of the grid.[4]

The flaws in the RAR continue. The Department overstates assumptions about demand growth and likely retirements while understating likely new entry, building into the RAR an inherent bias toward a finding of inadequate resource adequacy. The Department also departs from best practices by using a

[1] July 7, 2025, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf (attached as Ex. 1) (hereinafter, the "RAR").

[2] 90 Fed. Reg. 15521 (Apr. 8, 2025) (hereinafter "Grid EO").

[3] *Id.* at vi.

[4] *Id.* at i.

deterministic approach, which fails to account for necessary uncertainties and demonstrates that the RAR's findings should not be taken as conclusive or form the basis for further extraordinary actions. And on some critical aspects of the RAR analysis, the Department simply fails to explain its own methodology; while the Department describes two thresholds at which the RAR projects outages will occur, it fails to explain when it applies the standard threshold and when it applies the elevated one. These flaws render any reliance on the RAR to "guide reliability interventions" arbitrary and capricious.

While the Department acknowledges that the RAR is unsuitable to guide reliability interventions uniformly and provided no notice or opportunity to comment, the Department nevertheless does not clarify how it will use the RAR, creating confusion as to whether the RAR, in conjunction with the Grid EO, is intended to function as a final rule. Public Interest Organizations believe that the RAR should not be used as the basis for future action by the Department. We submit this request for rehearing in an abundance of caution, to the extent the Department later argues that any of these issues must have been raised in a request for rehearing within 30 days of the publication of the RAR, 16 U.S.C. § 825*l*. We also reserve our right to argue in later proceedings that 16 U.S.C. § 825*l* does not apply.

In sum, the RAR is a poorly crafted solution in search of a problem; there is no "energy emergency" and the regulatory bodies who actually possess authority to ensure resource adequacy are doing their jobs. Consequently, the RAR serves no useful purpose and should simply be withdrawn. By DOE's own admission, the RAR cannot reasonably be relied on to guide DOE interventions, nor, given the false premise and multiple mistaken assumptions, does it provide any value even as a purely informational report. On the contrary, it will only cause confusion for grid operators, energy providers, and members of the public. In the alternative, the Department should not use the RAR as support for any reliability intervention or other action until and unless it (1) provides notice of the statutory authority under which DOE issued the RAR and publishes all data underlying the RAR, (2) explains in detail the specific uses for the methodology, and (3) allows interested parties to comment on the RAR before finalizing it.

II. STATEMENT OF ISSUES

1. The Department intrudes on Federal Energy Regulatory Commission ("FERC" or "the Commission") and state authority. 16 U.S.C. §§ 824a(c),824o-1; 42 U.S.C. § 7113.
2. The RAR's findings, even if accurate, do not demonstrate any emergency allowing the Department to compel generation under the Federal Power Act. 16 U.S.C. § 824a(c); S. Rep. No. 74-621 (1935); 10 C.F.R. § 205.371; 10 C.F.R. § 205.375; 46 Fed. Reg. 39,985.

3. The RAR is analytically flawed and does not rely upon substantial evidence. 16 U.S.C. 824a(a); 16 U.S.C. § 824o(a)(3).
4. The Department cannot use the RAR as a "uniform methodology" without giving notice and taking public comment. 5 U.S.C. §§ 552, 553; 10 C.F.R. §§ 205.371; 205.373.
5. The Department cannot use the RAR as a "uniform methodology" without following National Environmental Policy Act procedural requirements. 42 U.S.C. § 4332(C).

III. INTERVENTION

Each of the Public Interest Organizations has interests that may be directly and substantially affected by the use of this RAR as a "uniform methodology" to guide "reliability interventions," including the issuance of Emergency Orders under Section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c).[5] To the extent that the RAR is determined to be an Order or Rule, each party may intervene in this proceeding.[6] And to the extent the Department treats the RAR as binding and uses it to guide reliability interventions, each of the Public Interest Organizations and their members will suffer concrete injuries that are redressable through rehearing.[7] Each organization is therefore aggrieved if the RAR is a "uniform methodology" for use in guiding interventions, as the Department purports, and each organization may properly apply for rehearing, assuming without conceding that the rehearing procedures apply.[8]

A. Natural Resources Defense Council

Natural Resources Defense Council ("NRDC") is a national non-profit membership organization whose mission includes ensuring the rights of all people to clean air, clean water, and healthy communities. NRDC has a longstanding organizational commitment to protect the interests of its members and to reducing pollution caused by fossil fuel fired power plants. NRDC works to achieve clean

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[5] *See* RAR, Ex. 1 at iv.

[6] *See* U.S. Dep't of Energy, DOE 202(c) Order Rehearing Procedures, https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures (last visited June 18, 2025) (archived version attached as Ex. 2) (hereinafter "DOE Rehearing Procedures"). This website was altered after June 18, 2025, and the procedures were removed. *Compare* https://web.archive.org/web/20250604093213/https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures with the current website. *See also* Email from Lot Cooke, U.S. Dep't of Energy to Linda Alle-Murphy Re: Rehearing procedures for DOE Order No. 202-05-3 (December 30, 2005) (recommending that "a party seeking rehearing can look for procedural guidance to [Federal Energy Regulatory Commission's ("FERC")] Rules of Practice and Procedure, 18 CFR Part 385.") (attached as Ex. 3).

[7] *See, e.g. Alcoa Inc. v. FERC*, 564 F.3d 1342, 1346 (D.C. Cir. 2009).

[8] *See* 16 U.S.C. § 825*l*(a); *Wabash Valley Power Ass'n, Inc. v. FERC*, 268 F.3d 1105, 1112-13 (D.C. Cir. 2001); *NextEra Energy Res. v. ISO New Eng., Inc.*, 157 FERC ¶ 61,059, at P 5 (2016).

energy solutions that will lower consumer energy bills, meet greenhouse gas emission reduction goals, accelerate the use of energy efficiency and renewable energy, and ensure that clean energy is affordable and accessible to all. NRDC has hundreds of thousands of members across the United States. These NRDC members are harmed by orders to operate fossil fuel powered generation past planned retirement dates because continued operation will subject NRDC members to air and water pollution in the areas where they live, work, and recreate. NRDC members are also exposed to the noise and visual impacts of these facilities' operations. In addition, NRDC members are ratepayers in regions who will be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. For that reason, NRDC filed requests for rehearing of DOE's 202(c) orders issued to the J.H. Campbell and Eddystone plants, the latter of which explicitly stated that it would be reexamined following publication of the methodology. NRDC has five U.S. offices that also will be subject to higher electric bills as a result of "reliability interventions" undertaken as a result of the RAR's "uniform methodology." Moreover, NRDC has a sustainable operations plan with a goal of reducing net creation of greenhouse gas emissions derived from building operational activity to zero. NRDC and its members therefore have a strong interest in promoting actions that displace less cost-effective fossil generation with more cost-effective clean energy.

B. The Ecology Center

The Ecology Center is a Michigan-based non-profit organization headquartered in Ann Arbor, Michigan, with additional offices in Detroit, Michigan. Ecology Center is a public interest organization with more than 50 years of experience advocating for clean energy production, healthy communities, environmental justice, and a sustainable future. Ecology Center works at the local, state, and federal level. Its programs address systemic sources of poor health and environmental degradation through unique partnerships with environmental health and environmental advocates. Ecology Center has over 6,000 members and supporters, that live, use electricity, and pay electric bills in Michigan and could be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. In addition, Ecology Center members are harmed by orders to operate fossil fuel powered generation past planned retirement dates because continued operation will subject Ecology Center members to air and water pollution in the areas where they live, work, and recreate.

C. Environmental Defense Fund

The Environmental Defense Fund ("EDF") is a non-profit membership organization with hundreds of thousands of members nationwide whose mission is to build a vital Earth for everyone by preserving the natural systems on which all life depends. Guided by expertise in science, economics, law, and business partnerships, EDF seeks practical and lasting solutions to address environmental problems and protect human health, including in particular by addressing pollution from the power sector. On behalf of its members, EDF works with partners across

the private and public sectors to engage in utility regulatory forums at the federal level and throughout the United States to advocate for policies that will create an affordable, reliable, and low pollution energy system. Recent 202(c) Orders issued by the DOE have harmed members of EDF by causing increases in pollution, which impact the health of people and nature, and in energy costs. EDF has submitted requests for rehearing regarding the DOE Orders related to the J.H. Campbell and Eddystone power plants and a Petition for Review regarding the DOE Order regarding the J.H. Campbell plant. Further 202(c) Orders issued as a result of the RAR, including extensions of the J.H. Campbell and Eddystone orders and orders directed at other generators, will result in further pollution and cost impacts that will harm EDF members.

D. Environmental Law and Policy Center

Environmental Law and Policy Center ("ELPC") is a not-for-profit environmental organization with members, contributors, and offices throughout the Midwest. Among other things, ELPC advocates before state public service commissions and the Federal Energy Regulatory Commission for clean, reliable energy generation in order to reduce ratepayer costs and improve environmental outcomes. ELPC members in the Midwest live, work, and recreate near power plants that burn coal or other fossil fuels and are directly impacted by their pollutants. In addition, ELPC members are ratepayers in regions who could be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. ELPC and its members could be subject to higher electric bills and impacted by additional pollution as a result of "reliability interventions" undertaken as a result of the RAR's "uniform methodology." ELPC has a longstanding organizational commitment to protect the interests of its members, to reduce pollution caused by fossil fuel-fired power plants, and to promote clean, reliable energy generation.

E. Public Citizen

Public Citizen, Inc. hereby intervenes in these proceedings. Public Citizen, Inc. is an active intervenor and participant before the Federal Energy Regulatory Commission in Federal Power Act proceedings, as well as before the U.S. Department of Energy in both electricity export and natural gas export dockets to ensure just and reasonable rates and that utilities' operations are consistent with the public interest. Established in 1971, Public Citizen, Inc. is a national, not-for-profit, non-partisan, research and advocacy organization representing the interests of American household consumers. Public Citizen has members in all 50 states and represents the interests of consumers, not represented by any other party in this proceeding. Financial details about our organization are on our website: www.citizen.org/about/annual-report/.

F. Sierra Club

Sierra Club is a national environmental non-profit whose purpose is to explore, enjoy, and protect the wild places of the earth; to practice and promote the responsible use of the earth's ecosystems and resources; to educate and enlist humanity to protect and restore the quality of the natural and human environment; and to use all lawful means to carry out these objectives. To those ends, the Sierra Club and its members have worked to limit pollution caused by fossil-fuel-fired power plants through public education and advocacy at the local, state, and federal level. Sierra Club represents over 640,000 members nationwide, many of whom reside and recreate in the regions in which the RAR purports to identify resource shortfalls requiring the continued operation of coal- and gas-fired generation. Sierra Club members in those areas would be harmed by the pollution and the increased utility rates caused by any such continued operation.

G. Vote Solar

Vote Solar is an independent 501(c)(3) non-profit working to re-power the U.S. with clean energy by making solar power more accessible and affordable through effective policy advocacy. In over half of the country, Vote Solar seeks to promote the development of solar at every scale, from distributed rooftop solar to large utility-scale plants. Vote Solar has over 90,000 members nationally. Vote Solar members are ratepayers in regions who could be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. Vote Solar is not a trade organization, nor does it have corporate members. Vote Solar is committed to promoting clean, renewable energy and transitioning away from coal generation.

IV. BACKGROUND

A. Executive Orders

The genesis of the RAR lies in the President's unsupported day one declaration of a national energy emergency: *Declaring a National Energy Emergency* ("Energy Emergency EO").[9] That declaration's lack of factual underpinning was highlighted in a recent report by DOE's independent statistics and analysis arm, the Energy Information Administration ("EIA"). The EIA report highlights how U.S. energy production and exports are currently at an all-time high.[10] Nonetheless, the Energy Emergency EO was cited as a basis for the

[9] Exec. Order No. 14,156, 90 Fed. Reg. 8433 (January 20, 2025) (hereinafter "Energy Emergency EO") (attached as Ex. 4). *See* also RAR, Ex. 1 at vi (explaining that the Grid EO "builds on" the Energy Emergency EO).

[10] *See* U.S. EIA, *U.S. primary energy production, consumption, and exports increased in 2024* (June 20, 2025), https://www.eia.gov/todayinenergy/detail.php?id=65524.

President's follow-up grid-specific executive order, the Grid EO, that led to DOE's publication of the RAR.[11]

The Grid EO directed DOE to take three steps to address the President's assertion that there may be lack of grid reliability in the future, including: 1) to streamline the processes to issue orders pursuant to Federal Power Act Section 202(c);[12] 2) to develop a reserve margin assessment methodology and use it to identify at risk regions and critical energy resources within those regions and to publish that methodology within 90-days of the Grid EO;[13] and 3) to establish a protocol for identifying critical generating resources and taking action to prevent retirement or conversion of the fuel source of such resources.[14]

Notably, the Grid EO was issued in conjunction with a series of actions by President Trump and DOE designed explicitly to prop up the coal and gas industries, including: 1) Executive Order 14,261, *Reinvigorating America's Beautiful Clean Coal Industry,*[15] which seeks to restart coal leasing and expand coal mining on federal lands, in addition to making these processes easier by offering loans and streamlining permitting;[16] 2) a Presidential Proclamation entitled *Regulatory Relief for Certain Stationary Sources to Promote American Energy* that exempts coal plants from complying with the U.S. Environmental Protection Agency's updated Mercury and Air Toxics Standards;[17] and 3) Executive Order 14,260, *Protecting American Energy from State Overreach*,[18] which directs the U.S.

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[11] Nor does the Energy Emergency EO supply legal support for the Grid EO. Under the National Emergencies Act, 50 U.S.C. § 1631, a declaration of national emergency does not authorize the exercise of emergency powers "unless and until the President specifies the provisions of law under which he proposes that he, or other officers will act." But as Congress made clear, the statute "is not intended to enlarge or add to Executive power" such as authority under Section 202(c), only to "establish clear procedures and safeguards for the exercise by the President of emergency powers conferred on him by other statutes." S. Rep. No. 94-1168, 3 (1976).

[12] Grid EO Section 3(a).

[13] *Id.* Section 3(b).

[14] *Id.* Section 3(c).

[15] *See* Exec. Order No. 14,261, 90 Fed. Reg. 15,517 (Apr. 8, 2025).

[16] DOE simultaneously announced several initiatives to subsidize the coal industry, including loan guarantees for coal-fired power plant projects. Dep't of Energy, *Energy Department Acts to Unleash American Coal by Strengthening Coal Technology and Securing Critical Supply Chains* (Apr. 8, 2025), https://www.energy.gov/articles/energy-department-acts-unleash-american-coal-strengthening-coal-technology-and-securing.

[17] Proclamation No. 10914, 90 Fed. Reg. 16777 (Apr. 8, 2025).

[18] Exec. Order No. 14,260, 90 Fed. Reg. 15513 (Apr. 8, 2025).

Department of Justice to take action to block states' exercises of their police powers to protect their residents from pollution caused by coal and fossil-fuel sources.[19]

B. RAR

On July 7, 2025, DOE published the RAR on its website. The RAR includes a deterministic analysis of the resource adequacy of the current electric system and three 2030 cases: (1) the Plant Closure case includes 104 GW of coal and gas retirements plus 100% of NERC's Tier 1 additions; (2) the No Plant Closures case includes no retirements but 100% of NERC's Tier 1 additions; and (3) the Required Build case begins with the Plant Closures scenario and projects what additional added perfect capacity would be needed to meet the RAR's determined reliability standards.[20] Each of the three 2030 scenarios assume 50 GW of load growth from data centers and an additional 51 GW of load growth from other sources.[21] The Department finds in the RAR that, under the current system, only ERCOT fails to achieve DOE's selected resource adequacy targets,[22] but that, based on the methodology used to forecast the 2030 scenarios, there will be broader resource adequacy issues in 2030.[23] And, notwithstanding the RAR's upfront acknowledgement that the analysis used "could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level,"[24] the Department proceeds to make broad declarations of future need based on its findings in the RAR.[25]

DOE explained that the RAR was being issued pursuant to the Grid EO. The RAR incorporates a full copy of the Grid EO and explains that "[t]his report serves as DOE's response to [the Grid EO's] Section 3(b) … by delivering the required uniform methodology to identify at-risk region(s) and guide reliability

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[19] These actions mimic President Trump's failed efforts to prop up the coal industry during his first term, including DOE's proposed rule, soundly rejected by FERC, that would have provided assured cost recovery (including a return on equity) for coal and nuclear plants (*see* 162 FERC ¶ 61,012), and the President's unfulfilled directive that DOE use Section 202(c) and the Defense Production Act to block closure of uneconomic coal plants while requiring grid operators to bear the costs. *See* Draft Memorandum (May 29, 2018), https://embed.documentcloud.org/documents/4491203-Grid-Memo/.

[20] RAR, Ex. 1 at 4-5.

[21] *Id.* at 2-3, 15-17.

[22] *Id.* at 7.

[23] *Id.* at 6-9.

[24] *Id.* at i.

[25] *Id.* at 1-2. *See also*, DOE Fact Sheet, https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf; DOE Press Release, https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security.

interventions."[26] DOE's statement that it intends to use the methodology "to guide reliability interventions" and that DOE will continue to use the RAR "on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States" suggests that the RAR may be intended to also serve as the protocol called for by Section 3(c) of the Grid EO.[27] But the RAR fails to clarify this, or, if the RAR does not also serve as DOE's response to Section 3(c), whether a protocol has been or will be developed, or whether any protocol will be made public. The RAR does not include any discussion of Section 3(a) of the Grid EO. To the extent that the Department addressed that portion of the Grid EO's directions, it has not made any process changes public. On the contrary, the Department has made its processes under Section 202(c) even less transparent by removing the existing process guidance from the DOE website.[28]

Notwithstanding the statement in the RAR that DOE intends to use the "methodology to identify at-risk region(s) and guide reliability interventions," e.g., Section 202(c) Orders,[29] other portions of the RAR make clear that it can't and shouldn't be used as a basis for interventions, specifically not issuance of 202(c) Orders. First and foremost, the reliability projections in the RAR focus on conditions five years from now and concede that there are not current grid conditions that fit within Section 202(c)'s definition of an "emergency." Second, the Department candidly concedes the RAR's lack of robustness: "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."[30]

C. Section 202(c) Orders

Section 202(c) of the Federal Power Act allows the Secretary of Energy, in certain emergency situations, to require by order temporary connections of facilities, and generation, delivery, interchange, or transmission of electricity as the Secretary

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[26] RAR, Ex. 1 at vi.

[27] *Id.*

[28] *Compare* https://web.archive.org/web/20250604093213/https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures with the current website.

[29] *See* 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 ("The methodology also informs the potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act.").

[30] RAR, Ex. 1 at i.

determines will best meet the emergency and serve the public interest. Section 202(c) has an important purpose: to mitigate electricity shortages caused by war, drought, and other emergencies. In granting DOE the authority that Section 202(c) provides, Congress considered the severe societal consequences of blackouts and determined that avoiding those consequences justified allowing DOE to act without notice and to require operations that override environmental laws. But Congress was also very careful to narrowly limit DOE's use of that authority, as the title of the provision makes clear, to "temporary" "emergency" situations.[31] And while the statute doesn't define "emergency," DOE's regulations include a lengthy definition which reinforces the key element in the statute: 202(c) orders are for situations that are sudden and unexpected, not for longer term grid management.[32]

1. DOE's Past Use of 202(c) Orders

The Department's application of Section 202(c) consistently confirms the urgency of the conditions necessary to invoke the provision and underscores the lack of authority for the planned implementation scheme described in the Grid EO and RAR.[33] The Department's predominant practice has been to use Section 202(c) to address specific, imminent, and unexpected shortages—not to address longer-term reliability concerns or demand forecasts.[34]

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[31] *See, e.g., Richmond Power & Light,* 574 F.2d at 617 (Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply and not at those in which supply is adequate but a means of fueling its production is in disfavor.").

[32] 10 C.F.R. § 205.371: "'Emergency,' as used herein, is defined as an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected 'entity' to prevent. An emergency also can result from a sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which prohibits the use of certain electric power supply facilities. Actions under this authority are envisioned as meeting a specific inadequate power supply situation. Extended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in these regulations. In such cases, the impacted 'entity' will be expected to make firm arrangements to resolve the problem until new facilities become available, so that a continuing emergency order is not needed. Situations where a shortage of electric energy is projected due solely to the failure of parties to agree to terms, conditions or other economic factors relating to service, generally will not be considered as emergencies unless the inability to supply electric service is imminent. Where an electricity outage or service inadequacy qualifies for a section202(c) order, contractual difficulties alone will not be sufficient to preclude the issuance of an emergency order."

[33] *See FTC v. Bunte Brothers, Inc.*, 312 U.S. 349, 352 (1941) ("[J]ust as established practice may shed light on the extent of power conveyed by general statutory language, so the want of assertion of power by those who presumably would be alert to exercise it, is equally significant in determining whether such power was actually conferred.").

[34] *See, e.g.,* Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) (responding to ongoing severe winter storm producing immediate and "unusually high peak load" between December 23 and

The law also requires the Department to narrowly tailor the remedies in Section 202(c) orders to ensure that the orders only address the stated emergency, limit the order to "only [the] hours necessary to meet the emergency," be "consistent with any applicable Federal, State, or local environmental law or regulation," and to "minimize[] any adverse environmental impacts.[35] Up until recently, the Department has routinely followed these provisions of the law.[36]

2. DOE's Recent Misuse of Section 202(c)

Prior to issuance of the RAR but consistent with the direction in the Grid EO, DOE issued two Section 202(c) orders blocking the planned closures of two fossil-fuel fired generation resources that were unreliable, uneconomic, and at the end of their useful lives: the J.H. Campbell coal-fired plant in West Olive Michigan,[37] and units 3 and 4 of the Eddystone oil and gas fired plant in Eddystone, Pennsylvania.[38] The Eddystone 202(c) Order stated that "DOE plans to use this methodology [i.e., the RAR] to further evaluate Eddystone Units 3 and 4," thus raising questions about DOE's intentions as to the legal status and efficacy of the RAR.

Public Interest Organizations filed requests for rehearing for both the J.H. Campbell and Eddystone 202(c) Orders.[39] In both cases DOE failed to identify conditions that would qualify as "emergencies" for the purpose of issuance of Section 202(c) Orders. And both Section 202(c) Orders impose significant costs on ratepayers,[40] while increasing emissions of air pollutants and providing no

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December 26) (attached as Ex.5); Department of Energy Order 202-20-2 (Sept. 6, 2020) at 10-2 (responding to shortages produced by ongoing extreme heat and wildfires) (attached as Ex.6); *see also* Benjamin Rolsma, *The New Reliability Override*, 57 CONN. L. REV. 789, 803-4 (describing "sparing[]" use of Section 202(c) outside of wartime shortages during the twentieth century) (attached as Ex. 7).

[35] 16 U.S.C.§ 824a(c)(2).

[36] *See, e.g.,* Ex.5, Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) at 4-7 (limiting order to the 3 days of peak load, directing PJM to exhaust all available resources beforehand, requiring detailed environmental reporting, notice to affected communities, and calculation of net revenue associated with actions violating environmental laws); Ex.6, Dep't of Energy Order 202-20-2 (Sept. 6, 2020) at 3-4 (limiting order to the 7 days of peak load, directing CAISO to exhaust all available resources beforehand, requiring detailed environmental reporting).

[37]Dep't of Energy Order No. 202-25-3 (May 23, 2025) (attached as Ex. 8).

[38]Dep't of Energy Order No. 202-25-4 (May 30, 2025) (hereinafter "Eddystone 202(c) Order") (attached as Ex. 9).

[39] Mot. to Intervene and Request for Rh'g and Stay of Pub. Int. Orgs., DOE Ord. No. 202-25-3 (June 18, 2025) (hereinafter "Campbell RFR") (attached as Ex.10);Mot. to Intervene and Request for Rh'g and Stay of Pub. Int. Orgs., DOE Ord. No. 202-25-4 (June 27, 2025) (hereinafter "Eddystone RFR") (attached as Ex.11).

meaningful corresponding reliability benefit.[41] The Department denied both of Public Interest Organization's requests for rehearing by operation of law.[42]

D. Existing Mechanisms Ensure Resource Adequacy

In the United States, how electricity is bought and sold varies by region. Electric utilities can be either traditionally regulated and operate as vertically integrated monopolies, or they can operate in deregulated, competitive markets where electric energy prices are set by the market. Both vertically integrated utilities and utilities in deregulated markets are subject to federal oversight, and in some of the deregulated states, the state nonetheless exercises oversight over the terms of retail supply offers, especially for retail customers. And all utilities are subject to reliability standards developed by the North American Electric Reliability Corporation ("NERC") and approved by FERC. In sum, FERC, Regional Transmission Organizations ("RTOs"), States, and NERC all play a hand in ensuring resource adequacy.

1. Vertically integrated utilities

Until the 1990s, utilities were generally vertically integrated such that generation, transmission, and distribution resources were all held by the same entity.[43] Vertically integrated utilities must seek state approval for power plant investments.[44] Many state regulators require utilities to demonstrate the necessity of proposed investments through an integrated resource planning process.[45] This process is used for long-term planning and requires the utility to justify its investments and demonstrate how it plans to meet customer electricity demand.[46] Even though vertically integrated utilities generate their own electricity, many

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[40] *See e.g.* U.S. Sec. and Exch. Comm'n, Form 10-Q, Consumers Energy Company Quarterly Report For the Quarterly Period Ended June 30, 2025, at 39, 62, 92 (2025) https://d18rn0p25nwr6d.cloudfront.net/CIK-0000201533/10a900b7-263b-4ccd-82a0-4162ba7ae5f2.pdf (describing costs of $29 million to operate Campbell through June 30, 2025); FERC Docket No. ER25-2653-000 (PJM proposed cost allocation to implement DOE Order 202-25-4).

[41] *See* Campbell RFR, Ex. 10 at 11-14; Eddystone RFR, Ex. 11 at 56-60. 87-88.

[42] Dep't of Energy, Notice of Denial of Reh'g by Operation of Law and Providing for Further Consideration of Ord. No. 202-25-3A (July 28, 2025) (attached as Ex. 12); Dep't of Energy, Notice of Denial of Reh'g by Operation of Law and Providing for Further Consideration of Ord. No. 202-25-4A (Aug. 1, 2025) (attached as Ex. 13).

[43] *See* Kathryne Cleary and Karen Palmer, *US Electricity Markets 101* (March 17, 2022), Resources for the Future, https://www.rff.org/publications/explainers/us-electricity-markets-101/.

[44] *Id.*

[45] *Id.*

[46] *Id.*

trade with other utilities during times of need. These wholesale market transactions are subject to regulation by FERC.[47]

2. Competitive markets

Advances in technology and statutory changes led to the development of energy markets and merchant generation that is not owned by incumbent utilities.[48] In the 1990s, FERC fostered competitive markets through rules that allowed the establishment of independently-operated voluntary RTOs that determine the prices for energy, capacity, and ancillary services based on procurement and dispatch of least-cost resources through Order Nos. 888, 890, and 2000.[49] As RTO markets expanded, many states deregulated their utility monopolies and required them to join RTOs. Deregulated states use markets to determine which power plants are necessary for electricity generation.[50] Even in deregulated states, the state sites new generation. Market price signals encourage new investment when supply is tight and encourage the retirement of facilities that are no longer competitive when capacity is plentiful. RTOs now account for approximately 2/3 of all electricity sales in the U.S. and have saved consumers billions of dollars, increased reliability, and reduced environmental harm.[51]

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[47] *See* FERC, *Electric Power Markets* (last updated March 27, 2025), https://www.ferc.gov/electric-power-markets.

[48] *See, e.g.,* Order Terminating Rulemaking Proceeding, Initiating New Proceeding, And Establishing Additional Procedures, 162 FERC ¶ 61,012, PP 7-11 (2018); Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,639-31,645 (1996), order on reh'g, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. *New York v. FERC*, 535 U.S. 1 (2002).

[49] Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 638-41 (1996), Order No. 890, FERC Stats. & Regs. ¶ 31,241, at 124-352 (1997), Order No. 2000, FERC Stats. & Regs. ¶ 31,089, at 99-130 (1999).

[50] State regulators in competitive markets still practice oversight over utilities. For example, some states, such as Michigan, use both the market and integrated resource planning. *See* Michigan Public Service Commission, *Phase III – Integrated Resource Plan* (last visited Aug. 4, 2025), https://www.michigan.gov/mpsc/commission/workgroups/mi-power-grid/phase-iii-integrated-resource-plan-mirpp-filing-requirements-demand-response-study-energy-waste-red. Other state legislatures or commissions have enacted subsidies to keep nuclear plants alive, such as in New York, Illinois, Ohio, and New Jersey. *See* U.S. EIA, Five states have implemented programs to assist nuclear power plants (Oct. 7, 2019), https://www.eia.gov/todayinenergy/detail.php?id=41534.

[51] *See, e.g.*, Judy Chang et al., The Brattle Group, Potential Benefits of a Regional Wholesale Power Market to North Carolina's Electricity Customers, 1, 3-7 (April 2019) https://www.brattle.com/wp-content/uploads/2021/05/16092_nc_wholesale_power_market_whitepaper_april_2019_final.pdf (discussing billions of dollars in estimated cost saving); Jennifer Chen & Devin Hartman, *Why wholesale market benefits are not always apparent in customer bills*, R Street (Nov. 10, 2021), https://www.rstreet.org/commentary/why-wholesale-market-benefits-are-not-always-apparent-in-

As explained by FERC, its "support of competitive wholesale electricity markets has been grounded in the substantial and well-documented economic benefits that these markets provide to consumers."[52] In addition to billions of dollars of consumer savings, FERC found that competitive markets protect consumers by "providing more supply options, encouraging new entry and innovation, spurring deployment of new technologies, promoting demand response and energy efficiency, improving operating performance, exerting downward pressure on costs, and shifting risk away from consumers."[53]

3. FERC and NERC Reliability Regulation

As part of its role in regulating the wholesale electric industry, FERC has implemented Congressional mandates to ensure system reliability, including establishing NERC as the Electric Reliability Organization, which sets industry standards for grid reliability that are approved by FERC;[54] coordination requirements for the natural gas and electricity market scheduling;[55] investigation and improvements required in light of the grid's response to extreme weather events;[56] and reviewing capacity accreditation processes to ensure that capacity markets generate reliable results.[57]

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customer-bills/ (same); Jeff St. John, *A Western US energy market would boost clean energy. Will it happen?*, Canary Media (Jun. 10, 2024), https://www.canarymedia.com/articles/utilities/a-western-us-energy-market-would-boost-clean-energy.-will-it-happen; John Tsoukalis et al., Assessment of Potential Market Reforms for South Carolina's Electricity Sector, at 6, 46, 77-78 (Apr. 27, 2019), https://www.scstatehouse.gov/CommitteeInfo/ElectricityMarketReformMeasuresStudyCommittee/2022-04-27%20-%20SC%20Electricity%20Market%20Reform_Brattle%20Report.pdf (discussing cost savings across regional wholesale markets).

[52] Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures, 162 FERC ¶ 61,012, P 11 (2018).

[53] *Id.* (citation omitted).

[54] PJM, NERC and Reliability Fact Sheet (Jan. 5, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/nerc-and-reliability-fact-sheet.pdf. *See also* PJM, PJM Ensures a Reliable Grid (Jan. 29, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/reliability-fact-sheet.pdf.

[55] PJM, PJM Promotes Gas/Electricity Industry Coordination (Jan. 29, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/gas-electric-coordination-fact-sheet.pdf. *See also* Order 787, 145 FERC ¶ 61,134 (2013); Order 809, 151 FERC ¶ 61,049 (2015).

[56] *See e.g.,* Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, 149 FERC ¶ 61,145 (2014) (order addressing technical conferences on, among other things, the 2014 Polar Vortex); Order Approving Extreme Cold Weather Reliability Standards EOP-011-3 and EOP-012-1 and Directing Modification of Reliability Standard EOP-012-1, 182 FERC ¶ 61094 (2023); Order Approving Extreme Cold Weather Reliability Standard EOP-012-2 and Directing Modification, 187 FERC ¶ 61,204 (2024). *See also* FERC, NERC and Regional Staff, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott (Oct. 2023), https://www.ferc.gov/sites/default/files/2023-11/24_Winter-Storm_Elliot_1107_1300.pdf; FERC, NERC and Regional Entity Joint Staff, The February 2021 Cold Weather Outages in Texas and the

V. ARGUMENT

A. The Department Is Intruding on FERC and State Authority.

The Department's authority over reliability is strictly circumscribed to respond to imminent emergencies;[58] this authority does not extend to regulating long-term or overarching aspects of the electricity sector. Rather, Congress reserved to the states and FERC the authority to regulate the electric sector generally and to regulate resource adequacy and reliability specifically. Recent actions—starting with the Energy Emergency EO and culminating in the RAR—indicate, however, that DOE is not remaining in its designated lane.[59] The RAR lays bare the Department's agenda to prop up fossil fuel businesses by utilizing emergency authority in a systematic fashion that goes well beyond the scope of DOE's authority under the Federal Power Act and illegally intrudes upon authorities that Congress has explicitly reserved to the states or given to FERC.

The authority to maintain a reliable electric system in the United States has evolved over the years to include parties at the federal, regional, state, and local levels.[60] But the Department of Energy has never been granted primary regulatory authority over either reliability or resource adequacy of the grid. Rather, the Department of Energy Organization Act of 1977 ("Organization Act")[61] and the

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South Central United States (Nov. 2021), https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/FERC%20Presentation-Phase%202.pdf; PJM, Winter Storm Elliott Event Analysis and Recommendation Report (2023), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.pdf.

[57] *Id.*; *see also* Order Accepting Tariff Revisions Subject to Condition, 186 FERC ¶ 61,080 (2024).

[58] *See* 16 U.S.C. §§ 824a(c),824o-1.

[59] *See* Energy Emergency EO, Ex. 4; Grid EO Sec. 3 (RAR, Ex. 1 at C); RAR Ex. 1; DOE, DOE Fact Sheet, https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf; DOE Press Release, https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security; Eddystone 202(c) Order, Ex. 9; Dep't of Energy Order No. 202-25-3 (May 23, 2025), Ex. 8.

[60] *New York v. FERC*, 535 U.S. 1, 5-8 (2002) ("Prior to 1935, the States possessed broad authority to regulate public utilities"). *See generally* Nat'l Ass'n of Reg. Util. Comm'rs ("NARUC"), *Resource Adequacy for State Utility Regulators: Current Practices and Emerging Reforms* (Nov. 2023) https://pubs.naruc.org/pub/0CC6285D-A813-1819-5337-BC750CD704E3?_gl=1*oyp366*_ga*MTc1NzM0NTE0LjE3NTM5ODk1NDA.*_ga_QLH1N3Q1NF*czE3NTM5ODk1NDAkbzEkZzEkdDE3NTM5ODk1NzUkajI1JGwwJGgw; NARUC, *Resource Adequacy Primer for State Regulators* (July 2021), https://pubs.naruc.org/pub/752088A2-1866-DAAC-99FB-6EB5FEA73042?_gl=1*1mituzu*_ga*MTc1NzM0NTE0LjE3NTM5ODk1NDA.*_ga_QLH1N3Q1NF*czE3NTM5ODk1NDAkbzEkZzAkdDE3NTM5ODk1NDAkajYwJGwwJGgw.

[61] 42 U.S.C. § 7111 *et seq.*

Federal Power Act[62] give to the Department only narrow, emergency authority over the electric system—for example through Federal Power Act Sections 202(c) and 215A.[63] The President's declaration of an energy emergency (even if it were legitimate) and other executive orders cannot expand these statutorily defined authorities.[64] And while the Department may of course analyze policy implications and issue reports on various topics—as it has done since its founding—DOE's statements indicate that the RAR is not simply a policy analysis. The Department states—without limitation—that it will use the RAR "to identify at-risk region(s) and guide reliability interventions."[65] Thus, taking DOE at its word, the RAR is beyond the Department's authority.

Further, to the extent that it is an indication of the Department's broader scheme, in the RAR, the Department ignores the limitations on its authority and the comparative breadth of authority explicitly reserved to the states and FERC over the Department. "States are responsible for resource adequacy in siting of electric facilities, establishing retail electric rates, and overseeing the reliability of the distribution system."[66] State public utility commissions review utility proposals for long-term impacts to the system's reliability. "Most states address resource adequacy by requiring large investor-owned utilities to file long-term planning documents like integrated resource plans that include strategies for reliably meeting future demand."[67]

The structure and language of the Organization Act and Federal Power Act reflect Congress's deliberate choices to preserve this traditional state authority over generating facilities and to circumscribe the Department's emergency authority in light of the states' role. Congress noted in the Organization Act that "[n]othing in this chapter shall affect the authority of any State over matters exclusively within its jurisdiction."[68] And the first sentence of the Federal Power Act declares that

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[62] Subsequent legislation has also amended and updated these authorities. *See e.g.* Fixing America's Surface Transportation Act (FAST Act), Pub. L. No. 114–94, 129 Stat. 1312 (2015); Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005).

[63] 16 U.S.C. §§ 824a(c), 824o-1.

[64] *See Biden v. Nebraska*, 600 U.S. 477, 500-01 (2023); *see also* S. Rep. No. 94-1168, 3 (1976), (the National Emergencies Act "is not intended to enlarge or add to Executive power. Rather, the statute is an effort by Congress to establish clear procedures and safeguards for the exercise by the President of emergency powers *conferred on him by other statutes*.") (emphasis added).

[65] RAR, Ex. 1 at vi.

[66] NARUC, *Resource Adequacy Primer for State Regulators*, at 9 (July 2021) https://pubs.naruc.org/pub/752088A2-1866-DAAC-99FB-6EB5FEA73042?_gl=1*1mituzu*_ga*MTc1NzM0NTE0LjE3NTM5ODk1NDA.*_ga_QLH1N3Q1NF*czE3NTM5ODk1NDAkbzEkZzAkdDE3NTM5ODk1NDAkajYwJGwwJGgw.

[67] Nat'l Renewable Energy Lab'y, *Explained: Fundamentals of Power Grid Reliability and Clean Electricity*, at 4 (Jan. 2024) https://docs.nrel.gov/docs/fy24osti/85880.pdf.

[68] 42 U.S.C. § 7113.

federal regulation extends "only to those matters which are not subject to regulation by the States."[69] Section 201(b)(1) further states that, except as otherwise "specifically" provided, federal jurisdiction does not attach to "facilities used for the generation of electric energy."[70] The courts have held that Section 201(b)(1) reserves to the states authority over electric generating facilities,[71] including the authority to order their closure.[72] Congress also recognized the states' exclusive authority over generating facilities in Section 202(b), which provides that FERC's interconnection authority does not include the power to "compel the enlargement of generating facilities for such purposes."[73] And when Congress added new authority regarding reliability to the Federal Power Act in 2005, it also still explicitly clarified that "[n]othing in this section shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard…."[74]

The RAR also intrudes upon authority that Congress explicitly and repeatedly gave exclusively to FERC, not the Department. In 1935, Congress passed the Federal Power Act, creating the Federal Power Commission to engage in "federal regulation of electricity in areas beyond the reach of state power."[75] However, until the 1970s, the federal government played a very limited role in energy policy and generally left to private industry and state and local governments the task of establishing energy policies and planning.[76] In 1977, Congress passed the Organization Act,[77] creating both the Department and FERC. The Organization Act transferred most of the authority for overseeing the electric system in the

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[69] 16 U.S.C. § 824(a).

[70] *Id.* § 824(b)(1).

[71] *See, e.g., Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 154 (2016).

[72] *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (2009) (under Section 201(b), states retain the right "to require retirement of existing generators" or to "take any other action in their role as regulators of generation facilities."). *See also 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.").

[73] 16 U.S.C. § 824a(b).

[74] 16 U.S.C. § 824o.

[75] *New York v. FERC*, 535 U.S. 1, 6 (2002).

[76] DOE, *A Brief History of the Department of Energy,* https://www.energy.gov/lm/brief-history-department-energy. *See also* DOE, *Department of Energy 1977-1994, A Summary History* (Nov. 1994), https://www.energy.gov/sites/prod/files/2017/09/f36/DOE%201977-1994%20A%20Summary%20History_0.pdf.

[77] Public Law 95–91 (1977), 42 U.S.C. § 7101 *et seq.*

Federal Power Act to FERC, not the Department;[78] the Department retained primary authority only over "emergency interconnection."[79]

While FERC is housed within the Department, FERC is an independent agency with distinct authority from the Department that the Department may not modify or supersede.[80] Generally the Department "is authorized to establish, alter, consolidate or discontinue such organizational units or components within the Department as [the Secretary] may deem to be necessary or appropriate."[81] But this authority explicitly does not extend to FERC. The Organization Act explains that the Department may not abolish "organizational units or components established by" the Organization Act, nor may it "transfer [] functions vested by this chapter in any organizational unit or component."[82] Because the Organization Act created[83] and transferred specific authority to FERC,[84] the Department has no authority to alter FERC itself nor to seize FERC's statutorily prescribed authority.

Further, "the decision of the Commission involving any function within its jurisdiction . . . shall be final agency action . . . and *shall not be subject to further review by the Secretary* or any officer or employee of the Department."[85] While the Department can propose rules under FERC's jurisdiction, FERC maintains "exclusive jurisdiction . . . to take final action on any proposal made by the Secretary."[86] And when the Department proposes a rule in the exercise of its own functions that FERC determines significantly affects any function within FERC's jurisdiction, FERC can insist on changes that DOE must adopt if DOE wants to issue the rule.[87]

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[78] 42 U.S.C. § 7172 (transferring functions from Federal Power Commission to FERC); 42 U.S.C. § 7151 (the function of the Federal Power Commission is transferred to the Secretary except as provided to FERC). The Department and FERC share authority over certain parts of the Federal Power Act that primarily address recordkeeping and administration. 42 U.S.C. § 7172(a)(2) ("The Commission may exercise any power under the following sections to the extent the Commission determines such power to be necessary to the exercise of any function within the jurisdiction of the Commission: (A) sections 4, 301, 302, 306 through 309, and 312 through 316 of the Federal Power Act.").

[79] *See* 42 U.S.C. § 7172(a)(1)(B).

[80] *See* 42 U.S.C.A. § 7112 (Congressional declaration of purpose in establishing Department); 42 U.S.C. § 7171 (establishment of FERC).

[81] 42 U.S.C. § 7253.

[82] 42 U.S.C. § 7253.

[83] 42 U.S.C. § 7171 (establishment of FERC).

[84] 42 U.S.C. § 7172(a) (transferring functions from Federal Power Commission to FERC).

[85] 42 U.S.C. § 7172(g) (emphasis added).

[86] 42 U.S.C. § 7173. *See* 162 FERC ¶ 61,012.

[87] 42 U.S.C. § 7174.

In 2005, Congress expanded FERC's authority to specifically encompass reliability by updating the Federal Power Act in the 2005 Energy Policy Act.[88] While "FERC had previously addressed electric grid reliability in an indirect manner, such as allowing the cost recovery of public utility expenditures that address discrete reliability matters,"[89] there had been no mandatory reliability standards adopted by any federal regulator. When providing recommendations on reliability in 1998, the Department had concluded "that the U.S. Congress should explicitly assign oversight of bulk-power reliability to the FERC."[90] The new Section 215 followed the Department's suggestion and "tasked FERC [—not the Department—] with a direct role over an entire new field of activity."[91] Section 215 authorizes FERC to certify an electric reliability organization; FERC designated NERC. It is therefore NERC that develops reliability standards that FERC reviews to ensure consistency with federal law.[92] The broad reliability authority Congress granted to FERC contrasts with the very narrow, emergency authority in Section 215A that Congress granted to the Department.[93] The RAR appears to duplicate FERC and NERC's reliability efforts, impermissibly intruding upon authority Congress chose to give FERC —subject to elaborate procedural and substantive limitations—not the Department.

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[88] Pub. L. No. 109-58, 119 Stat. 594 (2005).

[89] FERC, *Reliability Primer*, at 5 (2020) https://www.ferc.gov/sites/default/files/2020-04/reliability-primer_1.pdf.

[90] DOE, *Maintaining Reliability in a Competitive U.S. Electricity Industry* at vii-viii, xiv (Sept. 29, 1998), https://certs.lbl.gov/sites/all/files/basic-page/maintainting-reliability-in-competitive-electricity-industry-1998_0.pdf ("The Administration has proposed legislation that would provide the federal oversight necessary to make reliability standards mandatory. The NERC has begun to reinvent itself to respond to the changing needs of the industry. In addition, the FERC has undertaken several reliability initiatives. However, much more is needed. The Congress, for example, urgently needs to clarify the FERC's authority over an electric industry self-regulating reliability organization and expand the FERC's jurisdiction for reliability over the bulk-power system.") ("The Task Force is confident that the electricity industry, overseen by the Federal Energy Regulatory Commission (FERC) and a restructured self-regulating reliability organization (such as the planned North American Electric Reliability Organization [NAERO]), can and will maintain today's high levels of reliability."). *See also* S. Rep. No. 106-324, Electric Reliability 2000 Act (proposals from Congress such as this one gave FERC the authority over reliability).

[91] FERC, *Reliability Primer*, at 5 (2020) https://www.ferc.gov/sites/default/files/2020-04/reliability-primer_1.pdf.

[92] FERC, Reliability Explainer (Aug. 16, 2023) https://www.ferc.gov/reliability-explainer#:~:text=Both%20NERC%20and%20FERC%20have,blackouts%20or%20systematic%20compliance%20failures.

[93] The 2015 amendment to Federal Power Act creating Section 215A (16 U.S.C. 824o-1(d)) gives DOE the authority to issue orders to address emergencies related to malicious acts resulting from physical attacks to the grid at limited 15-day increments.

Finally, the Department arbitrarily and capriciously assumes that the existing systems are not working. The states and FERC have—pursuant to their authority—established systems to maintain resource adequacy and reliability including integrated resource planning processes and capacity markets. These existing systems are designed to signal to build more energy generation when energy demand rises.[94] Recently, as the Department notes in the RAR, energy demand has been rising; but the Department fails to acknowledge that the state and FERC systems already are appropriately responding, negating claims of an emergency or the need for the Department to interfere, as discussed *infra* in Section C.[95] For example, PJM's, SPP's, and MISO's new "fast track" processes—adopted to address concerns of resource adequacy—"alone would add roughly twice what the DOE assumed for the entire nation."[96] The RAR is written arbitrarily and capriciously incorporating the implicit assumption that capacity market results are not reliable, and that market-driven generator retirement is cause for alarm.

In sum, Congress has explicitly reserved to the states and FERC primary regulatory authority over resource adequacy and reliability. The Department's only authority to directly regulate reliability of the electric grid is narrow emergency authority such as Federal Power Act Sections 202(c) and 215A. The Department does not have broader authority to interfere with resource adequacy or reliability regulations. To the extent that the RAR is the confirmation of the attempt to usurp that authority from the states and FERC, via a "uniform methodology" in the RAR, it is outside of DOE's statutory authority and contrary to law.

B. The Department's Findings in the RAR, Even if Accurate, Do Not Demonstrate Any Emergency Allowing the Department to Compel Generation Under the Federal Power Act.

Even if the findings in the RAR were accurate (which they are not, as explained in Section C below), they would not empower the Department to exercise any statutory authority, under "section 202 of the Federal Power Act" or otherwise, to override state- or market-driven changes to the electricity generating facilities supplying the grid.[97] As discussed in Section A above, the Federal Power Act gives the Department tightly circumscribed authority over resource adequacy planning, to address "emergency" conditions through "such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy" as

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[94] *See e.g.* DOE, A Primer on Electric Utilities, Deregulation, and Restructuring of U.S. Energy Markets, at 3.8 (May 2002); GridLab, GridLab Analysis: Department of Energy Resource Adequacy Report, at 4 (July 11, 2025) (hereinafter "GridLab Analysis") (attached as Ex. 14).

[95] GridLab Analysis, Ex. 14 at 2-3.

[96] GridLab Analysis, Ex. 14 at 3.

[97] Grid EO at Sec. 3 (RAR, Ex. 1 at C-3).

"will best meet the emergency and serve the public interest."[98] The statutory text, structure, and history, as well as case law interpreting Section 202(c), the Department's regulations, and its historic use of Section 202(c), all establish that its "emergency" authority is confined to sudden, unexpected, imminent, and specific electricity shortfalls. The information in the RAR, at most, expresses the Department's view that bulk-power system reliability will be insufficient in 2030. The Department's conclusions in the RAR—even if assumed to be accurate for the sake of argument—consequently provide no basis for the Department to manipulate the electricity market.

1. The Federal Power Act only permits the Department to intervene when necessary to address an imminent, unexpected, and specific electricity shortfall.

The Federal Power Act's text, context, and structure, as well as caselaw and the Department's longstanding regulations, all establish that it does not permit the Department to "prevent" generating facilities "from leaving the bulk-power system" or "converting" from one fuel-source to another based on the Department's view of long-term reliability needs.[99] The Act provides the Department only authority to intervene in electricity markets when necessary to address imminent, near-term, and exigent electricity supply shortfalls requiring immediate response, through the cabined authority provided by Section 202(c) of the Act.

a. The Text of Section 202(c) Narrowly Limits the Department's Authority to Emergencies: Imminent, Unexpected, and Certain Shortfalls in Electricity Supply.

The Act's text empowers the Department to require generation only in an "emergency;"[100] the Act primarily reserves authority over generation to the states, allocating more limited federal regulatory power to different agencies, *see section* A above. The statute itself does not define "emergency." At the time Congress enacted Section 202(c), Webster's New International Dictionary of the English Language (1930) 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."[101] Contemporary dictionaries similarly define "emergency" as demanding imminence: an emergency

[98] 16 U.S.C. 824a(c).

[99] Grid EO at Sec. 3(c)(ii) (RAR, Ex. 1 at C-4).

[100] 16 U.S.C. § 824a(c).

[101] Emphasis added.

is "an *unforeseen* combination of circumstances or the resulting state that calls for *immediate* action."[102]

The remainder of Section 202(c) underscores the exigency inherent in the governing term "emergency." The authority granted by Section 202(c) is, in the first instance, a war-time power.[103] An "emergency" under the statute is limited to circumstances of similar urgency: "a *sudden* increase in the demand for electric energy," for example.[104]

The text's use of the present tense also underscores that focus on imminent and certain shortfalls: it empowers the Department to act only where "an emergency *exists*."[105] That near-term focus along with the statute's strictly "temporary" authority[106] precludes use of Section 202(c) to pursue long-term policy goals, such as "fear of overdependence" on foreign oil supplies,[107] or "energy independence."[108]

Section 202's overall structure further highlights Section 202(c)'s emphasis on imminent, near-term concerns. The preceding subsections 202(a) and (b) together define and limit the tools by which the federal government may pursue "abundant" energy supplies in the normal course.[109] The resulting statutory "machinery for the

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[102] Merriam Webster's Dictionary 407 (11th ed. 2009) (emphasis added); *see* 3 Oxford English Dictionary 119 (1st ed. 1913) (defining emergency similarly as "a state of things *unexpectedly* arising, and urgently demanding *immediate* action" (emphasis added)); *see also* Rolsma, Ex. 7 at 812 n.147 (noting that dictionaries have given the term "emergency" the "same meaning for many years").

[103] 16 U.S.C. § 824a(c) (beginning with "[d]uring the continuance of any war in which the United States is engaged"); *see Jarecki v. G.D. Searle & Co.*, 367 U.S. 303, 307 (1961) (noting that statutory terms should be interpreted in the context of nearby parallel terms "in order to avoid the giving of unintended breadth to the Acts of Congress").

[104] 16 U.S.C. § 824a(c) (emphasis added); *see Richmond Power & Light,* 574 F.2d at 615 (holding that Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances"); S. Rep. No. 74-621, at 49 (1935) (explaining that Section 202(c) provides "temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose").

[105] 16 U.S.C. § 824a(c) (emphasis added).

[106] 16 U.S.C. § 824a(c).

[107] *Richmond Power & Light*, 574 F.2d at 617.

[108] RAR, Ex. 1 at 1. *See Richmond Power & Light*, 574 F.2d at 614 (Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply and not those in which supply is adequate but a means of fueling its production is in disfavor.").

[109] 16 U.S.C. § 824a(a) (seeking "abundant supply of electric energy" by directing the federal government to "divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy") & 824a(b)

promotion of the coordination of electric facilities" comprises the following: in subsection (a), an instruction to establish a general framework meant to facilitate "coordination by voluntary action;" in subsection (b), "limited authority to compel interstate utilities to connect their lines and sell or exchange energy," subject to defined procedural and substantive requirements, when "interconnection cannot be secured by voluntary action;" and in subsection (c), "much broader" but "temporary" authority "to compel the connection of facilities and the generation, delivery, or interchange of energy during times of war or other emergency."[110]

That tiered structure—relying on voluntary action for quotidian energy planning, specifying limited authority where that voluntary system fails, and allowing for "temporary" central command-and-control only in case of "emergency"—requires that Section 202(c) remain narrowly bounded to instances of an immediate and unavoidable "break-down in electric supply,"[111] rather than mere want of more abundant supply in the future.[112] Interpreting Section 202(c)'s "emergency" powers to encompass longer-term concerns—e.g., potential shortfalls years into the future, or an expected "expansion of artificial intelligence data centers and an increase in domestic manufacturing,"[113]—would unwind the careful balance of voluntary, market-driven action and federal power set out in subsections 202(a) and 202(b). Such an interpretation cannot be squared with the statutory text and structure.[114]

b. Congress' Enactment of a Specific, Cabined Scheme to Address Reliability Concerns Confirms that Section 202(c) Cannot be Expanded to Impose Requirements Related to Long-Term Reliability.

That the Department's Section 202 powers may not be used to enforce the Department's view of long-term reliability needs is confirmed by Section 215 of the Federal Power Act—which specifically and directly delineates the scope of federal power to enforce mandatory long-term reliability requirements for the bulk-power system.[115] Congress added Section 215 to the Federal Power Act in 2005 precisely because the Act as it then existed—including Section 202—did not provide the

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(allowing federal government to order "physical connection … to sell energy or to exchange energy" upon application, and after an opportunity for hearing).

[110] S. Rep. No. 74-621 at 49 (1935).

[111] *Id.*

[112] *cf.* Eddystone 202(c) Order, Ex. 9 at 2 (imposing responsibility on PJM "to ensure maximum reliability on its system").

[113] Grid EO at Sec. 1 (RAR, Ex. 1 at C-4).

[114] *See Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232, 233-34 (1970) (holding that Section 202(c) "enables the Commission to react to a war or national disaster," while Section 202(b) "applies to a crisis which is likely to develop in the foreseeable future").

[115] 16 U.S.C. § 824o.

federal government with the power to enforce measures designed to ensure broad, long-term reliability.[116]

By enacting Section 215, Congress provided a comprehensive and carefully circumscribed scheme to empower the federal government to enforce long-term reliability requirements. That statutory scheme strikes a careful balance between state and federal authority, and between private, market-driven decisions and top-down control. Reliability standards are devised by NERC independent "of the users and operators of the bulk-power system" but with "fair stakeholder representation."[117] FERC may approve or remand those standards (but not replace them with its own) and is required to "give due weight" to NERC's "technical expertise" while independently assessing effects on "competition."[118] Section 215 provides specified enforcement mechanisms and procedures for reliability standards—which mechanisms conspicuously exclude the power to command specific generation resources to remain operational.[119] And Section 215 carefully preserves state authority over "the construction of additional generation" and in-state resource adequacy, establishing regional advisory boards to ensure appropriate state input on the administration of reliability standards.[120]

Interpreting Section 202(c) to permit the Department to mandate generation based on its own unfettered assessment of long-term bulk-system reliability would effectively allow the Department to bypass Section 215's procedural safeguards, constraints on federal authority, and protection of state power. Such a bypass would impermissibly "contradict Congress' clear intent as expressed in its more recent," reliability-specific "legislation," enacted "with the clear understanding" that the Department had "no authority" to address long-term reliability through Section

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[116] *See* 70 Fed. Reg. 53,118 ("In 2001, President Bush proposed making electric Reliability Standards mandatory and enforceable," leading to enactment of Section 215 in 2005); RAR of the National Energy Policy Development Group (May 2001) at p. 7-6, https://www.nrc.gov/docs/ml0428/ml042800056.pdf (noting that "[r]egional shortages of generating capacity and transmission constraints combine to reduce the overall reliability of electric supply in the country" and that "one factor limiting reliability is the lack of enforceable reliability standards" because "the reliability of the U.S. transmission grid has depended entirely on *voluntary* compliance," and then recommending "legislation providing for enforcement" of reliability standards (emphasis added)); S. Rep. No. 109-78 at 48 (2005) (Section 215 "changes our current voluntary rules system" for long-term reliability "to a mandatory rules system."). *See Alcoa, Inc. v. FERC*, 564 F.3d 1342, 1344 (D.C. Cir. 2009) (noting that prior to the Energy Policy Act of 2005, "the reliability of the nation's bulk-power system depended on participants' voluntary compliance with industry standards").

[117] 16 U.S.C. § 824o(c)-(d). *See also id.* 824o(a)(3) (defining reliability standards as "a requirement … to provide for reliable operation of the bulk-power system").

[118] *Id.* § 824o(d)(2)-(4).

[119] *Id.* § 824o(e).

[120] *Id.* § 824o(i)-(j).

202(c).[121] Congress has, in Section 215, directly established the mechanisms (and limitations) by which the federal government may compel action to ensure long-term electric-system reliability. In so doing, it has confirmed that the Department may not, through Section 202(c) "emergency" orders, use long-term reliability concerns to mandate the generation it views as required to address long-term reliability needs.

c. DOE's Regulations Similarly Establish that Section 202(c) Emergency Authority Can Only Be Invoked to Address Imminent, Certain Supply Shortfalls Requiring Immediate Response.

The Department's regulations demonstrate its own long-standing understanding that Section 202(c)'s authority is confined to imminent and unavoidable resource shortages, rather than a mechanism to address long-term concerns as to the reliability of the bulk-power system. The regulations define an emergency as "an *unexpected* inadequate supply of electric energy which may result from the *unexpected* outage or breakdown" of generating or transmission facilities—not a means of planning against distant expectations or risks.[122] Emergencies "may result" from a number of events.[123] The use of the verb "result," defined as "arise as a consequence, effect, or conclusion," suggests that the event triggering the emergency has already happened rather than that there is a speculation that it could occur.[124]

Moreover, the events are characterized by those produced by "weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected 'entity' to prevent."[125] Where the culprit is increased demand, it must be "a *sudden* increase in customer demand" producing a "*specific* inadequate power supply situation,"[126] rather than long-term demand projections producing general reliability concerns. The need for both specificity and certainty is repeated in the Department's regulations defining an inadequate energy supply: "A system may be considered to have" inadequate supply when "the projected energy deficiency . . . *will* cause the applicant [for a 202(c) Order] to be unable to meet its

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[121] *See FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 142 & 149 (2000); s*ee also Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 401–02 (D.C. Cir. 2004) ("Congress's specific and limited enumeration of [agency] power" over a particular matter in one section of the Federal Power Act "is strong evidence that [a separate section] confers no such authority on [agency].").

[122] 10 C.F.R. § 205.371 (emphasis added).

[123] *Id.* ("may result from the unexpected outage," "may be the result of weather conditions," "can result from a sudden increase in customer demand").

[124] Merriam-Webster's Collegiate Dictionary (11th ed. 2003) 1063.

[125] 10 C.F.R. § 205.371

[126] *Id.* (emphasis added).

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 customers."[127]

And while the regulations suggest that "inadequate planning or the failure to construct necessary facilities *can result* in an emergency," they recognize that the Department may not utilize a "continuing emergency order" to mandate long-term system planning.[128] An emergency may exist where past planning failures produce an immediate, present-tense shortfall (that is where, a shortfall *results* from insufficient planning); the Department has no authority to commandeer bulk-system reliability planning merely because it deems current plans inadequate to meet far-distant needs.[129] As the Department stated when it promulgated those regulations, the statute allows the Department to provide "assistance [to a utility] during a period of unexpected inadequate supply of electricity," but does not empower it to "solve long-term problems."[130]

d. Courts Have Uniformly Held that Section 202(c) Can Be Invoked Only in Immediate Crises.

Two courts have addressed the scope of authority under Section 202(c), and both determined that this Section applies only when there is a sudden, unexpected, imminent, and specific emergency.

Richmond Power and Light of City of Richmond, Indiana v. FERC, 574 F.2d 610 (D.C. Cir. 1978), arose out of the 1973 oil embargo. The Federal Power Commission needed to decide how to respond to oil shortages, and decided to call for the voluntary transfer for electricity from non-oil power plants to areas of the country that relied heavily on oil, such as New England.[131] The New England Power Pool was not convinced that the voluntary program would work and petitioned the Commission for a 202(c) order.[132] The Commission instead facilitated an agreement between state commissions and supplying utilities, which satisfied the New England Power Pool and it withdrew its petition.[133] A dissatisfied utility

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[127] 10 C.F.R. § 205.375 (emphasis added).

[128] 10 C.F.R. § 205.371 (also recognizing that "where a shortage of electricity is projected due solely to the failure of parties to agree to terms, conditions, or other economic factors" there is no emergency "unless the inability to supply electric service is *imminent*" (emphasis added)).

[129] *See* 10 C.F.R. § 205.375 (requiring present inability to meet demand to demonstrate inadequate energy supply).

[130] 46 Fed. Reg. at 39,985–86.

[131] 574 F.2d at 613.

[132] *Id.*

[133] *Id.*

sought judicial review of the Commission's decision to allow the withdrawal of the Section 202(c) petition.[134]

The court easily upheld the Commission's decision not to invoke Section 202(c).[135] Though the oil embargo had ended, the utility argued that the "high cost and uncertain supply of imported oil" justified an emergency order.[136] The Commission countered that the voluntary program had worked, the New England Power Pool never interrupted service, there was no need for a Section 202(c) order, and the court agreed.[137]

Trying another tactic, the utility argued that "dependence on imported oil leaves this country with a *continuing* emergency."[138] The court observed that Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances."[139] Interpreting this statutory language, the court upheld the Department's view that Section 202(c) cannot be used when "supply is adequate but a means of fueling its production is in disfavor."[140] Section 202(c) is not an appropriate means to implement long-term national policy to switch fuels. It is only a temporary fix for a temporary problem.

The Eighth Circuit has similarly held that Section 202(c) can only be used to respond to immediate crises. In *Otter Tail Power Co. v. Federal Power Commission*, 429 F.2d 232 (8th Cir. 1970), a utility insisted that the only way for the Federal Power Commission to properly order the utility to connect to a municipal power provider was to issue a Section 202(c) order. Demand for electricity in the city had increased, and the peak load of the municipal power provider was getting to be so high that both of its two generators would likely need to be used simultaneously in the near future, "causing a possible loss of service should one malfunction during a peak period."[141] To avoid this possible loss of service, the Federal Power Commission issued a Section 202(b) order, requiring the utility to connect the municipal power provider. The utility argued that the Federal Power Commission used the wrong section and should have used Section 202(c) instead.

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[134] *Id.* at 614.

[135] *Id.*

[136] *Id.*

[137] *Id.* at 615.

[138] *Id.* (emphasis added).

[139] *Id.*

[140] *Id.*

[141] *Id.* at 233-34.

The court explained that Section 202(c) "enables the Commission to react to a war or national disaster" by ordering "immediate" interconnection during an "emergency."[142] For non-emergency situations, "[o]n the other hand, Section 202(b) applies," including when there is a "crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission."[143] The court upheld the Commission's use of Section 202(b) instead of Section 202(c) because there was no immediate emergency.

The case law uniformly supports the interpretation that Section 202(c) can only be used in acute, short-term, urgent emergencies.

e. The Department's Prior Orders Recognize that Section 202(c) Does Not Confer Plenary Authority Over Long-Term Resource Adequacy.

The Department's past applications of Section 202(c) corroborate the urgency of the emergency conditions that are the necessary predicate for any Department intervention under that section.[144] The Department's predominant practice outside of wartime has been to use Section 202(c) to address specific, imminent, and unexpected shortages—not to address longer-term reliability concerns or demand forecasts.[145] The Department has also narrowly tailored the remedies in Section 202(c) orders to ensure that the orders only address the stated emergency, to limit the order to the minimum period necessary, and to mitigate violations of environmental requirements and impacts to the environment.[146]

Public Interest Organizations are not aware of any instance in which the Department has utilized Section 202(c) to mandate generation the Department

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[142] *Id.* at 234 (citing 16 U.S.C. § 824a(c)).

[143] *Id.*

[144] *See FTC v. Bunte Brothers, Inc.*, 312 U.S. 349, 352 (1941) ("[J]ust as established practice may shed light on the extent of power conveyed by general statutory language, so the want of assertion of power by those who presumably would be alert to exercise it, is equally significant in determining whether such power was actually conferred.").

[145] *See, e.g.,* Ex. 5, Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) (responding to ongoing severe winter storm producing immediate and "unusually high peak load" between Christmas Eve and Boxing Day); Ex. 6 Dep't of Energy Order 202-20-2 (Sept. 6, 2020) at 10-2 (responding to shortages produced by ongoing extreme heat and wildfires); *see also* Ex.7 Rolsma, 57 Conn. L. Rev. at 803-4 (describing "sparing[]" use of Section 202(c) outside of war-time shortages during the twentieth century).

[146] *See, e.g.*, Ex. 5, Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) at 4-7 (limiting order to the 3 days of peak load, directing PJM to exhaust all available resources beforehand, requiring detailed environmental reporting, notice to affected communities, and calculation of net revenue associated with actions violating environmental laws); Ex. 6 Dep't of Energy Order 202-20-2 (Sept. 6, 2020) at 3-4 (limiting order to the 7 days of peak load, directing CAISO to exhaust all available resources beforehand, requiring detailed environmental reporting).

views as necessary to ensure long-term resource sufficiency—and for good reason.[147] Any such use would exceed the Department's statutory authority.

2. In the RAR, DOE purports to identify only long-term, uncertain, and generalized concerns with bulk-power system reliability, which do not enable the Department to compel generation pursuant to Section 202(c).

Given the statutory limitations described above, the RAR provides no basis for the Department to use Section 202(c) to require that particular "generation resources" are "retained as an available generation resource," or to "prevent . . . an identified generation resource . . . from leaving the bulk-power system or converting" its fuel source.[148] Nor does the Department identify any other source of legal authority for DOE to impose such requirements. In the RAR, the Department only purports to identify capacity shortages that might affect bulk-system reliability in 2030.[149] The Department acknowledges that all but one region—ERCOT—currently meet its criteria.[150] Its claim that shortages might arise five years from now, even if it were correct—would present no "emergency" under Section 202(c). Those non-imminent resource needs are, rather, precisely the long-term reliability and resource adequacy matters over which Congress allocated responsibility to FERC and NERC.

Second, the Department identifies only a "risk of power outages" even in 2030[151] based on the Department's projected "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."[152] The Department acknowledges, meanwhile that its analysis "is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system."[153] The RAR—even by its own terms—thus does not specify any shortfall that is certain enough to justify invocation of the Department's emergency powers under Section 202(c). Its numbers are, rather, "indicators to determine where it may be beneficial to encourage increased generation and transmission capacity to meet an expected need."[154] Section 202(c) does not authorize the Department to order generation based on such non-certain shortfalls; it provides distinct, and

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[147] *See Richmond Power and Light,* 574 F.2d at 616.

[148] Grid EO at 2.

[149] *E.g.,* RAR, Ex. 1 at 1, 20, 27, 30, 32, 40.

[150] RAR, Ex. 1 at 7.

[151] *Id.* at 1.

[152] *Id.* at 7.

[153] *Id.*

[154] *Id.*

much more limited powers, by which the Department may facilitate "an abundant supply of electric energy throughout the United States."[155]

And third, the Department does not claim to identify any particular location in which a shortfall might occur, or the specific resources that might best serve to address such shortfall. Instead, in the RAR, the Department provides aggregate estimates of potential loss-of-load under "varied grid conditions and operating scenarios based on historical data."[156] But those estimates do not demonstrate that any single generating facility would best meet the resulting shortfall, and could not therefore justify an emergency order directing a facility to remain available.

Consequently—even setting aside methodological flaws—the Department asserts resource risks in the RAR that are neither imminent, certain, nor specific. Those risks do not describe an emergency that would permit the Department to intervene pursuant to Section 202(c). They represent, rather, the Department's view as to measures that might "assur[e] an abundant supply of electric energy throughout the United States."[157] Section 202 does not permit the Department to compel generation on that basis. The Department also describes in the RAR the measures the Department believes "necessary to provide for reliable operation of the bulk-power system."[158] But Section 215 gives FERC, not the Department, the power to provide for reliable operation of the bulk power system, and specifies the procedures by which such measures must be developed and enforced; the Federal Power Act does not permit the Department to end-run those limitations by deeming long-term reliability an emergency. The RAR consequently could not form the basis of any action by the Department to compel generation under Section 202 of the Federal Power Act.

C. The RAR Is Analytically Flawed and Does not Rely Upon Substantial Evidence.

The RAR is severely flawed and does not meet DOE's own information quality standards. There are significant informational and methodological limitations and clear analytical and data errors. Any reliance on the RAR to "guide interventions" or to serve as a basis for any DOE decisionmaking would be arbitrary and capricious and not based on substantial evidence, in violation of the Administrative Procedure Act.

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[155] 16 U.S.C. § 824a(a).

[156] RAR, Ex. 1 at 2. *See, e.g., id.* at 21.

[157] 16 U.S.C. § 824a(a).

[158] 16 U.S.C. § 824o(a)(3).

1. The RAR falls woefully short of informational and methodological best practices.

DOE admits the RAR was hastily thrown together without sufficient information. At the outset, DOE acknowledges the resource adequacy analysis in the RAR "could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level."[159] Indeed, "[h]istorically, the nation's power system planners would have shared electric reliability information with DOE through mechanisms such as EIA-411, which has been discontinued."[160] DOE continues to explain that a key takeaway of the RAR is the need 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."[161] The candor in these comments is revealing; these limitations prove that the RAR does not meet the requirements of the Information Quality Act ("IQA") or DOE's guidelines thereunder.[162] The RAR should be withdrawn so that the Department does not continue to disseminate this poor-quality information, and the RAR should not be relied on in any decisionmaking. In the alternative, the Department should not use the RAR as support for any final action until and unless it (1) provides notice of the statutory authority under which DOE issued the RAR and publishes all data underlying the RAR, (2) explains in detail the specific uses for the methodology, and (3) allows interested parties to comment on the RAR before releasing a final version that incorporates and responds to public comment.

The IQA directs agencies to "ensur[e] and maximiz[e] the quality, objectivity, and integrity of information (including statistical information) disseminated by Federal Agencies."[163] Office of Management and Budget ("OMB") guidelines issued

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[159] RAR, Ex. 1 at i.

[160] *Id.*

[161] *Id.*

[162] *See* Pub. L. 106-554 Sec. 515, 114 Stat. 2763A-153.

[163] *Id.* OMB's government-wide information quality guidelines direct agencies to issue their own implementing guidelines. Agencies must provide the public a way to administratively seek and obtain correction of information disseminated by the agency that does not comply with OMB or agency guidelines. *See* Office of Management and Budget, Guidelines for Ensuring and Maximizing the Quality, Objectivity, Utility, and Integrity of Information, 67 Fed. Reg 8452 (Feb. 22, 2002); Office of Management and Budget, Memorandum for the Heads of Executive Departments and Agencies (Apr. 24, 2019) (hereinafter "OMB Guidelines 2019 Update"), https://www.whitehouse.gov/wp-content/uploads/2019/04/M-19-15.pdf.

Pursuant to the OMB directive, DOE has issued its own agency-specific information quality guidelines. *See* Dep't of Energy, Final Report Implementing Office of Management and Budget Information Dissemination Quality Guidelines (Oct. 1, 2002), no. 6450-01-p, https://www.energy.gov/sites/prod/files/cioprod/documents/finalinfoqualityguidelines03072011.pdf; Dep't of Energy, Final Report Implementing Updates to the Department of Energy's Information

pursuant to the IQA require agencies to ensure that scientific information including "factual inputs, data, models, analyses . . . related to such disciplines as . . . engineering, or physical sciences" undergo certain review procedures to maintain quality standards.[164]

To that end, agencies must "choose a peer review mechanism that is adequate, giving due consideration to the novelty and complexity of the science to be reviewed, the relevance of the information to decisionmaking, the extent of prior peer reviews, and the expected benefits and costs of additional review."[165] Agencies must "strive to ensure that their peer review practices are characterized by both scientific integrity and process integrity," including the "rationale and supportability" of the agency's findings and ensuring "avoidance of real or perceived conflicts of interest" and "a workable process for public comment and involvement."[166] Agencies are encouraged to "have the choice of input data and the specification of the model reviewed by peers before the agency invests time and resources in implementing the model and interpreting the results," in order to "focus attention on data inadequacies in time for corrections . . . before the agency becomes invested in a specific approach."[167] Additionally, peer reviewers must "ensure that scientific uncertainties are clearly identified and characterized," and "ensure that the potential implications of the uncertainties for the technical conclusions drawn are clear."[168] OMB IQA guidelines also require agencies to evaluate "the sensitivity of the agency's conclusions to analytic assumptions."[169] These steps of peer review determine a report's "fitness . . . for policy purposes."[170]

DOE IQA guidelines further note that "in disseminating certain types of information to the public, other information must also be disseminated in order to ensure an accurate, clear, complete, and unbiased presentation."[171] Agencies should provide open access to data and modeling information underlying a report.[172]

Quality Act Guidelines (2019) (hereinafter "DOE IQA Guidelines 2019 Update"), available at https://www.energy.gov/cio/articles/2019-final-updated-version-doe-information-quality-guidelines.

[164] OMB, Final Information Quality Bulletin for Peer Review, 70 Fed. Reg. 2664, 2667 (Jan. 14, 2005); *see also* OMB Guidelines 2019 Update at 4.

[165] OMB Information Quality Bulletin for Peer Review, 70 Fed. Reg. at 2668.

[166] *Id.*

[167] *Id.*

[168] *Id.* at 2669.

[169] OMB Guidelines 2019 Update at 4.

[170] *Id.*

[171] DOE IQA Guidelines 2019 Update at 16.

[172] OMB Guidelines 2019 Update at 8; *See also*, e.g., *Chem. Mfrs. Ass'n v. U.S. EPA*, 870 F.2d 177, 200 (5th Cir. 1989) ("fairness requires that the agency afford interested parties an opportunity to challenge the underlying factual data relied on by the agency."); *United States v. Nova Scotia Food*

Additionally, DOE is "responsible for ensuring that the information [being disseminated in a report] is consistent with the OMB and DOE guidelines and that the information is of adequate quality for dissemination."[173] For reports containing "influential financial, scientific, or statistical information," DOE must "identify for the [Chief Information Officer] a high ranking official" who is responsible for higher level review of the report's conclusions.[174]

OMB's IQA guidelines recognized that the "[f]ederal government's assessment of risk can directly or indirectly influence the response actions of state and local agencies or international bodies."[175] Thus, under the OMB and DOE guidelines, influential information—information routinely embargoed because of "potential effect on markets" or information "on which a regulatory action with a $100 million per year impact is based"—must meet the highest standards of quality and transparency, and should undergo the rigorous review procedures outlined above.[176]

Here, the RAR does not comply with IQA requirements, rendering any further reliance on it to be arbitrary and capricious. For example, the RAR appears to be inconsistent with internal review processes required: it should have undergone peer review because of its "influential" nature, particularly if the RAR is, as it purports to be, a "uniform methodology" to guide reliability interventions, such as Federal Power Act Section 202(c) orders, which have outsize economic impacts. However, there is no evidence that the RAR underwent any peer review, and, given the time constraints, it is unlikely it did. The Department further failed to make available all underlying data and modeling information used to create the RAR. Additionally, as described in detail below, the RAR relies on improper analytic assumptions, including overstated demand and understated supply forecasts. The RAR includes faulty analysis based on these improper assumptions despite DOE's acknowledgment of significant informational limitations regarding regional- and utility-level engineering data. In addition, the RAR contains numerous errors, such as referring to appendices that do not exist or incorrect appendices,[177] stating

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Prods. Corp., 568 F.2d 240, 251-53 (2d Cir. 1977) (holding that regulation was promulgated in arbitrary and capricious manner where agency failed to disclose data on which it relied).

[173] DOE IQA Guidelines 2019 Update at 22.

[174] *Id.* at 22-23.

[175] OMB Information Quality Bulletin for Peer Review, 70 Fed. Reg at 2667.

[176] DOE IQA Guidelines 2019 Update at 7.

[177] *See* RAR, Ex. 1, at 12 (referring to nonexistent "Outputs" section of an unnamed appendix); *id.* (referring to Appendix B for further detail regarding retirement assumptions, whereas Appendix B describes Canadian transfer limits).

inaccurate units for generation capacity,[178] and falsely asserting bulk power system load shedding occurred in regions during certain events.[179]

2. In the RAR, the Department overstates assumptions about demand.

In the RAR, the Department assumes 101 GW of load growth by 2030—a 15% increase over 2025 load. This increase is more than double the high case in the U.S. EIA 2025 Annual Energy Outlook, which forecasts 6% growth.[180] This extraordinarily high assumed load growth contributes substantially to the findings of low resource adequacy under the Plant Closures scenario in the RAR. As explained below, in the RAR, the Department omits consideration of many factors that will likely dampen load growth in the coming 5 years, thus undermining the validity and usefulness of its results.

The Department assumes 50 GW of load growth from data centers by 2030, which it characterizes as the midpoint among other available forecasts.[181] However, it does not appear that DOE's forecast accounts for load flexibility at these data centers, which would significantly reduce the overall demand that these centers place upon the grid during the periods of peak system risk. While certain data centers may not be capable of load curtailment due to their purpose, many can be flexible. Even a small amount of data center load flexibility provides significant benefits. A recent study by experts at Duke University found that curtailment at data centers during only 0.25% of the year would enable 76 GW of data center power demand to be added to the system today, without triggering resource adequacy problems or requiring further expansion.[182] The White House recently issued an AI Action Plan endorsing demand flexibility as a means to maintain resource adequacy as data center capacity expands: "the United States should investigate new and novel ways for large power consumers to manage their power consumption during critical grid periods to enhance reliability and unlock additional power on the system."[183]

The Electric Power Research Institute has begun an initiative to enhance data center flexibility in light of its benefits for grid reliability, under which

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[178] *Id.* at 9 (text stating that PJM has a shortfall of 2.4 MW).

[179] *See infra* subsection C.6.

[180] *See* GridLab Analysis, Ex. 14 at 2.

[181] RAR, Ex. 1 at 2.

[182] Norris, T. H., T. Profeta, D. Patino-Echeverri, and A. Cowie-Haskell. 2025. Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems at 20. Durham, NC: Nicholas Institute for Energy, Environment & Sustainability, Duke University, https://nicholasinstitute.duke.edu/publications/rethinking-load-growth (attached as Ex. 15).

[183] White House, Winning the Race: America's AI Action Plan 15 (July 2025), https://www.whitehouse.gov/wp-content/uploads/2025/07/Americas-AI-Action-Plan.pdf.

demonstration projects were set to deploy in the first half of 2025.[184] Early results from other projects to test data center flexibility have been promising.[185] Evaluations of the RAR by GridLab and the NYU Institute for Policy Integrity ("IPI") both have concluded that the Department's failure to account for data center load flexibility renders its findings of elevated reliability risk in 2030 suspect.[186] This is particularly true for DOE's findings concerning the ERCOT region, considering that in June 2025, Texas enacted a law allowing curtailment of these loads during grid emergencies.[187]

Furthermore, it is unclear whether the RAR's data center load forecasts account for potential constraints on the growth of data centers, such as shortages of critical semiconductor chips,[188] and other grid equipment like transformers and switchgears.[189] In addition to the Texas policy mentioned above, states and utilities are proposing new tariff designs for data centers to ensure that data centers don't

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[184] Elec. Power Rsch. Inst., EPRI Launches Initiative to Enhance Data Center Flexibility and Grid Reliability (Oct. 29, 2024), https://perma.cc/75LY-PSP5 ("Led by EPRI, DCFlex will coordinate real-world demonstrations of flexibility in a variety of existing and planned data centers and electricity markets, creating reference architectures and providing shared learnings to enable broader adoption of flexible operations that benefit all electricity consumers. Specifically, DCFlex will establish five to ten flexibility hubs, demonstrating innovative data center and power supplier strategies that enable operational and deployment flexibility, streamline grid integration, and transition backup power solutions to grid assets. Demonstration deployment will begin in the first half of 2025, and testing could run through 2027.").

[185] *See* Anuja Ratnayake, Unlocking AI Potential with Data Center Flexibility, ENERGYCENTRAL (June 12, 2025), https://www.energycentral.com/intelligent-utility/post/unlocking-aipotential-with-data-center-flexibility-PtPoXIAuRMzs5Ff ("In a preliminary test of the depth of computational flexibility possible in an AI data center, the Arizona demonstration site experienced some early success. It showcased the potential for an AI data center to provide grid relief during a peak system event—such as a hot summer day with high power demand—by temporarily and precisely ramping down its electricity consumption without compromising data center performance.").

[186] NYU Institute for Policy Integrity, *Enough Energy*, at 25 (attached as Ex. 16) (hereinafter "IPI Report"); *see also* GridLab Analysis, Ex. 14 at 2 ("It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact.").

[187] S.B. No. 6 § 4, 89th Legislature (Tex. 2025) (to be enacted at Tex. Util. Code § 39.170), https://perma.cc/4Z7H-9XKQ; Brian Martucci, Texas Law Gives Grid Operator Power to Disconnect Data Centers During Crisis, UTILITY DIVE (June 25, 2025), https://perma.cc/SYK3-V4XX; Waleed Aslam & Robin Hytowitz, Elec. Power Rsch. Inst., Texas SB6 Explained: Addressing Large Load Impacts (2025), https://perma.cc/QD8S-3M5C.

[188] *See, e.g.* London Economics International LLC, *Uncertainty and Upward Bias Are Inherent in Data Center Electricity Demand Projections* at 39 (July 7, 2025) (attached as Ex. 17), https://www.selc.org/wp-content/uploads/2025/07/LEI-Data-Center-Final-Report-07072025-2.pdf.

[189] How big tech plans to feed AI's voracious appetite for power, The Economist (July 28, 2025), https://www.economist.com/business/2025/07/28/how-big-tech-plans-to-feed-ais-voracious-appetite-for-power.

pose risks to the distribution system or shift costs to other consumers, all of which could slow or redirect the forecasted data center load growth.[190] The Department fails to evaluate any of these dynamics in the RAR.

In addition to the overall rate of data center load growth, the Department also uses a poorly described and supported methodology to allocate data center load to different regions. As the IPI observes, DOE used state-level growth ratios to allocate the projected data center load across regions, "[b]ut it is unlikely that all the computing demand needs to be processed close to load centers (i.e., proportional to a region's current electric load)."[191] IPI posits that "some computing demand may be served from other regions if it will be cheaper to integrate the data center elsewhere," and observes that "[g]iven the scale of DOE's projected data center load compared to the relatively small resource adequacy shortfalls that the study identifies, these assumptions may have made the difference between whether a region achieves DOE's resource adequacy targets."[192] Figure 8 in the RAR (New Data Center Build) shows that DOE's estimates for the percentage of data center load growth that will be built in various RTOs in some cases differs substantially from the percentages in the various forecasts that DOE used to calculate its overall data center load growth estimate. DOE does not explain why it discards these studies' more geographically specific estimates and instead relies on a single state-level growth ratio derived from a different study.

The Department's approach to estimating non-data center load growth by 2030 is also poorly explained in the RAR and likely flawed. DOE relies upon NERC's 2024 Long-Term Reliability Assessment forecast for overall load growth, but because the Department otherwise seeks to include elevated levels of data center load growth in the RAR, it must back out an estimate of data center load growth from the overall forecast.[193] The estimate that DOE chooses to back out is a "low-growth" case for data center load from a different source (which DOE presents in volumetric consumption terms, rather than peak demand). This approach, without further information to understand DOE's analysis, could have resulted in DOE over-estimating non-data center load growth. This effect is likely exacerbated by recent changes in federal law that will reduce electricity consumption from

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[190] Jason Plautz, *Rulemakers play catch-up as data centers multiply*, E&ENews by Politico (July 18, 2025), https://www.eenews.net/articles/rulemakers-play-catch-up-as-data-centers-multiply/.

[191] IPI Report, Ex. 16 at 26.

[192] *Id.*

[193] RAR, Ex. 1 at 17 ("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 [Long-Term Reliability Assessment] forecast, for example, the 2024 [Long-Term Reliability Assessment] 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.").

specific sectors, including vehicles and hydrogen electrolysis. The utility forecasts included in the NERC Long-Term Reliability Assessment included projections of vehicle and building electrification that depend in part on tax credits and incentives that were revoked prior to publication of the RAR as part of the One Big Beautiful Bill Act ("OBBBA"). Recent analysis shows that the elimination or reduction of tax credits that supported new sources of electricity load growth will have a meaningful effect by 2030.[194] As a result, DOE's non-data center load growth projections are likely overstated.

3. Assumptions about supply are unsupported.

a. In the RAR, the Department Overstates Likely Retirements.

The Department finds the most dire resource adequacy shortfalls occur in the Plant Closures case, in which it assumes 104 GW of retirements by 2030.[195] This estimate is much higher than the most recent data from the EIA released in June 2025 in its authoritative Form 860, which shows 50 GW fewer retirements than assumed in the RAR.[196] As GridLab experts explained, DOE assumed not only "these 50 GW of likely retirements, but [also] included another 50 GW of *announced* retirements."[197] While it may be appropriate to include announced retirements in certain long-term planning exercises, it is unreasonable to assume such retirements will happen as the basis for extraordinary emergency actions. Without more detail about any formal or binding characteristics of those announcements, or the factors purportedly driving those announcements, it is impossible to verify the validity of this input that doubles the amount of otherwise projected resource retirements. Even EIA's Annual Energy Outlook, which does model projected retirements beyond those already formally noticed, finds 10 GW fewer thermal retirements by 2030 than does DOE.[198] Without further support for the 50 GW assumed retirement

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[194] *See, e.g.,* Princeton NetZero Lab and Evolved Energy Research, A Fork in The Road: Impacts of Federal Policy Repeal on the U.S. Energy Transition, at Tab 12 (last updated July 3, 2025), https://public.tableau.com/app/profile/evolvedenergyresearch/viz/AForkinTheRoad_ImpactsofFederalPolicyRepealontheU_S_EnergyTransition_June/1Title (showing approximately 100 TWh annual energy use reduction in 2030 compared to mid-range estimates of the status quo ante).

[195] RAR, Ex. 1 at 5.

[196] U.S. EIA, Annual Energy Outlook 2025: Table 9. Electricity generating capacity (March 2025), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2025&region=0-0&cases=ref2025&start=2025&end=2030&f=A&linechart=ref2025-d032025a.4-9-AEO2025&map=&sourcekey=0. *See also* GridLab Analysis, Ex. 14 at 2.

[197] GridLab Analysis, Ex. 14 at 2; *see also* IPI Report, Ex. 16 at 24 (explaining that DOE's "number includes both 'confirmed' retirements—resources that have notified their system operators of their impending retirements and begun the retirement process—and 'announced' retirements—which are publicly stated but not officially noticed.").

[198] According to the U.S. EIA's 2025 Annual Energy Outlook, coal-fired generating capacity is projected to decline by 93.6 GW between 2025 and 2030 in the Reference case, approximately 10

value, the Plant Closures case is nothing more than speculation about what might happen if certain assumptions were to come true.

Such assumptions are particularly unjustified given that, as GridLab notes, "[m]ost likely many plants will choose not to retire due to the changing regulatory and economic landscape."[199] The IPI makes a similar point in their critique of DOE's retirement assumptions, noting that "the economics of energy production have changed since 2024. The combined effect of new demand from data centers and the elimination of federal tax credits for new wind and solar resources improves the financial outlook for thermal resources."[200] As one snapshot of this trend, high capacity prices in the PJM region led to 1.1 GW of resources withdrawing formal deactivation notices since last summer.[201] IPI also observes that the Trump Administration is seeking to rescind or reexamine many federal environmental regulations that would have required thermal resources to make investments reducing their pollution or else retire before 2030, "which could cause resources to delay their retirements."[202]

b. In the RAR, the Department Understates Likely New Entry by 2030 and Other Sources of Supply.

Among the most impactful and unsupported assumptions in the RAR is that "only [generation] projects that are very mature in the pipeline (such as those with a signed interconnection agreement) will be built" by 2030.[203] DOE thus constrains its analysis to include only projects designated as Tier 1 in the NERC 2024 Long Term Resource Assessment, which it then maps to Interregional Transfer Capability Study regions. Because Tier 1 includes only resources that are already under construction, have signed construction service agreements, and similar

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fewer GW of retirements than modeled in the DOE report. No other fossil fuel technology shows a net decrease in generating capacity in the 2025 Annual Energy Outlook analysis. U.S. EIA, Annual Energy Outlook 2025: Table 9. Electricity generating capacity (March 2025), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2025&region=0-0&cases=ref2025&start=2025&end=2030&f=A&linechart=ref2025-d032025a.4-9-AEO2025&map=&sourcekey=0.

[199] GridLab Analysis, Ex. 14 at 2.

[200] IPI Report, Ex. 16 at 24.

[201] PJM Inside Lines, PJM Auction Procures 134,311 MW of Generation Resources; Supply Responds to Price Signal (July 22, 2025) https://insidelines.pjm.com/pjm-auction-procures-134311-mw-of-generation-resources-supply-responds-to-price-signal/ ("Since the 2025/2026 Base Residual Auction results were posted on July 30, 2024, 17 generating units totaling approximately 1,100 MW worth of Capacity Interconnection Rights have withdrawn their retirements").

[202] IPI Report, Ex. 16 at 24-25.

[203] RAR, Ex. 1 at 12.

characteristics,[204] this assumption "results in minimal capacity additions beyond 2026."[205] As experts at GridLab observe, the assumption that "no projects are built post 2026, [] is not realistic for a report forecasting to 2030."[206] This is especially true given rising energy prices due to increased demand, which is attracting more investment to the market and driving new construction of generation resources.

The Department also states in the RAR that of these Tier 1 additions, just 22 GWs of generator additions are "firm" (thermal) resources, which severely underestimates new gas generation compared to other projections. According to GridLab, "a more reasonable assumption for forecasted capacity additions is the EIA 860 released in June 2025, which has 35 GW of gas additions, and another 53 GW of batteries [for a total of] 88 GW of firm additions by 2030."[207] Other federal government projections are even higher: EIA's 2025 Annual Energy Outlook projects 90 GWs of new fossil generators added to the system through 2030.[208] 80 GWs of the EIA-projected natural gas growth are in earlier development stages and likely did not meet the 2024 NERC Long-Term Reliability Assessment Tier 1 criteria to be included in the RAR.

As researchers at the IPI conclude, DOE departed from best practice in declining to include any resources classified by NERC as "Tier 2" resources[209] in the overall resource adequacy analysis for 2030, even those at advanced stages of the interconnection process.[210] A reasonable process could have involved "examin[ing]

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[204] *See* IPI Report, Ex. 16 at n.155 (citing NERC, 2024 Long Term Reliability Assessment, 137 (last updated July 15, 2025) https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf).

[205] RAR, Ex. 1 at A-5.

[206] GridLab Analysis, Ex. 14 at 3.

[207] *Id.*

[208] According to the U.S. EIA, the policy-neutral reference case projects a 93.29 GW increase in combined cycle, fossil steam, and combustion turbine capacity between 2025 and 2030. U.S. EIA, Annual Energy Outlook 2025: Table 9. Electricity generating capacity (March 2025), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2025&region=0-0&cases=ref2025&start=2025&end=2030&f=A&linechart=ref2025-d032025a.4-9-AEO2025&map=&sourcekey=0.

[209] NERC defines Tier 2 resources as those having one of the following characteristics: "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)." NERC, 2024Long Term Reliability Assessment, 137 (Dec. 2024, updated July 15, 2025) https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[210] IPI Report, Ex. 16 at 23.

historical statistics of interconnection queue time by region, resource type, and resource size, along with differentiated queue withdrawal rates, estimating Tier 2 resource additions for each region."[211] For example, for the PJM region, the Independent Market Monitor's analysis shows that 15% of generation projects (on an energy basis) successfully enter service.[212] As of late 2024, PJM had over 44 GW of accredited capacity in its interconnection queue.[213] To assume that none of this capacity would enter service by 2030, as DOE's analysis does, is unreasonable.

Such an analysis should also consider factors pointing towards even faster queue times than those seen in the historical data, given factors now expediting interconnection queues such as implementation of FERC Order 2023, streamlining of tools to better utilize existing points of interconnection (e.g., surplus interconnection service), and various interconnection fast tracks that FERC has recently approved.[214] For example, it is unreasonable for DOE to exclude from consideration the over 9 GW of accredited capacity that PJM selected in May 2025 to participate in its Reliability Resource Initiative—the vast majority of these projects (primarily gas and battery energy storage systems) are committed to be online by 2030,[215] but are omitted in DOE's analysis because they do not yet have a signed interconnection agreement. DOE paints an inaccurate picture of new entry by ignoring recently adopted policies designed to address the very same tightening supply and demand conditions that DOE describes.

DOE also underestimates the extent to which interregional transfers of energy could help to prevent or address any shortfalls. Noting that it relies upon the interregional transfer capacities identified by NERC in its Interregional Transfer Capability Study, DOE explains that "[i]mports are assumed to be available up to the minimum total transfer capacity and spare generation in the

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[211] *Id.*

[212] Monitoring Analytics, 2024 State of the Market Report, at 705 (2024) https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024q2-som-pjm-sec12.pdf (noting 14.9% completion rate).

[213] PJM, Reliability Resource Initiative MRC Update, at slide 6 (Nov. 7, 2024) https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2024/20241107-special/item-04---reliability-resource-initiative---presentation.ashx.

[214] *Id. See also* Prefiled Statement of Manu Asthana on Behalf of PJM Interconnection, L.L.C., FERC Docket No. AD25-7, at 4 (May 27, 2025), https://www.ferc.gov/media/manu-asthana-pjm-president-and-ceo (touting recent improvements to PJM's interconnection queue by noting that "[a]n additional approximately 18 GW is being processed to move to the final study phase for completion this year, and an additional 56 GW (including projects from Transition Cycle 2 and Reliability Resource Initiative) will be through the queue by late 2026.").

[215] PJM, Reliability Resource Initiative Results Summary, at slide 9 (May 6, 2025) https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250506/20250506-item-06---reliability-resource-initiative---summary-results.pdf.

neighboring subregion."[216] Because the Interregional Transfer Capability Study calculated interregional transfer capacities for both summer and winter, and for each direction of flow, it is unclear what DOE means regarding allowing transfers up to the minimum. As the IPI observes: "If DOE picked the lesser of the summer and winter transfer capacities and applied that annually, doing so would inaccurately underestimate the amount of interregional transfer capacity."[217] This is yet another example of where DOE fails to explain its methodology with sufficient detail to enable an evaluation of whether its approach is reasonable, or is supported by substantial evidence.

4. DOE's use of a deterministic analysis provides an incomplete and inaccurate picture.

For the RAR, DOE employs a deterministic approach in examining resource adequacy; that is one that "evaluate[s] resource adequacy using relatively stable or fixed assumptions about the representation of the power system," rather than a probabilistic approach that "incorporate[s] data and advanced modeling techniques to represent uncertainty that require more computing power."[218] DOE explains it chose a deterministic approach "for transparency and to model detailed historic system conditions."[219] However, deterministic approaches have significant limitations; as NERC explained in the Interregional Transfer Capability Study on which DOE otherwise heavily relies, because that study did not employ a probabilistic approach, it "should not be considered a North American resource adequacy assessment."[220] The problem, as IPI explains, is that "[b]y examining whether regions would be resource adequate only under conditions that resemble the recent past, DOE's study does not sufficiently account for uncertainty."[221] Furthermore, as NERC itself has explained, under a deterministic approach, "some regions may look resource adequate because they happened to do well during the twelve years of data, while others look resource inadequate but be unlikely to perform as poorly in the future."[222] As IPI concludes, neither of DOE's professed reasons for using a deterministic approach justifies departing from best practices, as "DOE could document a probabilistic approach in a transparent way, and relying on a small sample of historic years is less accurate than a probabilistic approach."[223]

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[216] RAR, Ex. 1 at 12.

[217] IPI Report, Ex. 16 at 26.

[218] RAR, Ex. 1 at 2 n.2.

[219] *Id.*

[220] IPI Report, Ex. 16 at 21 (citing NERC, Interregional Transfer Capability Study, at 4 (2024) (hereinafter "NERC ITCS")).

[221] IPI Report, Ex. 16 at 21.

[222] *Id.* (citing NERC ITCS at 138).

[223] *Id.* at 21.

DOE may have chosen a less sophisticated and rigorous approach given the limited amount of time in which the Grid EO required this analysis to be completed, but regardless of the reason, the limitations inherent in DOE's deterministic methodology mean that its findings should not be taken as conclusive or form the basis for further extraordinary actions.[224]

5. DOE uses an elevated threshold for determining when outages will occur.

In the RAR, the Department projects a shortfall if "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."[225] This approach, and the particular values used as thresholds, come from the NERC Interregional Transfer Capability Study, which uses 3% as the default threshold and 6% only in a sensitivity analysis. NERC explains that the 3% value "was established based on an evaluation of average reserve requirements where load shed may occur" in order for a Balancing Authority to continue to hold the minimum reserves needed to protect the system from cascading or widespread outages.[226] In the sensitivity examined by NERC, using the 6% threshold "significantly altered the existence and extent of predicted outages in many regions, such as producing a 690% increase in the size of the maximum outage event in SERC-Florida."[227]

As the IPI analysis notes, DOE provides no further explanation for when and how it uses 6% as a threshold versus 3%.[228] While the Department directs readers to an appendix with further detail, the appendices do not in fact provide any further information regarding this critical assumption.[229] Furthermore, "the fact that DOE listed 6% first may suggest that 6% was not limited to a sensitivity analysis," and that if "DOE's model instead identifies shortage events even when a region still has 6% of load available as spare capacity, then DOE's results depart from NERC's practice and may overstate the extent of expected outages."[230] DOE's failure to explain its own methodology concerning such a critical input to its analysis, including through the failure to provide information in an appendix that the RAR states exists, renders the RAR arbitrary and capricious. Insofar as the RAR's results for 2030 scenarios depend upon the 6% threshold, DOE must explain why

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[224] *Id.* ("Given the high stakes associated with resource adequacy planning, any future DOE resource adequacy assessment should prioritize accuracy over expediency.")

[225] RAR, Ex. 1 at 12.

[226] IPI Report, Ex. 16 at 22 (citing NERC ITCS, at 91 n.90, 85).

[227] IPI Report, Ex. 16 at 22 (citing NERC ITCS at 105 tbl.8.4); *see also id.* ("Under the 6% sensitivity, NERC also recommended 58 GW of transmission additions to address resource adequacy instead of 35 GW, illustrating the sizable influence of shifting this assumption from 3% to 6%.")

[228] IPI Report, Ex. 16 at 22.

[229] *Id.*

[230] *Id.*

such a threshold is appropriate, given the departure from NERC's practice and the evidence in the NERC report considering the propriety of a far lower threshold.

6. DOE inconsistently applies its own methodology.

Several of the findings in the RAR are inconsistent with the methodology that DOE develops. For instance, DOE states that "[a]nalysis 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" (the standards DOE developed for this study).[231] DOE further explains that "[w]hen 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."[232] Despite these clear findings, DOE goes on to state that "PJM, ERCOT, 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," and asserts that this "results in a concentration of lost load within certain years such that some regions exceeded 3-hours-per-year of lost load."[233] As an initial matter, the PJM system did not experience any lost load due to resource inadequacy during Winter Storms Uri or Elliott.[234] Second, DOE's focus on whether a region had lost load or a risk of lost load in a particular weather year is inconsistent with DOE's own articulation of its resource adequacy standards, as "average indicators" assessed across all scenarios and years.[235] As the IPI notes, these standards are "not a requirement that must be achieved in each and every scenario."[236]

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[231] RAR, Ex. 1 at 7.

[232] *Id.*

[233] *Id. See also Id.* at 9 ("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.").

[234] PJM Inside Lines, PJM Releases Winter Storm Elliott Report (July 17, 2023) https://insidelines.pjm.com/pjm-releases-winter-storm-elliott-report/ ("PJM maintained system reliability and served customers throughout the extreme weather that affected the region Dec. 23–25 [2022], and even was able to support its neighbors during certain periods."); *see also* FERC, NERC and Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 16, 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and (noting that PJM was exporting power to neighboring regions during Winter Storm Uri, and investigating rolling blackouts only in Texas and south central states).

[235] RAR, Ex. 1 at 5.

[236] IPI Report, Ex. 16 at 20.

D. Notice and Comment Procedures Are Required for Any "Uniform Methodology" the Department Uses to Guide Reliability Interventions.

Under the Administrative Procedure Act, federal agencies must provide notice and an opportunity for public comment when issuing rules, with limited exceptions not applicable here.[237] If the RAR is, as the Department claims on page vi, a "uniform methodology" for agency decisionmaking on reliability interventions, then the Department needed to provide notice and seek and respond to public comment on this methodology. The Department cannot slip in "entirely new information critical" to its "determination[s]" without taking and responding to public comment.[238]

In the past, when the Department sought to create uniform triggers for reliability intervention within its authority, it issued notice and sought comment.[239] If the RAR is a "uniform methodology" for reliability interventions, then the Department has effectively amended those prior regulations on reliability interventions without following legally required procedures. For example, the Department has regulations defining "emergency" and setting forth procedures for an applicant to demonstrate an "emergency" in the context of Federal Power Act Section 202(c) orders.[240] If the RAR is now a mandatory factor in determining whether there is an "emergency," the Department has changed its existing regulations without following required notice and comment procedures.

E. NEPA Procedures Must Be Followed for Any RAR on Legislative Proposals or "Uniform Methodology" the Department Uses to Guide Reliability Interventions.

Under the National Environmental Policy Act ("NEPA"), agencies must include a "detailed statement" on the environmental impacts of a proposed action "in every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment."[241] If the RAR is a "uniform methodology" for agency decisionmaking on reliability interventions, it qualifies as a major federal action requiring, at a minimum, an Environmental Assessment and most likely, under the circumstances, a full

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[237] 5 U.S.C. §§ 553(b), (c).

[238] *Am. Pub. Gas Assoc. v. DOE*, 72 F.4th 1324, 1338 (D.C. Cir. 2023) (cleaned up).

[239] *See* Grid Security Emergency Orders: Procedures for Issuances, 83 Fed. Reg. 1174 (Jan. 10, 2018) (final rule on Federal Power Act section 215A procedures issued after notice and comment); Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39,984 (Aug. 6, 1981) (final rules concerning emergency interconnections under Federal Power Act sections 202(c) and 202(d) issued after notice and comment).

[240] 10 C.F.R. §§ 205.371; 205.373.

[241] 42 U.S.C. § 4332(C).

Environmental Impact Statement. However, the RAR does not contain any statement whatsoever, and certainly no "detailed statement," on environmental impacts.

Yet the RAR purports to guide "government decisionmakers" on one of the most significant issues that affect the environment—electricity generation. The electricity sector is responsible for wide-ranging environmental impacts—from smog to greenhouse gas emissions to toxic metals to acid rain.[242] Uniform rules on reliability interventions would significantly affect the environment because some of these reliability interventions allow environmental rules for electricity generators to be waived.[243]

VI. CONCLUSION

For the reasons set forth above, the undersigned Public Interest Organizations respectfully request that the Department withdraw the RAR. In the alternative, the Department should not use the RAR as support for any reliability intervention or other action until and unless it (1) provides notice of the statutory authority under which DOE issued the RAR and publishes all data underlying the RAR, (2) provides a detailed explanation of the specific uses for the methodology, and (3) allows interested parties to comment on the RAR before finalizing it.

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[242] *See* EPA, Human Health & Environmental Impacts of the Electric Power Sector (Feb. 6, 2025) https://www.epa.gov/power-sector/human-health-environmental-impacts-electric-power-sector.

[243] *See* 16 U.S.C. § 824a(c)(4)(A).

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-40a:
Department's Response to PIOs' RFR of July Resource Adequacy Report

Department of Energy
Washington, DC 20585

September 5, 2025

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RE: August 8, 2025 Submission

To Whom It May Concern:

Thank you for your August 8, 2025 submission on behalf of the Natural Resources Defense Council, the Ecology Center, the Environmental Defense Fund, the Environmental Law and Policy Center, Public Citizen, Sierra Club, and Vote Solar (collectively, the Public Interest Organizations). The submission was titled "Motion to Intervene and Request for Rehearing of Natural Resources Defense Council, the Ecology Center, Environmental Defense Fund, Environmental Law and Policy Center, Public Citizen, Sierra Club, and Vote Solar" (Submission). It was not filed in any active docket.

On July 7, 2025, the U.S. Department of Energy (DOE) issued the Report on Strengthening U.S. Grid Reliability and Security (Resource Adequacy Report or RAR), fulfilling Section 3(b) of Executive Order 14262. The RAR presents a unified, transparent methodology for assessing the reliability of the bulk power system and identifying regions at elevated risk of resource inadequacy under projected load growth and plant retirement scenarios. DOE developed this approach in coordination with NERC and leading industry experts to provide a consistent, data-driven framework for informing federal reliability interventions, particularly as the grid faces surging demand from AI-driven data centers, reindustrialization, and electrification.

In the Submission, the Public Interest Organizations seek rehearing of the RAR under section 313 of the Federal Power Act (FPA).[1] An application for rehearing under section 313 of the FPA[2] may be filed only by a "person, electric utility, State, municipality, or State commission" that is "aggrieved" by "an order issued by [DOE]."[3] If these prerequisites are not met, there is no basis for rehearing. Here, we note that the RAR is simply a report that details the current condition of the United States electrical grid. It contains no directives, nor does it impose legal duties upon any party, including the Public Interest Organizations. As such, it cannot be considered an "order" by which the Public Interest Organizations are "aggrieved" within the meaning of section 313 of the FPA, as would be required to request rehearing. Accordingly, DOE will take no action on the Submission.

---

[1] Submission at 1.
[2] 16 U.S.C. § 825*l*(a).
[3] *Id.*

Sincerely,

Tina Francone
Director of the Grid Deployment Office, Acting

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-41:
Inst. Pol'y Integrity Report

Enough Energy

A Review of DOE's Resource Adequacy Methodology

Jennifer Danis
Christoph Graf, Ph.D.
Matthew Lifson

July 2025

Institute *for*
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NEW YORK UNIVERSITY SCHOOL OF LAW

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The authors thank Dr. Adria Brooks and Rob Gramlich for their valuable feedback.

This report does not purport to present the views, if any, of NYU School of Law.

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Executive Summary

On April 8, 2025, President Trump issued an Executive Order on Strengthening the Reliability and Security of the United States Electric Grid (the EO) requiring the Department of Energy (DOE) to (1) "identify current and anticipated regions with reserve margins below acceptable thresholds" and (2) "establish . . . a protocol to identify which generation resources within a region are critical to system reliability."[1] DOE responded on July 7, 2025 with its *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (DOE Study).[2]

This report reviews best practices for analyzing whether a region is resource adequate and for identifying whether a particular resource is critical for resource adequacy. It next analyzes the DOE Study as compared to those best practices. Finally, it examines next steps for U.S. resource adequacy policy following the DOE Study, in light of different entities' respective authorities over the issue.

In Part 1, this report outlines a four-step process for evaluating whether a region is resource adequate and then identifying which resources are critical. Each step involves choices between traditional methods and best practices adapted to the evolving risks posed by the energy transition and the new conditions brought about by climate change.

- *Step 1*: *Set a Resource Adequacy Target*: Planners should define resource adequacy targets using a multi-metric approach that captures not just outage frequency but also magnitude and duration, possibly supplemented by metrics focused on tail risks instead of expected values. Targets should be region-specific and reflect a local cost-benefit analysis that weighs the incremental benefits and costs of achieving reduced outages.
- *Step 2: Conduct Resource Adequacy Modeling:* Rather than focusing narrowly on annual peak load, planners should assess whether a region achieves the target from Step 1 by modeling all 8,760 hours of the year in chronological order using probabilistic techniques that account for uncertainty like the Monte Carlo method. Best practices include incorporating weather-linked dependencies; climate-adjusted inputs; and realistic assumptions about retirements and additions, interregional imports, and storage and demand response dynamics. This modeling more accurately reflects the risks posed by variable generation and energy-limited resources.
- *Step 3: Establish Accreditation Values:* Resource accreditations—the specific contribution of a resource or resource type to resource adequacy—should be derived from Step 2's probabilistic modeling of a resource's ability to contribute during hours of highest risk.

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1 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

2 U.S. Dep't of Energy, Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid (2025), https://perma.cc/A587-S88S.

Effective Load Carrying Capability or related probabilistic methods should be applied to all resource types, including thermal plants, to accurately describe their contributions under a wide range of possible futures and hard-to-predict risk periods. Accreditation methods should be applied equally to thermal and variable resources to allow for technology-neutral comparisons.

- *Step 4: Calculate the Reference Margin Level and the Reserve Margin:* Using the resource adequacy modeling and accreditation values from Steps 2 and 3, planners should calculate a reference margin level—the amount of accredited capacity that corresponds to achieving the resource adequacy target. Comparing a region's actual resource fleet to this benchmark allows planners to determine whether the exit or entry of specific resources would affect achievement of the reference margin level and thus the resource adequacy target, given the resources' accreditations.

Part 2 compares the best practices from Part 1 to DOE's methodology in the DOE Study—in which DOE concluded that all transmission planning regions except ERCOT are currently resource adequate but that all regions except ISO-NE and NYISO will be resource inadequate in 2030. Across multiple dimensions, DOE's approach departs from best practices in ways that call these results into question.

- *Resource Adequacy Targets:* DOE's use of a multi-metric standard—2.4 hours of lost load per year and 0.002% normalized unserved energy—is consistent with best practices, but the choice of values is not. Neither value is 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. Additionally, DOE inappropriately attempts to label PJM as currently resource inadequate even though the region achieves DOE's own target according to DOE's modeling.

- *Resource Adequacy Modeling:* DOE models all 8,760 hours of the year chronologically but relies on a deterministic rather than probabilistic framework, limiting its ability to assess uncertainty or tail risks. This less accurate approach evaluates adequacy only under a fixed set of historical weather and load years. Further, DOE's truncated description of how its model decides whether an outage has been triggered makes this assumption impossible to fully evaluate, but DOE's limited explanation does suggest that it may have adopted an overly conservative approach that exaggerates resource adequacy risk. Finally, DOE's 2030 results are significantly shaped by unrealistic assumptions about additions, retirements, load, and possibly interregional imports.

- *Accreditation and Reference Margin Levels:* The DOE Study does not attempt to identify resources that are critical for any region's resource adequacy, and thus does not calculate accreditation values or reference margin levels. But DOE does estimate the amount of perfect capacity required to bring certain regions to the 0.002% NUSE target. DOE could build upon this approach in the future to calculate reference margin levels, but any future efforts should attend to all prongs of its multi-metric resource adequacy target. Additionally, DOE's perfect capacity additions inexplicably bring regions far beyond 0.002% NUSE, meaning that DOE overstates how difficult it would be to cure the purported resource adequacy shortfalls.

Part 3 answers what should happen next for U.S. resource adequacy policy now that DOE has published its study.

- Given how DOE's statutory authority under Section 202(c) of the Federal Power Act is limited to emergencies, DOE's own conclusion that most regions are not currently experiencing resource adequacy shortfalls suggests that DOE has limited legal authority to address potential problems in 2030. Moreover, the limitations of the DOE Study call into question the accuracy of DOE's forecasts.
- Instead of DOE, the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation could more appropriately—and less intrusively from the perspective of states, grid operators, and markets—support resource adequacy by issuing reliability standards that require best practices for regions' resource adequacy efforts. Rather than establishing a national resource adequacy target, these standards would govern how regions select resource adequacy targets, evaluate if they are achieving them, and measure the contributions of specific resources. This step would be in line with the Federal Energy Regulatory Commission's Order No. 747, which approved analytical guardrails for resource adequacy analysis for a portion of the U.S.

Introduction

How does a regional electric grid operator know when its region has enough electricity to meet demand and whether any specific generation resource, like a particular coal plant, is essential for doing so? President Trump's Executive Order on Strengthening the Reliability and Security of the United States Electric Grid (the EO) implicates these questions: The EO directs the Department of Energy (DOE) to assess if each region of the United States has sufficient energy resources to meet current and future demand, and to identify and retain critical resources.[3] On July 7, 2025, DOE responded to the EO by publishing its *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (DOE Study).[4]

This report addresses the EO and the DOE Study's fundamental concern: resource adequacy. Resource adequacy is one key aspect of a power system's reliability. It refers to a system's "ability . . . to generate and transmit adequate quantities of electricity to meet demand, taking into account scheduled and reasonably expected unscheduled system outages."[5] Resource adequacy thus concerns whether a system's supply of energy exceeds demand. Determining whether an area is resource adequate is, however, ultimately a policy question, rather than an engineering one, because it would be prohibitively expensive to build a system that serves 100% of demand under all conditions.[6] Deciding whether a region is resource adequate always explicitly or implicitly balances society's desire for reliable electricity with the cost of providing that reliability.

Starting from first principles, Part 1 examines how to determine whether a region meets its selected resource adequacy target and how a planner can know whether any one particular resource is critical for resource adequacy. Part 2 discusses whether the DOE Study reflects, rejects, or obscure these first principles. Part 3 explores next steps for U.S. resource adequacy policy following the publication of the DOE Study, considering the respective roles of the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), DOE, grid operators, and states.

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3 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025).

4 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2.

5 Burçin Ünel & Avi Zevin, Inst. for Pol'y Integrity, Toward Resilience: Defining, Measuring, and Monetizing Resilience in the Electricity System 11 (2018), https://perma.cc/UDB5-DEEM (citing a NERC "Frequently Asked Questions" page that is no longer available).

6 Energy Sys. Integration Grp., New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements 38 (2024), https://perma.cc/NXU4-N4UG.

Part 1: Best Practices for Resource Adequacy

The EO requires DOE to evaluate the sufficiency of regions' "reserve margins" and establish a resulting protocol to identify "critical" resources that should be retained.[7] To figure out what kind of buffer will ensure that a region achieves a given level of resource adequacy, and to label specific generators as essential for that resource adequacy, a planner would need to undertake a four-step process. At each step, the planner must pick between antiquated approaches and newer best practices.

First, the planner must make the policy choice of selecting a resource adequacy target for the region that, if achieved, would indicate resource adequacy. Second, it should use resource adequacy modeling to determine whether a region has achieved and will continue to achieve the selected target under foreseeable future conditions. Third, the planner should use its resource adequacy modeling with accurate data curation to derive how each generation and storage resource contributes to meeting the target (their "accreditation" values). Fourth, it should use the resource adequacy modeling plus resources' accreditation values to derive an acceptable reserve margin for the region (the "reference margin level"). At this fourth step, the planner can use the accreditation values to check whether the exit of a particular resource would cause a region to dip below the reference margin level.

These best practices have largely emerged to address the resource adequacy challenges caused by the energy transition and extreme weather events caused by climate change. Whereas traditional methods have focused on whether demand would exceed supply during peak load hours, system risk has shifted to *net* peak hours, i.e., when load minus variable generation is highest.[8] Measuring whether supply will meet demand has itself become more complicated. Increasingly, it has become important to perform modeling resource adequacy chronologically—each hour reflecting the conditions that came before it—to account for the dynamics of battery storage resources and demand response.[9] And policymakers now are also confronting the outdated idea that thermal resources are "perfect" capacity, given their weather-related vulnerabilities.[10]

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7 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

8 Juan Pablo Carvallo et al., Lawrence Berkeley Nat'l Lab'y, A Guide for Improved Resource Adequacy Assessments in Evolving Power Systems: Institutional and Technical Dimensions 13 (2023), https://perma.cc/5VLY-B7HF.

9 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, Evolving Planning Criteria for a Sustainable Power Grid: A Workshop Report 9 (2024), https://perma.cc/KE8D-W6VX.

10 Nat'l Ass'n of Regul. Util. Comm'rs, Resource Adequacy for State Utility Regulators: Current Practices and Emerging Reforms 32–34 (Nov. 2023), https://perma.cc/K88X-2JCR.

Step 1: Pick a Resource Adequacy Target

Before any analysis can determine if a system is resource adequate, policymakers must set a clear resource adequacy *target*.[11] This first step involves two distinct choices: (1) selecting one or more metrics to represent the variables by which resource adequacy will be judged, and (2) setting the numerical values for those chosen metrics to achieve the resource adequacy target.

Consider what it would take to set a target, not for resource adequacy, but for human health. First, you would pick the metrics that you think would best define whether a person is healthy, e.g., blood pressure, resting heart rate, or cholesterol levels. Using only one metric would not give you enough information. And paying attention to only each metric's average levels without also examining whether the metric ever reaches dangerous levels could obscure risk of a catastrophic health event. Second, you would pick a value for each metric, like a blood pressure of less than less than 120/80 mmHg. To pick that value, you would consider the best available evidence on what level is optimal.

Similarly, when it comes to resource adequacy, the best practice is to move beyond the standard approach of attending primarily to the *frequency* of outages and to also consider their *magnitude* and *duration*. Additionally, regions should consider metrics focused on the extremes of the probability distribution, rather than expected value metrics that could label a system as resource adequate when a low probability (but plausible) event would be catastrophic.

When selecting numerical values for the chosen resource adequacy metrics, the best practice is to consider the best available evidence on the tradeoff between the benefits and costs of additional resource adequacy. The optimal level of resource adequacy may be different in each region, depending on the local costs of the investments that would be needed to reduce shortfall events and the local consequences of a shortfall.[12] A resource adequacy target should ideally represent the level of resource adequacy that the system planner has identified as socially optimal because it balances costs and benefits.

Metrics

Historically, U.S. policymakers have framed their resource adequacy targets in terms of loss of load expectation (LOLE),[13] and this metric remains widespread.[14] LOLE typically refers to the number of days per year in which an outage occurs and is largely a measure of frequency.[15]

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11 *See* Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 2 tbl.1.

12 *Id.* at 39, 41.

13 Elec. Power Rsch. Inst., Metrics and Criteria: Insights from Case Studies and Recommendations and Considerations for Future Practice 31 (2024), https://perma.cc/W4VF-VQPD.

14 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 8 tbl.2.

15 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future 3, 8 (Apr. 2022), https://perma.cc/7G9V-CNWB. Technically, the number of days per year in which an outage occurs is "loss of load days" (LOLD), which is a special case of the broader concept of LOLE, which can be used with different event-periods. *Id.* at 7–8. In North America, however, LOLE typically means LOLD. *Id.* at 7; *accord* Gord Stephen et al., *Clarifying the Interpretation and Use of the LOLE Resource Adequacy Metric* at 2, https://perma.cc/A9DJ-C3B5.

Frequency is an important characteristic to track because consumers prefer fewer outages.[16] LOLE coarsely accounts for duration, too, in that an outage that stretches multiple days will count as an additional event for each additional day.

LOLE does, however, obscure important aspects of resource adequacy. It will not differentiate between (1) a 10-hour event with 1 GWh of load shed that is followed by a second identical event within the same day and (2) a 30-minute event with 5 MWh of load shed. Customers are not indifferent, however, between these two situations.[17] Because damages depend on outages' frequency, magnitude, and duration, LOLE neglects key dimensions of resource adequacy affecting customers' wellbeing.[18] Attending to these characteristics when setting resource adequacy targets is more important than ever, because changes in the resource mix and extreme weather due to climate change mean that loss-of-load events have become less uniform and thus less interchangeable.[19]

The Multi-Metric Approach

The best practice is to supplement the traditional LOLE metric (or a different frequency-focused metric like "loss of load events," which separately counts all events within a year and thus differentiates between events that occur during the same day[20]) with additional metrics that capture other dimensions of resource adequacy.[21] Both the Electric Reliability Council of Texas (ERCOT) and the Northwest Power and Conservation Council (NWPCC) have done exactly this, augmenting their LOLE-based targets to include magnitude and duration metrics.[22] Under a multi-metric approach, a system could be declared resource adequate if it achieves selected value targets for each and every metric,[23] or if it achieves some minimum number or combination of the metrics (e.g., any two of a system's three metrics).[24]

A leading magnitude metric that could be incorporated into a multi-metric approach is expected unserved energy (EUE): the amount of demand that the system will fail to serve during a period, typically a year.[25] A region's EUE can be contextualized by dividing it by the region's total annual load—this is called normalized unserved energy (NEUE).[26] Australia uses an annual unserved

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16 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 17.

17 *Id.* at 3.

18 *Id.* at 10.

19 *Id.* at 11, 15, 22.

20 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 8.

21 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 33–37; Elec. Power Rsch. Inst., Resource Adequacy Philosophy: A Guide to Resource Adequacy Concepts and Approaches 23 (2022), https://perma.cc/ZH4Y-ZD7J; Juan Pablo Carvallo et al., *supra* note 8, at 28–29; N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at vii.

22 Reliability Standard for the ERCOT Region, No. 54584, 2024 WL 4263493, at *24 (Tex. Pub. Utils. Comm'n Sept. 9, 2024); *Resource Adequacy*, Nw. Power & Conservation Council, https://perma.cc/39P6-VBNN.

23 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 35.

24 Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 31–32.

25 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 17.

26 *Id.* at 18.

energy metric,[27] as does NWPCC.[28] Planning around these magnitude metrics can help a region avoid catastrophic events associated with significant unserved energy.[29]

But, like LOLE, magnitude-focused metrics like EUE and NEUE are incomplete alone; they do not account for how the unserved energy is distributed throughout the year.[30] An alternative or complementary magnitude metric is "peak shortfall," defined as the largest expected outage of the period.[31] Peak shortfall is potentially useful because damages from a single outage increase nonlinearly with its scale.[32] Both ERCOT and NWPCC have versions of a peak shortfall metric (NWPCC's complements its EUE metric).[33]

For duration, a popular metric that could supplement frequency and magnitude metrics is loss of load hours (LOLH), which measures the number of hours per year in which an outage occurs.[34] LOLH fundamentally resembles LOLE, but is more granular because it analyzes each hour, rather than each day. As such, LOLH does a better job at expressing the aggregate duration of all shortfalls in a region.[35]

Many countries use LOLH as their sole resource adequacy metric,[36] but, in aggregating hours, it neglects the duration of individual events—even though damages increase nonlinearly with an outage's duration.[37] Supplemental metrics such as average shortfall duration[38] and the maximum shortfall length (used in Texas and NWPCC)[39] can capture this aspect of duration.

Accounting for Tail Risks

Beyond questions of frequency, magnitude, and duration, a separate question when using any chosen metric is whether to look at the mean of the distribution, extremes, or both. Traditionally, regions have framed their LOLE, EUE, and LOLH goals in terms of their *mean* values.[40] But the energy transition and climate change have increased the risk of extremely damaging tail risks,[41]

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27 *Id.* at 9.

28 Nw. Power & Conservation Council, *supra* note 22.

29 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 19 tbl.4.

30 *Id.*

31 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide 18 (2024), https://perma.cc/CB7Q-MXZM (using the equivalent phrase "MW Short").

32 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 3.

33 Reliability Standard for the ERCOT Region, No. 54584, 2024 WL 4263493, at *24 (Tex. Pub. Utils. Comm'n Sept. 9, 2024); *Resource Adequacy*, Nw. Power & Conservation Council, https://perma.cc/39P6-VBNN.

34 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 8.

35 *Id.* at 8.

36 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 8.

37 *Id.* at 3.

38 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 10.

39 Reliability Standard for the ERCOT Region, No. 54584, 2024 WL 4263493, at *24 (Tex. Pub. Utils. Comm'n Sept. 9, 2024); *Resource Adequacy*, Nw. Power & Conservation Council, https://perma.cc/39P6-VBNN.

40 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment 4 (2023), https://perma.cc/M3A5-2WAL; Juan Pablo Carvallo et al., *supra* note 8, at 12.

41 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 22.

making it increasingly appropriate to factor these risks into regions' metrics.[42] When it comes to resource adequacy, customers care not just about how the how severe and common outages will be on average, but also about how bad the worst outages they will experience could be.

One option for assessing these potentially severe consequences is the "value at risk" method. This method defines the selected metric (whether it is focused on frequency, magnitude, or duration), not in terms of its expected value, but in terms of how bad some relatively unlikely but still plausible scenario would be.[43] For example, one of NWPCC's metrics is the maximum shortfall length, framed in terms of what the maximum shortfall length will be at the 97.5th percentile of the distribution, i.e., how long the shortfall would be if there were only a 2.5% chance that the shortfall could be longer.[44] Planners can also frame a metric both in terms of expected value *and* value at risk for the same system: Belgium previously had an LOLE metric that simultaneously required an expected value of less than 3 LOLH and required the 95th percentile of the distribution to be less than 20 LOLH.[45]

An alternative to the value at risk method is the "conditional value at risk" method, in which the metric is framed not in terms of the value at some percentile of the distribution, but in terms of the average value of the distribution beyond the percentile.[46] Policymakers' preference between these two options will depend on their risk tolerance, as the value at risk method will equally weight all tail events while the conditional value at risk method effectively places more weight on extreme events even within the tail.[47]

Values

After picking resource adequacy metrics—whether singular or multi-valued, and based on expected values, tail risks, or a combination of the two—the second step for setting a resource adequacy target is picking the numerical value for the metric(s). In the U.S., the most common value for the LOLE metric is 0.1, i.e., outages should occur no more than 0.1 days per year.[48] Selecting a value inherently involves balancing customers' desire for resource adequacy with the cost of achieving it.[49]

Notwithstanding that tradeoff, U.S. resource adequacy planners have largely set these values without any economic analysis. The origin of the widespread 0.1 LOLE target is somewhat enigmatic, especially relative to its contemporary significance, but it appears to describe the

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42 *See* Juan Pablo Carvallo et al., *supra* note 8, at 29; Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 8; Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 10; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 26–27.

43 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 26–27.

44 Nw. Power & Conservation Council, Pacific Northwest Power Supply Adequacy Assessment for 2029 12 (2024), https://perma.cc/GZY2-PKY7.

45 Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 17.

46 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 26–27; Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 10.

47 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 27 fig.8.

48 *Id.* at 8.

49 *Id.* at 38.

level of resource adequacy that happened to exist in the 1940s.[50]

The values used in NERC's reports on regions' long-term resource adequacy similarly seem arbitrary. NERC uses a LOLH metric, labeling regions with greater than 2.4 LOLH as high risk, 0.1-2.4 as elevated risk, and less than 0.1 as normal risk. NERC does not explain the basis for these categories, but they appear to stem this from a common (but widely criticized) hourly conversion of the 0.1 LOLE standard.[51] And NERC's values for the NEUE metric—above 0.002% is high risk, less than 0.002% but above zero is elevated risk, negligible or zero is normal risk—is adapted from Australia's 0.002% NEUE target without considering the different national contexts.[52] Context matters because the U.S. and Australia may vary in terms of how damaging outages would be (e.g., how bad it would be to lose electric heating and cooling in light of the region's temperatures) and how expensive it would be to avert them (e.g., the country-specific cost of building a natural gas peaker plant).

A better practice would be to use economic principles to select a socially efficient resource adequacy target, i.e., to select the value at which the incremental costs of additional resource adequacy equal the incremental benefits of achieving it.[53] Where policymakers do estimate the *costs* of improving resource adequacy, they often turn to the concept of "cost of new entry" (CONE).[54] CONE, expressed in $/MWh, represents the marginal investment and fixed costs of adding additional capacity to the system to achieve a more stringent resource adequacy standard.[55] Historically, planners assumed the marginal resource was a combustion turbine, but today it is more accurate to assume a portfolio of diverse resources.[56] Considering CONE by itself, however, does not accurately capture the social marginal cost of achieving higher levels of resource adequacy, because adding capacity can have follow-on effects like reducing the cost of energy.[57] Accordingly, it is better to estimate total net CONE, which nets out potential system benefits such as reduced energy costs for loads and lower operating costs.[58]

To estimate the *benefits* of additional resource adequacy, planners typically rely on the value of lost load (VOLL).[59] The VOLL represents the societal cost of failing to serve a unit of energy

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50 Kevin Carden et al., Nat'l Regul. Rsch. Inst., The Economics of Resource Adequacy: Why Reserve Margins Are Not Just About Keeping the Lights On 2 (2011), https://perma.cc/LS2F-2EZR; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 6.

51 *See* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment 11–12 (2024), https://perma.cc/GJB2-VCZQ; Juan Pablo Carvallo et al., *supra* note 8, at 11 ("The LOLE is typically used as a target setting metric and has historically taken a value of 1 event-day in 10 years, commonly (and incorrectly) interpreted as 2.4 hours per year.").

52 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 141.

53 Kevin Carden et al., *supra* note 50, at 1; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 38–42; Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 35.

54 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 13, 41–42.

55 *Id.* at 42.

56 *Id.*

57 Christoph Graf et al., *Cost-Effective Capacity Markets* 29, https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4864513 (posted June 21, 2024); Kevin Carden et al., *supra* note 50, at 8–9.

58 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 42.

59 Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 35.

demanded by consumers and is denominated in $/MWh.[60] Estimates vary significantly across customer classes,[61] but modelers can capture this through averaging.[62] More challenging is capturing how the VOLL varies with an outage's particular characteristics. For relatively short outages, the first hour tends to the most expensive,[63] indicating that many frequent outages could be more socially disruptive than a consolidated one of equal length. Long-duration outages result in damages that increase nonlinearly (food spoilage, jeopardized medical care, and loss of access to safe drinking water).[64] Similarly, the VOLL can increase nonlinearly with magnitude: When the grid operator can no longer manage the situation through rotating outages, the resulting uncontrolled outage is much more damaging.[65] Accordingly, undertaking a cost-benefit analysis that allows VOLL to vary with duration and magnitude would produce a more accurate, cost-benefit-justified resource adequacy target.

Many jurisdictions use some version a cost-benefit analysis when setting their resource adequacy targets. In the European Union, countries solve for their specific LOLH targets by dividing a local CONE value by the local VOLL, which, in 2023, resulted in a range from 1 LOLH (Sweden) to 15 LOLH (Czechia).[66] The United Kingdom uses this same approach.[67] Australia periodically reviews its 0.002% NEUE target to ensure that the implied "value of customer reliability," which is akin the VOLL, is close to its estimated value.[68] Somewhat analogous to these examples, the administratively set, downward-sloping demand curves for capacity markets in U.S. regions like PJM embody the tradeoff between the benefits and costs of additional resource adequacy, because the curves dictate how much regions are willing to pay for each increment of additional capacity given the capacity's incremental benefits.[69] Technically, though, this cost-benefit thinking happens not when *setting* the resource adequacy target, but in deciding whether to under-, over-, or exactly *achieve* an already-determined target.

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60 Jennifer Danis et al., Inst. for Pol'y Integrity, Transmission Planning for the Energy Transition: Rethinking Modeling Approaches 6 (2023), https://perma.cc/5A6L-DJHL.

61 Michael J. Sullivan et al., Ernest Orlando Lawrence Berkeley Nat'l Lab'y, Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States xii, tbl.ES-1 (2015), https://perma.cc/CT53-8WEA.

62 *See* Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 35.

63 Michael J. Sullivan et al., *supra* note 61, at xii, tbl.ES-1.

64 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 23 fig.5.

65 *See, e.g.*, Joshua W. Busby et al., *Cascading Risks: Understanding the 2021 Winter Blackout in Texas*, 77 Energy Rsch. & Soc. Sci. (2021); Sergio Castellanos et al., *A Synthesis and Review of Exacerbated Inequities from the February 2021 Winter Storm (Uri) in Texas and the Risks Moving Forward*, 5 Progress in Energy (2023); Hassan Haes Alhelou et al., *A Survey on Power System Blackout and Cascading Events: Research Motivations and Challenges*, 12 Energies 1, 16–17 (2019).

66 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 39 fig.12, 40.

67 *Id.* at 40.

68 Reliability Panel AEMC, Final Report: Reliability Standard and Settings Review 2018 i, 14 (2018), https://perma.cc/TAN8-TPXZ.

69 *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at P 76 (2006) ("In addition, we agree with PJM that a downward-sloping demand curve provides a better indication of the incremental value of capacity at different capacity levels than the current vertical demand curve. Under a vertical demand curve, capacity above the Installed Reserve Margin is deemed to have no value. Incremental capacity above the Installed Reserve Margin is likely to provide additional reliability benefits, albeit at a declining level. This value is reflected in the positive (but declining) prices in the sloped demand curve to the right of the Installed Reserve Margin, but is not reflected in the current capacity market.").

Step 2: Conduct Resource Adequacy Modeling

Once the policymaker sets a resource adequacy target, a resource adequacy model can predict whether a region is achieving it (and will continue to do so). Traditionally, modeling was limited to examining whether demand would exceed supply during one or a few peak load hours. But the energy transition, combined with extreme weather from climate change, requires planners to rethink prevailing resource adequacy modeling techniques. For most systems, it is now important to model all 8,760 hours of the year, in chronological order, to accurately capture the risk of load shed.

Along with improving models' temporal resolution, it has become important to make more sophisticated assumptions about modeling inputs. In particular, it has become critical to capture how supply and demand have become more dependent on the weather, which, in turn, has become more extreme. In general, a best practice is to use the Monte Carlo method, and run many (on the order of hundreds or thousands) simulations of grid operations, allowing the model to randomly pull from a distribution of possible values for every input.[70] Additionally, best practices exist for curating the data for each input and their interdependencies, such as representing the relationship between the weather and thermal outages.[71]

Temporal Scope

Historically, resource adequacy modeling focused on the likelihood that supply would exceed demand during one (or a few) top demand hours, ignoring the risk of inadequate supply during the rest of the year.[72] This simplification was more plausible when the grid was dominated by dispatchable resources with relatively predicable outputs.[73]

Now, with the increased penetration of wind and solar, periods of resource adequacy risk have shifted from peak demand to "net peak" demand, defined as load minus energy from non-dispatchable resources.[74] In this new reality, the system is most likely to lack sufficient supply when there is high demand unserved by wind or solar. And, just as weather dictates the performance of these variable resources, it also affects outages at thermal generators (e.g., interruptions of natural gas supply) and load (not just by influencing customers' demand, but also by altering

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70 See Inputs, below, for a more detailed description of the Monte Carlo method.

71 For example, cold winter snaps have historically yielded correlated outages of thermal generators. Nick Wintermantel & Nick Simmons, Astrapé Consulting 8 (2022), https://perma.cc/6D7Y-QCZ2. Similarly, extreme hot weather can require both thermal and nuclear units to cease operations, if the unit can no longer use intake water bodies for cooling. *E.g., High French River Temperatures to Hit Nuclear Production Next Week*, Reuters (June 20, 2025), https://www.reuters.com/business/energy/high-french-river-temperatures-hit-nuclear-production-next-week-2025-06-20.

72 Juan Pablo Carvallo et al., *supra* note 8, at 9; N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 2.

73 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 2; Juan Pablo Carvallo et al., *supra* note 8, at 1, 27.

74 Jill Moraski et al., Clean Air Task Force, Beyond LCOE: A Systems-Oriented Perspective for Evaluating Electricity Decarbonization Pathways 21 (2025), https://perma.cc/3A39-FQLW.

behind-the-meter generation that typically provides "negative" load).[75] Given this confluence of variables, the best practice is now to examine all 8,760 hours of the year when evaluating the likelihood and expected characteristics of shortfalls.[76]

The increased prevalence of energy-limited resources like battery storage and demand response have similarly complicated more traditional resource adequacy modeling assumptions. Battery storage's ability to avoid a resource adequacy shortfall will depend on its state of charge.[77] For example, a battery could have sufficient energy to prevent a shortfall in the morning and then, if it has no opportunity to recharge, be empty for a second event that same afternoon. Similarly, demand response participants have only a limited willingness to curtail or shift their demand; activating the program degrades its later effectiveness.[78] Accordingly, the best practice for resource adequacy modeling is to not just to consider all 8,760 hours, but to do so sequentially, capturing how storage and demand response used in one hour can affect their subsequent availability.[79]

Inputs

To keep pace with the many uncertainties of contemporary resource adequacy analysis, planners have shifted to probabilistic modeling approaches like the Monte Carlo method.[80] Under this best practice, rather than assessing resource adequacy using specific expected values for each input, the user provides the model with a probability distribution for different inputs, and the model randomly samples from those distributions across hundreds or thousands of simulated scenarios.[81] The model will draw the load for each hour, along with potentially correlated variable generation, thermal resource availability, and transmission outages.[82]

While the Monte Carlo method can yield more accurate resource adequacy estimates than simpler methods, its accuracy depends on the user-provided probability distributions, as well as accurate specification of key interdependencies.[83] For weather data, the current best practice is to use as many years as are available, with hourly resolution and geographic granularity.[84] And, especially when forecasting longer-term resource adequacy, it has become important to account

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75 Juan Pablo Carvallo et al., *supra* note 8, at 27; Standard Authorization Request (SAR) Form, N. Am. Elec. Reliability Corp. at 2, https://perma.cc/Q8AU-9YWW.

76 Juan Pablo Carvallo et al., *supra* note 8, at 27; Standard Authorization Request (SAR) Form, N. Am. Elec. Reliability Corp. at 2, https://perma.cc/Q8AU-9YWW.

77 Energy Sys. Integration Grp., Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation 11 (2023), https://perma.cc/4ETD-JQK2.

78 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 55–56.

79 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 9; Juan Pablo Carvallo et al., *supra* note 8, at 9; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 44.

80 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 9.

81 *Id.* at 10.

82 Juan Pablo Carvallo et al., *supra* note 8, at 13.

83 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 12.

84 Juan Pablo Carvallo et al., *supra* note 8, at 30.

for climate change projections,[85] including the increasing severity of extreme events.[86]

For load, the best practice is to capture its relationship to the weather, and to add a probabilistically determined amount of distributed generation as negative load.[87] Similarly, for generation, the best practice is to derive the relationship between weather and its output, while also accounting for how technological improvements will improve production profiles,[88] along with the possibility of other types of common mode failures.[89]

Other important considerations include realistic assumptions about electricity imports from neighboring regions (e.g., probabilistically modeling neighbors' operations during tight periods),[90] intraregional transmission constraints,[91] the impact of probabilistic intraregional transmission failures,[92] and for when the model decides that an outage has been triggered.[93]

Additionally, for forecasting longer-term resource adequacy, modelers need to make assumptions about which resources retire and come online. These assumptions will have a large bearing on model outputs. For retirements, modelers should include announced retirements while also forecasting unannounced retirements by accounting for likely retirements due to federal and state policy, age-based retirements, and retirements driven by economics.[94] For near-term new generation and storage, modelers should consider projects that have cleared or will soon clear the interconnection queue, along with expected build times.[95] To anticipate later-term resource additions, modelers should consider resource costs and trajectories, regulatory incentives and barriers, and other relevant drivers. As with other inputs, modelers can implement retirements and additions through a distribution of probabilities, rather than strict assumptions about what will occur.[96]

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85 *Id.*

86 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 22.

87 Juan Pablo Carvallo et al., *supra* note 8, at 31.

88 *Id.* at 32.

89 Elec. Power Rsch. Inst., Modeling New and Existing Technologies and System Components in Resource Adequacy 17–18 (2023), https://perma.cc/3CWR-G5LM; Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 37–38; *How MISO Utilizes PLEXOS for Enhanced Resource Adequacy*, Energy Exemplar (Oct. 9, 2024), https://perma.cc/VQY8-WAVX.

90 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 31; Adria E. Brooks et al., Grid Strategies LLC, Resource Adequacy Value of Interregional Transmission 31 (2025), https://perma.cc/77FQ-L94V; Sam Hostetter & Derek Stenclik, Analysis of Resource Adequacy Across the Eastern Interconnection 7, 16 (2025), https://perma.cc/LCU4-LBZF.

91 Elec. Power Rsch. Inst., Resource Adequacy Scenario Selection Guide 6, (2024), https://perma.cc/FZ5A-5G2M.

92 Juan Pablo Carvallo et al., *supra* note 8, at 13–14; Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 12.

93 Kevin Carden et al., *supra* note 50, at 7.

94 Inst. for Pol'y Integrity, Comments on Policy-Driven Retirements in the Context of Order No. 1920 at 4–6 (Oct. 18, 2024), https://perma.cc/GB4R-X55D.

95 *E.g.,* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 137.

96 *See* Inst. for Pol'y Integrity, Comments, *supra* note 94, at 7–8.

Step 3: Accreditation

After resource adequacy modeling, the next step is to derive how much credit each resource deserves for its contribution towards the system's resource adequacy—a process called "accreditation." A resource's accreditation, typically expressed as a fraction of its nameplate capacity, captures the resource's estimated availability during the periods when resource adequacy is most strained.[97]

If a planner is interested in determining only whether a system is achieving its resource adequacy target, this step is unnecessary because Step 2 will accomplish that.[98] Nor is this step strictly necessary to determine how the retirement of any particular resource would affect reaching the resource adequacy target; a planner can accomplish that by re-running Step 2 without the resource included.

But, as explained further in Step 4, accreditation is important to calculate a region's *reference reserve margin*, i.e., the resource adequacy cushion that, when obtained, suggests that the system will achieve its resource adequacy target. Accreditation is also valuable because, once a planner calculates the reference margin level, having these accreditation values can allow a policymaker to quickly estimate how the retirement or addition of particular resources would affect maintaining that margin, without needing to re-run the resource adequacy modeling. This kind of analysis could satisfy the EO's call for a protocol to "identify which generation resources within a region are critical to system reliability."[99]

Historically, planners accredited thermal resources at their full nameplate capacity—reflecting an assumption that they could always generate at maximum capacity during the moments of greatest resource adequacy risk—or accredited them based on their nameplate capacity discounted by their average forced outage rate.[100] Variable resources have often been accredited based on their historical performance during peak load hours.[101]

With the energy transition and climate change, however, the best practice is to derive a resource's accreditation from the resource adequacy modeling described in Step 2 using a probabilistic

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97 An Pham et al., Nat'l Renewable Energy Lab'y, Average and Marginal Capacity Credit Values of Renewable Energy and Battery Storage in the United States Power System 5 (2024) (using the equivalent phrase "capacity credit"). These times have become increasingly decoupled with peak load events. Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 4.

98 Juan Pablo Carvallo et al., *supra* note 8, at 36 ("Capacity accreditation is not inherent to resource adequacy assessments . . . ."); Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at vii ("While resource adequacy analysis assesses whether there are enough resources to serve load across the system, capacity accreditation measures the contribution of individual resources toward meeting that goal, both in terms of capacity and energy.").

99 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15522 (Apr. 14, 2025).

100 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 9, 37; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 5.

101 Juan Pablo Carvallo et al., *supra* note 8, at 36.

method.[102] Probabilistic methods like Effective Load Carrying Capability (ELCC) analyze how slight changes in the modeled resource inputs would affect resource adequacy outcomes.[103] They typically work by adding more of the studied resource to the model, beyond what exists in the base case, and then adding load until the model's base case resource adequacy outcome is restored.[104]

The benefit of probabilistic approaches like ELCC is that, when the modeling inputs from Step 2 are well-curated, the resulting accreditations will more accurately reflect a resource's contribution to resource adequacy during the true risk periods.[105] Additionally, these methods consider a wide range of possible futures, including the possibility of tail events, rather than assuming the future will resemble the past.[106]

The best practice is to apply these ELCC-style methodologies to both variable and thermal resources, storage, and transmission.[107] It is important to treat all resource types equally because capacity accreditation provides a technology-agnostic way of comparing resources' resource adequacy contributions.[108] That purpose is compromised when the resource adequacy value of variable resources is reduced to account for myriad factors affecting their output, without parallel reductions capturing thermal resources' weather dependency and common mode outages.[109] With increased saturation of natural gas resources—which are susceptible to fuel disruptions and extreme weather—it is more important than ever to accurately account for thermal generations' winter risks, especially the risk that a significant amount of thermal capacity will become unavailable at once.[110] Probabilistic methods are ideal for understanding the effect of these risks, including tail risks, in light of the complicated interdependencies of all the factors that dictate the timing of resource adequacy shortfalls.[111]

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102 *Id.* at 36–37; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning 24–27 (2011), https://perma.cc/294F-25KU.

103 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 13.

104 *Id.*

105 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 12–14; Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 15; Christoph Graf et al., *supra* note 57, at 30. As explained in Step 2 above, these risk periods are becoming harder to predict due to weather's increased influence on supply and demand, and because of increased energy-limited resources in the generation mix.

106 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 14.

107 Juan Pablo Carvallo et al., *supra* note 8, at 37; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions, *supra* note 102, at 28; Adria E. Brooks et al., *supra* note 90, at 31.

108 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 32, 37.

109 *Id.* at 37–38.

110 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 24; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 40–41; Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 30; Elec. Power Rsch. Inst., Resource Adequacy Philosophy, *supra* note 21, at 27.

111 *See* Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 11 ("Increasingly, periods of risk are driven by correlation among many components that are often weather-related, including high load, low renewable resource availability, drought, and correlated outages and fuel supply disruptions from the fossil fuel generators."); N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 91 ("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

Step 4: Calculating the Reference Margin Level and the Reserve Margin

Using Step 2's resource adequacy modeling and Step 3's accreditations, a planner can assess whether a region's fleet would achieve its appropriate reference margin level.[112] The reference margin level typically expresses the amount of accredited capacity that a region would need to achieve its resource adequacy target. The planner will conduct resource adequacy modeling, adding or subtracting additional capacity or load until the system reaches the resource adequacy target. The reference margin level is the sum of the accredited capacity needed to achieve the target.

Once the planner derives the reference margin level (how much total accredited capacity the system requires), it is also possible to answer whether any particular resource is critical to achieving the margin. To check this, the planner would subtract the accredited capacity of the resource in question from the total accredited capacity of the region, and check whether the difference exceeds the reference margin level.

Reference Margin Levels

Historically, reference margin levels were—and, in some places, continue to be—resource adequacy targets in themselves (e.g., a target of accredited capacity that is 15% above peak load).[113] But setting a target framed entirely around the summed accredited capacity, even when informed by years of operating experience at different margin levels, yields a target that does not explicitly aim to achieve any particular outcome.[114] As explained in Step 1, targets are more typically expressed in terms of outcomes: the frequency, duration, and/or magnitude of shortfalls.

Yet the idea of a reference margin level has persisted, as planners often convert their outcome-focused targets into the equivalent reference margin levels.[115] For example, a region might have a 0.1 LOLE target and then determine that the 0.1 LOLE target is achieved when the region's installed capacity has an accreditation of at least 15% above peak load.[116] The same type of translation is possible for targets set using other metrics, like EUE or LOLH.[117]

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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.").

112 This is also commonly referred to as a planning reserve margin, connoting that it includes resources that are in reserve and only be dispatched in highly constrained scenarios.

113 Elec. Power Rsch. Inst., Resource Adequacy Philosophy, *supra* note 21, at 24; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 8–9.

114 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 5–6; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions, *supra* note 102, at 29–30.

115 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 7; Juan Pablo Carvallo et al., *supra* note 8, at 37; N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 1.

116 Juan Pablo Carvallo et al., *supra* note 8, at 28.

117 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 15; Juan Pablo Carvallo et al., *supra* note 8, at 29.

Given how resource adequacy risk has evolved, however, the best practice is to derive the reference margin level using the probabilistic resource adequacy modeling from Step 2 (itself conducted in accordance with best practices).[118] Doing this helps to ensure that the margin is calculated to comprehensively reflect year-round risks. Indeed, when resource adequacy risk shifts beyond peak load hours, the amount of accredited capacity necessary to achieve the resource adequacy target can become *lower* than peak load—because resources' accreditations will be based on their outputs during moments of greatest risk, which may be lower than their outputs at peak load.[119] Accordingly, calculating a reference margin level that matches accredited capacity to peak load would overestimate the necessary margin.

While there are multiple plausible ways to use probabilistic resource adequacy modeling to convert the resource adequacy target to a reference margin level, the general approach depends on whether the modeling reveals that the system is exactly achieving the target, underachieving it, or overachieving it. For the rare case in which the system happens to be exactly achieving the resource adequacy target, then the sum of the total accredited capacity installed on the system equals the reference margin level. It can be expressed as MW of accredited capacity, or in reference to some other amount, like a percentage of peak load.[120]

It is more likely, however, that the system is either above or below the resource adequacy target. In these instances, it is common to add or subtract accredited capacity in the model until the system achieves the target.[121] Then, the reference margin level will be the amount of accredited capacity on the modeled system when the target is achieved, again expressed as a quantity of MWs or as a percentage of peak load.

Effect of Particular Resources

Once the reference margin level and accreditation values have been calculated, it becomes possible to test how the exit (or entry) of a particular resource would affect the region's resource adequacy.

An example is useful in understanding how. Imagine that the reference margin level for a region is 25 GW, and its resource mix has 26 GW of accredited capacity. As is, the region would be exceeding its reference margin level by 1 GW. If any resource with an accreditation greater than 1 GW were to exit the grid, that would cause the actual reserve margin to dip below the reference margin level. Because the reference margin level was calculated following Steps 1–3,

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[118] Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 6, 11; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 95. *See also* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 11.

[119] Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 18.

[120] *Id.*; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions, *supra* note 102, at 6.

[121] Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 95. *See also, e.g.*, MISO, Planning Year 2025–2026 Loss of Load Expectation Study Report 34–35, https://perma.cc/4VV5-4FHU; Western Power Pool, Western Resource Adequacy Program, 102 Forward Showing Reliability Metrics 14 (2024), https://perma.cc/7A6Q-A96E; NYISO, 2024 Reliability Needs Assessment 44 (2024), https://perma.cc/LD5E-RMV9; IESO, Annual Planning Outlook: Resource Adequacy and Energy Assessments Methodology 19 (2024), https://perma.cc/26N7-QC5J.

this dip would indicate that the region can no longer be expected to achieve the resource adequacy target (e.g., 0.1 LOLE) underlying the 25 GW reference margin level. In contrast, any resource with an accredited capacity of 1 GW or less could retire without causing the system to violate its resource adequacy target.

Importantly, this technique for evaluating individual resources' impact works only for relatively small changes to the system, such as the exit or entry of one or a few plants. When larger changes happen in the region's resource composition, the new mix will itself affect resources' accreditation values, because these values inherently depend on the entire fleet composition.[122] To calculate the resource adequacy effect of major changes to the fleet (e.g., the retirement of half of the coal capacity in a region), it would be necessary to re-run the modeling from Step 2 with different inputs.

Having reviewed resource adequacy terms, methodologies, and best practices, Part 2 next uses this understanding to discuss DOE's recent resource adequacy modeling endeavor.

[122] Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 30.

Part 2: DOE's *Resource Adequacy Report*

On July 7, 2025, DOE published its *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (DOE Study), responding to the EO's request for a "uniform methodology to identify at-risk region(s) and guide reliability interventions."[123] The report does not fulfill the EO's separate request for a "a protocol to identify which generation resources within a region are critical to system reliability."[124]

The DOE Study generally examines the resource adequacy of two time periods: today and 2030. According to the study, today, only ERCOT currently fails to achieve DOE's selected resource adequacy targets.[125] Under DOE's assumptions about load growth (including load growth from data centers), resource additions, and retirements, its modeling shows that all transmission planning regions will be resource inadequate in 2030 except ISO-NE and NYISO.[126] When reporting that a region is or would be resource inadequate, DOE sometimes calculates the amount of perfect capacity that could restore the region to resource adequacy.[127]

The DOE Study borrows heavily from NERC's recent Interregional Transfer Capability Study, which analyzed interregional transmission capacity and evaluated how additional interregional capacity could improve resource adequacy.[128] In contrast to NERC's Interregional Transfer Capability Study, the DOE Study does not consider how shortfalls could be mitigated through additional interregional transmission, which can be an alternative to new generation.[129]

Building on Part 1's discussion of how a resource adequacy model's metrics, values, and input assumptions drive its results, this Part evaluates DOE's resource adequacy methodology, including its input choices for load growth, resource additions, and retirements. At each step, it discusses the assumptions embedded in DOE's modeling choices, and reviews why those assumptions provide a weak basis for commanding specific, aging resources to continue serving load at consumers' expense and outside of existing market structures.

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123 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at vi.

124 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025).

125 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 7.

126 *Id.* at 8.

127 *Id.* at 5. The exact meaning of these perfect capacity quantities is unclear due to contradictions within the DOE Study. At times, DOE explains that these are the perfect capacity quantities that restore the system to 0.002% while assuming projected retirements. *Id.* At other points, though, DOE states that these quantities assume no retirements. *Id.* at 9.

128 *Id.* at 2; N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study vi, ix (2024), https://perma.cc/U7M3-L56J.

129 *See generally* Adria E. Brooks et al., *supra* note 90.

Resource Adequacy Targets

The DOE Study uses a multi-metric resource adequacy target of 2.4 LOLH and 0.002% normalized unserved energy (NUSE), which is the deterministic equivalent to NEUE.[130] DOE's decision to use a multi-metric target aligns with best practices, and its decision to use LOLH and NEUE together is reasonable. But DOE's value selections for these metrics are problematic.

For LOLH, DOE indicated that it picked 2.4 because that value "translates into one day of lost load in ten years," i.e., the traditional 0.1 LOLE standard.[131] This decision does not align with best practices for two reasons. First, it seeks to unquestioningly replicate the already arbitrary 0.1 LOLE standard (which merely captures the level of resource adequacy that happened to exist in the 1940s).[132] DOE's choice thus does not reflect any meaningful cost-benefit analysis.

Second, DOE's conversion of 0.1 LOLE to 2.4 LOLH is inaccurate.[133] A region with 0.1 LOLE will experience only one day with an outage—of any length—across ten years, which will be 24 hours in only the most extreme case. A region with 2.4 LOLH will have 24 hours of outages across the decade, across any combination of hours. DOE's selection of 2.4 LOLH metric would therefore, in the vast majority of cases, permit a greater duration and frequency of outages.[134] Although this 2.4 LOLH target might indicate that, all else being equal, DOE's methodology is too permissive, DOE's inputs and assumptions likely dominate its analysis and lead DOE to overestimate potential shortfalls.

Turning to NUSE, DOE reports that it selected 0.002% because NERC uses that same value in its long-term resource adequacy assessments.[135] But, as discussed in Part 2, NERC adopted that value from Australia without any consideration of how the costs and benefits of resource adequacy differ in the U.S. context.[136] In contrast, DOE previously used 0.001% in the National Transmission Planning Study.[137]

Moreover, contrary to best practices, for both LOLH and NUSE, DOE imposes the same resource adequacy target across the entire continental United States, without considering regional differences. As noted in Part 1, when it comes to averting outages, regions face different costs and benefits with regard to resource adequacy and thus different socially optimal levels of resource adequacy.

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130 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4, 14 ("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.").

131 *Id.* at 4.

132 Kevin Carden et al., *supra* note 50, at 2; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 6.

133 Juan Pablo Carvallo et al., *supra* note 8, at 11 ("The LOLE is typically used as a target setting metric and has historically taken a value of 1 event-day in 10 years, commonly (and incorrectly) interpreted as 2.4 hours per year.").

134 Gord Stephen et al., *supra* note 15, at 3, https://perma.cc/A9DJ-C3B5.

135 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4 n.10.

136 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 141.

137 U.S. Dep't of Energy, National Transmission Planning Study: Chapter 2: Long-Term U.S. Transmission Planning Scenarios 4, 82 (2024), https://perma.cc/R8RA-23E2.

Finally, at times, the DOE Study appears to struggle with the very meaning of a resource adequacy standard: It questions both PJM's and SPP's resource adequacy, even though each satisfies the metrics DOE's itself picked for its analysis. For PJM in particular, DOE notes that the region currently satisfies both prongs of the resource adequacy metric, but not for the particular weather year that includes Winter Storm Elliot.[138] Seemingly for this reason, DOE concludes that PJM needs 2.4 GW of additional perfect capacity to be resource adequate now.[139] But DOE's resource adequacy targets are, in DOE's own words, "average indicators" to be achieved across all modeled scenarios, not a requirement that must be achieved in each and every scenario.[140] PJM is resource adequate today according to DOE's targets.

Of course, as discussed in Part 1, it may be reasonable for a system planner to set a resource adequacy target that depends, in part, on each region's performance during tail risks. But DOE has not done so here.

Resource Adequacy Modeling

DOE's resource adequacy modeling is inconsistent with best practices. DOE's high-level decisions about the study's overall modeling approach and data input decisions both diverge from the best practices described in Part 1.

Deterministic Model

While the DOE Study appropriately examines all 8,760 hours of the year in chronological order,[141] DOE departs from best practices by using deterministic modeling rather than a probabilistic approach (like the Monte Carlo method), perhaps because of the EO's relatively short timeline.[142] Rather than randomly sampling probability distributions for each input to construct hundreds or thousands of plausible scenarios, DOE "evaluates whether a power system has sufficient resources . . . under a pre-defined set of conditions which correspond to the past few years of real-world events."[143] DOE uses twelve years of data (2007–2013 and 2019–2023) for weather, load, and generation.[144]

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138 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 7, 9, 27.

139 *Id.* at 9.

140 *Id.* at 7.

141 *See* U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 10, 12–13.

142 *Id.* at 2. The EO provided an extremely accelerated deadline of 90-days for DOE to produce results. *See* Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025). The DOE Study itself provides additional evidence for this conclusion, with its acknowledgement that "[p]robabilistic approaches incorporate data and advanced modeling techniques to represent uncertainty" but "require more computing power." U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 2 n.2.

143 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 10.

144 *Id.* at 11. While DOE uses historical data for the years 2019–2023, it uses "synthetic" data for 2007–2013. *Id.* "The synthetic approach used historical weather data to estimate load and resource availability if those same weather conditions were to occur again in the future. The historic approach used historical measured data for load, as well as wind and solar resource output, from recent years and scaled it appropriately to represent future conditions." N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study, *supra* note 128, at 74.

By examining whether regions would be resource adequate only under conditions that resemble the recent past, DOE's study does not sufficiently account for uncertainty. Indeed, in the Interregional Transfer Capability Study, from which DOE borrowed, NERC itself explains the limitations of this same deterministic approach and same data: Some regions may look resource adequate because they happened to do well during the twelve years of data, while others look resource inadequate but be unlikely to perform as poorly in the future.[145] Addressing the deterministic vs. probabilistic distinction, NERC cautions that, because a "[p]robabilistic resource adequacy analysis was not conducted[,] . . . . the [Interregional Transfer Capability Study] should not be considered a North American resource adequacy assessment."[146]

DOE grounds its use of a deterministic model in "transparency" and an interest in "model[ing] detailed historic system conditions."[147] Neither is a reason to step away from best practices: DOE could document a probabilistic approach in a transparent way, and relying on a small sample of historic years is less accurate than a probabilistic approach. Given the high stakes associated with resource adequacy planning, any future DOE resource adequacy assessment should prioritize accuracy over expediency.

Outage Threshold

Another modeling choice is the threshold for determining when a shortfall event has occurred. DOE projects a shortfall if "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."[148] This choice means that DOE identifies shortfall events in the hours when, after exhausting imports and demand response, a region's excess energy falls below 6% or 3% of hourly load—but it is not clear when DOE uses 6% versus 3%. DOE states that more details are available in a section of the study's appendix entitled "Outputs," but, as of publication of this report, no such section appears to be available.[149]

NERC uses a 3% threshold in its Interregional Transfer Capability Study, using 6% only in a sensitivity analysis.[150] According to NERC, the 3% value "was established based on an evaluation of average reserve requirements where load shed may occur" and reflects how "a Balancing Authority will continue to hold reserves even if involuntary load shed is underway to safeguard the system from cascading or widespread outages."[151] It is impossible to tell from the DOE Study when DOE used 6% versus 3%, but the fact that DOE listed 6% first may suggest that 6% was not limited to a sensitivity analysis.

If DOE's model instead identifies shortage events even when a region still has 6% of load available as spare capacity, then DOE's results depart from NERC's practice and may overstate

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145 *Id.* at 138.
146 *Id.* at 4.
147 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 2 n.2.
148 *Id.* at 12.
149 *Id.*
150 N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study, *supra* note 128, at 84.
151 *Id.* at 91 n.90, 85.

the extent of expected outages. In NERC's Interregional Transfer Capability Study, this change alone *significantly* altered the existence and extent of predicted outages in many regions, such as producing a 690% increase in the size of the maximum outage event in SERC-Florida.[152] Under the 6% sensitivity, NERC also recommended 58 GW of transmission additions to address resource adequacy instead of 35 GW, illustrating the sizable influence of shifting this assumption from 3% to 6%.[153]

Inputs

DOE's prediction that most regions will experience resource inadequacy by 2030 depends heavily on its assumptions about resource additions, retirements, load growth, and interregional imports. In each instance, DOE makes choices that raise significant questions about the validity of its modeling results.

Additions

DOE assumes that the only resource additions by 2030 will be those NERC currently categorizes as "Tier 1."[154] To be a Tier 1 resource, the resource must have achieved at least one milestone from a NERC list that signifies the unit is "very mature in the development pipeline."[155] This assumption is very conservative: The study itself admits that "[t]his results in minimal capacity additions beyond 2026."[156] In other words, DOE's finding of widespread resource inadequacy in 2030 rests on the assumption that very little will be built from 2027–2030. For example, NERC identifies 17,047 MW of Tier 1 resources slated to come online in PJM throughout 2025 and 2026, but only 1,108 MW from 2027–2030.[157]

The drop-off in Tier 1 resources after 2026 is not due to a shortage of projects in development, but rather because NERC currently classifies much of the capacity that will come online between 2027 and 2030 as "Tier 2."[158] Tier 2 resources occupy a wide range of positions in the interconnection queue, from the earliest stages (e.g., those having completed a feasibility study) to the very end

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152 *Id.* at 105 tbl.8.4

153 *Id.*

154 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4.

155 *Id.* at A-5. More specifically, the resource must have finished construction, be under construction, have a signed/approved interconnection service agreement, have a signed/approved power purchase agreement, have a signed/approved construction service agreement, have a signed/approved wholesale market participant agreement, or (if it is in the footprint of a vertically integrated utility) be included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement. N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 137.

156 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at A-5. *See also* Ric O'Connell, *GridLab Analysis: Department of Energy Resource Adequacy Report*, GridLab (July 11, 2025), https://perma.cc/B3GC-T7GA ("The report assumes just 22 GW of new 'firm' capacity (narrowly defined as gas) is added which is based on NERC LTRA 'Tier 1' – projects with a very high likelihood of success. The report assumes no projects are built post 2026, which is not realistic for a report forecasting to 2030. A more reasonable assumption for capacity additions is the EIA 860 released in June, which has 35 GW of gas additions, and another 53 GW of batteries – **88 GW of firm additions by 2030**.") (bolded text in original).

157 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 89.

158 *See id.* at 137.

of the process (e.g., those that have requested an interconnection service agreement).[159]

In recent years, the median project has taken approximately 55 months (4.58 years) to go from entering the queue to commercial operation.[160] Extrapolating from this historical trend reveals that a large number of Tier 2 resources will likely be operating by 2030. DOE should have anticipated some of them in the 2030 resource mix, and it departed from best practices by excluding all Tier 2 resources.[161] To do this forecasting accurately, DOE should have examined historical statistics of interconnection queue time by region, resource type, and resource size, along with differentiated queue withdrawal rates, estimating Tier 2 resource additions for each region.[162]

And applying historical statistics for time spent in a region's interconnection queue would itself be a conservative methodology for DOE to use, as FERC Order 2023 and related regional interconnection queue updates are set to speed up waiting times.[163] For example, the DOE Study found a 10.5 GW resource adequacy deficit for PJM in 2030 but failed to consider the almost 12 GW of nameplate capacity—mostly gas—that PJM is fast-tracking through its Reliability Resource Initiative.[164] PJM expects that 90% of this capacity will be online by 2030.[165] PJM is simultaneously pursuing other resource adequacy interventions, including a FERC-approved change to surplus interconnection service (to allow new generators to come online faster by taking advantage of underutilized transmission capacity),[166] and a FERC-pending proposal to expedite the process to transfer capacity interconnection rights from retiring generators to new resources.[167]

Finally, recently "retired" resources represent another potential source of fast additions.[168]

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159 *Id.*

160 Joseph Rand et al., Lawrence Berkeley Nat'l Lab'y, Queued Up: 2024 Edition: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023 41 (2024), https://perma.cc/5DE4-XNK6.

161 *See* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 23 fig.2.

162 *See generally* Joseph Rand et al., Lawrence Berkeley Nat'l Lab'y, Queued Up: 2024 Edition: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023 (2024), https://perma.cc/5DE4-XNK6.

163 *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 61,054 (2023).

164 Donnie Bielak, PJM, Reliability Resource Initiative: Additional Summaries 2 (2025), https://perma.cc/Y2AB-3CEM; Donnie Bielak, PJM, Reliability Resource Initiative: Results Summary 6 (2025), https://perma.cc/MYQ8-Y53G. *See also* Ric O'Connell, *supra* note 156 ("The study ignores both utility plans for meeting increased load growth and how markets will respond. In fact, 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 will likely add another 30 GW of firm resources. Those three regional efforts alone would add roughly twice what the DOE assumed for the entire nation.").

165 *PJM Chooses 51 Generation Resource Projects To Address Near-Term Electricity Demand Growth*, PJM Inside Lines (May 2, 2025), https://perma.cc/8EW2-G2XZ.

166 *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,083 (2025).

167 Proposed Revisions to PJM's Open Access Transmission Tariff, PJM, Docket No. ER25-____-000 (Jan. 31, 2025), https://perma.cc/J9T3-MCGL.

168 *E.g.*, Francisco "A.J." Camacho & Daviel Schulman, *Mothballed Nuclear Plant on Brink of Revival*, EnergyWire (July 15, 2025), https://subscriber.politicopro.com/article/eenews/2025/07/15/mothablled-nuclear-plant-on-brink-of-revival-00445239.

Retirements

DOE's assumption that 104 GW of nameplate capacity will retire by 2030 likely overestimates retirements.[169] This number includes both "confirmed" retirements—resources that have notified their system operators of their impending retirements and begun the retirement process—and "announced" retirements—which are publicly stated but not officially noticed.[170] These data come from NERC's Long-Term Reliability Assessment 2024 model.[171] In turn, NERC receives reports of confirmed retirements directly from each region, while announced retirements come from multiple sources, including Energy Information Agency Form 860 data, trade press, and utility integrated resource plans.[172]

These data likely overestimate retirements.[173] First, the economics of energy production have changed since 2024. The combined effect of new demand from data centers and the elimination of federal tax credits for new wind and solar resources improves the financial outlook for thermal resources.[174] Second, federal environmental regulations that would have required thermal resources to make investments reducing their pollution or else retire were projected to result in significant retirements before 2030.[175] But the Trump Administration has begun to rescind or reexamine these rules, which could cause resources to delay their retirements.[176]

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169 *See* U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 5.

170 *Id.* at 12.

171 *Id.*

172 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 28 n.19.

173 Ric O'Connell, *supra* note 156 ("The report assumed 104 GW of retirements by 2030, with 3/4 of this coal and 1/4 gas. But the most recent data from the U.S. Energy Information Administration released in June (the EIA 860) has just **half** of this capacity retiring. In the report, the DOE assumed these 50 GW of likely retirements, but included another 50 GW of *announced* retirements, inconsistent with their assumption around capacity additions. Most likely many plants will choose not to retire due to the changing regulatory and economic landscape, driven by the administration's policies.") (bolded text in original).

174 Aurora Energy Research, Impact of Reform to Clean Energy Tax Credits on Investment, Jobs and Consumer Bills 10 (2025), https://perma.cc/VHR5-UEGP; ("Most demand is made up through more production from existing plants (35%), meaning these plants are running for longer hours and/or at higher output levels. Some projects that retired in the base case scenario see longer lifetimes in Tax Credit Removal scenario because of more favorable economics due to clean energy decline (making up 17% of lost generation), and the rest is made up for by new build thermal plants (29%)."); Energy Innovation Pol'y & Tech. LLC, Federal Clean Energy Tax Credits Make Energy More Affordable—A Meta-Analysis (2025) https://perma.cc/QH2E-7PLL ("The research is clear—repealing technology-neutral energy tax credits would raise annual energy bills up to $140–$220 per year nationally, and over $500 per year in some states."). *See also* Ethan Howland, *PJM Capacity Prices Hit Record Highs, Sending Build Signal to Generators*, Utility Dive (July 31, 2024), https://perma.cc/UC6U-QHYT ("Prices in the PJM Interconnection's latest capacity auction hit record highs, which should provide incentives for power plant companies to build new generating resources and keep existing ones operating, according to the grid operator."); Ethan Howland, *MISO Summer Capacity Prices Jump to $666.50/MW-day as Power Supplies Shrink*, Utility Dive (Apr. 29, 2025), https://perma.cc/A6S5-4A4U ("Capacity prices for the upcoming summer season jumped to $666.50/MW-day from $30/MW-day last year across the Midcontinent Independent System Operator's footprint—driven in part by declining surplus capacity, according to the results of its latest planning resource auction released Monday.").

175 PJM, Energy Transition in PJM: Resource Retirements, Replacements & Risks 8 (2023), https://perma.cc/7J3A-FL8U.

176 *EPA Launches Biggest Deregulatory Action in U.S. History*, EPA (Mar. 12, 2025), https://perma.cc/55MN-2SUB.

Load

The DOE Study assumes 50 GW of growth in data center load and 51 GW of additional non-data center load.[177] DOE does not account for the possibility that this data center load could be flexible, even as one study suggests that 76 GW of additional data center load could be accommodated today if it could be curtailed only 0.25% of the time, and relevant corporations have confirmed flexibility potential.[178]

In June 2025, Texas enacted a law that allows ERCOT to curtail certain new loads over 75 MW during emergencies.[179] DOE assumes an additional 8 GW of data center load in ERCOT by 2030 and finds a reliability shortfall of 10.5 GW (which is likely an overestimate for the reasons discussed elsewhere in this Part, including how this 10.5 GW brings ERCOT to 0.0008% NUSE instead of 0.002% NUSE).[180] Accordingly, Texas's new law could go a long way towards avoiding the DOE-identified resource adequacy problem. Other regions like PJM are considering strategies to soften the resource adequacy impact of data centers, including ways to better encourage their participation in demand response programs.[181] DOE should have considered the possibility that some of the projected data center load would be flexible, especially in ERCOT.

Additionally, how DOE chose to distribute the projected 50 GW of data center load across regions is questionable. The DOE Study explains it used state-level growth ratios to perform this allocation.[182] But it is unlikely that all the computing demand needs to be processed close to load centers (i.e., proportional to a region's current electric load). In fact, some computing demand

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177 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 2–3.

178 Tyler H. Norris et al., Nicholas Inst. for Energy, Env't & Sustainability, Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems 2 (2025), https://perma.cc/6693-3HZU; *EPRI Launches Initiative to Enhance Data Center Flexibility and Grid Reliability,* Elec. Power Rsch. Inst. (Oct. 29, 2024), https://perma.cc/75LY-PSP5 ("Led by EPRI, DCFlex will coordinate real-world demonstrations of flexibility in a variety of existing and planned data centers and electricity markets, creating reference architectures and providing shared learnings to enable broader adoption of flexible operations that benefit all electricity consumers. Specifically, DCFlex will establish five to ten flexibility hubs, demonstrating innovative data center and power supplier strategies that enable operational and deployment flexibility, streamline grid integration, and transition backup power solutions to grid assets. Demonstration deployment will begin in the first half of 2025, and testing could run through 2027."); Anuja Ratnayake, *Unlocking AI Potential with Data Center Flexibility*, EnergyCentral (June 12, 2025), https://www.energycentral.com/intelligent-utility/post/unlocking-ai-potential-with-data-center-flexibility-PtPoXIAuRMzs5Ff ("In a preliminary test of the depth of computational flexibility possible in an AI data center, the Arizona demonstration site experienced some early success. It showcased the potential for an AI data center to provide grid relief during a peak system event—such as a hot summer day with high power demand—by temporarily and precisely ramping down its electricity consumption without compromising data center performance."). *See also* Ric O'Connell, *supra* note 156 ("It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact.").

179 S.B. No. 6 § 4, 89th Legislature (Tex. 2025) (to be enacted at Tex. Util. Code § 39.170), https://perma.cc/4Z7H-9XKQ; Brian Martucci, *Texas Law Gives Grid Operator Power to Disconnect Data Centers During Crisis*, Utility Dive (June 25, 2025), https://perma.cc/SYK3-V4XX; Waleed Aslam & Robin Hytowitz, Elec. Power Rsch. Inst., Texas SB6 Explained: Addressing Large Load Impacts (2025), https://perma.cc/QD8S-3M5C.

180 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 40.

181 Tim Horger, PJM, Large Load Additions Workshop 28 (2025), https://perma.cc/4HSN-CW4W.

182 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 17.

may be served from other regions if it will be cheaper to integrate the data center elsewhere. Given the scale of DOE's projected data center load compared to the relatively small resource adequacy shortfalls that the study identifies, these assumptions may have made the difference between whether a region achieves DOE's resource adequacy targets.[183]

Interregional Imports

The DOE Study states that it has adopted the interregional transfer capacities from NERC's Interregional Transfer Capability Study but also notes that transfers are "available up to the *minimum* total transfer capacity."[184] NERC's values describe the available transmission capacity between regions, including sub-regions of larger transmission-constrained regions like PJM, SPP, and MISO.[185] NERC provides a summer value and a winter value for each interregional interface and for each direction of flow.[186]

It is unclear what DOE means when it says that transfers are allowed up to their "minimum." If DOE picked the lesser of the summer and winter transfer capacities and applied that annually, doing so would inaccurately underestimate the amount of interregional transfer capacity.

Accreditation & Reference Margin Levels

While DOE issued its study in response to the EO's request for a "methodology to identify current and anticipated regions with reserve margins below acceptable thresholds,"[187] it does so through resource adequacy modeling, rather than by calculating accreditation values and using them to derive reference margin levels. As explained in Part 2, properly performed resource adequacy modeling is sufficient to determine whether a region is resource adequate.

In contrast, accreditations and reference margin levels are useful in combination to quickly evaluate how the loss or addition of a particular resource would affect whether a region achieves its resource adequacy target without re-running regional resource adequacy modeling. They are thus more applicable to EO Section 3(c)'s separate command to establish a "protocol to identify which generation resources within a region are critical to system reliability.[188] Thus far, DOE has not released a study implementing this provision. DOE may eventually supplement the DOE Study with additional accreditation and reference margin level analyses.

Nonetheless, while the DOE Study does not calculate accreditation values or reference margin levels, it does undertake the related exercise of evaluating how much additional perfect capacity would bring certain regions to resource adequacy.[189] (DOE calculated these perfect capacity

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183 *See id.* at 9, 17.

184 *Id.* at 18, 12, A-1 (emphasis added).

185 N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study, *supra* note 128, at 7, 9–10.

186 *Id.* at 17–24.

187 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025).

188 *Id.* at 15522.

189 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 5.

additions for only four of the seven regions that failed to achieve 0.002% NUSE in 2030: PJM, SPP, SERC, and ERCOT—not MISO, CAISO, or West Non-CAISO.[190]) More specifically, DOE asked how much perfect capacity it would take for regions to achieve the 0.002% NUSE resource adequacy standard in 2030.[191]

If, in the future, DOE were to also calculate the accredited capacity of a region's fleet and then add the solved-for perfect capacity, it could calculate the region's reference margin level. Similarly, although DOE did not perform any perfect capacity analysis for regions that achieve 0.002% NUSE, DOE could subtract perfect capacity from the accredited capacity of the regional fleets to solve for reference margin levels. Once DOE calculates a region's reference margin, it could look at the accredited capacity of any resource to evaluate how its exit or entry would affect achievement of the reference margin level.

In calculating any reference margin levels, DOE should attend to all prongs of its multi-metric resource adequacy target. Here, DOE Study's perfect capacity exercise focuses exclusively on 0.002% NUSE. But if a region achieves 0.002% NUSE and not 2.4 LOLH, it would be resource inadequate according to the terms of this DOE Study. Separate reference margin levels may apply to each prong, and a region would be resource adequate only when the highest reference margin level is achieved.

Additionally, going forward, DOE should better prioritize accuracy in any new studies with respect to calculating a region's need for perfect capacity additions/subtractions. Critically, while DOE asserted that it added the amount of perfect capacity needed to bring each region to 0.002% NUSE, the 10.5 GW that it added to PJM actually brought it to 0.0003% NUSE; the 500 MW added to SERC brought it to 0.0002% NUSE; the 1.5 GW added to SPP brought it to 0.0002% NUSE; and the 10.5 GW added to ERCOT brought it to 0.0008% NUSE.[192] All of these values indicate significantly greater resource adequacy that 0.002% NUSE, sometimes by an order of magnitude.

While DOE explains that its perfect capacity additions were done "by hand with a limited number of iterations (15)" such that the capacity additions "should not be considered the minimum possible capacity to accomplish these targets," that approach does not appear to explain why DOE brought these regions far beyond the 0.002% NUSE target.[193] Rather, this explanation suggests that, for each of the regions, DOE could have achieved these high levels of resource adequacy using less perfect capacity than it added. Accordingly, to achieve 0.002% NUSE, DOE likely could have added much less perfect capacity than it did. Identifying resources that meet these overestimated capacity levels could result in overpaying to achieve a different resource adequacy target than selected.

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190 *Id.* at 20–42.
191 Id. at 5.
192 *Id.* at 27, 30, 32, 40.
193 *Id.* at 19.

Part 3: Next Steps

Having reviewed best practices for resource adequacy modeling and the DOE Study, this final section discusses next steps for U.S. resource adequacy policy considering the diverse actors in this space and their respective authorities.

The Federal Power Act (FPA) gives FERC, and FERC's designated "Electric Reliability Organization" (ERO), NERC, jurisdiction over and responsibility for ensuring "[e]lectric reliability" for the "bulk power system," i.e., the high-voltage transmission network and the energy that flows through it.[194] More specifically, the FPA requires NERC to "establish and enforce reliability standards," which take effect after FERC approves them.[195] Importantly, FERC can also order NERC to submit reliability standards on particular topics and can independently enforce reliability standards.[196] NERC's six regional entities (comprising the continental U.S. plus Canada) also have authority to propose reliability standards to NERC.[197]

Achieving reliability arguably requires that bulk power system be resource adequate because, as FERC explains, "[i]f resources cannot meet load, or are insufficient to provide a reserve margin above expected load, then instability, uncontrolled separation or cascading failures can result from the unanticipated loss of a system element."[198] But, although reliable grid operations depend in part on resource adequacy, the FPA does not put FERC and NERC in the driver's seat for this aspect of reliability. FERC lacks authority to *directly achieve* resource adequacy because it cannot order construction of electric generation facilities.[199] Rather, states retain their traditional authority "over facilities used for the generation of electric energy,"[200] which some exercise by requiring utilities to submit integrated resource plans describing their plans to meet future demand.[201] Other states fully or partially delegate this authority to the Regional Transmission Organizations (RTOs) that operate their regional grids, e.g., by relying on the RTOs to achieve resource adequacy through capacity markets.[202]

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194 16 U.S.C. § 824o(a).

195 16 U.S.C. § 824o(a)(2), (d). FERC does not have authority to create reliability standards directly. *See id.* at § 824o(d).

196 16 U.S.C. § 824o(d)(5), (e)(3).

197 16 U.S.C. § 824o(e)(4); *ERO Enterprise; Regional Entities,* N. Am. Elec. Reliability Corp., https://perma.cc/EQ9E-BXJW.

198 *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at P 25 (2011). Reliable operation also encompasses a second aspect of reliability not implicated by the EO—operational reliability—which refers to "ability of the electric system to withstand sudden disturbances while avoiding cascading blackouts." Burçin Ünel & Avi Zevin, *supra* note 5, at 11.

199 16 U.S.C. § 824o(a)(3). The FPA also prohibits FERC from directing utilities to build transmission, and states retain primary siting authority for transmission. *See id.*; *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, 187 FERC ¶ 61,068 at P258 (2024).

200 16 U.S.C. § 824(b)(1).

201 Coley Girouard, *Understanding IRPs: How Utilities Plan for the Future*, Advanced Energy United (Aug. 11, 2015), https://perma.cc/5MDN-26QY.

202 Dena Adler & Jennifer Danis, Inst. for Pol'y Integrity, Reducing Pollution Without Sacrificing Reliability 14–16

But FERC and NERC can still play an important role for resource adequacy: FERC and NERC, through reliability standards, can ensure grid operators are proactively conducting appropriate resource adequacy assessments and analyses. In Order No. 747, FERC approved a regional reliability standard for conducting resource adequacy assessments.[203] This enforceable reliability standard requires, at a minimum, that entities within the applicable footprint conduct an annual analysis of what reserve margin would be necessary to ensure no more than 0.1 LOLE, using specific inputs like the median load forecast and accounting for important factors like fuel availability.[204] This reliability standard does not require regions to actually achieve 0.1 LOLE, only to conduct the mandated analysis.[205] A future reliability standard could require regions to instead adopt best practices comparable to those described in Part 1.

Turning to DOE, the DOE Reorganization Act put emergency grid reliability powers in DOE's hands for addressing certain emergency situations. Section 202(c) of the FPA empowers DOE, upon the finding of an emergency, to require, among any things, "such generation . . . as in its judgment will best meet the emergency and serve the public interest."[206] Section 202(c) and its implementing regulations, along with the common understanding of the word "emergency," indicate that this authority is limited to unexpected events.[207] Additionally, DOE's implementing regulations indicate that a shortage caused by a resource's poor economics would not qualify as an emergency, unless the shortage is "imminent."[208] When promulgating these regulations, DOE noted that:

> 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.[209]

(2024), https://perma.cc/G6J3-9ZL4. These capacity markets are FERC-jurisdictional, and operate according to rules contained in tariffs filed with FERC, specifying particulars like demand curve type, resource accreditation, and formulas for calculating reserve margins. *See, e.g.*, *PJM Interconnection, L.L.C.*, 191 FERC ¶ 61,066, at P 8 (2025).

203 *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at P 1 (2011).

204 Standard BAL-502-RF-03, N. Am. Elec. Reliability Corp., https://perma.cc/9MB5-5H67.

205 *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at P 33 (2011) ("The only obligations under BAL-502-RFC-02 are analysis and documentation requirements. This regional Reliability Standard does not specify how the results of the analysis required in this standard are to be used. For example, BAL-502-RFC-02 does not require state commissions to use the resource assessment analysis resulting from BAL-502-RFC-02 for economic decisions regarding resource adequacy requirements.").

206 16 U.S.C. § 824a(c)(1).

207 16 U.S.C. § 824a(c)(1); 10 C.F.R. § 205.371; Burçin Ünel & Avi Zevin, *supra* note 5, at 37–38.

208 10 C.F.R. § 205.371 ("Situations where a shortage of electric energy is projected due solely to the failure of parties to agree to terms, conditions or other economic factors relating to service, generally will not be considered as emergencies unless the inability to supply electric service is imminent.").

209 Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39984, 39985 (Aug. 6, 1981) (codified at 10 C.F.R. pt. 205).

In a departure from prior practice,[210] DOE has now used this authority to prevent thermal plants from retiring.[211] These orders have already drawn challenges from multiple parties, including from a politically diverse coalition of utility regulators.[212] Parties argue, among other points, that the plants' retirements were not unexpected; that the regions would be resource adequate even without the plants; and that DOE's newly asserted authority over resource adequacy triggers the major questions doctrine.[213]

Having nationally set best practices and principles for determining resource adequacy in the face of rapidly escalating demand and the clean energy transition could be useful if they are well vetted and use appropriate legal constructs. The FPA in conjunction with the DOE Reorganization Act suggest that the appropriate course of action for the federal government to support resource adequacy would be for NERC and FERC to set national resource adequacy *planning* standards (not a national resource adequacy target) to help regions guard against potential resource adequacy risks that might materialize in the future, instead of allowing DOE to stretch its 202(c) emergency authorities.

The DOE study itself cautions, "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."[214] Despite DOE's press statement asserting that the study's methodology can help guide "guide Federal reliability interventions,"[215] presumably to address the EO's mandate that DOE find a way to routinize further 202(c) emergency orders,[216] the study reports a fundamental limitation for doing so: It does not find any near-term reliability risk from current levels of resource adequacy.

The study itself states that, "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

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210 Cong. Rsch. Serv., Federal Power Act: The Department of Energy's Emergency Authority 4 (updated 2025), https://perma.cc/AU8L-VR55.

211 *DOE's Use of Federal Power Act Emergency Authority*, U.S. Dep't of Energy, https://perma.cc/DPB9-6B74.

212 Ethan Howland, *Groups Appeal DOE "Emergency" Order Keeping Michigan Plan Online*, Utility Dive (updated June 20, 2025), https://perma.cc/P9YZ-FNLK; Ethan Howland, *Eight Utility Regulators Challenge DOE Order Keeping Michigan Coal Plant* Open, Utility Dive (June 26, 2025), https://perma.cc/55FE-2RYR; Motion to Intervene and Request for Rehearing of the Joint Consumer Advocates, Dep't of Energy Order No. 202-25-4 (June 27, 2025), https://perma.cc/PD74-6CNC.

213 Request for Rehearing by Michigan Attorney General Dana Nessel, Dep't of Energy Order No. 202-25-3, at 27–31, 35–36 (June 18, 2025); Motion to Intervene and Request for Rehearing and Stay of Sierra Club et al., Dep't of Energy Order No. 202-25-3, at 29–36 (June 18, 2025), https://perma.cc/4MYN-MHZC; Petition to Intervene and Request for Rehearing of the Organization of MISO States, Inc., Dep't of Energy Order No. 202-25-3, at 2–6 (June 23, 2025), https://perma.cc/D3PG-56H2. *See also* Brief of the Institute for Policy Integrity at 4–13, V.O.S. Selections, Inc. v. Trump, No. 25-00066-GSK-TMR-JAR (Ct. Int'l Trade May 8, 2025), https://perma.cc/5Z4T-8CHG (describing the major questions doctrine).

214 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at i.

215 *Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security*, U.S. Dep't of Energy (July 7, 2025), https://perma.cc/942V-L7VB.

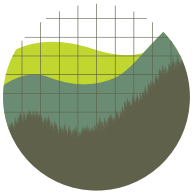
216 *See* Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

collective economic and national security." And it presents a pathway to fulfill DOE's discussion of what will happen next: "The report will inform joint planning processes and help integrate modern metrics into national reliability assessment methodology."[217] FERC directing NERC to develop national resource adequacy planning metrics, protocols, and input parameters would fit neatly within this call to action.

[217] *Reliability*, U.S. Dep't of Energy, https://perma.cc/RSW3-FNN2.

Conclusion

Given ever-increasing demand for electricity—proliferation of data centers for artificial intelligence; electrification of heating, cooling, and transportation; and pushes to onshore manufacturing—maintaining resource adequacy is essential. But there is no single answer to the question of when a system is resource adequate, or even what constitutes resource adequacy. Still, as this report explains, there are better and worse ways to pick resource adequacy targets, to evaluate whether the system has achieved and will maintain them, and to understand the resource adequacy impacts of a particular resource entering or exiting the system. The DOE Study uses some of these best practices but not other important ones, undermining the accuracy of its predictions. The DOE Study will hopefully focus additional attention on resource adequacy and speed up federal and state endeavors already underway to bolster resource adequacy. It does not, however, provide a rational basis for DOE to take action now to thwart ongoing plans for uneconomic, aging resources to retire. DOE's next best step would be to request that FERC open a proceeding eliciting proposals for nationwide, enforceable reliability standards mandating not a national resource adequacy target, but best practices for grid planners to conduct resource adequacy assessments. Additionally, states and grid operators should continue working together to expedite resource permitting, better forecast what hyperscaler demand will materialize, engage in holistic transmission planning, and speed interconnection queues—all of which will support future resource adequacy.



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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-42:
GridLab Report

1

GridLab Analysis: Department of Energy Resource Adequacy Report

Ric OConnell

Rethinking Reliability

July 11, 2025

Overview:

This memo provides a high-level overview of the recently released Department of Energy (DOE) Resource Adequacy Report, released on July 7, 2025. This report is a result of the Executive Order from the Trump Administration on Strengthening the Reliability and Security of the Grid, which directed the agency to develop and publish a 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."

The Executive Order also directs the DOE to prevent generation sources exceeding 50 MW from retiring or converting fuel sources if it would reduce generating capacity in at-risk regions, based on the new methodology. The DOE has so far issued two emergency orders under section 202(c) of the Federal Power Act. These orders directed plant owners and grid operators to delay by 90 days the retirement of the Campbell coal plant in Michigan owned by Consumers Energy and the Eddystone gas and oil plant in Pennsylvania, owned by Constellation. The EO and its methodology report did not include a mechanism for public input.

Bottomline of the DOE report:

The report warns of a 100X increased risk of outages if the forecasted retirements by 2030 take place. The report blames the lack of "firm" generation replacement in the planned supply.

Bottomline of GridLab analysis:

The report's conclusions are problematic since the **report undercounts the resources that are likely to be added to the grid,** and **overstates** the retirements expected. Utilities and markets *already* have plans to meet increased load growth, yet the **DOE report assumes they are doing nothing after 2026**

the **DOE report assumes they are doing nothing after 2026.**

DOE Report Analysis – Key Takeaways:

- The report is based on three key assumptions: (1) the amount of load that will be added to the grid over the next five years, (2) the number of plants assumed to retire, and (3) the amount of new capacity added to the grid. The study 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.
    - Load Growth: The report assumes 50 GW of data center load and allocates it regionally. It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact. The DOE report then adds 51 GW of non-data center load, which means overall load growth by 2030 is 101 GW or 15%. For comparison, EIA assumed 6% growth in their Annual Energy Outlook 2025 high growth case. This is very aggressive load growth, although not necessarily unreasonable, as it is collected from each of the RTOs and utilities.
    - Retirements: The report assumed 104 GW of retirements by 2030, with 3/4 of this coal and 1/4 gas. But the most recent data from the U.S. Energy Information Administration released in June (the EIA 860) has just **half** of this capacity retiring. In the report, the DOE assumed these 50 GW of likely retirements, but included another 50 GW of *announced* retirements, inconsistent with their assumption around capacity additions. Most likely many plants will choose

not to retire due to the changing regulatory and economic landscape, driven by the administration's policies.

- Capacity Additions: The report assumes just 22 GW of new "firm" capacity (narrowly defined as gas) is added which is based on NERC LTRA "Tier 1" – projects with a very high likelihood of success. The report assumes no projects are built post 2026, which is not realistic for a report forecasting to 2030. A more reasonable assumption for capacity additions is the EIA 860 released in June, which has 35 GW of gas additions, and another 53 GW of batteries – **88 GW of firm additions by 2030.**

- The study ignores both utility plans for meeting increased load growth and how markets will respond. In fact, 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 will likely add another 30 GW of firm resources. Those three regional efforts alone would add roughly twice what the DOE assumed for the entire nation.
- This national report attempts to address what is primarily a regional issue with regional solutions. A handful of regions face pressure due to rising load growth, and those regions have already enacted plans to address this growth. For example, MISO, SPP and PJM have all instituted "fast track" processes to get firm generation online (gas and batteries), which is expected to install 43 GW of new resources by 2030. The DOE report, however, shows just 13.5 GW of new firm resources in those three regions.

DOE Report Assumptions vs. U.S. Energy Information Administration

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

Previous post
London Calling: How UK Grid Innovation ...

Conclusion:

If the DOE report had used more consistent assumptions, it would have likely come to very different conclusions. Utilities and RTOs have planning processes and market mechanisms in place to build new resources in response to higher load growth and the retirement of older, uneconomic plants. The DOE's solution to keep older units online past retirement dates is a crude and expensive approach. The DOE should defer to state planning processes and regional markets to meet the challenge.

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Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-43:
Duke University Rethinking Load Growth Study

Duke NICHOLAS INSTITUTE *for* ENERGY, ENVIRONMENT & SUSTAINABILITY

Rethinking Load Growth

Assessing the Potential for Integration of Large Flexible Loads in US Power Systems

Tyler H. Norris, Tim Profeta, Dalia Patino-Echeverri, and Adam Cowie-Haskell

Nicholas Institute for Energy, Environment & Sustainability nicholasinstitute.duke.edu

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https://nicholasinstitute.duke.edu/publications/rethinking-load-growth

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Nicholas Institute for Energy, Environment & Sustainability

The Nicholas Institute for Energy, Environment & Sustainability at Duke University accelerates solutions to critical energy and environmental challenges, advancing a more just, resilient, and sustainable world. The Nicholas Institute conducts and supports actionable research and undertakes sustained engagement with policymakers, businesses, and communities—in addition to delivering transformative educational experiences to empower future leaders. The Nicholas Institute's work is aligned with the Duke Climate Commitment, which unites the university's education, research, operations, and external engagement missions to address climate challenges.

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INTRODUCTION

A New Era of Electricity Demand

Rapid US load growth—driven by unprecedented electricity demand from data centers, industrial manufacturing, and electrification of transportation and heating—is colliding with barriers to timely resource expansion. Protracted interconnection queues, supply chain constraints, and extended permitting processes, among other obstacles, are limiting the development of new power generation and transmission infrastructure. Against this backdrop, there is increasing urgency to identify strategies that accommodate rising demand without compromising reliability, affordability, or progress on decarbonization.

Aggregated US winter peak load is forecasted to grow by 21.5% over the next decade, rising from approximately 694 GW in 2024 to 843 GW by 2034, according to the *2024 Long-Term Reliability Assessment* of the North American Electric Reliability Corporation. This represents a 10-year compound annual growth rate (CAGR) of 2.0%, higher than any period since the 1980s (NERC 2024). Meanwhile, the Federal Energy Regulatory Commission's (FERC) latest five-year outlook forecasts 128 GW in peak load growth as early as 2029—a CAGR of 3.0% (FERC 2024b).

The primary catalyst for these updated forecasts is the surge in electricity demand from large commercial customers. While significant uncertainty remains, particularly following the release of DeepSeek, data centers are expected to account for the single largest growth segment, adding as much as 65 GW through 2029 and up to 44% of US electricity load growth through 2028 (Wilson et al. 2024; Rouch et al. 2024). Artificial intelligence (AI) workloads are projected to represent 50% to 70% of data center demand by 2030—up from less than 3% at the start of this decade—with generative AI driving 40% to 60% of this growth (Srivathsan et al. 2024; Lee et al. 2025).

Analysts have drawn parallels to the 1950s through the 1970s, when the United States achieved comparable electric power sector growth rates (Wilson et al. 2024). Yet these comparisons arguably understate the nature of today's challenge in the face of stricter permitting obstacles, higher population density, less land availability, skilled labor shortages, persistent supply chain bottlenecks, and demand for decarbonization and greater power reliability. While historical growth rates offer a useful benchmark, the sheer volume of required new generation, transmission, and distribution capacity forecasted for the United States within a condensed timeframe appears unprecedented.

The immensity of the challenge underscores the importance of deploying every available tool, especially those that can more swiftly, affordably, and sustainably integrate large loads. The time-sensitivity for solutions is amplified by the market pressure for many of these loads to interconnect as quickly as possible. In recent months, the US Secretary of Energy Advisory Board (SEAB) and the Electrical Power Research Institute (EPRI) have highlighted a key solution: load flexibility (SEAB 2024, Walton 2024a). The promise is that the unique profile of AI data centers can facilitate more flexible operations, supported by ongoing advancements in distributed energy resources (DERs).

Flexibility, in this context, refers to the ability of end-use customers to temporarily reduce their electricity consumption from the grid during periods of system stress by using on-site generators, shifting workload to other facilities, or reducing operations.[1] When system planners can reliably anticipate the availability of this load flexibility, the immediate pressure to expand generation capacity and transmission infrastructure can potentially be alleviated, mitigating or deferring costly expenditures. By facilitating near-term load growth without prematurely committing to large-scale capacity expansion, this approach offers a hedge against mounting uncertainty in the US data center market in light of the release of DeepSeek and related developments (Kearney and Hampton 2025).

Summary of Analysis and Findings

To support evaluation of potential solutions, this study presents an analysis of the existing US electrical power system's ability to accommodate new flexible loads. The analysis, which encompasses 22 of the largest balancing authorities serving 95% of the country's peak load, provides a first-order estimate of the potential for accommodating such loads with minimal capacity expansion or impact on demand-supply balance.[2]

Specifically, we estimate the gigawatts of new load that could be added in each balancing authority (BA) before total load exceeds what system planners are prepared to serve, provided the new load can be temporarily curtailed as needed. This serves as a proxy for the system's ability to integrate new load, which we term *curtailment-enabled headroom*.

Key results include (see Figure 1):

- 76 GW of new load—equivalent to 10% of the nation's current aggregate peak demand—could be integrated with an average annual load curtailment rate of 0.25% (i.e., if new loads can be curtailed for 0.25% of their maximum uptime)
- 98 GW of new load could be integrated at an average annual load curtailment rate of 0.5%, and 126 GW at a rate of 1.0%
- The number of hours during which curtailment of new loads would be necessary per year, on average, is comparable to those of existing US demand response programs
- The average duration of load curtailment (i.e., the length of time the new load is curtailed during curtailment events) would be relatively short, at 1.7 hours when average annual load curtailment is limited to 0.25%, 2.1 hours at a 0.5% limit, and 2.5 hours at a 1.0% limit
- Nearly 90% of hours during which load curtailment is required retain at least half of the new load (i.e., less than 50% curtailment of the new load is required)
- The five balancing authorities with the largest potential load integration at 0.5% annual curtailment are PJM at 18 GW, MISO at 15 GW, ERCOT at 10 GW, SPP at 10 GW, and Southern Company at 8 GW[3]

1 Note that while *curtailment* and *flexibility* are used interchangeably in this paper, *flexibility* can refer to a broader range of capabilities and services, such as the provision of down-reserves and other ancillary services.

2 For further discussion on the nuances regarding generation versus transmission capacity, see the section on limitations.

3 A complete list of abbreviations and their definitions can be found at the end of the report.

Overall, these results suggest the US power system's existing headroom, resulting from intentional planning decisions to maintain sizable reserves during infrequent peak demand events, is sufficient to accommodate significant constant new loads, provided such loads can be safely scaled back during some hours of the year. In addition, they underscore the potential for leveraging flexible load as a complement to supply-side investments, enabling growth while mitigating the need for large expenditures on new capacity.

We further demonstrate that a system's potential to serve new electricity demand without capacity expansion is determined primarily by the system's load factor (i.e., a measure of the level of use of system capacity) and grows in proportion to the flexibility of such load (i.e., what percentage of its maximal potential annual consumption can be curtailed). For this reason, in this paper we assess the technical potential for a system to serve new load under different curtailment limit scenarios (i.e., varying curtailment tolerance levels for new loads).

The analysis does not consider the technical constraints of power plants that impose intertemporal constraints on their operations (e.g., minimum downtime, minimum uptime, startup time, ramping capability, etc.) and does not account for transmission constraints. However, it ensures that the estimate of load accommodation capacity is such that total demand does not exceed the peak demand already anticipated for each season by system planners, and it discounts existing installed reserve margins capable of accommodating load that exceeds historical peaks. It also assumes that new load is constant throughout all hours.

This analysis should not be interpreted to suggest the United States can fully meet its near- and medium-term electricity demands without building new peaking capacity or expanding the grid. Rather, it highlights that flexible load strategies can help tap existing headroom to more quickly integrate new loads, reduce the cost of capacity expansion, and enable greater focus on the highest-value investments in the electric power system.

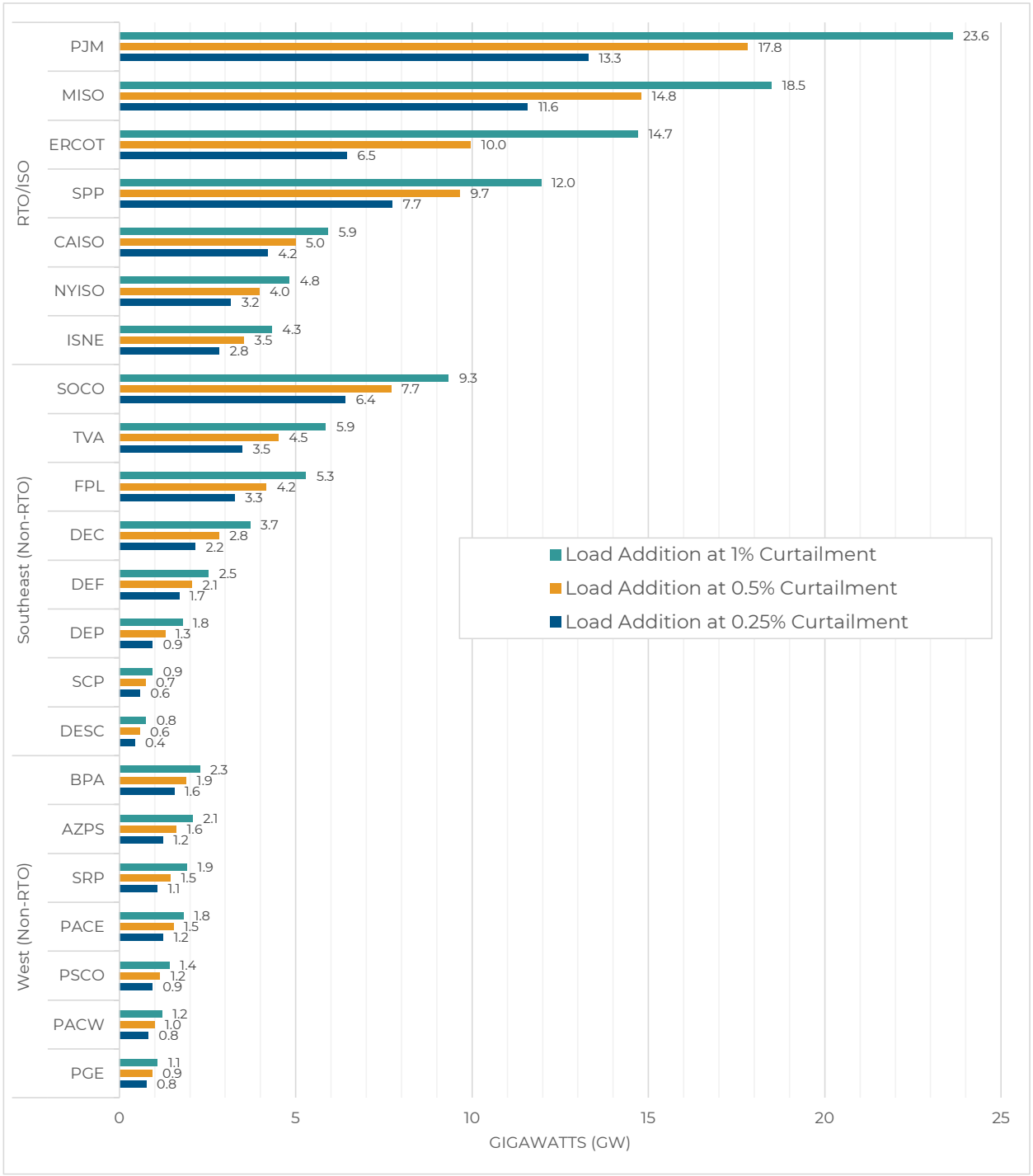
This paper proceeds as follows: the following section provides background on the opportunities and challenges to integrating large new data centers onto the grid. It explores how load flexibility can accelerate interconnection, reduce ratepayer costs through higher system utilization, and expand the role of demand response, particularly for AI-specialized data centers. We then detail the methods and results for estimating curtailment-enabled headroom, highlighting key trends and variations in system headroom and its correlation with load factors across regions. The paper concludes with a brief overview of key findings, limitations, and near-term implications.

BACKGROUND

Load Flexibility Can Accelerate Grid Interconnection

The growing demand for grid access by new large loads has significantly increased interconnection wait times, with some utilities reporting delays up to 7 to 10 years (Li et al. 2024; Saul 2024; WECC 2024). These wait times are exacerbated by increasingly severe transmission equipment supply chain constraints. In June 2024, the President's National Infrastructure Advisory Council highlighted that transformer order lead times had ballooned to two to five years—up from less than one year in 2020—while costs surged by 80% (NIAC 2024). Circuit breakers have seen similar delays: last year, the Western Area Power Administration

Figure 1. System Headroom Enabled by Load Curtailment of New Load by Balancing Authority, GW



Note: *System headroom* refers to the amount of GW by which a BA's load can be augmented every hour in the absence of capacity expansion so that, provided a certain volume of curtailment of the new load, the total demand does not exceed the supply provisioned by system planners to withstand the expected highest peak. The headroom calculation assumes the new load is constant and hence increases the total load by the same GW hour-by-hour.

reported lead times of up to four and a half years for lower voltage classes and five and a half years for higher voltage classes, alongside a 140% price hike over two years (Rohrer 2024). Wood Mackenzie reported in May 2024 that lead times for high-voltage circuit breakers reached 151 weeks in late 2023, marking a 130% year-over-year increase (Boucher 2024).

Large load interconnection delays have recently led to growing interest among data centers in colocating with existing generation facilities. At a FERC technical conference on the subject in late 2024 (FERC 2024c), several participants highlighted the potential benefits of colocation for expedited interconnection,[4] a view echoed in recent grey literature (Schatzki et al. 2024). Colocation, however, represents only a portion of load interconnections and is not viewed as a long-term, system-wide solution.

Load flexibility similarly offers a practical solution to accelerating the interconnection of large demand loads (SIP 2024, Jabeck 2023). The most time-intensive and costly infrastructure upgrades required for new interconnections are often associated with expanding the transmission system to deliver electricity during the most stressed grid conditions (Gorman et al. 2024). If a new load is assumed to require firm interconnection service and operate at 100% of its maximum electricity draw at all times, including during system-wide peaks, it is far more likely to trigger the need for significant upgrades, such as new transformers, transmission line reconductoring, circuit breakers, or other substation equipment.

To the extent a new load can temporarily reduce (i.e., curtail) its electricity consumption from the grid during these peak stress periods, however, it may be able to connect while deferring—or even avoiding—the need for certain upgrades (ERCOT 2023b). A recent study on Virginia's data center electricity load growth noted, "Flexibility in load is generally expected to offset the need for capacity additions in a system, which could help mitigate the pressure of rapid resource and transmission expansion" (K. Patel et al. 2024). The extent and frequency of required curtailment would depend on the specific nature of the upgrades; in some cases, curtailment may only be necessary if a contingency event occurs, such as an unplanned transmission line or generator outage. For loads that pay for firm interconnection service, any period requiring occasional curtailment would be temporary, ending once necessary network upgrades are completed.[5] Such "partially firm," flexible service was also highlighted by participants in FERC's 2024 technical conference on colocation.[6]

Traditionally, such arrangements have been known as *interruptible* electric service. More recently, some utilities have pursued *flexible* load interconnection options. In March 2022, for example, ERCOT implemented an interim interconnection process for large loads seeking to connect in two years or less, proposing to allow loads seeking to qualify as controllable load resources (CLRs) "to be studied as flexible and potentially interconnect more MWs" (ERCOT 2023b). More recently, ERCOT stated that "the optimal solution for grid reliability is for

4 For example, the Clean Energy Buyers Association (2024) noted, "Flexibility of co-located demand is a key asset that can enable rapid, reliable interconnection."

5 Such an arrangement is analogous to provisional interconnection service available to large generators, as defined in Section 5.9.2 of FERC's Pro Forma *Large Generator Interconnection Agreement* (LGIA).

6 MISO's market monitor representative stated, "instead of being a network firm customer, could [large flexible loads] be a non-firm, or partial non-firm [customer], and that could come with certain configuration requirements that make them truly non-firm, or partially non-firm. But, all those things are the things that could enable some loads to get on the system quicker" (FERC 2024c).

more loads to participate in economic dispatch as CLRs" (Springer 2024). Similarly, Pacific Gas and Electric (PG&E) recently introduced a Flex Connect program to allow certain loads faster access to the grid (Allsup 2024).

These options resemble interconnection services available to large generators that forgo capacity compensation, and potentially higher curtailment risk, in exchange for expedited lower-cost grid access (Norris 2023). FERC codified this approach with Energy Resource Interconnection Service (ERIS) in Order 2003 and revisited the concept during a 2024 technical workshop to explore potential improvements (Norris 2024). Some market participants have since proposed modifying ERIS to facilitate the colocation of new generators with large loads (Intersect Power 2024).

Ratepayers Benefit from Higher System Utilization

The US electric power system is characterized by a relatively low utilization rate, often referred to as the *load factor*. The load factor is the ratio of average demand to peak demand over a given period and provides a measure of the utilization of system capacity (Cerna et al. 2023). A system with a high load factor operates closer to its peak system load for more hours throughout the year, while a system with a low load factor generally experiences demand spikes that are higher than its typical demand levels (Cerna et al. 2022). This discrepancy means that, for much of the year, a significant portion of a system's available generation and transmission infrastructure is underutilized (Cochran et al. 2015).

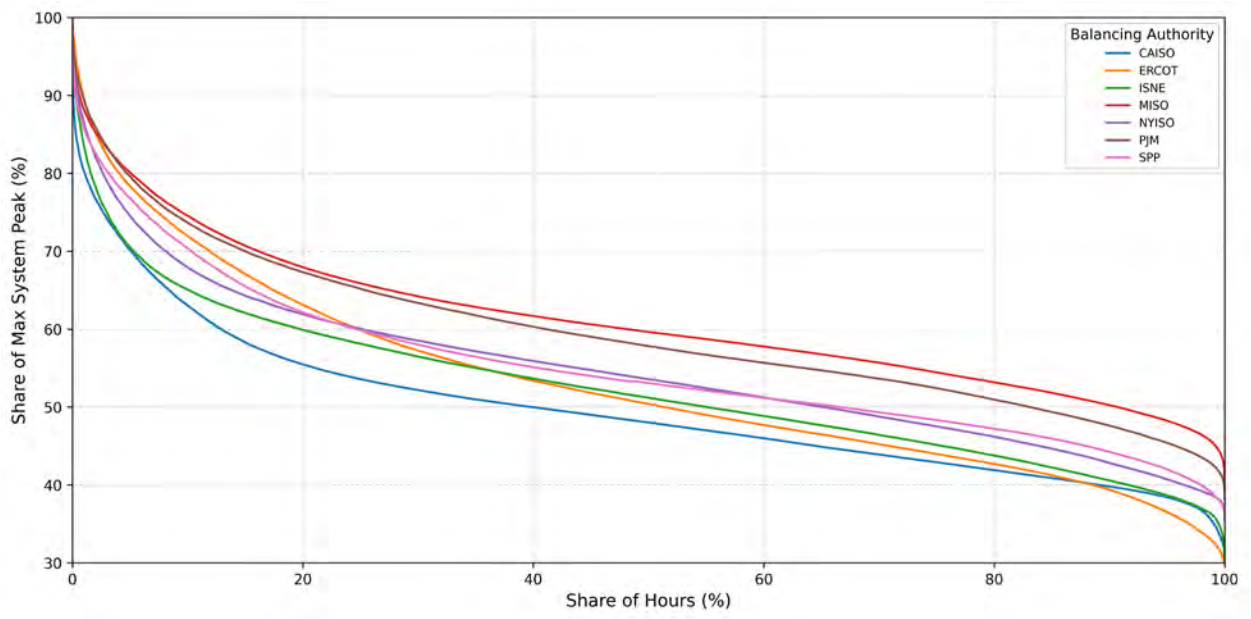
The power system is designed to handle the highest demand peaks, which in some cases may occur less than once per year, on average, due to extreme weather events. As a result, the bulk of the year sees demand levels well below that peak, leaving substantial headroom in installed capacity. Seasonal shifts add another layer of complexity: some balancing authorities may show higher load factors in summer, yet experience significantly lower utilization in winter, and vice versa.

The *load duration curve* (LDC) illustrates system utilization by ranking demand from highest to lowest over a given period. It provides a visual representation of how often certain demand levels occur, highlighting the frequency and magnitude of peak demand relative to average load. A steep LDC suggests high demand variability, with peaks significantly exceeding typical loads, while a flatter LDC indicates more consistent usage. Figure 2 presents LDCs for each US RTO/ISO based on hourly load between 2016 and 2024, standardized as a percentage of each system's maximum peak demand to allow cross-market comparisons.

A system utilization rate below 100% is expected for most large-scale infrastructure designed to withstand occasional surges in demand. Nevertheless, when the gap between average demand and peak demand is consistently large, it implies that substantial portions of the electric power system—generation assets, transmission infrastructure, and distribution networks—remain idle for much of the year (Riu et al. 2024). These assets are expensive to build and maintain, and ratepayers ultimately bear the cost.

Once the infrastructure is in place, however, there is a strong economic incentive to increase usage and spread these fixed costs over more kilowatt-hours of delivered electricity. An important consideration is therefore the potential for additional load to be added without significant new investment, provided the additional load does not raise the system's overall

Figure 2. Load Duration Curve for US RTO/ISOs, 2016–2024



This figure is adapted from the analysis section of this paper, which contains additional detail on the data and method.

peak demand and thereby trigger system expansion.[7] When new loads are flexible enough to avoid a high coincident load factor, thereby mitigating contribution to the highest-demand hours, they fit within the existing grid's headroom.[8] By strategically timing or curtailing demand, these flexible loads can minimize their impact on peak periods. In doing so, they help existing customers by improving the overall utilization rate—thereby lowering the per-unit cost of electricity—and reduce the likelihood that expensive new peaking plants or network expansions may be needed.

In contrast, inflexible new loads that increase the system's absolute peak demand can drive substantial additional needs for generation and transmission capacity. Even a modest rise in peak demand may trigger capital investments in peaking plants, fuel supply infrastructure, and reliability enhancements. These cost implications have contributed to increasingly contentious disputes in which regulators or ratepayer advocates seek to create mechanisms to pass the costs of serving large loads directly to those loads and otherwise ensure data centers do not shift costs via longer contract commitments, billing minimums, and upfront investment (Howland 2024a; Riu et al. 2024). Some examples include:

- The **Georgia Public Service Commission (GPSC)**, citing "staggering" large load growth and the need to protect ratepayers from the costs of serving those customers, recently implemented changes to customer contract provisions if peak draw exceeds 100 MW, mandating a GPSC review and allowing the utility to seek longer contracts and minimum billing for cost recovery (GPSC 2025). This follows GPSC's approval

7 See the discussion on limitations and further analysis in the following section for additional nuance.

8 Demand charges are often based on coincident consumption (e.g., ERCOT's Four Coincident Peak charge uses the load's coincident consumption at the system's expected seasonal peak to determine an averaged demand charge that may account for >30% of a user's annual bill).

of 1.4 GW of gas capacity proposed by Georgia Power in response to load growth "approximately 17 times greater than previously forecasted" through 2030/2031, a forecast it revised upward in late 2024 (GPC 2023, 2024).

- **Ohio**, where American Electric Power issued a moratorium on data center service requests, followed by a settlement agreement with the Public Service Commission staff and consumer advocates that calls for longer contract terms, load ramping schedules, a minimum demand charge, and collateral for service from data centers exceeding 25 MW (Ohio Power Company 2024).
- **Indiana**, where 4.4 GW of interconnection requests from a "handful" of data centers represents a 157% increase in peak load for Indiana Michigan Power over the next six years. Stakeholders there have proposed "firewalling" the associated cost of service from the rest of the rate base, wherein the utility would procure a separate energy, capacity, and ancillary resource portfolio for large loads and recover that portfolio's costs from only the qualifying large loads (Inskeep 2024).
- **Illinois**, where Commonwealth Edison reported that large loads have paid 8.2% of their interconnection costs while the remaining 91.8% is socialized across general customers (ComEd 2024).

These examples underscore the significance of exploring how flexible loads can mitigate peak increases, optimize the utilization of existing infrastructure, and reduce the urgency for costly and time-consuming capacity expansions.

Demand Response and Data Centers

Demand response refers to changes in electricity usage by end-use customers to provide grid services in response to economic signals, reliability events, or other conditions. Originally developed to reduce peak loads (also called *peak shaving*), demand response programs have evolved to encompass a variety of grid services, including balancing services, ancillary services, targeted deferral of grid upgrades, and even variable renewable integration (Hurley et al. 2013; Ruggles et al. 2021). Demand response is often referred to as a form of *demand-side management* or *demand flexibility* (Nethercutt 2023).

Demand response is the largest and most established form of virtual power plant (Downing et al. 2023), with 33 GW of registered capacity in wholesale RTO/ISO programs and 31 GW in retail programs as of 2023 (FERC 2024a).[9] As a share of peak demand, participation in RTO/ISO programs ranges from a high of 10.1% in MISO to a low of 1.4% in SPP. A majority of enrolled capacity in demand response programs are industrial or commercial customers, representing nearly 70% of registered capacity in retail (EIA 2024).

Following a decade of expansion, growth in demand response program participation stalled in the mid-2010s partially because of depressed capacity prices, forecasted over-capacity, and increasingly restrictive wholesale market participation rules (Hledik et al. 2019). However, the resurgence of load growth and increasing capacity prices, coupled with ongoing advancements in DERs and grid information and communication technologies (ICT) appears likely to reverse this trend.

9 RTO/ISO and retail data may overlap.

Studies of national demand response potential have identified a range of potential scenarios (Becker et al. 2024), ranging as high as 200 GW by 2030 in a 2019 study, comprising 20% of the then-forecasted system peak and yielding $15 billion in annual benefits primarily via avoided generation and transmission and distribution (T&D) capacity (Hledik et al. 2019). Notably, this research was conducted before recent load growth forecasts.

The Participation Gap: Data Centers and Demand Response

For nearly two decades, computational loads—and data centers in particular—have been identified as a promising area for demand response. Early studies explored these capabilities, such as a two-phase Lawrence Berkeley National Laboratory study drawing on six years of research, which concluded in 2010 that "data centers, on the basis of their operational characteristics and energy use, have significant potential for demand response" (Ghatikar et al. 2010) and in 2012 that "[certain] data centers can participate in demand response programs with no impact to operations or service-level agreements" (Ghatikar et al. 2012). The 2012 study provided one of the earliest demonstrations of computational load responsiveness, finding that 10% load shed can typically occur within 6 to 15 minutes.

Despite this promise, data centers have historically exhibited low participation rates in demand response programs as a result of operational priorities and economic incentives (Basmadjian 2019; Clausen et al. 2019; Wierman et al. 2014). Data centers are designed to provide reliable, uninterrupted service and generally operate under service-level agreements (SLAs) that mandate specific performance benchmarks, including uptime, latency, and overall quality of service. Deviation from these standards can result in financial penalties and reputational harm, creating a high-stakes environment where operators are averse to operational changes that introduce uncertainty or risk (Basmadjian et al. 2018).

Compounding this challenge is the increasing prevalence of large-scale colocated data centers, which represent a significant share of the data center market (Shehabi et al. 2024). These facilities house multiple tenants, each with varying operational requirements. Coordinating demand response participation in such environments introduces layers of administrative and logistical complexity, as operators must mediate cost- and reward-sharing agreements among tenants. Further, while data centers possess significant technical capabilities, tapping these capabilities for demand response requires sophisticated planning and expertise, which some operators may not have needed to date (Silva et al. 2024).

Economic considerations have further compounded this reluctance. Implementing a demand response program requires investments in advanced energy management systems, staff training, and integration with utility platforms for which costs can be material, particularly for smaller or midsized facilities. At the same time, financial incentives provided by most demand response programs have historically been modest and insufficient to offset the expenses and opportunity costs associated with curtailed operations. For operators focused on maintaining high utilization rates and controlling costs, the economic proposition of demand response participation may be unattractive.

Existing demand response program designs may inadvertently discourage participation. Many programs were originally created with traditional industrial consumers in mind, with different incentives and operational specifications. Price-based programs may require high price variability to elicit meaningful responses, while direct control programs without sufficient guardrails may introduce unacceptable risks related to uptime and performance. The

complexity of active participation in demand response markets, including bidding processes and navigating market mechanisms, adds another layer of difficulty. Without streamlined participation structures, tailored incentives, and metrics that reflect the scale and responsiveness of data centers, many existing demand response programs may be ill-suited to the operational realities of modern data centers.

Table 1. Key Data Center Terms

Term	Definition
AI workload	A broad category encompassing computational tasks related to machine learning, natural language processing, generative AI, deep learning, and other AI-driven applications.
AI-specialized data center	Typically developed by hyperscalers, this type of facility is optimized for AI workloads and relies heavily on high-performance graphics processing units (GPUs) and advanced central processing units (CPUs) to handle intensive computing demands.
Computational load	A category of electrical demand primarily driven by computing and data processing activities, ranging from general-purpose computing to specialized AI model training, cryptographic processing, and high-performance computing (HPC).
Conventional data center	A facility that could range from a small enterprise-run server room to a large-scale cloud data center that handles diverse non-AI workloads, including file sharing, transaction processing, and application hosting. These facilities are predominantly powered by CPUs.
Conventional workload	A diverse array of computing tasks typically handled by CPUs, including file sharing, transaction processing, application hosting, and similar operations.
Cryptomine	A dedicated server farm optimized for high-throughput operations on blockchain networks, typically focused on validating and generating cryptocurrency.
Hyperscalers/hyperscale data centers	Large, well-capitalized cloud service providers that build hyperscale data centers to achieve scalability and high performance at multihundred megawatt scale or larger (Howland 2024b, Miller 2024).
Inferencing	The ongoing application of an AI model, where users prompt the model to provide responses or outputs. According to EPRI, inferencing represents 60% of an AI model's annual energy consumption (Aljbour and Wilson 2024).
Model training	The process of developing and training AI models by processing vast amounts of data. Model training accounts for 30–40% of annual AI power consumption and can take weeks or months to complete (Aljbour and Wilson 2024).

Rethinking Data Centers with AI-Driven Flexibility

Limited documentation of commercial data center participation in demand response has reinforced a perception that these facilities' demands are inherently inflexible loads. A variety of recent developments in computational load profiles, operational capabilities, and broader market conditions, however, suggest that a new phase of opportunity and necessity is emerging.

In a July 2024 memo on data center electricity demand, the SEAB recommended the Department of Energy prioritize initiatives to characterize and advance data center load flexibility, including the development of a "flexibility taxonomy and framework that explores the financial incentives and policy changes needed to drive flexible operation" (SEAB 2024). Building on these recommendations, EPRI announced a multi-year Data Center Flexible Load Initiative (DCFlex) in October 2024 with an objective "to spark change through hands-on and experiential demonstrations that showcase the full potential of data center operational flexibility and facility asset utilization," in partnership with multiple tech companies, electric utilities, and independent system operators (Walton 2024a).[10]

The central hypothesis is that the evolving computational load profiles of AI-specialized data centers facilitate operational capabilities that are more amendable to load flexibility. Unlike the many real-time processing demands typical of conventional data center workloads, such as cloud services and enterprise applications, the training of neural networks that power large language models and other machine learning algorithms is deferrable. This flexibility in timing, often referred to as *temporal flexibility*, allows for the strategic scheduling of training as well as other delay-tolerant tasks, both AI and non-AI alike. These delay-tolerant tasks are also referred to as *batch processing* and are typically not user-prompted (AWS 2025).

This temporal flexibility complements the developing interest in *spatial flexibility*, the ability to dynamically distribute workloads across one or multiple data centers in different geographic locations, optimizing resource utilization and operational efficiency. As stated by EPRI in a May 2024 report, "optimizing data center computation and geographic location to respond to electricity supply conditions, electricity carbon intensity, and other factors in addition to minimizing latency enables data centers to actively adjust their electricity consumption … some could achieve significant cost savings—as much as 15%—by optimizing computation to capitalize on lower electric rates during off-peak hours, reducing strain on the grid during high-demand periods" (EPRI 2024). For instance, having already developed a temporal workload shifting system, Google is seeking to implement spatial flexibility as well (Radovanović 2020).

In addition to temporal and spatial flexibility, other temporary load reduction methods may also enable data center flexibility. One approach is dynamic voltage and frequency scaling, which reduces server power consumption by lowering voltage or frequency at the expense of processing speed (Moons et al. 2017; Basmadjian 2019; Basmadjian and de Meer 2018). Another is server optimization, which consolidates workloads onto fewer servers while idling or shutting down underutilized ones, thereby reducing energy waste (Basmajian 2019; Chaurasia et al. 2021). These load reduction methods are driven by advances in virtual workload management, made possible by the "virtualization" of hardware (Pantazoglou et al. 2016).

10 Pointing to EPRI's new DCFlex Initiative, Michael Liebreich noted in a recent essay, "For instance, when they see how much it costs to work 24/7 at full power, perhaps data-center owners will see a benefit to providing some demand response capacity… " (Liebreich 2024).

Finally, temperature flexibility leverages the fact that cooling systems account for 30% to 40% of data center energy consumption (EPRI 2024). For instance, operators can increase cooling during midday when solar energy is abundant and reduce cooling during peak evening demand.[11] While these methods may be perceived as uneconomic due to potential impacts on performance, hardware lifespan, or SLAs, they are not intended for continuous use. Instead, they are best suited for deployment during critical hours when grid demand reduction is most valuable.

Beyond peak shaving, data centers also hold potential to participate in ancillary services, particularly those requiring rapid response, such as frequency regulation. Studies have described how data centers can dynamically adjust workloads to provide real-time support to the grid, effectively acting as "virtual spinning reserves" that help stabilize grid frequency and integrate intermittent renewable resources (McClurg et al. 2016; Al Kez et al. 2021; Wang et al. 2019). This capability extends beyond traditional demand response by providing near-instantaneous balancing resources (Zhang et al. 2022).

Three overarching market trends create further opportunities for load flexibility now than in the past. The first is constrained supply-side market conditions that raise costs and lead times for the interconnecting large inflexible loads, when speed to market is paramount for AI developers. The second is advancements in on-site generation and storage technologies that have lowered costs and expanded the availability of cleaner and more commercially viable behind-the-meter solutions, increasing their appeal to data center operators (Baumann et al. 2020). The third is the growing concentration of computational load in colocated or hyper-scale data centers—accounting for roughly 80% of the market in 2023—which is lending scale and specialization to more sophisticated data center operators. These operators, seek-ing speed to market, may be more likely to adopt flexibility in return for faster interconnec-tion (Shehabi et al. 2024; Basmadjian et al. 2018). The overarching trends underpinning this thesis are summarized in Table 2.

An important consideration for future data center load profiles is the balance between AI-specialized data centers focused on model development and those oriented toward inferencing. If fewer AI models are developed, a larger proportion of computing resources will shift toward inferencing tasks, which is delay-intolerant and variable (Riu et al. 2024). According to EPRI, training an AI model accounts for 30% of its annual footprint, compared to 60% for inferencing the same model (EPRI 2024).

In the absence of regulatory guidance, most advancements in data center flexibility to date are being driven by voluntary private-sector initiatives. Some hyperscalers and data center developers are taking steps to mitigate grid constraints by prioritizing near-term solutions for load flexibility. For example, one such company, Verrus, has established its business model around the premise that flexible data center operations offer an effective solution for growth needs (SIP 2024). Table 3 highlights additional initiatives related to facilitating or demonstrating data center flexibility.

11 Cooling demand for servers is inherently dependent on server workloads. Therefore, reducing workloads saves on cooling needs as well.

Table 2. Trends Enabling Data Center Load Flexibility

Category	Legacy	Future
Computational load profile	• Conventional servers with CPU-dominated workloads (Shehabi et al. 2024) • Real-time, delay-intolerant, and unscheduled processing (e.g., cloud services, enterprise apps) • Low latency critical	• AI-specialized servers with GPU or tensor processing unit (TPU)-favored workloads (Shehabi et al. 2024) • Greater portion of delay-tolerant and scheduled machine learning workloads (model training, non-interactive services) • Higher share of model training affords greater demand predictability • Highly parallelized workloads (Shehabi et al. 2024)
Operational capabilities	• Minimal temporal load shifting • Minimal spatial load migration • High proximity to end users for latency-sensitive tasks • Reliance on Tier 2 diesel generators for backup • Limited utilization of on-site power resulting from pollution concerns and regulatory restrictions (Cary 2023)	• More robust and intelligent temporal workload shifting (Radovanović et al. 2022) • Advanced spatial load migration and multi–data center training (D. Patel et al. 2024) • Flexibility in location for model training • Backup power diversified (storage, renewables, natural gas, cleaner diesel) • Cleaner on-site power enables greater utilization
Market conditions	• Minimal electric load growth • High availability of T&D network headroom • Standard interconnection timelines and queue volumes • Low supply chain bottlenecks for T&D equipment • Low capacity prices and forecasted overcapacity • High cost of clean on-site power options • Small-scale “server room” model	• High electric load growth • Low availability of T&D network headroom • Long interconnection timelines and overloaded queues • High supply chain bottlenecks for T&D equipment • High capacity prices and forecasted undercapacity (Walton 2024b) • Lower cost of clean on-site power options (Baranko et al. 2024) • Data center operations concentrating in large-scale facilities and operators

Table 3. Implementations of Computational Load Flexibility

Category	Examples
Operational flexibility	• Google deployed a "carbon-aware" temporal workload–shifting algorithm and is now seeking to develop geographic distribution capabilities (Radovanović 2020). • Google data centers have participated in demand response by reducing non-urgent compute tasks during grid stress events in Oregon, Nebraska, the US Southeast, Europe, and Taiwan (Mehra and Hasegawa 2023). • Enel X has supported demand response participation by data centers in North America, Ireland, Australia, South Korea, and Japan, including use of on-site batteries and generators to enable islanding within minutes (Enel X 2024). • Startup companies like Emerald AI are developing software to enable large-scale demand response from data centers through recent advances in computational resource management to precisely deliver grid services while preserving acceptable quality of service for compute users
On-site power	• Enchanted Rock, an energy solutions provider that supported Microsoft in building a renewable natural gas plant for a data center in San Jose, CA, created a behind-the-meter solution called Bridge-to-Grid, which seeks to provide intermediate power until primary service can be switched to the utility. At that point, the on-site power transitions to flexible backup power (Enchanted Rock 2024, 2025).
Market design and utility programs	• ERCOT established the Large Flexible Load Task Force and began to require the registration of large, interruptible loads seeking to interconnect with ERCOT for better visibility into their energy demand over the next five years (Hodge 2024). • ERCOT's demand response program shows promise for data center flexibility, with 750+ MW of data mining load registered as CLRs, which are dispatched by ERCOT within preset conditions (ERCOT 2023a). • PG&E debuted Flex Connect, a pilot that provides quicker interconnection service to large loads in return for flexibility at the margin when the system is constrained (Allsup 2024, St. John 2024).
Cryptomining	• A company generated more revenue from its demand response participation in ERCOT than from Bitcoin mining in one month, at times accommodating a 95% load reduction during peak demands (Riot Platforms 2023).

ANALYSIS OF CURTAILMENT-ENABLED HEADROOM

In this section we describe the method for estimating the gigawatts of new load that could be added to existing US power system load before the total exceeds what system planers are prepared to serve, provided that load curtailment is applied as needed. This serves as a proxy for the system's ability to integrate new load, which we term *curtailment-enabled headroom*.[12] We first investigated the aggregate and seasonal load factor for each of the 22 investigated balancing authorities, which measures a system's average utilization rate. Second, we computed the curtailment-enabled headroom for different assumptions of ac-

12 SEAB proposed a similar term, *available flex capacity*, in its July 2024 report *Recommendations on Powering Artificial Intelligence and Data Center Infrastructure*.

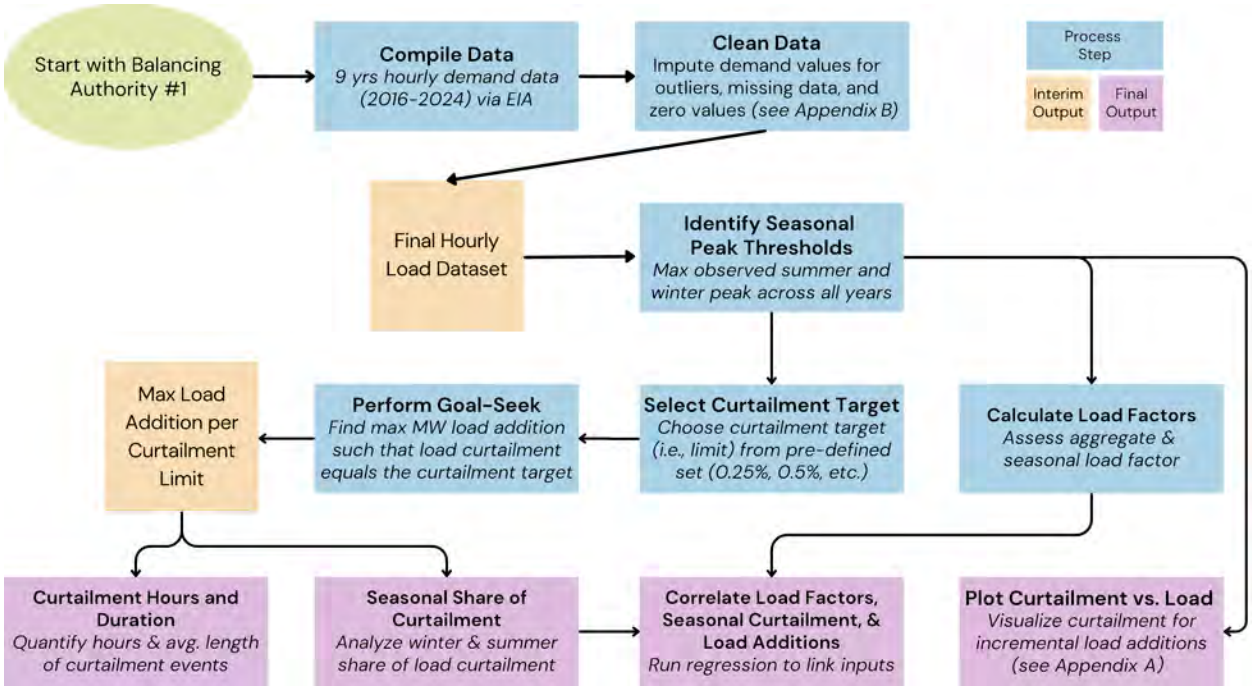
ceptable new load curtailment rates. In this context, *curtailment* refers to instances where the new load temporarily reduces its electricity draw—such as by using on-site generation resources, shifting load temporally or spatially, or otherwise reducing operations—to ensure system demand does not exceed historical peak thresholds. Third, we quantified the magnitude, duration, and seasonal concentration of the load curtailment for each balancing authority. Finally, we examined the correlation between load factor, seasonal curtailment, and max potential load additions. This process is summarized in Figure 3.

Data and Method

Data

We considered nine years of hourly load data aggregated for each of the 22 balancing authorities, encompassing seven RTO/ISOs,[13] eight non-RTO Southeastern BAs,[14] and seven non-RTO Western BAs.[15] Together, these balancing authorities represent 744 of the approximate 777 GW of summer peak load (95%) across the continental United States. The dataset, sourced from the EIA Hourly Load Monitor (EIA-930), contains one demand value per hour

Figure 3. Steps for Calculating Headroom and Related Metrics



13 CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP.

14 DEC; DEP; DEF; DESC; FPL; Santee Cooper, SCP; Southern Company (SOCO); and TVA. Note the different BA codes used by EIA: DUK for DEC, CPLE for DEP, SCEG for DESC, FPC for DEF, and SC for SCP. Also note that Southern Company includes Georgia Power, Alabama Power, and Mississippi Power. A complete list of abbreviations and their definitions can be found at the end of the paper.

15 AZPS, BPA, PACE, PACW, PGE, PSCO, and SRP. Note that EIA uses the code BPAT for BPA. A complete list of abbreviations and their definitions can be found at the end of the paper.

and spans January 1, 2016, through December 31, 2024.[16] Data from 2015 were excluded because of incomplete reporting.[17] The dataset was cleaned to identify and impute values for samples with missing or outlier demand values (see details in Appendix B).

Determining Load Additions for Curtailment Limits

An analysis was conducted to determine the maximum load addition for each balancing authority that can be integrated while staying within predefined curtailment limits applied to the new load. The load curtailment limits (0.25%, 0.5%, 1.0%, and 5.0%) were selected within the range of maximum curtailment caps for existing interruptible demand response programs.[18] The analysis focused on finding the load addition volume in megawatts that results in an average annual load curtailment rate per balancing authority that matches the specified limit. To achieve this, a goal-seek technique was used to solve for the load addition that satisfies this condition,[19] for which the mathematical expression is presented in Appendix C. The calculation assumed the new load is constant and hence increases the total system load by the same gigawatt volume hour-by-hour. To complement this analysis and visualize the relationship between load addition volume and curtailment, curtailment rates were also calculated across small incremental load additions (i.e., 0.25% of the BA's peak load).

Load Curtailment Definition and Calculation

Load curtailment is defined as the megawatt-hour reduction of load required to prevent the augmented system demand (existing load + new load) from exceeding the maximum seasonal system peak threshold (e.g., see Figure 4). Curtailment was calculated hourly as the difference between the augmented demand and the seasonal peak threshold. These hourly curtailments in megawatt-hours were aggregated for all hours in a year to determine the total annual curtailment. The curtailment rate for each load increment was defined as the total annual curtailed megawatt-hours divided by the new load's maximum potential annual consumption, assuming continuous operation at full capacity.

Peak Thresholds and Seasonal Differentiation

Balancing authorities develop resource expansion plans to support different peak loads in winter and summer. To account for variation, we defined seasonal peak thresholds for each balancing authority. Specifically, we identified the maximum summer peak and the maximum winter peak observed from 2016 to 2024 for each balancing authority.[20] These thresholds serve as the upper limits for system demand during their respective seasons, and all

16 Additional detail on EIA's hourly load data collection is available at https://www.eia.gov/electricity/gridmonitor/about.

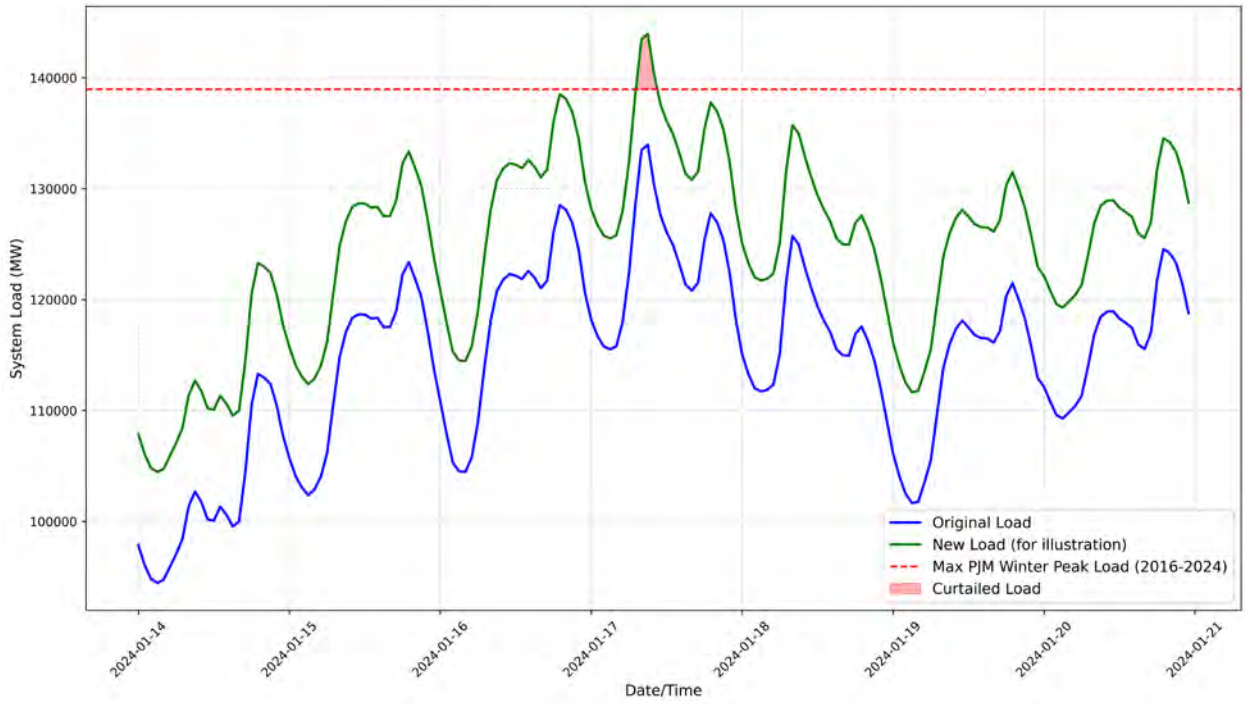
17 Fewer than half of the year's load hours were available, making the data unsuitable for inclusion.

18 For example, PG&E's and Southern California Edison's Base Interruptible Programs limit annual interruption for registered customers to a maximum of 180 hours (2.0% of all annual hours) or 10 events per month.

19 The goal-seek approach was implemented using Python's scipy.optimize.root_scalar function from the SciPy library. This tool is designed for solving one-dimensional root-finding problems, where the goal is to determine the input value that satisfies a specified equation within a defined range.

20 To identify the max seasonal peak load, summer was defined as June–August, while winter encompassed December–February. In a few cases, the BA's seasonal peak occurred within one month of these periods (AZPS winter, FPL winter, CAISO summer, CAISO winter), which were used as their max seasonal peak. To account for potential (albeit less likely) curtailment in shoulder months, the applicable summer peak was applied to April–May and September–October and the winter peak to November and March.

Figure 4. Illustrative Load Flexibility in PJM



megawatt-hours that exceeded these thresholds was counted as curtailed energy. This seasonal differentiation captures the distinct demand characteristics of regions dominated by cooling loads (summer peaks) versus heating loads (winter peaks).

Year-by-Year Curtailment Analysis

Curtailment was analyzed independently for each year from 2016 to 2024. This year-by-year approach captures temporal variability in demand patterns, including the effects of extreme weather events and economic conditions. For each year, curtailment volumes were calculated across all load addition increments, resulting in a list of annual curtailment rates corresponding to each load increment. To synthesize results across years, we calculated the average curtailment rate for each load addition increment by averaging annual curtailment rates over the nine years. This averaging process smooths out year-specific anomalies and provides an estimate of the typical system response to additional load. This analysis was also used to calculate the average number of hours of curtailment for each curtailment limit and the seasonal allocation of curtailed generation.[21] We also assessed the magnitude of load curtailment required during these hours as a share of the new load's maximum potential draw to calculate the number of hours when 90%, 75%, and 50% or more of the load would still be available.

21 Consistent with the curtailment analysis, summer was defined as June–August and winter as December–February. For BAs located on the Pacific coast (BPA, CAISO, PGE, PACE, PACW), November was counted as winter given the region's unique seasonal load profile.

Figure 5. Load Factor by Balancing Authority and Season, 2016–2024

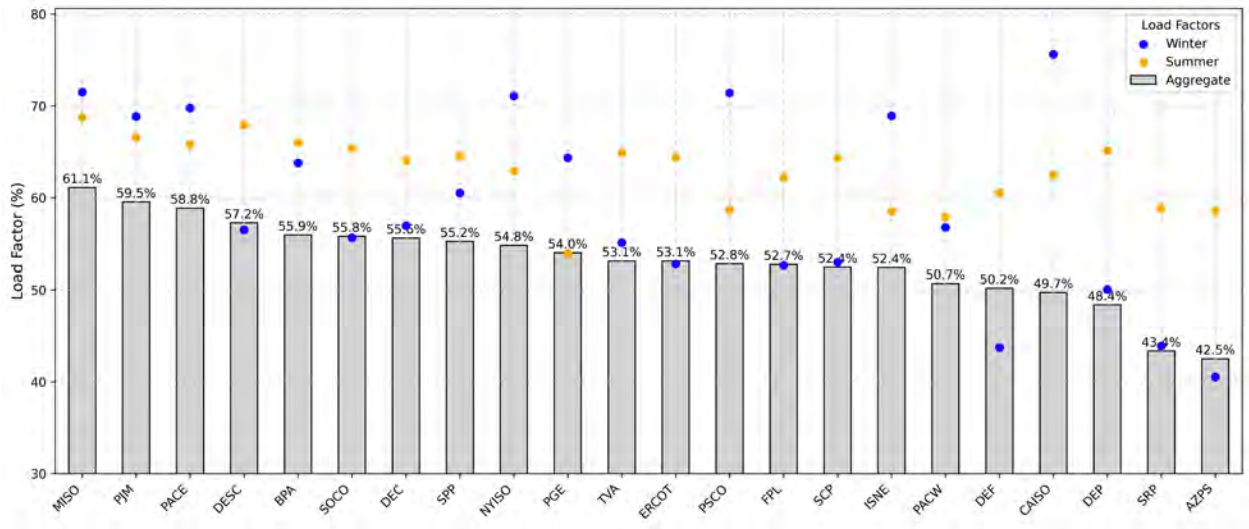
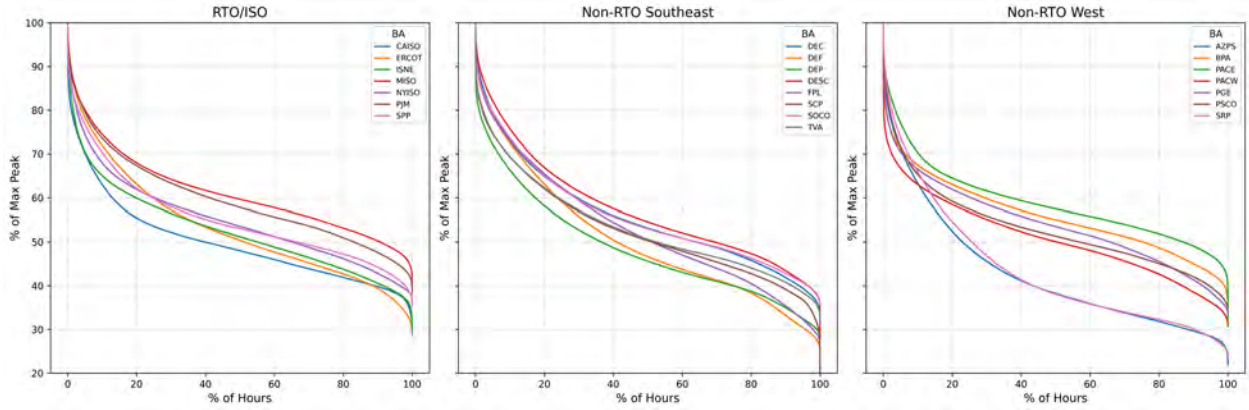


Figure 6. Load Duration Curves by Balancing Authority, 2016–2024



Results

Load Factor

In examining data for 22 balancing authorities, we found that aggregate load factors ranged between 43% to 61% (Figures 5 and 6), with an average and median value of 53%. The BAs with the lowest aggregate load factors were those in the desert southwest, Arizona Public Service Company (AZPS) and Salt River Project Agricultural Improvement and Power District (SRP). In terms of seasonal load factor, defined here as the average seasonal load as a share of seasonal maximum load (i.e., not as a share of the maximum all-time system load), winter load factors were notably lower than summer. The average and median winter load factor was 59% and 57% respectively, compared to 63% and 64% for summer. A majority of the balancing authorities had higher summer load factors (14) than winter (8).

Headroom Volume

Results show that the headroom across the 22 analyzed balancing authorities is between 76 to 215 GW, depending on the applicable load curtailment limit. This means that 76 to 215 GW of load could be added to the US power system and yet the total cumulative load would remain below the historical peak load, except for a limited number of hours per year

Figure 7. Headroom Enabled by Load Curtailment Thresholds, GW

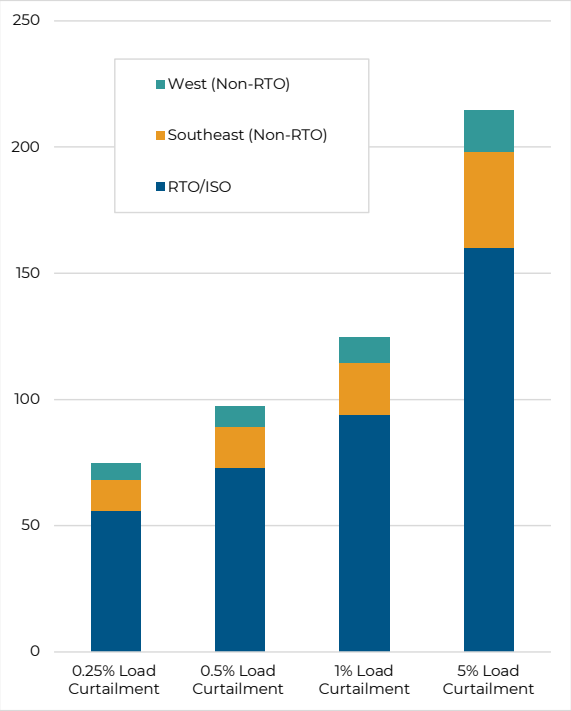


Figure 8. Headroom Enabled by 0.5% Load Curtailment by Balancing Authority, GW

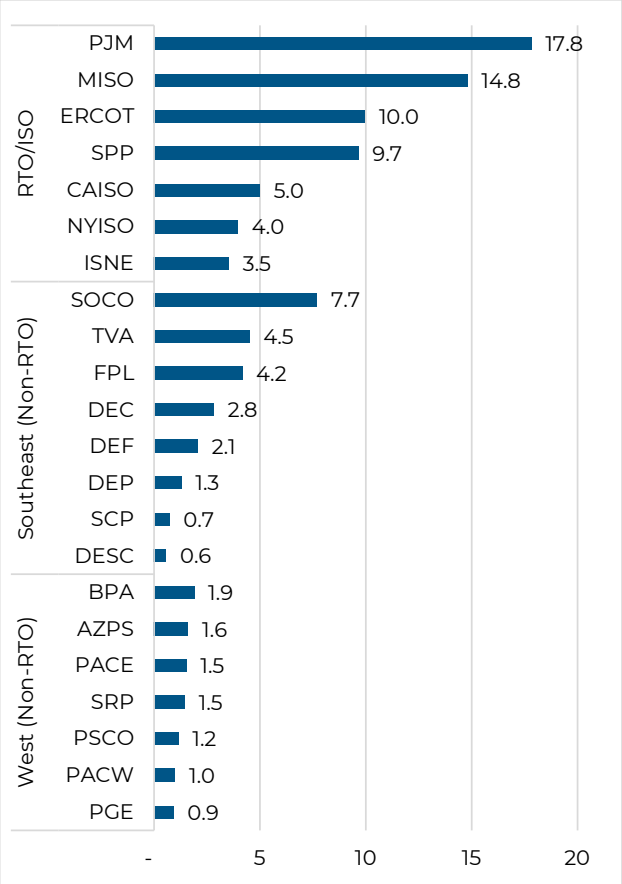
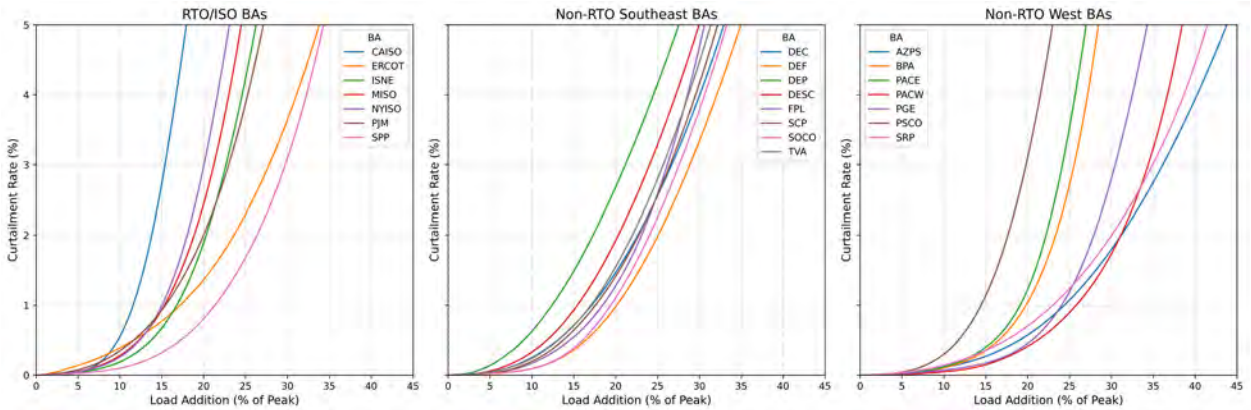


Figure 9. Load Curtailment Rate Due to Load Addition, % of System Peak



when the new load would be unserved. Specifically, 76 GW of headroom is available at an expected load curtailment rate of 0.25% (i.e., if 0.25% of the maximum potential annual energy consumption of the new load is curtailed during the highest load hours, or 1,643 out of 657,000 GWh). This headroom increases to 98 GW at 0.5% curtailment, 126 GW at 1.0% curtailment, and 215 GW at 5.0% curtailment (Figure 7). Headroom varies by balancing authority (Figure 8), including as a share of system peak (Figure 9). The five balancing authorities with the highest potential volume at 0.5% annual curtailment are PJM at 18 GW, MISO at 15 GW, ERCOT at 10 GW, SPP at 10 GW, and Southern Company at 8 GW. Detailed plots for each balancing authority, including results for each year, can be found in Appendix A.

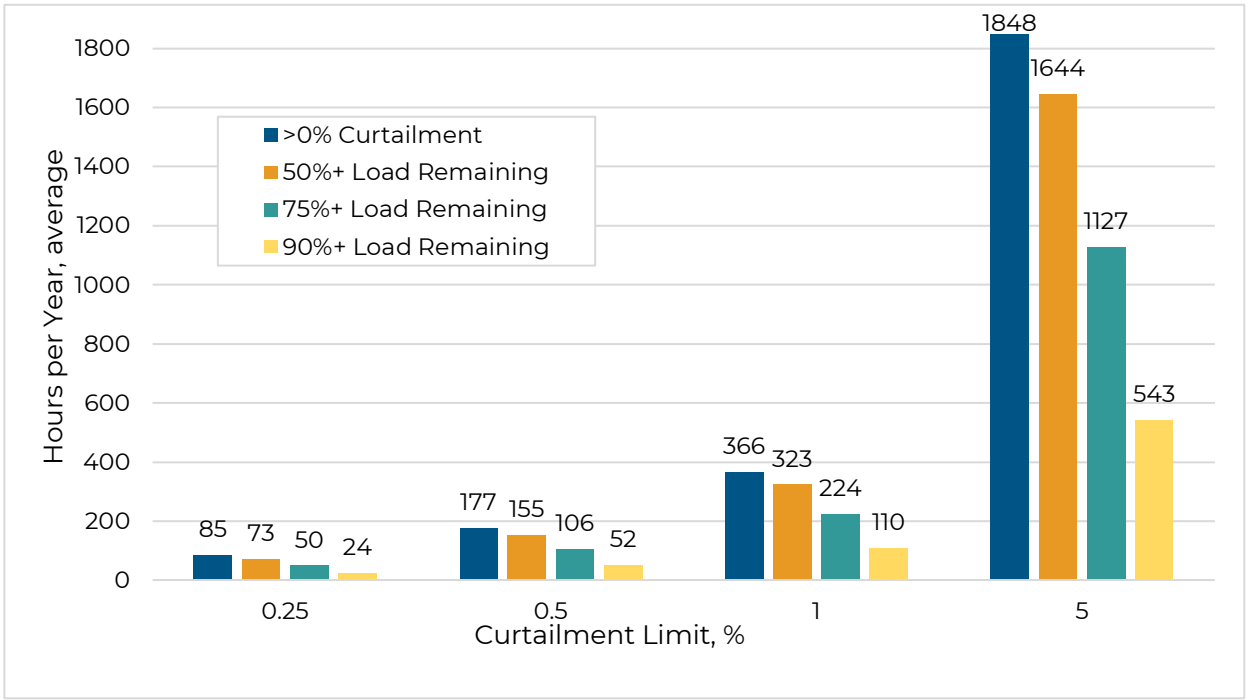
Curtailment Hours

A large majority of curtailment hours retain most of the new load. Most hours during which load reduction is required entail a curtailment rate below 50% of the new load. Across all 22 BAs, the average required load curtailment times are 85 hours under the 0.25% curtailment rate (~1% of the hours in a year), 177 hours under the 0.5% curtailment rate, 366 hours under the 1.0% curtailment rate, and 1,848 hours under the 5.0% curtailment rate (i.e., ~21% of the hours). On average, 88% of these hours retain at least 50% of the new load (i.e., less than 50% curtailment of the load is required), 60% of the hours retain at least 75% of the load, and 29% retain at least 90% of the load (see Figure 10).

Curtailment Duration

The analysis calculated the average hourly duration of curtailment events (i.e., the length of time the new load is curtailed during curtailment events). All hours in which any curtailment occurred were included, regardless of magnitude. The results for each balancing authority and curtailment limit are presented in Figure 11. The average duration across BAs was 1.7 hours for the 0.25% limit, 2.1 hours for the 0.5% limit, 2.5 hours for the 1.0% limit, and 4.5 hours for the 5.0% limit.

Figure 10. Hours of Curtailment by Load Curtailment Limit



Seasonal Concentration of Curtailment

The analysis reveals significant variation in the seasonal concentration of curtailment hours across balancing authorities. The winter-summer split ranged from 92% to 1% for CAISO (California Independent System Operator), where curtailment is heavily winter-concentrated, to 0.2% to 92% for AZPS,[22] which exhibited a heavily summer-concentrated curtailment profile (Figure 12a).[23]

Figure 11. Average Curtailment Duration by Balancing Authority and Curtailment Limit, Hours

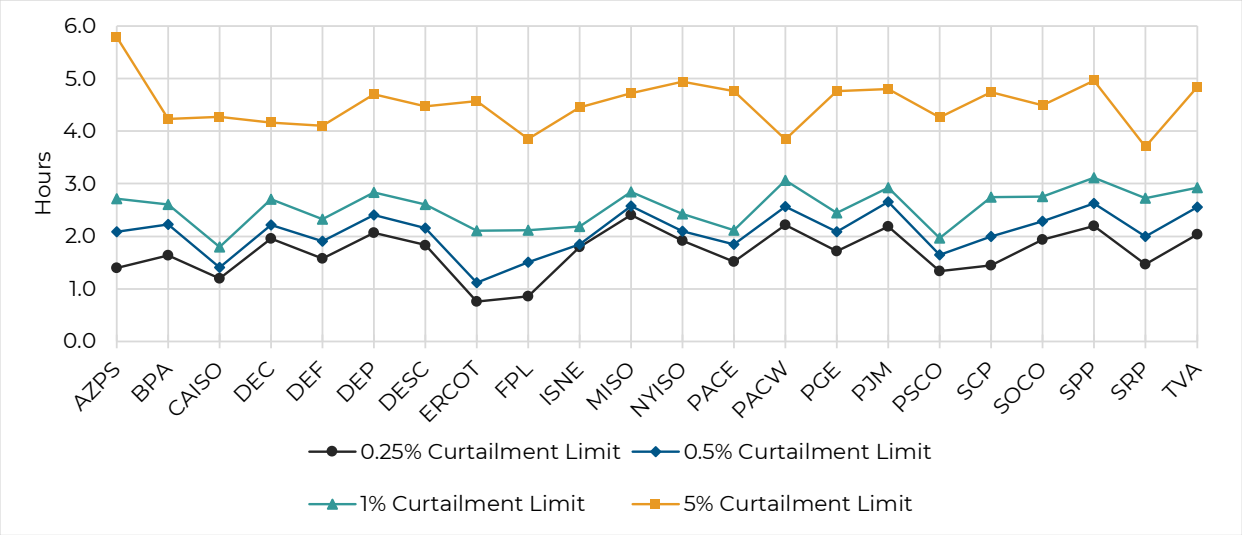
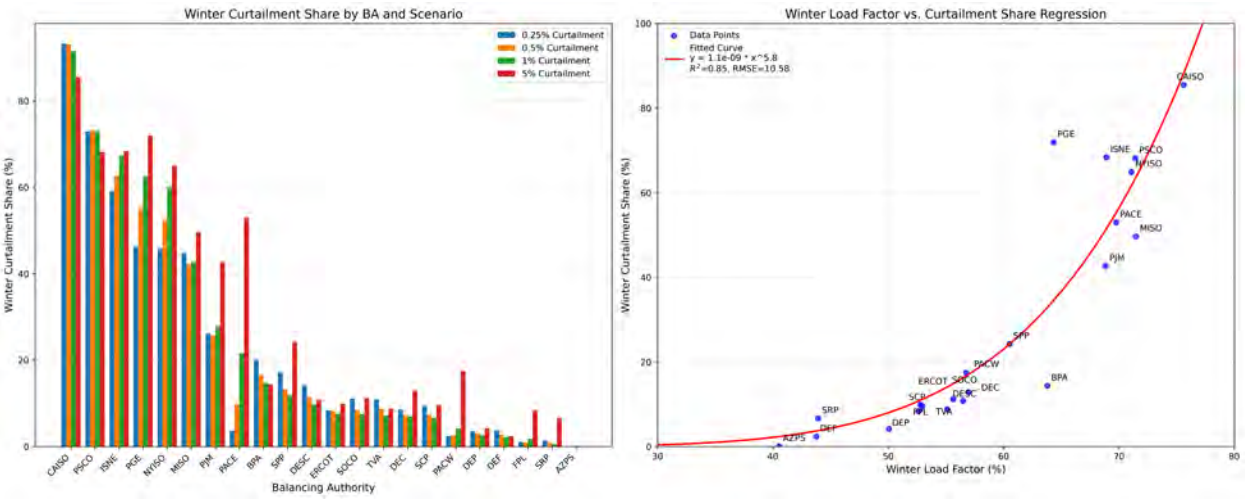


Figure 12. Seasonal Curtailment Analysis



(a) (b)

22 Note the remainder of the curtailment occurred in these BAs in shoulder months (i.e., not summer, not winter).

23 These values correspond to the seasonal curtailment concentration for the 1% curtailment limit.

A key observation is the strong correlation between the winter load factor (system utilization during winter months) and the seasonal allocation of curtailment hours (Figure 12b). BAs with lower winter load factors—indicating reduced system utilization during winter—tend to have greater capacity to accommodate additional load in winter while experiencing a dispro-portionately higher share of curtailment during summer months. This trend is particularly pronounced in balancing authorities located in the Sun Belt region, resulting in a lower win-ter concentration of curtailment hours.

While most BAs exhibited relatively stable seasonal curtailment shares across increasing load addition thresholds, some demonstrated notable shifts in seasonal allocation as load additions increased (e.g., PACW, FPL, NYISO, ISO-NE, PACE, PGE). These shifts highlight the dynamic interplay between system demand patterns and the incremental addition of new load.

Figure 12a illustrates this variability, showcasing the relationship between winter load factor and winter curtailment share across curtailment scenarios.[24]

Discussion

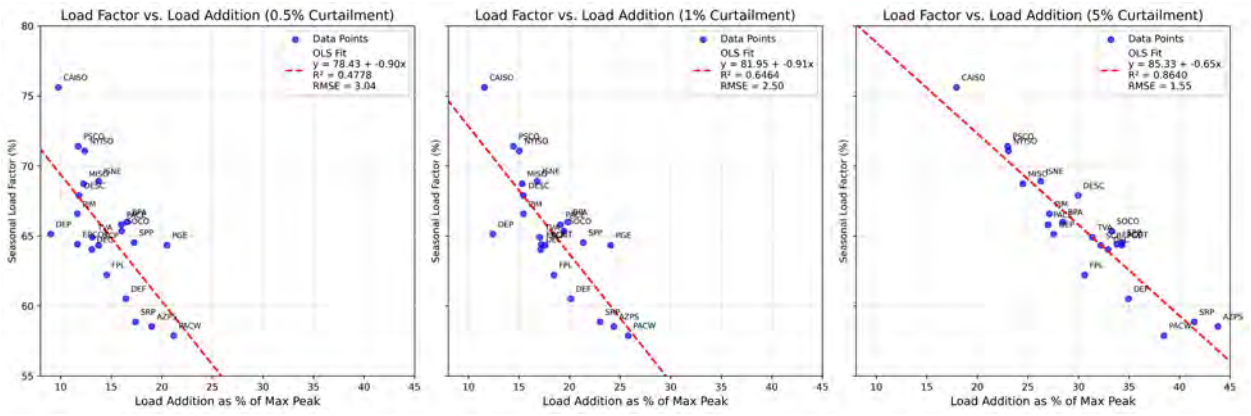
The results highlight that the significant headroom in US power systems—stemming from their by-design low load factors—could be tapped to enable the integration of substantial load additions with relatively low rates of load curtailment. They also underscore substantial variation in flexibility across balancing authorities, driven by differences in seasonal and aggregate load patterns. This variation suggests that seasonal load factors may be strongly linked to how much additional load a balancing authority can integrate without requiring high curtailment rates.

To explore this relationship, we analyzed system load factors in relation to the additional load that each balancing authority could accommodate while limiting the load curtailment rate to 0.5%, 1.0%, and 5.0% (i.e., the load curtailment limit). To allow for meaningful comparison across BAs, the additional load was standardized as a percentage of the BA's historical peak load. To account for whether a balancing authority's curtailment was concentrated in the summer or winter, the seasonal load factor was selected corresponding to the season with the highest share of curtailment.

The analysis revealed that BAs with higher seasonal load factors tended to have less headroom for the load curtailment limits examined (Figure 13). In simpler terms, systems with higher utilization during their busiest season had less power generation capacity planned to be available that could serve new load without hitting curtailment limits. For example, CAISO, with a seasonal load factor of 76%, could accommodate less additional load compared to PacifiCorp West (PACW) and AZPS, which exhibited lower seasonal load factors and supported larger load additions as a share of peak system load. This relationship grew in statistical significance as the load curtailment limit increased, yielding an R^2 value of 0.48 and an RMSE of 3.04 at the 0.5% curtailment limit, and an R^2 value of 0.86 and an RMSE of 1.55 at the 5% curtailment limit (i.e., 86% of the variation in load addition capacity across balancing authorities can be explained by differences in load factor at a curtailment limit of 5.0%).

24 Note in Figure 12b that a high-degree polynomial function captures the nonlinear growth in the area under the load curve as curtailed load exceeds a fixed peak threshold. This fit generally aligns with expectations, demonstrating that higher-degree terms are necessary to capture the relationship between load factor and curtailed load.

Figure 13. Load Factor Versus Max Load Addition as Share of Peak Load



These findings emphasize the importance of load factor as a predictor of curtailment-enabled headroom. BAs with more uneven peak seasonal demand—characterized by relatively low system utilization in winter or summer—tend to have greater capacity to integrate new loads with limited curtailment. Conversely, systems with more consistent demand across the winter and summer face tighter limits, as their capacity to absorb additional load is already constrained by elevated baseline usage.

Limitations

This analysis provides a first-order assessment of power generation capacity available for serving new curtailable loads, and hence is an exploration of the market potential for large-scale demand response. The primary focus of the analysis is to ensure that total demand, subject to curtailment limits for new load, stays below the system peak for which system planners have prepared. Other considerations important for planning—such as ensuring adequate transmission capacity, ramping capability, and ramp-feasible reserves, among others—are beyond the scope of this study and therefore the results cannot be taken as an accurate estimate of the load that can be added to the system. Additionally, the analysis assumes the new loads do not change current demand patterns but rather shift the existing demand curves upward, and a more precise assessment of the potential for integration of new loads would require detailed characterization of the temporal patterns of the load. There is significant variation in how system operators forecast and plan for system peaks, accounting for potential demand response, and as a result there will be differences in the methods used to estimate potential to accommodate new load. Despite these limitations, the results presented here signal a vast potential that, even if overstated, warrants further research.

On the other hand, some aspects of this study may have contributed to an underestimation of available headroom. First, the analysis assumes that each BA's maximum servable load in the winter and summer is equivalent to the BA's highest realized seasonal peak demand based on the available historical data. However, the available generation capacity in each balancing authority should materially exceed this volume when accounting for the installed reserve margin. In other words, system operators have already planned their systems to accommodate load volume that exceeds their highest realized peak. Second, the analysis removed outlier demand values in some BAs to avoid using unreasonably high maximum peak thresholds, which would understate the curtailment rates. However, if some of the removed outliers properly represent a level of system load that the system is prepared to serve reliably,

this analysis may have understated the curtailment-enabled headroom. Third, the analysis assumed all new load is constant and hence increases the total system load by the same gigawatt hour-by-hour, which would tend to overstate the absolute level of required gigawatt hour curtailment for a load that is not constant.

Future Analysis

Enhancing this analysis to more accurately assess the capacity to integrate large curtailable load would require addressing the following considerations:

Network Constraints

This analysis does not account for network constraints, which would require a power flow simulation to evaluate the ability of the transmission system to accommodate additional load under various conditions. As such, the results should not be interpreted as an indication that the identified load volumes could be interconnected and served without any expansions in network capacity. While the existing systems are planned to reliably serve their peak loads, this planning is based on the current load topology and the spatial distribution of generation and demand across the transmission network. A large new load could avoid exceeding aggregate peak system demand by employing flexibility, yet still cause localized grid overloads as a result of insufficient transmission capacity in specific areas. Such overloads could necessitate network upgrades, including the expansion of transmission lines, substations, or other grid infrastructure. Alternatively, in the absence of network upgrades, localized congestion could be addressed through the addition of nearby generation capacity, potentially limiting the flexibility and economic benefits of the new load. These factors underscore the importance of incorporating network-level analyses to fully understand the operational implications of large flexible load additions.

Intertemporal Constraints

This analysis does not account for intertemporal constraints related to load and generator operations. For load operations, response times affect system operations and management of operational reserves. Faster response times from flexible loads could alleviate system stress more effectively during peak demand periods, potentially reducing the reliance on reserve capacity. Conversely, slower response times may require additional reserves to bridge the gap between the onset of system imbalances and the load's eventual response. Moreover, the rapid ramp-down of large flexible loads could lead to localized stability or voltage issues, particularly in regions with weaker grid infrastructure. These effects may necessitate more localized network analyses to evaluate stability risks and operational impacts. On the generation side, intertemporal constraints such as ramping limits, minimum up and down times, and startup times can affect the system's ability to integrate fast-response demand. For instance, ramping constraints may restrict how quickly generators can adjust output to align with the curtailment of flexible loads, while minimum uptime and downtime requirements can limit generator flexibility.

Loss of Load Expectation

Peak load is a widely used proxy for resource adequacy and offers a reasonable indicative metric for high-level planning analyses. However, a more granular assessment would incorporate periods with the highest loss of load expectation (LOLE), which represent the times when the system is most likely to experience supply shortfalls. Historically, LOLE periods have aligned closely with peak load periods, making peak load a convenient and broadly

applicable metric. However, in markets with increasing renewable energy penetration, LOLE periods are beginning to shift away from traditional peak load periods. This shift is driven by the variability and timing of renewable generation, particularly solar and wind, which can alter the temporal distribution of system stress. As a result, analyses focused solely on peak load may understate or misrepresent the operational challenges associated with integrating large new loads into these evolving systems.

CONCLUSION

This study highlights extensive potential for leveraging large load flexibility to address the challenges posed by rapid load growth in the US power system. By estimating the curtailment-enabled headroom across balancing authorities, the analysis demonstrates that existing system capacity—intentionally designed to accommodate the extreme swings of peak demand—could accommodate significant new load additions with relatively modest curtailment, as measured by the average number, magnitude, and duration of curtailment hours.

The findings further emphasize the relationship between load factors and headroom availability. Balancing authorities with lower seasonal load factors exhibit greater capacity to integrate flexible loads, highlighting the importance of regional load patterns in determining system-level opportunities. These results suggest that load flexibility can play a significant role in improving system utilization, mitigating the need for costly infrastructure expansion and complementing supply-side investments to support load growth and decarbonization objectives.

This analysis provides a first-order assessment of market potential, with estimates that can be refined through further evaluation. In particular, network constraints, intertemporal operational dynamics, and shifts in loss-of-load expectation periods represent opportunities for future analyses that can offer a deeper understanding of the practical and operational implications of integrating large flexible loads.

In conclusion, the integration of flexible loads offers a promising, near-term strategy for addressing structural transformations in the US electric power system. By utilizing existing system headroom, regulators and market participants can expedite the accommodation of new loads, optimize resource utilization, and support the broader goals of reliability, affordability, and sustainability.

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ABBREVIATIONS

AI	Artificial intelligence
AZPS	Arizona Public Service Company
BA	balancing authority
BPA	Bonneville Power Administration
CAGR	compound annual growth rate
CAISO	California Independent System Operator
CLRs	controllable load resources
CPUs	central processing units
DEC	Duke Energy Carolinas
DEF	Duke Energy Florida
DEP	Duke Energy Progress East
DERs	distributed energy resources
DESC	Dominion Energy South Carolina
EIA	Energy Information Administration
EPRI	Electrical Power Research Institute
ERCOT	Electric Reliability Council of Texas
ERIS	Energy Resource Interconnection Service
FERC	Federal Energy Regulatory Commission's
FPL	Florida Power & Light
GPUs	graphics processing units
ICT	information, and communication technology
ISO-NE	ISO New England
LGIA	Large Generator Interconnection Agreement
LOLE	loss of load expectation
MISO	Midcontinent Independent System Operator
NYISO	New York Independent System Operator
PACE	PacifiCorp East
PACW	PacifiCorp West
PG&E	Pacific Gas and Electric
PGE	Portland General Electric Company
PJM	PJM Interconnection
PSCO	Public Service Company of Colorado
RMSE	Root mean square error
RTO/ISO	Regional transmission organization/independent system operator
SCP	Santee Cooper, South Carolina Public Service Authority
SEAB	Secretary of Energy Advisory Board
SLAs	service-level agreements
SOCO	Southern Company
SPP	Southwest Power Pool
SRP	Salt River Project Agricultural Improvement and Power District
TPU	tensor processing unit
TVA	Tennessee Valley Authority

APPENDIX A: CURTAILMENT-ENABLED HEADROOM PER BALANCING AUTHORITY

Figure A.1. Curtailment Rate Versus Load Addition by RTO/ISO, MW

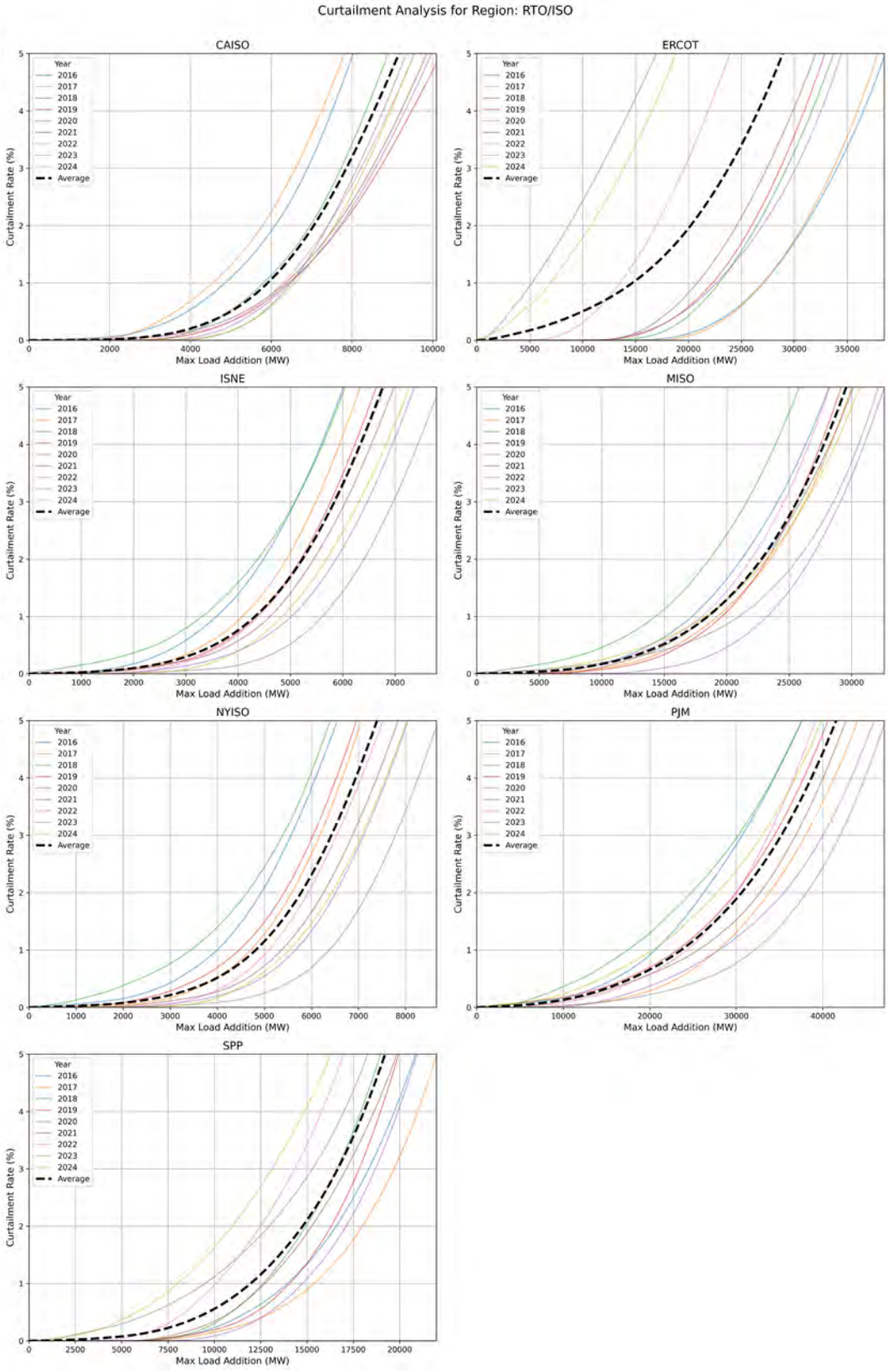


Figure A.2. Curtailment Rate Versus Load Addition by Non-RTO Southeastern Balancing Authority, MW

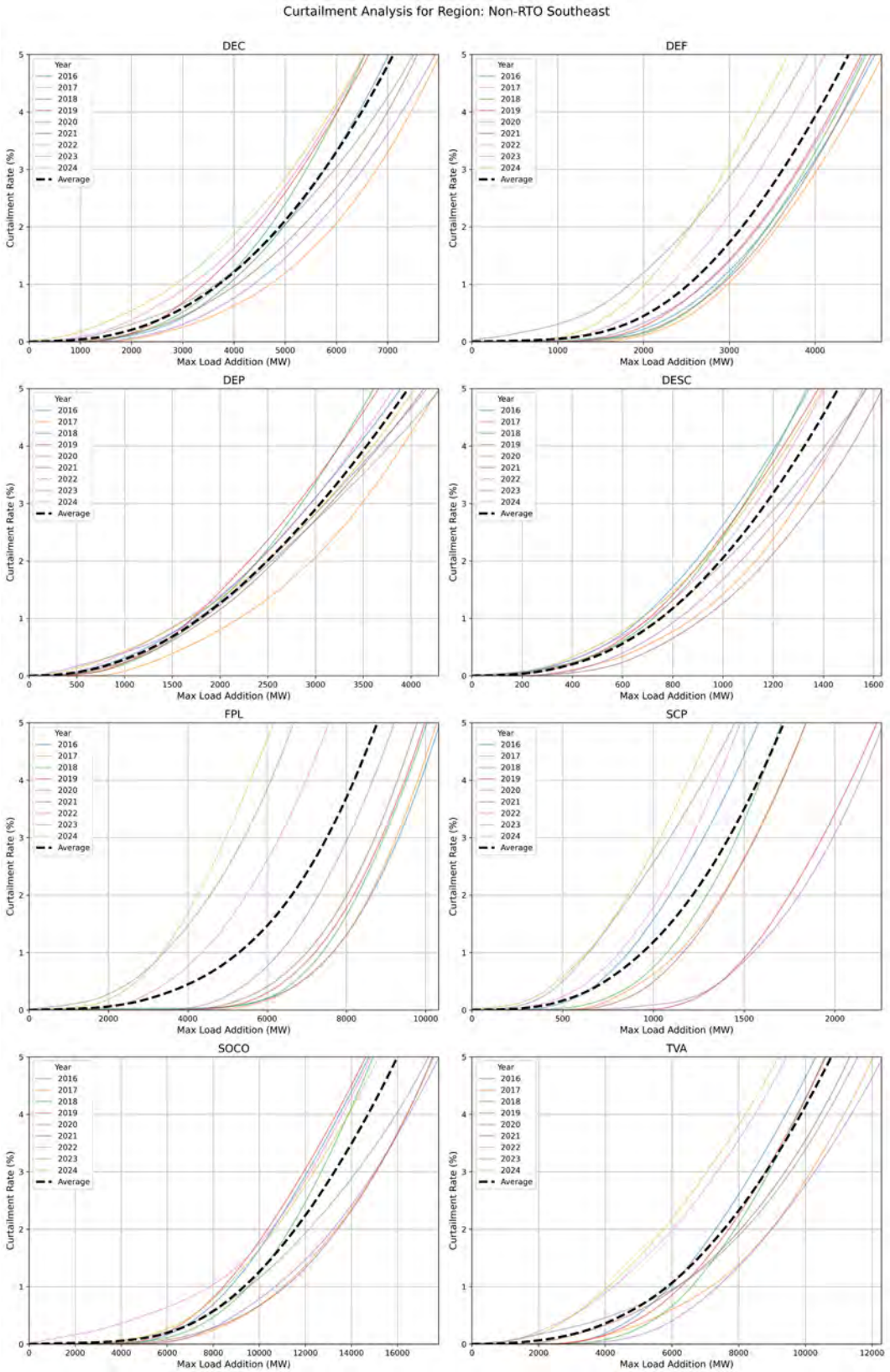
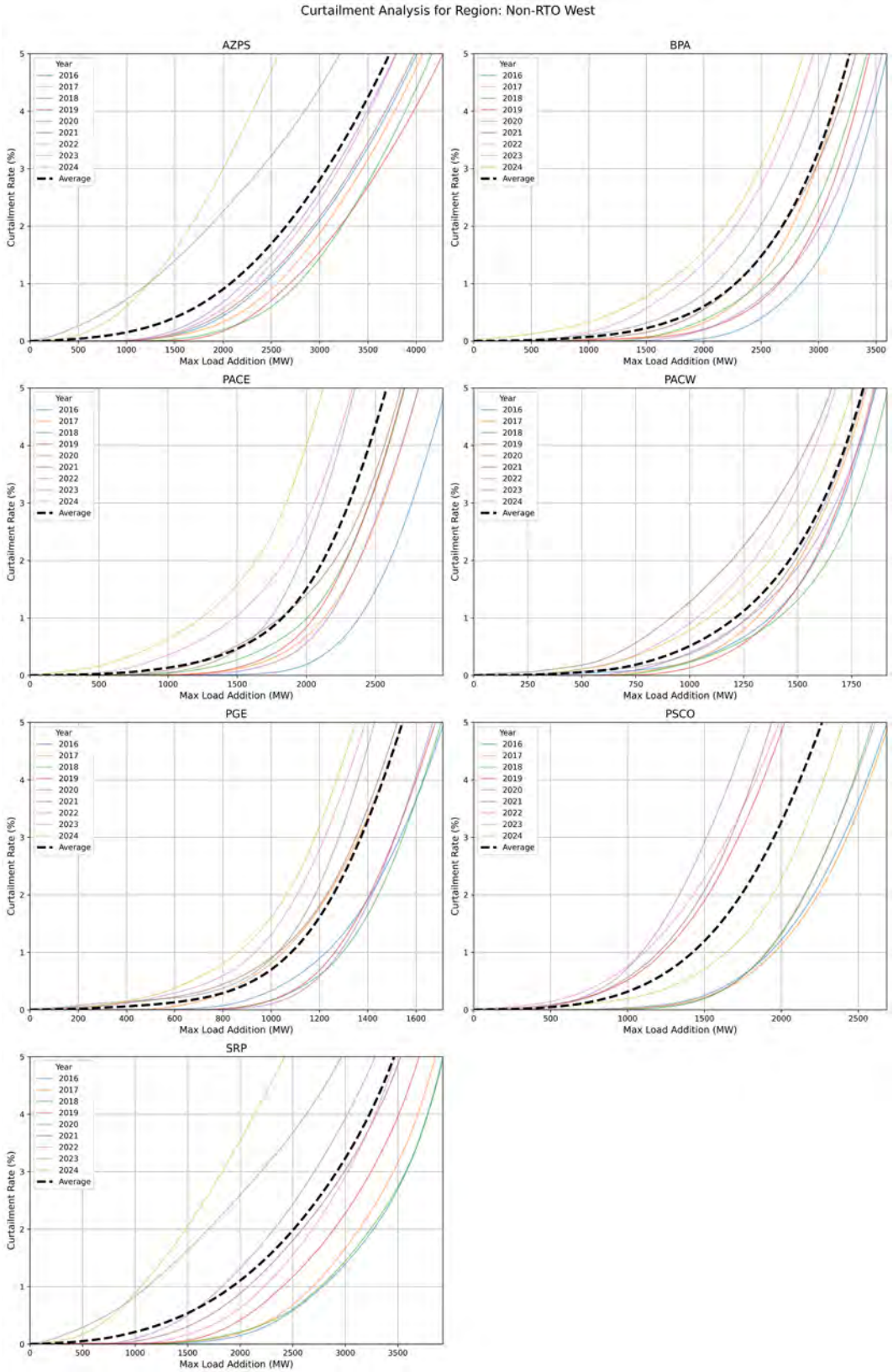


Figure A.3. Curtailment Rate Versus Load Addition by Non-RTO Western Balancing Authority, MW



APPENDIX B: DATA CLEANING SUMMARY

The data cleaning process attempted to improve the accuracy of nine years of hourly load data across the 22 balancing authorities, including the following steps:

1. Data normalization
    - **Dates:** Date-time formats were verified to be uniform.
    - **Demand data:** Where the balancing authority had an "Adjusted demand" value for a given hour, this value was used, otherwise its "Demand" value was used. The final selected values were saved as "Demand" and a log was kept.
    - **BA labels:** Labels were mapped to align with widely used acronyms, including:
        - CPLE → DEP
        - DUK → DEC
        - SC → SCP
        - SWPP → SPP
        - SCEG → DESC
        - FPC → DEF
        - CISO → CAISO
        - BPAT → BPA
        - NYIS → NYISO
        - ERCO → ERCOT
2. Identifying and handling outliers
    - **Missing and zero values:** Filled using linear interpolation between adjacent data points to maintain temporal consistency.
    - **Low outliers:** Demand values below a predefined cutoff threshold (such as 0 or extremely low values inconsistent with historical data) were flagged. Imputation for flagged low outliers involved identifying the closest non-outlier value within the same balancing authority and time period and replacing the flagged value.
    - **Spikes:** Sudden demand spikes that deviated significantly from historical patterns were flagged. Corrections were applied based on nearby, consistent data.
    - **Erroneous peaks:** Specific known instances of demand peaks that are outliers (e.g., caused by reporting errors) are explicitly corrected or replaced with average values from adjacent time periods.
3. **Data validation**:
    - Seasonal and annual peak loads, load factors, and other summary statistics were computed and inspected to ensure no unexpected results. Max peaks were compared to forecasted peaks collected by FERC to ensure none were out of range.
    - Logs summarizing corrections, including the number of spikes or outliers addressed for each balancing authority, were saved as additional documentation.

APPENDIX C: CURTAILMENT GOAL-SEEK FUNCTION

Mathematically, the function can be expressed as

$$\frac{1}{N}\sum_{y=1}^{N}\left(\frac{Curtailment_y(L)}{L \cdot 8{,}760}\cdot 100\right) = CurtailLimit$$

where

L	=	load addition in MW (constant load addition for all hours)
N	=	total number of years in the analysis (2016–2024)
$Curtailment_y(L)$	=	curtailed MWh for year y at load addition L
$L \cdot 8{,}760$	=	maximum potential energy consumption of the new load operating continuously at full capacity
$CurtailLimit$	=	predefined curtailment limit (e.g., 0.25%, 0.5%, 1.0%, or 5.0%).

For each hour t in year y, the curtailment is defined as

$$Curtailment_t(L) = \max(0, Demand_t + L - Threshold_t)$$

where

L	=	load addition being evaluated in MW
$Demand_t$	=	system demand at hour t in MW
$Threshold_t$	=	seasonal peak threshold applicable for hour t in MW (i.e., the maximum winter or summer peak across all years)

These hourly curtailments are aggregated to find the total annual curtailment

$$Curtailment_y(L) = \sum_{t \in T_y} Curtailment_t(L)$$

where

T_y	=	all hours in year y.

Replacing $Curtailment_y(L)$ in the original formula, the integrated formula becomes

$$\frac{1}{N}\sum_{y=1}^{N}\left(\frac{\sum_{t \in T_y}\max(0, Demand_t + L - Threshold_t)}{L \cdot 8{,}760} * 100\right) = CurtailLimit$$

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-44:
RMI Analysis of Coal Plants' Threats to Reliability

Reality Check: We Have What's Needed to Reliably Power the Data Center Boom, and It's Not Coal Plants

A range of clean, resilient solutions can help us meet the electrical needs of our growing digital economy while saving Americans money.

August 12, 2025

By Gabriella Tosado, Ashtin Massie, Joe Daniel

After decades of relatively flat electricity demand, the US power sector is expecting demand to grow due, in large part, to new data centers. These energy-intensive facilities are reshaping the grid, with some utilities now projecting over 20 percent load growth by 2035. In places like Virginia, which constitutes 13 percent of all reported data center capacity globally and 25 percent of the data center capacity in the United States, data centers already account for over a quarter of some utilities' total electric demand, and their footprint is only growing.

The myth

Utilities are struggling to maintain accurate forecasts and identify resources that can meet this growth. There is a high-profile effort to keep coal plants that are set to retire online and run them at unprecedented levels, ostensibly for reasons of reliability. But the truth is, coal-fired power plants, far from being a reliable backbone for this new era of electricity demand, are a brittle, outmoded technology that threatens to undermine the very grid resilience they're being proposed to protect.

> Coal-fired power plants, far from being a reliable backbone for this new era of electricity demand, are a brittle, outmoded technology that threatens to undermine the very grid resilience they're being proposed to protect.

Tweet

Reality #1: Aging coal plants are failing to consistently deliver under stress

Coal plants face a fundamental constraint: they are aging and increasingly unreliable. Most of the coal fleet was built in the 1970s and 1980s, and years of wear and tear have led to a rise in unplanned outages. In many cases the sheer cost to maintain and modernize these plants did not make sense with the availability of more reliable and affordable alternatives – and that's still the case.

According to the Energy Systems Integration Group (ESIG) *Ensuring Efficient Reliability* report, a coal plant's capacity accreditation, or the amount of time it can contribute to peak demand, is only 83 percent when adjusted for real-world performance. PJM also has capacity accreditation of coal plants at 83 percent and some plants fare even worse. Gridlab's reliability study found Colstrip, a large regional coal plant in Montana, operating with a capacity accreditation of only 54 percent – meaning it's effectively unavailable nearly half the time it's needed.

Extreme weather exacerbates these vulnerabilities. Cold snaps, heat waves, and storms have all exposed coal's fragility during grid stress events. Reliability is not just about being dispatchable, it's about delivering performance under stress. Coal plants struggle to do that consistently. For coal plants to truly meet the constant demands of data centers, they would need to run at high-capacity factors and avoid major outages, all of which fly in the face of current performance trends. If a large coal plant trips offline while supporting a cluster of data centers,

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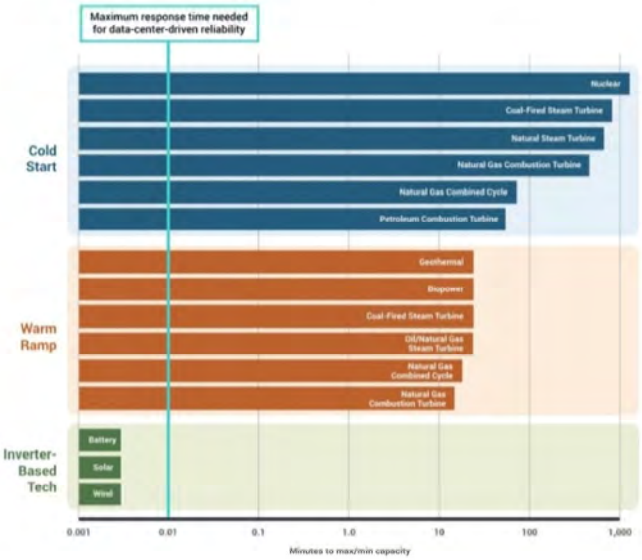
the sudden loss of supply could lead to cascading failures across the grid. This is because generation must equal load at all times, datacenter or no datacenter. As a result, relying on coal plants to support these high-density digital loads doesn't enhance reliability, it endangers it. And it's not a matter of *if* the coal plant will fail, but *when*.

Reality #2: The inflexibility of coal plants risks grid stability

Coal boosters often point to the "always-on" nature of coal plants as evidence of their reliability. But that characteristic is a liability, not a strength, when it comes to supporting large, fast-changing loads like data centers. Coal units are inherently inflexible: they ramp slowly, respond poorly to sudden load shifts, and are difficult to turn on or off quickly. This rigidity is a poor match for the dynamic and often unpredictable nature of data center demand. Further, inflexible coal plants can worsen grid congestion; by occupying limited transmission capacity with inflexible generation, they prevent cheaper or cleaner resources from being delivered. This issue has already been flagged by **independent market monitors** in regions like MISO – which covers 15 US states and a Canadian province – where congestion-related market distortions have cost **over $1 billion a year**. Coal plants displace faster-responding resources that are better suited to follow load. And the stakes are high.

As noted by the North American Electric Reliability Corporation (NERC), large, voltage-sensitive loads like data centers require flexible, responsive grid solutions, not slow-ramping generators that can take 12 or more hours to come online. NERC's recent ***Incident Review and Guidance on Voltage-Sensitive Large Load Integration*** describes an event in 2024 where a transmission fault triggered a sudden disconnection of 1,500 megawatts of voltage-sensitive data center load, leading to sharp frequency and voltage spikes that required operator intervention. The incident exposes the system's vulnerability to instability when inflexible generation cannot respond to large load fluctuations.

Minutes needed for a power plant to reach max/min capacity



If a data center either loses access to load or goes offline rapidly, a grid's generation needs to respond at sub-second speeds. The average coal plant ramp rate is **4 percent per minute** which translates to spending over 20 minutes to respond to a large load event. From a cold start, the average coal plant would take over **12 hours** to reach max capacity. Coal plants simply can't respond fast enough to support the reliability needs of modern data centers. Whether it's the hours-long startup time from a cold state or sluggish ramp rates to turn off, these plants are too slow to provide the real-time flexibility required during sudden load changes or outages.

Reality #3: Clean resources are available now that can better respond to and support data centers for less

The good news is that we don't need to rely on brittle coal plants to meet the needs of a digital economy. A range of cleaner, more resilient solutions is already available – and scalable. For example, we recently found that **more than 95 percent** of future demand can be met with fast, scalable, and clean solutions:

Shares

Alternative near-term solutions to meet load growth

Technology	Opportunity
Energy Efficiency	Over 50 GW of energy efficiency can be deployed – by both creating programs for new loads and expanding existing programs aligned with system needs. Energy efficiency can unlock benefits beyond system cost savings, improving comfort and resilience in homes.

Virtual Power Plants	60 GW of virtual power plants can be deployed by 2030, with programs stood up and enrolled in under 6 months. Policymakers in Virginia recently passed a bill that requires 450 MW of VPPs deployed rapidly to meet growing demand.
Advanced Transmission Technologies	Grid enhancing technologies and reconductoring can unlock over 80 GW of incremental peak capacity by reducing transmission and interconnection constraints. Lawmakers in New Mexico passed a bill requiring utilities to assess the use these technologies in plans to get more out of the existing grid.
Clean Repowering	There is 14 GW of fossil-fuel generation expected to retire, that could serve as sites for quick addition of new renewable energy and storage while reducing system costs. Market operators like PJM are enabling clean repowering by updating rules to allow for surplus interconnection.
Power Couples	New load can be co-located with renewable energy at the site of existing, underutilized generators with approved interconnections—a strategy which we call "Power Couples." There is over 30 GW of opportunity to deploy Power Couples under $100/MWh, and over 50 GW of opportunity under $200/MWh.

Coal plants are a legacy technology, not a solution for the future. Coal plants' operational characteristics make them less suited to meet the scale and speed of these new challenges. The path forward is not about discarding the past, but about building on it with cleaner, more adaptable resources that can reliably serve evolving grid needs.

Technologies like battery storage, demand flexibility, and clean energy portfolios offer practical, cost-effective options that align with modern load dynamics. As we noted in a recent **article**, by running coal plants only when it is economical to do so and using the extra transmission headroom that creates to reinvest with clean energy upgrades, our grid can support the next wave of economic growth with the flexibility it demands. There are reasons to manage the shift to new, clean resources **thoughtfully and intentionally**, but propping up coal plants that are not suited for the job is a step in the wrong direction.

RECOMMENDED READING

Gas Turbine Supply Constraints Threaten Grid Reliability; More Affordable Near-Term Solutions Can Help

June 18, 2025

Read More

Reinvesting at Coal Plant Sites with Clean Energy Upgrades Supports both Reliability and Affordability

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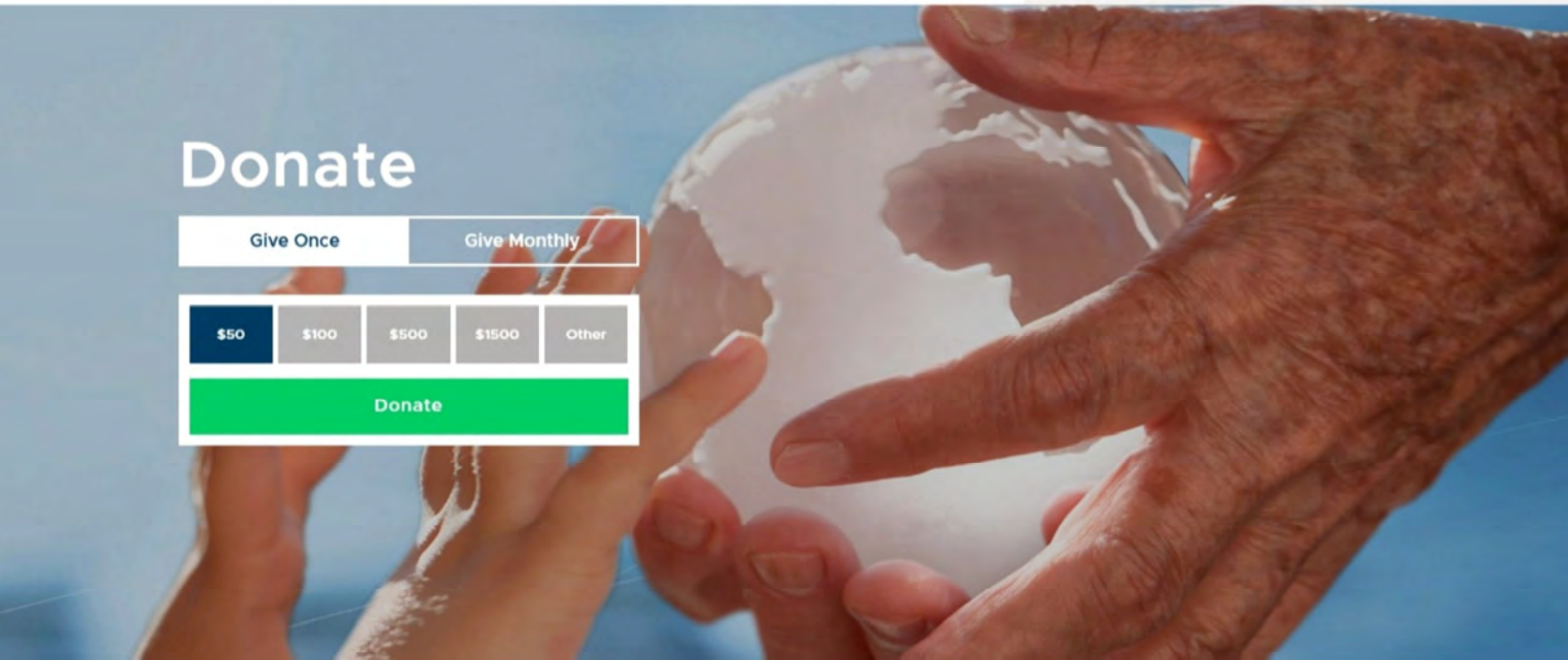

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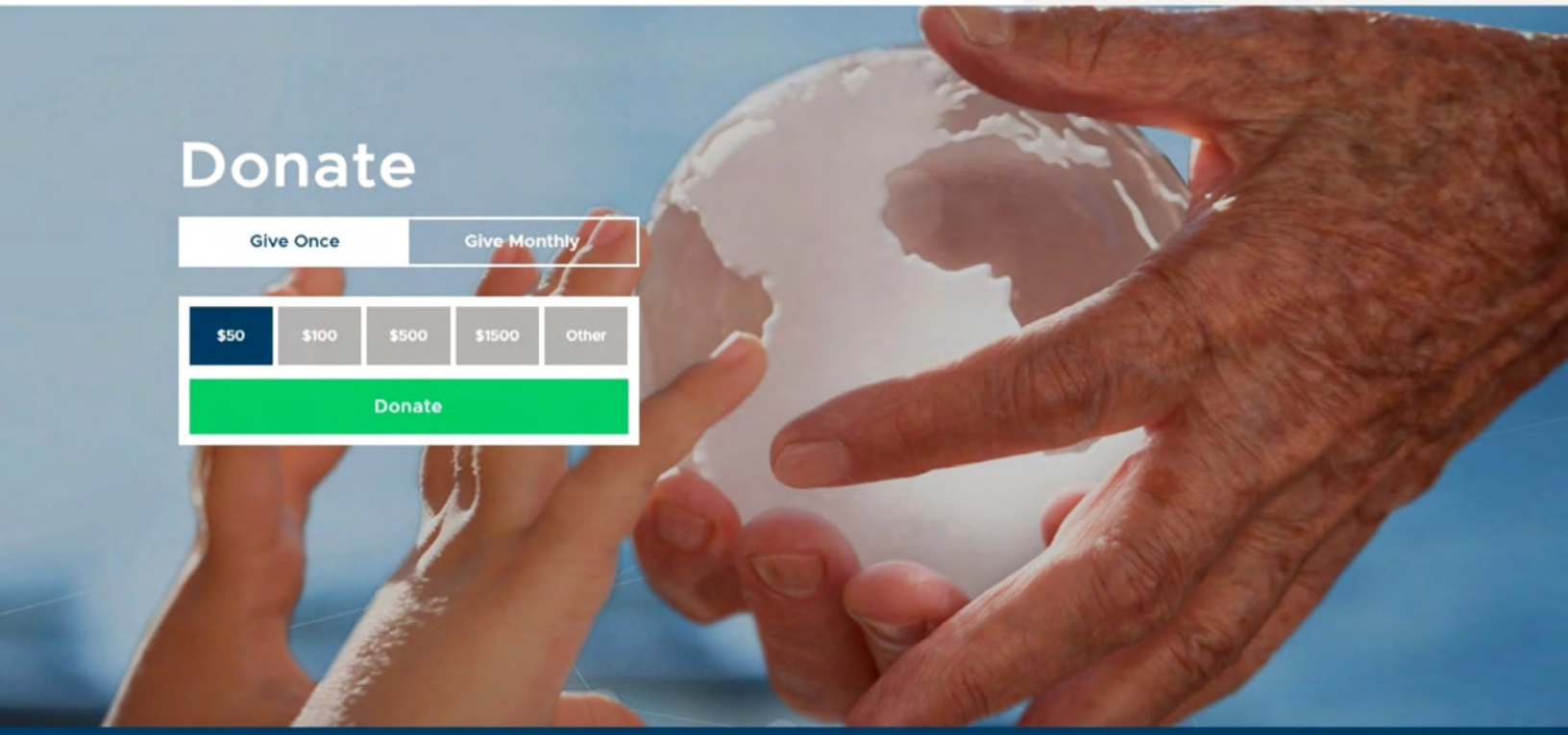

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-45:
Energy Innovation Report

ENERGY INNOVATION
POLICY & TECHNOLOGY LLC®

DODGING THE FIRM FIXATION FOR DATA CENTERS AND THE GRID

Eric G. Gimon

Senior Fellow, Energy Innovation

November 2025

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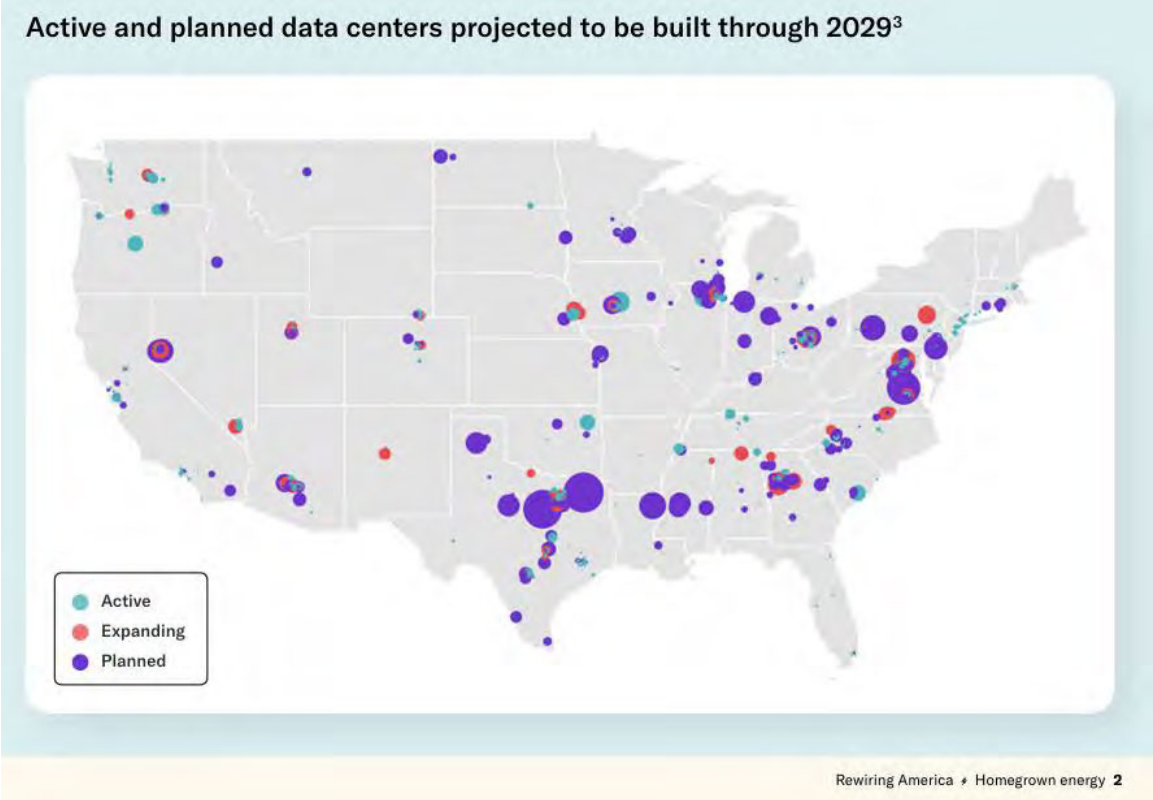
EXECUTIVE SUMMARY

In multiple states[1,2] (see Figure 1) massive new data center campuses and a coterie of smaller ones have reversed years of flat or declining electricity demand, leaving utilities and policymakers scrambling for solutions.

Figure 1 Existing and Projected data centers from Rewiring America's "Homegrown Energy" report[3].



Faced with this onslaught of new demand, many utilities and developers are depending on old habits by adding new gas plants, refurbishing coal units, or turning to nuclear partnerships along with extensive grid upgrades near new load centers – the "firm fixation."

It reflects a belief that only firm resources and major transmission upgrades can handle data centers' needs. Yet this approach overlooks two essential truths: (1) power plants and data centers are both parts of a larger, interconnected system, and (2) data center loads, especially those driven by artificial intelligence (AI), are far more dynamic than the flat, baseload profiles they are often assumed to be. Firm fixation leads utilities and regulators to default to outdated firm-generation solutions instead of modern, modular approaches that consider the full complexities of today's power grid. At the scale of even the most compact new data centers, connecting to the grid is no small matter.

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Regardless of approach, three features of recent growth are well known to the electricity industry and policy community, and to some extent the wider public. First, new data center load is being amplified by extreme investment interest in AI. Second, incremental load tends to be highly concentrated due to the nature of the growing individual server need for power and the geographic concentration of data centers. Third, the data center industry's appetite for new growth is so large, and other facility capital costs so high that new project owners are willing to pay more for power than average existing electricity consumers.

In a 2024 brief, Energy Innovation proposed instead that a portfolio of solutions – clean energy portfolios, advanced transmission technologies, demand-side flexibility, and efficiency – could work together to obviate the need to rush to meet demand with new fossil generation.[4] Reality so far has deviated significantly from this vision, setting up the power sector for failure: Either new demand will not be met or the negative cost and performance impacts of doing so on other grid users will challenge electricity markets and other long-standing arrangements in a dangerous manner.

The mad scramble to meet data center demand using traditional but crude resource investment methods can create potential missed opportunities to manage load growth that come from a deeper understanding of data centers. Of course, their electricity demand is problematic because it is concentrated, growing fast, and willing to outspend other users. However, it is also far more complex than the flat, 24/7 block it is often assumed to be. This primer identifies six defining features that provide a more nuanced version picture of data centers:

- **Agency and Split Incentives** – Multiple actors (developers, operators, and tenants) and ownership or usage types of data centers create a divided responsibility over grid interaction and access to energy-saving incentives that complicates energy decisions.
- **Clustering** – Facilities tend to concentrate geographically, amplifying local grid stress and transmission costs while creating systemic planning challenges.
- **Consumption Profiles** – Loads are not 24/7 blocks. Instead, they are choppy, with swings of hundreds of megawatts over short intervals, undermining assumptions of steady baseload behavior and potentially affecting the stability of the grid if safeguards are not put in place.
- **Flexibility** – While some AI-driven workloads can be scheduled for off-peak hours, this flexibility is uneven across facility types and even within users in the same data center campuses. While modest levels of curtailment or load-shifting based demand response during peak hours could ease interconnection bottlenecks and peak demand requirements, these may work best in combination with battery energy storage to overcome split incentives and other complexities.

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- **Backup Requirements** – Current reliance on diesel for backup generation is unsustainable. Batteries and longer-duration storage are cleaner, more scalable options that provide knock-on benefits for the grid if allowed to participate as both backup and demand response.
- **Modularity** – Data centers grow in phases just as demand grows in phases rather than all at once, aligning poorly with "lumpy" firm large one-time investments in dispatchable power plants and infrastructure upgrades, while fitting well with modular renewables and battery deployments.

When examined as a whole, these features undermine the firm fixation logic. One-to-one matching of data centers with dedicated or "captive" firm power plants is particularly unwise for both the power generator and the new data centers, even given their willingness to pay for speed-to-power. Relying on captive plants for all supply such as pairing a nuclear plant with a large data center exposes them to outages, inflexibility, and stranded-asset risks, while hybrid co-location deals still rely heavily on the broader grid.

Most new demand will need to be served fully or in-part through the bulk power system, requiring upgrades in three key areas: **connection infrastructure, grid services (especially peak capacity), and bulk electricity supply.**

Once this is established, it's clear that data centers can tap the grid's advantages as a "system of systems" that pools variable demand and generation resources solutions together and ensures supply and demand match in real-time. As peak demand rises, this crucial service must be met, but not necessarily by firm generation. A deeper understanding of data center demand attributes yields a more complete solution set which includes data center flexibility, onsite storage, portfolios of clean energy, and others.

The challenges data centers pose include lengthy interconnection queues, peak stress, price impacts, and rising emissions – but these are not insurmountable. Three core lessons emerge for policymakers and stakeholders:

- The process of connecting any new **large load is a key leverage point.** It is the moment to ensure consumption tariffs reflect cost causation, encourage flexibility, and align incentives without imposing unworkable burdens later. Interconnection is the moment of maximum leverage: not to extract unreasonable concessions, but to ensure new entrants cover the full costs of the infrastructure they trigger, and to nudge data center developers towards solutions such as flexible demand or local storage that relieves local bottlenecks and supports the broader grid. Likewise, developers and customers should lean toward local fixes that speed access to the grid, improve power quality, and ease broader impacts—reducing the likelihood of being saddled with extraordinary requirements later.

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- **Demand side is a resource hiding in plain sight**. Household electrification and distributed resources can free up tens of gigawatts (GW) at costs comparable to new gas plants and on a faster timetable, offering a more pragmatic and equitable path to integration. Yet at the state and regional level, policy innovation still lags behind. However, several widespread mechanisms exist to channel data center owners and operators' willingness to pay into new solutions that help other existing customers accommodate rapid data center load growth in a fair, fast and equitable way. Because grid connection bottlenecks can be managed by multiple possible combinations of diverse resources, data centers don't need to do all the work of mitigating their grid impacts onsite or through a single counterparty. Once a data center has invested in flexibility and equipment to resolve local connection issues, additional constraints such as upstream transmission and grid services bottlenecks as well as large incremental amounts of annual electricity delivery can be addressed with demand-side solutions from other grid users. A recent report from Rewiring America proposes that many of the resources needed to meet data center load growth could come from sponsoring household upgrades instead of new generation.[5]
- **Storage and flexibility deliver a two-for-one win.** Batteries and managed demand not only ease all manner of data center impacts but can also accelerate renewable integration, providing cleaner, faster, and cheaper capacity than firm fossil solutions. Because batteries are increasingly essential for buffering, backup, and power quality, they also provide a built-in solution for integrating variable renewables—a two-for-one advantage. Furthermore, these renewable-plus-battery solutions can capitalize upon existing surplus interconnection to more quickly connect data centers to the grid in co-located arrangements.

This report challenges the electricity and data center industries to move beyond a firm fixation and adopt solutions that leverage the full capabilities of modern power systems.

The next section describes six defining features of data centers: agency, clustering, consumption profile, flexibility, backup needs, and modularity. We then pivot to explaining why traditional firm responses fall short within the broader context of how the modern grid supplies power to consumers, especially large, new consumers. We will look at how new, modular solutions can meet digital demand more effectively. These steps will depend on a more nuanced understanding of data centers, as opposed to how they are often imagined.

Our hope is that this information will empower policymakers to make wiser decisions when faced with AI growth and proposed public investments, avoiding a firm fixation on simplistic approaches and reaching for more realistic answers that embrace the full complexities of the challenge that rapid data center load growth presents today. By moving beyond simplistic assumptions, policymakers can avoid overcommitting to

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outdated firm resources and instead adopt strategies that embrace modularity, flexibility, and clean energy. We want to leave policymakers with three key takeaways to avoid falling into a firm power matching fallacy and to instead embrace the ability to mix and match resources to meet data center needs.

What began as a major strain on the grid can become the catalyst for building a smarter one, supporting both the digital economy's explosive growth and the clean energy transition.

COMMERCIAL AND INDUSTRIAL REALITIES THAT APPLY TO DATA CENTERS

Actual data centers are not the simple "flat 24/7 block of demand" people imagine.

Six different demand features of data centers explain the diversity of data center types (agency, clustering, and profile) and their internal workings (flexibility, backup, and modularity).

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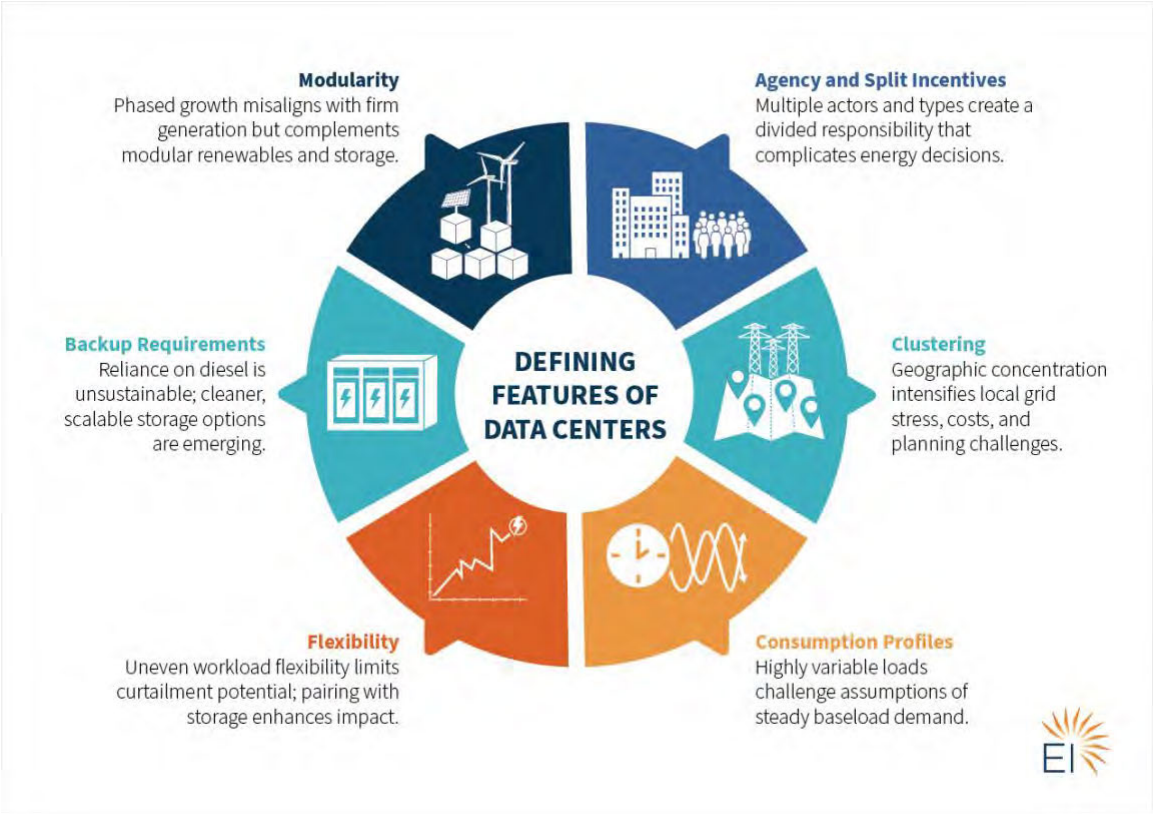
Figure 2 Actual data centers are not the simple "flat 24/7 block of demand" people imagine.



Data Center Feature 1: Agency and the split-incentive problem

Planning *and* operating *a data center* involves many decision-makers. *Some data centers (often called co-locations or "colos") are facilities where customers can rent space to house their servers and equipment or just run their software on provided equipment. This means the facility is developed and owned by a different company* from those *that rent rack space, buy* computing *capacity, and ultimately consume electricity. Multiple actors force complicated decisions around electricity supply.*

If we want new data centers to adapt their development approach to better integrate with the grid and increase their "speed-to-power," policymakers must understand the planning, construction, and operation of modern data centers. Many different actors are involved, creating a classic split-incentive problem. Loosely speaking, apart from the users or clients, three groups of actors dictate the energy and resource impacts of data centers: developers, facility operators, and service providers. These tend to be separate entities. Overlap sometimes occurs, but usually not enough to prevent split-incentive

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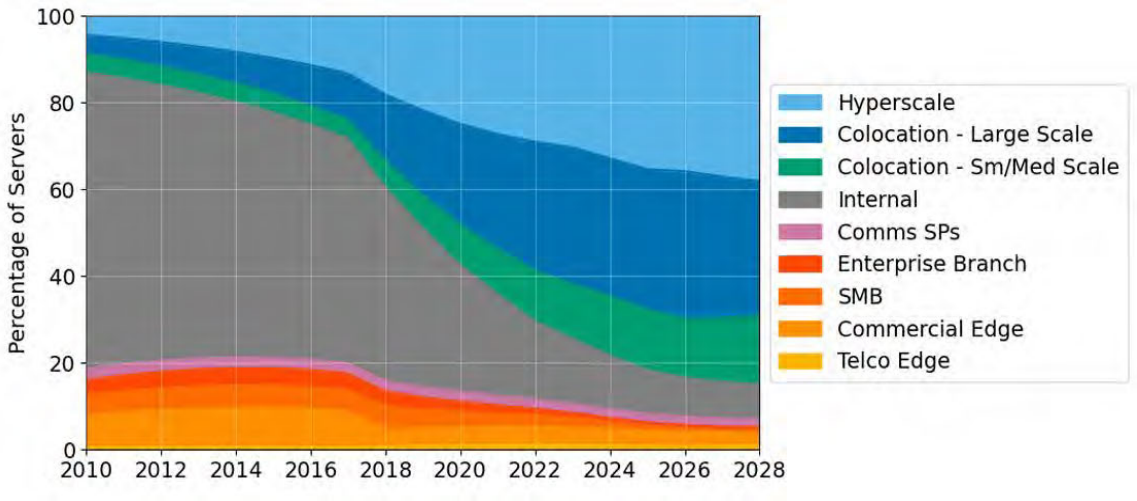
issues. More than half (and an even larger fraction of the current pipeline)[6] of data centers are categorized as co-location facilities—large facilities that rent out space to multiple separate entities.

Figure 3 Distribution of server types by data center type. 2024 United States Data Center Energy Usage Report[7]



We illustrate the split incentives by cataloguing some of the key concerns for each of the three types of decision-makers in the life of a data center. In early stages, data center development is mostly a real estate bet: developers acquire land, water, and electric connection rights and then these rights pass on to the projects they sell. The natural incentive for developers is to keep the range of future owners they could sell to as wide as possible. Hence, they are unlikely to want to enter contracts or agreements (or support legislation) that might prematurely impair any of the land, water, and power consumption rights for their projects. For example, they may not want to agree to be a flexible consumer in return for faster interconnection (load interconnection currently takes three to 11 years) because that might scare off some prospective buyers.

Similarly, owner/operators that lease capacity to data centers customers do not necessarily have much insight into how flexible these customers are or how their customers' usage pattern might change over time. They are conservative about aspects such as whether the tenant-user would be interested in avoiding on-peak usage, participating in time-varying rates, accessing clean energy tariffs, or participating in a demand-response program. Obviously, renters must abide by some rules (via master service agreements or service-level agreements[i]) about behavior that impacts power quality (voltage, frequency, harmonics, transients, etc.) or broader

[i] A master service agreement is an umbrella standardized contractual framework between a utility and the "customer of record" (which could be a data center owner/operator, a tenant/end-customer, or a special purpose entity created to hold the contract) across multiple facilities in the utility's territory. A load serving agreement is more specific to power delivery at a given site.

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electrical concerns (like grounding, interference, and surge protection), but that still leaves a lot of uncertainty for the data center owner/operator. Violations may also pass undetected until a severe problem occurs.

Because data centers are also large electricity consumers, utilities will want to know if contracts are backed by the ultimate users (e.g., hyperscalersii) or an intermediate company that could go bankrupt or disappear. Grid investments involve assets with multi-decadal lifetimes, while the service life of cutting-edge chips can be two to three years. Utilities and their regulators have a strong interest in recovering any incremental costs of investments needed to serve data centers and will look for contractual arrangements to make this happen.

Data Center Feature 2: Clustering, data centers are attracted by similar conditions or to each other

Data center locations tend to be concentrated in a few regions rather than evenly distributed. This clustering amplifies stress on already energy-dense grids. The main drivers are favorable conditions—reliable power, dense fiber, skilled workforce, tax regimes, and land—but anchor investments by hyperscalers or AI campuses could also accelerate the process. Policymakers should avoid treating projects as one-offs and consider the likelihood of a single facility snowballing into a larger cluster.

"Clustering" describes how data centers in the U.S. tend to collect in a handful of regions rather than being evenly distributed. Clustering creates stress for the bulk power system because it takes already energy-dense loads and adds even more load nearby. The easiest explanation for clustering is that it derives from favorable existing conditions: reliable electricity, dense fiber connectivity, neighboring trained workforce, supportive tax regimes, and land availability.

Large anchor projects also draw in more data center development: Once a hyperscaler or AI training facility establishes itself, it signals viability, brings new infrastructure, and lowers costs for additional entrants. Policymakers wanting to provide support for a big project by promises of jobs and tax revenue, risk underestimating the impacts of this attractive force as welcoming one project may quickly lead to a cascade of follow-on facilities, with both outsized benefits and mounting strains.[8]

Recent history reveals a pattern whereby anchor investments amplify favorable local conditions into enduring centers of digital infrastructure. Northern Virginia's "Data Center Alley" grew from early fiber and internet exchange into the world's largest concentration of data centers. Amazon Web Services (AWS) was an early and steady

---

[ii] A hyperscaler is a cloud service provider or operator that builds and manages massive data center networks supporting millions of virtual servers and petabytes of data, operating globally and designed to scale seamlessly across regions. Examples might include Amazon Web Services (AWS), Microsoft Azure, Google Cloud Platform (GCP), Meta (Facebook), Apple, Alibaba Cloud, and Tencent Cloud.

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investor in this cluster.[iii] Today, Data Center Alley reportedly handles roughly ~70 percent of the world's internet traffic, contains over 12 million square feet of commissioned data center space, and sustains hundreds of megawatts of power load.[9]. Reno's Tahoe-Reno Industrial Center became a global hub after Switch and Apple established major campuses, followed by Google and others[10]. Central Ohio offers a newer case: Google and AWS each invested in major builds, quickly attracting colocation providers.[11]. Atlanta and Phoenix look to be on similar paths[12].

In theory, diverse types of data centers should reinforce these patterns. Colocation facilities are drawn to network-dense hubs where they can maximize interconnection to other facilities. For example, enterprise servers might want to easily connect to multiple cloud providers—providers of cornerstone internet services stand to benefit from the reduced latency proximity affords, especially for content delivery like streaming video and games and so on. Hyperscalers could function as anchors, just like a department store in a shopping mall, investing billions into single campuses that create the vendor ecosystems others rely on. However, AI-focused facilities, with their unprecedented power needs, can also reshape the landscape by displacing other data centers competing for the same power network and generation resources.[13]

Electric power infrastructure both attracts and is stressed by clustering. Access to transmission lines and substations is a prerequisite, but as clusters grow, demand can overwhelm grids. Northern Virginia now faces multi-year waits for new hookups[14]. Reno's growth has raised water concerns and left Nevada utilities facing a potential doubling in necessary electrical infrastructure (also spurring them toward large renewable additions)[15]. Ohio illustrates the stakes most vividly: By March 2023, the utility AEP Ohio imposed a moratorium on new data center service agreements in Central Ohio, pending further study citing grid strain. Eventually regulators approved a new tariff[16] requiring data centers to pay for 85 percent of subscribed capacity whether it is used or not, with penalties for cancellation or under-performance and a four-year on-ramp[iv]. Clustering behavior can easily outrun planning and force regulators into reactive steps, introducing delays before more pro-active policies and tariffs can be put in place.

The policy lesson is not to avoid clusters—after all, they bring new jobs, tax revenue, and digital infrastructure—but to keep a skeptical eye on benefits claimed by developers and focus on smart planning. This should consider the multiple interests of stakeholders affected by a data center cluster and work in advance to align land use,

---

[iii] AWS is certainly not the only part of this story but has been called out as a major player. Dan Swinhoe, "The Amazon Factor in Virginia," Data Center Dynamics, November 6, 2024, https://www.datacenterdynamics.com/en/analysis/the-amazon-factor-in-virginia/. Amazon also touts its $51.9 billion investment in Virginia between 2011 and 2021 (capital + operations) in its data center infrastructure in Fairfax, Loudoun, and Prince William counties. Roger Wehner, "Learn About AWS's Long-Term Commitment to Virginia," Amazon, June 7, 2023, https://www.aboutamazon.com/news/aws/aws-commitment-to-virginia.

[iv] Under the decision, new data centers can access up to 50 percent capacity in the first year, 65 percent in the second, 80 percent in the third, and 90 percent in the fourth before getting full access to the grid.

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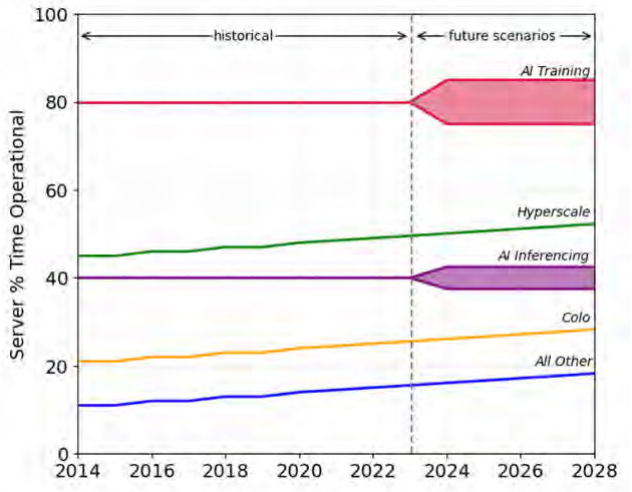
grid upgrades, generation, flexible loads, and permitting frameworks, ensuring that benefits can be captured without bottlenecks or backlash once clusters grow.

Data Center Feature 3: Consumption profile

Data center electricity usage is not steady or 24/7. Up close, it can be quite choppy and challenging. Batteries could act as a buffer—a keystone solution to managing power quality.

Figure 4 Server utilization by data center type. 2024 United States Data Center Energy Usage Report (LBNL).



Data centers exhibit considerable variability, especially going between operational and idle states. In Lawrence Berkeley National Laboratory's (LBNL) 2024 United States Data Center Energy Usage Report, the authors explain that in 2014 colos reported 21 percent utilization rates, hyperscalers 45 percent – rising to an estimated 35 percent and 50 percent respectively in 2027. The same report models AI learning centers and AI inferencing at 80 percent and 40 percent utilization rates, respectively. These don't directly translate into electricity consumption load factors because some electricity is used for other purposes like cooling that don't follow a 1:1 relationship with computing load.

Even looking at the whole power consumption profile of a data center, it's important to differentiate between actual load factor (the percentage of possible 24/7 full power use that a data center in fact uses) and availability (the percentage of maximum power a data center expects to have if it wants it, i.e., the *option* to use power). Whether power comes from on-site generation or from the grid, it needs to be prepared to provide power when the data center wants it, and back off when the data center doesn't.

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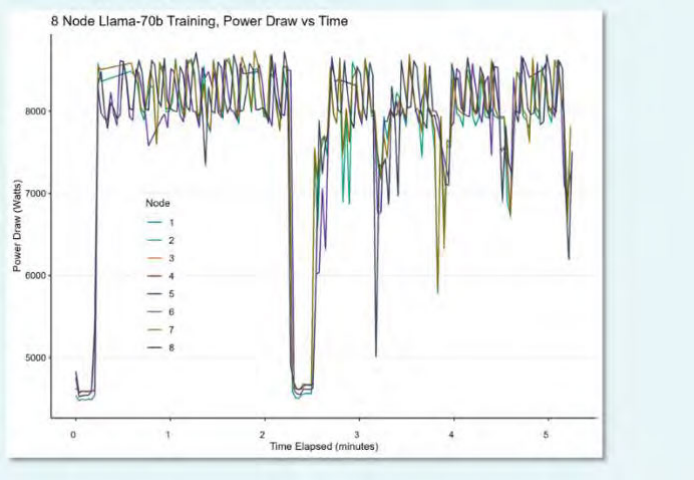
Figure 5 8 Node trace of power consumption in an AI learning cluster. 2024 United States Data Center Energy Usage Report (LBNL).



Big swings in data center demand will clearly be a challenge, even for the most flexible on-site generation. Given the scale at which many data centers operate, these swings can still create problems for large regional grids[v]. The CEO of Hitachi Energy reportedly commented "there can be swings of 200, 300 MW within a ten-minute period as data centers move from learn vs stop learn mode, and that these types of swings would not be acceptable from other grid customers."

At smaller time scales, large numbers of similar chips in one place switch on and off and can create an aggregate resonance effect[vi]. Existing electrical standards are inadequate for screening out these behaviors, and utilities may not have sufficient sensors to properly trace back issues to a particular data center. In aggregate, the evidence points to data centers deteriorating power quality metrics in their environs.[17]

More research needs to be done that focuses on new large digital loads, including variable generation resources with inverters that center around things like low-voltage ride through or fault clearing. For more information, context, and solutions on some of the challenges with interconnecting these large loads, see GridLab's recent Practical Guidance and Considerations for Large Load Interconnections.

Data centers are not a "perfect baseload" fit to directly couple with large mechanical generators or even the grid, and they will need significant electrical equipment to buffer this connection and prevent extra wear and tear on co-located generation or nearby grid users. Even if some data centers can learn to be flexible, incorporating battery energy storage, especially as the hardware cost decreases, will likely become a key element in managing data center impacts on the grid. When good wind and solar resources are available nearby, batteries can play a dual role in managing both load and generation variability at multiple time scales. Consider the Lancium Clean Campus in under construction in Abilene, Texas: "In addition to the 1.2 GW grid interconnection,

[v] See the GridLab report *Practical Guidance and Considerations for Large Load Interconnections*, with special attention to July 2024 Northern Virginia Data Center Event called out in Figure 1.2.
[vi] Some of these resonance issues can potentially be solved by on-chip energy management and storage. Rouslan Dimitrov et al., "How New GB300 NVL72 Features Provide Steady Power for AI," Nvidia, July 28, 2025, https://developer.nvidia.com/blog/how-new-gb300-nvl72-features-provide-steady-power-for-ai/?utm.

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Lancium's power plan for the site includes large-scale behind-the-meter battery storage and solar resources, which serve to ensure grid reliability, and economic and carbon optimization."[18]

Data Center Feature 4: Flexibility, or the lack thereof

Flexibility could be key to quickly connecting new data centers, especially those involved with AI learning. Managed demand is possible, but on-site batteries may be a better solution where split incentives or onsite needs make demand control too rigid or complex.

Data centers can be flexible, but different functions involve different levels of flexibility. This is probably hardest to achieve for co-location data centers because the third-party owner which interfaces with the grid and with utilities is not the one deciding what servers inside its facility are doing. Additionally, data centers are tasked with fluctuating sets of applications, creating uncertainty about how reliable or persistent demand management can be as a means of providing flexibility.

Data centers fully owned by large hyperscalers provide a higher degree of control over the whole facility. But the diversity of services being provided, often with low latency (response times) needs, may create constraints on what the hyperscaler can do. Hyperscale data centers provide both regular services—like AWS' cloud computing—and AI workloads such as inference, which involves answering client queries using pre-processed AI models.

For AI learning data centers, which create these large learning models, the goal is to cram as many chips as possible into the same square mile with the fastest internal connectivity so that the collection can operate as one big parallel machine[19]. Much of the possible flexibility here comes from adjusting the timing of computing batches, yet matching these adjustments to power supply flexibility needs is not a given, especially when considering that data center operators will want to prioritize computation over flexibility. This is a consequence of the relatively larger size of the capital investment in computing hardware versus energy generation and distribution for most applications.

Flexibility is a particularly important quality for data centers because they are such a large component of load growth, and just a little flexibility would reduce the need for new peaking resources and speed up interconnection[20]. A 2025 analysis[21] by the Nicholas Institute for Energy, Environment & Sustainability at Duke University finds that just 0.5 percent to 1 percent flexibility opens significant space on the grid: 98 GW of new load could be integrated at an average annual load curtailment rate of 0.5 percent, and 126 GW at a rate of one percent. This level of flexibility is similar to what is provided by demand-response programs that exist today for other loads, but as far as speeding up interconnection, it may be the AI-driven hyperscalers and learning centers, acting more directly under their owners' control and schedules, that can achieve more.

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AI loads are fundamentally more flexible than generic data center loads because they can be processed in batches, easily scheduled, and often internally orchestrated. For example, in a presentation[22] to the Texas grid operator Electric Reliability Council of Texas (ERCOT), the company Emerald AI demonstrated how it could implement flexibility at a data center. The company argued there is enormous potential to control AI data center load, and that "major hyperscalers are amenable to curtailing up to 25 percent for up to 200 hours in return for priority interconnection of 1 GW."

No one knows if any particular data center's operations will remain stable enough to guarantee a given level of flexibility or willingness to curtail over the lifetime of matching local grid upgrades. In some cases, the data center load can be flexible (willing to forgo some batches of work) but not exactly in the way that best serves the local grid. Some amount of local battery energy storage (providing multiple value streams like integrating local on-site variable energy, backup, and power quality services) could also help data centers be more flexible at their grid interface, especially those with less direct control over internal processes.

Data Center Feature 5: Backup needed for disturbances and outages

Most data centers require backup. Demand flexibility and short-duration batteries can either eliminate or lighten the load for traditional backup solutions.

Many data center customers aspire to high availability—as much as 99.999 percent uptime—hence the need for backup power to take over in case of any grid failure. The Uptime Institute, a widely followed source for industry tier certification in data center design, build, and operations,[23] defines four reliability tiers (I through IV) with increasing expectations for performance under challenging conditions, with an eye towards worst-case scenario planning. Many data centers serving enterprise needs require at least a Tier III level of reliability, either because of a direct need, like maintaining accessibility to data under adverse conditions, or as a proxy for operational trustworthiness. For mission-critical operations—major banks, stock exchanges, the military, or hyperscalers serving global customers—a Tier IV level of availability may be required.

Because Tier III and Tier IV facilities require 72 and 96 hours of on-site power capacity, respectively, simple economics dictate that backup is usually in the form of diesel generators with fuel storage on-site. Batteries can also be used to help ride-through disturbances in power supply,[vii] providing faster response times and reducing fuel and maintenance expenses on diesel. However, with today's technology, battery energy storage systems (BESS) that can cover critical needs for three to four days are not

[vii] In current facilities, this ride-through comes via the uninterrupted power system (UPS) usually provided by old-school lead-acid batteries, but modern lithium-ion battery energy systems can provide these services along-side the bulk of backup power needs.

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economically feasible, especially without some form of on-site generation to sustain their state of charge.[viii]

However, diesel does not scale well: As data centers get much larger, massive tank farms for the generators' on-site fuel require complex fire protection, spill containment, and environmental risk mitigation. Furthermore, many air districts (e.g., Virginia, California, or Oregon) place strict caps on generator run time and cumulative emissions in a site or region. Placing more than a hundred diesel generators on one site creates a cumulative permitting challenge and may well face serious local resistance along with the prospect of delays or outright rejection from regulators. Somewhat cleaner gas generators (turbines[ix] or reciprocating engines) are usually connected to a pipeline and require large propane or liquefied natural gas storage facilities to satisfy on-site capacity requirements.

Some large hyperscalers are opting to target better up-time based on statistical estimates rather than explicit proxies for reliability. For example, Microsoft has publicly committed to reducing the use of diesel generators by 2030. To that end, it contracted with Saft, a subsidiary of TotalEnergies, to install four battery energy storage systems, each in groups of four megawatt hours (MWh) and capable of 80 minutes of on-site power, to replace diesel backup.[24] In the U.S., Microsoft's newest Azure region in San Jose, California is also being built diesel-free, but is using natural gas turbines for backup (plus batteries for ride-through). In general, the U.S. grid is quite reliable, with the one-in-ten reliability standard[x] mostly achieved at the transmission service level.[xi] Most outages that do occur are less than one or two hours, so a battery can carry enough of the backup burden to get the facility to a high level of reliability while hardly, if ever, using on-site generation.

As longer-duration storage solutions like Form's 100-hour battery [25] or thermal batteries[26] connected to local renewables and steam turbines in local energy parks[27] emerge, data centers will be able to free themselves from fossil fuel backups while taking advantage of integrated design to combine multiple uses of batteries for flexibility, power quality, and backup.

[viii] To see how this is done in detail, see the NREL Vulcan platform demonstration in collaboration with Verrus. Deepthi Vaidhynathan et al., "Vulcan Test Platform: Demonstrating the Data Center as a Flexible Grid Asset" (National Renewable Energy Laboratory, June 2025), https://www.nrel.gov/docs/fy25osti/94844.pdf.

[ix] Although gas turbines face significant supply chain cost and delivery challenges currently. GridLab, *Gas Turbine Cost Report*, https://gridlab.org/gas-turbine-cost-report/.

[x] The one-in-ten reliability standard is a standard that applies for the bulk power system (i.e. transmission level) requiring transmission planners, system operators and reliability planners to aim for nor more than one "event" of involuntary load-shedding in ten years. If one "event" was 24 hours, that is already 99.97 percent up-time.

[xi] Actual recent figures for grid performance are quite good (see table 1.1). North American Electric Reliability Corporation, *2024 State of Reliability*, June 2024, https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2024_Technical_Assessment.pdf.

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Data Center Feature 6: Modularity—data centers are built in phases

Data centers expand in discrete phases, from racks to halls to entire campuses, with uncertain demand and rapidly rising power density. This modular growth pattern matches well with the modularity of renewables-plus-batteries deployment, which can be built in parallel to meet incremental load without the risks of lumpy firm power investments.

For utilities and data center developers, timing capital investments can be challenging. Matching these investments with energy supply for their increasingly electric power sub-components compounds the challenge. Building a new data center means committing to constructing a large building and grid capacity without knowing if consumers will come, how quickly they will deploy, or how their consumption will evolve over time. Tenants in a co-location situation, hyperscalers, and AI data centers may not immediately have all the chips available (or face some other bottleneck) so may want to deploy in phases: slowly building up electrical demand over time until reaching full capacity, if all the anticipated demand materializes. With a chip service life of around two to three years, the balance between increased efficiency and increased computing power may mean newer chips could either increase or decrease electricity demand in each physical asset footprint.[xii]

The digital world's infrastructure is itself modular—built from discrete, substitutable units. Data centers are not just abstract systems of bytes and tokens; they are also collections of tangible components: chips, servers, and, above all, racks. The rack is the main unit of reference: a cabinet holding multiple slender servers or "rack units." Racks are grouped into "pods" of 20–30, and an enterprise client might deploy a couple of pods at a time in either a dedicated or co-location facility. Some tenants lease only a handful of racks in a shared space, while hyperscalers may build entire halls of 200–400 racks, with multiple halls forming a single phase of expansion on a large campus[28].

The modular nature of data centers lets developers manage financial risk by building in phases, with the option to add new capacity quickly but in a planned way. Each phase, however, carries high stakes not only in capital cost but also in power demand. A 2024 Uptime Institute report[29], states finds that four- to six-kilowatt (kW) racks remain common, with a trend towards higher consumption today. Meanwhile, AI applications and high- performance computing are pushing the development of liquid-cooled racks with incredible increases in power density. Vertiv, an Ohio-based company that designs, manufactures, and services critical infrastructure for data centers, reported in its 2024 Investor Event Presentation[30] that extreme rack densities already reach 250 kW

[xii] This is certainly a question in flux. Google has reported that over a recent 12-month period, the energy footprint of the Median Gemini Apps text prompt dropped by 33x! At a given facility this can be achieved by increased throughput or reduced energy use, or both. Amin Vahdat and Jeff Dean, "Measuring the Environmental Impact of AI Inference," Google Cloud, August 21, 2025, https://cloud.google.com/blog/products/infrastructure/measuring-the-environmental-impact-of-ai-inference.

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per rack today and could exceed one MW within five years. That means a space the size of a bedroom closet could consume more power than a thousand average homes. As a result, a single phase of development for a data center might range from on the low end at 250 kW (two-dozen at 10–12 kW per rack) on the low end to 250 MW at the high end (a 1,000 liquid-cooled 250 kW racks) at the high end, with extra overhead for cooling.

The extreme end of data center development is exemplified by data center developer Vantage's recently announced plans [31] to build its $25 billion Frontier campus situated on 1,200 acres in Shackleford County, Texas, with an eventual total consumption of 1.4 GWs—close to average total consumptions of the states of either Rhode Island or Delaware. And this project is not alone: a September 2025 ERCOT staff report[32] to ERCOT's board details 130 GW of non-crypto data center load in the interconnection queue through 2030.[33] In the last few years, Texas has met new additional load with new, mostly clean generation. Of the 428 GWs of generation requests as of August 31, 2025, 204 GWs are for wind and solar and 180 GWs are for energy storage (together 90 percent of all requests).

Data center development may come in all levels of power consumption. However, because developers rarely build, install, and commission data centers in a single phase, projects of all sizes need a power supply that can grow and expand with them. When covering the incremental energy demand from a new data center, a large new single firm resource is an unwieldy indivisible capital investment. A modular approach with renewables plus batteries reduces risk and provides better economics: You're not committing to a single lump-sum investment in a 500 MW gas turbine; you can phase investments, optimize based on real usage, and spread spending—and risk—over time.

With computing loads that grow unevenly, modular investments let operators respond dynamically—deploy more solar, wind, or storage as AI racks come online. As a bonus, you can avoid supply chain bottlenecks because incremental installation bypasses the big lead times and equipment backlogs associated with large generator orders, enabling continuous expansion without project delays. Just as data centers grow in discrete steps, modular renewables and batteries let the grid grow in parallel.

These six features highlight why data center demand is complex, not just a flat, 24/7 block of constant load. We now turn to how supply options can, and cannot, match this demand.

THE BEST WAY TO MEET DATA CENTER DEMAND IS DIVERSE RESOURCE PORTFOLIOS

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When thinking about how to supply new demand from the rapidly growing data center industry, the key point to remember is **one-to-one matching with "firm" resources will not "solve" the load growth needs from data** centers.

In this section, we explain why single, stand-alone generation resource matching for any given industrial load has rarely been the historical course, and how and why that might change. We then describe the three resource buckets that new data center projects need to acquire to use the existing bulk power system. Finally, we discuss how the data center demand features described in the preceding section create further challenges and barriers in acquiring these resources.

Debunking the one-to-one matching myth

If you imagine data centers as large capital assets running power through expensive electronics 24/7, it seems natural to imagine a dedicated "captive" 24/7 power plant built to match this demand, with historical precedent for this one-to-one matching. For example, in the post-war era aluminum producer Alcoa built smelters near cheap grid sources of hydropower in New York and the Pacific Northwest along with captive coal plants in Indiana and Texas to feed the company's aluminum smelters and mills. Today, industrial facilities use on-site combined-heat-and-power (CHP) plants to consume both the electricity and waste heat from fuel-driven power plants to operate industrial facilities with high end-use efficiency, and thus lower energy costs. According to the U.S. Energy Information Administration's (EIA) latest Manufacturing Energy Consumption Survey from 2022, U.S. manufacturers produce around 17 percent of their electricity needs on-site (Table 11.1) and that on-site generation is 97 percent co-generation (Table 11.3).[xiii]

Single plants may not "play nice" with data centers

The demand characteristics of data centers described in the prior section raise immediate concerns regarding matching a captive plant with a data center. For example, while a data center may want 24/7 availability, its actual consumption will ramp up and down significantly with a profile that a large, single on-site generator might struggle to meet. Many fossil generators have a minimum dispatch level they cannot fall below, and "ramp rates" limits dictate how quickly they can adjust up and down. Furthermore, a modular, phased build-out does not lend itself to a single matching resource because in order to provide sufficient power for the full buildout,

[xiii] This survey defines co-generation as "the production of electrical energy and another form of useful energy, such as heat or steam, through the sequential use of energy. Cogeneration includes electricity generated from fossil fuels, such as natural gas, fuel oils, and coal; wood; and other biomass." In practice, the steam/heat is the main other energy output, so co-generation is often used as synonymous with CHP.

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the single resource would have to operate at lower, inefficient, dispatch levels during earlier phases of data center construction and operation.

Beyond a mismatch with the demand characteristics of data centers described in the prior section, there are additional reasons to question using a captive plant as a 1-1 match for a data center.

Captive power plants are not highly reliable alone

Table 4 from the North American Electric Reliability Corporation (NERC) 2024 State of Reliability Overview [34], shows the recent weighted forced outage rate (rate of unexpected failure) was 11.7 percent for coal, 7.7 percent for gas, 6.4 percent for hydro, and 2 percent for nuclear. Another relevant consideration is planned maintenance, like cleaning out coal boilers, maintaining and inspecting gas turbines, or refueling nuclear plants every 18-24 months.[xiv] This means a single supposedly "firm" plant will be unavailable for a double-digit percentage of time—not what data centers are looking for.

If an industry is set on self-supply, one strategy is to over-supply generation. Alcoa's Warrick, Indiana aluminum smelter and mill built three captive 144 MW coal plants alongside a 300 MW coal unit shared 50/50 with the local utility Vectren. With a total capacity of 732 MW but serving a local load of 550 MW,[35] the facility was clearly resilient to losing one unit and still running. But this effectively meant carrying 25 percent more capacity than necessary, without a guarantee of full reliability. Alcoa mitigated this extra cost by selling excess power to the grid and importing power from Unit 4 or the broader grid when necessary. This illustrates the general case that a grid connection remains both a sink for surplus and an important backup option; most on-site power is not fully independent and large loads will still want interconnection to the bulk power system. In fact, payment for grid backup (usually called "standby rates") is a common feature of CHP tariffs.[36].

What happens when the power plant is no longer needed?

An interesting postscript to the Alcoa Warrick plant story is that Alcoa announced it would shut down its aluminum smelter in 2016 (although it had partial restarts post 2018) because of poor market conditions [37] and transferred major rolling mill and finishing operations to Kaiser Aluminum in 2021.[38] It is now left with an unattractive coal generation asset, whose generation capacity now exceeds Alcoa's local demand and

[xiv] This is on average a 32-day process. Aaron Larson, "Planning Is Key to Successful Nuclear Refueling Outages," POWER Magazine, September 1, 2023, https://www.powermag.com/planning-is-key-to-successful-nuclear-refueling-outages/.

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will likely struggle to sell surplus capacity in the broader power market along with most coal assets,[39] which comes with significant environmental remediation liabilities.[xv]

This is always the risk with a captive power plant: One day the load will vanish because of changing economics. Investors will want to know if Plan B exists and that the captive plant is in and of itself an attractive asset with a bright future.

Co-location of prime power generation assets with data centers today

Grid bottlenecks create considerable talk about co-locating "prime power" generation[xvi] with new data centers. This might include leveraging existing nearby assets (for example, the Talen-Susquehanna deal which co-locates a data center next to a nuclear plant[40]), restarting mothballed generators, or building new on-site resources (such as gas plants). But these arrangements are not true one-to-one matches of generation with load, since they still depend heavily on a grid connection for full functionality, sometimes at the expense of other consumers.

For example, in the Talen-Susquehanna deal, the data center is physically adjacent to a pair of nuclear units. It is unlikely the units' output will ramp precisely in step with data center consumption. Therefore, matching local supply with demand creates net output—nuclear output minus on-site data center consumption—variability which must be managed by the grid operator. During the refueling of one nuclear unit, the other must pick up the data center load, thereby reducing exports to the grid. In effect, the grid acts as backup.

Hybrid arrangements using on-site power together with the grid can address bottlenecks. They combine physical and financial hedges. The Talen-Susquehanna deal, for instance, was eventually reshaped into a power purchase agreement after regulatory push-back.[41]. These hybrid deals share many of the properties—and many of the drawbacks—of other on-site generation deals discussed above.

If land is available, the best way to provide on-site prime power is not with a single firm resource but by using an energy park[42] with renewables and batteries, with backup from longer- duration storage and/or gas generators.[43] Then most of the generation is

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In 2024, Sierra Club and Environmental Integrity Project intervened in a case against Alcoa Warrick for "100+ permit violations" in 2022 and 2023, including releases of mercury, aluminum, chlorine, copper, fluoride, nickel, and zinc into the Ohio River. Environmental Integrity Project, "Groups Intervene in State Action to Stop Aluminum Smelting Plant's Illegal Dumping of Heavy Metals in Ohio River," February 21, 2024, https://environmentalintegrity.org/news/groups-intervene-in-state-action-to-stop-aluminum-smelting-plants-illegal-dumping-of-heavy-metals-in-ohio-river. There are also lingering questions regarding compliance for Warrick's "ash ponds" under the Environmental Protection Agency's Coal Combustion Residuals rules. Hoosier Environmental Council, "Today's EPA Action Means More Coal Ash Cleanup for Indiana" (press release), April 25, 2024, https://www.hecweb.org/wp-content/uploads/2024/04/PRESS-RELEASE-Todays-EPA-Action-Means-More-Coal-Ash-Cleanup-for-Indiana.pdf.

[xvi] Prime power is the continuous everyday power that powers the data center, as opposed to backup power There is also "bridge power" which is local generation which acts as prime power until a grid connection is put in place, and then becomes either backup or just a part of the supply portfolio.

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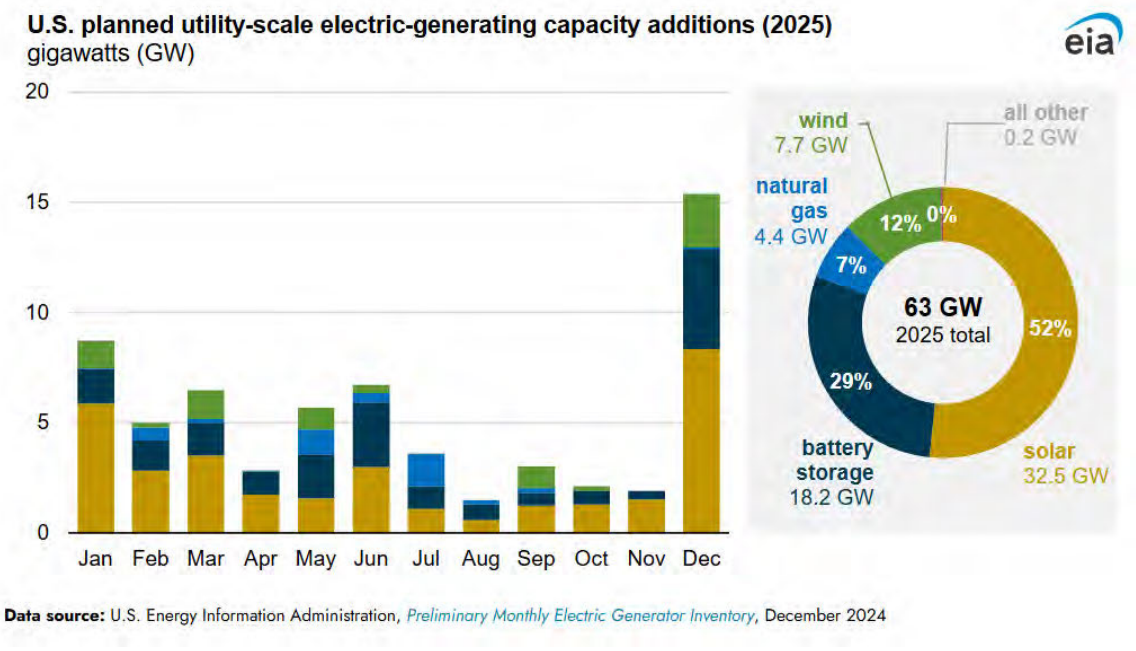
clean, faster, and cheaper to deploy than other generation and helpful for hyperscaler emissions commitments. In addition, the combined resource is more reliable, with fewer large points of failure than a handful of fossil units – a good Plan B if load never fully materializes or decreases. Included energy park resources would reflect a microcosm of trends in the wider U.S. market where the large majority of generation coming online[44] and waiting in interconnection queues are renewables and batteries.[45]

Figure 6 Solar, battery storage to lead new U.S. generating capacity additions in 2025. US EIA.



Data source: U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory*, December 2024

Providing new electricity supply for data centers from the bulk power grid

Given that most data centers will need to get some, if not all, of their power from the bulk power system, it is helpful to review how large commercial or industrial loads do this. The power grid is a system of systems including physical transmission and distribution poles and wires, the generation and loads they connect, operations and dispatch, power markets, and power purchase agreements.

As soon as a large new load decides to connect to the bulk power system, its needs can be disaggregated and met in many ways.

The grid resources a new data center project must collect to successfully draw from the bulk power system fall into three broad buckets: connection, grid services, and bulk electricity.

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New large data centers will require connection and network upgrades

How data centers connect to the grid depends on their size: scale matters. Smaller enterprise and co-location data centers (tens of MW or less) will often connect to a distribution system's high-end network (i.e., somewhere between 13.8 and 69 kilovolts) and may tie into an existing distribution substation with a new feeder. The utility typically owns and operates the primary substation equipment, while the data center customer owns the step-down transformer to its facility. The local utility conducts the impact studies and plans local upgrades to ensure compliance with NERC standards. Too many connections in the same area may trigger transmission upgrades and inclusion in transmission planning studies. In some geographies, like Virginia, this may involve an independent system operator (ISO) such as PJM [xvii] in planning and approving upgrades.

Larger data center campuses will have their own complex internal grid that connects directly to a bulk power system transmission substation. The data center must file a large load interconnection request with the local transmission owner or ISO. Tariffs and agreements will include matters like covering study costs, equipment ownership, and who pays for upgrades. The state may also require approvals for siting, environmental review, and cost recovery. The connection process can become long and painstaking once local capacity on the grid becomes tight. In Virginia's Dominion utility territory, data centers larger than 100 MW face up to a seven- year wait for power hookups.[46]

One important feature of new connection costs is that they are usually covered by the new load because cost causality is clear. Unfortunately, this may not hold true for more upstream transmission impacts where transmission upgrade costs are traditionally socialized more widely. A recent Natural Resources Defense Council (NRDC) report[47] tells the story in PJM: "Tight supply conditions led PJM to approve a $5 billion transmission expansion project to meet new data center demand in Virginia, where data centers already account for around a quarter of the state's electricity demand. The costs for this project were distributed by the Federal Energy Regulatory Commission (FERC), PJM, and utilities using varying cost allocation methods. Maryland residential customers were left with a bill of approximately $330 million, and Virginia residents had to foot $1.25 billion for transmission designed largely for a handful of data center customers in only a small region of the state."

Data centers create new stresses on a bulk power system planned around peak demand; they also consume other grid services

The main grid service data centers require regardless of size is peak capacity: the ability to serve up to their maximum interconnection rating during periods of system peak.

[xvii] Also referred to as a regional transmission operator, PJM covers 13 states in the mid-Atlantic and is one of the largest power markets in the world.

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Going back to PJM (often a source of current examples because it already serves so many data centers), the ISO's board chair communicated about future reliability concerns because: "PJM's 2025 long-term load forecast shows a peak load growth of 32 GW from 2024 to 2030. Of this, approximately 30 GW is projected to be from data centers."[48]

PJM's conundrum is how to keep the grid reliable as data center demand grows faster than new generation. Its "non-capacity-backed load" proposal would classify very large new loads (less than 50 MW) as customers outside the capacity market.[49]. The idea is to avoid shifting costs to others, but critics say that the 50 MW cutoff is arbitrary, curtailment rules could distort market signals, and contract and siting decisions may be disrupted.[50]. PJM is still debating whether the non-capacity-backed load should be voluntary or mandatory in shortage zones before filing at FERC for the 2028/29 delivery year.[51]

One challenge with resources like peak capacity is that once a project has been approved for interconnection, been built, and paid its share of costs, it becomes a load like any other. At that point, it is very difficult for the market to discriminate against it without creating efficiency concerns or legal risks. Data centers do more than strain peak supply; like all large loads with some variation, they also draw on ancillary services and other grid management resources.

If incremental demand is not met with increased supply, prices and emissions will rise

As the recent Nicholas Institute report[52] points out, some amount of flexibility from data centers could significantly reduce costs and delays associated with connection and peak demand constraints from new data centers. The report estimates peak load bottlenecks could be avoided for around 100 GW of so-called "curtailment-enabled headroom" on the U.S. grid. However, even if data centers avoid consumption during the most problematic hours, they still need power the rest of the time. Absent new supply on those same grids, the extra generation available off-peak will be from more expensive, and typically dirtier, marginal generation units.

Data centers' need to draw most of their power from existing units is thus a problem for other electricity customers because absent new matching supply, it will drive up their wholesale electricity costs. It is also problematic for the data centers themselves, which frequently are tied to corporations that have carbon reduction goals which are incompatible with increased emissions from existing fossil power plants. Conversely, new supply (especially cheap and clean supply) arriving quickly enough to offset data center consumption without requiring a large amount of new grid infrastructure creates potential for "beneficial electrification[53]" where more power over the same wires reduces other consumers' costs[54].

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Further consequences: Challenges and barriers specific to data centers

Connecting large new data center loads through the lens of three resource buckets faces three broad challenges required by all such loads. But these resource buckets also interact with the six more specific data center demand characteristics outlined in the preceding section.

Connection challenges specific to data centers

Because the source of many connection issues—or at least more expensive upgrades—come down to a limited set of hours and circumstances, flexibility is often cited as a master key for easing or speeding up connection. But flexibility is not always as simple to implement as first imagined, and other connection challenges specific to data centers are not necessarily circumvented with a touch of flexibility.

- **Agency:** Especially for co-location data centers, the operator is stuck between wanting to be more flexible to satisfy grid constraints and the imperative to be as generic as possible in contracts with tenants to accommodate as broad a class of customers as possible. Typical quality of service and service-level agreements also act as a barrier for to tapping flexibility.[55] Intervenors in public utility cases also question whether policies for ensuring new data centers cover all their incremental costs are effective[56].
- **Clustering:** Clustering leads to many data centers on the same part of the grid, necessitating more upstream transmission upgrades, as in the Virginia case mentioned cited by NRDC, mentioned above.
- **Consumption profile:** Big swings in power demand and power quality impacts on other consumers make data centers trickier for utilities and transmission providers to study and interconnect than simple 24/7 constant loads. Standard protection schemes and the collective behavior of 60 data centers recently caused a large reliability problem in Virginia in July 2024 when these data centers all dropped off the grid at once and caused a sudden surge in excess electricity that strained grid resources.[57]
- **Flexibility:** Some data centers are not flexible at all; others could be flexible but not in a manner consistent or predictable enough to satisfy the engineers running interconnection studies. These engineers are only likely to be satisfied after adding sophisticated energy management systems and large batteries, along with the promise of judicious backup power.
- **Backup:** As mentioned, backup power could be leveraged to facilitate connection or provide so-called "bridge power"[58] for data centers that cannot wait for interconnection. Unfortunately, backup power (used either for

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flexibility or bridge power) tends to be dirty, leading to siting and local community environmental concerns.[5960]

- **Modularity:** With a modular or phased build-out, a data center may ask up front for a large enough connection to accommodate all future phases, leading to stranded asset risk if all phases do not materialize.

Grid services challenges specific to data centers

Just as for solving connection issues, flexibility can help tamper the impact of new data centers on system-wide needs like peak capacity issues. A large overlap exists between local grid and larger grid issues with peak planning. However, as described in the prior section, flexibility is not always easy to implement or deploy in a manner which solves all challenges. Furthermore, the specific features of data centers tend to create additional challenges beyond help from simple load flexibility measures.

- **Agency:** Utilities often see new fossil resources like gas peakers as the easiest way to resolve new peak demand issues from data centers.[61] Because gas turbines are increasingly expensive, this may not be a good deal for other utility customers and may also entrench future emissions, working against many data center providers' and host states' clean power goals. Because eventual data center owner/operators tend to build where developers have prepared the ground, the fact that these developers may perceive emissions goals as secondary to "speed-to-power," and that utilities choose their own procurement path creates an agency mismatch.
- **Clustering:** The clustering of data centers tends to amplify their effects on the regional grid, with sharper surges in demand for grid services that cannot be accommodated fast enough through new resources builds.
- **Consumption profile:** While data centers don't run all the time, they plan their infrastructure for peak computing demand. This creates a knock-on effect for the bulk power system, which plans for peak power demand.
- **Flexibility:** Flexibility is not always a simple feature to implement or deploy.
- **Backup:** On-site backup power is a poor substitute for system resources because of expense as well as siting and local environmental concerns.
- **Modularity:** While the broader grid is in a good position to adjust to a phased build out of data center demand, this requires either coordination with the local utility or strong forward signals in the market to avoid disruptive demand shocks for grid services.

Bulk electricity challenges specific to data centers

Certain subcategories here (consumption profile, flexibility, modularity) concern time domains that do not apply when considering total annual consumption.

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- **Agency:** As with grid connection and services, intermediate entities between electricity provisioners and data center owner/operators with emissions goals may not consider the environmental impacts of reliance on using spare capacity from existing marginal resources.
- **Clustering:** Clustering means more annual electricity drawn from the same grid. This creates a greater need for new supply, amplifying the problems of price and emissions increases.
- **Consumption profile:** A variable but not necessarily predictable profile for large data center loads could create new challenges for grid operators, even at off-peak times.
- **Flexibility:** Data center demand flexibility could potentially alleviate emission concerns by targeting off-peak consumption more towards time periods with lower marginal emissions. This requires an extra layer of control on top of whatever that data center might have already committed to ease grid connection and mitigate impacts on grid operational resources.
- **Backup:** Supplying too much of the actual annual electricity use from backup power creates problematic environmental impacts.

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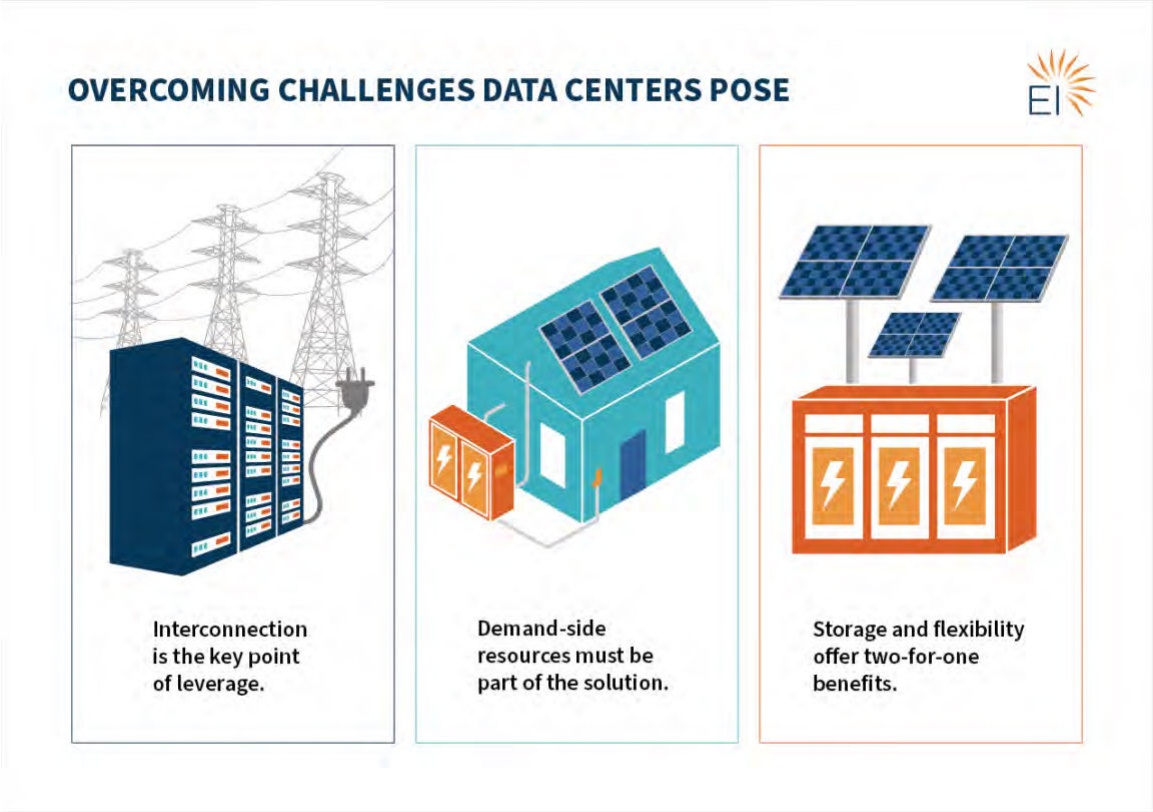
TAKEAWAYS FOR POLICYMAKERS AND OTHER STAKEHOLDERS

Figure 7 Three key takeaways



Many organizations (Clean Air Task Force/Brattle,[62] GridLab,[63] NRDC,[64] the Bipartisan Policy Center,[65] and the Regulatory Assistance Project[66]) have provided detailed and useful guides for coping with the challenges of meeting new data center loads.

This section distills the key lessons from the features and challenges discussed above.

Interconnection is the key point of leverage to influence when and how data centers join the grid

Accommodating large, dense new loads affects every grid participant, and the challenges show up at multiple scales. Geographically, they range from the substation where the data center connects to the entire interconnected system. In time, they span from sub-second transients to hours of local and bulk stress to the accumulation of annual demand.

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When issues are tied directly to a data center's load or its immediate connection, cost-causation principles are easier to apply. But at larger scales, like meeting new annual demand or rising peaks across a region, the problem is less about the nature of data centers than the pace and size of their growth. At that point, they can reasonably argue for being treated like any other customer buying power "at the pump," without special obligations.

This tension is what policymakers need to keep in mind. Interconnection is the moment of maximum leverage: not to extract unreasonable concessions, but to ensure new entrants cover the infrastructure costs they trigger, and to nudge them toward implementing solutions like flexible demand or local storage that relieve local bottlenecks and support the broader grid. Likewise, developers and customers should lean toward local fixes that speed access to the grid, improve power quality, and ease broader impacts—reducing the likelihood of being saddled with extraordinary requirements later.

Using other demand-side resources

In one of our earlier reports on meeting the load growth challenge,[67] we pointed out the importance of using demand-side resources to meet this challenge most efficiently. Often the discussion of demand-side solutions focuses on direct measures at a data center, especially in the wake of the efficiencies revealed in the DeepSeek announcement.[68] However, data centers can meet their resource needs with other demand-side resources elsewhere on the grid. Recently, Voltus, an aggregator of distributed energy resources (DERs), announced a deal with Cloverleaf Infrastructure—a data center developer—to meet new capacity needs from data centers with market-accredited capacity from DERs.[69] This kind of transaction compensates other existing customers and thus helps accommodate the rapid rise of data center loads fairly, speedily, and equitably. Since connecting to the grid can involve mixing and matching resources to relieve bottlenecks, once a data center has invested in the flexibility and extra equipment needed to resolve local connection issues, there is no reason why more upstream connection issues, grid services bottlenecks, and the need for a large amount of annual electricity delivery cannot be resolved with demand-side solutions from other grid users.

A recent Rewiring America report proposes many of the resources to meet data center load growth could come from sponsoring household upgrades.[70] The report finds that if hyperscalers paid 50 percent of the up-front cost of installing heat pumps in the tens of millions of U.S. households that currently use inefficient electric heating, cooling, and water heating, they could free up a total 30 GW of capacity on the grid. In addition, if hyperscalers paid 30 percent of the up-front cost of rooftop solar and storage in every single-family household in the U.S., they could add 109 GW of capacity on the grid. The cost of these upgrades would be comparable to the report's estimate of $315/kW-year to build and operate a new gas power plant.

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Storage and flexibility relieve data center challenges; they can also ease interconnection of new variable renewables

On-site prime generation solutions built around renewables and flexibility (modulating demand and using batteries) may provide cheaper, cleaner, and faster means for meeting new and existing data center demand. Because batteries are increasingly essential for buffering, backup, and power quality, they also provide a built-in solution for integrating variable renewables—offering a two-for-one advantage.

Furthermore, these renewable-plus-battery solutions can take advantage of existing surplus interconnection[71] to more quickly connect data centers to the grid in "power couples."[72]

By exploring the nuanced solutions, policymakers can avoid overcommitting to outdated firm resources and instead adopt strategies that embrace modularity, flexibility, and clean energy. Doing so will support both the digital economy's explosive growth and the clean energy transition.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-46:
R Street Institute Commentary: DOE "Zombies" Are Eating
Competitive Power Markets

REAL SOLUTIONS

Low-Energy Fridays: DOE "Zombies" Are Eating Competitive Power Markets

BY MICHAEL GIBERSON

ISSUES: ELECTRICITY POLICY, ENERGY AND ENVIRONMENT

NOV 13, 2025

This past May, the U.S. Department of Energy (DOE) used emergency authority to stop two scheduled power plant retirements. As we explained in July, these emergency orders are not a good way to boost grid reliability. That's not the only problem, though—the DOE's emergency orders also threaten to undermine competition in regional power markets.

The case invoked Section 202(c) of the Federal Power Act, which limits most orders to just 90 days. The DOE used this law to block the coal-fired J.H. Campbell Power Plant in Michigan and two units at the gas- and oil-fired Eddystone Generation Station in Pennsylvania from retiring. When those 90-day orders expired in August, the DOE issued new orders to keep the plants online. When these orders expire later in November, the DOE is expected to order the plants to stay online for *another* 90 days. Both currently operate with a safety net: If they lose money, the law makes area consumers cover those losses. And with losses covered no matter what, the plants have little reason to run efficiently. The result isn't grid reliability—it's creeping zombification of the market.

Markets require profits *and* losses to steer investment where it's needed (and away from where it's not). When a unit can't cover its costs at market prices, it should retire. When older, inefficient plants exit, space opens on the grid and in the market for better resources to jump in. Prices may initially rise, but consumers benefit in the end as competition grinds down average costs. Serial "emergency" orders break the economic feedback loop and undermine competitive forces.

The DOE's decision to keep two fossil-fueled power plants running raised speculation that the administration would block any fossil-fueled plant from retirement. However, a New Hampshire coal unit retired in October without federal intervention. That's good, because a plant that doesn't contribute to reliability and energy supplies at a competitive price *should* retire. But the lack of clear policy heightens uncertainty.

The economic damage shows up in three places:

- **Crowding out.** When zombie power plants are ordered to stay in the market, customers are stuck with the bill from any losses. Market revenues that would support efficient resources get skimmed by units the market has already rejected. The effect is subtle but

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important: Energy market prices flatten, clean and firm resources see less upside in tight hours, and generation turnover slows.

- **Planning.** Reliability planning depends on credible schedules—retirements that can be believed, new power plants that can be counted, and rules that don't change unnecessarily. A plant yo-yoing between "retired," "ordered to run," and "maybe extended" in 90-day increments can't fit into long-run reliability plans.

- **Policy-driven uncertainty.** States and stakeholders are suing the DOE over the emergency orders because the law is being employed in a manner different from what Congress intended. The DOE has not articulated a clear policy for how they will use their authority in the future, which leaves plant owners and potential investors in the dark.

Emergency orders do have their place. If a hurricane hits, fuel freezes, or a wildfire takes out a major power line, use 202(c) for the days or weeks necessary and then stand down. Utilities regularly ask for these emergency orders when they need them. The difference with zombie plant orders is that neither the plant owners nor the grid operators responsible for reliability in their regions requested them.

Nothing in this discussion denies reality—demand for electricity is rising, interconnection queues are clogged, and grid operators face tough winters and hot summers. The way forward is in policies that make better use of the existing grid, drive economical additions to transmission infrastructure, and let market forces drive power plant entry *and* exit. Competitive power markets are not responsible for rising electricity rates; in fact, a recent study pointed to increased spending on transmission and distribution wires as key factors in driving up customer rates.

Should the DOE continue to undermine market competition, consumers may get hit with the double-whammy of rising energy costs and rising infrastructure spending. Zombification of the electricity industry is no way to support a reliable, efficient power system.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-47:
Palgrave Handbook

The Palgrave Handbook of International Energy Economics

Edited by Manfred Hafner · Giacomo Luciani

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rotating standby state through the advanced control system, and the gas turbine is quickly started with load, and the power is immediately transmitted to the power grid.

3.4 Location

Coal power generation location is more restrictive compared to other technologies because coal is a solid and its transport cost is high, while its combustion efficiency is lower than for other technologies. Usually coal plants are located near coal mines and the choice of different means of transport will affect the location of the plant area as well as the size and form of the required land plot, especially for a large power plant. The transportation mode should allow for large volume, low freight, high speed, and flexibility, which will make the location of coal plant all the more difficult.

On the contrary, oil is easy to transport with multiple transportation options including by pipeline and by ship; therefore, oil-fired plants are usually located in coastal areas. A gas-fired power plant is characterized by little land occupation and is very suitable for countries and areas with dense population and scarce land resources. Compared with coal-fired power plants, gas power generation equipment is more compact and does not occupy a large area. Besides, it consumes one-third of the water needed for a coal-fired power plant.

3.5 Expected Service Life

Thermal power plants are designed for an economic lifetime of 30 to 40 years, but some plants have been also used beyond their design life in certain areas. The critical components are the boiler and the turbine. The operation of thermal power generation is faced with both tangible and intangible aging processes. Tangible or physical aging refers to the equipment operating under high pressure and temperature, and bearing mechanical stress, resulting in physical and chemical changes, such as wear, creep, corrosion, and so on, gradually making the equipment unable to continue operating safely under the required design parameters. Invisible aging refers to technological progress. The advent of more efficient or less labor-intensive production equipment means that older equipment will operate under less and less economic conditions. The physical aging of some equipment (such as condenser copper pipes, heater pipes, boiler heating surface pipes, turbine blades, furnace walls, etc.) can be removed during overhaul. However, it is often the aging of these important equipment components that determines the technical and consequently economic lifetime of thermal power plants. Operating experience shows that the service life of equipment operating under 450 °C is between 40 and 50 years. For equipment operating at temperatures above 450 °C, the operating hours could even be reduced to 100,000 hours.

Both gas and steam turbines are devices that drive the rotor to rotate at high speed through high-pressure gas with high temperature and humidity.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-48:
IEA Report

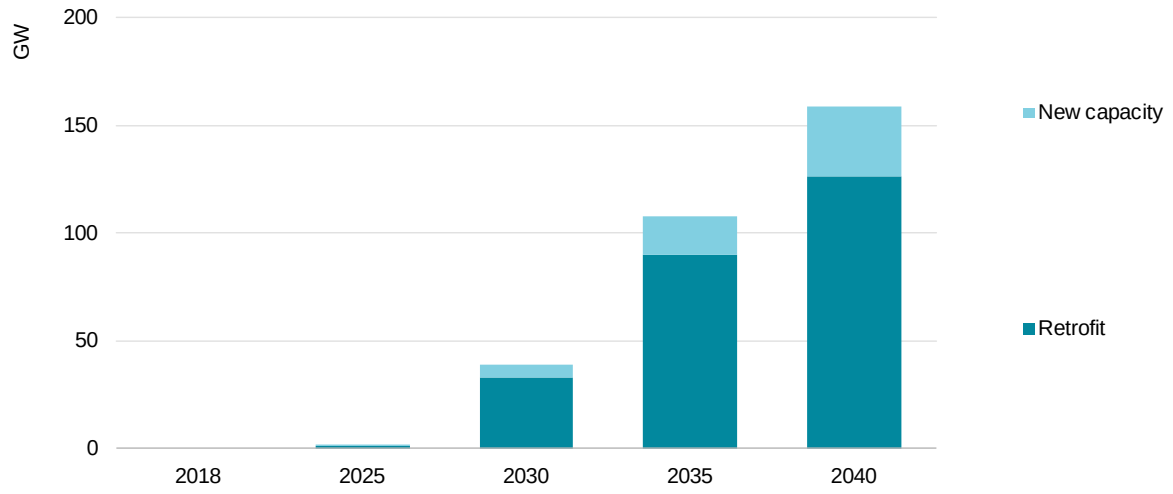
International Energy Agency

The role of CCUS in low-carbon power systems

Without carbon capture, meeting climate goals would ultimately mean almost eliminating the use of fossil fuels for power.

In the Sustainable Development Scenario, 120 GW of existing coal-fired capacity is retrofitted with carbon capture by 2040, accounting for some 80% of the coal plants equipped with these technologies. More than 110 GW of these retrofits are in China, representing a capital investment of around USD 160 billion. A further 10 GW are in the United States. Without carbon capture available at scale in power, coal-fired power generation, and eventually also gas-fired generation, would need to be virtually eliminated to meet long-term climate goals, with significant early retirements and potential stranding of assets.

Figure 4 **Coal-fired power plants equipped with carbon capture in the Sustainable Development Scenario**



Source: IEA (2019), World Energy Outlook 2019.

Over 750 GW of existing coal plants reduce operations to cut emissions in this Scenario, limiting electricity production but still providing system adequacy and flexibility. About one-quarter of the existing fleet would be retired before reaching the typical 50-year lifespan. Shutdowns and reduced operating hours are likely to lead to balance sheet write-downs for some owners of existing facilities. Coal plant retirements also imply greater investment in other low-carbon sources of electricity and associated network infrastructure.

Carbon capture retrofits also play an important role for the gas-fired power plant fleet, which currently has an average age of only around 19 years. In the SDS 155 GW of natural gas-fired power plants are equipped with carbon capture, utilisation and

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-49:
Tri-State Revised 2020 ERP Assessment of Existing Resources

Electric Resource Plan

Assessment of Existing Resources

REVISED

June 1, 2020 Informational Filing

for

Tri-State Generation and Transmission Association, Inc.

Submitted to:

Colorado Public Utilities Commission

August 3, 2020

Colorado PUC E-Filings System

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Compliance Table

Rule	Section
3605(c)(I)(A-E,J,K)	Owned and Leased Resources
3605(c)(I)(F-G,L)	Purchased Power Resources
3605(c)(I)(I)	Demand Side Management & Energy Efficiency
3605(c)(I)(C,H)	Projected Annual Emissions, Capacity Factors and Availability
3605(c)(II)	Benchmarking
3605(c)(III)	Ancillary Service Assessment

Background

Pursuant to Commission Decision No. C20-0304, in Proceeding No. 19R-0408E and Rule 3605 (a)(i) of the Colorado Public Utilities Commission's Rules Regulating Electric Utilities, Tri-State Generation and Transmission Association, Inc. (Tri-State) submits the following assessment of existing resources pursuant to paragraph 3605 (c) to the Public Utilities Commission of Colorado (Commission).

Summary

Tri-State is a wholesale cooperative electric generation and transmission association consisting of 43 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 between 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 Basin Electric Power Cooperative (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 power purchase agreements.

Figure 1 below illustrates the geographic diversity of Tri-State's load and resources along with Tri-State Merchant[1] 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)
- Public Service of Colorado (PSCo)
- Platte River Power Authority
- Western Area Power Administration (WAPA) Rocky Mountain Region Loveland Area Projects
- Black Hills Energy Colorado
- PacifiCorp

Additionally, Tri-State Merchant is a point-to-point transmission customer of many Transmission Providers in the Western Interconnection. Tri-State Merchant uses these network and point-to-point transmission rights within Western Electricity Coordinating Council (WECC) TOT 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.

[1] Tri-State Merchant is the marketing arm of Tri-State Generation and Transmission Association that is responsible for planning and originations in regards to energy, capacity and transmission necessary to serve Utility Member system load along with related dispatch, scheduling and settlements activity.

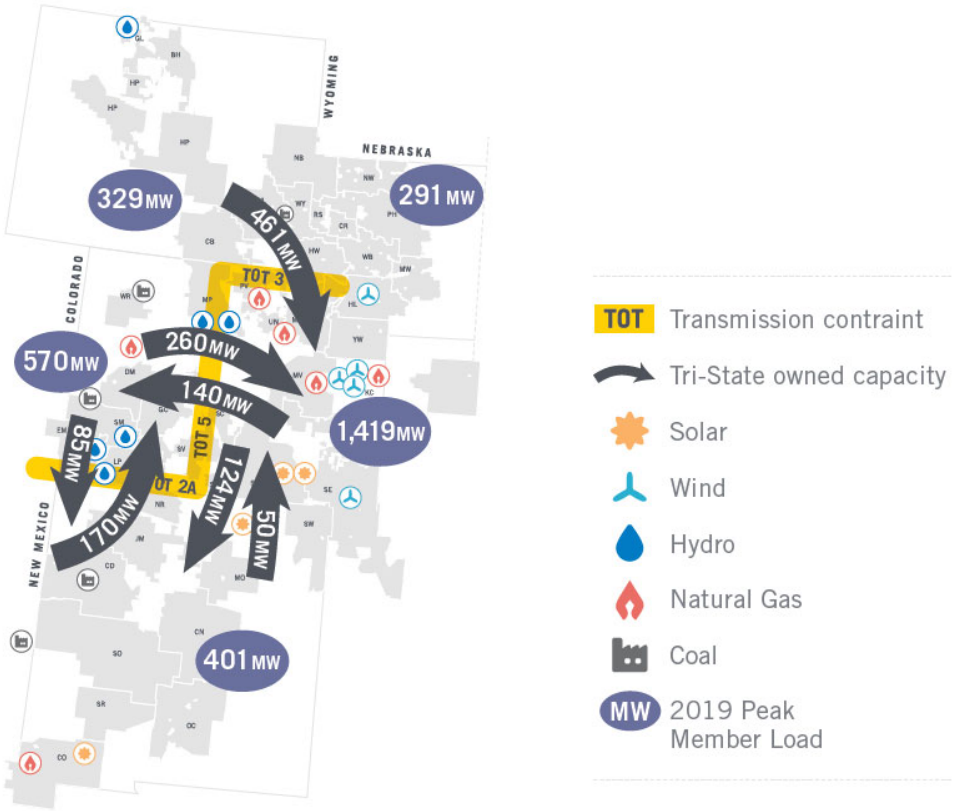

Figure 1 – Tri-State System Map

The following assessment describes existing resources both operational and contracted for at the time of this filing with appropriate detail as prescribed in 3605 (c).

Assessment of Existing Resources

1. Owned & Leased Resources

Assessment Approach

The following is a description of Tri-State-owned and leased resources in terms of unit characteristics, emission rates and revenue requirements. 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:

- Escalante is excluded, as it will be retired by December 31, 2020.
- Craig 1's useful life is identified as its announced retirement date. Original useful life was in the 2030s.

- 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 Resource Acquisition Period (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 our oil units are used for reliability events not economic dispatch and planning.
- Emissions rates are based on 2018 actuals data as provided by Tri-State Environmental; data will be refreshed as 2019 actuals are finalized and updated in the December 1, 2020 ERP filing.
- 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 are an average of annual expenses over the Resource Planning Period of 2021 to 2040 for the life of each resource as determined by useful life or planned retirement date.
- Costs associated with the use of emissions control systems are not separately forecasted, but are instead included in overall operating and maintenance costs.
- Although not a unit level revenue requirement, Social Cost of Carbon 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 Social Cost of Carbon is calculated as the resource carbon emission rate of each unit in tons per MWh times $46.00/ton social cost of carbon.
- 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))

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)[2], 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[3]. Tri-State's total share of Craig Station is 648 MW. In 2016, Tri-State announced an agreement with regulators and environmental groups to

[2] Yampa Project includes Craig 1 and Craig 2 and related common facilities.
[3] Yampa Project participants include Tri-State, Platte River Power Authority, PacifiCorp, Salt River Project and Public Service Company of Colorado.

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, 1,710 MW coal-fired electric generating facility located near Wheatland, Wyoming. As a participant in the Missouri Basin Power Project[4], Tri-State has a 27.1% interest (464 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.

Unit Characteristics

	Craig 1	Craig 2	Craig 3	LRS 2	LRS 3	SPV3
Average Heat Rate *(btu/kWh)*	10,316	10,219	10,135	9,926	10,286	9,945
Marginal Heat Rate *(btu/kWh)*	10,464	10,509	10,491	9,878	10,206	10,168
Quick Start Capable *(Yes/No)*	No	No	No	No	No	No
Minimum Operating Level *(MW)*	31	31	130	94	94	109
Useful Life	12/31/2025	12/31/2039	12/31/2044	12/31/2041	12/31/2042	12/31/2066

Emission Rates

lbs. per MWH	CO_2	SO_2	NOx	PM	HG
Craig 1	2319	0.378	2.771	0.042	0.00001700
Craig 2	2350	0.345	0.672	0.047	0.00001400
Craig 3	2090	1.308	2.248	0.061	0.00007800
LRS 2	2203	1.101	2.331	0.095	0.00004110
LRS 3	2407	1.823	2.410	0.177	0.00004680
SPV3	2139	0.838	0.787	0.031	0.00001600

CO2, SO2, and NOx are lbs. per net MWh; PM and HG are lbs. per Gross MWh

Revenue Requirements

	Fixed O&M Annual *($000s)*	Variable O&M *($/MWH)*	CapEx Costs Annual *($000s)*	Social Cost of Carbon *($/MWh)*	Integration & Cycling Costs *($/MWh)*	Fuel Curve *(See Figure 2)*
Craig 1	[redacted]		~$500	$53.34	$0.129	CRG (Inc)

[4] 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.

Craig 2	[redacted]	~$500	$54.05	$0.131	CRG (Inc)
Craig 3		~$3,000	$48.07	$0.124	CRG (Inc)
LRS 2		~$1,500	$50.67	$0.111	LRSG
LRS 3		~$1,500	$55.36	$0.108	LRSG

Tri-State forward coal prices change annually. Figure 2 below shows the current coal forward curve inclusive of inflation. CRG (All-In), LRSG and SPV3 values are all inclusive costs of fuel. CRG (Inc) is the Craig coal cost as an incremental value.

Figure 2 – Coal Price Curve

Gas & Oil-Fueled Generation Resources

Below capacity ratings are composite annual MW rating.

J.M. Shafer Generating Station: J.M. Shafer is a 272 MW natural gas-fueled, combined-cycle power plant located north of Fort Lupton, Colorado. The facility is a wholly-owned 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.

Unit Characteristics

	JM Shafer	Rifle	Limon	Knutson	Pyramid	Burlington
Summer Capacity *(MW)*	272	72	67	67	40	48
Winter Capacity *(MW)*	272	84	74	74	40	60
Fuel type	NG	NG	NG/FO	NG/FO	NG/FO	FO
Average Heat Rate *(btu/kWh)*	9,322	10,321	11,449	11,449	9,742	14,000
Marginal Heat Rate *(btu/kWh)*	9,282	10,965	10,852	10,835	9,985	-[5]
Quick Start Capable *(Yes/No)*	No	No	Yes	No	Yes	Yes
Minimum Operating Level *(MW)*	41	22	40	40	25	25
Useful Life	12/31/2047	12/31/2028	12/31/2048	12/31/2048	12/31/2049	12/31/2037

NG = Natural Gas; FO = Fuel Oil

Emission Rates

lbs. per MWH	**CO_2**	**SO_2**	**NOx**	**PM**	**HG**
JM Shafer	981	0.008	0.747	0.080	n/a
Rifle	1206	0.001	2.611	0.239	n/a
Limon	1495	0.008	0.378	0.062	n/a
Knutson	1502	0.009	0.341	0.124	n/a
Pyramid	1240	0.012	1.223	0.070	n/a
Burlington	2149	0.194	12.383	0.158	n/a

CO2, SO2, and NOx are lbs. per net MWh; PM is lbs. per Gross MWh

Revenue Requirements

	Fixed O&M Annual *($000s)*	**Variable O&M** *($/MWH)*	**CapEx Costs Annual** *($000s)*	**Social Cost of Carbon** *($/MWh)*	**Fuel Curve** *(See Figure 3)*
JM Shafer	[redacted]		~$1,500	$22.56	CIG
Rifle			~$200	$27.74	CIG
Limon			~$275	$34.39	CIG
Knutson			~$400	$34.55	CIG

[5] Burlington did not dispatch over the RAP

Pyramid	[redacted]	~$300	$28.52	WAHA
Burlington		~$450	$49.42	N/A

Tri-State forward gas prices change monthly. Figure 3 below shows the current gas forward curve without inflation. Additional transport costs apply.

Figure 3 – Forward Gas Curve

Third Party Assessment

In preparation for Tri-State's 2020 Colorado Electric Resource Plan (ERP) and Western Area Power Administration's Integrated Resource Plan (IRP) processes, Tri-State engaged Black & Veatch (B&V) to assist Tri-State with this assessment of existing resources by reviewing the following items for owned and leased resources:

- Heat Rates
- VOM
- Fixed costs
- Emissions
- Capacity Factors

Additionally, B&V reviewed these items to the extent applicable in regards to the Basin Contract Rate of Delivery (CROD) Western Interconnection contract, Basin Electrically East contract and Renewable Power Agreements[6] .

[6] More detail on these contracts can be found in the Purchase Power Resources section.

Specific areas of recommended change were as follows:

B&V Recommendation	Conclusion
Increase Burlington Heat Rate	Adjustment made to heat rate curve
Change Availability Factor of Combined Cycle resources to 90%	Tri-State will make accommodations in modeling to reflect these changes.
Change Availability Factor of Combustion Turbine dual fuel resources to 96%	Tri-State will make accommodations in modeling to reflect these changes.
Change Availability Factor of Combustion Turbine oil resources to 98%	Tri-State will make accommodations in modeling to reflect these changes.
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.
Increase to Rifle and Shafer SO_2 emission rates	Rifle and 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 forced outage factor for all gas units	Tri-State is reviewing this feedback and will take into consideration current and expected operation of gas and oil units and modify as determined to be necessary.

The Black & Veatch evaluation detail can be found in Appendix A Black & Veatch Report on Review of Existing Resources.

2. Projected Annual Emissions, Energy, Capacity Factors and Availability

This section contains representative scenario data for emissions, energy, capacity factors and availability during the RAP.

Base Case Scenario (typical dispatch):

The following values are based on a "typical" dispatch plan representative of Tri-State's current operations and announced resource additions and retirements. Expansion plan resources are required to support this dispatch. Greenhouse gas reduction requirements in the state of Colorado are not reflected in these numbers. Tri-State anticipates that an appropriate greenhouse gas reduction strategy will be developed in conjunction with the presently ongoing proceedings of the Colorado Air Quality Control Commission (AQCC) and as part of the ERP process.[7]

[7] The retirement of Craig 2 at the end of 2028 as illustrated in this dispatch was one of several possible scenarios. As of July 2020, the Yampa participants have announced a retirement date for Craig 2 of September 30, 2028.

The below calculated emissions are based on generation by resource from the plan and applicable historical emission rates as identified in the Owned & Leased Resources section or Purchased Power Resource section.

Projected CO_2 Emissions (000s of Short Tons)

CO_2	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	829	829	829	829	477	0	0	0	0	0
Craig 2	941	947	841	896	495	552	623	569	0	0
Craig 3	3357	3779	3352	3164	1851	2339	2156	2414	2955	0
LRS 2	2116	1847	2104	1935	1826	2116	2106	1872	2021	2031
LRS 3	2246	2144	1986	1933	2280	2039	2283	2281	1955	2198
SPV3	2025	1697	1920	1824	2292	2486	2583	2538	2648	2709
JM Shafer	376	285	46	142	226	182	145	104	111	125
Rifle	1	0	16	0	0	0	0	0	0	0
Limon	10	5	116	5	16	4	1	0	0	0
Knutson	23	16	137	6	14	2	1	0	0	0
Pyramid	11	34	8	5	90	90	84	83	46	37
Burlington	0	0	0	0	0	0	0	0	0	0
Basin CROD Western Interconnection	1815	1815	1815	1821	1815	1815	1815	1821	1815	1815
Basin Electrically East	469	472	476	479	482	486	489	492	496	499

Projected SO_2 Emission (Short Tons)

SO_2	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	135	135	135	135	78	0	0	0	0	0
Craig 2	138	139	123	132	73	81	91	84	0	0
Craig 3	2101	2365	2098	1980	1159	1464	1350	1511	1850	0
LRS 2	1058	923	1052	967	913	1058	1053	935	1010	1015
LRS 3	1701	1624	1504	1464	1727	1544	1729	1727	1480	1664
SPV3	793	665	752	714	898	974	1012	994	1038	1061
JM Shafer	2.99	2.27	0.36	1.13	1.80	1.45	1.15	0.82	0.88	1.00
Rifle	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Limon	0.05	0.03	0.62	0.02	0.09	0.02	0.01	0.00	0.00	0.00
Knutson	0.14	0.10	0.83	0.04	0.09	0.01	0.01	0.00	0.00	0.00
Pyramid	0.11	0.33	0.08	0.04	0.88	0.87	0.82	0.81	0.45	0.36
Burlington	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Basin CROD Western Interconnection	1151	1151	1151	1155	1151	1151	1151	1155	1151	1151
Basin Electrically East	530	534	537	541	545	548	552	556	560	563

Projected NOx Emissions (Short Tons)

NOx	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	990	990	991	991	570	0	0	0	0	0
Craig 2	269	271	240	256	142	158	178	163	0	0
Craig 3	3611	4064	3605	3404	1991	2516	2319	2596	3179	0
LRS 2	2239	1954	2226	2047	1932	2239	2228	1981	2138	2149
LRS 3	2249	2147	1989	1936	2283	2042	2286	2283	1957	2200
SPV3	745	624	706	671	843	915	950	934	974	997
JM Shafer	287	217	35	108	172	139	110	79	84	95
Rifle	3	0	34	0	0	0	0	0	0	0
Limon	2	1	29	1	4	1	0	0	0	0
Knutson	5	4	31	1	3	1	0	0	0	0
Pyramid	11	34	8	4	89	88	83	82	45	37
Burlington	0	0	0	0	0	0	0	0	0	0
Basin CROD Western Interconnection	1867	1867	1867	1872	1867	1867	1867	1872	1867	1867
Basin Electrically East	378	381	384	387	389	392	394	397	400	402

Projected Particulate Matter Emissions (Short Tons)

PM	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	16	16	16	16	9	0	0	0	0	0
Craig 2	20	20	18	19	11	12	13	12	0	0
Craig 3	106	120	106	100	59	74	68	76	94	0
LRS 2	98	86	98	90	85	99	98	87	94	95
LRS 3	178	170	157	153	180	161	181	180	155	174
SPV3	32	26	30	28	36	39	40	39	41	42
JM Shafer	31	24	4	12	19	15	12	9	9	10
Rifle	0.26	0.00	3.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Limon	0.42	0.21	4.99	0.20	0.71	0.15	0.05	0.00	0.00	0.00
Knutson	1.94	1.32	11.37	0.51	1.17	0.20	0.10	0.00	0.00	0.00
Pyramid	0.62	1.94	0.46	0.26	5.13	5.12	4.79	4.73	2.61	2.12
Burlington	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Basin CROD Western Interconnection	107	107	107	108	107	107	107	108	107	107
Basin Electrically East	UA	UA	UA	UA	UA	UA	UA	UA	UA	UA

UA = Unavailable[8]

[8] Data was not available for this sub region for particulate matter emissions.

Projected Mercury Emissions (Short Tons)

hg	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	0.007	0.007	0.007	0.007	0.004	0.000	0.000	0.000	0.000	0.000
Craig 2	0.006	0.006	0.005	0.006	0.003	0.004	0.004	0.004	0.000	0.000
Craig 3	0.135	0.152	0.135	0.127	0.074	0.094	0.087	0.097	0.119	0.000
LRS 2	0.042	0.037	0.042	0.039	0.037	0.042	0.042	0.038	0.041	0.041
LRS 3	0.047	0.045	0.042	0.040	0.048	0.043	0.048	0.048	0.041	0.046
SPV3	0.016	0.014	0.016	0.015	0.019	0.020	0.021	0.021	0.022	0.022
JM Shafer	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
Limon	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Burlington	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin CROD Western Interconnection	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035
Basin Electrically East	UA	UA	UA	UA	UA	UA	UA	UA	UA	UA

UA = Unavailable[9]

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 4 and 5 below 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 4 – Basin CROD Western Interconnection Stegall West 230KV Bus Hourly Profile

[9] Data was not available for this sub region for mercury emissions.

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	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 5 – Basin CROD Western Interconnection AU 230KV and STORY 230KV busses Hourly Profile

Basin Electrically East contract has an energy and demand profile based on forecasted 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 6 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.

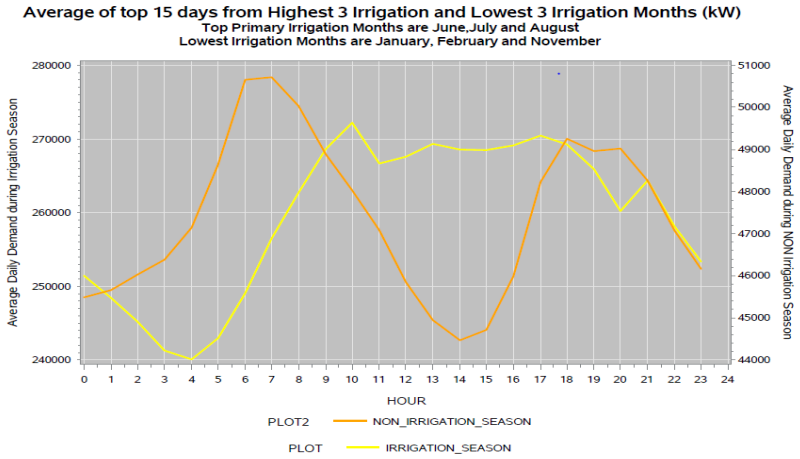

Figure 6 – Basin Electrically East Irrigation and Non-Irrigation Seasons Demand Profiles

Below is a snapshot of historical energy and demand for the Basin Electrically East contract by month:

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

Annual Projected Energy and Demand by Contract

Energy (GWh)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Basin CROD Western Interconnection[10]	1575	1575	1575	1580	1575	1575	1575	1580	1575	1575
Basin Electrically East [11]	757	762	767	773	778	783	788	795	800	805

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	1671	1683	1694	1705	1716	1727	1739	1751	1762	1773

Projected WAPA Contracts – Loveland Area Projects (LAP) and Colorado River Storage Projects (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.

Annual Projected Energy and Demand 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

[10] Energy is delivered to Colorado and Wyoming.

[11] ~15% of this purchase serves Colorado. Balance of purchase serves load in Nebraska.

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

Annual Demand [12] (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

Projected Annual Capacity Factors for Thermal Resources

	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Craig 1	80%	80%	80%	80%	46%	0%	0%	0%	0%	0%
Craig 2	93%	94%	83%	89%	49%	55%	62%	56%	0%	0%
Craig 3	82%	92%	82%	77%	45%	57%	53%	59%	72%	0%
LRS 2	95%	82%	94%	86%	82%	95%	94%	84%	90%	91%
LRS 3	92%	88%	81%	79%	93%	83%	93%	93%	80%	90%
SPV3	52%	43%	49%	47%	59%	64%	66%	65%	68%	69%
JM Shafer	32%	24%	4%	12%	19%	16%	12%	9%	9%	11%
Rifle	0%	0%	3%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	1%	13%	1%	2%	0%	0%	0%	0%	0%
Knutson	3%	2%	15%	1%	2%	0%	0%	0%	0%	0%
Pyramid	1%	4%	1%	1%	10%	10%	10%	10%	5%	4%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Projected Availability Factors 2021 to 2030 for Thermal Resources

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 is currently updating its models to reflect recommended forced outage factors as provided by Black & Veatch (Appendix A).

[12] Representative of monthly billing demands per the contracts. Actual maximum available hourly capacity in any given month varies.

Applicable Scheduled Outage Plan over the RAP:

	Craig 1	Craig 2	Craig 3	LRS 2	LRS 3	SPV3
Start Date						
Stop Date						
Start Date						
Stop Date						
Start Date						
Stop Date						

3. Purchased Power Resources

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 Power Purchase Agreements 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.

Contract Purchases:

Basin CROD Western Interconnection BEPC: Colorado & Wyoming: 268 MW summer capacity, ~1580 GWh/year[13]. Effective Date 1/16/1975; Renewed 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.

Basin Electrically East BEPC: All Requirements Purchase Contract for Electrically East Loads[14], Effective Date 1/16/1975; Renewed 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.

[13] Profile detail is shown in Projected Annual Emissions, Capacity Factors and Availability section
[14] Profile detail is shown in Projected Annual Emissions, Capacity Factors and Availability section

- 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 70% 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

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).

Energy and Capacity Payments for Contract Purchases

The following rates are averaged over the RAP:

Resource	**Energy Rate** *($/MWh)*	**Demand Rate** *($/KW-month)*
Basin CROD Western Interconnection	[redacted]	[redacted]
Basin Electrically East		
CRSP	$12.19	$5.18
LAP	$15.72	$4.12
Native American WAPA Allocations	[redacted]	N/A
Central Valley Electric		N/A

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.

[15] Composite rate encompassing energy and demand components
[16] Composite rate encompassing energy and demand components

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 are as follows:

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:

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	

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 modify energy 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.

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 Associated with Contract Purchases and Renewable Purchase Power Agreements

Tri-State receives Renewable Energy Credits (RECs) associated with its Renewable Purchase Power Agreements.

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.

Historical emissions for Basin CROD Western Interconnection and Basin Electrically East contracts are estimated below:

Estimated Historical Emission Rates

lbs. per MWH	**CO_2**	**SO_2**	**NOx**	**PM**	**Hg**
Basin CROD Western Interconnection	2305	1.462	2.3705	.13615	.00004395
Basin Electrically East	1239.8	1.4	1.0	UA	UA

UA= Unavailable[17]

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 information filing, Tri-State considered the following:

Basin CROD Western Interconnection Contract: Historically this contract has been primarily served by LRS generation so an average of LRS 2 and LRS 3 emissions factors was used. 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. Given this, the egrid[18] sub region of MRO West was used as a proxy to represent emissions for this contract. The total output emission rates were used for CO_2, NOx and SO_2.

Additionally, we note that Tri-State receives RECs related to both of the Basin contracts as a member of BEPC under an associated board policy.

While the above emissions for Tri-State's Basin contracts are estimates based on historical sourcing only, Tri-State will explore further the projected emissions sources for each of these contracts within the bounds of the Colorado AQCC regulations, both currently effective and under development, during its ERP process leading to the December 1 filing to accurately reflect the emissions of these contracts and their impact on carbon reduction in future years.

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 May 2020, 66 renewable or distribution generation projects, totaling 136 MW of capacity and capable of producing ~380 GWh/year are operating or under development. Approximately 85% of

[17] Data for this sub region was not available for particulate matter or mercury emissions.
[18] Environmental Protection Agency - egrid 2018 Summary Tables

Utility Member system distributed generation is located in Colorado, and on a capacity basis, approximately 75% 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 Members 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 Members' service territories.

These resources are not owned by, or contracted to, Tri-State, but instead serve Utility Member system load directly, so Tri-State has not attempted to provide a detailed assessment of these generation projects.

4. Demand Side Management & Energy Efficiency

As reported in Tri-State's 2019 Annual Progress Report an ongoing part of Tri-State's Action Plan is the implementation of Demand Side Management (DSM) and Energy Efficiency (EE) programs. 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 member feedback. As a reminder, Tri-State does not have retail load and is reliant upon Utility Member system participation in DSM and EE program implementations.

Current offerings for Demand Side Management include:

- Demand Response (DR) related to air conditioning, water heating and irrigation
    - Four Utility Member systems currently have irrigation DR programs
- Energy shaping related to electric thermal storage and electric vehicle charging station
    - Eleven Utility Member systems use time of use rates for storage heater control
    - Several Utility Member systems are investigating or have implemented residential demand rates in an attempt to control/shift load during peak times

Tri-State's current A-40 rate structure 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. Many 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.

Current offerings for Energy Efficiency include:

- Heat Pump Projects working with the Electric Power Research Institute (EPRI) and our Utility Member systems
- Rebates on education programs for training in Energy Auditing
- Irrigation program to educate Utility Member systems in regards to efficiency
- Incentives are offered in many areas such as residential and commercial lighting, appliances, air conditioning, motors, air and ground source heat pumps and assisting in energy efficient education and training

Year End 2018[19] Cumulative Energy Efficiency Results:

Category	Typical Measures	kW Savings	kWh Savings
Agriculutural	Irrigation Motors Variable Speed Drive Retrofits	13,080	21,902,726
C&I HVAC	Air Source and Ground Source Heat Pumps	7,275	9,263,112
C&I Lighting	LED Lighting Street & Parking Lot Lighting Refrigerated Case Doors	25,434	91,528,578
C&I Motors	Variable Speed Drive Retrofits	3,968	8,199,393
Residential HVAC	Air Conditioners Air Source and Ground Source Heat Pumps	83,891	57,344,907
Residential - Othe	LED Lamps, Energy Star Appliances Electric Water Heaters Low Income Weatherization	51,488	23,905,259
Total		**185,136**	**212,143,975**

Energy Efficiency Rebate History

- 2014 - $2,131,637
- 2015 - $2,128,582

[19] Table identifier corrected to 2018 from 2019 as shown in June 1 filing.

- 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 Demand Side Management (DSM) and Energy Efficiency (EE) Potential study with an outside consultant with the goal of receiving updated information in regards to achievable potential and cost savings in these areas 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 its DSM and EE products and services in a manner that is beneficial to Tri-State and Utility 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 but 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 Appendix C to this report.

5. Benchmarking

For the purposes of the Rule 3605(c)(II) Benchmarking requirement, Tri-State engaged Black and 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 contracts 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 Black & Veatch Benchmarking process are located in Appendix B: Black & Veatch Report on Benchmarking of Existing Resources

6. Ancillary Service Assessment

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 PacifiCorp, PSCo, Public Service of New Mexico 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.

The following is a list of the primary ancillary services required via applicable Open Access Transmission Tariffs and how Tri-State acquires these services including any applicability to Tri-State resources:

Scheduling, System Control & Dispatch: Tri-State pays for this service monthly from appropriate Transmission Providers or Balancing Authorities. Tri-State Resources do not have any impact on or relation to this service.

Reactive Supply & Voltage Control: Tri-State pays for this service monthly from appropriate Transmission Providers or Balancing Authorities. 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.

Regulation and Frequency Response (includes load following capabilities): Tri-State pays for this service monthly from appropriate Transmission Providers or Balancing Authorities. 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.

Tri-State generating resources that are AGC capable include:

- Craig 1, 2, and 3
- LRS 2
- Springerville 3
- JM Shafer
- Knutson 1,2
- Limon 1,2
- Pyramid 1,2,3,4
- Burlington 1,2

Energy Imbalance Service: Tri-State currently pays for this service monthly from appropriate Transmission Providers or Balancing Authorities. Beginning in 2021, a portion of Tri-State's load and resources will be in two energy imbalance markets – the Western Energy Imbalance Service (WEIS) and the Western Energy Imbalance Market (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.

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. Tri-State generating resources typically online and capable of carrying spinning reserves include:

- Craig 1
- Craig 2
- Craig 3
- LRS2
- LRS3
- Springerville 3
- JM Shafer

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.

Operating Reserve Supplemental Service:

Tri-State self-supplies spinning reserves through Southwest Reserve Sharing Group member and via two sub-entity Reserve Sharing Group Agreements. Tri-State generating resources with quick start capability to qualify for supplemental service include:

- Burlington 1,2
- Limon 1,2
- Pyramid 1,2,3,4

Generator Imbalance Service: Tri-State currently takes and pays for this service monthly from appropriate Transmission Providers or Balancing Authorities. 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.

Flex Reserve Service: Tri-State currently takes and pays for this service monthly from appropriate Transmission Providers or Balancing Authorities. 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.

Loss Supply Service: Tri-State either pays for this service monthly from appropriate Transmission Providers or Balancing Authorities or provides physical loss requirement depending on specific contractual arrangements.

Confidential Information

Pursuant to Commission Rule 3605(a)(IV)(K), the following is a list of information included in this Assessment of Existing Resources and which Tri-State has designated as confidential information:

- Scheduled Outage Plan (Maintenance

Highly Confidential Information

Pursuant to Commission Rule 3605(a)(IV)(K), the following is a list of information included in this Assessment of Existing Resources and which Tri-State has designated as highly confidential information:

- Fixed O&M Expenses
- Variable O&M Expenses
- Fuel Price Forward Curves (Gas and Coal)
- Contract/PPA Energy Rate, except in regards to Tri-State's LAP and CRSP hydro power purchase contracts with WAPA.
- Contract/PPA Capacity Rate, except in regards to Tri-State's LAP and CRSP hydro power purchase contracts with WAPA.
- Performance or Operating Output guarantees and any associated pricing adjustments included in Tri-State' Renewable Power Purchase Agreements
- Any information protected by a confidentiality clause in a PPA

Appendix A: Black & Veatch Report on Review of Existing Resources

BLACK & VEATCH

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.

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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)

	Resource	Non-Fuel Variable O&M Costs per MWh: 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

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August 3, 2020 Revision

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

	Resource	Renewable Capacity Factor (%) 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

Appendix B: Black & Veatch Report on Benchmarking of Existing Resources

BLACK & VEATCH

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

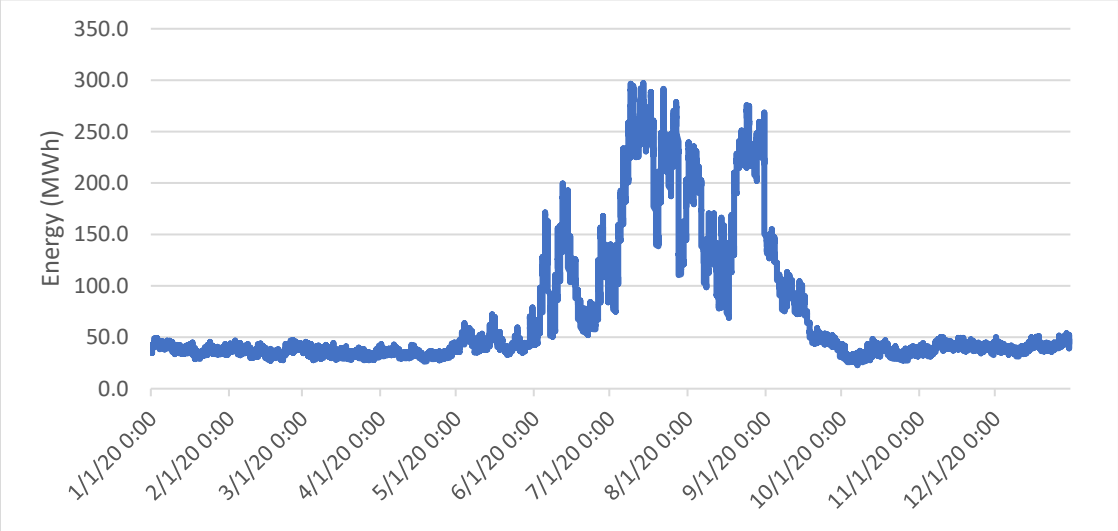
Selection Criteria. We set the Common Capacity Factor for the Pairing equal to fifteen (15) percent which is representative for combustion turbine resources.

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

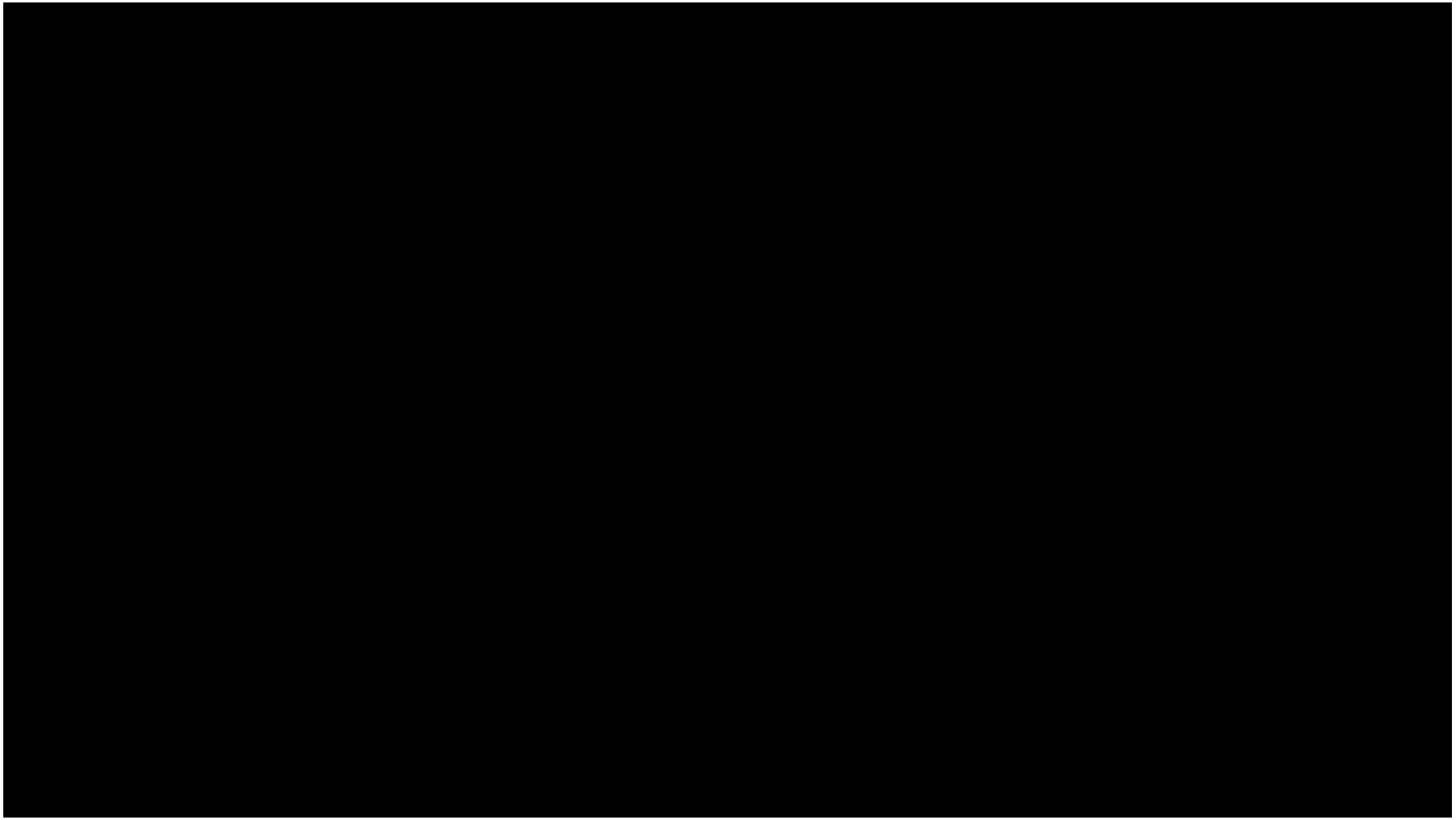


Figure 4 – LCOE Comparison for the Renewable Resource Pairings

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

Appendix C: Mesa Point Energy & BrightLine Group - Tri-State Demand Side Management and 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

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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

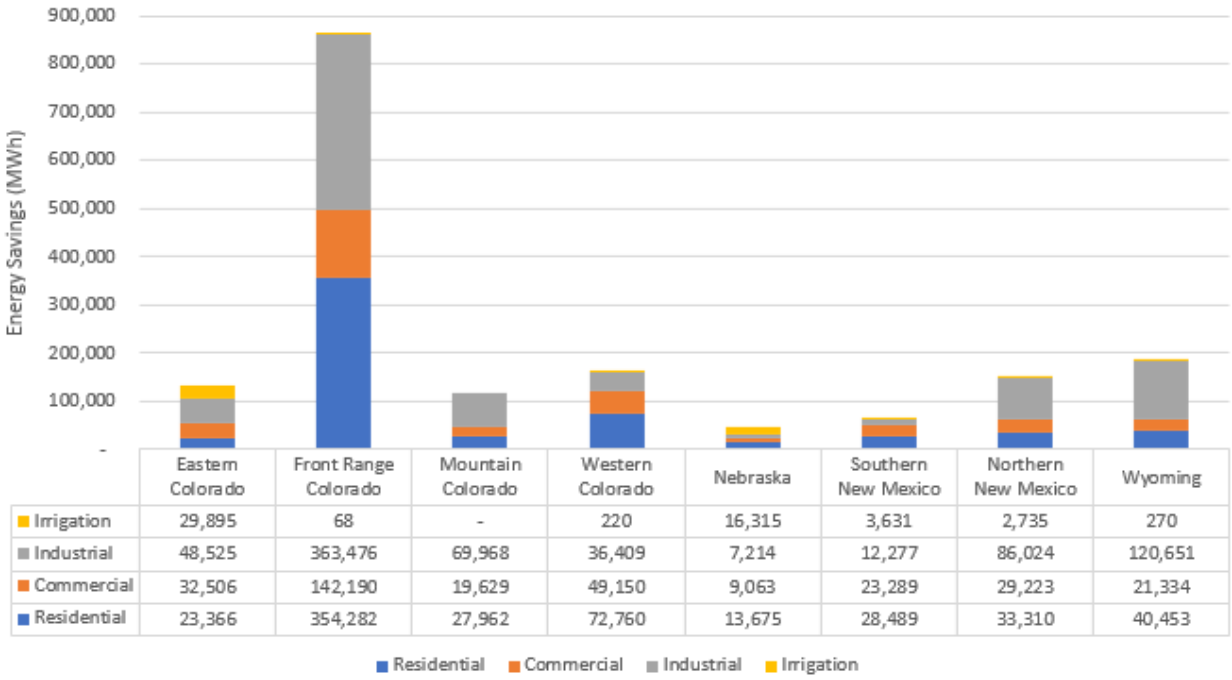
As summarized in Table ES-1, the Mesa Point Team found that the Achievable-moderate scenario would result in approximately 38 GWh (0.25% of sales) of energy efficiency saving in 2021 rising to 1,718 GWh (8.16% of sales) of savings through 2040.

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

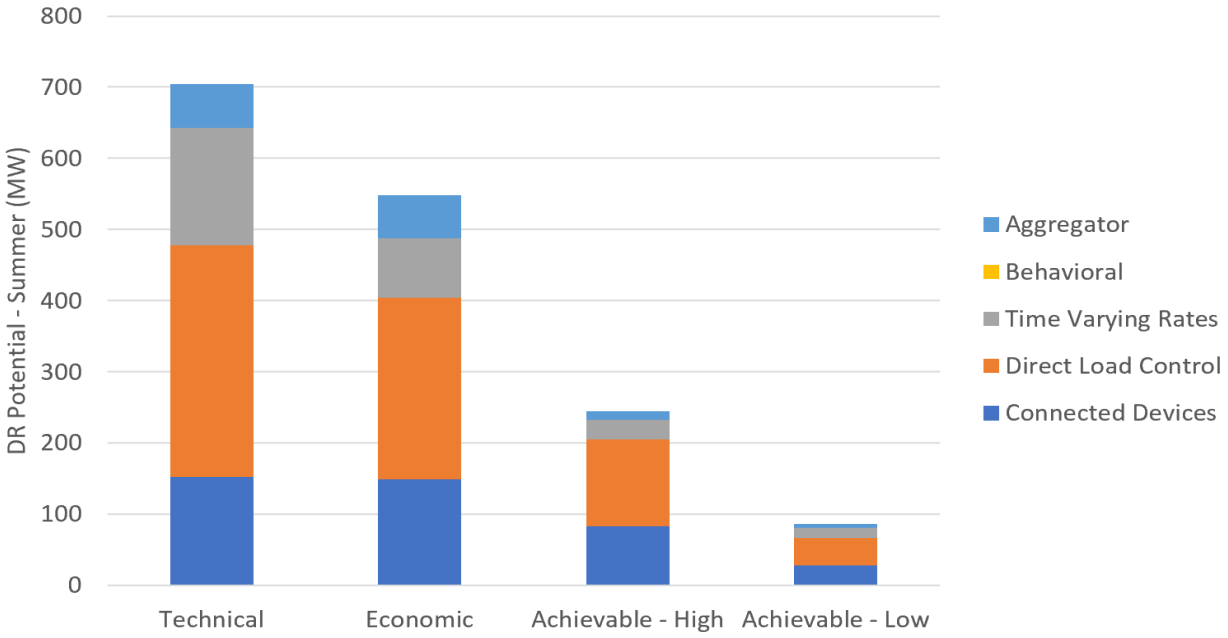
The study considered five different types of DR programs:

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

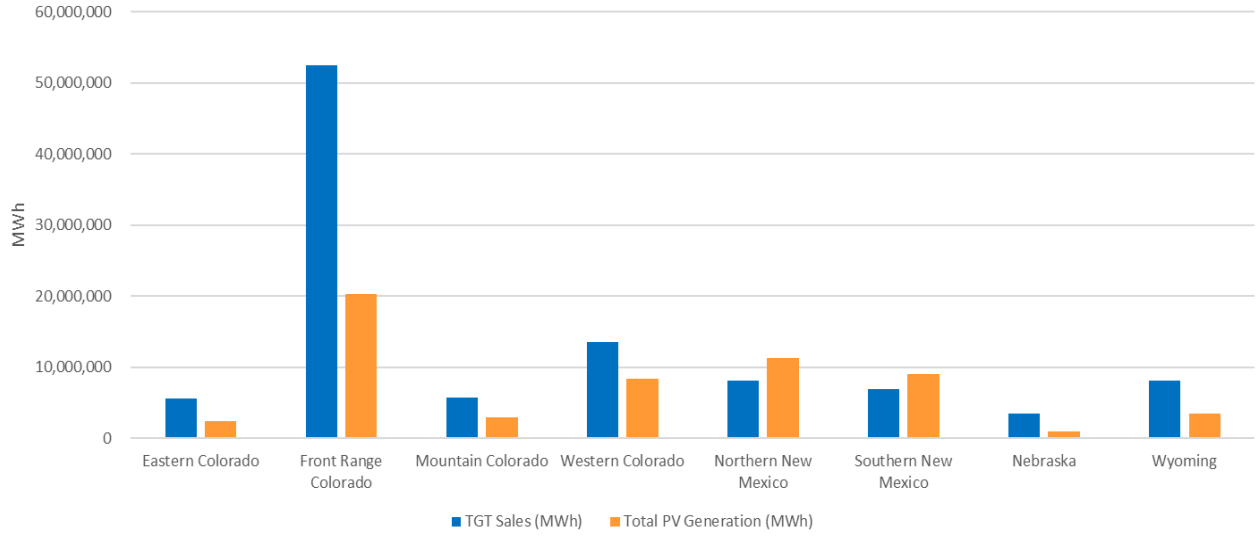
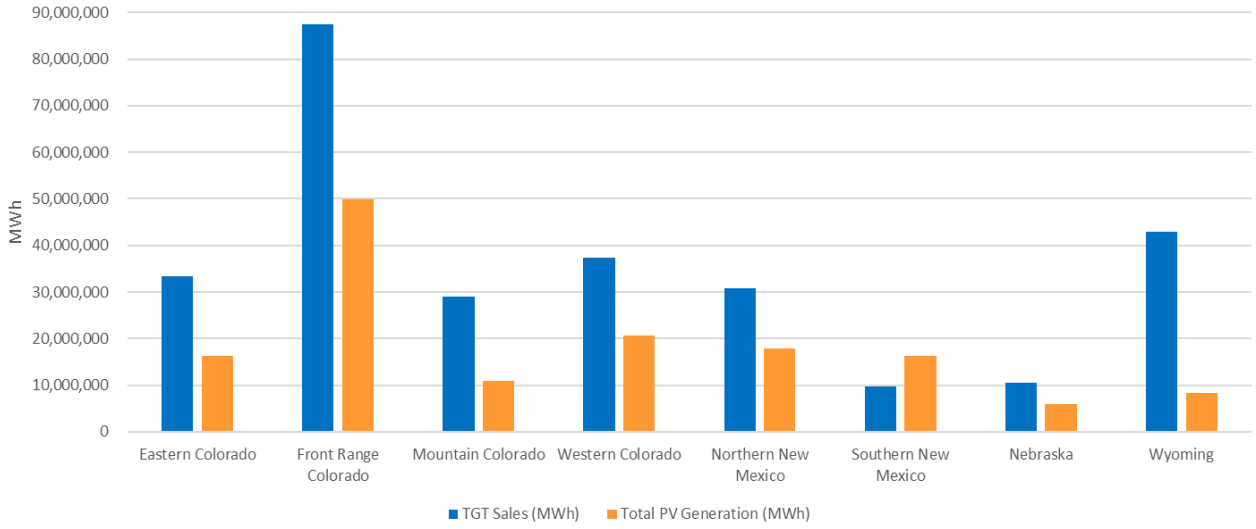
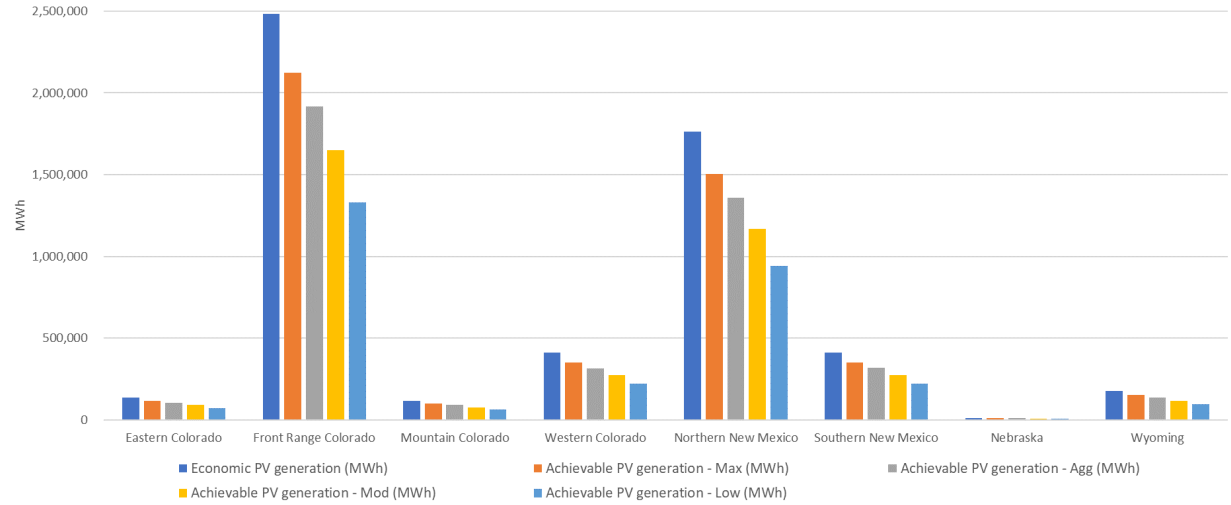


Figure ES-4. 2040 Technical Potential for Cumulative Non-Residential PV Generation vs Sales by Region



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

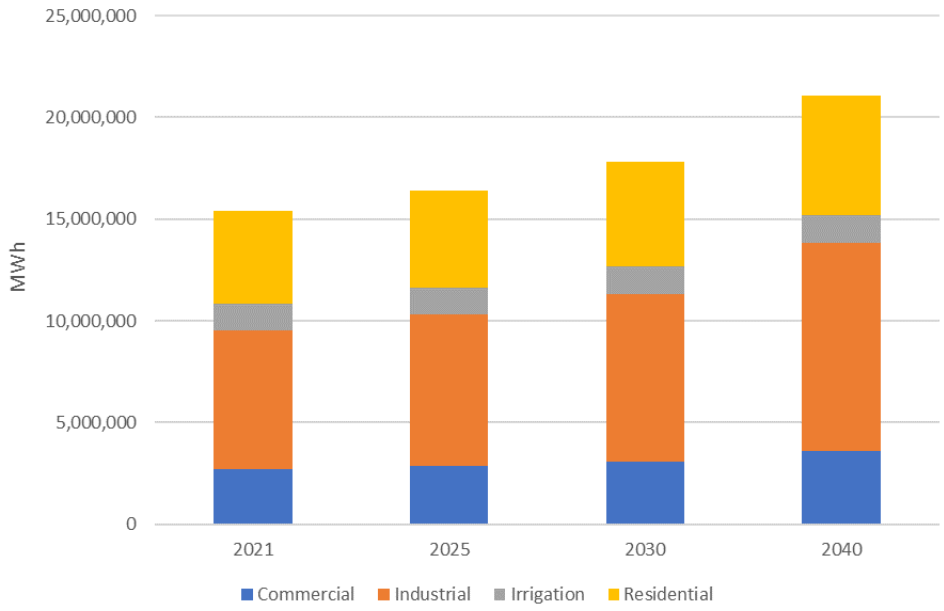
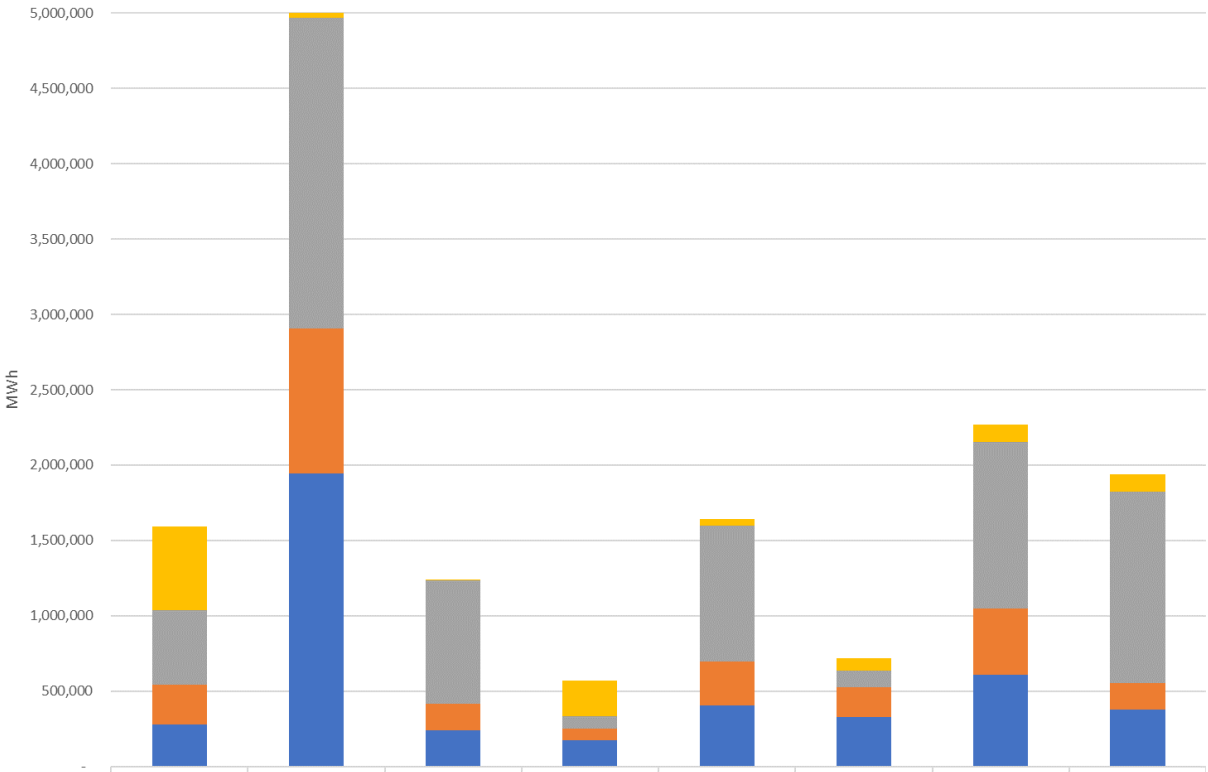


Figure ES-6. 2018 Baseline Energy Load by Customer Sector by Region



	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.

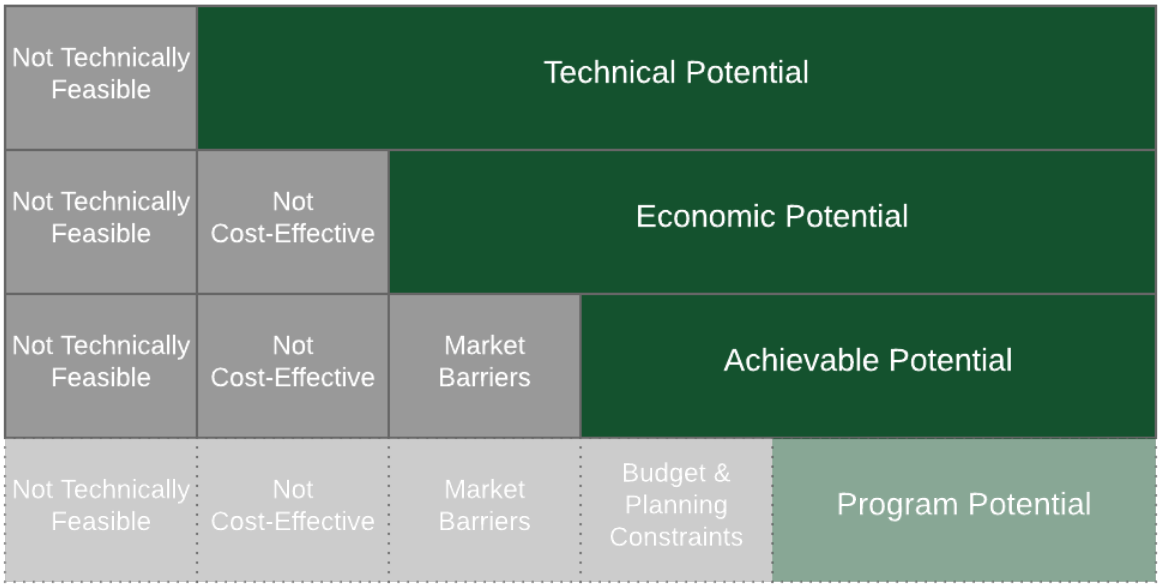
1.3. Study Approach Overview

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

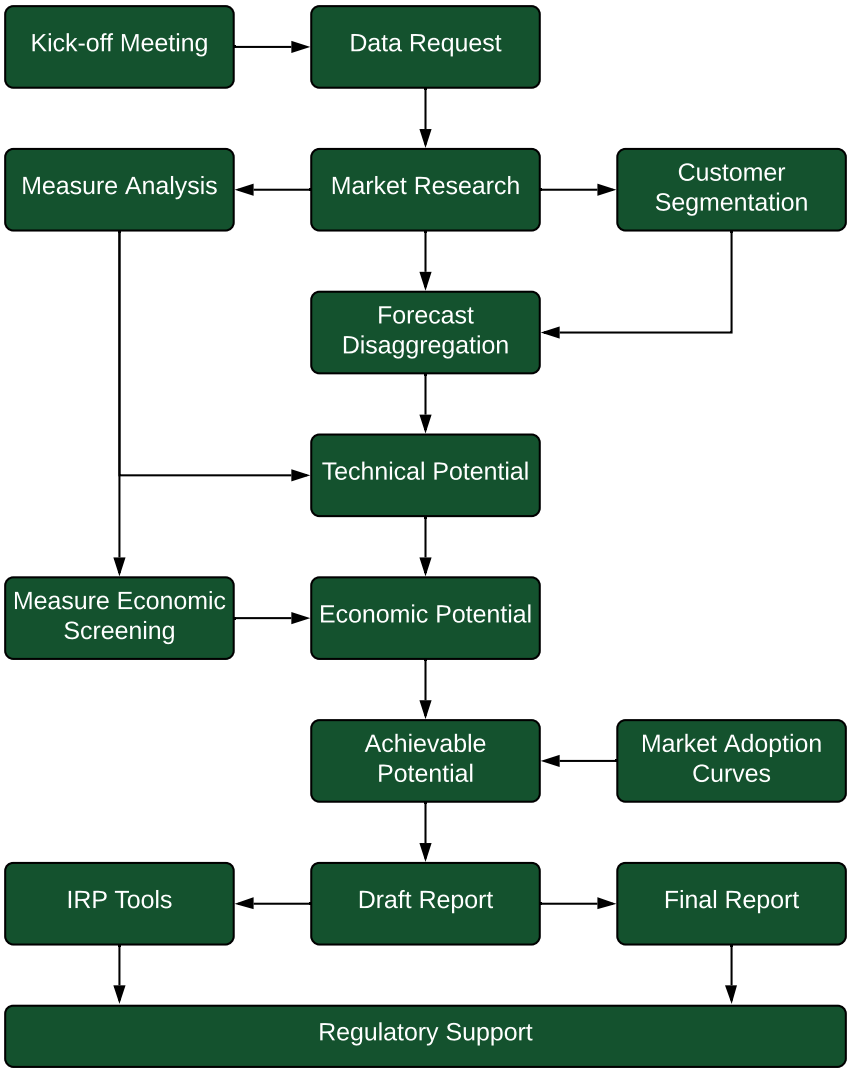
- Presents overall findings and recommendations.

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")

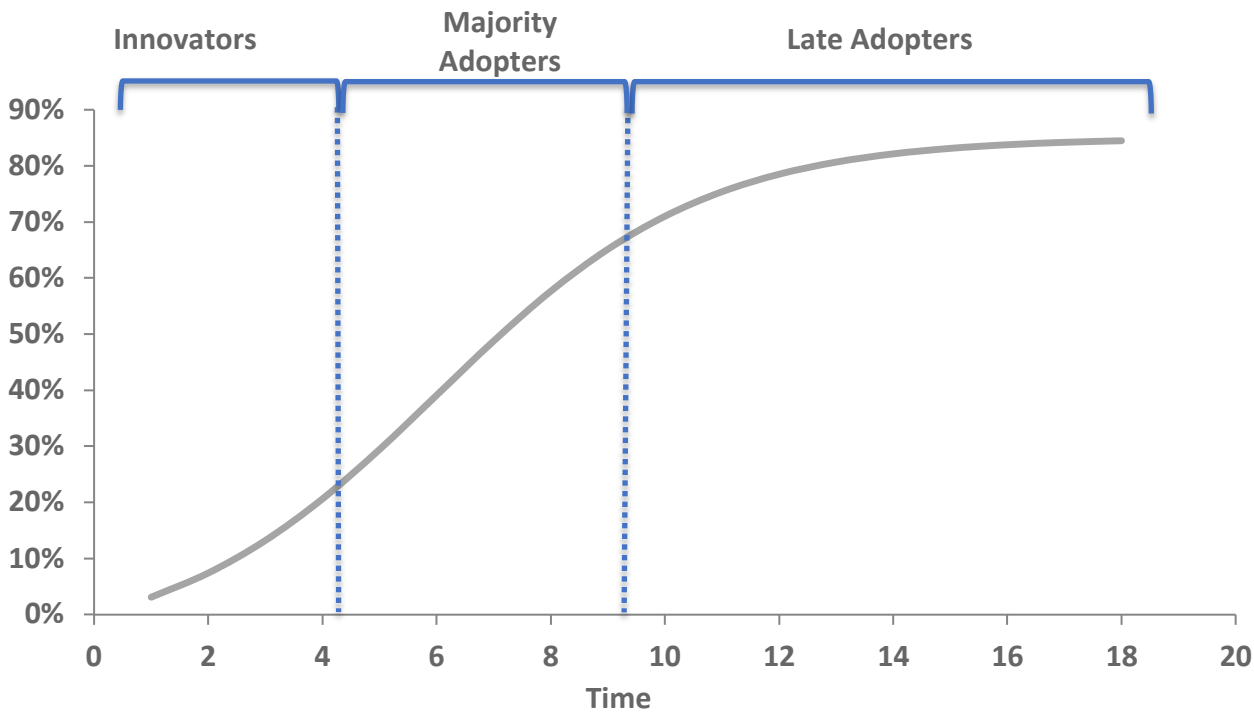
For instance, the moderate scenario approximates the market adoption achievable by incentivizing 50% of the incremental cost of the measure. Results are presented from the perspective of the Achievable Moderate scenario unless otherwise specified. This scenario represents a reasonable progression from 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

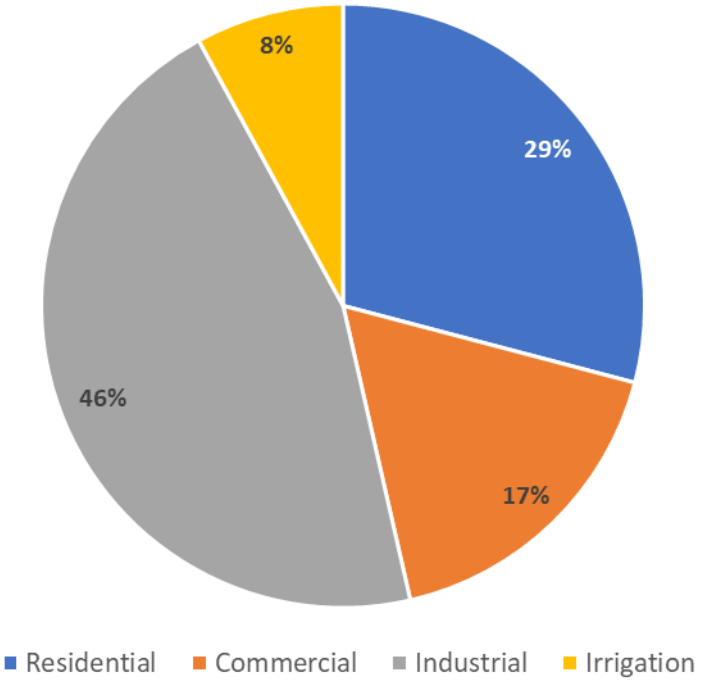


Figure 6. 2018 Energy Sales by Region

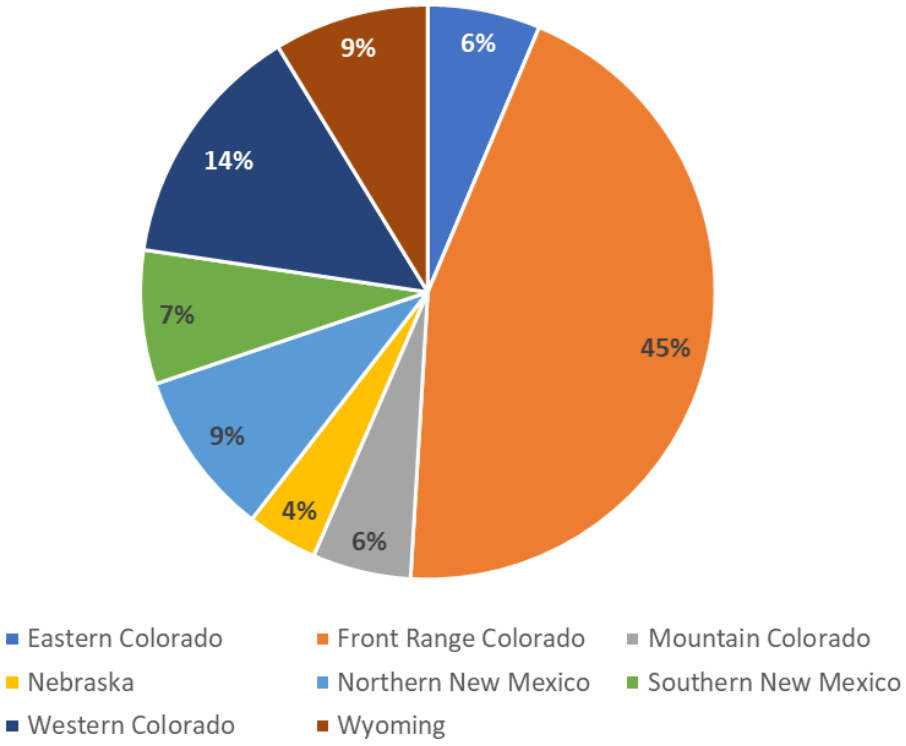
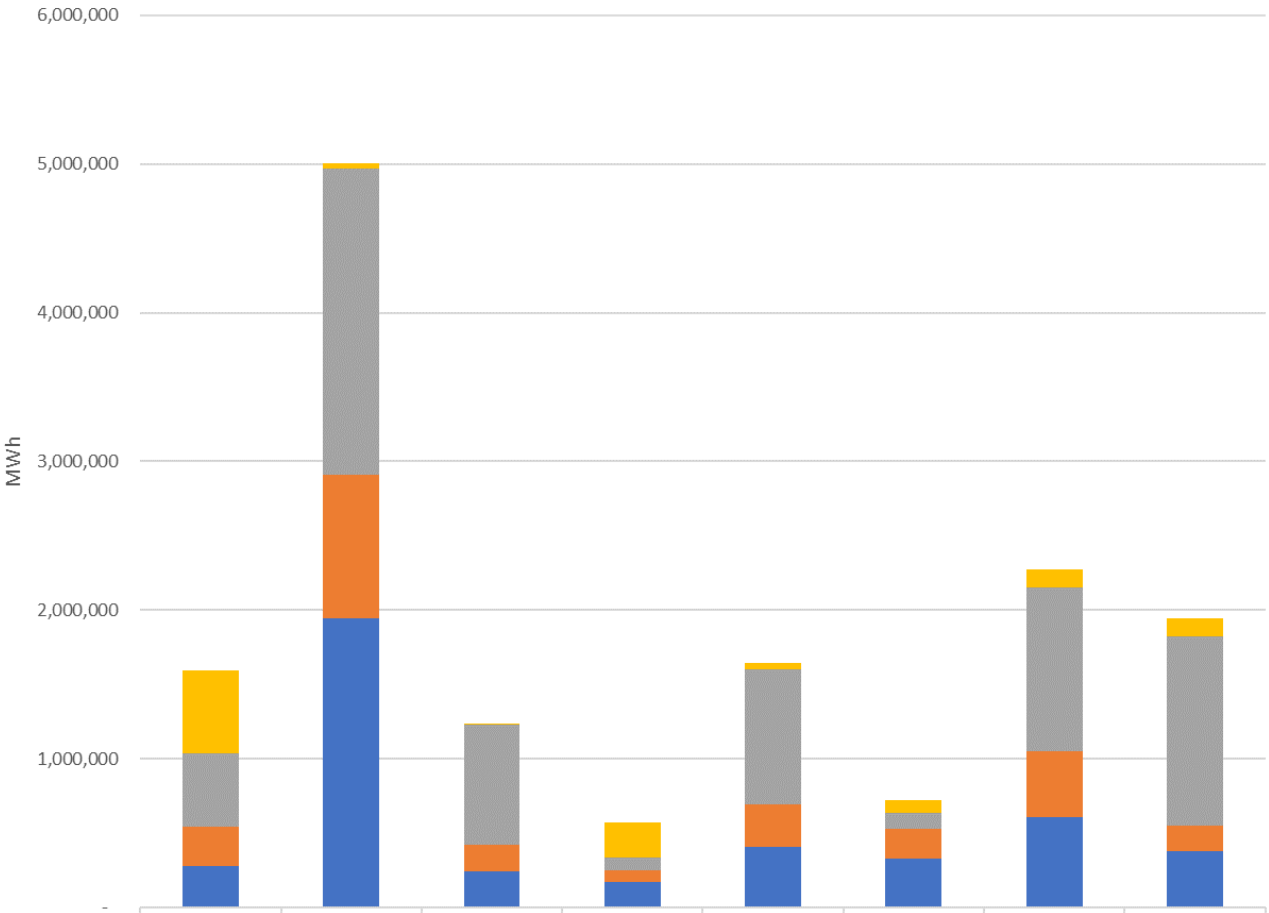


Figure 7. 2018 Energy Sales by Customer Sector and Region



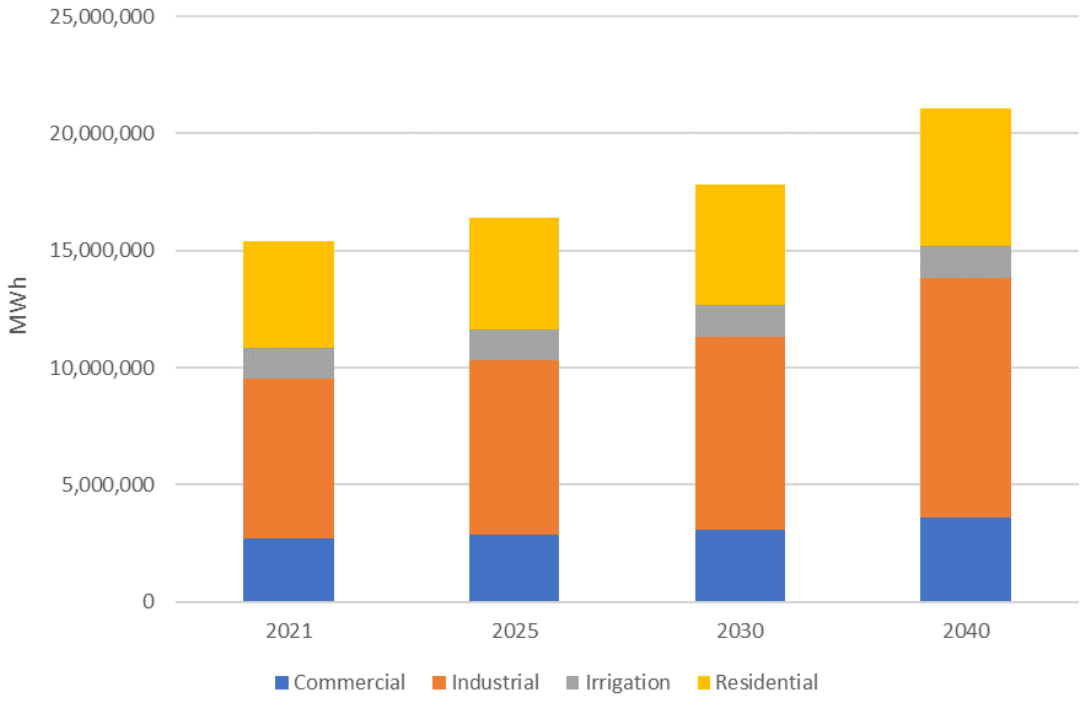
	Eastern Colorado	Front Range Colorado	Mountain Colorado	Nebraska	Northern New Mexico	Southern New Mexico	Western Colorado	Wyoming
Irrigation	554,724	31,967	861	237,972	41,763	85,091	116,352	119,890
Industrial	494,719	2,061,346	814,705	79,803	903,438	107,893	1,104,101	1,268,084
Commercial	268,177	964,547	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

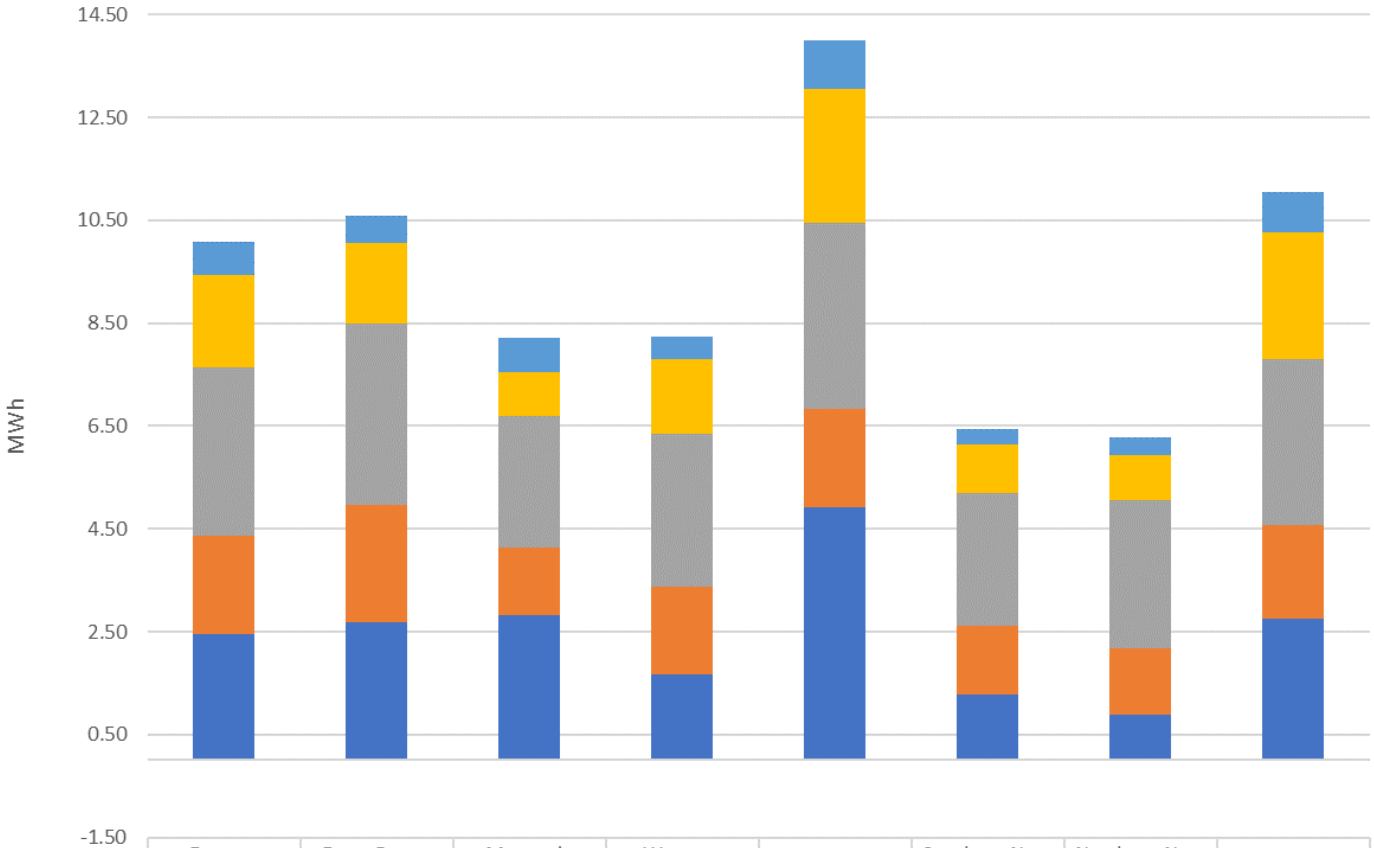


3.2. Residential End-Uses and Loads

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.

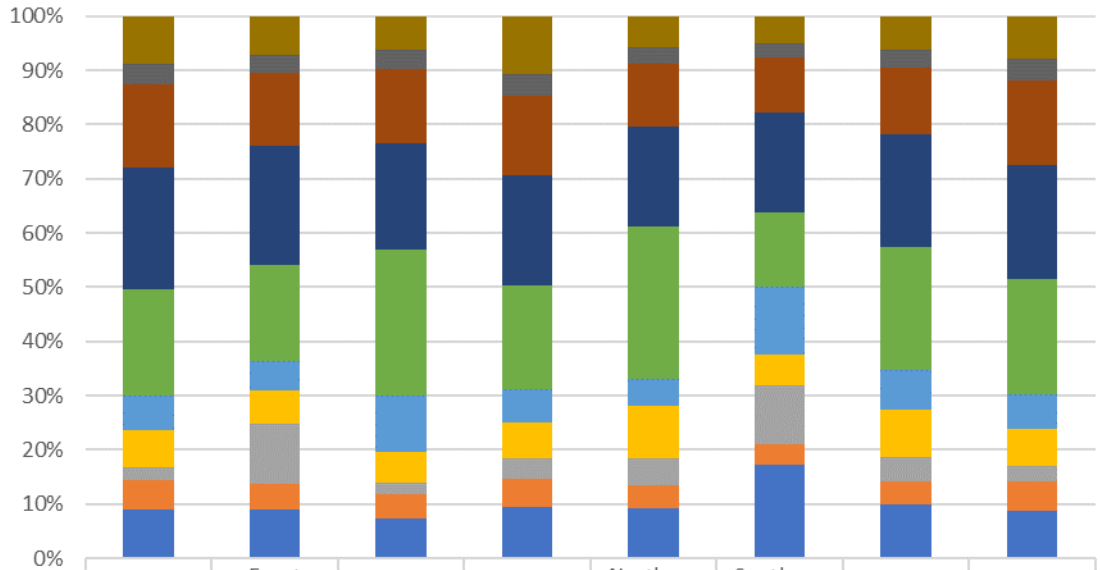
The analysis finds lower appliance saturations and smaller premise square footage for the New Mexico region residences. As expected, there is a higher prevalence of electric space and water heating in the colder climates of mountain Colorado, Nebraska, and Wyoming due to the lack of available natural 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)



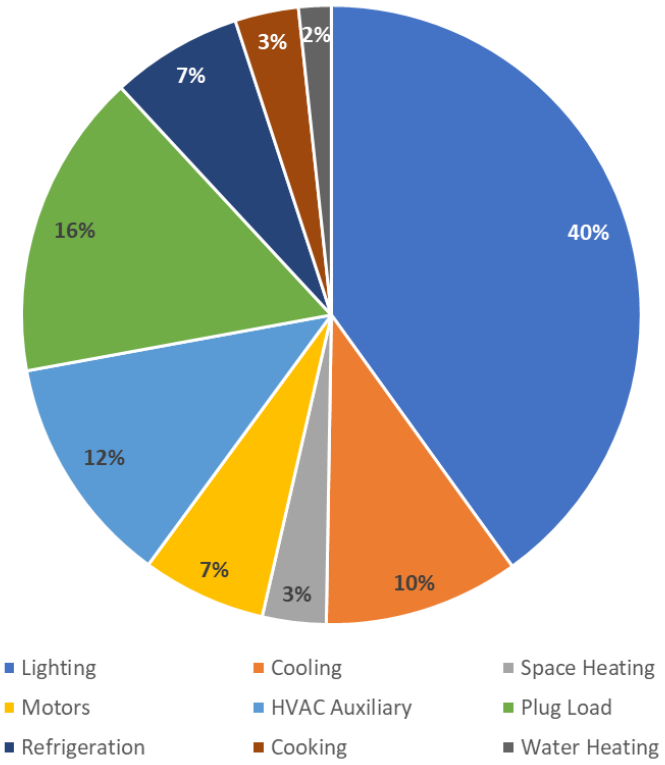
	Eastern Colorado	Front Range Colorado	Mountain Colorado	Nebraska	Northern New Mexico	Southern New Mexico	Western Colorado	Wyoming
Warehouse	9%	7%	6%	11%	6%	5%	6%	8%
Restaurant	4%	3%	3%	4%	3%	3%	3%	4%
Office	15%	13%	14%	15%	12%	10%	12%	15%
Retail	22%	22%	20%	20%	18%	18%	21%	21%
Miscellaneous	20%	18%	27%	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

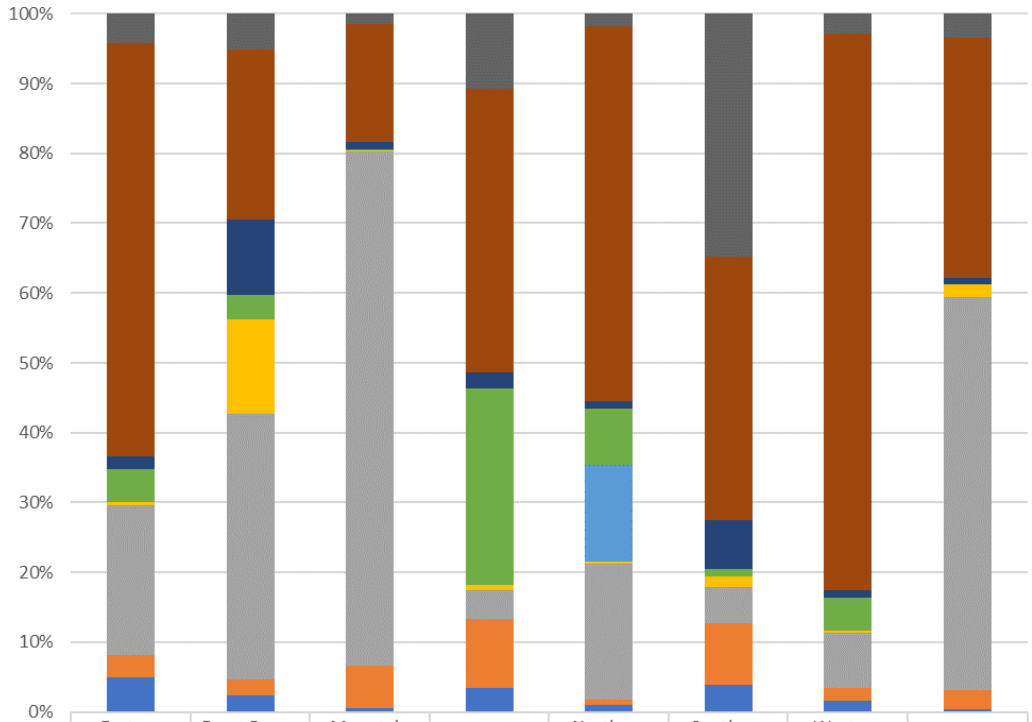


3.4. Industrial End-Uses and Loads

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.

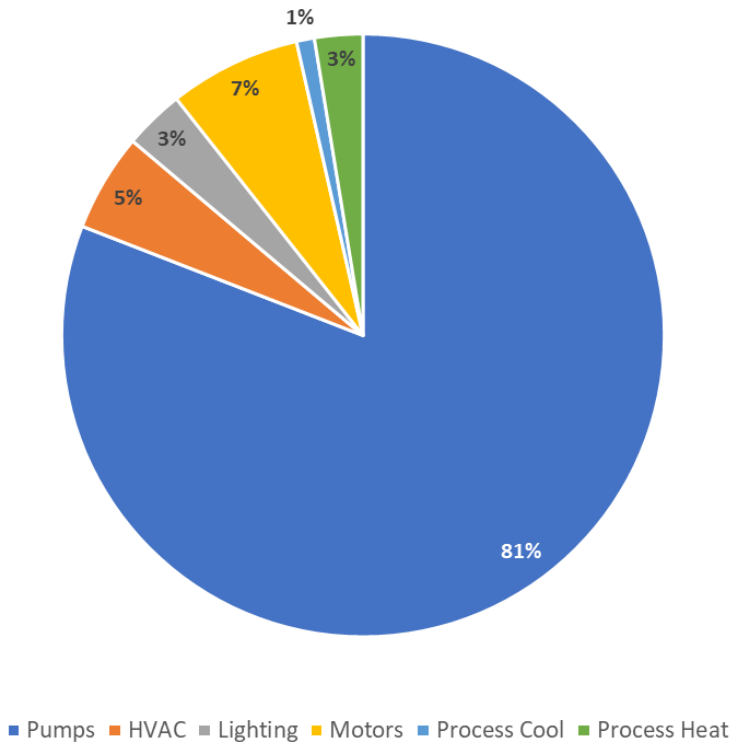
Figure 12. Industrial Sector Energy Shares by Business Segment and Region (2018)



	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).

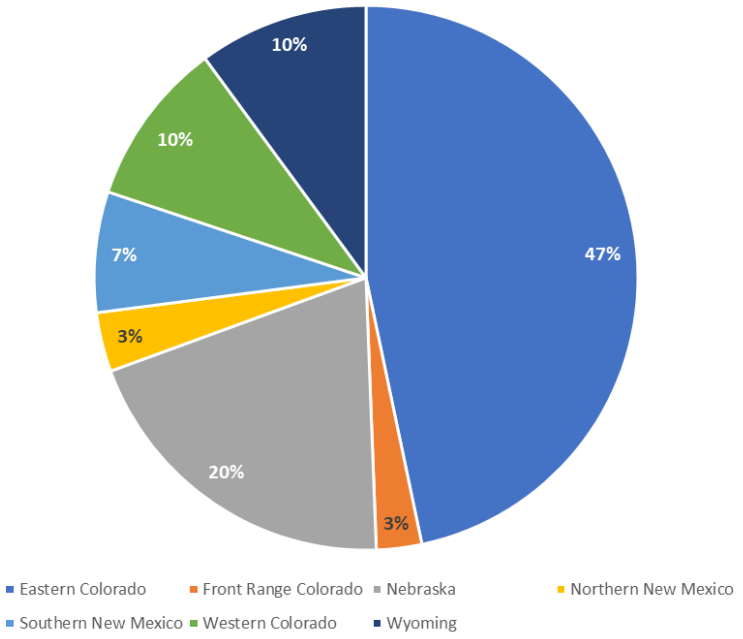
Figure 13. Industrial Sector Energy Shares by End-Use



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

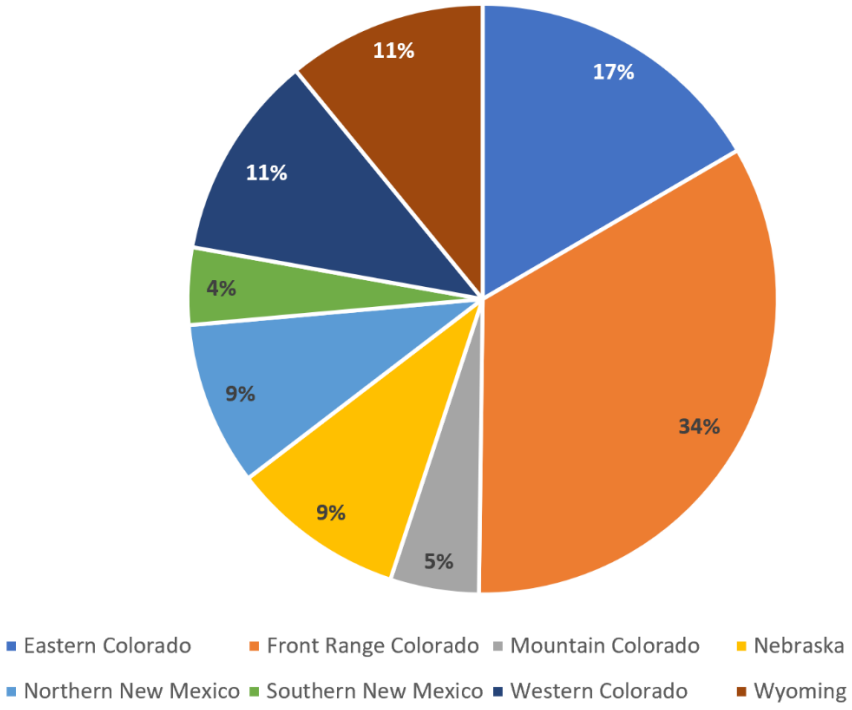


Figure 16. 2018 Coincident Peak Demand by Sector

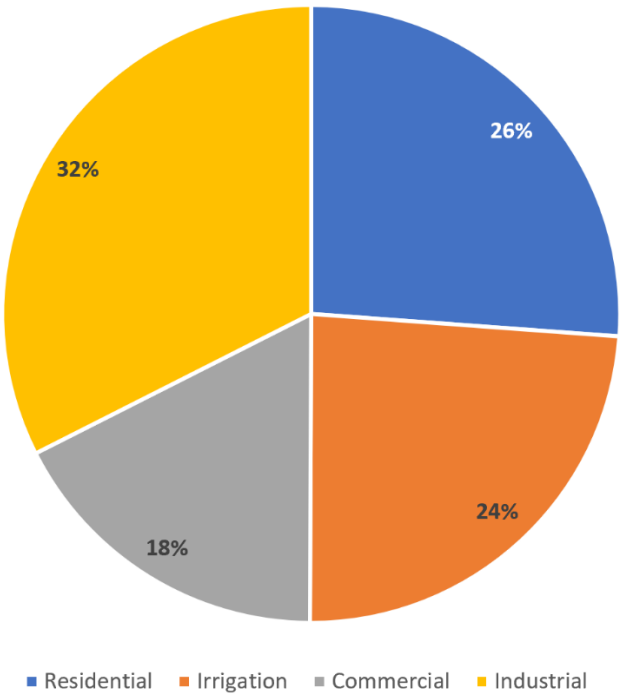
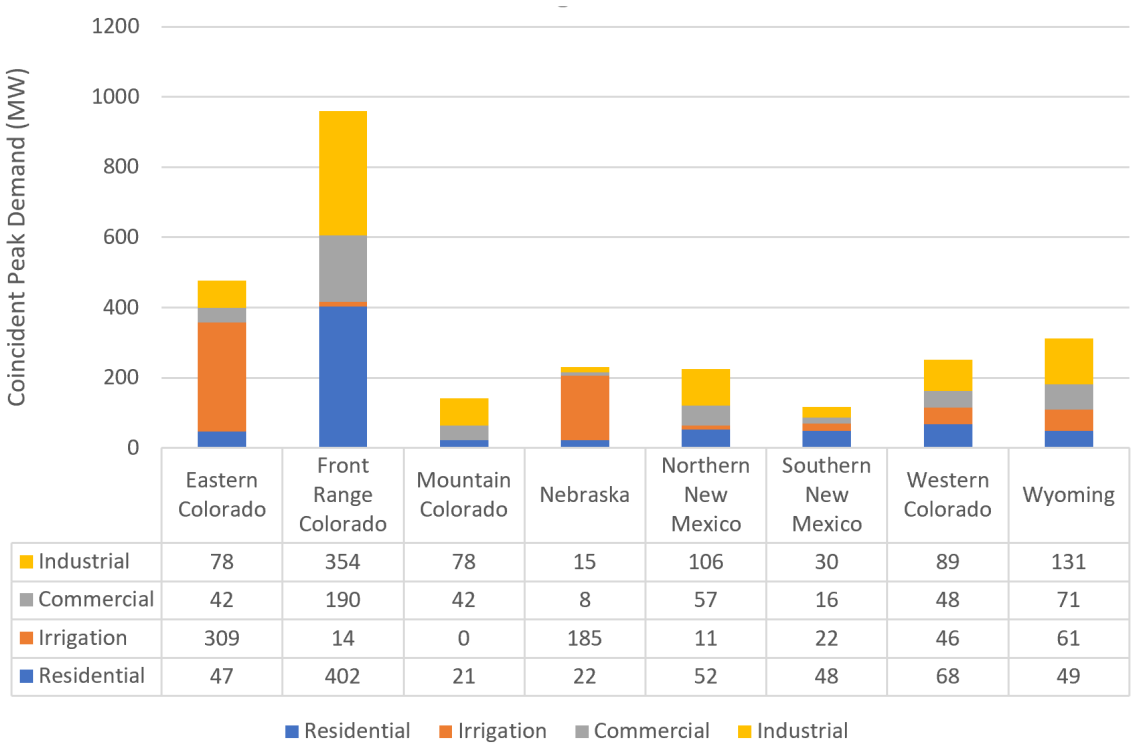


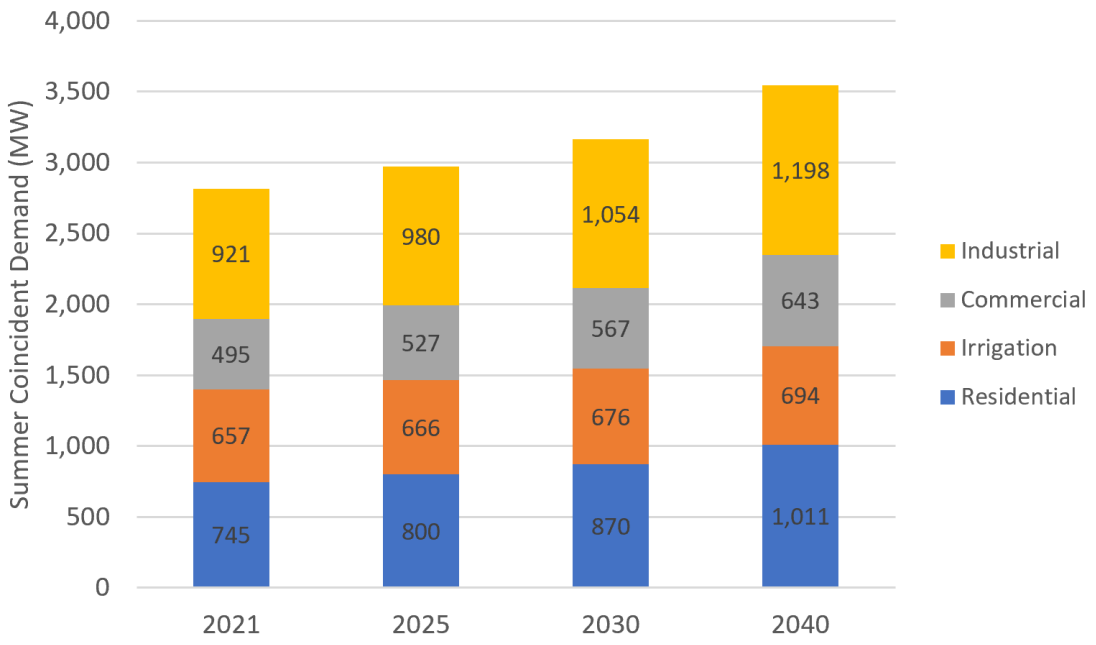
Figure 17. 2018 Coincident Peak Demand by Sector and Region



	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

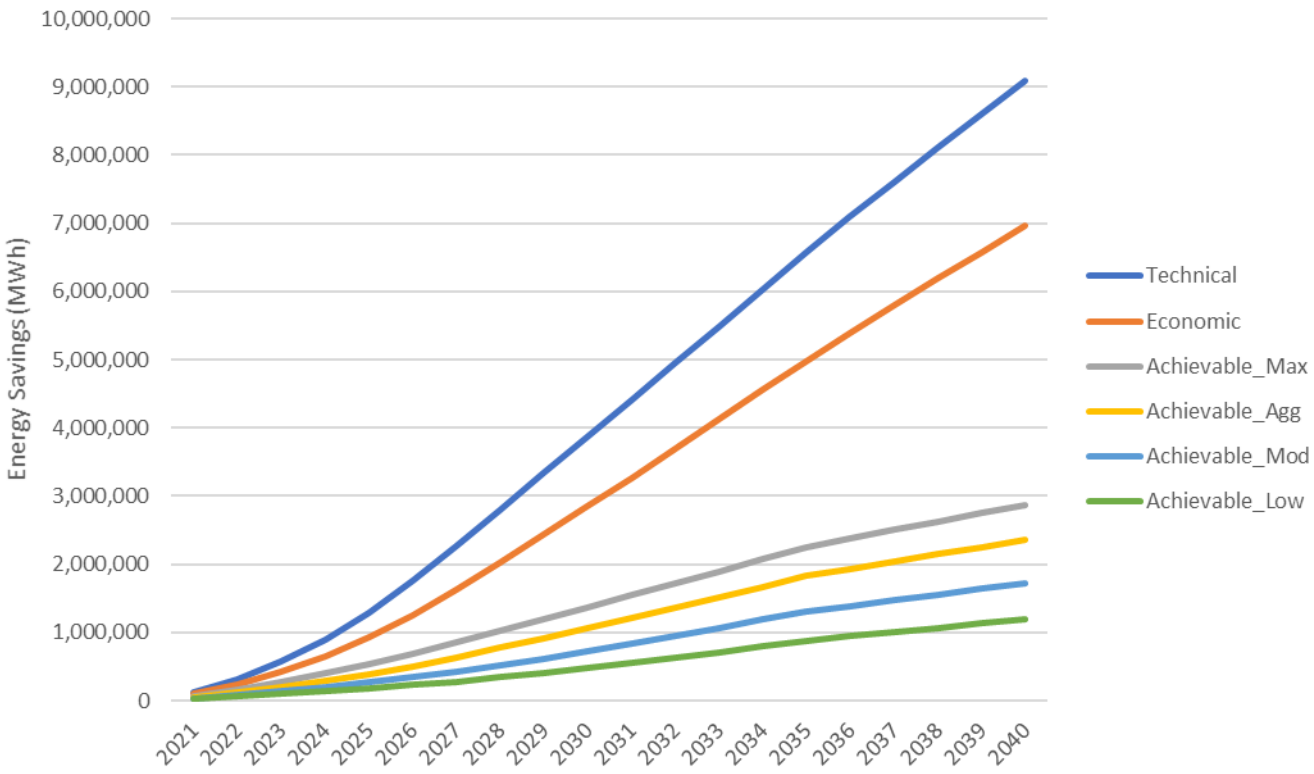


Table 11. shows the impacts of cumulative savings potential on Tri-State's baseline energy consumption forecast. The cumulative savings associated with the Achievable Moderate scenario would decrease Tri-State's baseline forecast consumption by approximately 0.25% in 2021. The reduction in baseline energy 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

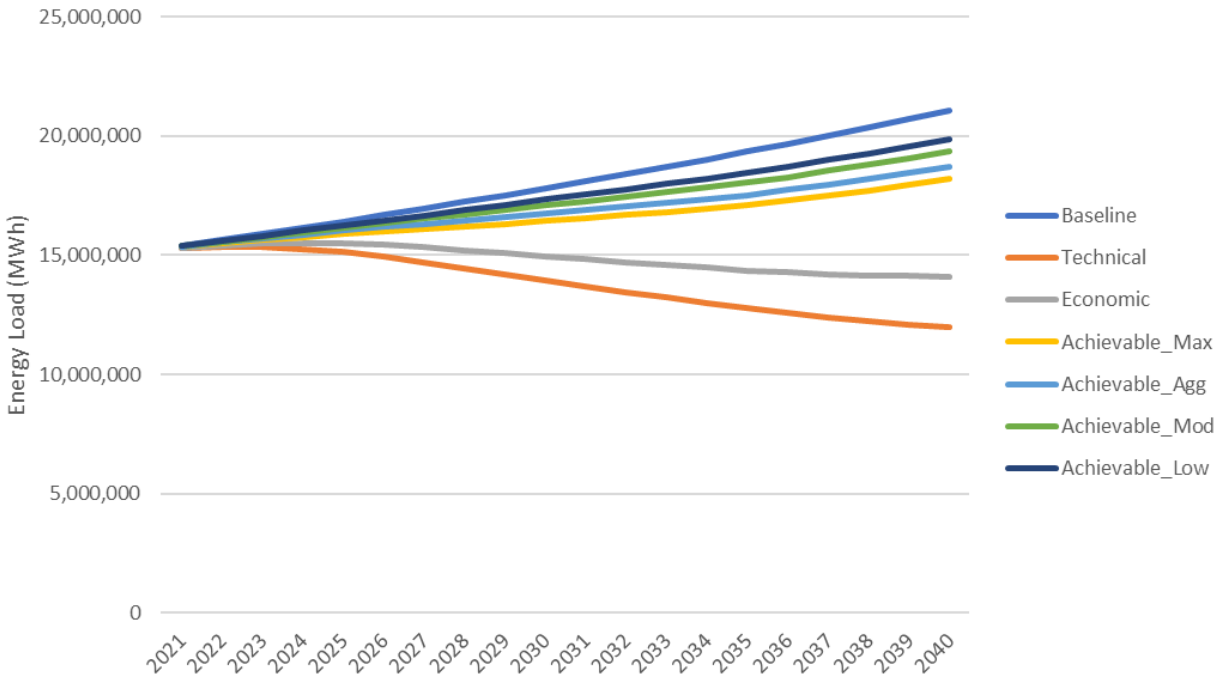
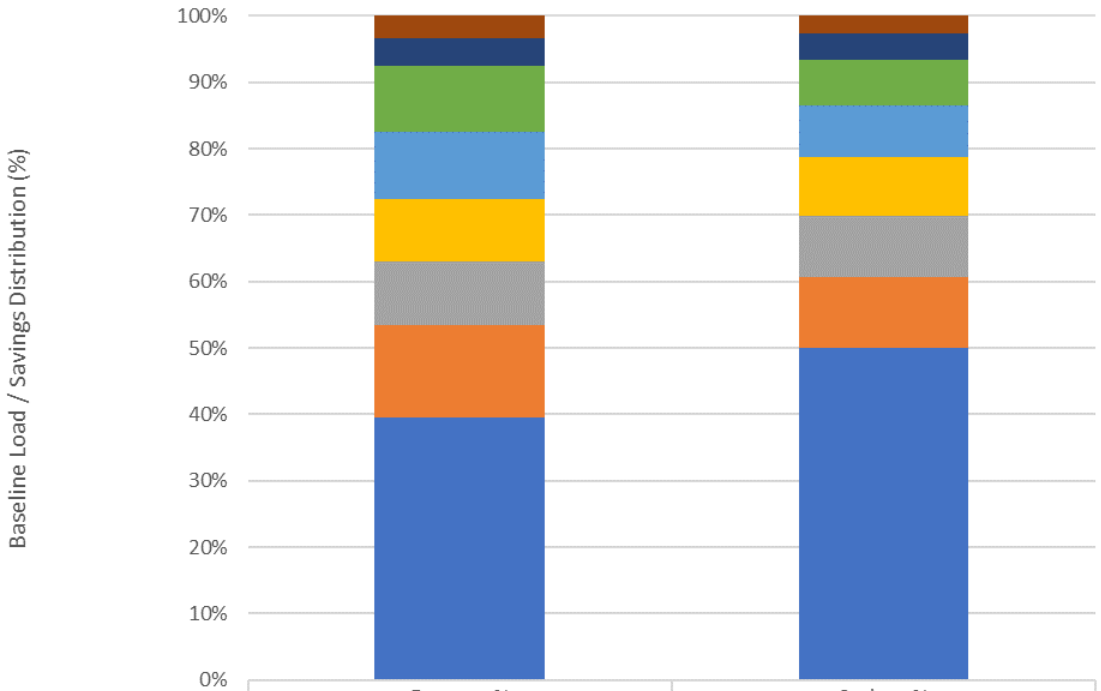


Figure 21 and Table 12 present energy savings potential by region. Front Range Colorado represents the largest share making up half the total. The other regions within Colorado account for nearly one quarter of the remaining savings potential. The two regions within New Mexico together comprise approximately 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



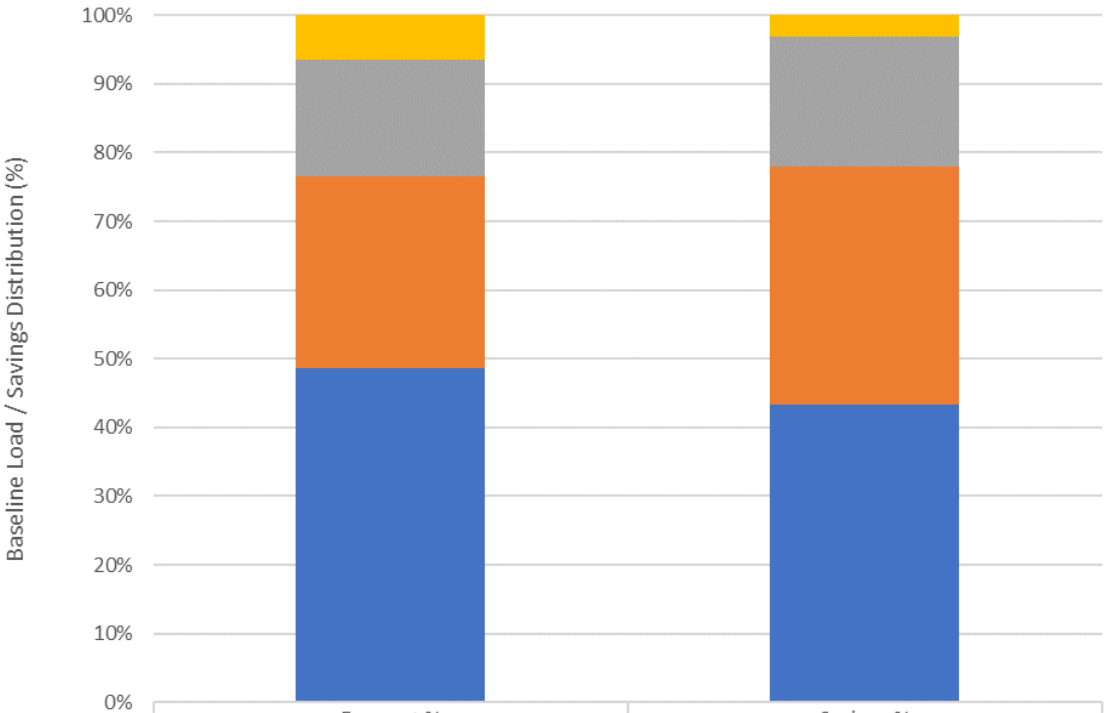
	Forecast %	Savings %
Nebraska	3.4%	2.7%
Southern New Mexico	4.1%	3.9%
Mountain Colorado	9.8%	6.8%
Eastern Colorado	10.2%	7.8%
Northern New Mexico	9.5%	8.8%
Western Colorado	9.6%	9.2%
Wyoming	13.9%	10.6%
Front Range Colorado	39.5%	50.0%

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)



	Forecast %	Savings %
Irrigation	6.6%	3.1%
Commercial	17.0%	19.0%
Residential	27.9%	34.6%
Industrial	48.6%	43.3%

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.

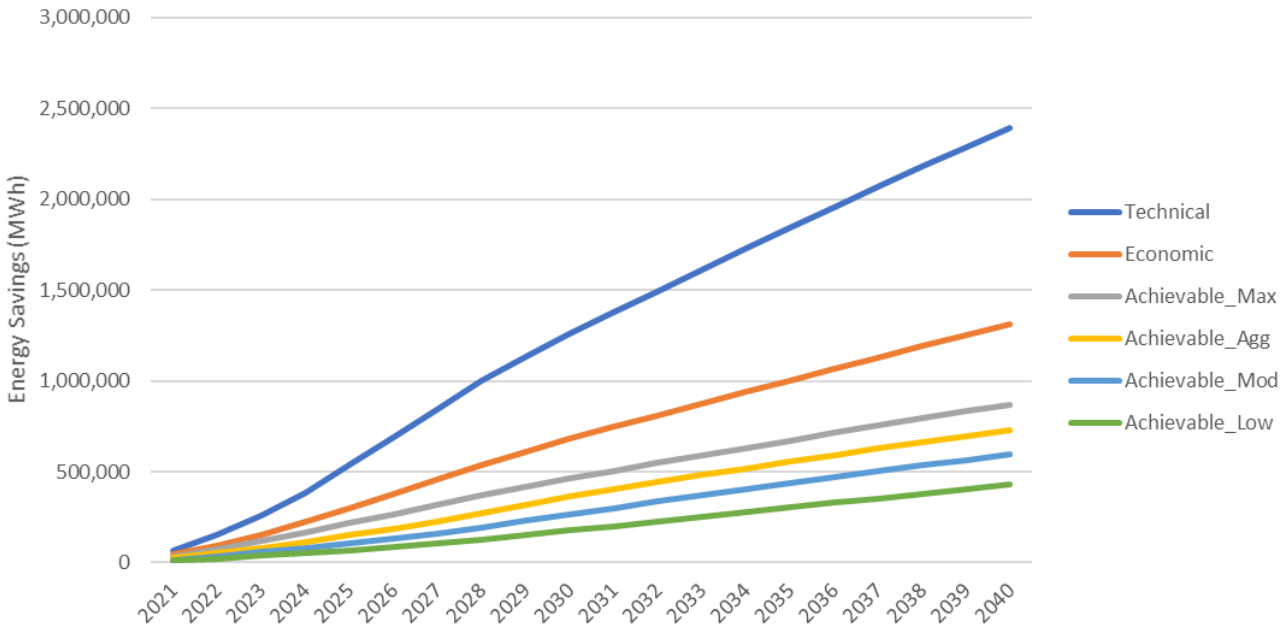
5.2. Detailed Results

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



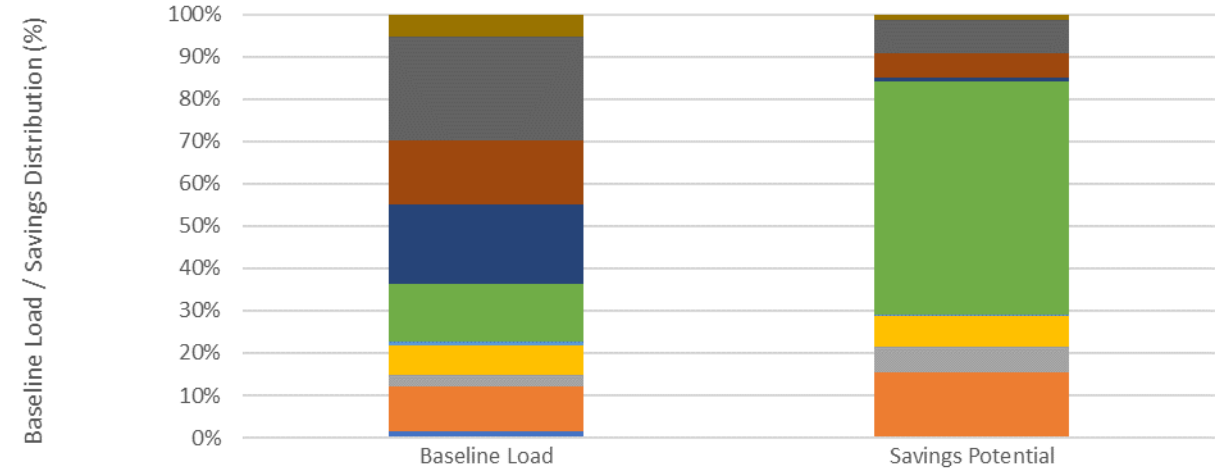
The cumulative residential savings potential under the Achievable-Moderate scenario equates to 9.1% of the residential baseline load forecast for 2040 (see Table 16.). The maximum achievable savings would equate to 16.2% of the forecast energy load for this sector.

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)



	Baseline Load	Savings Potential
Electric Water Heater	5.4%	1.3%
Plug Loads	24.5%	7.8%
Refirgerator/Freezer	14.9%	5.7%
Appliances	18.9%	1.1%
Lighting	13.6%	55.1%
Zonal Air	1.0%	0.2%
Central Air	6.8%	7.2%
HVAC Aux	2.9%	6.1%
Central Heating	10.4%	15.4%
Heat Pump	1.7%	0.1%

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

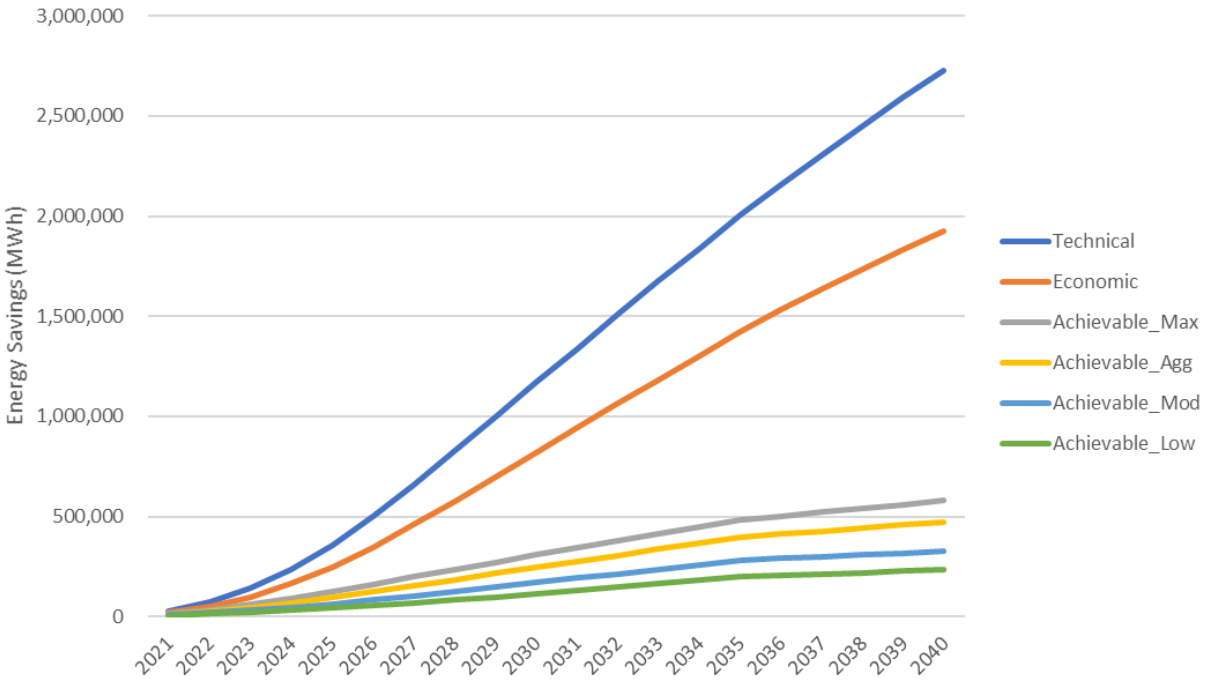
Table 19. presents cumulative savings potential for the commercial sector by scenario at various milestones in the analysis period and Figure 25 shows the growth in cumulative savings potential through 2040. The Achievable-Moderate scenario estimates 8.6 GWh of savings potential in 2021 rising to approximately 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)

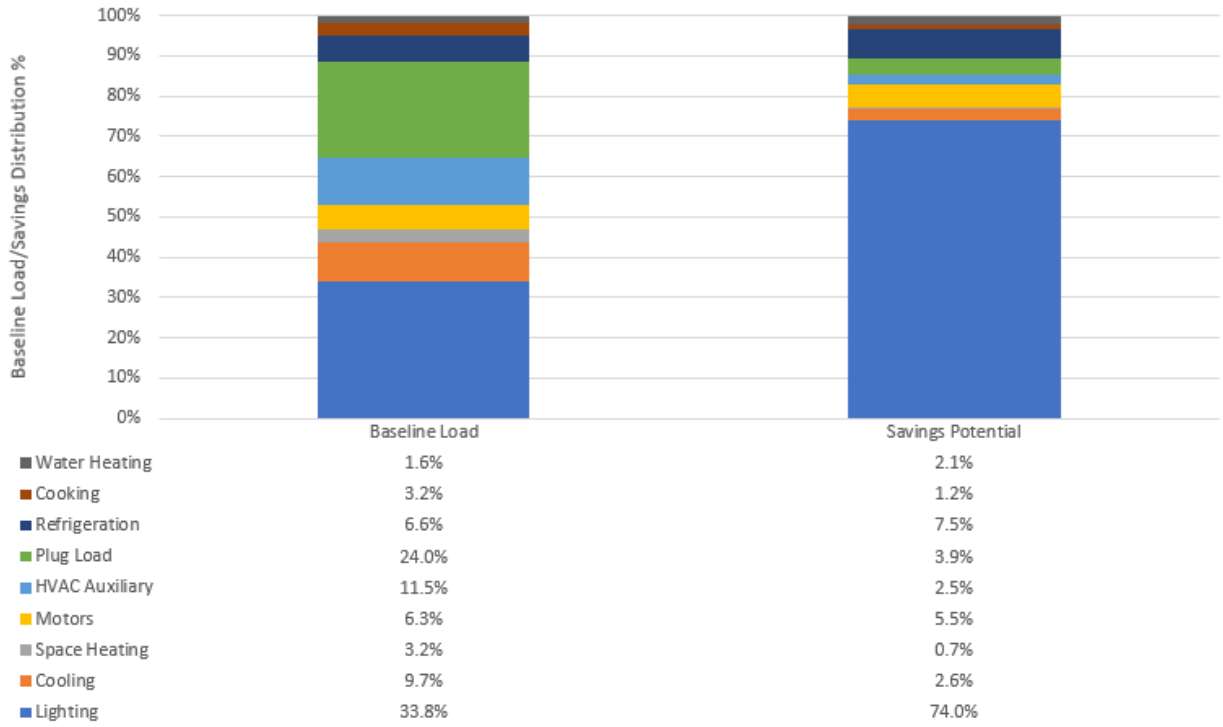


Table 21 presents cumulative commercial demand reductions by end-use by milestone year. Lighting accounts for nearly 55% of demand savings from commercial energy efficiency measures, producing almost 2,500 kW of demand reductions by 2040. Relative to their energy savings, the Cooling and HVAC Auxillary 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)

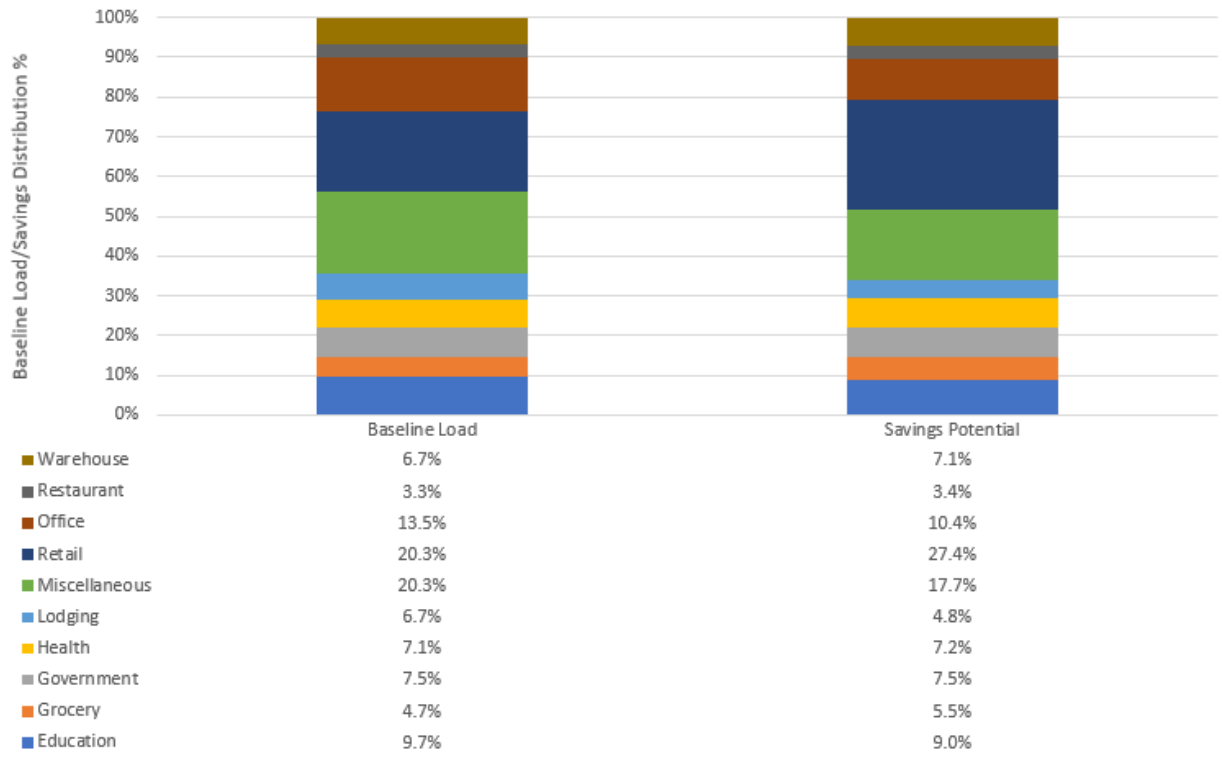


Table 22. summarizes cumulative commercial program cost metrics by milestone year. As shown, first-year program costs are approximately $1.4 million, rising to a 20-year average annual cost of roughly $4.1 millon. Acquisition costs start at $159/MWh during the first year of analysis and see a gradual 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.

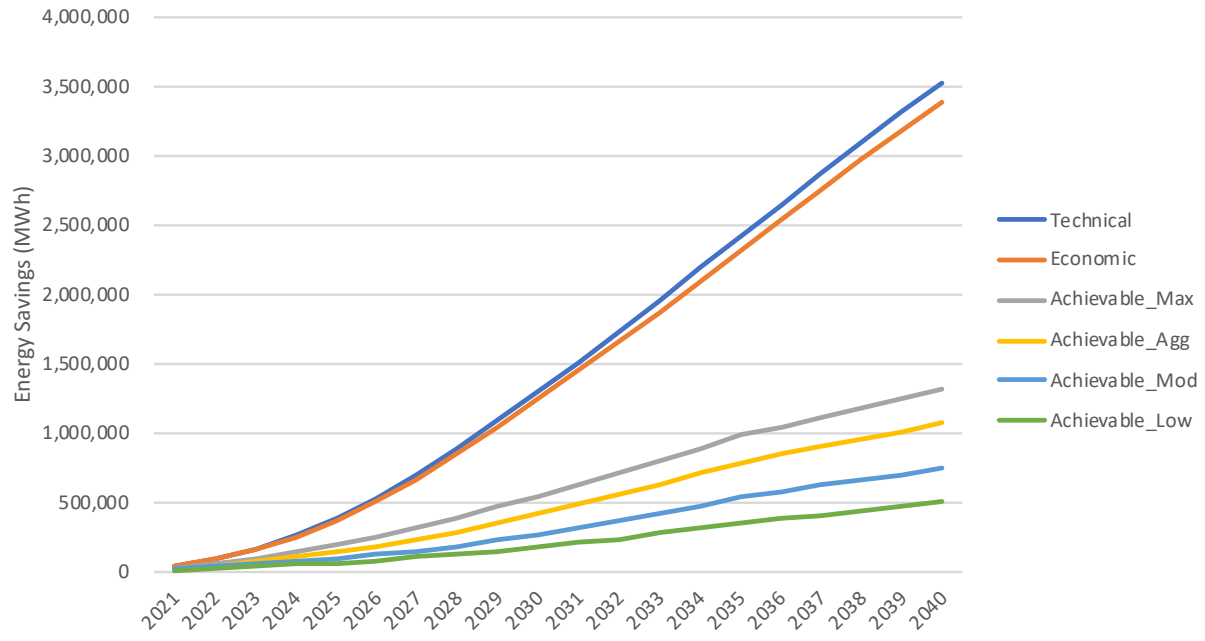
7.2. Detailed Results

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



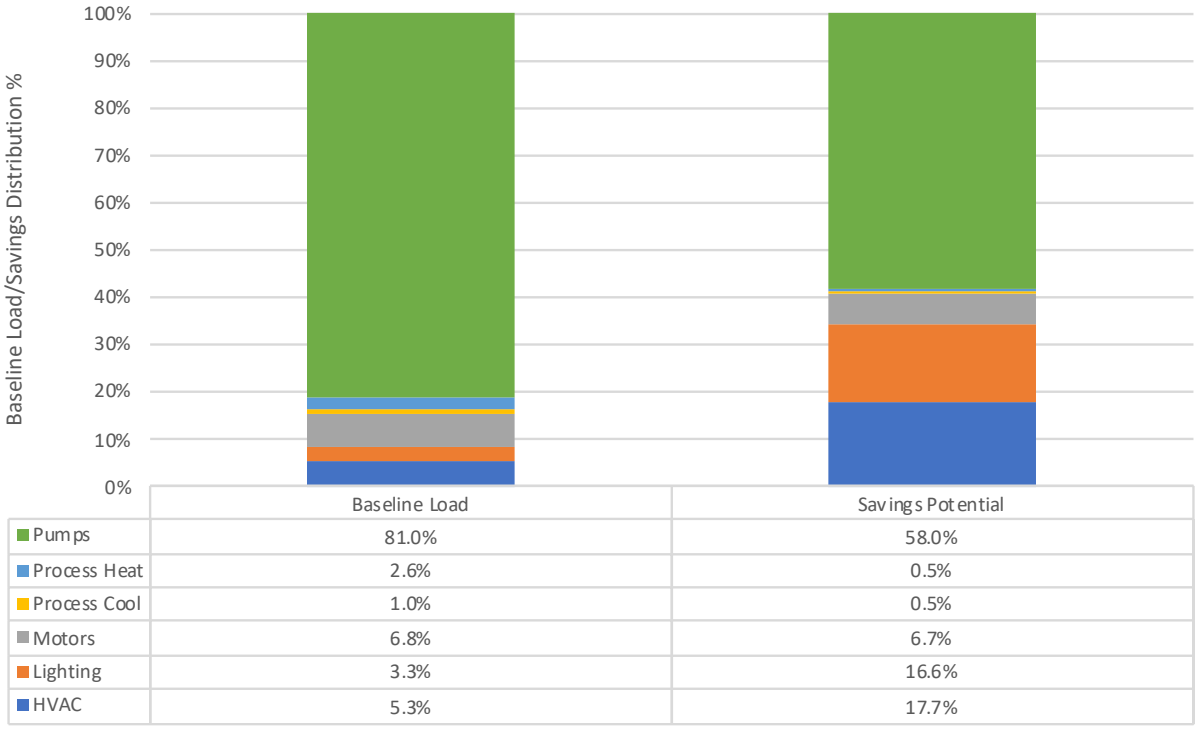
The cumulative industrial savings potential under the Achievable-Moderate scenario equates to a reduction of 0.21% of industrial baseline sales in 2021, a 1.24% reduction by 2025 and a 7.28% reduction by 2040 (see Table 24.). The analysis estimates a range in reduction of baseline energy sales for the 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

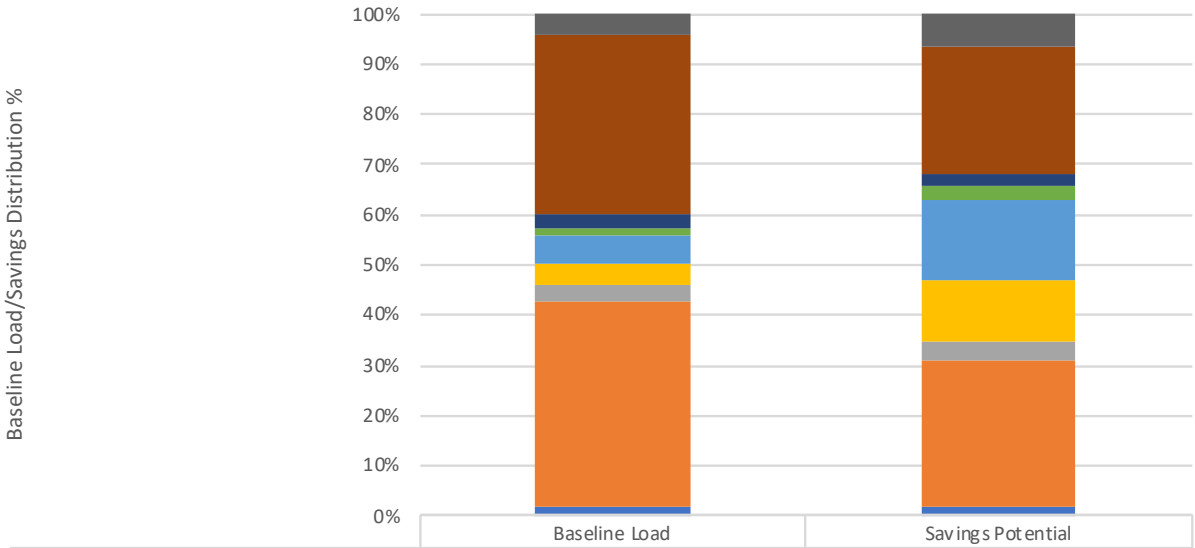
measures contribute nearly 6.6 MW of cumulative demand savings potential. Lighting efficiency measures have the potential to decrease demand by almost 1.3 MW and HVAC by nearly 1.7 MW.

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

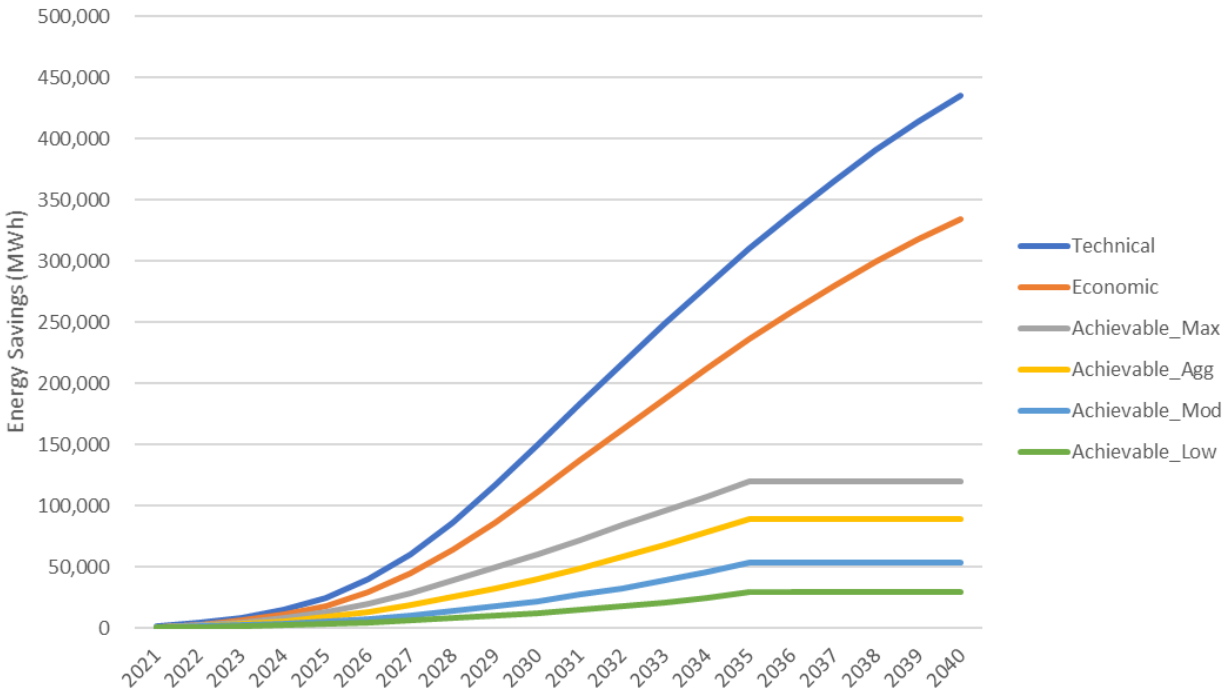


Table 28. shows the percentage impact of cumulative irrigation savings on the baseline forecast by scenario for each milestone year. Under the Achievable-Moderate scenario irrigation measures have the potential to reduce baseline load by nearly 4%. The maximum achievable scenario would more than double those savings to reduce baseline load by approximately 9%.

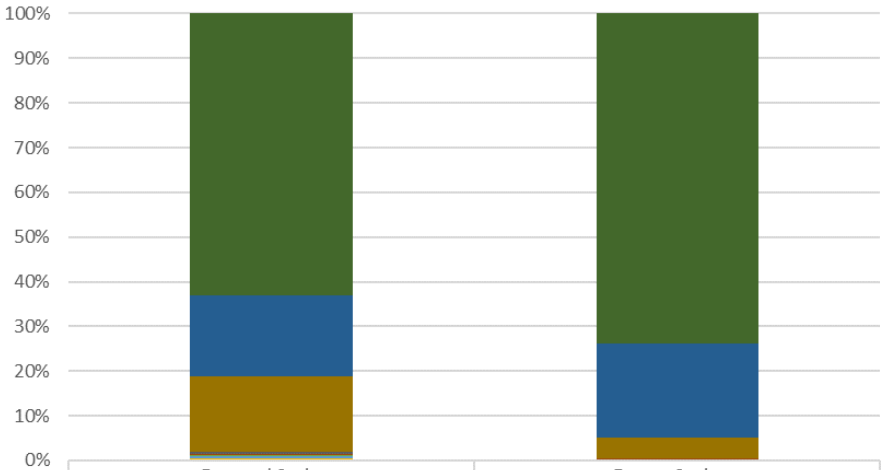
Eastern Colorado accounts for approximately half the irrigation savings potential, followed by Nebraska at approximately 30% of the total. Northern and Southern New Mexico together account for approximately 12% of total irrigation savings potential with the remaining regions making up a nominal share 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

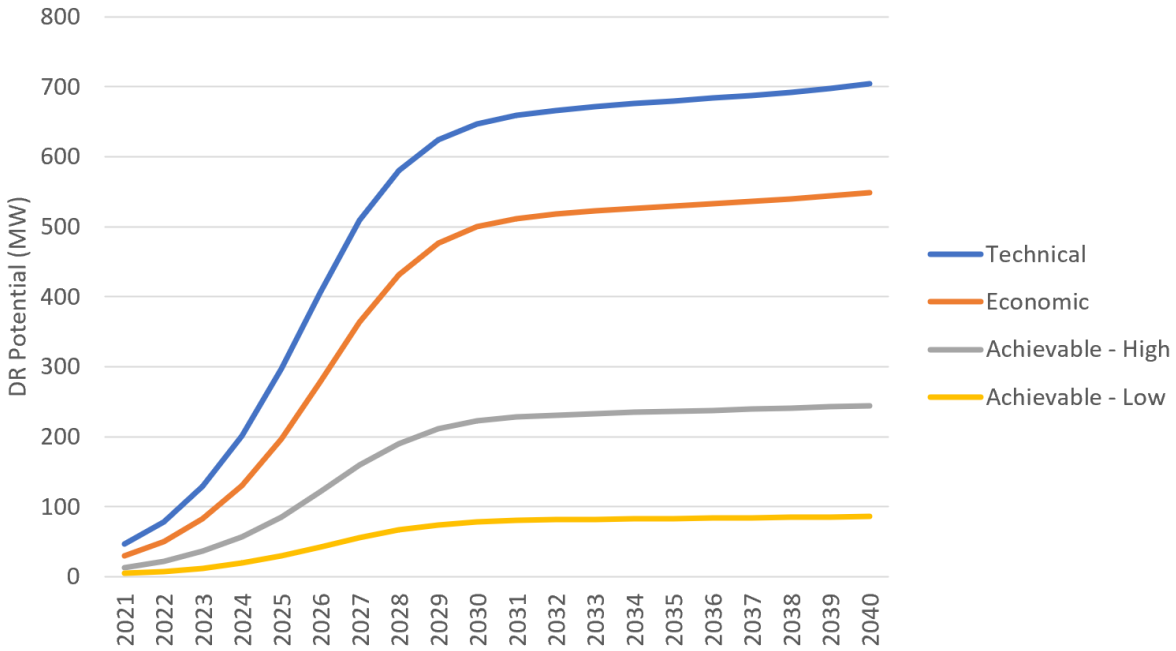


Table 31. shows the impacts of demand response potential relative to Tri-State's baseline demand forecast. The Achievable-High and -Low scenarios represent about 6.90% and 2.43% of forecasted coincident demand in 2040 respectively.

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)

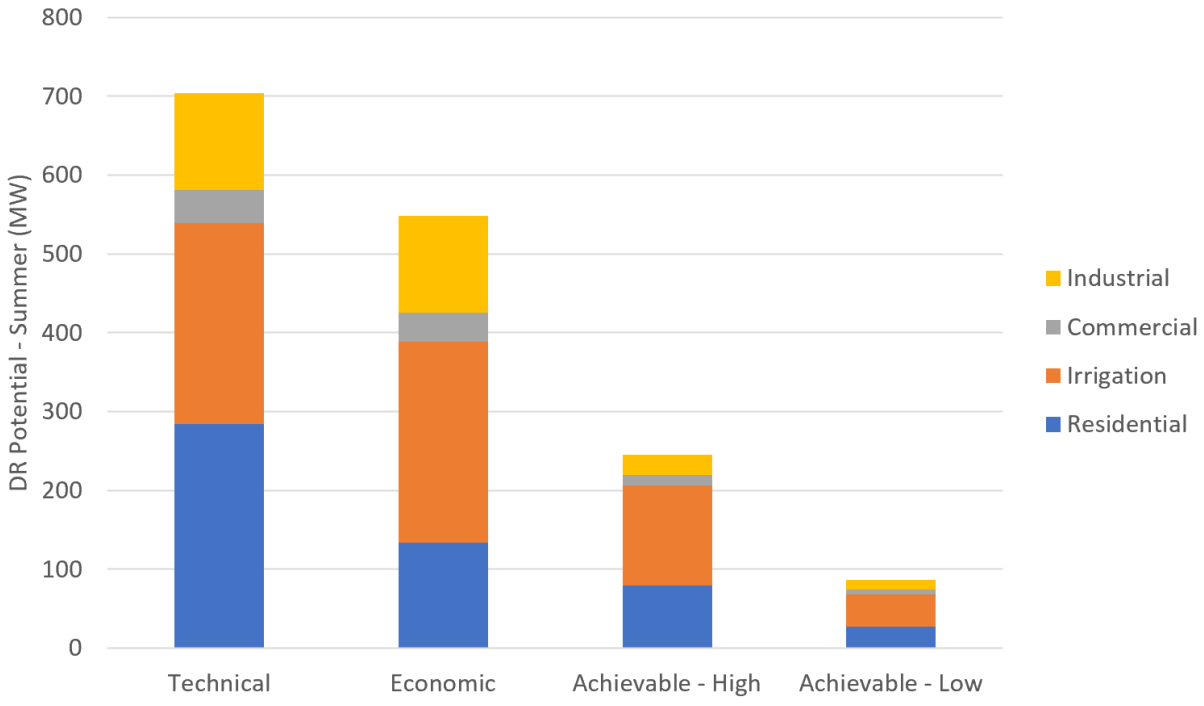
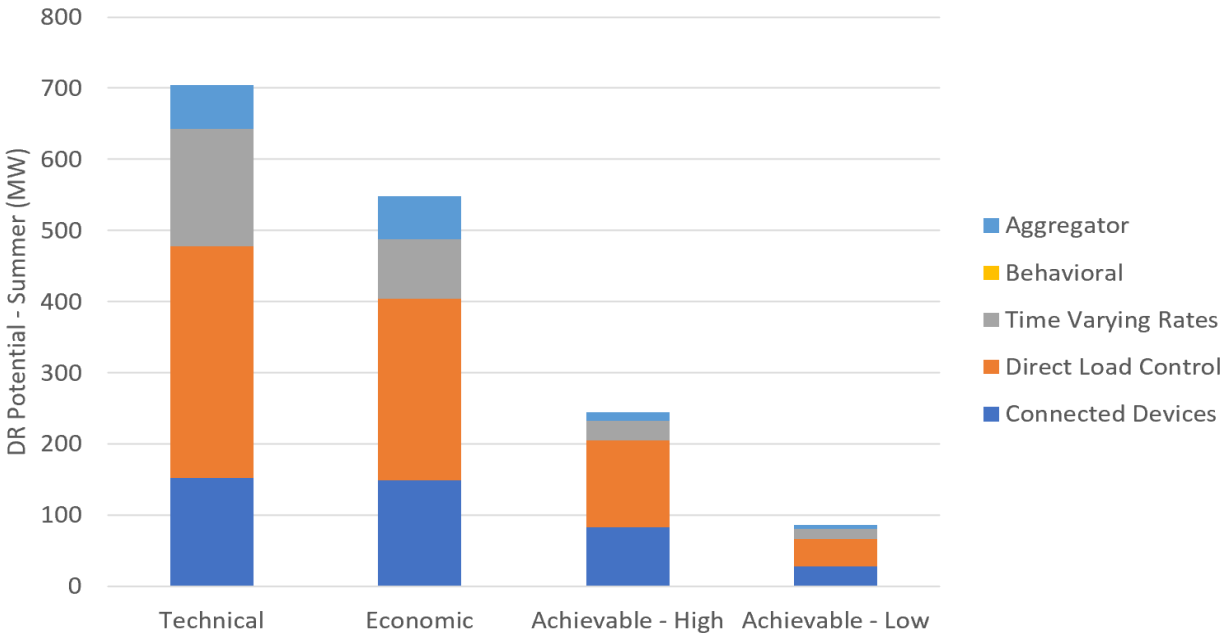


Figure 35. Portfolio Demand Response Potential by Program Type (2040)[16]



[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

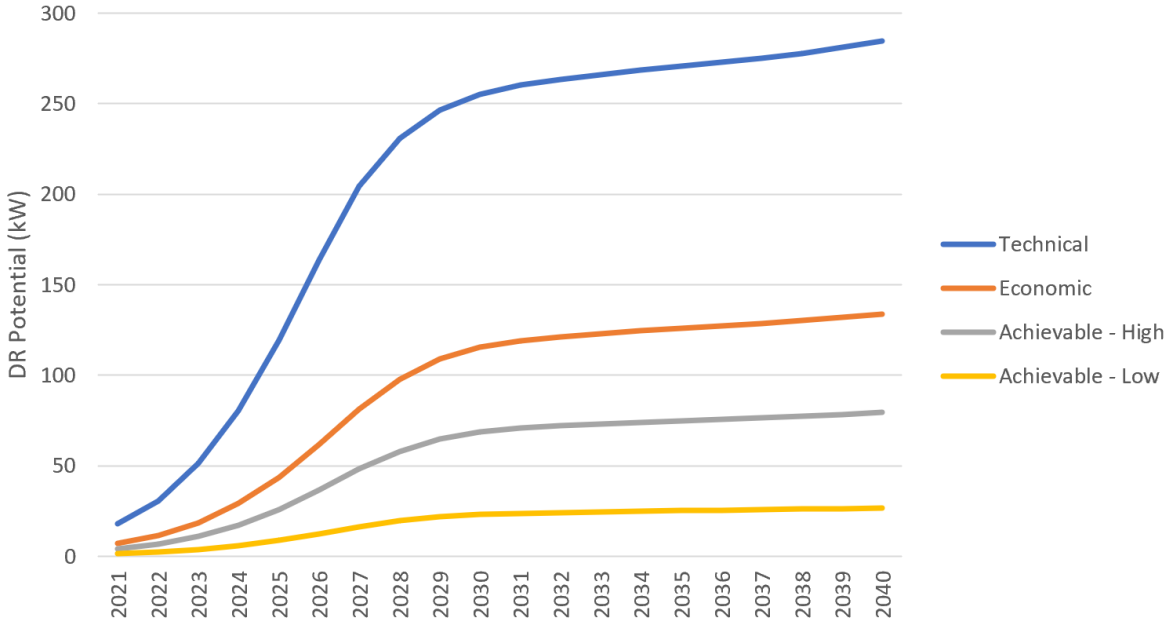
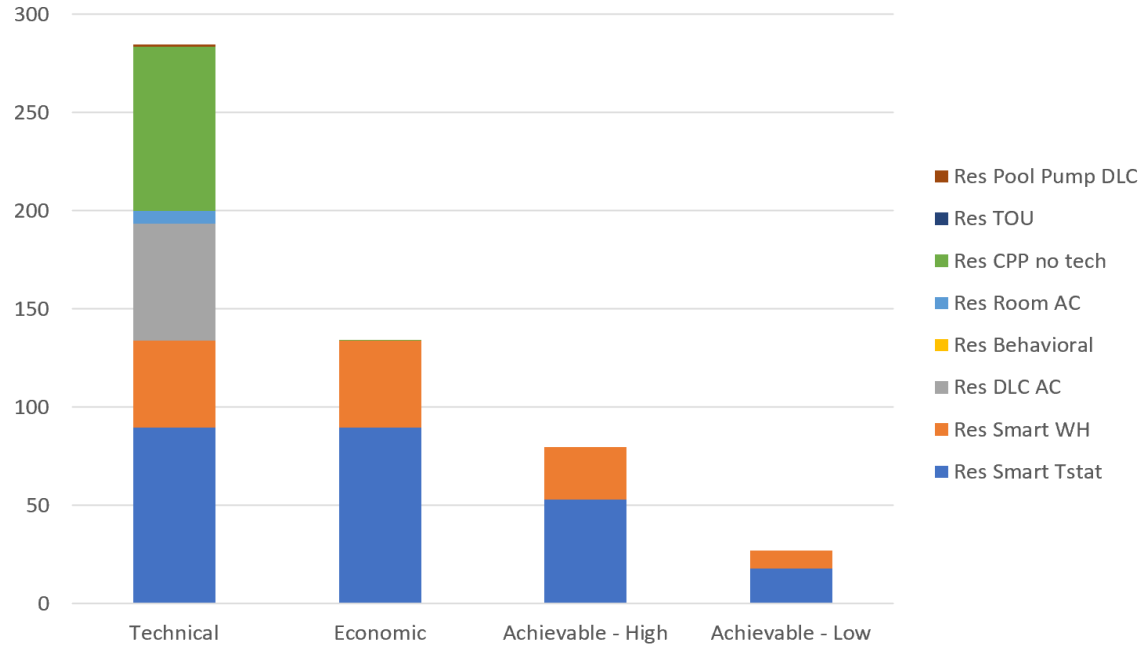


Figure 37. Residential Sector Demand Response Potential by Program (2040)



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

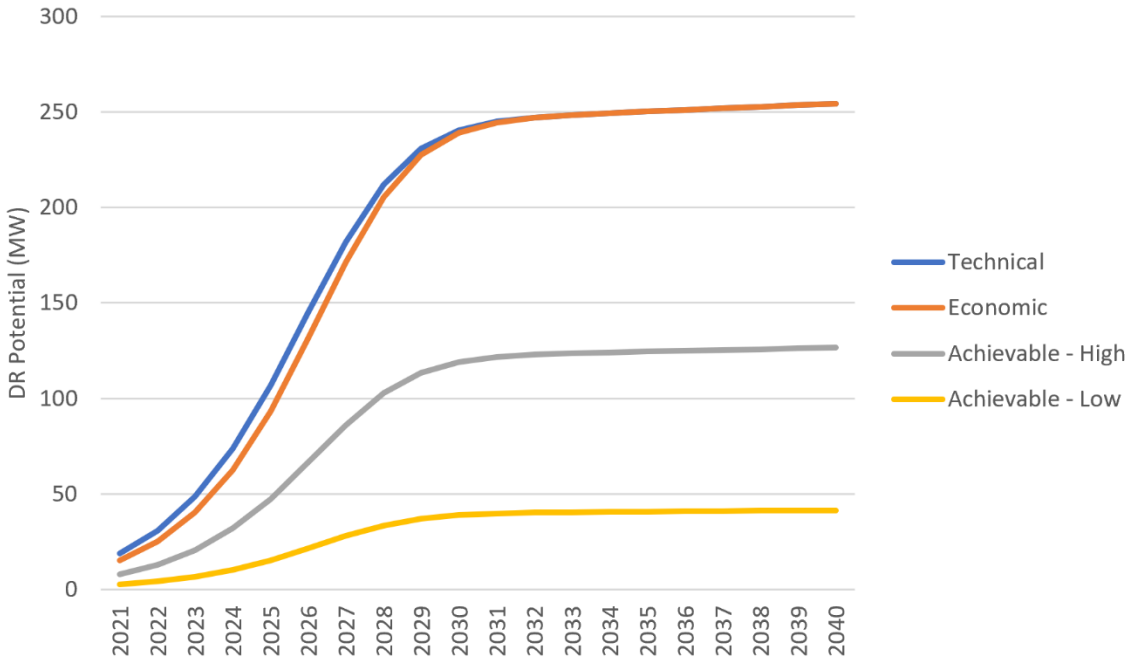
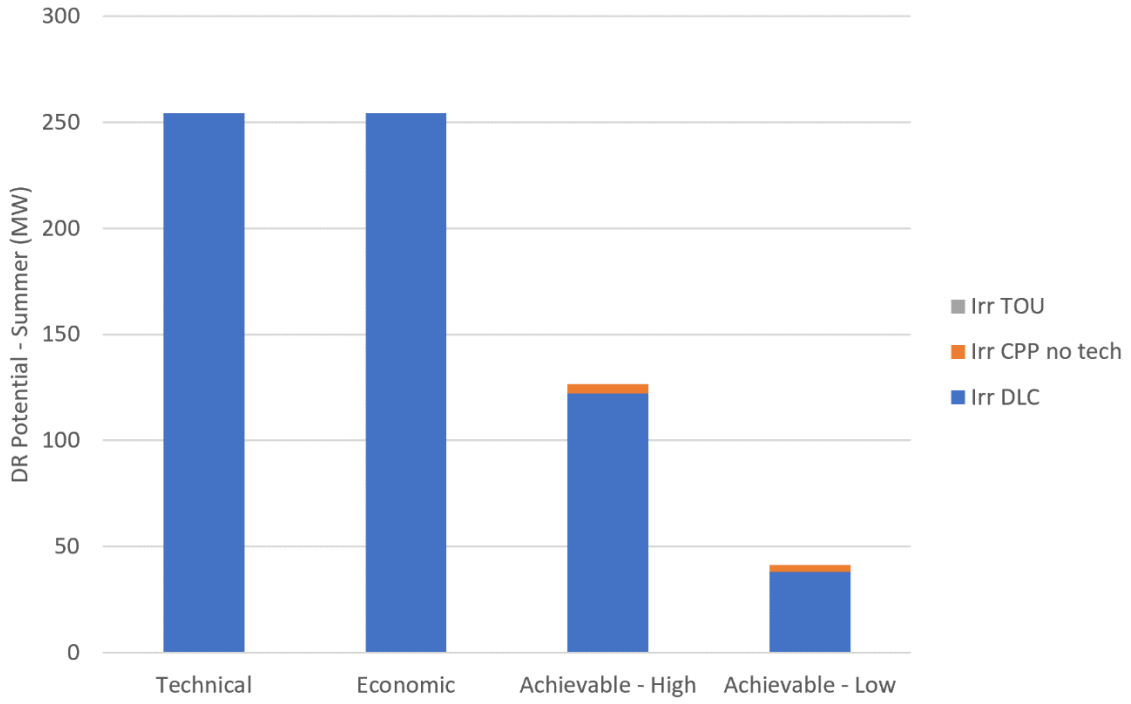


Figure 39. Irrigation Sector Demand Response Potential by Program (2040)



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

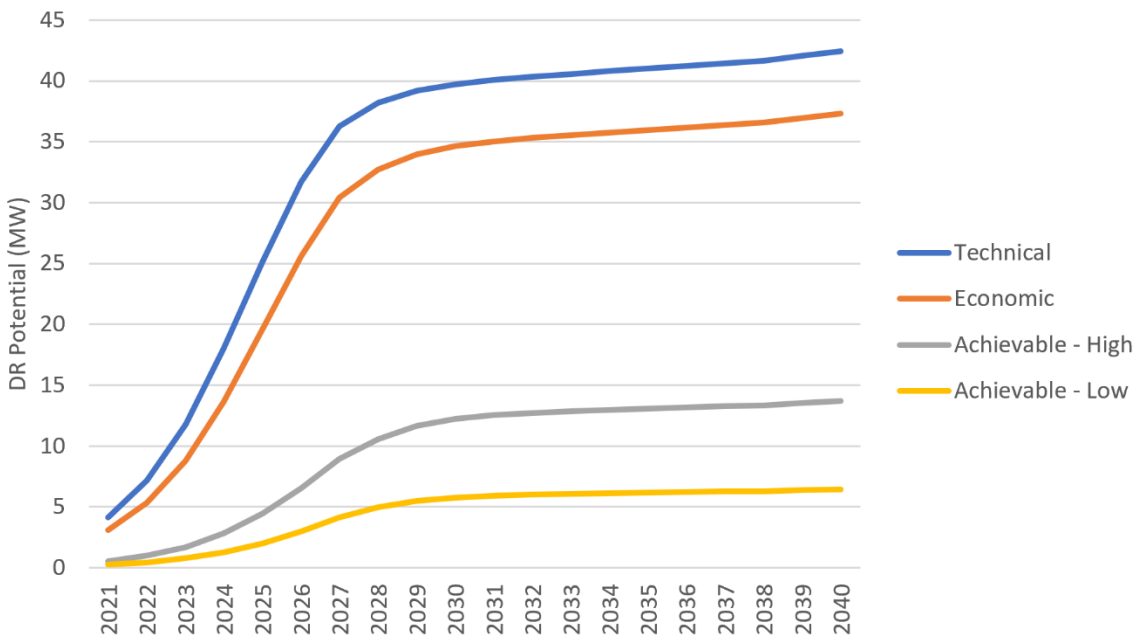
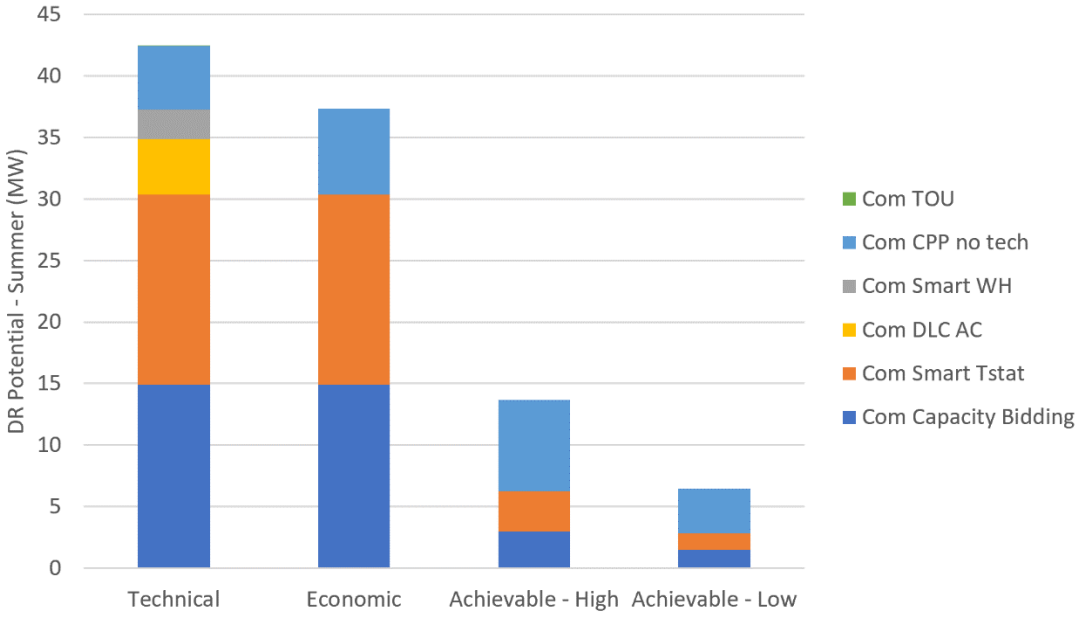


Figure 41. Commercial Sector Demand Response Potential by Program (2040)



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

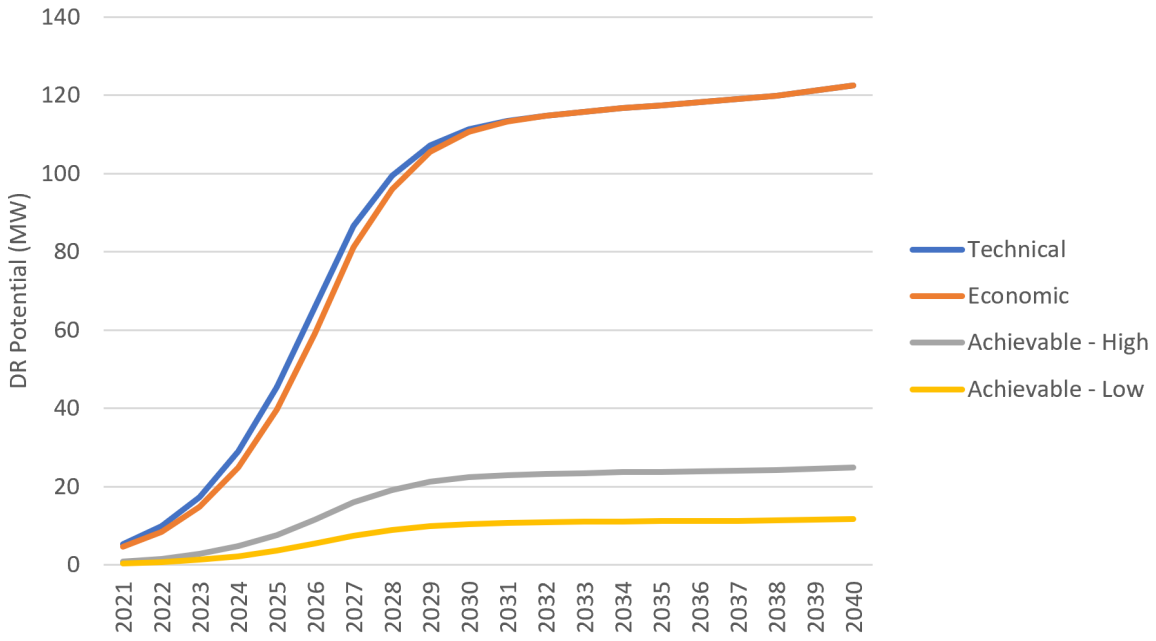
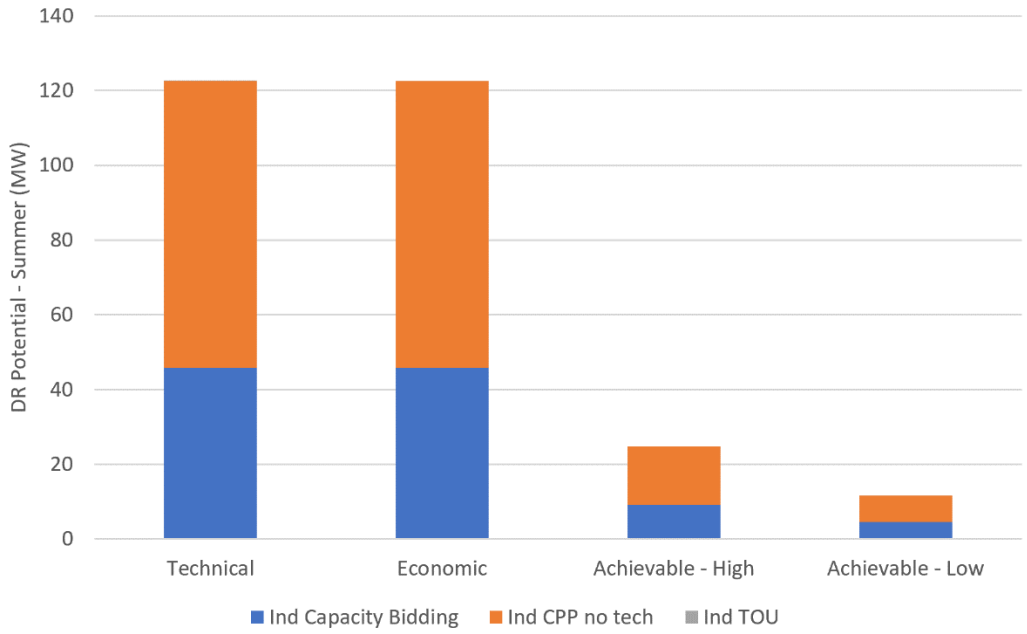


Figure 43. Industrial Sector Demand Response Potential by Program (2040)



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

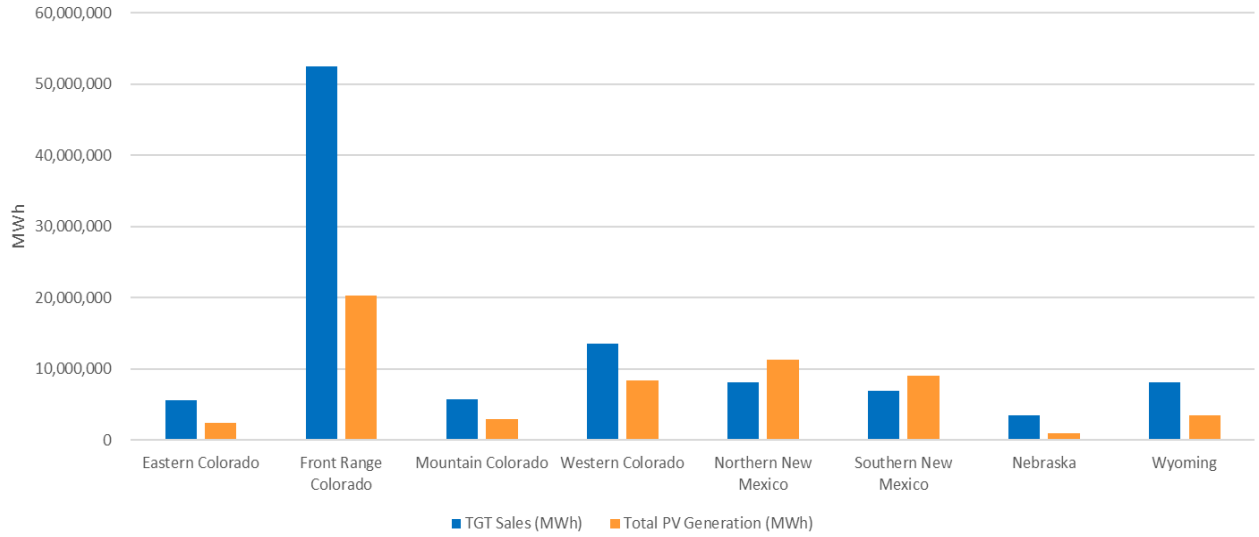
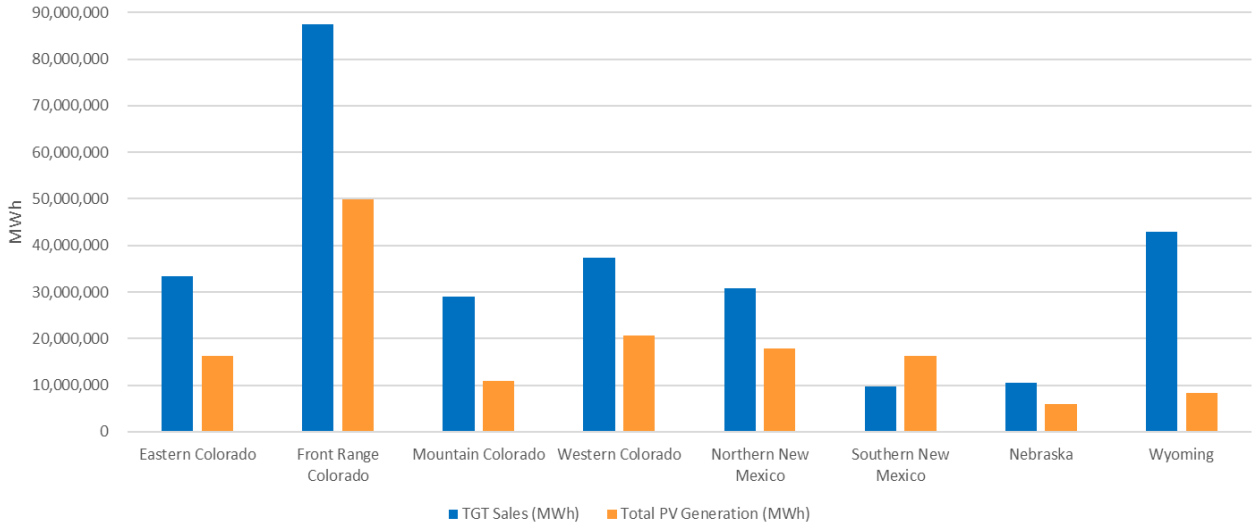


Figure 45. 2040 Cumulative Non-Residential PV Generation vs Sales by Region



10.4. Economic and Achievable DER Potential Findings

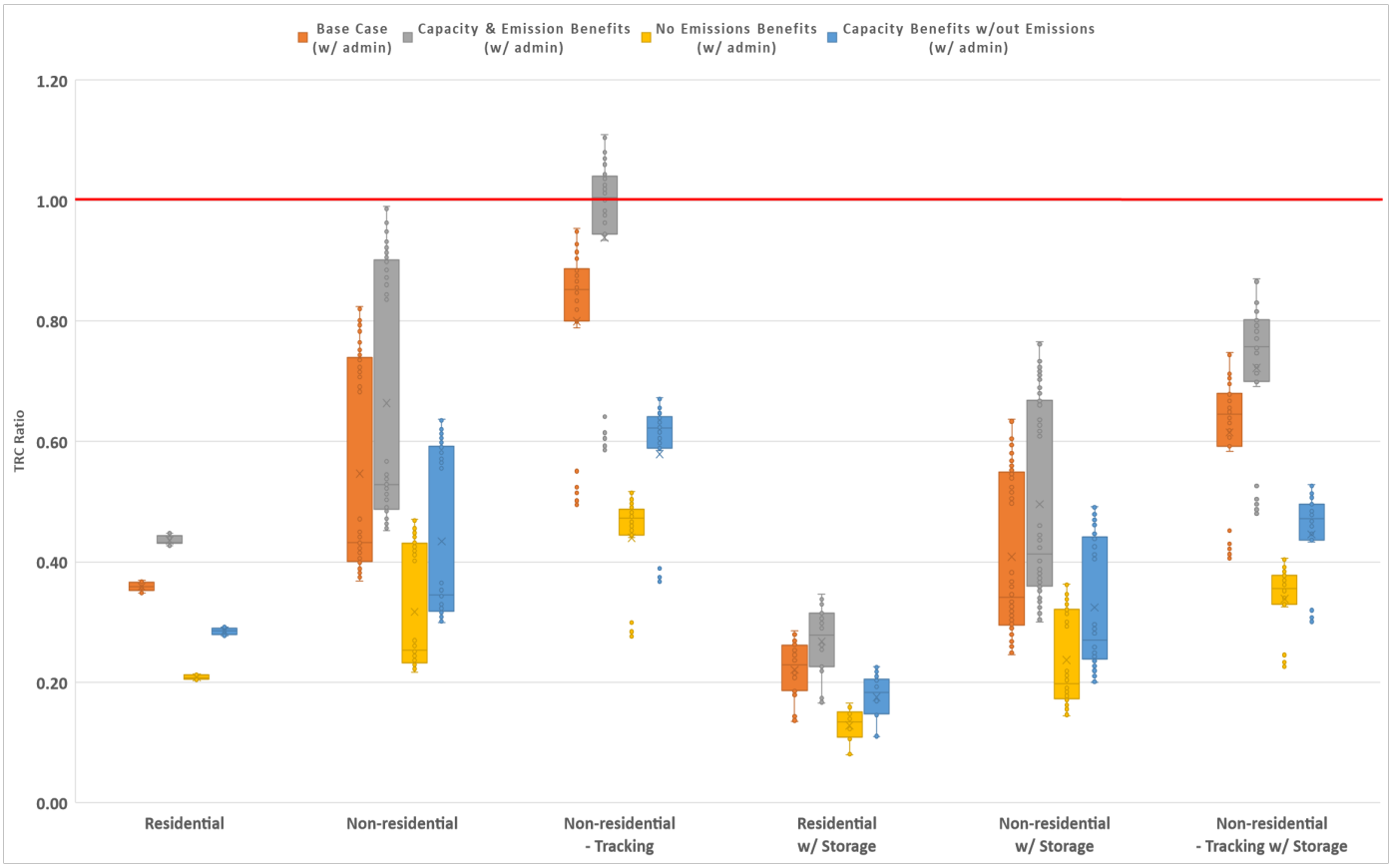
The Team screened economic potential using a TRC hurdle of 1.0 with the inclusion of CO_2 emission benefits based on the social cost of carbon of $46/ton and administrative costs of $0.05/kWh. However,

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.

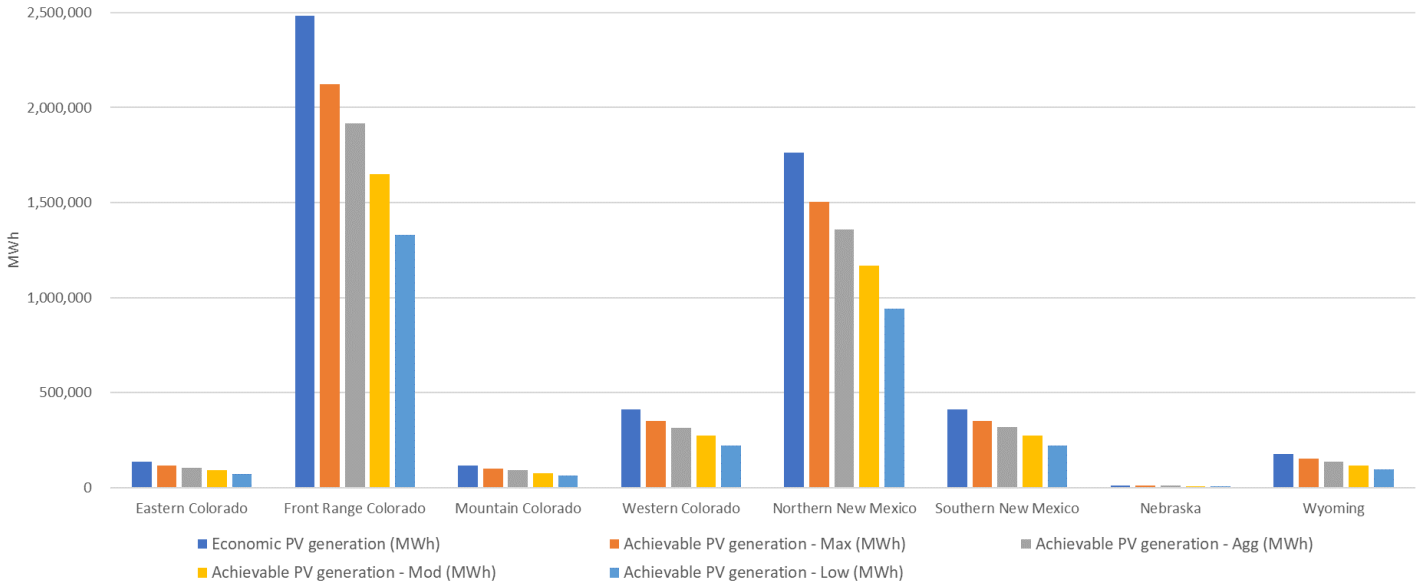
Figure 46. Solar PV TRC Ratios - Multiple Scenarios



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.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-50:
Insgold 2023 ERP Direct Testimony

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

DIRECT TESTIMONY AND ATTACHMENTS OF BARRY W. INGOLD ON BEHALF OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

December 1, 2023

Colorado PUC E-Filings System

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ATTACHMENTS

BWI-1	Statement of Qualifications for Barry W. Ingold

I. INTRODUCTION, QUALIFICATIONS, AND PURPOSE OF TESTIMONY

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Barry W. Ingold. 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 Chief Operating Officer.

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 BWI-1**.

Q: PLEASE SUMMARIZE YOUR BACKGROUND AND EXPERIENCE IN THE ELECTRICITY UTILITY INDUSTRY.

A: I have 26 years of experience in the electric utility industry. In my present position, I am responsible for managing Tri-State's generation and transmission operations. This includes all capital budget and construction projects for Tri-State's generation and transmission facilities. Prior to joining Tri-State, I was an Application Control Engineer and Project Manager for Honeywell International, Inc., a global provider of control solutions. In addition to my years of industry experience, I served for thirteen years in the submarine force of the United States Navy. I then transitioned to the Navy Reserve where I served for an additional thirteen years, during which

time I held command of five Navy Reserve Detachments. I attained the rank of Captain prior to retiring from the United States Navy. I hold a Bachelor's degree in Marine Engineering and Marine Transportation from the United States Merchant Marine Academy, a Master's degree in Mechanical Engineering from the Naval Postgraduate School, and a Master's degree in Business Administration from Arizona State University.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A: My Direct Testimony addresses certain technical and operational assumptions regarding Tri-State's owned and contracted thermal (coal and natural gas) resources relied upon as inputs to the 2023 Electric Resource Plan ("ERP"). I also address assumptions and analysis regarding the potential for new or expanded owned or contracted thermal resources during the resource acquisition period ("RAP").

Q. ARE YOU SPONSORING ANY ATTACHMENTS AS PART OF YOUR TESTIMONY?

A. Yes, as part of my Direct Testimony, I am sponsoring the following attachments:

- Attachment BWI-1: Statement of Qualifications for Barry W. Ingold

II. EXISTING COAL RESOURCES

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my Direct Testimony, I identify and describe Tri-State's current, existing coal-fired fleet, including forecasted operations and emissions reductions, during the RAP.

Q: PLEASE BRIEFLY DESCRIBE THE CURRENT COAL-FIRED GENERATION

RESOURCES IN TRI-STATE'S GENERATION FLEET.

A. Tri-State maintains a stake in three coal-fired generation facilities across its system footprint. These include:

- Craig Station (Units 1, 2, and 3), located in Colorado, with net generating capacity of 427 MW, 410 MW,[1] and 448 MW, respectively. Tri-State is the operator of Craig Station.
- Laramie River Station ("LRS"),[2] located in Wyoming, with net generating capacity of 1700 MW. LRS, and associated transmission, make-up the Missouri Basin Power Project ("MBPP"). Basin Electric Power Cooperative is the operator of the MBPP.
- Springerville Unit 3 ("SPV 3"), located in Arizona (primarily serving Tri-State's New Mexico load), has a net generating capacity of 419 MW. Tucson Electric Power Company is the operator of SPV 3.

Q. WHERE DOES TRI-STATE SECURE ITS COAL SUPPLY FOR THESE GENERATION RESOURCES?

A. Coal is supplied to Tri-State's fleet as follows:

- Craig Station: Colowyo Mine supplies coal for Tri-State and Public Service Company of Colorado's ("Public Service") portion of Craig Station. Trapper Mine supplies coal for the other three Yampa Partners'[3] portion of Craig

[1] Tri-State's net share of Craig 1 is 102 MW and Craig 2 is 98MW.
[2] LRS is a jointly owned unit under the Missouri Basin Power Project ("MBPP"). Tri-State is an MBPP participant with a 28.5 percent (484 MW) share and receives power from LRS 2 and LRS 3 due to their location in the western interconnection.
[3] Platte River Power Authority ("PRPA"), Salt River Project ("SRP"), and PacifiCorp.

Station. Unit 3 uses coal supply from only Colowyo, while Units 1 and 2 use a coal supply split from Trapper and Colowyo, with Trapper supplying a majority of the fuel for those two units.

- LRS: The MBPP procures and delivers coal from the Powder River Basin on behalf of the MBPP participants.
- SPV 3: Tri-State contracts with Peabody COALSALES, LLC, and the BNSF Railway Company to procure and deliver coal from the Powder River Basin to SPV 3.

The latest coal price forecast is a financial input to the 2023 ERP Phase I modeling and is identified in **Attachment B** ~~of the ERP Report (**Attachment LKT-1**).~~ LKT-7

Q: HOW ARE THESE UNITS FORECASTED TO OPERATE DURING THE RAP?

A: As further discussed within the Direct Testimony of Ms. Tiffin, Craig Station will conclude operations in 2028; and, if New ERA funding is received as requested, SPV 3 will retire in 2031, subject to reaching agreement with the applicable parties. LRS will continue its operations as it has previously, subject to applicable federal and state regulations.

Q: PLEASE DESCRIBE TRI-STATE'S GOALS AND ACHIEVEMENTS RELATED TO EMISSIONS REDUCTIONS FROM THE USE OF COAL-FIRED GENERATION.

A: Under Tri-State's Responsible Energy Plan ("REP"), we eliminated carbon emissions from Tri-State-owned coal generation in New Mexico in 2020. In Colorado, by 2030, we are targeting a 100 percent reduction in carbon emissions from Tri-State-owned coal generation. Additionally, by 2030, our goal is for 70

percent of the electricity our Members use system-wide to come from clean sources.

Additionally, under the 2020 ERP Phase I Settlement Agreement in Proceeding No. 20A-0528E, Tri-State committed that going forward, it will operate its system in a manner that achieves an 80 percent reduction in greenhouse gas ("GHG") emissions related to Tri-State's wholesale sales of electricity in Colorado in 2030.[4] As described by Ms. Tiffin in her Direct Testimony, all of the 2023 ERP Phase I scenarios were modeled in alignment with these REP and ERP commitments, with any modifications identified in **Attachment ~~B-3~~** ~~of the ERP Report (**Attachment LKT-1**).~~ LKT-10

Emissions and water use rates for each generator are identified in **Attachment ~~B~~** ~~of the ERP Report (**Attachment LKT-1**).~~ LKT-7

a. <u>Craig Station</u>

Q: DOES TRI-STATE'S COAL-FIRED GENERATION FACILITY LOCATED IN COLORADO HAVE A FIRM RETIREMENT DATE?

A: Yes. In January 2020, Tri-State voluntarily announced the planned retirement of all of Craig Station, including all three units, by 2030. The Craig Station units' closure dates are also identified in Colorado Regulation No. 23 Regional Haze Limits that were adopted by the Colorado Air Quality Control Commission ("AQCC") and made effective by publication in the Colorado Register on February

[4] 2020 ERP Phase I Settlement Agreement, Section 3.3.5. states: "Tri-State also 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, an eighty percent (80%) reduction in GHG emissions related to Tri-State's wholesale sales of electricity in Colorado in calendar-year 2030 ("the 2030 Emissions Reduction").

14, 2021, as discussed further in Mr. Berger's Direct Testimony. Within Decision No. C23-0437 in Proceeding No. 20A-0528E, the Commission ordered Tri-State to evaluate alternative retirement dates for Craig 3 within the 2023 Phase I ERP modeling assumptions and practices to analyze the benefits and costs associated with various retirement dates, including economically optimal retirement dates as part of its Direct Case.[5] Pursuant to Decision No. C23-0437, Tri-State has reflected this directive within the 2023 ERP Phase I modeling as further outlined within the Direct Testimony of Lisa K. Tiffin and in the scenario assumptions identified in **Attachment ~~B-3~~** LKT-10 of the ERP Report (**~~Attachment LKT-1~~**). The retirement dates considered for Craig Unit 3 provide time for Tri-State to work with the State of Colorado to complete and begin to implement a transition plan for those employees and communities impacted by the closure of Craig Station.

Q: WHAT IS THE STATUS OF TRI-STATE'S EFFORTS IN ENSURING A JUST TRANSITION FOR THE CRAIG COMMUNITY?

A. There are two elements to the Just Transition effort. The first being a Workforce Transition Plan, which was submitted to the Colorado Office of Just Transition ("OJT") in December 2022, pursuant to the 2020 ERP Phase I Settlement Agreement, Section 3.12.1. As part of the workforce transition, Tri-State also executed a Letter of Agreement ("LOA") with IBEW Local 111 that outlines the manner in which employees will be affected as part of the closure of Craig Station. The second component of the just transition is community assistance. Tri-State's

[5] Decision No. C23-0437, at ¶ 77 (Proceeding No. 20A-0528E).

community assistance approach will be informed by the Informational Community Assistance Plan ("ICAP") under development by Tri-State, OJT, the City of Craig, Moffat County, the Colorado Energy Office, and the Office of the Utility Consumer Advocate, led by a third-party facilitator. The ICAP is planned to be complete in June 2024; it will be filed on an informational basis in the 2020 ERP proceeding, as identified in the 2020 ERP Settlement Agreement. Following ICAP completion, Tri-State will review the areas of assistance of greatest interest to the community identified in the ICAP, determine a financially feasible approach to community assistance, and make a recommendation for Tri-State Board approval by Q1 2025. These Just Transition plans are further discussed in the Direct Testimony of Mr. Orvis.

Q: WHAT APPROACH IS TRI-STATE TAKING TO CAPITAL AND OPERATIONAL INVESTMENTS FOR CRAIG STATION OVER THE REMAINING LIFE OF THE PLANT?

A: Tri-State's investments in Craig Station are being appropriately limited to only actions necessary for ensuring safe operations and regulatory compliance, given the impending retirement of these units.

b. LRS

Q: PLEASE IDENTIFY THE KEY OPERATIONAL CONSIDERATIONS FOR LRS IN THE 2023 ERP.

A: Tri-State is a participant in the MBPP, with a 28.5 percent (484 MW) share. Tri-State receives a portion of LRS generation and transmission capacity through its MBPP contract. Tri-State has a contractual obligation to pay its share of LRS

MBPP costs through the plant's full useful life. Tri-State does not have unilateral decision authority regarding LRS operations.

c. SPV 3

Q: IDENTIFY THE KEY OPERATIONAL CONSIDERATIONS FOR SPV 3 IN THE 2023 ERP.

A: First, Tri-State is not a joint owner of the Springerville plant and is not the plant operator. Tucson Electric Power ("TEP") is the facility operator and owner of SPV Units 1 and 2 and Salt River Project ("SRP") is the owner of SPV 4. Second, Tri-State is the majority equity owner of the partnership that indirectly owns SPV 3; and one hundred percent of SPV 3 is leased by Tri-State. Third, Tri-State supplies 100 MW of unit contingent capacity from SPV 3 to a third-party offtaker, SRP, under a power purchase agreement ("PPA") that extends through summer 2036. Fourth, certain common facilities and operational and maintenance costs are shared across the four SPV units. TEP has indicated Unit 1 will retire at the end of 2027 and Unit 2 will retire after the summer of 2032.[6] SPV 3 operational and financial assumptions reflected in 2023 ERP Phase I modeling are provided in **Attachment ~~B~~** LKT-7 ~~of the ERP Report (**LKT-1**).~~

Q: HAS TRI-STATE INFORMED SRP, TEP, AND THE OTHER EQUITY OWNER OF THE IRA SCENARIO RESULTS FOR SPV 3?

A: Yes. Tri-State has informed these parties of the 2031 retirement date for SPV 3, subject to New ERA funding and reaching agreement with the applicable parties.

[6] https://www.tep.com/wp-content/uploads/TEP-2020-Integrated-Resource-Plan-Lo-Res.pdf (page 93).

Ms. Tiffin's Direct Testimony further discusses Tri-State's approach to implementation of the IRA Scenario resource plan.

III. EXISTING NATURAL GAS RESOURCES

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my Direct Testimony, I identify and describe both Tri-State's current natural gas resources, as well as a new gas unit addition planned during the RAP.

Q: PLEASE IDENTIFY AND BRIEFLY DESCRIBE THE CURRENT NATURAL GAS GENERATION RESOURCES IN TRI-STATE'S GENERATION FLEET.

A: Tri-State fully owns and operates four natural gas generation resources across its system footprint in Colorado and New Mexico. These resources are identified in **Attachment ~~C-3~~** LKT-17 of the ERP Report (**~~Attachment LKT-1~~**) and include both combined and simple cycle generating units. Specifically, the fleet includes simple cycle units that have dual-fuel capabilities.

Q: PLEASE DESCRIBE THE RELIABILITY BENEFITS OF OPERATING NATURAL GAS FACILITIES IN CONCERT WITH THE INCREASING DEPLOYMENT OF RENEWABLE RESOURCES.

A: As fully dispatchable resources, gas resources allow for response to gradual or abrupt changes in energy supply, within unit ramping characteristics, that may arise from the increasing deployment of renewables, which assists in maintaining system balance.

IV. NEW COMBINED CYCLE NATURAL GAS PLANT

Q: WHAT DOES THE 2023 ERP PHASE I IRA SCENARIO INDICATE REGARDING

THE NEED FOR AN ADDITIONAL GAS RESOURCE?

A: The IRA Scenario, which is Tri-State's preferred resource plan, selects a 290 MW natural gas combined cycle ("NGCC") resource in 2028 located in electrically western Colorado.[7] The IRA Scenario also adds carbon capture and sequestration ("CCS") to the combined cycle resource in 2031. The technical, operational, and financial assumptions modeled for the generic natural gas with CCS (NGCC with CCS) facility can be found in **Attachment ~~C-2~~** LKT-16 of the ERP Report (**~~Attachment LKT-1~~**).

Q: WHAT KEY BENEFITS DOES A COMBINED CYCLE GAS RESOURCE ADD TO TRI-STATE'S GENERATION FLEET?

A: As described above, natural gas resources provide a complementary and necessary reliability backbone for meeting load needs with an increasing amount of intermittent renewable resources. As identified in the ERP Report (**Attachment LKT-1**), 64 percent of Tri-State's system energy needs are forecasted to be served by renewable energy in 2030, even with the addition of this new gas unit. Also, firm capacity to deliver energy when called upon is critical to maintaining reliability across the Tri-State system, especially during prolonged periods of low or no solar and wind production.

Q: DID TRI-STATE EXPLORE ALTERNATIVE NATURAL GAS EXPANSION SOLUTIONS INSTEAD OF A NEW RESOURCE ADDITION?

A: Yes. Tri-State evaluated two alternative options for obtaining the additional natural

[7] See planning region definitions in the ERP Report (LKT-1).

gas capacity needed to maintain system reliability: (1) contracting for the capacity through near-term power purchase agreements ("PPAs"), and/or (2) expanding the capacity of Tri-State's existing natural gas generation facilities. Ms. Hunter's Direct Testimony addresses the first alternative and I address the second, along with Mr. Berger.

Q: COULD TRI-STATE EXPAND THE CAPACITY OF ITS EXISTING NATURAL GAS GENERATORS TO MEET THE NEED FOR A NATURAL GAS RESOURCE DURING THE RAP?

A: No. Tri-State assessed each of its four existing natural gas generating facilities and its Burlington oil-fired generation resource for the potential for expansion of capacity from these existing generators. The following describes the results of that assessment:

- J.M. Shafer and Knutson: These units are located in an ozone nonattainment area. Turbine upgrades would be difficult due to environmental permit limitations and expensive due to the capital expenditures associated with the locations. These challenges are further described in Mr. Berger's Direct Testimony.
- Pyramid: Without firm gas transport for the facility, Tri-State must purchase delivered gas, which is likely to make capacity expansion at this facility less financially viable. Additionally, the location of Pyramid relative to the majority of Tri-State load would make this option significantly less than optimal.

- Limon and Burlington: Rather than facility expansion, Tri-State will seek to utilize existing surplus interconnect for renewable generation to be co-located at these sites. The process and benefits for utilization of surplus interconnection are described in the Direct Testimony of Ms. Hunter and Mr. Hubbard.

Q: PLEASE OUTLINE THE HIGH-LEVEL STEPS THAT WILL ENABLE THIS UNIT TO COME ONLINE.

A: Following the Phase I plan approval and selection of an Engineering, Procurement, and Construction ("EPC") contractor for the natural gas facility through the Phase II procurement processes, Tri-State anticipates filing an Application seeking a Certificate of Public Convenience and Necessity ("CPCN") from the Commission if the resource is sited in Colorado. If the resource were sited in Wyoming, Tri-State would instead seek a permit from the Wyoming Industrial Siting Council. Site selection, obtaining land rights, and environmental permitting processes for both the NGCC unit and CCS emission controls would be supported by the EPC contractor, and the transmission interconnection process would be discussed by Mr. Hubbard in that future filing.

Q: WHAT STEPS IS TRI-STATE TAKING TO INFORM THE PHASE II PROCESS RELATED TO GAS RESOURCE SELECTION?

A: Tri-State has engaged a third-party consulting firm to perform a siting study to analyze factors related to siting this new gas resource, including land availability, assessing gas pipeline accessibility, transmission interconnection availability, water availability, and carbon sequestration viability.

Q: HOW WILL SELECTION OF AN EPC CONTRACTOR BE DETERMINED?

A: Tri-State intends to issue a Dispatchable Resources RFP as part of its 2023 ERP Phase II process to obtain competitive bids for the gas resource and associated EPC contractor costs and requirements. Ms. Hunter's Direct Testimony further discusses this process in more detail.

Q: DOES TRI-STATE INTEND TO BE THE GAS FACILITY OPERATOR OR OBTAIN AN OPERATIONS AND MAINTENANCE CONTRACTOR?

A: Tri-State has not firmly determined all facets of the proposed gas unit's operations given the current stage of the modeling and planning process but anticipates that Tri-State would be the facility operator.

Q: DOES TRI-STATE INTEND TO USE A PROJECT LABOR AGREEMENT FOR CONSTRUCTION OF THE FACILITY?[8]

A: Tri-State's mission is to provide our Member systems a reliable, affordable, and responsible supply of electricity in accordance with cooperative principles. Tri-State is committed to competitively bidding all major contracts to ensure affordability goals are met. As such, Tri-State has not made a determination whether or not a labor agreement will be utilized for the construction of the new gas facility. However, if the new gas facility is located in the original Colorado Ute territory, then the on-site Tri-State Operations and Maintenance craft labor would be subject to Tri-State's collective bargaining agreement with the IBEW Local 111.

Q: HOW WILL THE 2031 IMPLEMENTATION OF CCS BENEFIT THE NATURAL

[8] Rule 3605(g)(II)(b) requires that the utility "…specify whether it agrees to use a project labor agreement for the construction or expansion of a generation facility."

GAS PLANT INVESTMENT FOR TRI-STATE MEMBERS?

A: Tri-State's modeling, based on industry research and vendor data, forecasts achieving up to a 97 percent carbon capture rate which results in a transformative reduction in the plant's carbon dioxide emissions from 765 lbs per net MWh (pre-CCS) to a possible low of 23 lbs per net MWh (post-CCS).[9] Additionally, with this carbon reduction, the facility's useful life can reasonably be extended beyond 20 years to 30 years.

Q: WHAT IS THE LIFE OF A COMBINED CYCLE GAS RESOURCE?

A: From a technical perspective, a newly constructed, highly efficient NGCC with CCS unit can be expected to operate for 30 years. From a modeling perspective, as identified in **Attachment B** ~~of the ERP Report (**Attachment LKT-1**),~~ LKT-7 the assumed life of the combined cycle gas resource with CCS is 30 years. In Tri-State's 2020 ERP Phase II, the book life of gas resources was limited to 20 years pursuant to the 2020 ERP Phase I Settlement Agreement.[10] However, the gas resource selected in the IRA Scenario includes application of CCS which extends the life of the resource back to normal operational expectations, while meeting existing emission targets and in anticipation of potential future environmental regulations. A 30-year operating lifetime assumption is consistent with Tri-State's expectations for actual unit depreciation and amortization.

Q: DOES THE 2027 ERP PROVIDE AN OPPORTUNITY TO ASSESS THE

[9] Federal PTC eligibility requires a carbon capture rate of at least 75 percent. Tri-State intends to evaluate Phase II gas bids that have a carbon capture rate between 75-97 percent.
[10] Section 3.6.8.

CONTINUED VIABILITY OF THE 2031 CCS CONVERSION PATH FOR MANAGING CARBON FOR THE GAS PLANT?

A: At the time of the 2027 ERP Phase I filing anticipated on June 1, 2027, Tri-State will provide the Commission and stakeholders with an update on CCS conversion progress.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

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 CO LORADO)
) ss:
COUNTY OF ADAMS)

I, Barry W. Ingold, 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 15th day of November 2023, at Westminster, Colorado.

FAITH WARNER
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20184035614
MY COMMISSION EXPIRES 09/07/2026

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

By: Barry W. Ingold
Barry W. Ingold
Chief Operating Officer

Witness my hand and official seal.

Faith Warner
Notary Public

My Commission expires: 9/7/2026.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-51:
Tri-State 2020 ERP

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

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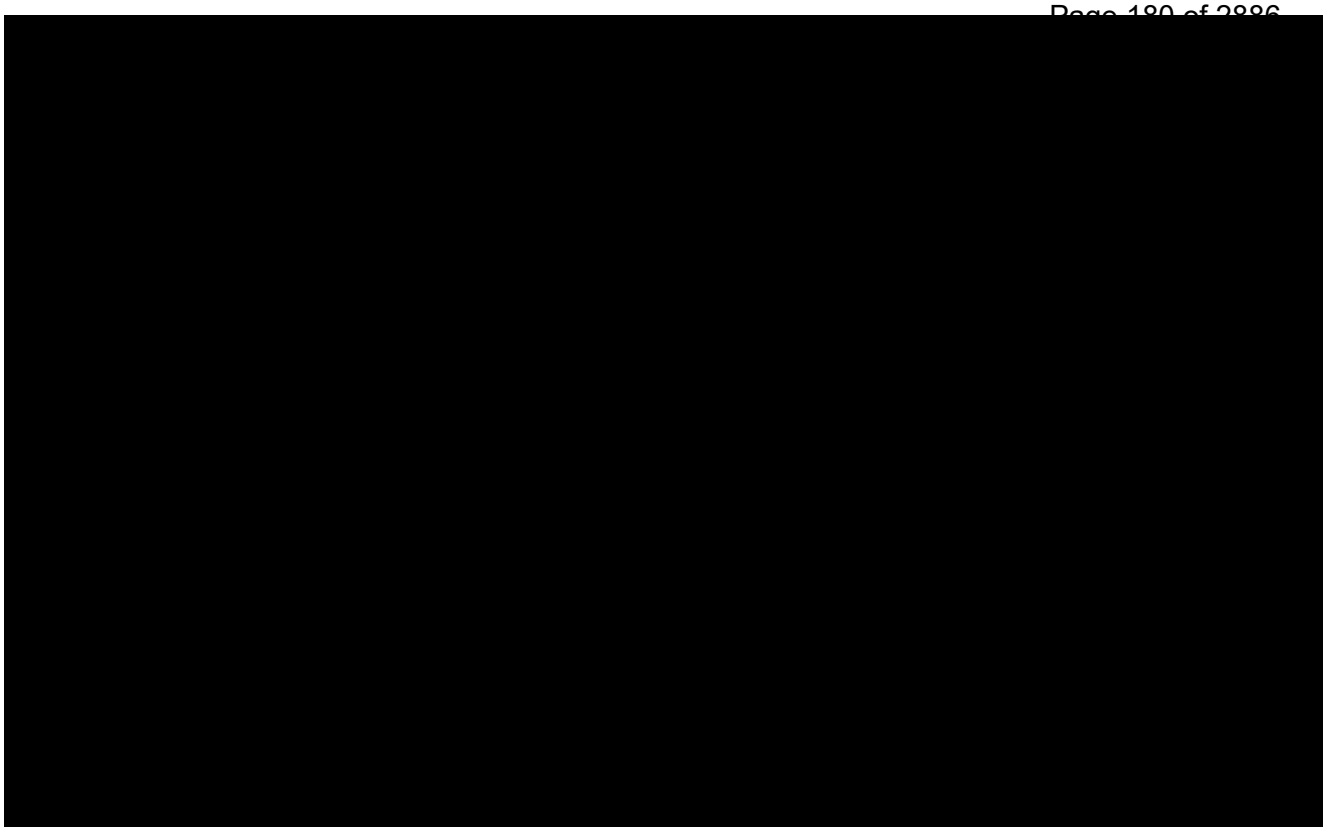

Figure 11: Coal Forward Curve for UIPlanner (Nominal dollars)

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.

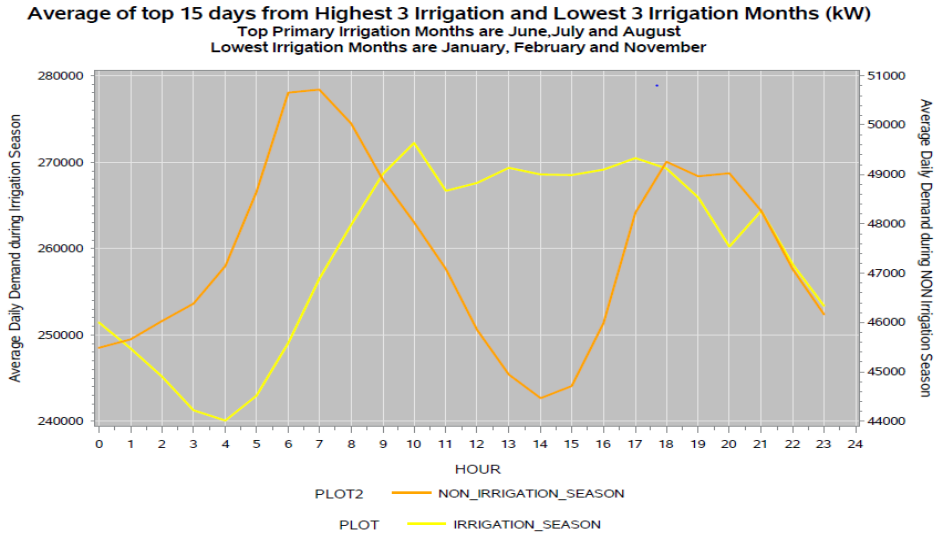

Figure 14: Basin Electrically East Irrigation and Non-Irrigation Seasons Demand Profiles

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

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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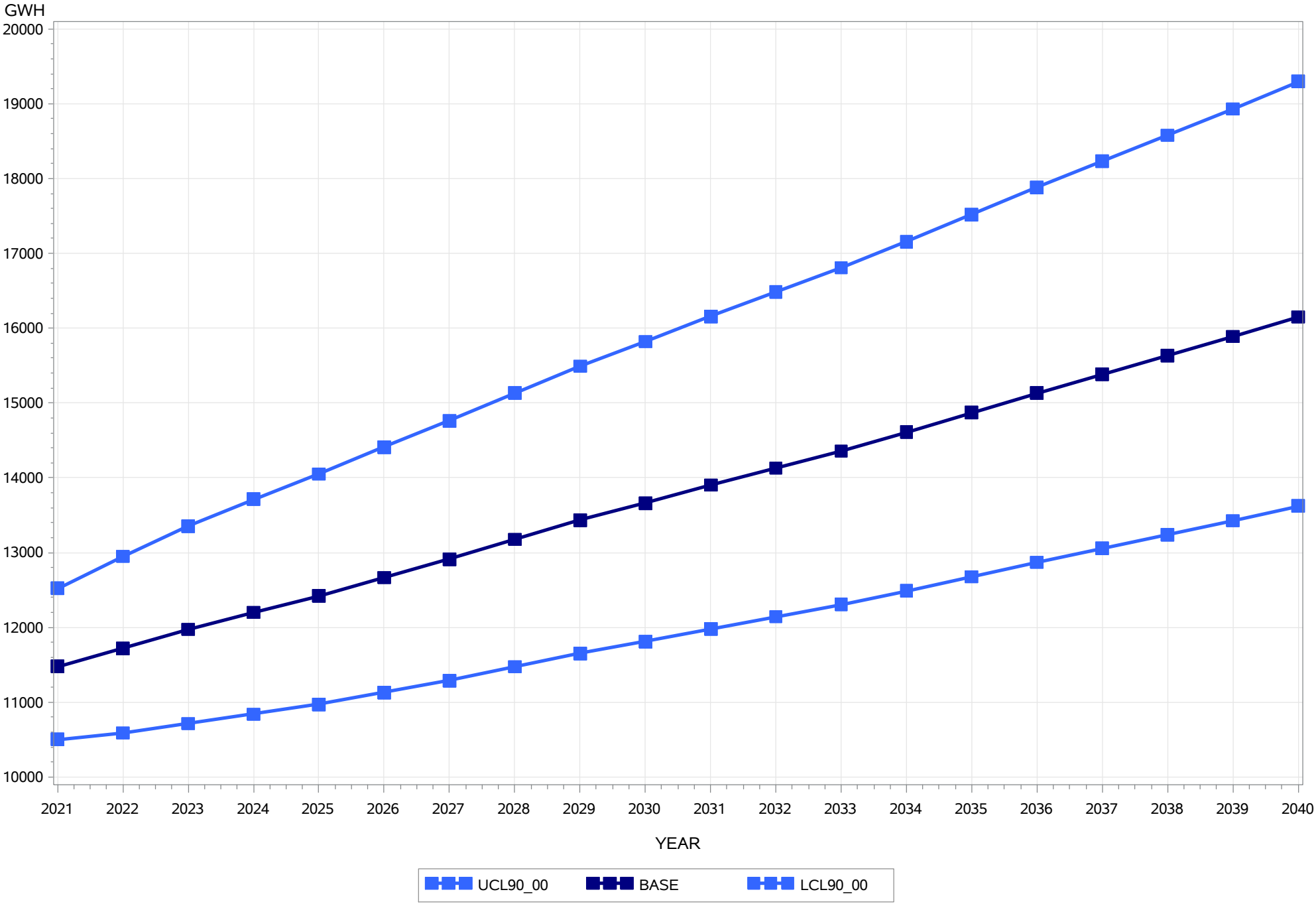
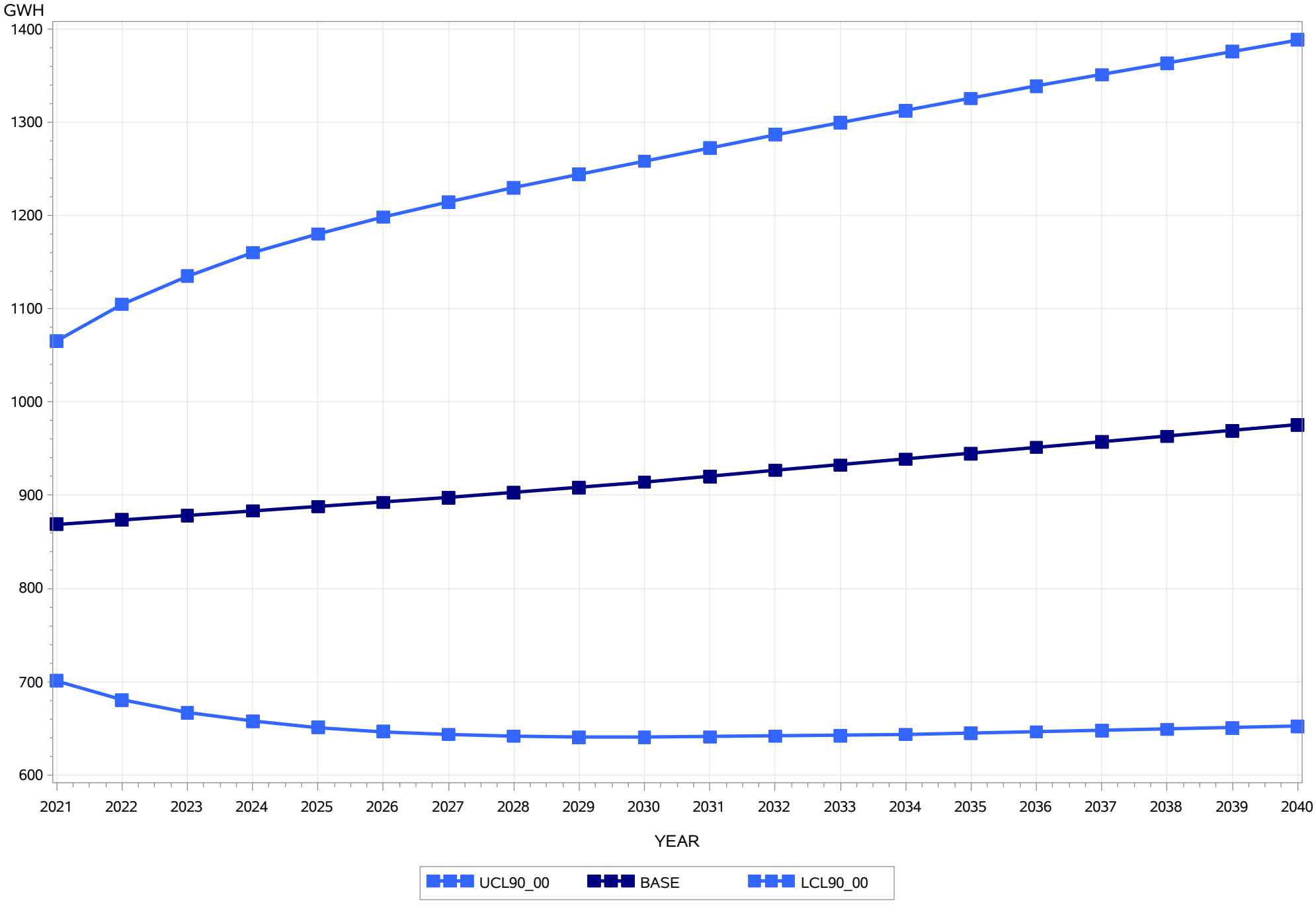
Attachment Vol II 1-1 Tri-State Load Forecasts by State & Member

Total Annual Energy Sales
STATE OF COLORADO



Total Annual Energy Sales
STATE OF NEBRASKA



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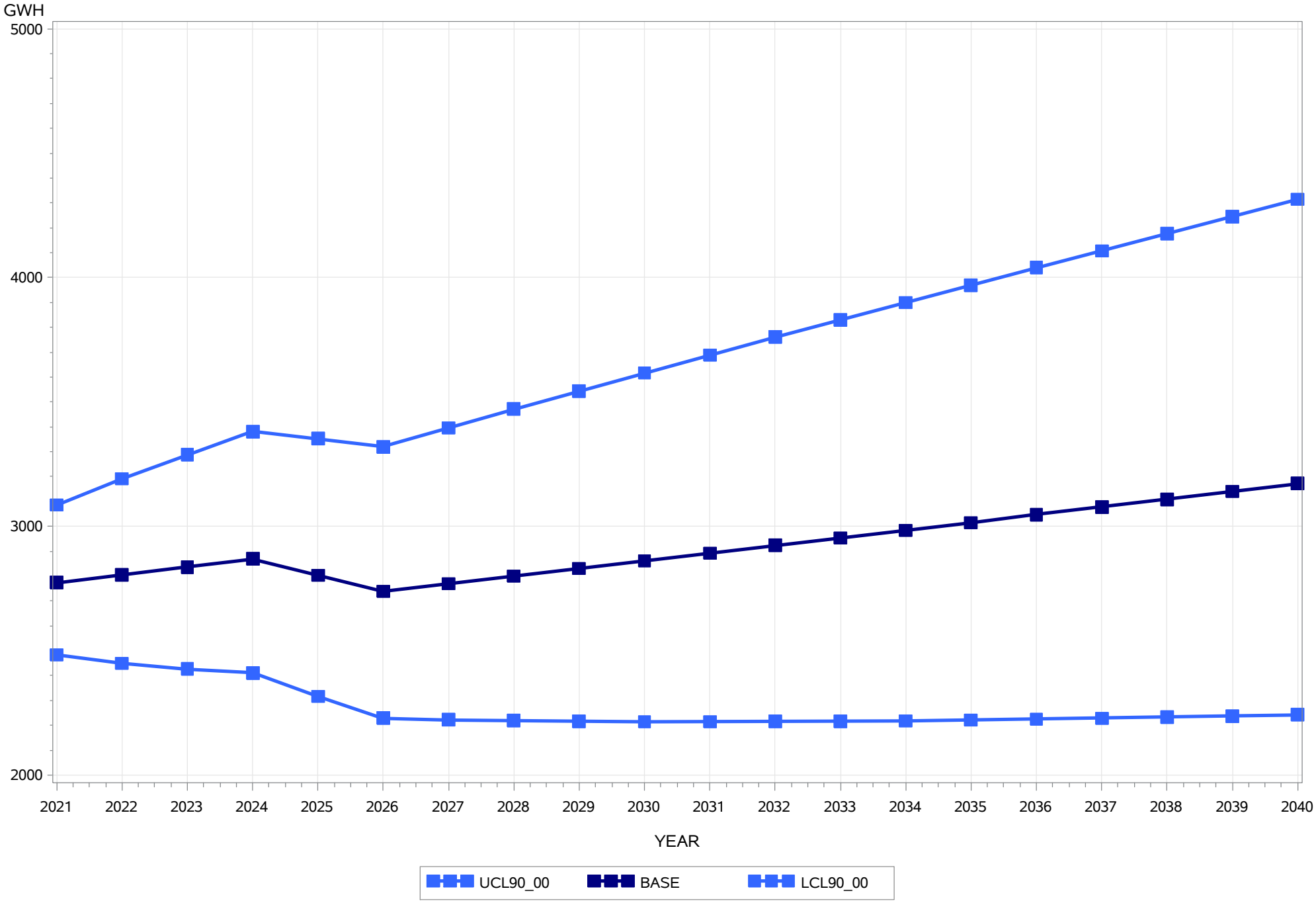
Total Annual Energy Sales
STATE OF NEW MEXICO



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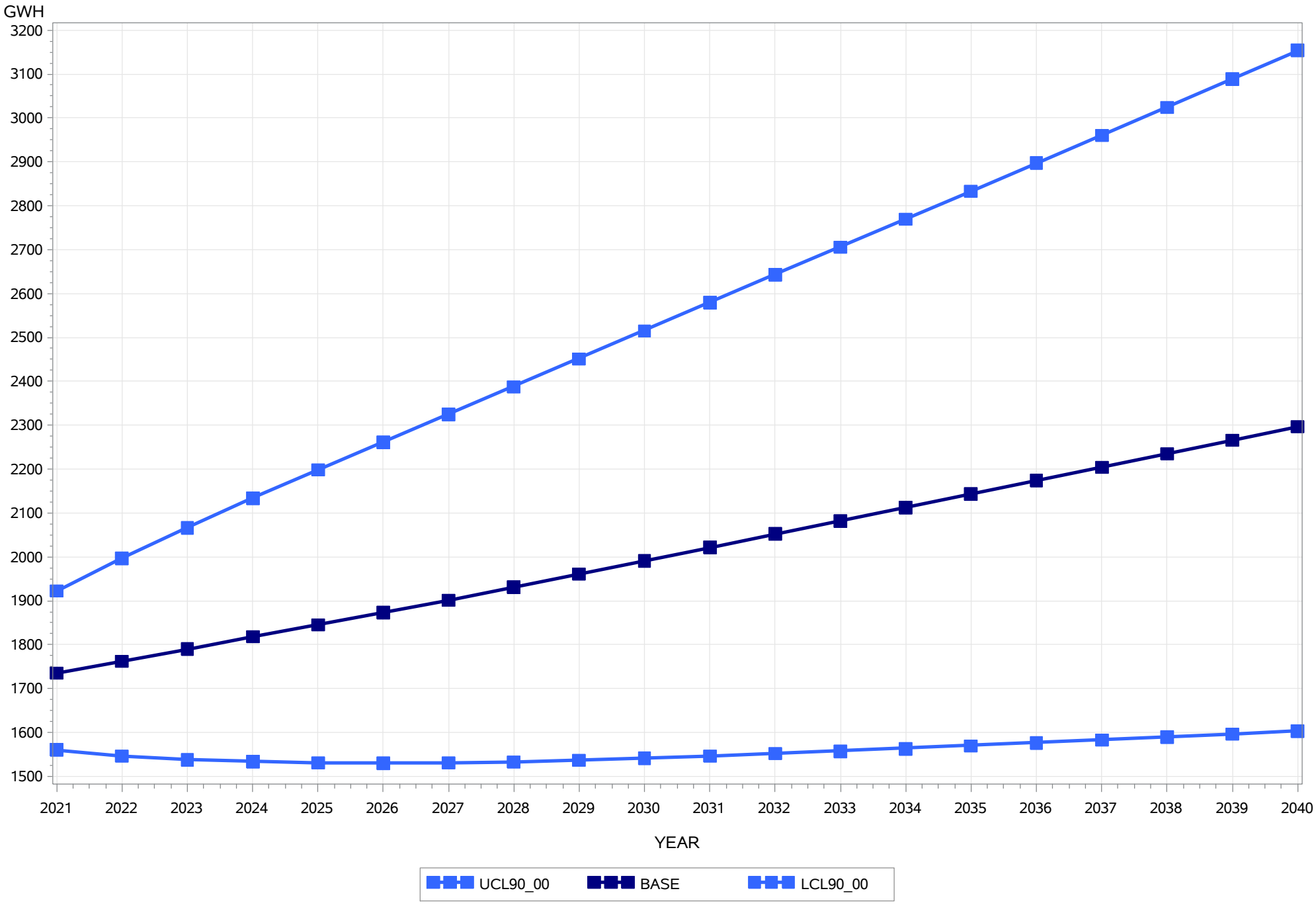
Total Annual Energy Sales
STATE OF WYOMING



Annual Summer Coincident Peak
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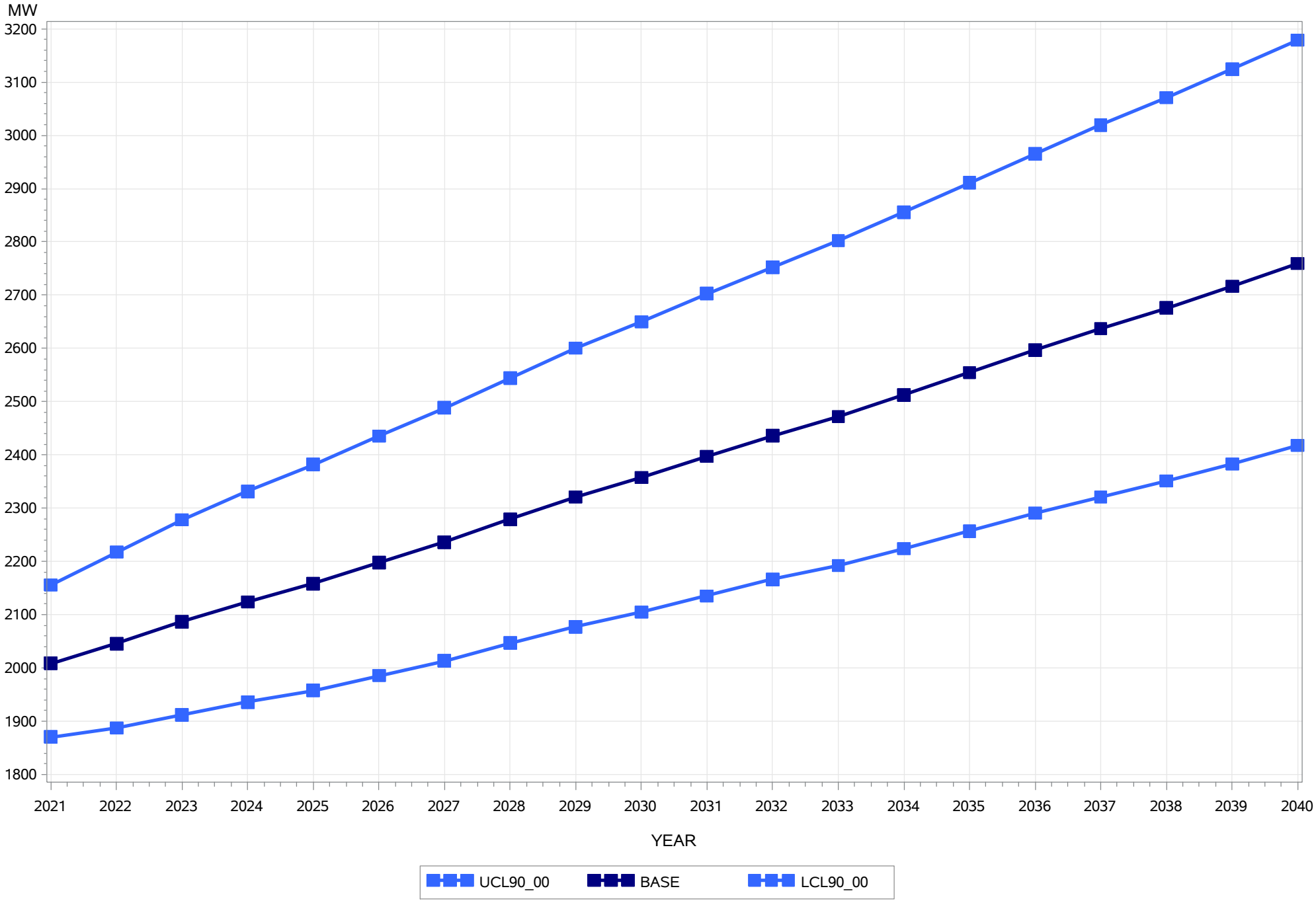
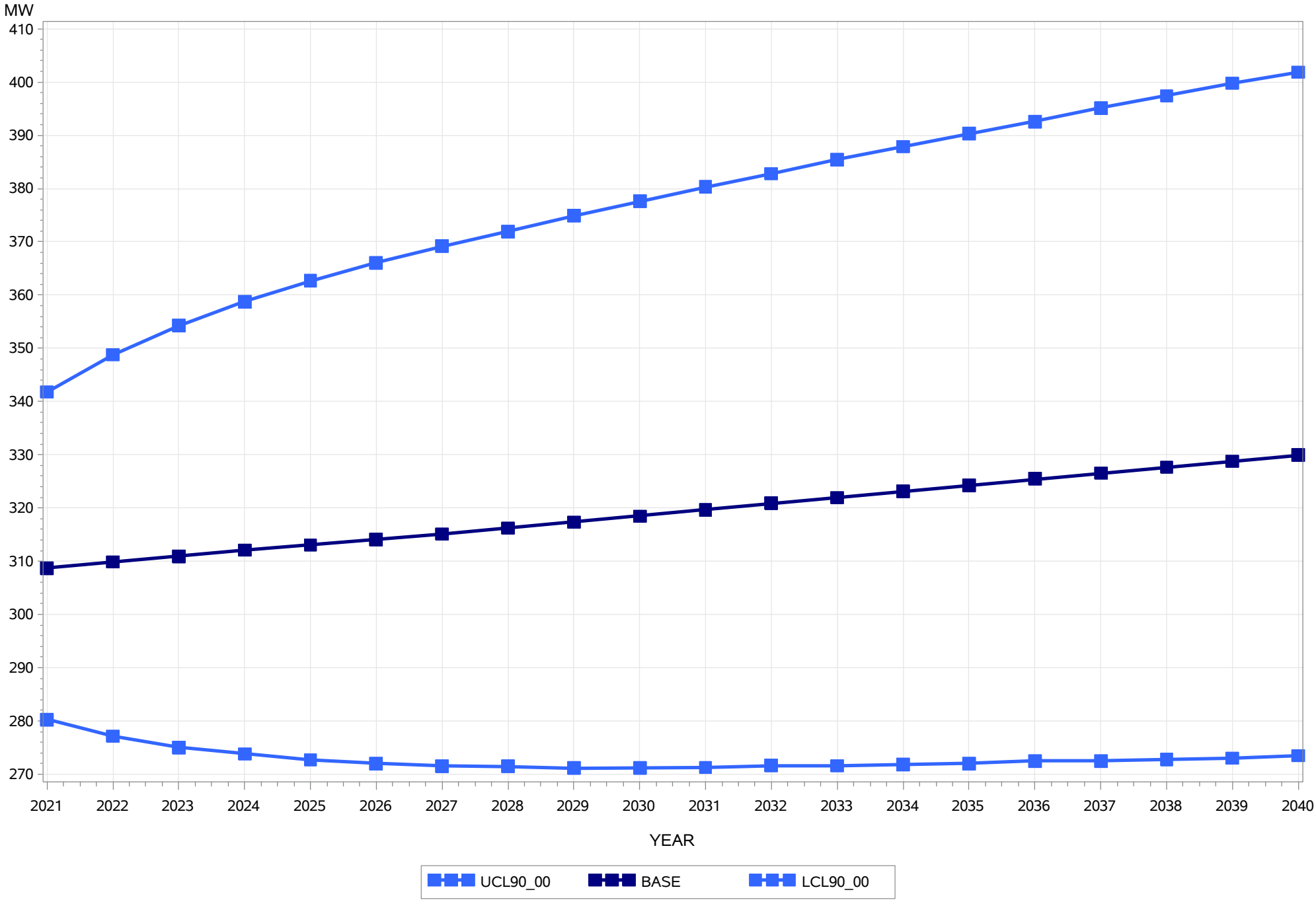


Annual Summer Coincident Peak
STATE OF NEBRASKA



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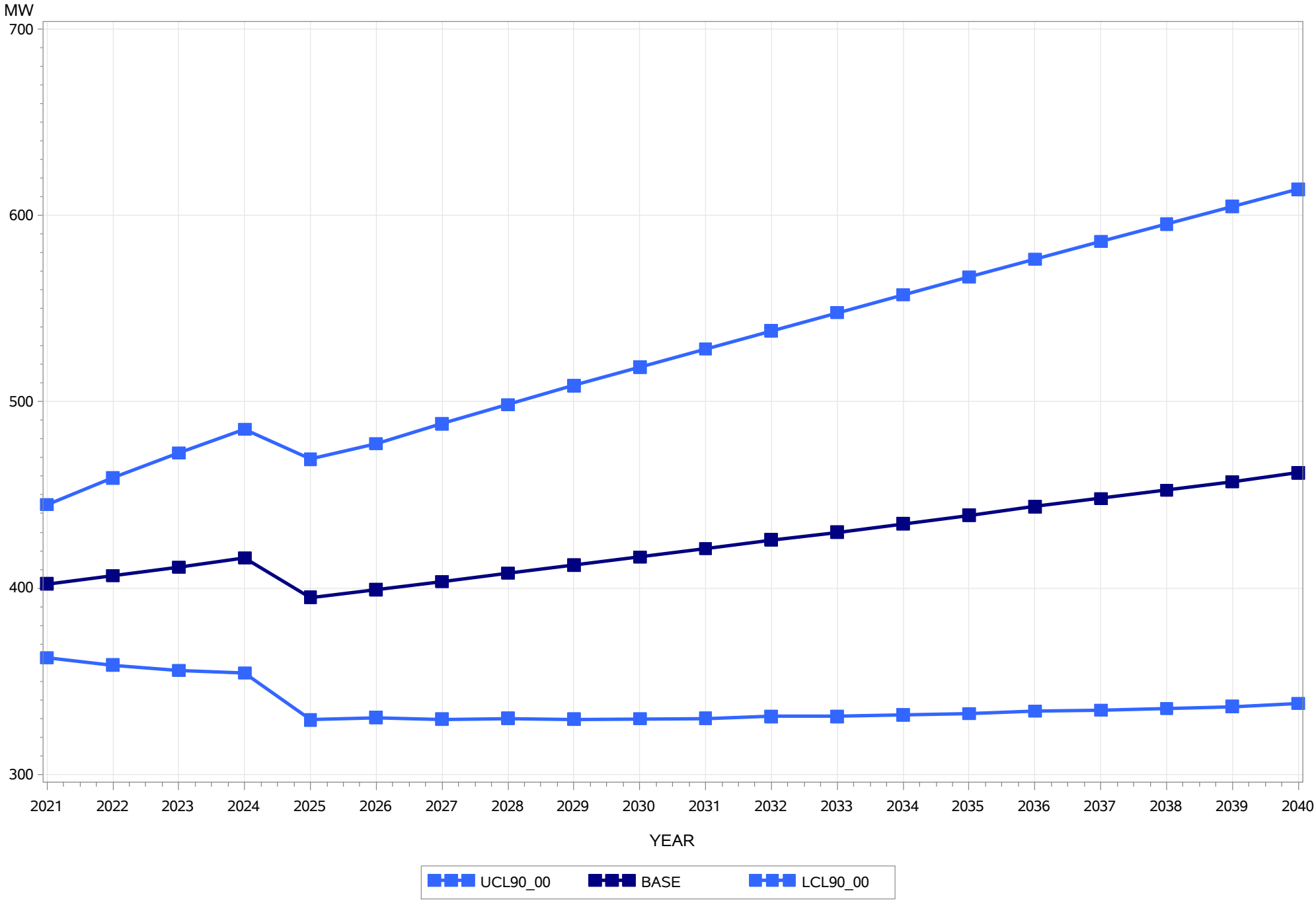
Annual Summer Coincident Peak
STATE OF NEW MEXICO



Annual Summer Coincident Peak
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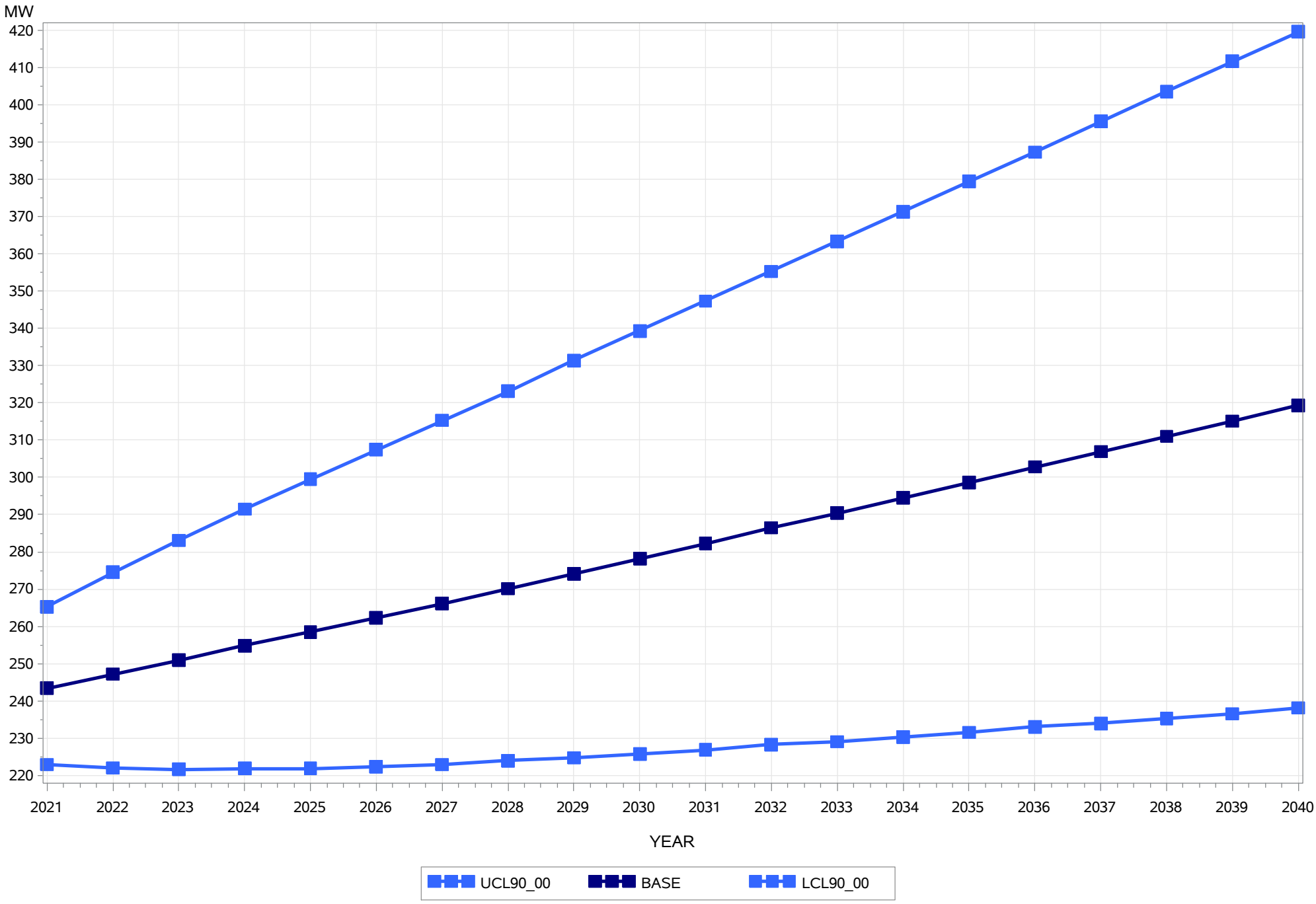

Annual Winter Coincident Peak
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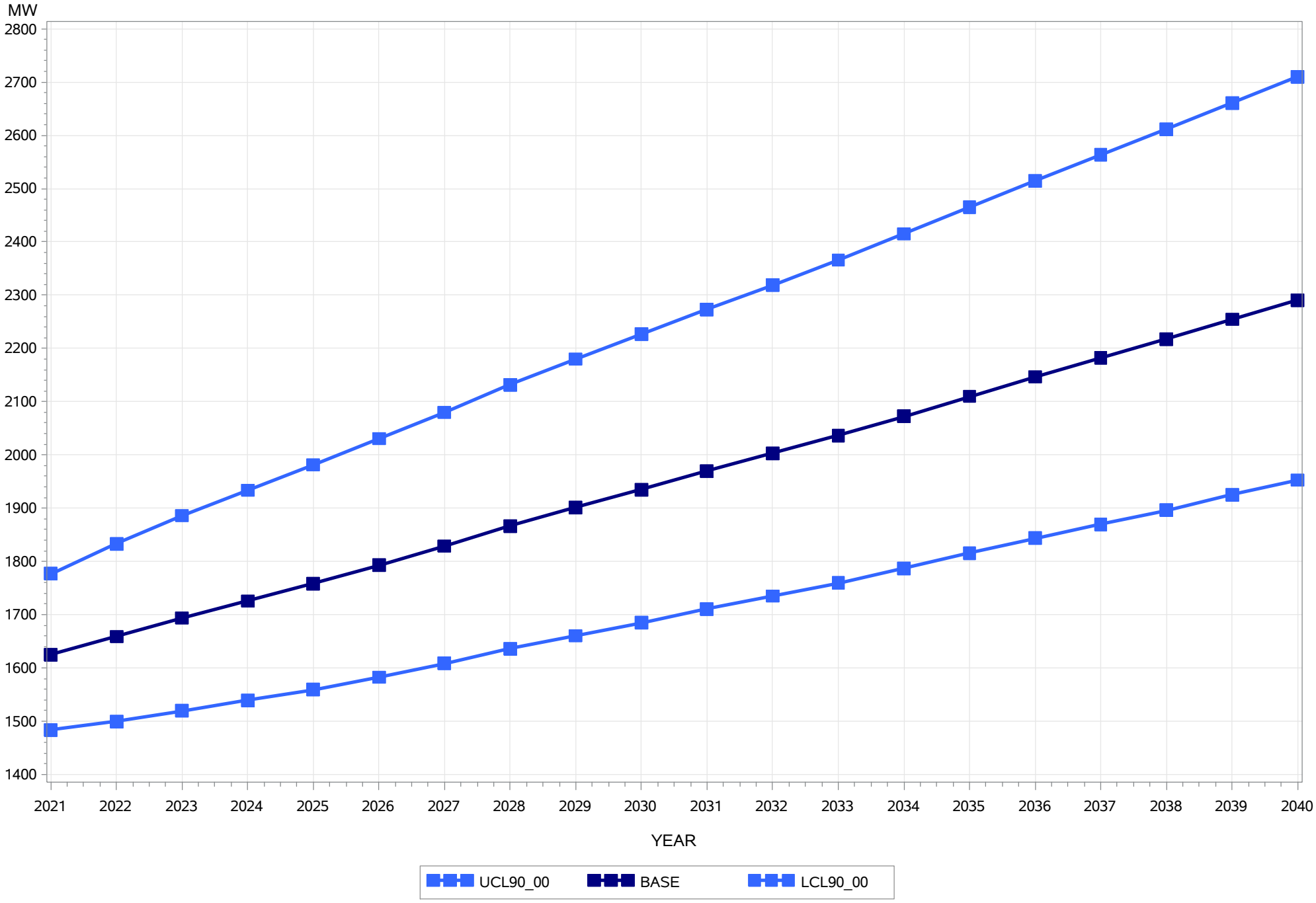

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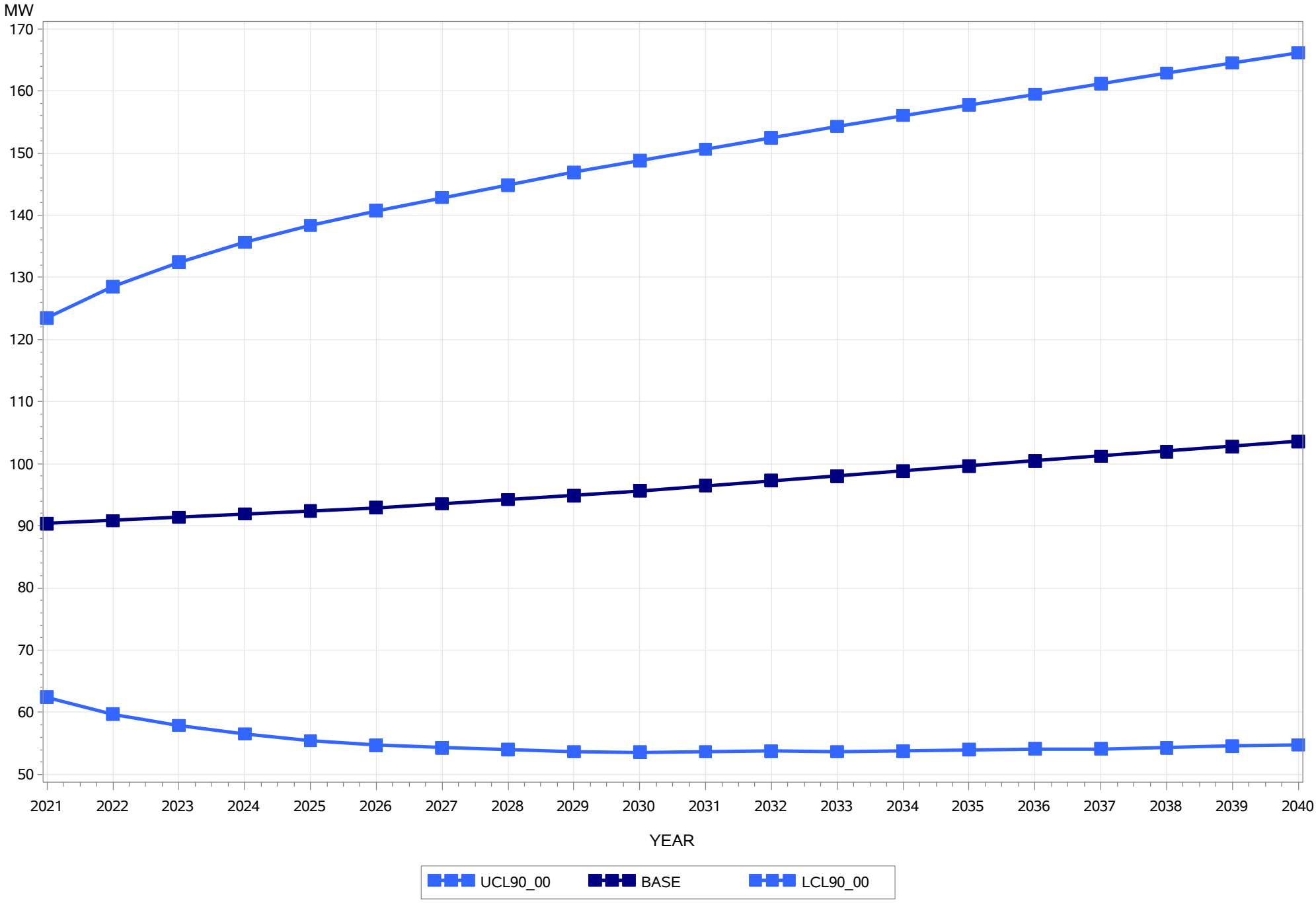

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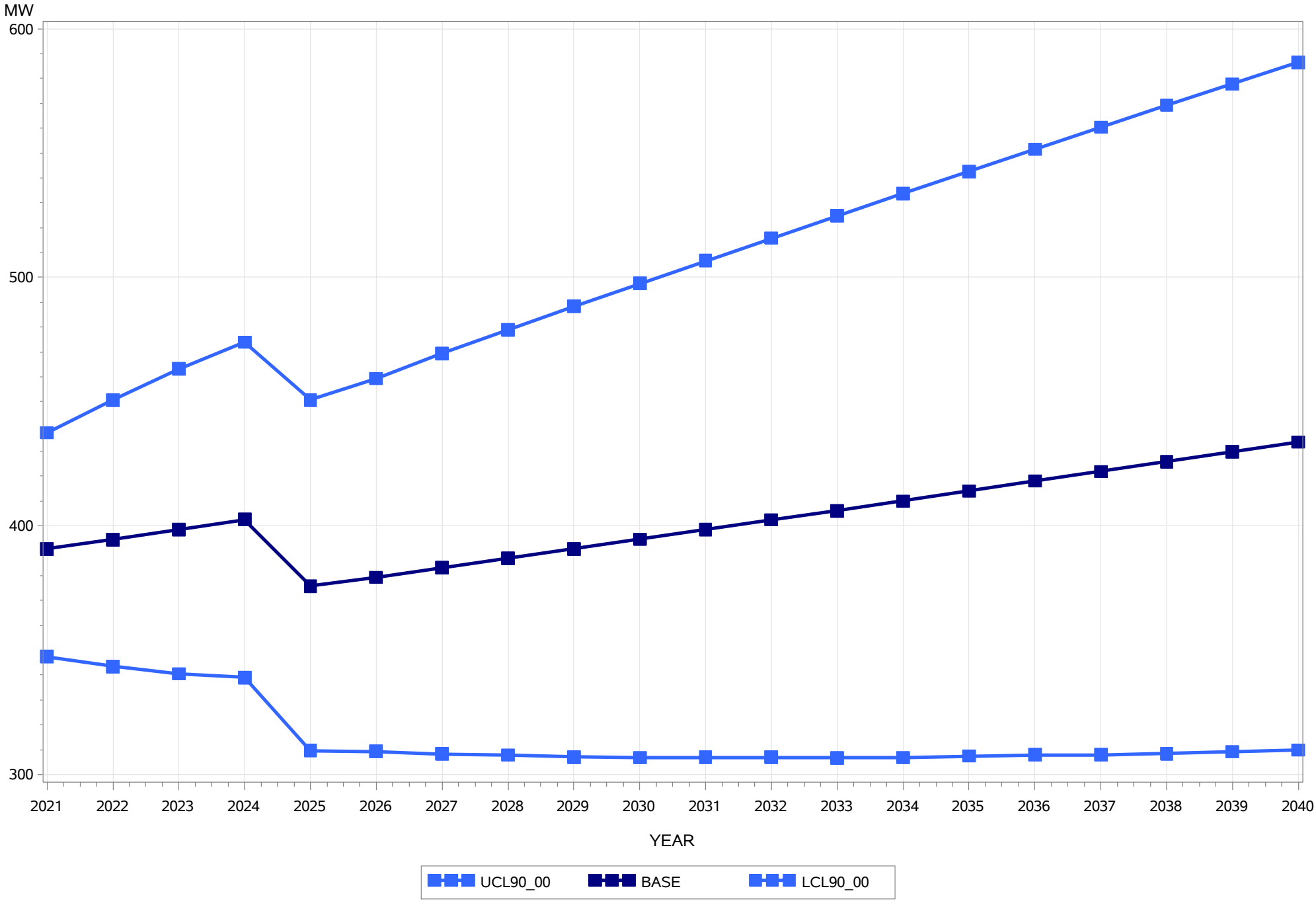
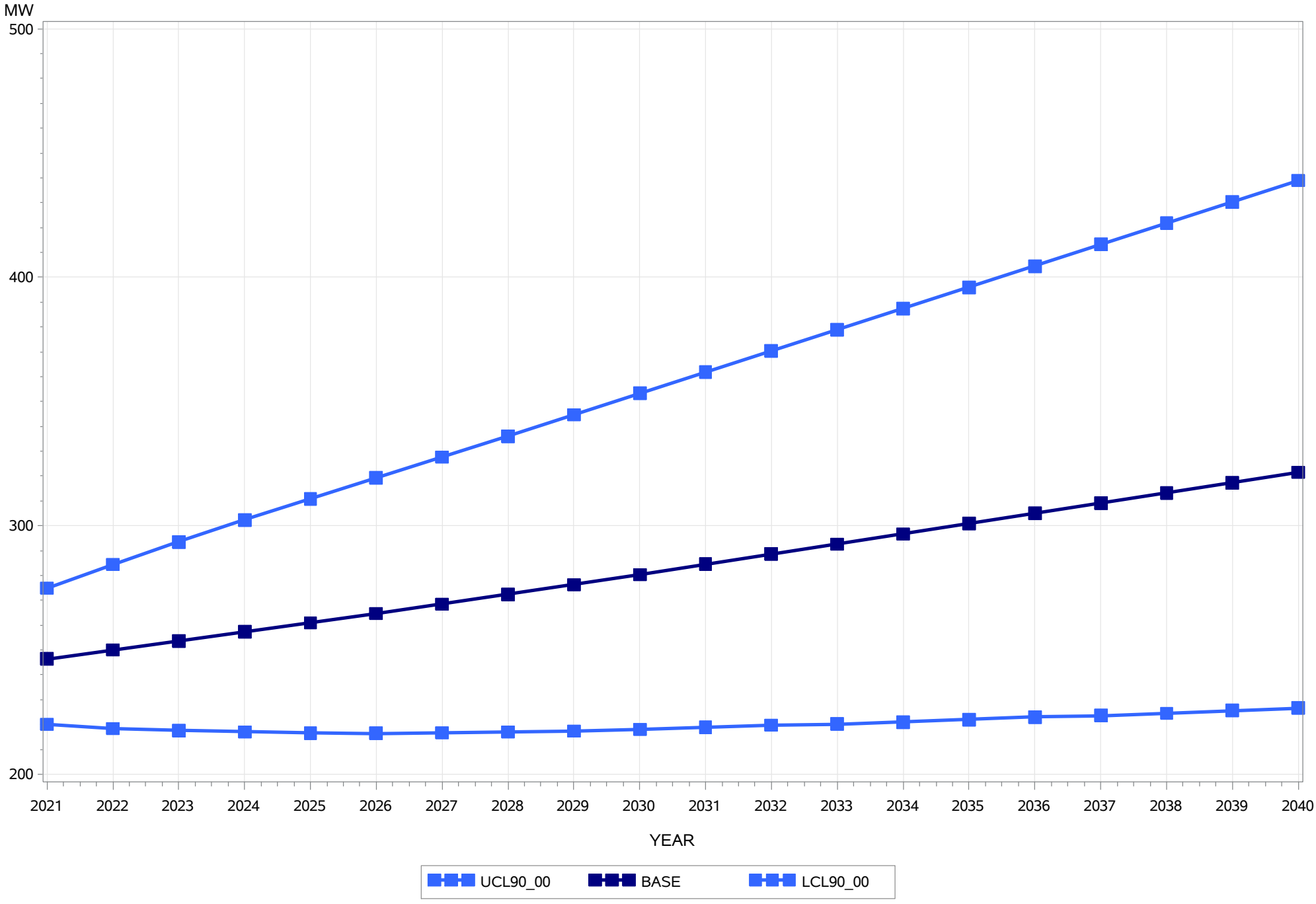
Annual Winter Coincident Peak
STATE OF NEW MEXICO



Annual Winter Coincident Peak
STATE OF WYOMING



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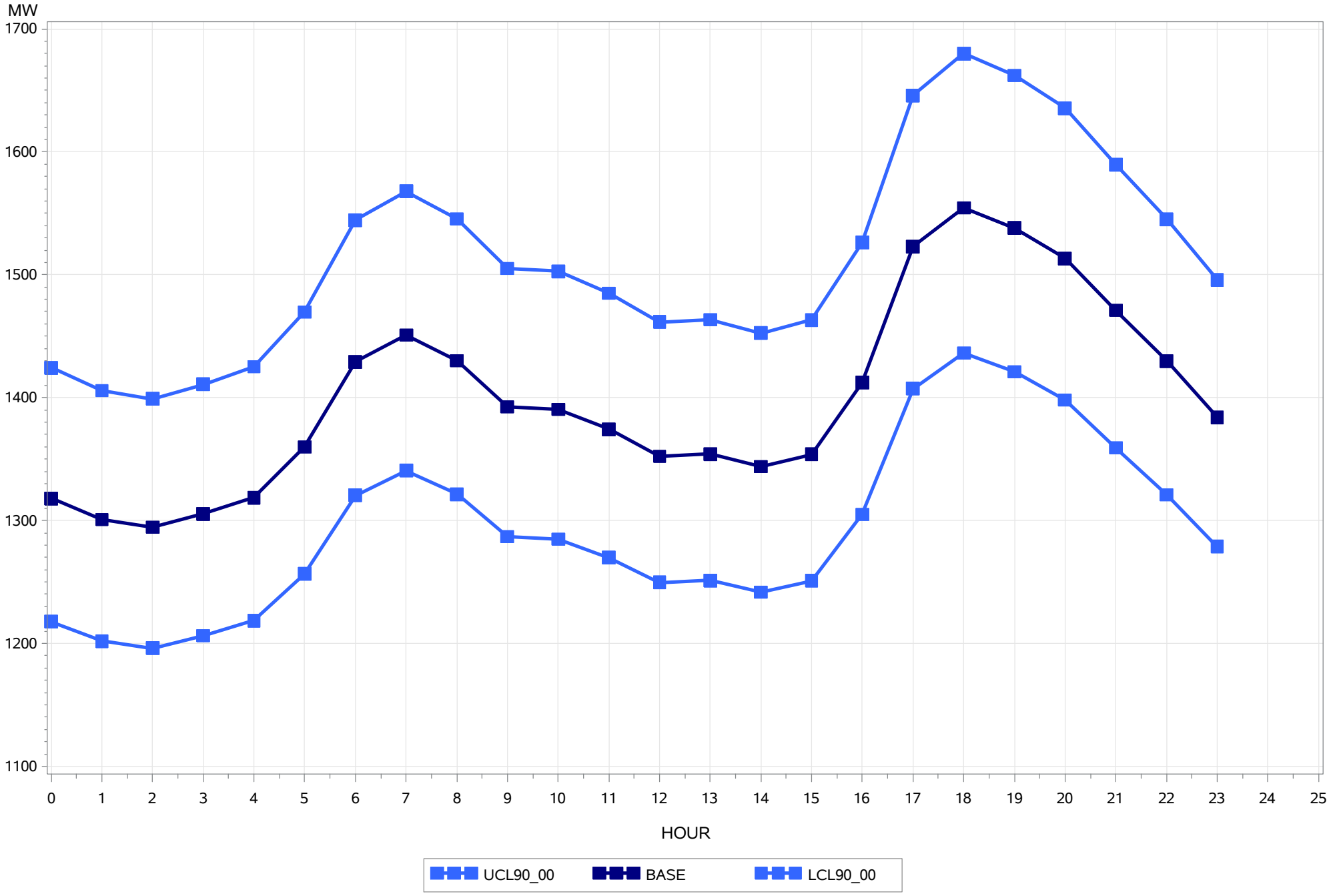
Member Forecasted On Peak Demand Day for January 2021

STATE OF COLORADO

Date of On Peak Day - 01/06/2021



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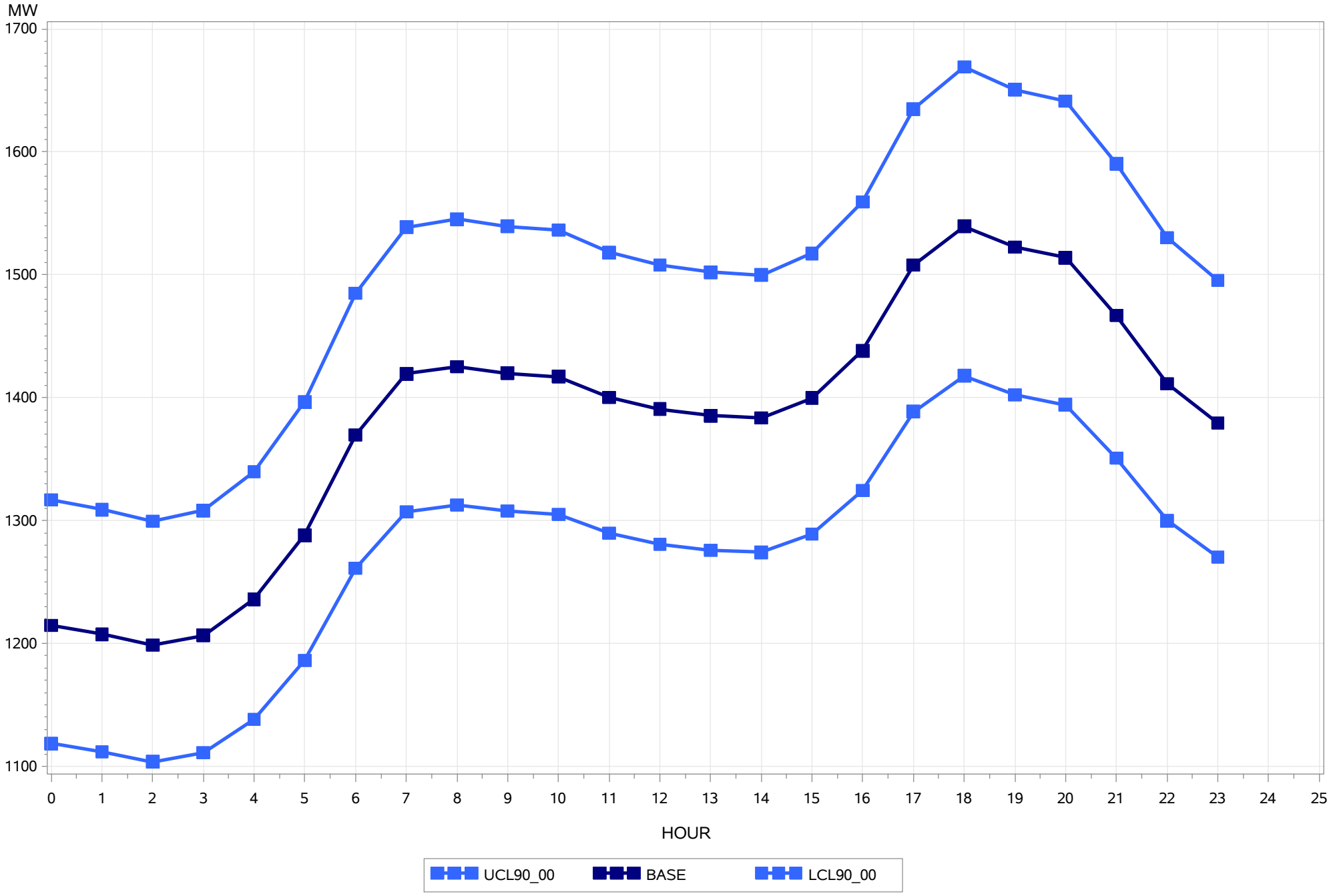
Member Forecasted On Peak Demand Day for February 2021

STATE OF COLORADO

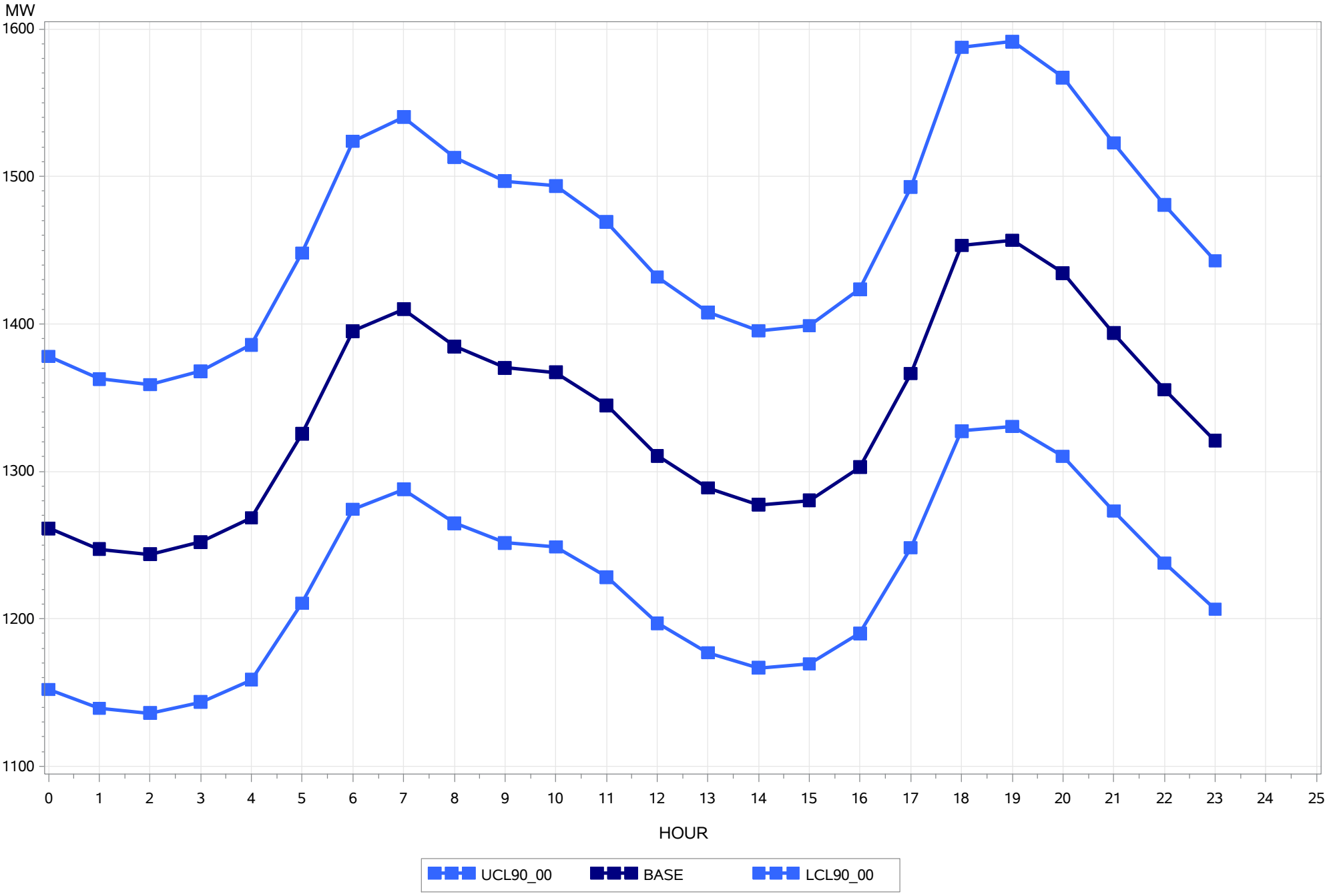
Date of On Peak Day - 02/01/2021



Member Forecasted On Peak Demand Day for March 2021

STATE OF COLORADO

Date of On Peak Day - 03/01/2021



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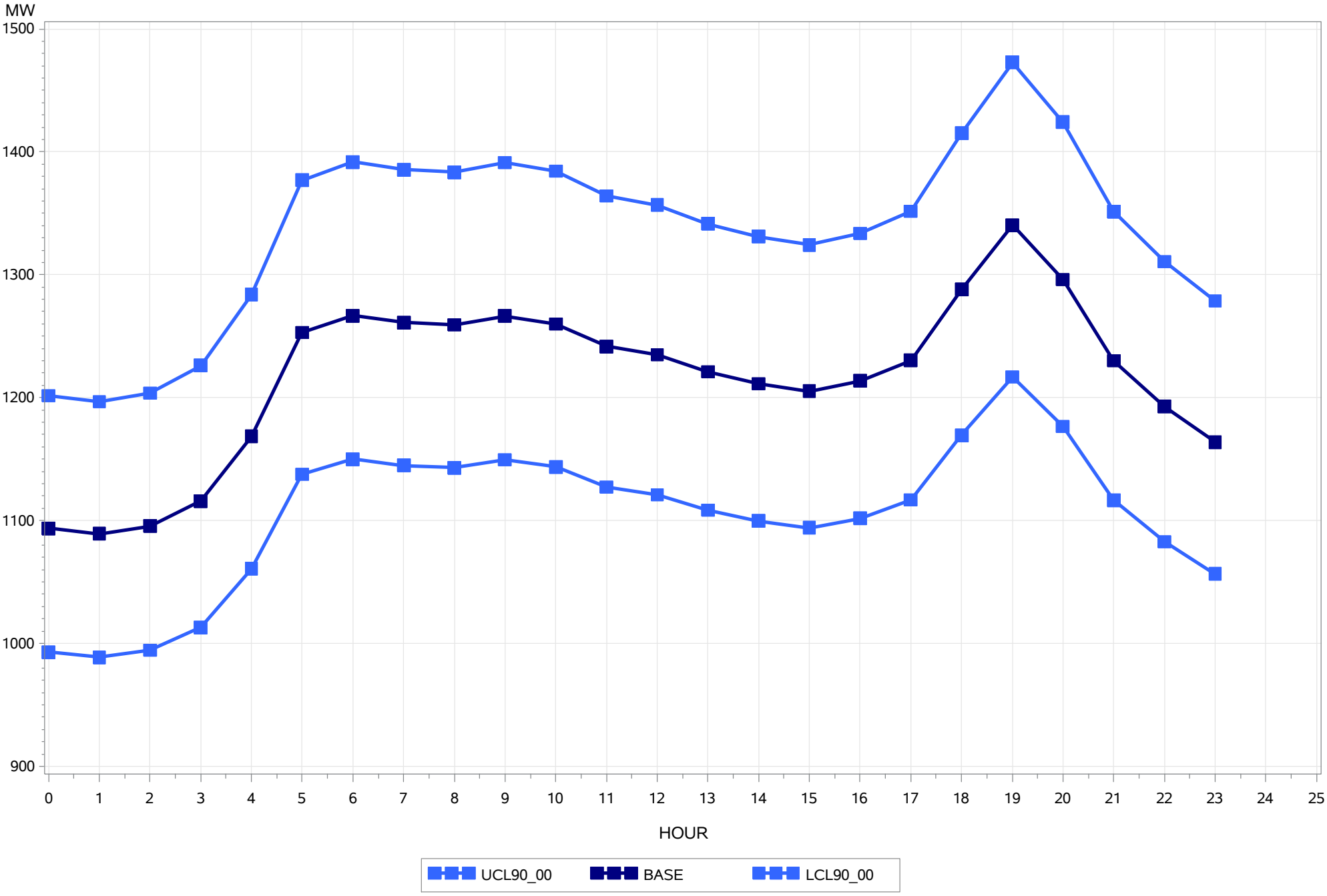
Member Forecasted On Peak Demand Day for April 2021

STATE OF COLORADO

Date of On Peak Day - 04/15/2021



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Member Forecasted On Peak Demand Day for May 2021

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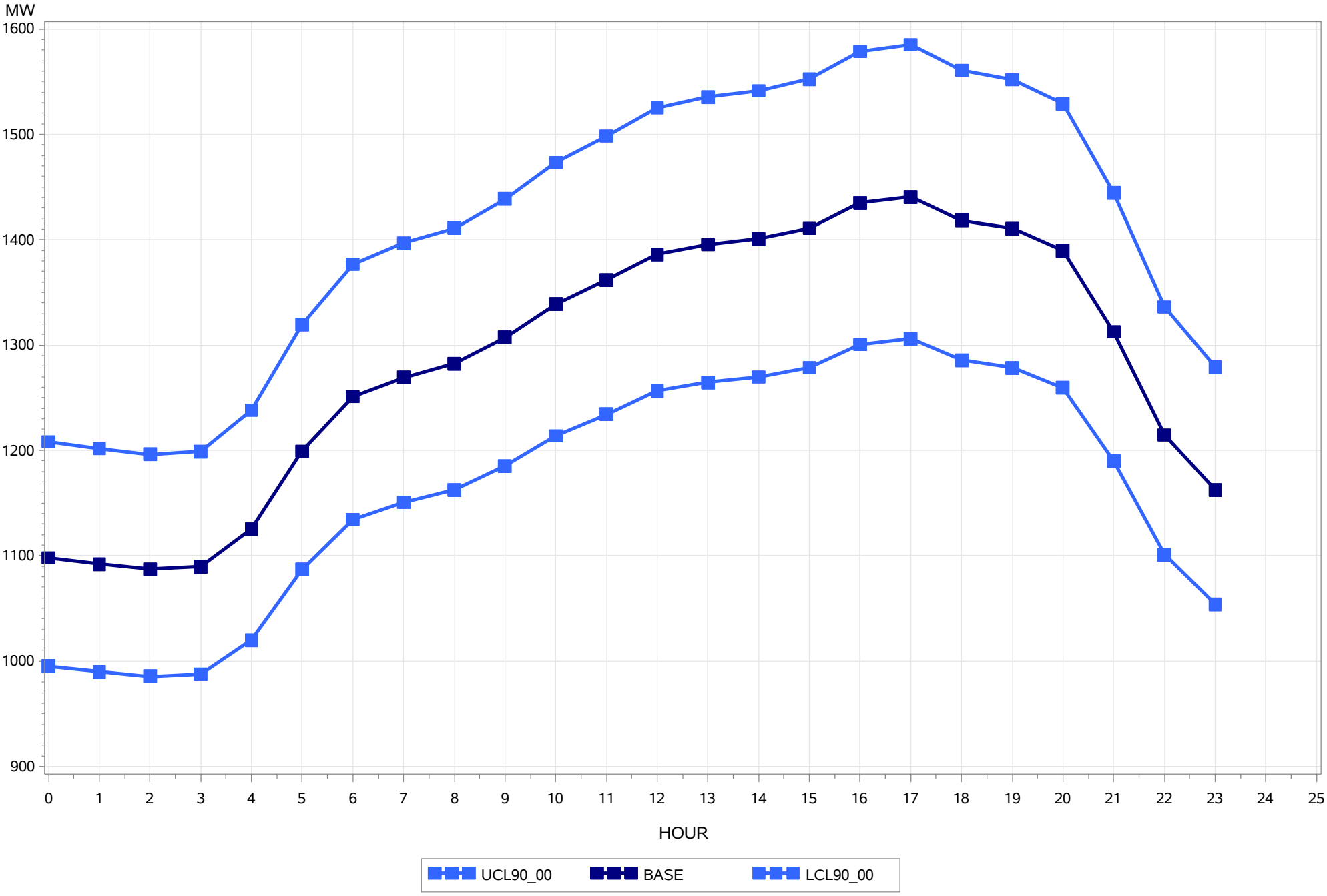
Date of On Peak Day - 05/31/2021



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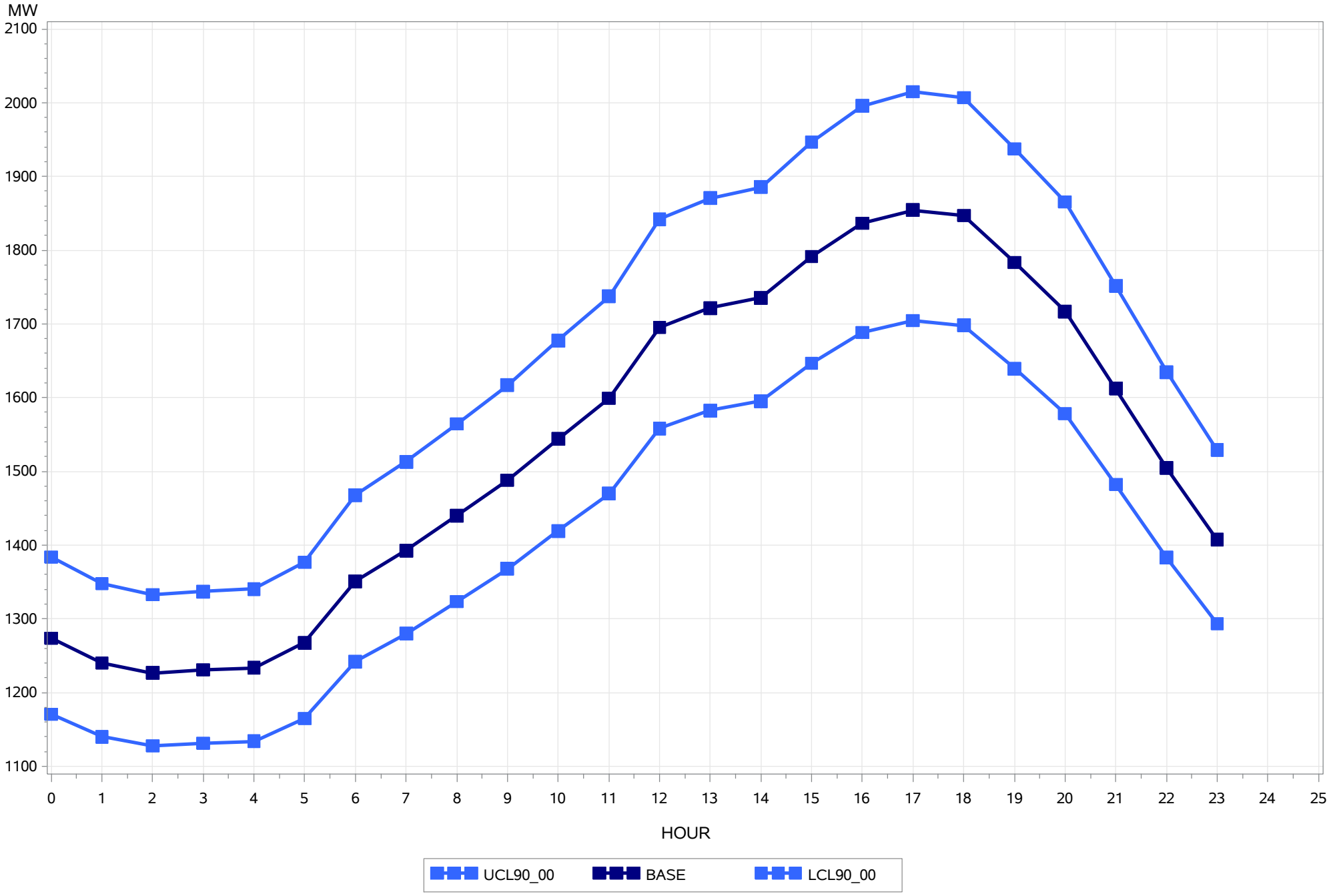
Member Forecasted On Peak Demand Day for June 2021

STATE OF COLORADO

Date of On Peak Day - 06/28/2021



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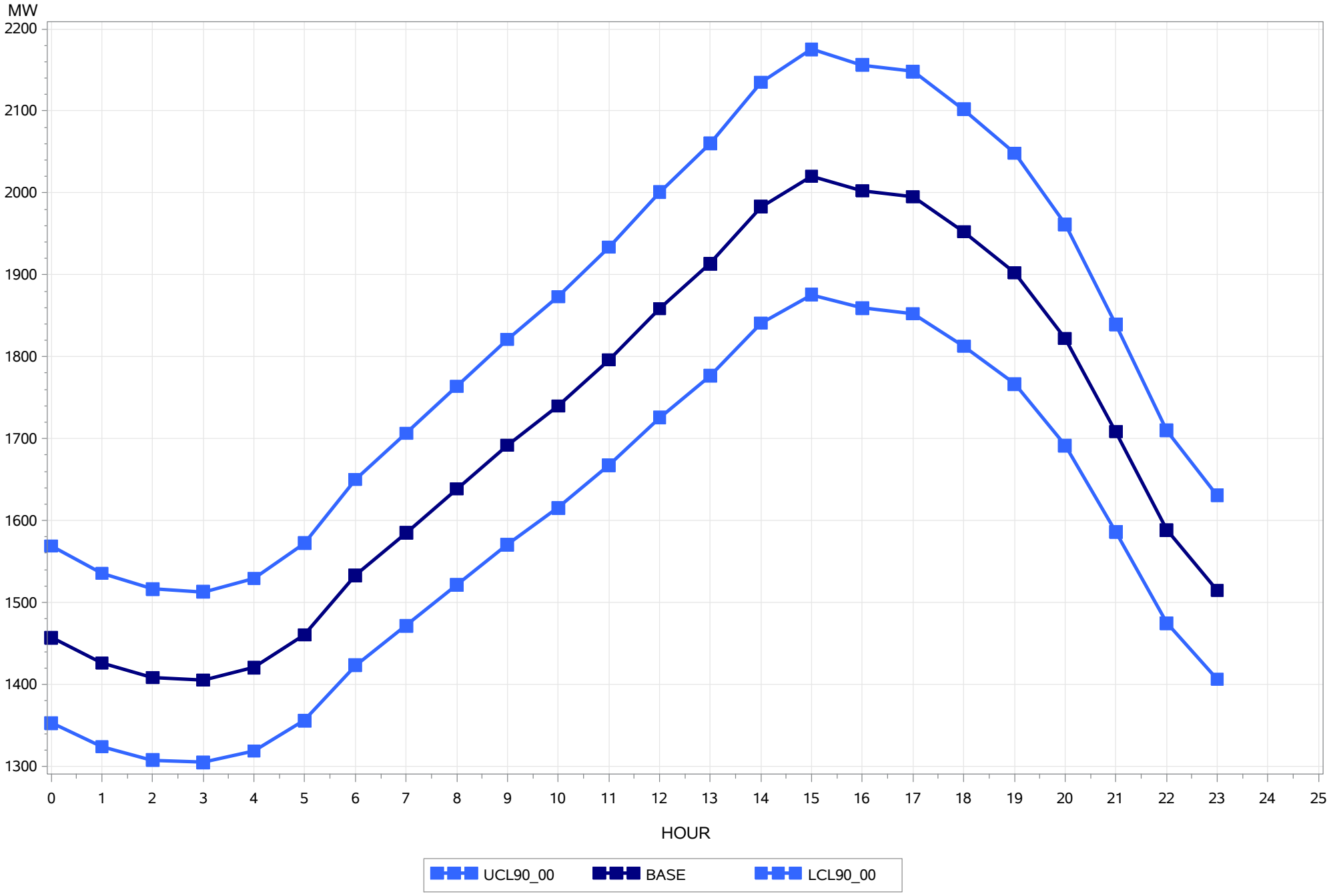
Member Forecasted On Peak Demand Day for July 2021

STATE OF COLORADO

Date of On Peak Day - 07/22/2021



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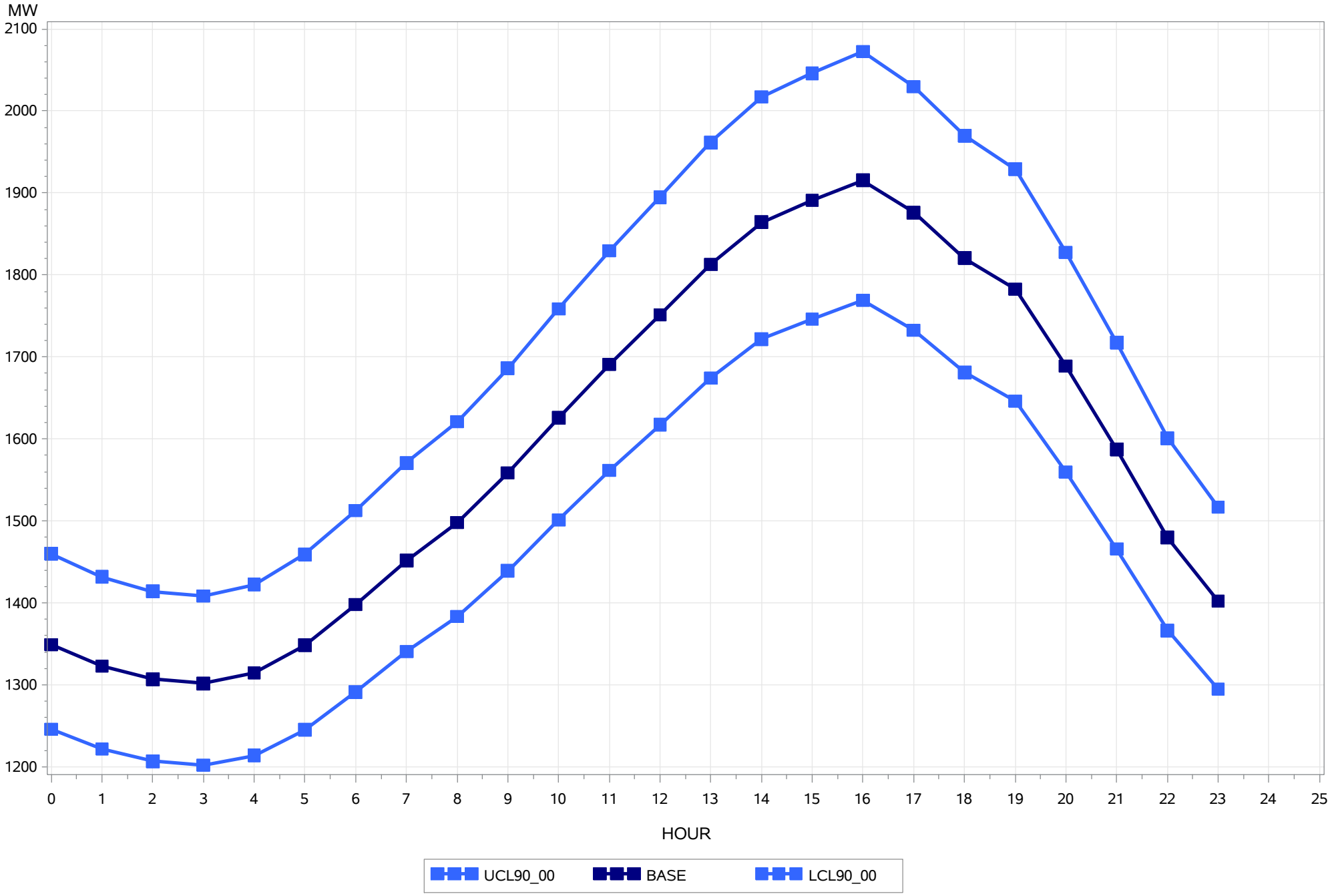
Member Forecasted On Peak Demand Day for August 2021

STATE OF COLORADO

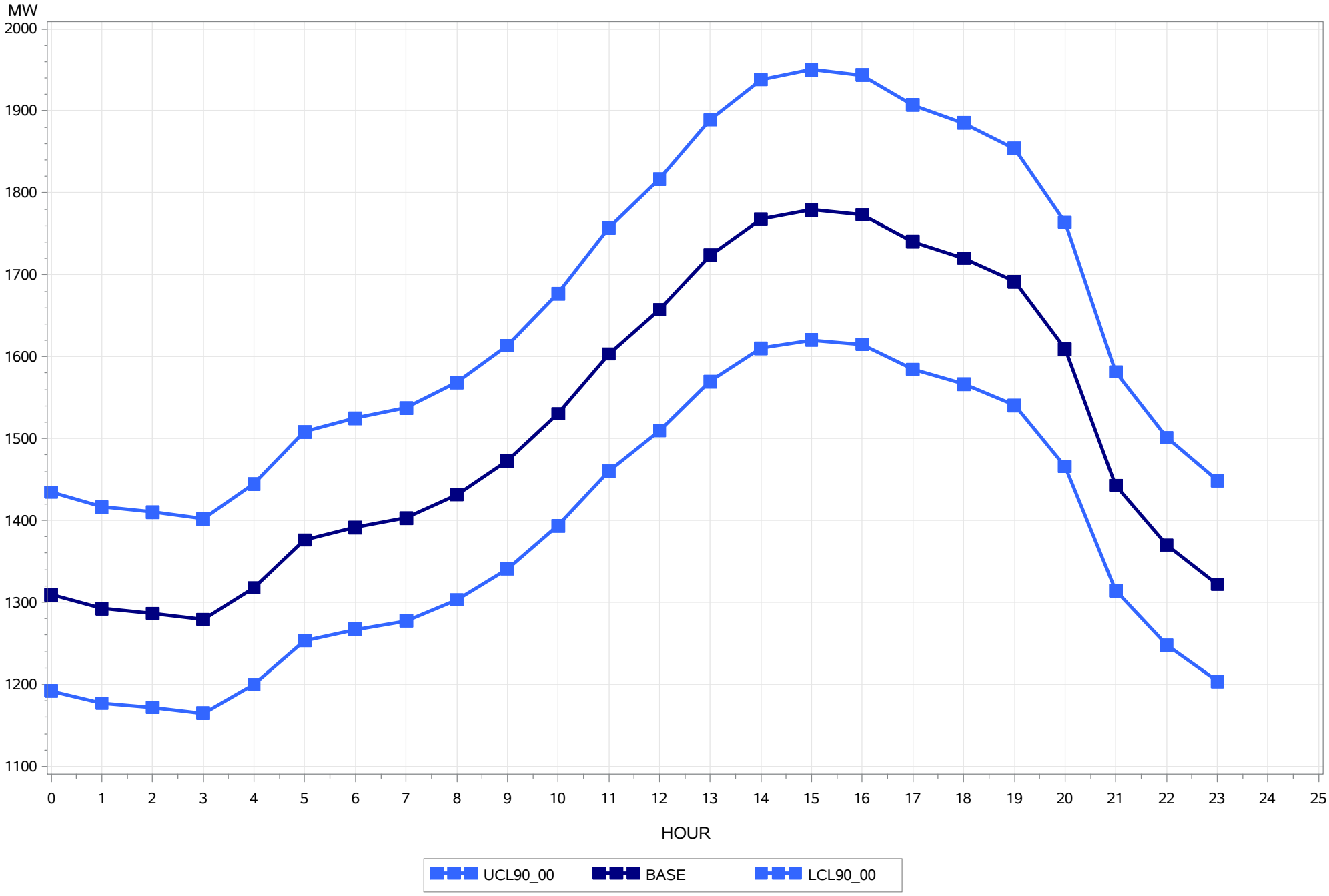
Date of On Peak Day - 08/28/2021



Member Forecasted On Peak Demand Day for September 2021

STATE OF COLORADO

Date of On Peak Day - 09/01/2021



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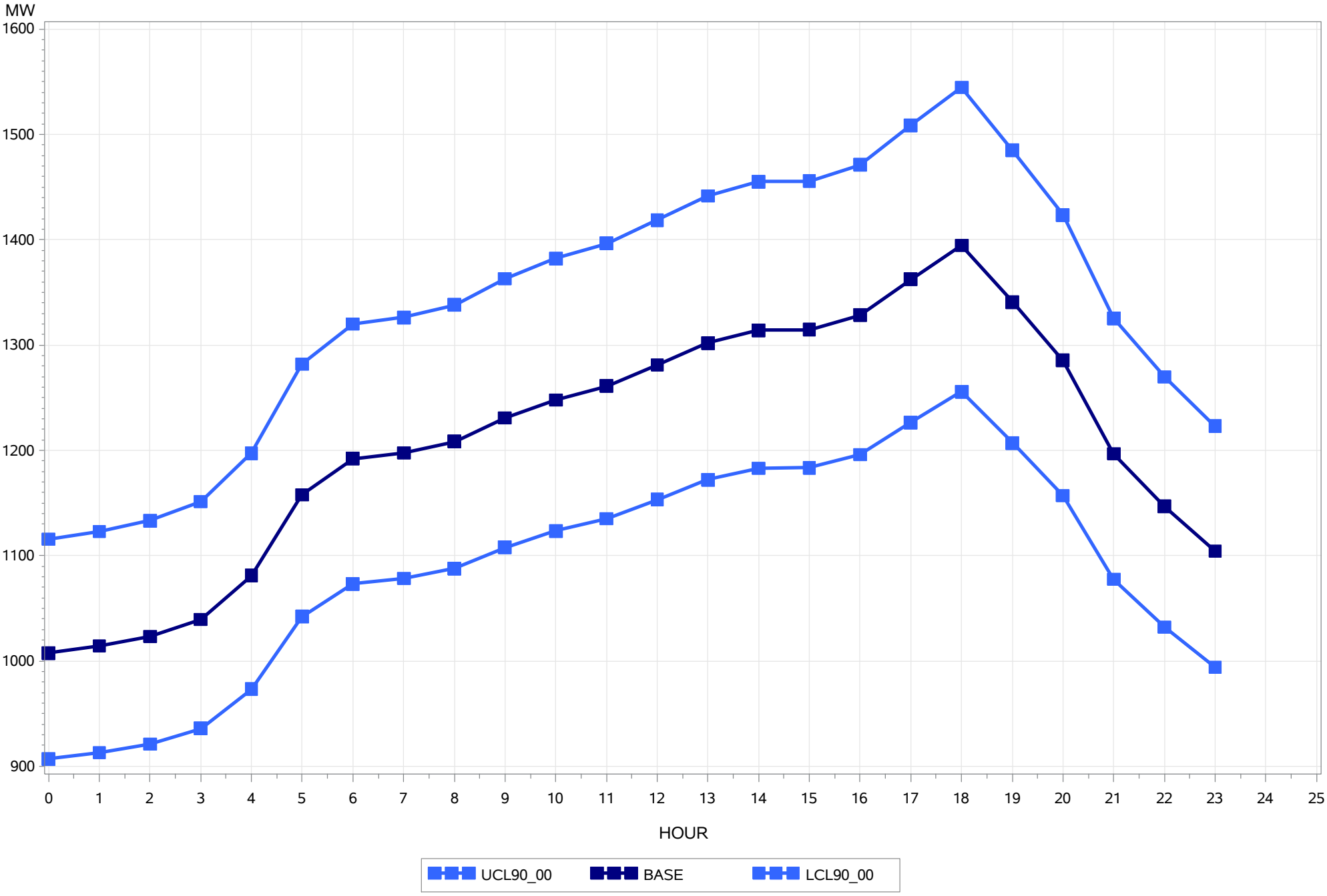
Member Forecasted On Peak Demand Day for October 2021

STATE OF COLORADO

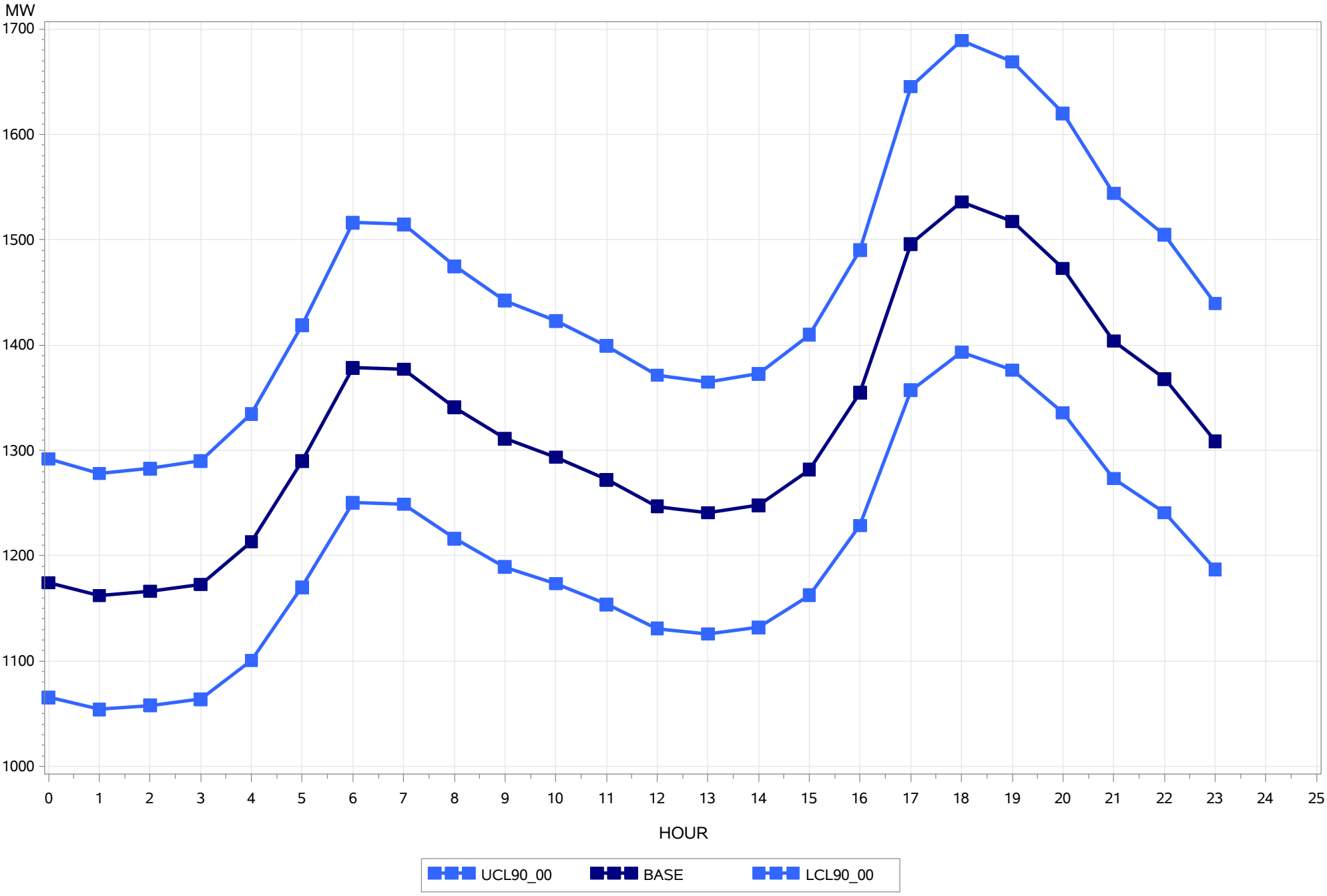
Date of On Peak Day - 10/11/2021



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

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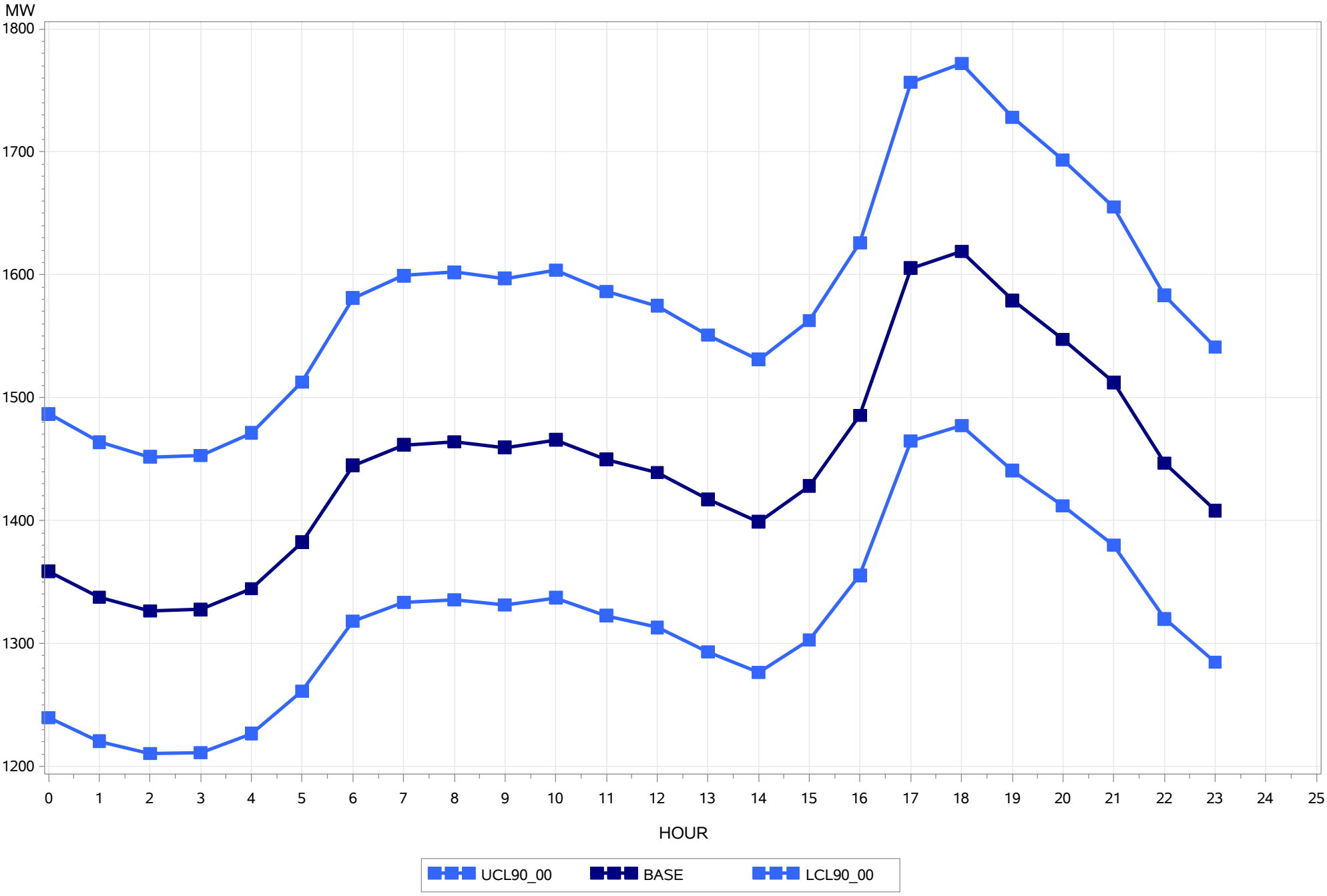

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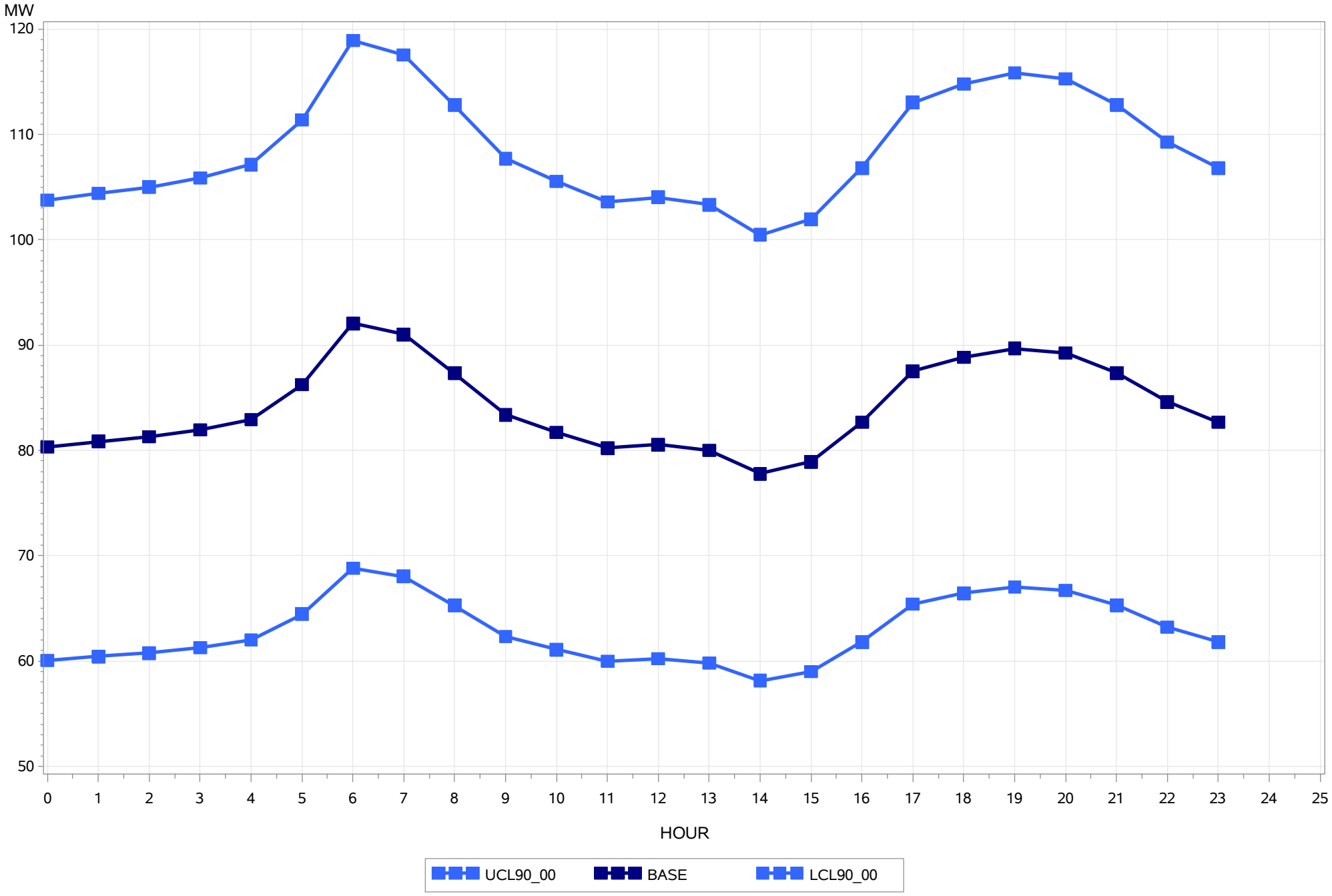
Member Forecasted On Peak Demand Day for January 2021

STATE OF NEBRASKA

Date of On Peak Day - 01/07/2021



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STATE OF NEBRASKA

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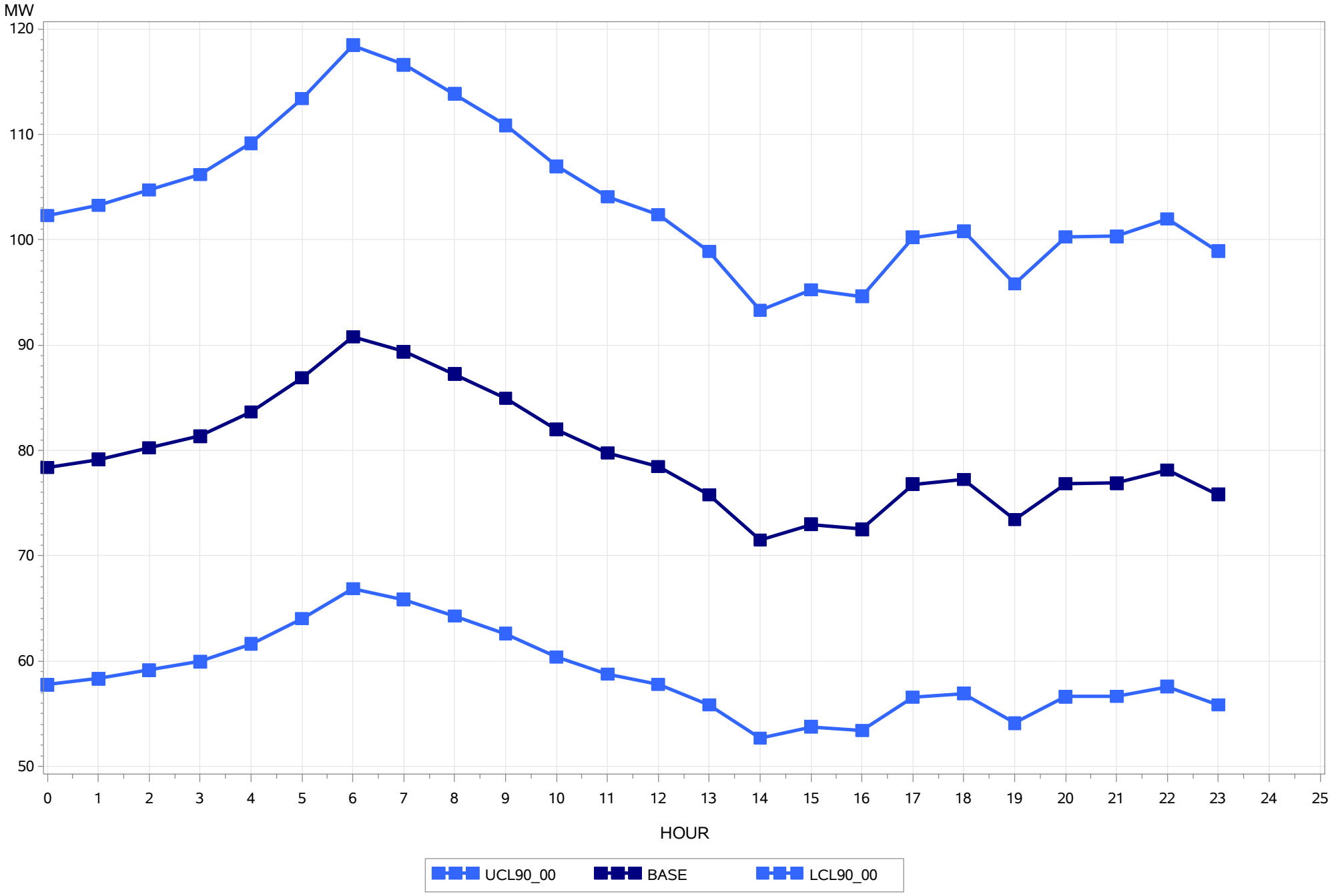

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STATE OF NEBRASKA

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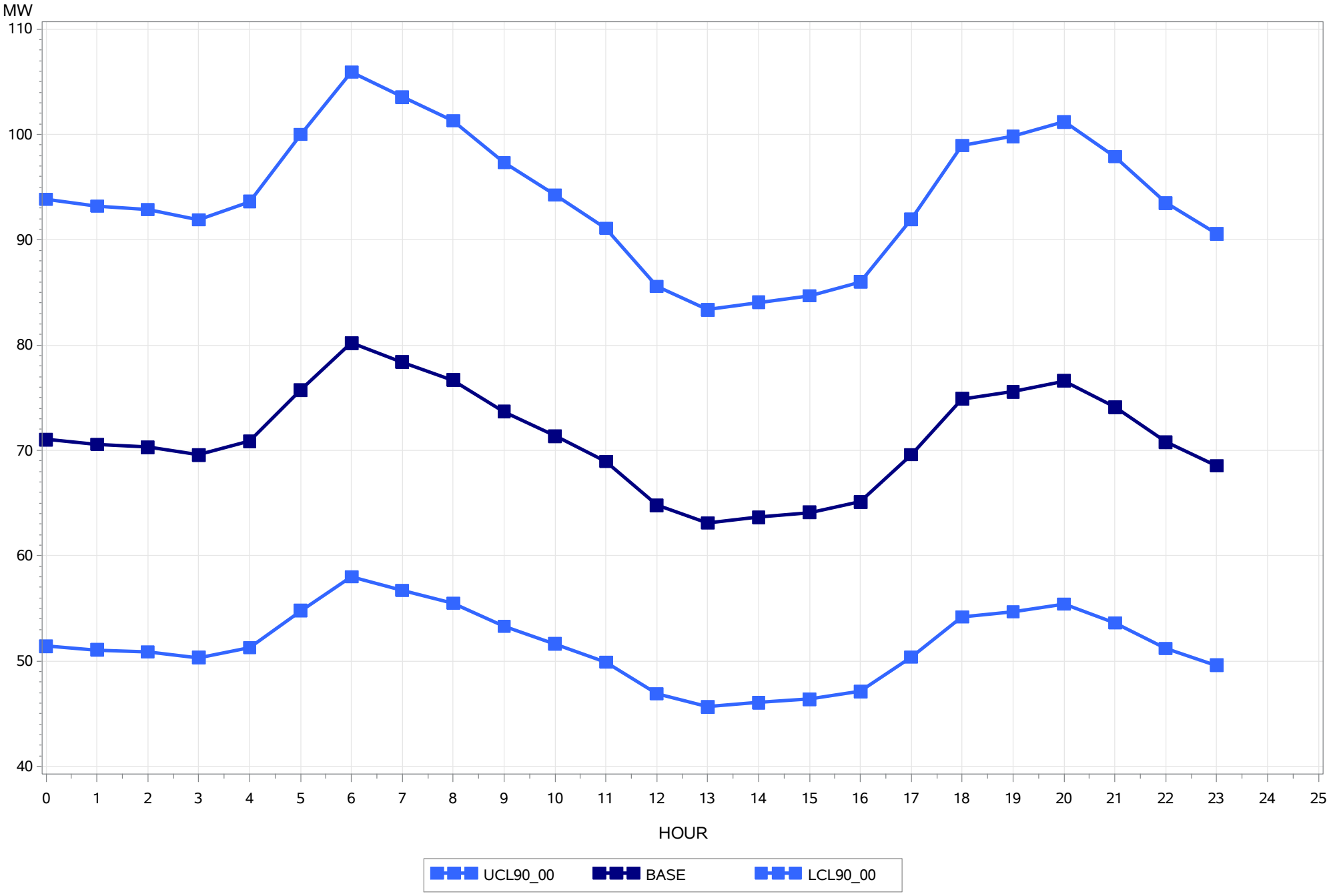

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STATE OF NEBRASKA

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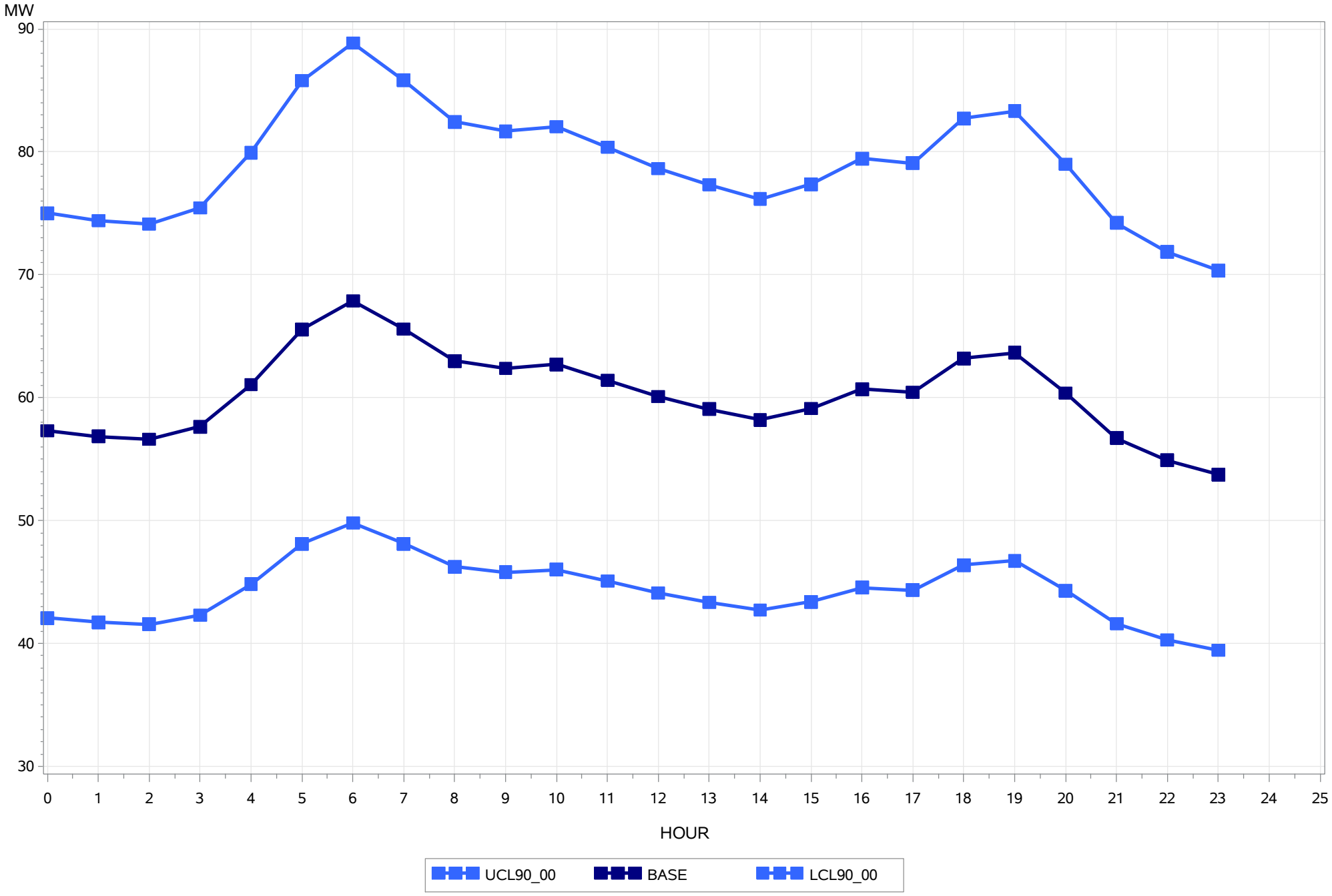

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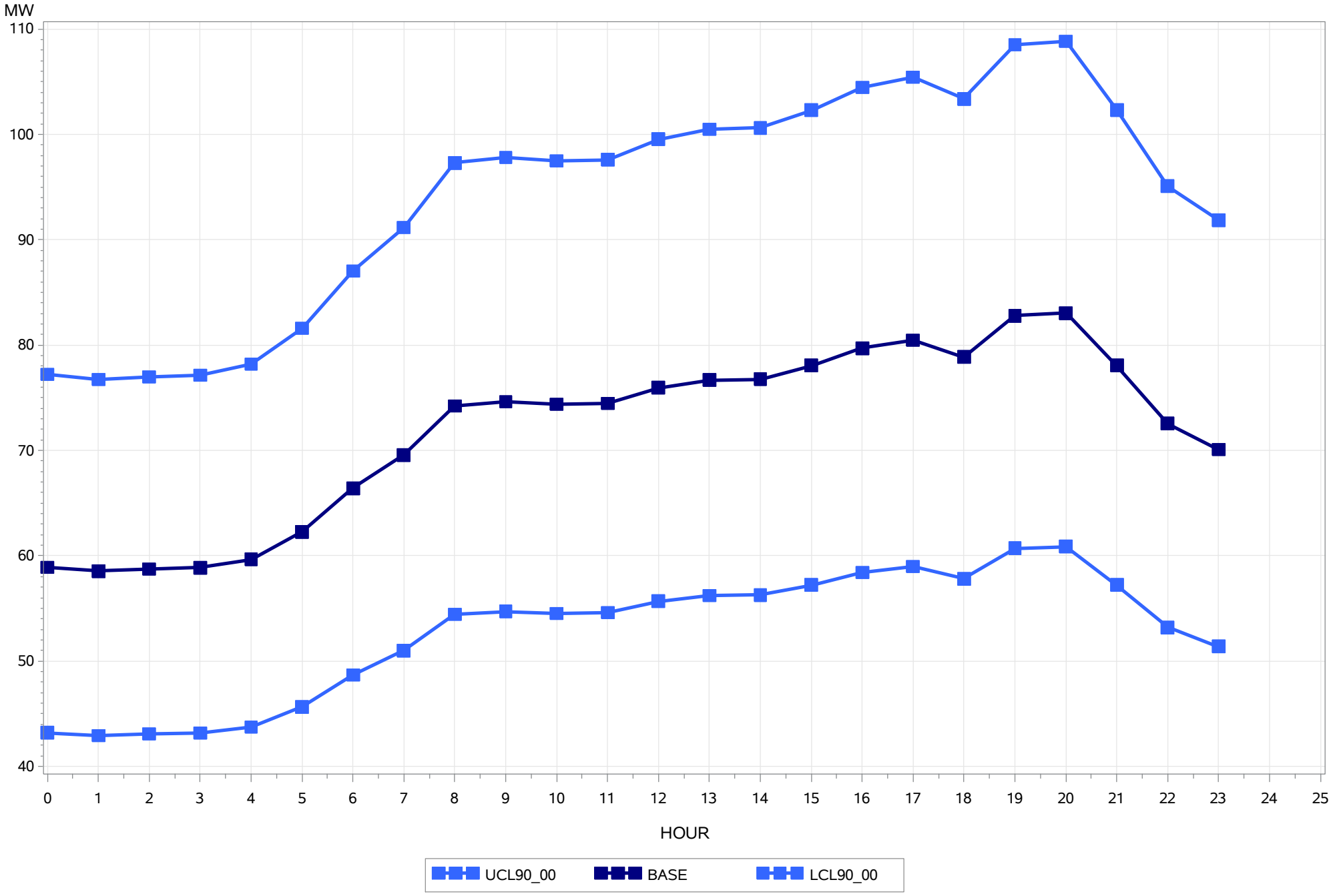

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Member Forecasted On Peak Demand Day for June 2021

STATE OF NEBRASKA

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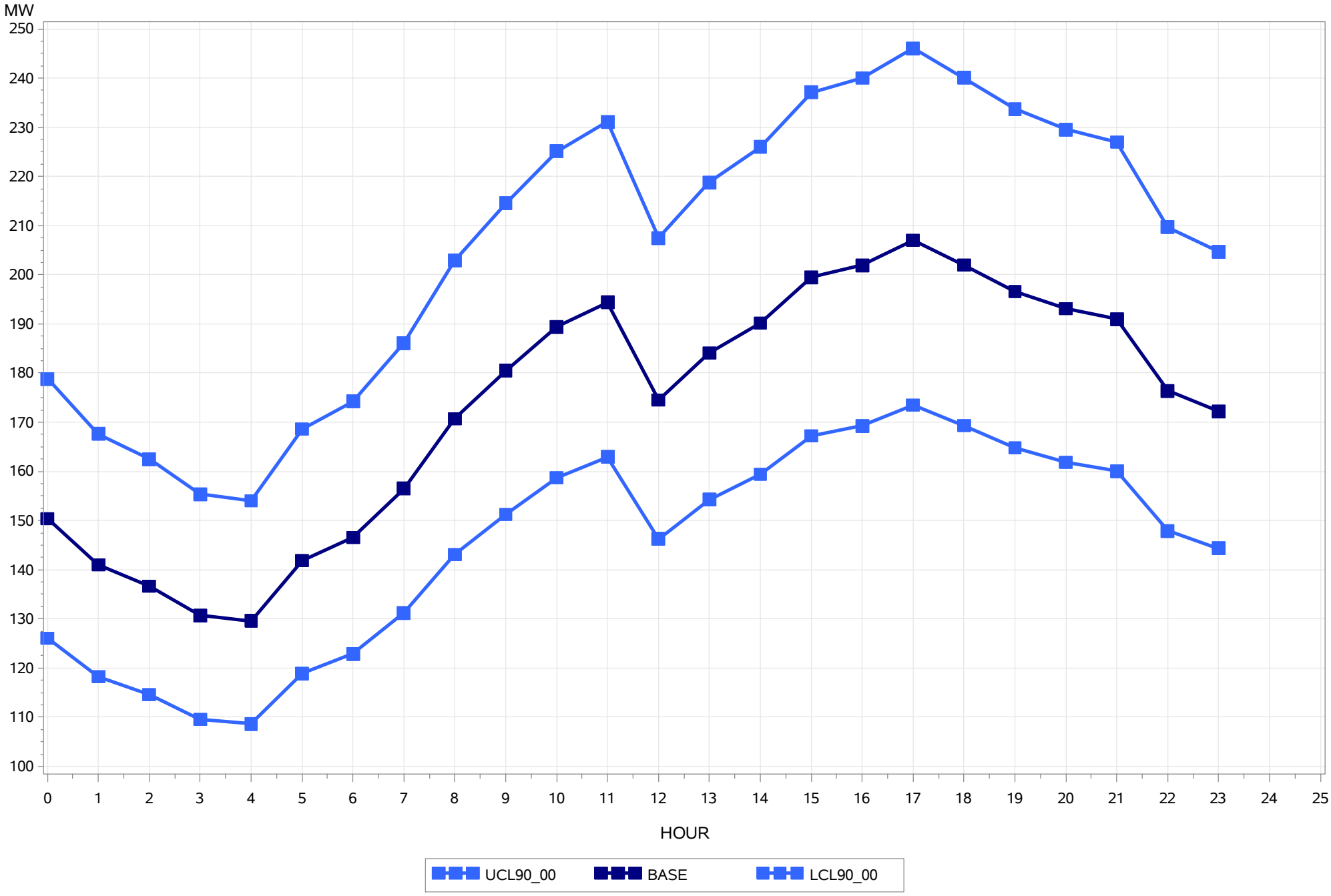

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STATE OF NEBRASKA

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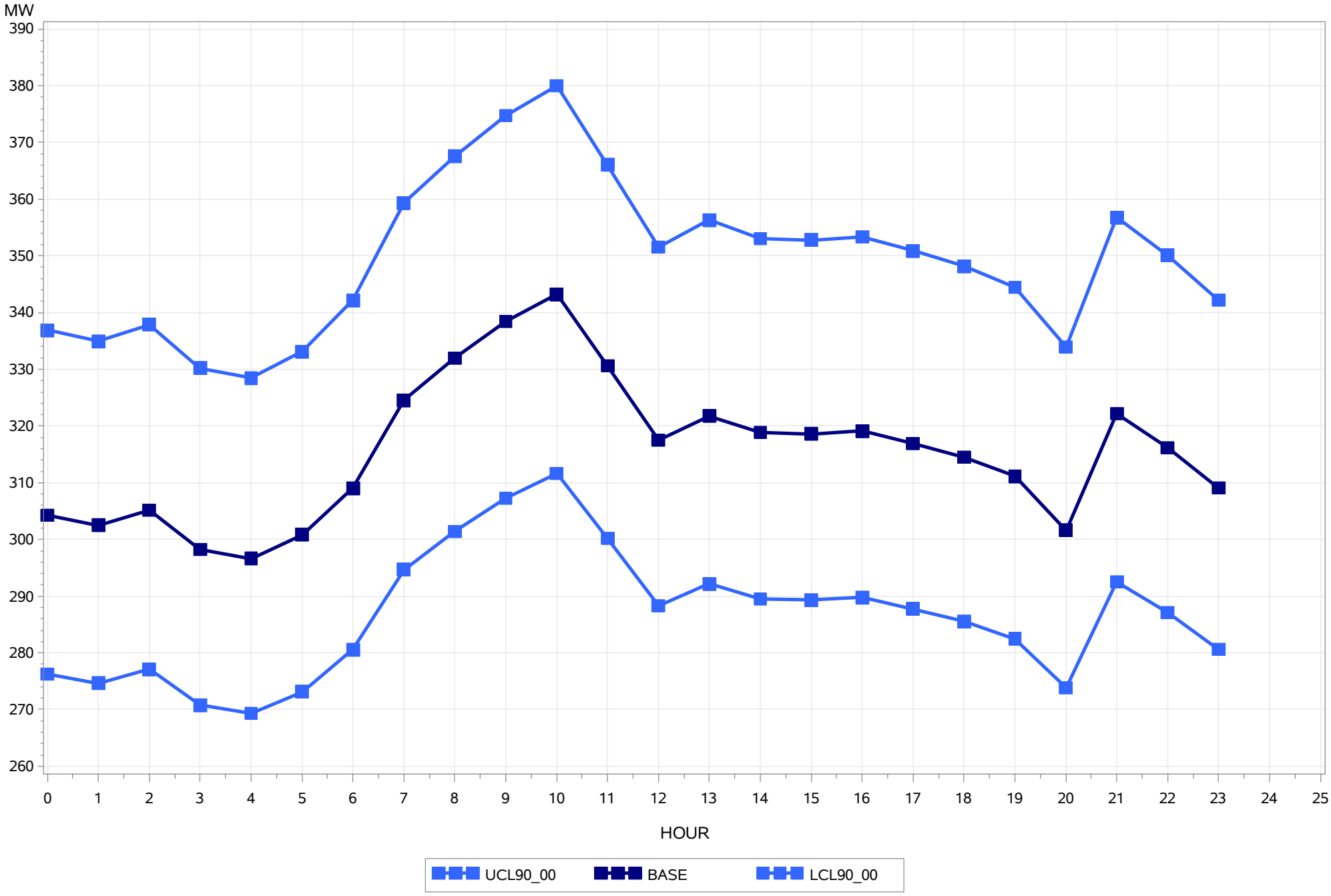

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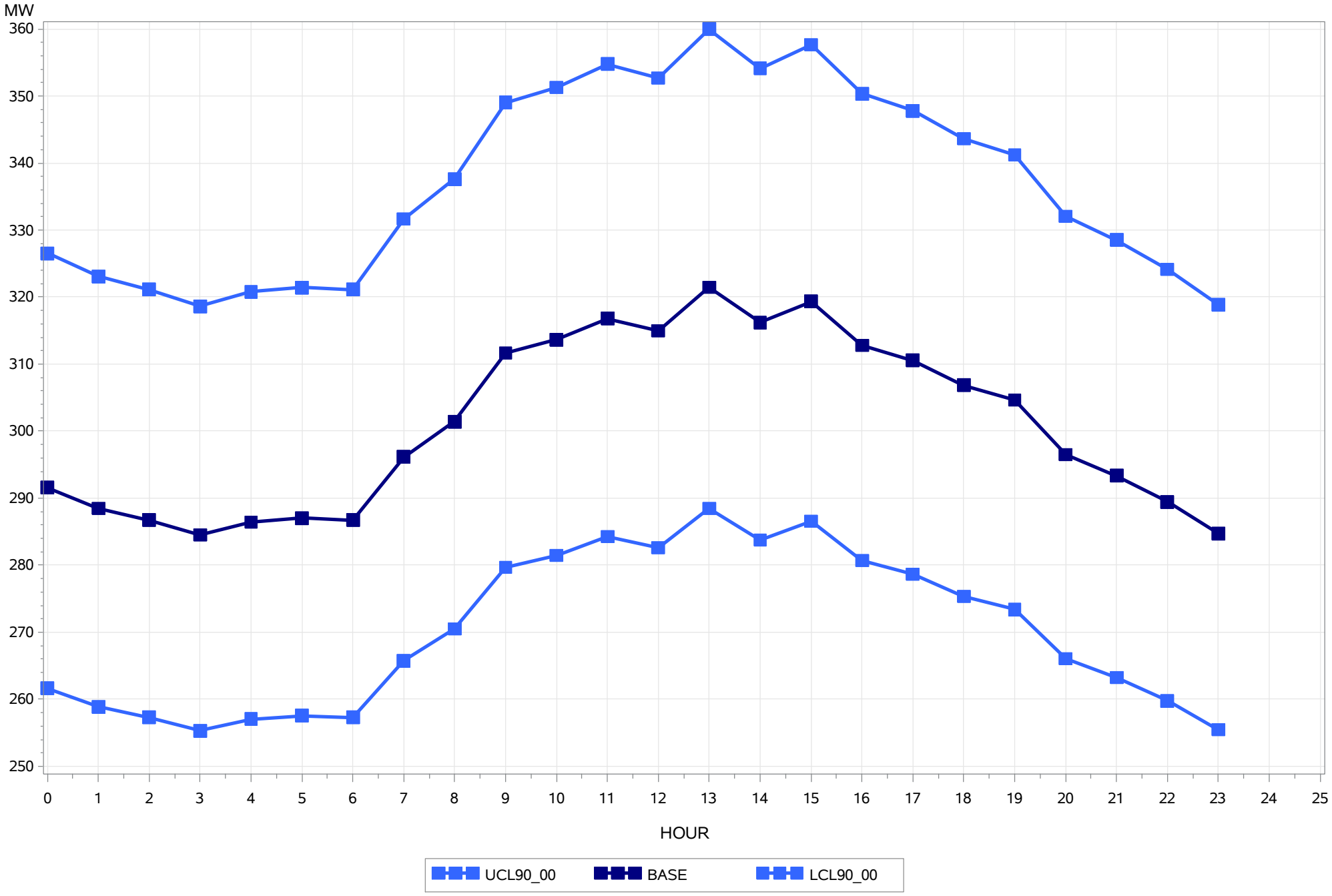
Member Forecasted On Peak Demand Day for August 2021

STATE OF NEBRASKA

Date of On Peak Day - 08/24/2021



Member Forecasted On Peak Demand Day for September 2021

STATE OF NEBRASKA

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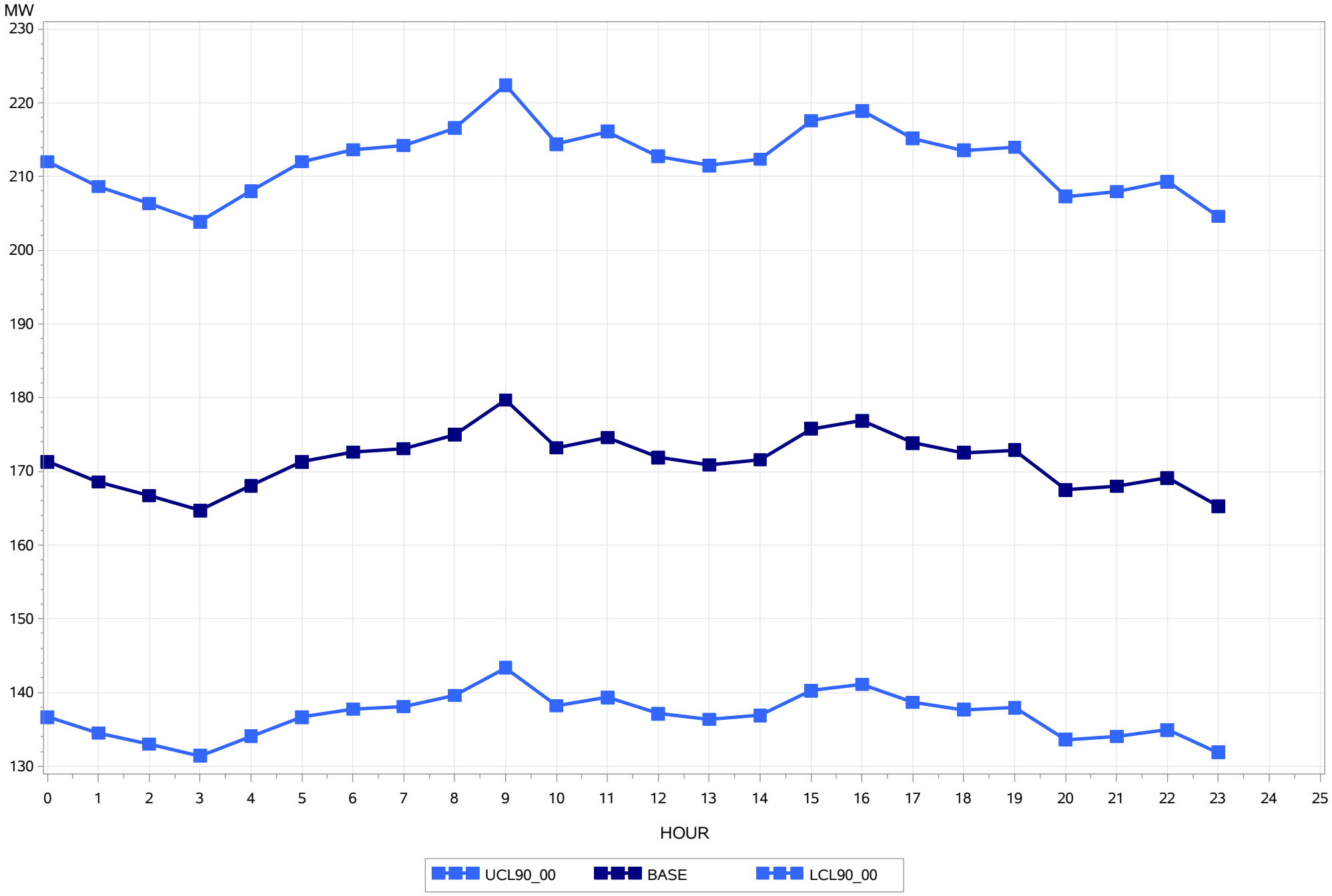

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Member Forecasted On Peak Demand Day for October 2021

STATE OF NEBRASKA

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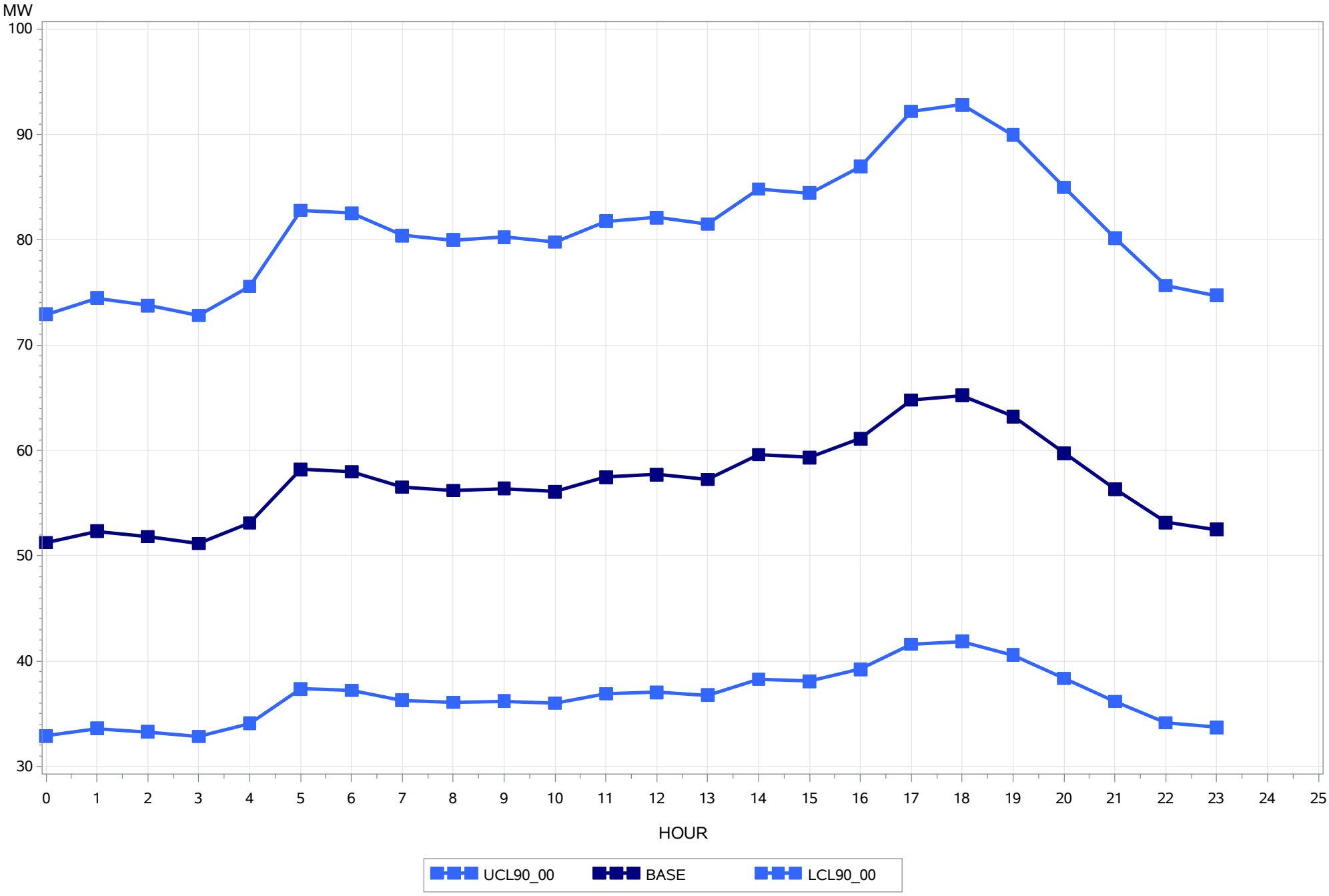

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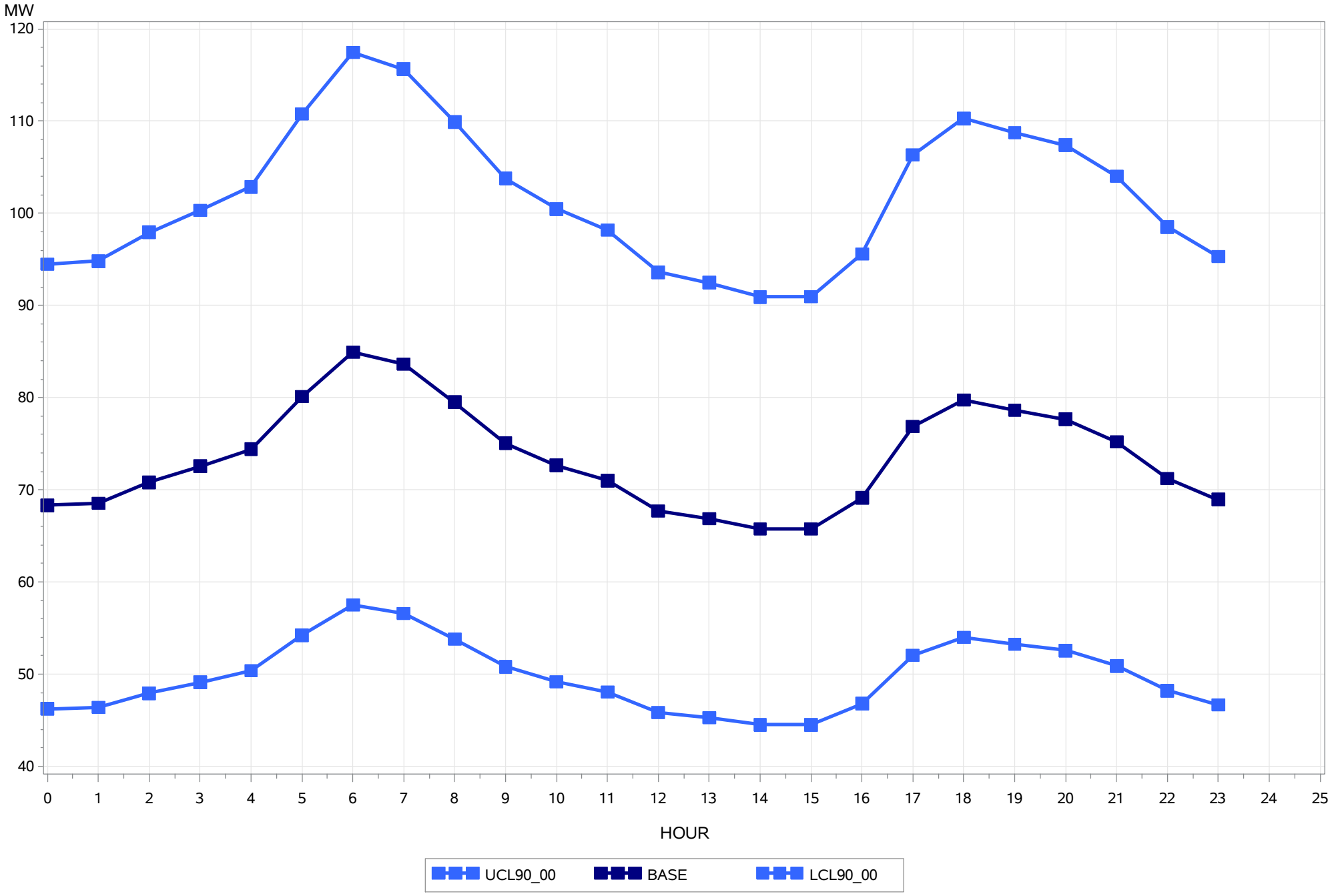
STATE OF NEBRASKA

Date of On Peak Day - 11/09/2021



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STATE OF NEBRASKA

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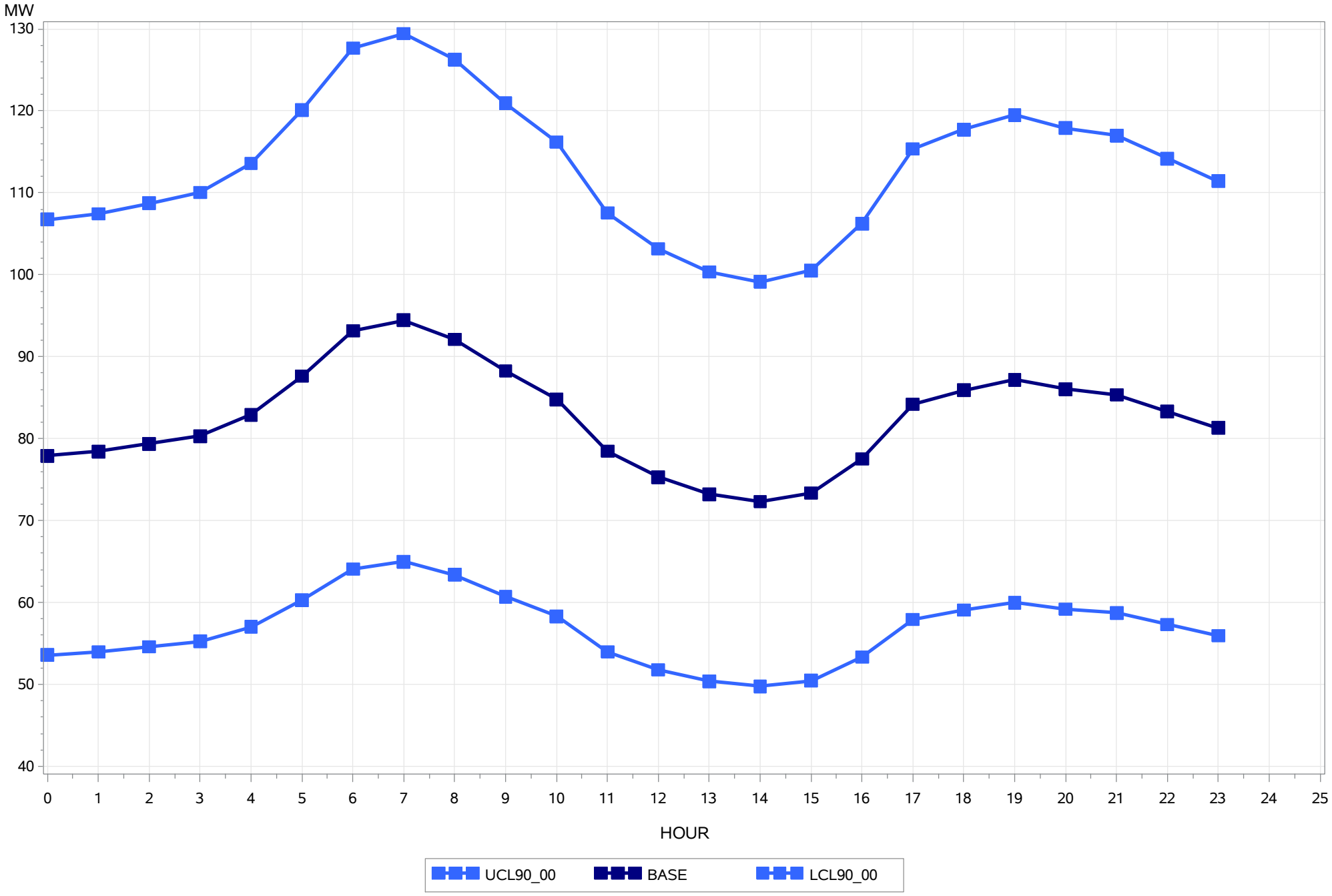

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STATE OF NEW MEXICO

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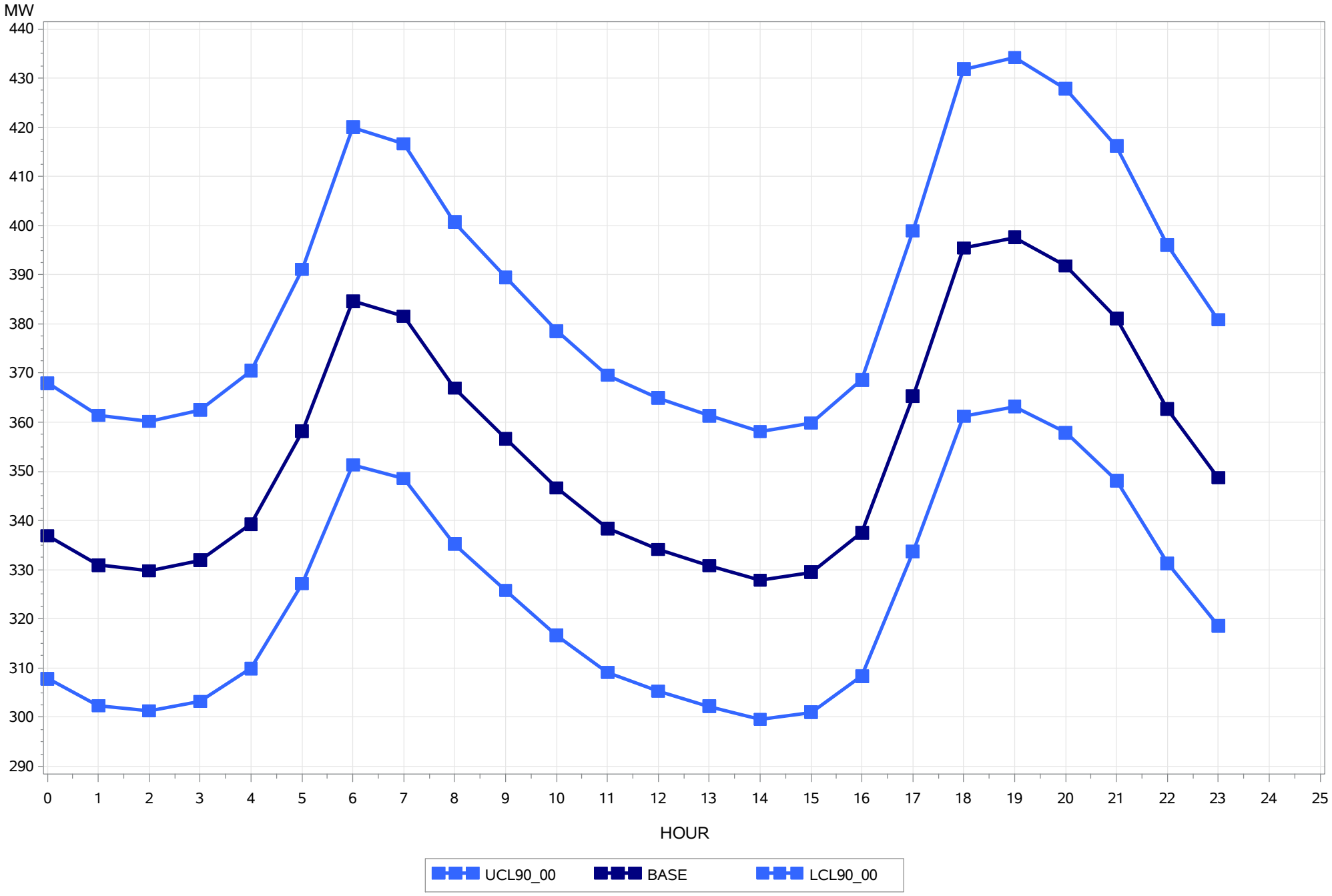

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STATE OF NEW MEXICO

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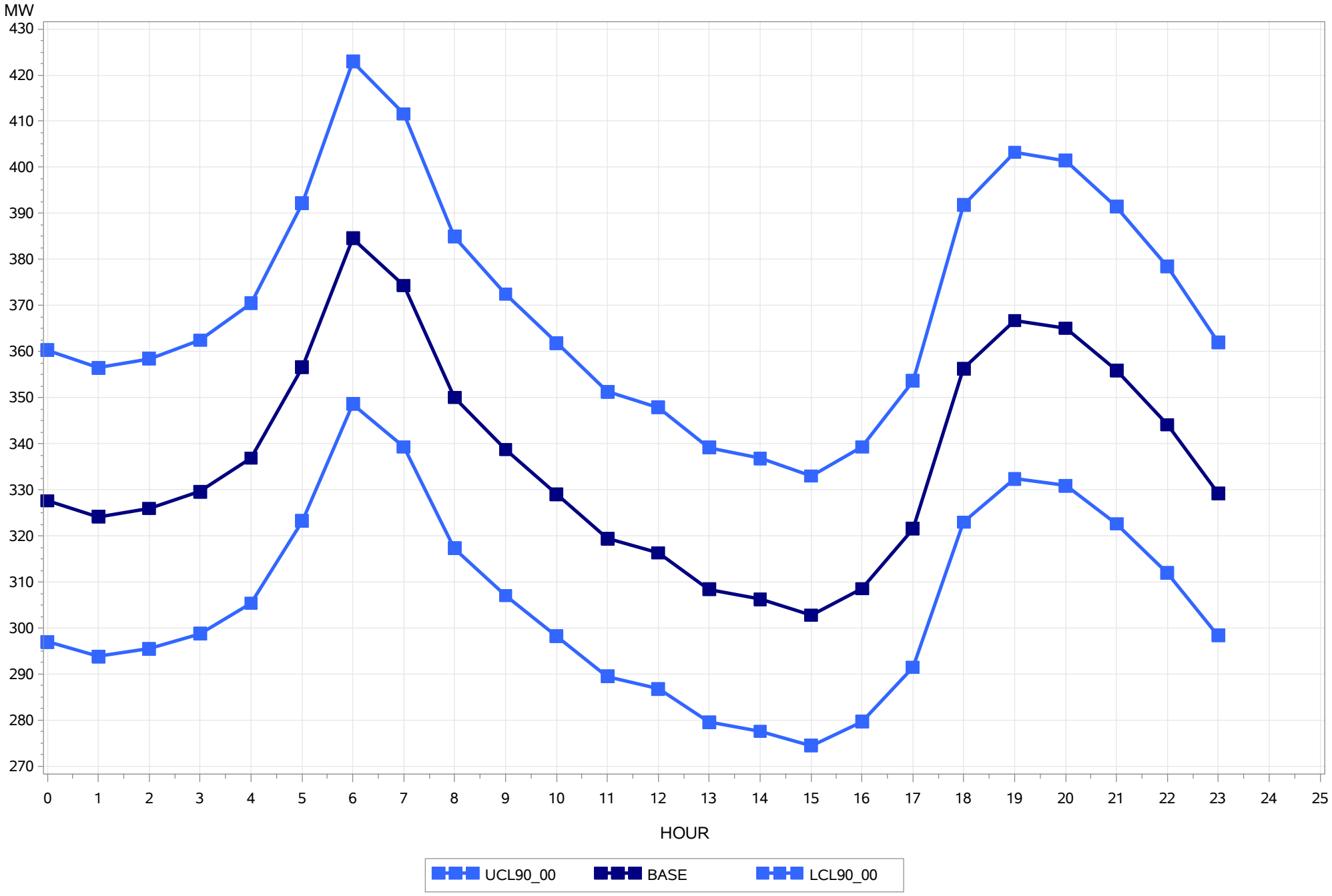

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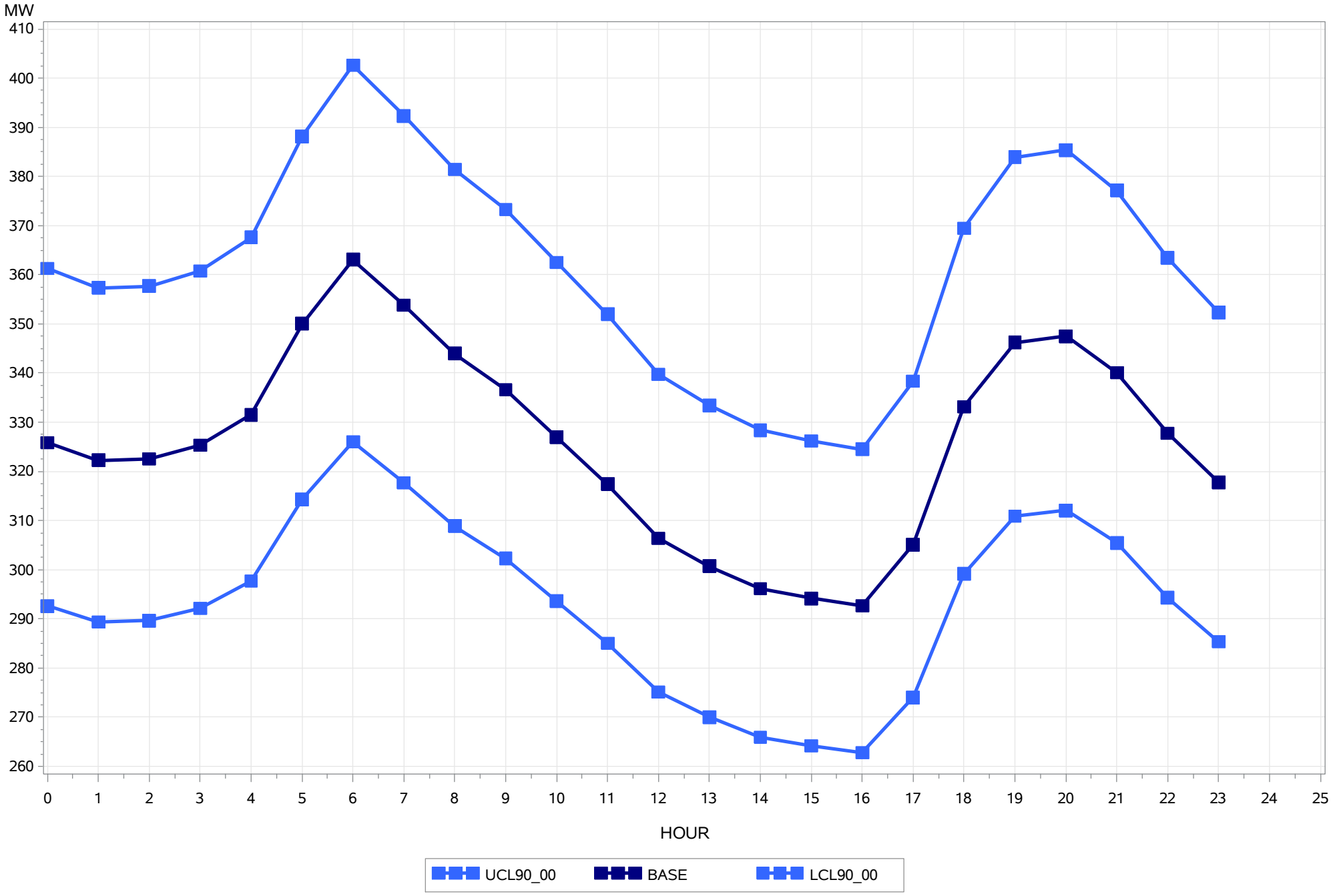

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STATE OF NEW MEXICO

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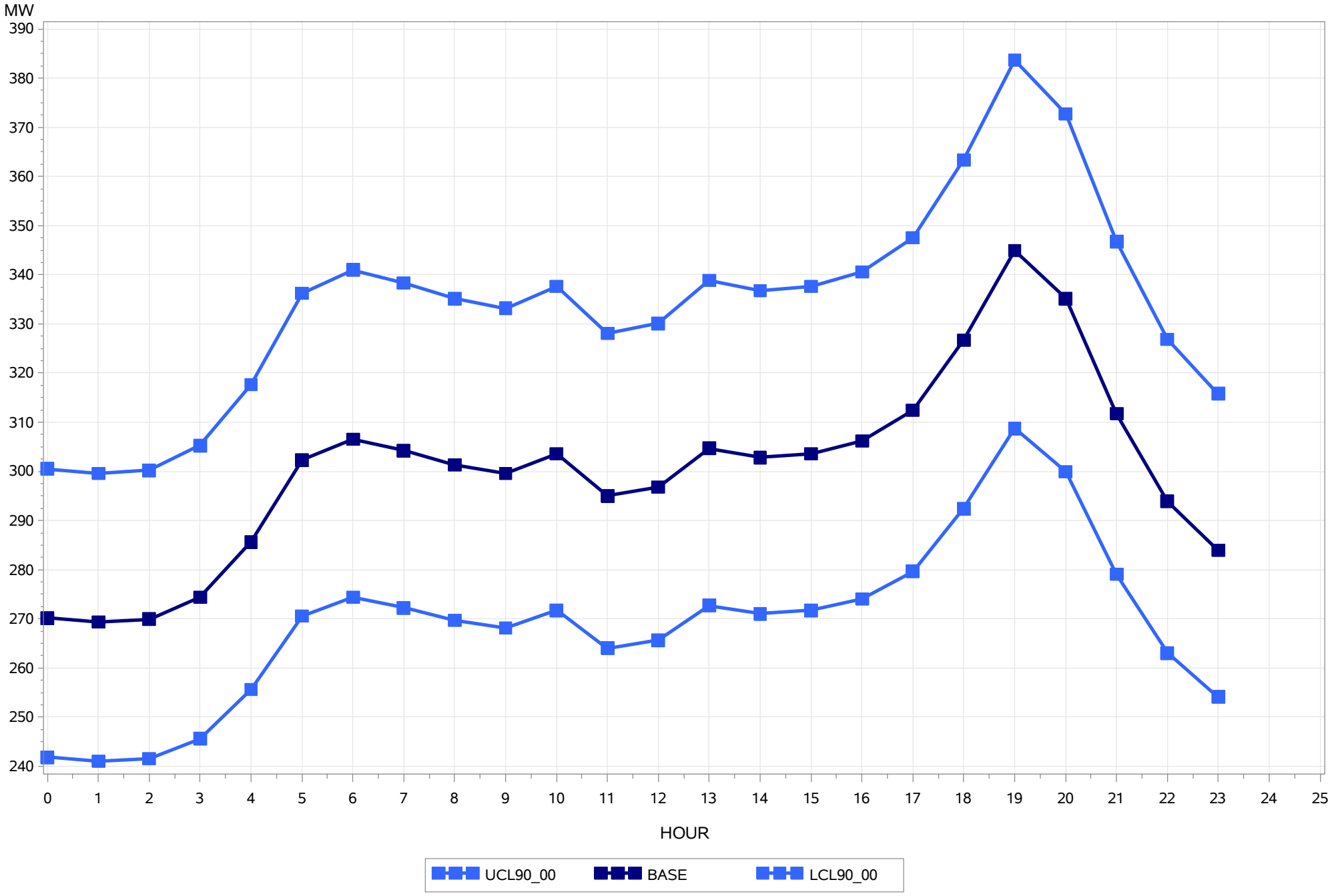

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STATE OF NEW MEXICO

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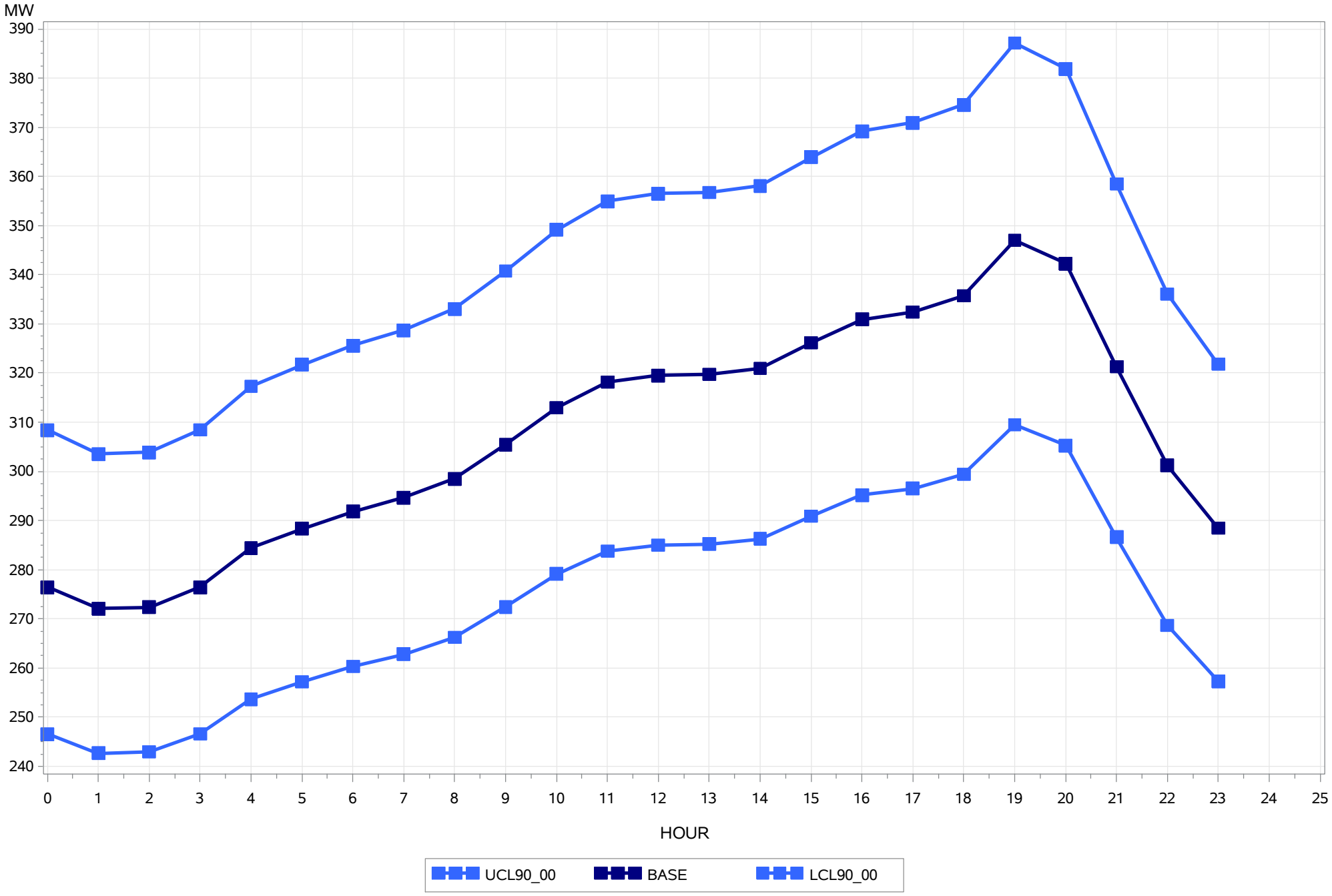

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STATE OF NEW MEXICO

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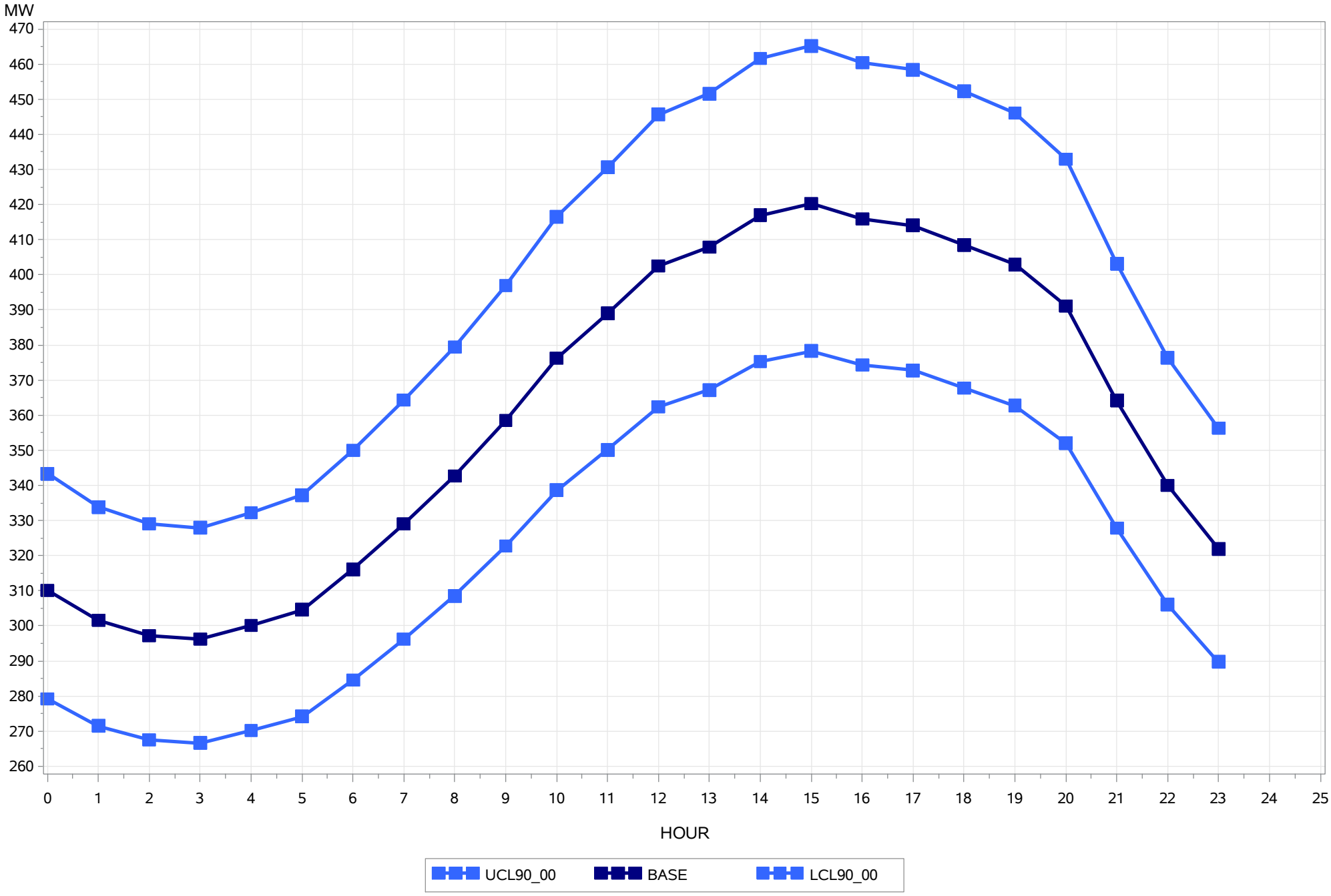

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STATE OF NEW MEXICO

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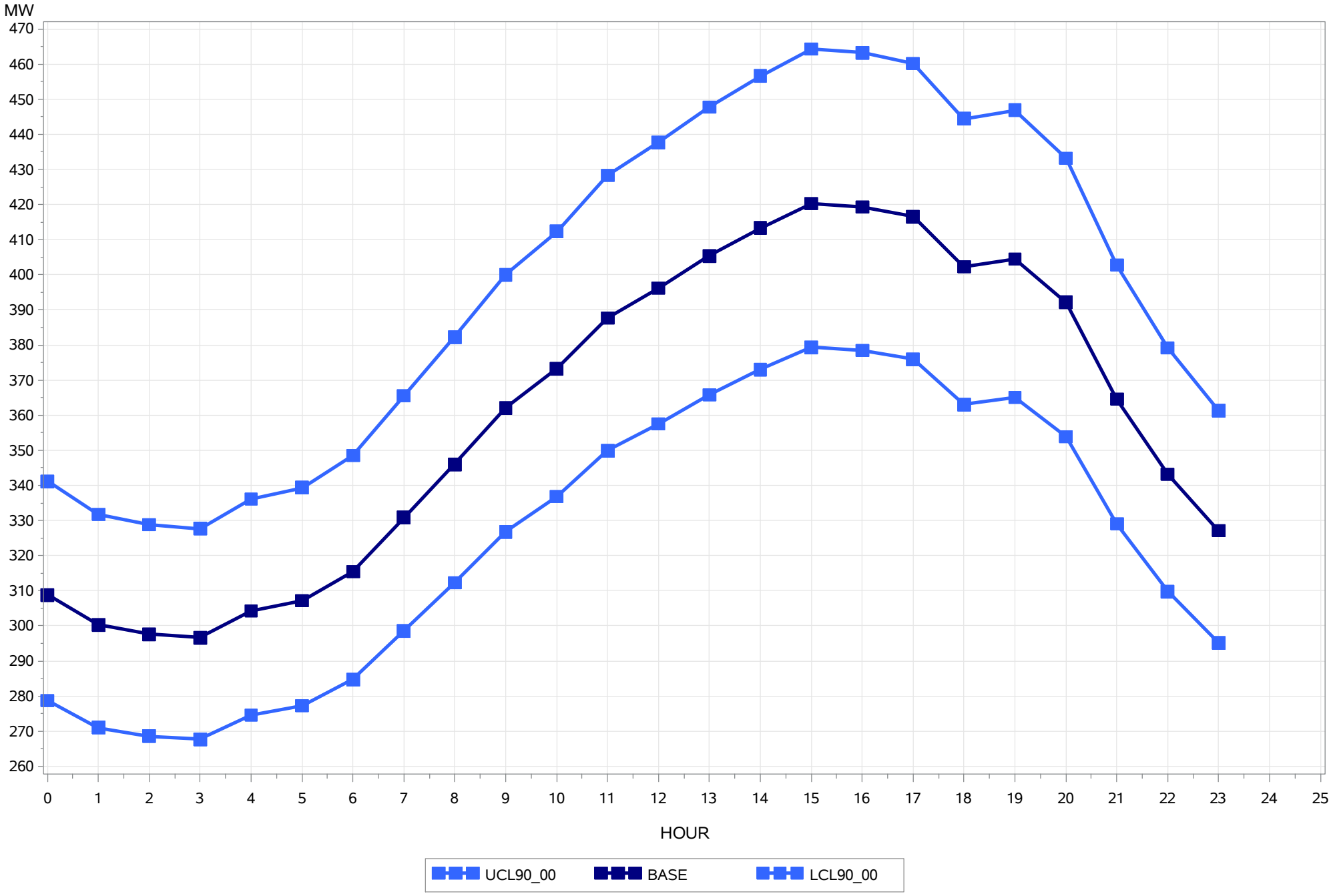

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STATE OF NEW MEXICO

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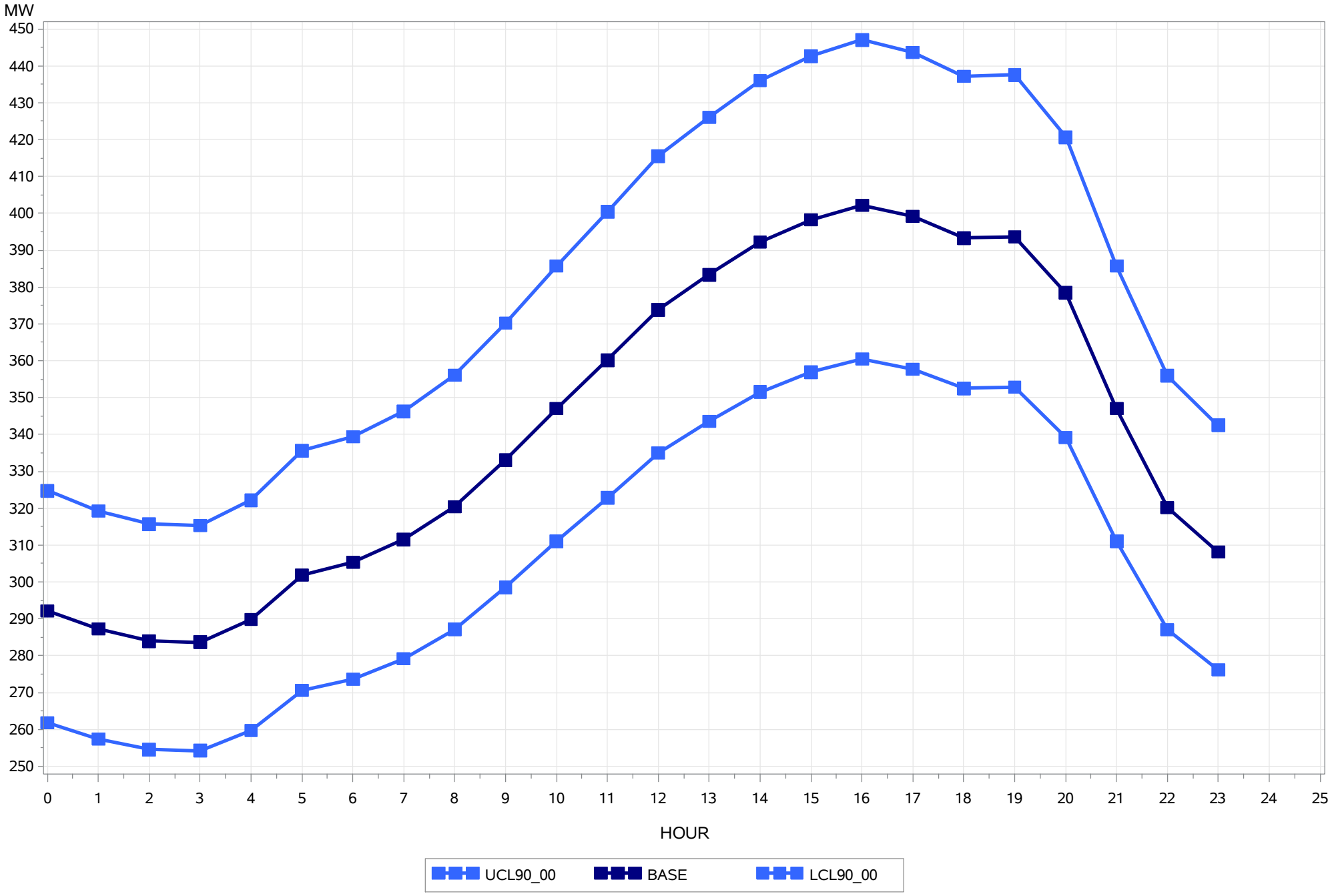

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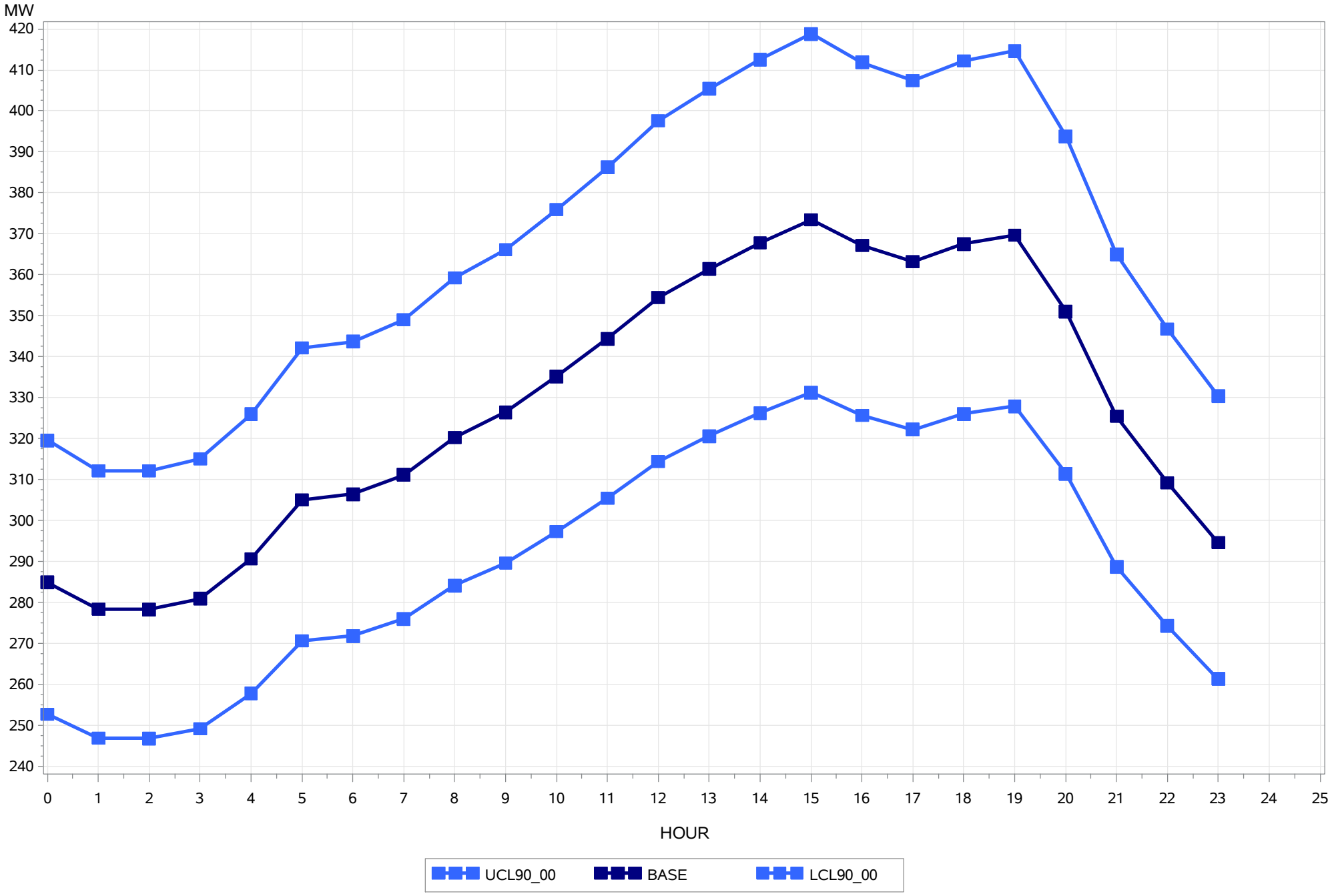

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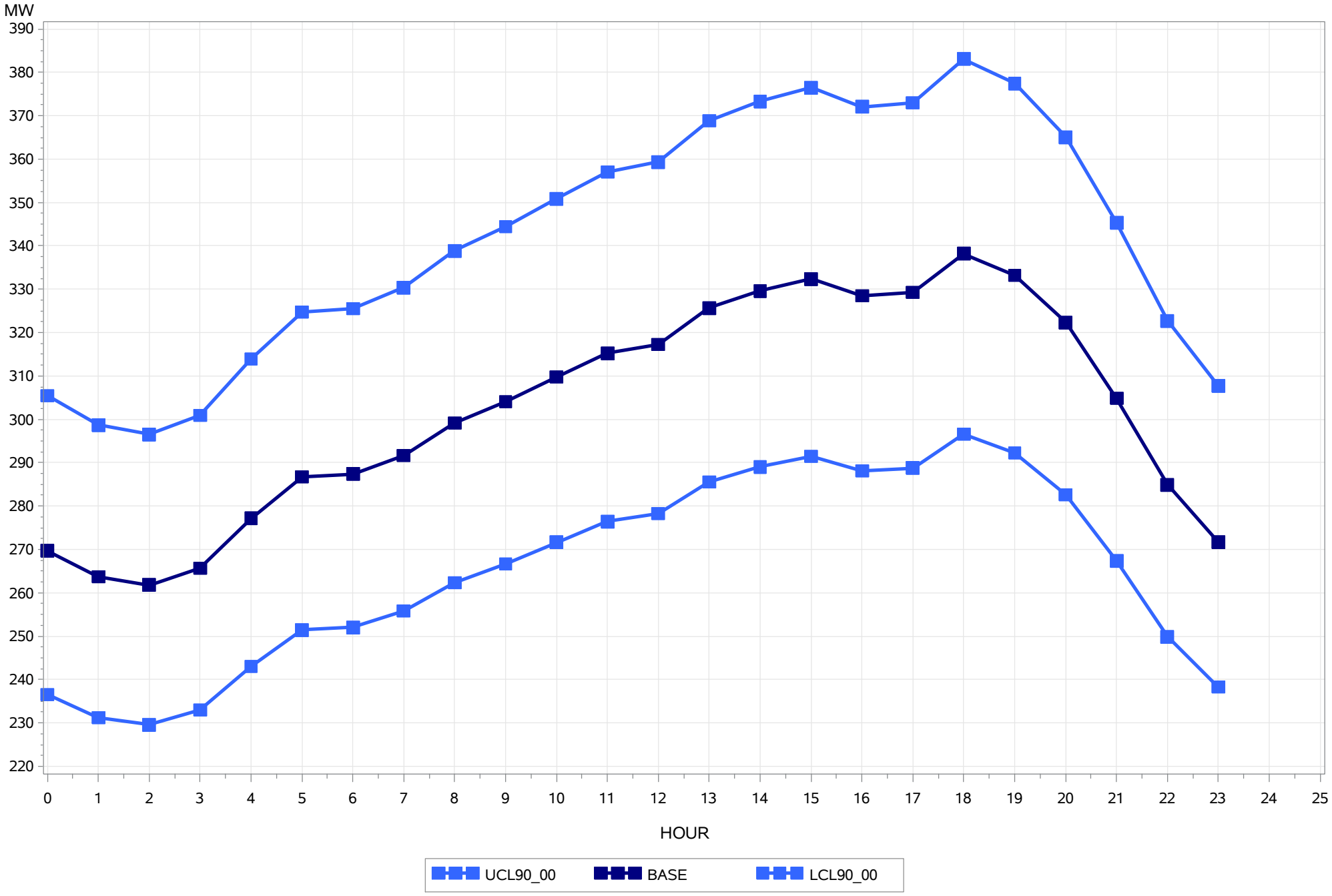

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STATE OF NEW MEXICO

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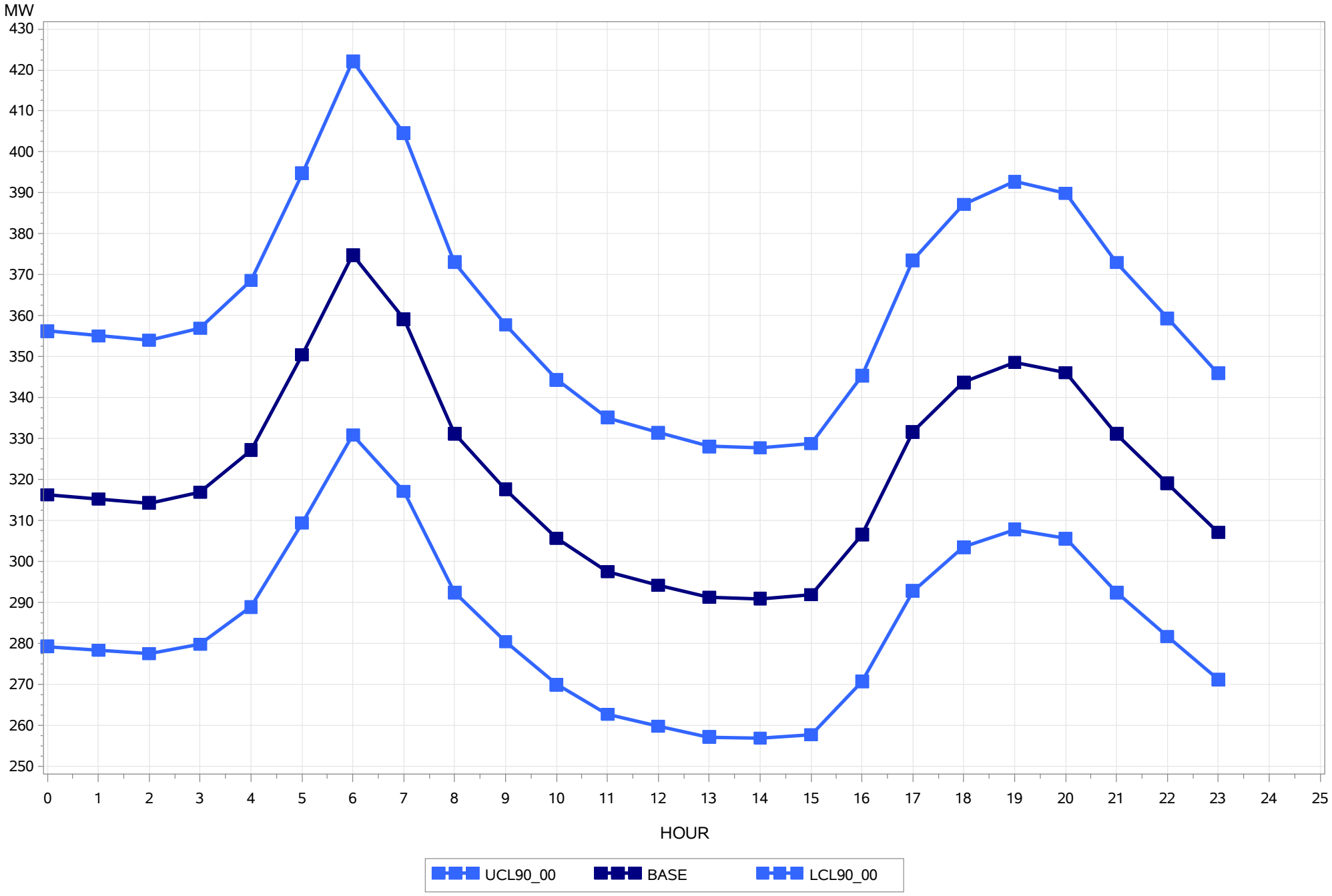

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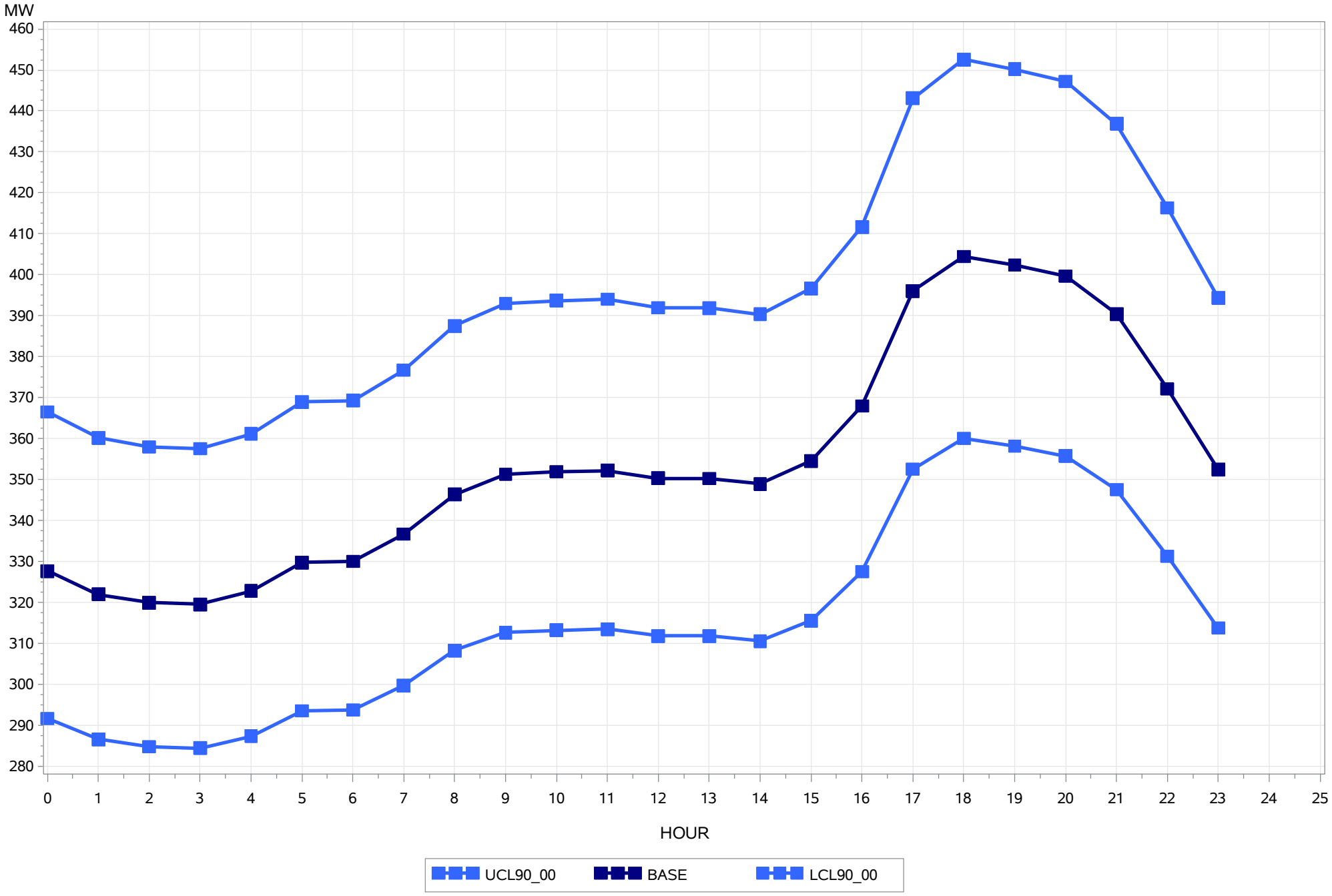

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Member Forecasted On Peak Demand Day for January 2021

STATE OF WYOMING

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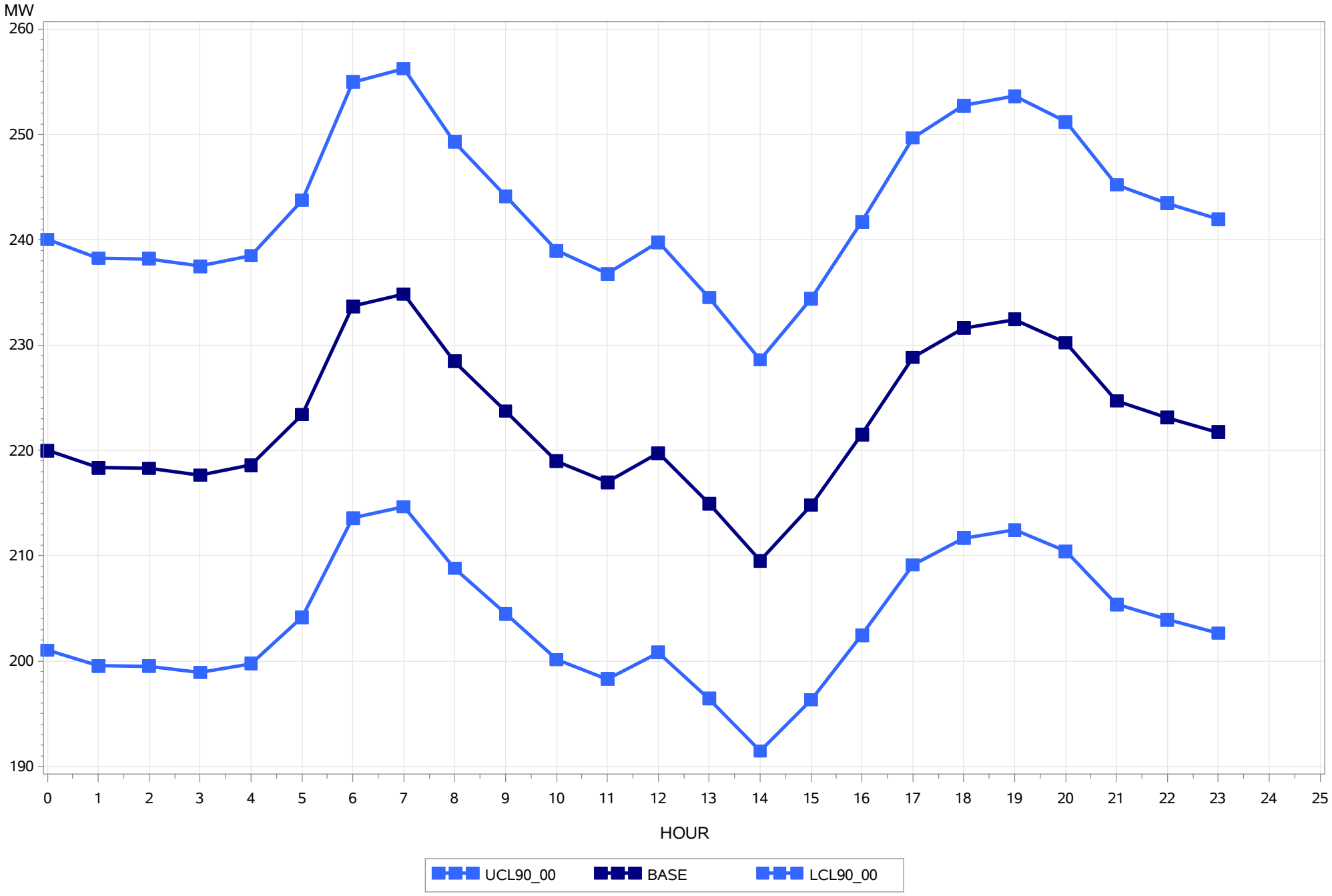

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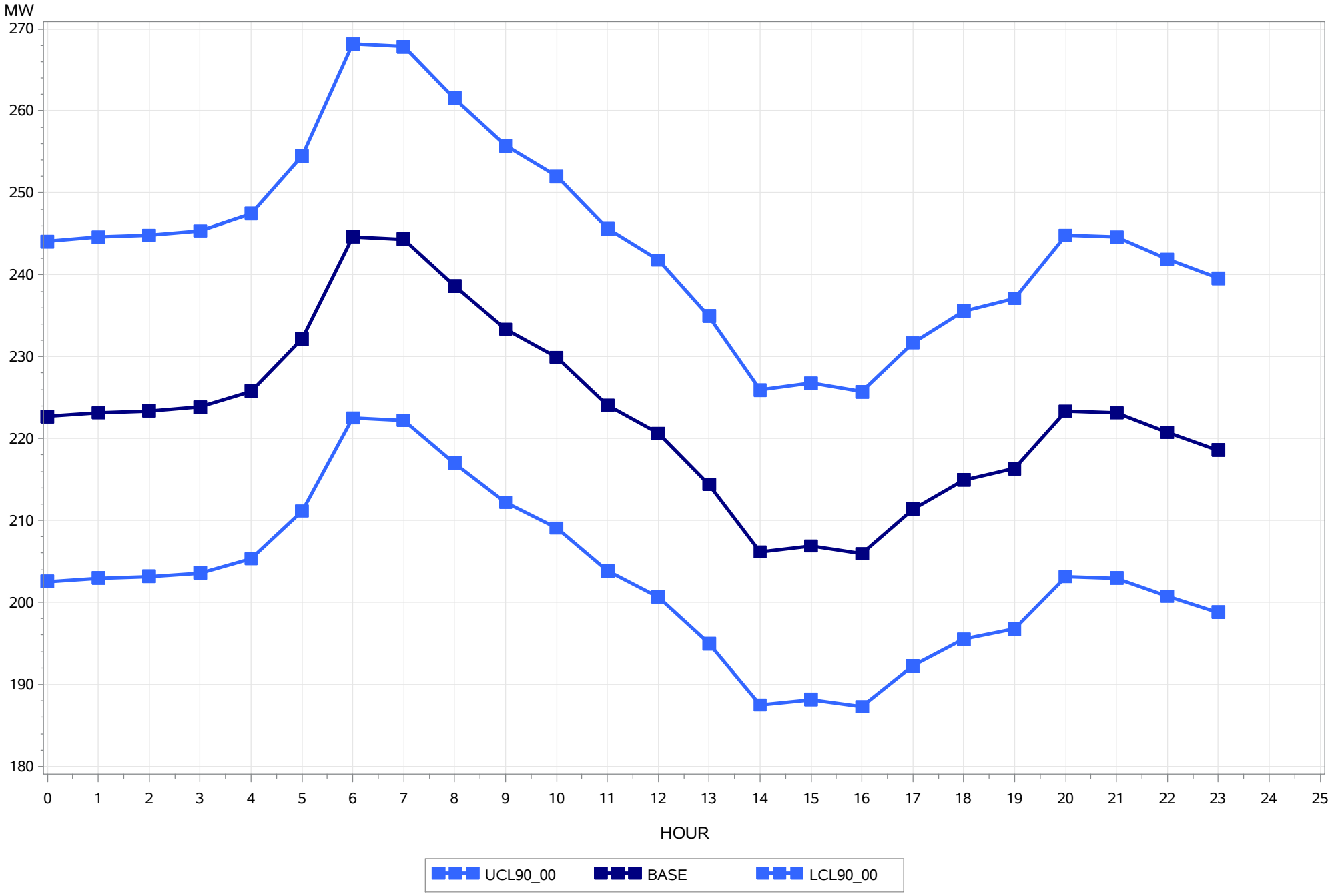

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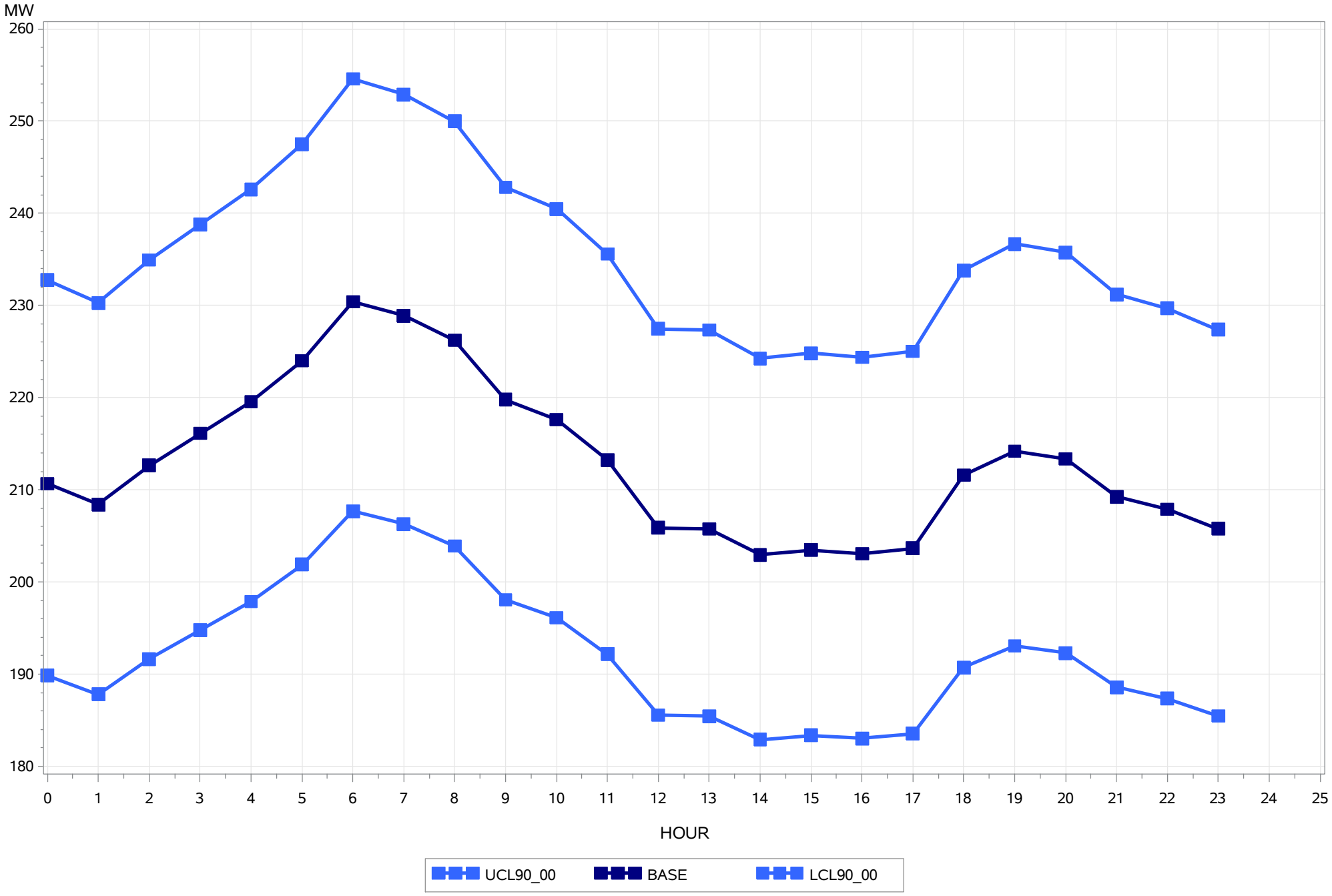

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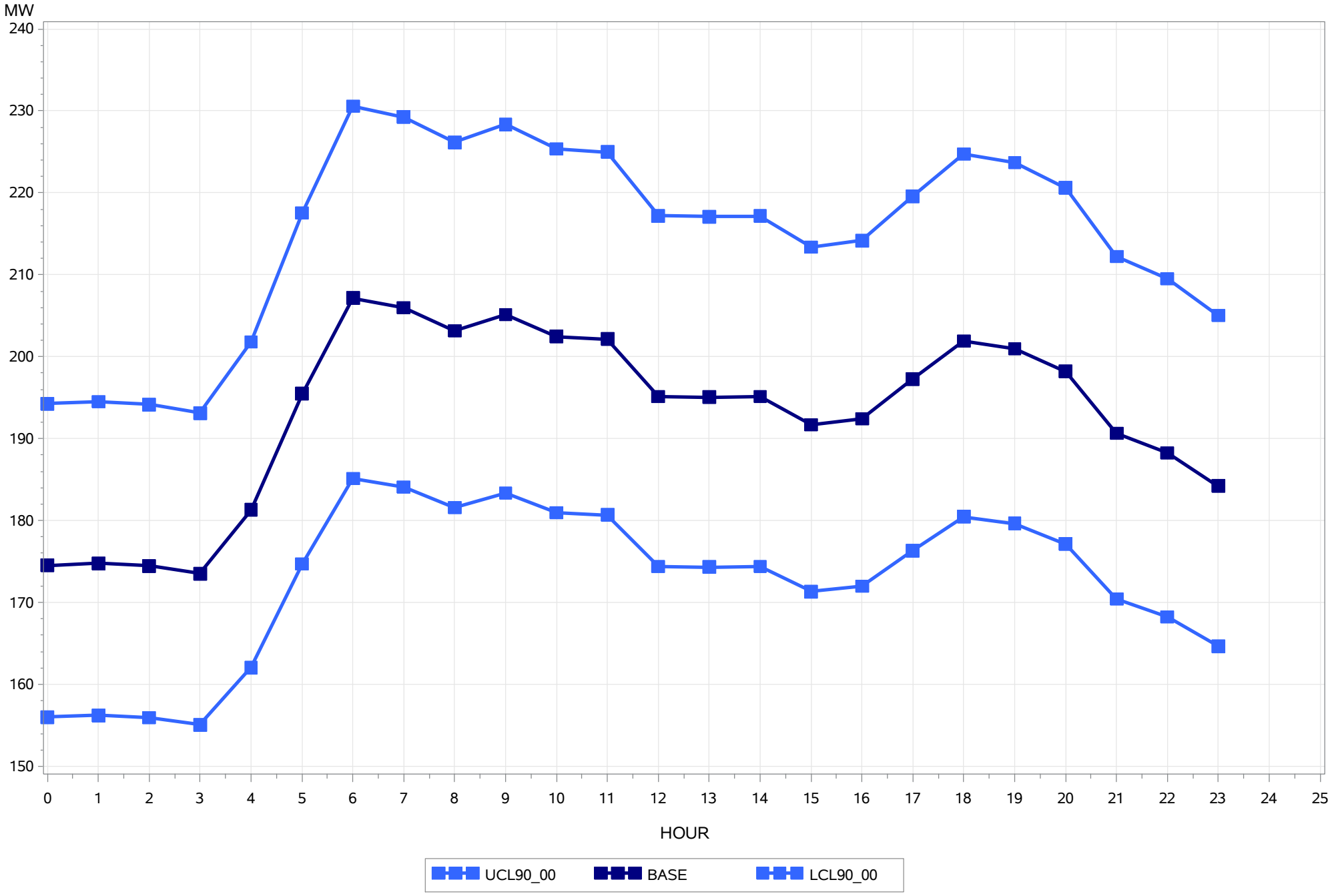

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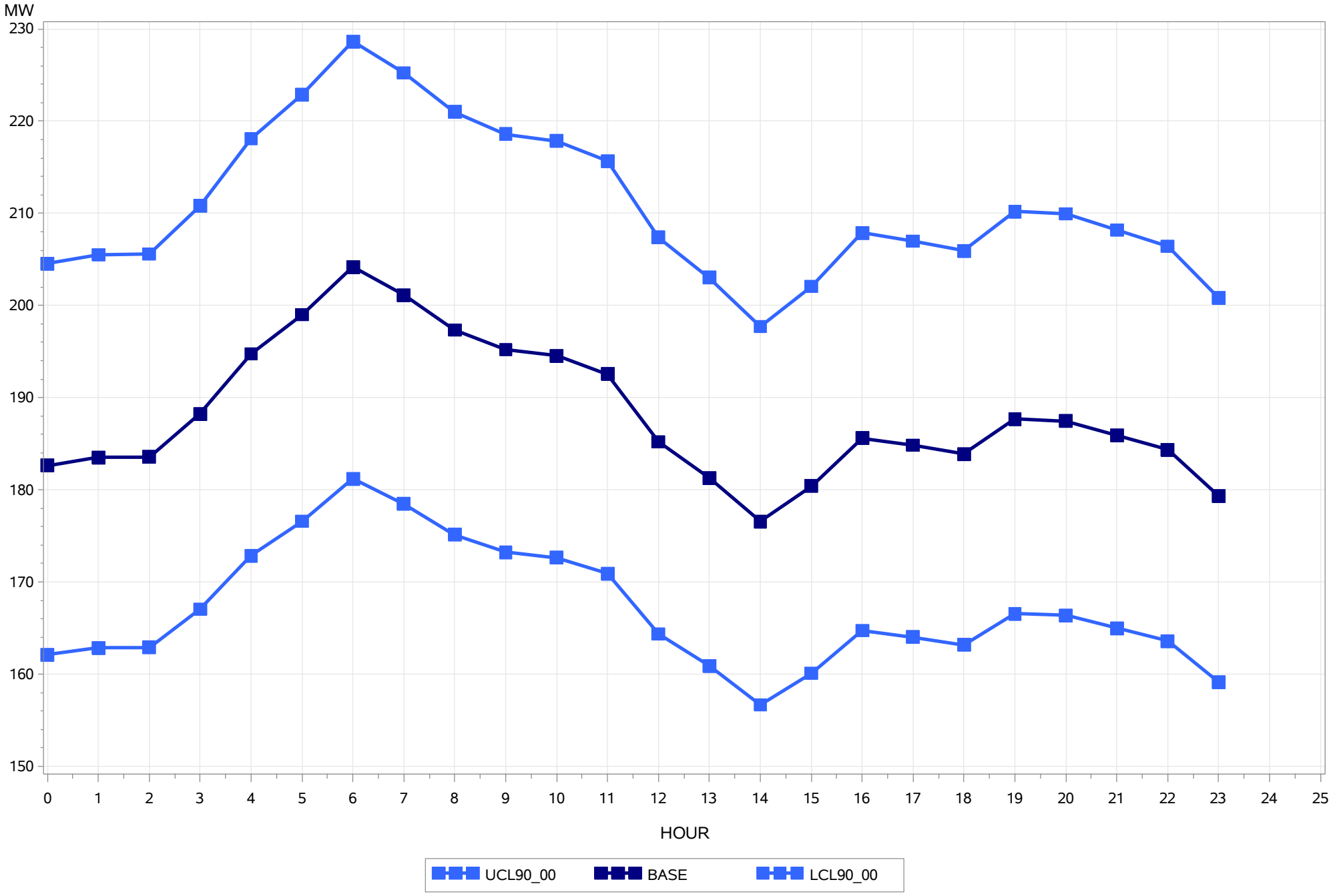

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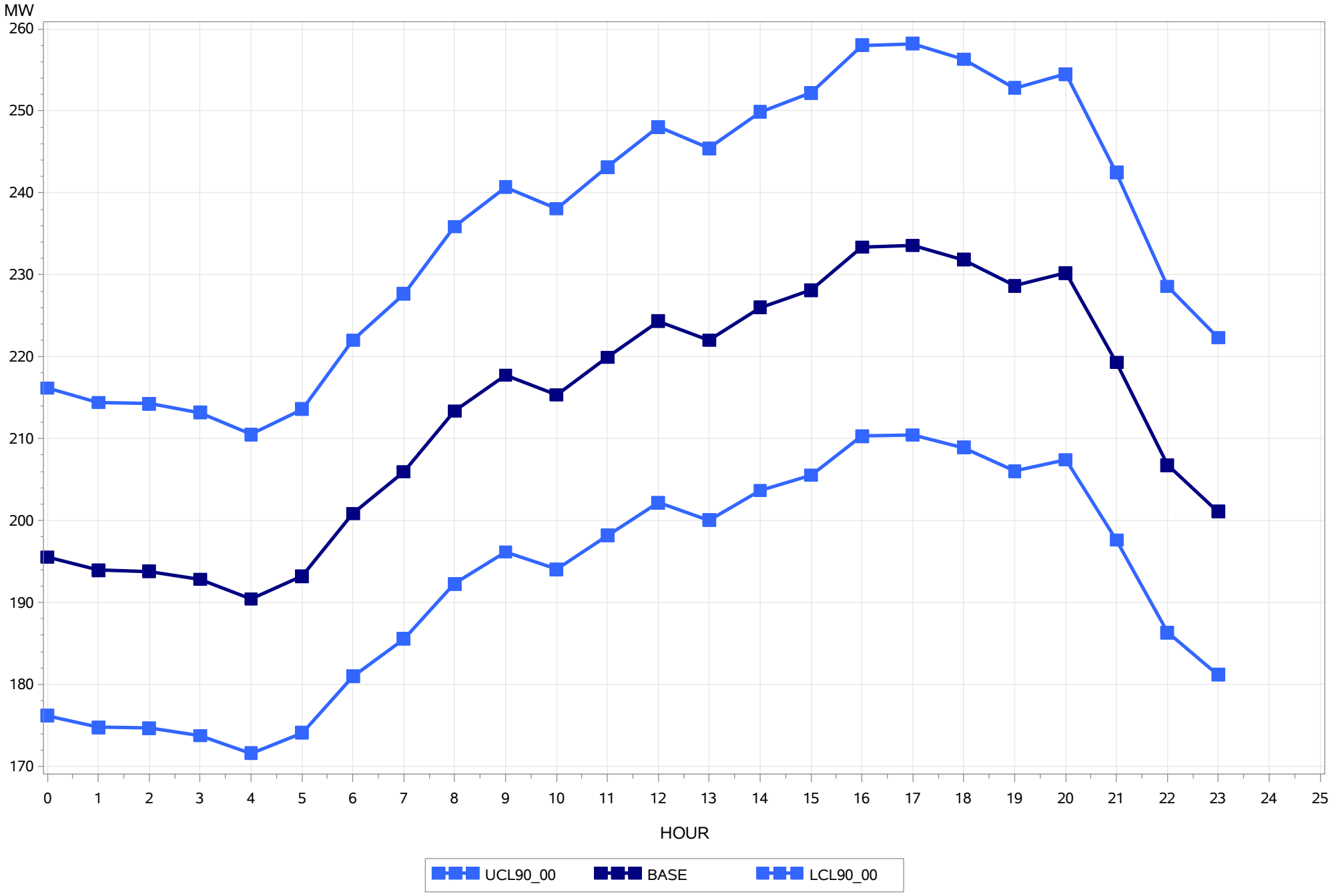

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Member Forecasted On Peak Demand Day for July 2021

STATE OF WYOMING

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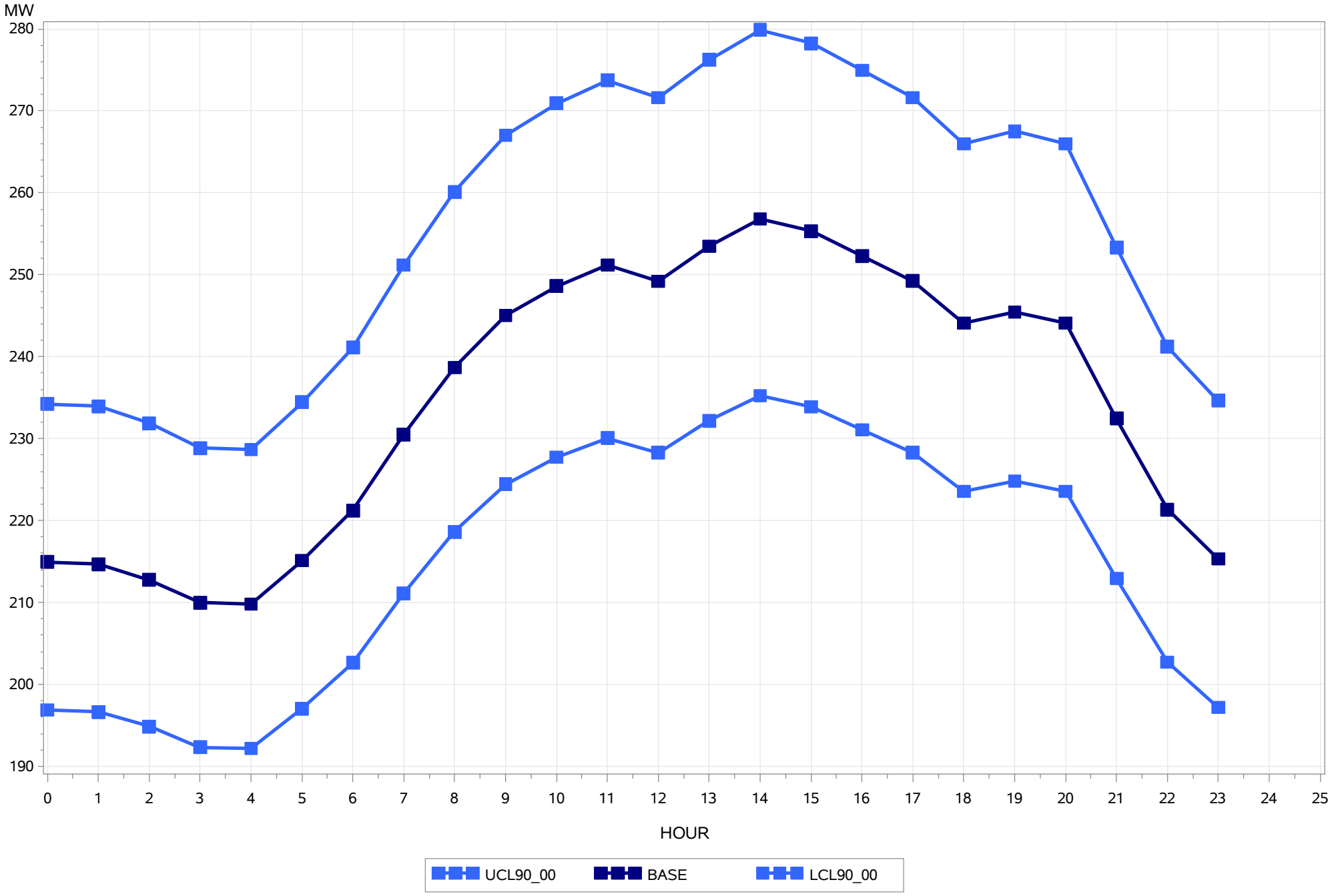

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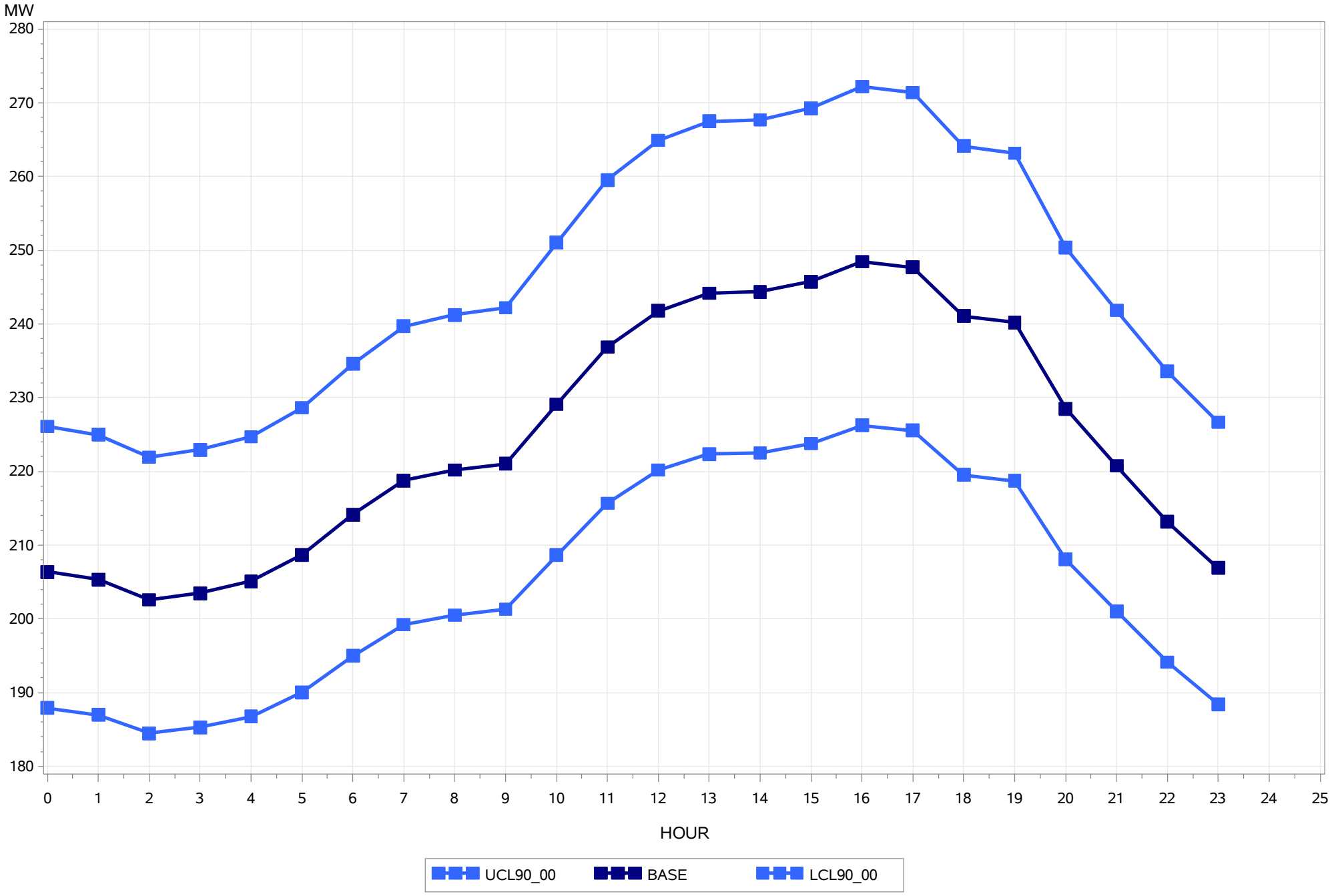

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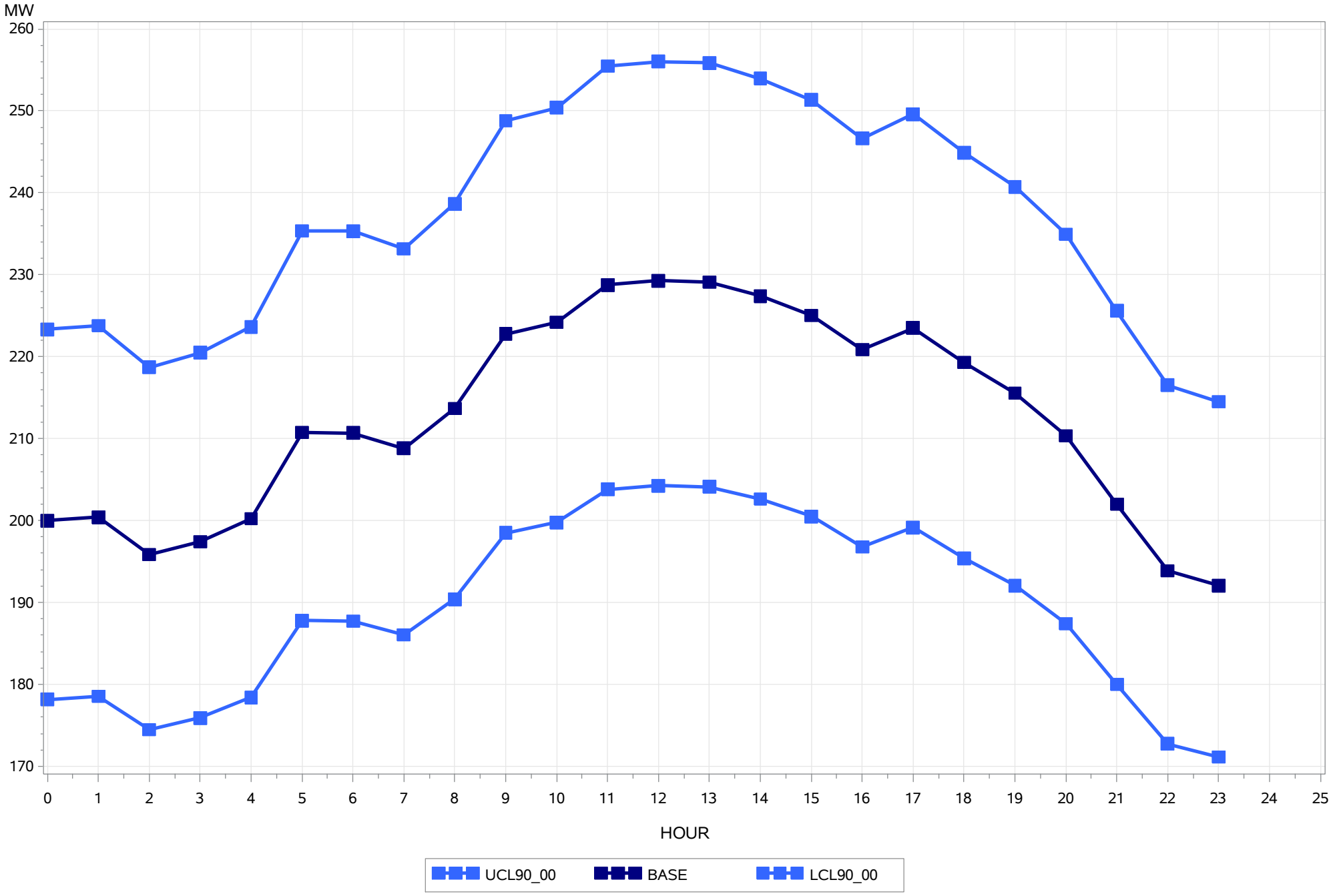

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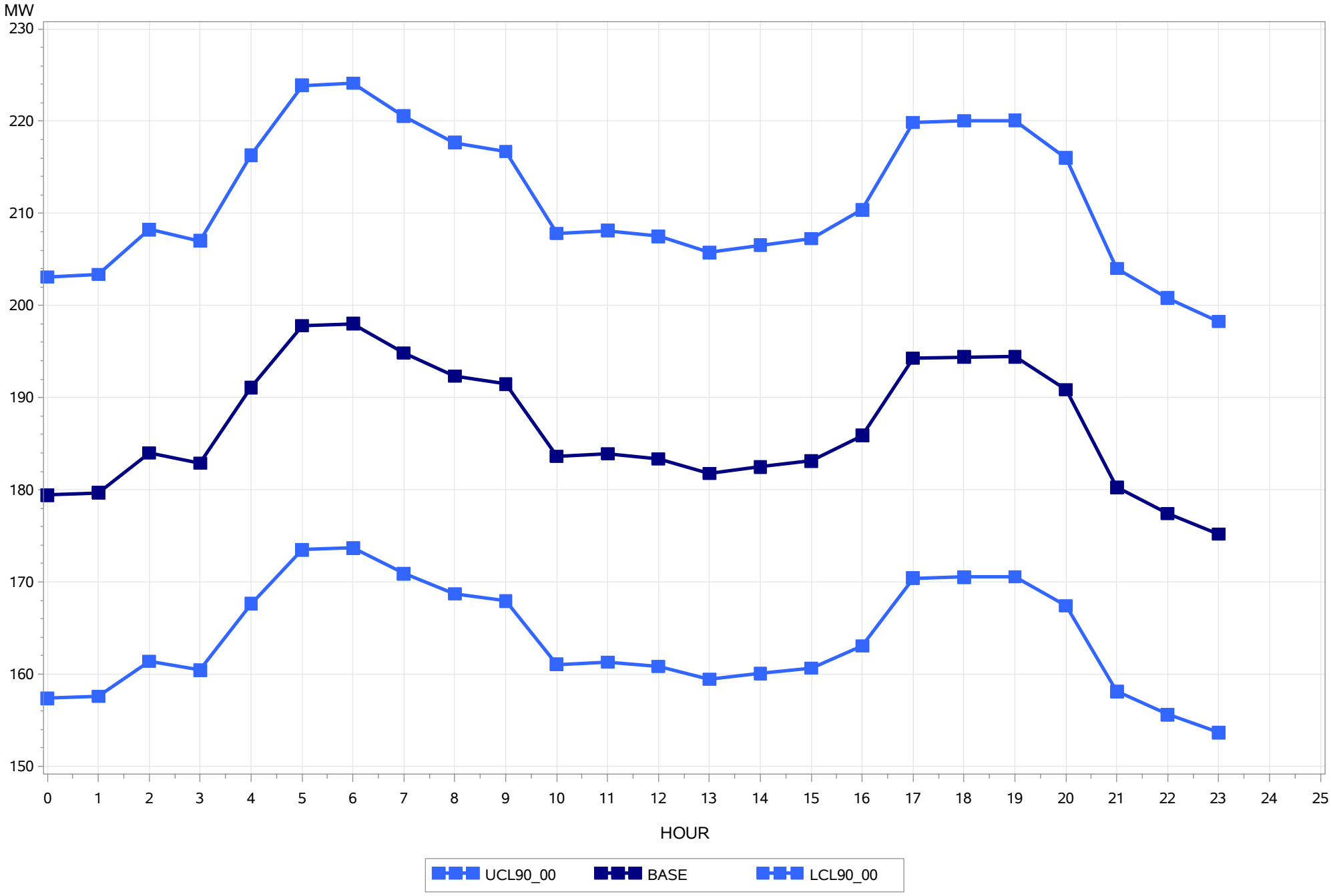

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STATE OF WYOMING

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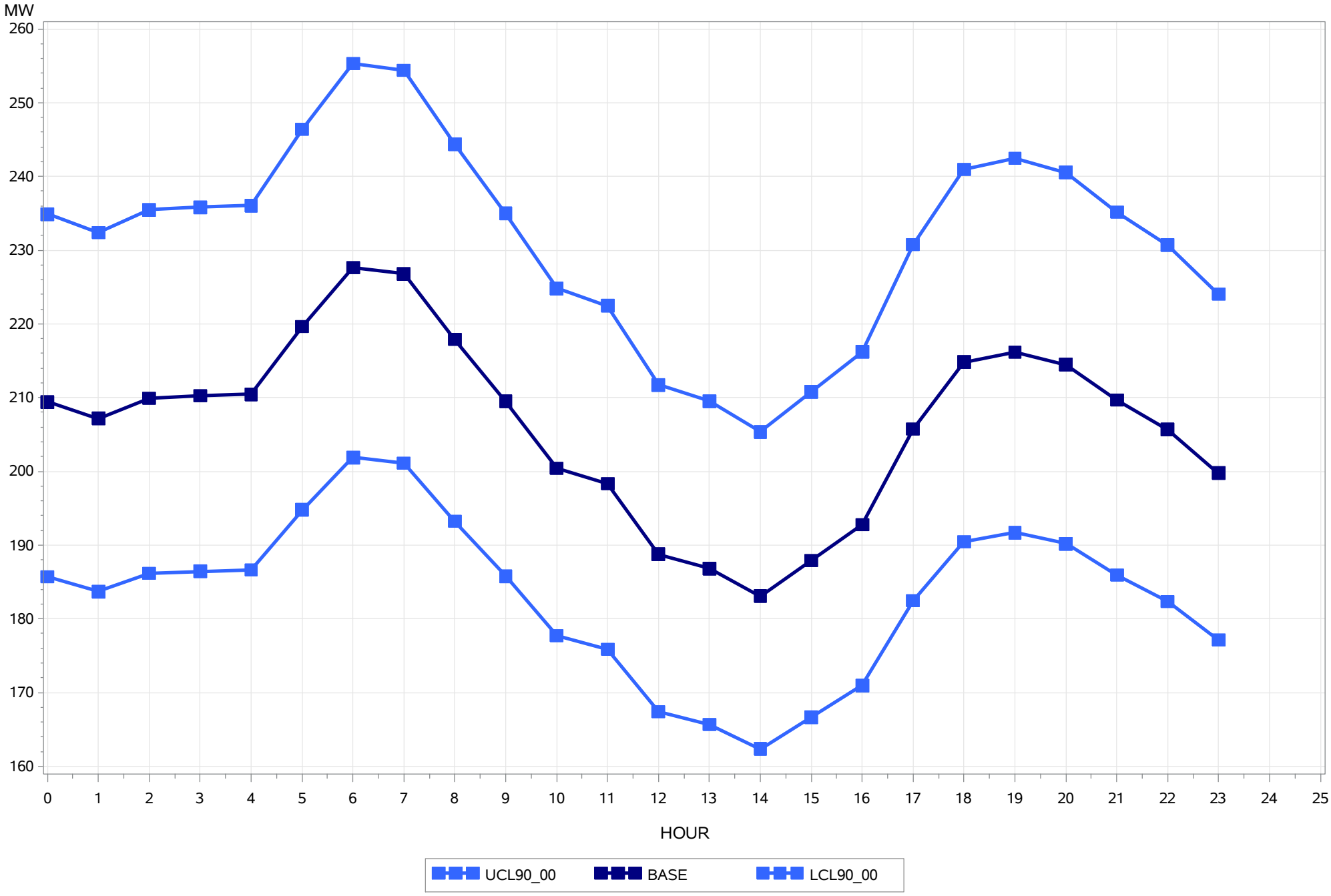

Member Forecasted On Peak Demand Day for December 2021

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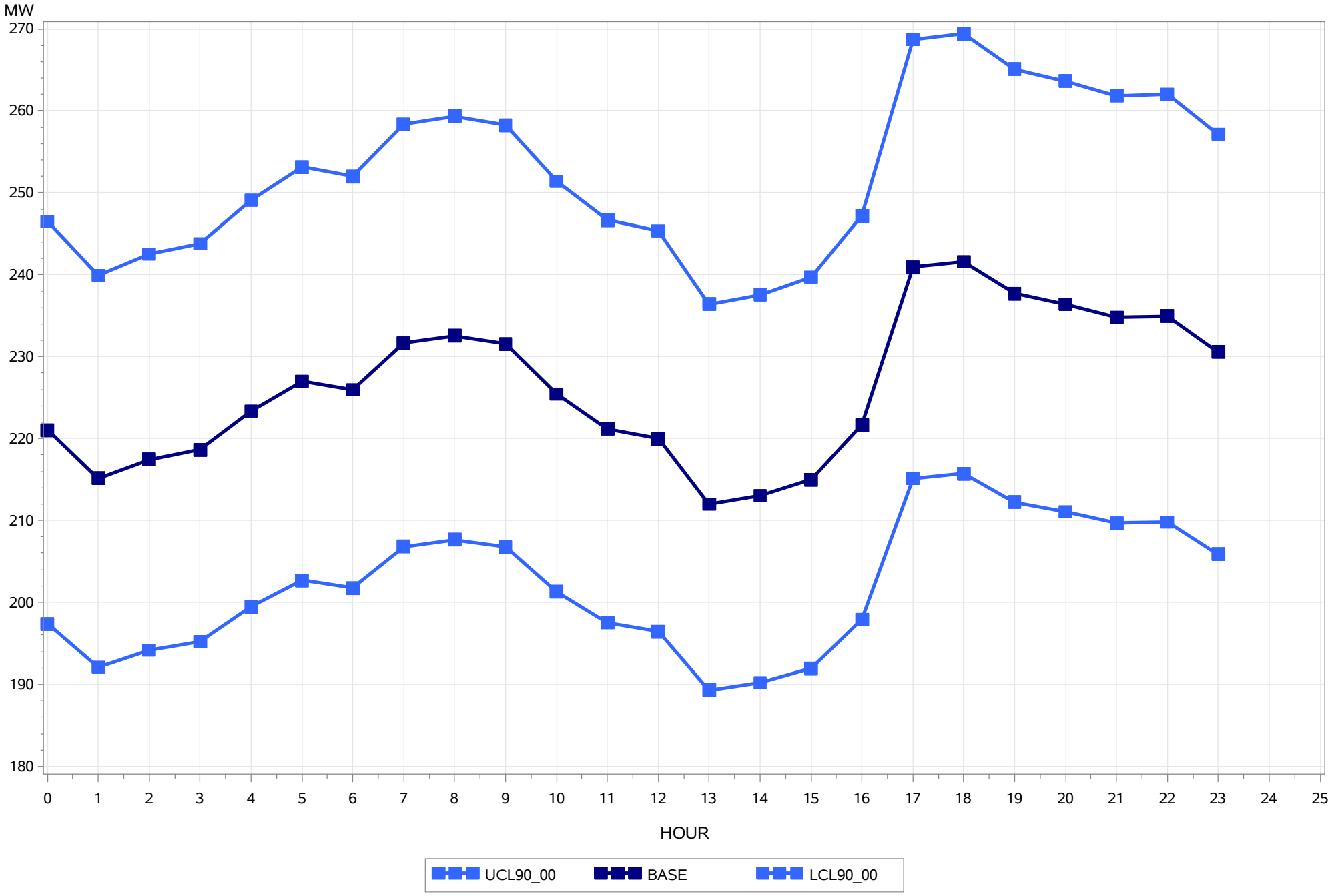

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-52:
2023 Colorado Water Plan

COLORADO WATER PLAN

COLORADO

Colorado Water Conservation Board

Department of Natural Resources

2023

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ACRONYMS

A.C.T.	Action Areas, Colorado Vision, Tools for Action
AFY	acre-feet per year
ARPA	American Rescue Plan Act
ASO	Airborne Snow Observatory
ASR	aquifer storage and recovery
ATM	Alternative Transfer Methods
BIL	Bipartisan Infrastructure Law
BIP	Basin Implementation Plan
BLM	U.S. Bureau of Land Management
BOR	Bureau of Reclamation
BRAT	Beaver Restoration Assessment Tool
CASM	Colorado Airborne Snow Measurement
CBT	Colorado-Big Thompson
CDA	Colorado Department of Agriculture
CDPHE	Colorado Department of Public Health and Environment
CDSS	Colorado's Decision Support Systems
cfs	cubic feet per second
CGWS	Colorado Growing Water Smart
CoRHAF	Colorado River Health Assessment Framework
COSWAP	Colorado Strategic Wildlife Action Program
CPW	Colorado Parks and Wildlife
CREP	Conservation Reserve Enhancement Program
CRO	Colorado Resiliency Office
CROS	Coordinated Reservoir Operations
CRSPA	Colorado River Storage Project Act
CSFS	Colorado State Forest Service
CSU	Colorado State University
CWA	Clean Water Act
CWCB	Colorado Water Conservation Board
CWLI	Colorado Water Loss Initiative
CWRPDA	Colorado Water Resources and Power Development Authority
CWSA	collaborative water sharing agreements
DCP	Drought Contingency Plan
DFPC	Division of Fire Prevention and Control
DHSEM	Division of Homeland Security & Emergency Management
DI	disproportionately impacted
DM	Demand Management
DNR	Department of Natural Resources
DOLA	Department of Local Affairs
DPR	direct potable reuse
DRCOG	Denver Regional Council of Governments
DROA	Drought Response Operations Agreement
DWR	Division of Water Resources
EDI	equity, diversity, and inclusion
EJ	environmental justice
EPA	Environmental Protection Agency
EQIP	Environmental Quality Incentives Program
ESA	Endangered Species Act
FACE	Future Avoided Cost Explorer
FERC	Federal Energy Regulatory Commission
FHZ	Fluvial Hazard Zone
GIS	geographic information systems
GOCO	Great Outdoors Colorado
gpcd	gallons per capita per day
HB	House Bill
HUC	Hydraulic Unit Code
IBCC	Interbasin Compact Committee
IIJA	Infrastructure Investment and Jobs Act
IPR	indirect potable reuse
ISF	Instream Flow
IWMP	integrated water management plan
LiDAR	light detection and ranging
N/A	not applicable
NEPA	National Environmental Policy Act
NGO	nongovernmental organization
NLL	natural lake level
NPS	National Park Service
NRCS	Natural Resources Conservation Service
OEDIT	Colorado Office of Economic Development and International Trade
OREC	Colorado Outdoor Recreation Industry Office
OWL	One Water Leaders
PEPO	Public Education Participation and Outreach
PRRIP	Platte River Recovery Implementation Program
RGDSS	Rio Grande Decision Support System
RICD	recreational in-channel diversion water right
SB	Senate Bill

SDO	State Demography Office
SJRIP	San Juan River Basin Recovery Implementation Program
SMP	stream management plan
SNOTEL	Snow Telemetry
STEM	science, technology, engineering, and mathematics
SUIT	Southern Ute Indian Tribe
SWE	snow water equivalent
SWSI	Statewide Water Supply Initiative
TAG	Technical Advisory Groups
TMD	transmountain diversion
TMDL	total maximum daily load

UCEFRP	Upper Colorado River Endangered Fish Recovery Program
UMUT	Ute Mountain Ute Tribe
USACE	United States Army Corps of Engineers
USDA	United States Department of Agriculture
USFS	United States Forest Service
USFWS	United States Fish and Wildlife Service
USGS	United States Geological Survey
WQCC	Water Quality Control Commission
WQCD	Water Quality Control Division
WSRF	Water Supply Reserve Fund
YWG	Yampa-White-Green Basin

COVER IMAGES AND STOCK PHOTO CREDITS

- Cover Birds take flight over the Yampa River near Steamboat Springs on the Daughenbaugh Ranch, Photo credit: M. Nager; Small Town and Suburban Sprawl In Colorado▲; Father and son fish by lake, dad looks at camera*; Aerial of green pastures and river, Photo credit: Kent Vertrees, Friends of the Yampa
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CWCB BOARD LETTER

Fellow Coloradan,

Thank you for opening the Colorado Water Plan. With this document, the Board and Staff of the Colorado Water Conservation Board (CWCB) seek to respond to this historic moment in time with a plan for thoughtful and bold initiative.

Much has changed since 2015, when the first Colorado Water Plan was finalized. The impacts of widespread drought, coupled with a global pandemic, challenged our communities with far-reaching uncertainties that shaped new water management realities. The pandemic pushed our stakeholders to begin meeting virtually, bringing a new way for people to connect, learn, and get involved with the work of planning for water. These experiences also highlighted the ways in which Colorado is connected by water.

Towns and farms on the Front Range are tied to high mountain streams on the West Slope through the complicated plumbing that brings water through the Continental Divide. Beyond these physical connections, there is a shared understanding that water supports Colorado's culture, communities, recreation, forests, and foods. The fresh produce, meat, and beer enjoyed in restaurants and kitchens around our state are supplied by farming and ranching families with diverse backgrounds and often multi-generational and historical ties to the land they steward. Coloradans value healthy rivers that drive robust recreation economies and provide important corridors for fish and wildlife, quality drinking water for cities and towns, and spaces for people to connect with nature. Colorado is the state we know and love because of its lakes, rivers, streams, wetlands, and aquifers. Because water inextricably links people across Colorado, our water management challenges must be faced together.

GET INVOLVED—NOW IS THE TIME FOR ACTION

The West is experiencing growth in population and demand for water while our hydrology is becoming less predictable. Our temperatures have warmed, and the timing and amount of precipitation has changed, causing shifts in runoff and streamflows. It is clear this is not a temporary phenomenon, but rather a permanent trend toward aridification of the West. These changes, on top of existing concerns, present increased water quantity and water quality challenges especially as the rate and magnitude of ecosystem changes in Colorado have increased. These collective impacts have changed the way we think about water planning and shifted our collective approach to swift action.

The Colorado Water Plan was informed by robust stakeholder input and complex modeling that provides a data-driven understanding of our current water supply and potential future scenarios. The plan also highlights Colorado's values and follows four fundamental themes of Thriving Watersheds, Resilient Planning, Vibrant Communities, and Robust Agriculture through discussions of each of our major river basins. Most importantly, the plan sets forth ambitious yet attainable actions that will help Coloradans do more with less water, increase resiliency in the face of a changing climate, and ensure broad and diverse voices are included in future water management conversations.

The CWCB cannot do this important work alone, which is why the partner actions take into account close working relationships with sister agencies and the critical efforts of partner organizations, water users, and water managers across the state. This will require thoughtful and strategic partnerships across state agencies, Tribal Nations, local governments, water providers, and stakeholders. Colorado needs collaborative and creative solutions for balancing competing water demands for a finite resource. Whether by personal action or developing a Water Plan grant project proposal, you have a role to play.

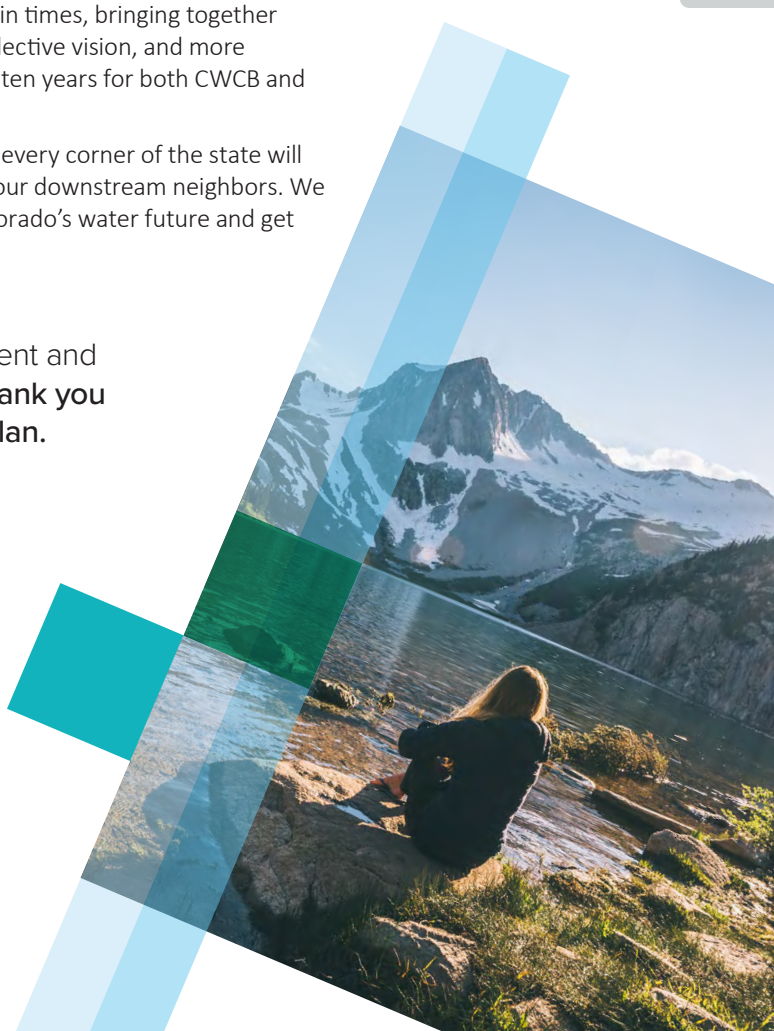
The CWCB will also continue to lead through funding, collaboration, and the agency actions it will take. Importantly, the plan outlines a 10-year schedule for future Water Plan updates and includes the addition of an annual operations plan, which will allow the CWCB Board to consider yearly priorities and respond to shifting conditions and needs. Addressing Colorado's water challenges through partnerships and collective action ensures that competing demands for water resources decisions are balanced and maximize the benefits to current and future generations.

Colorado has always been a place where the adversity of the landscape has been tempered by its ability to inspire. While our challenges are great, our natural and human resources are too. We have a long and celebrated history of innovation in water management, and we are confident the people of Colorado will continue to rise to the occasion and take on the critical work of protecting our water supply future. The Colorado Water Plan offers a light through dark and uncertain times, bringing together wide-ranging interests and voices into a collective vision, and more importantly, a plan for action over the next ten years for both CWCB and local communities across the state.

The collective actions we take today across every corner of the state will increase water resilience for Colorado and our downstream neighbors. We hope you will consider your own role in Colorado's water future and get involved—now is the time for action.

On behalf of the staff and the current and past board members of CWCB, **thank you for reading the Colorado Water Plan.**

—The Colorado Water Conservation Board



ACKNOWLEDGMENTS

CWCB BOARD:

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Vice Chair - Greg Felt
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Jessica Brody
Paul Bruchez
Heather Disney Dugan
Heather Dutton
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Where agency directors are included in the list of CWCB Board members they are not included in their respective agencies below.

CWCB Board members (listed left to right): Robert Sakata, Paul Bruchez, Steve Anderson, Greg Felt, Dan Gibbs, Heather Dutton, Kevin Rein, Jackie Brown, Rebecca Mitchell, and Jessica Brody (not pictured: Heather Disney Dugan, Kate Greenberg, Celene Hawkins, Curran Trick, and Phil Weiser). Photo Credit: Russ Sands

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OTHER STATE AGENCIES

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- **Other Support Governor and Lt. Governor Support Staff** - Jonathan Asher, Kathryn Redhorse
- **Department of Natural Resources Executive Director's Office*** - Chris Arend, Angela Boag, Carly Jacobs, Tim Mauck, Vanessa Mezal, Nate Pearson, Kelly Romero-Heaney

OTHER STATE ENTITIES, GROUPS, ORGANIZATIONS, AND TASK FORCES WHO PROVIDED WATER PLAN INPUT:

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COLORADO'S FEDERALLY RECOGNIZED TRIBES

Southern Ute Indian Tribe, Ute Mountain Ute Indian Tribe

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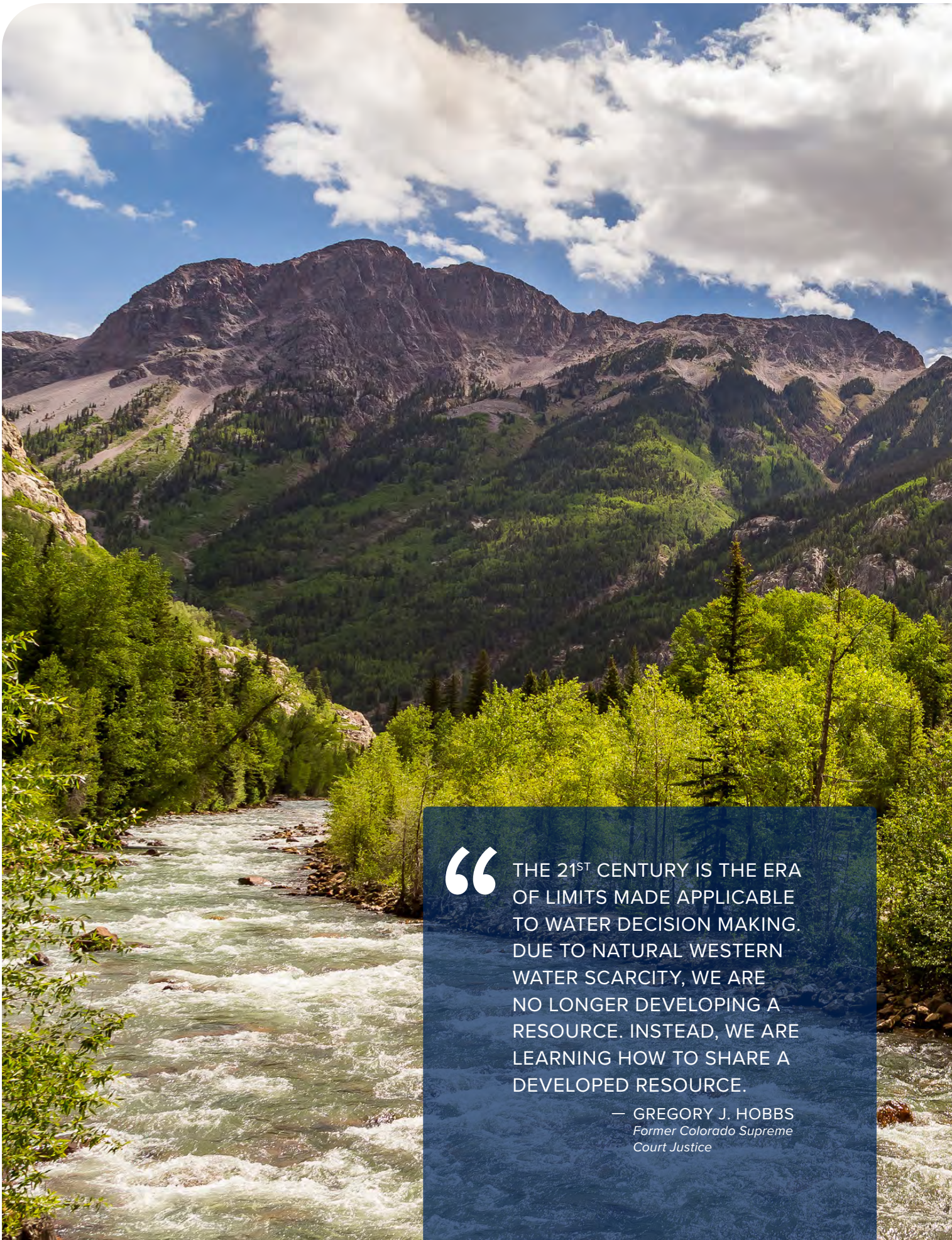
**Director participation noted through their role on the CWCB Board (See list above).*

CHAPTER 1

OVERVIEW



> “THE 21ST CENTURY IS THE ERA OF LIMITS MADE APPLICABLE TO WATER DECISION MAKING. DUE TO NATURAL WESTERN WATER SCARCITY, WE ARE NO LONGER DEVELOPING A RESOURCE. INSTEAD, WE ARE LEARNING HOW TO SHARE A DEVELOPED RESOURCE.
>
> — GREGORY J. HOBBS
> *Former Colorado Supreme Court Justice*

Colorado's water touches every aspect of our daily lives. Those that depend on the water face unprecedented challenges that require all Coloradans to embrace a new water ethic. We must come together to protect this critical resource in increasingly innovative ways. The time for action is now.

As a headwaters state, water flows from Colorado's snow-capped peaks, through forests and streams, to cities and farms, and then returns to streams. Along the way, water supports habitat, wildlife, recreation, local food production, energy, industry, drinking water supplies, and more. Water connects us all. The importance of water in Colorado has long been recognized by the ancestral and Indigenous peoples of Colorado – the 48 Tribes that historically were the original stewards of this land include Colorado's two federally-recognized Tribes, the Southern Ute Indian Tribe (SUIT) and the Ute Mountain Ute Indian Tribe (UMUT). As noted by the Tribes, "Water is life."

Nearly 6 million Coloradans depend on the water from our major river basins as do 19 other states and Mexico, but that water supply is at risk. Population growth, long-term warming trends, major wildfires, aridification, and multi-year droughts are straining the system like never before.

We must understand these challenges, their associated risks, and the tools we can use to drive change. Tools that shape actions and policy to mitigate our risks can reshape the future. We must also be collaborative and understand the perspectives of water users from across the state. Basin Implementation Plans, developed by Colorado's nine basin roundtables, provide summaries of regional challenges, strategies to overcome them, and valuable data to inform the state's Water Plan. **The Colorado Water Plan sets the stage for a shared understanding of our risks and describes actions that collectively contribute to a stronger, more water-resilient Colorado.**

While Colorado faces enormous water challenges, its opportunities are tremendous. A secure water future will depend on our working together to uplift every area of the Water Plan. In reading this plan, it is important to know that the opportunity to take action is driven by you. Whatever your background, whatever your job, all Coloradans are a part of the solution. **Collaborative action needs to occur at every level, and the need for action has never been more urgent than now.**

BUILDING ON PAST SUCCESS

The devastation of the 2002 drought and Hayman Fire launched a new era of resiliency planning and collaboration in Colorado that led to the creation of many of the state's grassroots water stakeholder groups, the Colorado Water Plan (Water Plan), and a continued investment in water. These efforts have made real progress since the 2015 Water Plan to better manage and fund Colorado's water, as noted below:

- Water conservation measures have **decreased statewide per capita water use by 5%.**
- Colorado Water Plan grants were established and funded **almost $55 million in projects covering every corner of the state.**
- Annual municipal leasing of **25,000 acre-feet** of agricultural water has helped cities and farms coexist.[1]
- **More than 25 new** stream management plans have been developed.
- **400,000 acre-feet** of storage has either been constructed or will soon be completed.[2]
- Water outreach, education, and messaging is estimated to have **reached up to 2.7 million people.**
- Legislation was **passed to integrate land use and water planning** in comprehensive plans.
- Reclaimed water regulations have been updated with **18 additional uses** to allow water reclamation in residential and commercial crop irrigation, among others. See Chapter 5 for more information on reclaimed water regulations.
- **62% of Coloradans** now live in communities whose leaders have been trained by the Growing Water Smart program to integrate water and land use planning.
- Multi-purpose, multi-benefit projects continue to receive grant funding and **more than $420 million in loans.**
- Watershed health received millions of dollars in support as statewide **watershed groups exceed 150.**
- Colorado voters **passed Proposition DD**[3] to dedicate funding for the Colorado Water Plan Grant Program.

These successes should be celebrated because they show significant progress, firm resolve, and a blueprint for collaborative action. Yet, the need for progress is now more urgent than ever. In the last two decades Colorado's population has increased by more than a million people. Several major wildfires have ignited our forests and grasslands, and drought, along with a larger trend in long-term warming and drying, known as aridification, continues to challenge water resources. Significant swaths of agricultural lands have been lost to buy and dry practices, water supply reductions, and urbanization; forests face continued risk from fire; and streams face new challenges for habitat protection.

In the face of this adversity, there has been a groundswell of collaborative action leading to real progress through holistic and multi-benefit projects. **It is increasingly important to make sure every water project or strategy uses water as wisely as possible, making it stretch as far as it can to realize its maximum value for cities, farms, streams, and people.** Doing so will require shared stewardship—a commitment to partnership in which the state government and every Coloradan must work together toward greater action.

Colorado's nine basin roundtables have been instrumental in fostering our past successes and forming the future vision described in the Water Plan. Chapter 4 describes local challenges, recent achievements, and strategies to meet future needs that each basin roundtable provided in their Basin Implementation Plans - all of which inform the Water Plan.

[1] Generalized findings from **Alternative Transfer Methods in Colorado, Status Update, Framework for Continued Support, and Recommendations for CWCB Action**

[2] Includes Chimney Hollow Reservoir (90,000 acre-feet), Glade Reservoir (170,000 acre-feet), Galeton Reservoir (45,600 acre-feet), Gross Reservoir Expansion (77,000 acre-feet), and Chatfield Reallocation (20,600 acre-feet)

[3] Proposition DD is a legislatively referred state statute on the November 2019 ballot that was ultimately codified in HB19-137 and provided funds from sports betting to be used, among other things, to fund the Water Plan through the creation of a Water Plan Implementation Cash Fund that is used to support CWCB's Colorado Water Plan Grant Program.

EMPOWERING STAKEHOLDERS

As the stewards of the Water Plan and the agency charged to conserve, develop, protect, and manage Colorado's water for present and future generations, CWCB works with partners to foster action by funding local water projects through grants and loans. The CWCB also works on multiple programmatic efforts related to interstate compacts, flood mitigation, species protection, water project financing, agricultural support, and climate adaptation, all of which advance the goals of the Water Plan.

The CWCB does not build projects. It advances projects, often focusing on proven methods, by supporting project proponents with funding, analysis tools, technical assistance, programs, and policies that can help advance toward a future envisioned by the values and ideas in this Water Plan. The real power of the Water Plan is often driven by local and regional innovation, action, and project development that advance when stakeholders take action. This is readily apparent in the work that the state's nine legislatively-created basin roundtables completed to identify more than 1,800 local projects and plans in the lead-up to the Water Plan update (See Chapter 4).

Meeting the moment extends well beyond what one agency or the entirety of the state government can do. The power of nearly 6 million Coloradans rallying to embrace a new water ethic in Colorado is what we need to be successful. The Water Plan is a call to action backed by governmental support that can catalyze local planning and projects.

The Water Plan was informed by and built through stakeholder input. Basin-specific technical analyses, local stakeholder input, and statewide outreach informed the Water Plan by explaining local conditions, offering examples of successful projects, and gathering information about future projects needed for increased water resilience. The process involved ongoing work with basin roundtables and the Interbasin Compact Committee (IBCC), engagement with more than 1,200 stakeholders providing feedback during Water Plan scoping, multiple partners (agencies, Tribes, nongovernmental organizations [NGO], and members of the public) as well as a governor-created Water Equity Task Force. Stakeholders were also engaged during public review of the draft Water Plan through outreach events in all 64 Colorado counties, more than 2,000 submitted public observations on the draft plan, and more than 500 pages of public comment letters. Approximately 130 public comments were submitted in Spanish. This spirit of collaboration and the focus on Colorado water resilience is at the heart of the Water Plan, and implementing the Water Plan is critical to Colorado's future.

PUBLIC ENGAGEMENT AND WATER EQUITY TASK FORCE

Building on years of ongoing grassroots input, CWCB included a scoping phase early in the Water Plan update process to evaluate the critical issues on stakeholders' minds and provide a platform to discuss CWCB's proposed direction for the Water Plan. As part of that effort, CWCB partnered with 20 agencies and NGOs to hold more than a dozen sector-specific workshops that engaged more than 1,200 stakeholders. Targeted interviews, online surveys, and an online stakeholder engagement platform supplemented the scoping outreach. This work gathered extensive input on stakeholder issues related to agricultural, municipal, watershed, and forest health needs. Themes that sparked a wide range of interest for incorporation in this Water Plan included addressing climate change and drought as well as the need to better recognize equity, diversity, and inclusion (EDI) in water issues.

Realizing that more time was needed to discuss EDI concerns and to bring in multiple perspectives, CWCB worked with the Department of Natural Resources (DNR) and the Governor's Office to create a year-long Water Equity Task Force that focused on developing a set of principles to help inform the update to the Water Plan. The 21-member task force included nine basin roundtable members (one from each roundtable), nine community members (one from each of the eight major river basins and the Denver metropolitan area), two members from each of Colorado's federally recognized Tribes, and one member from the Acequia community.

The Water Equity Task Force's guiding principles include a need to:

1. **Promote diversity** in career pathways in water-related fields through education and engagement.
2. **Promote collaboration**, new voices, and greater community engagement in water discussions.
3. **Recognize and address elements of the rural-urban divide** but focus on creating the rural-urban opportunity.
4. **Expand grant opportunities** to new audiences.
5. Support basin roundtables facilitating broad **community engagement and collaborative solutions.**

In addition to directly informing the Water Plan's development, CWCB uses these guiding principles to inform programming, policies, and engagement for the benefit of all Coloradans.

USING THE PLAN

The Water Plan can be used in three primary ways:

Use the plan to **become more informed about water and the future vision.**

The State of Colorado encourages its residents to be informed about water issues, but a 2021 Statewide Water Awareness Survey indicated that only 35% of Coloradans are confident they have the knowledge necessary to take action to manage our water use. Becoming more informed about water and the future vision is a critical first step. It creates ripple effects in what we value, how we invest, and how we conserve. It is also foundational to collaborative and inclusive water planning. For many, understanding the complex water challenges Colorado faces, the tools that can be used to find solutions, and Colorado's shared vision will be an important commitment.

Opportunities to participate at this level include:

- Support local water initiatives and projects
- Conserve water indoors and outdoors
- Practice wise stewardship of our rivers, lands, and natural resources
- Purchase water-saving products and locally grown food products
- Help promote water conservation and water outreach efforts
- Support local utility/city/county water conservation, local food, and resilience

Use the plan as a platform to **become more engaged and take action to advance the vision.**

The Water Plan is a starting point, and it provides a larger framework for next-level action. If you can do more, whether because you are a water rights holder, a county commissioner, a water utility worker, a city planner, a business owner, a local leader, or a concerned resident looking to become more engaged, this is your time. The Water Plan provides your roadmap to identify and collaborate in implementing solutions to Colorado's water resources challenges.

Opportunities to participate at this level include:

- Attend a local water meeting (e.g., **basin roundtable**)
- Join a water-focused stakeholder group (e.g., NGO or basin roundtable)
- Start a local food or watershed group
- Apply for a grant to take action on the Water Plan
- Invest in water-efficient equipment in your home, business, or farm
- Work with your local community leaders to advance water projects

Use the plan to **understand and leverage agency actions that advance the vision.**

For the State, the Water Plan serves as a call to action, shared leadership, and partnership. Elected officials throughout the state use the Water Plan to understand policy priorities. The executive, judicial, and legislative branches all have important roles in water discussions. Yet not one of these branches of government, nor the 180 or more state agencies, can create the necessary solutions alone. The State's role in the Water Plan is to use its collective resources to set a vision that is backed by funding and support tools to advance solutions.

Opportunities to participate at this level include:

- Attend a state water meeting (e.g., CWCB board meeting, basin roundtable meeting, legislative hearing, or committee meeting)
- Apply to join a water-focused board or commission
- Learn about and use State tools that have been developed to support action
- Engage with the State to create new supporting tools and processes
- Implement a local project that aligns with the Water Plan and, if possible, use state and federal resources to help fund the project
- Coordinate with local leaders to advance water policy

PLAN ORGANIZATION

The Water Plan is structured to create a line of sight from Colorado's water values to the specific actions that address challenges. The four values in the Water Plan are based on extensive work with stakeholders and include:

- A productive economy that supports vibrant, sustainable cities, agriculture, recreation, and tourism
- An efficient and effective water infrastructure system
- A strong environment with healthy watersheds, rivers, streams, and wildlife
- An informed public with creative, forward-thinking solutions that are sustainable and resilient to changing conditions and result in strong, equitable communities that can adapt and thrive in the face of adversity

Most simply, these values represent the Colorado way of life—they are the things that make Colorado great. They are also the values that help inform the Water Plan organization and drive us to act. Taken as an acronym, our values drive us to A.C.T. through **A**ction Areas, **C**olorado Vision, and **T**ools for Action.

Action Areas

The Water Plan is organized around four overarching action areas that loosely translate to cities, farms, streams, and people. The action areas are interrelated in that issues related to steams, river recreation, commerce, agriculture, diversity, and climate challenges often are interwoven and connected. The action areas are presented separately for organizational purposes, but the Water Plan also describes how they integrate. The action areas include:

VIBRANT COMMUNITIES: counties, municipalities, utilities, cities, towns, businesses, large industries, large and small urban and rural communities, etc.

ROBUST AGRICULTURE: established crops and farms, local food, orchards, ranching, ditch companies, acequias, urban agriculture, livestock, dairy, etc.

THRIVING WATERSHEDS: environment and recreation, river health, watershed health, forest health, wildfire mitigation, wildlife and aquatic species protection, etc.

RESILIENT PLANNING: climate adaptation, planning for climate extremes, embracing EDI (equity, diversity, inclusivity), education, outreach and engagement, supportive government, etc.

Sunset over Yampa River, Photo credit: Kent Vertrees, Friends of the Yampa

Colorado Vision

The Colorado Vision, outlined in Chapter 6, describes how Colorado can achieve greater resilience across and within the four action areas as we look to the planning horizon of 2050. The vision for each action area first describes our desired future and then provides examples of the kinds of local actions stakeholders and partners can take to help realize the vision. Example actions are grouped into categories, including thoughtful storage, meeting future water needs, wise water use, healthy lands, and engaged partners. In addition, each action area vision describes ways in which it intersects and integrates with other action areas to demonstrate how the areas are intertwined and relate. The overarching vision for each action area is described below.

VIBRANT COMMUNITIES

Holistic water management is essential for creating vibrant communities that balance water supply and demand needs to create a sustainable urban landscape. Colorado communities need resilient water supplies, water-conscious and attractive urban landscapes, planning that integrates land use and water solutions, and residents who understand the importance of water to their lives and economy. An integrated One Water ethic is necessary to create the transformative change needed to meet the moment and the future.[4]

ROBUST AGRICULTURE

Agriculture not only provides food and fiber, but it is also important to Colorado's culture, heritage, and economy, and it faces unprecedented challenges. Innovations are needed to sustain irrigated agriculture, including strategies to stretch available water supplies, increase resiliency, enhance food production, and maintain profitability. Water supplies for Colorado's urban growth should not come at the expense of our rural communities through indiscriminate buy and dry methods. Collaborative partnerships among agriculture, environmental groups, and municipal water providers should be used to create multi-purpose projects that help keep irrigated lands in production and maintain ecosystem services.

THRIVING WATERSHEDS

Colorado's watersheds hold the future of our water supply security. Comprehensive water resources planning should incorporate conditions of forests, streams, wetlands, and wildlife habitat. As our state's water source, the health of watersheds affects agriculture, downstream communities, recreation, tourism, and ecosystem function. Colorado will continue to follow a shared stewardship ethic to plan and implement multi-benefit projects to enhance the health of our watersheds.

RESILIENT PLANNING

Water security is critical to the quality of life, environment, and economy of Colorado. The future is uncertain, and Colorado needs to be adaptive and resilient to face the challenges ahead. Water security roadmaps, inclusively developed at a local level and informed by strong state leadership, can identify acute and chronic risks to water supply, integrate local planning strategies, prioritize collaborative solutions, and build adaptive capacity and resilience.

[4] "One Water" means matching the right water to the right use. See glossary and Chapter 6 for details and graphic.

Tools for Action

Tools for action are the means through which partners and agencies can address water issues and meet water needs. They include:

- Public outreach and education
- Funding
- Policy and regulatory changes
- Collaboration groups
- Watershed planning
- Climate adaptation
- Innovation
- Equity
- Endangered and threatened species recovery programs
- Natural hazard planning
- Land use and water planning integration
- Data collection and sharing
- Water storage
- Conveyance infrastructure
- Water efficiency and conservation programs
- Water reuse
- Collaborative water sharing agreements
- Stream/watershed restoration and enhancement
- Flow enhancement and maintenance

Actions include:

50 PARTNER ACTIONS

While the list of partner actions is limitless, the Water Plan describes approximately 50 ideas for potential actions that could be supported by Water Plan grants.

THESE INCLUDE ACTIONS AROUND

- Increased personal conservation
- Starting a new water initiative/project
- Developing collaborative solutions

50 AGENCY ACTIONS

The Water Plan includes 50 actions CWCB and supporting agencies will take to help advance local initiatives that support the wise development and conservation of water resources.

THESE INCLUDE ACTIONS AROUND

- Developing frameworks and convening groups
- Advancing research and science
- Creating support tools

Tracking Progress

This Water Plan replaces the previous plan with transparent and trackable actions. Partner actions will be tracked through CWCB's increasingly modernized process for tracking of grants and loans as well as projects through the Project Database. As CWCB tracks the completion of the agency actions it leads, CWCB will also document major legislative and basin advancements that occur—especially where the State has played a role.

Specific actions that inform the CWCB Board's annual operating plans and processes like the next Technical Update offer opportunities to identify trends, analyze progress, and explore new data and information that will help CWCB stay nimble and responsive to shifting conditions. Implementing the plan embraces the spirit of resilience—being adaptive to both acute and chronic challenges. The Water Plan is meant to be broad and flexible enough to do all of this, but it needs you to help carry out the larger vision for water management in Colorado that uplifts all areas and people in the state.

The Path Forward

The Water Plan is a call to action. Answering the call is a commitment to long-term water collaboration, resolve in the face of adversity, and developing creative solutions that allow Colorado to advance within the bounds of our legal framework. Coloradans must come together across diverse groups and geographies to envision and implement actions that will move us closer to a resilient water future. This is how we keep Colorado strong.

We are all interconnected from our headwaters to our homes by water and have a shared responsibility to it. However you interact with water—through your drinking water tap, buying food at your farmers market, enjoying the first snowfall, or recreating in one of Colorado's watersheds—you are a steward of the Water Plan. Embrace it.

Water Plan Layout

Following this introduction, the Water Plan describes the critical elements of Colorado's history, geography, legal setting, and water-planning efforts. The background and context provide key pieces of information that guide the direction of the Water Plan.

- Water Plan methods for analyzing future water conditions (Chapter 2)
- Geography, variability, and use of water in our state and legal underpinnings for managing it (Chapter 3)
- Basin context and summary information, including potential costs of projects to meet future water needs (Chapter 4)
- Tools that can be used to take action (Chapter 5)
- Statewide vision for a more water-resilient Colorado, along with partner and agency actions (Chapter 6)
- Process for tracking and updating the Water Plan (Chapter 7)

Accessing the Plan

The Water Plan allows the reader to engage at the levels that work best for them.

1. **Executive Summary** - High-level description and highlights of the Water Plan.
2. **Water Plan** (full document) - Foundational background information, future vision, and actions.
3. **CWCB Website** - Current CWCB efforts and background materials (cwcb.colorado.gov)

You can also find additional links and interactive resources at cwcb.colorado.gov

This updated Water Plan replaces the original Water Plan developed in 2015.

Potato Harvest
Photo credit: Sinjin Eberle

CHAPTER 2

TECHNICAL ANALYSIS, SCENARIOS, and DRIVERS

TECHNICAL ANALYSIS OVERVIEW

Following the launch of the Water Plan and the Basin Implementation Plans (BIP) in 2015, CWCB initiated the process of updating the underlying water supply and demand analyses, which culminated in the Analysis and Technical Update to the Colorado Water Plan (Technical Update), completed in 2019. The work began with the input of Technical Advisory Groups (TAG) that included representatives from across the state who provided expertise and advice on assumptions and methods for the Technical Update analyses. The resulting Technical Update (formerly known as the Statewide Water Supply Initiative or SWSI) established a new approach to statewide water analysis and data sharing.

The Technical Update leverages a significant investment of over three decades in statewide water modeling efforts, which began in 1992. To that end, the Technical Update provides a significant improvement in the scope, science, and approach to water supply planning. The approach positions Colorado for a streamlined and robust evaluation of its future water needs.

The 2015 Water Plan set an adaptive management framework for future water planning activities and described five plausible futures (or planning scenarios) under which demands, supplies, and gaps (difference between demand and supply) were to be estimated. The scenarios included new considerations, such as climate change, that were not a part of analyses prior to the 2019 Technical Update. In addition, CWCB has continued to work with the Division of Water Resources (DWR) to develop and refine consumptive use and surface water allocation models that were not ready for use in earlier analyses. The Technical Update data sets were developed to be readily updatable, and during the recent BIP update process some data sets were further refined with basin roundtable input. As a result of these factors, the Technical Update took a leap forward with a different and more robust approach to estimating future gaps.

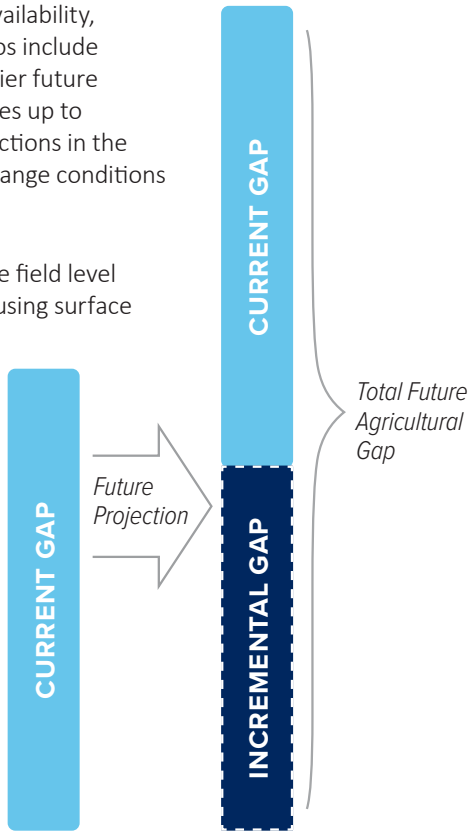
Click this link for more information on the Analysis and Technical Update to the Water Plan:
Analysis and Technical Update

Click this link for more information on Colorado's Decision Support Systems: **Colorado's Decision Support Systems**

Section 2 of the Technical Update (Volume 1) summarizes the methodologies used to estimate current and future municipal/industrial and agricultural demands, water supplies and potential gaps, and tools for evaluating environment and recreation needs. Volume 2 of the Technical Update includes technical memoranda with detailed descriptions of methodologies and analysis results. The methodologies used for the Technical Update build on previous datasets as well as new and improved data sources. To the extent possible, the Technical Update leveraged Colorado's investment in models and datasets developed through Colorado's Decision Support System (CDSS). Highlights of the new methodologies are described below.

- **Incorporation of scenario planning:** The 2015 Water Plan introduced scenario planning and included five scenarios that describe Colorado's potential water situation in the year 2050. The Technical Update conducted analyses of future demands, supplies, and additional water needs in the context of the potential future scenarios.
- **Municipal water use efficiency reporting data:** New data describing recent municipal water usage was employed to estimate municipal water demands. The data are collected and reported by water providers pursuant to House Bill (HB) 10-1051 (1051 data). The 1051 data were not available in prior SWSI efforts.
- **CDSS tools:** The Technical Update made extensive use of modeling tools available through CDSS. CDSS is a water resources data and modeling toolbox developed by CWCB and DWR for each of Colorado's major river basins for regional planning purposes. Tools in CDSS include HydroBase (a vast database of statewide water-related data), geographic information systems (GIS) data, surface water allocation models, and models that quantify consumptive use from crops and other vegetation. CDSS tools are available in most basins in the state. In basins where particular CDSS tools are not available, alternative methodologies were used to estimate demands and potential future gaps. The level of detail on hydrology, operations, and demands is appropriate for regional planning but does not capture daily changes in streamflow, routing of reservoir releases, or non-typical operations. As a result, the effect of local water uses on streamflows may not always be fully captured by the regional models.
- **Consideration of climate change:** The effects of climate change significantly influence hydrology, water demand and availability, and estimated gaps. Three of the five planning scenarios include assumptions and projections related to a hotter and drier future climate.[1] The analyses considered temperature increases up to 4.2 degrees Fahrenheit and were consistent with projections in the Colorado Climate Plan. Projections of future climate change conditions were not a part of past SWSI analyses.
- **Quantification of an agricultural gap:** Water demands and shortages for irrigated crops at the field level were estimated in SWSI 2010 but were not quantified using surface water modeling. Using the full suite of modeling tools available from CDSS made it possible to estimate agricultural gaps in the Technical Update under current and planning scenario conditions. Agricultural gaps are described in two ways:

  1. **Total Gap:** The overall shortage of water supplies (current plus potential incremental increases) to meet agricultural diversion demands required to provide full crop consumptive uses.
  2. **Incremental Gap:** The degree to which the gap could increase beyond what agriculture currently experiences under water shortage conditions.



[1] The planning scenarios developed for the Colorado Water Plan and the Technical Update were built on the foundational work of the multi-phase Colorado River Water Availability Study, Phase II (CRWAS-II). Detailed methodology and analysis results can be found in CRWAS-II Task 7: Climate Change Approach and Results.

- **Improved environment and recreation tools:** The Technical Update improved the data associated with environment and recreation attributes statewide. In addition, the Colorado Environmental Flow Tool (Flow Tool) was developed by CWCB to help assess potential flow conditions and associated ecological health in river segments in each basin. The Flow Tool was built on the framework of the Watershed Flow Evaluation Tool, a Colorado-specific application of a framework for assessing environmental flow needs at a regional scale. The tool uses flow data from the surface water allocation modeling developed for the Technical Update.

Link for the **Colorado Environmental Flow Tool**

Risk of Future Water Shortages

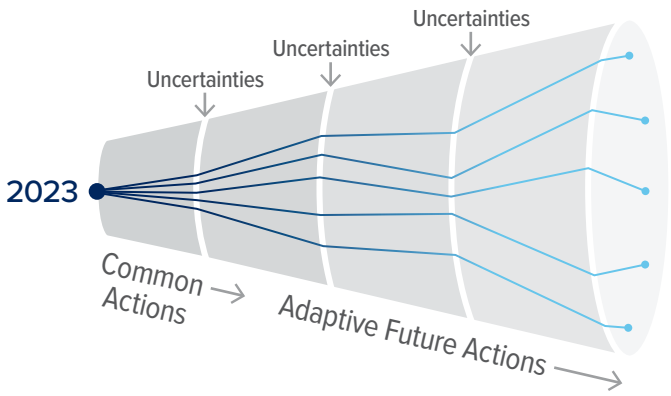
In the Technical Update, the calculated difference between water supplies and water demands for current and future conditions in the municipal and industrial and agriculture sectors was labeled the "gap." Gaps were presented for each of the five planning scenarios to reflect future uncertainty. Because gaps are estimated for future scenarios, they represent a future risk that water supplies will not be adequate to fully meet municipal, industrial, and agricultural demands. The bigger the gap, the higher the risk that Colorado will not be able to meet its future water needs. In a similar vein, potential future risks for environmental and recreational attributes based on projected future flow conditions were evaluated in the Technical Update using the Flow Tool.

Identifying potential future risks to all sectors of water use was a key objective of the Technical Update. Risk identification is a starting point and is foundational for discussions about projects and strategies that will help lessen future risk. Chapter 3 of the Water Plan summarizes the results of analyses conducted during the Technical Update and enhanced during the BIP update process.

The Water Plan uses scenario planning to identify and assess several potential water futures that together capture the most relevant uncertainties and driving forces

SCENARIO PLANNING APPROACH

The scenario planning process acknowledges that uncertainties exist in the future environmental state and social values of Colorado. As the time horizon increases, the uncertainty of these conditions increases as well. Particular scenarios can be based on assumptions about the states of future conditions. The scenario planning method is more sophisticated than a simplistic application of high-, medium-, and low-stress conditions (as were used in SWSI 2010).



Plausible range of water futures in 2050

The Water Plan uses scenario planning to consider a wide range of possible futures according to the best available science and stakeholder input. The approach considers uncertainties in future climate conditions, social conditions (such as values and economics), and supply-demand conditions (e.g., energy, agricultural, and municipal needs).

The scenario planning method included the six general steps described below and is intended to be cyclical and adaptive.

1. Evaluate drivers that impact future water conditions
2. Identify the most uncertain and impactful drivers
3. Develop future scenarios that consider variations in the drivers
4. Quantify future supply and demand conditions for each scenario
5. Calculate potential future risks of water shortages
6. Develop projects or strategies to mitigate future risks

IDENTIFICATION OF HIGH-IMPACT DRIVERS THAT INFLUENCE COLORADO'S WATER FUTURE

Before developing the 2015 Water Plan, CWCB initiated a multi-year stakeholder dialogue in conjunction with the nine basin roundtables and the IBCC to develop a methodology for projecting future water needs. The IBCC then developed a list of the following nine high-impact drivers that could greatly influence the direction of Colorado's water future. Several of these drivers are interrelated and can have integrated effects. The identification and monitoring of these nine drivers are important to understanding the direction of future water supply and demand.

1. SOCIAL / ENVIRONMENTAL VALUES

DRIVER DESCRIPTION

Social/environmental values reflect the public's perception of water use, support of water and energy conservation, and allocation of water supply toward environmental uses. Social values influence drivers such as regulations and adoption of water efficiency technologies, but they also affect the types of solutions that Coloradans pursue to meet future water needs or respond to climate change. For example, social values can impact the degree to which residents voluntarily adopt water-efficient technologies that may cost them money. They can also influence the demand for local agricultural products and the desire to maintain open space. Personal experiences, education, and outreach impact the degree of public awareness of water issues, which in turn can affect the public's perception of the water supply solutions as well as recreation and environmental protections that are pursued.

IMPACT ON WATER RESOURCES

If values trend toward greater water and energy conservation, new technologies may emerge that help conserve water. Also, development of new supplies may occur in ways that meet municipal and agricultural needs while preserving or enhancing the environment and providing recreational benefits.

2. POPULATION / ECONOMIC GROWTH

DRIVER DESCRIPTION

Population growth is driven by both state and national economic trends and land use planning and development statewide (see Driver #3). Colorado's moderate climate and quality of life draw both permanent residents and tourists. Population and economic growth/decline is forecasted by the State Demography Office (SDO) using census data and understanding of economic drivers.

IMPACT ON WATER RESOURCES

Population growth is a primary driver for municipal water demand and urbanization. Population change directly influences water use, while economic growth influences the types of water use (municipal, industrial, recreation, etc.). While Colorado's recent efforts to save water though efficiency and conservation have kept water demands steady in spite of growth, water demands are nevertheless projected to increase.

3. URBAN LAND USE / URBAN GROWTH PATTERNS

DRIVER DESCRIPTION

Urban land use and growth considers both density of development, as well as urbanization of undeveloped and agricultural lands. Zoning and other decisions affecting population density in cities and towns impacts how water is used inside and outside of single- and multi-family housing. It also impacts the degree to which urban sprawl may occur in the future.

IMPACT ON WATER RESOURCES

Population growth patterns can impact availability of water resources and how local governments use water (in-house use versus watering of green spaces). As urban areas grow into undeveloped areas of the watershed, both runoff into streams and water quality are affected. Finally, the urbanization of agricultural lands results in a shift of water use from the agricultural sector to the municipal sector, which can impact timing of use and return flows, wildlife habitat, and overall watershed health.

4. AVAILABILITY OF WATER EFFICIENCY TECHNOLOGIES

DRIVER DESCRIPTION

Availability and adoption of water efficiency technology drives water demands from municipal, industrial, and agricultural perspectives. Increased efficiency can be implemented in all sectors (municipal, industrial, energy, agricultural) and can offset growth through decreased demand by individual users.

IMPACT ON WATER RESOURCES

Indoor municipal demands can be reduced by installing low-flow fixtures, and outdoor demands are influenced by types of landscaping and efficiency of irrigation systems. On the agricultural side, irrigation efficiency technologies can reduce water losses on-farm and in ditches that deliver water from rivers and streams to farms. In addition, crop hybrids that are drought tolerant and crops that require less water can reduce irrigation demand.

5. CLIMATE CHANGE / WATER SUPPLY AVAILABILITY

DRIVER DESCRIPTION

Climate change is the long-term shift in temperature and regional weather patterns that results in a range of projected future conditions that include a warmer and potentially drier future for Colorado.

IMPACT ON WATER RESOURCES

Climate conditions impact both water supplies and water demands. Climate change may decrease streamflows and/or shift yearly streamflow patterns, which would impact agricultural, municipal, and industrial water supplies and create or increase risks for environment and recreation attributes. Higher temperatures associated with climate change will increase irrigation water demands for agricultural crops and outdoor urban landscapes and result in reduced return flows to streams.

6. LEVEL OF REGULATORY OVERSIGHT / CONSTRAINT

DRIVER DESCRIPTION

Regulatory oversight includes the legal framework in Colorado and nationwide through which water is administered, developed, and managed. This includes oversight from DWR, Colorado Department of Public Health & Environment (CDPHE), U.S. Environmental Protection Agency (EPA), and others.

IMPACT ON WATER RESOURCES

Regulatory constraints are influenced by social values, and they may drive changes in demands. For example, industrial water needs for energy extraction or thermoelectric energy production may be higher or lower in the future depending on state and local regulations and policies. Regulation can also drive the types of water supply solutions that stakeholders pursue. For example, the efficiency of permitting for certain types of water projects and the associated environmental mitigation requirements could influence their feasibility and cost.

7. AGRICULTURAL ECONOMICS / WATER DEMAND

DRIVER DESCRIPTION

Agricultural conditions, such as the amount of irrigated land in production, crops grown, and climate influence irrigation water demands. Urbanization, municipal transfers of agricultural water supply, and availability of surface and groundwater supplies all influence the amount of agricultural land that will be in production in the future. In addition, demands and prices for local agricultural products affect the economic sustainability of continued agriculture and resulting demands for water.

IMPACT ON WATER RESOURCES

Changes in the economics of the agricultural sector may impact the amount and types of crops grown, as well as the amount of land under irrigation. These changes will impact water demands for agricultural purposes.

8. ENERGY ECONOMICS / WATER DEMAND

DRIVER DESCRIPTION

The energy sector uses water in a variety of ways, including direct use for hydropower, or indirect uses such as steam generation or cooling. Water needs for energy expand relative to population growth and current regulations, policies, and planning for the energy industry. These needs are also affected by the type of energy production that is used in the future and can be influenced by state and national energy policies.

IMPACT ON WATER RESOURCES

As the sources of energy shift from non-renewable (coal and gas) to renewable (water, wind, and solar), the demand for water will shift as well. It is anticipated that renewable sources of energy will be less water consumptive.

9. MUNICIPAL AND INDUSTRIAL WATER DEMANDS

DRIVER DESCRIPTION

The municipal and industrial sector serves the residents and businesses of Colorado with water. Municipal water demands are influenced by changes in other drivers such as population, urban land use, adoption of conservation measures, and climate.

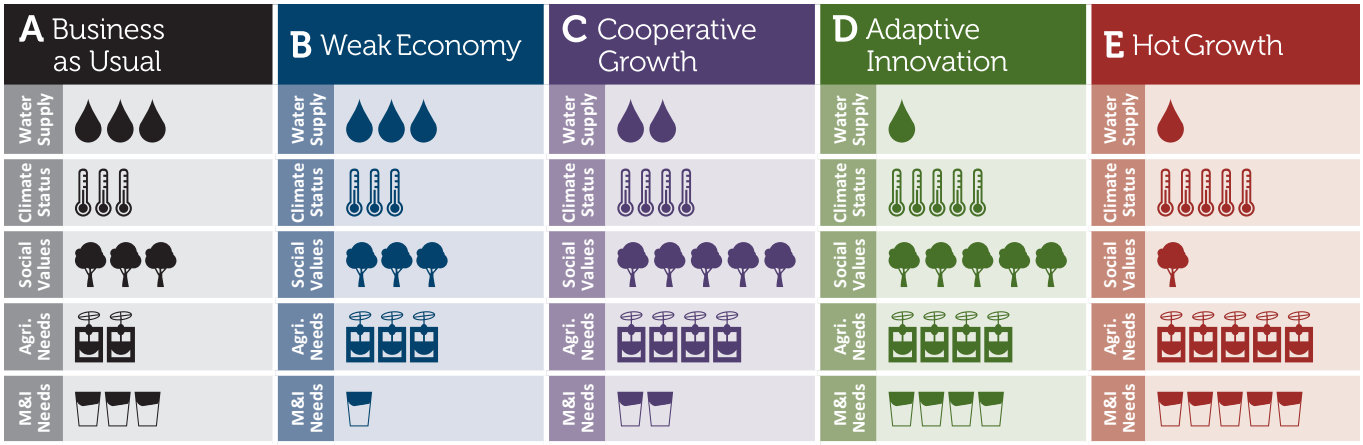
IMPACT ON WATER RESOURCES

Water in Colorado is scarce, and as the population grows, increased municipal and industrial demand for water is met through development of new supplies (if available), at the expense of water from a different sector, or through water conservation.

Using these drivers, the IBCC developed five scenarios that represent how Colorado's water future might look in 2050, knowing that the future is unpredictable and will contain a mix of multiple scenarios. A simplified graphic and descriptions of the five scenarios are shown below. The icons for each scenario illustrate the increase and decrease in levels for the generalized drivers compared to current levels (the five icons represent the combined effects of the nine drivers). The scenario names portray the overall story that each scenario tells in its respective views of the future.

Click this link for more information on the scenarios (including full text descriptions of each scenario). Refer to the Technical Update to the Water Plan, Sections 2.1.3 and 2.1.4: **Analysis and Technical Update**

SIMPLIFIED DESCRIPTION OF PLANNING SCENARIOS



A Business as Usual

- Population growth increases at trends predicted by the SDO.
- Future hydrology, per capita water demands, and adoption of conservation measures are similar to what's recently occurred.

B Weak Economy

- The world's economy slows, and the state's population growth is less than predicted.
- Hydrology is similar to recent patterns.
- This scenario puts the least amount of stress on future water supplies and is a bookend for scenarios.

C Cooperative Growth

- Climate is moderately warmer, and irrigation demands increase.
- Statewide population is similar to predictions by SDO, but it is distributed differently across the state.
- People seek to offset increased demands by more aggressively adopting water conservation.

D Adaptive Innovation

- Both scenarios assume that the climate is much warmer and drier and that population growth is higher than projected.
- The scenarios' primary differences revolve around conservation. In the Adaptive Innovation scenario, the state aggressively adopts conservation measures in both municipal and agricultural sectors. In the Hot Growth scenario, conservation is not a focus.

Monitoring the Drivers

The Water Plan will be updated periodically as part of a robust planning cycle to evaluate the state's changing water conditions. Part of the periodic update process will include monitoring the status of water resources drivers and adjusting the planning scenarios based on observed trends. Some of the drivers (e.g., population, per capita municipal and industrial water demands) can be monitored with readily available data being collected by state and local entities. Other drivers (e.g., regulatory constraints and social/environmental values) may require specific data gathering, such as surveys or collaboration with other entities who collect these types of information.

The interactions of drivers and their impact on risk is complex, which underscores the need for consistent monitoring of the drivers during Water Plan implementation. If certain drivers increase future demand (e.g., urban or energy sector growth) or decrease water supply (e.g., drier climate, increased regulation), then the risk of a future water shortage may increase; however, the risk may not increase if new water-efficient technologies emerge.

Monitoring and Uncertainty

Our future is uncertain, which is why monitoring is critical for identifying trends and adaptively planning for the future. For example, using SDO population projections developed in 2017 as a foundation, the Technical Update estimated a 2050 statewide population range of 7.7 million to 9.3 million. The SDO estimate, prepared in October 2022, projects a 2050 population of 7.5 million, which corresponds closely to the projection in the Weak Economy scenario. Trends in population and other water supply and demand drivers need to be monitored so that the Water Plan can adapt to uncertain and changing future conditions. The CWCB monitors drivers, identifies changes in drivers during Technical Updates, evaluates whether recent changes signal long-term trends, and assesses how trends may affect the future.

Actions can be taken that are useful in any future scenario

Near-term strategies and actions can be taken that provide benefits regardless of how the future unfolds (also known as "low regret strategies"). As future Technical Updates are conducted and the Water Plan is updated, new near-term strategies will be developed to adapt to conditions and lower our water-related risks.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-53:
Colorado Sun Article

In Colorado town built on coal, some families are moving on, even as Trump tries to boost industry

coloradosun.com/2025/12/08/colorado-coal-transition-jobs/

The Associated PressNews Agency, More by The Associated Press December 8, 2025

Matthew, Anna, Nathan and Matt Cooper prepare to drill a hole for a geothermal heat pump installation Thursday, Oct. 9, 2025, in Hamilton, Colo. (AP Photo/Brittany Peterson)

By Brittany Peterson and Jennifer McDermott, *The Associated Press*

CRAIG — The Cooper family knows how to work heavy machinery. The kids could run a hay baler by their early teens, and two of the three ran monster-sized drills at the coal mines along with their dad.

But learning to maneuver the shiny red drill they use to tap into underground heat feels different. It's a critical part of the new family business, High Altitude Geothermal, which installs geothermal heat pumps that use the Earth's constant temperature to heat and cool buildings. At stake is not just their livelihood but a century-long family legacy of producing energy in Moffat County.

Like many families here, the Coopers have worked in coal for generations — and in oil before that. That's ending for Matt Cooper and his son Matthew as one of three coal mines in the area closes in a statewide shift to cleaner energy.

"People have to start looking beyond coal," said Matt Cooper. "And that can be a multitude of things. Our economy has been so focused on coal and coal-fired power plants. And we need the diversity."

Many countries and about half of U.S. states are moving away from coal, citing environmental impacts and high costs. Burning coal emits carbon dioxide that traps heat in the atmosphere, warming the planet.

President Donald Trump has boosted coal as part of his agenda to promote fossil fuels. He's trying to save a declining industry with executive orders, large sales of coal from public lands, regulatory relief and offers of hundreds of millions of dollars to restore coal plants.

A drill sits outside the Cooper family ranch as they work to install a geothermal heat pump Thursday, Oct. 9, 2025, in Hamilton, Colo. (AP Photo/Brittany Peterson)

That's created uncertainty in places like Craig. As some families like the Coopers plan for the next stage of their careers, others hold out hope Trump will save their plants, mines and high-paying jobs.

Matt and Matthew Cooper work at the Colowyo Mine near Meeker, though active mining has ended and site cleanup begins in January.

The mine employs about 130 workers and supplies Craig Generating Station, a 1,400-megawatt coal-fired plant. Tri-State Generation and Transmission Association is planning to close Craig's Unit 1 by year's end for economic reasons and to meet legal requirements for reducing emissions. The other two units will close in 2028.

Xcel Energy owns coal-fired Hayden Station, about 30 minutes away. It said it doesn't plan to change retirement dates for Hayden, though it's extending another coal unit in Pueblo in part due to increased demand for electricity.

The Craig and Hayden plants together employ about 200 people.

Craig residents have always been entrepreneurial and that spirit will get them through this transition, said Kirstie McPherson, board president for the Craig Chamber of Commerce. Still, she said, just about everybody here is connected to coal.

"You have a whole community who has always been told you are an energy town, you're a coal town," she said. "When that starts going away, beyond just the individuals that are having the identity crisis, you have an entire culture, an entire community that is also having that same crisis."

Phasing out coal

Coal has been central to Colorado's economy since before statehood, but it's generally the most expensive energy on today's grid, said Democratic Gov. Jared Polis.

"We are not going to let this administration drag us backwards into an overreliance on expensive fossil fuels," Polis said in a statement.

Nationwide, coal power was 28% more expensive in 2024 than it was in 2021, costing consumers $6.2 billion more, according to a June analysis from Energy Innovation. The nonpartisan think tank cited significant increases to run aging plants as well as inflation.

Colorado's six remaining coal-fired power plants are scheduled to close or convert to natural gas, which emits about half the carbon dioxide as coal, by 2031. The state is rapidly adding solar and wind that's cheaper and cleaner than legacy coal plants. Renewable energy provides more than 40% of Colorado's power now and will pass 70% by the end of the decade, according to statewide utility plans.

Matt Cooper and his kids Anna, Nathan and Matthew prepare to drill a hole for a geothermal heat pump installation Thursday, Oct. 9, 2025, in Hamilton, Colo. (AP PhotoBrittany Peterson)

Nationwide, wind and solar growth has remained strong, producing more electricity than coal in 2025, as of the latest data in October, according to energy think tank Ember.

But some states want to increase or at least maintain coal production. That includes top coal state Wyoming, where the Wyoming Energy Authority said Trump is breathing welcome new life into its coal and mining industry.

Planning for the future

The Coopers have gone all-in on geothermal.

“Maybe we’ll never go back to coal,” Matt Cooper said. “We haven’t (gone) back to oil and gas, so we might just be geothermal people for quite some time, maybe generations, and then eventually something else will come along.”

While the Coopers were learning to use their drill in October, Wade Gerber was in downtown Craig distilling grain neutral spirits — used to make gin and vodka — on a day off from the Craig Station power plant. Gerber stepped over his corgis, Ali and Boss, and onto a stepladder to peer into a massive stainless steel pot where he was heating wheat and barley.

Gerber's spent three decades in coal. When closure plans were announced four years ago, he, his wife Tenniel and their friend McPherson brainstormed business ideas.

The Craig Station coal-burning power plant in Moffat County, here on Feb. 14, 2024, is expected to close in a few years. (Hugh Carey, The Colorado Sun)

"With my background in plumbing and electrical from the plant it's like, oh yeah, I can handle that part of it," Gerber said about distilling. "This is the easy part."

He used Tri-State's education subsidies for classes in distilling, while other co-workers learned to fix vehicles or repair guns to find new careers. While some plan to leave town, Gerber is opening Bad Alibi Distillery. McPherson and Tenniel Gerber are opening a cocktail bar next door.

Everyone in town hopes Trump will step in to extend the plant's life, Gerber said. Meanwhile, they're trying to define a new future for Craig in a nerve-wracking time.

"For me, my products can go elsewhere. I don't necessarily have to sell it in Craig, there's that avenue. For someone relying on Craig, it's even scarier," he said.

Questioning the coal rollback

Tammy Villard owns a gift shop, Moffat Mercantile, with her husband. After the coal closures were announced, they opened a commercial print shop too, seeing it as a practical choice for when so many high-paying jobs go away.

Villard, who spent a decade at Colowyo as administrative staff, said she doesn't understand how the state can throw the switch to turn off coal and still have reliable electricity. She wants the state to slow down.

Villard describes herself as a moderate Republican. She said political swings at the federal level — from the green energy push in the last administration to doubling down on fossil fuels in this one — aren't helpful.

"The pendulum has to come back to the middle," she said, "and we are so far out to either side that I don't know how we get back to that middle."

Type of Story: News Service

Produced externally by an organization we trust to adhere to high journalistic standards.

The Associated PressNews Agency

The Associated Press is an independent, not-for-profit news cooperative, serving member newspapers and broadcasters in the U.S., and other customers around the world. The Colorado Sun is proud to be one of them. AP journalists in more... More by The Associated Press

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-54:
PacifiCorp FERC Form 1

THIS FILING IS
Item 1: ☑ An Initial (Original) Submission OR ☐ Resubmission No.

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
PacifiCorp	End of: 2024/ Q4

GENERAL INFORMATION

Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

one million megawatt hours of total annual sales,

100 megawatt hours of annual sales for resale,

500 megawatt hours of annual power exchanges delivered, or

500 megawatt hours of annual wheeling for others (deliveries plus losses).

What and Where to Submit

Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426

For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/general-information-0/electric-industry-forms.

When to Submit

FERC Forms 1 and 3-Q must be filed by the following schedule:

FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is

For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).

Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

'Person' means an individual or a corporation;

'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; .....

"project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

'To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304.

Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from

estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309.

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

GENERAL PENALTIES

The Commission may assess up to $1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent	02 Year/ Period of Report
PacifiCorp	End of: 2024/ Q4

03 Previous Name and Date of Change (If name changed during year)
/

04 Address of Principal Office at End of Period (Street, City, State, Zip Code)
825 N.E. Multnomah Street, Suite 1900, Portland, OR 97232

05 Name of Contact Person	06 Title of Contact Person
Jennifer Kahl	External Reporting Director

07 Address of Contact Person (Street, City, State, Zip Code)
825 N.E. Multnomah Street, Suite 1900, Portland, OR 97232

08 Telephone of Contact Person, Including Area Code	09 This Report is An Original / A Resubmission	10 Date of Report (Mo, Da, Yr)
(503) 813-5784	(1) ☑ An Original (2) ☐ A Resubmission	04/15/2025

Annual Corporate Officer Certification

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name	03 Signature	04 Date Signed (Mo, Da, Yr)
Nikki L. Kobliha	/s/ Nikki L. Kobliha	04/15/2025
02 Title		
Senior Vice President and Chief Financial Officer		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent: PacifiCorp	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2025	Year/Period of Report End of: 2024/ Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
	Identification	1	
	List of Schedules	2	
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106	
7	Important Changes During the Year	108	
8	Comparative Balance Sheet	110	
9	Statement of Income for the Year	114	
10	Statement of Retained Earnings for the Year	118	
12	Statement of Cash Flows	120	
12	Notes to Financial Statements	122	
13	Statement of Accum Other Comp Income, Comp Income, and Hedging Activities	122a	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200	
15	Nuclear Fuel Materials	202	N/A
16	Electric Plant in Service	204	
17	Electric Plant Leased to Others	213	N/A
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224	
22	Materials and Supplies	227	
23	Allowances	228	
24	Extraordinary Property Losses	230a	N/A
25	Unrecovered Plant and Regulatory Study Costs	230b	N/A
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254b	
33	Long-Term Debt	256	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262	
36	Accumulated Deferred Investment Tax Credits	266	
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272	
39	Accumulated Deferred Income Taxes-Other Property	274	

40	Accumulated Deferred Income Taxes-Other	276	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310	
46	Electric Operation and Maintenance Expenses	320	
47	Purchased Power	326	
48	Transmission of Electricity for Others	328	
49	Transmission of Electricity by ISO/RTOs	331	N/A
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant (Account 403, 404, 405)	336	
53	Regulatory Commission Expenses	350	
54	Research, Development and Demonstration Activities	352	N/A
55	Distribution of Salaries and Wages	354	
56	Common Utility Plant and Expenses	356	N/A
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
61	Electric Energy Account	401a	
62	Monthly Peaks and Output	401b	
63	Steam Electric Generating Plant Statistics	402	
64	Hydroelectric Generating Plant Statistics	406	
65	Pumped Storage Generating Plant Statistics	408	N/A
66	Generating Plant Statistics Pages	410	
66.1	Energy Storage Operations (Large Plants)	414	N/A
66.2	Energy Storage Operations (Small Plants)	419	N/A
67	Transmission Line Statistics Pages	422	
68	Transmission Lines Added During Year	424	
69	Substations	426	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: ☑ Two copies will be submitted ☐ No annual report to stockholders is prepared		

Name of Respondent: PacifiCorp	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2025	Year/Period of Report End of: 2024/ Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Nikki L. Kobliha

Senior Vice President and Chief Financial Officer

825 N.E. Multnomah Street, Suite 1900, Portland, OR 97232

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

PacifiCorp was initially incorporated in 1910 under the laws of the state of Maine under the name Pacific Power & Light Company. In 1984, Pacific Power & Light Company changed its name to PacifiCorp. In 1989, it merged with Utah Power and Light Company, a Utah corporation, in a transaction wherein both corporations merged into a newly formed Oregon corporation. The resulting Oregon corporation was re-named PacifiCorp, which is the operating entity today.

State of Incorporation:

Date of Incorporation:

Incorporated Under Special Law:

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not applicable.

(a) Name of Receiver or Trustee Holding Property of the Respondent:

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created:

(d) Date when possession by receiver or trustee ceased:

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

PacifiCorp is a United States regulated electric utility company headquartered in Oregon that serves approximately 2.1 million retail electric customers, including residential, commercial, industrial, irrigation and other customers in portions of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp is principally engaged in the business of generating, transmitting, distributing and selling electricity. In addition to retail sales, PacifiCorp buys and sells electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants. PacifiCorp delivers electricity to customers in Utah, Wyoming and Idaho under the trade name Rocky Mountain Power and to customers in Oregon, Washington and California under the trade name Pacific Power.

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) ☐ Yes

(2) ☑ No

Name of Respondent: PacifiCorp	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2025	Year/Period of Report End of: 2024/ Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.

Berkshire Hathaway Inc.
Berkshire Hathaway Energy Company ("BHE") (wholly owned by Berkshire Hathaway, Inc.)
PPW Holdings LLC (wholly owned by BHE)
PacifiCorp (wholly owned by PPW Holdings LLC)

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PACIFICORP
NOTES TO FINANCIAL STATEMENTS

(1) Organization and Operations

PacifiCorp is a United States ("U.S.") regulated electric utility company serving retail customers, including residential, commercial, industrial, irrigation and other customers in portions of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp owns, or has interests in, a number of thermal, hydroelectric, wind-powered and geothermal generating facilities, as well as electric transmission and distribution assets. PacifiCorp also buys and sells electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants. PacifiCorp is subject to comprehensive state and federal regulation. PacifiCorp is an indirect subsidiary of Berkshire Hathaway Energy Company ("BHE"), a holding company based in Des Moines, Iowa that has investments in subsidiaries principally engaged in energy businesses. BHE is a wholly owned subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Basis of Presentation

These financial statements are prepared in accordance with the requirements of the Federal Energy Regulatory Commission ("FERC") as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America ("GAAP"). These notes include certain applicable disclosures required by GAAP adjusted to the FERC basis of presentation and include specific information requested by the FERC.

The following are the significant differences between the FERC accounting and reporting standards and GAAP.

Investments in Subsidiaries

In accordance with FERC Order No. AC11-132, PacifiCorp accounts for its investment in subsidiaries using the equity method for FERC reporting purposes rather than consolidating the assets, liabilities, revenues and expenses of subsidiaries as required by GAAP. GAAP requires that entities in which a company holds a controlling financial interest be consolidated. Also in accordance with FERC Order No. AC11-132, PacifiCorp does not eliminate intercompany profit on transactions with equity investees as would be required under GAAP. The accounting treatment described above has no effect on net income or the combined retained earnings of PacifiCorp and undistributed earnings of subsidiaries.

Costs of Removal

Estimated removal costs that are recovered through approved depreciation rates, but that do not meet the requirements of a legal asset retirement obligation ("ARO") are reflected in the cost of removal regulatory liability under GAAP and as accumulated provision for depreciation under the FERC accounting and reporting standards.

Income Taxes

Accumulated deferred income taxes are classified as net non-current assets or liabilities on the balance sheet for GAAP. Under the FERC accounting and reporting standards, accumulated deferred income taxes are classified as gross non-current assets and gross non-current liabilities. Additionally, there are certain presentational differences between FERC and GAAP for amounts related to unrecognized tax benefits associated with temporary differences in accordance with FERC guidance. For GAAP, unrecognized tax benefits associated with temporary differences are reflected as other liabilities while for FERC the income tax impact of uncertain tax positions associated with temporary differences are reflected in accumulated deferred income taxes.

Interest and penalties on income taxes for GAAP are classified as income tax expense. All such amounts are classified as interest income, interest expense and penalties under the FERC accounting and reporting standards.

Pensions and Postretirement Benefits Other Than Pensions

Pension and postretirement benefits other than pensions ("PBOP") are comprised of several different components of net periodic benefit costs. As required by GAAP, the service cost component is reported with other compensation costs arising from services rendered by employees, while the other components of net periodic benefit costs are presented outside of operating income. Additionally, only the service cost component of net periodic benefit costs is eligible for capitalization under GAAP. In accordance with FERC guidance, PacifiCorp continues to report the components of net periodic benefit costs for pension and PBOP on the statement of income and follows GAAP guidance to capitalize only the service cost component of net periodic benefit costs.

Reclassifications

Certain other reclassifications of balance sheet, income statement and cash flow amounts have been made in order to conform to the FERC basis of presentation. These reclassifications had no effect on net income.

Use of Estimates in Preparation of Financial Statements

The preparation of the financial statements in conformity with the FERC and GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; certain assumptions made in accounting for pension and other postretirement benefits; AROs; income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for loss contingencies and applicable insurance recoveries, including those related to the Oregon and Northern California 2020 wildfires (the "2020 Wildfires") and a wildfire that began in the Oak Knoll Ranger District of the Klamath National Forest in Siskiyou County, California in July 2022 (the "2022 McKinney Fire"), referred to together as "the Wildfires" as discussed in Note 14. Actual results may differ from the estimates used in preparing the financial statements.

Accounting for the Effects of Certain Types of Regulation

PacifiCorp prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, PacifiCorp defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in rates occur.

If it becomes no longer probable that the deferred costs or income will be included in future rates, the related regulatory assets and liabilities will be recognized in net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Different valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress. Nonperformance or credit risk is considered when determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange.

Cash Equivalents and Restricted Cash and Cash Equivalents

Cash equivalents consist of funds invested in money market mutual funds, U.S. Treasury Bills and other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted cash and cash equivalents included in other special funds consist substantially of funds representing vendor retention, nuclear decommissioning and custodial funds. A reconciliation of cash and cash equivalents and restricted cash equivalents as of December 31, 2024 and 2023 as presented on the Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Comparative Balance Sheets (in millions):

	2024	2023
Cash (131)	$ 20	$ 14
Other special funds (128)	16	53
Temporary cash investments (136)	21	114
Total cash and cash equivalents and restricted cash and cash equivalents	57	181

Investments

Available-for-sale securities are carried at fair value with realized gains and losses, as determined on a specific identification basis, recognized in earnings and unrealized gains and losses recognized in AOCI, net of tax. As of December 31, 2024 and 2023, PacifiCorp had no unrealized gains and losses on available-for-sale securities. Trading securities are carried at fair value with realized and unrealized gains and losses recognized in earnings.

Allowance for Credit Losses

Trade receivables are primarily short-term in nature with stated collection terms of less than one year from the date of origination, and are stated at the outstanding principal amount, net of an estimated allowance for credit losses. The allowance for credit losses is based on PacifiCorp's assessment of the collectability of amounts owed to PacifiCorp by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. In measuring the allowance for credit losses for trade receivables, PacifiCorp primarily utilizes credit loss history. However, PacifiCorp may adjust the allowance for credit losses to reflect current conditions and reasonable and supportable forecasts that deviate from historical experience. The changes in the balance of the allowance for credit losses, which is included in accumulated provision for uncollectible accounts on the Comparative Balance Sheet, is summarized as follows for the years ended December 31 (in millions):

	2024	2023
Beginning balance	$ 30	$ 19
Charged to operating costs and expenses, net	26	34
Write-offs, net	(34)	(23)
Ending balance	$ 22	$ 30

Derivatives

PacifiCorp employs a number of different derivative contracts, which may include forwards, options, swaps and other agreements, to manage price risk for electricity, natural gas and other commodities and interest rate risk. Derivative contracts are recorded on the Comparative Balance Sheet as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect offsetting permitted under master netting agreements with counterparties and cash collateral paid or received under such agreements.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not marked-to-market and settled amounts are recognized as operating revenue or operations expenses on the Statement of Income.

For PacifiCorp's derivative contracts, the settled amount is generally included in rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in rates are recorded as regulatory liabilities or assets. For a derivative contract not probable of inclusion in rates, changes in the fair value are recognized in earnings.

Inventories

Inventories consist mainly of materials, supplies and fuel stocks and are stated at the lower of average cost or net realizable value.

Net Utility Plant

General

Additions to utility plant are recorded at cost. PacifiCorp capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs, which include debt and equity allowance for funds used during construction ("AFUDC"). The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed.

Depreciation and amortization are generally computed on the straight-line method based on composite asset class lives prescribed by PacifiCorp's various regulatory authorities or over the assets' estimated useful lives. Depreciation studies are completed periodically to determine the appropriate composite asset class lives, net salvage and depreciation rates. These studies are reviewed and rates are ultimately approved by the various regulatory authorities. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as either accumulated provision for depreciation or an ARO liability on the Comparative Balance Sheet, depending on whether the obligation meets the requirements of an ARO. As actual removal costs are incurred, the associated accumulated provision for depreciation or ARO liability is reduced.

Generally when PacifiCorp retires or sells a component of regulated utility plant, it charges the original cost, net of any proceeds from the disposition, to accumulated provision for depreciation. Any gain or loss on disposals of all other assets is recorded through earnings.

Debt and equity AFUDC, which represents the estimated costs of debt and equity funds necessary to finance the construction of utility plant is capitalized as a component of utility plant, with offsetting credits to the Statement of Income. AFUDC is computed based on guidelines set forth by the FERC. After construction is completed, PacifiCorp is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets.

Asset Retirement Obligations

PacifiCorp recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. PacifiCorp's AROs are primarily associated with its generating facilities. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to utility plant, net) and for accretion of the ARO liability due to the passage of time. The difference between the ARO liability, the corresponding ARO asset included in utility plant and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability.

Impairment

PacifiCorp evaluates long-lived assets for impairment, including utility plant, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the appropriate FERC accounts are adjusted to write down the asset to the estimated fair value and any resulting impairment loss is reflected on the Statement of Income. The impacts of regulation are considered when evaluating the carrying value of regulated assets.

Leases

PacifiCorp has non-cancelable operating leases primarily for land, office space, office equipment, and generating facilities and finance leases consisting primarily of office buildings, natural gas pipeline facilities, and vehicles. These leases generally require PacifiCorp to pay for insurance, taxes and maintenance applicable to the leased property. Given the capital intensive nature of the utility industry, it is common for a portion of lease costs to be capitalized when used during construction or maintenance of assets, in which the associated costs will be capitalized with the corresponding asset and depreciated over the remaining life of that asset. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. PacifiCorp does not include options in its lease calculations unless there is a triggering event indicating PacifiCorp is reasonably certain to exercise the option. PacifiCorp's accounting policy is to not recognize right-of-use assets and lease obligations for leases with contract terms of one year or less and not separate lease components from non-lease components and instead account for each separate lease component and the non-lease components associated with a lease as a single lease component. Right-of-use assets will be evaluated for impairment in line with GAAP when a triggering event has occurred that might affect the value and use of the assets being leased.

PacifiCorp's leases of generating facilities generally are in the form of long-term purchases of electricity, also known as power purchase agreements ("PPA"). PPAs are generally signed before or during the early stages of project construction and can yield a lease that has not yet commenced. These agreements are primarily for renewable energy and the payments are considered variable lease payments as they are based on the amount of output.

PacifiCorp follows FERC accounting and reporting requirements and records operating and finance right-of-use assets in Account 101.1, Property under capital leases, and the current and noncurrent operating and finance lease liabilities in Account 243, Obligations under capital leases – Current and Account 227, Obligations under capital leases – Noncurrent, respectively.

Revenue Recognition

PacifiCorp uses a single five-step model to identify and recognize revenue from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services in an amount that reflects the consideration to which PacifiCorp expects to be entitled in exchange for those goods or services. PacifiCorp records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Statement of Income.

Substantially all of PacifiCorp's Customer Revenue is derived from tariff-based sales arrangements approved by various regulatory commissions. These tariff-based revenues are mainly comprised of energy, transmission and distribution and have performance obligations to deliver energy products and services to customers which are satisfied over time as energy is delivered or services are provided.

Revenue recognized is equal to what PacifiCorp has the right to invoice as it corresponds directly with the value to the customer of PacifiCorp's performance to date and includes billed and unbilled amounts. Payments for amounts billed are generally due from the customer within 30 days of billing. Rates charged for energy products and services are established by regulators or contractual arrangements that establish the transaction price as well as the allocation of price amongst the separate performance obligations. When preliminary regulated rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and classified in accordance with FERC accounting standards.

The determination of customer billings is based on a systematic reading of meters. At the end of each month, energy provided to customers since the date of the last meter reading is estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns, total volumes supplied to the system, line losses, economic impacts and composition of sales among customer classes. Unbilled revenue is reversed in the following month and billed revenue is recorded based on the subsequent meter readings.

Unamortized Debt, Premiums, Discounts and Debt Issuance Costs

Premiums, discounts and debt issuance costs incurred for the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

Income Taxes

Berkshire Hathaway includes PacifiCorp in its U.S. federal income tax return. Consistent with established regulatory practice, PacifiCorp's provision for income taxes has been computed on a stand-alone basis.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using enacted income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities associated with components of other comprehensive income ("OCI") are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities associated with certain property-related basis differences and other various differences that PacifiCorp deems probable to be passed on to its customers in most state jurisdictions are charged or credited directly to a regulatory asset or liability and will be included in regulated rates when the temporary differences reverse or as otherwise approved by PacifiCorp's various regulatory commissions. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more-likely-than-not to be realized.

Investment tax credits are deferred and amortized over the estimated useful lives of the related properties or as prescribed by various regulatory commissions.

PacifiCorp recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement.

Government Grants

From time to time, PacifiCorp enters into grant agreements with federal agencies, as well as agreements with third parties as a subrecipient of a federal grant, subjecting PacifiCorp to various federal compliance requirements. Most commonly these are cost share grants where PacifiCorp expenditures match the amount of grant proceeds. Grant proceeds most frequently support capital projects but are also used to cover operating costs. Grant proceeds received to reimburse capital project costs are applied as a direct offset to construction work-in-progress, ultimately serving to reduce PacifiCorp's investment in net utility plant. Grant proceeds received to reimburse operating costs are applied as an offset to operation expense.

Segment Information

PacifiCorp currently has one reportable segment, its regulated electric utility operations, which derives its revenue from regulated retail sales of electricity to residential, commercial, industrial and irrigation customers and from wholesale sales. PacifiCorp's chief operating decision maker ("CODM") is its Chief Executive Officer. The CODM uses net income, as reported on the Consolidated Statements of Operations in PacifiCorp's GAAP financial statements that are filed with the U.S. Securities and Exchange Commission ("Consolidated Statements of Operations"), and generally considers actual results versus historical results, budgets or forecasts, as well as unique risks and opportunities, when making decisions about the allocation of resources and capital. The segment expenses regularly provided to the CODM align with the captions presented on the Consolidated Statements of Operations. PacifiCorp's segment capital expenditures are reported on the Statement of Cash Flows as cash outflows for plant. PacifiCorp's segment assets are reported on the Comparative Balance Sheet as total assets.

New Accounting Pronouncements

In November 2023, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2023-07, Segment Reporting Topic 280, "Segment Reporting—Improvements to Reportable Segment Disclosures" which allows disclosure of one or more measures of segment profit or loss used by the chief operating decision maker to allocate resources and assess performance. Additionally, the standard requires enhanced disclosures of significant segment expenses and other segment items as well as incremental qualitative disclosures on both an annual and interim basis. This guidance is effective for annual reporting periods beginning after December 15, 2023, and interim reporting periods after December 15, 2024. Early adoption is permitted and retrospective application is required for all periods presented. PacifiCorp adopted this guidance for the fiscal year beginning January 1, 2024 under the retrospective method. The adoption did not have a material impact on PacifiCorp's financial statements and disclosures included within Notes to Financial Statements.

In December 2023, the FASB issued ASU No. 2023-09, Income Taxes Topic 740, "Income Tax—Improvements to Income Tax Disclosures" which requires enhanced disclosures, including specific categories and disaggregation of information in the effective tax rate reconciliation, disaggregated information related to income taxes paid, income or loss from continuing operations before income tax expense or benefit, and income tax expense or benefit from continuing operations. This guidance is effective for annual reporting periods beginning after December 15, 2024. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. PacifiCorp is currently evaluating the impact of adopting this guidance on its financial statements and disclosures included within Notes to Financial Statements.

In November 2024, the FASB issued ASU No. 2024-03, Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures Subtopic 220-40, "Disaggregation of Income Statement Expenses" which addresses requests from investors for more detailed information about certain expenses and requires disclosure of the amounts of purchases of inventory, employee compensation, depreciation and intangible asset amortization included in each relevant expense caption presented on the income statement. This guidance is effective for annual reporting periods beginning after December 15, 2026 and interim reporting periods beginning after December 15, 2027. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. PacifiCorp is currently evaluating the impact of adopting this guidance on its financial statements and disclosures included within Notes to Financial Statements.

Subsequent Events

PacifiCorp has evaluated the impact on its financial statements of events occurring after December 31, 2024 up to February 21, 2025, the date that PacifiCorp's GAAP financial statements were filed with the U.S. Securities and Exchange Commission and has updated such evaluation for disclosure purposes through April 15, 2025. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

(3) Net Utility Plant

The average depreciation and amortization rate applied to depreciable utility plant was 3.2% and 3.4% for the years ended December 31, 2024 and 2023, respectively, including the impacts of $29 million and $29 million in 2024 and 2023, respectively, primarily related to Idaho's, Utah's, Wyoming's and Washington's shares of incremental decommissioning costs for certain coal-fueled units.

Government Grants

In November 2024, PacifiCorp accepted two cost share grants from the U.S. Department of Energy ("DOE") under the DOE's Grid Resilience and Innovation Partnerships ("GRIP") Program supported by the Infrastructure Investment and Jobs Act. The two GRIP grants will provide cash proceeds totaling approximately $150 million as cost reimbursements supporting PacifiCorp's investment in certain wildfire mitigation projects, such as system hardening for fire resistance and prevention and new substation infrastructure, and other investments in technologies that significantly enhance situational awareness to reduce or mitigate wildfires and improve electric grid flexibility, reliability and resiliency. The period of performance for both GRIP grants begins September 2024 and runs through September 2028 and 2029. No costs incurred after the period of performance will be eligible for reimbursement.

In conjunction with the two GRIP awards, the DOE and U.S. Department of Labor accepted PacifiCorp's request for a temporary exception regarding the Davis-Bacon Act weekly pay and certified payroll reporting requirements with which PacifiCorp is required to comply under the terms of the grants. The parties agreed to a curative plan that provides for a temporary means to achieve the goals of these requirements and allows PacifiCorp to have until April 1, 2026, to fully comply with these requirements.

Other current DOE cost share grants primarily support electric vehicle infrastructure programs and energy efficiency programs. The period of performance for the electric vehicle infrastructure grant ended December 2024, and was for total cash proceeds of $6 million. The period of performance for the energy efficiency grant ends May 2028, and is for total cash proceeds of $5 million.

On January 20, 2025, U.S. federal executive order entitled *Unleashing American Energy* was issued requiring federal agencies to immediately pause disbursement of federal funds appropriated under the Inflation Reduction Act of 2022 and the Infrastructure Investment and Jobs Act, subject to respective agency review within 90 days of the date of the order of the agency's processes, policies and programs for issuing grants consistent with the policies stated in the executive order. PacifiCorp is monitoring federal activities associated with the executive order to determine whether the funding associated with its grants will be impacted.

Various compliance requirements are associated with the DOE grants, including demonstration that the costs are allowable under the grants. In the event PacifiCorp fails to meet these requirements, it could be required to return funds to the DOE.

During the year ended December 31, 2024, approximately $11 million of federal grant funds reduced additions to net utility plant on the Comparative Balance Sheet and approximately $4 million of federal grant funds reduced operation and maintenance expenses on the Statement of Income. Federal grant funds received prior to 2024 were insignificant.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements with other utilities, PacifiCorp, as a tenant in common, has undivided interests in jointly owned generation, transmission and distribution facilities. PacifiCorp accounts for its proportionate share of each facility, and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on the Statement of Income include PacifiCorp's share of the expenses of these facilities.

The amounts shown in the table below represent PacifiCorp's share in each jointly owned facility included in net utility plant as of December 31, 2024 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1 - 4	67%	$ 1,570	$ 1,030	$ 4
Hunter No. 1	94	509	256	3
Hunter No. 2	60	315	162	1
Wyodak	80	492	303	—
Colstrip Nos. 3 and 4	10	263	228	2
Hermiston	50	191	118	6
Craig Nos. 1 and 2	19	373	217	—
Hayden No. 1	25	77	58	—
Hayden No. 2	13	45	35	—
Transmission and distribution facilities	Various	932	351	308
Total		$ 4,767	$ 2,758	$ 324

(5) Leases

The following table summarizes PacifiCorp's leases recorded on the Comparative Balance Sheet as of December 31 (in millions):

	2024	2023
Right-of-use assets:		
Operating leases	$ 11	$ 12
Finance leases	24	12
Total right-of-use assets	$ 35	$ 24
Lease liabilities:		
Operating leases	$ 11	$ 12
Finance leases	24	12
Total lease liabilities	$ 35	$ 24

The following table summarizes PacifiCorp's lease costs for the years ended December 31 (in millions):

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-55:
Platte River Power Authority Coal Energy

Rawhide Energy Station

Commercial operation: 1984
Net capacity: 280 MW
Fuel type: coal
Operations: baseload

Operations

- Platte River's largest single source of system capacity at 280 net megawatts
- Used for baseload energy needs
- Provides approximately half of Platte River's annual delivered energy
- One of the highest-performing coal units in the U.S., averaging 97.28% equivalent availability and 85.08% capacity factor (as of May 31, 2020)
- Reliable fuel supply from Powder River Basin coal reserves in close proximity to plant
- Will be removed from Platte River's energy mix by Dec. 31, 2029

Financials

- Platte River's lowest operating cost generating resource
- Original debt retired in 2018
- Long-term rail and fuel contracts
- Fuel cost volatility mitigated through flexibility of existing contracts

Environmental

- Uses state-of-the-art air quality control technology to reduce emissions
- Maintains full compliance with strict environmental laws and regulations

EN

- Healthy bison and waterfowl habitats at Rawhide demonstrate the ability for nature and industry to share space
- Water-efficient design utilizes reclaimed water from a domestic wastewater treatment plant
- No discharge of industrial wastewater from the facility due to beneficial reuse of all process water

Craig units 1 & 2 (Yampa Project)

Commercial operation: Unit 1—1980; Unit 2—1979
Net capacity: 151 MW
Fuel type: coal
Operations: baseload

Operations

- Platte River's ownership of Craig units 1 and 2 is 18%
- Operated by Tri-State Generation and Transmission
- Co-owners include Tri-State Generation and Transmission, Salt River Project, PacifiCorp and Xcel Energy
- Craig Unit 1 to be removed from Platte River's mix by Dec. 31, 2025
- Craig Unit 2 to be removed from Platte River's mix by Sept. 30, 2028

Financials

- Platte River's second-lowest operating cost resource
- Fuel prices are based on production costs and not subject to market price volatility
- No debt service
- Fuel cost volatility mitigated by management of mine production levels and costs through an ownership share of Trapper Mine (27.14%), located adjacent to Craig units 1 and 2

Environmental

- Upgraded technology to reduce sulfur and particulate emissions
- Maintains full compliance with strict environmental laws and regulations

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View all generation resources

Accessibility Notice:
Per the Americans with Disabilities Act (ADA), Platte River Power Authority will provide reasonable accommodation to qualified individuals with a disability who need assistance. Please email us at communications@prpa.org or call 970-226-4000. "Walk-in" requests for auxiliary aids and services may be honored to the extent possible but can be unavailable if advance notice is not provided.

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For any accessibility requests, please call 970-226-4000.

EN

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-56:
Xcel FERC Form 1

THIS FILING IS
Item 1: ☑ An Initial (Original) Submission OR ☐ Resubmission No.

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Public Service Company of Colorado	End of: 2024/ Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

one million megawatt hours of total annual sales,

100 megawatt hours of annual sales for resale,

500 megawatt hours of annual power exchanges delivered, or

500 megawatt hours of annual wheeling for others (deliveries plus losses).

What and Where to Submit

Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426

For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/general-information-0/electric-industry-forms.

When to Submit

FERC Forms 1 and 3-Q must be filed by the following schedule:

FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).

Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

'Person' means an individual or a corporation;

'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; .....

"project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

'To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

"Sec. 304.

Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309.

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

GENERAL PENALTIES

The Commission may assess up to $1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent	02 Year/ Period of Report
Public Service Company of Colorado	End of: 2024/ Q4

03 Previous Name and Date of Change (If name changed during year)
/

04 Address of Principal Office at End of Period (Street, City, State, Zip Code)
1800 Larimer Street, Suite 1100, Denver, CO 80202

05 Name of Contact Person	06 Title of Contact Person
Melissa L. Ostrom	Senior Vice President, Controller

07 Address of Contact Person (Street, City, State, Zip Code)
414 Nicollet Mall, Minneapolis, MN 55401

08 Telephone of Contact Person, Including Area Code	09 This Report is An Original / A Resubmission	10 Date of Report (Mo, Da, Yr)
(612) 330-5500	(1) ☑ An Original (2) ☐ A Resubmission	04/04/2025

Annual Corporate Officer Certification

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name	03 Signature	04 Date Signed (Mo, Da, Yr)
Melissa L. Ostrom	Melissa L. Ostrom	04/04/2025
02 Title		
Senior Vice President, Controller		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent: Public Service Company of Colorado	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
	Identification	1	
	List of Schedules	2	
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2	**Control Over Respondent**	102	
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5	**Directors**	105	
6	**Information on Formula Rates**	106	
7	**Important Changes During the Year**	108	
8	**Comparative Balance Sheet**	110	
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10	**Statement of Retained Earnings for the Year**	118	
12	**Statement of Cash Flows**	120	
12	**Notes to Financial Statements**	122	
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14	**Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep**	200	
15	**Nuclear Fuel Materials**	202	N/A
16	**Electric Plant in Service**	204	
17	**Electric Plant Leased to Others**	213	N/A
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19	**Construction Work in Progress-Electric**	216	
20	**Accumulated Provision for Depreciation of Electric Utility Plant**	219	
21	**Investment of Subsidiary Companies**	224	
22	**Materials and Supplies**	227	
23	**Allowances**	228	
24	**Extraordinary Property Losses**	230a	N/A
25	**Unrecovered Plant and Regulatory Study Costs**	230b	
26	**Transmission Service and Generation Interconnection Study Costs**	231	
27	**Other Regulatory Assets**	232	

28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254b	N/A
33	Long-Term Debt	256	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262	
36	Accumulated Deferred Investment Tax Credits	266	
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272	
39	Accumulated Deferred Income Taxes-Other Property	274	
40	Accumulated Deferred Income Taxes-Other	276	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
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52	Depreciation and Amortization of Electric Plant (Account 403, 404, 405)	336	
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54	Research, Development and Demonstration Activities	352	
55	Distribution of Salaries and Wages	354	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
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63	Steam Electric Generating Plant Statistics	402	

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66.1	**Energy Storage Operations (Large Plants)**	414	
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67	**Transmission Line Statistics Pages**	422	
68	**Transmission Lines Added During Year**	424	
69	**Substations**	426	
70	**Transactions with Associated (Affiliated) Companies**	429	
71	**Footnote Data**	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: ☑ Two copies will be submitted ☐ No annual report to stockholders is prepared		

Name of Respondent: Public Service Company of Colorado	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

1. Summary of Significant Accounting Policies

Business and System of Accounts - PSCo is principally engaged in the regulated generation, purchase, transmission, distribution and sale of electricity and in the regulated purchase, transportation, distribution and sale of natural gas. PSCo is subject to regulation by the FERC and the Colorado Public Utility Commission (CPUC).

Basis of Accounting - The accompanying financial statements were prepared in accordance with the accounting requirements of the FERC as set forth in the Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than Generally Accepted Accounting Principles (GAAP). The following areas represent the significant differences between the Uniform System of Accounts and GAAP:

- Current maturities of long-term debt are included as long-term debt, while GAAP requires such maturities to be classified as current liabilities.
- Accumulated deferred income taxes are shown as long-term assets and liabilities at their gross amounts in the FERC presentation, in contrast to the GAAP presentation as net long-term assets and liabilities.
- Regulatory assets and liabilities are classified as current and noncurrent for GAAP presentation, while the FERC requires all regulatory assets and liabilities to be classified as noncurrent deferred debits and credits, respectively.
- Unrecognized tax benefits are recorded for temporary differences in accounts established for accumulated deferred income taxes in the FERC presentation, in contrast to the GAAP presentation as taxes accrued and noncurrent other liabilities.
- Removal costs for future removal obligations are classified as accumulated depreciation on the utility plant in the FERC presentation and as regulatory liabilities in the GAAP presentation.
- Certain commodity trading purchases and sales transactions are presented gross as expenses and revenues for the FERC presentation; however the net margin is reported as net sales for the GAAP presentation.
- Various expenses such as donations, lobbying, and other non-regulatory expenses are presented as other income deductions for the FERC presentation and reported as operating expenses for the GAAP presentation.
- Income tax expense is shown as a component of operating expense in the FERC presentation, in contrast to the GAAP presentation as a below-the-line deduction from operating income.
- Wholly-owned subsidiaries are reported using the equity method of accounting in the FERC presentation and are required to be consolidated for GAAP.
- Borrowings and repayments with subsidiary companies are investing activities in the FERC statement of cash flows; however, they are operating activities in the GAAP statement of cash flows.
- For certain capital projects where there is recovery of a return on construction work in progress (CWIP), certain amounts of allowance for funds used during construction (AFUDC) are not recognized in CWIP for GAAP, while for the FERC presentation, they are recorded in CWIP but the benefit is deferred as a liability and amortized over the life of the property as a reduction of costs.
- Deferred debt issuance costs are included as a deferred debit, while GAAP presentation includes them with long-term liabilities.
- Regulatory baselines have been specified for qualified and non-qualified pension cost, which are compared to costs recorded for GAAP; amounts above or below these baselines are deferred on a FERC basis.
- A 15-year fixed FERC regulatory amortization is being recorded to reduce the GAAP qualified pension prepaid asset included in rate base, while GAAP remeasures the prepaid amount each period based on actuarial measurement of net periodic pension cost and employer cash contributions to the trust.

If GAAP were followed, these financial statement line items would have values greater/(lesser) than those shown by the FERC presentation of:

(Millions of Dollars)	
Balance Sheet:	
Net utility plant	$ 385
Current assets	142
Current liabilities	426
Other long-term assets	(1,050)
Long-term debt and other long-term liabilities	(949)
Statement of Income:	
Operating revenue	$ (77)
Operating expenses	(69)
Other income and deductions	37
Net interest charges	4

Subsequent Events - Management has evaluated the impact of events occurring after Dec. 31, 2024 up to Feb. 27, 2025, the date PSCo's GAAP financial statements were issued and has updated such evaluation for disclosure purposes through the date of the draft. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

Use of Estimates — PSCo uses estimates based on the best information available to record transactions and balances resulting from business operations. Estimates are used for items such as plant depreciable lives or potential disallowances, asset retirement obligations (AROs), certain regulatory assets and liabilities, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations, actuarially determined benefit costs and wildfire contingencies. Recorded estimates are revised when better information becomes available or actual amounts can be determined. Revisions can affect operating results.

Regulatory Accounting — PSCo accounts for income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

- Certain costs, which would otherwise be charged to expense or other comprehensive income (OCI), are deferred as regulatory assets based on the expected ability to recover the costs in future rates.
- Certain credits, which would otherwise be reflected as income or OCI, are deferred as regulatory liabilities based on the expectation the amounts will be returned to customers in future rates, or because the amounts were collected in rates prior to the costs being incurred.

Estimates and assumptions for recovery of deferred costs and refund of deferred credits are based on specific ratemaking decisions, precedent or other available information. Regulatory assets and liabilities are amortized consistent with the treatment in the rate setting process.

If changes in the regulatory environment occur, PSCo may no longer be eligible to apply this accounting treatment and may be required to eliminate regulatory assets and liabilities. Such changes could have a material effect on PSCo's results of operations, financial condition and cash flows.

See Note 3 for further information.

Income Taxes — PSCo accounts for income taxes using the asset and liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Income taxes are deferred for all temporary differences between pretax financial and taxable income and between the book and tax bases of assets and liabilities utilizing rates that are scheduled to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the period that includes the enactment date.

Utility rate regulation has resulted in the recognition of regulatory assets and liabilities related to income taxes. The effects of PSCo's tax rate changes are generally subject to a normalization method of accounting. Therefore, the revaluation of most of its net deferred taxes upon a tax rate reduction results in the establishment of a net regulatory liability, refundable to utility customers over the remaining life of the related assets. PSCo anticipates that a tax rate increase would predominantly result in the establishment of a regulatory asset, subject to an evaluation of whether future recovery is expected.

Tax credits are recorded when earned unless there is a requirement to defer the benefit and amortize over the book depreciable lives of related property. The requirement to defer and amortize these credits specifically applies to certain federal investment tax credits (ITCs), as determined by tax regulations and PSCo tax elections. For tax credits otherwise eligible to be recognized when earned, PSCo considers the impact of rate regulation to determine if these credits and related adjustments should be deferred as regulatory assets or liabilities.

Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized. This evaluation includes consideration of whether tax credits are expected to be sold at a discount and impact the realization of amounts presented as deferred tax assets. Transferable tax credits are accounted for under ASC 740, *Income Taxes*, and valuation allowances and any adjustments for discounts incurred on sales transactions are recorded to deferred tax expense, typically recovered in regulatory mechanisms.

PSCo measures and discloses uncertain tax positions that it has taken or expects to take in its income tax returns. A tax position is recognized in the financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position. Recognition of changes in uncertain tax positions are reflected as a component of income tax expense.

Interest and penalties are recorded separately to their respective line items in the income statement.

Xcel Energy Inc. and its subsidiaries, including PSCo file consolidated federal income tax returns as well as consolidated or separate state income tax returns. Federal income taxes paid by Xcel Energy Inc. are allocated to its subsidiaries based on separate company computations. A similar allocation is made for state income taxes paid by Xcel Energy Inc. in connection with consolidated state filings. Xcel Energy Inc. also allocates its own income tax benefits to its direct subsidiaries.

See Note 5 for further information.

Utility Plant and Depreciation in Regulated Operations — Utility plant is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and AFUDC. The cost of plant retired is charged to accumulated depreciation and amortization. Amounts recovered in rates for future removal costs are recorded as regulatory liabilities. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs and replacement of items determined to be less than a unit of property are charged to expense as incurred.

Utility plant is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made. For investments in utility plant that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary.

Depreciation expense is recorded using the straight-line method over the plant's commission approved useful life. Actuarial life studies are performed and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Plant removal costs are typically recognized at the amounts recovered in rates as authorized by the applicable regulator. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.8% in 2024 and 3.6% in 2023.

AROs — PSCo records AROs as a liability in the period incurred (if fair value can be reasonably estimated), with the offsetting/associated costs capitalized as a long-lived asset. The liability is generally increased over time by applying the effective interest method of accretion and the capitalized costs are typically depreciated over the useful life of the long-lived asset. Changes resulting from revisions to timing or amounts of expected asset retirement cash flows are recognized as an increase or a decrease in the ARO.

See Note 8 for further information.

Benefit Plans and Other Postretirement Benefits — PSCo maintains pension and postretirement benefit plans for eligible employees. Recognizing the cost of providing benefits and measuring the projected benefit obligation of these plans requires management to make various assumptions and estimates.

Certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are deferred as regulatory assets and liabilities, rather than recorded as other comprehensive income, based on regulatory recovery mechanisms.

See Note 7 for further information.

Environmental Costs — Environmental costs are recorded when it is probable PSCo is liable for remediation costs and the amount can be reasonably estimated. Costs are deferred as a regulatory asset if it is probable that the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. For certain environmental costs related to facilities currently in use, such as for emission-control equipment, the cost is capitalized and depreciated over the life of the plant.

Estimated remediation costs are regularly adjusted as estimates are revised and remediation is performed. If other participating potentially responsible parties exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for PSCo's expected share of the cost.

Future costs of restoring sites are treated as a capitalized cost of plant retirement.

See Note 8 for further information.

Revenue from Contracts with Customers — Performance obligations related to the sale of energy are satisfied as energy is delivered to customers. PSCo recognizes revenue that corresponds to the price of the energy delivered to the customer. The measurement of energy sales to customers is generally based on the reading of their meters, which occurs systematically throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recognized.

A separate financing component of collections from customers is not recognized as contract terms are short-term in nature. Revenues are net of any excise or sales taxes or fees.

PSCo recognizes physical sales to customers (native load and wholesale) on a gross basis in electric revenues and cost of sales. PSCo participates in SPP WEIS. Revenues for short-term physical wholesale sales of excess energy transacted through the imbalance market are recorded on a gross basis. Other revenues and charges settled/facilitated through SPP WEIS are recorded on a net basis in cost of sales.

Cash and Cash Equivalents — PSCo considers investments in instruments with a remaining maturity of three months or less at the time of purchase to be cash equivalents.

Accounts Receivable and Allowance for Bad Debts — Accounts receivable are stated at the actual billed amount net of an allowance for bad debts. PSCo establishes an allowance for uncollectible receivables based on a policy that reflects its expected exposure to the credit risk of customers. As of Dec. 31, 2024 and 2023, the allowance for bad debts was $50 million and $56 million, respectively.

Inventory — Inventory is recorded at the lower of average cost or net realizable value.

Fair Value Measurements — PSCo presents cash equivalents, interest rate derivatives, commodity derivatives and pension and postretirement plan assets at estimated fair values in its financial statements.

For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used to estimate fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price, quoted prices for similar contracts or internally prepared valuation models may be used to determine fair value.

For the pension and postretirement plan assets, published trading data and pricing models, generally using the most observable inputs available, are utilized to determine fair value for each security.

See Notes 6 and 7 for further information.

Derivative Instruments — PSCo uses derivative instruments in connection with its commodity trading activities, and to manage risk associated with changes in interest rates and utility commodity prices, including forward contracts, futures, swaps and options. Derivatives not qualifying for the normal purchases and normal sales exception are recorded on the balance sheets at fair value as derivative instruments. Classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship.

Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms.

Gains or losses on commodity trading transactions are recorded as a component of electric operating revenues.

Normal Purchases and Normal Sales — PSCo enters into contracts for purchases and sales of commodities for use and sale in its operations. At inception, contracts are evaluated to determine whether they contain a derivative, and if so, whether they may be exempted from derivative accounting if designated as normal purchases or normal sales.

Commodity Trading Operations — Commodity trading activities are not associated with energy produced from PSCo's generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value and commodity trading results include the impact of all margin-sharing mechanisms.

See Note 6 for further information.

AFUDC — AFUDC represents the cost of capital used to finance utility construction activity and is computed by applying a composite financing rate to qualified CWIP. The amount of AFUDC capitalized as a utility construction cost is credited to other nonoperating income (for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in PSCo's rate base.

Alternative Revenue — Certain rate rider mechanisms (including decoupling and demand side management (DSM) programs) qualify as alternative revenue programs. These mechanisms arise from instances in which the regulator authorizes a future surcharge in response to past activities or completed events. When certain criteria are met, including expected collection within 24 months, revenue is recognized, which may include incentives and return on rate base items. Billing amounts are revised periodically for differences between total amount collected and revenue earned, which may increase or decrease the level of revenue collected from customers. Alternative revenues arising from these programs are presented on a gross basis and disclosed separately from revenue from contracts with customers.

Conservation Programs — The costs incurred for DSM programs are deferred if it is probable future revenue will be provided to permit recovery of the incurred cost. Revenues recognized for incentive programs designed for recovery of DSM program costs and/or conservation performance incentives are limited to amounts expected to be collected within 24 months from the year in which they are earned.

PSCo's DSM program costs are recovered through rider mechanisms. Regulatory assets are recognized to reflect the amount of costs or earned incentives that have not yet been collected from customers.

Emission Allowances — Emissions allowances are recorded at cost, including broker commission fees. The inventory accounting model is utilized for all emissions allowances and any sales of these allowances are included in electric revenues.

Renewable Energy Credits (RECs) — Cost of RECs that are utilized for compliance is recorded as electric fuel and purchased power expense. An inventory accounting model is used to account for RECs.

Sales of RECs are recorded in electric revenues on a gross basis. Cost of these RECs and amounts credited to customers under margin-sharing mechanisms are recorded in electric fuel and purchased power expense.

2. Joint Ownership of Generation, Transmission and Gas Facilities

Jointly owned assets as of Dec. 31, 2024:

(Millions of Dollars, Except Percent Owned)	Plant in Service	Accumulated Depreciation	Percent Owned
Electric generation:			
Hayden Unit 1	$ 158	$ 117	76 %
Hayden Unit 2	152	93	37
Hayden common facilities	45	33	53
Craig Units 1 and 2	82	58	10
Craig common facilities	40	27	7
Comanche Unit 3	933	212	67
Comanche common facilities	29	5	77
Electric transmission:			
Transmission and other facilities	190	75	Various
Gas transmission:			
Rifle, CO to Avon, CO	28	10	60
Gas transmission compressor	8	3	50
Total [a]	$ 1,665	$ 633	

[a] Projects additionally include $28 million in CWIP

PSCo's share of operating expenses and construction expenditures is included in the applicable utility accounts. Respective owners are responsible for providing their own financing.

3. Regulatory Assets and Liabilities

Regulatory assets and liabilities are created for amounts that regulators may allow to be collected or may require to be paid back to customers in future electric and natural gas rates. PSCo would be required to recognize the write-off of regulatory assets and liabilities in net income or OCI if changes in the utility industry no longer allow for the application of regulatory accounting guidance under GAAP.

Components of regulatory assets:

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-57:
2018 SIP Element Adopted

Chapter 6 Best Available Retrofit Technology

Table 6 - 2 BART Determinations for Colorado Sources

Emission Unit	Assumed ** NOx Control Type	NOx Emission Limit	Assumed ** SO_2 Control Type	SO_2 Emission Limit	Assumed ** Particulate Control and Emission Limit
Cemex - Lyons Kiln	Selective Non-Catalytic Reduction System	255.3 lbs/hr (30-day rolling average) 901.0 tons/yr (12-month rolling average)	None	25.3 lbs/hr (12-month rolling average) 95.0 tons/yr (12-month rolling average)	Fabric Filter Baghouse * 0.275 lb/ton of dry feed 20% opacity
Cemex - Lyons Dryer	None	13.9 tons/yr	None	36.7 tons/yr	Fabric Filter Baghouse* 22.8 tons/yr 10% opacity
CENC Unit 4	Low NOx Burners with Separated Over-Fire Air	0.37 lb/MMBtu (30-day rolling average) Or 0.26 lb/MMBtu Combined Average for Units 4 & 5 (30-day rolling average)	None	1.0 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.07 lb/MMBtu
CENC Unit 5	Low NOx Burners with Separated Over-Fire Air, and Selective Non-Catalytic Reduction System	0.19 lb/MMBtu (30-day rolling average) Or 0.26 lb/MMBtu Combined Average for Units 4 & 5 (30-day rolling average)	None	1.0 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.07 lb/MMBtu
Comanche Unit 1	Low NOx Burners*	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)	Lime Spray Dryer*	0.12 lb/MMBtu (30-day rolling average) 0.10 lb/MMBtu (combined annual average for units 1 & 2)	Fabric Filter Baghouse* 0.03 lb/MMBtu

Comanche Unit 2	Low NOx Burners*	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)	Lime Spray Dryer*	0.12 lb/MMBtu (30-day rolling average) 0.10 lb/MMBtu (combined annual average for units 1 & 2)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Craig Unit 1	Selective Catalytic Reduction System	***	Wet Limestone scrubber*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Craig Unit 2	Selective Catalytic Reduction System	0.08 lb/MMBtu (30-day rolling average)	Wet Limestone scrubber*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Hayden Unit 1	Selective Catalytic Reduction System	0.08 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Hayden Unit 2	Selective Catalytic Reduction System	0.07 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Martin Drake Unit 5	Ultra Low-NOx Burners (including Over-Fire Air)	0.31 lb/MMBtu (30-day rolling average)	Dry Sorbent Injection	0.26 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Martin Drake Unit 6	Ultra Low-NOx Burners (including Over-Fire Air)	0.31 lb/MMBtu (30-day rolling average)	Lime Spray Dryer or Equivalent Control Technology	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Martin Drake Unit 7	Ultra Low-NOx Burners (including Over-Fire Air)	0.29 lb/MMBtu (30-day rolling average)	Lime Spray Dryer or Equivalent Control Technology	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu

* Controls are already operating

** Based on the state's BART analysis, the "assumed" technology reflects the control option found to render the BART emission limit achievable. The "assumed" technology listed in the above table is not a requirement.

*** Craig Unit 1 will either close on or before December 31, 2025 ***or*** cease burning coal no later than August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu will be effective after August 31, 2021. Effective January 1, 2017 (first compliance date January 31, 2017), Craig Unit 1 will be subject to a NOx emission limit of 0.28 lb/MMBtu 30-day rolling average until closing or converting to natural gas. Additionally, an annual NOx limit of 4,065 tons per year will be effective December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1. The Division shall be notified in writing by the owner-operator no later than February 28, 2021 whether Craig Unit 1 will close or convert to gas.

6.4.3.4 BART Determination for Tri-State Generation and Transmission Association's Craig Facility

Craig Units 1 and 2 are BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and having commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change. Tri-State submitted a BART Analysis to the Division on July 31, 2006 with revisions, updates, and/or comments submitted on October 25, 2007, December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

SO2 BART Determination for Craig - Units 1 and 2

Wet FGD Upgrades – As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Therefore, the following wet scrubber upgrades were considered for Craig Units 1 and 2, if technically feasible.

- *Elimination of bypass reheat*: The FGD system bypass was redesigned to eliminate bypass of the FGD system except for boiler safety situations in 2003-2004.
- *Installation of liquid distribution rings:* Tri-State determined that installation of perforated trays, described below, accomplished the same objective.
- *Installation of perforated trays:* Upgrades during 2003-2004 included installation of a perforated plate tray in each scrubber module.
- *Use of organic acid additives:* Organic acid additives were considered but not selected for the following reasons:
  1. Dibasic Acid (DBA) has not been tested at the very low inlet SO_2 concentrations seen at Craig Units 1 and 2.
  2. DBA could cause changes in sulfite oxidation with impacts on SO_2 removal and solids settling and dewatering characteristics.
  3. Installation of the perforated plate tray accomplished the same objective of increased SO_2 removal.
- *Improve or upgrade scrubber auxiliary equipment:* 2003-2004 upgrades included installation of the following upgrades on limestone processing and scrubber modules on Craig 1 and 2:
  1. Two vertical ball mills were installed for additional limestone processing capability for increased SO_2 removal. The two grinding circuit trains were redesigned to position the existing horizontal ball mills and the vertical ball mills in series to accommodate the increased quantity of limestone required for increased removal rates. The two mills in series also were designed to maintain the fine particle size (95% <325 mesh or 44 microns) required for high SO_2 removal rates.

2. Forced oxidation within the SO_2 removal system was thought necessary to accommodate increased removal rates and maintain the dewatering characteristics of the limestone slurry. Operation, performance, and maintenance of the gypsum dewatering equipment are more reliable with consistent slurry oxidation.
3. A ventilation system was installed for each reaction tank.
4. A new mist eliminator wash system was installed due to the increased gas flow through the absorbers since flue gas bypass was eliminated, which increased demand on the mist eliminator system. A complete redesign and replacement of the mist eliminator system including new pads and wash system improved the reliability of the individual modules by minimizing down time for washing deposits out of the pads.
5. Tri-State installed new module outlet isolation damper blades. The new blades, made of a corrosion-resistant nickel alloy, allow for safer entry into the non-operating module for maintenance activities.
6. Various dewatering upgrades were completed. Dewatering the gypsum slurry waste is done to minimize the water content in waste solids prior to placements of the solids in reclamation areas at the Trapper Mine. The gypsum solids are mixed or layered with ash and used for fill during mine reclamation at Trapper Mine. The installed system was designed for the increased capacity required for increased SO_2 removal. New hydrocyclones and vacuum drums were installed as well as a new conveyor and stack out system for solid waste disposal.
7. Instrumentation and controls were modified to support all of the new equipment.

- *Redesign spray header or nozzle configuration:* The slurry spray distribution was modified during 2003-2004. The modified slurry spray distribution system improved slurry spray characteristics and was designed to minimize pluggage in the piping.

Therefore, there are no technically feasible upgrade options for Craig Station Units 1 and 2. However, the state evaluated the option of tightening the emission limit for Craig Units 1 and 2 through the five-factor analysis and determined that a more stringent 30-day rolling SO_2 limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control for this wet FGD control technology based on current emissions and operations. The tighter emission limits are achievable without additional capital investment. An SO2 limit lower than 0.11 lbs/MMBtu would likely require additional capital expenditure and is not reasonable for the small incremental visibility improvement of 0.02 deciview.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Craig – Unit 1		Craig – Unit 2	
	SO2 Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.17		0.16	
Wet FGD	0.11	0.03	0.11	0.03
Wet FGD	0.07	0.05	0.07	0.05

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART is the following SO2 emission rates:

Craig Unit 1: 0.11 lb/MMBtu (30-day rolling average)
Craig Unit 2: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). The 30-day rolling SO2 limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control associated with semi-dry FGD control technology.

Particulate Matter BART Determination for Craig - Units 1 and 2

The Division has determined that the existing Unit 1 and 2 emission limit of 0.03 lb/MMBtu (PM/PM_{10}) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for PM/PM_{10}. The state assumes that the BART emission limit can be achieved through the operation of the existing pulse jet fabric filter baghouses.

NOx BART Determination for Craig - Units 1 and 2

Potential modifications to the ULNBs, neural network systems, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at Craig Units 1 and 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Craig Unit 1 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	779	$3,797,000	$4,877
SCR	4,048	$25,036,709	$6,184

Craig Unit 2 - NOx Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	806	$3,797,000	$4,712
SCR	3,975	$25,036,709	$6,298

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, and hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Craig – Unit 1		Craig – Unit 2	
	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.35		0.35	
SNCR	0.24	0.31	0.23	0.31
SCR	0.07	1.01	0.08	0.94

While potential modifications to the ULNB burners and a neural network system were also found to be technically feasible, these options did not provide the same level of reductions as SNCR or SCR, which are included within the ultimate BART determination for Units 1 and 2. Therefore, these options were not further considered in the technical analysis.

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART is the following NOx emission rates:

Craig Unit 1: 0.070 lb/MMBtu (30-day rolling average)

Craig Unit 2: 0.080 lb/MMBtu (30-day rolling average)

The 0.08 lb/MMbtu limit for Unit 2 was based upon evidence before the AQCC in 2010, and took into consideration both cost and feasibility. Significant progress towards installation of SCR at Unit 2 has been made, and the vendor has guaranteed performance at the 0.08 lb/MMBtu 30-day rolling average NOx limit. Both vendor performance and equipment performance can improve over time, and the Division has determined, and Tri-State has agreed, that Tri-State can achieve a 0.07 lb/MMBtu NOx limit at Unit 1. The state assumes that the BART emission limits can be achieved through the operation of SCR. For SCR at Units 1 and 2, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls above the guidance criteria presented earlier in Chapter 6. The criteria guide the state's general approach to these policy considerations, but are not binding. Therefore, the state deviates from the guidance criteria in this case due to the fact that Tri-State has agreed to achieve the proposed emission rates at Craig Units 1 and 2 and the notable visibility improvements..

- Unit 1: $6,184 per ton NOx removed; 1.01 deciview of improvement
- Unit 2: $6,298 per ton NOx removed; 0.94 deciview of improvement

To the extent practicable, any technological application Tri-State utilizes to achieve these BART emission limits shall be installed, maintained, and operated in a manner consistent with good air pollution control practices for minimizing emissions. Once EPA approves this revision to the Regional Haze SIP, Tri-State will be required to meet the 0.07 lb/MMBtu NOx emission limit by August 31, 2021. Once the revised emission limit is approved, Tri-State will begin the design and development of bid documents, engage in a process to review bids and select a contractor for the multi-year construction project. Based on Tri-State's experience at Unit 2 (where construction and installation of SCR is already underway), and taking into consideration such factors as the weather in Craig, Colorado, the coordination necessary between the various owners of Unit 1, electric utilities and regional entities responsible for the bulk electric system, and compliance deadlines for other similar types of facilities in Colorado, Arizona and Wyoming, the Division has determined that the compliance deadline of August 31, 2021 is as expeditiously as practicable as SCR can be installed at Unit 1. This BART determination is the result of an agreement between Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state to resolve an appeal of EPA's approval of Craig Station –related elements of Colorado's Regional Haze Plan. This BART determination is consistent with the information provided by the FLMs and is supported by the associated visibility improvement information as well as the SCR cost information provided in the SIP materials and otherwise reflected in the 2014 hearing record.

In 2016, based on new information provided from an agreement amongst Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state, the state conducted a BART reassessment for Craig Unit 1. This reassessment evaluates the additional scenarios:

Scenario 1 (Close by December 31, 2025): The first table below assumes an amortization period of four years and four months of operation from the projected compliance date to the date of retirement (December 31, 2025) and that control technology could be installed by August 31, 2021, consistent with the 2014 BART determination. In the second table below, an assumed amortization period of eight years of operation[1] is used since a projected compliance date could occur earlier depending on the alternative selected. Both of these assumed amortization periods change the remaining useful life for the alternatives as Craig Unit 1 will no longer remain in service for the 20-year amortization period used in the 2014 BART determination, depending on the alternative selected[2]. Both of these reduced timeframes change the cost effectiveness for the alternatives as follows:

[1] Operation period begins calendar year 2018 (December 31, 2017).
[2] EPA finalized revisions of the Air Pollution Cost Control Manual (Chapters 1 and 2) in May 2016; these revisions change the amortization period for SCR from 20 years to 30 years. The amortization period for SNCR remains 20 years.

Craig Unit 1 - NO_x Cost Comparisons (assuming four years, four months of operation)			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	779	$6,172,522	$7,928
SCR	4,048	$64,106,699	$15,835

Craig Unit 1 - NO_x Cost Comparisons (assuming eight years of operation)			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	779	$4,755,842	$6,109
SCR	4,048	$41,476,535	$10,245

Based on this assessment, regardless of the amortization period used, both SNCR and SCR are not cost effective when the remaining useful life is shortened, and when considering the remaining BART factors as discussed in Appendix C. For Craig Unit 1, a NOx emission limit of 0.07 lb/MMBtu (2014 BART determination) is BART under a 20 or 30 year remaining useful life.

or;

Scenario 2: A cease coal burning date of August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu applies after August 31, 2021. This scenario (without the inclusions below) is equivalent to the 2014 BART determination.

Both of these scenarios include a 30-day rolling average NOx emission limit of 0.28 lb/MMBtu that will commence on January 1, 2017 (first compliance date January 31, 2017) and be effective until either closure or conversion to natural gas. Additionally, an annual NOx limit of 4,065 tons per year will be effective December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1.

The scenario options under this BART reassessment are the result of an agreement. This reassessment relies on the 2014 BART determination for Craig Unit 1 and supplements that determination to reflect the terms of the agreement. This agreement achieves greater air quality benefits than the 2011 Regional Haze SIP. Both of these scenarios achieve greater NOx reductions and other environmental co-benefits compared to the 2014 BART determination. Consistent with the agreement, Craig Unit 1 will either close on or before December 31, 2025 ***or*** cease burning coal by August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu will apply after August 31, 2021. Effective January 1, 2017 (first compliance date January 31, 2017), Craig Unit 1 will be subject to a NOx emission

limit of 0.28 lb/MMBtu 30-day rolling average until closure or conversion to natural gas. Additionally, an annual NOx limit of 4,065 tons per year will be effective on December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1.

A complete analysis that supports the BART determination for Craig Station Units 1 and 2 and the BART reassessment for Unit 1, including substantial cost information for NOx controls, can be found in Appendix C.

8.5.2 Point Source RP Determinations

The following summarizes the RP control determinations that will apply to each source.

Table 8-2 RP Control Determinations for Colorado Sources

Emission Unit	Assumed** NOx Control Type	NOx Emission Limit	Assumed** SO_2 Control Type	SO_2 Emission Limit	Assumed** Particulate Control and Emission Limit
Rawhide Unit 101	Enhanced Combustion Control*	0.145 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
CENC Unit 3	No Control	246 tons per year (12-month rolling total)	No Control	1.2 lbs/MMBtu	Fabric Filter Baghouse* 0.07 lb/MMBtu
Nixon Unit 1	Ultra-low NOx burners with Over-Fire Air	0.21 lb/MMBtu (30-day rolling average)	Lime Spray Dryer	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Clark Units 1 &2	Shutdown 12/31/2013	0	Shutdown 12/31/2013	0	Shutdown 12/31/2013
Holcim - Florence Kiln	SNCR	2.73 lbs/ton clinker (30-day rolling average) 2,086.8 tons/year	Wet Lime Scrubber*	1.30 lbs/ton clinker (30-day rolling average) 721.4 tons/year	Fabric Filter Baghouse* 246.3 tons/year
Nucla	No Control	0.5 lb/MMBtu (30-day rolling average)***	Limestone Injection*	0.4 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Craig Unit 3	SNCR	0.28 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.15 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.013 lb/MMBtu filterable PM 0.012 lb/MMBtu PM10
Cameo	Shutdown 12/31/2011	0	Shutdown 12/31/2011	0	Shutdown 12/31/2011

* Controls are already operating

** Based on the state's RP analysis, the "assumed" technology reflects the control option found to render the RP emission limit achievable. The "assumed" technology listed in the above table is not a requirement.

*** Nucla Station will close on or before December 31, 2022. Additionally, an annual NOx limit of 952 tons per year will be effective on January 1, 2020 beginning in 2020 on a calendar year basis for Nucla Station.

8.5.2.6 RP Determination for Tri-State Generation and Transmission Association's Nucla Facility

The Tri-State Nucla Station is located in Montrose County about 3 miles southeast of the town of Nucla, Colorado. The Nucla Station consists of one coal fired steam driven electric generating unit (Unit 4), with a rated electric generating capacity of 110 MW (gross), which was placed into service in 1987. Nucla Unit 4 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}) at a facility with a Q/d impact greater than 20. Tri-State Generation and Transmission Association (Tri-State) provided information relevant to RP to the Division on December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

SO2 RP Determination for Nucla – Unit 4

Limestone injection improvements, a spray dry absorber (SDA) system (or dry FGD), limestone injection improvements with a SDA, hydrated ash reinjection (HAR), and HAR with limestone injection improvements were determined to be technically feasible for reducing SO2 emissions from Nucla Unit 4. Study-level information for HAR systems at Nucla or any other EGU in the western United States were not available for use in evaluating costs. Since the option to install a dry FGD alone (even without improving limestone injection) provides a better estimated control efficiency than a HAR system plus limestone injection improvements, the HAR system was not considered further in this analysis.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Nucla Unit 4 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Limestone Injection Improvements	526	$914,290	$4,161
Spray Dry Absorber (dry FGD)	1,162	$7,604,627	$6,547
Limestone Injection Improvements + dry FGD	1,254	$9,793,222	$7,808

A dry FGD system, or limestone injection improvements plus dry FGD system, were eliminated from consideration by the state as unreasonable during this planning period due to: 1) the excessive costs, 2) that they would require replacement of an existing system and installation of a completely new system (with attendant new capital costs and facility space considerations), and 3) the lack of modeled visibility affects associated with these particular SO2 reductions.

There is no energy and non-air quality impacts associated with limestone injection improvements. For dry FGD, the energy and non-air quality impacts include less mercury removal compared to unscrubbed units and significant water usage.

There are no remaining useful life issues for alternatives as the source will remain in service for the 20-year amortization period.

Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis.

Nucla already has a system in place to inject limestone into the boiler as required by current state and federal air permits. This system achieves an approximate 70% SO2 emissions reduction capture efficiency at a permitted emission rate of 0.4 lbs/MMBtu limit. Increased SO2 capture efficiency (85%) with the existing limestone injection as an effective system upgrade, by use of more limestone (termed "limestone injection improvements") was evaluated and determined to not be feasible under certain operating conditions. The system cannot be 'run harder' with more limestone to achieve a more stringent SO2 emission limit; the system would have to be reconstructed or redesigned with attendant issues, or possibly require a new or different SO2 system, to meet an 85% capture efficiency.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that the existing permitted SO2 emission rate for Unit 4 satisfies RP:

Nucla Unit 4: 0.4 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved through the operation of the existing limestone injection system.

PM10 RP Determination for Nucla – Unit 4

The state has determined that the existing regulatory emissions limit of 0.03 lb/MMBtu represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limit is RP for PM/PM_{10}. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

NOx RP Determination for Nucla – Unit 4

Selective non-catalytic reduction (SNCR) was determined to be technically feasible for reducing NOx emissions at Nucla Unit 4. SCR is not technically feasible on a circulating fluidized bed coal-fired boiler, and is otherwise not cost-effective, as discussed in Appendix D. With respect to SNCR, however, there is substantial uncertainty surrounding the potential control efficiency achievable by a full-scale SNCR system at a CFB boiler burning western United States coal. The state and Tri-State's estimates vary between 10 – 40% NOx reduction potential, which correlates to between $3,000 - $17,000 per ton NOx reduced and may result in between 100 to 400 tons NOx reduced per year.

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis. There are several qualitative reasons that NOx controls may be warranted at Nucla. First, NOx control alternatives may result in between 100 – 400 tons of NOx reduced annually. Second, Nucla is within 100 kilometers in proximity to three Class I areas, depicted in the figure above, and within approximately 115 kilometers to five Class I areas, including Utah's Canyonlands and Arches National Parks. Third, Nucla has a limited, small-scale SNCR system for emissions trimming purposes installed.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the State has determined that NOx RP for Nucla Unit 4 is no control at the following NOx emission rate:

Nucla Unit 4: 0.5 lb/MMBtu (30-day rolling average)

Additional Analyses of SO2 and NOx Controls for Nucla

As state-only requirements of this Reasonable Progress determination, the Commission requires, and Tri-State agrees, that Tri-State conduct a comprehensive four factor analysis of all SO2 and NOx control options for Nucla using site-specific studies and cost information and provide to the state a draft analysis by July 1, 2012. A protocol for the four-factor analysis and studies will be approved by the Division in advance. The analysis will include enhancements or upgrades to the existing limestone injection system for increased SO2 reduction performance, other relevant SO2 control technologies such as lime spray dryers and flue gas desulfurization, and all NOx control options. A final analysis that addresses the state's comments shall be submitted to the state by January 1, 2013. By January 1, 2013, Tri-State shall also conduct appropriate cost analyses, study and, if deemed necessary by the state and the source, testing, as approved by the Division, to inform what performance would be achieved by a full-scale SNCR system at Nucla to determine potential circulating fluidized bed (CFB) boiler-specific NOx control efficiencies. By January 1, 2013, Tri-State shall conduct CALPUFF modeling in compliance with the Division's approved BART-modeling protocol to determine potential visibility impacts the different SO2 and NOx control scenarios for Nucla. Finally, Tri-State shall propose to the state any preferred SO2 and NOx emission control strategies for Nucla by January 1, 2013. On December 26, 2012, Tri-State submitted an updated four-factor analysis and visibility modeling to the Division, with the conclusion that limestone for SO2 control and existing SNCR for NOx reduction remained the preferred strategy.

Requirements for Nucla Station

On December 31, 2012, EPA approved Colorado's Regional Haze SIP, including Colorado's Reasonable Progress determination for Nucla Unit 4 (0.5 lb/MMBtu (30-day rolling average)). In 2016, based on new information provided from an agreement amongst Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state, the state conducted a Reasonable Progress review of Nucla. This review adds a requirement of a closure date on or before December 31, 2022 for Nucla Station. Additionally, an annual NO_x limit of 952 tons per year will be effective January 1, 2020 on a calendar year basis beginning in 2020.

These requirements are the result of an agreement. The 2022 closure achieves further NOx reductions and other environmental co-benefits than the 2011 RP determination. Consistent with the agreement and in lieu of being subject to stringent requirements as part of the long term strategy for the second implementation period of Regional Haze, Nucla Station will close by December 31, 2022.

Additionally, an annual NOx limit of 952 tons per year will be effective on January 1, 2020 on a calendar year basis beginning in 2020. Nucla Unit 4 will still comply with the 2011 RP determination of 0.5 lb/MMBtu (30-day rolling average) until closure. A complete analysis that supports the RP determination and review for the Nucla facility can be found in Appendix D.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-58:
Lisa Tiffin 2020 ERP Direct Testimony

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

PROCEEDING NO. 20A-0528E

APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2020 ELECTRIC RESOURCE PLAN

DIRECT TESTIMONY AND ATTACHMENTS OF LISA K. TIFFIN ON BEHALF OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

December 1, 2020

Colorado PUC E-Filings System

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ATTACHMENTS

Attachment LKT-1	Curriculum Vitae of Lisa K Tiffin

GLOSSARY

Term	Meaning
ARIMA	Auto-Regressive Integrated Moving Average
AQCC	Colorado Air Quality Control Commission
BA	Balancing Authority
BE	Beneficial Electrification
BEA	U.S. Department of Commerce Bureau of Economic Analysis
CAISO	California Independent System Operator
CDPHE	Colorado Department of Public Health and Environment
CEP	Clean Energy Plan
EIA	Energy Information Administration
ERP	Electric Resource Plan
GHG	Greenhouse Gas
PNM	Public Service Company of New Mexico
RAP	Resource Acquisition Period
RES	Renewable Energy Standard
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
RUS	Rural Utilities Service
SAE	Statistically Adjusted End-Use
SIP	State Implementation Plan
SPP	Southwest Power Pool
WEIM	Western Energy Imbalance Market
WEIS	Western Energy Imbalance Service
W&P	Woods & Poole Economics, Inc.
WAPA	Western Area Power Administration

A: While the Commission need not consider New Mexico's RPS when evaluating Tri-State's Colorado ERP, Tri-State operates an integrated, interconnected, interstate generation and transmission system that must meet the legislative and regulatory requirements of all of the states in which it is located. Tri-State must ensure that its system and associated resources comply with Colorado's and New Mexico's relevant laws and regulations.

Q: IS TRI-STATE'S 2020 ERP CONSISTENT WITH ALL STATE AND FEDERAL LAWS RELATED TO RENEWABLE STANDARDS?

A: Yes. As described in Volume I, "Base Case and Alternative Scenario Comparison" and in Volume II Attachment 6-2 of the ERP, Tri-State is exceeding the requirements of both the Colorado RES and the New Mexico RPS.

XIII. COSTS AND BENEFITS OF EARLY RETIREMENTS

Q: HOW WERE THE ANNOUNCED EARLY RETIREMENT DATES OF CRAIG UNIT 1, CRAIG UNIT 2 AND CRAIG UNIT 3 DEVELOPED?

A: The owners (Yampa Participants) of Craig Unit 1 will retire Craig Station Unit 1 by December 31, 2025, as is required by the current Colorado Regional Haze State Implementation Plan. The Yampa Participants also agreed to a September 30, 2028, retirement date for Craig Unit 2. December 31, 2029, was selected as the retirement date for Craig Unit 3 in order to meet carbon reduction goals in 2030.

Q: DID TRI-STATE CONSIDER THE COSTS AND BENEFITS OF EARLY RETIREMENTS OF GENERATION RESOURCES?

A: Yes. In all scenarios, including the base case, Tri-State modeled the previously announced early retirements of Escalante, Craig Unit 1, Craig Unit 2 and Craig Unit 3. In each scenario except the base case, Tri-State enabled modeling consideration of retirement of coal resources prior to their planned early retirement dates or, as applicable, prior to the end of their useful life. In the social cost of carbon scenario, Tri-State enabled modeling consideration of both coal and gas retirements prior to end of useful life or scheduled retirement date. Assumptions related to retirements, which varied by scenario, are outlined in Volume I "Base Case & Alternative Scenario Results" section of the ERP.

Q: HOW DOES THIS ANALYSIS RELATE TO THE BENCHMARKING ANALYSIS YOU DESCRIBED EARLIER IN YOUR TESTIMONY?

A: Whereas the benchmarking analysis is intended to provide information regarding the relative performance of Tri-State's resources compared to generic resources, it does not specifically consider early retirements. Instead, the benchmarking analysis informs the consideration of early retirements by providing information on generation units that may be underperforming.

XIV. ASSESSMENT OF NEED FOR ADDITIONAL RESOURCES

Q: PLEASE DESCRIBE TRI-STATE'S APPROACH TO ASSESSING ITS NEED FOR ADDITIONAL RESOURCES.

A: Tri-State's assessment of the need for additional resources is driven by a number of factors, including early retirement of existing fossil units; Utility Members' load forecasts; RES/RPS requirements; potential for growth in demand-side management and energy efficiency; regulations addressing carbon emissions; implementation of beneficial electrification; and Tri-State's entry into an organized market.

Q: PLEASE DESCRIBE TRI-STATE'S PLANNED RETIREMENTS OF EXISTING RESOURCES.

A: Tri-State retired the Escalante Generating Station in November 2020. Tri-State has announced planned retirements of Craig Unit 1 by December 31, 2025, Craig Unit 2 by September 30, 2028, and Craig Unit 3 by December 31, 2029. Craig Unit 1 and Unit 2 are owned by the Yampa Participants, and the retirement decisions were made jointly by the participants.

Q: PLEASE DESCRIBE THE IMPACT OF TRI-STATE'S LOAD FORECAST ON THE ASSESSMENT OF RESOURCE NEEDS.

A: Tri-State's load forecast of peak demand and firm peak obligations, together with losses and reserve requirements, are compared to existing resources, while accounting for planned retirements and contract expirations, to determine system balance capacity needs.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-59:
Intertek Reliability Study

intertek
Total Quality. Assured.

Update of Reliability and Cost Impacts of Flexible Generation on Fossil-fueled Generators for Western Electricity Coordinating Council

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1 | Introduction

The addition of variable generation (VG) places new constraints and costs on conventional generation of power in utility systems, particularly due to an increase in the variability and uncertainty associated with VG. There is a need to include the change in reliability and cost of operating fossil-fueled power plants with operating patterns that include increased generator flexibility.

Fossil-fueled power plants operated in flexible mode are likely to have increased wear and tear on the equipment and/or reliability impacts that do not necessarily occur if the plants were run in baseload operation mode. This is particularly true for power plants designed for baseload operation. A power plant designed for baseload operation typically operates at full load for long periods of time between cold shutdowns. Critical components operate at design temperatures, with temperature imbalances which occur only at that load. Startups and shutdowns are infrequent, and the load ramp rates consistent, so fatigue damage is less of a concern.

Flexible or cycling operation, on the other hand, requires several different modes of operation: two-shifting, load following, and low load operation, as well as frequent startups (hot, warm, and cold), faster ramp rates, and more thermal cycles than originally designed for. Temperature imbalances may be exacerbated by operation at non-optimum, non-design loads. Temperature differences between components may cause flexibility issues and subsequent fatigue damage.

The Western Electricity Coordinating Council (WECC) and the Production Cost Model Data Work Group are seeking to update the estimate of the cost of flexible generation and reliability impacts on the conventional fossil-fueled generators for operation in calendar year 2030.

Intertek AIM (previously Aptech Engineering Services) had provided an estimate of increased wear and tear costs and reliability impacts to WECC [Intertek Project AES 11077831-2] and National Renewable Energy Laboratory (NREL) [Contract No. DE-AC36-08GO28308].[1]

In our previous study, Intertek AIM had organized the results by the following eight generator plant types in the following eight groups:

1. Small coal-fired sub-critical steam (35-299 MW)
2. Large coal-fired sub-critical steam (300-900 MW)
3. Large coal-fired supercritical steam (500-1300 MW)
4. Gas-fired combined-cycle plants (combustion turbine (CT)-steam turbine (ST) and heat recovery steam generators (HRSG)
5. Gas-fired simple cycle large frame (GE 7/9, N11, V94.3A, and similar types)
6. Gas-fired simple cycle Aero-Derivative CT (LM 6000, 5000, 2500)
7. Gas-fired steam (50-700 MW)
8. Retrofitted coal-fired steam (plants retrofitted to provide load following or regulation) – these plants should be parsed by size/type same as Types 1 through 7.

[1] https://www.nrel.gov/docs/fy12osti/55433.pdf

The primary task of the study included the estimation of "lower bound" cycling cost data for the above identified groups of generator plant types, including the following:

- Hot, warm, and cold start costs
- Baseload variable operations and maintenance (VOM) costs

Figure 1 was a key output of the analysis showing the spread of cycling-related costs.

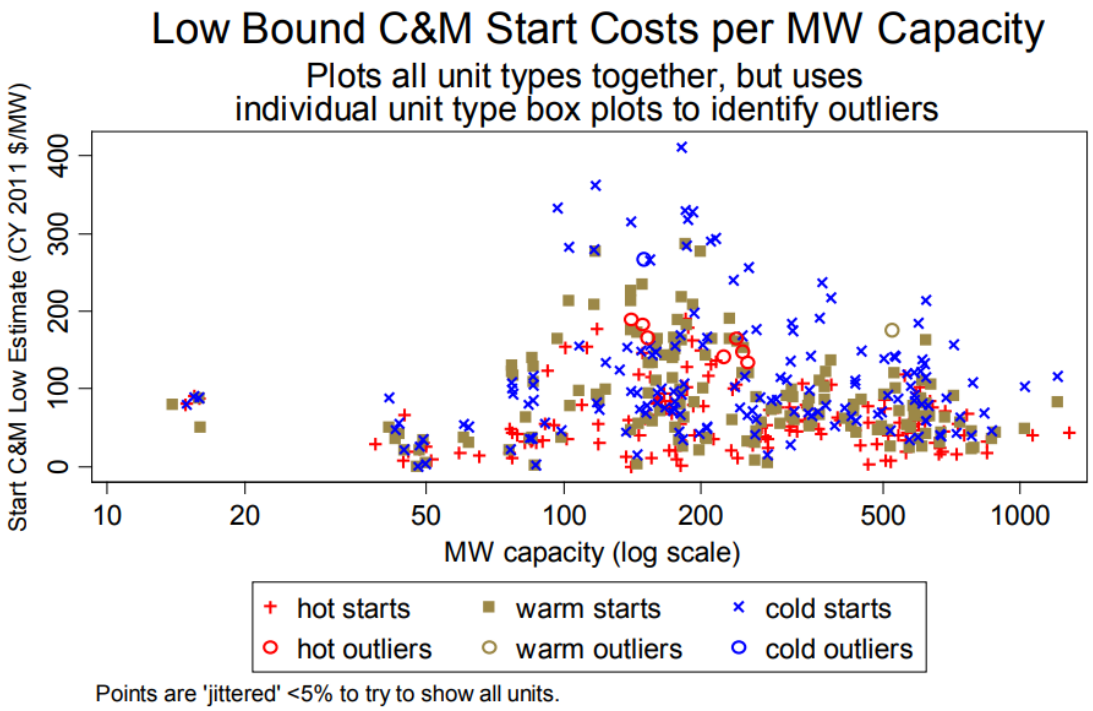


Figure 1 — Lower Bound – Capital and Maintenance Start Costs per MW Capacity.

Background

Since Intertek AIM and WECC collaborated on this work in 2011, several changes have occurred with respect to power plant operating profiles and technologies. Further, different regions in the U.S. have witnessed different outcomes from the integration of VG.

A combination of market deregulation, increasing VG, changes in fuel prices, and other factors have forced operators to cycle aging fossil units that were originally designed for mainly base load operation. As shown in previous studies, all fossil generators can perform cycling operation, but the impact of cycling on wear and tear cost or damage and the reliability of the plants from the cycling differs from one unit to another (see figure 1).

Intertek AIM has performed evaluation of the evolving operating regime of several hundred power plants in the U.S.[2] As an example, Figure 2 shows the change in operating mode of the fossil generation fleet in California from 2005 to 2015. The change in operating profile is largely driven by the rapid increase in solar generation in the state. Solar generation in the state forces the natural gas fleet in California (about 40% of capacity) to operate with increased cycling. Fossil units are staying offline for more hours in 2015 compared to 2005, and when they are online, they typically ramp up to full load (as solar generation falls at night). There is also a trend of increased operating hours at lower loads in 2015 versus 2005.

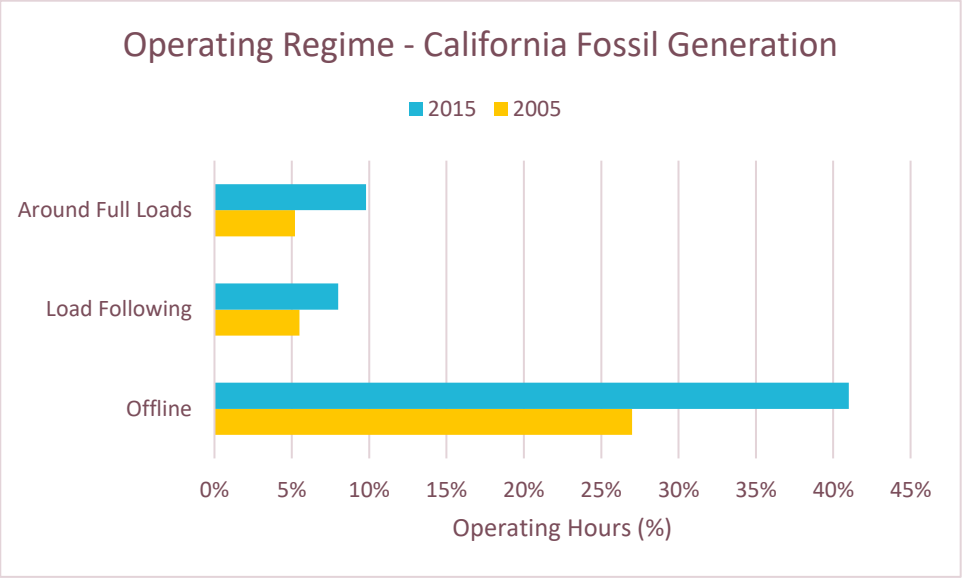


Figure 2 — Operating Regime of California Fossil Generators (2005 vs. 2015).

Characterizing fossil power generation impacts from large VG on the grid requires an understanding of the operating regime of the power plants. Further, the analysis should cover a long enough time horizon to account for the "time lagged" wear and tear damage on fossil generation equipment. When a power plant is relatively new, there is a much larger time lag between increased cycling and failures, compared to an older plant[3]

Flexible generation or cycling refers to the operation of electric generating units at varying load levels, including on/off and low load variations, in response to changes in system load requirements. Every time a power plant is turned off and on, the boiler, steam lines, turbine, and auxiliary components go through unavoidably large thermal and pressure stresses, which cause damage. This damage is made worse by the phenomenon we call creep-fatigue interaction. Creep and fatigue are terms commonly used in engineering mechanics. Creep is time-dependent change in the size or shape of a material due to constant stress (or force) on that material. In fossil power plants, creep is caused by continuous stress that results from constant high temperature and pressure in a pipe or tube occurring during

[2] Impact of Large-Scale Wind & Solar Integration on Existing Fossil Generation in United States, N. Kumar et al., 15th Wind Integration Workshop, Vienna (2016)
[3] "Power Plant Cycling Costs," N. Kumar et al. http://www.nrel.gov/docs/fy12osti/55433.pdf.

steady-state base load operation. Fatigue is a phenomenon leading to cracking and possible fracture (failure) when a material is under repeated, fluctuating stresses. In a fossil power plant, such fluctuating stresses result from large transients in both pressures and temperatures. The worst of these transients typically occur during cyclic operation. Because base load fossil units are designed to operate in the creep range, they experience increased outages when they are additionally subjected to cycling-related fatigue. The term creep-fatigue interaction suggests that the two phenomena (creep and fatigue) are not necessarily independent, but act in a synergistic manner to cause premature failure. In fact, materials behave in a complex manner when both types of stresses occur.

Relating this discussion to power plants, if an older, base loaded plant (that used to have three to six starts per year and is at 40 to 80% design life from creep damage) is now suddenly dispatched to operate at 50 starts per year, it may take only 2 to 6 years to cause component failures. Thus, while cycling-related increases in failure rates may not be noted in the first months, critical components will eventually start to fail. Shorter component life expectancies will result in higher plant equivalent forced outage rates (EFOR) and/or higher capital and maintenance costs to replace components at or near the end of their service lives. In addition, cycling increases may result in reduced overall plant life. How soon these detrimental effects will occur will depend on the amount of creep damage present and the specific types and frequency of the cycling.

As a power plant ages, the equipment degrades even though it is maintained and inspected and is unable to perform as well as brand new equipment. It becomes necessary to upgrade or replace degraded equipment to "new condition". For example, even though condensers are cleaned annually or more often, condenser retubing becomes necessary every 10 or 15 years. In other words, maintenance is necessary to minimize the effect of equipment degradation with age and operating regime. With cycling operation, some components face accelerated life degradation from the effects of aging and the off-design operations.

Capital expenses, as well as variable and fixed operations and maintenance (O&M) costs at a generating facility, can be analyzed to assess maintenance and equipment replacements at a power plant and determine the current condition. Costs associated with plant cycling and the impact of the cycling on reliability can also be gauged and quantified. Plants that have underspent on capital and/or O&M are likely to suffer with lower historical reliability or are at risk of future forced outages.

The unit's specific analysis results depend heavily on the regression analysis of the costs versus cycles and the unit signature data during cyclic operations including the range of all load changes. A comprehensive methodology to determine the cost associated with plant cycling has been discussed in recent renewable integration studies.

The increased incremental costs that are attributed to cycling are broken down into the following categories[4]:

1. Increases in maintenance and overhaul capital expenditures.
2. Forced outage effects including forced outage time, replacement energy, and capacity.

[4] Lew, D.; Brinkman, G.; Ibanez, E.; Florita, A.; Heaney, M.; Hodge, B.-M.; Hummon, M.; Stark, G.; King, J.; Lefton, S.A.; Kumar, N.; Agan, D.; Jordan, G.; Venkataraman, S. (2013). The Western Wind and Solar Integration Study: Phase 2. NREL/TP-5500-55588. Golden, CO: National Renewable Energy Laboratory. Accessed May 2, 2014: http://www.nrel.gov/docs/fy13osti/55588.pdf.

3. Efficiency, both long-term losses as well as operational losses associated with startups and low/variable loads.
4. Cost of startup fuel, auxiliary power, chemicals, and extra startup manpower.

Report Goals

WECC's Production Cost Model Data Work Group required Intertek AIM to update the cost and reliability impacts estimated in the 2012 study for modes of operation in calendar year 2030.

The following technical approach was used to quantify the wear and tear cost impacts:

- Characterize historical operations of thermal units within WECC.
- Evaluate and control for recent and projected power plant Capital Expenditures (CapEx) and Operating Expenditures (OpEx)
- Calculate changes to cycling duty and the potential impacts on wear and tear costs, as well as reliability impacts.

The results presented in this report include the following generation types:

1. Small coal-fired sub-critical steam (35-299 MW)
2. Large coal-fired sub-critical steam (300-900 MW)
3. Large coal-fired supercritical steam (500-1300 MW)
4. Gas-fired steam (50-700 MW), includes both supercritical and subcritical technologies
5. Gas-fired simple cycle large frame (GE 7/9, N11, V94.3A, and similar types)
6. Gas-fired simple cycle Aero-Derivative CT (LM 6000, 5000, 2500). New data set to include, New Fast Start Gas Turbines – Aero-Derivative (LMS 100 and similar)
7. Gas-fired combined-cycle plants (CT-ST and HRSG) – Conventional[5]
8. Gas-fired combined-cycle plants (CT-ST and HRSG) – High Efficiency Gas Turbines (H Class and Similar)
9. Gas-fired combined-cycle plants (CT-ST and HRSG) – Fast Start
10. Gas Reciprocating Engines

Intertek AIM has limited the sample size of units to the Western Interconnect where reasonable; however, we have included other U.S.-based power plants if sample size is small.

[5] F-Class based machines. F-class turbines are typically in the 170-230 MW range. Products include GE's 7F.03-.05 models, Siemen's SGT6-5000F, and Mitsubishi Hitachi's M501F

The results of the projected 2030 cost of cycling and reliability impacts will be provided in the following format:

- **Hot, Warm, and Cold Start Costs**

  Costs per start for hot, warm and cold starts (2020$).

  Physical Constraints: Intertek AIM will also provide typical ramping capabilities, minimum up and down time, startup time for the different generation technologies, and the corresponding cost impacts.

- **Load Following Costs**

  Costs for various load following modes – mild, significant, and operation at minimum load (2020$).

  Minimum load operation to be evaluated may be at approximately 80%, 50%, and 30% of maximum load. Generation technologies that are unable to operate below any minimum load operation described above will be noted. These costs will inherently include all cycling-related costs (except forced outage costs).

  Physical Constraints: Ramping capabilities at various low loads will be listed, including cost impacts.

- **Base-loaded Variable O&M Costs**

  Intertek AIM determines the cycling-related O&M cost (listed above) and subtracts that from the total O&M costs to generate a baseload VOM cost. These costs assume a power plant running at steady load without any on/off cycling. This will ensure no double counting of VOM costs in WECC's production cost modeling.

- **Reliability Impacts**

  While cycling, increases in failure rates may not be noted immediately, critical components will eventually start to fail. Shorter component life expectancies will result in higher plant EFOR and/or higher capital and maintenance costs to replace components at or near the end of their service lives. Intertek AIM will provide the expected "lower-bound" increase in EFOR (in added percentage for a single year) due to each cycle type.

2 | Flexible Generation Costs and Reliability Impacts

Calculated cycling costs for typical load cycles of any power plant unit are recorded by Intertek AIM as the total present-valued future cost of the next "incremental" cycle.

These numbers are best estimates based on the assumption that the overall amount of cycling (i.e., equivalent hot start (EHS) per year) continues at no more than 75% of the level of past operations. If the amount of cycling of a given unit increases dramatically, the cost per cycle would also increase due to nonlinear creep-fatigue interaction effects.

However, if CapEx and OpEx spend is reduced for any reason, such as an impending retirement of the asset, then the net cost of cycling is reduced. The reduced spend will manifest as reduced reliability. Such trends have been observed at other sites assessed by the author.[6]

Basic Premise

Maintenance requirements are based on an assessment of hours of operation or cycling of a unit (besides any reactionary events). Major costs for each inspection are for labor, consumables, and capital replacement parts. Labor is the extra manpower needed to perform the inspection. The consumables are material which will be used during the inspection or maintenance activity, such as gaskets, welding products, etc. Capital replacement parts are the parts that are examined for corrosion and wear during each inspection. Generally, the capital replacement costs dominate the overall ratio of costs, as this is primarily to counter for the life shortening effects of aging or additional cycling.

Cost is one of the key factors influencing the choice of fuels and technologies used to generate electricity. Capital, maintenance, operating, and financing costs often vary significantly across technologies and fuels. In addition, regional differences in construction, fuel, transmission, and resource costs mean that location also matters. Because electricity prices differ throughout the day, the timing of a plant's output affects its cost recovery.

The underlying premise of Intertek AIM's approach is that cycling directly causes a significant proportion of annual non-fuel unit costs. For economic modeling, the independent cycling-related variable was taken to be equivalent hours of operation.

Costs per Start

The desired result is an estimate of the cycling cost elements combined to determine the effect of an additional equivalent start. Intertek AIM's methodology brings all future forecasted costs to their present value using the client's discount rate, cost escalation factor (or simply inflation rate), and aging effects.

[6] Cochran, Jaquelin, Debra Lew, and Nikhil Kumar. Flexible Coal: Evolution from Baseload to Peaking Plant. NREL, 2013 https://www.nrel.gov/docs/fy14osti/60575.pdf

The present value of future wear and tear cycling costs for the plant equipment is the sum of two components: added costs and accelerated costs:

- Specifically, the first component, adding costs, is the cost of extra cycling-related maintenance necessary to avoid shortening of the component's life caused by an additional start.

- The second component, accelerated costs, is the cost of "moving up" future maintenance costs in time (i.e., maintenance costs occur sooner) caused by adding one "start". Adding a "start" to a unit's operation will cause the time required before maintenance is needed to decrease. Thus, this second component represents the present value of the acceleration of costs incurred for ordinary maintenance costs due to an additional start, especially overhaul costs and other large non-annual costs.

Further, it is important to highlight the impact of life shortening as a result of increased flexible operation. Increased cycling can have a significant life-shortening impact on certain units. This cost element can be significant for units that are near their end-of-life, but less important in cases of planned retirements. Note that as long as capital and maintenance expenditures are made to counter cycling effects, this cost element will be small compared to such costs as maintenance and extra fuel. In other words, the cost of maintenance is essentially countering the effects of life shortening over time.

It is important to note that since not all subsystems have the same life expectancy; targeted spending patterns for critical subsystems are required. Intertek AIM looks at both total spending and spending patterns to determine if current and projected critical subsystem spending is enough to maintain efficiency and reliability.

Table 1 provides definitions of costs included in the wear and tear estimates.

Table 1 — Definitions of the Cycling-related Costs

	Cost Includes	Cost Excludes
Cost of O&M	• Operator non-fixed labor • General engineering and management cost (including planning and dispatch) • Maintenance and overhaul maintenance expenditures (preventative and scheduled) for boiler, turbine, generator, air quality control systems, and balance of plant key components	• Fixed labor • Fixed maintenance and overhaul maintenance expenditures for boiler, turbine, generator, air quality control systems, and balance of plant key components • Preventative maintenance and routine maintenance on auxiliary equipment like buildings, HVAC, etc.
Cost of Capital Maintenance	• Overhaul capital maintenance expenditures for boiler, turbine, generator, air quality control systems, and balance of plant key components	• Replacement due to obsolescence • Preventative maintenance and routine maintenance on auxiliary equipment like buildings, HVAC, etc.

Damage Modeling & Cost Estimation

Intertek AIM's full comprehensive top-down and bottom-up methodologies for estimating cycling costs provide better and high confidence estimates, which require extensive cost and operational data. That approach models the relationship between total cycling costs (wear and tear, EFOR, startup costs, etc.) and historical cycling operations for the unit or plant. To set up and run a complete cost of cycling program, we require 8 to 10 years of cost and hourly megawatt and plant reliability data as a minimum. In the absence of these required considerable data, we have found that a reasonable (though less accurate) method is to "benchmark" or measure the cost estimates from those units against those from similar units previously analyzed for which we have completed the more rigorous cost estimate methodology with detailed information.

Figure 3 shows the overview of our process to estimate lower bound cycling costs.

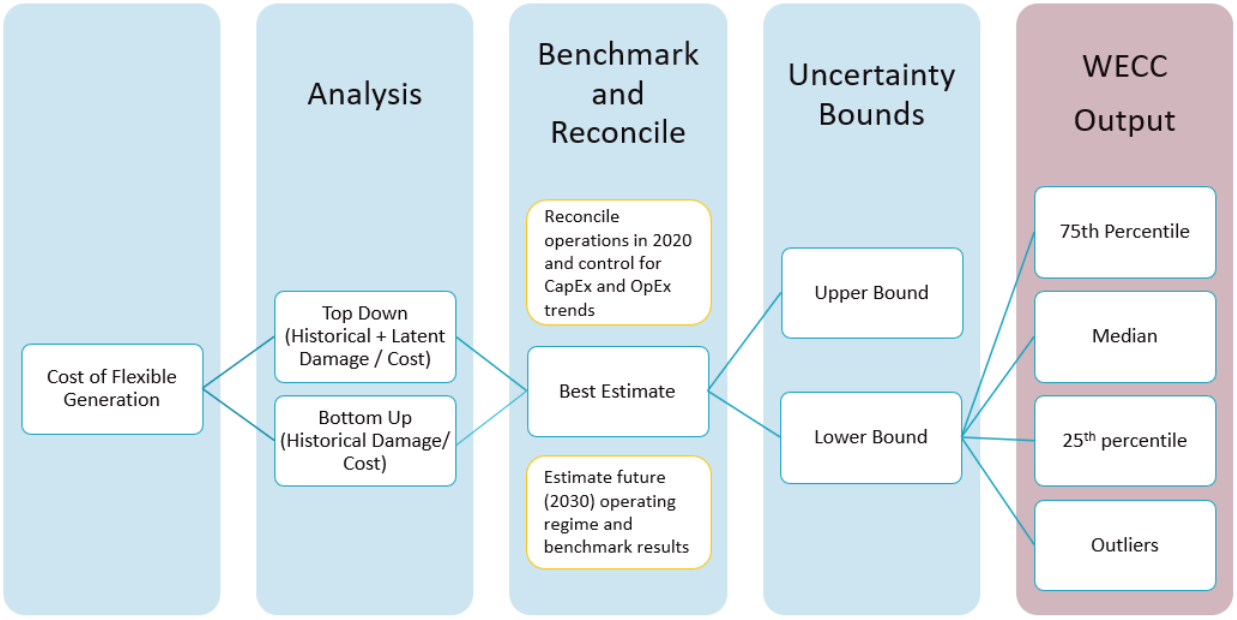


Figure 3 — Lower Bound Cost Estimation Methodology.

To establish the reference unit cycling costs, we used our top-down methodology. We used elaborate statistical models to develop "lower bound" estimates of the total unit equipment damage costs due to cycling, which include the incremental wear and tear costs and the capitalized maintenance and O&M costs in the full-blown, top-down cost of cycling analysis. The results of these statistical analyses are then used as benchmarks for calculating the cycling costs presented in this report.

The control variables in our benchmarking approach are listed below:

- Size — We defined size by the megawatt capacity of generators for the unit (for combined-cycle units, we sum the capacities of the ST and gas turbine(s)).

- Cycling rate and age — These factors account for unit age and for differing annual and cumulative rates of cycling damage expressed in EHS, as measured using Intertek AIM's damage algorithm – Loads Model[7].
- Vintage and design characteristics — Some technologies are better suited to operate flexibly (example, gas turbines or reciprocating engines).
- Typical cycle damage ratio (in units of EHS per cycle) — The ratio of the average damage for the subject unit's start or load follow to that of the benchmark unit; again, as estimated using the Loads Model, the cycle ratios for each start type (hot, warm, and cold) and load follow are considered, along with typical load follows.
- Annual plant maintenance costs — Plant maintenance and capitalized maintenance costs of benchmarked units were compared to the top-down reference unit costs.
- Reliability — Flexible operation, as well as aging of equipment, influence reliability.

Operating Profile of Different Generation Technologies

An important step in estimating cycling costs and reliability impacts is to characterize the operating regime of the 10 groups of generation technologies. The next series of charts shows the operating regime of the coal steam and combined-cycle generation technologies over a 20-year horizon. Highlights from the analysis are:

- On average, the coal steam units have not witnessed increases in on/off cycling; however, they are operating with increased load following. Figures 4 and 5 highlight the operation of the sample of subcritical coal units within WECC. Evidently both the large and small coal units are operating more hours at lower loads in the recent years, and while the number of starts has not trended higher, when the units do go offline, they stay off for longer periods (cold starts).
- Simple cycle CTs continue to perform as peaking units, with low capacity factors. The generation peaks in the summer months as expected and shown in Figure 6.
- The combined-cycle fleet, with lower natural gas prices and a growing share of the overall grid capacity have transitioned to more baseload operation. Figure 7 shows the annual starts for a sample of conventional combined-cycle, newer high efficiency and fast start combined-cycle units.

[7] An EHS is Intertek AIM's unit of cycling intensity. One normal hot start and shutdown cycle would produce about one EHS. One abrupt hot start with especially damaging ramp rates and other load range characteristics would produce well over one EHS, as would most warm starts and all cold starts. The usually more numerous load follow cycles each typically produce a small fraction of an EHS.

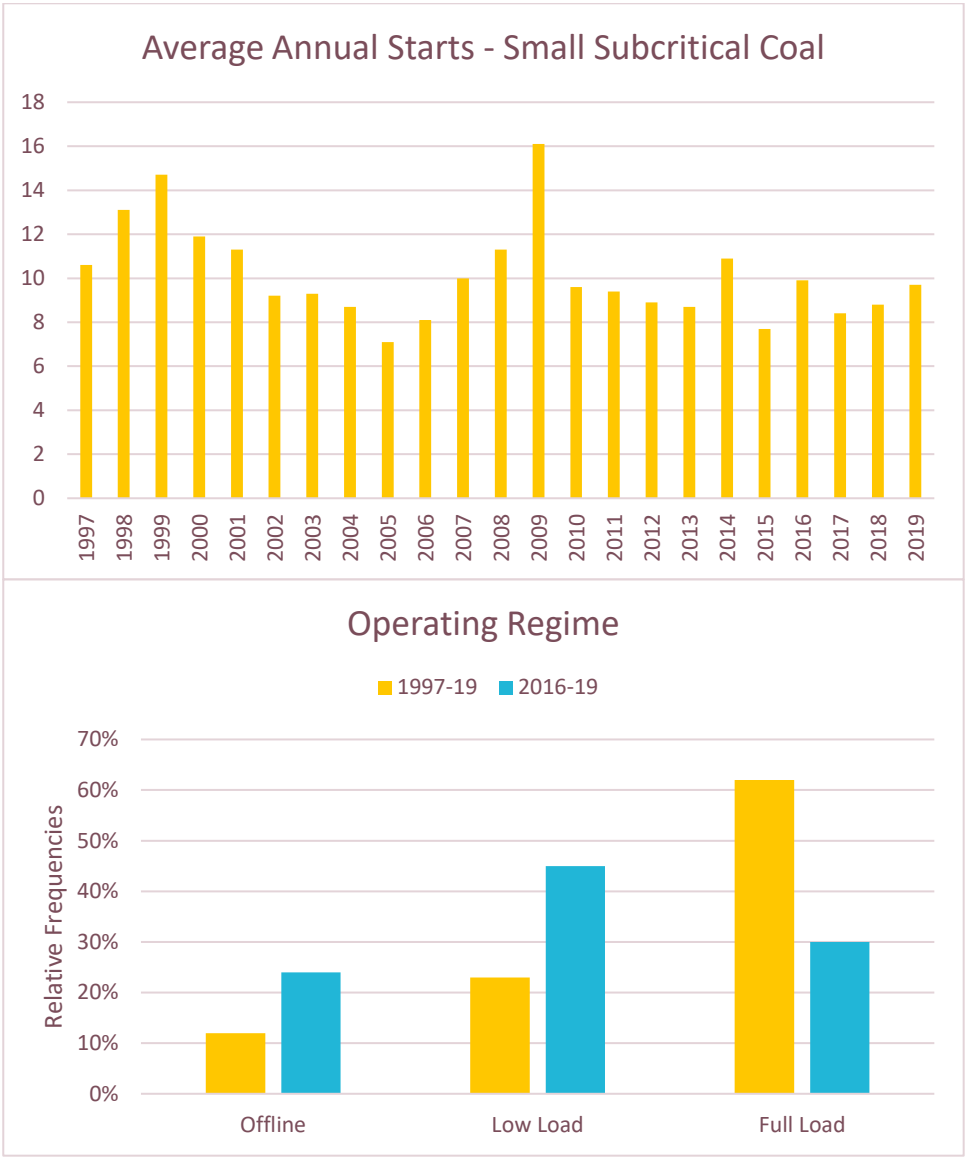


Figure 4 — Small Subcritical Coal (<300 MW) Operating Regime.

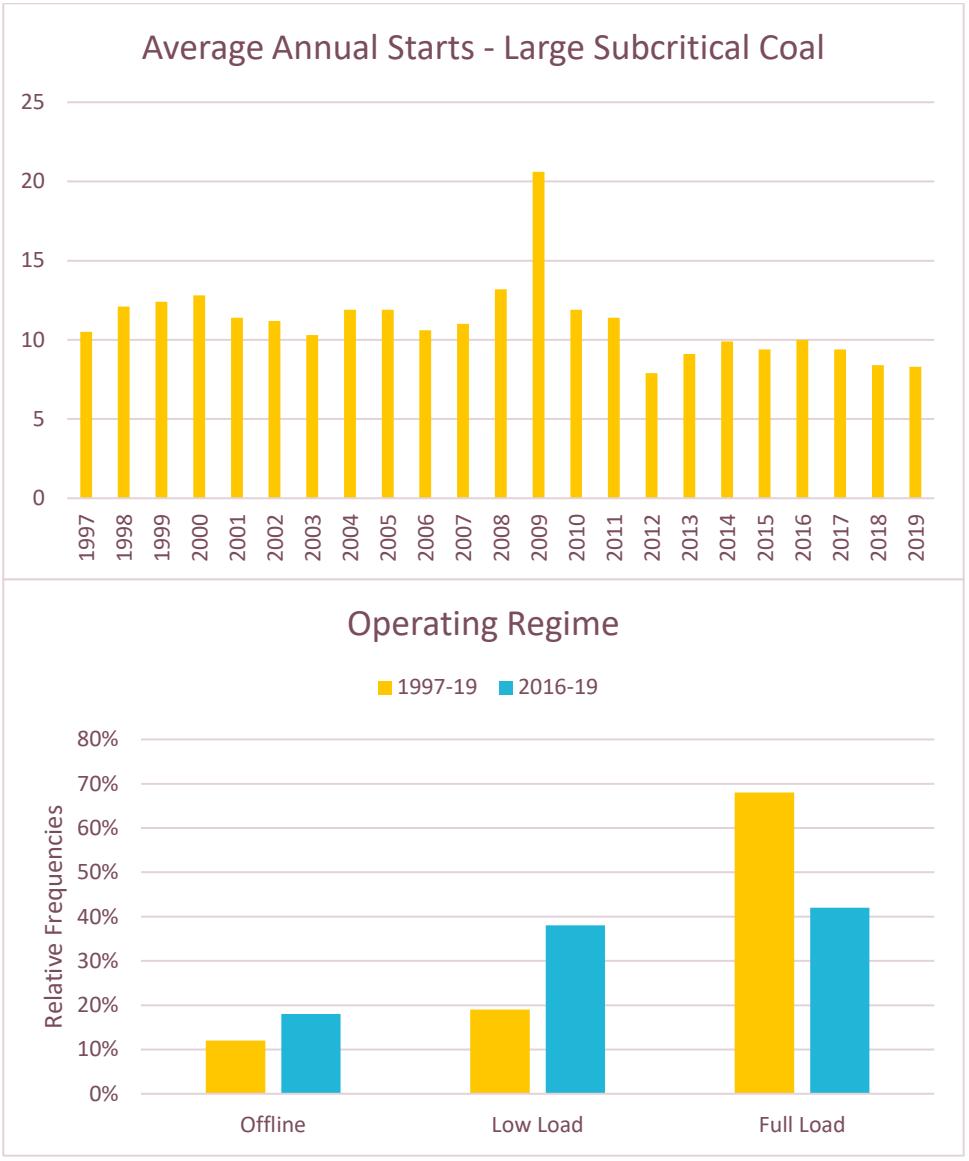


Figure 5 — Large Subcritical Coal (>300 MW) Operating Regime.

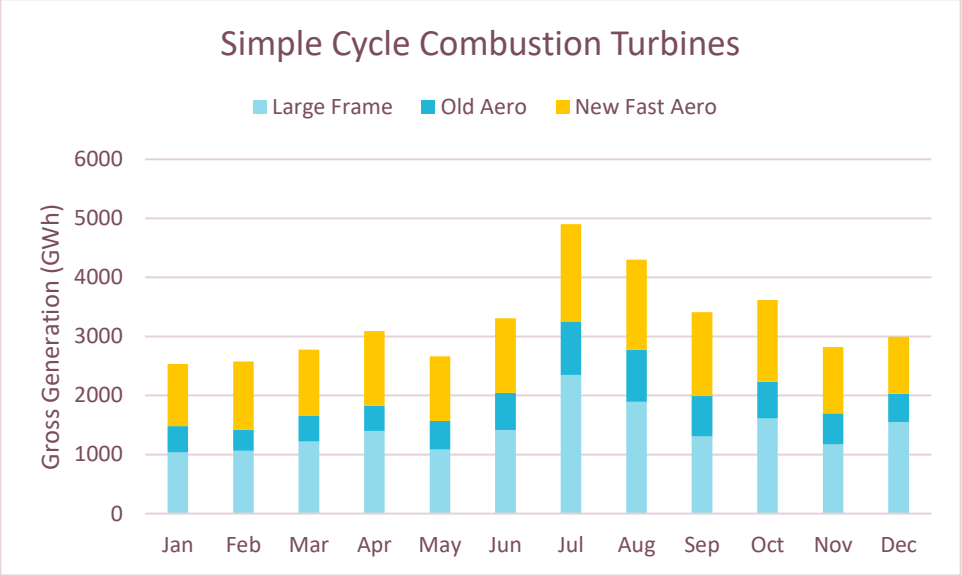


Figure 6 — Simple Cycle CT Monthly Operating Regime.

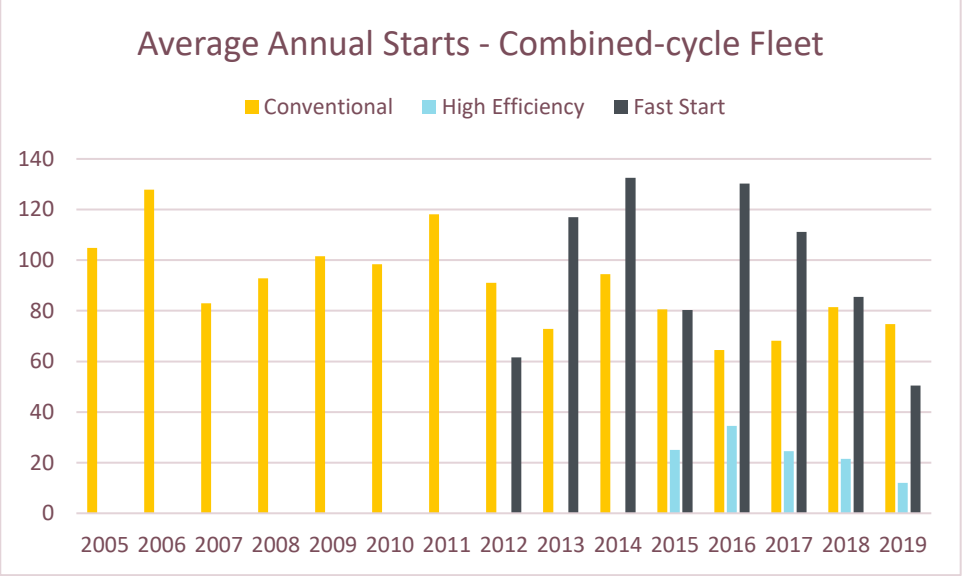


Figure 7 — Annual Starts – Combined-cycle Fleet.

Flexible Generation Impacts and Results

Power plant operations that start, stop, cycle, two shift, base load, and operate above a unit's rating have a quantifiable impact on component life and on total associated unit operating costs. The true costs of cycling and low load operations are often not known or not well understood because of the complex effects of these operations on additional capital and/or maintenance spending requirements, increased EFOR, increased heat rate, and reduced life effects.

Figure 8 shows a risk chart from a small sample of units that show a relation between cycling and forced outage rates. To help reduce the clutter in the chart, some key units have been highlighted to illustrate the impact of cycling on forced outage rates for different design units[8].

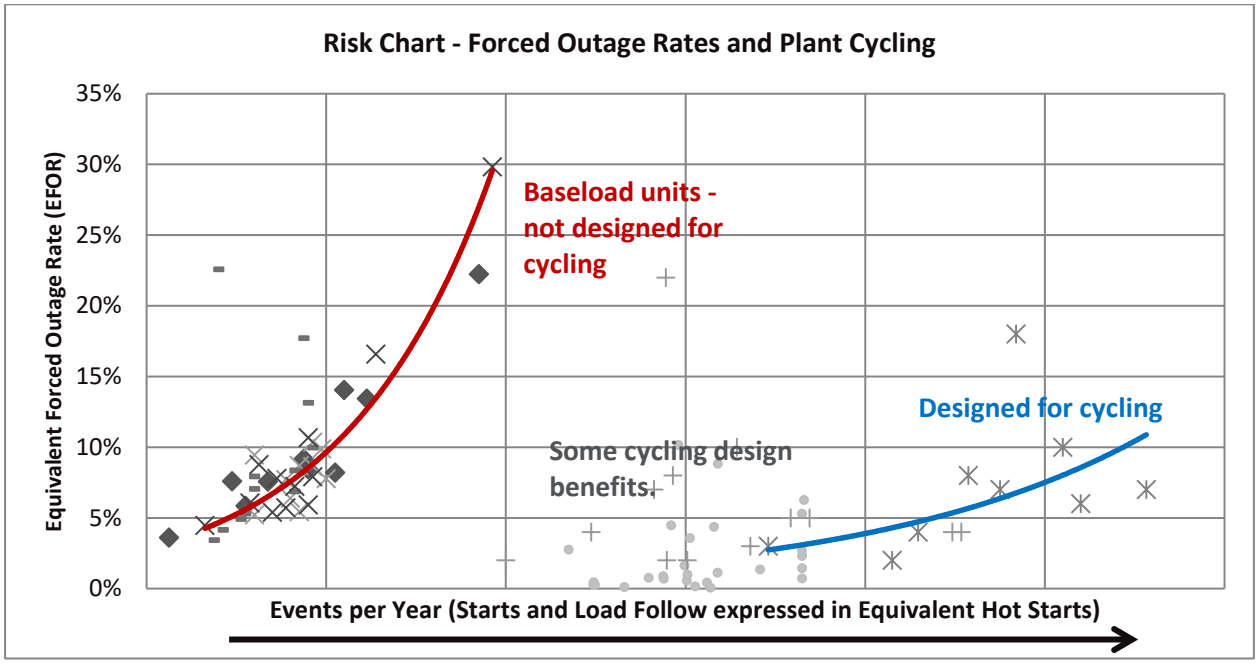


Figure 8 — Flexible Generation and Reliability Impacts.

Even when a unit is thought to be properly designed for cycling, there are external effects in the balance-of-plant design, water chemistry, etc., that make some units more susceptible to cyclic damage than others.

Another risk factor for an aging fleet of fossil generators is High Impact Low Probability (HILP) events. With increased cycling and an aging plant, operators of older assets, conventional steam as well as older combined-cycle units, are putting the units at increased risk of increased forced outages and HILP events. Older units have a much higher chance of experiencing HILP-related forced outages. Figure 9 shows hazard rates for aging power plants. Intertek AIM analyzed NERC GADS data and defined a HILP as a full forced (i.e., unplanned) outage greater than 350 hours.[9]

[8] Impact of plant cycling on availability, N. Kumar et al., ASME Power 2015, POWER2015-49359
[9] Impact of Aging on Power Plant Reliability, N. Kumar and P. Besuner, Intertek Engineering Technical Paper 214

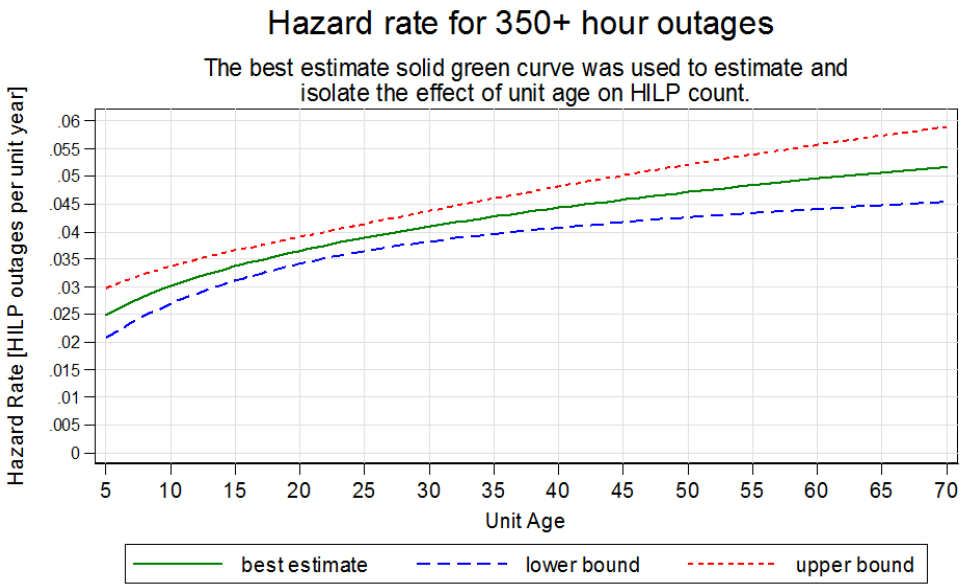


Figure 9 — Hazard Rate for HILP Outages.

Costs associated with plant cycling and the impact of the cycling on reliability can also be gauged and quantified. As a power plant operates with increased cycling and ages, the equipment degrades even though it is maintained and inspected and is unable to perform as well as brand new equipment. It then becomes necessary to upgrade or replace degraded equipment to "new condition."

Increased maintenance spend is necessary to minimize the effect of equipment degradation with age and changing operating regime. Plants that have underspent on capital and/or O&M are likely to suffer lower historical reliability or are at greater risk of future forced outages. As discussed earlier, Intertek AIM assessed the existing fleet operations within WECC to estimate accumulated cycling damage, and then benchmarked cost of flexible generation to reference units in our database. Over time, most North American operators have tended to minimize O&M spend.

Figure 10 shows the historical trend of real O&M for all plants and weighted by generation has decreased from 1990-2005 and has leveled out in recent years. Highlights of our analysis are discussed below: [10]

- While O&M spending is levelling off, capital costs are much higher than any other costs covered in our analysis. Essentially, even with extensive maintenance, the performance of the equipment will deteriorate over time to the point where it must be replaced.
- Coal power plant O&M has not been very high but there are some signs of increased coal O&M among the oldest plants. This tendency to keep O&M costs down for coal plants may also explain Intertek AIM's observation and analysis of increased forced outages with age.
- Combined-cycle units tend to have lower O&M spend, particularly in recent years.

[10] Power Plant O&M Spend in U.S. – Trends and Impact, N. Kumar & P. Besuner Intertek Technical Paper 305

- There are observed variations in O&M costs by state. California is an exception to low overall western state O&M costs, with moderately high O&M spending; but well below that of some of the highest O&M states in the U.S.

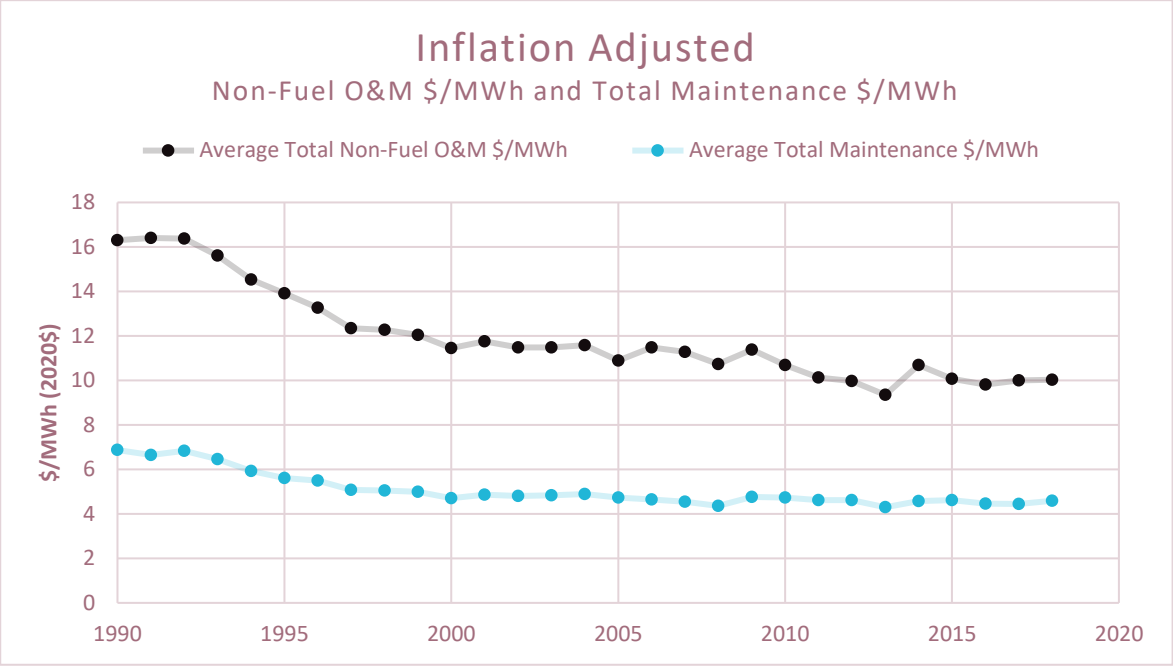


Figure 10 — Historical Non-fuel O&M Spend.

Finally, we referenced the U.S. Energy Information Administration (EIA) Annual Energy Outlook 2020 to forecast likely operating regime of the various fossil generation technologies in 2030[11].

The general trend discussed by the EIA, and our own assessment forecasts that:

- While there will be additional coal generation retirements by 2030, the remaining higher efficiency (thermal or economical) coal units will tend to operate similar to how they operate in 2016-2019 (Figures 4 and 5). However, these units are likely to suffer from lower O&M spend, increased offline hours, and deterioration of reliability as these units age.
- Simple cycle CTs and reciprocating engines are designed for cycling operation, and the operating profile will not differ significantly in 2030. Also, by definition, a majority of the VOM spend on these units is associated with cycling operation, which is reflected in our results.
- Conventional combined-cycle units would have accumulated several thousand hours of operation, as these units continue to operate more baseload. By 2030, several of these units would be over 25 years old, with competition from newer higher efficiency units, and therefore likely to operate with more on/off cycling. Per the EIA, "The currently most common combined-cycle units, with their

[11] https://www.eia.gov/outlooks/aeo/

lower efficiency, and the new single-shaft (1 x 1 x 1 configuration) combined-cycle units decline in utilization as a group, from 56% in 2020 to 36% by 2035".

- Fast start combined-cycles will see modest increase in on/off cycling, while the higher efficiency combined-cycle fleet will predominantly operate as they do now.

Results

Table 2 shows the physical constraints and capabilities of the ten (10) generation types analyzed:

- As expected, the simple cycle aeroderivative CTs and the reciprocating engines provide significant flexibility, with fast ramping capabilities and relatively short down times. Reciprocating engines have extremely fast ramp rates and can get up to full load at a ramp rate of 50% (as a percent of Gross Dependable Capacity (GDC)) per minute. Large frame CTs are not quite as flexible as aero derivative machines.
- Coal units have improved the low load capabilities, and more so on the larger subcritical coal units. Coal steam units are limited in terms of gas/oil support availability and/or number of mills in operation at low loads. Larger units have been able to improve low load operation from about 50% in the past to about 35-40% minimum load (as a percent of GDC). Coal units are also less flexible in terms of startup times and up times. Some units have been transitioning to sliding pressure operation, which may limit ramping response.[12]
- The median age of operating gas steam units is over 55. Most of the units in WECC are subcritical and have low capacity factors (<30%). Typically, these units perform no more than 40 starts a year and are utilized infrequently. The units can operate at low loads (around 20-30%) for extended periods of time but are not as efficient and used sparingly. These units are also operated with ramp rates that are significantly higher than coal steam units.
- Combined-cycle units typically have a minimum emissions compliance load, which limits the operating range. Multiple gas turbine configuration on these units lend increased flexibility in operation. Some of the new higher efficiency combined-cycle units are, however, in 1x1 configuration and operate mostly baseloaded. The ST is often a limiting factor for high ramp rates, and unless the plant is designed for cycling operation (e.g., bypass system), the units tend to have some limitations in terms of flexibility.
- Fast start combined-cycle units have HRSGs with a Benson® high pressure section or are single-pressure non-reheat units that minimize damage on the components. These units also might take advantage of the shutdown purge sequence (in compliance with NFPA® 85) to improve startup times.
- The high efficiency combined-cycle units can achieve efficiencies in excess of 60%. These units are typically constrained on ramp rates as well as low loads.

The values presented in Table 2 are for typical power plants and do not include units that may have been retrofitted or best in class.

[12] https://www.babcockpower.com/wp-content/uploads/2018/02/constant-and-sliding-pressure-options-for-new-supercritical-plants.pdf

Table 2 — Capabilities and Physical Constraints of Fossil Generators

Unit Types	Coal - Small Sub Critical	Coal - Large Sub Critical	Coal - Super Critical	Gas - Steam	Gas - Large Frame CT	Gas - Aero Derivative CT	Typical CC [GT+HRSG+ST]	High Eff. - CC [GT+HRSG+ST]	Fast Start - CC [GT+HRSG+ST]	Gas - Recip. [per Engine]
Time (min)										
Minimum Up Time	720	720	1440	120	60	60	120	120	60	30
Minimum Down Time	360	480	480	240	60	30	360	480	360	15
Startup Ramp Rate (%GDC/min)										
Typical - almost no diff. by start type	2.0%	3.5%	3.5%	10.0%	10.0%	90.0%	6.0%	5.5%	8.0%	95.0%
Turndown Ramp Rate (%GDC/min)										
Don't see significant changes in rates for level of turndown. However, some steam units use sliding pressure.	5%	8%	8%	20%	15%	90%	10%	10%	15%	95%
Minimum Load (% GDC)										
Typical	40%	35%	45%	20%	50%	50%				-
1x1							48%	48%	48%	
2x1							25%	25%	25%	

Tables 3 and 4 below present the lower bound cycling cost results for the ten (10) unit types for projected operations and annual spend in 2030. As with our analysis in 2012, it should be emphasized that there are large variations in costs between individual units of each type, and that the results provided by Intertek AIM are *low bounds*[13].

All cost numbers in this report have been adjusted for calendar year 2020$.

Use of the generic lower bound costs, without accounting for actual unit operations and spend can result in significant under/over estimation of power plant cycling costs.

Table 3 presents the typical load following costs for three different operating regimes: mild load change (20% of GDC); typical load change (for each unit type); and minimum load operation. Figure 11 presents the same information in a graphical form. The load following costs are not significantly impacted by modest changes to ramp rates. In our assessment for load follow operation, an increase of 25% will have no measurable increase in costs. However, doubling of current ramp rates on the steam units (limited by design) will result in increased costs as indicated in Table 3. For the gas turbine-based technologies, the original equipment manufacturer limits ramp rate capabilities, and typically there is little leeway for operators to increase these rates (without control upgrades, or retrofits).

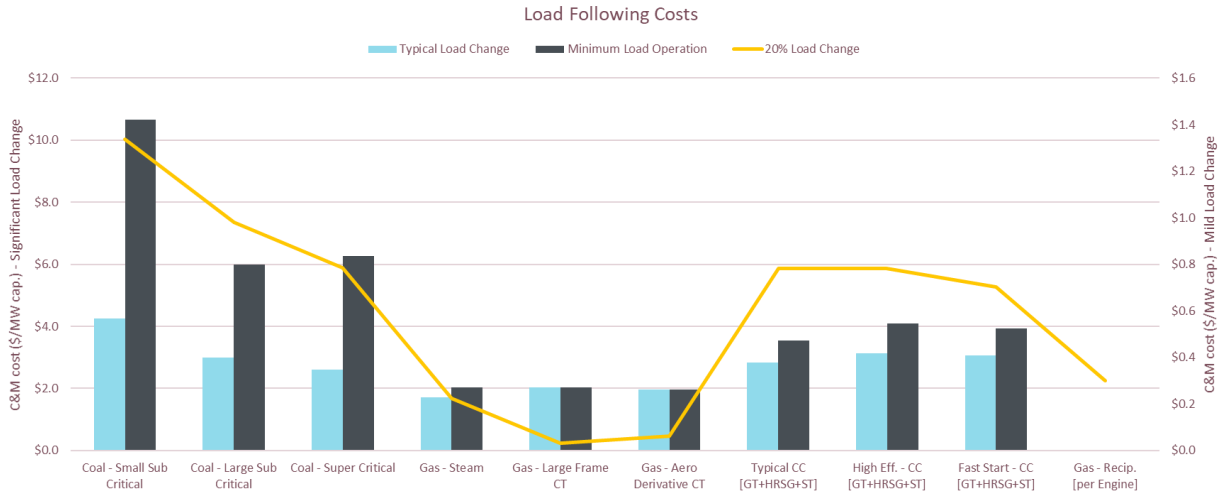


Figure 11 — Load Following Costs.

Note: Mild load change costs are shown on the secondary y-axis.

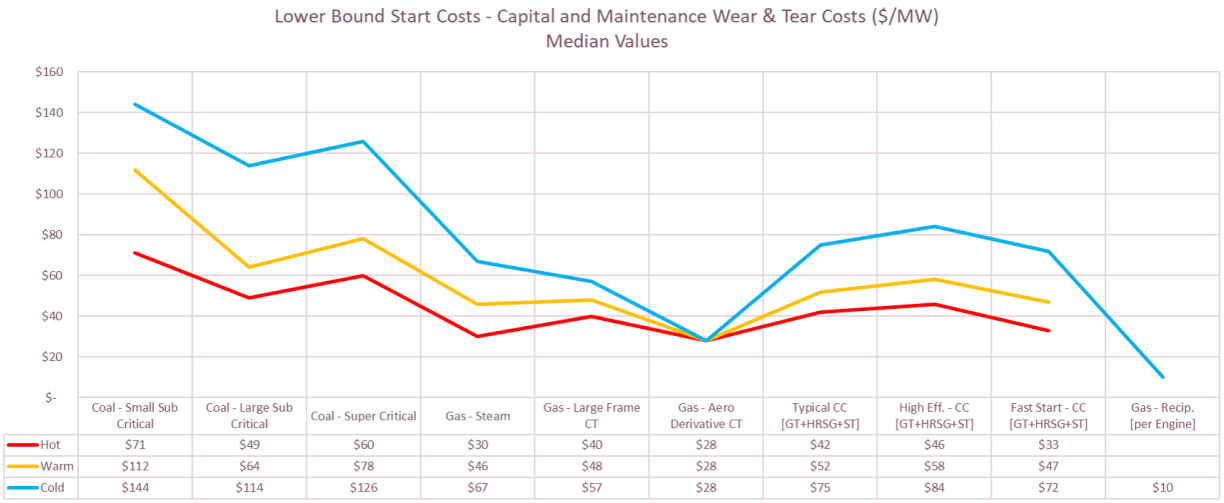
[13] Care should be taken to implement the lower bound cycling cost. For example, if a unit goes through 200 starts per year and the start cost is underestimated by $1,000/start, then the annual cost of this erroneous number can be significant. Moreover, if this unit is indeed cycled on/off more often due to the lower cost estimate, then it would accumulate damage at a significantly higher rate.

Table 3 — Projected 2030 Load following cost estimates (lower bound, 2020$)

Unit Types	Coal - Small Sub Critical	Coal - Large Sub Critical	Coal - Super Critical	Gas - Steam	Gas - Large Frame CT	Gas - Aero Derivative CT	Typical CC [GT+HRSG+ST]	High Eff. - CC [GT+HRSG+ST]	Fast Start - CC [GT+HRSG+ST]	Gas - Recip. [per Engine]
Typical Load Follows Data										
-C&M cost ($/MW cap.) - 20% Load Change										
Median	1.34	0.98	0.78	0.22	0.03	0.06	0.78	0.78	0.70	0.30
~25th_centile	0.76	0.56	0.61	0.14	0.02	0.04	0.37	0.37	0.33	0.25
~75th_centile	1.54	1.24	0.95	0.27	0.05	0.14	0.90	0.90	0.81	0.40
-C&M cost ($/MW cap.) - Typical Low Load										
Median	4.26	2.99	2.61	1.70	2.03	1.96	2.84	3.13	3.06	
~25th_centile	2.44	1.71	2.02	1.04	1.20	1.31	1.33	1.47	1.44	
~75th_centile	4.90	3.79	3.17	2.06	3.57	5.28	3.29	3.61	3.54	
-C&M cost ($/MW cap.) - Minimum Load										
Median	10.66	5.98	6.27	2.02	2.03	1.96	3.55	4.08	3.92	
~25th_centile	6.10	3.42	4.86	1.23	1.20	1.31	1.67	1.91	1.84	
~75th_centile	12.26	7.57	7.61	2.45	3.57	5.28	4.11	4.72	4.53	
							Doesn't include a GT start			
Ramp Rate Effect										
-Typical Range X 1.25	-	-	-	-	-	-	-	-	-	-
-C&M cost ($/MW cap.) - Typical Range X 2										
Median	6.40	5.38	4.70	2.13						
~25th_centile	3.66	1.97	2.33	1.19						
~75th_centile	7.35	11.36	9.51	2.68						

Table 4 below presents the updated cost of starts (and stops) and non-cycling baseload VOM costs for the different generation technologies. Figure 12 presents the start cost per megawatt capacity for each of the generation types graphically (median values). As a reminder, these are 2030 projected costs in 2020$.

Table 5 presents the expected increase in EFOR (in added percentage for a single year[14]) due to each cycle type. Baseload or cycling operation both cause forced outages at plants. Cycling operation can accelerate EFOR, especially on a baseload design power plant. Countering the impact on reliability can only be done by replacing or repairing equipment, that is, increased CapEx and OpEx. This is evident in the results of this study. With lower spending, there is a general trend of increased cycling-related reliability impact. Further, in our experience, we know that cycling-related increases in failure rates may not be noted immediately, but critical components will eventually start to fail as the plant accumulates cycling-related damage. Since a vast sample of the units in 2030 will have accumulated several thousand operating hours, the forecasted impact on reliability is valid, and perhaps conservative considering lower O&M spending.



	Coal - Small Sub Critical	Coal - Large Sub Critical	Coal - Super Critical	Gas - Steam	Gas - Large Frame CT	Gas - Aero Derivative CT	Typical CC [GT+HRSG+ST]	High Eff. - CC [GT+HRSG+ST]	Fast Start - CC [GT+HRSG+ST]	Gas - Recip. [per Engine]
Hot	$71	$49	$60	$30	$40	$28	$42	$46	$33	
Warm	$112	$64	$78	$46	$48	$28	$52	$58	$47	
Cold	$144	$114	$126	$67	$57	$28	$75	$84	$72	$10

Figure 12 — Typical Lower Bound Load Following Costs (Median Values).

[14] For example, Table shows a median (lower bound) EFOR impact of 0.0194% per hot start for small sub critical coal units. Assume that the EFOR = 2% for some future year and the Unit typically sees 10 hot starts annually. If 5 additional hot starts are imposed, the EFOR will be raised to 2.097% (2 + 0.00194*5) for a single near-future year.

Table 4 — Projected 2030 Start Cost and Baseload VOM Costs (Lower Bound, 2020$)

Unit Types	Coal - Small Sub Critical	Coal - Large Sub Critical	Coal - Super Critical	Gas - Steam	Gas - Large Frame CT	Gas - Aero Derivative CT	Typical CC [GT+HRSG+ST]	High Eff. - CC [GT+HRSG+ST]	Fast Start - CC [GT+HRSG+ST]	Gas - Recip. [per Engine]
Cost Item/										
Typical Hot Start Data										
-C&M cost ($/MW cap.)										
Median	71	49	60	30	40		42	46	33	
~25th_centile	71	36	43	25	18		32	35	26	
~75th_centile	130	70	77	47	122		82	99	80	
Typical Warm Start Data										
-C&M cost ($/MW cap.)										
Median	112	64	78	46	48		52	58	47	
~25th_centile	94	52	60	34	19		29	32	26	
~75th_centile	211	82	109	91	131		108	139	96	
Typical Cold Start Data										
-C&M cost ($/MW cap.)										
Median	144	114	126	67	57	28	75	84	72	10
~25th_centile	92	66	85	57	20	11	41	46	39	6
~75th_centile	333	159	154	104	138	66	117	157	112	15
Typical Non-cycling Related Costs										
- Baseload Variable Cost ($/MWH)										
Median	1.79	2.40	3.76	0.29	0.56	0.45	2.10	1.80	1.72	0.00
~25th_centile	1.14	1.62	3.15	0.24	0.47	0.18	1.65	1.27	1.30	0.00
~75th_centile	2.70	3.42	4.79	1.74	1.10	0.66	4.42	4.40	4.53	0.00

Table 5 — Projected Impact of Cycling on EFOR

Unit Types	Coal - Small Sub Critical	Coal - Large Sub Critical	Coal - Super Critical	Gas - Steam	Gas - Large Frame CT	Gas - Aero Derivative CT	Typical CC [GT+HRSG+ST]	High Eff. - CC [GT+HRSG+ST]	Fast Start - CC [GT+HRSG+ST]	Gas - Recip. [per Engine]
Cost Item/										
Typical Hot Start Data										
-EFOR Impact										
Median	0.0194%	0.0071%	0.0046%	0.0062%	0.0020%		0.0028%	0.0027%	0.0025%	
~25th_centile	0.0045%	0.0035%	0.0030%	0.0015%	0.0007%		0.0021%	0.0021%	0.0021%	
~75th_centile	0.0495%	0.0164%	0.0130%	0.0285%	0.0145%		0.0081%	0.0084%	0.0070%	
Typical Warm Start Data										
-EFOR Impact										
Median	0.0308%	0.0088%	0.0068%	0.0114%	0.0028%		0.0043%	0.0041%	0.0039%	
~25th_centile	0.0058%	0.0059%	0.0059%	0.0025%	0.0007%		0.0023%	0.0023%	0.0023%	
~75th_centile	0.0624%	0.0390%	0.0390%	0.0308%	0.0165%		0.0095%	0.0205%	0.0186%	
Typical Cold Start Data										
-EFOR Impact										
Median	0.0318%	0.0114%	0.0114%	0.0171%	0.0035%	0.0089%	0.0058%	0.0056%	0.0055%	0.0020%
~25th_centile	0.0085%	0.0047%	0.0060%	0.0041%	0.0007%	0.0036%	0.0033%	0.0033%	0.0033%	0.0011%
~75th_centile	0.0652%	0.0300%	0.0202%	0.0467%	0.0118%	0.0199%	0.0091%	0.0215%	0.0195%	0.0031%

3 | Conclusions

Some of the observations from the figures and tables are as follows:

- There is a large spread of cycling costs as well as reliability impacts.
- On a per megawatt basis, small coal units have the highest cost, while the gas reciprocating engines are the lowest cost. This trend is reflected in terms of the reliability impacts also. Small coal units have the most significant impact while reciprocating engines are designed for flexible operation and hence have the least effect.
- Examining the results published by Intertek AIM in 2012, we estimate the cost of hot and warm starts on conventional steam units (subcritical coal and gas steam units), will be slightly lower in 2030 (results are in 2020$). The drivers for the lower start cost are both the expected increase in the different start types, as well as lower overall spend.
- Small subcritical coal will be subject to increased cycling (lower capacity factors), along with reduced total O&M spend similar to recent trends. This increased cycling, as well as aging, results in significant impact on reliability.
- Larger coal units have similar lower future O&M spend but will likely operate in load following mode with extended shutdowns (cold starts). Therefore, cold start costs increase, while other start costs remain similar or lower to results published in 2012.
- Supercritical coal power plants are operated at baseload and do not cycle on/off much. As these units age and are forced to operate in more flexible mode, the cost of cycling is likely to increase. This will result in slightly lower “baseload VOM” costs compared to historical results. These units cannot easily be brought online under these circumstances and such factors are not fully captured in this dataset. Note that there is a relatively small sample of supercritical coal units in WECC.
- Median cold start cost for each of the generation types is about 1 to 3 times the hot start capital and maintenance cost. For the lower bound 75th percentile, this ratio of cold start cost versus hot start cost is only slightly higher.
- Aeroderivative gas turbines and reciprocating gas engines are designed for flexible operation, and therefore have lower costs. These units also do not get heavily impacted in terms of reliability. In the case of gas turbines, the typical maintenance cycle of the units essentially renews the wear and tear damage. Note that fast starts are deviations to standard start sequence, which may result in increased cycling costs.
- There are some important economies of scale for large steam units that lower their per cycle costs. So, the highest costs per capacity, as shown here, occur in some less efficient or older smaller units, especially for cold starts.
- There is an inherent “tradeoff” relation between higher capital and maintenance expenditure and corresponding lower EFOR.
- Aging effects on conventional combined-cycle units is significant (in 2030). Older units act more like the present coal fleet, while the newer combined-cycle units tend to operate baseload or load following.

- Conventional (older) combined-cycle units were designed for baseload operation and when operated in cycling mode can have higher cycling costs. Similarly, the more efficient, higher temperature gas turbine-based combined-cycle units are also not designed for frequent start/stops. Hence, the cost per cycle of the high efficiency gas combined-cycle units is modestly higher than older combined-cycle units. The fast start combined-cycle units, as expected, are much more economical to operate in on/off mode.
- Reciprocating engines almost always operate as flexible units. The baseload VOM cost for these units is negligible as all the costs are cycling related. These units also do not see much effects on reliability from increased on/off cycles. At low load operation, typically engines on a site may be turned off.
- The coal-fired small and large units were the expensive load following units. As an example, the mill cycle from full load to low load adds significant costs. Emissions control equipment is also affected when units are operated at minimum load for extended hours.
- The combined-cycle units tend to have slightly lower but significant load following costs. This is true because the steam cycle components (i.e., the HRSG, ST, and balance of plant equipment) are impacted by changing operating transients at lower loads. The HRSG is the significant contributor to the cost, though some STs in the industry have been adversely affected by extended low load operation.
- Modest increases in ramp rates during load following results in almost no increase in damage or costs. Doubling accepted ramp rates (subject to design limit or original equipment manufacturer recommendation) is possible on the steam units, though such operation will increase costs. Yet, there might be market mechanisms that allow units to take advantage of the faster ramp rates.
- Aggregating cycling costs at the system level results in ignoring the “flash flood” situation of heavy cycling on individual units on the grid. Transmission expansion studies should include power plant cycling as an input.

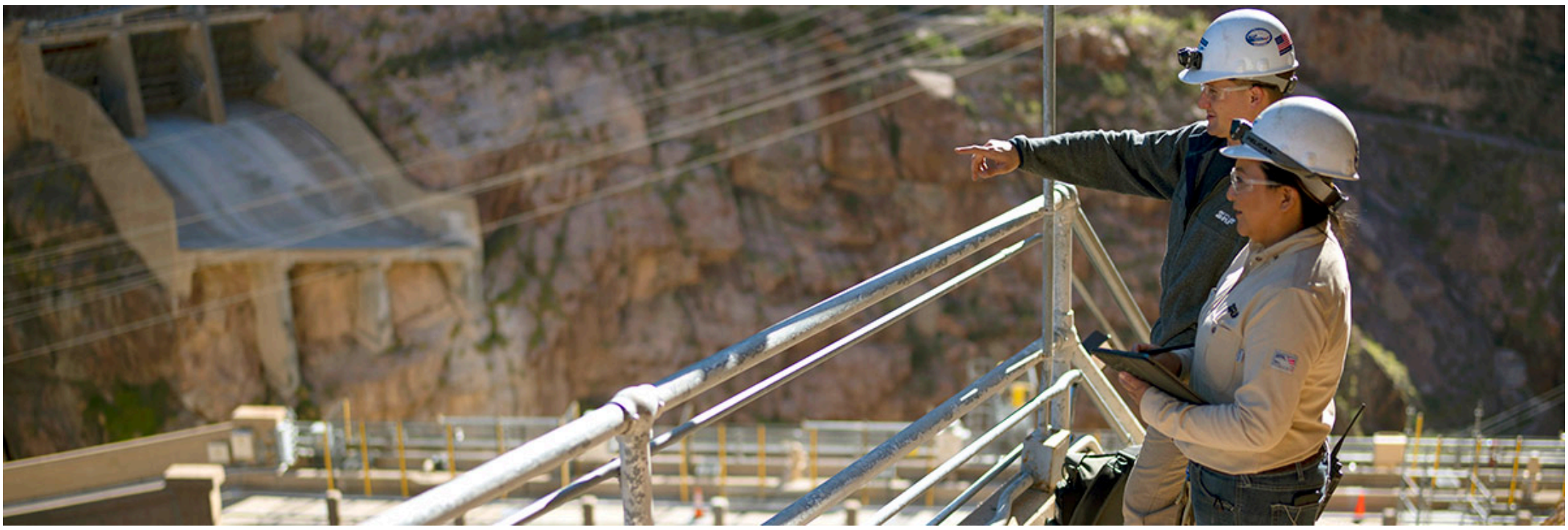
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-60:
SRP Power Generation Sources



SRP power generation sources

SRP is strengthening and preparing the grid for a future that's powered by renewable energy while maintaining the reliability we need to keep your family safe.

On this page:

Explore SRP power sources

Sustainability at SRP

Technology and innovation

On related pages:

Santan Generating Station reports & action plans

Coolidge Generating Station reports & action plans

Feedback

Explore SRP power sources

SRP operates and participates in a number of major power plants and generating facilities in Arizona and around the Southwest. As we add more renewable energy sources to our energy mix, we're strategically using traditional energy sources like natural gas and coal to reliably strengthen our power grid, especially during the hot summer months when energy needs are at their highest.

Explore our diverse energy mix by source or location on the map below.

Filter by Technology

Coronado

Apache County, AZ

Operating Year: 1979

Conventional Steam Coal

Craig (CO)

Moffat County, CO

Operating Year: 1980

Conventional Steam Coal

Davis

Mohave County, AZ

Operating Year: 1951

Conventional Hydropower

Desert Basin

Casa Grande, AZ

Operating Year: 2001

Natural Gas

Dorman Battery

Chandler, AZ

Operating Year: 2018

Battery

Dry Lake Wind

Navajo County, AZ

Operating Year: 2009

Onshore Wind Turbine

East Line Solar

Coolidge, AZ

Operating Year: 2020

Solar Photovoltaic

Craig (CO): Conventional Steam Coal

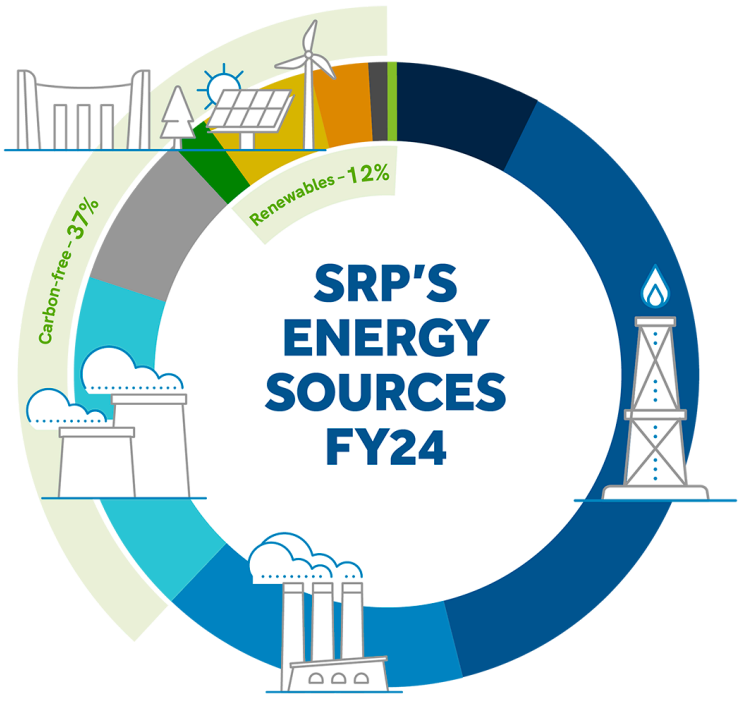
Operated by Tri-State Generation and Transmission, SRP owns a share of this three-unit station (29% of Unit 1 and 29% of Unit 2) located in northwestern Colorado. SRP is committed to reducing our carbon emissions, and we are starting to decommission certain coal-fired plants. The plan includes decommissioning Craig Unit 1 in 2025 and Unit 2 in 2028.

Esri Community Maps Contributors, © OpenStreetMap, Microsoft, Esri, TomTom, Garmin, SafeGraph,… Powered by Esri

Feedback

Sustainability at SRP

As part of our commitment to achieve net zero carbon by 2050, we are expanding our mix of clean, renewable energy sources.



We are committed to net-zero carbon emissions by 2050.

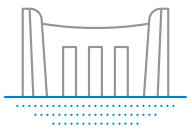
MARKET – 8%
NATURAL GAS – 38%
COAL – 16%
NUCLEAR – 18%
CUSTOMER PROGRAMS – 8%
HYDRO – 2%
SOLAR – 5%
GEOTHERMAL – 3%
WIND – 1%
BIOMASS – <1%

The pie chart shows how the power needs of SRP's retail customers were met during fiscal year 2024 (May 1, 2023–April 30, 2024). This chart represents generation output from all generating facilities operational in FY24. Generation data is pending third-party verification by The Climate Registry.

SRP is committed to cutting carbon emissions intensity by 65% by 2035 and reaching net zero by 2050. Learn more about sustainability at SRP.

Renewables

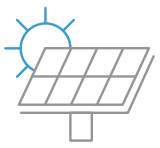
At SRP, we're steadily expanding our energy portfolio to include more power from carbon-free sources.



Hydropower

SRP manages eight dams on the Salt River and Verde River watersheds that provide more than 230 megawatts (MW) of hydropower.

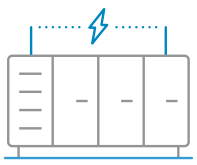
Learn more



Solar

SRP is harnessing the power of America's sunniest city to support a variety of solar solutions for homes and businesses.

Learn more



Battery storage

SRP uses large-scale battery storage projects to store renewable energy for when it is most needed to support grid reliability.

Feedback

Learn more

Other renewables

SRP is investing in additional carbon-free resources like wind, geothermal and biomass.

Learn more

SRP generation resources comply with local, state and federal air quality regulations which are protective of human health and the environment. Learn more about our environmental policies and programs.

Technology and innovation

We're continually working to provide reliable, affordable and sustainable power today and for Arizona's future. Check out the stories below to learn how we're innovating today to ensure Arizona continues thriving tomorrow.

Powering the grid with solar

Learn more

Feedback

Powering carbon neutrality with new energy storage technology

Learn more

BACK TO TOP

RELATED TOPICS

[Future plan for energy | SRP]

Ensuring that the Valley's energy future remains reliable requires energy experts and communities working together. Learn about SRP's energy plan for the future.

[Environmental policy and programs | SRP]

Protecting and preserving natural and cultural resources is at the core of SRP's mission. Learn more about SRP's environmental programs here.

[Sustainability at SRP]

The future of our water and power resources depends on the actions we take today. See how we're working toward a sustainable future.

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